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REPORT

STRENGTHENING THE REGULATION OF ENHANCED OIL RECOVERY TO ALIGN IT WITH THE OBJECTIVES OF GEOLOGIC CARBON DIOXIDE SEQUESTRATION

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Executive Summary

Climate change is a pressing problem that demands urgent action. To mitigate it, governments, corporations, and citizens must take decisive action on the policy, technological, and economic fronts to reduce and eliminate man-made emissions of greenhouse gases. No "silver-bullet" solution exists; instead, many measures and technologies must contribute to this effort. Increasing energy efficiency, reducing demand in all energy-consuming sectors, and switching to renewable energy sources should be at the forefront of the mitigation effort. However, the use of fossil fuels is still responsible for unacceptably large amounts of carbon pollution being emitted to the earth's atmosphere, and finding ways to reduce that pollution can increases our chances of averting the worst effects of climate change.

Capturing carbon dioxide (CO_2) from large point sources, such as power plants and refineries, and permanently disposing of it in deep underground geologic formations through a set of technologies known as carbon capture & geologic sequestration (CCS) can complement the mainstay efforts to use energy more efficiently and to switch to renewable sources. Pursuing emission reductions through CCS can increase the chances of achieving our climate mitigation targets, expedite the pace of reductions, and lower the overall cost of mitigation.[1]

There are now sixteen integrated CCS projects in North America alone that capture, transport and sequester CO_2 from a variety of sources, including fuel processing, power, fertilizer, and chemical plants, and several more around the world.[2] However, many more will be needed if this technology is to contribute meaningfully to mitigating climate change. CCS technology is mature and ready for broad-scale deployment.[3] The biggest barrier stalling further development is—and has been for years now—the high cost of capturing CO_2 from its source.[4] Unless carbon emissions are priced or regulated, and unless initial government support drives this cost down (a recipe that has been successful with solar and wind energy), the technology will not achieve broad deployment.

A technique known as CO_2-Enhanced Oil Recovery (CO_2-EOR) offers a faster and more likely pathway to the deployment of CCS projects in the near and mid term. Suitable geologic disposal sites for CO_2 include deep sedimentary rocks containing brine ("deep saline formations"), oil fields, and gas fields, where fluids have been naturally trapped in the earth's subsurface for millions to hundreds of millions of years.[5] Injecting CO_2 in mature oil fields can also aid in the production of oil that otherwise would remain stranded, and the primary goal of CO_2-EOR is to recover that oil.

Injecting CO_2 in oil fields offers an economic advantage to the CCS project developer: the revenues from producing stranded oil through CO_2-EOR can help make projects financeable and more likely to be constructed. Today, CO_2-EOR has gained sufficient attention in the public policy realm as a potential climate mitigation, job creation and energy security option to merit closer regulatory scrutiny. The results of our in-depth analysis indicate that the potential for CO_2-EOR to function as a climate mitigation technology—as opposed to purely an oil extraction technique—is limited by flaws in the way geologic sequestration during CO_2-EOR is regulated and certified today. Improvements are needed that would provide the transparency and confidence necessary to show that the injected CO_2 is indeed being stored permanently.

THE CURRENT UNDERGROUND INJECTION REGULATORY FRAMEWORKS ARE INADEQUATE FOR ENHANCED OIL RECOVERY USING CO_2 TO PROPERLY SERVE AS A CLIMATE MITIGATION TOOL

Underground injection of CO_2 is regulated through the U.S. Environmental Protection Agency's Underground Injection Control (UIC) program, under the authority of the Safe Drinking Water Act (SDWA). The UIC program's objective is to protect Underground Sources of Drinking Water (USDWs), and divides wells into classes based on their function. Each well class has its own regulations: CO_2-EOR wells are regulated under Class II (dating from the 1980s), whereas the geologic sequestration of CO_2 is regulated under Class VI (promulgated in 2010). Aside from their time of promulgation, there are numerous and substantial differences between Class II and Class VI regulatory requirements. On many counts, Class VI requirements are more comprehensive and stringent than Class II requirements, which allow for CO_2 injection with comparatively little scrutiny. In addition, the primary enforcement responsibility ("primacy") for permitting Class II wells and enforcing those regulations has been mostly delegated to individual states. There is significant variability among state rules in terms of both regulatory topics covered and stringency.

The more comprehensive requirements and safeguards of Class VI almost never apply to CO_2-EOR operations. UIC rules draw a sharp distinction between CO_2 sequestration that is not associated with oil production on one hand, and CO_2 sequestered as part of CO_2-EOR operations on the other. They artificially assume that sequestration in the CO_2-EOR context occurs only after the cessation of oil production. This regulatory construct does not reflect the real-life nature of CO_2-EOR projects whereby both oil production and sequestration occur simultaneously. Furthermore, even if a CO_2-EOR operator declares the "primary purpose" of a project to be geologic sequestration, Class VI requirements only apply if there is an additional perceived threat to groundwater resources.[6] At the time of writing no CO_2-EOR projects have been required to obtain Class VI permits.

There are numerous critical differences between Class II and Class VI regulations that create an unlevel playing field for CO_2 sequestration combined with oil production versus pure sequestration. These differences, summarized in the table below, call into question the ability of Class II rules by themselves to ensure that CO_2-EOR projects can also be regarded as legitimate geologic sequestration projects.

Requirement	Class VI (Geologic Sequestration)	Class II (EOR)
SITE CHARACTERIZATION		
Wells must be sited in a geologically suitable location	X	
The geologic system must have:		
An injection zone with sufficient properties to receive the total anticipated volume of injectate	X	
A confining zone:	X	X
Free of transmissive faults and fractures	X	X
Of sufficient areal extent to contain injected and displaced fluids	X	
With sufficient integrity to allow injection at maximum proposed pressure without initiating or propagating fractures	X	
AREA OF REVIEW AND CORRECTIVE ACTION		
The owner/operator must delineate an area of review (AoR) by:	X	X
Performing computational modeling that takes into account the physical and chemical properties of the CO_2 and is based on the available site characterization, monitoring, and operational data	X	
Calculating a "zone of endangering influence" or using a fixed-1/4 mile radius		X
Within the AoR, owner/operator must:		
Identify all penetrations (e.g. mines, wells, etc.) of the confining zone	X	
Identify all known wells that penetrate the injection zone		X
Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information required	X	
Determine which abandoned wells have been plugged in a manner to prevent the movement of CO_2 and fluids into USDWs, including using CO_2-compatible materials	X	
Perform corrective action on all wells in the AoR for which it has been determined that corrective action is needed	X	X
WELL CONSTRUCTION		
Wells must be designed and completed to:		
Prevent movement of fluids into or between USDWs	X	X
Prevent movement of fluids into any unauthorized zones	X	
Permit the use of testing/workover devices	X	
Permit continuous monitoring of the annulus between the tubing and casing	X	
Surface casing must extend through the base of the lowermost USDW and be cemented to the surface	X	
At least one long string casing must extend to the injection zone and must be cemented to the surface	X	
Well construction materials must be compatible with the fluids with which they may come into contact	X	
Injection must occur through tubing set on a packer	X	

MECHANICAL INTEGRITY		
The owner or operator of an injection well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs	X	
MONITORING		
Corrosion monitoring must occur on a quarterly basis	X	
Periodic monitoring of groundwater quality above the injection zone must be performed	X	
Testing and monitoring to track the extent of the injectate plume and the presence or absence of elevated pressure is required	X	
POST INJECTION SITE CARE AND CLOSURE		
The owner or operator must prepare, maintain, and comply with a plan for post-injection site care and site closure	X	
Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs	X	

A number of studies have documented problems with the Class II program in practice.[7] Implementation of Class II regulations has been inconsistent and problematic.[8] The EPA has been lax in evaluating how states are administering and implementing the Class II program.[9] In addition, the data and documentation on mechanical integrity failure rates, testing, and groundwater contamination are incomplete, sometimes unreliable, and not always held centrally or overseen by the EPA.[10] Available data and research suggest that the Class II program may not be adequately protecting USDWs.

AIR REGULATIONS DO NOT FILL CRITICAL GAPS IN UNDERGROUND INJECTION REGULATIONS OR MEET FUNDAMENTAL PRECAUTIONARY NEEDS

The UIC program is focused on protecting groundwater but does not address the threat of CO_2 escaping directly to the atmosphere. On the air side, operators of both CO_2-EOR and geologic sequestration projects must report under the EPA's Greenhouse Gas Reporting Program (GHGRP). There are two reporting tracks to the EPA for CO_2 injection wells: subpart UU, which applies to wells that inject CO_2 into the subsurface, and subpart RR, which applies to wells that geologically sequester CO_2. All wells used for geologic sequestration must report under subpart RR, whereas wells used for CO_2-EOR must report under subpart UU and may choose to "opt in" and report under subpart RR.

However, information reported under subpart UU is completely insufficient to determine whether the injected CO_2 is indeed remaining underground. Subpart RR does contain provisions to that effect, but they are broadly worded. Its application could be significantly different under different permit reviewers, ranging from valuable and meaningful to limited in scope and usefulness when it comes to establishing proper sequestration.

Additionally, it is important to note that the GHGRP is simply a reporting program and does not require any prevention, or any mitigation in the event of leakage—subpart RR simply requires that leakage be estimated and reported. Subpart UU does not require leakage to be estimated at all. This means that the only regulatory mandate for intervention or mitigation relating to an injection well is linked to the contamination of USDWs. If no USDWs are endangered, then an operator may simply continue to vent CO_2 to the atmosphere from a well (provided no local or other regulatory conditions are being violated).

DECADES OF EXPERIENCE IN THE FIELD POINTS TO THE NEED FOR OPERATOR DILIGENCE AND REGULATORY MANDATES TO ENSURE SOUND OPERATIONS

In CO_2-EOR fields, the wells themselves are one of the most likely pathways by which injected fluids may migrate into unauthorized zones or to the surface.[11] For a typical field, it is reasonable to expect to have to replug and abandon at least some portion of existing wells to mitigate the risk of leakage to an acceptable degree for successfully sequestering CO_2.[12] So-called orphan wells, which are inactive wells for which the operator is unknown or insolvent, are ubiquitous in regions that have undergone oil and gas exploration. Orphan wells lacking mechanical integrity could represent a fast pathway for injected or displaced fluids to reach USDWs or the surface, yet Class II regulations fail to adequately address this important potential leakage pathway.

Well materials degrade over time and, if not properly monitored and maintained, such degradation can eventually lead to a loss of mechanical integrity, which in turn can result in groundwater contamination and/or leakage of CO_2 to the surface. Numerous studies have documented the challenges of achieving and maintaining mechanical integrity, and the consequences of the failure to do so.[13] To address this threat, new wells must be constructed using best available technologies and practices, and both existing and new wells must be monitored for defects or compromised performance. A prudent monitoring strategy will assume that well defects and compromised integrity will be encountered, and will place emphasis on an early-detection strategy to limit the extent and magnitude of potential leakage. Operators have proven capable of implementing such an approach. However, experience has shown that without regulatory mandates there is no guarantee that this will happen in time, or at all. Current Class II regulations for well construction and mechanical integrity are outdated and inadequate and do not mandate sufficient monitoring or use of the techniques necessary to ensure that well failures will be detected if they do occur.

SOUND PROJECT OR PROBLEM CHILD? THE CHOICE IS OURS

The shortcomings and failures of the Class II program and suboptimal operational practices can, and have resulted in real world consequences, but undesirable outcomes are not a foregone conclusion, as demonstrated by two case studies of CO_2-EOR projects. One—the Salt Creek Field in Wyoming—has been the site of repeated CO_2 seeps to the surface,[14] while the other—the SACROC Field in Texas – has had no documented signs of groundwater contamination from CO_2 injection despite decades of CO_2-EOR injection and production and rigorous monitoring.[15] The case studies highlight some potential pitfalls of CO_2-EOR operations and the need for sound regulation, but also the potential to operate fields prudently in a safe and effective manner.

Proper site characterization and corrective action, as required under the tougher Class VI rules, could have prevented some of the CO_2 leaks that occurred at Salt Creek. Particularly for fields with very long production histories, like Salt Creek, lax Area of Review and Corrective Action requirements and the lack of adequate monitoring requirements may allow improperly constructed or abandoned wells that could potentially cause leakage to go uncorrected.

SACROC, on the other hand, serves as an example of a field that appears to have had little to no effect on local groundwater quality despite many years of CO_2 injection. More reliable well records, a deeper reservoir overlain by multiple sealing layers, and operator practices that exceed the minimum federal Class II standards likely have all contributed to this. From a commercial standpoint, SACROC has been a successful project, which shows that the commercial realities of CO_2-EOR and the protection of groundwater can both be served at the same time. The project does not, however, constitute evidence that the Class II regime is adequate to produce such results, and the operator admits to exceeding those requirements.

The case studies also show that not all oil fields are suitable for permanent sequestration of CO_2, and that the current Class II regulations are insufficient to screen out fields that should not be utilized for that purpose. Even at fields that are suitable for permanent sequestration, Class II regulations alone are inadequate to ensure that CO_2 will be permanently retained in the subsurface. The implementation and enforcement of its requirements have been problematic in some cases. The substantially different regulatory treatment of CO_2 sequestration combined with oil production compared to pure CO_2 sequestration creates a dangerous double standard for CCS projects.

THE CASE FOR NEW REGULATIONS SPECIFIC TO ENHANCED OIL RECOVERY USING CO_2

Regulation of CO_2-EOR projects that claim to sequester CO_2 must be improved, both at the state and federal level, to address two major shortcomings:

- Existing federal and state Class II underground injection regulations are outdated and inadequate to ensure that CO_2 injected for EOR and sequestration will remain permanently trapped; and
- Existing federal air rules do not fully make up for the shortcomings of Class II, and they do nothing to prevent or stop CO_2 from escaping directly to the atmosphere.

That said, regulating all CO_2-EOR operations under Class VI and subpart RR requirements is not necessary or appropriate. Class VI regulations today exempt the overwhelming majority of existing or contemplated oil field injections, and regulation under Class II appears to be their most likely fate in the near future. Oil and gas operators to date have also uniformly rejected regulation under Class VI, citing prohibitive cost, regulatory burden, and uncertainty. However, for CO_2-EOR operations that seek to certify the geologic sequestration of CO_2, Class VI rules materially improve on Class II in terms of preventing, detecting, and remediating atmospheric emissions.

We recommend a new regulatory regime focused on CO_2-EOR as the best path forward to address the need for certainty in commercial CO_2-EOR operation, trust in environmental and public health protection, and credibility of operations. We suggest the fairest and most transparent approach would be for the EPA to examine its regulatory options under existing authorities and propose a time line for a rulemaking that will codify a tailored set of requirements specifically targeting concurrent CO_2-EOR and geologic sequestration. Such an approach would enable a fresh and detailed examination of the risks, regulatory needs, and commercial constraints. It would also circumvent the current debates on the merits and deficiencies of existing injection well classes and reporting regimes.

New regulations should, at a minimum, include the following:

- a demonstration that sites are capable of long-term containment of CO_2;
- identification and characterization of potential natural and man-made leakage pathways, and appropriate risk management and corrective actions;
- design, construction, and operation parameters that prevent, mitigate, and remediate the creation or activation of leakage pathways or the migration of CO_2 or other fluids into any zone in a manner not authorized by the administrator (or pursuant to a state program approved by the administrator as meeting the requirements of these regulations);
- minimizing fugitive CO_2 emissions from project operations;
- monitoring and modeling to predict and confirm the position and behavior of the CO_2 and other fluids in the subsurface during and after injection;
- accounting and reporting of CO_2 quantities sequestered, injected, recycled, leaked, vented, and any other categories as appropriate; and
- post-injection site closure and financial responsibility requirements that ensure the long-term containment of injected CO_2.

Such an approach focuses on preventing leakage by placing emphasis on sound site selection, early detection of problems through appropriate monitoring, timely action to limit the extent of a detected leakage, if any, and site care and stewardship over an appropriate time horizon. With appropriate input from operators, the design of these requirements can be done within the constraints of commercial operations.

A credible regulatory framework is central to the acceptability of the practice of CCS. Many stakeholders, as well as the general public, are already skeptical of geologic sequestration technology, especially in light of the impacts of shale oil and gas production and high-profile well failure incidents with serious consequences (such as the Deepwater Horizon and Aliso Canyon events). Poorly conducted CO_2-EOR operations may further jeopardize the social license of CCS technology to operate and result in a backlash against geologic sequestration.

We remain hopeful that, with meaningful participation from all stakeholders, such requirements can be worked out expeditiously—and in a manner that not only satisfies the need to protect the environment and public health but also lends legitimacy and credibility to the practice of underground injection of CO_2 for climate mitigation. We consider these requirements ultimately inevitable, but also in the best interests of ensuring a timely and smooth deployment of CCS technologies.

ENDNOTES

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2 See Appendix A and also "Global Carbon Capture & Storage Institute, Projects Database", accessed on 09Aug, 2017, https://www.globalccsinstitute.com/projects/large-scale-ccs-projects#map

3 International Energy Agency, "20 Years of Carbon Capture and Storage – Accelerating Future Deployment", 2016.

4 U.S. Department of Energy and U.S. Environmental Protection Agency. "Report of the Interagency Task Force on Carbon Capture and Storage.", August 2010.

5 IPCC, *Special Report on Carbon Dioxide Capture and Storage*, prepared by Working Group III, Metz, B., et al., eds. (Cambridge University Press: Cambridge, UK, and New York, NY), p. 199.

6 Class VI regulations at 40 CFR §144.19(a) state that, "*Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations [emphasis added]*"

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Chapter 1: The Potential Role of CO_2-Enhanced Oil Recovery in Climate Mitigation

Climate change is a pressing problem that demands urgent action. It is now widely recognized as being far more than just an environmental issue and is understood to threaten human security, health, well-being, and prosperity. If left unchecked, climate change will negatively affect both human civilization and the natural world.[1]

The production and burning of fossil fuels since the beginning of the industrial era has released large amounts of greenhouse gases into the atmosphere, such as carbon dioxide, nitrous oxides, and methane. The concentrations of those gases in the atmosphere are now the highest in at least the past 800,000 years, and scientists worldwide almost unanimously believe that this human activity is the cause of the observed warming of the planet since the mid 20th century.[2] To mitigate climate change, it is imperative that governments, corporations, and citizens take decisive action on the policy, technological, and economic fronts to reduce and eliminate man-made emissions of greenhouse gases. No "silver-bullet" solution exists; instead, many measures and technologies must contribute to this effort. Increasing energy efficiency, reducing demand in all energy-consuming sectors, and switching to renewable energy sources should be at the forefront of the mitigation effort. However, the use of fossil fuels is still responsible for unacceptably large amounts of carbon pollution being emitted to the earth's atmosphere, and finding ways to reduce that pollution can increase our chances of averting the worst effects of climate change.

Carbon capture & geologic sequestration (CCS) is a valuable technology that can complement the mainstay efforts to use energy more efficiently and to switch to renewable sources. CCS is the practice of capturing carbon dioxide (CO_2) from large point sources, such as power plants and refineries, and disposing of it in deep underground geologic formations, where it can be permanently trapped. Its contributions to the mitigation portfolio are several: CCS can provide emissions reduction opportunities for sectors that do not have many, or scalable, alternatives, expedite the pace of action to reduce emissions, and assist in removing carbon dioxide from the atmosphere. Its use may also lower the overall cost of climate mitigation.[3]

Suitable disposal sites for CO_2 include deep sedimentary rocks containing brine ("deep saline formations"), oil fields, and gas fields. Fluids like brines and hydrocarbons have been naturally trapped in the earth's sedimentary rocks for millions to hundreds of millions of years.[4] Injecting CO_2 in mature oil fields can also aid in the production of oil that otherwise would remain stranded, through a technique known as CO_2-Enhanced Oil Recovery (CO_2-EOR).

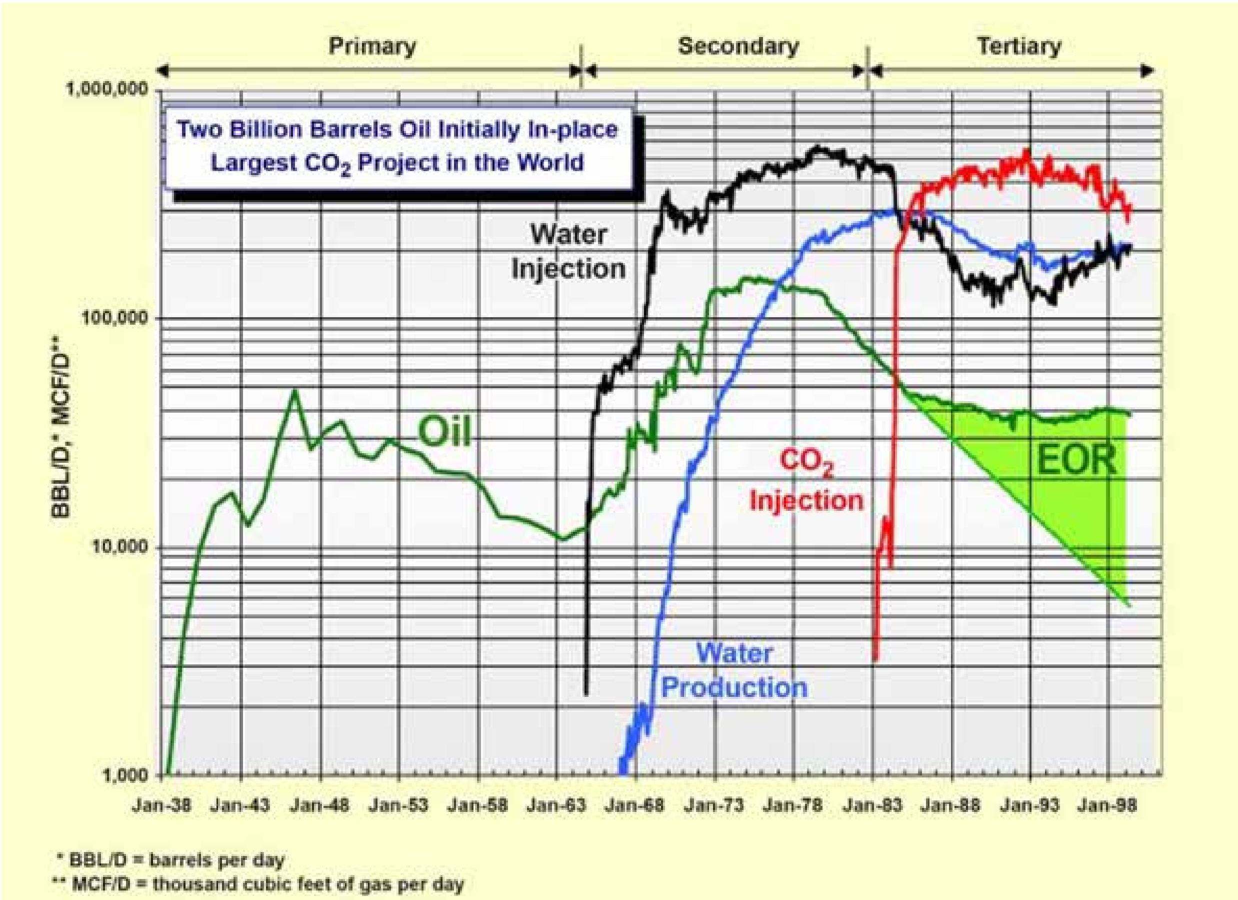
WHAT IS CO_2-ENHANCED OIL RECOVERY?

Developed oil fields still hold large petroleum resources; in fact, the majority of the oil originally in place when conventional oil fields were first exploited still remains in the subsurface despite decades of production. Accessing these reserves currently relies on a set of practices and technologies collectively called Enhanced Oil Recovery (EOR).

Conventional oil production begins with the primary production phase, in which a reservoir is drilled and natural reservoir pressure lifts oil to the surface, sometimes aided by artificial lift. This phase is usually followed by secondary recovery, in which fluids like produced brines or gas are injected into the reservoir in order to increase pressure and achieve further production. On average, primary production recovers only 10 to 20 percent of the original oil in place (OOIP). Secondary recovery will yield an additional 15 to 25 percent, leaving 55 to 75 percent of the OOIP still in the reservoir. Currently used EOR practices will typically yield an additional 10 to 15 percent of the OOIP (See, e.g., Figure 1).[5] Emerging EOR techniques could yield significantly more.[6]

FIGURE 1: OIL PRODUCTION VERSUS TIME FOR PRIMARY, SECONDARY (WATERFLOOD) AND TERTIARY (CO_2-EOR) OIL PRODUCTION PERIODS FOR THE DENVER UNIT OF THE WASSON FIELD IN WEST TEXAS

Incremental oil production due to EOR is represented by the green area under the curve at right.



Source: National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution."

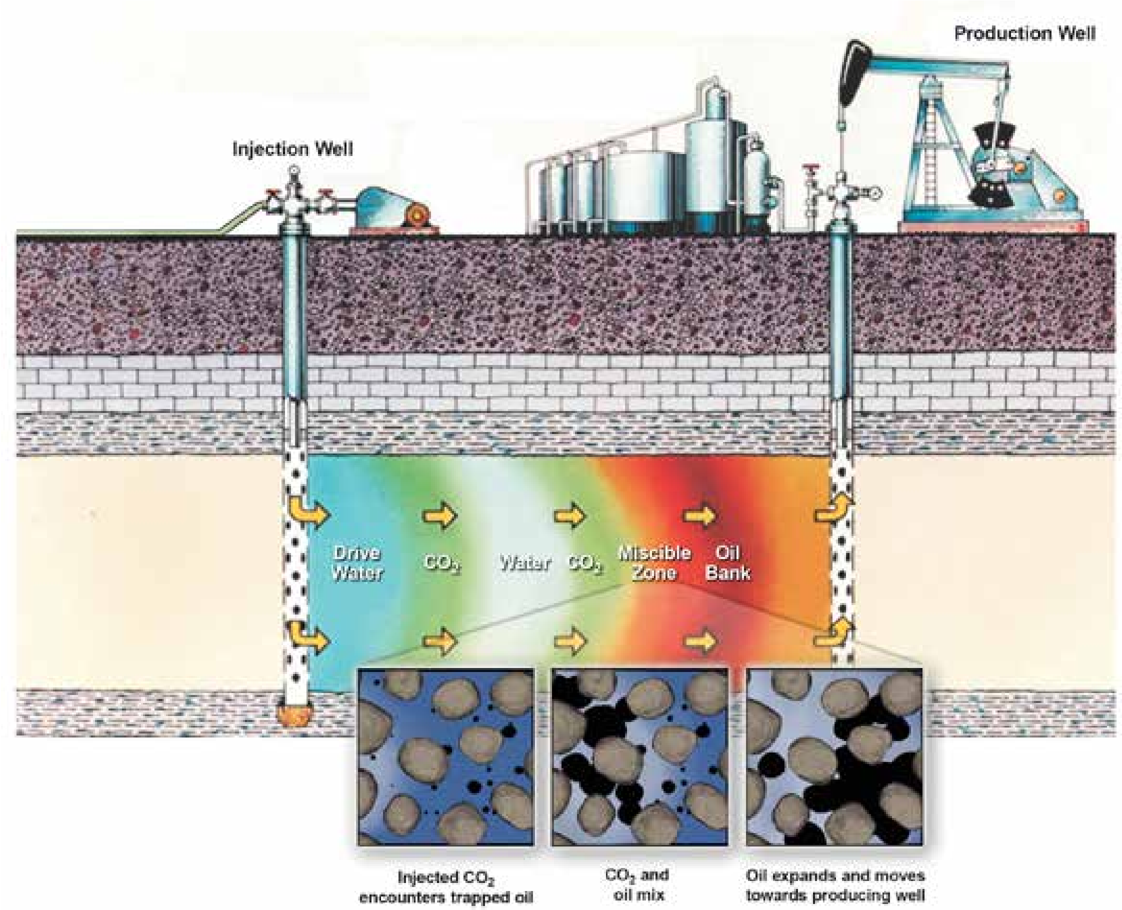
HOW IT WORKS

There are several methods of EOR, also referred to as tertiary recovery. These include chemical flooding, thermal recovery, and injection of gas (such as steam or nitrogen). CO_2 flooding is one of the most common types of gas-injection EOR, offering unique opportunities due to properties of CO_2 that other injection fluids lack.

The CO_2 is first compressed, often to the point where it becomes a so-called supercritical fluid.[7] It is then injected into the oil-bearing formation through a series of injection wells, forming a bank of oil that is swept toward production wells. Depending on temperature, pressure, and oil composition, supercritical CO_2 and oil can be miscible, meaning that the CO_2 and oil dissolve into each other, forming one homogeneous mixture that has a lower viscosity than oil alone. The added CO_2 also greatly increases the volume of the oil and raises the reservoir pressure. Some of the injected CO_2 remains trapped in the reservoir, and some is drawn from the ground with the oil, to be separated in aboveground equipment and re-injected many times over the life of an EOR project.[8] (See Figure 2.)

In oil fields where conditions are such that miscibility cannot be achieved, immiscible flooding may be used, but this is less common. Even though CO_2 and oil do not form one homogeneous substance under these conditions, the CO_2 causes the oil to swell, reducing its density and improving mobility, making it easier to produce.[9]

FIGURE 2: SCHEMATIC OF HOW EOR WORKS



Source: National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution."

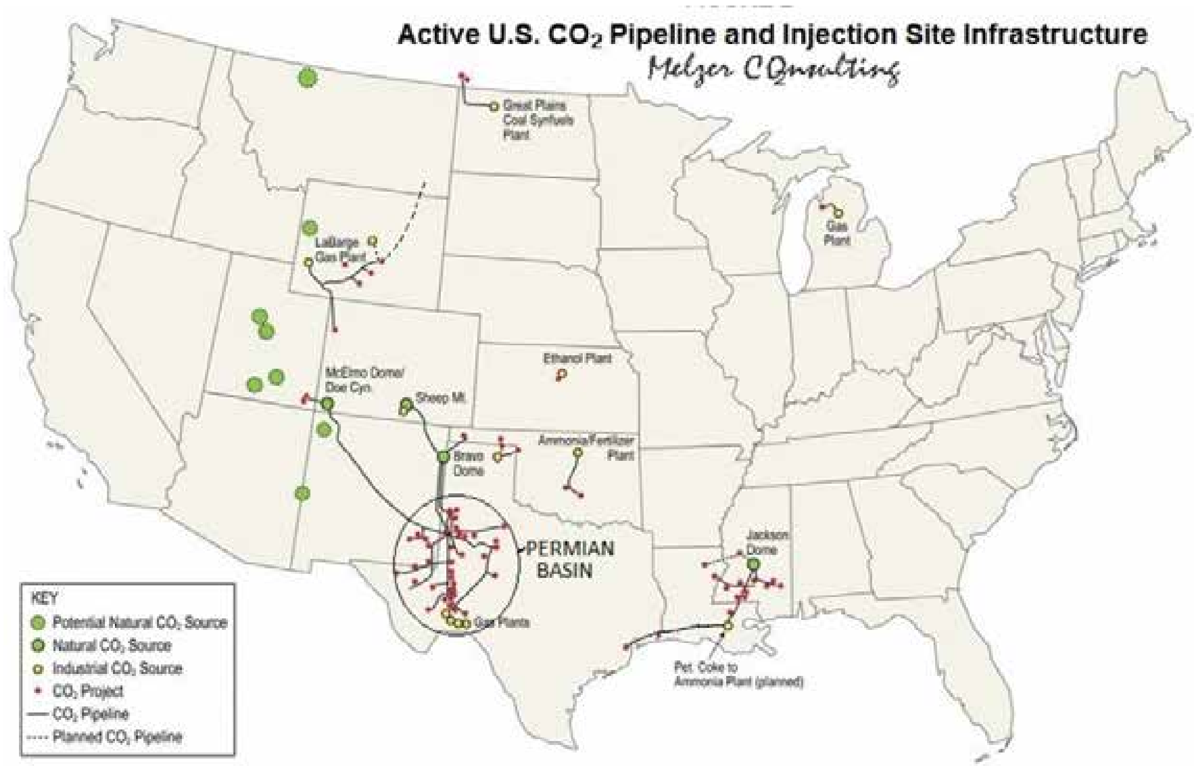
CO_2-EOR was pioneered in the Permian Basin of West Texas in the early 1970s. Today more than 110 CO_2-EOR projects operate in the United States, and more than 4,500 miles of pipelines transport CO_2 from its sources to oil fields for injection.[10,11] The bulk of the operations are in oil fields in West Texas, along the Gulf Coast, and in the Rockies, with additional projects in Oklahoma, Kansas, and Michigan.[12]

EARLY CCS PROJECTS ARE MORE LIKELY TO BE PURSUED WITH ENHANCED OIL RECOVERY

Injecting CO_2 in oil fields offers an economic advantage to the CCS project developer: the revenues from producing stranded oil through CO_2-EOR can help make projects financeable and more likely to be constructed. CO_2-EOR operators have an interest in further expanding their production, but this has been limited by the scarcity of the CO_2 supply.

Although the initial CO_2 supplies for EOR in the 1970s were sourced from natural gas processing plants, today about 80 percent of the CO_2 used for EOR comes from naturally occurring underground accumulations of CO_2, which industry produces expressly for this purpose.[13] These natural "domes" include Bravo Dome in New Mexico; Jackson Dome in Mississippi; and McElmo Dome, Sheep Mountain Field, and Doe Canyon Deep in Colorado. The remainder comes primarily from natural gas processing and fertilizer production plants. Some increase in production of natural CO_2 is expected in the near and possibly medium term,[14] but CO_2 demand will most likely continue to exceed supply. This creates an incentive for CO_2-EOR operators to pursue opportunities to capture man-made CO_2 from large industrial facilities.

FIGURE 3: EXISTING EOR PIPELINE AND SOURCE NETWORK.



Source: Melzer Consulting.

There are currently sixteen integrated projects in North America alone that capture, transport and sequester CO_2 from a variety of sources, including fuel processing, power, fertilizer, and chemical plants (see Appendix A).[15] Of these, only two inject in deep saline formations – the rest provide CO_2 for EOR operations. Even though the available CO_2 storage capacity in deep saline formations is far greater than that in oil fields,[16] CO_2-EOR offers a faster and more likely pathway to the deployment of CCS projects in the near and mid term, and is the focus of this report.

THE GOALS OF THIS REPORT

CO_2-EOR has gained sufficient attention in the public policy realm as a potential climate mitigation, job creation and energy security option to merit closer regulatory scrutiny. In fact, the potential for CO_2-EOR to function as a climate mitigation technology—as opposed to purely an oil extraction technique—is limited by flaws in the way geologic sequestration during CO_2-EOR is regulated and certified today. Improvements are needed that would provide the transparency and confidence necessary to show that the injected CO_2 is indeed being stored permanently. The chapters of this report examine the following:

- how CO_2 injection and geologic sequestration are regulated today;
- the track record of existing regulatory structures;
- what can go wrong in practice during CO_2-EOR;
- two case studies contrasting a sound project against one that has proven problematic;
- important features of how CO_2-EOR is conducted in practice;
- the nature and risk of CO_2 leakage; and
- recommendations for a path forward that is environmentally sound, workable by operators, and credible by stakeholders and the public.

Chapter 2: Current Regulatory Structures for Geologic Sequestration and CO_2-EOR

In 1974, Congress passed the Safe Drinking Water Act (SDWA) to protect public health by regulating the nation's public drinking water supply and activities that can threaten it. The Safe Drinking Water Act seeks to protect drinking water and its sources: rivers, lakes, reservoirs, springs, and groundwater wells. SDWA authorizes the U.S. Environmental Protection Agency (EPA) to set national health-based standards for drinking water to protect against contaminants that may be found in it.[17] SDWA also gave the EPA the authority to regulate the underground injection of fluids.

In 1980, the EPA established the Underground Injection Control (UIC) Program under the authority of SDWA for the purpose of preventing contamination of Underground Sources of Drinking Water (USDWs) caused by the subsurface injection of fluids. According to the EPA, the UIC program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal.[18] The initial program was created with five classes of wells, depending on their purpose and injected fluid, with unique regulations for each class.

UNDERGROUND INJECTION: CLASS II, CLASS VI, AND KEY DIFFERENCES

Today there are six injection well classes, and the two that are most relevant to commercial-scale CO_2 injection are Class II and Class VI. Class II was created with the initial program in 1980 and is used for injecting brines, CO_2, and other fluids associated with oil and gas production, and liquid hydrocarbons for storage.[19] Class VI was added in 2010 to regulate the underground injection of carbon dioxide (CO_2) for geologic sequestration (GS). The EPA listed more than 180,000 Class II wells in its 2015 state and tribal inventories.[20] In contrast, only a handful of injection well permits under Class VI rules have been issued at the time of this writing.[21]

In SDWA, Congress specified that the EPA must not "interfere with or impede" oil and gas production unless "essential to ensure that underground sources of drinking water will not be endangered by such injection."[22] Accordingly, the philosophy of Class II regulations is to facilitate oil and gas production while requiring some environmental safeguards. On the whole, and as will become apparent throughout this report, Class II regulations are brief and general. In addition, the primary responsibility (or "primacy") for regulating Class II wells and enforcing those regulations has been mostly delegated to individual states, which introduces a degree of separation between the EPA and operators.[23] Forty states and two Native American tribes have primacy for Class II; those states and tribal regions contain approximately 94 percent of all Class II wells and produced 99 percent of U.S. onshore oil in 2015.[24,25] No state has yet been granted primacy for Class VI at the time of this writing.

States and tribes may be granted primacy for any or all of the six well classes, but SDWA allows states to assume primacy for Class II wells under conditions less stringent than for any other well type.[26] The standard for Class II wells consists of a general effectiveness demonstration as opposed to meeting individual stringency and adequacy criteria, which is required for all other well classes. Because state and tribal rules are not required to meet the minimum standards laid out in federal rules, there is significant variability among these rules in terms of both regulatory topics covered and stringency. By our analysis, no state rules adequately fill the regulatory gaps discussed above and below, even when accounting for other state-level rules for oil and gas wells generally.

In writing the Class VI regulations, the EPA chose to draw a sharp distinction between CO_2 sequestration in non-oil-bearing formations and CO_2 sequestered as part of CO_2-EOR operations. The agency's rules assume that sequestration in the CO_2-EOR context occurs in two distinct phases: injection of CO_2 in order to produce incremental oil, followed by injection of CO_2 for sequestration after the cessation of oil production. As is discussed further in following sections, this regulatory framework does not reflect the real-life operation of CO_2-EOR projects, in which both oil production and sequestration may happen simultaneously. The result is that, at the time of writing, no CO_2-EOR projects have been required to obtain Class VI permits.

Apart from their age and time of promulgation, there are numerous and substantial differences between Class II and Class VI regulatory requirements. Those for Class VI are more comprehensive than for Class II on many counts. Appendix B summarizes the most important differences.

WELL CONSTRUCTION

In a typical EOR setting, wells may be constructed with only surface and "long string" production casing or production liner without intermediate casing.[27] Class II rules do not specify setting depths for these casing strings. To adequately protect USDWs, however, the surface casing should extend to below the base of the deepest USDW; an intermediate string should be used if any other fluid- or hydrocarbon-bearing zones or abnormally pressured zones are present above the injection zone; and a full string of production casing should be used, as opposed to a production liner, and extend all the way from the injection/production interval to surface.

Cementing production casing all the way to the surface is required only for Class VI wells; it is not required for Class II wells.[28] The procedure does impose additional costs, but these may be modest, and if cementing to surface is not done in the first place and it is later discovered that additional zones need to be isolated, remedial cementing options are limited and often unsuccessful. Fully cementing the production casing gives the greatest assurance that potential flow zones are isolated and provides the greatest level of protection to USDWs. However, it is not always technically feasible, and so cementing operations should be designed and performed by experienced and qualified crews. While cementing to surface may not always be desirable or possible, it should be at the very least considered in an EOR setting where CO_2 sequestration is the goal—Class II regulations do not provide for this.

The cement must also be evaluated to ensure that it was properly placed. Conventional cement bond logs, which are an evaluation tool for cement integrity, are not reliable in detecting defects in the cement that could lead to CO_2 leaks. The reason is that they will derive average cement coverage but not the distribution of voids or the presence of channels, which could act as CO_2 movement pathways. Radial cement evaluations using ultrasonic methods are more sophisticated and better at detecting such defects. Class II regulations do not require their use, however. In addition, they cannot be used where tubing or packer is in place, or in plugged wells.

CLASS VI AND THE ATMOSPHERE

UIC regulations are designed to protect drinking water from contamination by underground injection activities. However, injection activities may result in other environmental impacts not related to groundwater. For example, in the case of CO_2 injection, it may be possible for sequestered CO_2 to escape to the atmosphere. Although Class VI requirements have been promulgated with the express purpose of protecting USDWs, standards such as site characterization and screening, demonstration of an adequate confinement zone, and duty to act when confinement is breached can also help prevent the release of CO_2 to the atmosphere. However, select cases where sequestered CO_2 could escape to the atmosphere without endangering USDWs may not be covered. This could be possible if, for example:

- a USDW is not present where injection is taking place
- the USDW is part of an exempt aquifer
- a pathway is created directly to the atmosphere, for example if a well loses mechanical integrity but CO_2 is still isolated from groundwater; or
- CO_2 migrates out of the current flood boundaries and is produced through wells not tied into CO_2 recycle facilities, which could result in CO_2 being vented to the atmosphere.

In such a scenario, it is not clear whether the EPA will have authority to require such a leak to be remediated or to prevent intentional venting, given that the EPA's regulatory authority under the UIC program is to prevent endangerment of USDWs. In cases where particular mechanical integrity or other requirements to protect USDWs are violated, then action may be mandatory. In others, it may not be.

CLASS VI AND OIL/GAS RESERVOIRS

As discussed above, Class VI rules do not allow for the concurrent production of oil and geologic sequestration of CO_2, and consequently Class VI does not cover all cases of sequestration in oil and gas reservoirs. In fact, it appears to exclude most cases of real-world CO_2 injection in such fields, in which sequestration happens concurrently with enhanced recovery.

Current Class VI regulations state that:

> *Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations [emphasis added].*[29]

The phrases underlined above create ambiguity as to when, or even whether, Class II CO_2-EOR projects must transition to Class VI. If an operator does not continue to inject CO_2 once oil production ceases, the current regulations would not require a transition to Class VI, even if the operator does not recover the CO_2 remaining in the field, thereby sequestering it. If an operator does meet the first standard under which transition to Class VI must be contemplated, by injecting CO_2 "for the primary purpose of long term storage," then the regulations provide a list of factors that must be considered when evaluating whether the second standard is met, i.e., whether "there is an increased risk to USDWs compared to Class II operations." These 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.[30]

The "primary purpose" test prevents operations with any significant hydrocarbon production from needing a Class VI permit. The transition provisions intentionally invent a false scenario under which CO_2 injection in an oil field will first take place as enhanced recovery, and under a lower risk level, but may then transition to a higher risk level at a distinct point in time when geologic sequestration becomes the primary objective and extracted fluid volumes decrease while injected CO_2 volumes increase. This sequential theoretical construct is not representative of real-world situations where CO_2 injection might be taking place.

In reality, well operators are most likely to pursue oil recovery in the manner they have been used to while concurrently seeking recognition for CO_2 that is incidentally sequestered in the process. In addition, the EPA has provided no evidence to support its implication that there will be a sharp increase in risk at a distinct point in time when GS becomes an objective. In reality, risk will depend on a variety of site-specific parameters and operator decisions during the entire life of the project, and the objective to concurrently sequester CO_2 and enhance oil recovery could result in increased risks.[31]

Draft guidance by the EPA on transitioning wells from Class II to Class VI did not clarify the term "primary purpose" highlighted above, nor did it make concrete recommendations for evaluating increased risk to USDWs against the nine factors listed above.[32] In addition, an April 2015 memo by the EPA signaled the agency's intention to continue to regulate injection for concurrent CO_2-EOR and GS under Class II unless CO_2 is injected for the "primary purpose" of sequestration and increased risks to USDWs arise.[33] As described briefly above and in more detail later, the EPA's decision to intentionally shield CO_2-EOR operators from the more protective Class VI requirements without at the same time promulgating new, tailored requirements for sequestration in oil or gas reservoirs leaves a significant gap in terms of ensuring the safety, effectiveness, and credibility of these operations, due to both the relatively superficial nature of Class II regulations and their problematic implementation in practice.

GREENHOUSE GAS REPORTING

In addition to regulation under the UIC program and SDWA, the Clean Air Act (CAA) provides the EPA with the authority, under the agency's Greenhouse Gas Reporting Program (GHGRP), to require the reporting of data that are relevant to the EPA's implementation of a wide variety of CAA provisions.[34] Different requirements apply to CO_2-EOR projects and geologic sequestration projects.

Subpart RR of the GHGRP applies to wells that inject a CO_2 stream for long-term containment in subsurface geologic formations. Subpart UU applies to wells that inject a CO_2 stream into the subsurface (without the objective of long-term containment). All wells used for geologic sequestration must report under subpart RR, whereas wells used for CO_2-EOR must report under subpart UU and may choose to "opt in" and report under subpart RR. In other words, even though a CO_2-EOR well may in fact be used for sequestration, the GHGRP allows the well operator to simply declare that long-term containment of CO_2 is not an objective while hydrocarbons are being recovered and then proceed to report under subpart UU, which contains very sparse reporting requirements, as discussed in detail below.[35] Table 1 summarizes the differences in requirements between subparts RR and UU.

TABLE I: KEY DIFFERENCES IN REPORTING REQUIREMENTS BETWEEN SUBPARTS RR AND UU OF THE FEDERAL GREENHOUSE GAS REPORTING PROGRAM		
Requirement	**RR**	**UU**
Report mass of CO_2		
received	X	X
injected into the subsurface	X	
produced	X	
emitted by surface leakage	X	
emitted from equipment leaks and vented from surface equipment located between the injection flow meter and the injection wellhead	X	
emitted from equipment leaks and vented from surface equipment located between the production flow meter and the production wellhead	X	
sequestered in subsurface geologic formations	X	
reported as sequestered in subsurface geologic formations in all years since the facility became subject to reporting requirements under this subpart, cumulatively	X	
Submit a monitoring, reporting, and verification (MRV) plan that includes:		
identification of CO_2 leakage pathways in the minimum monitoring area (MMA), including likelihood, magnitude, and timing of possible leaks	X	
delineation of the monitoring area	X	
a strategy for detecting and quantifying any surface leakage of CO_2	X	
a strategy for establishing expected baselines for monitoring CO_2 surface leakage	X	

As shown in Table 1 above, unless Class II well operators voluntarily decide to report under subpart RR, the information that will be reported to EPA will be limited to the mass of CO_2 received. By itself, the mass of CO_2 received is, of course, inadequate for determining whether CO_2 is being permanently trapped underground or escaping to the subsurface or atmosphere.

However, even subpart RR requirements may be inadequate to prevent leakage. Even though this list covers many of the bases of sound injection regulation and could indeed be adequate, there is no guarantee of adequate oversight, given the generality of the provisions and possible variability in enforcement and implementation by different permit reviewers. There are no specific requirements for these actions and strategies analogous to the Class VI requirements.

The submitted MRV plan is also not required to be made public. The Administrator may request changes, and then issues a final MRV plan, which is then published and may be challenged by interested parties via the EPA's Environmental Appeals Board (EAB).

Finally, it should be noted that none of the reporting rule subparts require any mitigation in the event of leakage—subpart RR simply requires that leakage be estimated and reported, and subpart UU does not require leakage to be estimated at all. This means that the only regulatory mandate for intervention or mitigation relating to an injection well is linked to the contamination of USDWs. If no USDWs are endangered, then an operator may continue to vent CO_2 to the atmosphere from a well, assuming no other regulatory conditions are being violated.

SUMMARY AND CONCLUSIONS

To review, there are two main sets of regulations that apply to underground injection of CO_2: the Underground Injection Control regulations and the Greenhouse Gas Reporting Program rules. Class II regulations apply to EOR projects, whereas Class VI regulations are designed for the geologic sequestration of CO_2. There are fundamental differences between the regulatory requirements of the two well classes, with Class II being far less stringent and comprehensive on many counts than the more recent Class VI.

In addition, there are two separate tracks for reporting to the EPA GHGRP for CO_2 injection wells: subparts UU and RR. Subpart UU applies to wells that inject CO_2 into the subsurface, whereas subpart RR applies to wells that geologically sequester CO_2. Operators of CO_2 injection wells only have to report under subpart UU, though they may voluntarily report under subpart RR. Information reported under subpart UU is completely insufficient to determine whether the injected

CO_2 is indeed remaining underground. Subpart RR does contain provisions to that effect, but they are broadly worded; its application could be significantly different under different permit reviewers, ranging from valuable and meaningful to very limited in scope and usefulness when it comes to establishing proper sequestration.

Finally, if CO_2 does escape to the atmosphere but does so without endangering USDWs, neither the UIC regulations nor the GHGRP mandate any remedial action.

On paper, therefore, there are two regulatory tracks for injecting CO_2 underground. If pursued in connection with EOR, it can be done under relatively minor regulatory scrutiny. Only when the applicant declares its purpose is to carry out geologic sequestration do more comprehensive requirements and safeguards apply.

We have now looked at the regulations on paper. Before drawing broader conclusions on the suitability of Class II to ensure effective CO_2 sequestration in EOR operations, however, we must also look at how these regulations are implemented in practice. The following chapter explores this in more detail.

Chapter 3: Shortcomings of the UIC Program and the Federal Class II Rules

In theory, federal Class II regulations are the minimum standards to which EOR projects are held. As the previous section explained, these regulations are significantly less stringent in several ways than the Class VI regulations, which were designed specifically with geologic sequestration of CO_2 in mind. Additionally, in practice a number of factors, such as exemptions and poor implementation, can further dilute the effectiveness of Class II regulations. We examine some of these factors in this section.

CLASS II RULES PROBLEMATIC FROM THE START

The last comprehensive assessment of underground injection in oil and gas operations under the Class II program, including the program's effectiveness in preventing groundwater contamination, was conducted more than 20 years ago. In 1989, what is now the U.S. Government Accountability Office (GAO) published a report entitled "Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wastes."[36] The report identified 23 cases of drinking water contamination caused by Class II wells.[37] The researchers also concluded that the full extent of the problem was unknown, given that the Class II program did not require proactive monitoring (nor does so today) and many groundwater contamination incidents were identified only when users of the water detected problems. The causes of contamination were as follows:

- Improperly plugged wells (9 cases, 39 percent)
- Leaks in casing (5 cases, 22 percent)
- Injection into the USDW itself (9 cases, 39 percent)

The report found that close to half of the contamination cases were detected by routine casing pressure tests or record reviews. More than a third of contamination cases were due to improperly plugged wells in the immediate vicinity of the injection well. The report concluded that the Class II program had failed to prevent contamination caused by injected fluids leaking through nearby abandoned wells.

The GAO stated that the root cause of this failure was the decision to exempt existing injection wells that were in operation before the UIC program came into effect—so-called rule-authorized wells—from the area of review (AoR) and corrective action requirements of Class II. These provisions require operators to search for, evaluate the integrity of, and if necessary perform corrective action on any improperly sealed, completed, or abandoned wells in the immediate vicinity of the injection well (usually within a radius of ¼ mile). Wells already injecting when the UIC program was created were required to obtain a Class II permit but were exempted from these particular provisions. The reasoning was that because of the proximity of new wells to existing wells, "the searches undertaken in the ¼-mile radius of new wells would eventually uncover and result in the plugging of all the old wells."[38] The GAO estimated that, at the time, about 70 percent of Class II wells were "rule authorized" and therefore not subject to the Class II AoR requirements. The agency also estimated that these wells accounted for nearly all the contamination cases documented.

As a result of these findings, the report recommended that the program be revised to rescind the exemption and require rule-authorized wells to perform AoR and Corrective Action reviews. A federal advisory committee charged with conducting a midcourse evaluation of the UIC program made the same recommendation.[39]

In the early 1990s the EPA proposed revisions to Class II regulations, reversing the exemption from the AoR requirements for rule-authorized wells and improving well construction standards. The new construction standards would have required that all new injection wells be constructed as follows:

- Surface casing was to be set below the base of the deepest USDW with total dissolved solids of 3,000 mg/L or less and cemented to surface.
- Long-string casing was to be cemented to isolate the injection interval.
- The well was to be equipped with tubing set on a packer.

Existing wells that did not meet these construction standards would have been required to undergo more frequent mechanical integrity testing. The proposed revisions would have required that an AoR be established for any rule-authorized wells that had not been subject to a previous AoR, and that any corrective action be taken within five years of the promulgation of the new rules.[40]

The proposed rules never took effect. Current regulation still exempts rule-authorized wells from the area of review requirements, and construction rules still provide no specificity other than the requirement that Class II wells be "cased and cemented to prevent movement of fluids into or between underground sources of drinking water." The EPA does not maintain statistics on the number of rule-authorized Class II wells currently in operation, so it is not possible to determine the percentage of the more than 180,000 Class II wells that are operating under this exemption.

GAO also found deficiencies in the implementation of the UIC program at the time, based on its review of data from four states. These deficiencies included significant percentages of well files with no evidence of required pressure tests ever having been performed, lack of internal controls to ensure proper documentation, and incomplete or lagging reviews and actual tests for the wells that predated the UIC program.[41]

IMPLEMENTATION OF CLASS II AREA OF REVIEW REQUIREMENTS IS PROBLEMATIC

Reports indicate that Class II AoR and corrective action provisions are problematic, even when they are required. In 2004 the UIC National Technical Workgroup (NTW) prepared a report entitled "Does a Fixed Radius Area of Review Meet the Statutory Mandate and Regulatory Requirements of Being Protective of USDWs Under 40 CFR §144.12?"[42] The report examined whether the AoR requirements are adequate in preventing contamination of USDWs from new Class II wells.[43]

Federal regulations offer Class II well owners and operators the option to draw the area of review as a fixed ¼-mile radius around the well, or to calculate the zone of endangering influence (ZEI).[44] Specifically, the purpose of the 2004 report was to summarize available information on the use of each option. The researchers summarized the process that led to the development of the two different AoR approaches, stating, "The final AoR regulation at 40 CFR §146.6 was adopted even though much existing evidence showed that the actual pressure influence of any authorized underground injection operation is not limited to any pre-determined radius around any proposed or existing injection well, but is a function of specific physical parameters (including initial pore pressures in both the injection zone and in the lowermost USDW and actual injection rate)."

The researchers expressed concern that when state primacy was awarded for Class II under section 1425 of the Safe Drinking Water Act, many states chose to use only the fixed-radius approach instead of including both the fixed-radius and ZEI approaches outlined in the federal standards. They concluded that some state programs were authorizing wells without performing the analyses necessary to assess the pressure influence of long-term injection and were failing to collect pertinent geologic and engineering information about the injection zone, which could ultimately lead to injection that would endanger USDWs. The researchers noted incidents where injected fluids contacted improperly abandoned wells beyond a ¼-mile radius, including one case on the Texas–Louisiana border where injected fluids flowed out of orphan wells located more than a mile from the injection well, impacting a local public water supply.

Accordingly, the researchers recommended that the EPA develop and adopt technical guidance regarding the AoR determination and that every UIC program reevaluate the area of review of all authorized injection activities. They stated: "The majority of EPA UIC National Technical Workgroup members understand the magnitude of the suggested action and consider this proposal as a long-term solution to *a long-standing inadequate permitting practice* [emphasis added]." The researchers went further to state: "A majority of the UIC National Technical Workgroup members believe that enough evidence exists to challenge the assumption that a fixed radius AOR is sufficient to assure adequate protection of USDWs from upward fluid migration through artificial penetrations within the pressure influence of authorized injection operations."

The researchers recognized that the oil and gas industry and regulators in states with primacy for Class II wells might have objections to the recommendations of the report but concluded, "Based on threat evidence that existed at the time of initial UIC regulatory development and subsequent EPA UIC oversight evaluations of State UIC programs, the Agency could be petitioned to withdraw UIC primacy from some State UIC programs through SDWA or APA provisions unless EPA develops and implements clear guidance and regulatory interpretation of this issue."

Despite these clear and unequivocal conclusions and recommendations made by the EPA's own experts, in a 2006 memo to UIC program managers, EPA headquarters stated its intent to take no further action in response to the NTW report.[45] The rationale for this failure to act was that, although the majority of NTW members agreed with the conclusions and recommendations in the report, some state members of the NTW did not agree.

GROUNDWATER CONTAMINATION AND MECHANICAL INTEGRITY TESTING UNDER THE UIC PROGRAM

Several factors can prevent a leak (in this context, loss of well integrity, movement of injected or displaced fluids out of an intended injection zone, or actual groundwater contamination) from ever becoming known in the public domain.

First, such incidents have to be discovered. Except in obvious cases of visible blowouts or severe contamination, this requires active monitoring. Federal Class II regulation does not, however, require comprehensive, ongoing monitoring of wells or of USDWs that may be impacted by injection operations. We are also not aware of any state requirements for ongoing monitoring. Absent a report of an incident or contamination, regulators are less likely to conduct their own routine inspections or testing. A study by the Bureau of Economic Geology in an oil-producing area in Texas found that, out of 107 surveyed sites with anomalies potentially indicative of contamination, at least 42 were contaminated with brine associated with oil production and, of those, 22 are attributable to potentially leaking wells.[46] This does not, by itself, imply that leaks are commonplace, but it highlights that a significant percentage of leaks may go by unnoticed in the absence of active monitoring. It also demonstrates that discovering new leaks/contamination can be complicated by historic contamination.

Second, a leak has to be either detected by, or reported to, the regulator. Reporting requirements vary from state to state, and no concrete data are obtainable on the number or size of leaks that occur but are not reported to regulators. As is discussed in more detail below, EPA data on inspections of UIC wells are incomplete and inconsistent.

Finally, any data must be made publicly available in a way that can be accessed in a practical manner.

AVAILABLE STUDIES RAISE CAUSE FOR CONCERN

A number of studies have looked at the mechanical integrity of wells under the UIC program, examining documented failure rates, how states implement federal requirements in practice, the amount and reliability of information that exists on this subject, and the consequences of shortcomings and failures.

A study by Koplos et al. was published in 2006 assessing the availability of mechanical integrity testing (MIT) information and information on the types, causes, and consequences of mechanical integrity failures for well Classes I and II.[47] For Class II wells, the study found that, "of the seven States with the most Class II wells, only three (Illinois, Kansas, and Ohio) explicitly required both internal and external MIT for all Class II wells." The researchers found that information on mechanical integrity tests and failures was lacking, both in quantity and in scope.

Koplos et al. also reviewed what are known as 7520 forms, which are documents used to report information about the UIC program to state and federal regulators. Although the forms contain a great deal of data, analyzing national-level data is difficult because the forms exist on paper only; they are not compiled in an electronic database. Furthermore, the forms do not distinguish what type of fluid is injected into the well—brine or CO_2—and therefore analysis cannot be performed to assess injectate-specific failure rates. The researchers reviewed a subset of forms for fiscal year 2005 and found an overall low failure rate of approximately 2 percent. There was only one alleged case of contamination of a USDW, from a brine disposal well.

A report prepared in 2011 for the Ground Water Protection Council reviewed investigations of groundwater contamination caused by the oil and gas industry in Ohio and Texas.[48] According to the report, which relied on data from the respective state regulators, more than 98 percent of all produced water in both states is disposed of via Class II wells. The author writes that "over the past 25 years, Ohio has not identified a single incident of groundwater contamination from subsurface injection at a permitted Class II disposal well." The report does identify two cases of drinking water contamination in Ohio from EOR wells but states that the problems were a result of historic construction and operation practices no longer permitted under the UIC program.

The report identifies six cases of groundwater contamination in Texas caused by Class II injection operations from 1993 to 2008. Five were the result of mechanical integrity failures and one resulted from migration of injected fluids through nearby, improperly abandoned wells.

This report suggests a notable improvement over the average nationwide track record highlighted in the GAO report of 1989. However, the report did not assess the adequacy of the monitoring, inspection, and reporting requirements in each state to determine whether contamination incidents were in fact not occurring or were just not being detected. It is difficult to generalize from two states only, and significant data gaps remain that could affect any conclusions. As noted in the GAO report, determining the full extent of groundwater contamination is difficult because the Class II program relies heavily on self-reporting by operators except in cases where users of groundwater notice impacts. One key piece of information lacking in this and other studies is the number of inspectors/inspections versus the number of contamination incidents. If the number of incidents tracks the number of inspections, then it brings into question whether incidents are actually happening more/less frequently, or only being detected more/less frequently.

NRDC conducted its own review of the UIC 7520 reporting forms from three EPA regions—5, 6, and 8—and two reporting years—1988 and 2011. The three regions selected contain a large number of Class II wells (approximately 63 percent of the

Class II wells in operation in 2010) and existing EOR projects. The years were selected for the purpose of obtaining data from early in the life of the UIC program and more recently. Like other researchers, NRDC found that the forms are often incomplete, and it is difficult to draw conclusions about the performance of the UIC program based on the information they contain. The forms provide an accounting of the number of mechanical integrity violations, for example, but give very little information as to the type or cause of the violation and any remedial action taken. The forms also fail to list the total number of wells in operation in a given year, so for our analysis it was not possible to determine the rates of failure.

In 2012, ProPublica published the results of a study examining injection well records under the UIC program, case histories, and government summaries of more than 220,000 well inspections.[49] The author concluded that well integrity failure in injection wells is common. ProPublica's analysis of case histories and EPA data from October 2007 to October 2010 catalogued more than 25,000 violations issued for loss of mechanical integrity in UIC wells, USDW contamination, over-pressurization, and significant leaks (movement of fluids outside an authorized zone).

Table 2, below, summarizes ProPublica's results. As can be seen in the table, violations are sometimes reported for all well classes combined, making it difficult to draw conclusions regarding well failures within one particular class. The study found that more than 17,000 mechanical integrity violations were issued for Class II wells, of which the vast majority were for enhanced recovery and not brine disposal.[50] Mechanical integrity violations can be issued for a number of reasons, from actual mechanical flaws in injection wells to incomplete records or paperwork. The table also lists 22 cases of USDW contamination from Class II wells and 77 cases from other well classes.

Class II regulations require mechanical integrity tests (MITs) to be performed only once every five years, which means that a mechanical integrity problem may persist for years before being discovered. In terms of response times, ProPublica concluded, on the basis of EPA data, that most well failures are repaired within six months of being discovered, but also that repair is not possible every time, in which case the wells are plugged and abandoned.

<table>
<tr><th colspan="7">TABLE 2: SUMMARY OF RESULTS OF PROPUBLICA'S ANALYSIS OF EPA UIC WELL RECORDS</th></tr>
<tr><th></th><th>Class II</th><th>Class I Haz.</th><th>Class I Non-Haz.</th><th>Class III</th><th>Class IV</th><th>Class V</th></tr>
<tr><td>No. of UIC Wells (2010)</td><td>150,851</td><td>113</td><td>537</td><td>21,368</td><td>24</td><td>507,275</td></tr>
<tr><td>Mechanical Integrity Violations (Oct. 2007–Oct. 2010)</td><td>15,565 Enhanced Recovery

1,559 Brine Disposal</td><td colspan="2">46</td><td colspan="3"></td></tr>
<tr><td>Cases of USDW Contamination</td><td>22</td><td colspan="5">77</td></tr>
<tr><td>Cases of Over-Pressurized Injection</td><td colspan="6">1,199</td></tr>
<tr><td>Test Failures for Significant Leaks</td><td colspan="6">6,723</td></tr>
</table>

Source: ProPublica, http://projects.propublica.org/graphics/underground-injection-wells.

The study further found that regulatory oversight is problematic on many levels. The author concluded, based on conversations with the EPA, that the agency does not process injection permit violation records or data in a systematic way, and that it often accepts state data that are incomplete. Further, the EPA's national injection well database was found to contain complete information from only a handful of states, accounting for a small fraction of the deep wells in the country, with fewer than half of regulatory agencies reporting.[51]

A 2014 study examining the risk and public perception of CO_2 well blowouts found that collecting data on well control incidents was very challenging.[52] The authors stated, "There are no standard formats for reporting loss of control events at the Federal or state level; consequently, many states have varying levels of accessibility for reporting ranging from relatively organized to completely unavailable." They found that some states kept online data, others only paper records, and one state kept no records but instead managed blowouts "on a verbal basis between the regulatory authority and the operator of the field where the blowout occurs."

A 2016 GAO report found that "EPA has not consistently conducted oversight activities necessary to assess whether state and EPA-managed programs are protecting underground sources of drinking water."[53] Consistent with NRDC's analysis, GAO found that violation and contamination data collected on 7520 forms "were not sufficiently complete or comparable to allow EPA to aggregate state information and report on the status of the Class II program nationally" or to assess whether states are meeting inspection goals. GAO also found that a lack of complete and consistent enforcement data may be limiting the EPA's ability to take action on significant violations. The EPA has also been failing to consistently carry out annual on-site evaluations of state Class II programs. To be able to enforce state Class II regulations if necessary, the agency is required to incorporate state program requirements into federal regulations, but GAO found that it has not consistently been doing so. GAO also found that the EPA has failed to maintain complete and accurate records on aquifer exemptions and as a result does not know the location and size of all aquifers for which it has approved exemptions.

These studies demonstrate that determining the precise number of violations, tracking mechanical integrity and contamination incidents, and assessing their variation with time or location are not possible with existing data. Information is incomplete, outdated, or nonexistent, making it difficult to infer exact MIT failure rates or the number, extent and frequency of contamination incidents. While it is theoretically possible that the UIC Program is performing in a satisfactory way, our view is that there are problems with the performance and oversight of some Class II wells, the extent of which will require a far more comprehensive effort to decipher.

EXPERIENCE WITH CLASS I HAZARDOUS WELLS HIGHLIGHTS ROOM FOR IMPROVEMENT IN CLASS II

The regulations pertaining to the underground injection of hazardous waste—UIC Class I Hazardous—are among the most stringent—if not the most stringent—well construction, operation, and maintenance regulations that exist currently at the federal level. Numerous studies have evaluated the performance of the UIC Class I program since it was created in 1980.

A 1986 study by the Underground Injection Practices Council (UIPC) found that while approximately 9 percent of Class I wells experienced integrity problems, only 2 percent experienced problems that led to contamination of a USDW.[54] A 1987 GAO study documented two confirmed cases of drinking water contamination and one suspected case of drinking water contamination.[55] However, most of the wells in the UIPC study and all the wells in the GAO study were constructed prior to the inception of the UIC program. Both studies concluded that the water contamination was the result of siting, construction, or other practices that, under the UIC program, are no longer allowed.

Two studies were conducted more recently by outside consultants for the EPA. The first study, from 1993, examined records for all of the Class I Hazardous wells and 75 percent of the Class I nonhazardous wells in operation from 1988 to 1991.[56] The second study, from 1999, examined records from all of the Class I Hazardous wells and 85 percent of the Class I nonhazardous wells in operation from 1993 to 1998.[57] The researchers in both studies found that wells injecting hazardous fluids have MIT failure rates two to three times higher than wells injecting nonhazardous fluids. However, of the 136 reported cases of mechanical integrity failure from the 1993 study and the 122 reported cases from the 1999 study, none resulted in contamination of drinking water.[58]

It is possible that drinking water contamination has gone unreported or undetected in the case of Class I Hazardous wells. However, judging by available data, the UIC Class I Hazardous well program appears to be largely successful at protecting drinking water from contamination. In contrast, as discussed above, even though drawing absolute conclusions about the success or failure of the Class II program to protect drinking water is not possible with existing data, research to date suggests genuine cause for concern. The differences between the two programs suggests that, properly implemented, more thorough (but still commercially workable) regulations can significantly reduce the risk of water contamination due to injection operations.

SUMMARY AND CONCLUSIONS

A number of studies have documented problems with the Class II program in practice. Implementation of Class II regulations has been inconsistent and problematic. Responsibility to implement the Class II program has largely been delegated to individual states, and given the lower standard for awarding primacy for Class II, there is significant variation among state regulations in terms of stringency and completeness, as well as in enforcement. The EPA has been lax in evaluating how states are administering and implementing the Class II program. The data and documentation on mechanical integrity failure rates, testing, and groundwater contamination are incomplete, sometimes unreliable, and not always held centrally or overseen by the EPA. Thus, a definitive assessment of the program's effectiveness is not possible at this point. However, available data and research suggest that the Class II program may not be adequately protecting USDWs.

The studies cited above do not generally distinguish between types of Class II wells. Given the limited geographic scope of CO_2 pipelines and injection (see Figure 3.) and the very small portion of national oil production attributable to CO_2-EOR,[59] CO_2 injection wells may be a small subset of the Class II universe of wells that the studies listed in this chapter focus on, if they are represented in the data at all. As such, the problems identified here may not be inherent to, or even as frequently encountered in, CO_2-OR operations. To our knowledge, though, there are no available data to demonstrate this. Since the same regulatory regime applies to all Class II injection wells under the UIC program, a credible case for superior quality of CO_2-EOR operations cannot be made on the basis of their regulation alone, even if it is believed or suspected.

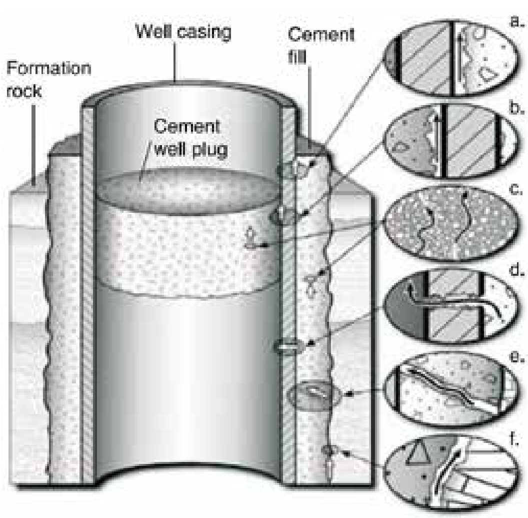
Chapter 4: All Wells May Not End Well: What Can Go Wrong in Practice

This section discusses the potential mechanisms that could lead to leakage of injected CO_2 to the surface from CO_2-EOR operations. Note that these are applicable to underground injection of fluids in general and are not specific to CO_2-EOR. Some practical dimensions that are specific to CO_2-EOR are discussed in Chapter 6.

When the EPA launched the UIC program in 1980, it identified six main “pathways of contamination” through which fluids can escape the well or injection horizon and enter underground sources of drinking water:[60]

FIGURE 4: POSSIBLE LEAKAGE PATHWAYS IN AN ABANDONED WELL

(a) between casing and cement wall; (b) between casing and cement plug; (c) through cement plug; (d) through casing; (e) through cement wall; and (f) between cement wall and rock.



Source: IPCC Special Report on CCS, 2005.

- movement of fluids through a faulty injection well casing;
- movement of fluids through the annulus located between the casing and well bore;
- vertical movement of fluids through improperly abandoned and improperly completed wells;
- movement of fluids from an injection zone through the confining strata;
- lateral movement of fluids from within an injection zone into a protected portion of that stratum; and
- direct injection of fluids into or above an underground source of drinking water.

The first three pathways pertain to wells, the others to geology. In EOR projects, there is often a proven seal and trap that are capable of retaining fluids over geological time, as evidenced by the presence of the oil field itself, which means that there is often a high degree of confidence in the ability of the geologic system to contain injected fluids.[61] The first three pathways are therefore the ones posing the highest risk in CO_2-EOR projects, given that these fields often have long operating histories and commonly contain a large number of wells. These wells can be active or idle production and/or injection wells, plugged and abandoned wells, and potentially orphan wells, too. The risk of migration through geologic pathways still exists, and therefore proper site selection and characterization are still critical, but the quantity and history of the wells will, on balance of probability, usually outweigh the risk of leakage through geological features. Figure 4, from the Intergovernmental Panel on Climate Change (IPCC), expands on EPA’s list of pathways and shows the various ways in which CO_2 could leak through an abandoned, or improperly constructed or maintained well.

Well construction, maintenance, and plugging techniques have evolved significantly in the more than 150 years of oil and gas production in the United States, but the observed quality of construction and maintenance in the field varies considerably with location, operator, and age. Good results rely on knowledgeable and capable crews following good operational practices in order to prevent a number of possible occurrences that can compromise well integrity, as we examine in more detail below.[62] In addition, not all wells are under an operator’s control, and there is a very real possibility, too, that old, undocumented wells may lurk in the field without the operator being aware of them.

“Mechanical integrity” refers to the absence of leakage pathways in the casing or cement. Internal mechanical integrity refers to the absence of leakage pathways inside the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing. There are numerous studies of mechanical integrity in wells and lines of evidence that point to wells as potentially problematic. We present some of these below, first as they apply to wells in general, and then more specifically to wells regulated under the UIC program.

ORPHAN WELLS

So-called orphan wells are ubiquitous in regions that have undergone oil and gas exploration.

A 2008 report from the Interstate Oil and Gas Compact Commission defined an orphan well as "a well that is not producing or injecting, has not received state approval to remain idle, and for which the operator is unknown or is not solvent." It concluded that there were an estimated 149,371 orphan wells in the United States as of 2006.[63] Of these, the locations of 59,222 were known, and these wells were on designated waiting lists for plugging. Through a variety of methods, the states surveyed for the study estimated that there could be an additional 90,149 that were undocumented or unidentified—meaning that their locations were unknown. The report also found that "while states have established plugging funds, those funds are insufficient to address timely cleanup of the remaining orphan wells."

Orphan wells, especially orphan wells that are undocumented/unidentified or mislocated in records, are a potentially significant leakage risk for CO_2-EOR projects. Among oil fields with long operating histories or those that have had multiple owners over time, proprietary well files and well histories may be missing or incomplete, obscuring the location and plugging status of some wells within the field. State and federal records may also be incomplete, given that oil exploration and production in the United States predated the regulation of the practice by several decades in some cases. Orphan wells may have been constructed or plugged using outdated methods and may not have been maintained over time to ensure the integrity of the construction and plugging materials.

Orphan wells lacking mechanical integrity could represent a fast path for injected or displaced fluids to reach USDWs or the surface. Detecting and remediating problematic orphan wells proactively should be a priority if EOR and sequestration of carbon dioxide are to coexist. As discussed above, Class II area of review requirements are lax, requiring only that owners and operators "identify the location of *all known wells* within the injection well's area of review which penetrate the injection zone [emphasis added]." Given that the location or even existence of orphan wells is often *unknown*, Class II regulations fail to address this potentially significant leakage pathway.[a]

MECHANICAL INTEGRITY OF KNOWN WELLS

There can be several main causes for the loss of mechanical integrity, such as tubing failures, packer failures, and casing failures. Improper primary cementing and cement degradation are also significant risks for loss of mechanical integrity and possible groundwater contamination. The Westport Technology Center International conducted a survey among 18 worldwide cementing experts on the failure rate of primary cement jobs.[64] An average failure rate of 15 percent was reported.[65] The biggest culprit was fluid (gas or water) migration behind the casing.[66] Old wells are more likely than new ones to have mechanical integrity failure and leakage in general, due to the degradation of materials and the evolving nature of technical knowledge and regulatory oversight.

One study examined over 10,000 mandated MITs in four states and found an overall 10.5 percent failure rate, although the authors estimated the actual rate could be 50 percent higher due to failures being identified and corrected prior to scheduled tests.[67] The researchers found that the records were very incomplete, with only 46 percent of the records identifying the cause of the failure. Similarly, the consequences of the failures were not well reported. The researchers suspected that at least one-fifth of the failures may have allowed waste to migrate outside the casing. Further, they found that about one-quarter of the wells with casing failures were plugged within 60 days of the failed test, implying that these wells had significant mechanical integrity failures that could not be remediated.

Another study, published in 2009, attempted to quantify the risk of CO_2 leakage from a storage site through and along well bores by examining records of more than 315,000 oil and gas production and injection wells drilled through 2004 in Alberta, Canada.[68] The researchers collected information including but not limited to well configuration; production, stimulation, and abandonment methods; producing formation; and instances of surface casing vent flow (SCVF), gas migration (GM), casing failures, and nonroutine abandonment.[69,70] Both SCVF and GM can be caused by poor initial well design and construction or improper abandonment, or a combination of both.

The researchers documented an occurrence rate of SCVF/GM of 4.6 percent for the entire province of Alberta and 15.5 percent in their test area. Further, they analyzed factors that have varying degrees of impact on the occurrence of SCVF and GM. Factors showing major impact are summarized in Table 4.

a See the Salt Creek case study below.

TABLE 4: FACTORS WITH MAJOR IMPACT ON SURFACE CASING VENT FLOW (SCVF) AND GAS MIGRATION (GM)	
Factor	**Description**
Geographic Area	A special test area within the larger study area had a high percentage of wells with SCVF/GM.
Well Bore Deviation	The occurrence of SCVF/GM was higher in deviated, or slanted, wells than in vertical wells, possibly due to technological challenges in constructing deviated wells.
Well Type	Drilled and abandoned wells had a lower rate of SCVF/GM (approximately 0.5 percent), and cased and abandoned wells had a higher rate of SCVF/GM (approximately 14 percent), compared with an overall average of 4.5 percent. Cased wells accounted for more than 98 percent of all instances of SCVF/GM.
Abandonment Method	Certain well abandonment practices are anticipated to have higher rates of failure over time, in particular the use of bridge plugs capped by cement. Welded casing caps, which seal off the well bore just below the surface, are "highly unreliable."
Oil Price, Regulatory Changes, and SCVF/GM Testing	There was a strong correlation between oil price and occurrence of SCVF/GM from 1973 to 1999, perhaps due to increased activity levels and decreased equipment availability, leading to less stringent well construction practices. This correlation began to diverge in 2000, perhaps due to testing requirements implemented in 1995 that may have led to greater SCVF/GM detection.
Uncemented Casing/Hole Annulus	Low cement top and exposed casing were the most important factors for the occurrence of SCVF/GM. Low cement top and poor cement quality were also key factors in external casing corrosion. Failure to isolate formations behind cement caused the vast majority of SCVF/GM and casing failures.

Source: Watson and Bachu, 2009

For this particular setting, the researchers concluded that:

- general well attributes that are catalogued can be used to deduce which wells have a high leakage likelihood;
- the main cause of leakage lies with time-independent mechanical factors controlled during drilling, construction, and abandonment—mainly cementing; and
- enforced regulations are critical in controlling and detecting such leakage.

Dusseault et al. separately investigated the specific mechanisms that lead to gas migration and concluded that cement shrinkage is a major contributing cause.[71] Cement shrinkage results in the creation of circumferential fractures in the cement column. Gas invasion into the annular space increases pressure at the fracture tip, causing the fracture to continue to grow vertically, eventually leading to gas migration to the surface.

A more recent study by Dusseault et al. on the occurrence of leakage across Canada concluded that the phenomenon occurs nationwide (across all provinces with oil and gas wells) through a variety of mechanisms, and with potential consequences such as air emissions, groundwater contamination, and operational health and safety risks.[72]

Studies surveying offshore wells show even higher rates of sustained casing pressure.[73] These studies are not necessarily a good direct analogue for onshore wells since, generally speaking, the offshore environment tends to be a more challenging one to operate in. Nevertheless, they indicate that proper well construction and achieving zonal isolation are problems that plague the oil and gas industry across all sectors. Two independent studies of well integrity on the Norwegian continental shelf produced similar results, identifying 18 to 25 percent of wells in their sample space as having integrity problems or leaks.[74,75] They also identified injector wells as being at higher risk of leakage, reporting a leakage rate of 37 to 41 percent compared with 13 to 19 percent for producer wells.[76] A 2003 study of natural gas well integrity found that 43 percent of wells in the Outer Continental Shelf (OCS) area of the Gulf of Mexico reported sustained casing pressure (SCP) on at least one casing annulus. It also found that the rate of SCP increased with well age.[77]

Surface casing vent flow, sustained casing pressure and gas migration represent only a subset of the consequences of loss of mechanical integrity (see Figure 4). Other consequences may include leakage in the subsurface, with the ultimate fate of the injected fluids depending on the surrounding geology and hydrology rather than migration along a well itself. If the injected fluids remain within the geologic containment system, then such migration may not result in endangerment to USDWs or emissions to the atmosphere. In other cases, the injectate may encounter migration pathways such as wells or faults/fractures that may cause its eventual migration to the surface or into USDWs.

A recent study examined "75,505 compliance reports for 41,381 conventional and unconventional oil and gas wells in Pennsylvania drilled from January 1, 2000–December 31, 2012."[78] The goal was to "determin[e] complete and accurate statistics of casing and cement impairment."[79] The authors reviewed inspection records for keywords and violation codes they considered to be related to casing and cement integrity issues, but they cautioned that interpreting these indicators is sometimes not straightforward.[80] Based on this analysis, the authors concluded that 1.9 percent of the oil and gas production wells for which drilling commenced between 2000 and 2012 showed a loss of well integrity.[81] They also concluded that unconventional wells had integrity issues at a rate six times higher than that of conventional wells. Looking at a subset of unconventional wells drilled in northeastern counties prior to 2009, they found that 9.84 percent of them had indicators of integrity issues. The authors used the results to model future rates of integrity issues. They estimated that wells in the northeast region had a 20 percent chance of developing an integrity issue in the first three to four years of operation and that unconventional wells in that region had a 40 percent chance of developing an integrity issue by year seven. As the authors note, however, not every integrity issue will lead to a contamination or emissions event.

Duguid et al. in 2010 estimated leakage potential through existing wells based on existing data for the Thrall-Aagard CO_2-EOR project in Kansas.[82] Primary production at the field occurred in the 1920s, and secondary production in the 1950s and 60s. The selected study area in the field contained 457 abandoned and active wells. Seven wells were producing wells, 13 had casing issues, and 9 had plug issues. The majority of wells had been plugged in the 1960s. No field-specific probability values for leakage existed for the field at the start of the project, partly because well records, including plugging and completion reports, could be incomplete, missing, inconsistent over time, and inconsistent between different operators. Given this, expert judgment was applied to derive "risk factors" for leakage from the wells. According to the risk factor derived, a course of action was decided for each well.

The expert evaluation resulted in a recommended course of action that involved replugging the 270 riskiest wells and monitoring the 94 riskiest. Each prospective CO_2-EOR field is unique and must be assessed independently by qualified experts, but Thrall-Aagard represents one example of the significant remedial work that may be necessary in order to prepare a field for CO_2-EOR operations due to concerns about existing wells.

In the absence of regulations that mandate such an evaluation of wells in a field and preventive or corrective action, one can expect different approaches from operators. Some may choose to plug wells preemptively, whereas others may prefer deferring action and cost until leakage has been observed or is causing a problem. Class II regulations, which almost always default to a ¼- mile area of review around a CO_2 injection well, compound this concern by not requiring any action when wells fall outside that radius.

MONITORING

Monitoring is an integral part of any sound geologic sequestration project, regardless of whether the CO_2 is being injected in an oil field or another type of formation. A properly designed and implemented monitoring plan serves several purposes:

- It verifies that injected CO_2 is indeed staying within its intended confinement zone.
- It provides a warning when the risk of leakage increases or when confinement is breached.
- It serves as a means of refining model inputs and improving operators' predictive capabilities regarding the injection and their knowledge of the structure and geochemistry of the subsurface.
- It provides a quantitative basis upon which to make operational decisions that can affect the integrity of storage.

Monitoring is essentially the eyes and ears of the operator, enabling detection and characterization of leakage and promoting an understanding of a subsurface environment that is otherwise inaccessible. A monitoring strategy may cover several intervals, based on the needs of the project and regulatory requirements. Starting from the deepest, these may include:

- the injection zone (including both the CO_2 plume itself and areas that have not yet been contacted by CO_2);
- geologic formation(s) above the primary seal, sometimes referred to as above-zone monitoring intervals (AZMI). This is an important area of focus, as the effectiveness of the geologic seals can be directly tested and the earliest warning signs of geologic leakage are likely to be found. A number of factors must be considered when selecting optimal AZMI, including but not limited to the lateral extent, permeability, thickness, and depth of the prospective intervals;
- near-surface intervals including drinking water aquifers, the soil, and the vadose zone; and
- the atmosphere.

The mix of technologies and monitoring strategies will depend on the nature of the sequestration project. For a greenfield project utilizing two injection wells in a deep saline formation without a history of oil or gas production, for example, the focus should be on the geology. Emphasis would likely be placed on monitoring techniques that target the interval above the injection zone and primary seal.

In the context of an EOR field, however, the trapping qualities of the field are likely already established, and the main concern is the presence of numerous wells that could act as conduits for migration. Given the vulnerable and fallible nature of wells described in this chapter, it is clear that a sound monitoring strategy for a sequestration project in an EOR field should place particular emphasis on detecting leakage from wells.

The monitoring techniques selected for any project must be shown to be effective at detecting unacceptable storage performance.

SUMMARY AND CONCLUSIONS

It is clear that wells, to varying degrees, are prone to defects and faults in their operation at some point in their life. Not every well will exhibit loss of mechanical integrity, but it appears that this can be expected routinely in the average oil field that features hundreds of wells. Older wells or wells in more hostile environments (such as offshore) are more prone to leakage. In addition, orphan wells are a legacy that is commonplace in regions that have undergone exploration for a long time. Their old age, combined in some cases with inadequate plugging, makes them prime candidates for leakage. For a typical field, it is reasonable to expect to have to replug and abandon at least some portion of existing wells in order to mitigate the risk of leakage to an acceptable degree for successfully sequestering CO_2.

The failure-prone nature of wells does not mean that the associated risks cannot be managed. Constructing new wells to the appropriate standard will render them less likely to fail or exhibit leaks, and both existing and new wells can be monitored for defects or compromised performance. A prudent monitoring strategy will assume that well defects and compromised integrity will be encountered and will place emphasis on an early-detection strategy to limit the extent and magnitude of potential leakage.

Operators have proven capable of implementing such an approach. However, experience has shown that without regulatory mandates there is no guarantee that this will happen in time, or at all. The current Class II regulatory framework does not mandate sufficient monitoring or use of the techniques necessary to achieve this.

Chapter 5: Two Case Studies Clearly Delineate Good Practices from Bad Ones

EOR operators do not always limit their practices to the minimum requirements set by regulations. It is often in their interest to exceed those regulations in order to prevent potential incidents, expenses, or noncompliance; to gain a better understanding of and optimize their CO_2 floods; and to maximize economic returns from the field. Such efforts could involve reworking all existing wells at the field before commencing CO_2 flooding, looking for unknown wells, using geophysical or other methods to better understand the evolution of the CO_2 plume and field geometry, and more.

However, in the absence of regulations, there is no guarantee that operators will follow sound practices. Below we examine two examples of CO_2-EOR projects. One has been the site of repeated CO_2 seeps to the surface, while the other has had no documented signs of groundwater contamination from CO_2 injection despite decades of CO_2-EOR injection and production and rigorous monitoring. The case studies highlight some potential pitfalls of CO_2-EOR operations and the need for sound regulation, but also the potential to operate fields prudently in a safe and effective manner.

SALT CREEK CO_2-ENHANCED OIL RECOVERY FIELD, MIDWEST, WYOMING

HISTORY

The presence of oil at the Salt Creek Field was known as early as 1880 due to surface oil seeps. The first well was drilled in 1899 into the Shannon Formation (Figure 5). The first well to tap the Wall Creek member of the Frontier Formation—the most productive formation in the field—was drilled in 1906.[83] Primary production occurred until 1926, gas injection was implemented from 1926 to 1961, water flooding has been used from 1961 to the present, and CO_2 flooding of the Wall Creek II began in 2004.[84] A phased approach was taken to CO_2 flooding, with the field broken into separate phases and the onset of CO_2 injection occurring sequentially in each phase.[85]

Multiple oil and gas companies have operated the field in the more than 100 years since it began producing. More than 4,000 wells have been drilled in that time, approximately 70 percent of them prior to 1930. When Anadarko Petroleum Corp. acquired the field in 2002 with the intent to commence CO_2-EOR operations, it contained more than 3,000 plugged and abandoned wells with questionable cement integrity and plugging quality. Due to Salt Creek's long operation history and multiple owners, well records and data were incomplete, and many unknown well bores existed in the field.[87]

INCIDENT

According to public documentation prepared by the Bureau of Land Management, after the onset of CO_2 injection in 2004, CO_2 seeped to the surface over an area of approximately one-quarter square mile in Phases I and II (the entire field covers about 34 square miles).[88] The BLM report states that the rate of leakage averaged 12 thousand cubic feet per day (MCFD) (about 222 metric tons per year).[89] At the time, approximately 150 million cubic feet of CO_2 per day (about 2.7 million metric tons per year) was being injected into the field. The operator determined that some seeps were the result of improperly constructed or maintained wells, but remediation of these wells failed to completely eliminate the seeps.[90] The BLM report does not indicate how the seeps were discovered.

The 12 MCFD estimate was determined on the basis of field data collected by Cameron-Cole, a consulting firm hired to conduct air dispersion modeling.[91] During two site visits in January and February 2005, Cameron-Cole collected field data including but not limited to flow rate measurements, ambient real-time gas concentration monitoring, and gas samples for analytical determination of gas concentrations. However, these data were collected for only six leakage points (referred to in the firm's report as "pressure integrity events," or PIEs). The total number of PIEs was not publicly reported. Cameron-Cole states that the six measured PIEs were "selected to establish a size and flow (based on visual observation) distribution that was representative of the site while biased toward higher, and therefore more conservative, flow rates."

Average flow rates from the measured PIEs ranged from 1.6 cubic feet per minute (cfm) to 23.6 cfm, or approximately 2 MCFD to 34 MCFD. The maximum recorded flow rate was 30.5 cfm (44 MCFD). Field measurements of CO_2 concentration were not obtained for two of the six PIEs. For three others, field-measured CO_2 concentrations exceeded the upper limit of the monitor range (20,000 ppm). Analytically measured CO_2 concentrations ranged from 1.1 to 90.7 percent.

In response to continued leakage after well remediation, the operator undertook efforts to identify areas where the geology may be susceptible to leakage by identifying major faults and comparing surface and subsurface features to help predict areas where CO_2 seeps might occur.[92] A full 3-D seismic survey of the field was performed.[93] The presence of surface seeps indicates that pathways from oil-bearing formations to the surface exist, although the field contains 11 separate productive horizons, only one of which was undergoing CO_2 flooding at the time of the incident.[94] Some faults extend from the injection zone to the surface, but the operator contends that the field is being operated at pressures below the "leak point" of the faults.[95]

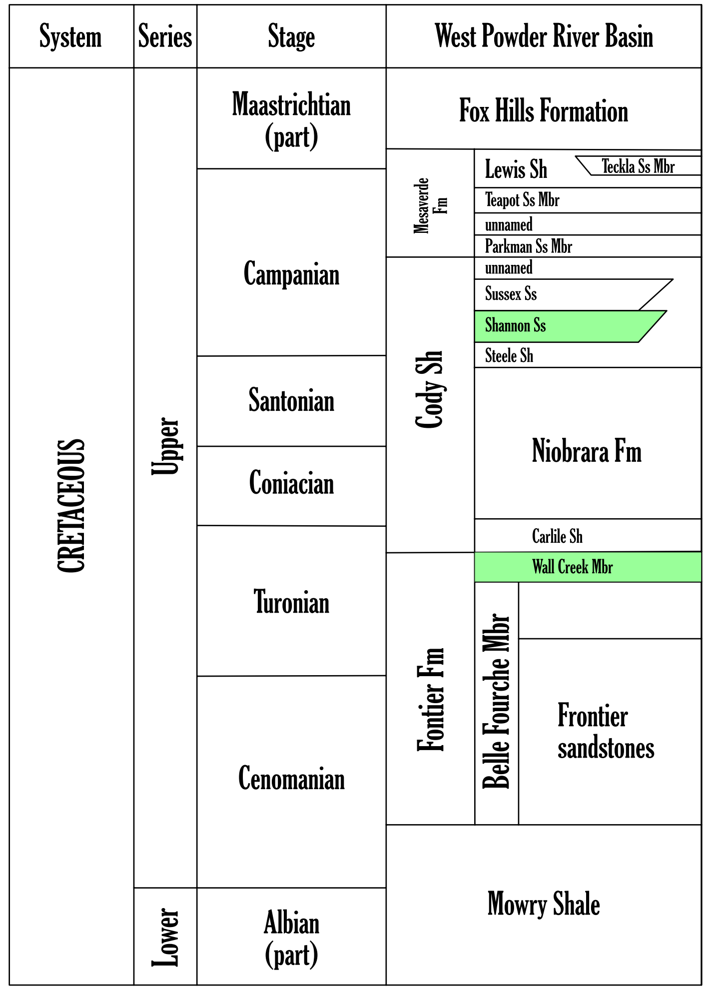
To remediate seeps, the operator developed a containment plan consisting of the following steps:[96]

1. Install shallow vertical wells (between 100 and 800 feet below ground surface) that would be completed in naturally fractured zones.
2. Install horizontal bores that would be drilled about 20 to 80 feet below a CO_2 seep.
3. Install drains in or near natural draws, which appear to be the primary areas where CO_2 seeps surface.
4. For both the shallow vertical wells and horizontal bores, install pumps at the lowest available point to remove shale fluids displaced by the CO_2. These fluids would be collected and processed, along with the CO_2 flood–produced fluids.
5. Liquids collected by drains in or near natural ravines would be removed by vacuum truck and transported to nearby processing facilities. CO_2 recovered during these procedures would be gathered into a low-pressure system and compressed by blowers into the main CO_2 recycle system.
6. Fence prominent CO_2 seeps to restrict human and animal access directly into the seep area.
7. Continue to investigate and evaluate new technology and update the CO_2 Seep Containment Plan design, as necessary, and continue to communicate directly with the BLM and the towns of Midwest and Edgerton regarding any changes to the Plan.

The operator also began to employ "water curtain" technology—a series of water injection wells designed to confine CO_2 to a particular phase—and to monitor wells to check for fluid migration outside the development area.[97]

FIGURE 5: STRATIGRAPHIC COLUMN OF UPPER CRETACEOUS STRATA IN THE POWDER RIVER BASIN (PRB)

Mbr, member; Ck, creek; Fm, formation; Sh, shale; Ss, sandstone.



Source: Modified from United States Geological Survey[86]

The operator also developed a series of steps to identify abandoned wells throughout the field and perform corrective action in advance of CO_2 injection into a new phase. An aeromagnetic survey was performed to aid in locating unknown wells.[98] After those wells were located, the following process, described by Meyer, was used to ascertain their condition and perform remedial work as necessary:[99]

1. Where they existed, cement bond logs were examined to ascertain the condition of individual well bores with regard to bonding between the casing and the adjoining formation.
2. For wells that were plugged and abandoned, a pulling unit was set up and the well bore drilled from the top of the surface conductor to the bottom of the target formation to remove any accumulated debris (cement, bridge plugs, tree stumps, etc.).
3. For those wells with cement bond logs, if insufficient or inadequate bonding was detected, a squeeze cement procedure was used to place cement behind the casing and the cement bond log rerun to validate successful wellbore remediation.
4. For every well, a casing mechanical integrity test was run. This required pressurizing the wellbore and monitoring it, to see if any pressure falloff occurred. If not, the wellbore was competent.
5. When pressure fall off was observed, it was indicative of casing leaks. The leaking section of casing was first identified and then re-sealed by squeeze cementing. In extreme cases, it was necessary to install a liner over the leaking section.

In addition to aerial and surface magnetic detection techniques, the BLM lists spectroscopy and well file research as methods used to identify undocumented wellbores.[100]

Despite these efforts to address seeps from wells, faults, and fractures, it appears that seeps continue to be an issue at the field. In August 2012, the Wyoming Department of Environmental Quality served Anadarko Petroleum with a Notice of Violation and Order for "the unpermitted release of a pollutant (CO_2) into a water of the state resulting in chemical changes to the water quality.[101] Gas was observed bubbling in Castle Creek, and water quality analyses revealed that pH levels were below the Wyoming standards for surface waters. Anadarko was ordered to identify and remediate the source of the leak and continue to monitor the pH of the creek. In May 2016, staff at Midwest School, located above the Salt Creek Field, reported a strange odor, and subsequent air quality testing revealed high levels of carbon dioxide as well as volatile organic compounds and methane.[102] As of mid-June 2016 the field's operator, Fleur de Lis, had "plugged one leaking well near the school, worked on another six, and was continuing to monitor as many as 30 other wells in the area."[103] Several homes were temporarily evacuated, and classes for Midwest School students were held at a different location for the remainder of the school year.[104]

DISCUSSION

There does not appear to be a comprehensive, publicly available assessment of the total volume of CO_2 that has seeped to surface since the start of CO_2 injection at Salt Creek. The rate of leakage reported in the BLM Phase III/IV Environmental Assessment (EA) (12 MCFD) is small relative to the reported injection rate at the time of the incident (approximately 0.008 percent of the average daily injection rate at the time).

However, this represents an average seepage rate, and the BLM EA does not include an estimate of the total duration of the seeps. As stated above, these seep rate data were collected for the purpose of air dispersion modeling in order to help determine human health risk in the event of a well blowout, not for the purpose of determining the total volume of CO_2 that seeped from the field. No upper bound can be inferred for the leaks on the basis of these measurements, and it does not appear that any attempt was made to determine the total leaked volume.

Regardless of the actual leakage rate and total leaked volume, the Salt Creek example highlights the need for comprehensive site characterization and corrective action before CO_2 injection commences, as well as ongoing monitoring during injection. It also highlights the need for proper regulatory oversight and enforcement. Based on available data, it appears that the leakage is likely not large enough to call into question the viability of sequestration in the EOR setting in general, but large enough to call for significant improvements in the operation, regulation, and oversight of EOR projects that also claim to sequester CO_2.

Furthermore, incidents like this call into question the suitability of EOR fields for geologic sequestration in the eyes of the public and stakeholders. Reported incidents of dead animals in the immediate vicinity of the leaks at Salt Creek could further exacerbate a backlash against CO_2 injection, even though these have not been and may not be definitively linked to the leaks.[105] Nonetheless, we believe that proper regulation and enforcement could and should have prevented such a situation at Salt Creek.

The heart of the problem is that the operator failed to take basic steps to predict and prevent leakage before beginning injection in the field, and these steps were not required by regulation. The BLM reports suggest that efforts to detect undocumented or problematic wells were not undertaken until after surface seepage of CO_2 began.

Anadarko also subsequently used repeat 3D seismic surveys (referred to as "4D seismic"), stating that the technique "improves confidence in CO_2 containment," has led to decisions relevant to "when to WAG [and] pattern realignment,"[106] "helped characterize reservoir heterogeneity" and was used "in geologic modeling and reservoir simulation."[107] Repeat 3D seismic surveys are not the norm in EOR operations due to their higher cost compared with other geophysical monitoring techniques but can be highly effective in tracking CO_2 movement.[108] Depending on the nature of the CO_2 seeps in the field, which still appears not to have been completely established, they may be of varying usefulness in this case.

Overall, the actions taken to characterize the geology more comprehensively and remediate existing wells at the Salt Creek Field in response to the CO_2 seeps, ranging from magnetic surveys to reworking all existing wells in the field, indicate that these types of activities, which some operators may view as overly cumbersome or expensive, can be performed within the context of commercial EOR projects and may be necessary to ensure CO_2 is contained in the target injection zone.

Lax Class II regulations and their lack of focus on identifying, assessing, and mitigating potential leak pathways contributed to the events at Salt Creek. We believe that such events would have been preventable under stronger regulations and enforcement, such as those required under Class VI.

Specifically, the more comprehensive site characterization requirements for Class VI wells require a detailed analysis of the geology of the injection site to determine geologic suitability. Similarly, the requirements for determining the area of review to look for pathways by which injected fluids may reach groundwater are much more comprehensive for Class VI than for Class II wells. Class VI rules require operators to perform sophisticated modeling to predict CO_2 movement, including a plan to delineate, periodically review, and if necessary update the AoR designation. Typical practice for Class II wells is to default to a ¼-mile fixed radius, an approach that the EPA itself has recognized may not be sufficiently protective, as discussed previously.[109] Once the AoR is determined, operators of Class VI wells must identify any penetrations of the confining zone and, in the case of wells, ensure that those wells have been properly constructed and (if relevant) plugged and abandoned. Operators of Class II wells are required only to identify "known wells" that penetrate the injection zone. Furthermore, as explained earlier, rule-authorized wells were grandfathered into the Class II program, exempting operators from the requirement to delineate an AoR or perform corrective action. Additionally, Class II rules do not require operators to take into account production history, well patterns, or the planned injection and withdrawal ratio when determining the AoR, all of which are key to characterizing CO_2 movement in the subsurface. Table 5 outlines some of the federal Class II provisions most relevant to this incident, and contrasts them with the equivalent Class VI provisions.

TABLE 5: COMPARISON OF CLASS II VS. CLASS VI REGULATIONS THAT MIGHT HAVE PREVENTED LEAKAGE AT THE SALT CREEK CO_2-EOR PROJECT

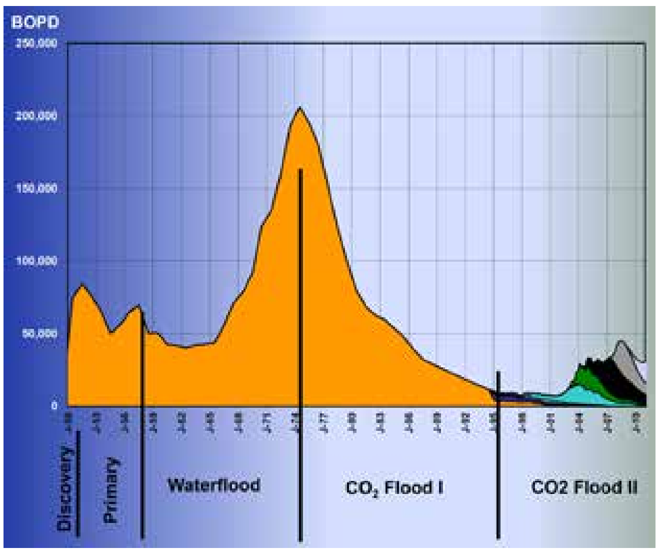
Requirement	Class VI (Geologic Sequestration)	Class II (EOR)
Site Characterization		
Wells must be sited in a geologically suitable location	X	
The geologic system must have:		
An injection zone with sufficient properties to receive the total anticipated volume of injectate	X	
A confining zone:	X	X
Free of transmissive faults and fractures	X	X
Of sufficient areal extent to contain injected and displaced fluids	X	
With sufficient integrity to allow injection at maximum proposed pressure without initiating or propagating fractures	X	
Area of Review and Corrective Action		
The owner/operator must delineate an area of review (AoR) by:	X	X
Performing computational modeling that takes into account the physical and chemical properties of the CO_2 and is based on the available site characterization, monitoring, and operational data	X	
Calculating a "zone of endangering influence" or using a fixed 1/4-mile radius		X
Within the AoR, owner/operator must:		
Identify all penetrations (e.g. mines, wells, etc.) of the confining zone	X	
Identify all known wells that penetrate the injection zone		X
Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information required	X	
Determine which abandoned wells have been plugged in a manner to prevent the movement of CO_2 and fluids into USDWs, including using CO_2-compatible materials	X	
Perform corrective action on all wells in the AoR for which it has been determined that corrective action is needed, using methods designed to prevent movement of fluids into USDWs, including the use of CO_2-compatible materials, where appropriate	X	

THE SACROC UNIT, SCURRY COUNTY, TEXAS

A counterexample to the Salt Creek case is offered by the Scurry Area Canyon Reef Operators Committee (SACROC) unit in the eastern Permian Basin of Texas. SACROC was the site of the first commercial CO_2 flood, starting in 1972, and is the oldest continuously operated CO_2-EOR field in the United States. The operator at the time, Chevron Corp., transported CO_2 220 miles from natural gas processing plants in the southern part of the basin for injection at SACROC. The success of this project provided the platform for the growth of CO_2 flooding in the Permian Basin and eventually led to the construction of three major CO_2 pipelines connecting the Permian Basin oil fields with natural underground CO_2 sources in Colorado and New Mexico. These sources supply the bulk of the basin's CO_2 use today.[110]

The SACROC unit has a complex history. Comprising about 98 percent of the Kelly-Snyder oil field, it was discovered by the Standard Oil Company of Texas in November 1948. From 1948 to 1951, more than 1,200 producing wells with 81 individual operators were drilled in a formation known as the Canyon Reef complex.[111] Secondary production and water injection had started by 1954, directly after the formation and approval of the SACROC "unit." Chevron initially operated the unit. Pennzoil Co. later took over the operation until its upstream operations were merged with Devon Energy Corp. Kinder Morgan bought Devon's interest in SACROC in June 2000.[112,113]

FIGURE 6: PRODUCTION HISTORY FOR SACROC



Source: Kinder Morgan CO_2 Company LP.

Initial efforts at CO_2 flooding were largely of the immiscible type. Upon taking over the field, Kinder Morgan aimed to increase and sustain the pressure in the field and moved the flood into the miscible regime, with corresponding increases in production rates. By 2012, the company was operating 400 producer and 450 injector wells and injecting 1 billion cubic feet per day (BCFD) of CO_2 (18.9 million metric tons per year) total, of which 120 million cubic feet per day (MMCFD) (2.3 million metric tons per year) was "fresh" CO_2 (i.e., CO_2 that is not separated from the produced oil and reinjected, but imported afresh).[114] According to Kinder Morgan, more than 175 million metric tons of CO_2, primarily from a natural source in Colorado, were injected at SACROC for EOR between 1972 and 2010 (See Fiure 6).[115]

Clearly, SACROC has a complex production history and several potential leakage pathways in the form of hundreds of old and new wells; thus it makes an interesting and valuable case study in terms of CO_2 retention and potential groundwater contamination. SACROC was the subject of a study by the Southwest Regional Carbon Sequestration Partnership from 2006 through 2010. Researchers from the Bureau of Economic Geology at the University of Texas at Austin led a project that studied the groundwater in the field to establish whether CO_2 injection into the deep subsurface had degraded shallow drinking water resources.[116] Staff from New Mexico Tech also participated.

The researchers performed extensive groundwater monitoring within an area of approximately 1,000 square miles and supplemented their data with the historical database from the Texas Water Development Board (TWDB). The field study found no trend of preferential degradation below drinking water standards in areas of CO_2 injection (inside SACROC) compared with areas outside as a result of CO_2 injection over 35 years in the deep subsurface (6,000 to 7,000 feet).[117] Water samples were tested for analytes for which the EPA has set primary and secondary drinking water standards. While some samples from both inside and outside SACROC had some analytes in excess of EPA standards, the researchers found that "the percentage of samples with analytes in excess of USEPA standards is higher outside than inside of SACROC." The authors concluded that "the quality of shallow drinking water over SACROC has not been impacted by CO_2 injection," calling this "strong evidence that it is possible to safely sequester CO_2 in deep subsurface reservoirs."

Several factors could be contributing to SACROC's success in isolating CO_2 from the overlying aquifer for now.[118] First of all, the injection zone is at significant depth (6,000 to 7,000 feet) and is overlain by multiple seals. The SACROC unit, the main part of the Kelly-Snyder Field, is located in the southeastern segment of the Horseshoe Atoll within the Midland Basin in western Texas. The atoll itself is a 282-kilometer-long, 914 meter-thick trend of fields with a total area of 15,540 square kilometers, and it is a reef mound. The Wolfcamp Shale Formation, about 150 meters thick, is the primary caprock overlying the Cisco and Canyon Formations that are the main oil-bearing formations and the CO_2 injection zones (See

Figure 7).[119,120] In addition, several secondary sealing layers consisting of mudstone, shale, and evaporites (all of which are known for their ability to limit the movement of CO_2) lie between the primary seal and the drinking water horizon. Finally, due to the fairly recent history of exploration and production at the unit, well records at SACROC are good, and the potential for unknown well bores in the area is greatly reduced. This enables the operator to have a handle on which wells to remediate and/or monitor and avoids the potential for an improperly abandoned, unknown well to act as a conduit for CO_2 leakage, as in the case of Salt Creek.

It is worth noting that the current operator, Kinder Morgan, exceeds the federal regulatory requirements of Class II on several fronts. The company describes the components and materials it used in the tubing, casing, and packers as well as the practices it used to ensure wellbore integrity for new and old wells at SACROC, as well as its maintenance and work-over regimes, which go beyond what is required in a number of respects.[122] Nonetheless, this does not mean that the operation is free of incidents. Table 6, below, contains those incidents listed by the state regulator in Texas (the Railroad Commission) for the period of Kinder Morgan's ownership and operation of SACROC. These represent common human errors or equipment failures that may be encountered in an oil field and do not call into question the notion of safe sequestration of CO_2. However, they do point to the need for sound operating practices and procedures, as well as regulatory oversight and enforcement. Without these, such incidents can multiply and intensify to the point where the potential for CO_2 leakage from the operation ceases to be insignificant.

TABLE 6: BLOWOUTS AND WELL CONTROL PROBLEMS IN DISTRICT 8A FOR THE KELLY-SNYDER FIELD IN THE SACROC UNIT (SCURRY COUNTY, TEXAS) FOR OPERATOR KINDER MORGAN PRODUCTION CO. LLC

Date	Well #	Fire	H2S	Injuries	Deaths	Remarks
6/11/2009	260-04	N	Y	0	0	5-6 homes evacuated as a precaution. Well was leaking from bradenhead or casing annulus. H2S was monitored the entire time.
12/2/2008	177-04	N	Y	0	0	
11/2/2007	178-01	N	N	0	0	Bottom valve failed while changing out master valve on tree.
6/25/2007	36-5	N	N	0	0	Contractor broke casing nipple.
6/14/2007	5203	N	N	0	0	Operator snagged a valve on the well casing.
2/15/2006	27-09	Y		0	0	Pipe nipple blew out.
2/12/2006	215-04			0	0	Valve on tubing/casing annulus failed.
8/2/2004	293-04		N	0	0	Sub pump mandrel corroded.

Source: Railroad Commission of Texas website, updated 01/04/12, http://www.rrc.state.tx.us/data/drilling/blowouts/district8a.php.

SUMMARY AND CONCLUSIONS

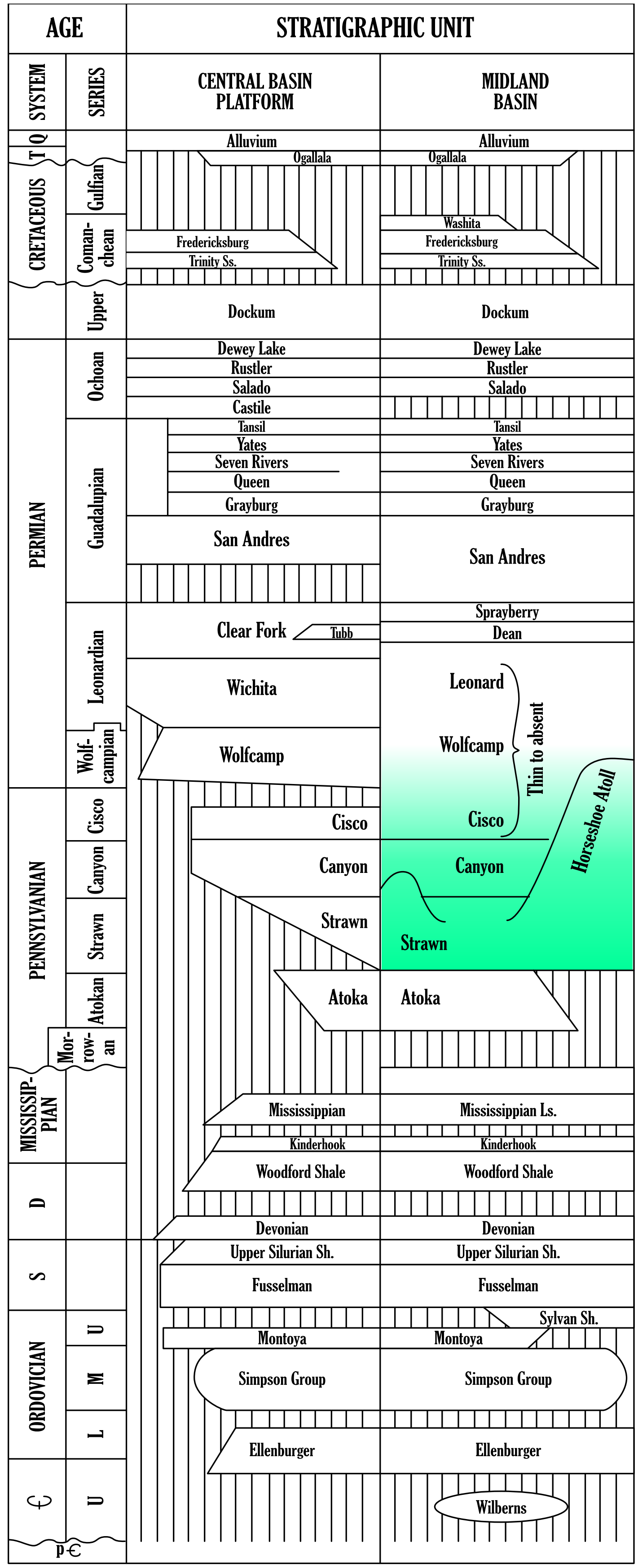
Proper site characterization and corrective action could have prevented some of the CO_2 leaks that occurred at Salt Creek. Although the operator eventually remediated faulty wells responsible for at least some of the seepage, this was only after CO_2 had already migrated to the surface. The more strict Class VI requirements would likely have prevented this migration from happening in the first place. Particularly for fields with very long production histories, like Salt Creek, the rule-authorized well loophole and lax area of review and corrective action requirements may allow improperly constructed or abandoned wells to go uncorrected.

The publicly available analysis for Salt Creek indicates that the seepage was only partially remediated by correcting deficient wells, suggesting that other pathways may exist.[123] Federal Class II site characterization, area of review, and corrective action rules are not adequate to ensure that all potential migration pathways are identified, assessed, and remediated if necessary. The more comprehensive Class VI site characterization requirements would likely have resulted in the identification and remediation of potential migration pathways before injection began. If the objective had been to permanently sequester CO_2 as well as produce oil, the Class VI siting requirements might have even ruled out Salt Creek as a candidate field due to the unacceptable risks of leakage from both man-made and natural pathways.

SACROC, on the other hand, serves as an example of a field that appears to have had little to no effect on local groundwater quality despite many years of CO_2 injection. More reliable well records, a deeper reservoir overlain by multiple sealing layers, and operator practices that exceed the minimum federal Class II standards likely have all contributed to this. From a commercial standpoint, SACROC has been a successful project, which shows that the commercial realities of EOR and the protection of groundwater can both be served at the same time. The project does not, however, constitute evidence that the Class II regime is adequate to produce such results, and the operator admits to exceeding those requirements.

The case studies show that not all oil fields are suitable for permanent sequestration of CO_2, and that the current Class II regulations are insufficient to screen out fields that should not be utilized for that purpose. Even at fields that are suitable for permanent sequestration, Class II regulations alone are inadequate to ensure that CO_2 will be permanently retained in the subsurface.

FIGURE 7: GENERALIZED STRATIGRAPHIC COLUMN FOR SACROC, INTERVAL OF INTEREST HIGHLIGHTED



Source: Modified from Reeves, 2007.[121]

Chapter 6: Challenges and Benefits of CO_2-EOR Fields as Sequestration Sites

CO_2-EOR developed as, and still fundamentally is, a commercial operation with an objective of maximizing profit for the operator. The purchase of CO_2 to inject is usually the largest operating cost for an EOR project, and this creates an incentive to reduce losses of CO_2, either in the subsurface or in aboveground processing operations.[124] However, this does not mean that losses or migration are entirely eliminated, or even minimized.[125] The degree of diligence, effort, and expenditure that goes into reducing migration of CO_2 in the subsurface outside authorized or intended zones and the escape of CO_2 to the atmosphere will depend on the relative (real and perceived) costs of prevention and remediation, the degree of oversight and effectiveness of enforcement by the regulator, the operator's corporate attitude, and ultimately the price of CO_2.

For example, when preparing a field for CO_2 injection, an operator will have to make decisions within a wide range of possibilities about how much time, effort, and capital to expend to convert the field. Will the operator use existing wells without any modifications and construct new wells as cheaply as possible, or will it instead develop a comprehensive strategy to locate and rework all existing wells and go to the added expense of some preventive measures to reduce the possibility of CO_2 escape from new wells (including adopting particular practices and materials for cementing)? Or will the operator opt for something in between?

The same applies for the amount spent on monitoring CO_2 and its behavior. An operator could choose to monitor only basic quantities such as pressure or choose to undertake additional monitoring using geophysical methods, direct sampling at observation wells, or other methods. Ultimately, as long as the operation is deemed "compliant" with laws and regulations, operators may choose to spend less up front and remediate wells, migration, or leaks only if the need arises, or they may decide to spend initially on prevention and detection in order to avoid future costs. Some operators, instead of making sure that all operations are always compliant, may even bank on regulators' not discovering all instances of noncompliance and be prepared to pay fines for those that are brought to light.

Below we point out some of the practical realities of CO_2-EOR that have implications for the security and permanence of CO_2 storage in those fields. This is not meant as a complete point-by-point examination of all possible advantages and disadvantages of CO_2-EOR, but rather as an overview of a few important dimensions that have a direct impact as well as policy or regulatory implications.

PRACTICAL DIMENSIONS OF EOR

OLDER WELLS AND THEIR IMPLICATIONS

Wells are by far the largest source of risk to CO_2 containment in a generic EOR operation. Oil fields that are candidates for CO_2-EOR may contain wells with a large range of ages, including old ones where mechanical integrity problems are more likely due to out-of-date practices as well as corrosion and other wear and tear on mechanical components. The presence of a large number of wells by itself greatly multiplies the potential leakage pathways that must be assessed, monitored, and managed. The locations and condition of wells in the field are not always known due to a lack of records and no requirement under federal Class II rules to actively identify and assess all such wells.[126] As a result, some of the oldest and potentially most problematic wells may not be detected prior to injection. In addition, well records, if they exist at all, can be inaccurate and unreliable. For example, objects not noted in the official well record have been found when wells were reentered.

Reentering every old well in a CO_2-EOR field in order to assess their condition may add significant costs. In addition, particularly in old fields with long operating histories, the presence of unpredictable foreign objects in some of these wells may make reentering them difficult or impossible. Federal Class II regulations impose only the generic requirement that injection wells "be cased and cemented to prevent movement of fluids into or between underground sources of drinking water."[127] In practice, this means that the specific design and construction of each well is left almost entirely to the discretion of the operator, with the result often being that wells are not cemented between the surface casing down to just above the injection zone. This absence of specific casing and cementing requirements makes cement integrity even more important if zonal isolation is to be achieved, since any breach in the casing along any uncemented interval could result in a direct release of CO_2 outside the injection zone. When primary cementing operations fail to achieve necessary isolation, remedial or "squeeze" cementing must be performed. Unfortunately, remedial cementing is not straightforward or foolproof.[128]

CORROSION

In CO_2 floods, carbonic acid is produced as a result of the CO_2-water interaction. This can create a corrosive environment, which in turn can result in the degradation of commonly used well components in the absence of techniques or materials to prevent such corrosion. It is common for the tubing to develop leaks, at which point it is usually pulled and replaced. The cement can also suffer as a result of the acidic environment and has been reported to be entirely missing below the packer at times.[129] If a transmissive pathway through the cement—such as bubbles, voids, or fractures—and an upward gradient are present, acidic fluid may be able to cause cement degradation above the injection zone, which may in turn create a pathway for CO_2 or other fluids to migrate outside of the confining zone into unauthorized zones or potentially to the surface. This threat may be greater in Class II wells, given that they are not required to have production casing cemented to surface. In cases of severe corrosion, more serious intervention may be required or the well may need to be plugged and abandoned.

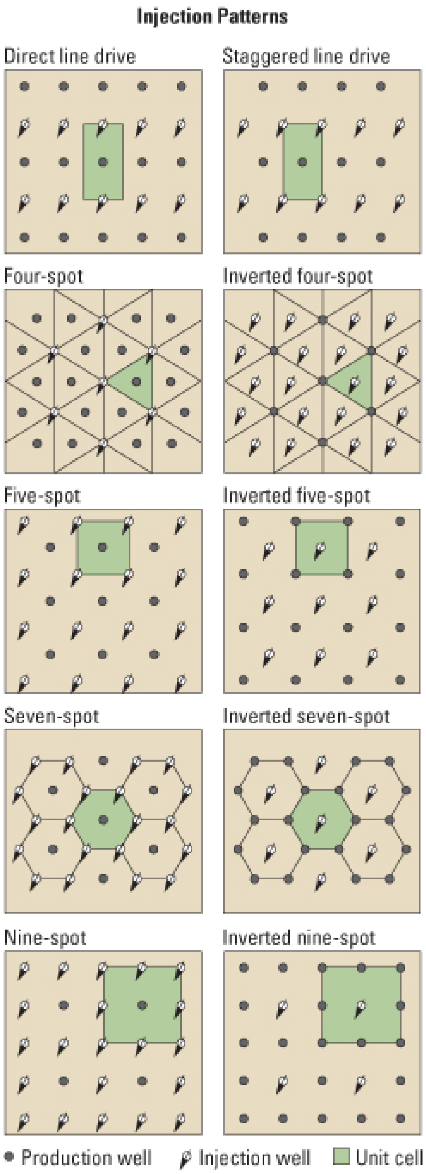
In a remedial or "squeeze" cement job, an operator perforates the casing above the existing cement and attempts to inject new cement in order to create a seal. It typically takes three attempts to perform a successful remedial cement job.[130] Less than successful remedial jobs might be able to mitigate large leaks, but not necessarily in their entirety. Squeezing cement into openings in the casing for remediation is inherently difficult and often unsuccessful due to the high viscosity of the cement.[131] In addition, perforating the casing creates additional weaknesses that could exacerbate mechanical integrity problems. It is often best (and potentially more economical) to abandon an old well and drill a new one rather than to attempt a remedial squeeze. For this reason, Dusseault et al. emphasize that "getting it right the first time—i.e., creating a robust seal during primary cementation—was uniformly agreed by industry and regulators to be the best approach for reducing leakage development over the operational and post-operational lifetime of a well."[132]

The practical implication is that, when assessing the likely integrity of wells in a CO_2-EOR operation, the mix of new and old wells is of importance. In addition, if sufficient budget is not available for remedial cementing or plugging of old wells and drilling of new ones, there may be reason to expect an increased incidence of mechanical integrity failures and potential CO_2 leakage (although not all mechanical integrity failures result in leakage). Unless operators engage in proactive mechanical integrity testing and employ monitoring systems to detect leakage, prolonged leakage and loss of integrity at one or several wells may occur.

THE RANGELY-WEBER FIELD

Chevron operates the Rangely-Weber Field, in Colorado. The field was discovered in 1933, commercialized in 1943, and unitized[133] in 1957. Water flooding started in 1958, and CO_2 flooding began in 1986. According to a study by members of the CO_2 Capture Project, Rangely is a good example of a CO_2 project where old (1940s vintage) wells have been used successfully.[134] The wells in the field span a number of decades, with 478 of them drilled between 1944 and 1949, 416 wells drilled mostly between 1966 and 1987, and 48 modern wells. The study states that "[w]hile minor UIC issues do arise (as they do with all Class II injection projects), there have not been the dramatic failure rates and catastrophic failures that were predicted with the CO_2 flood in the aging well bores. On average," the report continues, "the injection wells have about a 10-year mean time between failure for UIC. Failures are typically caused by packer or tubing failures causing pressure in the tubing/casing annulus and are repaired by running new or inspected tubing with a new downhole assembly (packers, tailpipe, etc.). On occasion, a liner is run in the 7" casing to ensure well bore integrity."[135]

FIGURE 8: TYPICAL INJECTION PATTERNS FOR EOR. DOTS REPRESENT INJECTION AND PRODUCTION WELLS, AND SHADED AREAS SHOW THE PATTERNS



Source: Schlumberger Oilfield Glossary.

CO_2-TRAPPING ATTRIBUTES OF AN EOR FIELD

CO_2-EOR fields have certain advantages as a setting for CO_2 sequestration. The oil field is in many ways "self-characterized," meaning that the trap and seal have been proven over geologic time by the mere fact that oil and other fluids have been trapped for tens of millions to hundreds of millions of years. Without the trap and seal, oil would not have accumulated to form the field as it is known today. However, not all fields are fully sealed. There are examples of fields that have leaked and continue to leak, as is the case with some fields in California where seeps are commonly witnessed.[136] For those fields, the discharge rate is likely to be comparatively low and occurring over geologic time scales, otherwise the continued accumulation of oil would not have been possible. But if such a field were to be used, this would need to be studied and proven in the context of an EOR project. Given that the properties of supercritical CO_2 and oil are different (in terms of viscosity, density, and so on), a geologic unit that has retained oil may or may not retain CO_2 exactly as well. However, the uncertainty of "focused-flow leakage" is greatly reduced compared with a formation that has never proven its trapping ability.[137] It may also be theoretically possible for a seal to become fractured due to the reduced pressure in a reservoir that may follow primary oil production, although to the cited author's knowledge this has not yet been documented or geomechanically modeled in the published scientific literature.

In general, more is likely to be known about the structure and properties of a reservoir in an EOR setting than at a greenfield site. The injectivity of a reservoir will probably be well known or inferred from the production history (which is often held in regulatory files). It is likely to be understood at an aggregate level for the field, however, and not necessarily for individual wells. In addition, robust reservoir models may have been prepared to aid with production optimization, although not all details may be publicly known.[138]

While large numbers of wells in an oil field can be a disadvantage from a migration pathway standpoint, they can be an advantage for geologic and reservoir characterization. Many wells may have open hole petrophysical logs and/or whole or sidewall cores, which provide information about the stratigraphy, structure, and petrography. Geophysical surveys (seismic or other) are sometimes performed in order to better understand the reservoir and characterize its structure. The presence of available wells also enables direct measurement methods to be used in place of indirect monitoring, as well as hydrologic testing; both are preferable to some indirect techniques in terms of reliability and accuracy.[139] However, the commercial nature of a CO_2-EOR operation also means that certain elements of diligence that would be required in a pure sequestration operation may be overlooked. The characterization of the subsurface, for example, will likely focus on the reservoir itself and not on the overlying intervals, which could determine the fate of leaked CO_2. Stacked reservoirs may also be present in oil field settings, where oil and gas are produced from shallower reservoirs. Brine or other fluids may also be injected into these shallower intervals for either disposal or EOR (potentially including CO_2-EOR). Monitoring in these shallower zones for signs of leakage from the CO_2 injection zone may be confounded by these other operations, making above-zone monitoring more challenging or impossible.

OPERATIONAL CONSIDERATIONS

The working unit in a typical CO_2-EOR field is the injection, well, or flood "pattern." A pattern is a spatial arrangement of injection and production wells designed to optimize the areal sweep of the reservoir.[140] There are several possible configurations, which are repeated throughout the field (see Figure 8). In order to track sweep efficiency and optimize field operations, the process of "pattern balancing" compares the volumes (or mass) of injected and produced fluids in a pattern and sometimes across neighboring patterns and is the main tool used by operators to monitor and assess field performance.

However, pattern balancing itself does not focus on how much CO_2 is leaving the patterns, but instead on the CO_2 that is injected and produced. Active methods for detecting CO_2 leaving the pattern are not typically used. This means that missing CO_2 may be noticed only if balancing the pattern proves impossible, but in that case allocating the missing CO_2 to specific wells can be difficult, especially when the CO_2 moves between patterns. The result is that gross imbalances will likely be caught, but CO_2 migration will not be detected or tracked accurately. The quantities that are monitored and measured are primarily volume and pressure, which are a reasonable starting point but not sufficient by themselves to establish sequestration or track CO_2. Pattern balancing therefore is a good step, but not suitable by itself for ruling out leakage of CO_2.

The presence of nearby wells owned and operated by another entity may also create problems with keeping track of the injected CO_2. If injected CO_2 migrates into a zone operated by another producer, it could be produced and vented without ever being accounted for. Although operators have an incentive not to lose CO_2 in their patterns, this is not a requirement. Methods aimed at minimizing loss, such as the use of water curtains, have never been tested rigorously in terms of their effectiveness; rather, they are used in the field as practical methods either because they work well enough on economic grounds or because there are no alternatives. In some circumstances, communication between fields may be detectable through interference testing, whereby an injection in one field is compared against the pressure response in the other. But this may not be effective if the fields are not in immediate proximity, and it may not be pursued if regulations do not mandate it. Moreover, such tests are subject to interpretation and are not necessarily definitive.

TIME AND PLANNING HORIZON

The commercial time horizon for a CO_2-EOR flood (a few years to decades) is shorter than the time horizon of interest for achieving effective sequestration of CO_2 from the atmosphere (centuries, or longer). CO_2-EOR thus lacks the long-term outlook of a sequestration operation specifically designed for the purpose. The focus of CO_2-EOR is the operational phase and not the post-closure phase. Migration of CO_2 out of pattern, out of authorized zones, or to the atmosphere is possible after injection and production cease. Standard cement plugs that are used in the field to decommission wells have not been designed to withstand the presence of CO_2 in the long term and could prove to be leakage pathways long after the operator has walked away from a field.

In the same vein, expenditures and preventive investments in features or technologies that would decrease the risk of leakage or migration may be made in a commercial CO_2-EOR setting, or may be deferred to a later time. In the Illinois Basin Decatur Project, which is not a CO_2-EOR project but instead injects in a saline formation, additional steps were taken to prevent potential leaks from the injection well in the future.[141] Instead of stainless steel tubulars, 13-chrome steel was used for those that would contact CO_2. In addition, CO_2-resistant cement was used in the injection well. These steps are not routinely undertaken in a commercial CO_2-EOR project and may not be necessary or recommended in all cases, but rather are examples of the types of preventive measures that should be considered. Rather than spending preventively, companies usually prefer to postpone these costs for the future until there is a reason to intervene. By that point, however, intervention may be more difficult for some of the reasons outlined above, or simply too late to prevent migration or leakage.

The point at which ownership of a field changes is important in ensuring continued and consistent stewardship of the stored CO_2. When a field changes hands, well files are typically handed over. These contain information such as the production history of the well, logs, and any seismic surveys that might have been conducted. Interpretive information such as reservoir models is not handed over, however, and the new owner or operator has to essentially retrace some of the previous one's steps in establishing an understanding of the field. It is distinctly possible that knowledge about the field and its geology that is important to CO_2 retention will not be passed on to the new operator, thereby increasing the risk of future mishaps.

Finally, even after tertiary recovery, conventional oil fields are expected to still contain an average of 35 to 50 percent of the original oil in place.[142] If oil companies develop advanced EOR techniques, operators may choose to reenter CO_2-EOR fields at a future date to recover these reserves. It is possible that such operations could necessitate removing CO_2 from the field ("blowing down" the field), in which case the operator would need to ensure that the CO_2 is not released to the atmosphere if it has already received credit for being sequestered.

COMMON GROUND AND TENSIONS BETWEEN PROPER MONITORING AND COMMERCIAL CO_2-EOR OPERATIONS

A number of steps may be taken in a commercial CO_2-EOR setting that are potentially beneficial both for the production efficiency of the field and for ensuring greater environmental integrity. However, some tension may exist between cost-cutting and production gains. In general, these steps shed light on the location, properties, and behavior of the injected CO_2, enabling operators to refine their understanding and modeling of the field and adjust operational parameters to optimize production. Below we provide some examples of available techniques for achieving this, without attempting to compile a comprehensive list:

- Pulsed neutron logs detect fluid properties in the immediate vicinity of the well bore and can be used to infer the nature of the CO_2-water-oil contact there. They cost about $10,000 to $20,000 per well per run and would be deployed approximately once per year.
- 4-D seismic monitoring is useful in showing movement of the CO_2 plume, including movement out of the intended injection zone, and also in gaining a better understanding of field structure. However, the technique is not likely to be used by many operators due to its expense. It may also be redundant if a sufficient network of producing wells at intervals above the primary injection zone exists to enable sufficient direct sampling of produced fluids for CO_2. In some floods, however, not even basic pressure measurements take place, let alone periodic produced fluid sampling. Beneficial use of 4-D seismic monitoring has been reported by Anadarko Petroleum at the Salt Creek CO_2 flood (discussed earlier).[143]
- Crosswell or VSP techniques have higher resolution than 3-D seismic techniques and can be used to image the subsurface and gain better understanding of structure and potential flow pathways in great detail. However, this technique provides information on only a small rock volume and therefore is unlikely to be used on every well due to the cumulative expense.
- Drilling new or using existing monitoring wells above the primary seal is an important way to monitor potential CO_2 breakthrough. However, for the operator the primary interest lies within the injection zone and not above it. Thus, such monitoring is not likely to be adopted.
- Tracers can help with understanding the extent and portion of the CO_2 contact in the flood, but these can be difficult to handle well, making it a challenge to obtain consistent, uncontaminated results.
- Temperature logs are used to detect temperature anomalies that may be indicative of a leak. These are already required by Class II.
- Noise logs are used to detect acoustic anomalies that may be indicative of a leak. These are already required by Class II.
- A comprehensive risk assessment for a field for preventive purposes is not prohibitively expensive (in the region of a few hundred thousand dollars at the time of this writing) and can help identify potential problems and pathways in advance.[144] Some components that relate to containment are typically done by CO_2-EOR operators in the field anyway.

Chapter 7: Leakage Pathways and Worst-Case Scenarios

If something does go wrong in a CO_2-EOR project, how severe can the leakage rate be, and what are the possible consequences? Having established that wells are susceptible to failure, and having examined some of the practical realities of CO_2-EOR wells in the field, in this section we take a brief look at leakage from wells and geologic features, some of its traits, and its possible extent in the CO_2-EOR context. This is not intended to be an exhaustive discussion of mechanisms and impacts, but rather a summary of features that are particularly applicable to CO_2-EOR and to preventing or quantifying such leaks.

LEAKAGE PATHWAYS AND CONSTRAINTS ON LEAKAGE RATES

Two main pathways are pertinent to CO_2-EOR sites: wells and geologic features such as faults and fractures. Several studies have attempted to quantify and place bounds on the potential magnitude of CO_2 leakage from storage sites by examining natural and industrial analogues and incidents.

LEAKAGE THROUGH WELLS

Over the years a number of incidents have taken place that provide valuable information on the rate and total volume of leakage from wells. The most rapid releases have occurred during well blowouts. A blowout takes place when an operator loses control of the pressure in the well, resulting in fluids flowing out of the well. This is typically due to mechanical failure of a component or an external event directly affecting the well.[145]

Of the documented CO_2 well blowouts, the largest release rate occurred in 1982 at the Sheep Mountain CO_2 Dome in Colorado, a naturally occurring subsurface CO_2 accumulation that is being produced for the purposes of transporting CO_2 to injection sites. Researchers state that "[f]low rates were estimated between 7000 and 11 000 t CO_2/day, with integrated leakage of —200 000 t (roughly 7 days CO_2 output from a 1 GW coal-fired power plant)." CO_2 also leaked through the soil and fractures in the rock near the well.[146]

The rate of leakage through a compromised well is variable and dependent on the nature of the well failure. The largest rates will occur for wells drilled to great depth (and hence having higher pressure), of large diameter, and with the least obstructions in the pipe. A study that modeled possible rates of CO_2 leakage from a completely unobstructed pipe found a maximum hypothetical CO_2 flow rate of approximately 20,000 metric tons per day.[147] The researchers found that the maximum exit gas velocity, and hence flow rate, is capped by the speed of sound.[148] This theoretical maximum is approximately two times greater than the highest documented actual well leak rate of 11,000 tons per day, which occurred at Sheep Mountain. A blowout like this would be possible only at an unplugged well where a catastrophic event completely compromises its integrity (such as a bulldozer shearing off the wellhead); it would not be triggered by smaller component failures.

It is unlikely that leakage at such a high rate would go unnoticed for a significant period of time. The length of time before detection depends on several factors including the particular well configuration, whether the well is equipped with automatic sensors and alarms, the remoteness of the well, and how often personnel perform site visits. At high leakage rates, adiabatic cooling causes the CO_2 to freeze at the wellhead, making the problem visually obvious. Large leaks would also likely be audible. At wells with slow leakage, however, incidents may be more difficult to detect, and leakage may go uncorrected for a longer period.

LEAKAGE THROUGH THE CAPROCK AND FAULTS

Natural analogues for leakage through faults in a sedimentary sequestration project include volcanic settings and natural subsurface CO_2 accumulations. These examples are not necessarily good analogues for bounding possible leakage rates because of the differing mechanisms of CO_2 generation and accumulation. However, they can serve as analogues for potential leakage pathways. For both analogues, leakage pathways include compromised caprocks (due to seismic activity or over-pressurization) and transmissive faults and fractures. Faults and fractures can be fast paths for large quantities of CO_2 to reach the surface. Leakage through the caprock or through faults or fractures is also more difficult to remediate than leakage through compromised wells. Unlike wells, faults and fractures cannot be remediated and plugged. In order to stop or slow leakage, injection rates may have to be significantly decreased or injection may need to be halted completely.

A related concern is the possibility that injection pressure and increased reservoir pressure will exceed in situ stress and induce slippage along faults that intersect the injection reservoir, causing earthquakes or causing previously sealing faults to become transmissive. Expert opinion varies on the overall probability of either situation occurring and the overall level of risk associated with each. Induced seismicity associated with underground injection is a well-documented phenomenon.[149] A 2013 study concluded that CO_2 injection in the Cogdell Field north of Snyder, Texas, may have contributed to triggering 18 earthquakes of magnitude three and greater that occurred between 2006 and 2011.[150] However, a recent study by the National Academies of Science found that no induced earthquakes large enough to be felt at the surface are documented to have been caused by either carbon capture and storage or tertiary oil recovery (EOR).[151,152] A study performed to assess the seal integrity of the Teapot Dome oil field in Wyoming found that the pressure necessary to cause slippage along a reservoir bounding fault, thereby creating a potential leakage pathway, far exceeded the injection capacity of the reservoir, leading researchers to conclude that reactivation of the fault by CO_2 injection was unlikely.[153] In any event, site-specific information would need to be gathered and analyzed in order to assess the risk of a fault slip occurring at a specific injection project.

LEAKAGE THROUGH MULTIPLE PATHWAYS

Combinations of any of these leakage pathways may allow fluids to escape to the surface. The Leroy natural gas storage site in Wyoming experienced several episodes of leakage. The storage reservoir is a fault-bounded anticline, and injection is occurring into the lower Thaynes formation sandstone. In 1978, gas was detected bubbling in a creek and pond above the field. Gas was likely leaking both through wells and through the caprock, which possibly failed due to over-pressurization. It was hypothesized that two leakage pathways were operating:

1. Gas was leaking directly from the storage reservoir to the surface; and
2. Gas was migrating from the storage reservoir to a shallower, secondary reservoir and then to the surface.

Tracers were injected with the gas and were detected at the surface within days to weeks of injection. The leakage pathways could not be remediated, but the rate of leakage was controlled by limiting the maximum reservoir pressure. One study reported that the average annual leakage rate from 1976 to 1981 was approximately 3 percent of the total gas stored.[154] Another study found that the leakage rate totaled about 0.7 percent per year.[155]

Regardless of the leakage pathway or mechanism, if CO_2 is allowed to leave the intended injection zone it may be very difficult to predict or determine how and to where it will migrate through the subsurface. It may be able to travel along multiple vertical and horizontal flow paths that allow it to seep into groundwater or to the surface in unexpected locations. As mentioned above, geologic leakage pathways such as faults and fractures cannot be plugged as such. Leakage through them can only be avoided or mitigated, highlighting the critical importance of proper site selection and geologic characterization.

HOW BAD CAN A LEAKING WELL BE?

The consequences of leaking wells can range from minor to spectacular. At one end of the spectrum, loss of mechanical integrity in a geologic setting that is devoid of drinking water or other resources of value might not be detected or seen as problematic, even if a permitted containment zone has been breached. At the other end, the consequences can be very serious. It is important to note that the following are not examples of CO_2 leakage. Compared with other gases, CO_2 has a nature of its own in terms of toxicity, flammability, explosiveness, and detectability through odor. However, the examples below still hold useful lessons for avoiding leaks of any gas and are indicative of some of the broader consequences of large leakage events, in particular the loss of public trust.

LA SALLE, COLORADO

On February 18, 1984, a lumber showroom in the small town of La Salle, Colorado, blew up (without causing injuries) when natural gas accumulated in an abandoned well underneath it. The well had been abandoned when a municipal water system was set up in 1917. After the explosion, a pipe was employed to vent the gas from the well.[156] The incident caused evacuations and widespread disruption as efforts were made to uncover the location of approximately 200 more wells believed to have been drilled to depths of as much as 1,100 feet.[157] A study by the U.S. Geological Survey determined that the vent gases in La Salle were "almost identical in both chemical and isotopic composition to those produced from the Codell Sandstone Member of Carlile Shale at depths of about 2130 m (7000 ft.)." However, data were insufficient to determine whether the incident had been caused by drilling activity in the area or had occurred naturally.[158]

Regardless of the origin of the gas, the incident demonstrates what would be a rare but plausible outcome from the combination of a flammable gas, well leakage, and orphan wells. It also suggests that significant migration of fluids underground in unexpected ways is possible.

DEEPWATER HORIZON

On April 20, 2010, BP's Macondo well, accessed by the Deepwater Horizon offshore platform in the Gulf of Mexico, blew out, resulting in a massive explosion. Eleven lives were lost, more than 4 million barrels of crude oil poured into the ocean, and the resultant slick covered some 3,000 square miles. Despite the enormous scale of the response effort, it took 87 days to cap the well.[159] In response to ongoing concerns about the safety of offshore drilling, the U.S. Department of the Interior instituted a six-month moratorium on drilling on the Outer Continental Shelf.[160]

The investigation, jointly conducted by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) and the U.S. Coast Guard, concluded that a "central cause" of the blowout was the failure of a cement barrier in the drilling apparatus. The cement job was done by a contractor, Halliburton, but the report states that BP was, as designated operator, "ultimately responsible" for safety on the rig. It also stated that, in the days before the blowout, BP had "made a series of decisions that complicated cementing operations, added incremental risk, and may have contributed to the ultimate failure of the cement job." The blowout preventer, which is supposed to guard against such instances on the ocean floor, failed as well. Inadequate design that renders this device subject to such failure was later identified as the cause.[161]

ALISO CANYON

A well failure was discovered on October 23, 2015, at Southern California Gas's Aliso Canyon underground storage facility in the Porter Ranch neighborhood of Los Angeles. The well proceeded to leak massive quantities of natural gas into the soil and air for nearly four months thereafter. Tens of thousands of families live in the Porter Ranch neighborhood and were affected by this leak. As of January 7, 2016, 2,824 households—about 11,296 people—had been temporarily relocated by SoCal Gas and more than 6,500 families had filed for help.[162,163] Preliminary estimates from the California Air Resources Board (CARB) put the total leakage at approximately 94,500 tons of methane. The maximum estimated leak rate was 1,392 metric tons per day.[164]

The failed well was originally drilled in 1953 as an oil production well and was converted to a gas storage well in 1973, before the UIC program even existed. Well construction practices have evolved significantly since that time, but the well was not updated. At the time of this writing, a "rootcause analysis" was underway to determine the precise cause of the well failure, but current information suggests that the production casing failed at an approximate depth of 500 feet. Although the well was equipped with tubing and packer, the tubing was fitted with flow control equipment including sliding sleeves that allowed the operator to produce gas through both the tubing and the tubing-casing annulus. This reduced the number of barriers present to prevent migration of gas in case of the failure of one barrier. In addition, the upper 6,000 feet or so of the production casing was uncemented, and thus when the casing failed this allowed gas to escape into the annular space behind the production casing and migrate through the subsurface to the surface.

The well was regulated under the flawed Underground Injection Control program run by the California Division of Oil, Gas, and Geothermal Resources. Under this same program, thousands of wells were improperly permitted to inject oil and gas wastewater and other fluids into federally protected drinking water aquifers. Independent audits of California's UIC program found that it is plagued by systemic problems including poor recordkeeping, inadequate staffing, and failure of regulators to perform crucial required tests to ensure that injection wells are mechanically sound.[165]

Chapter 8: Addressing the Gaps

TODAY'S UNSATISFACTORY STATE OF AFFAIRS

As we have described at length above, several problems exist today with the regulation of underground injection. Wells, especially older ones, are inherently prone to defects. The current regulatory language for wells injecting in oil fields under Class II is very broad and general, leaving significant discretion to operators, and was written decades before CO_2 sequestration per se was contemplated. Implementation and enforcement of its requirements have clearly been problematic on many occasions. Most of these problems are not specific to CO_2-EOR but apply to the Underground Injection Program in general.

As a whole, the UIC Program remains largely unchanged since it was created more than three decades ago, despite significant advances in technology and scientific understanding of the environmental and public health threats of underground injection. In our view, the regulation of underground injection in general is in need of significant improvement, both federally and in the states. However, this is not within the scope of this paper. Here we focus more narrowly on injection of CO_2 in the context of EOR as a climate mitigation technique. Under that smaller umbrella, it may seem logical to set aside risks to groundwater and regulation under the UIC program and instead focus on the risk of atmospheric emissions from sequestration sites and regulation under applicable air rules. However, we consider this unwise for two main reasons.

First, some have attempted to make a case that existing Class II regulations by themselves, without any additional air regulations, are adequate to ensure and certify sequestration in oil fields where CO_2 is being used for EOR. Some have gone even further to argue that any additional air regulations would be detrimental to the commercial practice of CO_2-EOR.[166] Therefore, we must evaluate UIC regulations by themselves at face value in terms of their ability to prevent, detect, and remediate atmospheric CO_2 emissions. For reasons elaborated on in previous sections, we consider them insufficient.

Second, existing federal air rules do not fully make up for the shortcomings of Class II. In particular, supplemental requirements under subpart RR of the EPA's greenhouse gas reporting rule are very general and open to interpretation, and they are not mandatory for wells injecting CO_2 in oil fields. Moreover, they are mere reporting requirements. They put no emphasis on precaution or prevention and do not mandate any action should a problem be detected.

We do not contend that the problems highlighted in this report are likely to result in a likelihood or magnitude of leakage that changes the carbon balance of CO_2 sequestration through CO_2-EOR as a whole. In fact, we consider that kind of leakage a very remote possibility. However, geologic sequestration is not the same as oil production in the eyes of stakeholders and the public. Oil production has a very long history and has come to be accepted as a widespread and routine industrial activity, even if some local conflicts arise. Geologic sequestration, on the other hand, is a recent concept that is linked to mitigating climate change. It has been practiced for that explicit purpose only to a very limited extent in comparison to CO_2 injection to enhance oil recovery, and only in recent years.

If the practice is to succeed as an emissions reduction strategy, government assistance will very likely be necessary in the early years. In addition, projects will need to be sited and permitted. Both of these tasks will require support from a broad spectrum of stakeholders and local actors, some of whom are skeptical—often with good reason—about the notion of injecting large volumes of compressed CO_2 underground. The reason relatively little opposition has been registered to date against geologic sequestration—although there are notable exceptions—is that projects and their drivers have been limited. If, however, the pieces fall in place for deployment of the technology at a scale that can make a difference as a climate mitigation strategy, the level of scrutiny will increase sharply. Maintaining an excellent safety and effectiveness track record is paramount, and having a robust and credible regulatory framework in place will be essential to ensuring both this track record and confidence in the practice. This need is even more pressing lately, with a general mistrust of injection running high due to the proliferation of hydraulic fracturing for shale gas and oil, as well as high-profile accidents such as Aliso Canyon.

Regulating all CO_2-EOR operations under Class VI and subpart RR requirements is not necessary or appropriate. But for EOR operations that seek to certify geologic sequestration of CO_2, it is our view that, administered properly, those rules could materially improve on Class II in terms of preventing, detecting, and remediating atmospheric emissions. However, Class VI regulations today exempt the overwhelming majority of existing or contemplated oil field injections, and regulation under Class II appears to be their most likely fate in the near future. Oil and gas operators to date have also uniformly rejected regulation under Class VI, citing prohibitive cost, regulatory burden, and uncertainty.

In our view, this stance is due to several factors: an ideological predisposition against the EPA as a regulatory body and an affinity for the much more familiar state oil and gas regulators that these companies deal with routinely, lack of established precedent on how these regulations will be administered,[167] a misunderstanding of the actual regulatory provisions, and a desire to avoid any added regulatory requirements over and above what has been customary for decades. Even under Class II, virtually no operations were reporting greenhouse gas emissions under subpart RR at the time of this writing—only three Monitoring, Reporting and Verification plan had been filed voluntarily to the EPA by two operators.[168] All other operators had opted to report under subpart UU, which requires much less information.

THE CASE FOR A NEW REGULATORY REGIME

We firmly believe that a new regulatory regime specifically focused on CO_2-EOR best serves the needs of workability in a commercial EOR operation, environmental and public health protection, and credibility of operations. Such a regime would be sensitive to the particulars of CO_2-EOR and address existing shortcomings and concerns. In addition, Class VI was conceived and written primarily with sequestration in deep saline formations in mind. Although a good deal of common ground exists between those formations and oil fields where CO_2-EOR is practiced, several geological, operational, and even logistical differences delineate the two.

As discussed above, there is likely greater confidence in the trapping mechanism at CO_2-EOR projects due to the demonstrated ability of oil fields to trap hydrocarbons. Further, the geology is likely to be better characterized than that of saline projects, due to the long operating histories and large number of wells in the oil field setting. The small number of injection wells that will likely be encountered in a typical saline project (in some cases a single well may suffice) will likely give rise to a continuous CO_2 plume and a pressure front. In an EOR setting, multiple injection points will likely give rise to a body of CO_2 in the subsurface that is much less uniform and continuous, and that does not form a unique plume or pressure front. Importantly, saline injection is likely to elevate pressure in the subsurface since no withdrawal is anticipated.[169] This is in stark contrast to EOR, where substantial fluid volumes are produced, with the result that the pressure in the field remains more balanced. Given that pressure is the primary driver of fluid movement, this has distinct implications for the risk of EOR.

On the other hand, hundreds or even thousands of wells may be present in an EOR operation, compared with just a handful or so for saline sites. This also has distinct implications for risk, given that each well may act as a leakage pathway for CO_2 and other fluids. Leakage risk mitigation in EOR operations is therefore much more focused on wells, particularly given that some of those wells may be of questionable or unknown integrity or history. The nature of the monitoring that is most useful in an EOR field may also be significantly different from what is used in a saline setting. In EOR, monitoring and comparing pressures throughout the field and matching with models and production histories may be more informative than geophysical or other indirect methods that may be best suited to the saline setting.

Some operational and logistical elements of EOR shift the focus of maintaining the integrity of sequestration to areas that may not be a concern in a saline context. For example, arrival of injected CO_2 at production wells that are not prepared to receive it and not connected to the separation and recycling facilities in the field could result in the venting of produced CO_2. Unwanted or even unaccounted venting could also occur if injected CO_2 migrates from an adjacent oil field lease and is produced by another operator who is not involved in the sequestration project. This could happen during or after the sequestration project and has legal and regulatory implications. Finally, the nature of regulation under Class VI is to require a significant degree of diligence on the part of a small number of wells. In an EOR setting, the necessary permits may need to be applied to a much larger number of wells or an entire lease or field, and permitting needs to be expeditious enough (perhaps on the order of weeks rather than many months or years) to accommodate commercial pressure as well as environmental protection.

All this, in our view, dictates a fresh regulatory approach for sequestration in EOR settings as the best path forward for all parties involved.

WHAT DOES CLASS VI REALLY REQUIRE?

Class VI regulations are often portrayed as "prohibitive" within the commercial realities of oil field operations. In some cases, this may reflect an ideological predisposition against EPA regulations or a misunderstanding of the actual regulations. In other cases, it may reflect the fundamental differences between a commercial EOR operation and a greenfield saline injection site, as outlined above. Additionally, given the newness of Class VI regulations, there may not yet be enough of a working precedent for operators to be confident in, and familiar with, the process. If sequestration during EOR is to be regulated under Class VI for an interim period or more permanently, these points will need to be ironed out.

At the very top of the complaint list is the notion that Class VI requires 50 years of post-injection site care. The regulations do specify a default period of 50 years but in fact allow operators to demonstrate that an alternative time frame is appropriate based on site-specific evidence.[170] An oil field with a well-documented structural closure that would limit CO_2 movement in ways that would be absent in a uniformly dipping saline formation, for instance, would be a prime candidate for demonstrating that an alternative period is appropriate.

Under a grandfathering provision, owners or operators seeking to convert existing Class I, Class II, or Class V experimental wells to Class VI geologic sequestration wells must demonstrate that the wells were engineered and constructed to meet the general objectives of Class VI well construction requirements and ensure protection of USDWs, in lieu of meeting the specific well construction requirements in Class VI. All other requirements of Class VI then apply. This provision enables Class II wells to transition to Class VI without complete work-overs or redrilling of wells in an existing EOR operation. Given the practices and risks analyzed in this report, this provision may not be appropriate in all cases.

A PATH FORWARD

We believe that the fairest and most transparent approach would be for the EPA to examine its regulatory options under existing authorities and propose a time line for a rulemaking that will codify a tailored set of requirements specifically targeting concurrent EOR and geologic sequestration. Such an approach would enable a fresh and detailed examination of the risks, regulatory needs, and commercial constraints and would circumvent the current debates on the merits and deficiencies of existing injection well classes and reporting regimes.

In order to strive for sound, problem-free operations, any EPA regulations should, at a minimum, include the following:

- a demonstration that sites are capable of long-term containment of carbon dioxide;
- identification and characterization of potential natural and man-made leakage pathways, and appropriate risk management and corrective actions;
- design, construction, and operation parameters that prevent, mitigate, and remediate the creation or activation of leakage pathways or the migration of CO_2 or other fluids into any zone in a manner not authorized by the administrator (or pursuant to a state program approved by the administrator as meeting the requirements of these regulations);
- minimizing fugitive CO_2 emissions from project operations;
- monitoring and modeling to predict and confirm the position and behavior of the CO_2 and other fluids in the subsurface during and after injection;
- accounting and reporting of CO_2 quantities sequestered, injected, recycled, leaked, vented, and any other categories as appropriate; and
- post-injection site closure and financial responsibility requirements that ensure the long-term containment of injected CO_2.

Such an approach focuses on preventing leakage by placing emphasis on sound site selection, early detection of problems through appropriate monitoring, timely action to limit the extent of a detected leakage, if any, and site care and stewardship over an appropriate time horizon. With appropriate input from operators, the design of these requirements can be done within the constraints of commercial operations.

NRDC has long supported the safe and effective application of geologic sequestration as a valuable tool in combating climate change. Our support is not shared universally, however, and a lack of confidence in the regulatory treatment of the matter will only serve to delay implementation of carbon capture and storage projects. A credible regulatory framework is central to the acceptability of the practice of CCS. Many stakeholders, as well as the general public, are already skeptical of geologic sequestration technology, especially in light of the impacts of shale oil and gas production and high-profile well failure incidents with serious consequences (such as the Deepwater Horizon and Aliso Canyon events). Poorly conducted CO_2-EOR operations may further jeopardize the social license of CCS technology to operate and result in a backlash against geologic sequestration.

We remain hopeful that, with meaningful participation from all stakeholders, such requirements can be worked out expeditiously—and in a manner that not only satisfies the need to protect the environment and public health but also lends legitimacy and credibility to the practice of underground injection of CO_2 for climate mitigation. We consider these requirements ultimately inevitable, but also in the best interests of ensuring a timely and smooth deployment of CCS technologies.

Appendix A: Existing Integrated CCS Projects in North America

- **1972: Terrell gas processing plant in Texas:** A natural gas processing facility (along with several others) began supplying CO_2 in West Texas through the first large-scale, long-distance CO_2 pipeline to an oilfield.
- **1982: Koch Nitrogen Company Enid Fertilizer plant in Oklahoma:** This fertilizer production plant supplies CO_2 to oil fields in southern Oklahoma.
- **1986: Exxon Shute Creek Gas Processing Facility in Wyoming:** This natural gas processing plant serves ExxonMobil, Chevron and Anadarko Petroleum CO_2 pipeline systems to oil fields in Wyoming and Colorado and is the largest commercial carbon capture facility in the world at 7 million tons of capacity annually.
- **2000: Dakota Gasification's Great Plains Synfuels Plant in North Dakota:** This coal gasification plant produces synthetic natural gas, fertilizer and other byproducts. It has supplied over 30 million tons of CO_2 to Cenovus and Apache-operated EOR fields in southern Saskatchewan as of 2015.
- **2003: Core Energy/South Chester Gas Processing Plant in Michigan:** CO_2 is captured by Core Energy from natural gas processing for EOR in northern Michigan, with over 2 million MT captured to date.
- **2009: Chaparral/Conestoga Energy Partners' Arkalon Bioethanol plant in Kansas:** The first ethanol plant to deploy carbon capture, it supplies 170,000 tons of CO_2 per year to Chaparral Energy, which uses it for EOR in Texas oil fields.
- **2010: Occidental Petroleum's Century Plant in Texas:** The CO_2 stream from this natural gas processing facility is compressed and transported for use in the Permian Basin.
- **2012: Air Products Port Arthur Steam Methane Reformer Project in Texas:** Two hydrogen production units at this refinery produce a million tons of CO_2 annually for use in Texas oilfields.
- **2012: Conestoga Energy Partners/PetroSantander Bonanza Bioethanol plant in Kansas:** This ethanol plant captured and supplies roughly 100,000 tons of CO_2 per year to a Kansas EOR field.
- **2013: ConocoPhillips Lost Cabin plant in Wyoming:** The CO_2 stream from this natural gas processing facility is compressed and transported to the Bell Creek oil field in Montana via Denbury Resources' Greencore pipeline.
- **2013: Chaparral/CVR Energy Coffeyville Gasification Plant in Kansas:** The CO_2 stream (approximately 850,000 tons per year) from a nitrogen fertilizer production process based on gasification of petroleum coke is captured, compressed and transported to a Chaparral-operated oil field in northeastern Oklahoma.
- **2013: Antrim Gas Plant in Michigan:** CO_2 from a gas processing plant owned by DTE Energy is captured at a rate of approximately 1,000 tons per day and injected into a nearby oil field operated by Core Energy in the Northern Reef Trend of the Michigan Basin.
- **2014: SaskPower Boundary Dam project in Saskatchewan, Canada:** SaskPower commenced operation of the first commercial-scale retrofit of an existing coal-fired power plant with carbon capture technology, selling CO_2 locally for EOR in Saskatchewan.
- **2015: Shell Quest project in Alberta, Canada:** Shell began operations on a bitumen upgrader complex that captures approximately one millions tons of CO_2 annually from hydrogen production units and injects it into a deep saline formation.
- **2017: NRG Petra Nova project in Texas:** NRG commenced operations on the Petra Nova project in January, 2017. It is the first American retrofit of a coal-fired power plant with CCUS and the world's largest post-combustion capture project. It captures up to 90% of the CO_2 from a 240 MW slipstream of flue gas from the existing WA Parish plant. The CO_2 is transported to an oil field nearby.
- **2017: ADM Illinois Industrial Carbon Capture & Storage Project:** Archer Daniels Midland began capture from an ethanol production facility in April, 2017, sequestering it in a nearby deep saline formation. The project can capture up to 1.1 million tons of CO_2 per year.

Appendix B: Key Differences Between Federal Class II and Class VI Requirements

A central feature of Class VI is the requirement to submit a comprehensive series of site-specific plans, which is new to the UIC program. Owners or operators must submit, with their permit applications, the following:

- an area of review and corrective action plan;
- a monitoring and testing plan;
- an injection well plugging plan;
- a post-injection site care and site closure plan; and
- an emergency and remedial response plan.

Class II does not echo this structure.

Another unique feature of Class VI regulations is the requirement to review and update these plans at least every five years. This creates a continuous feedback loop between monitoring, operations, modeling and other data collection, and the various plans.

The information that needs to be submitted at the time of a permit application is more extensive under Class VI. For example, key geological, geomechanical, lithological, and geochemical properties of the confining zone have to be submitted under a Class VI permit application, as does information on faults or fractures that may interfere with confinement, seismic history, and wells within the area of review. Class II does not have such requirements, or requires only information that is in the public record about known wells. It does not mandate the use of any methods to discover orphaned or abandoned wells.

Class VI siting requirements include demonstrating the presence of an injection zone with sufficient properties to receive the total anticipated volume of CO_2 injectate and a confining zone big enough to contain injected and displaced fluids, and with sufficient integrity to allow injection without initiating or propagating fractures. Computational geologic modeling is required to demonstrate that the injection and confining zones are suitable for CO_2 sequestration. Class II only requires a confining zone that is free of transmissive faults and fractures, and no modeling is required to demonstrate this.

Class VI requirements include an extensive testing and monitoring plan that covers operational parameters for the well, direct and indirect methods to track the extent of the CO_2 plume and the area of elevated pressure, water quality measurements, and surface monitoring if required by the Director. Monitoring requirements for Class II are limited to analyzing injected fluids with sufficient frequency to yield data representative of its chemical and physical characteristics, as well as injection rate, pressure, and volume measurements.

Class VI requirements for a well plugging plan are tailored to individual situations, while Class II calls for predetermined methods to be used.

Class VI requires post-injection monitoring for 50 years—or an alternative period if such a period is shown to be sufficient—in order to establish the evolution of the injected CO_2 and displaced fluids and to ensure that no USDWs are being endangered. Once no endangerment is established, then the Director may authorize site closure, at which point owners' and operators' financial responsibility ceases. Class II lacks any post-injection site care and site closure requirements.

The Area of Review (AoR) and corrective action requirements are broader for Class VI than for Class II. In Class VI the AoR does not rely on default distances, needs to be updated at least every five years, requires modeling of certain specifications to determine the extent of the CO_2 plume and displaced fluids, and requires more extensive identification of penetrations within the AoR. Data must be periodically reviewed to determine whether the AoR is still appropriate, and any revision of the AoR may require revision of other plans as well. Under Class II, the AoR can either be a fixed ¼-mile radius or the so-called zone of endangering influence (ZEI), which is the lateral distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water. The AoR does not have to be reviewed or updated once approved, and there is no requirement to track the actual movement of injected fluids in the subsurface to verify that the AoR is appropriate.

Financial responsibility obligations go further under Class VI than under Class II. Under Class VI, owners and operators must demonstrate financial responsibility sufficient to cover the cost of corrective action, well plugging, post-injection site care and closure, and emergency and remedial response. Under Class II, owners and operators only have to demonstrate financial responsibility to cover the cost of closing, plugging, and abandoning the underground injection operation.

Class VI emergency and remedial response provisions require actions by the owner or operator to address movement of the injection or formation fluids that may endanger a USDW during construction, operation, and post-injection site care periods. Class II has no such requirements.

Construction requirements, as well as requirements for logging, sampling, and testing, are much more detailed and stringent in Class VI than in Class II, which requires only that wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water, and that the materials be designed for the life expectancy of the well.

The standard for granting primacy to states for the implementation of the program is weaker for Class II wells; states must demonstrate general effectiveness as opposed to the ability to meet individual stringency and adequacy criteria. Forty U.S. states and two Native American tribes have primacy for Class II, and those states and tribal regions contain approximately 94 percent of all Class II wells.[171] Because state and tribal rules are not required to meet the minimum standards laid out in federal rules, there is significant variability among these rules in terms of both regulatory topics covered and stringency. By our analysis, no state rules adequately fill the regulatory gaps discussed herein, even when accounting for other state-level rules for oil and gas wells generally.

ENDNOTES

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21 40 CFR §144.6(f) defines Class VI wells as "[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)."

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26 The Safe Drinking Water Act allows states to apply for "primacy," i.e., primary enforcement responsibility for UIC wells. The standard for granting primacy for Class II wells (under Sec. 1425 of SDWA) is less stringent than for all other well types (which is authorized under Sec. 1422 of SDWA). In particular, Sec. 1425 of SDWA allows primacy to be granted for Class II wells if states with existing oil and gas programs make an optional demonstration that their program is effective in protecting USDWs. For all other well types, Sec. 1422 of SDWA requires that state programs be at least as stringent as the federal program and show that their regulations contain effective minimum requirements (e.g., inspection, monitoring, and recordkeeping requirements) that well owners and operators must meet.

27 A typical thickness for the casing would be 1⅜″.

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29 40 CFR §144.19(a).

30 40 CFR §144.19(b).

31 For example, an operator may be contractually bound to sequester CO_2 from an industrial source that is seeking to comply with limits to atmospheric emissions of CO_2. The details of such a contract cannot be known in advance, nor are such documents publicly available. The contractual obligation to sequester the received CO_2 continuously or in its entirety may therefore result in a preference by the owner/operator to continue injecting CO_2 even if signs of abnormal operation or increased risk are emerging from the field (such as a loss of pressure or the buildup of unacceptably high pressures).

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33 EPA, memorandum from Peter C. Grevatt, Office of Ground Water and Drinking Water, to Regional Water Division Directors, April 23, 2015, http://www.epa.gov/sites/production/files/2015-07/documents/class2eorclass6memo_1.pdf.

34 In particular, under Clean Air Act section 114(a)(1), "the [EPA] Administrator may require emissions sources, persons subject to the CAA, manufacturers of emission control or process equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information as the Administrator requests for the purposes of carrying out any provision of the CAA."

35 Furthermore, subpart PP applies to facilities that capture or produce a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground and to importers or exporters of bulk CO_2. Subpart W applies to offshore and onshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, and natural gas distribution.

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