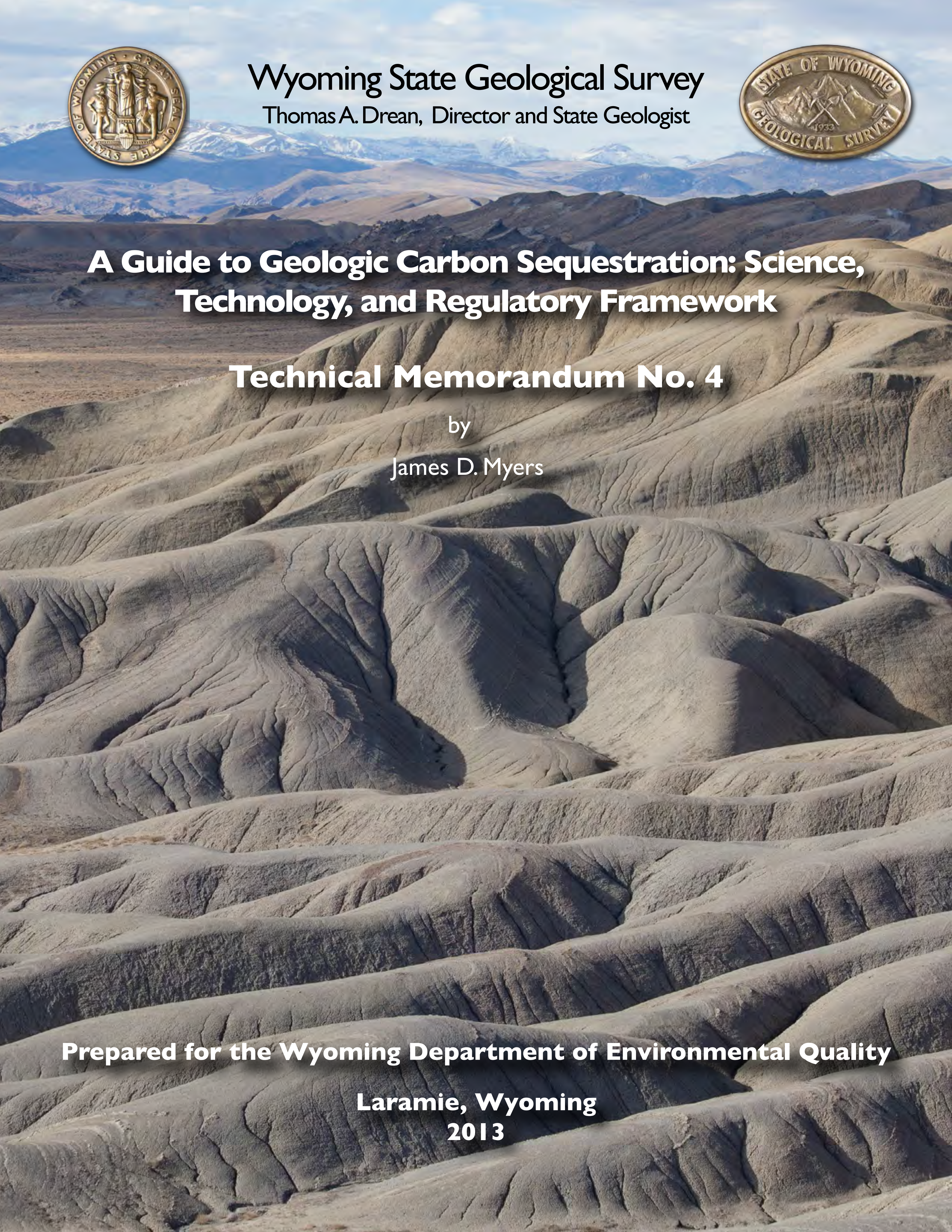

Wyoming State Geological Survey

Thomas A. Drean, Director and State Geologist

A Guide to Geologic Carbon Sequestration: Science, Technology, and Regulatory Framework

Technical Memorandum No. 4

by

James D. Myers

Prepared for the Wyoming Department of Environmental Quality

Laramie, Wyoming
2013

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Cover: *Western Owl Creek Mountains, Fremont County Wyoming. Photo by Robert Kirkwood.*

A Guide to Geologic Carbon Sequestration: Science, Technology, and Regulatory Framework

Technical Memorandum No. 4

June 2013

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Chapter 1
Introduction

In recent years, carbon capture and storage (CCS) has been advocated as a means to continue using fossil fuels until carbon-free energy systems are developed while at the same time reducing anthropogenic carbon emissions (IPCC, 2005). CCS entails capturing carbon dioxide (CO_2) from fossil fuel combustion and sequestering it from the atmosphere for thousands to hundreds of thousands of years. Storage can be accomplished through mineral carbonation, ocean storage, biological storage, or geologic storage. For a variety of reasons, geologic carbon sequestration (GCS) is the technology that can be deployed in the shortest timeframe while capturing significant amounts of CO_2.

For the last several years, the United States has actively pursued geologic carbon sequestration as a means to continue using its abundant fossil fuel resources, especially coal. Toward this end, the U.S. Department of Energy (DOE) has funded considerable research on all stages of the GCS implementation chain while the Environmental Protection Agency (EPA) has developed the environmental regulations under which large volumes of CO_2 can be captured from a stationary point source and safely injected into the subsurface for long-term sequestration.

This publication is intended as an introduction for citizens, regulators, and policy-makers to the regulatory framework that is under development in the United States and Wyoming to ensure that geologic carbon sequestration is carried out safely and in a manner that protects human health and the environment. In particular, this publication focuses on the new regulations the EPA and the Wyoming Department of Environmental Quality (WDEQ) have developed to oversee geologic carbon sequestration under the Safe Drinking Water Act's Underground Injection Control (UIC) program. Specifically, this publication concentrates on the new Class VI geologic sequestration injection well classification. The intention of this publication is to assist all stakeholders in understanding geologic carbon sequestration and the risks and benefits associated with this particular carbon emission reduction strategy.

A thorough understanding of the new regulation requires not only knowledge of the rule itself, but an appreciation for the larger context within which the Class VI well class was developed and will operate. Thus, this publication lays out the basics of carbon capture and storage. It looks at the unique character of geologic carbon sequestration, which will be most relevant for Wyoming stakeholders. A background summary of the Safe Drinking Water Act (SDWA) and its attendant UIC program is provided to allow the reader to place the new Class VI well in a broader context of how the SDWA legislation and its accompanying regulations protect the nation's underground drinking water sources. Class VI well regulations center, to a large degree, on the potential for leakage of CO_2 from geologic formations. Since oil and gas wells are one of the main factors in potential leakage, a brief discussion describes how oil and gas wells are drilled, constructed, completed, and abandoned. With this background, the details of the Class VI well regulation are examined.

To effectively reduce anthropogenic CO_2 emissions, CCS will have to be deployed commercially on a global scale. This deployment will be exceedingly complex, because CCS represents the merging of a number of seemingly unrelated scientific, engineering, and technical disciplines with a variety of other professions, such as legal, business, etc. Even within a single profession, the ranges of expertise required to understand the details of different components of the CCS chain are varied. For instance, geologic carbon sequestration draws on the sciences of chemistry, physics, and geology among others. Similarly, relevant engineering fields are as varied as gas handling, combustion technologies, and oil and gas well construction. Once engineered, a CCS technology must meet regulatory guidelines; its operation must be economically viable and meet certain legal statutes, e.g., issues of pore space ownership. Given this breadth of perspectives, it is not surprising that few individuals, regardless of profession, understand all the details of the entire CCS technology chain.

Given the wide range of stakeholders this publication is intended for and its broad subject matter, it is unlikely that any one reader will be well versed in all topics. Thus, this report has introductory material incorporated into each content area to guide the reader through these possibly unfamiliar subjects. For example, in discussing the chemistry of CO_2, phase diagrams are explained, so the discussion of the phase relations of injected CO_2 and its implications for project design, safety, and monitoring can be understood by the non-specialist. Likewise, the regulatory section provides an overview of environmental laws before investigating the details of the Safe Drinking Water Act's UIC program. Equipped with this background information readers can effectively assess the various claims and counterclaims about CCS.

Chapter 2

Carbon Capture and Storage (CCS) Overview

Introduction

Fossil fuels currently supply over three quarters of the world's primary energy, energy consumption and demand are growing, and fossil fuel combustion adds to atmospheric CO_2 levels. The world community is seeking a means of using fossil fuels while limiting the emission of anthropogenic CO_2 from these essential fuels. Although no single change in our energy system will reduce CO_2 emissions to what are viewed by many as 'safe' levels (Pacala and Socolow, 2004), carbon capture and storage (CCS) is one potential bridging technology from our current carbon-intensive energy system to a lower carbon energy system. CCS may provide a means of reducing anthropogenic CO_2 emissions while using the world's abundant fossil fuel resources to supply a growing global demand for energy. Carbon mitigation strategies, like CCS, also allow maintenance of a diversified energy portfolio in which fossil fuels play an important role, while allowing continued leverage of the existing energy infrastructure, a global, multi-trillion dollar investment.

The world's reliance on fossil fuels as a primary energy source (PES) has reduced the residence time of carbon in the lithosphere. In essence, human activities have significantly altered the carbon cycle by augmenting the carbon flux between the lithosphere and atmosphere and changed the amount of carbon in both the atmosphere and upper ocean by burning large amounts of fossil fuels (Orr and others, 2005). For any business-as-usual energy future, this flux will continue to grow in size to produce even higher atmospheric CO_2 concentrations. Climate models suggest high levels of CO_2 may lead to catastrophic climate change (Lenton and others, 2008).

Given the world's growing energy demand (Bazilian and others, 2010) and the impact such energy use will have on CO_2 emissions, what can global society do to reduce its carbon footprint? At least three possible responses exist: 1) ignore the problem, 2) stop using fossil fuels, or 3) reduce future CO_2 emissions. Since the first option has potentially dire consequences and the second option would end modern civilization, humanity must, over both the short- and long-terms, work to reduce carbon emissions from energy production. What are the best approaches to reducing emissions and how are the benefits and risks of reduction equitably and justly shared among nations? One approach that has been suggested is CCS (Pacala and Socolow, 2004; IPCC, 2005).

Overview

Carbon capture and storage is an industrial process that can be incorporated into new fossil fuel-fired industrial facilities or retrofit onto existing facilities with the correct combination of physical, technological, and economic conditions. CCS consists of three separate components each utilizing a different set of technologies: capture, transport, and storage (Fig. 1). Capture refers to the separation of CO_2 from a source. Most current research focuses on a gas stream produced by the combustion of fossil fuels. Once captured and compressed, supercritical CO_2 is transported from its source to a storage site. Transportation is likely to be predominantly by pipeline, although as this industry grows, transport may also occur by ship. Finally, the CO_2 is stored such that it will remain isolated from the atmosphere for thousands of years.

All technologies required for capture, transport, and storage are currently available on a commercial scale. However, they have never been combined together on the spatial, temporal, and mass-transfer scales that will be required if CCS is to contribute significantly to the reduction of anthropogenic CO_2 from fossil fuel combustion. On this scale, there are also economic, legal, regulatory, political, and social (to name just a few) barriers that must be overcome if CCS is to be a viable carbon emissions reduction strategy (Keith and others, 2005; Wilson and others, 2008; Terwel and others, 2011).

To understand the ramifications of any CCS scheme, comparing a complete CCS facility to a conventional thermal electricity generation plant is useful. Such a comparison illustrates the changes in process inputs and outputs of a system (power or industrial plant) that are critical when an industrial facility is fitted with CCS capabilities. A 'simple' power plant has three inputs and two primary outputs (Fig. 2). The inputs include the fuel necessary to power the process, an oxidant, and any other materials, such as water, chemicals,

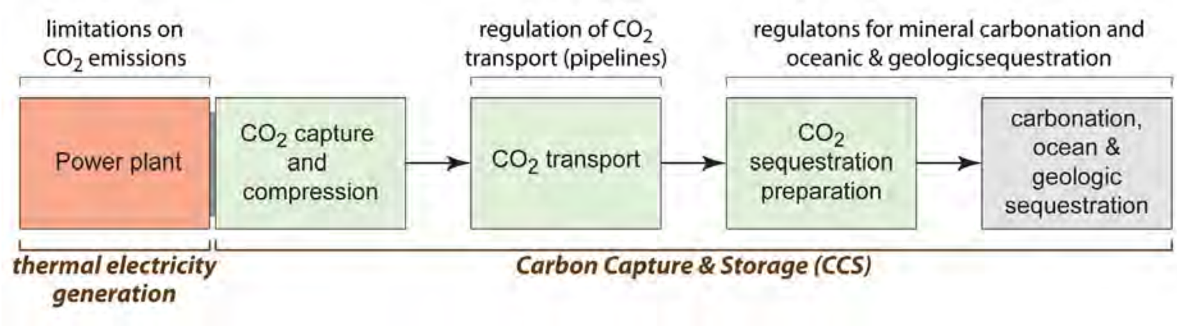

Figure 1. The three fundamental components of carbon capture and storage are CO_2 capture and compression, transport, and storage. Storage can be via carbonation, ocean or geologic sequestration. (Copyright J.D. Myers. Used with permission.)

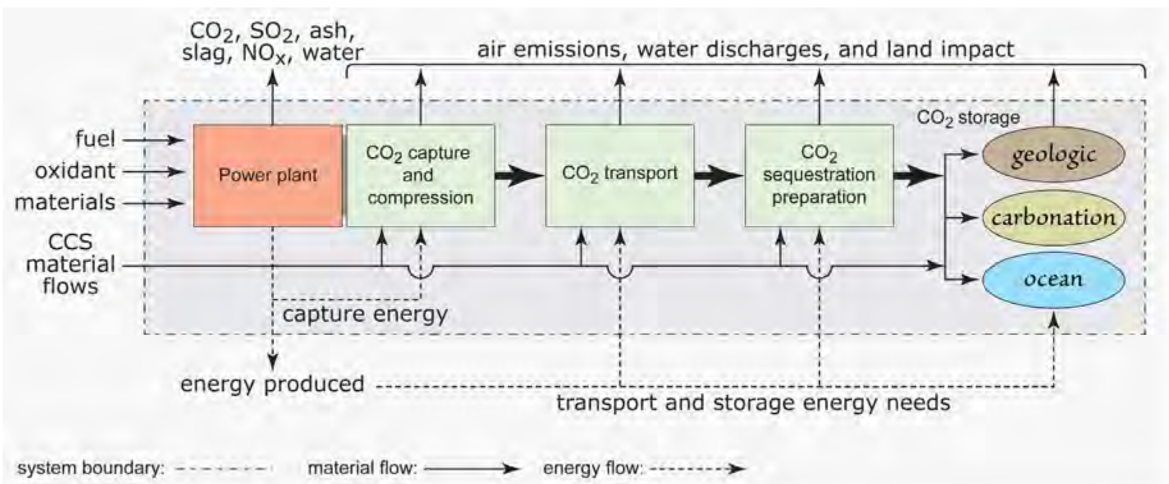

Figure 2. Material and energy flows for a carbon capture and storage system at a thermal power plant. (Copyright J.D. Myers. Used with permission.)

etc., needed for the process. Outputs consist of the produced product (energy or other industrial product) plus emissions to air, water, and land that may be generated by the plant. These emissions may be gas, liquid, solid, or a combination of all three depending on the facility of interest.

The carbon capture and storage technology added to a basic industrial facility is a three component industrial process that has a large spatial footprint. At the start of this chain, CO_2 from combustion is captured at an industrial facility, either through a pre- or post-combustion process. In post-combustion capture, CO_2 contributes only a small percentage of the flue stream (<15 percent), so capture is an energy intensive process. The captured CO_2 is compressed until it reaches a supercritical state, thereby significantly increasing its density and reducing its volume. Although expensive in terms of energy, compression reduces the volume of gas requiring transport and ultimately storage. After compression, the supercritical fluid is transported to a storage site. The three potential storage methods discussed most frequently are oceanic sequestration (Ohsumi, 1995; Ozaki, 1997; Herzog, 1998; ; Ozaki and others, 2001; Adams and Caldeira, 2008), geologic sequestration (Benson and Cole, 2008), and mineral carbonation, or chemically reactions that combine CO_2 gas with metals to produce carbonate minerals (Lackner and others, 1995; Oelkers and others, 2008; Khoo and others, 2011; Renforth and others, 2011). All three options are designed to isolate CO_2 from the atmosphere for thousands of years.

The capture, transportation, and storage of CO_2 make the energy system, i.e. the power plant, much more complex because of the additional equipment and industrial processes. At the same time, the sequestration infrastructure requires additional power for operation. Thus, either the output of the plant will be lowered because of this need or the plant must be expanded to produce the same amount of deliverable product, e.g., electricity, cement, etc. In the case of plant expansion, additional energy is necessary to power the plant. In addition, a new output (stored CO_2) is added to the system.

CO_2 Chemistry and Physics

Understanding the various stages of CCS requires an appreciation of the chemistry and physics of CO_2. At standard temperature and pressure (STP), carbon dioxide is a colorless, non-flammable gas. When present in low concentrations, it is also odorless, but as the concentration rises it develops a sharp, acidic odor. CO_2 is only moderately reactive. Most importantly, CO_2 has a density 1.5 times that of air (1.98 kg/m^3) at STP. Carbon dioxide comprises about 0.039 percent of the gases that make up the Earth's atmosphere. Carbon dioxide concentration, however, varies seasonally particularly in the northern hemisphere, and has been increasing during historic times. At STP, CO_2 is dangerous to animal life and at concentrations greater than 50,000 ppmv, or about 5 percent, and can be lethal.

Chemically, CO_2 is a linear molecule with a single carbon atom and an oxygen atom on either side (Fig. 3a). Because of this physical arrangement, CO_2 lacks an electrical dipole like water. The carbon and oxygen are held together by covalent, double bonds (Fig. 3b). carbon dioxide is, therefore, fully oxidized, making it non-flammable and not particularly reactive. Because of these characteristics, CO_2 behaves chemically very different from H_2O, the other dominant dioxide molecule on Earth.

Like all substances, CO_2 behaves differently at different temperature-pressure conditions. Such behavior is summarized by phase diagrams, or plots of temperature versus pressure that show the pressure-temperature combinations at which

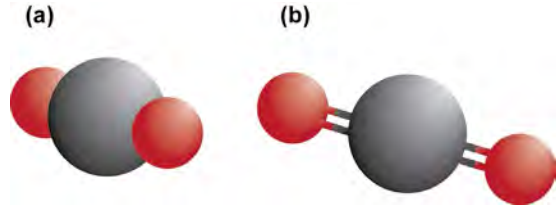

Figure 3. Chemical structure of CO_2. (a). CO_2 is a linear molecule with a central carbon atom (black) sandwiched between two oxygen atoms (red). (b) Carbon is bonded to each of its oxygen atoms by a double, covalent bond.

solid, liquid, gas, and supercritical fluid are stable (Fig. 4a). Although there are different ways of constructing phase diagrams, one common configuration plots pressure on the vertical axis and temperature on the horizontal. Many phase diagrams plot pressure in bars and temperature in degrees celsius. One bar is approximately equal to one atmosphere, the pressure the atmosphere exerts on a surface at sea level.

All phase diagrams define four distinct phase regions, each representing a stable phase (Fig. 4a). At any temperature-pressure (T-P) combination within each field, a single phase is stable. The phase regions are separated by lines, or phase boundaries, along which two phases, such as gas + solid, co-exist in equilibrium. Phase boundaries also mark the positions of reactions between the phases, i.e., melting of a solid to produce a liquid when temperature is increased or condensation of a gas to a liquid as the system is cooled. At low temperature and pressure, CO_2 gas is the stable phase so the gaseous region exists below the solid-gas (sublimation/condensation reaction curve) and liquid-gas (evaporation/precipitation reaction curve) phase boundaries. Along the solid-gas curve, solid sublimates to gas as temperature rises (gas converts directly to solid [deposition] as pressure increases). At any temperature-pressure pair along this phase boundary, both solid and gas phases coexist in equilibrium. Above the solid-gas boundary and to the left of the solid-liquid curve, only solid is stable. In the upper middle part of the phase diagram between the lower liquid-gas and upper solid-liquid fields, lies the region where liquid is stable.

On phase diagrams, two points are of special interest: the triple point, where three phases (solid, liquid, and gas) coexist simultaneously and the

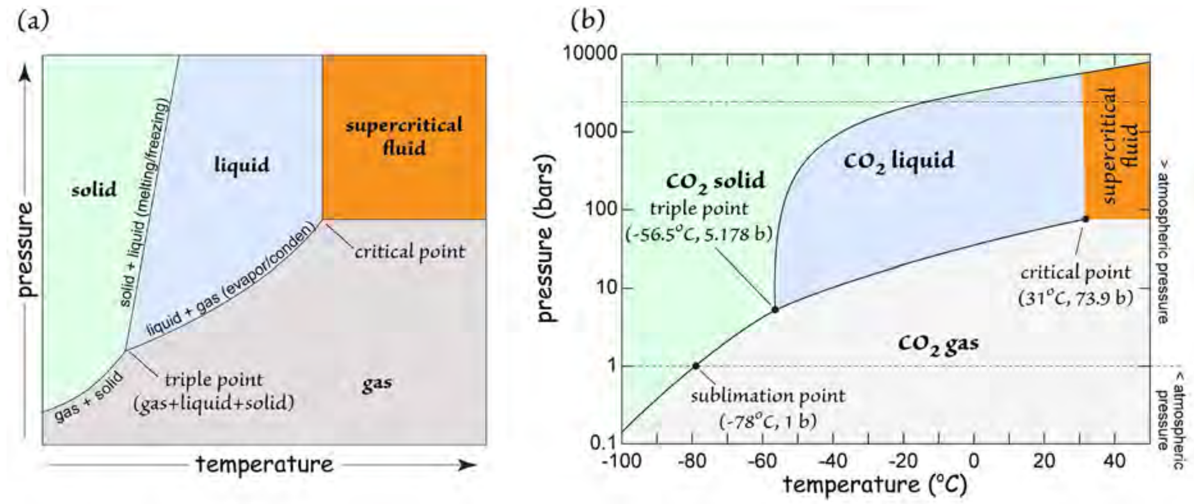

Figure 4. (a) Generic phase diagram showing the important relations and features of such a diagram. (b) CO_2 phase diagram showing the locations of its four important phase fields and its triple and critical points. (Copyright J.D. Myers. Used with permission.)

critical point (Fig. 4a). A fourth phase region occurs to the right and above the critical point. In this T-P region, a substance acts as a supercritical fluid. A supercritical fluid has properties intermediate between a gas and a liquid. For example, if a container is filled with a supercritical fluid, it will expand to fill the entire container (as a gas would), but its density will be closer to that of a liquid than a gas. Supercritical fluids also have gas-like viscosity, liquid-like compressibility, and a liquid-like solvent behavior.

On the CO_2 phase diagram, the temperature axis varies from -140°C to +100°C, whereas pressure ranges from 0.001 bars to 10,000 bars (Fig. 4b). Carbon dioxide's critical point occurs at 31°C and 73.9 bars (1,085 psi). At one bar, solid CO_2 sublimates to a gas at approximately -78°C. For CO_2, the triple point, or the phase assemblage of solid, liquid, and gas, occurs at -56.5°C and 5.1 bars. The critical point, above which CO_2 occurs as a single supercritical fluid, occurs at 31°C and 73.9 bars (Fig. 4b). In the subsurface, temperatures and pressures above CO_2's critical point are found below depths of about 800 meters. Supercritical CO_2 has a density only half that of water, so it is buoyant in a water-CO_2 mixture. Thus, when mixed with water, supercritical CO_2 will rise upward. This latter point is important because it plays an important role in how CO_2 behaves physically during geologic carbon sequestration (see Carbon Storage section later in this chapter). Supercritical CO_2 is used extensively in a variety of industrial applications including use as solvents and cleaners. Recent research has investigated using CO_2 as the working fluid for heat engines, particularly nuclear reactors, but also enhanced geothermal energy systems.

Another important property of CO_2 that must be considered for carbon capture, transport, and storage is how the density of CO_2 changes with pressure (Fig. 5). On a plot of density versus pressure, the saturation line stretches from the critical point to lower pressure and higher density until it terminates at the triple point of CO_2. Along this line, density increases from slightly below 600 kg/m^3 to just less than 1200 kg/m^3. Temperature contours on the diagram increase in temperature from left to right and display distinctly different characteristics above and below the saturation curve. In the gas field, density increases rapidly with only small changes in pressure (Fig. 5). As is to be expected, the more incompressible liquid shows only small increases in density over a large pressure range. Supercritical fluids have significantly lower densities than liquid, but greater than gas. These relationships will be a fundamental role in determining how CO_2 is transported and stored (see Carbon Transport and Storage sections later in this chapter).

Because pressure correlates to depth, in both a

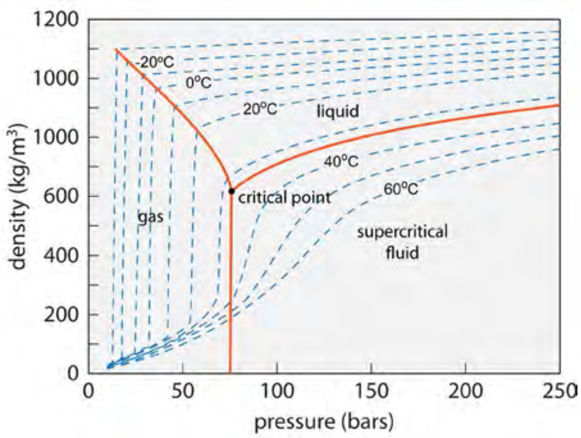

Figure 5. Density-pressure relations contoured for temperature. (Modified from DNV, 2010)

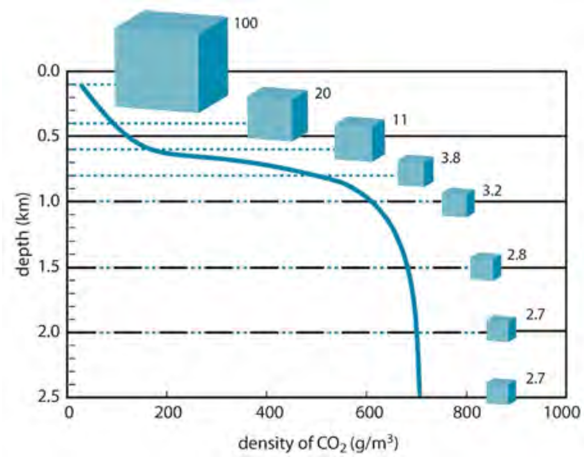

Figure 6. Depth versus CO_2 density plot showing the decrease in the volume occupied as density increases with depth. The smaller volume means that a deeper geologic reservoir can store a greater mass of CO_2 than a shallower reservoir with the same porosity. (Modified from IPCC, 2005)

geologic and an oceanic sequestration site, another important physical characteristic of CO_2 is how its volume changes with depth. As depth increases, density increases and the volume occupied by the same mass of CO_2 decreases (Fig. 6). This volume reduction is important because injecting CO_2 underground means the same amount of gas will require less storage space. That is, more CO_2 can be injected into a smaller reservoir volume at greater depths. The smaller volume means that a deeper geologic reservoir can store a greater mass of CO_2 than a shallower reservoir with the same porosity (IPCC, 2005).

In oceanic and geologic sequestration, supercritical CO_2 will be injected either directly into seawater or into pore spaces filled with formation water, which is typically a brine. The manner in which these two compositionally distinct fluids interact is important in determining physically how the system will behave over time. These relationships are best illustrated by plotting temperature (vertical axis) versus composition (horizontal axis) at some fixed pressure (Fig. 7). The compositional axis plots the proportion of the two end member compositions in either mole percent or weight percent. Because it is a mixture of only two end members (a binary mixture), the compositional axis shows the percentage of one end member composition as its abundance changes from 0 to 100 percent. Since it is a binary mixture, the amount of the other end member varies from 100 to 0 percent in the opposite direction (Fig. 7). If the two end members mix to form a single liquid, meaning they are miscible across the entire compositional range, the diagram shows a single field of one liquid or fluid phase.

If the liquids are immiscible and do not mix to form a single phase, a miscibility gap extending across the compositional range of immiscibility will appear on the diagram. Outside of the gap toward either compositional extreme, a single fluid exists. Inside the gap, the two separate fluids will exist, like water and oil. As temperature increases, the compositional range of the immiscibility gap decreases until eventually it closes entirely (Fig. 7). Again to use the water-oil analogy, heating an oil-water mixture to sufficient temperature will cause the two liquids to form a single liquid phase. Armed with the basics of this type of diagram, the interaction between water and injected CO_2 can be quantitatively investigated. Miscibility is also a function of pressure. Depending on the solution, the gap will either widen or thin as pressure is increased.

At 1,500 bars, CO_2 and water are immiscible, that is they do not mix to form a single liquid but form a mixture of two different liquid phases (Fig. 8a; Kaszuba and others, 2006). This behavior is the same as that of oil and water at normal temperatures and pressures. At temperatures below 275ºC, a miscibility gap exists toward the water

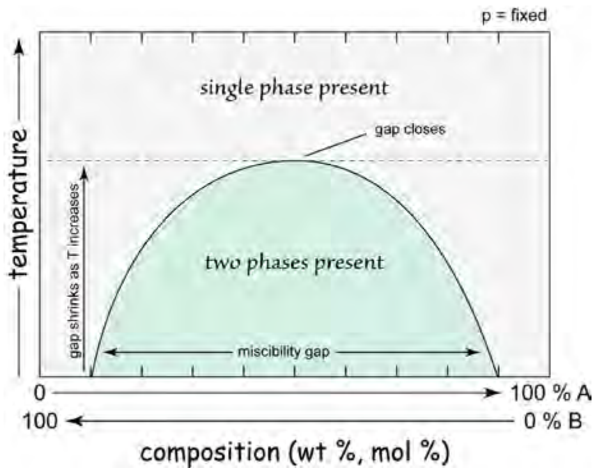

Figure 7. Temperature-composition diagram showing the general relationships in a system displaying immiscibility between two compositionally different fluids/liquids at constant pressure. See text for discussion. (Copyright J.D. Myers. Used with permission.)

side of the diagram. Outside this gap on the high water side, a single water-rich liquid exists whereas a high-CO_2 liquid exists on the opposite side of the gap. In the gap itself, a CO_2 liquid and water will coexist simultaneously. As temperature increases, the gap narrows until it finally closes above 275°C (Fig. 8a). Thus at temperatures above 275°C and 1500 bars, there will be a single CO_2-H_2O liquid phase.

The nature of the miscibility gap between water and CO_2 is not only a function of temperature and pressure, but water composition as well (Kaszuba and others, 2006). In deep geologic formations, the fluid present is likely to be a brine, i.e., water with total dissolved solids (TDS) much higher than pure water. When six weight percent NaCl is dissolved in the water (now a brine) phase, the miscibility gap expands outward and upward (Fig. 8b). Even at temperatures of 300°C, the miscibility gap extends from about 10 mole percent to approximately 95 percent CO_2. Regardless of temperature or salt content, two fluids will exist simultaneously until CO_2 chemically dissolves into the dominant water-rich (brine) phase, which is a slow process on a reservoir scale.

This behavior is important because initially in oceanic and geologic sequestration, the storage reservoir will be characterized by the presence of two different phases with different densities. Because it is lighter, CO_2 will rise upward following any path to the surface. This raises serious issues about how effectively CO_2 will be trapped underground and for how long (see Carbon Storage section later in this chapter).

Carbon Capture

Overview

The first step in the CCS chain is carbon capture. That is, the capture of CO_2 from some type of industrial source. Currently, most practical targets for CO_2 capture are the gaseous exhaust streams produced by the combustion of fossil fuels. Although such streams are produced by a variety of economic activities, e.g., transportation, industry, commerce, etc., the least challenging with respect to current capture technologies are stationary sources, such as electricity generators, iron and steel mills, cement plants, refineries, or natural gas-processing facilities. About 75 percent of the global CO_2 emissions are, in fact, from such sources. Most of these types of large (> 0.1 million tons CO_2/yr), stationary CO_2 sources around the world are concentrated in developed nations, such as, Europe, the eastern part of United States, as well as in the emerging economies of Asia, i.e., China (Fig. 9).

In terms of electricity generation, thermal power plants may be fired by coal, natural gas, petroleum, or biomass. Given the small number of biomass-burning power plants, the limited generation of electricity by petroleum in the developed world, and the low emissions of natural gas plants, the logical choice for early capture efforts is coal-fired power plants. Because of their smaller carbon footprints, industrial facilities that are smaller consumers of fossil fuels, e.g., natural gas processing facilities, ammonia plants, cement production plants, and iron and steel mills are likely to be targets of carbon capture and storage as the CCS industry evolves.

Power Plant Technological Variants

The thermal generation of electricity is a mature and robust technology that has seen only incremental improvement over nearly two centuries. These technologies uses a heat engine to liberate

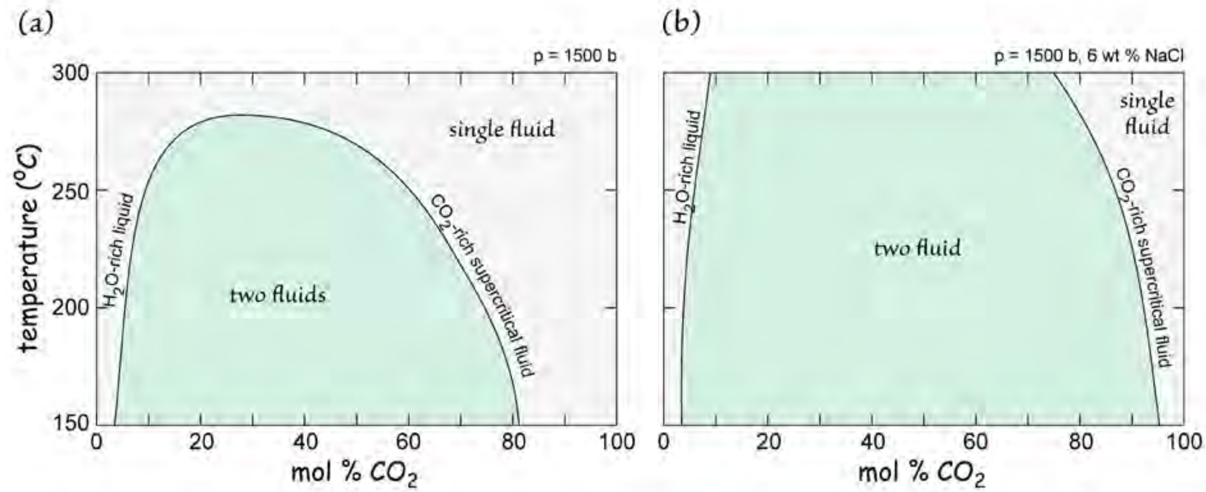

Figure 8. Temperature versus CO_2 content for mixtures of water and CO_2 at 1,500 bars. (a) CO_2 and pure water are immiscible up to 275°C. (b) In a brine, the miscibility gap spans a larger compositional range and extends to higher temperatures. In most cases, CO_2 injection in ocean water or formation brine will produce a two fluid system which has important ramifications for storage behavior. (Modified from Kaszuba and others, 2006)

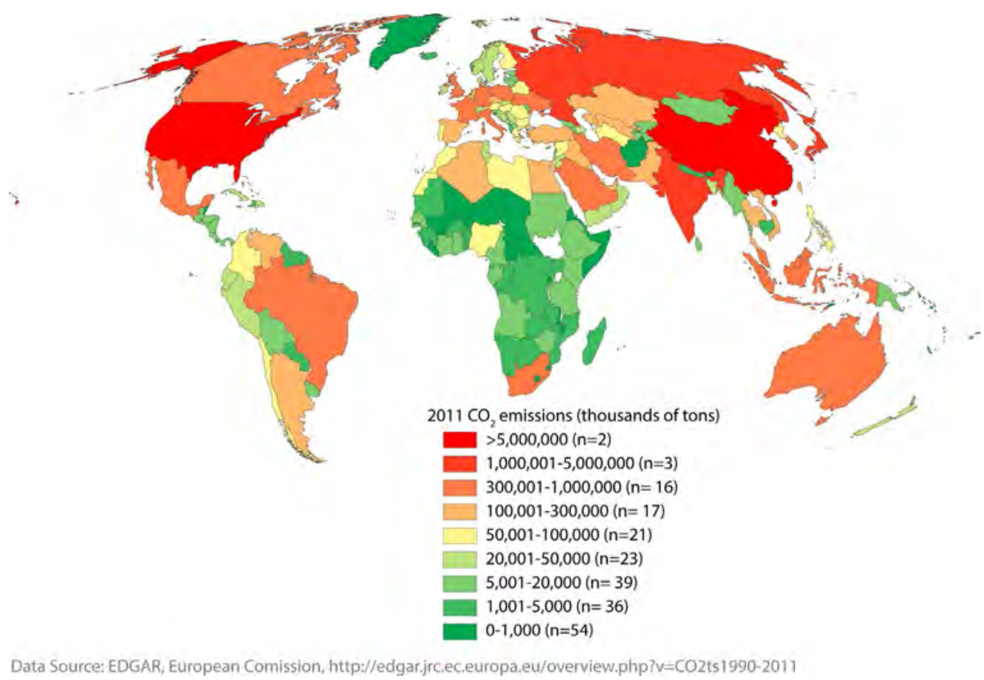

Figure 9. Map of annual CO_2 emissions by country. The largest emitters are concentrated in North America, Europe and Asia. These countries are, therefore, the most likely candidates for early deployment of CCS.

the chemical energy of a fuel as heat. The heat is converted into kinetic energy which is, in turn, used to drive a turbine-generator unit. When designing a thermal power plant, engineers have three fundamental choices to make (Fig. 10); the type of fuel the facility will burn, the oxidant that will combust the fuel, and the technology that will harness the kinetic energy generated by the heat engine.

Combustion: Decisions about fuel and oxidant determine the combustion processes occurring in the power plant and the nature of the resultant waste streams. The combustion process powering any heat

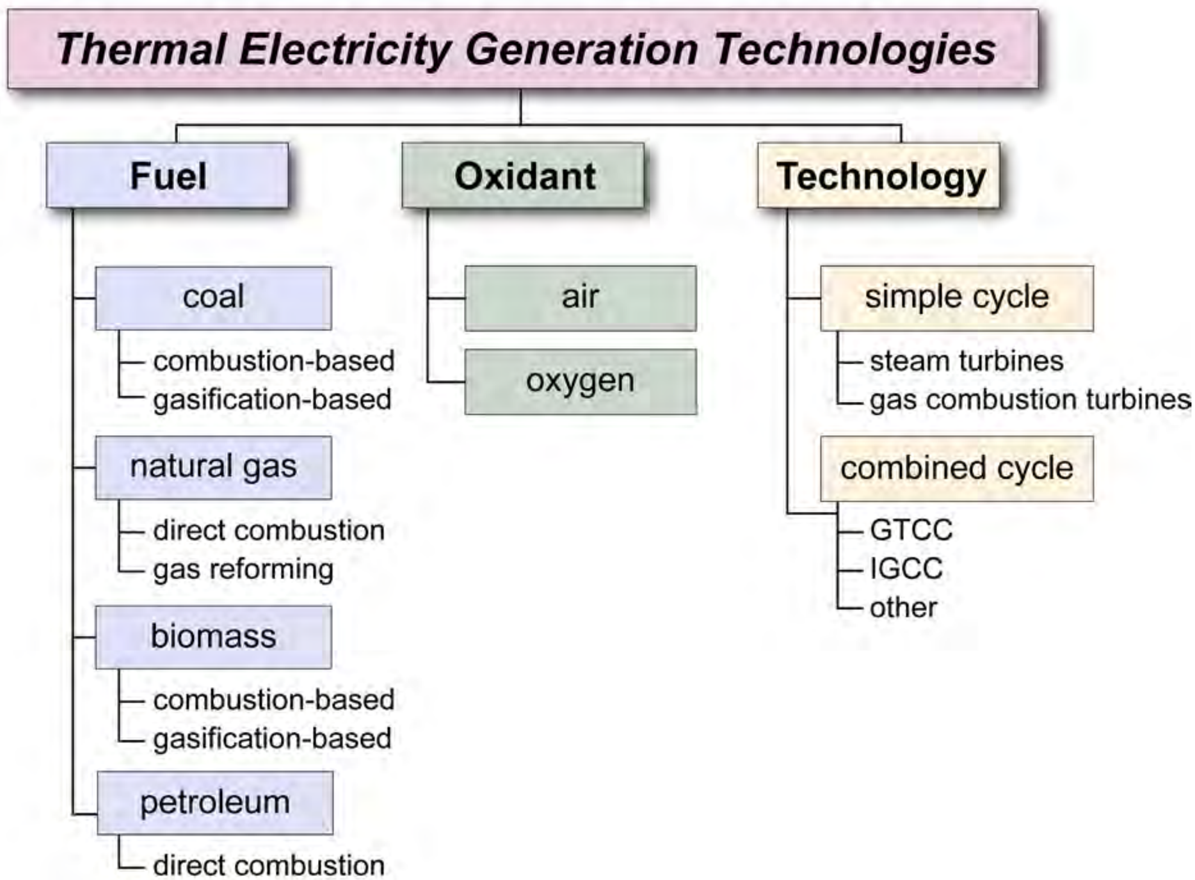

Figure 10. Flow chart illustrating main choices for the three major power plant variables, e.g., fuel, oxidant, and technology. (Modified from Rao and Rubin, 2002)

engine has two fundamental inputs: 1) an oxidant to chemically combust the fuel, and 2) a fuel source (Fig. 11). After combustion, there are two primary outputs from the plant: 1) electricity, and 2) exhaust or flue gases. The exact nature of the inputs and outputs are specific to each power plant.

Nearly all existing thermal power stations (excluding nuclear) combust their primary fuel with air as the oxidant. Since air contains gases other than oxygen, the exhaust gas also contains a wide range of chemical species. The most important of these include carbon monoxide, CO_2, and a variety of sulfur oxides (SO_Xs) and nitrogen (NO_Xs) oxides. In addition, a range of particulates, including metals such as mercury, are released with the gases. These gases are vented at atmospheric pressure, a point that has important ramifications for carbon capture energetics and economics. For example, as mentioned later CO_2 is stored geologically as supercritical fluid. Thus, the low pressure CO_2 vent from a power plant must be compressed to higher pressures, an energy intensive and therefore expensive process.

In the power plant system, CO_2 can be captured at three different points in the process of converting a fuel to electricity. Two methods alter the inputs to combustion and one modifies its outputs. *Post-combustion capture* reduces carbon emissions by capturing CO_2 from the exhaust gas stream after combustion has occurred. This approach has the benefit that, if conditions are favorable, it can be retrofit onto existing power plants that still have significant operational lifetime. *Pre-combustion capture* involves gasifying the fuel before combustion to strip the resultant gas stream of CO_2 leaving a hydrogen stream that when combusted, produces mostly water. This approach is most likely to be applied to new

Figure 11. For the purposes of understanding CCS, the combustion process in a thermal power station relies on two inputs, fuel and oxidant; and produces two outputs, exhaust gases and power.

plants constructed under carbon emission limiting regulations. The third path to carbon capture is *oxyfuel combustion*. In this approach, oxygen is separated from air and the fuel is combusted in an oxygen-pure or oxygen-rich atmosphere. Thus, the exhaust stream is nearly pure CO_2 and cost savings are realized in terms of stripping low concentration CO_2 from a mixed gas exhaust stream. Like post-combustion, oxyfuel combustion can be used to retrofit existing power plants.

Post-combustion capture: Post-combustion carbon capture alters the nature of the exhaust gas from the combustion process (Fig. 12). In this process, fuel and air (the oxidant) are combusted together to produce a flue gas with a wide range of components. For a typical coal-fired power plant, the exhaust gas contains about 12–15 percent CO_2 by volume. The flue gas is processed to remove the CO_2, which is sent to a storage site. The remaining gases from the separation process are simply vented to the atmosphere through the exhaust stack.

The major benefit of post-combustion capture is it can be retrofit to many pulverized coal plants currently in operation today. Because it materially increases a plant's spatial footprint, only plants with sufficient space would be candidates for retrofitting. Additionally, the plant must have sufficient operational lifetime left to warrant the considerable cost of the retrofitting the plant with a CO_2 capture unit. Post-combustion capture works for pulverized coal (PC) and natural gas combined cycle (NGCC) plants, although the lower CO_2 content (3–5 percent by volume) of the exhaust stream from the latter makes the process much less efficient.

Pre-combustion capture: Pre-combustion carbon capture involves reacting a fuel with oxygen/air and/or steam to produce a synthesis gas (syngas), which is a mixture of carbon monoxide (CO) and hydrogen (Fig. 13). The CO is reacted with steam in a catalytic converter to produce CO_2 and additional hydrogen in a gas shift reaction (Eq. 1):

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{1}$$

The CO_2 and hydrogen are separated into two gas streams. The hydrogen stream goes to a combustion chamber to be burned to produce steam or to a gas combustion turbine. The hydrogen-rich syngas is combusted with an oxidant thereby producing only water and heat (Eq. 2):

$$H_2 + O_2 \rightarrow H_2O + heat \tag{2}$$

In a conventional power plant, the heat is used to generate steam and drive a steam turbine to produce electricity. For the combustion turbine, the exhaust gases from the burning of hydrogen are used to drive a turbine directly. The exhaust gas stream may or may not be used to produce steam and drive a secondary steam turbine. Although

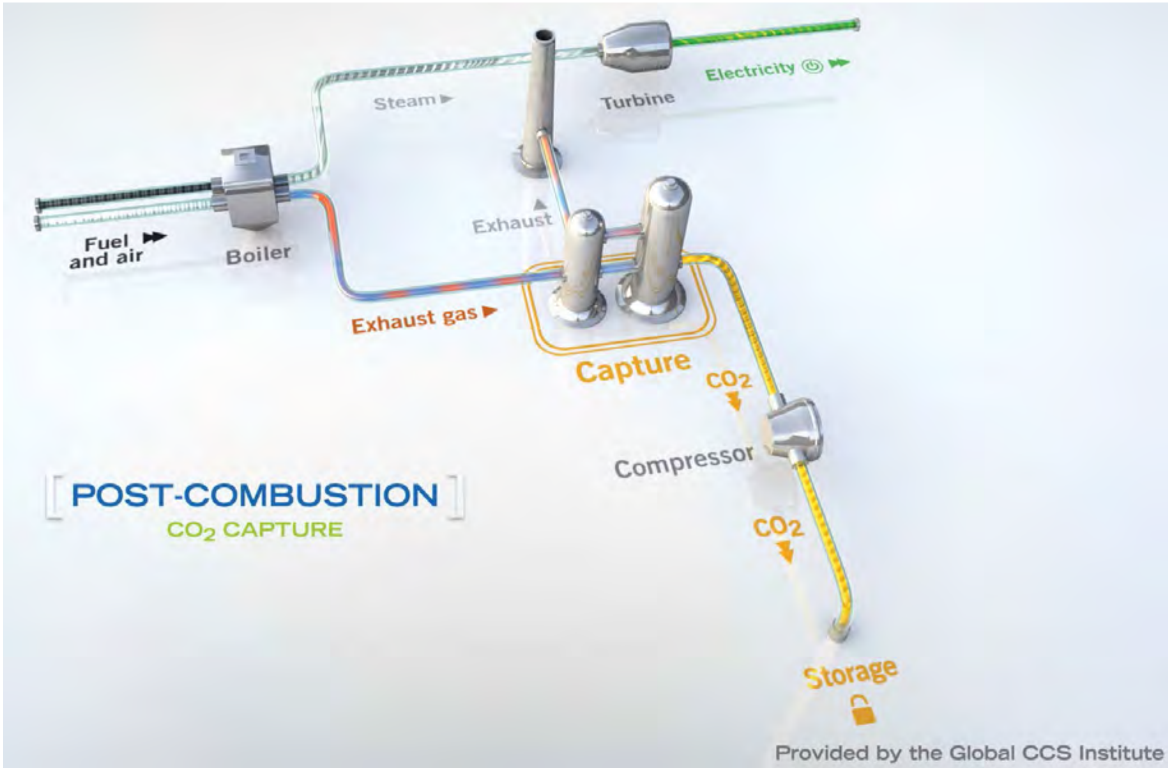

Figure 12. In post-combustion capture, fuel and air are combusted in a furnace-boiler unit and the exhaust gas sent to a capture unit where CO_2 is removed from the gas stream for storage. (Source: Global CCS Institute, www.globalccsinstitute.com)

Figure 13. Pre-combustion carbon capture. In these plants, the fuel is gasified before combustion and CO_2 remove early in the process. Heat is supplied by the burning of hydrogen to produce water, not carbon to generate CO_2. (Source: Global CCS Institute, www.globalccsinstitute.com)

the final exhaust gas has reduced CO_2 levels, it can cause environmental problems without further treatment because it contains SO_Xs and NO_Xs (produced by combustion in air) as well as other environmental pollutants, e.g., mercury. Meanwhile, the captured CO_2 stream is compressed and sent to storage. Unlike the post-combustion process, this type of capture technology cannot be retrofit on existing power stations. In addition, it is not yet commercially viable. This capture technology is likely to be deployed on a large scale only when new power stations are built specifically to lower CO_2 emissions.

Oxyfuel combustion: Oxyfuel combustion is an alternative way to change the inputs to the combustion process. This process uses cryogenic separation, i.e., liquefaction and distillation, to separate the gaseous components of air based on their different liquefaction temperatures. It removes oxygen from the other gases in air, e.g., argon and nitrogen. The pure oxygen stream (Fig. 14) is combined with a fuel in a combustion chamber. Combustion produces CO_2 in gaseous form and H_2O vapor, which are easily separated by dehydration, a physical process. Because oxyfuel combustion temperatures are too high for most of today's metals, a portion of the CO_2 stream is cycled back into the combustion system to reduce temperatures. The remaining CO_2 is captured, compressed, and transported to a storage site. Oxyfuel combustion plants are candidates only for new power plant constructions because oxyfuel combustors cannot be retrofit onto the existing generation of thermal power plants.

Separation Mechanisms

After combustion, CO_2 must be separated from the other gases in an exhaust stream. There are five basic chemical or physical means of separating gases from each other, although only four are used for CO_2 separation (Fig. 15). These are:

- absorption: incorporation of a substance

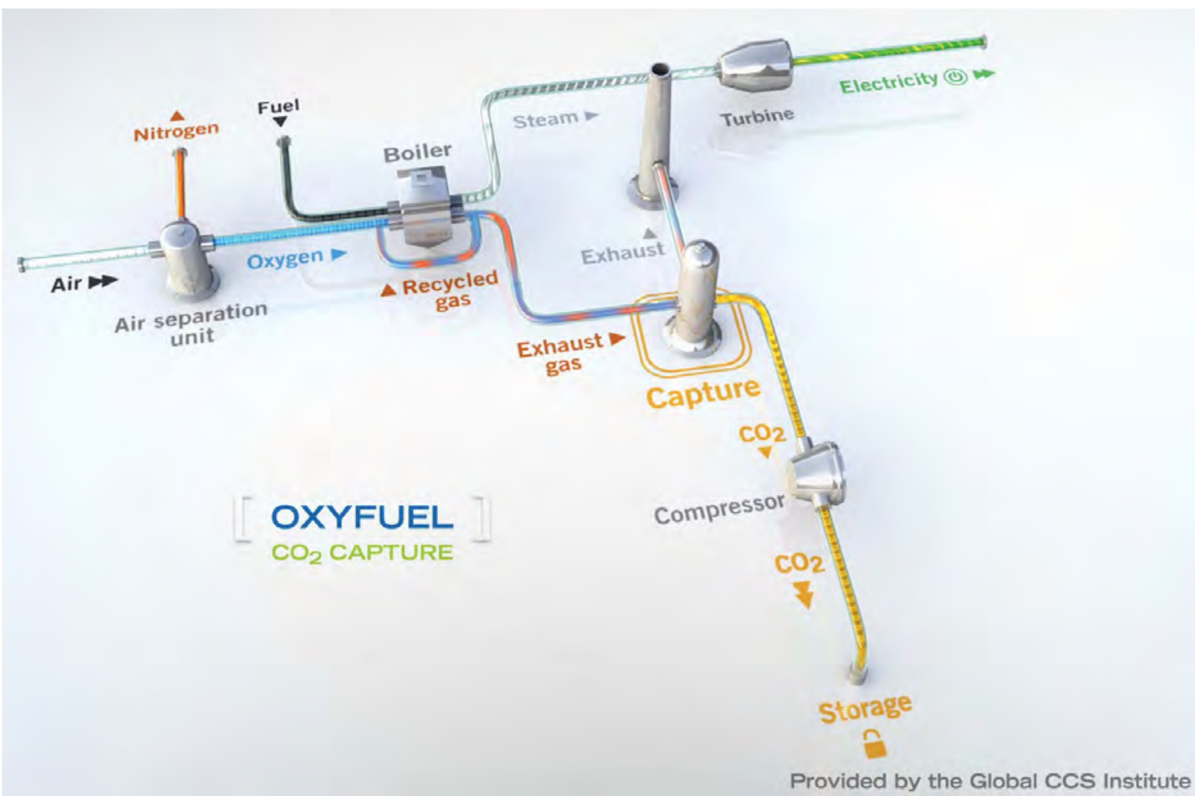

Figure 14. Schematic process for oxyfuel combustion. The fuel is burned in an oxygen-rich environment producing a syngas consisting of carbon monoxide (CO) and hydrogen (H_2). If the fuel is a hydrocarbon or biomass, it produces a nearly pure stream of CO_2. This process eliminates the need to separate a dilute CO_2 stream from the exhaust gas. (Source: Global CCS Institute, www.globalccsinstitute.com)

in one state into a different state (liquid absorbed by a solid, gas absorbed by a liquid)

- adsorption: physical adherence or bonding of ions, atoms, or molecules onto the surface of another phase
- membrane separation: separation by selective permeability through a porous material
- cryogenic distillation: compressing, cooling, and purifying the flue gas stream in a series of stages to liquefy it and separate different gases by low-temperature distillation of the resultant liquid
- microbial/algal separation: separation by biological activity of microbes or algae

Absorption is a bulk process where a substance in one phase is incorporated in the bulk volume of a different phase. In contrast, adsorption attaches a substance from one phase to the surface of another phase.

Absorption

Absorption occurs by both physical and chemical processes (Fig. 15). Physical absorption involves a mass transfer across the interface between the two phases, usually a gas-liquid exchange. The rate of separation is controlled by how fast the transferred substance diffuses away from the interface into the solvent phase. Chemical absorption involves a chemical reaction between the absorbate and the solvent. Accordingly, it is also referred to as reactive absorption. Because it involves a chemical reaction, the process rate is determined by the proportions of the reactants and products of the reaction (its stoichiometry), as well as reactant concentration. The removal of acid gases from an exhaust stream is an example of chemical absorption, whereas the trademark solvents Selexol™ and Rectisol™ employ physical absorption. Chemical or physical absorption can be either reversible or irreversible. A reversible process is one in which some environmental parameter can be altered to release the absorbed substance. For CO_2 separation, only reversible absorption processes are practical because the solvent can be regenerated and reused in the process. Irreversible absorption processes would produce a CO_2-rich product that had to be disposed of continually and new absorbent added to the process.

Many CCS projects and natural gas processing plants use an amine-based liquid as the primary solvent for CO_2 capture by absorption (Fig. 15; Rubin and others, 2007). The amine solvent most commonly used is the organic compound monoethanolamine (MEA). This solvent is non-selective meaning that it chemically absorbs all acid gases, e.g., H_2S, not just CO_2. Because it reacts with SO_2 and NO_2, the presence of these gases will significantly reduce the absorption capacity. Thus, a MEA-based capture system requires a flue gas with low SO_2 (<10 ppm). Power plant exhaust gas streams

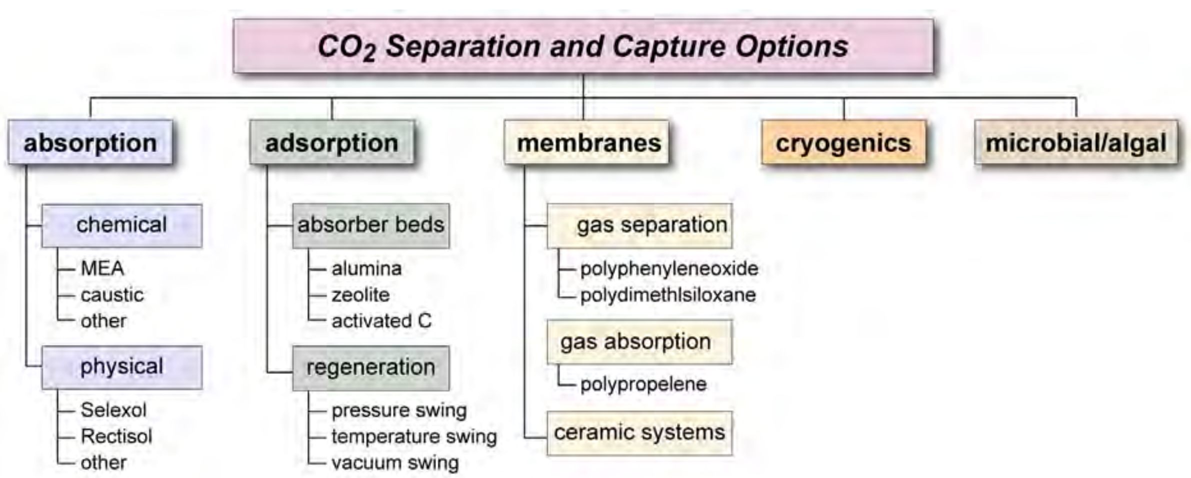

Figure 15. The five options available for CO_2 separation and capture and the various alternatives being pursued within each category. (Modified, Rao and Rubin, 2002)

typically have 700–2,500 ppm SO_2 depending on the nature of their fuel, therefore a SO_2 scrubber must be placed before the CO_2 capture unit unless co-sequestration of sulfur-rich CO_2 is permitted. MEA captures 75–90 percent of CO_2 in the exhaust gas and produces nearly pure (> 99 percent) CO_2 stream. A large amount of heat is required to drive off the absorbed CO_2 and regenerate the solvent. Energy is also required to run pumps and fans and after capture compress the CO_2.

The trademark solvents Rectisol™ and Selexol™ capture CO_2 physically (Fig. 15). Both are acid gas, e.g., hydrogen sulfide, CO_2, nitrogen oxides, etc., solvents. Selexol™ is a glycol-based solvent that separates absorbed acid gases at high pressures (20.7–138 bars). To release the gases, the pressure is lowered or the solvent interacted with steam to strip the acid gases. By adjusting the operating conditions, this type of absorption process can be used to generate different acid gas streams. As a physical absorption process, less energy is required to regenerate the solvent. Because power plants exhaust their flue gas at atmospheric pressure, a Selexol™-based separation unit would require pressurizing the gas stream. Rectisol™ is a separation process that absorbs acid gases at low temperature (-40°C) and high pressure (27.6–68.9 bars). Regeneration and acid gas release is accomplished by lowering the pressure of the charged solvent. Although less expensive than Selexol™, Rectisol™ requires considerable energy to maintain the optimum low operating temperatures.

Absorption is a cyclic process in which CO_2 is absorbed and desorbed in different columns (Fig. 16). Typically absorption is applied to a post-combustion exhaust stream, where the CO_2-bearing flue gas is cooled and decontaminated of soot and fly ash. After cleaning, the flue gas enters the bottom of an absorber column or tower (Fig. 16). The tower is filled with a packing material through which the gas ascends. At the same time, lean or CO_2-free solvent is pumped into the top of the column. As the liquid percolates down the column through the packing, it physically contacts the up-flowing gas. During the process, CO_2 diffuses from the gas into the solvent. At the top of the column where the flue gas has the lowest CO_2 content, the solvent is completely recharged and can absorb CO_2 effectively even at the low concentrations of CO_2 in the flue gas near the top of the tower. Moving down the column, the flue gas is richer in CO_2 and the solvent more charged. Thus at the base of the column, the nearly saturated solvent is in contact with the CO_2-richest flue gas. Under such conditions, the solvent still has the thermodynamic capacity to absorb more CO_2 because of the higher concentration of CO_2 in the flue gas stream. At the bottom of the tower, the charged solvent is transferred to a desorber tower/column (Fig. 16). The flue gas at the top of the absorber column, which is now mostly nitrogen and other gases, is simply exhausted to the atmosphere.

As the charged solvent falls through the desorber tower, it is heated to more than 100°C. Heating releases CO_2 from the solvent. The CO_2 vapor exits the top of the tower where it is cleaned of any water it might contain. It is then compressed for transport to a storage site. The volume of solvent required is, however, very large. For a 500 MW plant, six ML of solvent split between the two towers is necessary (CO2-CRC, 2013).

Adsorption

Adsorption, unlike absorption, is a surface process, but it too is cyclic. In this case, the gas molecules (adsorbate) are adsorbed onto the surface of a liquid or solid (adsorbent). For CO_2 capture, the solvent is usually a solid, generally zeolite, a class of fibrous silicate minerals. The process consists of three stages: adsorption, purge, and evacuation (Fig. 17). Because the active material is now a solid not a liquid, the capture unit is physically very different. If there is only one adsorbent bed in the unit, the process would have to work in batch mode. When the bed reaches full charge, the flow of flue gas would cease so the adsorbent bed could be regenerated. Thus, to handle the continuous exhaust gas stream of a power plant, the exhaust gas is cycled through three adsorbent beds (Fig. 17). In one bed, the flue gas continuously flows over the bed until it can no longer capture CO_2. In the unit with a fully charge adsorbent bed, the bed is purged of parasitic gases like nitrogen by flowing pure CO_2 gas through the unit displacing nitrogen molecules that attached to the surface. In the third, purged unit, a pump evacuates the bed by setting up a partial vacuum and drawing the CO_2 off the surface and out of the unit (Fig. 17).

Like absorption, adsorption can occur

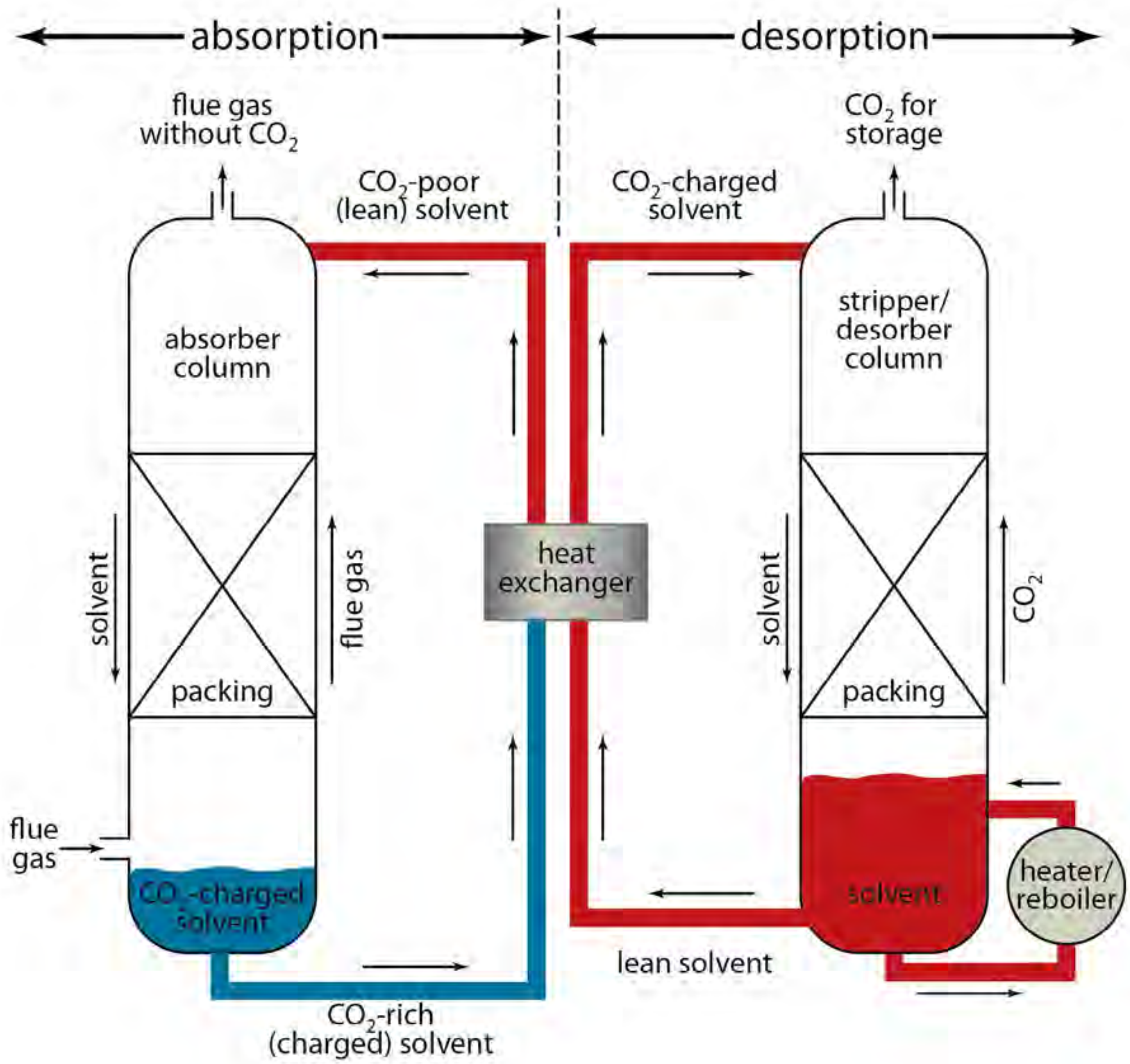

Figure 16. Carbon dioxide is stripped from the flue gas in the absorber column (left) to produce a nearly CO_2-free exhaust gas. In the desorption column (right), heat is applied to the solvent forcing the CO_2 out and regenerating the solvent, which is pumped back through the cycle.

chemically or physically. In the physical version, the adsorbate is held onto the surface by van der Vaals and electrostatic forces. When adsorption occurs, heat is given off in an exothermic reaction. For chemical adsorption, covalent bonds form between the adsorbate and adsorbent. A variety of materials are used as adsorbents. The most common are metal organic frameworks, zeolites, and mesoporous carbons. To release the CO_2 from the surface, a change in external conditions is necessary. These can be produced by using a thermal swing (increase in temperature), vacuum swing (creation of near vacuum), pressure swing (generally a decrease in pressure to near atmospheric), and/or an electrical swing (application of a voltage). Desorption by thermal swing is slow and energy intensive because the entire adsorbent must be heated. The vacuum swing can operate at ambient temperature so it requires less energy.

Membranes

Membranes are porous media that can be made of polymers or ceramics and separate CO_2 from a gas stream in a number of different ways (Fig. 15). Gas separation membranes selectively

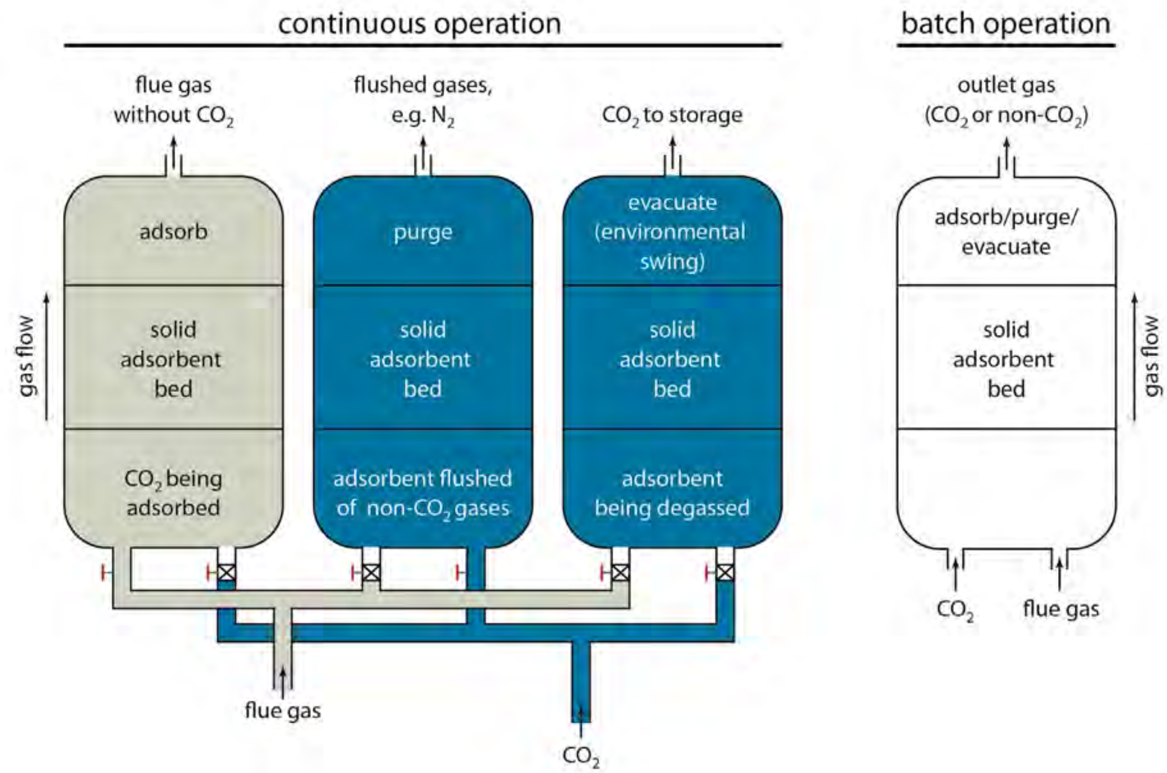

Figure 17. Adsorption captures CO_2 on to an adsorbent's surface. Left: To handle the continuous exhaust gas stream of a power plant, the three stages of the process—adsorb, purge and evacuate—are divided between three adsorber units. As the beds charge and discharge, the exhaust gas stream is switched cyclically between them. Right: A batch type of operation cycles the three stages of adsorption in a single physical unit. This type of arrangement is not optimum for carbon capture from a continuous gas source, e.g. power plant.

pass different gases through them based primarily on the gas molecule size. Typically, the use of gas separation membranes results in smaller equipment sizes. A pressure differential across the membrane drives separation. The biggest energy demand with this technique is creating a sufficiently steep pressure gradient to achieve effective separation. In essence, the membrane is a semi-permeable barrier like a cell wall. The rate at which gas is separated is a function of molecule size, gas concentration, and pressure differential. This process has not been applied on a large scale for CO_2 separation, and the high temperature of flue gases represents a serious barrier to widespread deployment for CO_2 capture because of the negative impact they have on the mechanical properties of the membrane.

An alternative approach to CO_2 scrubbing is to use membrane separation in conjunction with a liquid solvent (Fig. 18). In this case, the membrane maintains a stable permanent interface between the gas and liquid solvent and allows CO_2 exchange between the two (Fig. 18). The physical separation of gas and liquid flows eliminates some of the flow problems inherent in more traditional liquid absorption techniques, i.e., the problem of maximizing surface area contact between liquid solvent and flue gas. Specific sized gas molecules that pass through the membrane are then captured by the absorbent. This technique is useful when CO_2 has a low partial pressure (i.e., low concentration in the flue gas stream), which is the case for flue gas.

Cryogenic Separation

Cryogenic approaches to CO_2 separation use low temperatures to cool, condense, and purify CO_2 from a mixed gas stream. There are two variations of this method (Fig. 19). In the first type, the flue gas is cooled to sub-zero temperatures

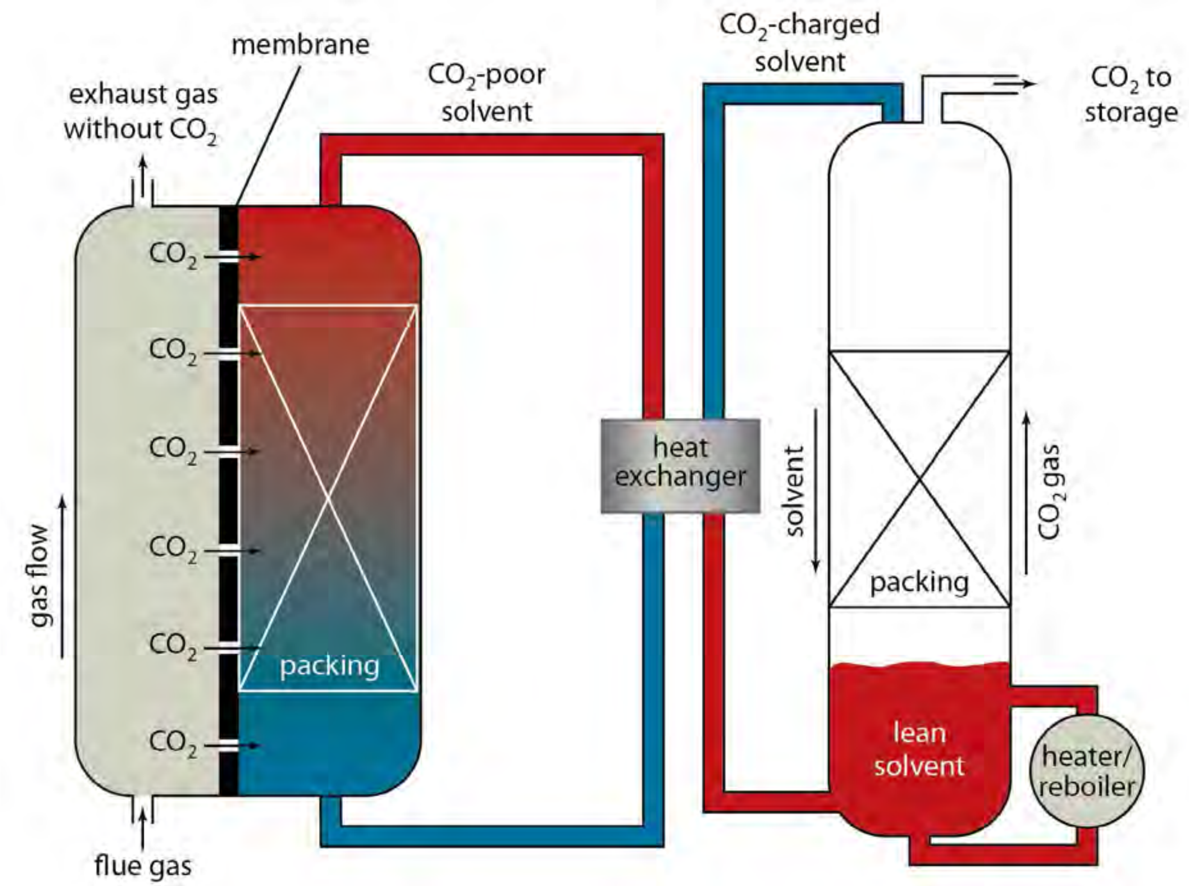

Figure 18. Gas absorption uses a porous membrane to separate gas and liquid solvent. The CO_2 diffuses through the membrane and is absorbed by the solvent.

at which only CO_2 condenses to a liquid. The remaining gases simply exit the chamber and are emitted. In the second case, the temperature and pressure are adjusted to reside in the hydrate stability field and chilled water is passed through the gas. The water freezes to form ice crystals with trapped CO_2. The hydrates are moved to a second process unit and heated, thereby releasing the CO_2.

Efficiency Penalty

The addition of CO_2 capture units to a thermal power plant adds a large parasitic electrical demand to the plant. Separation units have pumps, fans, and other equipment that require power. In addition, a large amount of energy is needed to regenerate solvents and adsorbents. The compression of captured CO_2 to supercritical temperatures and pressures, which facilitates transport and storage, is an additional energy sink. Thus, if these units are retrofit to an existing 'reference' power plant, the electricity that can be delivered to the grid is reduced significantly, i.e., the parasitic load consumes electricity that would normally be delivered to the grid (Fig. 20). Some estimates place this parasitic load as high as 60 to 100 percent of the reference plant's generating capacity (IPCC, 2005). For clarity, the term 'reference plant' refers to the power plant design without carbon capture (CC) equipment. To deliver the same amount of grid electricity as the comparable reference plant, additional generating capacity must be added to any power plant with carbon capture technology installed (Fig. 20).

This change in power plant electrical output has an impact on how much CO_2 is actually produced, emitted, and captured (Fig. 20). Although a capture unit will capture a significant portion of the produced CO_2, some CO_2 will

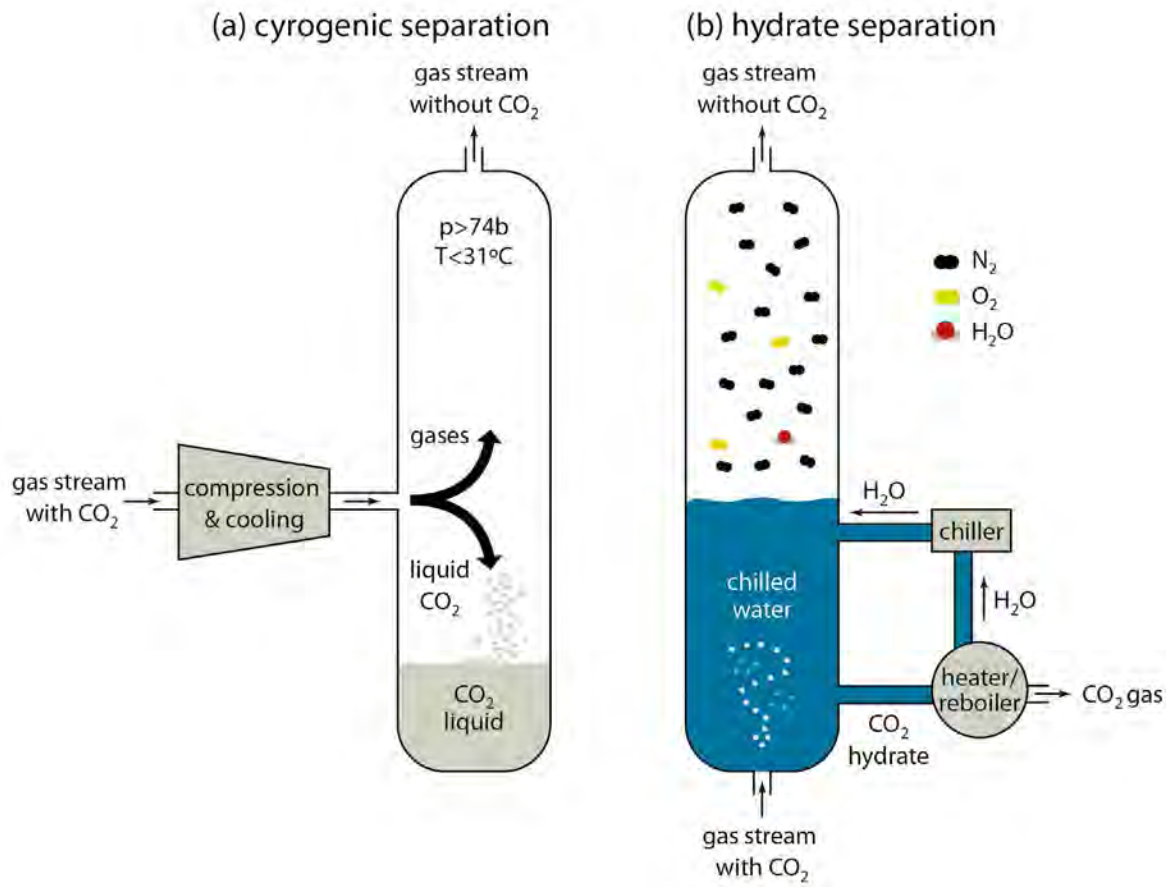

Figure 19. There are two variants of cryogenic separation. (a) The gas is cooled to a temperature at which CO_2, and only CO_2, condenses to a liquid. (b) Gas is cooled to a temperature where CO_2 hydrates are formed. Subsequent application of heat releases the CO_2 from the solid, hydrate phase.

necessarily be emitted to the atmosphere because no process is 100 percent effective. The difference between the emitted CO_2 and that produced and emitted by the reference power plant is the *CO_2 avoided*. Because it would not have been released under a BAU carbon scheme, the remainder of the captured CO_2 from the CC power plant is not a positive contribution to overall CO_2 emission reduction. Increasing the generating capacity of the reference plant to account for the parasitic load and deliver the same amount of grid electricity requires combustion of more fossil fuel. With this additional fuel consumption, more CO_2 is produced and the capture unit must process a larger produced CO_2 stream to capture a larger amount of CO_2 (Fig. 20). As with the smaller capacity, CC-equipped plant, only a portion of this captured stream is actually avoided CO_2 relative to the reference plant. In this instance, the amount of CO_2 avoided actually decreases as plant electrical generating capacity is increased. The ironic consequence of installing capture units is that they will increase the combustion of fossil fuels for the same amount of electricity, thereby necessitating ever larger CO_2 transport systems and storage capacities.

Carbon Transport

Transport links carbon capture and storage sites (Fig. 21). Currently, CO_2 is transported in three physical states, i.e., gas, liquid and solid; however, commercial scale transport involves only gaseous and liquid CO_2. Transport of CO_2 at atmospheric pressure would require very large facilities because of the large volume of gas that would have to be moved. Gas volume can be reduced by compression, liquefaction, solidification, or hydration. Only

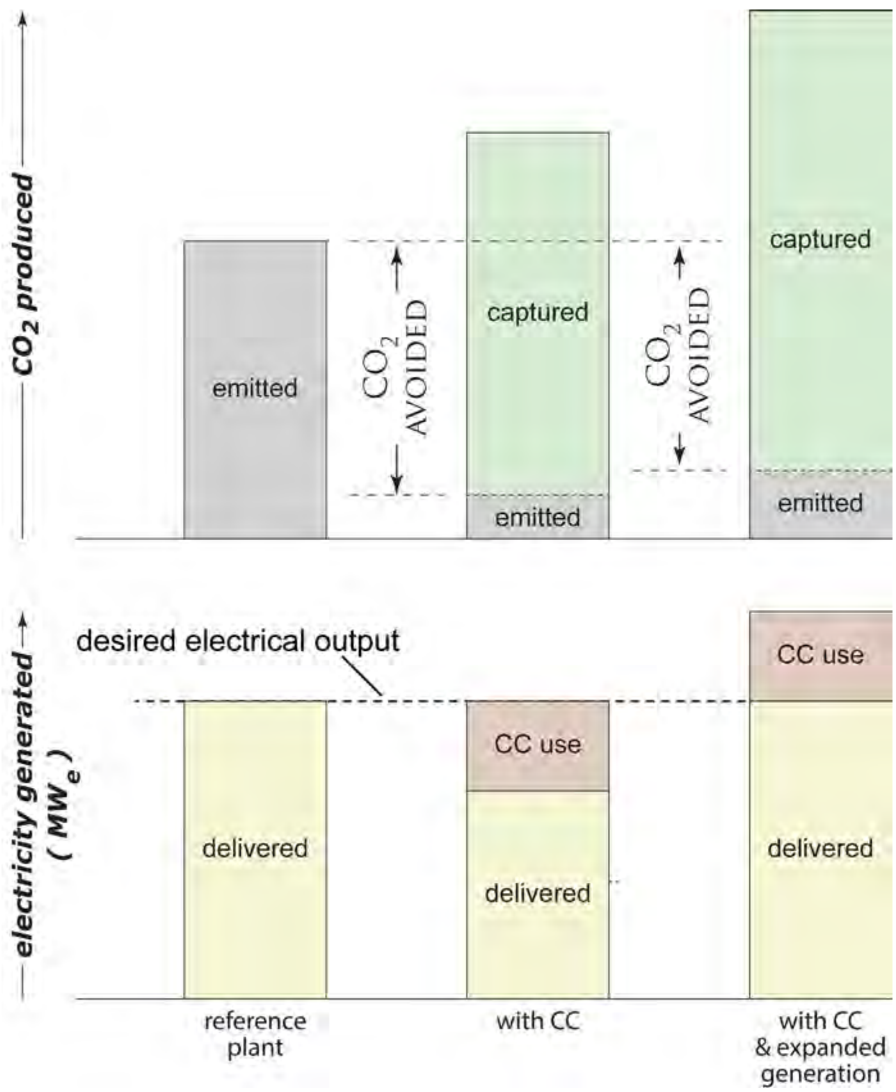

Figure 20. Operating a CO_2 capture unit requires considerable amounts of energy, i.e., a parasitic load. This parasitic load reduces overall plant efficiency, thereby impacting the electricity available for export to the grid as well as the amount of CO_2 produced. Relative to the original reference power plant only a portion of the captured CO_2 is actually avoided atmospheric emissions. The remaining portion of the captured stream is a consequence of adding the CC unit and under a BAU carbon management system would not have been produced because fossil fuel consumption would have been less. Abbreviations: CC – carbon capture.

compression and liquefaction are used commercially. Compression is common for pipeline transport whereas liquefaction is used for ship transport of LPG (liquefied petroleum gas) and LNG (liquefied natural gas). Solidification of a gas for transport requires too much energy to be cost effective.

In the United States, the major pipelines moving CO_2 are concentrated in the Texas Panhandle, Wyoming, Colorado, and across the U.S.-Canada border (Fig. 22). Nearly all of this CO_2 is transported for enhanced oil recovery (EOR) operations. Because of the location of current CO_2 pipelines, their expansion will do little to increase the nation's ability to move massive amounts of CO_2 from stationary sources to storage sites, i.e., from coastal regions where most CO_2 is produced to the continental interior where the geologic storage sites are located. The major obstacle to scaling up the CO_2 pipeline system is not technical, but the difficulty associated with gaining right of ways for new pipeline routes. Most of the new routes will originate in populated areas

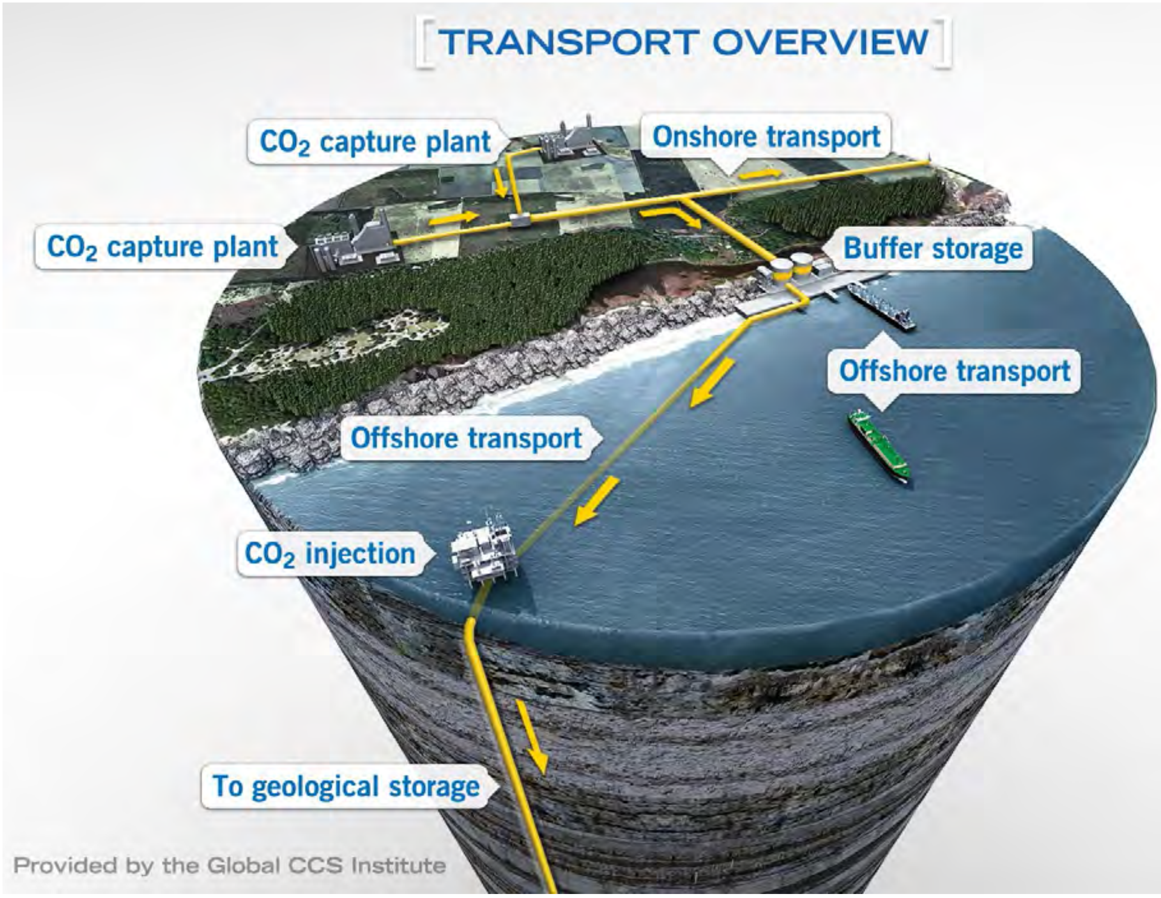

Figure 21. CO_2 transport moves captured CO_2 from its source to a storage site. Given the wide range of possible storage options, a fully developed CO_2 transportation system is likely to consist of both onshore and offshore components. (Source: Global CCS Institute, www.globalccsinstitute.com)

(areas with large CO_2 sources) on the coasts and move toward the continent's interior where the storage sites are located.

If the carbon capture and storage industry becomes global in scale, ships will have to be added to the CO_2 transportation system. This change would spawn a new transportation industry similar to that moving liquefied natural gas (LNG) today. Moving CO_2 by ship will require construction of loading and unloading facilities, as well as building of new ships. It is not unreasonable to expect an increase in not-in-my-backyard (NIMBY) opposition to the siting of such facilities, much like the current opposition to LNG terminals.

Currently, commercial transport of gaseous and liquid CO_2 (albeit at small volumes) is by truck-rail, pipeline, and ship. If 80 percent of the CO_2 from fossil-fueled electrical power plants was captured, the resultant CO_2 stream would be about 1,800 Mt/y (Newcomer and Apt, 2008). As the CCS industry grows, a new CO_2 transport infrastructure will have to be built on a massive scale, probably similar in size to that for oil and gas. Much of the experience from these industries can be directly applied to a CO_2 transport system. It is most likely that a global scale CO_2 transport system will consist of two components: 1) pipelines for transport across and within continents, and 2) ships for moving CO_2 between continents or to ocean disposal sites.

Pipelines

Because stationary sources, like power plants, produce CO_2 continuously, pipelines are a logical choice for moving CO_2 from them to onshore geologic sequestration sites. This mode of transport has been used successively to move natural gas, crude oil, refined petroleum products, condensate, and water for decades. Indeed, the crude oil portion of this global pipeline system alone covers thousands of kilometers and moves a vast amount of material every day. Pipelines can be laid on land across all types of terrains and in water to depths of 2,200 meters. Because pipeline operation is continuous, it can accommodate a constant stream of CO_2 captured from a power plant source. Pipelines do, however, require construction of intermediate storage facilities for potential interruptions in pipeline operation.

A pipeline can move CO_2 as a gas, liquid, gas plus liquid, or as a high density gas at high pressure (Skovholt, 1993). By necessity, pipelines transport fluid at ambient temperatures unless they are heated or refrigerated, an expensive operation. Onshore, buried pipelines experience stable soil temperatures of approximately 5–7°C. Offshore in deep water, a CO_2 pipeline is likely to be at 0°C. Before transport, gas volume is typically compressed. Most gas pipelines operate at pressures of 100–800 bars. When in hilly terrain, pipelines experience pressure drops when crossing high ground (Skovholt, 1993; Svensson and others, 2004). For liquid CO_2 pipelines, these pressure decreases could be great enough that the liquid evaporates to a vapor, thereby producing a region of two phase fluid flow in the pipeline. This type of flow creates operational and material problems. For example, cavitation can occur in pumps and booster stations (Svensson and others, 2004). In cold offshore environments where pressure is more stable because of the overlying water column, liquid transport of CO_2 should not be as problematic.

In the United States, pipelines have been transporting large amounts of CO_2 for almost 50 years without any major problems (IPCC, 2005). Although significant, these pipelines extend for slightly more than 3,600 miles (5,800 km) compared to the 500,000 miles (800,000 km) for natural gas and hazardous liquids pipelines. Yearly, the CO_2 pipeline system moves 50 $MtCO_2$, nearly all (> 90 percent) for EOR operations, especially those in the Permian basin of Texas. Comparatively, natural gas pipelines in the U.S. annually transport 455 Mt/y of gas over 300,000 miles (482,803 km) via inter- and intrastate pipelines.

In the U.S., some important pipelines include (IPCC, 2005):

- Canyon Reef: The first CO_2 pipeline, built in 1972, moves CO_2 from a natural gas processing plant to the SACROC field in Texas for EOR. The pipeline is 219 miles (352 km) long and moves 12,000 tons of CO_2 per day (4.4 $MtCO_2$/yr)
- Bravo Dome: A 20-inch (508 mm), 217 mile (350 km) pipeline that connects the Bravo Dome CO_2 field with other pipelines. Its capacity is 7.3 $MtCO_2$/yr
- Cortez: This 30-inch (762 mm), 499 mile (803 km) long pipeline moves CO_2 from McElmo Dome in southwest Colorado to Texas for EOR. The pipeline has a capacity of 20 $MtCO_2$/y and connects to other CO_2 lines in the mid-continent region
- Sheep Mountain: This 24-inch (610 mm), 410 mile (660 km) pipeline moves CO_2 from a natural CO_2 accumulation in southeast Colorado to Texas for EOR. The Sheep Mountain pipeline has a capacity of 9.5 $MtCO_2$/yr
- Wyoming: A pipeline originating in southwest Wyoming carries CO_2 from a natural gas processing plant near LaBarge, Wyoming to EOR operations in Colorado and Wyoming. One branch of the pipeline (24 inch, 48 mile [77 km]) goes to Rangley in northwest Colorado and the other extends to Salt Creek, Wyoming (20 inch, 112 mile [180 km]) near the center of the state

Another important CO_2 pipeline is the Weyburn pipeline, which connects the Great Plains Synfuels Plant in North Dakota with the Weyburn EOR project in Saskatchewan, Canada (Fig. 22). The pipeline is 190 miles (305 km) long and 12–14 inches (305–356 mm) in diameter with a total capacity of 1.8 $MtCO_2$/yr (5,000 tons/day). Unlike other pipelines, the gas stream is a mixture of 96 percent CO_2, 0.9 percent H_2S, 2.3 percent C_2+ hydrocarbons, 0.1 percent CO, 0.7 percent CH_4, less than 300 ppm N_2, less than 50 ppm O_2, and less than 20 ppm H_2O. The gas source is gasification of lignite for electricity generation.

In the U.S., existing pipelines do not connect regions of CO_2 source with potential storage sites. Thus, a CCS industry will require an extensive new

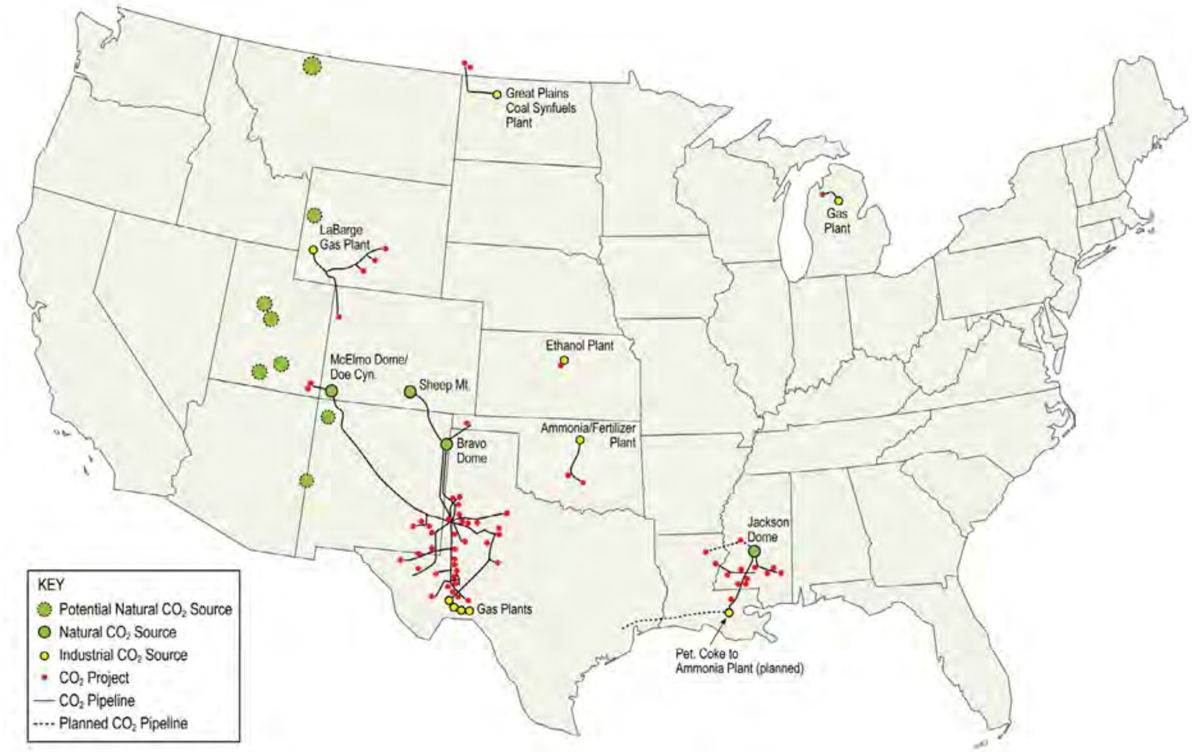

Figure 22. Major carbon dioxide pipelines in the United States. If a CCS industry on the scale necessary to reduce significantly anthropogenic CO_2 emissions is built, this pipeline system will have to expand out of the mid-continent region to both coasts to increase capacity. (Source: NETL, 2010a)

pipeline system. Because some of this system will have to transverse highly populated areas, gaining right-of-way access may be problematic. Newcomer and Apt (2008) suggest a pipeline moving CO_2 from electricity generation plants for sequestration will be an order of magnitude greater than the existing CO_2 pipeline system. This new infrastructure could be as large as the U.S. natural gas pipeline system. Although four times more CO_2 than natural gas would need to be transported, a new pipeline system will not be four times bigger because the same length of CO_2 pipeline carries three times the mass of a natural gas pipeline. Although CO_2 does not form flammable or explosive mixtures when combined with air, it is a potential physiological hazard for humans and animals. Carbon dioxide is denser than air, so dangerous concentrations can accumulate in low-lying areas. This characteristic of CO_2 will require constant internal (pipeline inspection gauge or PIG) and external (aerial and foot) pipeline monitoring.

Ship

Similar to transport in the LNG and LPG industries, an alternative means of moving large volumes of CO_2 long distances is by ship (Fig. 23). Currently, the only commercial movement of CO_2 by ships is the four small vessels that transport food-grade CO_2 in Europe (IPCC, 2005). Thus, there is little operational experience on how a large, global fleet transporting CO_2 would operate or what it would cost. Unlike a pipeline, moving CO_2 by ship is a discontinuous process, so massive intermediate storage facilities would have to be built. Transporting CO_2 by ship is a multistage process (Fig. 23), requiring both departure and offload terminals. Gas is first received at a terminal where it is liquefied and processed. It is moved into intermediate storage to await transport. From intermediate storage, CO_2 is piped to a ship for loading. At the final destination, the ship is unloaded (Fig. 23).

The most economic approach to moving various gases by ship is to liquefy them, thereby

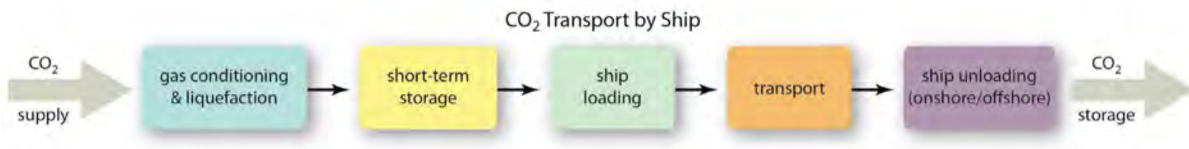

Figure 23. Stages in ship transport of CO_2.

significantly reducing their volumes. For CO_2, simply lowering the gas temperature at atmospheric pressure would produce only solid CO_2 (dry ice) (Fig. 4b). Thus, for CO_2 liquefaction requires low temperatures *and* pressures above atmospheric values. Depending on gas temperature, pressures above about 8 bars are required to liquefy CO_2. Pressurization results in another large energy penalty, i.e., another energy cost in the production chain, and places important constraints on the type of tank a ship can use for CO_2 transport, because the tank must be pressurized to maintain CO_2 in the liquid state.

Liquid gas transport ships have used three types of tank designs: 1) pressurized; 2) low temperature; and 3) semi-refrigerated. A pressurized tank prevents gas from boiling under ambient conditions, thereby reducing product loss but increasing construction cost. Low temperature tanks are designed to maintain CO_2 as a liquid at atmospheric pressure. Conversely, semi-refrigerated tanks adjust temperature and pressure in the tank to keep CO_2 in a liquid state. Because of the phase behavior of CO_2, only pressurized and semi-refrigerated tanks will maintain CO_2 in the phase necessary for economic ship transport. Because shipping CO_2 is a discontinuous process, transport by ship requires intermediate storage to handle the continuous flow of gas from a combustion point source, which is a continuous process.

Depending on the storage option, the unloading site would vary. For sub seafloor geologic sequestration, the off-load site would be an offshore platform from which the CO_2 would be injected underground (Fig. 24). In contrast, oceanic sequestration would unload to a platform, floating storage facility, single-buoy mooring system, or some sort of an intermediate storage system, e.g., an oil platform.

As with marine transport, a ship is subject to accidents that may result in loss of CO_2 containment. A ship can fail through collision, foundering, stranding, or fire. Carbon dioxide tankers have low fire risk, but there is the danger of asphyxiation during accidents. Spills could release liquid CO_2 on the sea surface, but such an event would not have the long-term environmental impact of a crude oil spill. In addition, a CO_2 spill will behave differently than a LNG spill. The CO_2 is not as cold as and much denser than LNG so it will probably hydrate and form ice. At the same time, CO_2 will dissolve into seawater and evaporate to the atmosphere.

Carbon Storage

The last component of the CCS chain is storage. As with transport, many of the technologies and processes used for storage have been developed and refined by the oil and gas industry over the last 50–60 years. The major hurdle will be to implement these practices on the scale necessary to significantly reduce global anthropogenic carbon emissions. Furthermore, CO_2 must be stored safely for thousands of years and prevented from escaping to the atmosphere. Three primary types of carbon storage have been proposed and are actively being investigated: mineral carbonation, oceanic sequestration, and geologic sequestration.

Mineral Carbonation

One possibility for long-term storage of CO_2 is *mineral carbonation*, which incorporates CO_2 into solid minerals. The main advantage of mineral carbonation is that prolonged storage is ensured by locking CO_2 in a stable solid. This process mimics the natural weathering of minerals, particularly silicate minerals, at the Earth's surface.

A very important class of sedimentary rocks is carbonates, which are rocks comprised predominantly of carbonate minerals. The most abundant carbonate rocks are limestone, marble, dolostone, and chalk.

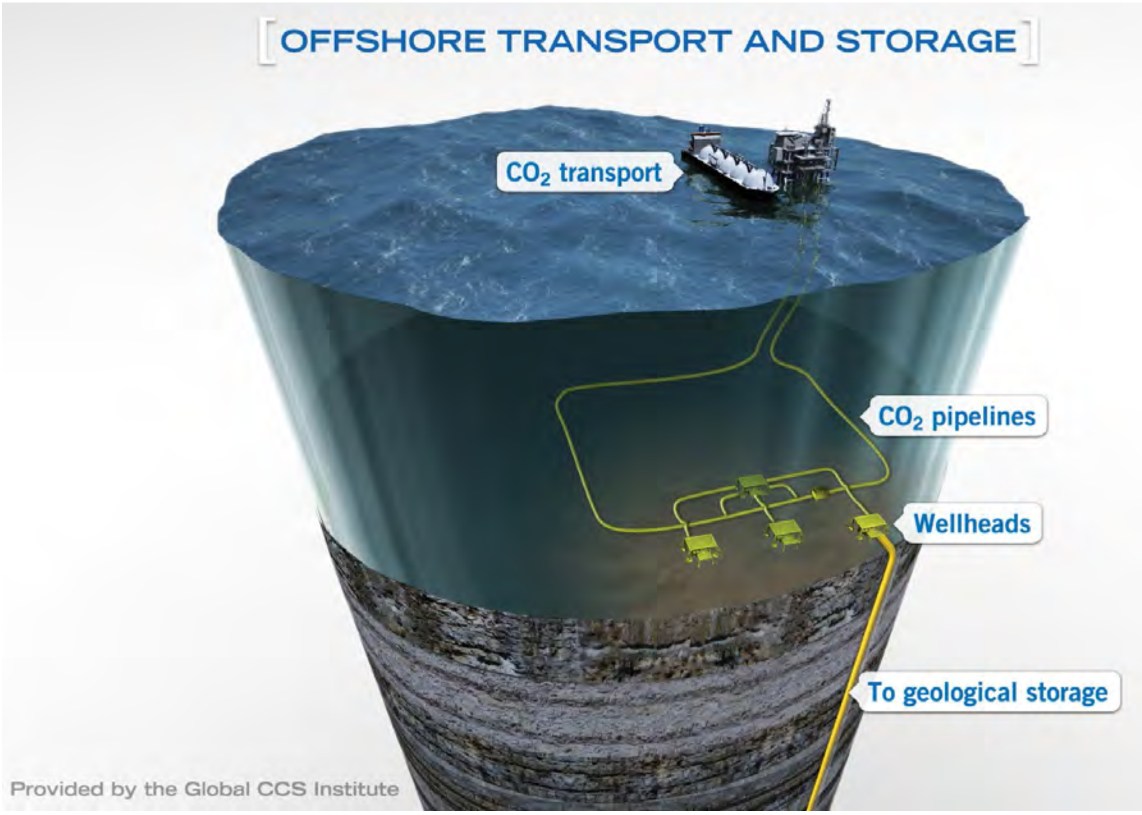

Figure 24. For geologic sequestration in offshore reservoirs, the CO_2 from a ship might be offloaded at a platform and CO_2 injected into the subsurface through a series of seabed manifolds. (Source: Global CCS Institute, www.globalccsinstitute.com)

Carbonate rocks are an important lithospheric reservoir of the carbon cycle, containing an estimated 70 million billion tons of CO_2. In fact, carbonate rocks are the single largest reservoir in the carbon cycle. However, formation and destruction of carbonate rocks is an exceedingly slow process so they play only a small role in the carbon cycle when it is considered on a human timeframe.

The dominant minerals of the carbonate rocks are carbonates, that is minerals in which the primary anion is the $(CO_3)^{2-}$ complex. This anion bonds to divalent cations, most commonly calcium (Ca^{2+}), magnesium (Mg^{2+}), and ferrous iron (Fe^{2+}). These minerals form by two primary, natural chemical processes: precipitation and weathering. Precipitation of carbonates from ocean water by either organic or inorganic processes transfers CO_2 in the carbon cycle from the hydrosphere to the lithosphere. Weathering of silicate minerals exposed at the Earth's surface forms carbonate minerals by removing CO_2 from the atmosphere. Indeed, Gaillardet and others (1999) estimate that nearly 0.1 GtC is fixed each year by weathering of silicate minerals.

The primary carbonate minerals bond $(CO_3)^{2-}$ with the divalent cations Ca^{2+}, Mg^{2+}, and Fe^{2+} (Table 1). Calcite forms when the divalent cation calcium (Ca^{+2}) bonds with the carbonate ion and is the most common mineral in limestone (sedimentary rock) and marble (metamorphic rock). It is also the primary component of the shells of marine organisms. When dilute acid is placed on calcite, the mineral fizzes and dissolves releasing CO_2. Dolomite is another calcium-bearing mineral, but unlike calcite some of the calcium has been replaced by magnesium. Because the crystalline structure of dolomite is different from that of calcite, the former does not fizz like calcite when acid is applied to it. Dolostones are chemical sedimentary rocks formed of dolomite. When the cation is ferrous iron, the carbonate mineral is siderite. Siderite is primarily found in hydrothermal veins, veins formed from hot fluids circulating in the Earth's crust. If iron is

mineral	formula	mass produced per ton C (ton)	volume produced per ton C (m^3)
calcite	$CaCO_3$	8.34	3.08
siderite	$FeCO_3$	9.65	2.49
magnesite	$MgCO_3$	7.02	2.36
ankerite	$Ca(Fe,Mg)(CO_3)_2$	8.60	2.81
dawsonite	$NaAl(CO_3)(OH)_2$	12.00	4.95

Table 1. Resultant masses and volumes of common carbonate minerals formed from CO_2. (Oelkers and others, 2008)

replaced with magnesium, the carbonate mineral magnesite forms. Magnesite is much rarer than the other carbonate minerals and is found in veins in ultramafic rocks and as an alteration product. Ankerite is even rarer and is similar to dolomite, but some of the magnesium has been replaced by iron. Its chemical formula is, $Ca(Fe,Mg)(CO_3)_2$. Ankerite occurs in both sedimentary and metamorphic rocks, but not in large amounts. Another carbonate mineral that may be important in geologic carbon sequestration is dawsonite, a hydrated carbonate that contains the $(OH)^{-1}$ ion. Dawsonite may form in sequestration sites through the interaction of injected CO_2 and minerals in the host rock.

Since weathering of carbonate minerals is slow, it keeps CO_2 out of the atmosphere for hundreds of thousands, if not millions of years. Because of the difference in mineral chemistry and structure, the reaction of a ton of carbon with the various divalent metals will produce different amounts of carbonate mineral (Table 1). For example, reacting carbon with calcium and oxygen to form calcite will produce 8.34 tons of calcite occupying a volume of 108 cubic feet (3.08 cubic meters). In contrast, the amount of dawsonite formed in the same manner would weigh 12 tons and occupy 175 cubic feet (4.95 cubic meters).

Mineral carbonation reacts captured CO_2 with metal-bearing minerals to form a solid carbonate mineral and a solid by-product, typically silica (SiO_2). In most instances, the CO_2 stream is a high-pressure, concentrated stream of gas. By producing a mineral, this process fixes CO_2 in a solid state thereby ensuring storage for geologically long periods of time. Because solid is more stable than gas, mineral carbonation is an exothermic process, i.e., it releases heat and occurs spontaneously. Unfortunately for sequestration purposes, the kinetics of the reactions are too slow to capture the large quantity of CO_2 produced by power plants. If carbonation is to be a viable option for CO_2 sequestration, a means must be found to increase the reaction rate while also improving the conversion efficiencies of the reactions.

Chemically, the general mineral carbonation reaction can be represented as (Eq. 3):

$$M^{2+}_{(s)} + \left(CO_3\right)^{2+}_{(aq)} \rightarrow MCO_{3_{(s)}} \qquad (3)$$

where M^{+2} is a divalent metal cation such as calcium, magnesium, or iron. Producing carbonate minerals on the scale necessary for sequestration requires a large source of divalent cations, a mechanism for enhancing the reaction efficiency, and a source of energy to speed the kinetics of the reaction.

A potential source of divalent cations is silicate minerals, those minerals formed from the bonding of a variety of cations with the silicon tetrahedron $[(SiO_4)^{-4}]$. Silicate minerals are the most abundant minerals in the Earth's crust. On the Earth's surface, silicates exposed to the atmosphere naturally weather to carbonate minerals. Typical silicate mineral weathering reactions include

$$\underbrace{Mg_2SiO_{4_{(s)}}}_{forsterite} + 2CO_{2_{(g)}} \rightarrow 2\underbrace{MgCO_{3_{(s)}}}_{magnesite} + \underbrace{SiO_{2_{(s)}}}_{quartz}$$

$$\underbrace{CaAl_2Si_2O_{8_{(s)}}}_{anorthite} + CO_{2_{(g)}} + 2H_2O \rightarrow \underbrace{CaCO_{3_{(s)}}}_{calcite} + \underbrace{Al_2Si_2O_5\left(OH\right)_{4_{(s)}}}_{kaolinite}$$

(4)

There are two main variations of mineral carbonation. *Ex-situ mineral carbonation* is conducted in a chemical plant on the Earth's surface. In contrast, *in-situ mineral carbonation* involves injecting CO_2 into silicate-rich formations or alkaline groundwater in the subsurface to initiate mineral reactions.

Ex-situ Mineral Carbonation

When carbonation occurs on the surface of the Earth, it is referred to as *ex-situ mineral carbonation*. For this type of process, a chemical carbonation plant would be built close to the mineral source and the CO_2 brought from the power plant where it was captured to the processing plant probably by pipeline (Fig. 25). The preference to move CO_2 in the gaseous state long distances rather than as a solid reflects the more expensive nature of transporting solid minerals compared to pipeline transport. Carbonation also adds additional material flows to the CCS chain (Fig. 25). These include input of metal-oxide bearing minerals and several outputs including the carbonate minerals formed, the by-product mineral, and non-reacted minerals from the original mineral feed (Fig. 25). At the same time, carbonation alters energy inputs and outputs in the CCS chain thereby impacting costs.

Ex-situ mineral carbonation involves several additional system steps. The mining and mine reclamation necessary for large scale carbonation of power plant flue gas would be comparable in scale to that of the modern mining industry (Oelkers and Cole, 2008; Oelkers and others, 2008). A mineral processing system including crushing, grinding, and milling, and classification, would be required to prepare the mineral input physically and chemically for reacting with CO_2. Milling the mineral feed would produce small mineral grains thereby increasing the solid surface area, which would accelerate carbonation reactions. Data from the ore processing industry on the various mineral processing steps reveals that they are extremely energy intensive and would materially increase energy needs and costs (Donoso and others, 2012; Norgate and Haque, 2010). In addition to the mineral processing plant, ex-situ carbonation requires an industrial facility for pre-processing the CO_2 by compressing, pressurizing, and heating it to 100°–500°C. The exact temperature required would depend on whether the reaction occurs in an aqueous or a solid state. In most cases, the reaction would be in the aqueous state because solid reactions are likely to be too slow. Lastly, the final carbonation system must be equipped with a carbonation reactor where the mineral feed and gas stream are combined and the carbonation reaction occurs. This reactor would probably suspend the silicate minerals in an aqueous solution saturated with CO_2. The silicate minerals would dissolve in the solution releasing their divalent metals. When in contact with carbonic acid (H_2CO_3) of the aqueous solution, the divalent cations react to precipitate carbonate minerals. By its nature, mineral carbonation in the reactor is a coupled reaction. The first reaction is the dissolution of the silicate mineral to contribute divalent cations to the solution. The second reaction is the interaction of these cations with the aqueous solution to precipitate the carbonate minerals. The rate controlling step in this coupled reaction is the silicate dissolution step. Ultimately, the fine particles (carbonates) in the solution would be separated by filtration for final disposal.

Some of the likely silicate minerals that might be feedstocks for ex-situ mineral carbonation include forsterite, serpentine, wollastonite, and anorthite (Table 2). Since the carbonation reaction combines a solid with a gas, the mass of the resultant carbonate mineral will be greater than that of the original mineral feedstock. For example, one ton of carbon reacted with magnesium will produce 5.86 tons of magnesite (Table 2). For anorthite, the amount of carbonate mineral produced is nearly four times greater than for fosterite (Table 2). Thus, the amount of solid material requiring disposal after carbonation will be considerably greater than what was originally mined. Solid wastes from the mineral processing stages will also require disposal. The estimates in Table 2 represent minimums because they assume pure mineral compositions when, in fact, the minerals mined will be solid solutions not pure end members. Thus, the igneous rocks mined will contain olivine, not the pure end member forsterite. This means some of the magnesium will have been replaced by other elements such as iron.

Sequestering the annual CO_2 output for a 1 GW station would require approximately 55,000 tons of rock per year (Oelkers and others, 2008). However, this number depends on the effectiveness of the carbonation reactor. If efficiency is low,

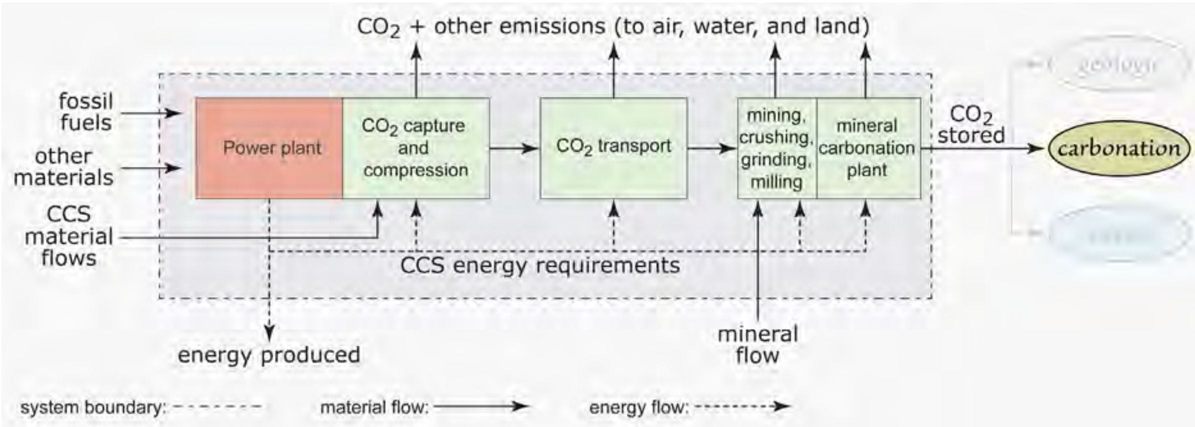

Figure 25. Ex-situ mineral carbonation adds very large material flows to the CCS project chain and increases energy demands. An increase in the emissions to air, water, and land concurrent with the materials input. (Copyright J.D. Myers. Used with permission.)

mineral feedstock may not react with the solution or may react only partially. Thus, the amount of mineral input needed would be higher. Regardless of the exact size of the rock mass necessary to complete the reaction, the mineral demand would have to be multiplied several thousand times to make a significant reduction in CO_2 emissions given the thousands of power plants worldwide. In light of this huge materials need, there are several concerns about the viability of ex-situ mineral carbonation as a means of significantly reducing anthropogenic CO_2 emissions on a global scale (Khoo and others, 2011). One set of concerns revolves around environmental impacts. The large scale mining necessary to obtain mineral feedstocks will have a significant impact on land and water resources and significantly increase global energy use. Ore preparation uses large amounts of water and produces large waste volumes that will have to be properly disposed. In addition, mining is energy intensive, which would contribute additional carbon emissions if fueled by fossil fuels. Different carbonation steps, e.g., mining, crushing, etc., will amount to 30–50% of a power plant's energy generation. The tailings produced during processing must be disposed of in an environmentally safe manner to protect land, soil, air, and water. At the other end of the carbonation process, the carbonate minerals now holding the CO_2 must also be disposed of safely. Another concern associated with ex-situ carbonation is a second large energy penalty at the power plant (IPCC, 2005). Carbon dioxide capture requires an additional 10–40 percent of the plant's output. This energy demand coupled with expenditures for mineral mining and preparation results in a total energy demand maybe 60–180 percent more than for the same power plant without CCS.

In-situ Mineral Carbonation

A potentially better option for mineral carbonation is *in-situ mineral carbonation*. This process would inject CO_2 into underground

mineral	formula	carbonate	t/tC seq.
forsterite	Mg_2SiO_4	$MgCO_3$	5.86
serpentine	$Mg_3Si_2O_3(OH)_4$	$MgCO_3$	7.69
wollastonite	$CaSiO_3$	$CaCO_3$	9.68
anorthite	$CaAl_2Si_2O_8$	$CaCO_3$	23.1

Table 2. Likely silicate minerals and the carbonate minerals formed from their reaction with CO_2. There is a significant difference in the mass of mineral required to sequester a ton of carbon. (t/tC=ton of mineral reacted per ton of carbon sequestered). (Source: Oelkers and others, 2008)

geologic formations where the mineral reactions would take place naturally. For in-situ mineral carbonation, the CO_2 is brought to the solids, not the solids to the gas. Thus, mining, ore processing, and solid handling are eliminated from the CCS chain, dramatically reducing costs and the energy associated with these activities. In addition, the need to dispose of large volumes of solids produced at the surface is avoided. Any rock formation that might potentially host an in-situ mineral carbonation project must contain large amounts of easily dissolved metal cations, have sufficient permeability and pore volume for injected fluid and resultant carbonate mineral and silica products, and be capped by an impermeable formation to prevent migration of CO_2 while carbonation reactions are occurring. To speed up the mineral reactions, water must be present. It may be present as formation water or CO_2 can be dissolved in water at the surface and injected as an aqueous solution. Two potential types of rock formations have been considered for in-situ mineral carbonation. These are sandstone and sandstone-shale formations, and basaltic and ultramafic rocks.

Mineral carbonation in sandstones and sandstone-shale hosts has been modeled geochemically (Xu and others, 2005). Because they are typically poor in minerals containing divalent cations, any shale or sandstone target would have to be characterized by the presence of some iron-bearing minerals such as chlorite. In this case, carbonation would result in production of iron-bearing carbonate minerals, e.g., siderite or dawsonite. Geochemical modeling suggests 100,000 years are needed to produce 90 kg of carbonate minerals per cubic meter of sandstone. As expected, modeling also confirms the need for sufficient Na, Al, and Fe, which are elements often lacking in sandstones. All studies to date suggest that in-situ mineral carbonation in sandstones or sandstone-shale formations is impractical.

An alternative host for in-situ carbonation consists of basaltic and ultramafic rocks (Oelkers and others, 2008). These are rocks that have high magnesium content and are globally widespread. Mafic rocks are volcanic and igneous in origin and contain abundant divalent cations, particularly iron and magnesium, but also some calcium. These are the same types of rocks that would likely be mined for ex-situ mineral carbonation operations and they occur in very large exposures at the Earth's surface. In the U.S., massive basaltic flows occur along the Columbia River in the northwestern United States. Geochemical modeling suggests that significant carbonation occurs in 10–100 years in a basaltic glass host (Matter and others, 2007). These rates are much faster than those calculated for sandstones. Although the reaction rates are faster in these hosts, the resulting mineral phases have a much greater volume than the original rock. The resultant expansion may clog pore space and significantly redue in the amount of CO_2 the formation can ultimately hold. Any volcanic or igneous unit targeted for in-situ mineral carbonation must be capped by an impermeable seal rock. Until the minerals in the host rock react to form carbonates, the injected CO_2 will exist as a supercritical fluid, which is bouyant. Without a stable and impermeable cap rock, the CO_2 may leak out of the reservoir and either escape to the surface or contaminate groundwater aquifers.

Despite the advantages of a basaltic or ultramafic host or in-situ carbonation, there are several potential major problems. First, there are significant water availability and quality concerns. In-situ mineral reactions speed up in the presence of water. Thus, CO_2 fluid must be injected into volcanic and igneous rocks with ample groundwater, or an aqueous solution containing CO_2 must be created at the surface and injected. Either case will result in more acidic formation water because of the additional CO_2. This increased acidity will dissolve silicate minerals in the host rock. From the standpoint of carbonation, this is a positive result because it releases the divalent cations necessary for carbonate precipitation. However, dissolution may simultaneously release toxic metals that could potentially contaminate groundwater. Finally, potential basaltic and igneous hosts are not proximal to large, stationary CO_2 sources (Fig. 26). In the United States, stationary CO_2 sources are concentrated in the east, but the potential basaltic hosts in the far northwest. A similar mismatch of source and sink is also exists in Asia and Europe. Thus, CO_2 would have to be transported to the injection site, thereby entailing additional energy and economic penalties. Currently, research suggests in-situ mineral carbonation is not feasible as a means of significantly reducing CO_2 emissions.

Oceanic Sequestration

The oceans have an extremely large capacity for storing CO_2. Presently, 40,000 Gt of carbon are contained in the oceans. This is the largest surface reservoir in the carbon cycle. The atmosphere contains a mere 800 GtC, whereas terrestrial biomass stores 2,000 GtC. The difference in amount of CO_2 stored in the atmosphere and ocean is very important. The amount of carbon that would double the atmosphere's carbon content if put in the oceans instead would only increase the latter's carbon content by two percent. Thus, the ocean's large carbon mass could buffer it from significant chemical and physical changes associated with increased carbon storage.

The ocean and atmosphere are in dynamic communication chemically and physically. Presently, because of anthropogenic carbon emissions to the atmosphere, the ocean-atmosphere system is not in equilibrium. Thus, two GtC (seven $GtCO_2$) per year enters the oceans from the atmosphere (Adams and Caldeira, 2008). In the last 200 years, the oceans have absorbed 500 of the 1,300 $GtCO_2$ emitted by human activities. Almost all this CO_2 has ended up in the upper part of the oceans and resulted in a 0.1 unit decrease in the pH of the upper ocean (Orr and others, 2005b; Doney and others, 2009). Because of the vertical structure of the ocean, little of this additional CO_2 has yet reached the intermediate or deep ocean. Hence, these parts of the ocean have been little affected by humans and their pH has remained constant. Over the next hundreds of years, 70–80 percent of CO_2 emitted to the atmosphere will ultimately end up in Earth's oceans.

As concerns about anthropogenic CO_2 emissions have grown, several arguments have been advanced to inject CO_2 directly into the deep ocean (Marchetti, 1977; Ohsumi, 1995; Ozaki, 1997; Herzog, 1998; Ozaki and others, 2001; Adams and Caldeira, 2008). Deep ocean sequestration would accelerate natural processes and protect the upper ocean by slowing CO_2 increase. Unlike in the upper ocean, most marine biota that inhabits the deep ocean would not be at risk from increased CO_2 levels due to the more localized nature of the CO_2 sequestration. Because of the more limited interaction between the upper and deep ocean as compared to the upper ocean-atmosphere, sequestration of CO_2 in the deep ocean would also extend the time CO_2 takes to reach the upper ocean, thereby reducing the danger of ocean acidification.

Simulations of different oceanic sequestration

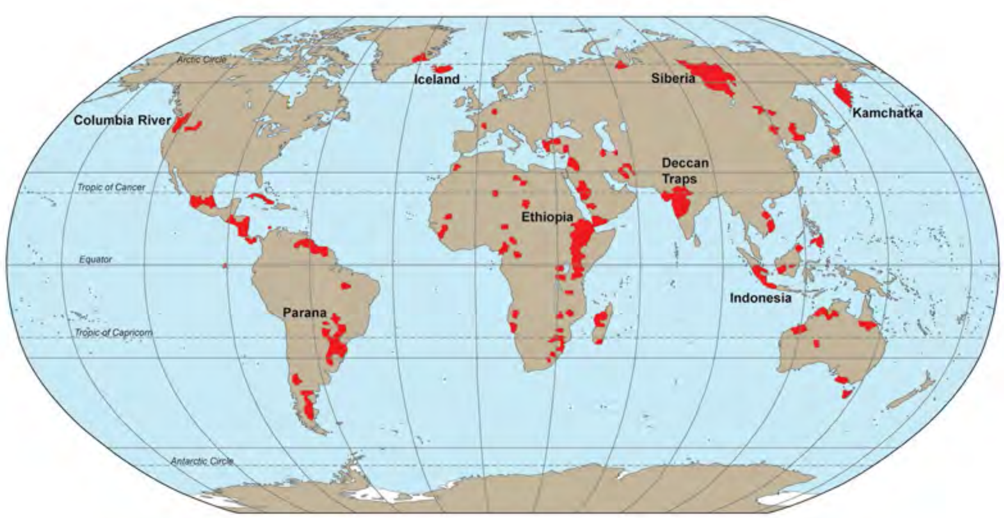

Figure 26. Global distribution of mafic and ultramafic rocks that are likely targets for in-situ mineral carbonation. In most cases, these carbon sinks are far from large stationary sources of CO_2, thereby necessitating the construction of additional CO_2 pipelines. (Modified from Oelkers and others, 2008)

scenarios clearly show significant reductions in future peak atmospheric CO_2 concentration (Fig. 27; Kheshgi and Archer, 2004; IPCC, 2005). In these simulations, the fossil fuel era is assumed to be of finite duration, i.e. eventually fossil fuels will be exhausted and CO_2 emissions from their combustion will sharply decline (Kheshgi and Archer, 2004). To simulate future cumulative emissions, a logistics curve, i.e. an S-shaped curve with gradual early growth, rapid intermediate growth, and a slow tapering off of growth as a maximum value is approached, was assumed with two different cumulative emission maxima (5,000 vs. 2,000 GtC). For the higher cumulative CO_2, 100 percent emission to the atmosphere produces atmospheric CO_2 levels above 1,900 ppm in the year 2,300 (Fig. 27). If instead of emitting the CO_2 to the atmosphere all is injected into the deep ocean, i.e., below 9,842 feet (3,000 meters), peak atmospheric CO_2 levels are under 800 ppm and delayed until nearly 3000 (Kheshgi and Archer, 2004). A more conservative sequestration scheme in which only half of the emissions are injected into the deep ocean results in nearly a halfing of peak atmospheric CO_2 levels. Clearly, oceanic sequestration could have a dramatic impact on atmospheric CO_2 concentrations, while slowing the decrease in upper ocean pH.

Understanding how CO_2 injected into the

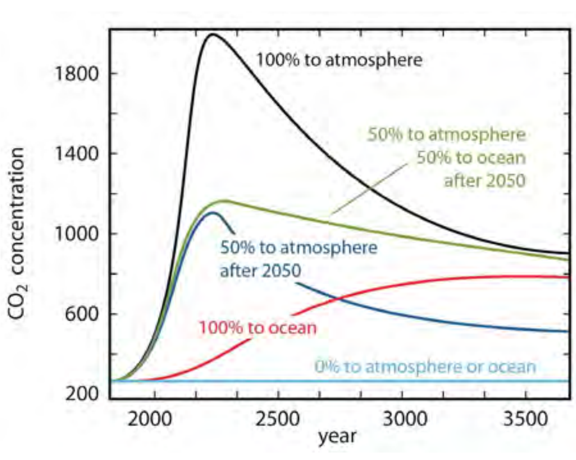

Figure 27. Carbon dioxide concentration-time curves illustrating the impact of different sequestration or non-sequestration scenarios on atmospheric CO_2 levels. The different curves represent different schemes for partitioning future CO_2 emissions between the atmosphere and deep ocean. See text for details. (Modified from Kheshgi and Archer, 2004)

oceans behaves requires understanding its physical and chemical behavior. These factors interact in different ways to determine how an injected CO_2 phase moves, where it ultimately resides, and what the impact of additional CO_2 will be on ocean chemistry, particularly pH. When dissolved into seawater, CO_2 behaves in a number of different ways. Seawater-CO_2 equilibrium is described by the carbonate system, which can be summarized by the following coupled reactions:

$$CO_{2_{(g)}} + H_2O \leftrightarrow \underbrace{H_2CO_{3_{(aq)}}}_{\text{carbonic acid}} \leftrightarrow H^+ + \underbrace{HCO^-_{3_{(aq)}}}_{\text{bicarbonate ion}} \leftrightarrow \underbrace{2H^+}_{\text{hydronium ion}} + \underbrace{CO^{2-}_{3_{(aq)}}}_{\text{carbonate ion}} \tag{5}$$

In seawater, the principal CO_2 dissolution reactions are:

$$\begin{gathered} CO_2 + H_2O + CO_3^{2-} \leftrightarrow 2HCO_3^- \\ CO_2 + H_2O \leftrightarrow H^+ + HCO_3^- \end{gathered} \tag{6}$$

The physical phase CO_2 will assume when injected into the ocean depends on the depth of injection. At shallow depths, CO_2 will be a gas, but a liquid at greater depths (Fig. 28). When in contact with seawater, injected CO_2 at the appropriate temperature and pressure combination can react to form CO_2 hydrate ($CO_2 \cdot 6H_2O$), that is, a CO_2 molecule trapped in a cage of six H_2O molecules, the water molecules are bonded together by hydrogen bonds. Thus, at depth and low temperatures, injected CO_2 could be trapped as a solid phase. In this form, CO_2 is denser than seawater and would sink to accumulate on the ocean floor. A more familiar example of this type of phase behavior is the abundant methane hydrate ($CH_4 \cdot 6H_2O$) found in seafloor sediments and viewed as a possible future energy source.

The density of liquid CO_2 varies with the depth, i.e., pressure, more so than seawater (Fig. 29). The steeper density curve for seawater than CO_2 means that the latter is more compressible than the former. Because of this difference in seawater-CO_2 compressibility, the behavior of liquid CO_2 in the ocean water column depends on the depth where the two density curves cross

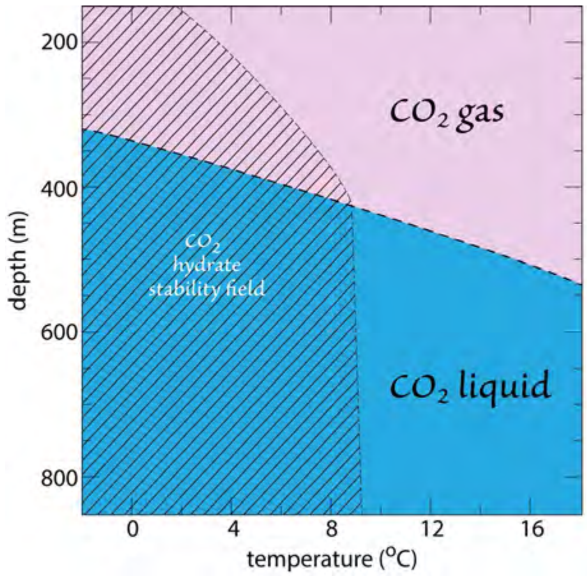

Figure 28. Ocean depth-temperature diagram for CO_2 showing its three phase stability fields. Above the dotted line, CO_2 exists as a gas. At the higher temperatures and pressures below the line, CO_2 will be in liquid form. (Modified from IPCC, 2005)

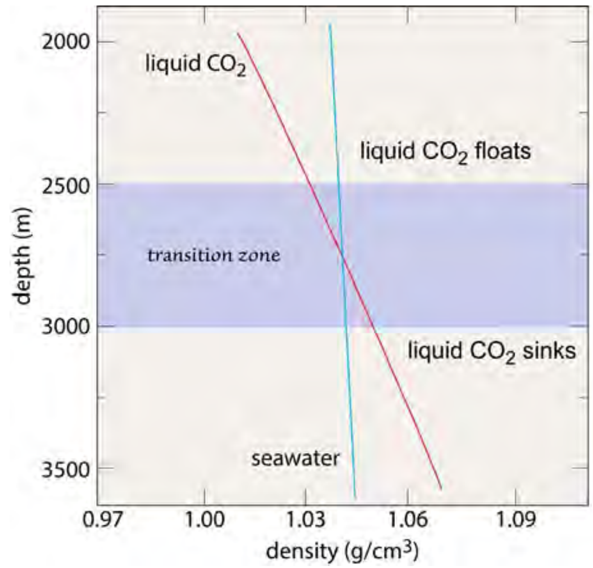

Figure 29. Density curves for seawater (blue) and liquid CO_2 (red). Since these two lines cross, the behavior of liquid CO_2 in the water column will vary as a function of depth of injection. Above the cross-over point, liquid CO_2 will rise, whereas below it the liquid will sink.

(approximately 2,750 meters [9,022 feet]). Above 9,842 feet (3,000 meters), CO_2 is less dense than seawater. For example, at 3,280 feet (1,000 meters), CO_2 liquid is 6 percent less dense than seawater. Consequently at depths less than 9,842 feet (3,000 meters) CO_2 will move upward in the water column. At depths greater than 3,000 meters, it is denser than seawater and will sink through the water column.

Oceanic sequestration, like mineral carbonation, starts with CO_2 capture, compression and transport by either ship or pipeline (probably both). The captured CO_2 can be injected either into the upper 600 m of the water column or into the deep ocean. The former option is probably not an optimal choice because of present concerns about already on-going acidification of the uppermost ocean. A number of means of injecting CO_2 directly into the deep ocean have been suggested (Adams and Caldeira, 2008). These include injection from stationary ships to form rising or sinking plumes, dispersal from moving ships to produce a CO_2-enriched volume of seawater, or discharge directly onto the seafloor. The physical and/or chemical state in which to inject CO_2 is also a matter of debate. Options include pure gas or liquid (direct dissolution), an aqueous solution of seawater and CO_2, or solid CO_2 hydrate.

Plumes: Sinking or rising plumes can be created by releasing CO_2 from a manifold on the seafloor or from a ship (Fig. 30). The fate of the plume depends on the depth of injection. At depths less than 9,842 feet (3,000 meters), the plume will rise, whereas deeper depths result in a sinking plume. The size of CO_2 droplets in the plume can be adjusted to fix the distance it travels in the water column before it dissolves into seawater. Injection could also be from a moving ship thereby maximizing mixing and dilution. Both mechanisms produce a vertical column of CO_2-enriched seawater. In an alternative method, CO_2 could be reacted with seawater before injection, thereby producing a solution heavier than seawater with subsequent injection from a stationary or moving ship, or seabed manifold. A third approach would be to mix CO_2 with seawater under the correct pressure-temperature conditions to produce hydrates. These are 10 percent heavier than seawater and dissolve more slowly than liquid CO_2.

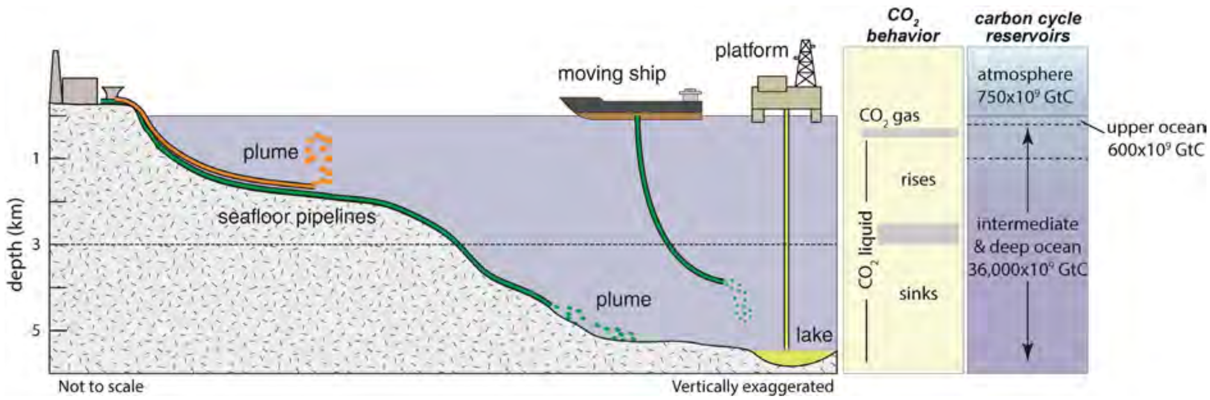

Figure 30. Proposed ocean sequestration schemes. Because the deep ocean holds much greater amounts of CO_2 than the atmosphere (rightmost panel) and mixing between the deep ocean and the atmosphere is exceedingly slow, an alternative to atmospheric emissions of anthropogenic CO_2 is to sequester it in the deep ocean by injection, oceanic carbon sequestration. How the injected CO_2 behaves, e.g. physical state and rise/sink, depends upon the depth of injection (center panel). Carbon dioxide injected below 984 to 1,640 feet (300-500 meters) will be in the liquid state, whereas injection at shallower depths yields gaseous CO_2. Below approximately 11,483 feet (3,500 meters), liquid CO_2 is denser than sea water and will sink. Injection in the water column as plumes, either from pipelines or ships, results in plumes that will ultimately dissolve into sea water (left panel). Injection of liquid CO_2 into depression on the seafloor will produce lakes of liquid CO_2 that are gravitationally stable.

Lakes: An alternative to injecting CO_2 into the water column is to discharge CO_2 onto the seafloor. At seafloor depths below 9,842 feet (3,000 m), CO_2 would be a liquid denser than seawater. Hence, it would not rise through the water column. If CO_2 was piped into depressions, it would form a lake (Fig. 30). Some of the liquid in the lake would react to form hydrate, which has a slower dissolution rate in seawater. Eventually this liquid will equilibrate with seawater above its surface, i.e., some of it will dissolve into seawater above the sea bed, but it will be slower than liquid dispersed in the water column; thereby maximizing retention time.

Clearly, oceanic sequestration will have attendant environmental effects (Adams and Caldeira, 2008). Marine organisms will be impacted in two different ways: change in seawater pH; and increased concentration of CO_2 in the water. The results of these changes on sea life are varied and include difficulty to make shells, respiratory stress, acidosis, and metabolic depression. The scale of these effects will vary with distance from the injection point. For the far-field organisms, the impacts will be less. In contrast, near-field organisms will be significantly impacted. These impacts can be minimized or mitigated by diluting the CO_2 liquid.

It is unclear if there will be the political, social, and regulatory acceptance necessary for ocean sequestration. The major advantage of this type of sequestration is that the shallow ocean impacts of ocean sequestration are significantly less than those that would arise if the CO_2 was emitted directly to the atmosphere. Two small international field tests of ocean sequestration have been stopped by environmental opposition. Off Norway, a small field test would have injected five tons of CO_2 for a week (Giles, 2002). A planned injection of 60 tons of CO_2 at 2,624 feet (800 m) off Hawaii was also stopped by public opposition (Gewin, 2002). There are also legal issues regarding ocean carbon sequestration (e.g., Does the London Conference permit it?). International discussions on this issue are already underway.

Geologic Carbon Sequestration (GCS)

Natural accumulations of CO_2 in the subsurface have existed for hundreds of millions of years and clearly show that the lithosphere can store buoyant fluids for the geologic time periods relevant to climate change mitigation. Thus, one of the most researched sites for storing CO_2 is the lithosphere, i.e., pumping capture CO_2 into underground rock units or formations (geologic carbon sequestration, or GCS). The four primary targets for geologic sequestration are (Fig. 31): 1) saline formations; 2) deep, unmineable coal seams (with or without enhanced coalbed methane (ECBM) recovery); 3) enhanced oil (EOR) and natural gas (ENGR) recovery; and 4) depleted oil and gas fields.

Enhanced Oil Recovery (EOR)

Two of the primary targets for geologic sequestration are producing and depleted oil and gas reservoirs. Although similar geologically, these sites are very different in terms of operation and economics. Enhanced oil recovery occurs when a hydrocarbon reservoir still contains economically recoverable amounts of hydrocarbons. Thus, the field is still in production and an oil and gas infrastructure is in place and operational. Conversely, depleted oil and gas fields are no longer capable of producing economic quantities of hydrocarbons even with secondary and tertiary recovery mechanisms like EOR. If the field has been abandoned, the surface infrastructure for oil and gas production will have been removed and wells plugged and abandoned. In the case of a producing field, there is an economic benefit to pumping CO_2 underground because it facilitates recovery of additional oil and/or gas. Conversely, injection into depleted oil and gas reservoirs is strictly a sequestration activity from economic, regulatory, and legal perspectives. In either of these cases, the subsurface geology is similar and well-documented. According to the IEA (2006), depleted oil and gas reservoirs have a potential storage capacity of 900 Gt of CO_2.

Oil and gas fields are prime candidates for CO_2 storage for a number of important reasons. They have stored oil and gas, both buoyant fluids like CO_2, for geologically significant periods of time. In some instances, this storage has been for tens or even hundreds of millions of years. This fact implies that oil and gas fields have proven safe as potential storage sites. Because they have been the subject of extensive geologic and petroleum engineering investigations, often for several decades, these fields are generally well-characterized. These data often have been used to create complex computer models of how fluids flow in the subsurface. Such models, with minor modification, could be used to model how injected CO_2 would behave in the reservoir. Unless fully abandoned, existing infrastructure may provide a starting point for constructing the surface gas-handling system necessary to process CO_2 during any subsequent storage operation.

Petroleum production normally recovers only a fraction of the oil originally in place (OOIP) in a hydrocarbon reservoir. Primary production, i.e., that relying on natural reservoir pressure to extract the oil (Fig. 32), may recover anywhere from 5 to 40 percent of the OOIP. As reservoir pressure falls, enhanced recovery mechanisms may be used to maintain or increase reservoir pressure, thereby increasing ultimate recovery. Secondary recovery often uses water and chemical flooding along with gas re-injection to extract another 10–20 percent of OOIP. If oil prices are high enough, tertiary recovery such as steam flooding, reservoir burning, or CO_2 injection may extract another 7–23 percent of the oil before reservoir pressures fall to the point that economic amounts of oil can no longer be produced and the field is ultimately abandoned. Because CO_2 flooding for enhanced oil recovery leaves some of the injected CO_2 in the ground, CO_2-EOR has been viewed by some as an intermediate step to commercial GCS. Proponents argue that CO_2-EOR, while sequestrating some CO_2, will more importantly provide operational, geologic, and engineering experience that will be valuable to future, commercial GCS projects. Accordingly, many now refer to CCS as CCUS, i.e., carbon capture, *utilization*, and storage. Critics of CO_2-EOR as a means of reducing anthropogenic CO_2 emissions point out that the additional oil recovered will be combusted, thereby contributing to CO_2 emissions (Aycaguer and others, 2001; Jaramillo and others, 2009).

Carbon dioxide flooding is increasingly used as a means of tertiary petroleum recovery and potentially represents an early mode of CO_2 sequestration. In particular, large amounts of CO_2 have been used for enhanced oil recovery in the United States for nearly five decades. While some of the injected CO_2 is sequestered, these operations are more important because of the operational experience they have provided for injecting CO_2. Depending on conditions, oil and CO_2 display two distinctly different phase behaviors. At lower

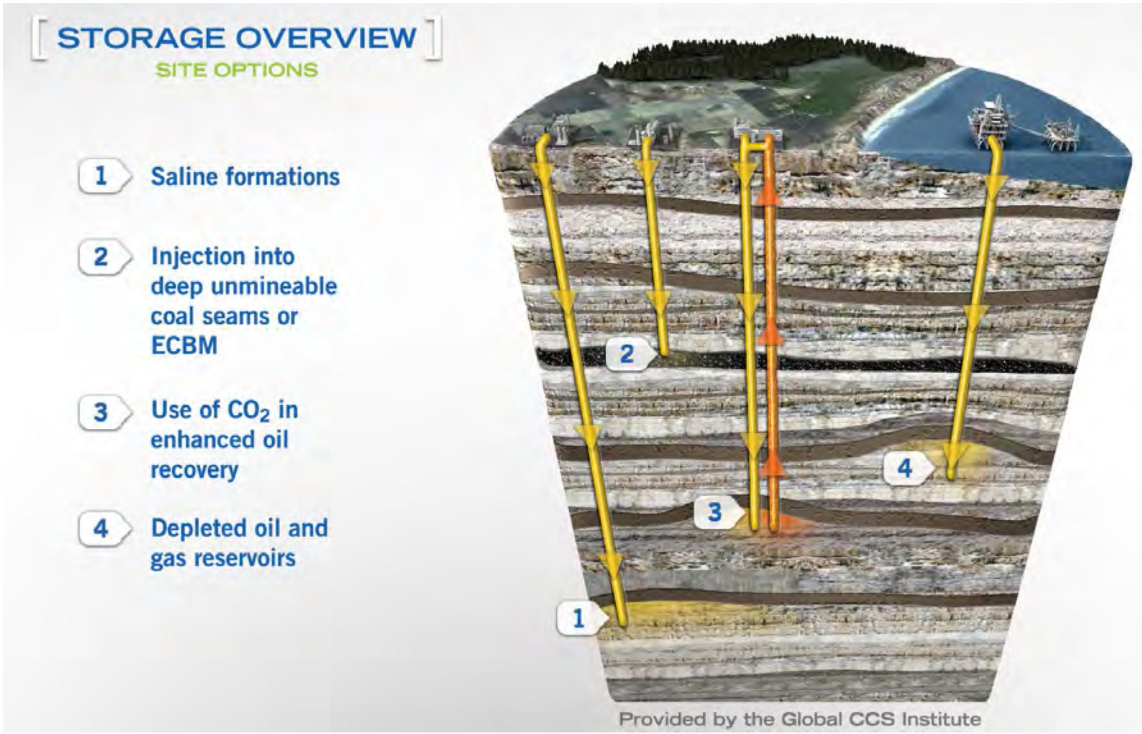

Figure 31. The four primary target reservoirs for geologic carbon sequestration. (Source: Global CCS Institute, www.globalccsinstitute.com)

temperatures and pressures, the two phases are not miscible, i.e., they do not form a single, homogenous liquid phase (Fig. 7). Under these conditions, CO_2 injection will produce immiscible flooding where CO_2 and oil do not mix, but form two physically distinct phases in the reservoir. When oil and CO_2 mingle or mix to form one homogeneous liquid, they display miscible behavior. Phase behavior not only depends on the temperature, pressure, and depth of the reservoir, but also on the composition of the crude oil, particularly its API gravity.

The most desirable type of CO_2-EOR project is a miscible flood (Shah and others, 2010) where CO_2 and oil mingle to form a single homogeneous fluid. This new fluid flows more readily because of the solvent behavior of CO_2, i.e., it frees oil from mineral surfaces just like a solvent removes oil from a surface better than pure water. The CO_2-rich oil also swells in volume and decreases in viscosity. Both factors aid in the movement of oil out of the reservoir. A miscible state is most likely to be achieved with light (25-48 API), low-viscosity oils, low reservoir temperatures and reservoir depths greater than 1,969 feet (600 m), presumably where reservoir pressure is greater than the miscibility pressure, i.e., the pressure where the miscibility gap closes.

Operationally, there are two ways to conduct a CO_2 flood. The simplest is to continuously inject CO_2. This type of injection produces a miscible zone along the interface between the CO_2 and oil (Fig. 33). In front of this zone is an oil bank, a region enriched in oil. These fronts move away from the injection wells and toward the production wells where additional oil is recovered. Eventually, CO_2 will reach the production wells, an occurrence known as breakthrough. Because CO_2 is buoyant, it will also rise within the reservoir if any significant vertical permeability is present. If the CO_2 plume finds a section of the reservoir with significantly increased horizontal permeability, it can breakthrough to the production well and bypass much of the oil in the reservoir. Once this happens, CO_2 subsequently injected will flow along this established path. Thus, injection of CO_2 alone may lack sweep efficiency and by-pass much of the residual oil in the reservoir.

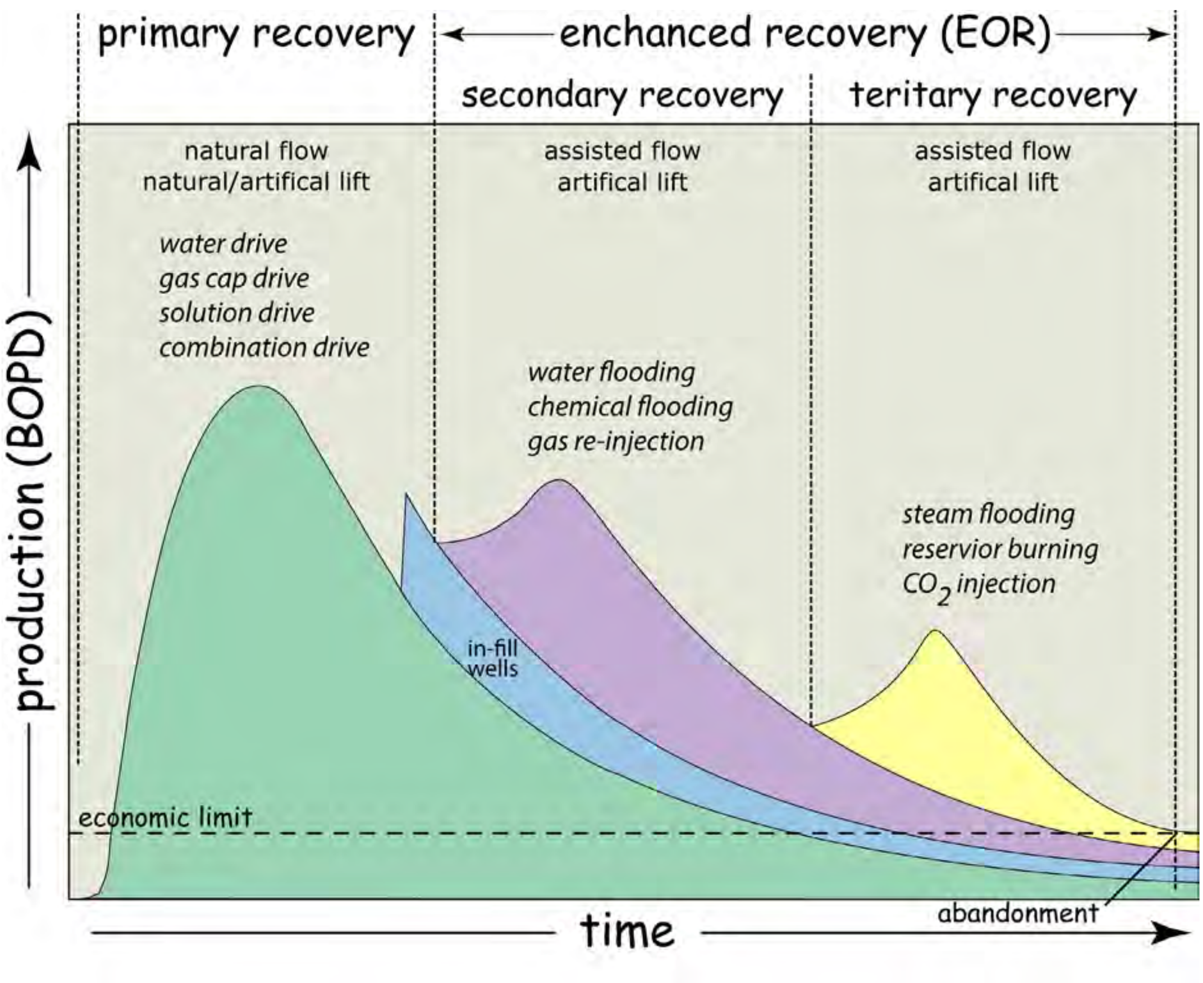

Figure 32. The different stages in the production life of an individual oil well or oil field. (Copyright J.D. Myers. Used with permission.)

A means of overcoming the tendency of CO_2 to bypass much of the formation is the tertiary recovery method called water alternating gas (WAG). In a WAG operation, CO_2 is injected for a period of time to form a miscible zone and oil bank (NETL, 2010b). Subsequently, injection is switched to water. Because water is not buoyant and has a higher viscosity than CO_2, it does not have a tendency to rise and sweeps the entire reservoir front more effectively. This slug of water forces CO_2 toward the production wells (Fig. 33). With time, oil recovery falls because water is not a solvent like CO_2. By following the water with another slug of CO_2, the solvent behavior of CO_2 further increases recovery. Alternating water and CO_2 injection improves sweep efficiency of the operation ultimately recovering more oil. Water/CO_2 injection ratios vary from 0.5–4 and cumulative CO_2 volumes comprise 15–30 percent of the reservoir pore volume (NETL, 2010b). Both of these techniques, immiscible and miscible flooding, use separate injection and production wells. An alternative CO_2 injection strategy, called cyclic CO_2 simulation, or "huff-and-puff" uses a single well for both injection and production (Fig. 34). Carbon dioxide is injected and the well shut-in for a soak period during which the injected CO_2 interacts with the oil causing it to swell and lowering its viscosity. When the well is opened, the CO_2 provides a solution gas drive to move the now less viscous oil toward the well. This process of inject-soak-produce is repeated in a cyclic manner until the cost of operation exceeds the value of the oil recovered.

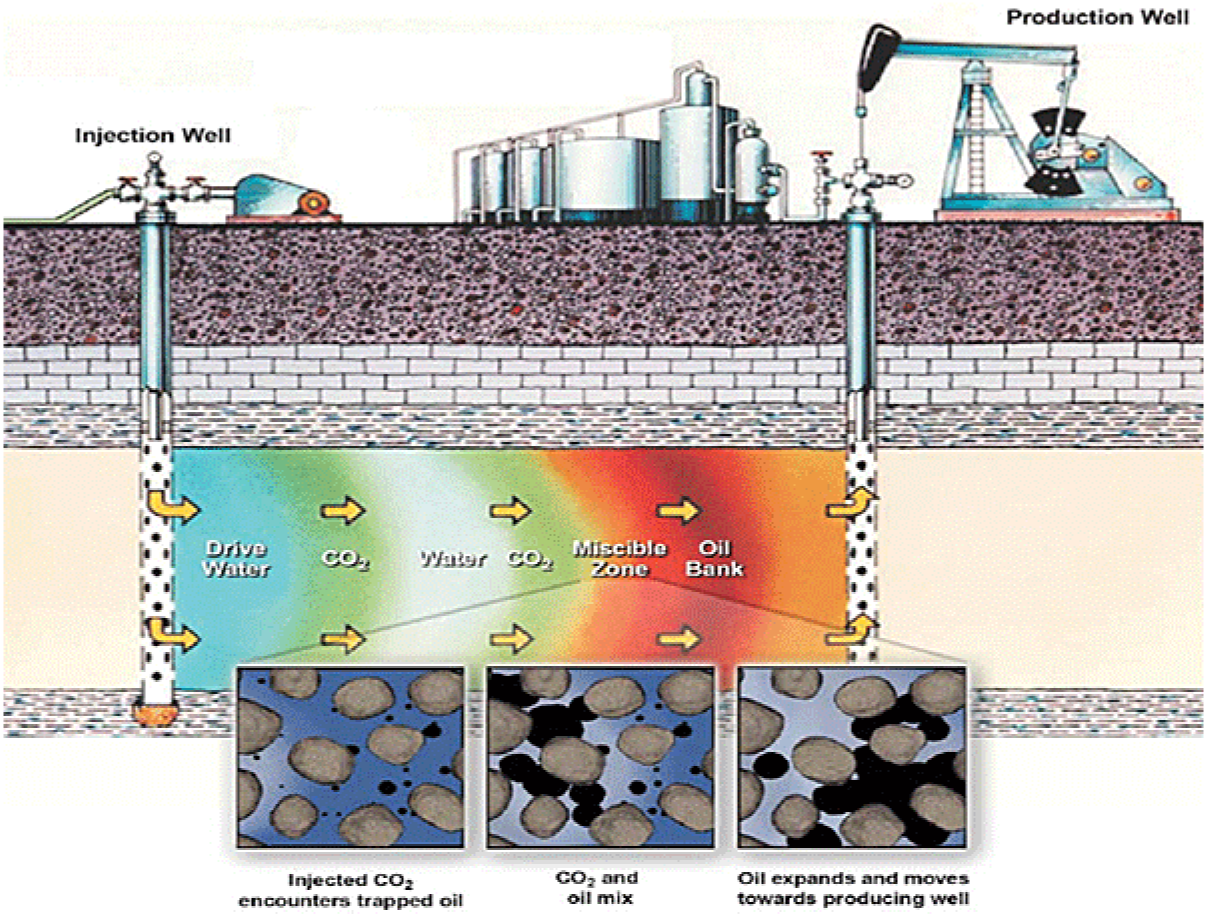

Figure 33. In a CO_2 flood, CO_2 is injected down an injection well and oil, gas, water, and CO_2 are pumped from a production well. (Source: NETL, 2010a)

In both WAG and huff-and-puff operations, some of the CO_2 injected for EOR remains in the reservoir. Thus, it is effectively sequestered from the atmosphere. Unlike for sequestration of CO_2 for emissions reduction, there is an economic purpose for injecting the CO_2. Once a monetary value is placed on carbon through laws or regulation, commercial GCS projects could use the knowledge gained from the extensive CO_2-EOR projects for this new industry.

Despite the obvious advantages, there are disadvantages to using oil and gas fields for CO_2 sequestration. First, previous oil and gas activities may have compromised the integrity of the seal and introduced new potential leakage pathways including existing and abandoned wells. Improperly plugged and abandoned wells as well as orphaned wells are of particular concern for leakage risk (see Well Plugging in Chapter 7). In addition, any artificially-induced fracturing may create new leakage pathways. It is also unclear how CO_2 will react with the reservoir fluid and rocks over very long periods of time. One of the biggest problems with using oil and gas fields as potential sequestration sites is they are not generally located near power plants, the likely source of anthropogenic CO_2. Therefore, extensive CO_2 transportation networks will have to be built over long distances. Another question is legal and regulatory. When performing carbon accounting for an EOR project is the oil field a sequestration site or an enhanced oil recovery project? These legal questions will have to be resolved as the sequestration industry evolves.

Saline Formations

Another geologic sequestration target is deep, saline formations. These are sedimentary formations in which the pore space is filled with

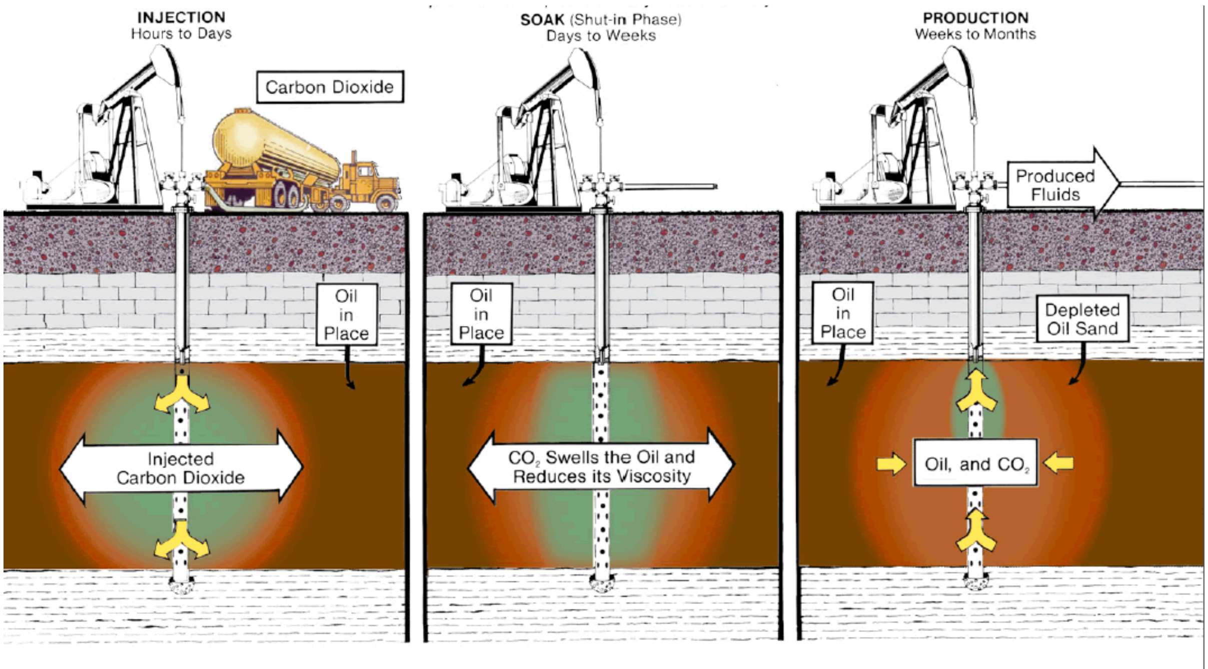

Figure 34. Cyclic CO_2 simulation, or huff-and-puff, is a tertiary oil recovery method that uses a single well for CO_2 injection and subsequent oil production. (Source: DOE)

saline water. These waters have high concentrations of total dissolved solids (TDS), more than 10,000 parts per million (ppm). According to EPA regulations, waters with these TDS levels are unsuitable for agriculture or human use. Thus, they would never be future sources of drinking water. These types of formations are widespread and have large storage capacity. Since it is desirable to inject CO_2 as a supercritical fluid, which requires depths of 2,625 feet (800 meters) or more, only deep saline aquifers are of interest. Most of these are also below underground sources of drinking water making it easier to protect these resources from potential contamination.

Once injected into the subsurface, CO_2 is held underground by a combination of four trapping mechanisms. *Structural or stratigraphic trapping*, also known as physical trapping, depends on geology to hold buoyant CO_2 fluid beneath an impermeable rock formation. This is similar to hydrocarbon traps, which may be either structural or stratigraphic. This is the primary trapping mechanism for CO_2-EOR sequestration since these are primarily sandstones and limestones that lack the divalent cations necessary for mineral carbonation. When CO_2 is retained in the pore spaces of the storage formation, the process is referred to as *residual* or *capillary trapping*. This occurs when the CO_2 in formation pores becomes disconnected or isolated from the main body of the CO_2 plume, thereby immobilizing the disconnected fluid. Over time, CO_2 dissolves into the formation water resulting in a single phase occupying the pore space, a process known as *solubility* or *dissolution trapping*. This process eliminates the buoyant phase thereby curtailiing upward migration of fluid. Finally, the injected CO_2, whether a separate phase or dissolved in formation water, will ultimately react with the minerals in the storage formation and caprock to form new carbonate minerals. This process, called *mineral trapping,* converts CO_2 to a solid rendering it very immobile. Residual and capillary trapping are the result of physical processes or conditions whereas solubility and mineral trapping result from chemical reactions. As these processes proceed, injected CO_2 becomes less mobile with time. Thus, the longer the time since CO_2 was injected, the lower the prospects for migration or leakage.

Over time, the effectiveness of trapping relies on a combination of physical and chemical trapping. Also, the relative importances of the trapping mechanisms vary (Fig. 35). Initially, physical trapping is most important in keeping CO_2 from escaping. With CO_2 migration, residual trapping plays an increasingly important role. Similarly, solubility and mineral trapping become important only in later stages of storage, but result in markedly more secure storage. These factors combine to make storage more secure as time passes.

Unmineable Coal Seams

The last potential geologic target for geologic CO_2 storage is unmineable coal seams, that is, coal seams that are too deep to be mined using current production methods. Coal contains fractures, known as cleats that form an interconnected network throughout a coal seam (Fig. 36). Between the cleats, the coal contains many micropores, small openings or voids in the coal. These micropores and cleats often tightly hold a range of gases tightly. Commonly, the trapped gas is methane derived from the original coalification process. A coal seam can contain as much as 25 cubic meters of methane per ton of coal.

Because coal has a greater affinity for CO_2 than methane, CO_2 can be injected into a seam where it will replace methane on the coal maceral surfaces. The ratio of absorbable CO_2:CH_4 varies from 1:1 in anthracite to greater than 10:1 in lignite. If CO_2 is available, it will be release and replace methane. If gaseous CO_2 is injected into coal seams, it moves through the cleat system to the micopores where it will eventually displace methane and increase coalbed methane (CBM) production. Enhanced coalbed methane (ECBM) recovery can increase production from about 50 percent of the methane initially trapped in coal seams to as much as 90 percent depending on coal rank.

If CO_2 is injected into a coal seam at conditions above its critical point, i.e., at depths of greater than 2,625 feet (800 m), the storage process changes, although these changes are not yet completely understood. Under supercritical conditions, adsorption changes to absorption, i.e., CO_2 diffuses or "dissolves" into the solid coal itself. Because CO_2 is a plasticizer, it lowers the temperature at which coal becomes a rubbery, plastic substance instead of the more familiar glassy, brittle solid. This behavior, along with the accompanying swelling of the coal,

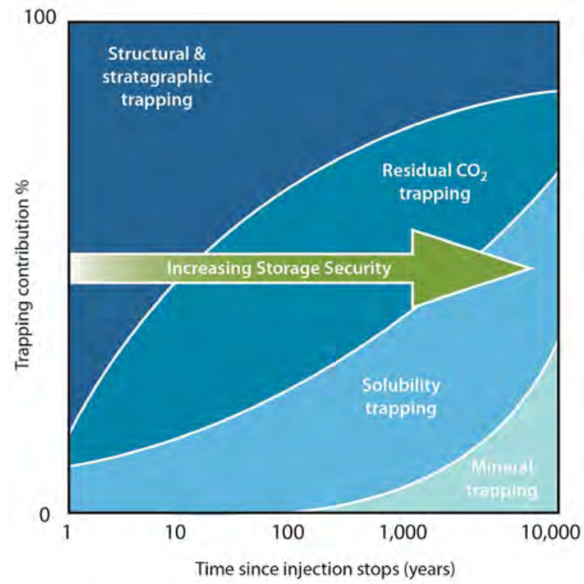

Figure 35. Conceptual diagram showing how the type of CO_2 trapping mechanism changes over time. As the time since injection increases, the effectiveness of trapping increases and the CO_2 becomes increasingly immobile. (Modified from IPCC, 2005)

may lower permeability and hence reduce injectivity as a coal sequestration project progresses.

Some of the factors that are important for choosing a seam for CO_2 storage are permeability, coal rank, geometry, structural influences, seam depth, ability to dewater the seam, and its future use. Obviously, coal seams with high permeability will exhibit better injectivity. Likewise, more CO_2 can be stored in a seam with high porosity and hence pore volume. Coal rank is important because higher rank coals, e.g., sub-bituminous or anthracite, can store more CO_2 than lower rank bituminous coal or lignite. The geometry of a seam also determines how the CO_2 can be injected. For example, a single thick seam will require simpler injection infrastructure, i.e., fewer well completions, than multiple thin seams separated by layers of rock. Structurally undisturbed seams are better potential storage formations because folding or faulting of a seam has the potential to introduce additional leakage pathways. Ideally, a seam deeper than 800 meters is preferable because any injected CO_2 will form a supercritical fluid, thereby allowing more mass to be stored in a given pore volume. In addition to methane, coal

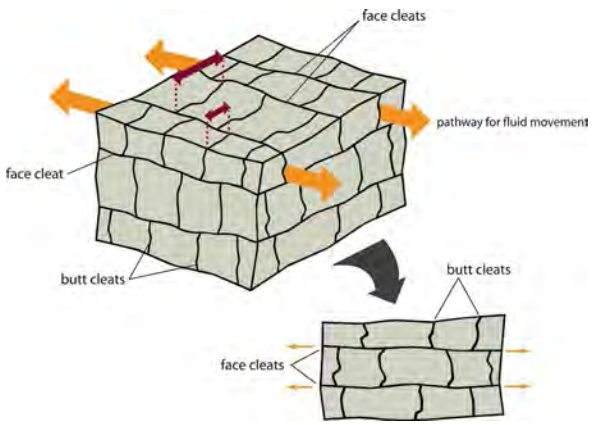

Figure 36. The cleat network in coal provides a pathway for fluid. When injected into a coal seam, CO_2 displaces the methane on the coal surfaces. Thus, carbon dioxide is sequestrated while the recovery of coalbed methane is enhanced. (Copyright J.D. Myers. Used with permission.)

seams also contain water, which is commonly under hydrostatic pressure. Because water pressure facilitates the adsorption of methane to the coal surface, CBM production involves dewatering to reduce the hydrostatic pressure and release methane more readily. Dewatering a seam will also enhance desorption of CO_2; therefore how easily a seam can be dewatered will play a role in storage selection. Finally, the future possibility that a coal seam targeted for CO_2 storage could be mined must be carefully considered when choosing a target reservoir. This will be a difficult question to answer since what might be unmineable today may be mineable in the future given new technology and increased coal prices.

Summary

Carbon capture and storage (CCS) is an industrial process that captures anthropogenic CO_2 emissions and isolates them from the atmosphere for thousands of years. This process is viewed as a means of utilizing the world's abundant and valuable fossil fuel resources to meet growing energy demands, while reducing greenhouse gas emissions. CCS consists of three stages: 1) capture at a source, 2) transport from source to sink, and 3) long-term storage away from the atmosphere.

The first step in the CCS chain is capture of CO_2 at a point source. The nature of the capture process is determined, in part, by the combustion process. Present technologies focus on capturing CO_2 both before and after combustion. An alternative to either of these approaches is oxyfuel combustion, in which fuel is burned in an oxygen-rich environment to produce a much more concentrated CO_2 stream than in pre- and post-combustion processes. Separating CO_2 from an exhaust gas stream can be accomplished via a variety of techniques. Absorption is a bulk or volume process in which CO_2 is incorporated into a liquid solvent. Currently, this is the most widely used capture technology and employs amine solvents. Because the absorbent must be heated to remove the CO_2 and restore its functionality (i.e., be regenerated), this process is energy intensive. Adsorption occurs when CO_2 attaches to an adsorbent's surface and is subsequently freed by changing some external condition, e.g., temperature, pressure, vacuum, or electrical swings. Finally, membranes phyiscally sieve different size gas molecules to isolate CO_2 from other flue gas compounds. However, membranes have not seen widespread or commercial scale use for CO_2 capture and face significant development problems because of the high temperatures of the exhaust gases.

Transport of CO_2 is primarily by pipeline, but in the future ships may also play a role in transport. The U.S. has extensive experience with CO_2 pipelines because of CO_2-EOR operations. Unfortunately, this pipeline system does not connect major anthropogenic CO_2 sources with geologic sinks. Thus, expansion of CCS in the United States will necessitate the creation of a very large, new pipeline system. As a CCS industry grows, ships may play a larger role in CO_2 transport. They can move CO_2 to offshore sites for disposal below the seafloor or for ocean sequestration. Marine transport of CO_2 will likely follow the model established by LPG and LNG transport, although dedicated ships designed specifically for moving CO_2 will be needed. Because of its phase relations, shipping CO_2 in the liquid state will require maintaining low temperatures and pressure above atmospheric.

There are three primary options to safely store CO_2 for thousands of years. These are mineral carbonation, oceanic sequestration, and geologic carbon sequestration. Each has advantages and disadvantages. Mineral carbonation involves reacting CO_2 with divalent cations to produce a variety of carbonate minerals. It can be done on the surface, i.e., ex-situ carbonation, by mining feedstock minerals and reacting them with CO_2 in an industrial facility. Alternatively, CO_2 can be injected into appropriate underground formations where the mineral reactions will occur naturally, i.e., in-situ mineral carbonation. Oceanic sequestration involves injecting CO_2 in a variety of physical states into the deep ocean layers. The behavior of CO_2 in the ocean depends, in large part, on the depth of injection. The ocean's very large carbon content (it is the largest surface reservoir in the carbon cycle), would buffer against many harmful effects. In contrast, the same amount of CO_2 added to the atmosphere would significantly change the atmosphere's overall composition.

Finally, supercritical CO_2 can be injected into subsurface geologic formations for long-term sequestration. There are four potential geologic targets for sequestration. These are oil and gas reservoirs, both active and depleted; saline formations; and unmineable coal seams. The best reservoirs are those that lie below 2,625 feet (800 meters) where CO_2 will be denser than gaseous CO_2. Thus, more mass can be stored in a given volume of pore space. In saline aquifers, CO_2 is trapped by a variety of physical and chemical processes including structural, residual, solubility, and mineral trapping. Each process acts over a different timeframe. Over time, the trapping mechanism becomes increasingly secure. Carbon dioxide storage in unmineable coal seams is primarily by adsorption of gaseous CO_2 onto coal surfaces. Because coal has a greater affinity for CO_2 than methane, the CO_2 displaces methane and coal sequestration can be used as a form of enhanced coalbed methane recovery. At depths below 2,625 feet (800 meters), CO_2 absorbs into the coal structure.

Chapter 3

Geologic Carbon Sequestration (GCS)

Recent and on-going research suggests that geologic carbon sequestration is the CCS option most likely to contribute to carbon emissions reduction in the short term. Under the London Protocol, ocean sequestration raises legal issues of ocean dumping, and environmental impact on seafloor ecosystems. Mineral carbonation requires mining and transportation of significant amounts of metal-bearing rocks and subsequent transport and disposal of the solid carbonate. In contrast, geologic carbon sequestration requires scaling up of proven technologies that have been used successfully in the petroleum industry for over fifty years, i.e., transport and injection (Fig. 37). These scaled up technologies must also be tied to commercially unproven carbon capture technologies that together produce a new industrial arrangement.

Additionally, natural accumulations of CO_2 in the subsurface that have existed for hundreds of millions of years clearly show that the lithosphere can store buoyant fluids for the geologic time periods relevant to climate change mitigation. Thus, one of the most researched options for storing CO_2 is injecting it into the lithosphere, i.e., pumping it into underground rock units or formations (GCS). As noted previously, the four primary targets for geologic storage or sequestration are: 1) producing oil and natural gas fields (as part of enhanced oil recovery [EOR] or enhance natural gas recovery [ENGR]), 2) depleted oil and gas fields, 3) saline formations, and 4) unmineable coal seams with or without enhanced coalbed methane (ECBM) recovery (Fig. 30).

Site Characterization

A viable geologic sequestration site must have a reservoir unit capable of holding injected CO_2 as well as a cap or seal rock that will prevent the upward migration of the buoyant CO_2 plume. EPA (2008) identified these as the injection and confining zones, respectively. Forming as complete a picture as possible of these two geologic systems is one of the primary goals of geologic sequestration site selection and characterization.

The injection zone is a geologic formation or group of formations that can accommodate the anticipated CO_2 injection volume and injection rates. It must also be able to withstand changes in formation brine pressure due to injection. To demonstrate a geologic unit can satisfy these geologic requirements, the parameters of the injection zone must be fully characterized and evaluated. This characterization aims to demonstrate that the proposed injection zone has the lateral extent, thickness, permeability, and porosity to function as an acceptable CO_2 repository for thousands of years. EPA (2008) identified the important characteristics for evaluating a potential reservoir. These characteristics include physical capacity, injectivity, and geomechanical and geochemical stability. Capacity refers to the pore volume in the injection zone that is capable of holding injected CO_2. Prior to injection, this volume will contain brine that the injected CO_2 will displace. The added fluid volume will increase the pressure in the injection zone. Dewatering of the injection zone may alleviate some of this problem, but introduces the need to dispose of the water once it is produced. The ease with which CO_2 can be pumped into the injection zone defines the zone's injectivity. This parameter determines the rate at which CO_2 can be injected, an important parameter in matching supplied to injected CO_2. If these two parameters do not match, an interim storage

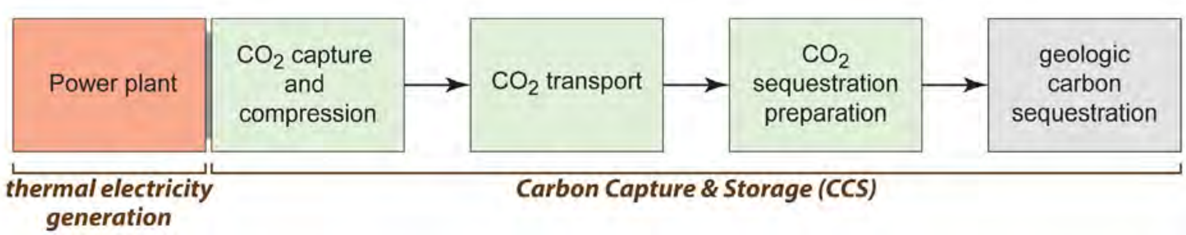

Figure 37. Major components of a geologic carbon sequestration project. (Copyright J.D. Myers. Used with permission.)

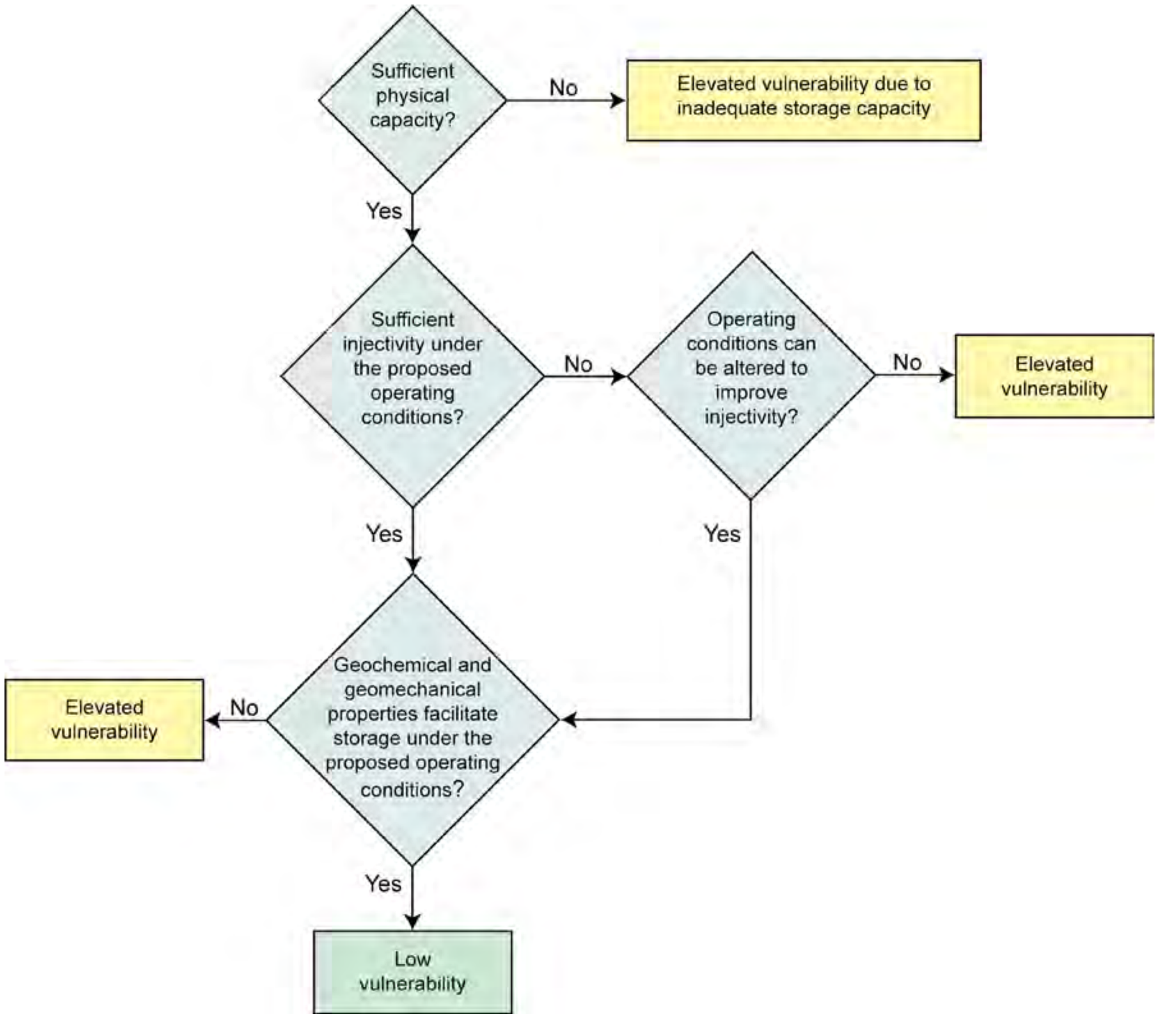

Figure 38. Flowchart demonstrating one potential procedure for using data acquired during site characterization to evaluate a geologic formation's or group of formations' suitability to store CO_2. (Source: EPA, 2008)

facility may need to be constructed. Injectivity is influenced by permeability, unit thickness, and initial formation pressure. With the injection of CO_2 into the injection zone, the geochemical equilibrium between the formation fluids and the host rock's minerals will be disturbed. This disturbance will initiate a series of geochemical processes and reactions that will ultimately restore a new equilibrium state in the host reservoir. Such reactions include dissolution of injected CO_2 into the formation fluid or dissolution of carbonate minerals in the injection zone, both of which would positively affect storage. Negative impacts could be the formation of new non-carbonate minerals that reduce permeability and porosity, thereby impacting physical capacity and injectivity, Groundwater acidification may leach heavy and toxic metals from the host rock EPA (2008). Processes impacting the structural integrity of the injection zone are classified as geomechanical processes, and include anything that deforms or fractures the reservoir or its constituent minerals.

After collecting this information, it must be used to evaluate whether the proposed injection zone can safely hold CO_2 for thousands of years. This evaluation is complex and the process is still under development. Although there are many potential ways to use this information in a site evaluation scheme, the diagram in Figure 39 represents one option proposed by (EPA, 2008). The series of decision points involved can only be evaluated after the site has been thoroughly characterized.

Because CO_2 is buoyant, any injection zone must have a confining zone separating it from overlying USDWs. The confining zone is an impermeable formation or group of formations that prevents upward fluid flow (EPA, 2008). Some of the geologic characteristics that define a unit's suitability as a confining zone include lateral extent, capillary entry pressure, permeability, travel time, faults/fractures, tectonic history, and geomechanical and geochemical properties. In addition to these geologic parameters, the presence of artificial penetrations or wells that intersect and penetrate the confining zone must also be assessed. To trap CO_2 in the injection zone, the cap must extend over the entire subsurface area that the injected CO_2 and displaced brine will impact, an area called the site's footprint. The area covered by the confining zone is defined as the confining zone's lateral extent (EPA, 2008). The capillary entry pressure is the pressure at which fluid will be forced into the pores of the cap rock. Permeability refers to how well the pore spaces in the cap rock are interconnected and the ease with which fluid can be transmitted throughout the formation. The time a fluid requires to cross the confining zone is the travel time. Obviously, longer travel times contribute to safer and more secure carbon sequestration. Faults and fractures represent potential pathways for the migration of CO_2. Faults can be either sealing or transmissive, so site characterization needs to establish how faults will behave with respect to fluid movement. If faults or fractures are present, it must also be determined if they transverse the entire confining zone or just a portion of it. Existing faults may be reactivated by increases in formation pressure. High induced pressures could fracture the cap rock if they exceed formation fracture pressure, thereby compromising the integrity of the confining zone. For this reason, site characterization must establish limits on likely fracture pressures. The impact the injected CO_2 stream has on the chemical stability of the confining zone is important in evaluating long-term confinement. Similarly, the impacts of increased formation pressure on the mechanical behavior of the confining zone are important. Lastly, the level of tectonic activity of the area must be assessed (EPA, 2008). Tectonically active regions are more likely to have transmissive faults and fractures. Combing this diverse information enables evaluation of the likelihood that the proposed confining zone will perform adequately over the long timespans necessary for CO_2 sequestration (Fig. 39).

In recent years, alternatives to the step-wise, deterministic flowchart evaluation procedure proposed originally by EPA (2008) have been developed. With these approaches, a quantitative computer model (CO_2-PENS) considers all aspects of the proposed injection site, as well as infrastructure, CO_2 sources, and other parameters to evaluate the sequestration site from a systems approach (Oldenburg and others, 2009).

Project Timeline

Any future geologic carbon sequestration project will require a significant investment of time, money, and resources. Pre-operational, operational, and decommissioning phases are likely to span four to five decades or more (Fig. 40). This timespan is not very different from that of a current coal-fired or nuclear power plant. It will be, however, different in terms of the post-closure phase. Although not officially established yet, this phase may extend another one to five decades. It may also involve a monitoring phase from 100 to 1,000 years. The only other human industrial activity with a similar timeline and mass input is the storage of high-level nuclear waste in a geologic repository, none of which have been completed and commissioned to date. (Finland is close, however, with their Onkalo repository scheduled to open in 2020).

The lifetime of a GCS project can be divided into five stages, each of varying duration and with different business, technological, engineering and regulatory constraints. The five stages are site screening, site permitting, site operation, post-closure, and long-term stewardship. The shortest of these stages is anticipated to be of site screening (Fig. 40), the stage in which potential geologic storage sites are identified by regional surveys of sedimentary basins.

Once a geologic site has been tentatively identified for a sequestration project, site permitting begins (Fig. 40). Because no Class VI sequestration well has yet been permitted in the U.S., it is hard to estimate how long this phase might take (see

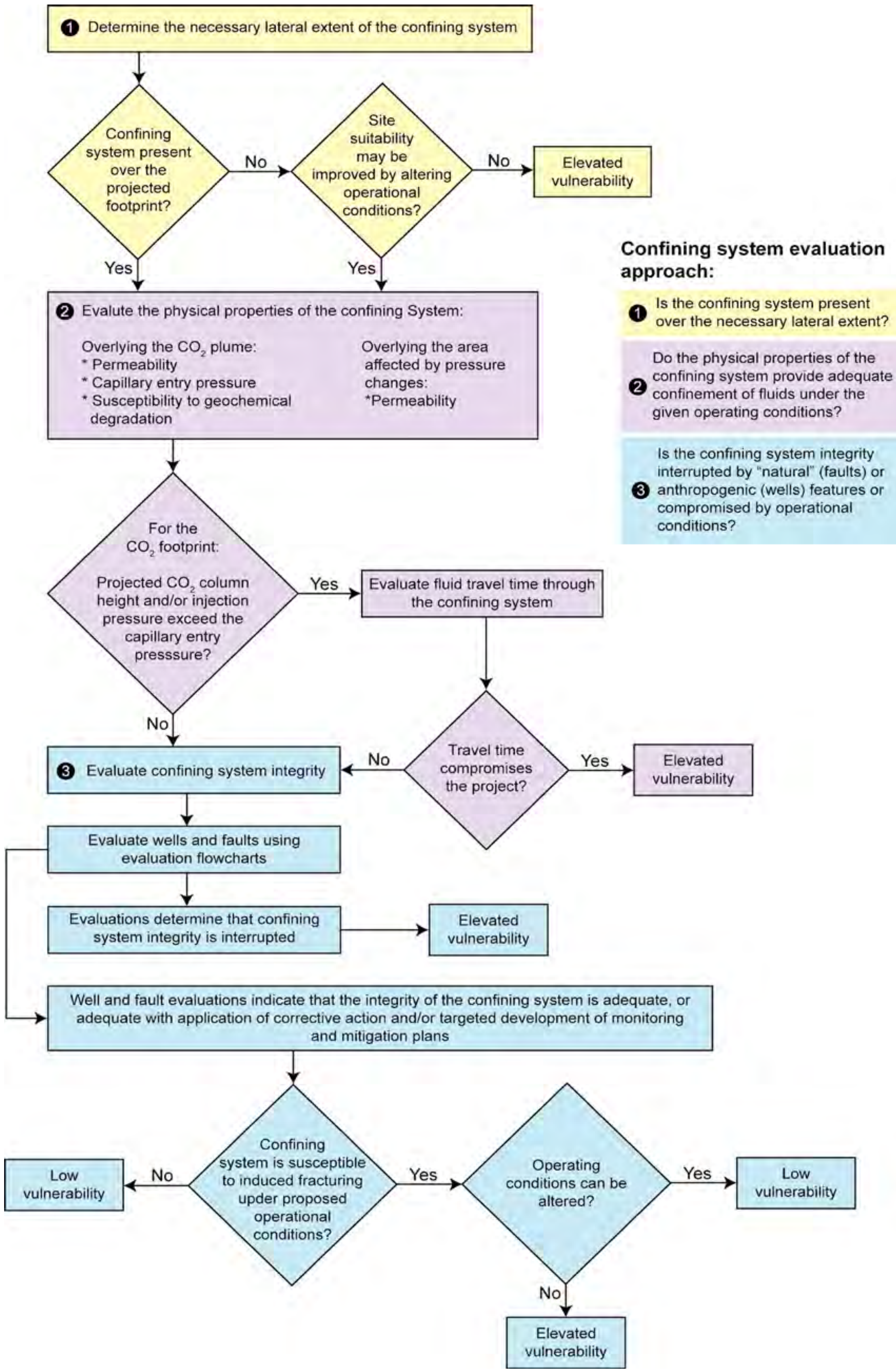

Figure 39. EPA flowchart for evaluating the effectiveness of a proposed confining system. (Source: EPA, 2008)

Chapter 7). Estimates based on other large energy infrastructure projects suggest a decade or more might be a reasonable estimate. This stage will consist of two parts. In the first phase, permitting, the proposed sequestration site undergoes a detailed and comprehensive site characterization to evaluate its suitability for safe storage of CO_2 for a sufficiently long time. Permitting will entail collecting, cataloging, and analyzing data from all available public sources. Data acquisition might include conducting geophysical surveys, performing additional field mapping and sampling, drilling stratigraphic test wells for logging and sampling purposes, and sampling water wells to establish baseline groundwater chemistry. Once gaps in the available data have been identified, additional work may be necessary to fill in these gaps and reduce uncertainty. This information will be used to construct a static three dimensional geologic model that approximates the site. Complimentary to site characterization will be the identification of the CO_2 source, determination of volumes of CO_2 to be injected annually and over the project's lifetime, and establishment of the nature of the CO_2 stream to be injected, e.g., is it pure or will it contain impurities like H_2S. These data are combined with the static geologic model to derive a dynamic injection model for the area that anticipates the behavior of the CO_2 plume over the project's lifetime. Once the site has been characterized to the operator's confidence, the actual process of permitting a Class VI well for the project will begin. Among other functions, permitting entails defining an area of review (AoR) for the project and devising a monitoring program, etc. (See Chapter 7 for additional details). On completion, the application will be submitted to the appropriate EPA regional office or state UIC program office. Review of the permit application could be a time consuming effort – again there is no actual experience to base an estimate for the review process. Once the permit application is approved, the project moves into the operational phase.

Three phases constitute the operational stage of a GCS project. In the initial phase, the operator prepares the site for injection by drilling, completing, and testing the Class VI injection well (Fig. 40). At the same time, the surface infrastructure necessary for project operations, including pipelines, roads, pumps, and monitoring stations will be installed and constructed. In addition, monitoring wells will be drilled, completed, and monitoring instruments installed and tested. If the permitting process identified any artificial penetrations, i.e., legacy wells, with a high leakage risk, well remediation must occur prior to commencing injection. After passing all inspections, the injection and monitoring phase of the project begins (Fig. 40). Some of the activities during this stage include injecting CO_2, recording, and reporting operational details, maintaining a safe working environment, monitoring the development of the CO_2 plume and associated pressure front, periodically revising the AoR with new monitoring and operational data, and monitoring reservoir pressure and brine movement. This stage of a GCS project is estimated to span 30–50 years, the likely lifetime of a coal-fired power plant. After injection operations cease, the monitoring and site closure stages are entered (Fig. 40). First the injection well is plugged and abandoned following the methods specified in the approved Class VI well permit. The monitoring stage, in the U.S., lasts at least 50 years and tracks the movement of the CO_2 plume and associated pressure front. When it can be shown that the site no longer poses a threat to USDWs, the site is closed. On closure, the monitoring wells are plugged and abandoned according to regulations. All surface equipment is removed and the land reclaimed. Active monitoring of injected CO_2 is continued through this operational phase.

The last two stages of a GCS project exhibit the greatest uncertainty (Fig. 40). In addition, regulatory responsibility for this part of the project will move from the UIC authority to other regulatory bodies. In many instances, these stages will be regulated by laws developed on a state-by-state basis. Currently, no state yet established the requirements for these final stages of a GCS project. Immediately after the cessation of injection, post-injection and site care stage begins. During this stage, the injection well is plugged or repurposed as a monitoring well and active monitoring of the CO_2 plume is maintained. Wells are monitored for leakage and any remediation to plug leaking wells, if necessary, is carried out. It is anticipated that this GCS stage will cease when stability of the injected plume has been fully

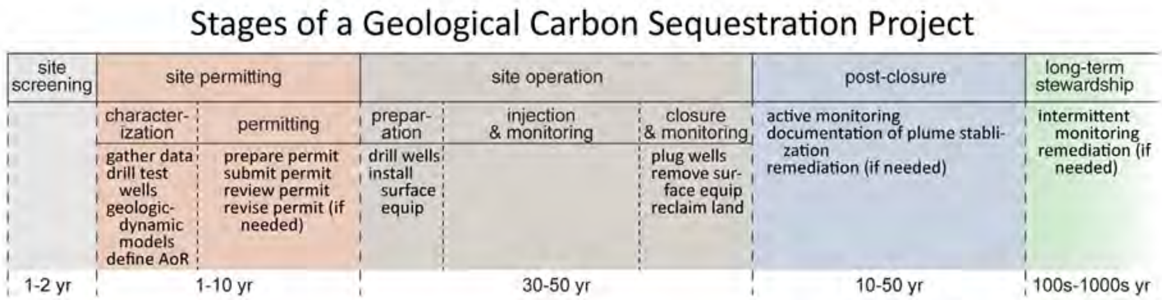

Figure 40. The stages in a GCS project. (Copyright J.D. Myers. Used with permission.)

established. Estimates for the length of this stage vary from 10 to 50 years. The biggest unknown about the closing of a GCS project is the long-term stewardship of the injected CO_2 (Fig. 40). There have been discussions that at this point responsibility of the injected CO_2 should be turned over from the commercial operator to the states. However, Wyoming has already expressly forbidden this type of stewardship. Conversely, there have been suggestions that this long-term commitment should be the responsibility of the federal government, not the states. To date, little has been decided legally with regard to these issues. Given the need to isolated CO_2 from the atmosphere for thousands of years to mitigate anthropogenic climate change, this stewardship could conceivably last for thousands of years. The requirement that hazardous wastes injected by Class I wells not migrated from the injection zone for 10,000 years, a similar constraint on spent nuclear fuel, clearly sets regulatory precedent for such long time frames.

CO_2 Leakage Risk

Because it is less dense that water or brine, CO_2 is a buoyant in the subsurface. Consequently, it will migrate upward over time. Given this movement, there are many paths that CO_2 may encounter that will let it migrate out of the injection zone (Fig. 41). Movement into a USDW will impact water supplies, whereas movement into oil or gas reservoirs can have economic impact. If the CO_2 migrates to the surface, the reason it was sequestered in the first place has been invalidated. In this situation, the time, money, and effort invested in placing CO_2 underground would be wasted. Thus, it is vital that a potential geologic carbon sequestration site is evaluated fully for the potential pathways CO_2 can follow out of the injection zone. Indeed, a major purpose of the UIC Class VI well permitting program is to prevent such movement as a means of protecting USDWs. If this objective is realized, CO_2 will not reach the atmosphere.

Given the complexity of subsurface geology, it is not surprising that there are many pathways that permit the migration of CO_2 in the subsurface (Fig. 41). Some of them are related to natural conditions and others to human activities. Natural features that could allow CO_2 migration include thinning or absence of the cap rock and transmissive faults or fractures that cut the cap rock (Fig. 41). Detailed geologic analysis of a potential sequestration system is designed to identify these geologic risks. If injection pressures are too high, they may exceed the capillary pressure of the cap rock. In this case, the injected CO_2 may enter the cap rock and possibly leak into upper formations where secondary pathways can allow CO_2 to reach USDWs or the surface. Careful analysis of the cap rock during site characterization and monitoring of injection activities should prevent such an event from happening. In some cases, hydrodynamic flow of formation fluids may carry CO_2 that has dissolved into the formation brine out of the injection zone (Fig. 41). This possibility illustrates the need to map fluid flow regimes during site characterization. Finally, site characterization must identify all wells in the AoR and evaluate their individual leakage risk. Those wells at higher risk must be remediated to prevent movement of CO_2 along them.

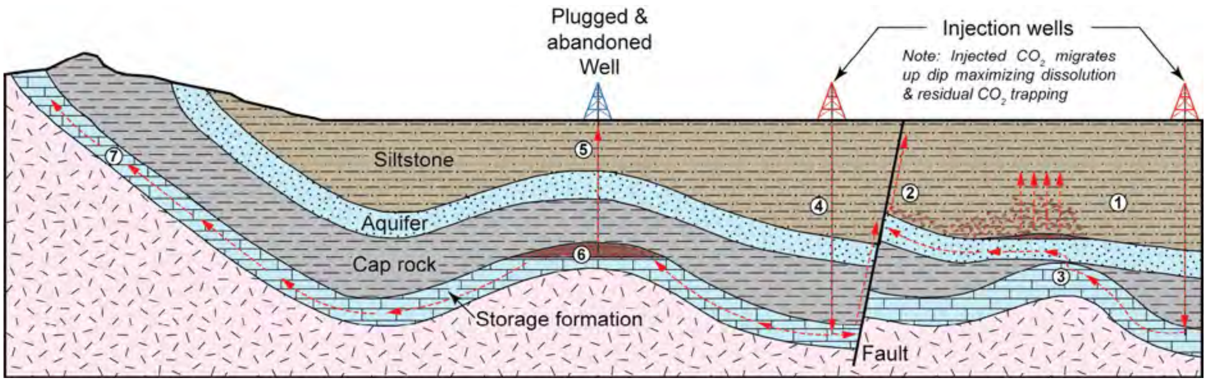

Figure 41. Schematic geologic cross-section illustrating some of the many potential pathways by which CO_2 can migrate out of the injection zone. (1) escape through confining formation; (2) movement along fault; (3) migrating through gap in confining formation; (4) reactivation of fault; (5) escape via artificial penetrations; (6) movement of dissolved CO_2 in formation fluid; (7) migration up-dip to surface exposure. (Modified from IPCC, 2005)

Summary

Of the three primary means of sequestrating carbon, geologic carbon sequestration (GCS) is the one that is mostly likely to be deployed within a near term timeframe on a scale large enough to significantly impact anthropogenic carbon emissions. GCS injects supercritical CO_2 into subsurface geologic formations with sufficient pore space and injectivity to accommodate large volumes of CO_2. In addition to the receiving or injection formation, a GCS system includes an upper impermeable layer, the confining zone, that prevents the buoyant CO_2 from migrating vertically to the surface. The four primary geologic candidates for GCS are active oil and gas fields (enhanced oil recovery), depleted oil and gas fields, deep saline formations, and unmineable coal seams.

The first stage in selection of a GCS site is site characterization. This process will ensure that once injected, CO_2 remains in the subsurface for hundreds to thousands of years. To accomplish this task, site characterization builds a static three dimensional geologic model of the sequestration system including the confining and injection zones, the underground sources of drinking water, locations of natural, e.g., faults, fractures, and artificial, e.g., wells, mines, CO_2 pathways, and geologic structures, e.g., folds. Once constructed, the geologic model can be used to determine if the proposed injection zone has the lateral extent, thickness, permeability, and porosity necessary to store large volumes of CO_2 for thousands of years. This model is coupled with fluid modeling to predict how CO_2 injected into the injection zone will behave. Construction of a geologic model requires an extensive dataset on the subsurface formations. Formation characteristics that must be assessed include physical capacity, injectivity, and geomechanical and geochemical stability.

The lifetime of a GCS project can be divided into five stages with different business, technological, engineering, and regulatory constraints. The five stages are site screening, site permitting, site operation, post-closure, and long-term stewardship. Each of these phases will last for a varying amount of time. Site characterization is designed to create the dataset necessary to complete an application to inject CO_2 for the purposes of sequestration. Given the expense and effort required for site characterization and permit application, the operational phase of a GCS project is anticipated to span 30 to 50 years, a timeframe consistent with the lifespan of a typical coal-fired power station. This phase involves facility construction, injection and monitoring, and site closure. A post-injection phase follows after the site is closed. Currently, environmental regulations in the U.S. mandate this phase last 50 years, although it may be shortened or lengthened depending upon site characteristics. The most poorly known phase of a GCS project is the long-term stewardship. Questions are currently being debated about who will be responsible for the site during this phase and how long it should last.

Chapter 4

Environmental Laws Impacting CCS

Like any industrial activity in the U.S. or any other developed nation, GCS will be subject to a variety of environmental laws and regulations at each stage of a project's lifespan (Fig. 42). The regulations most pertinent to GCS are the Safe Drinking Water Act (SDWA), the Clean Air Act (CAA) and the Clean Water Act (CWA). The SDWA will determine what and where CO_2 is or is not injected underground. The fate of brine produced from a reservoir to maintain formation pressure will be impacted by the CWA. Finally, the CCA will impose reporting requirements on the amount of CO_2 GCS projects inject and may ultimately, through its potential to place limits on CO_2 emissions from anthropogenic sources, provide the impetus for moving GCS from the demonstration to commercial stage.

Historical Context

In the late 1960s and early 1970s, growing awareness of a serious and increasing deterioration in the quality of the nation's air, land, and water grew (Fig. 43). This awareness led Congress to pass a suite of wide sweeping environmental laws in the 1970s. These laws were passed with bipartisan support and many during President Richard Nixon's administration.

Some of the important federal environmental laws that regulate resource extraction activities include the Clean Air Act (CAA, 1970); National Environmental Policy Act (NEPA, 1972); Water Pollution Control Act (1972); Endangered Species Act (ESA, 1973); Safe Drinking Water Act (SDWA, 1974); Resource Conservation and Recovery Act (RCRA, 1975); Water Pollution Control Act Amendments, popularly known as the Clean Water Act (CWA, 1977); and Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, 1980), also known as Superfund (Fig. 44). Many of these laws have been amended in the years since their initial passage. In addition to these laws, there are many other miscellaneous federal laws designed to protect the environment. Similarly, there are a variety of federal laws that cover health and safety issues that will accompany any geologic sequestration project. Individual states also have their own laws intended to protect the public, workers and the environment. However, the three most important pieces of legislation for carbon capture and storage are the SDWA, CAA, and CWA.

These environmental laws regulate toxic substances, pesticides, and ocean dumping while protecting public health, wildlife, wilderness, and wild and scenic rivers. They represented a major shift in how the nation viewed its environment and lead to environmental groups switching from

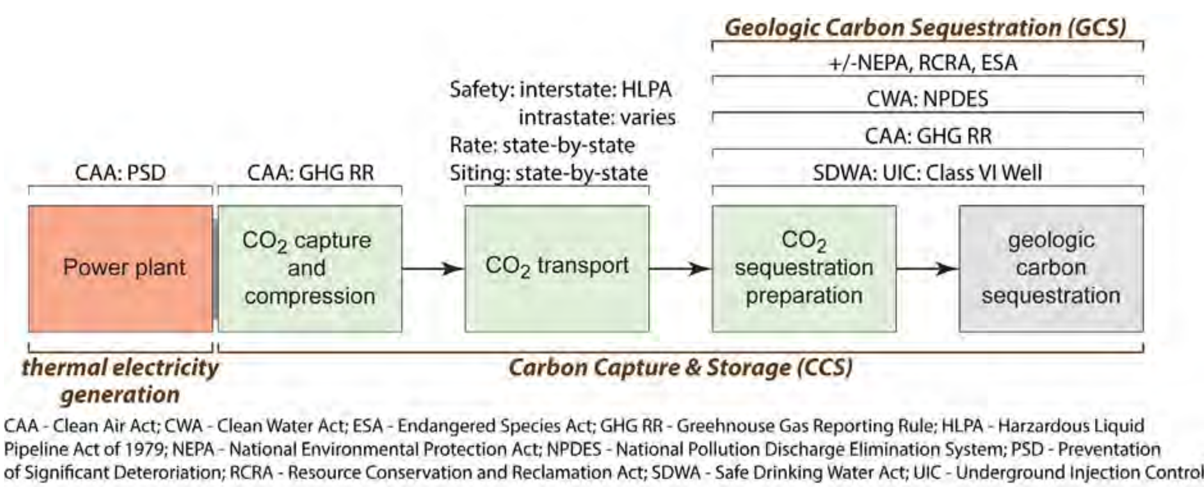

Figure 42. GCS project stages showing the different U.S. environmental laws relevant to a geologic carbon sequestration project. This summary is not a comprehensive list of all relevant statutes, but focuses on the operating and permitting of the GCS portion of a carbon capture and storage project. (Copyright J.D. Myers. Used with permission.)

Figure 43. Smoke billowing from a plant burning discarded automobile batteries before the passage of the Clean Air Act. (Source: EPA, www.epa.gov/40th/images.html).

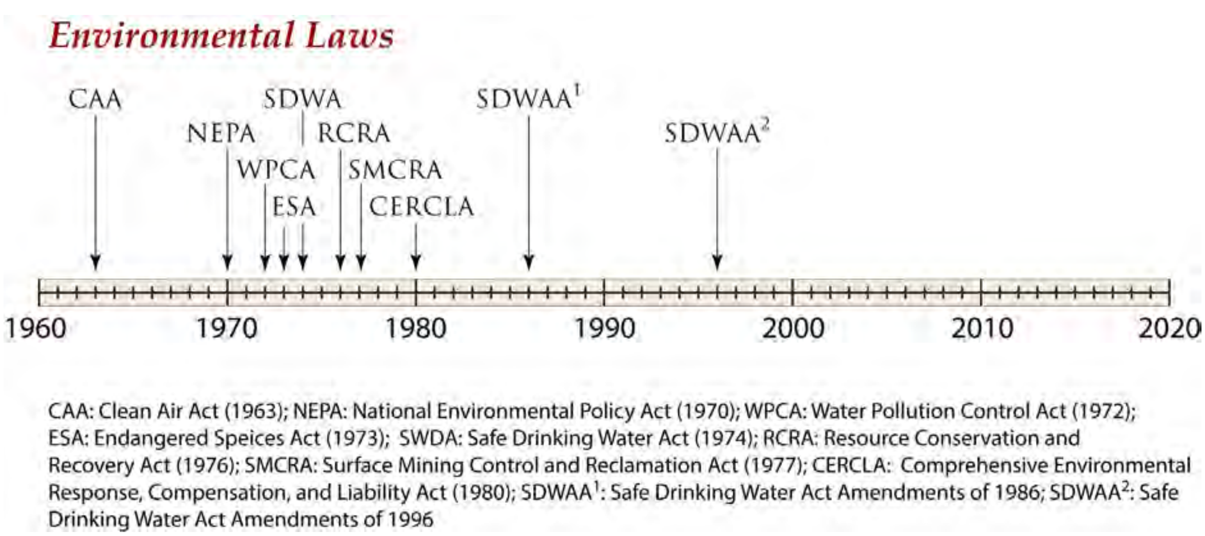

Figure 44. Timeline showing year of passage of the principal environmental laws of the 1970s and some of their significant amendments. (Copyright J.D. Myers. Used with permission.)

a local to a national focus. They were an attempt to protect the commons—the shared land, air and water resources—from destruction. The laws were a fledgling attempt to address the tragedy of the commons problem first articulated by (Hardin, 1968). Although none of the acts specifically discuss it, they are the first attempts to internalize the external costs (externalities) that industry had passed on as a cost of business-as-usual (BAU) to other groups or stakeholders.

The Environmental Protection Agency (EPA) was authorized by an executive order issued by President Nixon in 1970. Besides creating the agency, it consolidated the environmental activities of numerous federal agencies into one. EPA's mission is to protect human health and the environment. An administrator, appointed by the president, leads the agency and is generally afforded cabinet-rank although the agency itself is not a cabinet department. EPA has 10 regions with a regional office for each (Fig. 45). The agency works with state agencies to implement environmental law in the U.S. Under this cooperative arrangement, EPA sets discharge or emission standards, establishes guidelines, determines risk, and establishes penalties, whereas the environmental state agencies do the day-to-day implementation of the programs. Should a state choose not to create an environmental state agency, EPA implements and enforces the rules and regulations in that state.

Safe Drinking Water Act (SDWA)

Historical Background

In the 1960s, there were few national enforceable requirements for drinking water standards. Problems with water quality increased as industrial and agricultural activities grew with an expanding population and booming economy. It also marked a time when analytical techniques were improving and contaminants could be measured at increasingly lower concentrations.

The *Safe Drinking Water Act (SDWA)* ensures the quality of drinking water in the United States whether from surface or underground sources. It protects drinking water sources including rivers, lakes, reservoirs, springs, and groundwater aquifers. Under SDWA authority, EPA sets

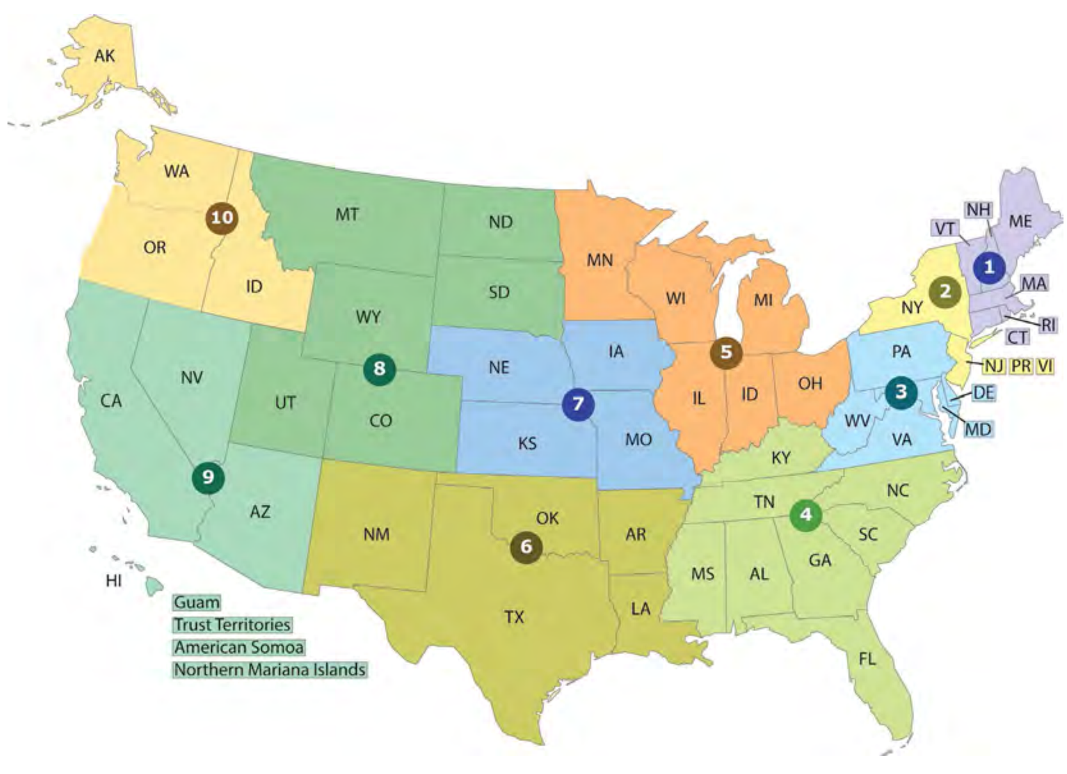

Figure 45. The ten EPA regions. (Source: EPA, www2.epa.gov/aboutepa)

national health standards for drinking water to protect against both naturally-occurring and human-made contaminants. The act was passed in 1974 and signed into law by President Gerald Ford on December 16, 1974. Major amendments of the act were passed in 1986 and 1996. It has been impacted by the Energy Policy Act of 2005 (with respect to hydraulic fracturing for oil and gas recovery). An amendment to the act (The Fracturing Responsibility and Awareness of Chemicals Act—FRAC Act) was proposed in 2009, but failed passage.

The SDWA covers all public water systems (PWSs) in the United States. For the purposes of the law, a PWS is defined as any water system providing drinking water to at least 15 service connections or 25 people for at least 60 days per year. Currently, there are 170,000 PWSs in the U.S. supplying 250 million people with drinking water. PWSs get their water from surface water, i.e., rivers, lakes, reservoirs, etc. In addition, PWSs tap water from underground sources. The SDWA does not regulate private wells nor bottled water, which is regulated by the Food and Drug Administration. The original laws focused on treatment of water to provide safe drinking water at the tap. It was not designed to protect the quality of water sources.

Act and Amendments

The SDWA has been modified a number of times since it was first passed in 1974 (Tiemann, 2010). These amendments have been designed to address a number of problems with earlier versions of the law and to change the law to deal with new circumstances that arose (Fig. 46).

1974 Safe Drinking Water Act: This law authorized EPA to set concentration levels in drinking water for a specified list of contaminants. For each contaminant regulated under SDWA, EPA sets standards at two levels: maximum interim contaminant levels (MCLs) that are mandatory and non-enforceable health goals (MCLGs). Thus, it mandated treatment when drinking water supplied by a PWS failed to meet standards. It was signed into law on December 16, 1974 by President Gerald Ford.

1986 SDWA Amendment: This amendment established MCLs that had been only interim regulations set under authority of the 1974 act. The interim limits had been reviewed and established through the original act, but not finalized. In addition, two new regulations established the Surface Water Treatment Rule (SWTR) and the Total Coliform Rule (TCR). The 1986 amendment also required EPA to set standards limiting lead

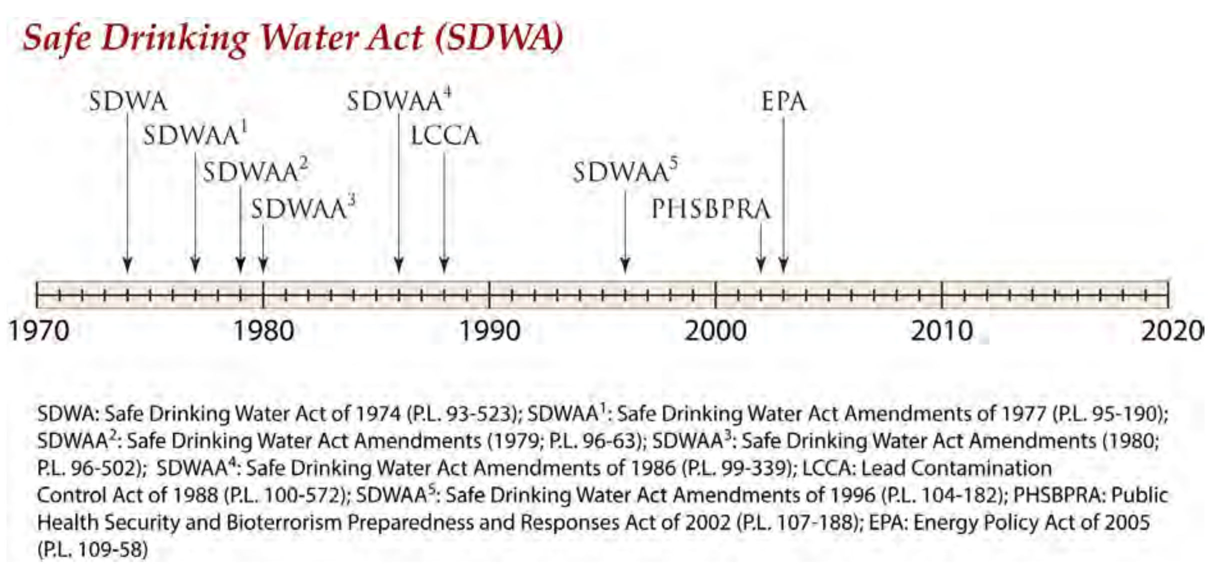

Figure 46. Timeline showing the major changes to the Safe Drinking Water Act since its passage in 1974. See text for additional details. (Copyright J.D. Myers. Used with permission.)

concentrations in public water systems, and to define "lead free pipes." This effort reflected the recognition of the importance of lead as an environmental pollutant and represented the initial effort to reduce human exposure to this contaminant in the United States. Other features of the amendment included the establishment of a well head protection program, the addition of new substances to SDWA's monitoring program, introduction of filtration systems for surface water systems, the disinfection treatment for certain groundwater systems, and an increase in enforcement powers granted under the original law. The 1986 SDWA Amendment was signed into law by President Ronald Reagan on June 19, 1986.

1996 SDWA Amendment: The SDWA Amendment of 1996 recognized the importance of protecting drinking water at its sources, not just when delivered. Thus, the philosophy of the law changed from one of treatment to meet MCLs at the tap to protecting water from the source to the tap. It also emphasized sound science and risk-based standards. This amendment provided a mechanism for assistance to small water supply systems and water system financial assistance. It required PWSs to distribute Consumer Confidence Reports annually to its clients. When setting new contaminant standards, a cost-benefit analysis was to be used for every new standard. A Drinking Water State Revolving Fund that states could apply to fund infrastructure improvement projects was also implemented. Standards for microbial contaminants and disinfection by-products were strengthened. An Operator Certification Program was initiated to ensure operators of PWSs were qualified to operate their systems safely. The consumer's right to know about their drinking water was established through a Public Information and Consultation program. Finally, small water systems in the U.S. were given special consideration and rights. The 1996 SDWA Amendment was signed into law by President Bill Clinton on August 6, 1996.

Public Health Security and Bioterrosim Preparedness and Response Act of 2002: This act was in response to a number of security issues and includes provisions for protecting public drinking water sources. The act requires that all public water systems serving more than 3,300 people conduct vulnerability assessments of their systems for risk of intentional disruption and report the results of this survey to the EPA. A provision in the bill prevents such information from being disclosed under the Freedom of Information Act. Penalties, both civil and criminal, were established for anyone tampering, attempting to tamper, or making threats to tamper with a public water system (Tiemann, 2010). President George W. Bush signed this act into law on June 12, 2002.

Energy Policy Act of 2005: A specific provision of the Energy Policy Act of 2005 changed how the energy industry is regulated under the SDWA and its attendant UIC program (see Chapter 5). Specifically, hydraulic fracturing ("fracking") operations for shale gas and shale oil wells were exempted from the SDWA (Dammel and others, 2011). This act prevented such wells from being re-classified as injection wells. Hydraulic fracturing is also exempt from reporting fracking fluid compositions to EPA's Toxics Release Inventory. The Energy Policy Act did not exempt fracking operations that used diesel fuel in their hydraulic fluids. Operators also do not have to obtain stormwater permits regulating how fracturing fluids are handled at the surface. The Energy Policy Act of 2005 was signed into law by President George H.W. Bush on August 8, 2005. The impact of this law on shale gas and shale oil operations has been the subject of controversy ever since.

Fracturing and Awareness of Chemicals Act: The Fracturing and Awareness of Chemicals Act, or FRAC Act, was introduced into both houses of the 111th Congress on June 9, 2009. The proposed law would have repealed hydraulic fracturing's exemption from the SDWA, make such operations a regulated activity under the UIC program, and require disclosure of chemicals used in fracking fluids. The bill was strongly opposed by the natural gas industry. It was never voted on during the 111th Congress and was not re-introduced into the 112th session. In its Fiscal Year 2010 budget report, the U.S. House of Representatives Appropriation Conference Committee identified the need for a study of hydraulic fracturing and its potential impact on drinking water. They asked EPA to conduct such a study. EPA released an outline of their planned study in November, 2011 (EPA, 2011). Subsequently, the first progress report from the study group was released in December, 2012 (EPA, 2012c). A final draft report is expected to be released for public comment sometime in 2014.

Major Components and Programs

The main focus of the Safe Drinking Water Act is to provide quality drinking water whether from surface or underground sources. To accomplish this goal, the act sets drinking water standards for both natural and artificial contaminants, controls injection of wastes into the subsurface, regulates public water systems, whether public or private, oversees state programs, and enforces compliance.

Some of the major SDWA programs are (Tiemann, 2010):

- *National Drinking Water Regulations*: EPA sets minimum standards for 90 contaminants in drinking water that may pose health risks and are often present in water supplied by public water systems. For each contaminant, EPA sets a maximum contaminant level goal (MCLG) below which there is no known adverse health risks. The agency as incorporates a margin of safety when setting the limit by lowering it from the known risks levels. The MCLG is a non-enforceable standard. Based on the MCLG, an enforceable maximum contaminant level (MCL) is set as close to the MCLG as the best technology, treatment techniques, and cost allow. Classes of contaminants for which MCLs are set include microorganisms, disinfectants, disinfectant by-products, inorganic chemicals, organic chemicals, and radionuclides. The list of regulated contaminants is periodically reviewed to determine if new ones need to be added to the list.
- *State Primacy*: The SDWA authorizes states to assume oversight and regulation for public water systems in their jurisdiction. State rules must be as strict as federal rules, but may also be more stringent.
- *Groundwater Protection Programs*: Recognizing that most public water systems obtain their water from underground sources, SDWA provides protection for underground sources of drinking water. This oversight is primarily through the Underground Injection Control (UIC) Program, which requires a permit to inject into the subsurface. The UIC Program defines classes of injection wells and specific requirements for their siting, construction, operation, and closure. (See Chapter 7 for more details.)
- *Source Water Assessment and Protection Programs*: Based on the 1996 amendments, the SDWA extended its pollution prevention efforts to include surface water and groundwater. These programs assist states in identifying potential pollution sources for surface waters.

Relevance to GCS

The SDWA is of critical importance to carbon capture and storage, because its UIC program regulates any geologic carbon sequestration projects in the United States through its Underground Injection Control program. In 2010 under the authority of the SDWA, EPA defined a new well class dedicated solely to the underground injection of large volumes of CO_2 for the purpose of long-term storage (see Chapter 7). The requirements of permitting a Class VI well would have a profound impact on whether or not GSC projects are or can be commercially viable when and if a price is placed on carbon emissions (see Chapter 7 for additional details).

Clean Air Act (CAA)

Historical Background

In the early 1950s, several state and local governments recognized the adverse impacts of air pollution and passed legislation to start dealing with the problems. Finally in 1955, the federal government passed the first federal law dealing with air pollution and its causes. This landmark legislation has been revised and amended several times and its current form is the Clean Air Act (CAA) of 1990 (Fig. 47). These changes have reflected growing scientific understanding of the sources of air pollution as well as an evolving public attitude toward mitigation. The major clean air laws include the Air Pollution Control Act of 1955, the Clean Air Act of 1963, the Clean Air

Act of 1970, and the Clean Air Act of 1990. Over time, these acts have moved from recognizing air pollution as a major health problem and promoting research to instituting steps to reduce the emission of air pollution-causing chemicals.

Acts and Amendments

Air Pollution Control Act of 1955: The Air Pollution Control Act of 1955 was the first attempt at the federal level to deal with air pollution. Specifically, it did little to reduce pollution, but recognized its dangers to public health, agriculture, livestock, and property. The law provided $5 million annually for five years for the Public Health Service to conduct research on air pollution. The act was amended in 1960 to extend funding for another four years. Amendments in 1962 authorized the U.S. Surgeon General to determine the health effects of various motor vehicle emissions.

Clean Air Act of 1963: In 1963, the first Clean Air Act was passed to promote health and welfare. The act gave state and local governments $95 million over three years to conduct research and create air pollution control programs. It also promoted technology to remove sulfur from coal and oil by setting emission standards for stationary sources such as power plants and steel mills. No provisions were enacted for mobile emission sources, which were, in fact, a significant source of air pollution. The act recognized pollution from both vehicles and stationary sources. The Motor Vehicle Air Pollution Control Act of 1965 amended the original act by establishing standards for automobile emissions. Additional amendments in 1966 expanded local air pollution control programs.

Motor Vehicle Air Pollution Control Act of 1965: This act extended emission standards to automobiles and raised the issue of transboundary pollution. It promoted research on the impact of air pollution on Mexican and Canadian public health and welfare.

Air Quality Act of 1967: In 1967, the Air Quality Act divided the nation into air quality control regions to monitor ambient air. In addition, national emission standards were established for stationary pollution sources. This decision represented a significant policy initiative since previous discussions had centered on defining the emissions standards individually by industrial sector. It also established fixed timelines for State

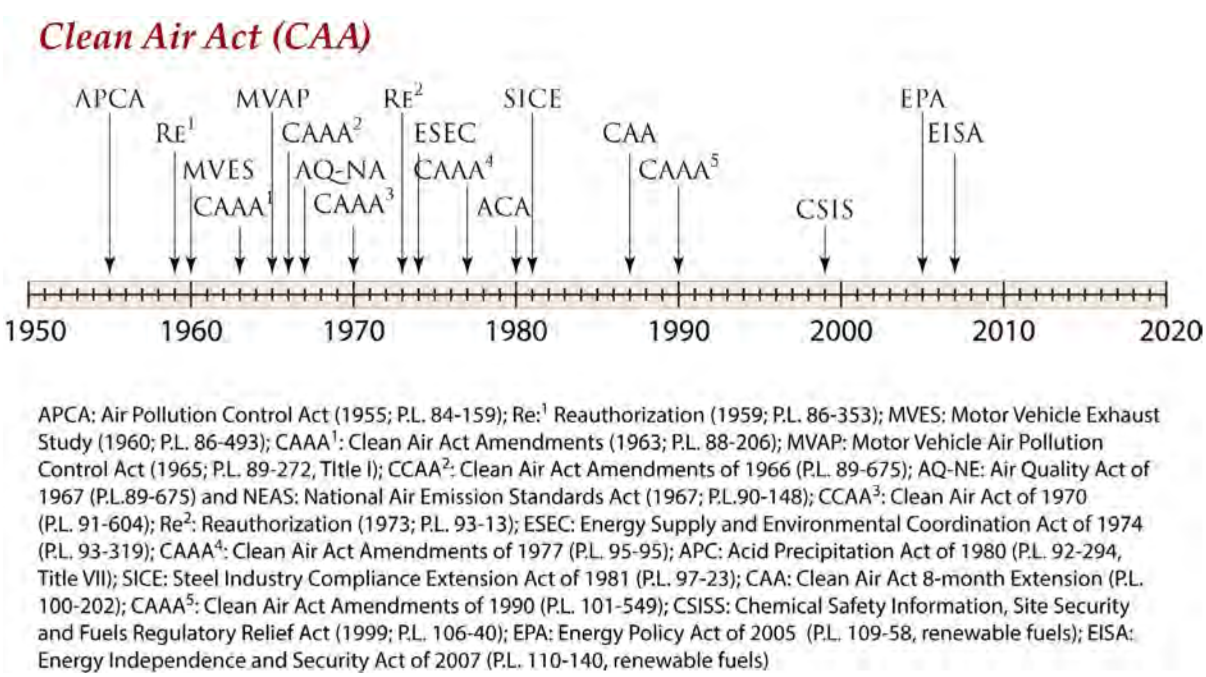

Figure 47. The timing of important U.S. laws aimed at addressing air pollution. (Copyright J.D. Myers. Used with permission.)

Implementation Plans (SIP) and recommended technologies to achieve these timetables. A 1969 amendment extended mandates for low emission fuels and automobiles.

Clean Air Act of 1970: The Clean Air Act of 1963 was almost entirely rewritten in 1970. The Clean Air Act of 1970 set new National Ambient Air Quality Standards (NAAQS) designed to protect public health and welfare. New sources of air pollution in an area were closely controlled by the New Source Performance Standards (NSPS). In addition, the new act set standards for hazardous emissions from stationary sources as well as motor vehicle emissions. A total of $30 million was devoted to research on noise pollution in large urban areas. Setting new precedent, the act gave citizens the right to take legal action against any individual or organization, including the government, who violated these standards. Amendments in 1977 saw the first attempt by the U.S. government to protect stratospheric ozone by implementing policy that reflected the international Montreal Protocol on ozone.

Clean Air Act of 1990: After over 20 years of legislative inaction on air pollution, Congress made another major revision of the Clean Air Act in 1990. This new act left the responsibility for areas that did not meet standards to the states, but prompted the states to establish compliance deadlines for different air pollution sources. It also raised automobile emission standards and established definite timelines for reductions. To reduce sulfur dioxide emissions, the act encouraged the use of low-sulfur fuels. It also mandated the use of Best Available Control Technology (BACT) to reduce emissions of air pollutants. Finally, the new law mandated reductions in the use of chlorofluorocarbons (CFCs) to protect stratospheric ozone.

Major Components and Programs

The goals of the CAA are to improve public health, preserve property, and benefit the environment. It identifies primary standards for those air pollutants that impact human health. The main criteria pollutants covered are ozone, sulfur dioxide, particulate matter, nitrogen oxides, and carbon monoxide. A secondary set of standards address pollutants that have the potential to cause environmental and property damage. Hazardous air pollutants (HAPs) emitted by chemical plants, dry cleaners, printing facilities, and motor vehicles are also regulated. The law sets specific limits for criteria pollutants and specifies timelines and procedures for reducing them. Nationally, the act requires classification attainment and non-attainment areas depending on whether or not primary air standards have been achieved. In non-attainment areas, additional regulatory steps are taken to achieve compliance with national air standards.

Some of the important provisions of the Clean Air Act of 1990 include (McCarthy, 2005; McCarthy and others, 2008):

- *National Ambient Air Quality Standards (NAAQS)*: NAAQS authorizes EPA to set outdoor air quality standards for six air pollutants (ozone, CO_2, sulfur dioxide, lead, nitrogen oxides, and suspended particulates). Every five years, EPA must review the scientific data for each pollutant and when necessary, revise the standards.
- *National Emissions Standards for Hazardous Air Pollutants*: The act creates programs for setting emissions standards set for toxic air pollutants not covered by NAAQS, but that adversely affect public health and the environment. EPA must establish Maximum Achievable Control Technology (MACT) emission standards for 188 pollutants listed in the original act. The EPA must also specify which categories of sources are subject to these standards. These standards are reviewed and potentially revised every eight years. EPA also has the authority to add or remove substances from the list.
- *New Source Performance Standards*: As categories of new industrial facilities develop, EPA is to establish national, uniform, technology-based (New Source Performance Standards—NSPS) emission standards. In this manner, a pollution control baseline was set with which all businesses in a category had to achieve. The law also has provisions that prevented states from lowering their own air quality standards to attract polluting industries. Further, the standards preserve clean air

for future growth and its own intrinsic value. Technologies for various sources must be periodically reviewed to ensure the installation of new and better control technologies. Existing facilities that were modified were also subject to these regulations by a New Source Review (NSR) process.

- *Prevention of Significant Deterioration (PSD)*: Some areas of the country have air quality that exceed those specified by NAAQS. In such areas, decreases in air quality due to new emissions would not trigger any regulatory response unless they were in non-compliance with the NAAQS. Obviously, these types of situations are counter to the intent of the CAA. To prevent this type of deterioration, the PSD program establishes three classes of air quality in the U.S. and specifies how SO_2 and particulate matter can increase in those regions. Class I areas have the highest air quality and include national parks, wilderness areas, and other natural areas. In Class I areas, allowable increments of new pollution are limited. Class II areas include all attainment areas and allow only modest increases in new pollution. Class III areas are those regions designated for development and allow larger increases in new air pollution, but not beyond NAAQS limits. The only air pollutants covered by PSD are SO_2, particulate matter, and NO_2. EPA is supposed to establish standards for the other criteria air pollutants, but has not yet done so.
- *Control of Ozone-depleting Chemicals*: This section of the act limits production and consumption of particular ozone-depleting substances. In particular, the use of Class I substances, e.g., CFCs, methyl chloroform, carbon tetrachloride and halogens, have been phased out. Beginning in 2015, new uses for Class 2 substances (hydrochlorofluorocarbons —HCFCs) will be banned except under special circumstances. This section of the CAA represents the implementation of U.S. obligations under the Montreal Protocol on Substances that Deplete the Ozone Layer. As such, details and schedules in this section adjust to maintain compatibility with the protocol and its amendments.
- *Operating Permit Program (Title V)*: Title V requires states to set up a permitting program for any source that emits air pollutants. Any source that emits or has the potential to emit 100 tons of any regulated pollutant a year must obtain an emission permit. Sources emitting HAPs are also subject to a permit, although the emission levels that trigger the need for a permit are lower than for criteria air pollutants. States, which administer the program, must collect fees to cover the administrative cost of the program. Excluding carbon monoxide, permits must cost at least $25/ton of regulated pollutant. A permit specifies how much of a pollutant can be emitted and is valid for only five years. After a permit expires, the source must apply for a new permit.

Relevance to GCS

The Clean Air Act will have a profound impact on geologic carbon sequestration projects of all sizes. This impact arises from two separate issues, one of which is direct and the other indirect. First, it will impose reporting requirements on any sequestration project through Subpart RR of the Clean Air Act of 1990. The second impact will be more indirect, but in the long run may be of greater consequence. This impact may prevent significant deterioration and Title V permitting requirements of the Clean Air Act for CO_2 emissions. These reporting requirements have already taken effect, but at this time, they do not mandate reductions in CO_2 emissions. They may, in the future, impose requirements to lower GHG emissions from a variety of industrial sources as EPA works through the process of regulating GHGs under the CAA. For those sources using fossil fuel energy, GCS may be the only technically viable option available for lowering their GHG emissions.

CAA GHG Reporting Program: The GHG Reporting Program is part of the CAA and is designed to provide information about carbon injected into the subsurface. EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule, Subparts RR and UU, with the final rule issued on November 22, 2010. This rule requires all facilities that inject CO_2 underground to report annually greenhouse gas data to EPA. The rule has two parts covering two different types of injection activities. Subpart RR covers those facilities that inject CO_2 for the purpose of long-term geologic sequestration. Under the rule, these facilities must report basic information on the CO_2 received for injection; develop a monitoring, reporting, and verification program (MRV) that is site specific; and report CO_2 sequestered using mass balance and annual monitoring. This information will allow EPA to determine how geologic sequestration is evolving over time and its effectiveness as a strategy for reducing GHG emissions. Reporting complements the Class VI UIC permit requirements under the SDWA. Facilities that report under this section do not have to report under Subpart UU. Reporting of CO_2 emissions began on March 31, 2012.

The second part of the reporting rule, Subpart UU, covers all other injectors of CO_2 including enhanced oil and gas recovery. These operations must report CO_2 received for injection. Except for two situations, they do not have to report under Subpart RR. If the owner or operator chooses, they may opt into Subpart RR. Any facility that has a Class VI permit must report under Subpart UU. Reporting requirements for non-sequestration activities also began on March 31, 2012.

GHG Emissions Permitting under CAA: In 1999, EPA was petitioned to regulate GHG emissions from new motor vehicles under the CCA. The petitioners claimed the authority for such action came from CAA Section 202(a)(1). In 2003, EPA determined that CAA did not give it the power to regulate GHGs and, even if it did, EPA would not issue any GHG emissions standards for policy reasons (Meltz, 2007). Subsequently, the state of Massachusetts brought suit against the EPA to force them to regulate GHG as pollutants under CCA. This case went all the way to the U.S. Supreme Court (*Massachusetts v. EPA*). Additional petitioners in the suit were California, Connecticut, Illinois, Maine, New Jersey, New Mexico, New York, Oregon, Rhode Island, Vermont, and Washington. Several cities, including New York, Baltimore, and Washington, D.C., also joined the suit against EPA. Organizations backing Massachusetts included environmental groups such as the Friends of Earth, Greenpeace, National Resources Defense Council, Sierra Club, and Union of Concerned Scientists. States supporting EPA's original finding included Alaska, Michigan, Idaho, Kansas, Nebraska, North Dakota, Ohio, South Dakota, Texas, and Utah. Industry groups supporting EPA included the Alliance of Automobile Manufacturers and the Engine Manufacturers Association, among others.

In April 2007, the Supreme Court decided 5-4 that the term "air pollutant," as used in the CAA, did cover greenhouse gases. As a result, EPA was required to determine if GHGs represent a danger to American's health and welfare. At the same time, the court stated that the act required EPA to consider the science of climate change relevant to the decision. Justice Stevens, writing for the majority, stated the agency could not use policy considerations in making their decision. With this decision, the court sent the case back to EPA to reconsider their earlier decision on GHGs. The ruling left EPA with only three options to consider (Meltz 2011). Fundamentally, the EPA could decide that motor vehicle GHG emissions: 1) do "endanger public health or welfare," 2) do not endanger public health or welfare, or 3) the science is too uncertain to make a determination. On April 17, 2009, EPA issued its "endangerment finding." After additional study, the EPA found six GHGs (CO_2, CH_4, N2O, HFCs, PFCs, and SF_6) that "…in the atmosphere may reasonably be anticipated to endanger public health and … public welfare." With this finding, EPA was obligated under Section 202(a) to issue greenhouse gas emissions standards for light-duty motor vehicles. This decision represents the first time GHG emissions were considered a pollutant under the CAA. With that finding, GHGs also became subject to "prevention of significant deterioration" and Title V operating-permit provisions of the act. The original ruling was for mobile sources of GHGs, but once an endangerment finding was made for mobile sources, it automatically applied to stationary sources emitting GHGs as well. This ruling means GHG emissions will be regulated regardless of whether or not Congress passes climate change legislation.

The EPA issued rules for GHG emissions for light-duty vehicles on April, 2010. These rules set stringent GHG emission and fuel efficiency standards for 2012–2016 models. At the same time, the Department of Transportation issued a ruling requiring that 2016 models achieve a fuel efficiency of 35.5 mpg, which matches California's Clean Car Standards. California's Clean Car Standards have been adopted by 13 other states and California has agreed that vehicles meeting the federal standard will be accepted as complying with that state's requirements on mobile GHG emissions. For stationary sources, permitting began January 2, 2011. Standards have been proposed for heavy duty vehicles beginning with model year 2014.

With GHGs regulated as an air pollutant, they will be subject to prevention of significant deterioration provisions and permitting requirements of Title V of the CCA. Thus, a facility will have to get a permit for emissions of a pollutant above threshold values. The original CCA had threshold emissions of 100–250 tons/year for traditional pollutants such as lead, ozone, particulate matter, and nitrogen dioxide. If this regulatory level was used for GHGs, especially CO_2, EPA estimated the number of regulated emitters would be as large as six million, an administratively untenable number (McCarthy and Parker, 2010). Consequently, EPA created the *Greenhouse Gas Tailoring Rule* that raises the emissions threshold to levels more appropriate for GHGs in a phased-in manner. This rule would allow EPA to focus on the largest emitters of GHGs and over a six year period, determine the best way to deal with smaller sources (McCarthy and Parker, 2010). Because the GHGs covered by EPA's finding have different global warming potential, the international practice is to express GHGs in CO_2 equivalents, i.e., CO_2e, as calculated by accepted mathematical procedures (IPCC, 2007). Converting the amounts of GHGs other than CO_2 to CO_2e standardizes the impact of different GHGs and permits determining whether or not they exceed allowable emission limits.

There were three stages to the tailoring rule:

- January 2, 2011–June 30, 2011 (Step 1): Industrial facilities that already must get CAA PSD permits for other pollutants also require GHG permits provided they meet one of two criteria. First, if they are new constructions with the potential to emit 75,000 or more tons per year (tpy) CO_2e. Alternatively, facilities are subject to permitting if changes are made to the facility that will increase GHG emissions by 75,000 tpy CO_2e even if there are no increases in other pollutants. These projects will need to use Best Available Control Technology (BACT) to handle their GHG emissions under the PSD program. As for operating permits under Title V, only those facilities that already have operating permits for non-GHG pollutants would require GHG operating permits.
- July 1, 2011 to June 30, 2013 (Step 2): All new facilities emitting GHGs in excess of 100,000 tpy and modified facilities whose emissions will increase by 75,000 tpy will require PSD permits, regardless of whether or not they exceed non-GHG emission levels. Similarly, modifications of existing facilities that increase GHG emissions by at least 75,000 tpy will be subject to PSD permits. Operating permits will be required for all facilities emitting at least 100,000 tpy CO_2e. This is true even if they do not exceed limits for the other CAA controlled pollutants. With this change, industrial facilities will be, for the first time, subject to Title V operating permit requirements based solely on GHGs.
- July 1, 2014 (Step 3): As specified in the original rule, EPA had to ultimately decide if they would lower the emission standard to cover smaller emitters. On June 29, 2012, EPA indicated they would not regulate smaller emitters. Thus, they chose

not to implement the original Step 3. Their justification cited the lack of time to gather experience from the state and EPA staffs to develop the necessary infrastructure and expertise to handle a significant increase in GHG related permit applications if small emitters were also regulated.

Clean Water Act (CWA)

Historical Background

The Clean Water Act (CWA) is the primary federal law governing the quality of waters in the United States. It regulates 35,000 to 45,000 facilities that discharge waste to the nation's waterways. Another 12,000 facilities that discharge to publicly owned treatment facilities are also governed by the law. It is estimated that the CWA prevents the discharge of almost 700 billion pounds of pollutants each year. The law has been particularly successful in reducing pollutant discharge from specific sources, i.e., point sources. It does not cover non-point source pollution, i.e., runoff from streets, farms, and yards. Non-point pollution is largely responsible for the poor quality of half of the nations' rivers, lakes, and bays, which are not safe for fishing and swimming.

The first federal law dealing with water pollution, the Federal Water Pollution Control Act of 1948 (Fig. 48), was totally revised in 1972. In 1977, the initiative got its current name with the passage of the Clean Water Act.

Acts and Amendments

Federal Water Pollution Control Act (FWPCA) of 1948: This act was the first to express federal interest in water quality. Previously, water pollution was viewed as a state or local government issue. The act provided funds for technical expertise for dealing with water pollution and encouraged research on water quality issues. Four acts through the 1950s and 1960s extended federal control to interstate and intrastate waters, set water quality standards (1965), extended assistance to municipalities, and outlined enforcement provisions. Despite these laws, public anger at the slow pace of clean-up led to a major revision of the original act.

Federal Water Pollution Control Act Amendments (FWPCA) of 1972: This amendment virtually rewrote the original act. It expressly stated its goal to restore and maintain the chemical, physical and biological health of the nation's water. The discharge of pollutants was to cease by 1985 and the quality of the nation's waterways by mid-1983 was to be "fishable" and "swimmable." This act gave EPA regulatory authority to limit pollutant discharge from point sources through the NPDES program. It also allowed EPA to give authority for this program to states while maintaining oversight responsibility. Lastly, the law created a construction grants program to help municipalities construct

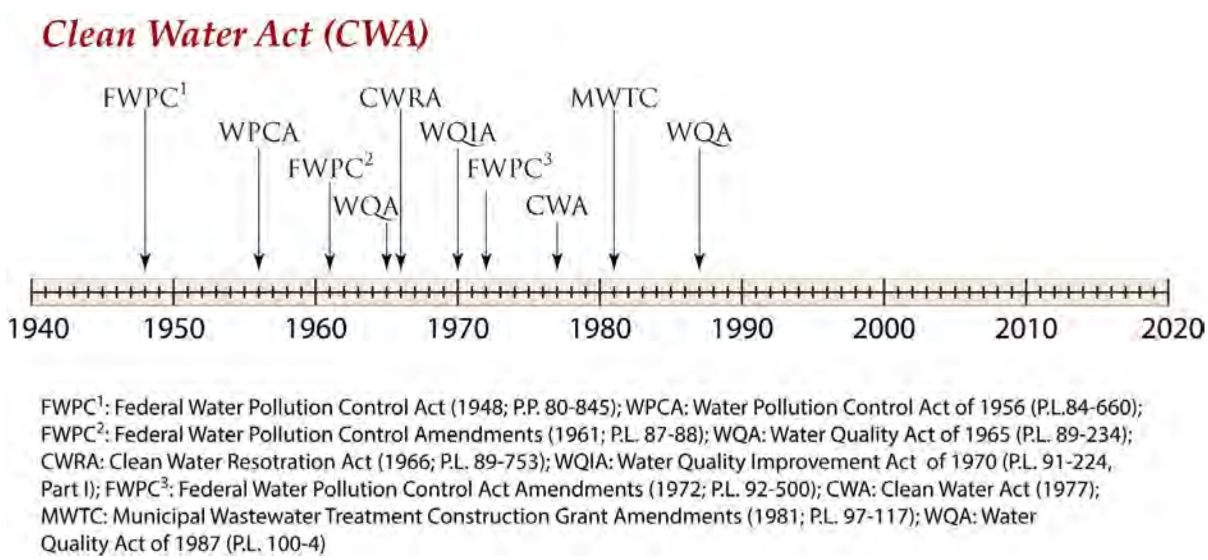

Figure 48. Key water pollution acts in the United States. (Copyright J.D. Myers. Used with permission.)

sewage treatment plants or publicly-owned treatment works (POTWs).

Clean Water Act of 1977: This law created three categories of pollutants: conventional, non-conventional and toxic. It specified that BACT applies to non-conventional, and toxic pollutants, but best conventional technology would apply to conventional pollutants.

Water Quality Act of 1987: This amendment replaced the construction grant program with the State Water Pollution Control Revolving Fund, which further developed EPA-state cooperation. It also encouraged states to develop and manage nonpoint pollution control programs.

Major Components and Programs

The CWA and its amendments intend to restore and protect the quality of surface waters in the U.S. Originally, the goal was to restore all navigable waters to a level where they would be "fishable and swimmable" and ultimately eliminate all discharges to surface waters. Although this goal is not cited as much as it once was, the law still considers discharge to surface water as illegal unless the provisions of the CWA are followed. Surface waters are broadly defined and include rivers, lakes, intermittent streams, and wetlands. The law does not cover groundwater, which is addressed by the Safe Drinking Water Act. The law covers three main classes of pollutants: conventional pollutants (biochemical oxygen demand (BOD); total suspended solids (TSS); fecal coliform, oil and grease, and pH); priority pollutants (various toxic pollutants); and non-conventional pollutants (all those that do not fit into the other two categories).

Some of the key provisions of the Clean Water Act of 1987 include:

- *National Pollutant Discharge Elimination System (NPDES)*: This program prohibits discharge of pollutants into United States waters without a permit issued by the EPA, a state, or a designated tribal government (for discharges on reservations). These permits are for direct discharges from a point source such as a sewer, pipe, or discharge ditch. A permit must be obtained before discharge is begun and places limits on effluents the source may discharge. In their permit application, the emitter must identify the types of pollutants present in the effluent.
- *Storm Water Management Regulations*: This program addresses storm water run-off from industrial facilities. It requires facilities submit a Storm Water Prevention Plan (SWPP) for monitoring storm water runoff that ensures Total Maximum Daily Load of all pollutants does not exceed established standards. Facilities must have a NPDEs permit for storm water discharge if it is associated with industrial activity, if it originates from a large or medium municipal storm sewer system, or if the discharge is considered by EPA or the state to violate a water quality standard or contribute significantly to water pollution of the waters of the United States. The storm water rule requires capture and treatment of storm water at facilities producing chemicals or related products. Treatment will remove suspended soils, organic material (BOD material), or conventional pollutants as well as toxic pollutants, e.g., metals and organic compounds.
- *Dredge and Fill Permits*: The CWA exempts the placement of dredge and fill material into the nation's surface waters through the NPDES permitting process. Rather, this activity is covered by a permit issued by the Army Corps of Engineers (COE). The COE program covers activities such as dam construction, flow regulation, water diversion for canals, irrigation systems, stock tanks, streambed modification and stabilization, real estate subdivision development, and stream crossings. Because wetlands are considered part of surface water, permits to modify wetlands fall under the control of the COE.
- *Spill Prevention Control and Countermeasures*: This program covers facilities that store and manage petroleum and/or hazardous materials with the potential for releases to waterways. These facilities are required to develop and implement Spill Prevention and Control Countermeasure (SPCC) plans. SPCC

plans must contain spill contingency plans if a facility cannot provide secondary containment, e.g., berms surrounding oil storage tanks.

Relevance to GCS

Of the four potential geologic carbon sequestration targets, the one with the largest capacity for CO_2 storage is saline formations (IPCC, 2005). Yet, these formations are filled with formation fluid and any CO_2 injected into them must be accommodated by displacing or compressing existing formation fluid (Oldenburg and others, 2009). Alternatively, the reservoir rock could accommodate this additional fluid by compressing or displacing its original brine. In either case, the pressure in the formation will increase. If not monitored carefully, CO_2 injection could cause fluid pressure within the formation to exceed the fracture pressure of the cap inducing fracturing. Fracturing of the cap could threaten the integrity of the storage site by opening up new leakage pathways. Even if the induced pressure is kept below the fracture pressure, brine displacement will cause a pressure front to form around the growing CO_2 plume (Birkholzer and Zhou, 2009). Displaced brine and pressure front could intercept improperly abandoned wells it they were not properly accounted for in the original permitting process (Nicot and others, 2009) or reactivate faults outside the original area of review (Mazzoldi and others, 2012) (see Chapter 7). Clearly, pressure management during injection is a critical component of the operational stage of any GCS project.

One suggestion for managing formation pressure is to produce some of the formation brine (Bergmo and others, 2010). In this manner, room is made for the new fluid being injected into the formation. Such accommodation would minimize pressurization within the reservoir. Yet, co-production of formation fluids would create its own problems. Because this brine would necessarily have total dissolved solids of greater than 10,000 ppm, disposing of it to any surface water would require a discharge permit under the NPDES program. Conversely, re-injecting brine into another formation, if a suitable one could be found, would require a UIC permit. In either case, management of any formation fluid produced as a pressure management strategy will encounter regulatory hurdles.

Summary

Geologic carbon sequestration projects will face a variety of geologic, engineering and technical, and logistical problems that will be, in large part, site-specific. These considerations will determine if a site is suitable for the long-term storage of CO_2. Yet, counteracting these problems is only the first hurdle for a potential site. The site will also have to clear a number of significant regulatory hurdles. First, it will have to satisfy the very strict, detailed, and comprehensive criteria for a Class VI sequestration injection well. An operational GCS project will have to report amounts of CO_2 injected under Subpart RR of the CAA. Finally, if a GCS project extracts brine from the target reservoir as a means of managing formation pressure, it will be regulated by the discharge permits of CWA if discharges to surface water bodies are involved. Conceivably, regulatory requirements could potentially lead to a geologically and technologically acceptable GCS site to be rejected. Thus, these regulatory constraints must or should be considered from the earliest stages of project evaluation and development.

Chapter 5

SDWA: Underground Injection Control (UIC) Program

Overview

One of the primary sources of drinking water in the United States is wells that tap groundwater. The original SDWA established the *Underground Injection Control (UIC)* program to regulate the injection of fluids into the subsurface and protect groundwater suitable for human consumption from contamination. It is designed to protect both present and future sources of drinking water. The UIC program sets minimum federal standards for all wells that inject hazardous and non-hazardous fluids above, into, or below formations containing *underground sources of drinking water (USDW)*. The siting, construction, operation, maintenance, monitoring, testing, and closing of injection wells are all regulated by this program.

A USDW is defined as an aquifer or portion of an aquifer that 1) supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, 2) currently supplies drinking water for human consumption, 3) contains less than 10,000 milligrams/liter (or 10,000 ppm) total dissolved solids (TDS) and/or 4) is not an exempted aquifer (see Class III discussion in this chapter). The high TDS limit is set because water with up to 10,000 ppm conceivably could be treated to yield drinkable water in the future.

As part of the SDWA, UIC regulates underground injection of all fluids (liquid, gas or slurry). Some operations involving natural gas (hydrocarbon) storage, oil and gas production and hydraulic fracturing are exempt from the program. Potable water is defined as water with less than 500 ppm TDS. This standard is a secondary water quality standard, meaning it is recommended but not enforceable. Water classifications based on TDS are: freshwater (< 1,500 ppm), brackish water (1,500-5,000 ppm), and saline water (> 5,000 ppm). (For comparison, seawater has an average TDS of 35,000 ppm.) These secondary standards are non-enforceable guidelines, but cover contaminants that may cause cosmetic effects (such as skin or tooth discoloration) or aesthetic effects (such as unpleasant taste, odor, or color).

Major changes have occurred to the UIC program over its 39 year history (Fig. 50). In 1980, EPA finalized the regulations that define the five well classes. It also set the minimum standards that states must meet to be granted primacy (primary enforcement responsibility) over the UIC program within their jurisdictions. Between 1982 and 1985, most state programs were approved (Fig. 49). In 1985, EPA submitted a report to Congress on the injection of hazardous wastes and its impact on USDWs. The Hazardous and Solid Waste Amendments to RCRA in 1984 required EPA revise the standards for Class I wells to include injection of hazardous wastes. This amendment banned the land disposal of certain wastes, although EPA can grant exemptions when petitioned. The ensuing regulations issued in 1988 strengthened the requirements for Class I well construction and added the requirement that an operator must certify the injected hazardous waste will not leave the injection zone for 10,000 years. In 1999, EPA issued a 23 volume report summarizing the types and numbers of Class V wells and the materials they inject into USDWs. The study was prompted by an agreement with the Sierra Club to determine if Class V wells endangered USDWs and if additional Class V well types were necessary. In 2002, EPA issued its final determination regarding Class V wells and concluded they posed no danger to USDWs and that no new well classes were necessary. This study did not address large capacity cesspools or motor vehicle waste disposal wells, the two types of Class V wells mostly likely to cause groundwater contamination. In 1999, the Class V Rule was issued banning all new permits for these wells after April, 2000 and requiring the phasing out of existing wells by April, 2005.

In 2008, EPA proposes its first new class of wells designed for long-term sequestration of CO_2. After a two year rule making process (see Chapter 7 for details), the final rule for Class VI wells was issued along with a series of guidance documents for preparing Class VI permits.

Well Classes

The UIC program defines six classes of injection wells that cover a range of activities and industries. The six classes are creatively named Classes I, II, III, IV, V and VI (Fig. 50). Classes I through III regulate the injection of material below the deepest USDWs in a region. Class IV wells, which were originally designed to inject hazardous

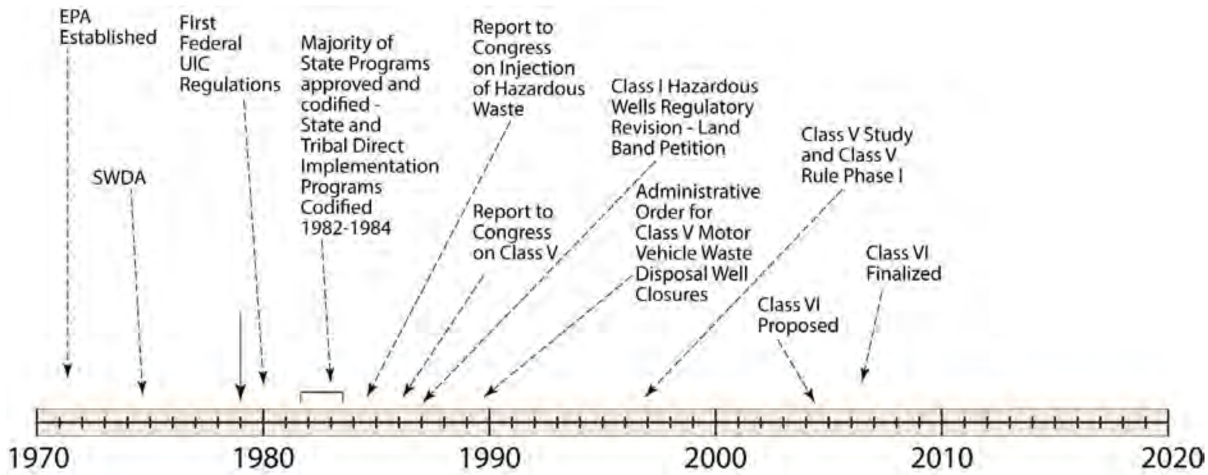

Figure 49. Timeline for major milestones in UIC program.

or radioactive materials into or above USDWs, were banned nationwide in 1984 and can now be used only for approved remediation projects. Class V wells regulate injection of non-hazardous materials into or above USDWs. The new Class VI well is for the injection of supercritical CO_2 for the purpose of long-term geologic storage, generally at depths below the lowermost USDW.

Class I

Class I wells isolate hazardous, industrial, and municipal wastes through deep injection far below the lowermost USDW. Injection zones for Class I wells typically range from 1,700 to more than 10,000 feet (3,048 meters) below the surface (Fig. 50a). The injected fluids are separated from USDWs by an impermeable "cap" rock, called the confining layer or seal, which prevents flow of the injected fluid into USDW aquifers. In many settings, there may be additional layers of permeable and impermeable rock between the injection zone and the overlying USDWs. Industries using Class I wells include: petroleum refining, metal production, chemical production, pharmaceutical production, commercial disposal, food production, and municipal wastewater treatment facilities. The types of fluids injected in these operations include manufacturing and mining waste, waste defined as hazardous by the Resource Conservation and Recovery Act (RCRA), treated municipal effluent, and radioactive waste. In the thirty year history of the UIC program, Class I wells have isolated four trillion gallons of waste fluid from USDWs across the country. There are approximately 550 Class I wells operating in the United States (EPA, 2013e). Because of favorable geologic conditions, most of these wells are found in the Great Lakes and Gulf Coast regions.

There are four primary types of Class I wells. *Hazardous waste disposal wells* inject RCRA-defined hazardous waste, mostly at industrial facilities. For these wells, hazardous waste must not move from the injection zone for 10,000 years or as long as waste is deemed hazardous. There are operational Class I wells in ten states with the most in Texas and Louisiana. In total, there are 120 hazardous waste disposal wells that comprise 22 percent of all Class I wells. *Non-Hazardous industrial waste disposal wells* are used to dispose of non-hazardous waste below USDWs. They are permitted in 19 states, mostly in Texas, Louisiana, Kansas, and Wyoming and number about 380 wells, or 48 percent of Class I wells. In Florida, *Municipal wastewater disposal wells* inject municipal wastewater. These wells have large diameter casing (up to 36 inches [91 meters]) and rely on gravity to place fluids underground. Thirty percent of Class I wells are of this type. *Radioactive waste disposal wells* inject waste containing radioactive material below the lowermost USDW. The waste must be contained within the injecting formation within one quarter mile of the wellbore. Currently, there are no

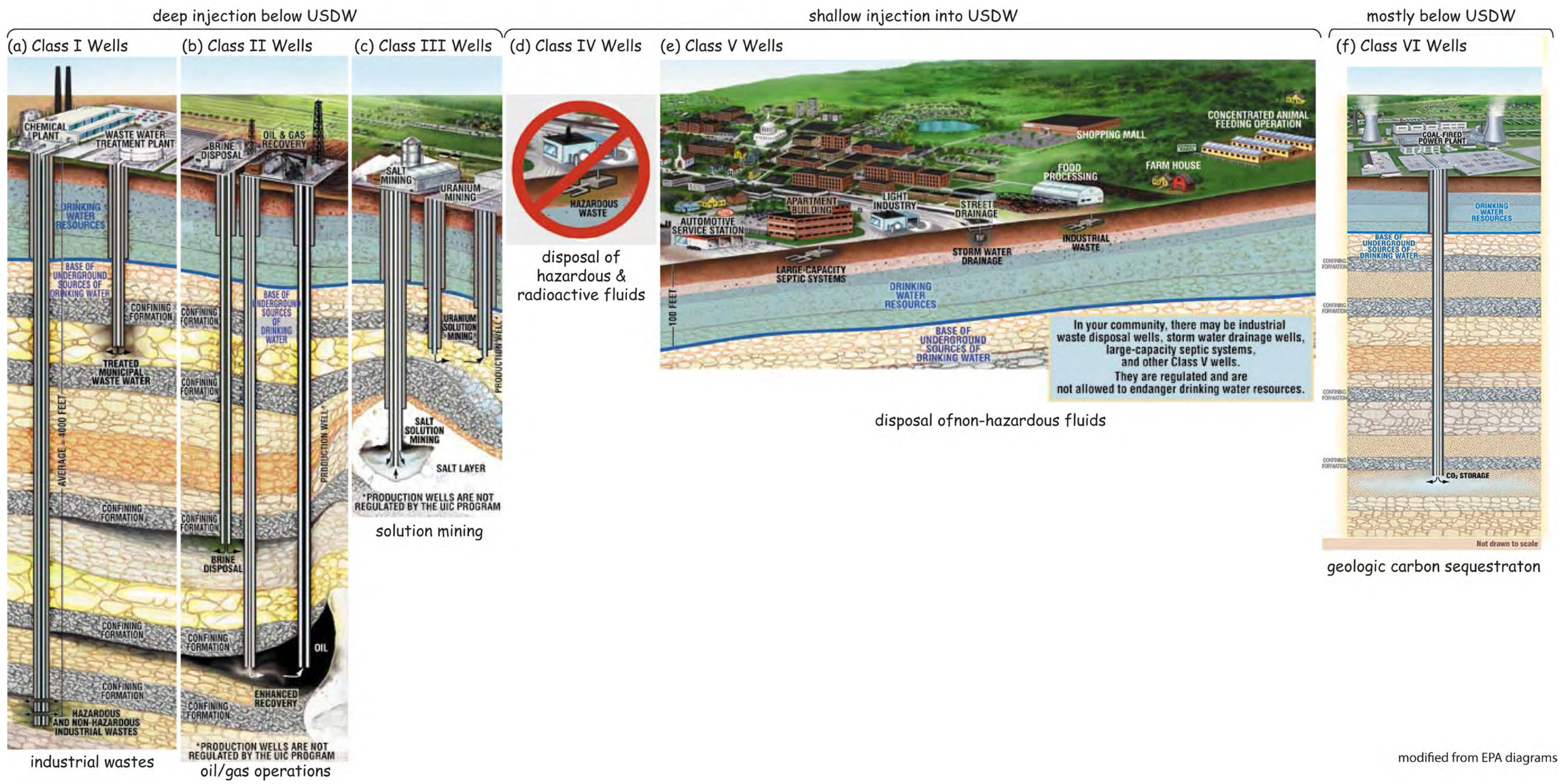

Figure 50. The six well cases of the UIC program under the SDWA. (Modified from EPA 2013a, 2013b, 2013c, 2013d, 2013e, 2013f)

known radioactive waste disposal wells operating in the United States (EPA, 2013e).

Each Class I well operates under a permit authorized by the EPA that may last for up to ten years. EPA regulations specify strict standards for siting, constructing, monitoring, testing, and closure of a Class I well. Wells that inject hazardous materials have an additional set of governing regulations. Siting of a Class I well begins with a geologic study that is required to demonstrate the injection formation(s) has characteristics, e.g., permeability, porosity, thickness, homogeneity, etc., that will allow the formation to receive the injected fluids at the planned injection rate and that excessive pressure will not be necessary to accomplish the injection. The receiving formations must be large enough so that over the duration of the project pressure does not build up and displaced fluids do not reach aquifer recharge zones. The geologic study must also demonstrate that a low permeability cap zone will prevent upward movement of injected fluid. The repository must be geologically stable and have no other economic value. Finally, the injected fluids must be physically and chemically compatible with the well materials and the rock and formation fluids they are injected into. The geologic study must evaluate the artificial penetrations (other wells) that occur in the area of review (AoR) centered on the injection wells. The AoR can be defined mathematically or defined by specifying a fixed radius centered on the well. In either case, the minimum AoR radius is a quarter mile. All artificial penetrations in the AoR must be evaluated to determine if they may allow injected fluids to migrate out of the injection zone. A corrective plan must be submitted for all improperly completed or plugged wells in the AoR. If the well intends to inject hazardous material, the geologic study must also include a structural study. This additional study must demonstrate that the injection and seal rocks do not have vertical fissures or faults that could allow fluid movement and that the area is seismically stable. The study should also show that injected fluid and subsequent formation pressurization will not cause earthquakes or increase the occurrence of natural earthquakes. Hazardous injection wells also have additional AoR constraints. For these wells, the minimum radius of the AoR is two miles.

Class I hazardous injection wells must be designed with a series of multilayer barriers to ensure injected fluids cannot reach USDWs. The well must be cased with two sets of casing and cementing, with the surface casing cemented along its entire length to the surface (see Chapter 6 for details on well construction). Proposed tubing and packer design must account for the nature of the borehole, the injected fluid, and the proposed rate of injection. All of these parameters must be explained in detailed engineering schematics that show subsurface well construction architecture and must be submitted with the permit application. During the actual drilling and construction phase of the well, tests must be conducted to confirm that there is no vertical fluid movement within the casing or in the cemented annulus around it. The additional details for a hazardous injection well include prior approval of all well construction details before construction starts and cementing of the long-string tubing to the surface. This is in addition to the cementing of the production casing in a similar manner.

Once the well is operational, monitoring and testing is conducted to ensure no leaks occur in any of the construction layers of the well and that injected fluid is remaining in the injection formation. To accomplish these goals, the operator must continuously monitor the annulus pressure and the nature of the fluid being injected. In addition, external and internal mechanical integrity tests (MITs) of the well must be conducted every five years. For a hazardous injection well, the requirement for internal MITs is every year as well as an annual cement test at the bottom of the well. Operators must also have plans in place for waste and wastewater analysis and responding to MIT failures.

The results of the monitoring program are used to create records and report to the EPA on the operation of the well. These include quarterly reports on monitoring of the AoR. MIT results must be reported to the relevant state or federal UIC program office, along with any changes to the facility itself. Injection volumes and maximum injection pressure must also be reported quarterly. Finally, the results of the waste analysis plan must also be reported to the EPA.

Ultimately, the well injection zone will reach capacity or the parent industrial facility will close. When this occurs, the well must be closed and abandoned in a manner that safely protects USDWs in the region into the future. For a non-hazardous well, only a report on plugging and abandonment is necessary. The closure steps for a hazardous injection well are considerably more detailed. Pressure fall off and MITs must be conducted and the groundwater continuously monitored until the pressure in the injection zone falls to levels that cannot impact USDWs. The well must be flushed with non-reactive fluid and authorities must be notified of the well's location and its zone of influence.

Class II

Class II wells are related to oil and gas operations and typically involve the disposal of brine as well as activities for enhanced oil recovery (EOR). This class of well is used almost exclusively by the oil and gas industry to disposed of produced brines. Brines are formation water with high TDS normally produced during the recovery of oil and natural gas. This water is separated in surface facilities from the oil and natural gas and must be disposed of in an approved manner. They typically contain toxic metals and radioactive materials and cannot be safely disposed of by discharge to surface water. In addition, oil field brines often have salt or total dissolved solid concentrations many times greater than seawater. Oil and gas producing states require brine re-injection into originating or similar formations. Types of fluids injected include highly saline water produced during oil and gas extraction, crude oil for storage, polymers/viscosifiers for EOR, and drilling fluids and muds. Fluids injected using Class II wells can only be injected into formations below the lowermost USDW (Fig. 50b). Approximately 144,000 Class II wells inject over two billion gallons of brine a day or 700 million gallons of fluid yearly. The majority of these wells are in Texas, California, Oklahoma, and Kansas (EPA, 2013a).

There are three primary types of Class II wells. *Enhanced recovery wells (EOR)* are used in secondary or tertiary recovery of oil. EOR wells are the most numerous type of Class II well, comprising as much as 80 percent. The UIC Program does not regulate production wells or those wells used to bring hydrocarbon fluids to the surface. EPA does regulate hydraulic fracturing wells if their fluids contain diesel fuels, but not hydraulic fractured wells that do not use diesel fuel in the hydraulic fluid. *Disposal wells* inject brines and other fluids associated with the production of oil and natural gas underground for safe disposal. On average each gallon of oil produced in the U.S. is accompanied by approximately ten gallons of co-produced water. Because of its chemical composition, this water cannot be safely disposed of by surface discharge. About 20 percent of Class II wells are disposal wells. The last type of Class II wells is *hydrocarbon storage wells*, which inject liquid hydrocarbons into underground formations, such as salt caverns, for storage. The U.S. Strategic Petroleum Reserve along the U.S. Gulf Coast is an important example of this type of operation. Currently, there are about one hundred liquid hydrocarbon storage wells in operation in the United States.

If states desire regulatory primacy (see Primacy section in this chapter), they have two options with respect to Class II wells under two different sections of SDWA, section 1422 or 1425. Under section 1422, a state must meet the minimum standards EPA has set for the UIC program. Under this section, there are strict requirements for all stages of a Class II well, including construction, operation, monitoring and testing, reporting, and closure. Approval for disposal and EOR wells are handled differently under this section. For the latter, approval is by permit, but EOR wells can be authorized by rule or issued a permit. State requirements are very different under section 1425. In this situation, the state need only demonstrate that their existing standards will protect USDWs. Effectiveness is demonstrated by showing that their permitting, inspection, monitoring and record-keeping, and reporting have been effective in preventing contamination of USDWs by oil and gas operations active within their state boundaries.

Class III

The last deep injection well class is Class III, which is designed to minimize environmental impacts from solution mining operations (Fig. 50c). As such, the industries using Class III wells are metal and chemical mineral mining. They typically inject freshwater to extract salt (NaCl), sodium bicarbonate to extract uranium, steam to extract sulfur, and proprietary solutions for various minerals and metals, such as copper. Mining copper by injection occurs in only a few states. At the present time, sulfur mining by injection is not occurring in the U.S. (EPA, 2013f). There are 165 mining sites with approximately 18,500 Class III wells in operation across the nation. Mining fluids injected by Class III wells are generally confined to geologic formations below the lowermost USDW in the region, although exemptions to this requirement can be granted. As with the oil and gas industry, solution mining production wells, that is the wells that extract the dissolved product, are not regulated under the UIC program. Class III wells are used to mine uranium, salt, copper, and sulfur. Approximately, 50 percent of salt and 80 percent of uranium mined in the U.S. are extracted using Class III wells.

Class III wells are divided into four categories or types. The majority of Class III wells are *uranium in-situ leaching (ISL) wells* used for injection, extraction, and monitoring of uranium mining. Eighty percent of the uranium produced in the United States use Class III wells. To dissolve salt, clean water is pumped underground using *salt solution mining wells*. The resulting brine is pumped to the surface. Salt solution wells comprise five percent of Class III wells. *Copper wells* inject a dilute sulfuric acid solution into copper-bearing formations to dissolve the copper and return it to the surface in solution through extraction or production wells. The dissolved copper is extracted from solution at the surface. Sulfeur wells mine sulfur in situ. Super-heated steam is injected into sulfur formations to dissolve the sulfur (the Frasch process) producing a sulfur solution. This solution is pumped to the surface where the sulfur is precipitated. To prevent migration of any of these mining solutions out of the production zone, more fluid is extracted than injected.

The great majority of Class III wells are ISL wells used for the extraction of uranium from porous sedimentary rocks. To develop this resource, injection wells are drilled into the uranium-bearing formation in a precise geometric pattern (Fig. 51). A lixiviant, a solution containing water and other chemicals, is injected into the formation and allowed to contact the uranium minerals long enough to dissolve them. When the lixiviant is nearly saturated, it is pumped to the surface where the uranium is extracted to produce yellowcake. After adjusting the chemistry, the lixiviant is recycled through the mining cycle.

The other major industry that uses Class III wells is salt mining. These wells inject clean water into a salt formation. On contact, the water dissolves the salt producing a brine that is pumped to the surface. There are two methods for injecting water. In the *normal flow* approach, the water is injected down the tubing in the well and the brine is produced through the annulus between the tubing and casing (see Chapter 6 for a discussion of tubing and casing). Conversely, the water can be injected through the annulus and produced through the tubing, i.e., *bottom flow*. Salt units that occur as bedded, tabular formations generally require a number of injection wells. In contrast, a single injection well placed at or near the crest of the dome may be sufficient to mine the entire structure. Although the second most common Class III well type in the U.S., salt wells make up only about five percent of this UIC well class.

To operate a Class III well, an operator needs either an individual permit or one for multiple wells in a well field. In some cases, uranium ore minerals occur in a USDW. If this is the case, the operator must get an aquifer exemption before beginning injection. An aquifer or portion of an aquifer can be exempted if it is not currently used as a drinking water source or is unlikely to be used in the future. This exemption may be because of high total dissolved solids content in the aquifer. The USDW standard for total dissolved solids is 10,000 ppm, much higher than the standard for potable water (<3,000 ppm TDS). Class III wells must be cased and tubed with materials compatible with the injected lixiviant and prevented from possibly contaminating USDWs during mining operations. In addition, the operator must pressure test the wells before injection begins. Injection pressure and flow rate must be monitored during operation and injection cannot be between the outer casing and the wellbore. In addition, for exempted formations with <3,000 ppm TDS, USDWs above and below the injection zone must

Figure 51. A newly installed in-situ leach field at an in-situ uranium mine in Wyoming. The white objects in the middle foreground are the tops of injection and production wells. (Photograph by J.D. Myers. Used with permission.)

be monitored for possible impacts from mining. This entails drilling a series of monitoring wells into the USDWs that continuously monitor the groundwater for any changes from pre-mining base line chemistry. For salt wells, wells must be tested for leaks every five years. As with other UIC well classes, Class III wells must be properly plugged and abandoned after operations cease. To ensure proper closure of a well, the operator must also provide assurances that they have the financial resources to properly close the wells when mining ceases.

Class IV

Class IV wells were originally designed as a class of disposal well for injecting hazardous or radioactive waste into or above USDWs. This type of well was banned for disposal purposes in 1984 (Fig. 50d). Presently, Class IV wells can only be used to inject hazardous material as part of authorized environmental cleanup activities (EPA, 2013g). For example, such wells can be used to inject treated contaminated groundwater back into the original aquifer. This type of injection must be part of an EPA or state approved RCRA or CRCLA (Superfund) clean-up project. Currently, there are 32 waste Class IV clean-up sites in the U.S.

Unlike the first three well classes, this class is designed for shallow injection into or above USDWs. In construction, they can be very similar to Class V wells, which are designed for similar types of injection. The difference between the two wells is the nature of the injected fluid, hazardous for Class IV and non-hazardous for Class V. The only circumstances that would allow injection of hazardous material into a USDW via a Class IV well is in a groundwater remediation project. In these cases, water is pumped from the contaminated aquifer and treated on the surface. After treatment, the water is re-injected into the same aquifer. Because a single stage treatment cannot completely remove the contaminant, the re-injected water would still classify as hazardous. This style of "pump and treat" is repeated until the quality of treated water no longer improves. Although this type of treatment can improve the quality of contaminated water in an aquifer, it cannot completely restore it to its original quality.

Class IV wells are authorized by rule on a case-by-case basis. To obtain permission to operate one, an owner must meet minimum federal requirements including obtaining authorization for the treatment project from a federal or state UIC program. Permission for a Class IV well also requires authorization from a RCRA or CERCLA program. A voluntary treatment project (one initiated without a legal finding of environmental law violation) is not allowed under this well class. If approved, the operator must ensure that other USDWs are not impacted by the remediation operation. States with primacy have the right to ban this class of well entirely. They, or an EPA regional office, may also require a permit for operation.

Class V

Wells in Class V are used to inject non-hazardous material into USDW formations or formations above them (Fig. 50e). They are often associated with shallow on-site disposal systems although some many involve deep injection. In these designs, fluid enters the aquifer via gravity, not pumping. Some of the types of fluids injected include storm water runoff, incidental/process wastes from industry, car washing fluids, food processing wastes, treated sanitary wastes, agricultural drainage, and non-hazardous fluids for aquifer remediation. This class does not regulate individual residential septic systems/cesspools or non-residential septic systems/cesspools serving less than 20 people/day. Unlike other wells, Class V wells can be used for ancillary benefits other than disposal. Among these uses are aquifer recharge, aquifer storage and recovery, subsidence control, establishment of saline intrusion barriers, and to return brine from mineral recovery and energy production. Geothermal injection wells that inject geothermal fluids extracted for the generation of electricity also fall into this well class. There are somewhere between 500,000 and 685,000 Class V wells in the United States.

There are 32 different classes of Class V wells divided into seven groups: drainage wells, geothermal reinjection wells, domestic wastewater disposal wells, mineral and fossil fuel recovery related wells, industrial/commercial/utility disposal wells, recharge wells, and miscellaneous wells. Municipal drainage wells form the majority of Class V wells.

Class V Rule Phase I established minimum standards for two subtypes of Class V wells (Fig. 50e). New large capacity cesspools (i.e., a dry well with an open bottom and/or perforated sides that receives untreated sanitary waste) were banned in 2000 and existing facilities were forced to close nationwide by 2005. New motor vehicle waste disposal wells were banned in 2000 and existing wells were banned in some regulated areas. States can waive the ban and issue permits for motor vehicle waste disposal wells.

One type of Class V well is the *experimental technology wells* designed for testing new or unproven technologies. Some early CO_2 storage injection wells were regulated as Class V experimental wells. However with the establishment of Class VI, carbon sequestration wells can no longer be permitted in this class. All current wells with these permits will eventually have to convert to Class VI wells.

Class VI

The newest UIC well class was published in the Federal Register on December 10, 2010, and is designed for the long-term storage of CO_2 as a means of mitigating anthropogenic emissions, mostly associated with fossil fuel combustion (Fig. 50f). As with all UIC well classes, Class VI wells are designed to ensure that wells are sited, constructed, operated, tested, monitored, and closed in a manner that protects USDWs.

This new well class is based on existing UIC well classes and regulations, but takes into account the unique nature of geologic carbon sequestration and the physical and chemical properties of CO_2 in the subsurface. The unique character of large-scale CO_2 injection includes the new application of existing technology, the relative buoyancy of CO_2, CO_2 mobility (related to viscosity) in the subsurface, the corrosivity of CO_2 in water (CO_2 plus water produces carbonic acid), the large anticipated injection volumes, and potential impurities, such as hydrogen sulfide, mercury, etc., in the injection stream. Because these features are not accounted for in Classes I-V regulations, a new well class was deemed necessary for geologic carbon sequestration. Briefly, permitting a Class VI well entails extensive site characterization, unique well construction using materials compatible with long-term exposure to CO_2, comprehensive monitoring of a variety of aspects of the operation (well integrity, volumes of CO_2 injected and stored, both pre- and post-injection monitoring, and final responsibility for injected CO_2), and financial responsibility to assure the availability of funds for the life of the GCS project, including post-injection site care and emergency response. Under authority of the Clean Air Act, EPA has introduced a new rule describing requirements under the Greenhouse Gas Reporting Program, necessitating geologic sequestration facilities report amounts of CO_2 injected. This complimentary rule will enable the EPA to track the amount of CO_2 received and injected by geologic sequestration projects.

Primacy: Federal vs. State Control

In establishing the UIC program, EPA intended that once the program was designed it would be adopted by states, tribes, or territories to administer the program themselves. To be granted primacy, the relevant legal entity must demonstrate that their regulations are as strict as federal regulations and they have the necessary authority under state law to enforce administrative, civil, and criminal penalties to remedy non-compliance. A state seeking UIC primacy has two different options it can pursue. It can elect to control and administer all UIC injection well classes (SDWA 1422) or just control Class II wells (SDWA 1425).

Currently, 33 states and four territories have primacy for all well classes (Fig. 52). Seven states share responsibility for the UIC program with the EPA. Shared responsibility means that in these states, EPA has control of some well classes, whereas the state controls the others. Only two tribal organizations have UIC primacy. There are ten states in which EPA administers the UIC program entirely (Fig. 52). At present, EPA manages Class VI wells across the entire nation. However, states can apply for primacy and some, including Wyoming, have indicated their intentions to do so. At this point, however, no state has been awarded primacy of Class VI wells.

Summary

The Underground Injection Control (UIC) program, a major component of the SWDA,

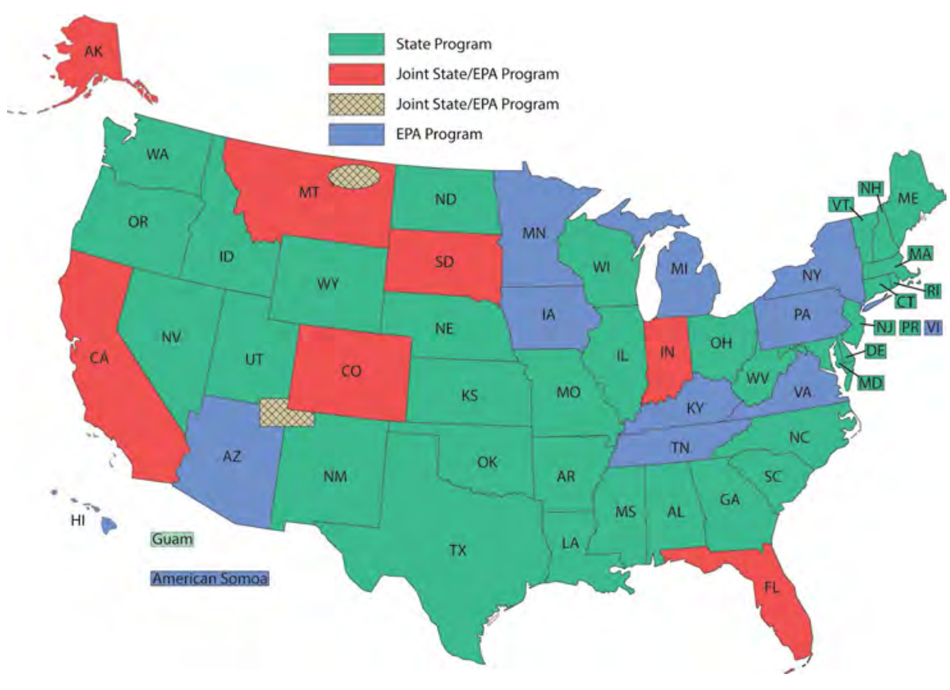

Figure 52. Thirty-three states have primacy over the UIC program within their boundaries. Some states have a joint program with EPA whereas others allow EPA to run the UIC program within their state. (Modified from EPA, http://water.epa.gov/type/groundwater/uic/Primacy.cfm)

regulates the injection of all fluids (gas, liquid, slurry) into the subsurface. By defining the manner in which hazardous and non-hazardous fluids can be injected into geologic formations, the program protects current and future underground sources of drinking water (USDWs), a primary drinking water source for many Americans. The UIC program is critical to a wide variety of industries including chemical processing, oil and gas operations, uranium and salt mining, and food production. Without the UIC program, disposing of waste generated by these industries to surface water bodies would be economically prohibitive.

The UIC program defines six classes of injection wells, i.e., Class I, Class II, Class III, Class IV, Class V, and Class VI. Class I wells are for the injection of hazardous and non-hazardous fluids below the lowermost, regional USDW. These wells are deep disposal wells with significant permitting requirements. Wells that inject fluids in conjunction with oil and gas operations are regulated under Class II of the UIC program. The vast majority of Class II wells are used by the oil and gas industry to dispose of brine generated during oil and gas production. Solution mining operations use Class III wells to inject lixiviants into resource-bearing formations to dissolve or melt the resource. Production wells (not regulated by UIC) bring the saturated solution to the surface for extraction. Class IV wells were originally designed for the injection of hazardous waste into or above USDWs. This well class has since been banned and can be used in only special circumstances, e.g. RCRA or CERCLA approved environmental clean-up projects. Class V wells are a broad class of wells for injecting non-hazardous materials into or above USDWs. The new Class VI well class is used to inject CO_2 into the subsurface for long-term storage. They are envisioned as a means to reduce anthropogenic carbon emissions from point sources such as power plants or refineries.

The UIC program can be regulated by EPA regional offices or state, tribe, or territorial agencies. Currently, 33 states have primacy over Class I–V wells as well as four territories and two tribes. Seven states share responsibility of the UIC program with the EPA. In ten states, the UIC program is administrated by the EPA, not a state agency. To have primacy, a state UIC program must have regulations as strict as those of the federal program. A state may also choose to enforce stricter standards if it wishes.

Chapter 6
An Oil & Gas Well Primer

The oil and gas industry in the U.S. began in 1859 with the drilling of a well in Titusville, Pennsylvania expressly for the production of oil, known at the time as rock oil. Since then, petroleum production has grown to one of the largest industries in the nation. In Wyoming, there are approximately 114,533 active and abandoned oil and gas wells (WOGCC, 2013), whereas Texas has over one million wells (Nicot, 2008). Because the geologic structures conducive for the sequestration of CO_2 are similar to those that hold or held significant hydrocarbon resources, sequestration sites may be characterized by the presence of both operating and abandoned oil and gas wells. These wells have the potential to provide a pathway for CO_2 to escape to the surface. Thus, EPA's Class VI regulations are written, in part, to assess and mitigate the potential of CO_2 leakage through pre-existing oil and gas wells. Understanding the reasoning for various components of the rule requires a rudimentary understanding of how oil and gas wells are drilled, completed, and ultimately abandoned.

As discussed in the previous chapter, wells and well construction are also an integral part of EPA's UIC program. For Class I, II, and III wells, construction methods and materials as well as testing procedures are specified for each well class (see Chapter 5). These criteria are critical in ensuring that hazardous materials do not migrate to and contaminate USDWs. Chapter 7 will discuss the new Class VI carbon sequestration injection wells. For this class of wells, there are equally stringent well construction and operating regulations. Thus, understanding how deep injection wells are drilled, constructed, tested, and operated is also critical in understanding how the UIC program protects USDWs from contamination by injection activities. This section provides a short primer on the procedures and methods of oil and gas drilling.

Oil and natural gas are extracted using highly complex and engineered production wells. Onshore oil and gas wells are drilled in all types of environments, from the deserts of the Middle East to the frozen tundra north of the Arctic Circle in Alaska and Canada. The deepest exploration well was drilled to 24,606 feet (7,500 meters) by the Chinese National Petroleum Company (CNPC) in 2008 (RigZone, 2008). The deepest onshore well is 37,016 feet (11,282 meters) deep and was drilled by ExxonMobil on Sakhalin Island. As onshore oil reservoirs have become harder to find, the industry has also moved offshore and into increasingly deeper waters in the search of oil and gas (Leffler and others, 2011). Offshore wells are now drilled in 7,000 feet (2,134 meters) of water and nearly 40,000 feet (12,192 meters) below the seafloor. For example, BP's Atlantis deepwater oil and gas platform is moored in 7,100 feet (2,164 meters)of water (offshore technology.com, 2013). These wells can cost upwards of a $100 million to drill with onshore wells in the five to ten million dollar range (deeper, more complex wells are much more costly). In the United States, the average depth of a development well has increased from 3,568 feet (1,088 meters) in 1949 to 5,923 feet (1,805 meters) in 2008 (EIA, 2013a). In the same time period, the average depth of exploratory wells grew from 4,232 to 7,778 feet (1,289 to 2,370 meters). Drilling, completing, operating, and abandoning these structures requires a wide range of legal, geologic, engineering, and technological skills. Although understanding how a petroleum well is constructed and operated may seem like arcane knowledge only useful to professionals, recent events have proved otherwise. The cause of the Deepwater Horizon accident as well as the safety of hydraulic fracturing, in general, all depend on the details of oil and gas operations, and in particular, well construction. Making decisions about these highly relevant social issues that are based on sound knowledge, not celebrity or politician soundbites or opinions, requires, at the minimum, a rudimentary understanding of how oil and gas wells are built and operated. This knowledge also provides a broader perspective for the factors that go into the cost of gasoline at the pump.

Drilling

Wells are drilled for a number of reasons in the oil and gas industry. They may be used to explore the subsurface, i.e., exploratory wells. These types of wells provide the only direct evidence geologists have of the nature of subsurface geologic formations and their fluids. Exploratory wells provide chips of geologic units (cuttings), cylinders of solid rock (cores), as well as a variety of well logs. Geophysical signals acquired from an assortment of tools lowered into the borehole record various properties of adjacent rock units. At the same time, various tools can be lowered into an exploratory well to sample the fluids, e.g., hydrocarbon or water, in the formations intersected by the well. Other wells are drilled to produce economic amounts of hydrocarbons, i.e., production wells. Finally, an injection well is drilled to facilitate the injection of fluids into the subsurface. Injection wells can be used to enhance the recovery of hydrocarbons or to dispose of cuttings, wastes, and brine generated during oil and gas production. Despite the different purposes, all wells are drilled, completed, and abandoned in a similar manner. There are two primary methods for drilling an oil and gas well: percussion and rotary.

Percussion Drilling

The earliest oil and gas wells were completed using percussion drilling. This drilling method repeatedly strikes the rock at the base of the well with a steel bit breaking the rock into chips. The chips are removed (bailed) from the hole using a variety of devices. In the past, percussion drilling was done by lifting and dropping the drill bit, which was suspended from a cable (hence the old name cable rig). A cable rig employs a heavy bit shaped like a chisel and suspended from a wire cable. Drilling is accomplished by raising the bit off the bottom of the hole and dropping it. The impact of the bit hitting the bottom of the borehole fractures the rock. Successive drops fracture more rock and deepen the hole. The bit is raised using a series of wheels and cables attached to a walking beam. The beam produces the up and down motion necessary for drilling. Historically, this type of drilling had been used for drilling water wells so it was a logical choice when people started drilling for oil. Percussion drilling was the workhorse of the oil and gas industry for well over a century.

Percussion drilling is still used today, but is done by pneumatic or hydraulic hammers mounted at the end of a drill string. Chips are removed from the hole by a drilling fluid, which is either air or water. To facilitate removal of chips, the drill string is often rotated simultaneously with the percussion action. However, the primary means of advance is the percussion (impact) action not rotary grinding. Percussion drilling is limited to shallow depths (300 feet [100 meters]) and produces only small holes. It works more efficiently in hard or abrasive rock than does rotary drilling. For these reasons, it is used more in hard rock mining exploration and engineering applications than the oil and gas industry.

Rotary drilling

Today almost all oil and gas wells are drilled using rotary drilling. Rotary drilling employs rotatory motion and weight to grind and fracture rock at the bottom of the hole, thereby advancing the depth of the well. Since the end of World War II, the rotary drilling rig has become the standard of the oil and gas industry. It is used for both onshore and offshore drilling and can routinely reach depths of 30,000 feet (9,144 meters) or more. Although there are major differences between onshore and offshore drilling rigs, the basic tasks they need to accomplish and the mechanical systems they use are very similar.

Basic Operation: Rotary drilling is accomplished by a drill string with a bit on the end. Sections of drill pipe are screwed together to form a drill string. A derrick on the drill rig raises and lowers the drill string into and out of the hole. It also controls the amount of weight the drill string places on the drill bit, an important drilling parameter. The drill string is rotated at the surface by either a kelly or top drive and transmits this rotation down the hole, sometimes over 30,000 feet (9,144 meters), to the drill bit. Drilling fluid, called mud, is circulated down the center of the drill string and up the annulus, i.e., the circular void between the rock and drill string, to the surface. The drilling fluid cools the bit, flushes cuttings from the bottom of the hole, and prevents formation fluids from entering the well. It also serves to stabilize the borehole against collapse.

Drill Rig: Rotary drilling rigs, regardless of size or drilling environment, must perform four basic tasks: handle the drill string, transmit torque from surface power units through the drill string to the bit at the bottom of the borehole, pump drilling mud to the bottom of hole and back to the surface, and control subsurface formation pressures (Jahn and others, 2008; Hyne, 2012). In addition to these tasks, there is also a need for lighting and control/instrumentation systems to monitor the operation of the rig. A primary power source is necessary to power this equipment. Fuel, water, and drilling fluids must also be stored near the rig. In remote locations or offshore, there must be adjacent housing accommodations for the drill rig crew.

The primary tasks of a rotary drilling rig are performed by five major systems (Fig. 53). The prime movers, mostly diesel engines and electrical motors, provide the energy to power the four other systems. The drill string transmits the power produced by the rotary drives from the surface to the drill bit at the bottom of the hole. The hoisting system, with its derrick, the iconic representation of a drill rig, raises and lowers the drill string, supports the weight of the string and any casing lowered (run) into the hole, and determines how much of the weight of the drill string is transmitted to the drill bit. The major components of the hoisting system are the crown and traveling blocks, the draw-works and drilling cable. The travel block attaches the drill string to a steel cable, which slides over the crown block at the top of the derrick. The draw-works consists of a large drum onto which the drilling cable is wound (raising) or unwound (lowering).

The rotating equipment, either a kelly bushing or top-drive, generates rotation and transfers that rotation to the drill string. A kelly bushing is a flat, rotating disk on the floor of the rig. In its center is a hexagonally shaped hole. The kelly, a six-sided piece of steel attached to the drill string, passes through the hole in the kelly bushing and is rotated with the bushing (Fig. 53). As the hole deepens, the kelly slides down through the kelly bushing until it reaches the top of the bushing and a new drill pipe joint must be attached. This is accomplished by setting slips that grasp the drill string and hold it in place as the kelly is unscrewed from the drill string. A new joint of pipe is added, the kelly reconnected, slips released, and drilling resumed. Many modern rigs have replaced the kelly and kelly bushing with a top-drive system. Top-drive systems are mounted in the derrick above the rig floor and slide up and down on a set of parallel rails. The unit is attached to the top of the drill string and imparts rotary motion directly to the drill string. With this system, segments of 3–4 joints (stands) that are 90 to 120 feet (27 to 37 meters) long are attached to the drill string instead of single joints. This produces faster drill speeds, which decreases costs. These rigs generally have automatic pipe handling systems to put together the stands before they are attached to the drill string.

Finally the circulating system pumps drilling fluid down the drill string, out jets in the drill bit, and up the annulus between the string and the borehole or casing to the surface. The motion of the drilling fluid lubricates the bit and removes cuttings from the bottom of the borehole, while its weight controls external pressures acting on the borehole itself. Because the drill string is rotating, a swivel at the top of the drill string is used to attach the stationary hose of the mud pumping system to the drill string. On return from the well, the mud passes through a shale shaker, which removes cuttings and solids from the mud. Separate desanders and desilters placed in sequence remove successively smaller solids. The mud mixer is used to introduce additives to the mud before it is pumped through the swivel. Drilling muds, which can be either water- or oil-based depending on the formations drilled, are highly engineered fluids. They must satisfy a range of needs including being pumpable, stable under a wide range of pressures and temperatures (from the surface to 40,000 feet [12,192 meters]), able to control formation pressures through density and weight, compatible with formations encountered (i.e., prevent formation damage), and low-cost and environmentally safe (Jahn and others, 2008).

Drill string: A key component of rotary drilling is the drill string, i.e., the collection of components that transmits rotary motion from the rig to the bit and transfers drilling fluid to the drill bit (Fig. 54). It is an assemblage of many different components that are customized for each well. As the well is drilled, the composition of the drill string changes to reflect changing subsurface conditions. A typical drill string consists of three subparts, the bottomhole assembly (BHA), transition or heavy weight drill pipe (HWDP), and drill pipe. Each of these is, in turn, comprised of a number of different subcomponents that are threaded together using special connectors. A drill string for a typical vertical well is generally 15,000 feet (4,472 meters) long, but for extended and deviated wells typically drilled offshore, it may be over 30,000 feet (9,144 meters) long.

<u>Bottomhole Assembly</u>: At the bottom of the drill string is the bottomhole assembly consisting of

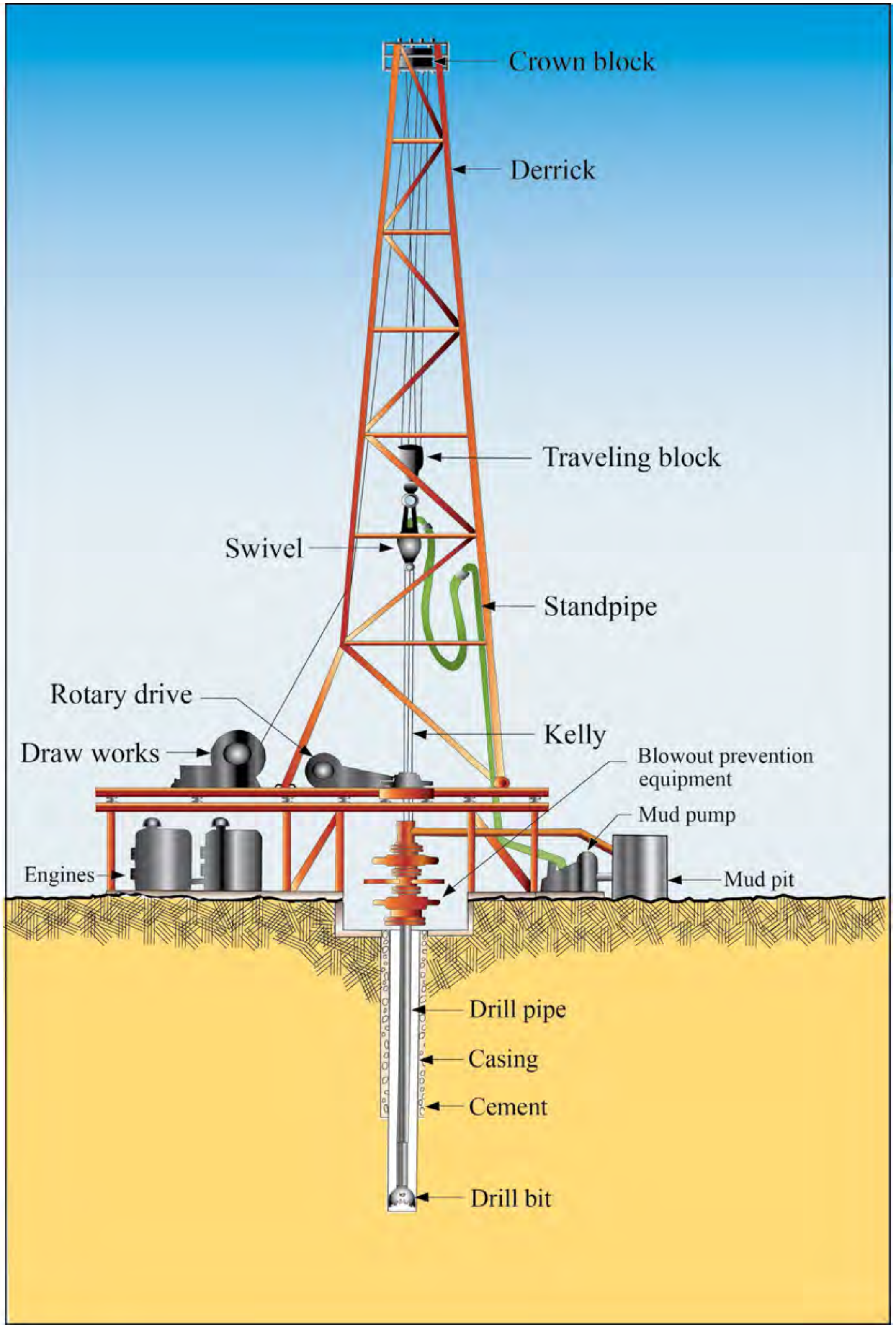

Figure 53. An onshore rotary drilling rig and its five major mechanical systems, i.e., prime movers, drill string, hoisting, rotary and circulating. (Source: California Department of Conservation, www.conservation.ca.gov/dog/picture_a_well/Pages/qh_dril_rig.aspx)

the drill bit, drill collars, and stabilizers (Fig. 54). The drill collars are thicker and heavier sections of pipe that add weight to the drill bit and keep the drill string in tension. The BHA is centered in the borehole using stabilizers. When drilling complex wells, additional components such as a downhole motor, rotary steerable system, measurement-while-logging (MWD), or logging-while-drilling (LWD) tools may be included in the BHA. A BHA must transmit enough force to break rock, while surviving a mechanically harsh environment and providing directional drilling control.

The drill bit at the end of the drill string is the rig component that actually 'makes hole.' It chips, crushes, cuts, gouges, grinds, scrapes, and shears rock at the bottom of the well through its rotary motion. During drilling, geologic formations of different hardnesses and abrasiveness are encountered. To accommodate these variations, two classes of drill bits have been developed: the roller cone and fixed cutter (Kennedy, 1983). Perhaps the most widely recognized is the tricone, or three cone roller bit. This bit consists of three cones mounted on shafts extending from the drill bit. Bearings around the shafts allow the cones to roll as the drill string is rotated. As the bit rotates and the cones roll, the teeth protruding from the cones intermesh.

As the drill bit rotates, the cones roll over the bottom of the hole. The teeth on the cones chip, crush, and gouge the rock producing cuttings, i.e., rock chips. For soft formations, the teeth are milled from the same steel block from which the cone itself is made. To drill harder formations, the bit uses tungsten carbide insert teeth, which are pressed into holes drilled in the cone. For the hardest rocks, some tricones use natural or synthetic diamond inserts. To drill soft rock, the teeth on the bit are longer than those on bits for drilling hard rock.

An alternative to the roller cone bit is the fixed cutter bit. This type of bit has no moving parts and drills by shearing and scraping the rock. Fixed cutter bits are used to core, sidetrack, and ream, as well as simply to make hole. There are three types of fixed cutter bits: polycrystalline diamond compact (PDC), diamond, and core. PDC bits use synthetic, industrial grade diamonds compressed and mounted on a tungsten carbide disk, called a compact, to actually drill the rock. The compacts are mounted on the bit head so that they face in

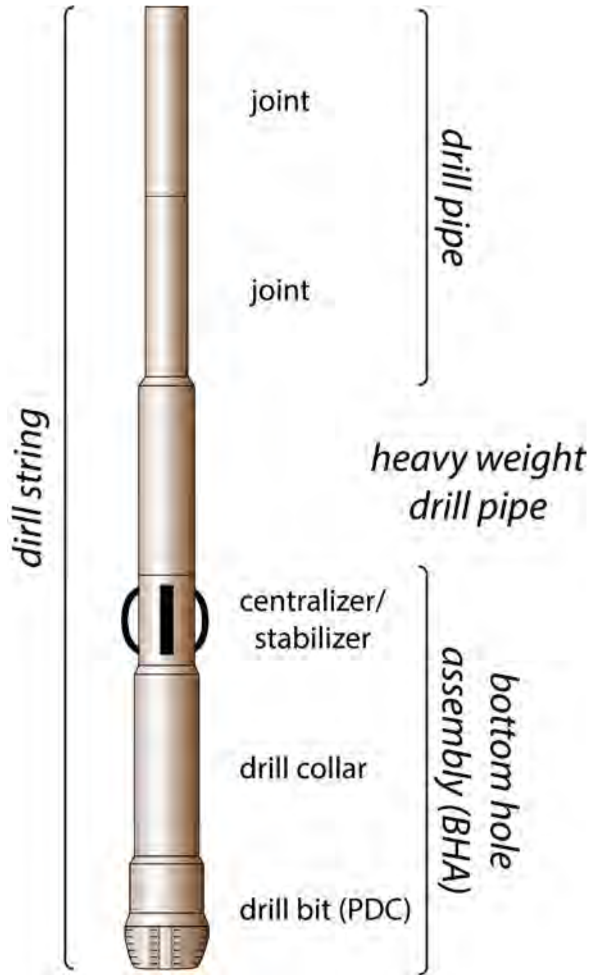

Figure 54. The drill string transfers rotational motion and weight to the drill bit. It is comprised of several different segments each with a number of different subcomponents. Drill strings can be tens of thousands of feet long weighing several hundred tons. (Modified from Jahn and others., 2008)

the direction of rotation. As the bit rotates, the compacts shear the rock. PDC bits have a faster rate of penetration, longer lifetimes, and work better with fast rotations of the drill string than roller cone bits, but are more expensive. Diamond bits have industrial grade diamonds embedded in the surface of the drill bit. Unlike for the PDC bits, the diamonds protrude from the surface of the bit. Drill bits range in diameter from 2 to more than 36 inches (95.1 to 91.4 centimeters). Regardless of type, all bits have openings through which drilling mud is jetted out of to flush away the cuttings being produced during drilling. The mud also lubricates and cools the bit during drilling.

To provide information about particular formations intersected during drilling, core is often collected, especially in exploratory wells. A core is a solid cylinder of rock drilled out to preserve the spatial and textural relations of the geologic formations intersected. It may be hundreds of feet long and is usually taken in reservoir formations, but occasionally in the cap rock as well. When core is taken, a fixed cutter core bit is used. It consists of a cylindrical, hollow tube with diamonds embedded on the front and sides. The bit cuts an annulus of rock leaving the center, i.e., the core, intact. Behind the coring bit is a core barrel, which is 30–90 feet (9–27 meters) long, into which the core slips. The core barrel allows the drill crew to recover the core. When coring thick intervals, the core barrel might have to be tripped out of the hole several times. Thus, coring is an expensive operation.

As drilling proceeds, the constant abrasion wears down the cutting surfaces of the bit and the penetration rate decreases. When the penetration rate drops below a set minimum value, the bit must be replaced. To change a bit, the entire drill string must be pulled from the hole and broken down into sections, a timely and costly procedure known as tripping. A drill bit may also have to be changed when the hardness or abrasiveness of the formation being drilled changes and the drilling rate falls. Excessive time changing bits results in longer drilling times and increased costs.

Drill collars are tubular segments with very thick walls. They are manufactured from a single steel bar by drilling them lengthwise to create a channel for mud flow and cutting male and female threads on opposite ends. The outside of the collar may be machined smooth or cut with spiral groves running its length to allow for easier movement of cuttings with the drilling fluid. Typical drill collars have diameters of 3–11 inches (7.6–27.9 centimeters) and are most commonly 30 feet (9 meters) long. Generally, the deeper the hole and the denser the material drilled, the more drill collars in the BHA are needed to facilitate drilling under difficult circumstances.

Transition pipe: Above the BHA is a section of heavyweight drill pipe (HWDP) that makes the transition from the drill collars to the standard drill pipe that comprises the majority of the drill string. In conjunction with the drill collars, HWDP adds additional weight to the drill bit, while applying tension to the drill string. Equally important, a strong transition between the BHA and drill pipe reduces the number of failures experienced at this junction.

Drill Pipe: The drill string is composed mostly of drill pipe. These are hollow pipes of varying diameter and 30 or 45 feet (9 or 14 meters) long (Fig. 55). Each segment is fitted with male and female threaded ends so they can be screwed together. As the hole is deepened, additional joints are attached on the rig floor. Instead of breaking the string down at every section, the joints are broken in sets of three and the segments, or stands, are stacked vertically in the derrick to permit faster reassembly.

Figure 55. Stacks of drill pipe joints sitting near a drilling rig. (Source: OSHA, 2013)

Well Configurations

Historically, oil and gas wells were drilled vertically or as near vertical as conditions permitted (Fig. 56). Although this simplified drilling operations, it produced short production zones and the development of an oil field required drilling at multiple surface sites. These factors increased costs and environmental impacts. Such operations were adequate when recovery rates of individual wells were high and environmental regulations lax.

As wells moved offshore, it became desirable to drill multiple wells from a single production platform to reach targets located outside the footpad of the platform. Directional drilling provided this capability. It involves drilling a deviated borehole at a predetermined angle from the vertical away from the drill pad or platform (Fig. 56). Directional drilling is slower and more expensive than vertical drilling, but can reduce environmental impacts and deployment costs. In recent years, directional drilling has progressed into horizontal drilling. In this type of drilling, a vertical well is drilled to a depth near the target horizon and deviated to the horizontal (Fig. 56). This horizontal well section is drilled within and parallel to the reservoir unit, thereby greatly increasing the length of a well's producing zone. This siting of the borehole in the formation can increase ultimate production 5–20 times that of a vertical well while increasing production rates. Horizontal wells are classified as short, medium, or long-radius depending on how sharply the well is deviated from vertical to horizontal (Fig. 57).

Another new type of well, the extended reach well, is created using extended reach drilling (ERD). These are wells with horizontal or near horizontal segments (departures) that extend long distances from the vertical segment of the well (Fig. 56). Although not precisely defined in the oil and gas industry, an extended reach well typically has a horizontal distance to vertical depth ratio of two or greater. ERD minimizes environmental impacts, reduces capital costs, allows access to offshore reservoirs from onshore, increases productivity and recovery, enhances production from thin reservoirs, and increases the flow of heavy oils by replacing transport through cold seafloor pipelines with movement along wells at higher subseafloor temperatures. ERD and horizontal drilling allow production from oil zones only 42–72 feet (13–22 meters) thick. ERD wells drilled from onshore in England reach 34,967 feet (10,658 meters) into the North Sea to tap thin, shallow reservoirs (Allen and others, 1997). In 2011, Exxon Neftegas Limited drilled the Odoptu OP-11 extended reach well on Shaklin Island to a total measured depth of 7.67 miles (12.34 meters) with a horizontal segment of 37,648 feet (11,475 meters), making it the longest extended reach well at the time. This well took only 60 days to drill (Exxon Neftegas Limited, 2013). Multilateral wells consist of multiple production legs drilled from the same vertical wellbore (Fig.

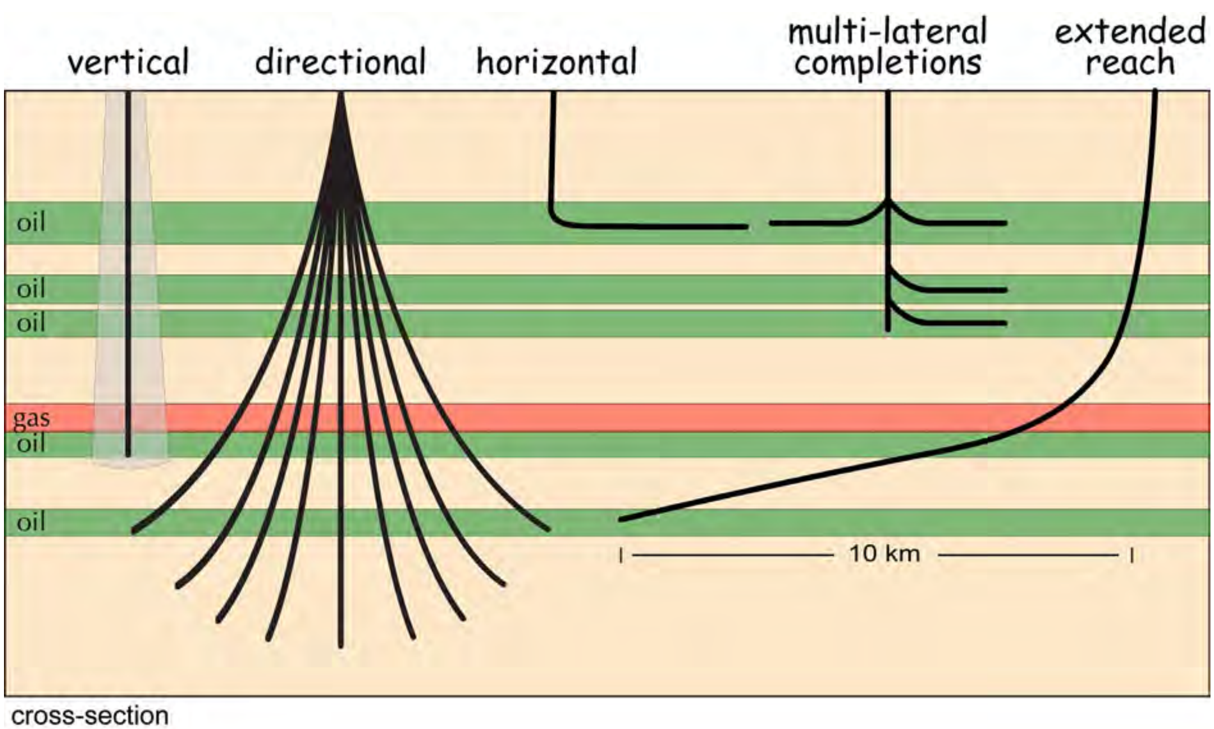

Figure 56. Schematic cross-section showing the different types of wells drilled and constructed to extract oil and gas. (Copyright J.D. Myers. Used with permission.)

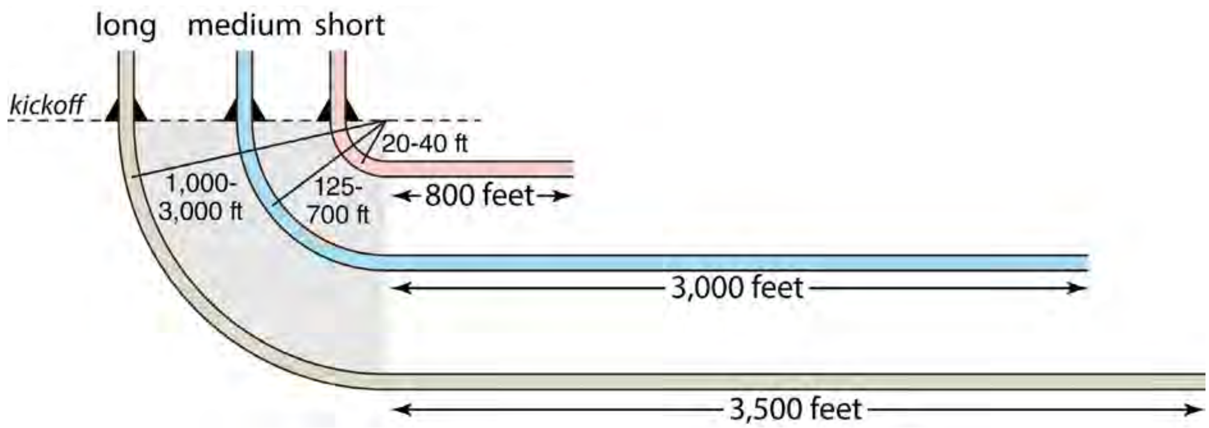

Figure 57. Typical horizontal drilling radii for long, medium, and short radius wells and average lengths of horizontal segments. (Copyright J.D. Myers. Used with permission.)

56). They are used to access oil zones that are thin and would not justify the cost of traditional drilling. The use of multilaterals in the Troll oilfield in the North Sea allowed the development of oil zones as thin as 42 feet (13 meters) and added another 90 MMbbl of reserves to the field (Oberkircher and others, 2004).

Well Construction

Oil wells are commonly drilled to depths of 15,000 to 20,000 feet (4,572–6,096 meters) and increasingly to greater than 40,000 feet (12,190 meters). These wells are subjected to a range of large forces. For a variety of reasons, drilling wells in one single operation would be impractical for a number of reasons (Jahn and others, 2008; Hyne, 2012). Near the bottom of the hole, pressures from the surrounding rocks would collapse the hole and entomb the bit (Fig. 58). At shallow depths, the pressure of the drilling fluid column could damage shallow aquifers by forcing drilling fluids into the formations. At intermediate depths, drilling fluids might invade and damage oil-bearing formations (Fig. 58). Alternatively, formation fluids from highly pressurized zones could enter the borehole, thereby triggering surface blow-outs. These problems are overcome by drilling an oil well in stages that are cased and cemented before drilling to deeper depths (Hyne, 2012; Jahn and others, 2008).

Before a drill rig is positioned, a conductor is either pile-driven into soft ground or set in hard ground in a hole bored by a large diameter auger. Conductors typically vary from 20 to over 40 inches (50 to 101 centimeters) in diameter and are driven to different depths depending on the planned depth of the well. The deeper the well, the bigger the conductor diameter, and the deeper it is set. The conductor serves to stabilize the hole for drilling, confines drilling mud to the well pad, moves drilling fluid to the mud tanks, and protects freshwater near or at the surface. All subsequent drilling operations are performed through the conductor (Fig. 58).

After the conductor is set, a drill rig is brought in to start drilling. The rig drills through the conductor to below the lowermost USDW. The drill string is removed and surface casing set to protect groundwater aquifers. The casing is run (lowered) into the hole using the drill rig's derrick for hoisting. The surface casing is run from the bottom of the hole to the surface. It has a guide shoe or round pipe with a hole in it at the bottom of the string. To clean the hole of drilling mud caked on the walls of the borehole, reamers are attached to the outside of the casing string. Arms extending from the reamers scrape the walls of the borehole as the casing is lowered into the well and/or rotated. To enhance cleaning, the casing string is often rotated and jigged vertically once it is in place. Centralizers with extended arms are placed at intervals along the casing string to center the casing in the borehole. The base of a casing string is generally positioned 10 to 30 feet (3 to 9 meters) above the bottom of the borehole.

When the casing string is set, it is cemented in place by a cement job. Cement slurry is pumped

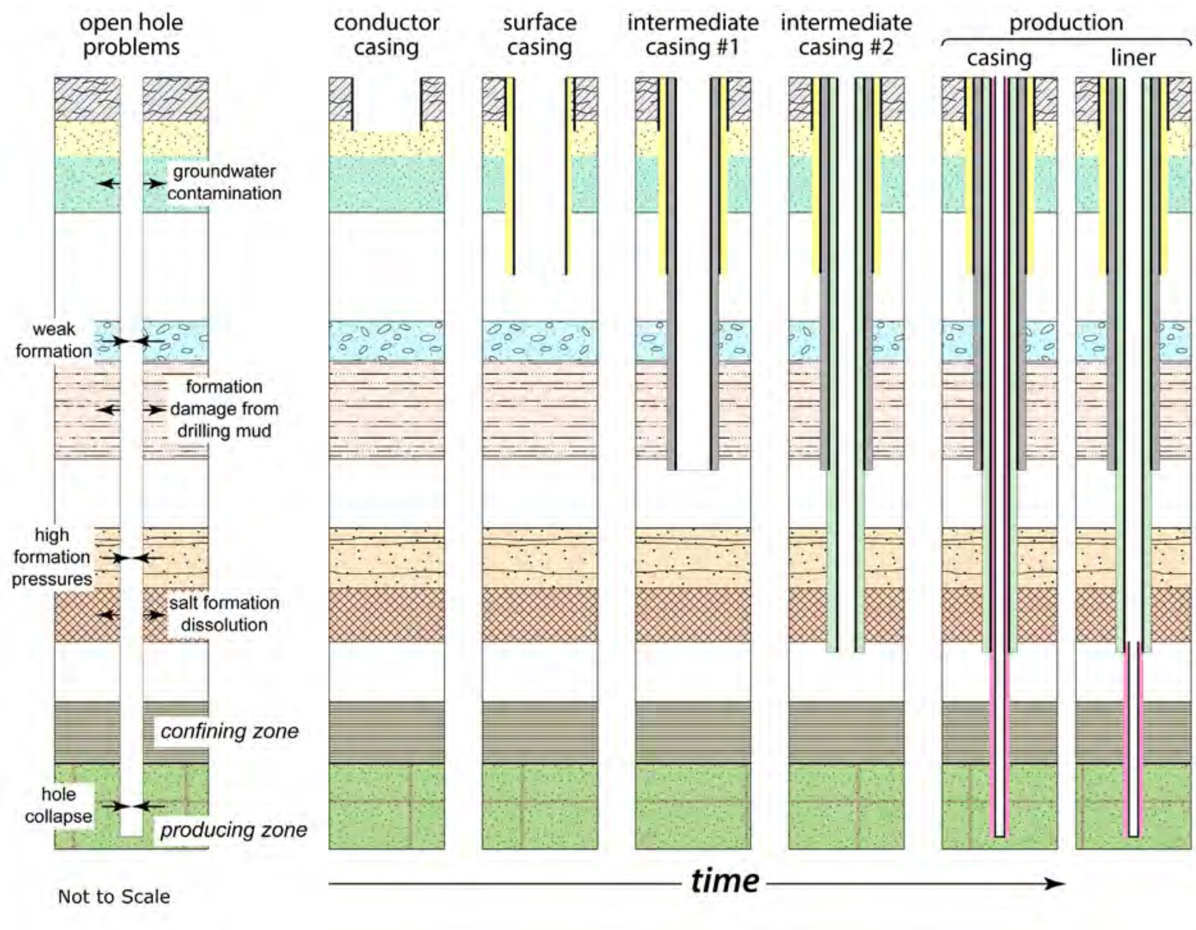

Figure 58. Drilling an oil and gas well in a single stage as an open hole presents a number of problems (left). Consequently, casing is set in stages as subsurface conditions warrant. At the minimum, a well has conductor, surface, and production casing. (Copyright J.D. Myers. Used with permission.)

down the casing string, out its base, and up the annulus between the casing and the borehole. When the cement sets or hardens (usually 8–10 hours), the casing is bonded to the formations. This bonding prevents fluid flow in the annulus and possible groundwater contamination or dilution of hydrocarbons by formation fluids (Fig. 58). At the same time, it provides stability to the casing.

With the surface casing set and cemented, operations resume by drilling through the cementing tools, casing shoe, and cement that now sit inside the base of the surface casing. Depending on the depth of the well and subsurface conditions encountered, one or more intermediate casing strings may also be set and cemented. These are used to control zones of weak rock or high formation fluid pressures as well as isolate salt formations that might dissolve if contacted by water-based drilling muds. Each of these casing strings is cemented using the same procedure as used for the surface casing. However, unlike the surface casing string, they may or may not be cemented all the way to the surface.

Finally, production casing is run from the surface to the producing hydrocarbon zone. This casing string controls the hydrocarbon-bearing formations by providing structural integrity through the producing zone. Normally, it is the smallest diameter casing used in the hole and is run the entire depth of the well. Depending on geology, a production liner may be run in place of or in addition to the production casing. Unlike production casing, a production liner is attached to the bottom of the production or intermediate casing and is not run all the way to the surface (Fig. 58). This saves the expense of casing pipe in very deep wells. The production casing or liner may stop at the top of the producing formation or it may continue through to the bottom of the production zone. A liner is hung from the production string using a liner hanger positioned at the top of the liner. The hanger uses wedge slips to set the liner against the inside of the casing. The hanger slips are extended by either applying mechanical force or hydraulic pressure (see Packer section in this chapter). The production casing or liner is cemented, at a minimum, through the hydrocarbon zones. With the setting and cementing of the production casing or liner, the construction of the well is finished.

Casing

Casing is steel pipe of varying diameter, wall thickness, and grade that is used to stabilize the borehole, prevent formation fluids from entering the borehole, and protect shallow aquifers from contamination (Kennedy, 1983; Jahn and others, 2008; Hyne, 2012). It varies in outside diameter from 4.5 to 36 inches (11.4 to 91.4 centimeters), tubulars less than 4.5 inches (11.4 centimeters)are refered to as tubing. API classifies casing into three classes based on length: R-1: 16–25 feet (4.9–7.6 meters); R-2: 25–34 feet (7.6–10.4 meters); and R-3: >34 feet (>10.4 meters). Because they require fewer joints, casing strings of R-3 class are the most commonly used. Casing is also classified by its weight, which is mass per length, e.g., lbs/ft. The greater the weight, the thicker the wall of the casing. External, male threads are cut on each end of a casing joint. Joints are joined together with a coupling, which has internal threads. Threads also vary depending on the hydrocarbons the well will produce.

Casing is subject to a variety of stresses while being set and once in place its ability to resist these forces is determined by its various strengths. These include burst, collapse, tensile, and compression forces (Fig. 59). Running in, casing is exposed to a tensile load as it is suspended from the derrick, lowered, and rotated into the borehole (Jahn and others, 2008). If it gets stuck during setting, casing may be forced into the hole by applying a weight to it in an attempt to break it loose. The buckling

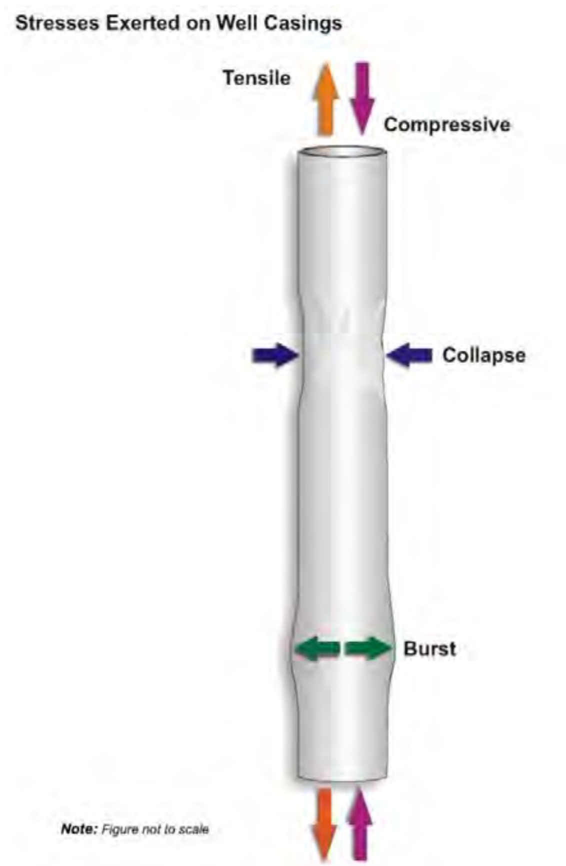

Figure 59. Casing is subject to multiple stresses acting at different times during a well's operational lifetime. Burst results from failure due to internal pressures, whereas collapse is caused by external forces. The casing is subject to tensile stresses as it is being run into the hole and cemented. During casing, the string may be subject to compressive stresses if it becomes stuck and must be forced into the hole. (Source: EPA, 2012a)

resistance of the casing will determine how well it handles this compressive stress. Once set, casing is continuously exposed to several loads or forces during routine well operation. Collapse load is the force on the casing produced by deforming formations or hydrostatic forces from drilling fluids, formation fluids, and cement slurries. The burst load results from the internal pressures within the casing during operation, e.g., hydrocarbon flow. During production, extreme temperature, and temperature shifts also place additional, cyclic stresses on casing (EPA, 2012a). In some environments, the casing may be exposed to corrosive formation fluids, e.g., hydrogen sulfide (H_2S), or injection fluids, e.g., CO_2 during tertiary hydrocarbon recovery. How well the casing stands up to these corrosive elements is determined by its corrosive service. In special circumstances, the standard carbon steel casing may have to be replaced with special corrosion-resistant steel (Jahn and others, 2008). Perhaps surprisingly, the rock column does not normally impart a stress on casing because the forces it produces operate parallel to the wellbore. In wells that intersect weak formations or unconsolidated zones, there is additional stress from the rock column. Likewise, curved and horizontal wells experience greater stress from the weight of the rock column. Curved sections of casing also impart bending stresses on the casing, particularly when it is being run through the curvature. To function properly, a well must be designed to withstand all the stresses it will be subject to in the downhole environment. This can be accomplished by varying the grade of the casing, the metal(s) it is made from, and the thickness of the casing wall.

A well will have multiple sets of casing strings, i.e., multiple sections (joints) of casing of the same diameter screwed together (Fig. 60). Each casing string serves a different purpose. Casing consists of joints 16 to 42 feet (5–13 meters) long, but most commonly 30 feet (9 meters) long, which are screwed together as the string is lowered into the hole. A typical well will have: a conductor, a surface casing, and a production casing. Depending on the depth of the well and subsurface conditions, it may also have one or more intermediate casing strings. Intermediate casing strings are set to control weak formations, isolate overpressurized zones, and protect against corrosive formation fluids. Sometimes the production casing is replaced with a production liner at the very bottom of the well. Each successive string of casing extends deeper into the well and has a smaller diameter (Fig. 60). Each well is cased in response to the subsurface conditions anticipated or encountered, thus each well, to varying degrees, is unique. Blow-out preventers are attached to the top of the casing to prevent uncontrolled release of hydrocarbons in the case of an accident. Ultimately, when the well goes

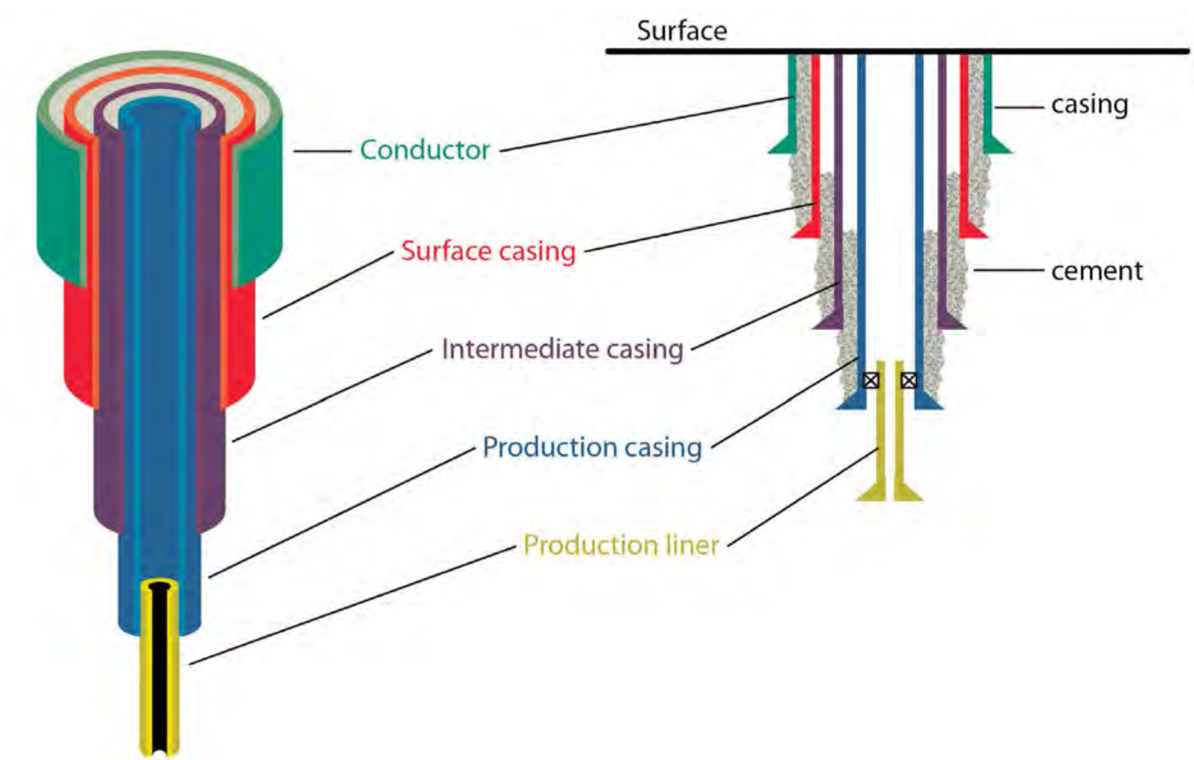

Figure 60. Well casing consists of a series of smaller diameter steel pipe set inside each other and separated by zones of cement (left). It provides stability to boreholes, while managing fluid flow in and out of the well. A typical well casing diagram (right).

into production, the blow-out preventer is removed and replaced by a wellhead or artificial lift device to control the flow of hydrocarbons from the well. These are attached to the casing.

Cementing

Cementing is done throughout drilling, operation and closure of a well for a number of different reasons. During drilling, i.e., a primary cement job, cementing is done to bind the casing to the borehole formations, thereby preventing fluid migration behind the casing, stabilizing the casing string structurally, and protecting it from corrosion (Nelson, 2012). Every time a new casing string is set, a new primary cement job is performed. Cementing is also used to seal off porous or weak formations, thereby stopping or preventing loss of drilling fluid. During operation, cementing is used to isolate non-producing formations, e.g., one that now produces more water than oil, or to kick-off multilaterals from the main borehole. Squeeze cement jobs may be used to repair casing that has been damaged or corroded, or to fix a poor primary cementing job. When a well is permanently plugged and abandoned for closure, cementing is used to isolate the well from the enclosing formations so fluids cannot enter or leave the well and migrate between formations.

Types: Cement is a solid formed by mixing water and Portland cement and allowing the resultant slurry to hydrate (harden). Portland cement is made by heating limestone with small amounts of clay in a kiln to 1,450°C to produce clinker. Clinker with added gypsum is ground to a fine powder. When mixed with water, the cement will harden as water in the slurry reacts, i.e., (hydrates), with minerals in the cement to produce a suite of new interlocking minerals that give cement its strength. Portland cement mixed with water and aggregate creates concrete used in construction. Because it must be pumped through small openings for long distances, i.e., the annulus between casing and borehole, cement used in the oil and gas industry is thinner and has less strength than cement used for construction projects.

Cements used in the oil and gas industry are based on Portland cement, but are formulated differently. In 1952, the American Petroleum Institute (API) formulated a series of API Oilwell Cement classes (Ide and others, 2006; NPC, 2011). The cements in the different classifications are ground to different fineness. In addition, they have different water mixing requirements (Table 3). The cements are used at different depths because of changing subsurface temperatures and pressures.

Additives: Cements must function at temperatures varying from less than 0°C in Arctic regions to greater than 400°C in geothermal wells (Nelson, 2012). To modify the physical and chemical performance of cements for special circumstances, oilfield service companies add a range of additives to the cement before it is injected. More than 100 different additives exist (Nelson, 2012). These additives either modify the characteristics of the cement slurry to aid emplacement or the properties of set cement to enhance task performance. Density, setting time, strength, and flow properties are just some of the properties that can be fine-tuned using additives. Additives come in both liquid and dry forms. Some of the important additive classes include (NPC, 2011):

- retardants: slows setting time to allow longer pumping intervals and tubing removal

API classification	Depths (ft)	Water requirement (gal/sk)	Slurry density (lb/gal)	Description
Class A	0 to 6,000	5.2	15.6	Common or regular cement; used when no special requirements necessary.
Class B	0 to 6,000	5.2	15.6	Used when moderate to high sulfate resistance needed.
Class C	0 to 6,000	6.3	14.8	High-early cement. Fine grind, good availability. Used when early strength needed.
Class D	6,000 to 10,000	4.3	varies	For moderate temperature and pressure. Coarse grind plus retarder.
Class E	10,000 to 14,000	4.3	varies	High pressure, high temperature. Useful at all depths with retarders
Class F	10,000 to 16,000	4.3	varies	Use for extremely high temperature and pressure.
Class G	0 to 8,000	5	15.8	Basic well cement. Used over range of temperatures and depths when retarders or accelerators are added.
Class H	0 to 8,000	4.3	16.4	Basic well cement. Used over range of temperatures and depths when retarders or accelerators are added.

Table 3. Summary of the various API cement classes. Abbreviations: sk = sack of cement. (modified from NPC, 2011; EPA, 2012a)

- accelerators: shortens setting time to prevent gas infiltration or channeling, shortens waits between plugs, prevents backflow
- lost circulation material: reduces loss of cement to porous formations, it includes a variety of bulky materials
- weighting: increases cement slurry density as a means of controlling high formation fluid pressures
- lightening: reduces cement slurry density to minimize loss to porous or fractured formations
- water-loss retardants: prevents premature loss of water, which precludes cement from hardening properly

By combining these different additives in different proportions, the cement can be tailored to specific downhole temperature and pressure ranges (Ide and others, 2006). At the same time, the physical properties of the cement can be adjusted to better achieve the task(s) they are intended to for.

Primary cement jobs: One of the most important cementing jobs during the evolution of a well is that which binds casing to the borehole wall, or the primary cement job. This is done to ensure controlled fluid access to the well and to prevent communication of fluids between different formations along the borehole. The goal of a primary cement job is to position a sheath of cement with no channels or voids around the casing and extending out to the borehole wall. Cementing is typically done by a specialized oilfield service company.

To start a cement job, the drill string is removed from the well and a casing string put together. The hoisting system on the rig is used to make up the casing string as it is lowered into the borehole. The bottom of the casing string has several special tools designed to ensure a proper casing and cementing job (Fig. 61). At the very bottom is a guide (casing) or a float shoe. Both are a short assembly of heavy steel pipe of the same diameter as the casing, but with a rounded end. Although the outsides of the shoes are steel, the interiors are cement or a thermoplastic that permits the tool to be readily drilled out if the borehole is to be deepened later. The rounded shape of the shoes assists lowering the casing string around

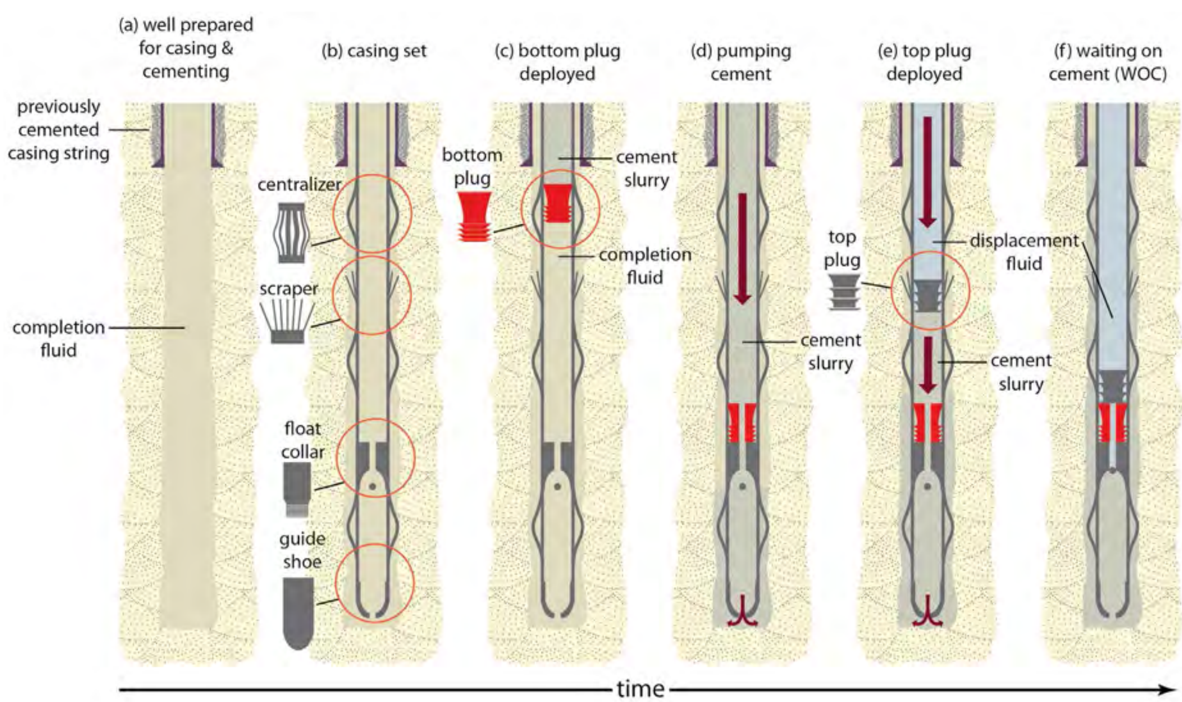

Figure 61. Setting and cementing casing is a complex job that is critical to the future production success of a well. A complex assemblage of tools at the bottom of the well, e.g., guide shoe, centralizers, and float collar, are instrumental in protecting cement from contamination and ensuring a good binding of the casing and formations.

ledges, washouts or obstructions that occur in the borehole. A float shoe has a check valve while a guide shoe does not. The check valve prevents fluid from entering the casing string either during cementing or setting of the casing. By controlling the amount of fluid allowed to enter the string through a float shoe, the casing string can be 'floated' into place during setting. This means the hoisting system and derrick do not need to carry the entire weight of the casing string. Above the guide or float shoe and at various points along the string are centralizers (Fig. 61). These components have protruding arms that centralize the casing in the hole so that a cement sheath can be emplaced all around the casing. The next component of the casing string is the float shoe or float collar. A short piece of casing, the float collar prevents cement slurry from re-entering the casing after it is pumped into the annulus. The collar also catches the cement plugs that deliver the cement slurry for placement. As with the shoes, the inner parts of this tool are made of cement so they can be readily drilled out. As the string is lowered into the borehole, it fills with drilling mud. Because this fluid and the cement are incompatible, the drilling fluid must be removed from the casing and borehole before cement is pumped. Prior to pumping cement, a spacer or displacement fluid is pumped down the casing to displace drilling mud and clean it off the casing (Nelson, 2012).

Once the spacer fluid is in the well, a cementing head is attached to the top of the casing (Fig. 61). The head allows cement slurry from the pumping truck to be pumped down the string. The top of the cementing head contains two plugs situated one above the other. Just before cement pumping begins, the first or bottom plug, which is red for identification, is released. The plug is hollow with an upper diaphragm and wiper blades on the outside (Nelson, 2012). The cement slurry forces the plug downwards displacing the spacer fluid ahead of it while also wiping the casing of mud and spacer fluid. Thus, the cement slurry behind the plug is protected from contamination by the drilling mud (Fig. 61). When the bottom plug encounters the float collar, it is caught and kept in place. As pumping continues, pressure builds and the diaphragm in the bottom plug ruptures, allowing cement slurry to flow out the guide shoe and up the annulus sheathing the casing in cement. Continued pumping sends the cement slurry further up the annulus. When the volume of cement slurry calculated to fill the annulus has been pumped into the casing string, the top, a black plug, is released. This plug is shaped like the bottom plug, but is solid. A displacement fluid is pumped into the casing, forcing the top plug and cement slurry down the well (Fig. 61). With this additional cement slurry, the height of cement in the annulus increases further. When the top plug encounters the bottom plug, pressure is maintained on the plugs to hold the cement slurry in place and prevent it from U-tubing back up the casing. The cement slurry is allowed to harden and cure for 12 to 24 hours, referred to as waiting-on-cement (WOC). Once the cement is hardened, the plugs, float collar, and shoe, as well as any cement in the case below these tools, are drilled out for deepening of the well or completion.

Cementing Problems

Cementing is a complex process that is critical to the success of a production well. There are many things that can go wrong with a cement job. If the cement slurry does not have the correct density, gas or formation fluids can enter the slurry and cause channeling before the cement sets (von Flatern, 2011). This produces voids along which fluids can migrate (Fig. 62a). Alternatively, poor removal of mud built up on the borehole wall during drilling, i.e., mudcake, can hinder the bonding of the cement to the formations (Fig. 62b). Thus, a thin open zone between the cement and borehole wall can allow fluid transfer. Premature setting or gelation can cause the cement to shrink and open up channels (Fig. 62c). Excessive loss of fluid from the slurry to the formations will interfere with proper hardening and result in decreased cement strength (Fig. 62d). Another problem that may result in a poor cement job is having calculated the volume of cement needed incorrectly. If the volume needed is underestimated, the resultant cement sheath will not cover as much of the vertical distance of the casing as originally planned. Too much cement overpressurizes the annulus and can damage casing structurally. It may also force cement into production zones, thereby damaging

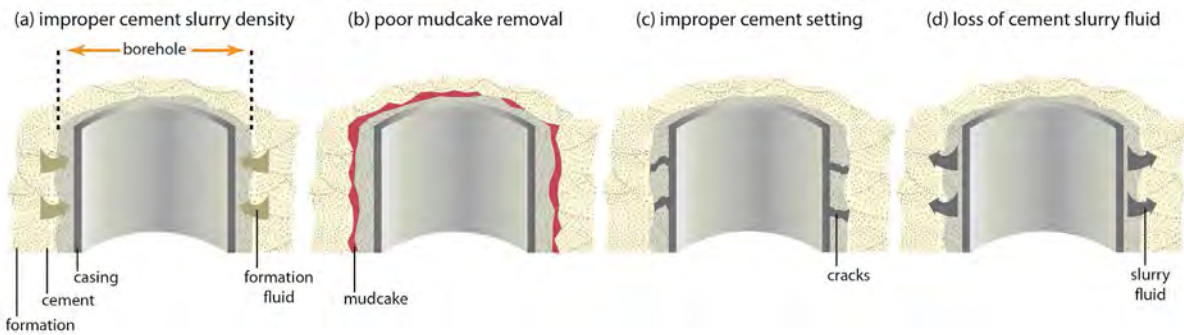

Figure 62. Potential cementing problems. (a) incorrect cement slurry density, (b) inadequate removal of mudcake from the borehole wall, (c) premature gelation or hardening, and (d) excessive fluid loss resulting in improper hardening and reduced cement strength. (Modified from von Flatern, 2011)

the formations and possibly reducing the amount of oil and gas that can ultimately be recovered.

Testing

Before proceeding with the next stage of well construction, it is necessary to determine if the primary cementing of the just set casing string is adequate. If not, the cement job must be remediated before the well can be deepened or completed. The cement job is tested using two approaches: hydraulic testing and well logging. The primary hydraulic test is the pressure test. The casing is filled with fluid and the pressure increased until it reaches the maximum pressure that will be encountered in the next drilling stage. If no leakage is detected, the cement job is assumed successful. A series of log tests are conducted to determine the nature of the cementing job. Because hardening and curing of cement is an exothermic process, i.e., it releases heat, it will raise the temperature behind the casing. Thus, running a temperature log approximately twelve hours after cementing can readily determine the top of cement. A series of acoustic or sonic logs are run to determine the quality of the bonds between cement-casing and cement-borehole wall (Nelson, 2012). A cement bond log (CBL) allows evaluation of cement integrity along the borehole, and identification of voids behind the casing. A CBL logging tool has a rotating acoustic transmitter that sends a sound signal into the casing. The signal propagates through the casing and is picked up by the receiver in the tool. Where the casing is bonded to cement, some of the signal's energy is transmitted into the cement. Thus, well cemented sections of casing have low return signals whereas poorly cemented sections have high returns (Fig. 63). Cement logs can be run as transmitter-receiver pairs or transmitter-receiver-receiver combinations, known as a 3'-5' bond tool. The closer receiver three feet below the transmitter picks up the signal of sound at the casing-cement interface, whereas the five foot receiver picks up the sound signal that has penetrated to the cement-formation interface. Older types of CBL measured only along a vertical line of the casing and inferred this linear measurement characterized the entire annulus. Newer cement evaluation logs (CEL) provide a full 360° view of the annulus in a horizontal plane (Schlumberger, 2013). An ultrasonic log emits a sonic pulse that causes the casing to vibrate. The vibration is dampened when cement is behind it. Thus, attenuated signals indicate a good casing-cement bond. A high signal suggests there is fluid, not cement, behind the casing (Fig. 63).

A variable density log is another sonic log, but it measures the travel time of the sonic signal. The receiver is placed five feet (1.5 meters) from the transmitter and produces a photographic display of alternating light and dark bands (Fig. 63). The degree of regularity of the signal indicates the quality of the cement bond (EPA, 1982; EPA, 2012a). Early arriving signals (on the left), which have traveled the shortest distance, indicate the nature of the casing-cement log. They complement the cement bond log. Bands on the right (late arriving) are produced from the cement-formation

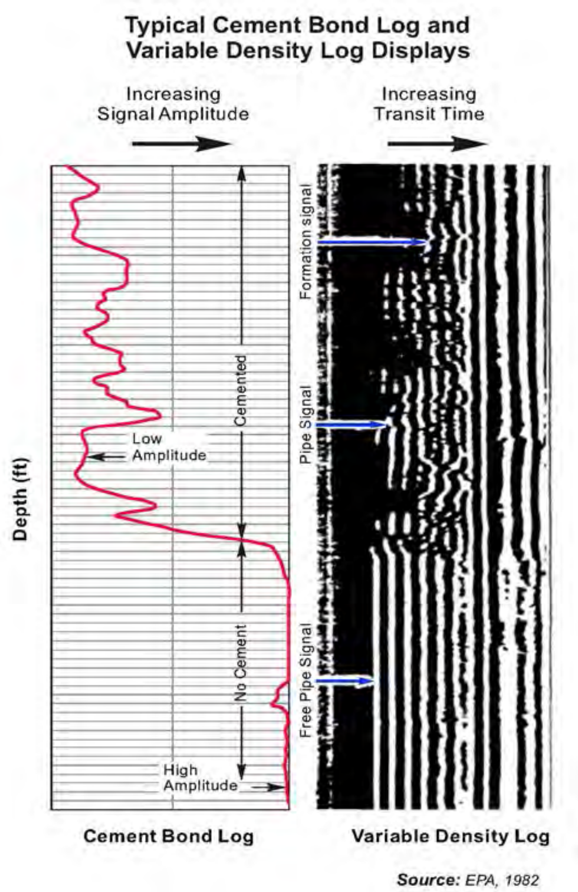

Figure 63. Cement bond (left) and variable density (right) logs are used to assess the quality of a primary cement job. The cement bond log identifies if cement is behind casing whereas the variable density log evaluates the cement-formation bond quality. Both logs are run simultaneously. (Source: EPA, 1982, 2012a)

interface. Sections of casing that are properly cemented are marked by weak signals on the left and wavy, irregular formation signals on the right.

When problems with the primary cementing are detected, they must be remediated by a squeeze cement job. In this cementing procedure, the casing is perforated where the problem with the primary cementing occurs. Plugs are positioned above and below the perforated zone and cement pumped into the well between plugs. As the pressure rises, cement is squeezed out through the perforations into the annulus. In this manner, the integrity of the cement sheath is restored. After cementing, the plugs are removed.

Well Completion

Once the planned depth of the well has been reached, called *total depth*, a decision must be made as to whether or not to complete the well as a production well or plug it as a dry hole (von Flatern, 2011). To assess the potential for recovery of economic volumes of hydrocarbons, a formation evaluation of the open borehole is done. If the hole is deemed uneconomic, it is classified as a dry hole and permanently plugged (see Well Abandonment section later in this chapter). When economic amounts of hydrocarbons are identified, the production casing or liner is run and cemented.

After the production casing string or production liner has been set and cemented, a well must be completed to enable it to produce hydrocarbons. Well completion starts by circulating a completion fluid into the well to flush out the drilling mud. The completion fluid, which is solid-free, removes any solids in the drilling mud from the wellbore. This cleaning prepares the well for completion and ultimately improves recovery. Once the well has been flushed, the drill string is pulled, the large drilling rig removed, and a smaller workover or completion rig deployed. Because the latter does not need to handle the heavy drill or casing string, it is smaller and therefore less expensive to operate. Completing a production well entails installing equipment at the bottom of the hole in the production zone, stimulating or treating production zones, running production tubing in the casing, placing packers to isolate different zones of the well, and attaching a wellhead or installing artificial lift. Since these activities occur both at the bottom of the well near the producing reservoir and in the upper section of the well above the reservoir, they are called bottomhole (lower or reservoir) and tubing (upper) completions (Jahn and others, 2008).

Well Completion Components

To complete an oil and/or gas well for production, a large number of well components must be installed in the cased and cemented borehole. The design of a well completion is unique to that well and depends on downhole pressures and temperatures, chemical composition of production streams, anticipated flow rates, and whether production is expected to be intermittent or continuous. Perhaps the most important components of well completion are tubing, packers, and pumps. Tubing is used to produce fluids, whereas packers permit the isolation of different parts of the wellbore. Pumps are used to lift fluids to the surface when the natural drive in the reservoir is insufficient to move the fluids all the way to the surface, i.e., non-flowing wells.

Tubing: Tubing is small diameter (1.25-4.4 inch [3-11 centimeter]), hollow steel pipe that is run down the casing to conduct water, oil and/or gas (produced fluids) to the surface. It protects the casing from corrosion by produced fluids. For further protection of both casing and tubing, a completion fluid, usually treated water or diesel oil, is used to fill the tubing-casing annulus. Because it is simply suspended in the well, tubing is easier to repair or replace than casing cemented in place. When it needs to be replaced during a well workover, tubing is pulled using a workover rig.

Segmented tubing comes in 30 feet (9 meters) lengths, like casing called *joints*. The ends of a joint have a thickened section into which male threads are cut on the outside of the joint (the *upset*). Joints are screwed together using *collars* which are short steel cylinders with internal, female threads. Most tubing is centered in the casing using annulus packers that also seal off different portions of the casing from hydrocarbon fluids. API classifies tubing based on dimensions, strength, performance, and thread configuration. If downhole pumps are installed, they are typically placed at the bottom of the tubing string.

Coiled tubing is a continuous length of steel or composite tubing. It is flexible enough to be wrapped onto a large reel or spool for transportation (Fig. 64). Coiled tubing comes in diameters ranging from 0.75 to 4 inches (1.9 to 10.2 centimeters) and lengths greater than 30,000 feet (9,144 meters). The tubing is uncoiled and straightened before it is inserted into the wellbore. During insertion, coiled tubing is unwound from a reel and passed through an injector head attached to the well. The head straightens the tubing and provides the drive to force the tubing into the well against the well pressure. The head can also pull tubing out of a well. Compared to segmented tubing, coiled tubing does not need to be screwed together, does not require a workover rig for emplacement and can be run while the well is producing. Another advantage of coiled tubing is it does not rely on gravity to emplace tubing into the well. Coiled tubing can be used for production or logging a well, among other tasks.

Figure 64. A coiled tubing rig. The tubing is stored and transported by wrapping it around a drum positioned on a truck trailer. It is played out and forced into the well by a drive motor on a derrick positioned above the well. Coiled tubing can be used to conduct many well tasks that were traditionally done by wireline. A major advantage of coiled tubing over traditional tubing is the ability to force it into the well rather than relying on the pull of gravity to set tubing in the well. Photograph:

Packers: Packers are devices used to isolate different portions of a borehole or wellbore by sealing an annular space. They protect casing from pressure and produced fluids and isolate producing zones for temporary abandonment. In an uncased or open hole, a packer seals the annulus between the tubing and the formation. For cased holes, the annulus between the tubing and casing is sealed off by a packer. Packers, in conjunction with tubing, control production, treatment, and injection. Production packers are used during the production phase of a well. Service packers are used to isolate zones of a well when it is being serviced, e.g., during cementing, acidizing, fracturing, or testing.

A packer is anchored, or set, into casing by two actions, gripping and sealing (Fig. 65). Gripping is accomplished by metal arms, *slips*, that wedge against the casing and dig their teeth into the casing steel. Thus, slips anchor a packer in place, but do not stop fluid flow. Sealing is accomplished by packing elements whose outside diameter expands under an applied compressive force until it squeezes against the casing wall, thereby sealing off vertical fluid flow in the tubing-casing annulus. To function properly, packers must be set at points where the casing is clean, non-corroded and free of debris. Thus, a well should be prepared before a packer is set. Commonly, casing scrapers are run to remove any mud, mud cake or cement that is adhered to the casing (Fig. 65). Junk baskets are run on a wireline through the well to collect any debris that is suspended in the well. The well is also cleaned by circulating solid-free fluid through it to flush out solids. Getting packers to their set points without damaging their various components, especially the critical slips, is difficult in deviated, crooked, or damaged wells. Thus, junk baskets are also run with a gauge ring that has the same outside diameter as the unexpanded packer. In this manner, any tight spots in the casing that might catch or damage the packer are identified.

A packer is a complexly designed and engineered component that must withstand a

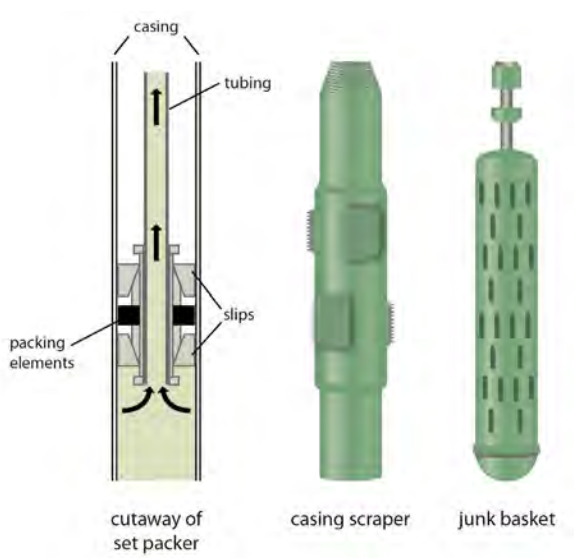

Figure 65. (Left) A packer isolates different zones in a wellbore. Slips anchor it in position by gripping the casing and resist upward and downward forces on the packer. Elastomeric packer elements seal the tubing-casing annulus off against vertical fluid motion. (Right) To prepare the wellbore for casing, casing scarpers are run to remove cement or mud cake on the casing and junk baskets collect any solid debris suspended in the drilling fluid.

number of forces. The packer may experience differential pressure from unbalanced pressures above and below the packer. It may also be exposed to corrosive fluids and a variety of downhole temperatures and pressures. The basic components of a packer are slips, cones, packing elements, and a mandrel (Fig. 66a). Slips are rectangular, wedges with wickers (teeth) on their outside surface. They are attached to the packer with pivot points at one end. A packer can have either one or two sets of slips. Cones are beveled sections of the packer forming ramps that slips will slide along when they are set (Fig. 66a). A packing element is comprised of a flexible, expandable elastomeric material sandwiched between two steel rings (Fig. 66a). An elastomeric material is any material made of polymer that will return to its original form when a deforming force is released, e.g., natural or synthetic rubber. If more than one packing element is present, the combination of elements is referred to as the *packing system*. These packer components are positioned around a *mandrel*, a cylindrical tube with an inside diameter that matches that of the tubing and which can be sealed to tubing above and below the packer. The mandrel serves two purposes: 1) allows passage of fluid through the packer, and 2) permits the components of the packer to move relative to each other along the mandrel. When a packer is set, applied forces slide the slips along the mandrel and up the cone ramp. This motion forces the slips outward until they press tightly against the casing wall (Fig. 66a). Continued shortening of the packer length compresses and extends the packing element(s) until it is seated against the casing wall. The setting of a packer may be through mechanical or hydraulic forces. Mechanical setting is done by some combination of tension, compression, or rotation applied to the packer by moving the tubing or wireline up, down, or sideways. Packers set by tension have slips above the packing element and facing downward (Fig. 66b). Upward tension on the tubing causes the slips to deploy and remain deployed as long as the tubing is under tension. They are particularly resistant to movement caused by higher pressures above the packer. Compression packers (Fig. 66c) have upward facing slips and are particularly resistant to movement by higher pressures below the packer. Dual slip packers

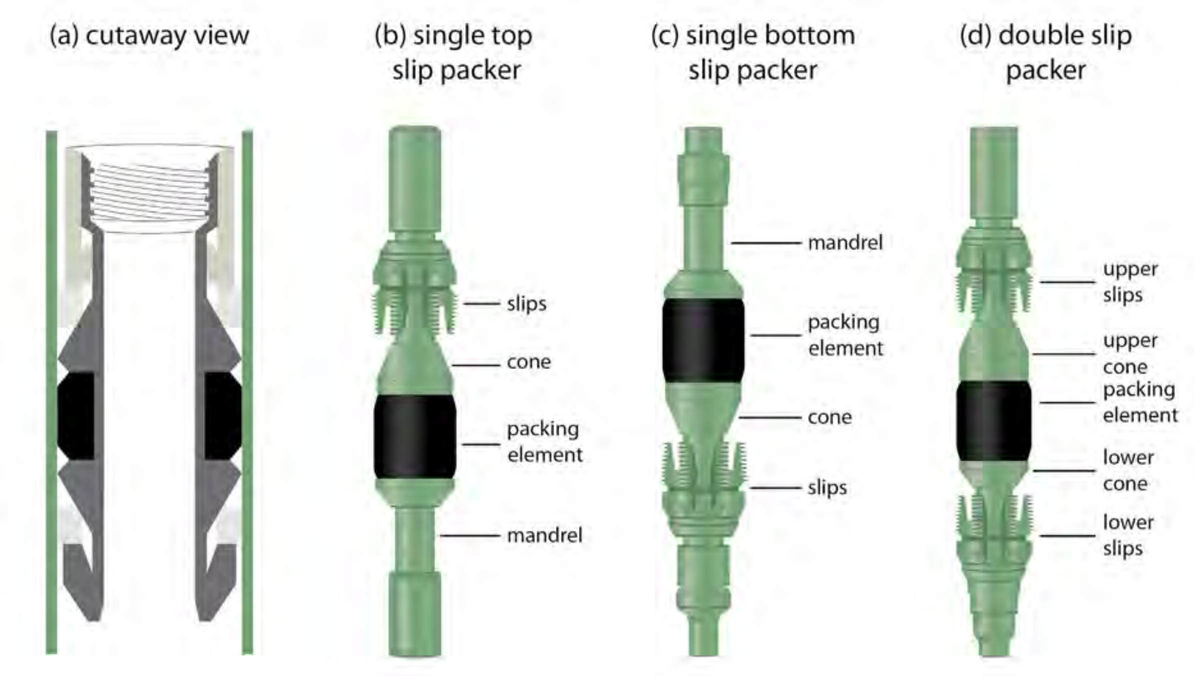

Figure 66. Packers are highly engineered elements used to isolate zones of a wellbore. (a) A packer consists of slips, cones, and packing elements positioned around a mandrel, i.e., a shallow cylindrical tubular. (b) A single-slip packer that is set by tension. (c) A single-slip mechanical packer set by compression. (d) A dual-slip packer that is resistant to differential pressures above and below the packer.

have a set of slips above and below the packer element and pointing toward each other (Fig. 66d). They provide resistance to both upward and downward differential pressures. Hydraulic packers are set by pumping a hydraulic fluid into the packer, thereby causing movement of the packer elements. The activation of a mechanical lock or trapping or pressure keeps the packer set, i.e., the slips extended and packing element compressed. Hydraulic packers are useful in crooked or deviated holes where it is difficult to provide the necessary setting force using tubing or wireline.

In open holes where the wellbore has an irregular boundary, inflatable packers are used. This type of packer has a bladder into which a fluid is pumped, thereby expanding it. Once the maximum diameter is reached, either continued pressure or locking mechanisms are used to keep the packer inflated and in position. These types of packers seal off the tubing-formation annulus.

A packer can be either permanent or removable. The latter are used when it is assumed that there will be no need to remove the packer later. Because operational needs may change, permanent packers are produced from materials, usually cast iron, aluminum, plastic, or other brittle material, that can be drilled or milled out later. Permanent packers are less complicated and therefore cheaper than removable packers. They can also withstand greater pressure differentials. Retrievable packers are constructed such that particular actions will release the slips and allow the packing elements to return to their original shape. They are much more complicated than permanent packers and, therefore, much more expensive. Because they are often subject to pressure differentials across them, retrievable packers typically have by-pass valves that let fluid flow between the annulus zones thereby equalizing the pressure above and below the packer. With the pressure across the packer equalized, it is easier to unseat the packer for retrieval.

Pumps: The majority of wells in the U.S. (~96 percent) are not free-flowing, but require additional energy to move the oil to the surface. In these cases, an artificial lift is deployed at the top of the casing. As reservoir pressure declines over time, free-flowing wells may reach a point where oil no longer makes it to the surface and they must be retrofit with artificial lift and the wellhead permanently removed. An artificial lift supplies energy to the oil in the well, not the reservoir as during EOR operations. Artificial lifts can be divided into pumps and gas lift systems.

Pumps transmit mechanical energy to the oil by squeezing, pushing or pulling (Jahn and others, 2008; Hyne, 2012). There are five types of pumps used to produce oil: beam pump, progressive cavity pump, electric submersible pump (ESP), hydraulic submersible pump (HSP), and jet pump. All pumps require a source of energy to operate, so they increase production costs. A beam or rocker pump uses the up-and-down motion of a plunger to move oil up the well (Fig. 67). Cavity pumps consist of a rotating corkscrew at the bottom of the well. The rotation of the screw moves oil upwards where it is lifted to the surface by a beam pump. This type of pump works well with heavy oils and low production volumes. ESPs consist of multistage centrifugal pumps that operate by lifting fluid a given vertical distance at each stage. Power is supplied by a downhole electrical motor. An HSP is similar to an ESP, but powered by a turbine that is turned by a high-pressure fluid pumped down the hole from the surface. Because it turns faster, fewer stages are needed with HSP, but there are problems with handling the power fluid. The jet pump is also hydraulically powered, but it creates a low-pressure region in the oil by passing the power fluid through a restriction. The low pressure region literally sucks oil up the well. Most of the world's oil wells pumps. Stripper wells, producing less than 10 barrels of oil per day, employ beam pumps.

Gas lift systems do not involve transmitting mechanical energy to the fluid column. Rather, they add a low density fluid, (gas) to the oil column thereby decreasing its density and reducing its resistance to upward flow. The gas is pressurized at the surface and passed down the casing in the tubing-casing annulus. Different

Figure 67. A "beam pump" pumping oil from a non-flowing well. (Photograph by Robert Kirkwood. Used with permission.)

gas lift systems vary where they add gas to the oil column and whether it is added continuously or intermittently. Gas lift systems can use gas from the well itself after it is conditioned and do not consume the gas used in the process. It is, however, necessary to power the surface pump for pressurization.

Bottomhole Completion

The lower completion depends on where the production casing/tubing stops and the geologic nature of the reservoir (Fig. 68). The simplest is the barefoot completion used when the producing zone has been left open so oil, gas, water, and solids can flow unrestricted into the borehole. An alternative is to run a production casing or liner with pre-existing holes into the producing zone, but not cement it.

There are three main completion options for a cased bottomhole (Fig. 68). One of the most common is for a well cased and cemented through the producing zone. To allow fluid flow between the formations and well, the casing and cement are perforated using a special tool, the perforation gun that is lowered into the well on the drill string. At production depth, a series of shaped charges are detonated sending high-velocity jets of gas through the casing and cement into the reservoir formation (Smithson, 2012). The charges are arranged so that they face in different directions and are located at different heights. Perforating guns are expendable or retrievable and the charges can be adjusted to provide for maximum hole diameter or formation penetration length (Jahn and others, 2008; Hyne, 2012; Smithson, 2012).

The last two types of reservoir completions are used for production zones that consist of weak sands (Fig. 68). In these formations, the main problem is keeping solids out of the well and ensuring that they do not block fluid flow. For these situations, a zone around the well is packed with gravel. A screen is run across the producing zone to keep solids from entering the well. Alternatively, the section is cased and perforated using a perforation, or perf, gun.

A single completion is used for wells with one producing zone (Fig. 69a). A packer is positioned above the producing zone. Once the packer is set in the well, the fluid is confined to flowing up the tubing to the surface. In multiple completion wells, two tubing strings and multiple packers are used to separate two producing zones (Fig. 69b). Thus, fluids from the different zones are not co-mingled, which could cause flow problems if the fluids were under different pressures and chemically and physically different (Jahn and others, 2008). Alternatively, multiple zones can be produced through a single tubing string. In this case, packers are used to separate the two producing zones as before. Now the tubing allows fluid entry at the base and through a series of openings in the upper zone. The upper zone has, however, a sliding sleeve that can close off

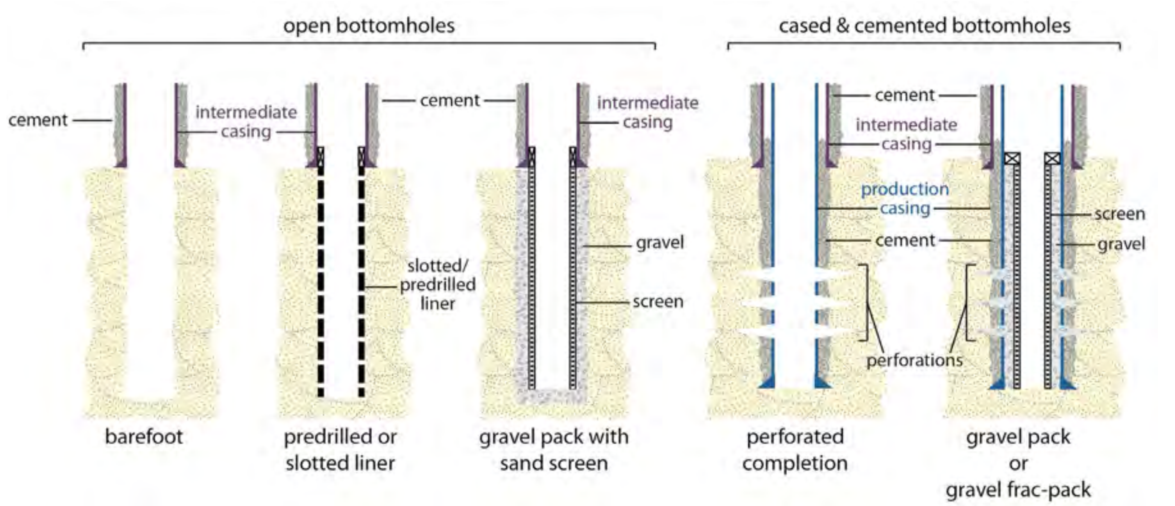

Figure 68. Different types of bottomhole completions depending on the nature of the producing zone and the manner in which the bottom of the hole was completed. (Copyright J.D. Myers. Used with permission.)

the openings (Fig. 69c) providing multiple ways to produce the formations (von Flatern, 2011). In one scenario, the lower zoning can be produced until it is depleted, a plug set and the sliding sleeve opened to produce from the upper zone. If tests indicate the oil from the two zones can co-mingle without flow problems, the sliding sleeve could be opened and both zones produced simultaneously through the same tubing string.

Upper Completion

The upper completion determines how the produced fluids are conveyed from the production zone to the surface as well as the components at the top of the well. Crude oil can be extracted to the surface through the production casing/liner or in production tubing. In a tubeless completion, crude oil is run to the surface in the casing itself. This provides for larger flow rates, but may lead to casing corrosion and does not provide adequate barriers to stop flow in the event of a loss of well control. An alternative approach is to run tubing down the well, and produce oil through both the tubing and casing. This is used for wells producing at low rates and with significant gas. The gas is funneled up the annulus between the tubing and casing whereas the crude oil is pumped up the tubing. This arrangement produces better pump performance.

The configuration for the topmost portion of a well depends on the flow of produced fluids. For both free-flowing wells, i.e., wells in which hydrocarbons are forced all the way to the surface by reservoir drive, and non-flowing wells, the top of the well is finished by installing a wellhead.

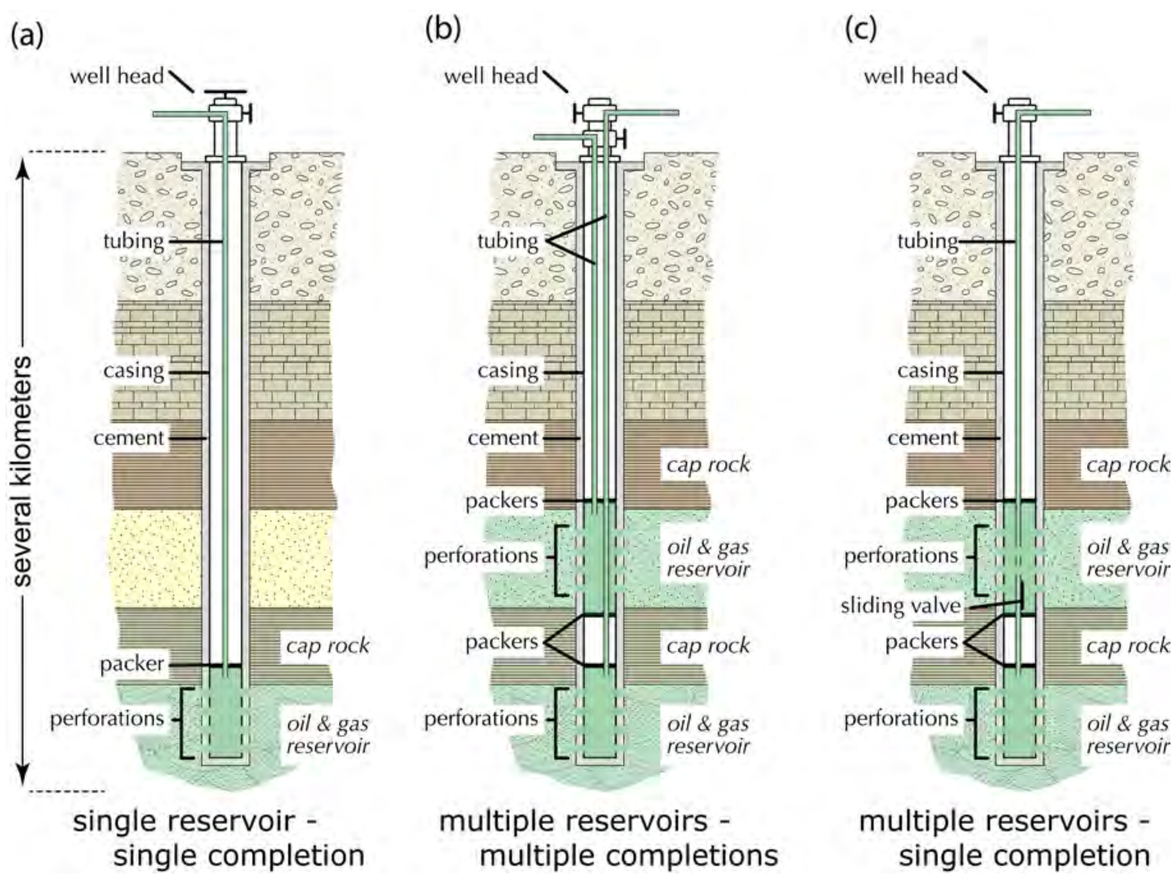

Figure 69. Diagrams illustrating different types of well completions for a free flowing oil well. (a) Single completion for production from a single reservoir. (b) Multiple completions for production from multiple reservoirs. (c) Single completion for production from multiple reservoirs. Production can be sequential or simultaneous as determined by sliding the valve open or closed. (Copyright J.D. Myers. Used with permission.)

A wellhead consists of a permanent, forged or cast steel fitting that is welded to the conductor or surface casing. The wellhead from bottom to top consists of the casing head, tubing head, and Christmas tree (Fig. 70). A casing head contains hangers for a casing string and a gas outlet for pressure release. Each casing string has a separate casing head and the lowermost and largest is for the surface casing. Above the casing head is the tubing head with the hanger for the tubing string. It also seals the casing-tubing annulus. The casing head allows opening and closing of the casing and in the case of pressure build-up, bleeding of the gas in the casing. Monitoring casing pressure allows the operator to detect leaks in the tubing. Above the tubing housing is the Christmas or production tree. This device contains a series of valves used to control the flow of oil and gas from the well. At the Christmas tree base is a master valve to cut off flow from the well in an emergency (Fig. 70). A pipe, the wing, extends horizontally out from the tree and is connected to a tubing string. It carries the flow of oil from the well. Whereas single completions will have one wing, multiple completions will have a wing for each tubing string. On each wing, there are chokes which are used to regulate the flow of hydrocarbons. Oil is rarely allowed to flow at the maximum rate possible. This would lead to a rapid depletion in reservoir pressure and decrease ultimate recovery. The large pressure difference between the well and the reservoir created by high flow rates could also allow gas to exsolve from the oil, thereby forming bubbles. This could potentially block flow to the well. Above the wings are valves that can be opened to lower wireline tools into the well for maintenance and testing. Finally, at the top of the wellhead, a pressure gauge measures the pressure in the tubing (Fig. 70). Because of their important safety role in controlling a well and its fluid

Figure 70. Photograph of a wellhead for a flowing gas well. (Photograph by Robert Kirkwood. Used with permission.)

production, Christmas trees are often machined from a solid block of steel (Hyne, 2001).

Well Mechanical Integrity (MI)

Obviously, construction of an oil and gas well is a complex task. Proper isolation of different fluid zones along the borehole requires the successful completion of multiple barriers at different times during well construction. At the same time, completed and functioning oil and gas wells are subject to enormous pressures, high temperatures, and exposure to a variety of formation fluids, including some that are very corrosive, for long periods of time. Thus, over time well materials can degrade and ultimately fail, thereby compromising zonal isolation. To ensure proper construction, a production well is generally checked for mechanical integrity using a mechanical integrity test (MIT) after completion. Federal and state UIC regulations also require MITs for injection wells before injection begins. They also require periodic MITs during the lifetime of an injection well.

The UIC program defines two types of mechanical integrity:

- internal MI is achieved when there are no leaks in casing, tubing or packers; and
- external MI is attained if there is no significant movement of fluid into a USDW via channels in the primary cement sheath.

UIC regulations indicate what types of testing can be used to document internal and external MI. Not surprisingly, the details of the tests vary considerably from state to state. If alterative tests are proposed by well operators, they must be approved by the originating state's UIC program and forwarded to EPA for evaluation. Details of any newly approved MITs are published in the Federal Register.

Internal Mechanical Integrity

Internal MI is concerned with the integrity of zones inside the casing. Primarily, it addresses leaking from the injection tubing into the casing-tubing annulus. In addition, it focuses on leaking packers that permit fluids from the injection zone of the well to leak into the casing-tubing annulus, thereby allowing vertical motion of fluid along the well. UIC regulations specify five ways to demonstrate internal MI for an injection well: annulus pressure test, annulus monitoring test, radioactive tracer test, water-brine interface test (Class III), and pressure test with liquid, gas, or monitoring of records to show no significant changes between injection flow rate and pressure (certain Class II wells only) (Koplos and others, 2006; EPA Region 5, 2008).

The primary test for internal mechanical integrity is the standard annulus pressure test (SAPT). This test applies a pressure to the annulus and monitors that pressure over a specified period of time. To pass the test, the pressure can increase or decrease by only some specific percentage of the initial pressure during the test period. Different states mandate different test pressures, test durations, and allowable pressure changes. The fluid in the annulus can be either a liquid or gas and is used as a pressurizing medium. The assumption behind a SAPT test is that the annulus is a closed vessel and it should maintain the applied pressure. Pressure increases or decreases suggest the presence of leaks. One source of pressure change could be temperature variations, but the limited duration of the test (typically 30 minutes) is believed to be too short to see significant temperature changes along the borehole. The SAPT is inexpensive and easy to interpret, but provides only a single tested point in time. The standard annulus monitoring test (SAMT) is similar to the SAPT except it is carried out continuously during normal injection operations. SAMTs provide continuous monitoring of MI and are easy to implement and interpret in simple annulus systems. SAMTs are preceded by a SAPT that proves MI and then commences measurement.

Radioactive Tracer Survey: The radioactive tracer survey (RTS) injects a radioactive tracer (RT) of short half-life into the injectate above the position of the suspected leak. The RT moves down the well as a slug in the injectate. If a leak is present, some of the RT will enter the annulus through the leak. Subsequent testing by a wireline logging tool will pick up a separation in the RT slug in the tubing and annulus because vertical movement in the annulus will be slower. The advantages of a RTS are that it locates the depth of the leak, but is expensive and requires injection of a radioactive substance (EPA Region 5, 2008).

The RTS wireline tool consists of an injector, one or more gamma detectors, and a collar locator (EPA, 2013d). The collar locator detects the positions of threaded collars connecting two joints of casing. In addition to determining the position of the leak relative to permanent markers, it also reveals if the leak is at a collar. The gamma detector measures gamma radiation emitted by the radioactive tracer (Fig. 71). The injector releases a radioactive tracer into the well at a known location. The tracer is usually iodine-131, because of its eight day half-life. If the well has internal MI, the tracer will follow the injectate and enter the injection zone. A leak in the tubing or packer will allow injectate and tracer into the tubing-casing annulus where it will remain trapped. Similarly a casing test will result in tracer positioned behind the casing. When the gamma detector is deployed, it will detect regions of increased radioactivity along the wellbore (EPA, 2013d). Because the borehole formations also emit gamma radiation, the RTS log must be compared against gamma ray logs performed before injection (Fig. 71).

There are two different procedures for running a RTS. Both variations release the tracer as a slug into the tubing above the suspected leak, but the movement of the tool varies. For slug tracking, the tool is moved up and down in the well repeatedly to track the position of the slug as it moves through the well. Conversely, the velocity shot method holds the tool stationary and monitors the time at which the slug passes the detectors. RTS are typically run during injection and ideally at maximum allowable injection rate (EPA, 2013d).

External Mechanical Integrity

External MI is related to the quality of cementing between the casing and the borehole walls. If the primary cement job created a good seal between these and avoided the creation of channels in the cement sheath, fluid cannot move between formations along this pathway. Conversely, a poor cement-bond, defects in primary cementing, e.g., channels, poor setting, etc., could provide pathways for formation fluids to move between formations and into USDWs (Fig. 62). UIC approved external MIT tests include temperature, noise, oxygen-activation, and cement bond logs as well as radioactive tracer surveys and cementing records (Class II only).

Temperature Log: Temperature logs are a continuous record of temperature along the well (Koplos and others, 2006; EPA Region 5, 2008). With depth, temperature increases with the geothermal gradient (Fig. 72). The normal gradient is typically 1.7°F/100 feet (3°C/100 meters). However, fluids entering or leaving the borehole will perturb this temperature gradient. For example, gases entering the well expand, an endothermic process, thereby causing a cooling. Thus, temperature logs can identify gas entry zones. Likewise, injection fluids will cause temperature changes in the injection zone, because they are unlikely to have the same temperature as the formation's fluids. At deep levels, injection normally produces cooling. Shallower injection can result in either cooling or warming depending on depth and the original temperature of the injected fluid. Temperature logs are also good for identifying fluid moving along channels adjacent to the casing or wellbore. To compare against subsequent temperature logs, a temperature log is run after well completion to provide a baseline temperature profile. This log should be run at least 36 hours after completion to let temperature changes associated with drilling and completion re-equilibrate (EPA, 2013d). They are best run while entering the hole with the logging tool, so as not to disturb the well's original thermal profile. Temperature logs provide a continuous vertical record of high resolution.

The temperature log tool uses changes in the electrical resistivity of a circuit as a function of temperature to detect temperature anomalies along the wellbore. The temperature-restivity relationship is linear and sensitive enough to detect very small variations in temperature. These logs require good thermal coupling between wellbore and the tool, so they work best in liquid-filled wells and very poorly in wells that are primarily gas-filled. Readings are taken at short intervals producing a continuous temperature record along the wellbore (Fig. 72). Because of the time lag between the temperature and the tool's response, there is an inherent time lag in the measurements. The slower the log is run into

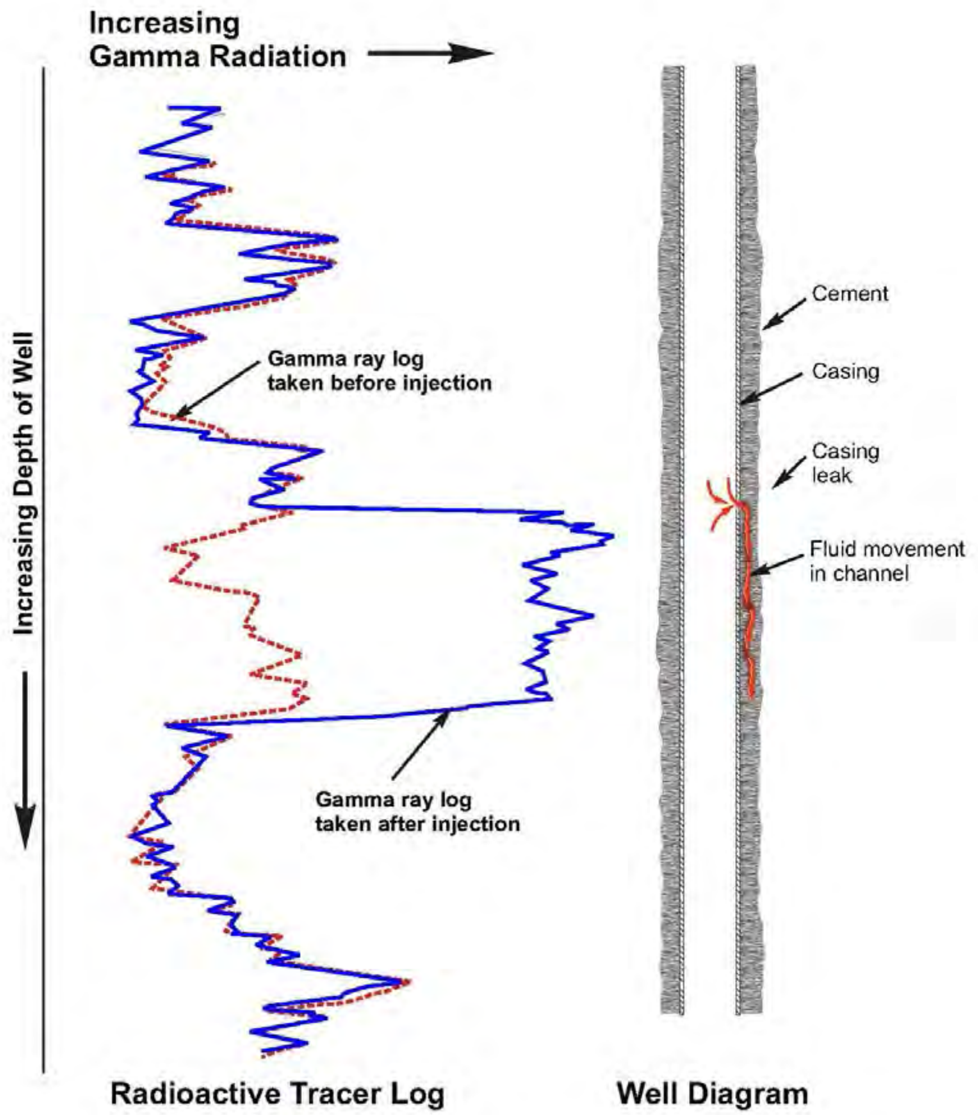

Figure 71. Radioactive tracer test to determine the position of a casing leak. In the test illustrated, the tubing has been removed from the injection well to simplify casing evaluation (right). The gamma recording made after tracer injection (left) clearly shows a region of higher radioactivity compared to the baseline gamma log. The collar locator in the RTS tool determines the tool position in the wellbore by counting casing collars. (Source: EPA, 1982, 2013d)

the well, the smaller this time lag and the closer the measured temperature profile is to the actual profile (EPA, 2013d).

Noise Log: Noise logs can also be used to evaluate external MI. At some point, fluid flow that is occurring behind the casing will encounter irregularities in the channels it is flowing in, thereby resulting in turbulent flow (Fig. 73). Turbulence causes noise, which can travel long distances in solids. Gas entering the wellbore is also likely to produce a hissing sound as it expands. A noise log can be either static or continuous, although static noise logs are more common. A static noise log is run by lowering the tool to a specific depth, waiting three to four minutes and collecting the signal. The sensor is dropped to the next position (usually spaced 50 or 100 feet [15 or 30 meters] apart) and the test run again. Continuous noise logs are less effective, because the signal is dominated by the noise

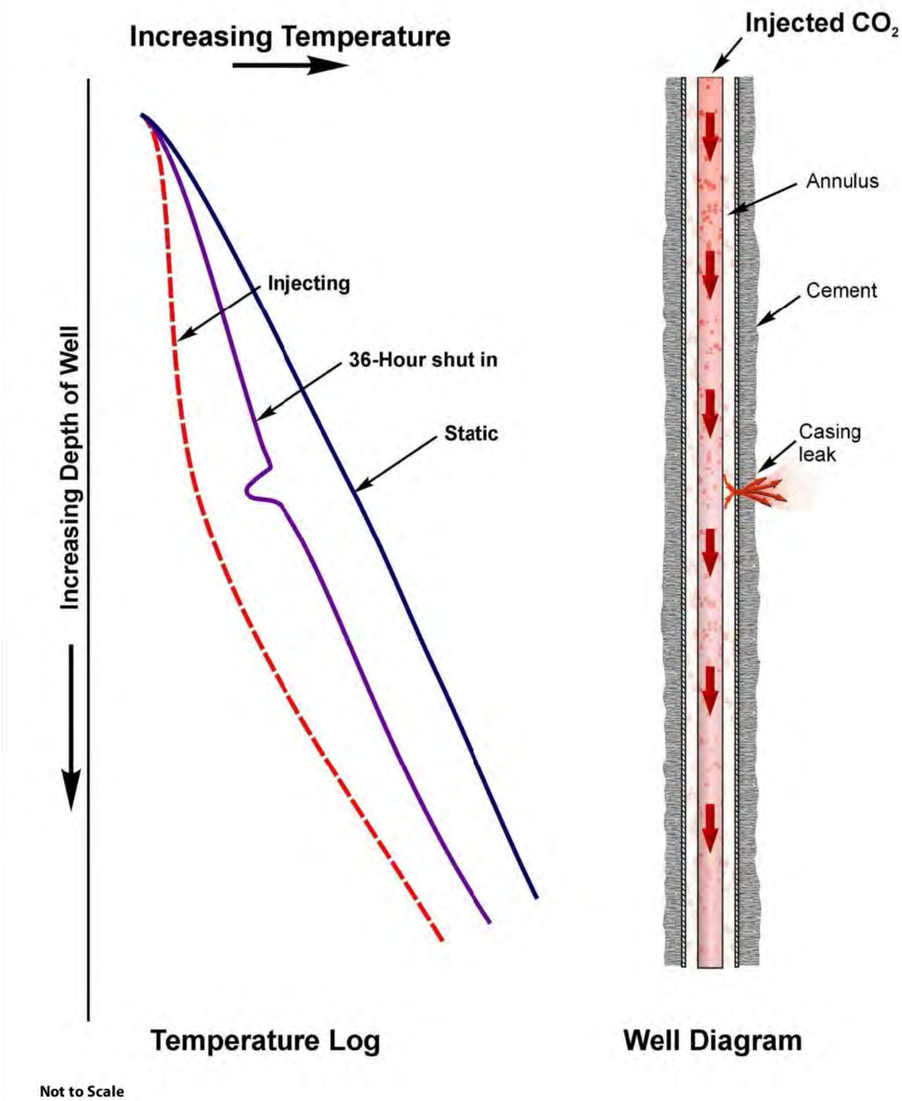

Figure 72. A temperature log measures variations in electrical resistance caused by variations in temperature along the borehole. Because injectate temperature is unlikely to be the same as formation fluids it will modify the temperature gradient along the well (left). A leak along the wellbore will cause a temperature dip, particularly if the injectate expands after it enters the formation. After shut-in, a temperature log will detect this anomaly. (Source: EPA, 2013d)

of the movement and scrapping of the wireline and tools in the casing. Noise logs are a good alternative to temperature logs where shut-in times sufficient to establish thermal equilibrium are not possible.

Because the sound generated by turbulence is in the audible range, the noise logging tool consists of a very sensitive microphone (EPA, 2013d). The tool transmits the recorded signal to a recorder that measures the strength of the signal. The tool can record flow behind casing because sonic energy travels long distances through solids, i.e., cement and casing. To make a good sonic coupling between the tool and the well walls, a liquid filled well is best. Different turbulences produce different frequency ranges. Single-phase flow produces low-frequency sound, whereas two-phase flow emits higher frequencies. EPA (2013d) recommends using a staged approach to conduct noise logs. The first log uses a coarse spacing of 100 feet (30 meters) between sampling positions. If high noise is detected along the wellbore, the survey is run again

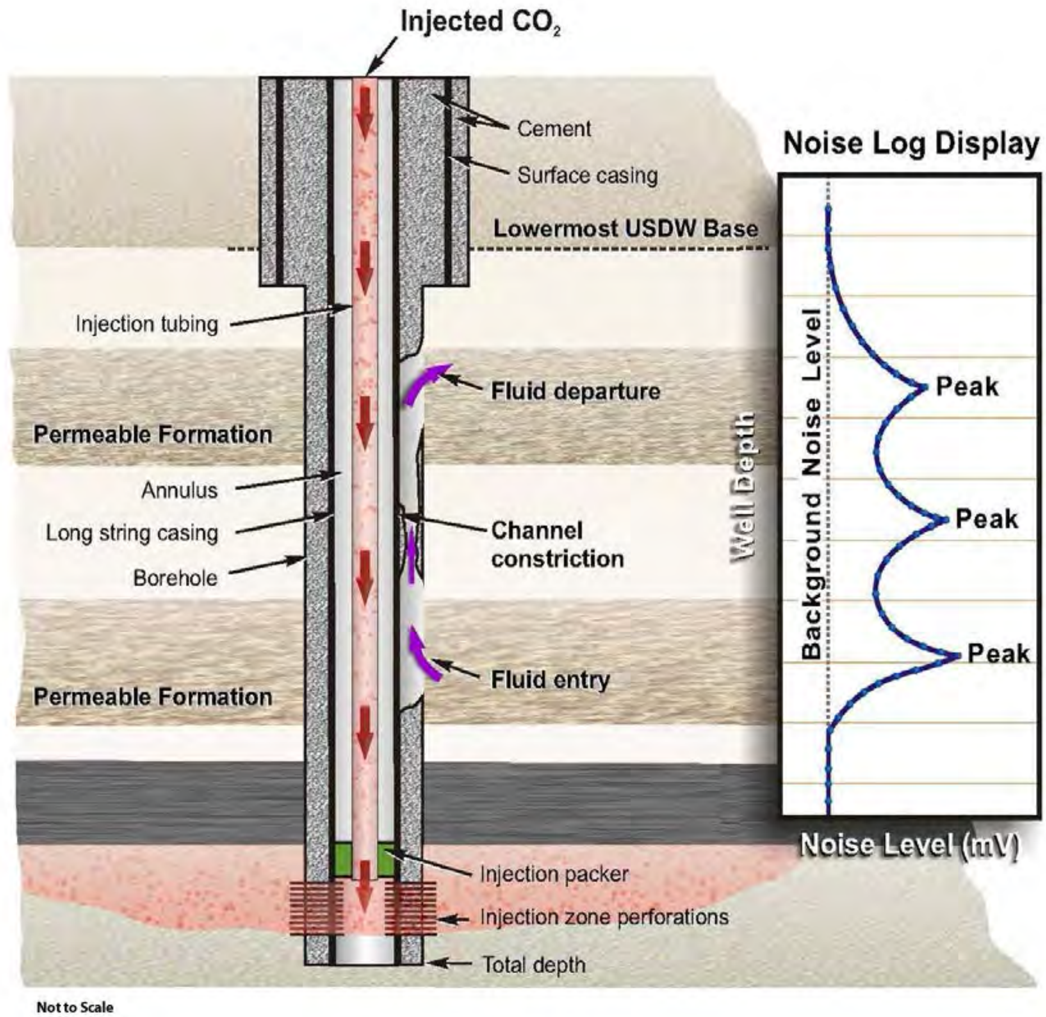

Figure 73. Noise logs measure sonic signals produced by fluids flowing turbulently in irregular channels in the primary cement job. (Source: EPA, 2013d)

over this interval at 20 foot (6 meter) intervals. Spacing should be at 10 foot (3 meter) increments starting 50 feet (15 meters) above the injection zone and at 20 foot (6 meter) intervals within 100 feet (30 meters) of a USDW (EPA, 2013d). The UIC program requires noise logs for other injection well classes so this logging tool is well-established and proven. Noise logs can be run during injection if there is a baseline noise log against which to compare and detect anomalies (EPA, 2013d).

Oxygen Activation Log: An oxygen activation log (OAL) uses a high-energy neutron source to convert oxygen into unstable nitrogen-16 (^{16}N). This isotope has a half-life of 7.13 seconds and decays to oxygen with the emission of gamma rays for 65 percent of the decays (EPA, 2013d). Detectors in the logging tool measure this increased gamma ray activity and can use it to measure water flow in the wellbore. OA logs do not require shut-in time and can be run in either liquid or gas-filled wells. There are several major drawbacks with the OAL, however. Logging time and costs are higher than for other logs. There is also a history of false positives, and they have limited penetration depth, in some instances less than casing or borehole diameter. Indications of MIT failure suggested by OAL should, therefore, always be checked by other MI tests.

Cement Log: For Class II injection wells and some Class III wells, cement logs can be used to demonstrate external MI (EPA Region 5, 2008). These records must show that cement is present behind casing across the interval from the injection zone to the base of the lowermost USDW. This test relies on existing information, but is an indirect demonstration of MI. The presence of cement does not necessarily ensure good casing-cement or cement-formation bonds. It is also a one-time demonstration and does not account for changes in the nature of the well construction materials due to exposure to high temperatures and pressures as well as varying operational forces.

Well Abandonment

Ultimately, all oil and gas wells reach the end of their useful lifetime. For a production well, this occurs when the well no longer produces economic amounts of hydrocarbons or the well has been damaged and the costs of repairs are too great to be economically justifiable. In these cases, the well would have been previously cased and completed. An exploratory well's usefulness ends immediately if tests show the well will produce insufficient hydrocarbons to justify the great expense of completing the well. In this case, much of the lower part of the well may be an open hole. In either case, a well that has reached the end of its useful lifetime must be plugged and abandoned (P&A). How a well is plugged and abandoned is determined by a regulatory agency, either federal or state, as well as the condition of the well at the time of abandonment. Because oil and gas operations are generally regulated at the state level, the requirements for plugging operations differ from state to state. Most require that cement plugs be placed and tested across any open hydrocarbon-bearing formations, all casing shoes, freshwater aquifers, and perhaps several other areas near the surface, including the top 20 to 50 feet (6 to 15 meters) of the well.

There are many reasons a well has to be properly abandoned. These include isolating and protecting freshwater aquifers, isolating and protecting hydrocarbon-bearing units, and preventing leaks into or out of the well. Improperly abandoned wells have a number of possible risks associated with them including entry of contaminated surface water, surface leakage from shallow zones through well or cement, leakage from aquifer to surface, leakage from surface to aquifer, and the danger of falling into an open hole. In the past, P&A was mandated mostly to protect economic resources, because the majority of oil fields are abandoned with 60–80 percent of the oil and 10–20 percent of the gas still in place. New technology could make these reservoirs economic in the future. In recent decades, recognition of the importance of freshwater sources has driven the effort to ensure wells are properly plugged and abandoned. In some instances, only a portion of the well will be plugged and abandoned. For example, when a deep, producing reservoir is exhausted, but there is a shallower hydrocarbon-producing zone, the well will be plugged between the two formations. In this manner, the bottom part of the borehole is plugged and abandoned and the top part re-completed in the shallower, hydrocarbon-bearing formation. Onshore P&A operations are generally not that expensive. Costs for plugging orphaned vertical onshore wells in Texas averaged $4,500 per well (Texas Railroad Commission, 2000), but costs climb for horizontal or extended reach wells. Offshore wells can cost from hundreds of thousands to several millions of dollars to plug and abandon a single well properly.

In the Wyoming oil and gas industry, three types of abandonment well statuses are defined by WOGCC regulations. A *shut-in well* is one in which the well is not producing oil or gas because choke valves are closed and/or pumps are turned off. However, the production equipment is still in place, the production zone has not been isolated from the rest of the well, and with re-energizing and reconditioning, if needed, the well could be put back in production. Wells may be shut-in for a variety of reasons including waiting for a workover, i.e. performing maintenance, simulation, or remedial work on a well to improve production rate, awaiting field development or redevelopment, or economic conditions do not currently warrant production, but may in the future. A well in which the producing zones have been isolated from the zones above and the surface is a *temporarily abandoned well*. Zonal isolation may be via a retainer, bridge plug, cement plug, packer with a tubing plug, or any combination. A *permanently abandoned well* is one that is no longer active and permanently plugged and abandoned according to regulations so that fluids, (oil, gas, water), cannot migrate from their original host formations. For sequestration purposes, there is a fourth type of abandoned well, the *orphaned well*, which is extremely important in terms of leakage risk. These are oil and gas wells which have not been properly abandoned either physically or in a regulatory sense, but for which the operator is no longer assuming responsibility. This often arises when operators go out of business or wells are transferred to owners later in their production history and the new owners do not have the financial resources to properly abandon the well. The status of orphaned wells, e.g., active, shut-in, or temporarily abandoned, can be difficult to determine from public records since the relevant paperwork may not have been filed properly. From a GCS perspective, orphaned wells present the greatest risk to the physical security of a sequestration reservoir. Even properly abandoned wells may present some leakage risk because of evolving regulatory regimes for plugging and abandoning a well and the absence of a regularly scheduled monitoring program (Ide and others, 2006; Nelson, 2013).

Isolation

The primary purpose of P&A is to prevent fluid movement along the well or the cement sheath between the casing and the borehole. This is most readily achieved by isolating the various regions where fluid can enter or leave the well. That is, restore the barriers that naturally existed before the well was drilled and prevented fluid flow between formations, i.e., hydraulic isolation. In an open hole, the entire borehole length is vulnerable to fluid entry. In a cased hole, there are particular places where fluids can enter or exit the wellbore. These include producing zones, perforations, damaged sections, multilaterals, corroded zones (sections where casing and cement have been chemically attacked by corrosive formation fluids, such as, saltwater), and liner tops (Fig. 74). Knowing the depths where these zones occur requires detailed knowledge of the well and its status. Zones are isolated in a number of ways. The two most important are cement plugs and mechanical plugs or bridges. Often these are used in combination.

P&A Operation

Properly plugging and abandoning a well involves a number of stages. First, any pumps are pulled from the well along with packers and tubing using a workover rig. Depending on regulatory requirements, plugs are set across the various zones of communication between the well, wellbore, and formations. These plugs can be cement or mechanical, or more commonly a combination of both. Regulations will commonly specify which zones have to be plugged and how far above and below the zone the plug must extend. Plugging and abandoning a well is typically done by a service company and almost always involves cement plugs. To set cement plugs, dry cement is dispatched to the well site in a bulk cement truck. At the well site, the cement truck is connected by hose to a pumping truck. The pumping truck adds water and whatever additives are needed just before the cement slurry is pumped down the hole. Tubing is used to place the cement at the desired plug depth. The most commonly used method of setting a cement plug is the displacement method. In this method, cement is pumped out of the tubing at the desired depth and flows up and around tubing. When the calculated volume of cement has been pumped, water is pumped down the tubing to displace the cement downward. The tubing is slowly pulled out when the cement-water interface reaches a predetermined depth. As the tubing rises, the cement still in the tube falls out filling the space previously occupied by the tubing. In this manner, a good solid plug can be set without mud contamination. A plug and abandon job can take several days to two weeks depending on the number of plugs that must be set.

Cement: The same cements used to set casing are also used to set plugs in P&A operations. In designing a cement plug, the plugging company uses information from the well design to calculate where the plug must be placed and how far it should extend above and below the weak point. From this information and knowledge of casing diameter, the volume of cement needed to set the plug can be calculated.

Setting a plug is not an easy task. Because zones not plugged are filled with drilling fluid, cement is placed on mud. If the cement is not

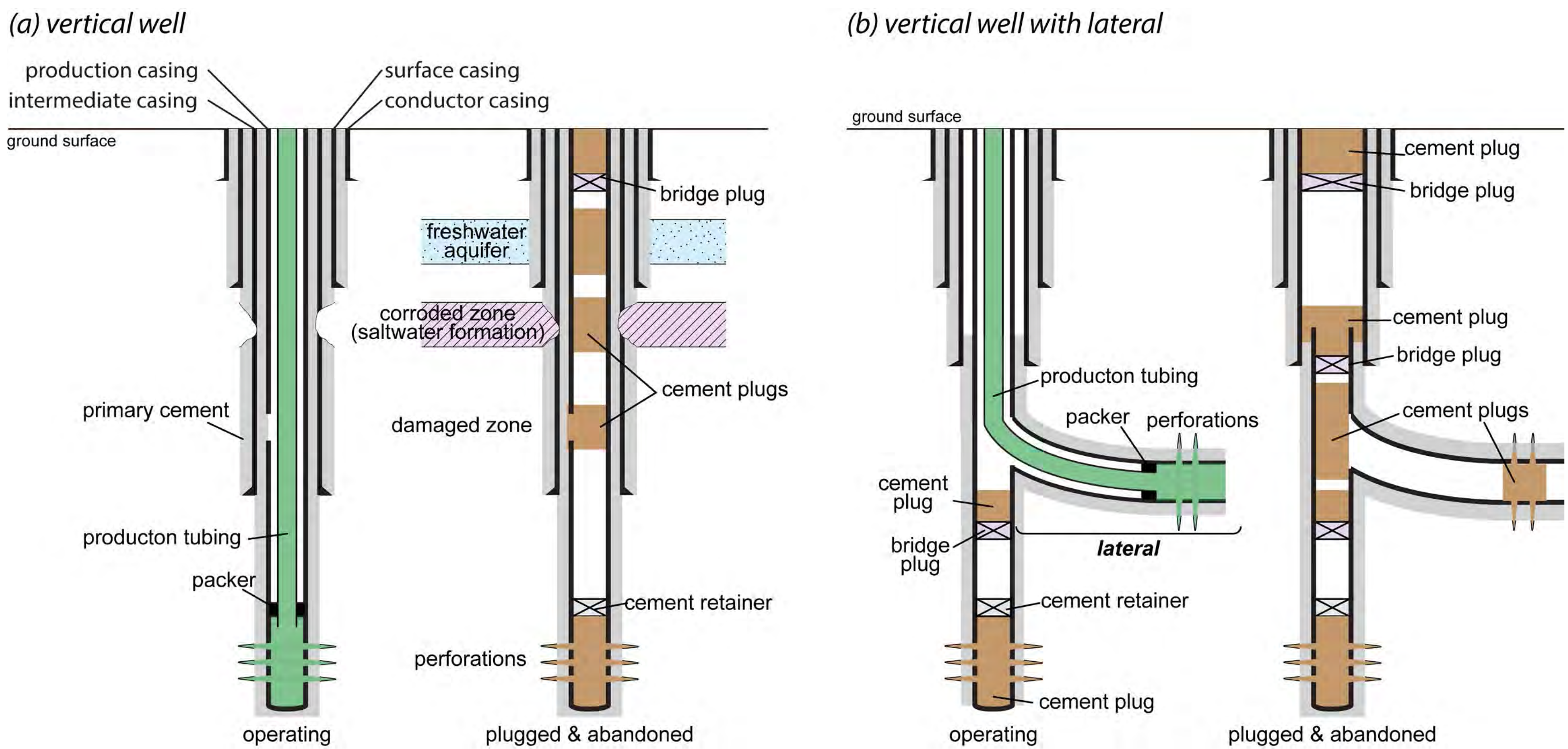

Figure 74. Cement, mechanical, or combination plugs are placed where fluid can enter or exit the well. For all wells, plugs are set across freshwater and production zones and near the surface. (a) For wells with corroded zones and damaged zones, plugs are also set across these zones of potential fluid exit or entry. (b) Plugs are also set across laterals entries and perforations.

placed properly, it will fall through the mud and the plug will not set (Fig. 75). This situation results from too dense cement, too low mud viscosity, cross flow, or ejecting cement from the tubing with too much downward momentum. Without proper setting, there is no isolation. Cement plugs also fail because of contamination from mud or inaccurate calculation of the volume of cement needed.

Drilling Mud: The entire borehole is generally not completely filled with cement because of cost. If the zones between plugs were left empty, loss of casing integrity would allow fluids to enter the borehole and place additional stresses on plugs. For this reason, drilling mud and bentonite are often used to fill the empty segments of an abandoned well. These fluids play the same role as they do during drilling, i.e., their weight and density balance formation pressure and keep fluids from entering the well.

Mechanical plugs: A P&A plan may specify setting bridge plugs in conjunction with cement slurries to ensure that they higher density cement does not fall through the wellbore (Fig. 75). In this case, a mechanical or bridge plug would be set and cement pumped on top of it. A mechanical plug creates compressive force by expanding against the casing in the well. This force holds it in place in the well. Mechanical bridges consist of a body, slips, packing material, and an on/off tool (NPC, 2011). The body that forms the plug core can be made of steel, cast iron or a composite material. The slips are moveable metal parts that expand outward and grab the casing to set the plug. On setting, the packing material is squeezed outward by compression and forms a seal against the casing. The on/off switch allows the plug to be unset and repositioned or removed from the casing. To set the plug, it is lowered to the desired depth and rotated, thereby releasing the slips. With the slips set, the plug is raised or lowered to expand the packing material against the casing. There are two types of mechanical plugs: bridge plug and cement retainers (NPC, 2011).

A bridge plug is a mechanical plug that provides a solid plugging seal. Typically, they are made of cast iron with packer material sandwiched between two slips (NPC, 2011). Bridge plugs are often set to provide a solid base for a cement plug.

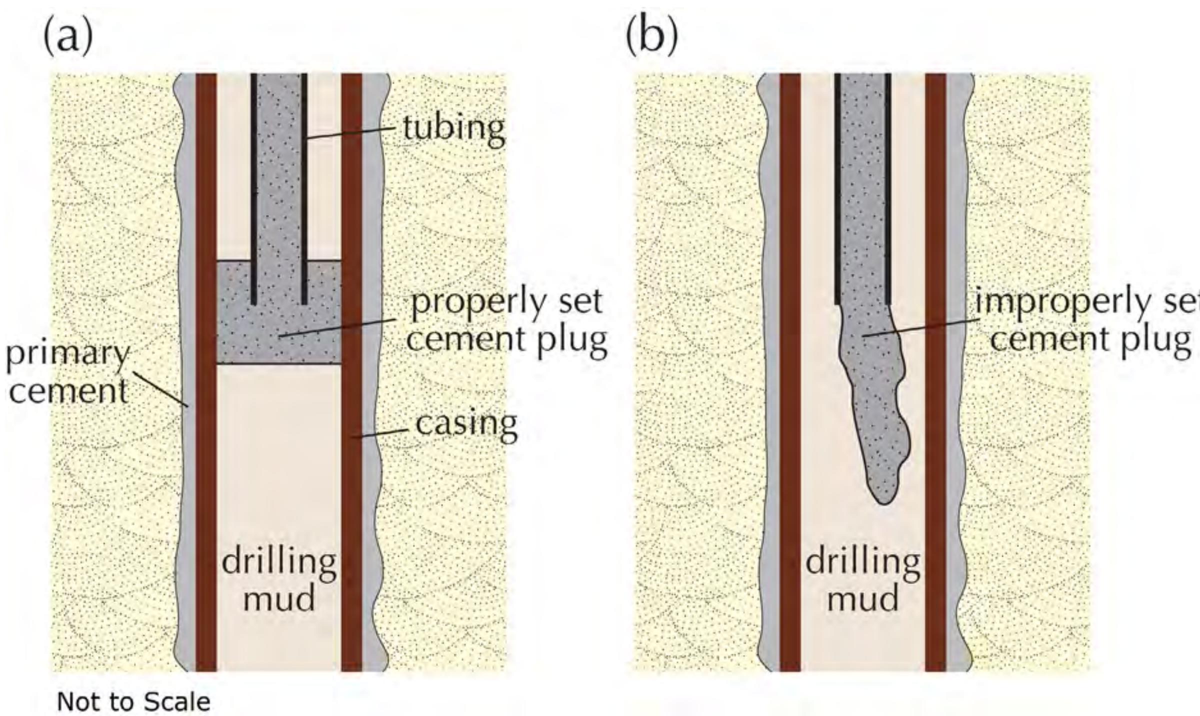

Figure 75. Illustration of a cement plug failure because of density mismatch. (a) Plug that is properly set and ensures zonal isolation. (b) Improperly set plug. Cement has not formed a structurally sound plug because of density or viscosity mismatch between cement and drilling mud or cement pumping was too fast.

Thus, they seal off the wellbore below the plug. In formations with high gas pressure, setting a bridge plug prevents the gas from contaminating the cement while it sets. Bridge plugs can be designed to be drilled through at later times. A cement retainer plug is set above the zone to be cemented and before cement is pumped into the hole. They are set mechanically in the same manner as bridge plugs. Once set, cement is pumped below the plug through tubing that extends through the plug. With the plug set, cement can be forced into the well zone at high pressure. This is useful for doing a cement squeeze of perforations or open holes. With the cement retainer set, the high pumping pressure will not force cement up the wellbore, but into the perforations or formation. After setting of the cement, the tubing is withdrawn and a mechanical valve is closed. To ensure a good seal, cement is usually placed on top of the cement retainer as well.

Potential Well Leakage Pathways

Numerous problems can arise that compromise the ability to confine fluids to their host formations (Gasda and others, 2004). Two types of failures are associated with plugs placed in the wellbore and allow fluids to move vertically between zones in the casing. An improper seal between plug and casing can allow fluid to travel along the casing interface. Deterioration of the cement plug could result in fluid movement through pore spaces within the cement plug. The other possible leaks allow fluid to either enter or leave the casing. Vertical movement can occur along the outside of the casing if the casing-cement bond is poor. Corrosion of the casing can permit fluid to enter the casing from the exterior. Formation fluids can reach the outer surface of the casing via fractures in the cement sheath. Finally, another vertical pathway for fluids can exist between the cement and borehole if the cement-rock bond is poor.

Wyoming Oil and Gas Regulations

Wyoming has had a long history of oil and gas activity. The first documented well was drilled in 1883 near Lander (Roberts, 2008). Since that time Wyoming has seen an expansion of drilling activity to nearly all parts of the state. In January, 2013, Wyoming produced 167,000 barrels of oil per day (EIA, 2013b) making it the eighth largest U.S. producer of crude oil (EIA, 2013c). In 2011, Wyoming was the third largest producer of natural gas behind Texas and Louisiana with 2,159 billion cubic feet (61 billion cubic meters) produced. In 2012, there were 47 active drilling rigs in Wyoming representing nearly 3 percent of active rigs nationwide (EIA, 2013c). Oil and gas activity in the state is concentrated in eight energy basins, which also contain potential targets for future geologic carbon sequestration projects (Fig. 76).

WOGCC

In Wyoming, oil and gas operations are regulated by the Wyoming Oil and Gas Conservation Commission (WOGCC) established by the state legislature in 1951. Prior to this, drilling on state-owned land was under the direction of the State Mineral Supervisor from 1933 to 1951 and by the Commissioner of Public Lands before that (Nelson, 2013). The State Oil and Gas Supervisor is head of the WOGCC and appointed by the governor. The primary functions of the WOGCC are to regulate oil and gas development throughout the state, handle drill permitting, enforce Wyoming statues and regulations, and ensure compliance by the industry to state laws and regulations. The WOGCC also manages Class II injection wells of the state's UIC program.

The rules and regulations of the WOGCC are spelled out in five chapters. Chapters 1 and 2 define the authority under which the agency acts as well as some general rules and definitions. Chapter 3 covers drilling rules and Chapter 4 environmental rules including those related to the UIC program for Class II wells in the state. Chapter 5 covers some general rules and procedures. Thus, for carbon sequestration projects that might occur in the state Chapters 3 and 4 are most important.

Drilling Regulations (WOGCC Chapter 3)

The 34 sections of Chapter 3 of WOGCC's rule and regulations cover nearly all aspects of drilling. These include sections on Applications for Permit to Drill, well designations and markers, general drilling rules, blowout preventers, vertical and directional drilling, measurement of oil and gas, authorization

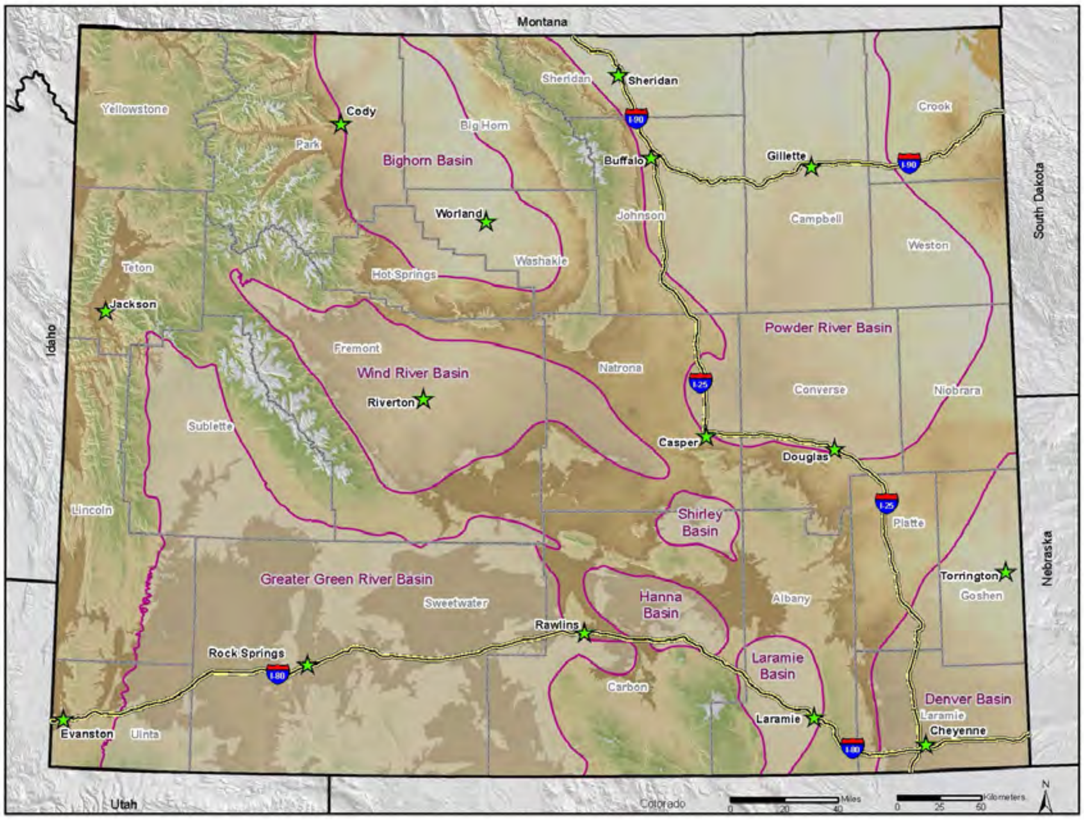

Figure 76. Oil and gas activities in Wyoming are concentrated in eight energy basins scattered across the state. (Copyright J.D. Myers and R. Kirkwood. Used with permission.)

for flaring and venting of gas, unit operations, and well stimulations. It also describes the procedure for unitizing a reservoir for carbon sequestration (Sec. 43).

To drill an oil or gas well in Wyoming, an operator must file an Application for Permit to Drill (APD) with the WOGCC. This application must include drilling and completion plans for the well. If changes are made to these original plans, a Sundry Notice must be filed with the WOGCC describing these changes. WOGCC regulations specify the spacing required between oil and gas wells for both vertical and horizontal wells. To ensure proper operation and abandonment, WOGCC requires an operator to post a bond before drilling commences. For wells less than 2,000 feet (610 meters) deep, the bond is $10,000 per well, but increases to $20,000 per well for deeper wells. Operators with multiple wells can post a blanket bond for $75,000 covering all their wells. These bonds are not released until the well is properly plugged and abandoned according to regulations unless it has been converted to a water well. Wells that are not producing, injecting, or disposing are classified as idle wells and the original bond must be supplemented by an additional bond. This new bond is calculated at $10 per foot (10.3 meters) for each idle well when an operator's total footage of idle wells exceed 2,500 feet (762 meters) or 7,500 feet (2,286 meters) depending on whether the original bonding was for a shallow (<2,000 feet [610 meters]) or deep well. These costs increase every three years the well is left idle. As an idle well's status changes, the bonding required will be decreased up to $10 per foot.

For carbon sequestration, one of the most important components of the drilling rules is the APD (Sec. 8). This document, which costs $50 to file, describes in detail how the well will be drilled and constructed. As such, it will provide a wealth of details necessary to determine an individual well's potential CO_2 leakage risk. Some of the important information for risk assessment in the APD include total depth, formation depth, casing plan, cementing program and anticipated completion and stimulation plans. For directional wells, a diagram showing direction of deviation and horizontal distance between surface entry and bottomhole locations must accompany the application. Likewise, horizontal wells must be identified with the prefix H and a permit acquired for each lateral separately. A permit is good for one year and must be renewed before expiration and a new $50 filing fee paid. A similar procedure is followed for a stratigraphic test well or a core hole (Sec 9). Proposed changes in an approved drilling plan must be reported in a Notice of Intent (Sec. 10) and approved before such changes can be made. Section 21 requires filing of all completed well logs with the Supervisor as well as a variety of other information, e.g., drillstem test, formation water analyses, core analyses, etc. Casing and cementing requirements are specified under the General Drilling rules (Sec. 22). All wells are required to install blowout preventers (Sec. 23) and to be drilled as nearly vertical as possible, except for horizontal wells (Sec. 24). Details for permitting and drilling directional wells, including specifying depth, azimuth, horizontal length, etc., as well as surveying requirements, are outlined in Section 25.

Environmental Regulations (WOGCC Chapter 4)

Chapter 4 of the WOGCC rules and regulations deals with environmental rules. This section also addresses Underground Injection Control rules for enhanced oil recovery (EOR) and disposal programs. Of the fifteen sections in the chapter, only six are pertinent to carbon sequestration projects. Injection wells for oil and gas waterflooding are regulated under this chapter of WOGCC rules (Sec. 7). All such wells must be permitted and are charged an annual $75 fee. In the permits for such injection wells, the applicant must demonstrate that their injection activities will not endanger oil, gas, or freshwater sources. An application must submit a description of the proposed operation, name and depth of (oil) pools affected, well casing description or proposed casing program, average and maximum injection pressures, evidence that injection will not produce new fractures, proof of exempt nature of aquifer to be injected into, and depth and areal extent of USDWs underlying the area proposed for exemption. Mechanical integrity of the well must be established once every five years. The types of tests that can be used to demonstrate MI are also specified. All injection wells are required to be cased and cemented so as not to allow leakage or damage to oil, gas, or freshwater sources in accordance with the general casing and cementing rules as outlined in Chapter 3, Section 22 (Sec. 8). Operators must notify the Supervisor of the commencement date of injection and, within ten days, the discontinuance of injection (Sec. 9). Details of all injection activities must be reported on a monthly basis to the Commission (Sec. 10). According to Chapter 1, Section 2(a) an aquifer is any "…geologic formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring." An aquifer can be exempt from this definition if the Commission determines the unit is mineral, hydrocarbon, or geothermal energy producing; situated at depth or location that makes fresh and potable water recovery economically or technologically impractical; too contaminated to be rendered fresh and potable; located in mining area subject to subsidence or catastrophic collapse; or contains total dissolved solids between 5,000 and 10,000 milligrams per liter. To exempt an aquifer, an application must be submitted to the Commission justifying such a decision by citing one of the conditions listed above. This application must have a structure or isopach map, geologic description, and legal description of the area to be exempted. The Commission must hold a public hearing addressing the exemption application and provide 30 days public notice before such a hearing is held.

Plugging and Abandoning Regulations (WOGCC Chapter 3)

Four of the sections of Chapter 3 deal specifically with plugging and abandoning wells. To abandon a well, a Notice of Intent to Abandon Well must be filed with the Supervisor showing the reason for abandonment and the types, locations, and lengths of plugs that will be set as well as mudding and cementing plans for abandonment (Sec. 15). If approved, the approval for abandonment is good for one year. As an alternative to permanent abandonment, a well may be temporarily abandoned or shut-in for up to two years (Sec. 16). Two year extensions are possible, but the Supervisor may require a mechanical integrity test before issuing such an extension. Permissible MITs must be consistent with the UIC Program pressure testing rules. Once properly abandoned, a Subsequent Report of Abandonment (SRA) providing details of the abandonment must be filed with the Commission (Sec. 17). The SRA shall indicate mud weights, types and quantities of plugging material used, and location and extent of plugs set. Within one year of permanent abandonment, well site reclamation must begin. Reclamation must be in accordance with landowner's requests and resemble original vegetation and surface contouring. On completion of site reclamation, a Sundry Notice will inform the Commission. The SRA and bond release is only approved after inspection by a commission staff member.

Detailed requirements for plugging and abandoning wells of all types are set out in Section 18 of Chapter 3. The operator or owner of a well must plug the well in a "…manner sufficient to properly protect all freshwater-bearing formations and possible or probable oil or gas bearing formations." As such, the rules specify the position and length of plugs, require the use of API class cement and additives, mandate the placement of fluid between plugs, etc. There are also specific requirements for abandoning Powder River Basin coalbed methane wells and wells in the Special Sodium Drilling Areas (SSDA), i.e., two areas in southwest Wyoming where trona mining occurs or may occur.

Plugged and abandoned wells must be identified with a permanent marker consisting of a pipe not less than 4 inches (10 centimeters) in diameter and extend no less than 10 feet (3 meters) above ground level. The marker must identify the operator, lease, well number, and location (Sec 19 [b]). The pipe must be set in cement. The need for a marker can be waived by the Supervisor when requested on a Notice of Intent to Abandon or Sundry Notice. In this case, the well casing must be cut off at least 3 feet (1 meter) below ground level and a plate welded to the casing stub. The plate must have all the same information as required for a permanent marker.

Summary

Pre-existing oil and gas wells represent potential leak pathways for any geologic carbon sequestration project targeting a depleted oil and gas field or an on-going EOR operation. Thus, the Class VI well regulation is designed to evaluate the potential leakage along pre-existing wells in the area of review. Understanding how these wells can leak CO_2 and the reasoning for the Class VI well requirements necessitates a fundamental understanding of how oil and gas wells are drilled, constructed, operated, maintained, tested, and ultimately abandoned.

Nearly all modern oil and gas wells are drilled using rotary drilling. A rotary rig uses a drill string and bit to transmit rotation to the bottom of the well where the bit crushes, grinds, and breaks the rock. Drilling fluid removes cuttings, cools the bit, and controls formation pressures. Wells are drilled in stages with each stage cased, cemented, and tested before the next stage is drilled. Wells can be drilled vertically, horizontally, or in a specified direction. Extended reach drilling allows drilling of multiple wells from the same pad and accessing of offshore oil and gas fields from an onshore drilling site. Multilaterals permit draining of multiple oil zones from a single vertical wellbore.

Once drilled and cased, a well must be completed for hydrocarbon production. This involves a number of different stages and the installation of a wide variety of different types of downhole and surface equipment. Packers and tubing isolate production zones and move hydrocarbons to the surface. Hydrocarbons enter a well through perforations, which have been blasted through casing, cement, and formation via shaped charges fired from perforation guns. Wellheads at the surface control fluid flow, prevent surface blowouts, and protect surface freshwater. Ultimately, wells no longer have economic value and must be abandoned. This typically involves setting cement and/or mechanical plugs across different zones in the well where fluid could enter or leave the well and/or borehole. Abandonment procedures are specified by state and federal UIC programs.

Besides producing the greatest amount of oil and gas possible, one of the primary functions of a modern oil and gas well is to provide zonal isolation of different fluid-bearing zones from cross contamination. This is achieved by constructing wells with multiple barriers to fluid migration along the wellbore. How well these barriers function is determined by the mechanical integrity (MI) of a well. The UIC program requires that injection wells have both internal and external MI. Internal MI is attained when there are no leaks in the casing, tubing, and packers, that is, leaks in the interior of the well. External MI is the prevention of vertical fluid flow in the cement sheath or wellbore behind the casing. Different mechanical integrity tests are used to demonstrate the different types of mechanical integrity of injection wells. MITs acceptable for proving MI for UIC injection wells are determined by EPA.

Chapter 7

Class VI Wells: The Carbon Sequestration Well Class

Class VI Rationale

Although the injection of CO_2 for enhanced oil (EOR) and natural gas (ENGR) recovery is a long-standing oil and gas industry practice, the injection of CO_2 for long-term geologic sequestration raises a new set of technical issues. For example, these projects will extend over a much larger spatial footprint, entail much greater CO_2 injection volumes, and span much longer project timeframes. Thus, EPA announced in October of 2007 that it intended to develop a set of regulations that would cover permitting of full-scale geologic carbon sequestration projects through the creation of a new well class, i.e., the Class VI wells. EPA stated that Class VI wells are to be "... used for geologic sequestration of CO_2…" As with the other UIC well classes, the ultimate purpose of this new well class is to protect USDWs. To accomplish this, Class VI wells must prevent movement of fluids to USDWs, allow continuous tubing-long string annulus monitoring, meet published Class VI casing/cementing requirements, and utilize prescribed tubing and packer construction.

The original UIC well classes were designed to ensure that injection wells are sited, constructed, operated, tested, monitored, and closed in a manner that protects underground sources of drinking water (USDWs). However, when considering the commercial scale deployment of geologic carbon sequestration, EPA concluded that the unique characteristics of GCS could not be handled through any of the existing UIC well classes. Some of the unique characteristics EPA considered are the new application of existing technology (underground injection), the large volumes of CO_2 likely to be injected, the buoyancy and mobility of CO_2 in the subsurface, the corrosivity of CO_2 in the presence of water, and the possibility of impurities in the injected carbon stream. Concerns about corrosivity arise from the reaction of CO_2 with water to produce carbonic acid, i.e., $CO_2 + H_2O = H_2CO_3$. The resultant acidification of formation waters and the CO_2 plume may lead to mobilization of trace elements, such as, arsenic, barium, cadmium, mercury, lead, antimony, selenium, zinc, and uranium, as well as other contaminants, e.g., organic compounds, that occur naturally in the subsurface. Enhanced mobility may adversely impact water quality and pose a greater threat to USDWs. Additionally, contact of the more corrosive injectate and formation fluids with materials used to construct injection, monitoring, and oil and gas wells could result in increased rates of deterioration and more frequent premature loss of well mechanical integrity. Thus, well construction procedures are more important than in some of the other UIC classes. Finally, depending on where and how CO_2 is captured, the injection stream may be characterized by the presence of a variety of impurities, e.g., hydrogen sulfide, mercury, etc. These impurities can impact well materials as well as react with formation fluids and rocks with consequences that might threaten USDWs. All of these factors led EPA to propose the creation of a new UIC well class.

To develop the Class VI Rule, EPA started with the basic components of the other UIC well classes (Fig. 77). These primary components include site characterization, area of review, well construction and operation, site monitoring, post-injection site care, public participation, financial responsibility, and site closure. In the years since the establishment of the UIC program, these regulatory components have been successful at protecting USDWs. As a means of accommodating the unique characteristics of the injected carbon stream, these components were modified, often significantly. For example, the area of review for Class VI wells is defined as that spatial footprint within which the potential for USDW endangerment exists, not the fixed radius approach used for Class I and III wells. Because it is in a more corrosive environment, Class VI well construction guidelines require the use of materials that are compatible with the fluids they will contact. In this manner, the new Class VI well class incorporates proven regulatory approaches while accounting for the unique nature of GCS.

General Background

Rulemaking History

EPA announced in 2007 its intention to create a new UIC well class, Class VI, for the purpose of geologic sequestration of CO_2. To support this effort, EPA held a series of technical

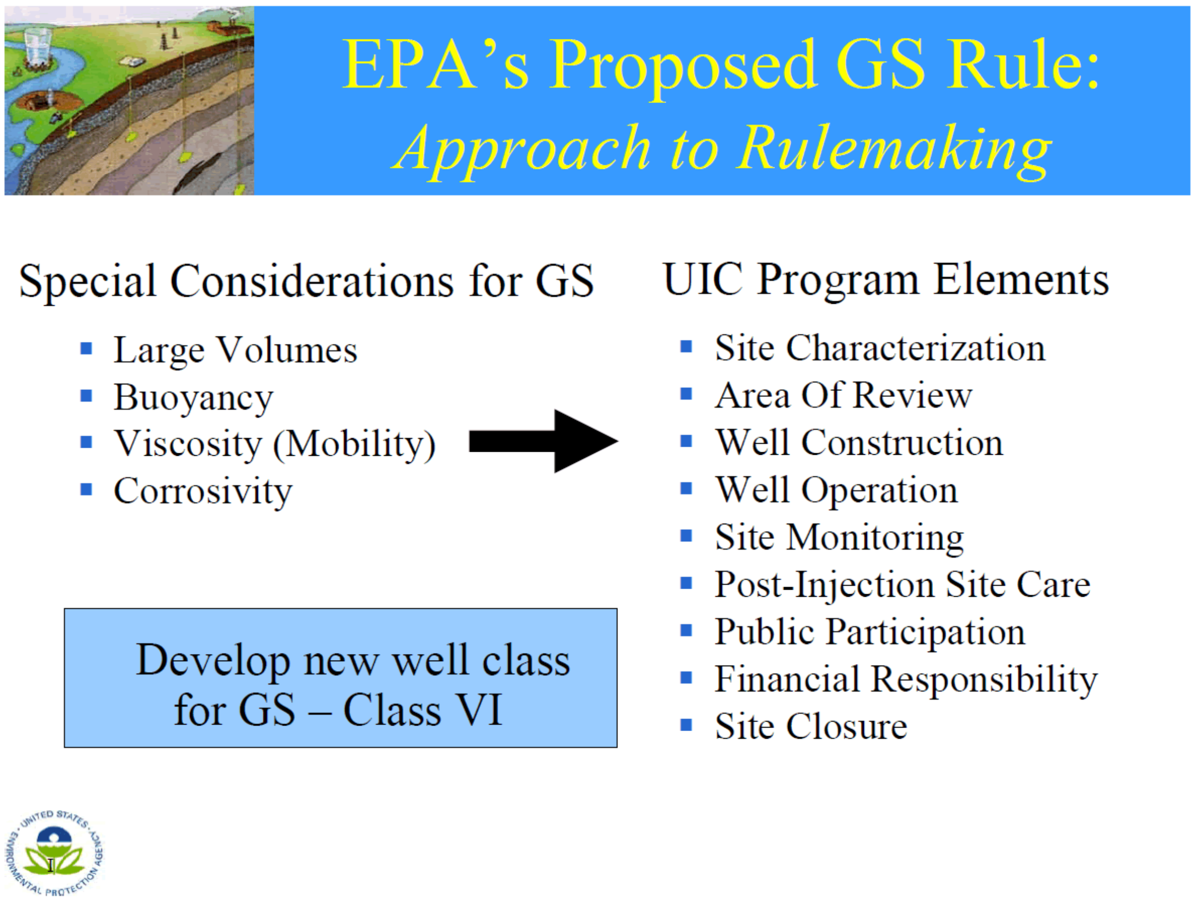

Figure 77. EPA's development of the Class VI Rule was based on many of the components of existing UIC well classes. These included a long list of requirements that have proven effective in protecting the nation's USDWs. In light of CO_2's unique characteristics, these components were modified as necessary and new ones added. (Source: EPA, undated-a)

and stakeholder workshops (Fig. 78). These meetings were designed to gather information about current and on-going GCS research, to involve a variety of technical stakeholders in the rulemaking process, and to inform EPA staff on issues pertinent to Class VI rulemaking. Just prior to the publication of the proposed Class VI Rule, EPA held two stakeholder workshops. Information gathered during these meetings was used to assist in the creation of the draft Class VI Rule, which was published in the Federal Register on July 25, 2008. After publication of the proposed rule, two public hearings were held to gather feedback from the general public on the proposed well class. In addition, a public comment period on the rule was open from July 24 through November 24, 2008. As part of the rulemaking process, EPA reviewed all public comments submitted and issued a Notice of Data Availability and Request for Comment on August 31, 2009. The final rule was signed by EPA Administrator Lisa Jackson on November 22, 2010, and published in the Federal Register on December 10, 2010 (Fig. 78).

Technical Workshops: The use of injection wells to sequester large volumes of CO_2 underground for very long periods of time represents a new purpose for injection wells. Although it would rely on technologies proven in the oil and gas industry for over 50 years, it was a marriage of these technologies for a new purpose on a much larger scale. Thus, in writing the GCS rule, EPA reached out to industry, national laboratories, other federal and state agencies, and academia for knowledge about the research being conducted on geologic carbon sequestration. This collaboration was evidenced

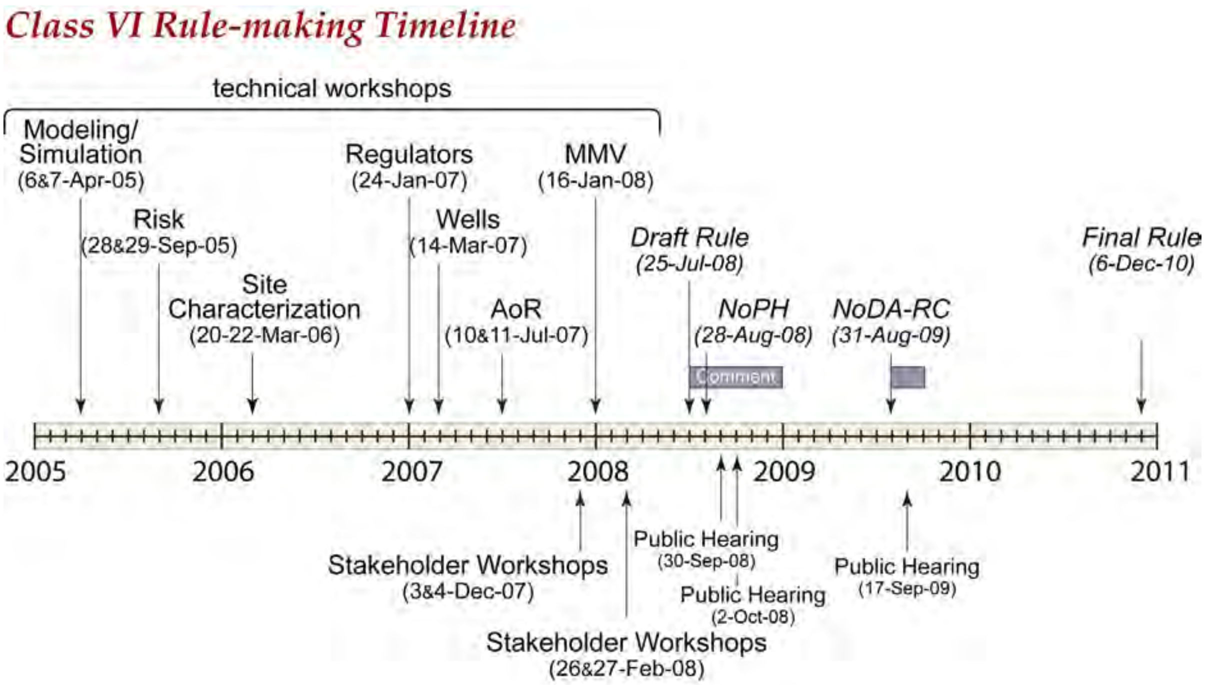

Figure 78. A timeline of the Class VI rule-making process showing the major events. Development of the Class VI regulation took nearly five years and involved input from a wide variety of stakeholders including other federal agencies, state and local government agencies, industry, and academia. Input from the general public was also solicited and addressed in the final rule. Abbreviations: NoPH – Notice of Public Hearing, NoDA-RC – Notice of Data Availability and Request for Comment.

by a series of seven technical workshops that were held from 2005 through 2008. The first of these workshops met on April 6–7, 2005 in Houston, Texas to discuss modeling and reservoir simulation for geologic carbon sequestration. The workshop brought together 60 experts in this field. The group concluded that reservoir simulation was important for selecting and characterizing sites; predicting CO_2 subsurface movement; envisaging potential reactions between injectate, reservoir rock and formation fluids; and verifying long-term contaminant and leakage risk (EPA, undated-a).

A workshop on risk assessment for GCS was held September 28–29, 2005 in Portland, Oregon. The purpose of the workshop "…was to discuss the development of a risk assessment framework using participant expertise to identify potential risks and consider relevant field experience that could be applicable to underground injection and long-term storage of CO_2" (EPA, undated-b). Discussion at the workshop focused on abandoned wells, faults, and groundwater displacement. Site characterization was the topic of the International Symposium on Site Characterization for CO_2 Geological Storage in Berkeley, California, March 20–22, 2006. This workshop considered a wide range of GCS related issues and involved participants from a number of international organizations. The fourth technical workshop was held in San Antonio, Texas on January 24, 2007. This meeting was in collaboration with DOE's National Energy Technology Laboratory (NETL) and the Ground Water Protection Council (GWPC). It covered a wide range of topics, e.g., AoR, site characterization, modeling, etc., formulated questions about GCS relevant to the Class VI Rule, and identified needed areas of research. Wells were the topic of a workshop held March 14, 2007 in Albuquerque, New Mexico. The 51 participants focused mainly on wellbore integrity and its impact on site risk. Washington, D.C. was the site of the Geological Considerations and Area of Review Studies workshop July 10–11, 2007. This workshop had 71 participants representing numerous organizations and focused primarily on how to define the AoR. The final technical workshop occurred January 16, 2008 in New Orleans, Louisiana and was co-sponsored by the GWPC. The meeting focused on monitoring, measurement, and verification (MMV) and consisted of approximately 100 participants from organizations as diverse as the Interstate Oil and Gas Compact Commission (IOGCC), oil field service companies, and consulting firms.

Stakeholder Workshops: EPA held two stakeholder workshops focused on the evolving regulatory approach to geologic sequestration and storage of CO_2 under the UIC program. One meeting was held December 3–4, 2007 in Washington, D.C. The other stakeholder workshop was held in Arlington, Virginia on February 26–27, 2008. These meetings allowed EPA to share its GCS rulemaking process with a variety of stakeholders and get feedback on the evolving rule. These meetings were attended by over 200 participants each.

Public Input: After the publication of the draft Class VI Rule on July 25, 2008, EPA published a notice of public hearing in the Federal Register on August 28, 2008 (Fig. 78). One public hearing was held in Chicago, Illinois on September 30, 2008 with the other in Denver, Colorado on October 2, 2008. In addition, EPA conducted a 150 day written public comment period from July 25, 2008 (the date the proposed rule was published) through December 24, 2008. During this period, EPA received 385 public submissions of which 151 contained unique comments. As a result of these comments and continuing GCS research, EPA published a Notice of Data Availability and Request for Comment (NoDA-RC) on August 31, 2009. The notice described important developments in GCS research that had occurred since the draft rule had been published. In particular, the notice reviewed regional DOE CO_2 injection field tests and computer modeling results from Lawrence Livermore National Laboratory. The NoDA described the impact of each of these developments on the proposed rule. The announcement also requested comments on a possible change in the injection depth requirement in the original proposed rule. Specifically, EPA was considering adding a waiver procedure to the rule that would allow injection of CO_2 into and between USDWs based on feedback from various states. Comments on NoDA and RC requested and accepted until October 15, 2009 and a public hearing about the notice and comments was held in Chicago, Illinois on September 17, 2009.

Class VI guidance documents

With the final publication of the Class VI Rule, EPA is currently developing a series of guidance documents to support the permitting process for Class VI wells. These documents are geared toward UIC program directors, and owners and operators of Class VI wells. The documents go through a review process before they are finalized. Thus, documents for different stages of a GCS project are in various phases of development. To date, seven of the guidance documents have been finalized including:

- Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance
- Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance
- Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Construction Guidance
- Geological Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Class VI Program: Financial Responsibility Guidance
- Research and Analysis in Support of UIC Class VI Program: Financial Responsibility Requirements and Guidance
- Geological Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Class VI Well Site Characterization Guidance
- Geological Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Class VI Well Area of Review and Corrective Action Guidance

A second set of guidance documents are closed for public comment and in the final stages of revision. These draft documents are: Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program

Class VI Well Recordkeeping, Reporting and Data Management Guidance for Owners and Operators; and Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Class VI Well Recordkeeping, Reporting and Data Management Guidance for Permitting Authorities. The only guidance document currently open for public comment (as of June, 2013) is Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance (this document has just recently been posted). These documents can be accessed at EPA's Class VI web page (http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm).

Disclaimer

The following sections provide an overview of the details of UIC program's new Class VI well class. It was compiled from examination of the Class VI Rule, the Class VI guidance documents, various EPA publications and factsheets, and a variety of EPA workshop presentations. The resultant information is for educational and informative purposes only and is not intended as legal advice on the responsibilities of Class VI owners or operators. Although every effort has been made to be accurate and precise, the reader should refer to the original rule for specifics about the Class VI well class. In addition, the discussion in this chapter addresses only the federal version of the Class VI well class. States or tribes with primacy over the Class VI well will develop or have developed their own Class VI rules and regulations based on the original federal rule. Thus, the appropriate UIC program within a state should be consulted for specifics of the Class VI Rule within that state.

The Class VI Rule

Overview

EPA's Class VI Rule is described in 40 CFR, Parts 124, 144, 145, 146, and 147 of the Code of Federal Regulations. Its primary elements occur in 40 CFR Part 146 Subpart H, a new section to the UIC code. Some of the new elements of the Class VI Rule include extensive permitting requirements, expanded site characterization, changes to the definition of the area of review (AoR), expansion of the corrective action for artificial penetrations, new injection well construction requirements, specification of a new suite of pre-injection activities (e.g., logging and sampling), constraints on injection well operation, heightened emphasis on mechanical integrity, expansion of testing and monitoring requirements, increased financial responsibilities, new reporting and recordkeeping obligations, a detailed injection well plugging process, addition of post-injection site care (PISC) and site closure protocols, and obligation to plan for emergency and remedial responses. The new rule is part of what EPA calls adaptive rulemaking. Thus, the Class VI Rule will be evaluated and modified every six years to incorporate new research, data, and experience. States with Class VI primacy can modify their rule as well.

A major change of the Class VI Rule compared to other well classes is associated with the duration of the project permit. Instead of being for a fixed time period with the need to reapply periodically for a new permit, a Class VI permit is issued for the lifetime of the project. To ensure proper injection operation and ensure USDWs are not endangered, a Class VI well permit application requires the submission of five site-specific project plans. The five plans are an Area of Review and Corrective Action Plan, a Testing and Monitoring Plan, an Injection Well Plugging Plan, a Post-Injection Site Care and Site Closure Plan, and an Emergency and Remedial Response Plan. These plans are site-specific, inter-related, and guide project operation and management over a long period of time. Thus based on site-specific information acquired during site characterization and operation, they must be developed and reviewed as a package (see Plan Preparation section later in this chapter). These plans are reviewed by the UIC Program Director to ensure that they will not endanger any USDW in the AoR. If approved, these plans become part of the well permit [40 CFR 146.84(b)].

To ensure that plans incorporate the latest site information and still protect USDWs, three of these plans are continually reviewed throughout the project lifetime in light of new site, operational, and monitoring data. In particular, the AoR defined in the original Area of Review and Corrective Action Plan must be reviewed at least every five years and sooner if specific conditions warrant it. Because they are defined based on the AoR, changes in this plan will require a review and, if necessary, modification of the AoR and Corrective Action Plan; Testing and Monitoring Plan; and the Emergency and Remedial Response Plan. Any changes to these plans must be reviewed and approved by the UIC Program Director. The rule does not require review of the Injection Well Plugging and PISC and Site Closure Plan, but EPA suggests in their guidance documents that periodic review of these plans will leave the owner/operator better prepared for the cessation of injection and site closure.

Class VI wells are authorized by permit, not rule [40 CFR 144.18]. No area permits are allowed for Class VI wells, rather each well must be permitted independently [40 CFR 144.31(a)(4)]. To prepare a Class VI permit application, the owner/operator conducts an extensive site characterization process that gathers geologic information to identify potential risk and eliminate unacceptable sites. Site data provides background for development of well construction plans and operating plans, criteria for delineation of AoR, and geochemical, geophysical, and hydrological baseline data for future site monitoring. The data are used to construct maps and geologic cross-sections of the site that are submitted with the application. On receipt of an application, the UIC Program Director checks the application for consistency and compares it against industry standards and regional information. The director may request additional information. If satisfied the proposed well will not endanger USDWs, the UIC Program Director issues a permit for injection well construction. On completion of the injection well, the owner/operator applies for a permit for injection that incorporates new information learned during construction. This application is reviewed to see if operation should be authorized. Injection can begin only after this permit has been approved. An operational permit last for the lifetime of a facility, but is reviewed every five years to determine if it should be modified, revoked and reissued, or terminated [40 CFR 144.36(a)]. Permits cannot be automatically transferred from permittee to a new owner/operator [40 CFR 144.38(a)].

Compared to other UIC well classes, there are several unique elements to Class VI wells. One of these requirements is a comprehensive geologic site characterization before permit application [40 CFR 156.86(b)(1)]. The rule specifies many aspects of the well's construction and operation. For example, all materials used to construct the well must be compatible with the injectate [40 CFR 146.88(e)(2)] and alarms and surface shut-offs that prevent fluid movement into unintended zones must be installed in onshore wells [40 CFR 146.88(e)(3)]. Offshore injection wells within state territorial waters must also have automatic down-hole alarms. At the UIC Program Director's discretion, down-hole shut-off systems may be required for onshore wells. Periodic re-evaluation of area of review that incorporates new monitoring and operational data is required to verify CO_2 is moving as predicted. This review must occur every five years at a minimum [40 CFR 146.84(e)]. The expanded testing and monitoring requirements mandate periodic testing of the mechanical integrity of the injection well [40 CFR 146.89] and groundwater [40 CFR 146.90(d)]. It also requires direct and indirect tracking of the injected CO_2 plume and associated pressure front [40 CFR 146.90(g)]. The rule clarifies and expands financial responsibilities to ensure adequate corrective action, well plugging, PISC, site closure, and emergency and remedial response [40 CFR 146.85]. Extended post-injection monitoring and site care mandates tracking the location of the injected plume and subsurface pressure front until it can be demonstrated that they no longer represent a danger to USDWs [40 CFR 146.93]. By default the rule mandates injection below the lowermost USDW, but it contains a site-specific waiver process that accommodates injection into various formation types while still protecting USDWs [40 CFR 146.95]. A mechanism for transitioning wells from Class II to Class VI defines the point where the well transitions from EOR operations to long-term CO_2 storage [40 CFR 144.19].

Permit Application Process and Elements

Based on regulatory requirements, the operation of a Class VI injection well can be divided into three fundamental stages each with specific regulatory milestones.

- Site permit application: determines if site is suitable for GCS project
- Well operation application: after a well is constructed, this application reviews mechanical integrity tests and formation logging and sampling to determine if operation is warranted
- Operational reviews: periodic reviews to ensure CO_2 injection is proceeding safely and as planned and approved

Obviously, the entire GCS regulatory process starts with the initial permit application. The information about the GCS project solicited in the Class VI well permit [40 CRD 146.82(a)] is designed to assure the UIC Program Director that injection of CO_2 at the proposed sequestration site will not endanger USDWs. The major components of the permit application include general contact information, a site map and geologic cross-sections, a well tabulation, and five project- and site-specific plans (AoR & Corrective Actions, Testing & Monitoring, Well Plugging, PISC and Site Closure, ERR).

Map and Site Characterization: In addition to showing the injection well location and the AoR footprint (Fig. 79), the site map accompanying the permit application must show all artificial penetrations and natural conduits (known or suspected faults and fractures) within the AoR [40 CFR 146.82(a)(2)]. For all injection, producing, abandoned, plugged, and drinking water wells, the map must show number (including the PWSID number), name (e.g., UIC permit well ID number, if previously assigned), and location. Dry holes, deep stratigraphic boreholes, and state or EPA approved subsurface clean-up site wells must also be located on the map. Surface water bodies, springs, mines (surface and subsurface),

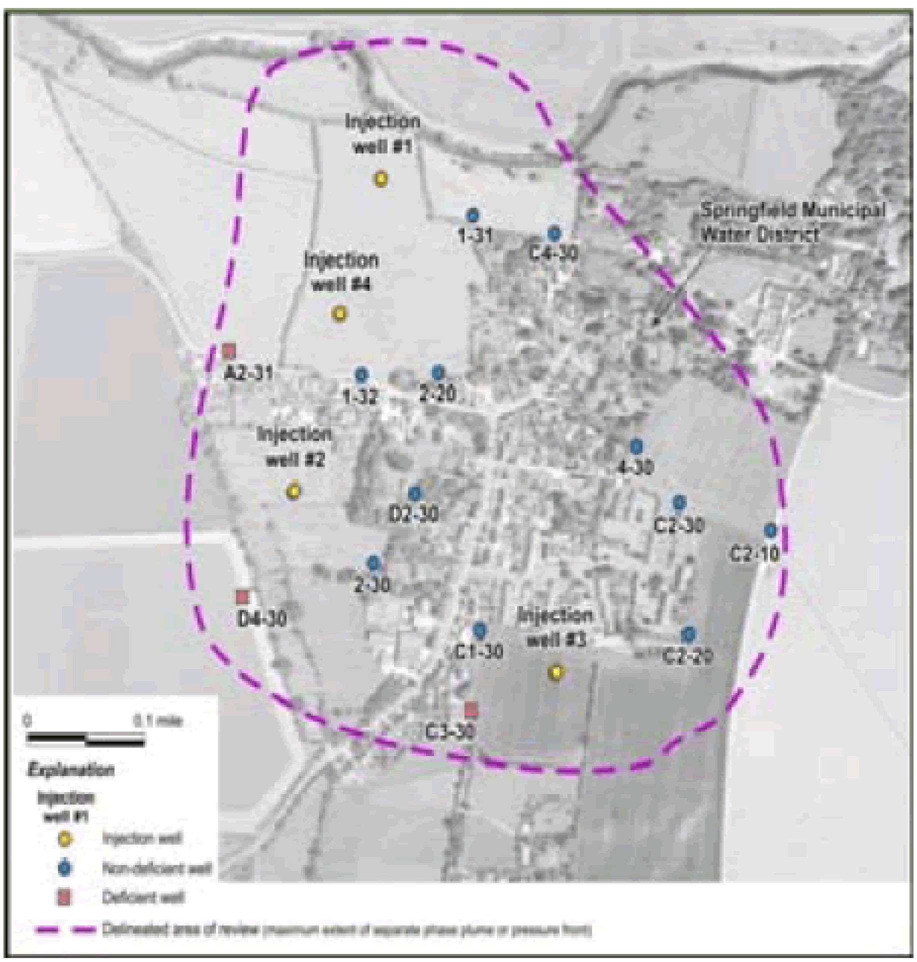

Figure 79. Example of a site map that must accompany a Class VI well permit application. (Source: EPA, undated-a)

and quarries must also be identified. The map must also plot important surface features such as roads, buildings and political boundaries. These data must be assembled from public records during the site characterization phase of the GCS project. Along with the map, the application must contain site characterization data including geologic, geochemical and geomechanical data about the injection and confining zones as well as all USDWs in the area [40 CFR 146.82(a)(3), 146.82(a)(5), 146.82(a)(6)].

Well Tabulation: The permit application must include a table of all wells in the AoR [40 CFR 146.82(a)(4)]. For each well, the table must include well name/number, type, completion date, location, depth, and plugging completion record (Table 4). Although not required, EPA recommends including those wells that will need corrective action in this table as well.

Operational Data: The permit application must also describe, in detail, the proposed operating procedures, formation testing program, and, if planned, the proposed stimulation program [40 CFR 146.82(a)(7)-146.82(a)(10)]. With regards to the injection well itself, a detailed proposed well schematic [40 CFR 146.82(a)(11)] and construction procedures [40 CFR 146.82(a)(12)] must be provided. If an alternative to the default post-injection site care timeframe of 50 years is proposed, details of the alternative PISC timeline must be provided [40 CFR 146.82(a)(14)]. The applicant must also provide documentation of financial responsibility [40 CFR 146.82(a)(18)].

Project Plans: A Class VI permit application must provide five project plans: AoR and Corrective Action [40 CFR 146.82(a)(13)], Testing and Monitoring [40 CFR 146.82(a)(15)], Injection Well Plugging [40 CFR 146.82(a)(16)], PISC and Site Closure [40 CFR 146.82(a)(17)], and Emergency and Remedial Response [40 CFR 146.82(a)(19)]. In the UIC Program, this planning component is unique to Class VI wells. These plans will be reviewed by the UIC Program Director in relation to the site characterization data. Because these plans are interrelated, changes in one could necessitate changes in others. As the project moves through its different stages, these plans must be revisited and revised as dictated by additional site, operational, and monitoring data. Some of these reviews are mandated at specific times, whereas others may be requested by the UIC Program Director. EPA envisions the management of the regulatory responsibilities of a GCS project as an iterative and interactive dialog between owner/operator and UIC Program Director (Fig. 80).

Project Plan Development

Introduction

A critical and unique component of the Class VI well definition is the requirement to prepare five, project- and site-specific plans. These plans are designed to provide the flexibility to cover the wide variety of geologic settings that are anticipated to be targeted for geologic sequestration. At the same time, they provide the framework to protect USDWs. These plans guide the operation and management of a geologic sequestration project

Well	Type	Status	Deficient	Completion date	Total depth (ft)
82-40	gas	producing	no	01 8 95	1,274
82-30	gas	producing	no	08 16 92	1,288
A2-21	brine	active	no	08 3 92	2,013
A2-31	brine	active	no	09 9 92	2,161
A2-41	gas	plugged	yes	09 27 90	3,585
D4-30	gas	plugged	yes	11 29 81	4,175

Table 4. Example of the layout of the well tabulation table that must accompany a Class VI well permit application. A producing well is oil and gas well that is pumping hydrocarbons from the ground. An active well refers to a well disposing of oil field brine by injecting it into a subsurface geologic formation. (Source: EPA, undated)

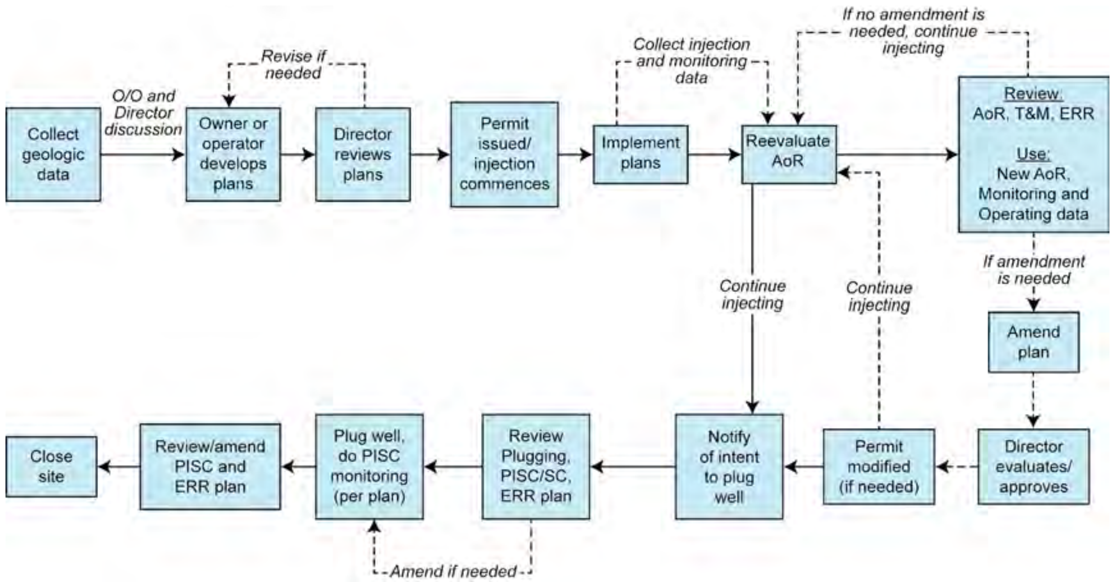

Figure 80. A workflow diagram illustrating the regulatory process associated with a Class VI injection well permit as envisioned by EPA. (Source: EPA, undated-a)

and must be developed and submitted as part of the permit application. When approved, the plans become an enforceable part of the Class VI permit (EPA, 2012b). Using site-specific information acquired during the site characterization, the project owner/operator must develop and submit:

- *Area of Review and Corrective Action Plan*: describes how the AoR will be defined, identifies artificial penetrations in AoR that require corrective action, discusses corrective actions to be taken for remediating deficient wells
- *Testing and Monitoring Plan*: describes how the required testing and monitoring will be conducted
- *Injection Well Plugging*: documents how the injection well will be plugged when injection ceases to prevent USDW endangerment
- *Post-Injection Site Care (PISC) and Site Closure*: describes how the CO_2 plume and associated pressure front will be monitored; explains how a finding of no endangerment, the criteria for site closure, will be documented; describes how he data for such a finding will be acquired, recorded and reported
- *Emergency and Remedial Response Plan*: explains actions to be followed if injectate or formation fluids endanger a USDW

Because Class VI permits are issued for the lifetime of the project and do not undergo periodic reapplication, the mandatory periodic review of these three plans minimize the risk that CO_2 injection will endanger USDWs. When operational, testing, and monitoring data warrant, the plans can be amended with the UIC Program Director's approval. This iterative process is designed to accommodate the unique characteristics of GCS projects and ensure they are managed in a manner than protects USDWs.

The plans are linked and changes in one, or information gathered from the implementation of one, may require changes in other plans (Fig. 81). A fundamental, underlying parameter for all the plans is the Area of Review. The Class VI Rule mandates that the AoR be reviewed, at least every five years [40 CFR 146.84]. Within one year of an AoR review, the Area of Review and Corrective Action, Testing and Monitoring, and Emergency and Remedial Response Plans must also be re-examined. If the present plans are found to be satisfactory, documentation for this finding must be submitted to the UIC Program

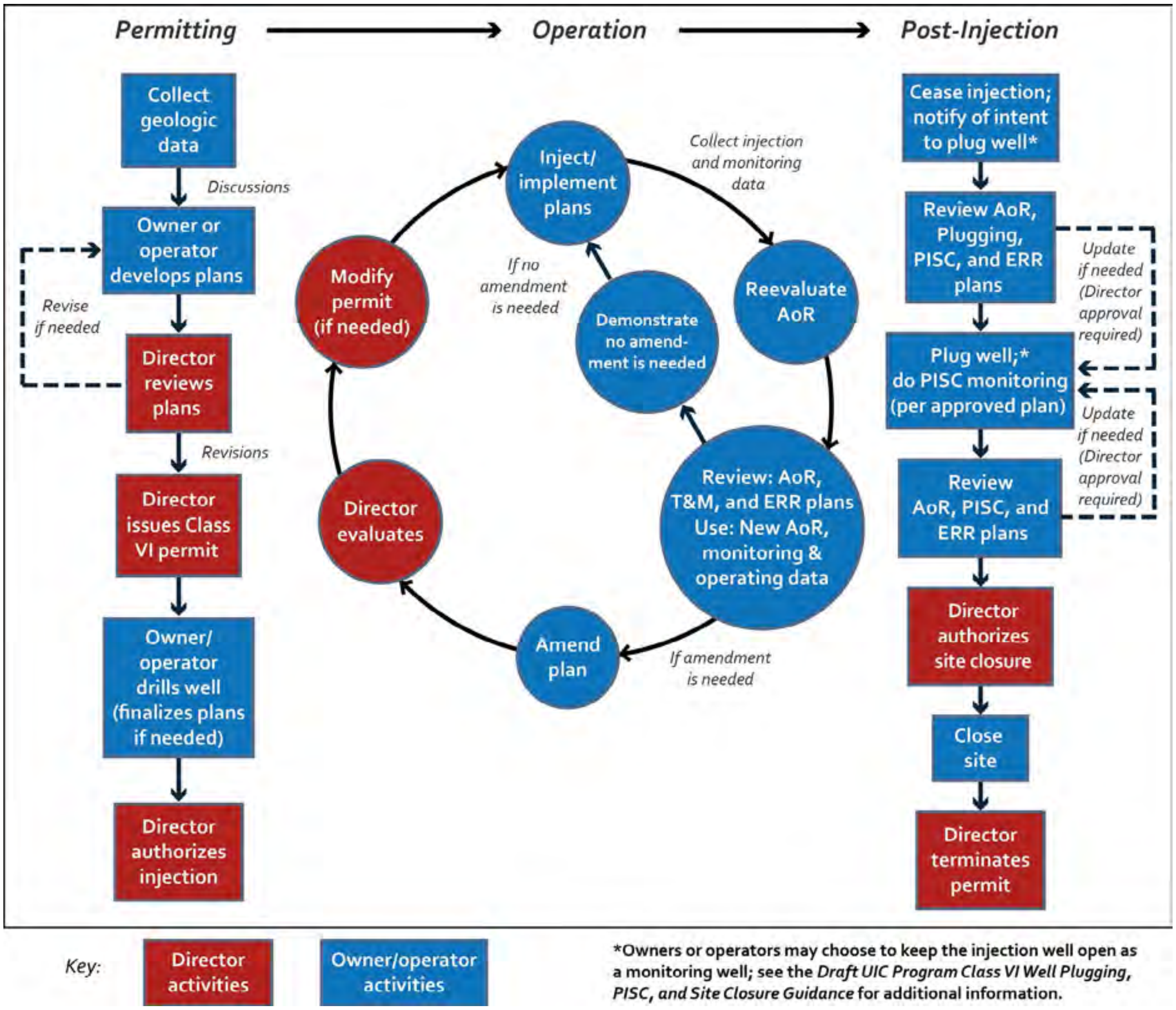

Figure 81. Workflow for developing, approving and amending GCS project plans. This process is continual throughout the entire lifespan of the project, i.e., during the operational phase as well as the post-injection and site care phase. (Source: EPA, 2012b)

Director for approval. Should changes be necessary, the amended plans are submitted to the UIC Program Director for approval. When approved, amendments become part of the permit. Minor changes can be approved by the Director [40 CFR 144.41], but significant changes to any of the plans necessitate a call for public comment [40 CFR Part 124].

Area of Review and Corrective Action Plan

One of the primary goals of the Area of Review and Corrective Action Plan is to predict over time the evolution of the CO_2 plume and the pressure front through computational modeling. The extent of the pressure front/CO_2 plume defines the AoR and is used to identify all artificial penetrations that occur within the plume/front footprint. The plan must describe the computational model in detail. Geologic and geochemical information used in the computational modeling include, but is not limited to: type and number of subsurface formations; formation fluid pressures; groundwater flow direction and rate; presence, location, and nature of faults and fractures; CO_2 stream composition; multi-phase properties; and formation porosity and permeability. Proposed operational data, e.g., injection pressures, rates, and depths, are also used in AoR modeling (EPA, 2012b).

The AoR must be periodically reviewed in light of new operational and monitoring data. The

Area of Review and Corrective Action Plan must specify how often the plan will be reviewed [40 CFR 145.84(b)(2)(i)]. EPA recommends a variety of information be considered when determining the frequency of review. Some of these variables are presence/absence of other injection wells in the region, population growth in the area, frequency and types of land use changes, nature of phased corrective action plan, level of confidence in modeling results, project duration, injection volume and rate, and public acceptance of the project. In addition to setting the interval for periodic AoR review, the plan must identify those types of changes or events that would mandate an earlier review [40 CFR 145.84(b)(2)(ii)]. Unexpected events, changes in operation, a seismic event, exceedance of permit operational limits, or new available site data could trigger an AoR review.

The Class VI Rule requires all improperly plugged artificial penetrations in the AoR be identified in the Area of Review and Corrective Action Plan. To protect USDWs, these wells must be properly plugged with materials that are compatible with the injected CO_2 stream [40 CFR 145.84(d)]. For large AoRs, the rule permits a phased corrective action plan that specifies the schedule for remediating deficient wells [40 CFR 145.84(b)(2(iv)]. By not specifying how corrective actions should be carried out, the rule allows the owner/operator maximum flexibility in responding to site-specific characteristics. The plan does require the corrective action plan detail how the wells will be remediated. Well age, depth, and maintenance, as well as cement condition, CO_2 stream and formation fluid composition, and USDW presence are all factors to be considered when formulating a corrective action plan. Another component of the plan is a schedule of when corrective action will be carried out. On permit approval, the Area of Review and Corrective Action Plan becomes an enforceable component of the permit [40 CFR 146.93(a)].

Testing and Monitoring Plan

A key component for protecting USDWs over the lifetime of the project is the Testing and Monitoring Plan. Information acquired through these activities allows the owner/operator to determine site performance, check the validity of computational results, and provide warning of USDW endangerment. Injectate analysis, operational monitoring, analysis of subsurface geochemistry, mechanical integrity tests, pressure fall-off testing, and plume and pressure front monitoring are all required components of the testing and monitoring program [40 CFR 146.90]. The manner in which these activities are carried out is highly site-specific and must be described in detail in the Testing and Monitoring Plan.

During the project's lifetime, the Class VI Rule requires analysis of the chemical, e.g., impurity types and concentrations, and physical, i.e., pressure and temperature, characteristics of the CO_2 stream [40 CFR 146.90]. Sampling methods, analyte, analytical techniques, and quality assurance methods must all be described in detail. The testing portion of this plan focuses on evaluating the performance of the injection well itself. Continuous recording devices must monitor injection pressure, rate and volume, tubing and long-string annulus pressure, and annulus volume [40 CFR 146.90(b)]. This monitoring helps ensure internal mechanical integrity, which the rule does not require explicitly testing. Because of the potential corrosive nature of CO_2 injection, the well must be continually monitored for potential corrosion damage. Loss of mass, thinning, cracking, and pitting would be evidence of corrosion and must be monitored for on a quarterly basis [40 CFR 146.90(c)]. Such monitoring could be carried out by placing coupons of well materials in contact with the injection stream. Alternatively, a loop of similar material as used to construct the well could be built and periodically checked for corrosion effects (EPA, 2013d). Unlike for internal MI, the Class VI Rule does mandate periodic external MI testing. This testing must be performed annually and must be conducted with specific, approved methods, e.g., oxygen-activation, temperature or noise logs [40 CFR 146.89(c)]. In the event monitoring reveals evidence of corrosion, the UIC Program Director can require a casing inspection log [40 CFR 146.89(d)]. An internal MIT is required after well construction and before injection operations commence [40 CFR 146.82(c)(8)]. Finally, pressure fall-off tests must be conducted at least once every five years unless required more frequently by the UIC Program Director [40 CFR 146.90(f)]. This test allows verification that injection is proceeding as predicted by the computational modeling.

The other major component of the testing and monitoring plan focuses on detecting and tracking subsurface properties that might be impacted by the injection activities. Groundwater quality and geochemistry must be periodically monitored above the confining zone [40 CFR 146.90(d)]. The location, number, and depth of monitoring wells to be installed must be determined by site-specific information and reported in the Testing and Monitoring Plan [40 CFR 146.90(d)(1)]. In addition, the depth, formations tested, and screened intervals for each well must be specified. Proof must be provided that the owner/operator has the rights to drill and sample all planned monitoring wells. A key component of the monitoring plan is tracking the position of the CO_2 plume and pressure front. With this type of information, it is possible to show rate and direction of plume movement and to assess whether it is fully confined. Both indirect and direct methods of monitoring are specified in the Class VI Rule. Direct methods must be used to monitor the plume front and the presence/absence of elevated pressure in the injection zone [40 CFR 146.90(g)(1)]. Unless determined otherwise by the UIC Program Director, indirect methods, e.g., seismic, electrical, gravity, or electromagnetic surveys, must be selected for monitoring purposes based on site geology. The Testing and Monitoring plan must specify direct and indirect monitoring methods that will be used, test frequency, and recording and reporting procedures. It must also prove the owner/operator has guaranteed site access to conduct monitoring. The planning for tracking the plume and pressure front should consider AoR shape and size, site-specific geology, and USDW locations and depths (EPA, 2012b). The owner/operator may want to consider the use of tracers, such as, stable carbon and oxygen isotopes, perfluorocarbon, or radioactive substances, to monitor the plume position. Because such surveys are not appropriate for all GCS sites, they are not a mandatory component of the GCS rule. As with the other plans, the Testing and Monitoring Plan becomes an enforceable component of an approved permit [40 CFR 146.93(a)].

Injection Well Plugging Plan

As with Class I and Class II injection wells, regulations for Class VI wells require development of an injection well plugging plan. Under Class VI, the Injection Well Plugging Plan is one of the five mandatory project plans that must accompany the well permit application. The well must be plugged with materials compatible with the injected CO_2 stream as well as downhole conditions and formation fluids. The Class VI Rule requires measuring bottomhole pressure at the cessation of injection [40 CFR 146.92(b)(1)] and performing an external MIT [40 CFR 146.92(b)(2)]. If the well fails the external MIT, it must be remediated before plugging can occur. The plugging plan must describe the type and number of plugs to be set [40 CFR 146.92(b)(3)]; the position of each plug [40 CFR 146.92(b)(4)]; the type, grade, and quantity of plugging material [40 CFR 146.92(b)(5)]; and the method of plug emplacement, e.g., balance, retainer, or two plug method [40 CFR 146.92(b)(6)]. When designing this plan, the owner/operator should consider the location and thickness of the lowermost injection zone, well construction, subsurface formations intersected, CO_2 stream geochemistry, and formation and fluid compositions. Unlike other project plans, this one does not have to be reviewed periodically during the injection phase of the project. A Notice of Intent to plug the injection well must be submitted to the UIC Program prior to plugging and a plugging report filed after the plugging operation. On approval, the Injection Well Plugging Plan becomes an enforceable component of the permit [40 CFR 146.93(a)].

Post-Injection Site Care (PISC) and Site Closure Plan

After injection ceases, the owner/operator must continue to monitor the GCS site until it can be shown that it no longer poses a risk of endangerment to USDWs. The finding of no endangerment is based on a combination of fixed timeframes and measured parameters that are site specific [40 CFR 146.93]. The PISC and Site Closure plan must outline how a no endangerment finding will be justified and describe how the necessary information will be collected (EPA, 2012b). Some of the elements of the PISC portion of the PISC and Site Closure Plan must report are: 1) difference between pre-injection and predicted post-injection injection zone pressures [40 CFR 146.93(a)(2)(i)]; 2) predicted positions of plume and pressure front at closure [40 CFR 146.93(a)(2)(ii)]; 3) monitoring well locations, methods, and frequency [40 CFR 146.93(a)(2)(iii)]; and a schedule for reporting PISC monitoring results [40 CFR 146.93(d)]. On approval of a well permit, the PISC and Site Closure Plan becomes an enforceable component of the permit [40 CFR 146.93(a)]. At the beginning of the PISC stage, continuity in monitoring procedures with the injection stage is anticipated. As the plume dissipates and the pressure front abates, monitoring will presumably decrease in frequency and coverage.

Once non-endangerment has been documented, the PICS stage ceases and the site can be closed. The Site Closure portion of the PISC and Site Care Plan describes how the owner/operator will close the site. This is likely to include plugging of monitor wells, removal of surface equipment, and restoration of the sites prior condition. The UIC Program Director must be notified at least 120 days prior to site closure [40 CFR 146.93(a)(2)(ii)]

Emergency and Remedial Response (ERR) Plan

Whereas the requirements of the Class VI Rule are designed to prevent endangerment of USDWs, planning must be in place to respond effectively and quickly to an emergency or adverse event. The Emergency and Remedial Response Plan is designed to cover just such circumstances and is required as part of the original permit application. The ERR plan must cover the lifetime of the project including PISC [40 CFR 146.94(a)]. The plan ensures that owner/operators know who and what organizations should be contacted and what actions need to be taken to protect threatened USDWs. Because responses are site-specific, the Class VI Rule does not specify the elements that must be incorporated into the ERR. To develop an effective ERR, the owner/operator must consider resources and infrastructure in the AoR, and potential risk scenarios. Based on these considerations, the ERR should describe the actions that will be taken in response to an emergency or adverse event as well as list the personnel and equipment necessary to carry out such responses. The first component of any response action must be cessation of injection [40 CFR 146.94(b)]. In addition, the release must be identified and characterized as quickly as possible and the UIC Program Director notified within 24 hours of the event [40 CFR 146.94(b)]. The ERR Plan must be periodically reviewed during injection. Specifically, it must be reviewed within one year of any re-evaluation of the AoR. On approval of a Class VI well permit, the ERR Plan becomes an enforceable component of the Class VI permit [40 CFR 146.93(a)].

Site Characterization

Site characterization is designed to identify geologic sites that are appropriate for GCS and eliminate those that are not. For example, sites subject to seismic activity or that may have faults or fractures that may allow CO_2 to escape from the injection zone would not be appropriate for long-term safe storage of CO_2. At the same time, the information collected for site characterization is necessary for the formulation of Class VI well construction and operating plans. The geologic data is input data into the computer models used to define the AoR. An adequate site characterization program also establishes the geochemical, geophysical, and hydrological baselines against which monitoring data collected over the lifetime of the project are compared.

Operators use site characterization to document an injection zone has sufficient areal extent, thickness, porosity, and permeability to receive the anticipated CO_2 stream [40 CFR 146.83(a)(1)]. It also shows that a confining zone of sufficient integrity and areal extent will prevent upward movement of CO_2 or displaced formation fluids. For sites operating under a depth waiver, confinement must also prevent downward motion of these fluids. The site characterization effort must also show that anticipated maximum pressures and fluid volumes will not cause or propagate fractures in the confining zone [40 CFR 146.83(a)(2)].

As part of the well permit application, site characterization must develop geologic and topographic maps of the AoR as well as geologic cross-sections, ideally two at right angles to each other [40 CFR 146.82(a)(3)(i) and (iii)]. The locations and orientations of known or suspected faults and fractures that intersect the confining zone within the AoR must be identified on these maps and geologic cross-sections. Any faults present must be shown to not interfere with containment. The depth and areal extent of confining and injection zones must be shown and their mineralogy, porosity, permeability, and thickness noted. Similarly, the capillary pressure of the two zones must be determined. The owner/operator must submit stratigraphic sections, well and wireline logs, as well as facies analysis, e.g., mineralogy, lithology, grain size, and texture for all core examined. Seismic survey data must also be submitted. Together these data should define a subsurface stratigraphy that demonstrates the injection zone is capable of receiving the injected CO_2 and the confining zone can contain the fluid [40 CFR 146.82(a)(3)(i), 146.82(a)(3)(iii)].

To characterize the tectonic regime, the owner/operator must submit a variety of geomechanical data including fracture locations, stress, ductility, rock strength, and fluid pressures in the confining zone(s). Pore pressures, vertical stress magnitude and orientation, and horizontal maximum and minimum stresses must also be reported. The seismic history of the site must be documented by compiling a history of the seismic events in the region. For each event, the magnitude, epicenter, and focus depth must be tabulated. Additionally, it must be determined if an event caused movement along faults cutting or intersecting the injection or confining zones. Geochemical data must be obtained from the subsurface formations to demonstrate formation-CO_2 compatibility, susceptibility of the wellbore to corrosion and the potential to leach and mobilize contaminants from the injection zone [40 CFR 146.82(a)(3)(iv)-(v), 40 CFR 146.82(a)(6)].

Maps and cross-sections must show drinking water wells and springs in the AoR and their spatial relation to the injection zone. The extents, vertical and lateral, of all USDWs must be clearly identified. Groundwater flow directions, both vertical and horizontal, must, if known, be shown for each USDW [40 CFR 146.82(a)(3)(i).

Site characterization also requires the submission of one mandatory plan and one optional plan. The mandatory plan is for formation testing, which must collect and analyze fluids in the injection and confining zones for chemical and physical characteristics [40 CFR 146.82(a)(8)]. The plan must indicate which formations will be sampled and at what depths. In addition to analyzing fluids, EPA recommends analysis of solids from the two zones for mineralogy, porosity, permeability, capillary pressure, and geomechanical properties. To improve injection, the owner/operator may propose an optional stimulation program, e.g., hydraulic fracturing. If so, plans for such stimulation must accompany the application and must demonstrate that the proposed activity will not compromise the integrity of the sequestration site. Once operational, any additional stimulation must be approved by the UIC director before the program can begin. In AoRs encompassing oil and gas fields, information about prior stimulation programs must be included in the permit application [40 CFR 146.82(a)(9)]. All the information in the permit is public and will be made available for public comment.

Area of Review and Corrective Action

A major component of most UIC well classes is the Area of Review (AoR). The AoR is the area around an injection well where USDWs may be endangered by the leakage of injectate or formation fluid. Historically, AoRs have been defined by either a fixed radius circle centered on the injection well or a simple radial calculation. Within the AoR, the owner/operator must identify and remediate any natural or human-produced conduit that might allow fluid movement into USDWs. Potential human-produced pathways include artificial penetrations, i.e., wells and mines. Any well within the AoR that might endanger a USDW must be assessed for mechanical integrity. If mechanical integrity is absent, corrective action must be performed to restore the well's ability to maintain zonal isolation and protect USDWs from endangerment by leaking injectate or formation fluids. Such corrective action must be accomplished before injection can begin.

For the Class VI well, EPA has substantially modified how the AoR is defined, but left the corrective action requirement unchanged. The increased or enhanced AoR of the Class VI well reflects the unique threat that GCS poses to USDWs. In this new well class, the AoR is an integral component of the Area of Review and Corrective Action Plan, one of the five project plans required for a Class VI permit. The basic requirements of a Class VI AoR and Corrective Action Plan include:

- the design, implementation, and compliance with an Area of Review and Corrective Action Plan [40 CFR 146.84(b)]
- delineation of the AoR using computational modeling and identification of wells that do not have MI and need corrective action [40 CFR 146.84(c)]
- completion of corrective action on all deficient wells located in the AoR [40 CFR 146.84(d)]
- periodic re-evaluation of the AoR during the project lifetime [40 CFR 146.84(e)]
- confirmation that the Area of Review and Corrective Action, Testing and Monitoring and the Emergency and Remedial Response Plans are consistent with the most recently approved AoR [40 CFR 146.84(f)]
- archiving for ten years all computational model inputs and data used during AoR reevaluations [40 CFR 146.84(g)]

Because CO_2 injection is likely to elevate pressures in the Class VI well's injection zone, CO_2 and/or formation fluid are expected to migrate out of the injection zone and potentially endanger USDWs. The region at greatest risk for endangerment is the area overlying the CO_2 plume and the zone of elevated formation pressures, i.e., the AoR.

According to the Class VI Rule, the AoR "…is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring and operational data" [40 CFR 146.84(a)]. At least every five years, the AoR must be reevaluated [40 CFR 146.84(e)]. Corrective actions required by the Class VI Rule are similar to those for other well classes. The only major difference is the possibility, if approved by the UIC Program Director, of implementing corrective action in a phased manner [40 CFR 146.84(b)(2)(iv)].

A major component of the Class VI well permit application is the Area of Review and Corrective Action Plan [40 CFR 145.84(b)]. Such a plan must describe the AoR delineation method; indicate the minimum frequency for AoR review; list the site- and project-specific information that would trigger an earlier AoR review; describe how monitoring and operational data would initiate such a review; identify the artificial penetrations in the AoR, as well as the subset requiring corrective action; describe how corrective action will be accomplished; document how corrective actions will be modified when changes in the AoR occur; and demonstrate site access for future corrective actions. This plan must be approved by the UIC Program Director prior to the submission of the initial AoR and permit issuance. On UIC Program Director approval, the plan becomes an enforceable condition of the permit [40 CFR 146.84(b)].

Computational Modeling

A *computational model* is a mathematical representation of the GCS project that is built from knowledge of site geology and hydrology, the locations of injection wells and artificial penetrations, and fluid flow behavior. The model is customized to a particular site by incorporating data about the site itself and the proposed operational injection plan. This information is encoded in the *computational code*, i.e., the computer code that describes the multiphase fluid flow mathematically. The code calculates the flow of a multiphase fluid, e.g., groundwater and CO_2 with or without hydrocarbons, through a porous media (the rock formations) as a function of time. It also computes the phase changes CO_2 may undergo over time, the movement of heat through the subsurface, and pressure changes [40 CFR 145.84(a)]. Although not required by the rule, some codes also simulate chemical reactions between fluid and rock, i.e., reactive transport, and/or geomechanical processes initiated by fluid flow, which may propagate or activate faults. To be possible, computational models must make simplifying assumptions about geology, fluid behavior, and the spatial variability of rock and mineral properties. These models also often require simplifications in their underlying mathematics. Thus, computational models are only approximations of the actual sequestration site. They are also marked by uncertainty in parameter characterization. Given these limitations, sensitivity analysis and model calibration are critical aspects of computational modeling.

A computational model divides a subsurface volume into a series of adjoining three-dimensional cells (Fig. 82). Each cell represents a block of rock characterized by parameters such as rock type, permeability, porosity, thickness, etc. By specifying this information for each cell in the model, a static, i.e., time independent, model of the subsurface geology is constructed. Static 3D geologic models of this type are routinely used in mineral exploration and extraction. Such a model captures, however, only a portion of the physical and chemical nature of a sequestration site. For sequestration, a computational model must also simulate the flow of fluid through the rock matrix. To produce such a computational model, the static 3D geologic model is merged with a fluid flow model. For sequestration, the fluid consists of more than one phase, i.e., water and CO_2, so it is referred to as multiphase. The resultant computational model is now time-dependent, that is, the fluid flow field varies as a function of time. To simulate the lifetime of a sequestration project, the computational code moves through a series of time steps. At each time point, the model calculates the temperature, pressure, and thermal energy of each cell. At the beginning of the model (time equals zero), the fluid in each cell has an initial temperature, pressure, and density. Because the cells are in contact with each other but not in equilibrium, cells exchange energy, momentum, and mass. This exchange is described by a series of equations describing the conservation of these three quantities. At each time interval, a new temperature and pressure is calculated for each cell in the model.

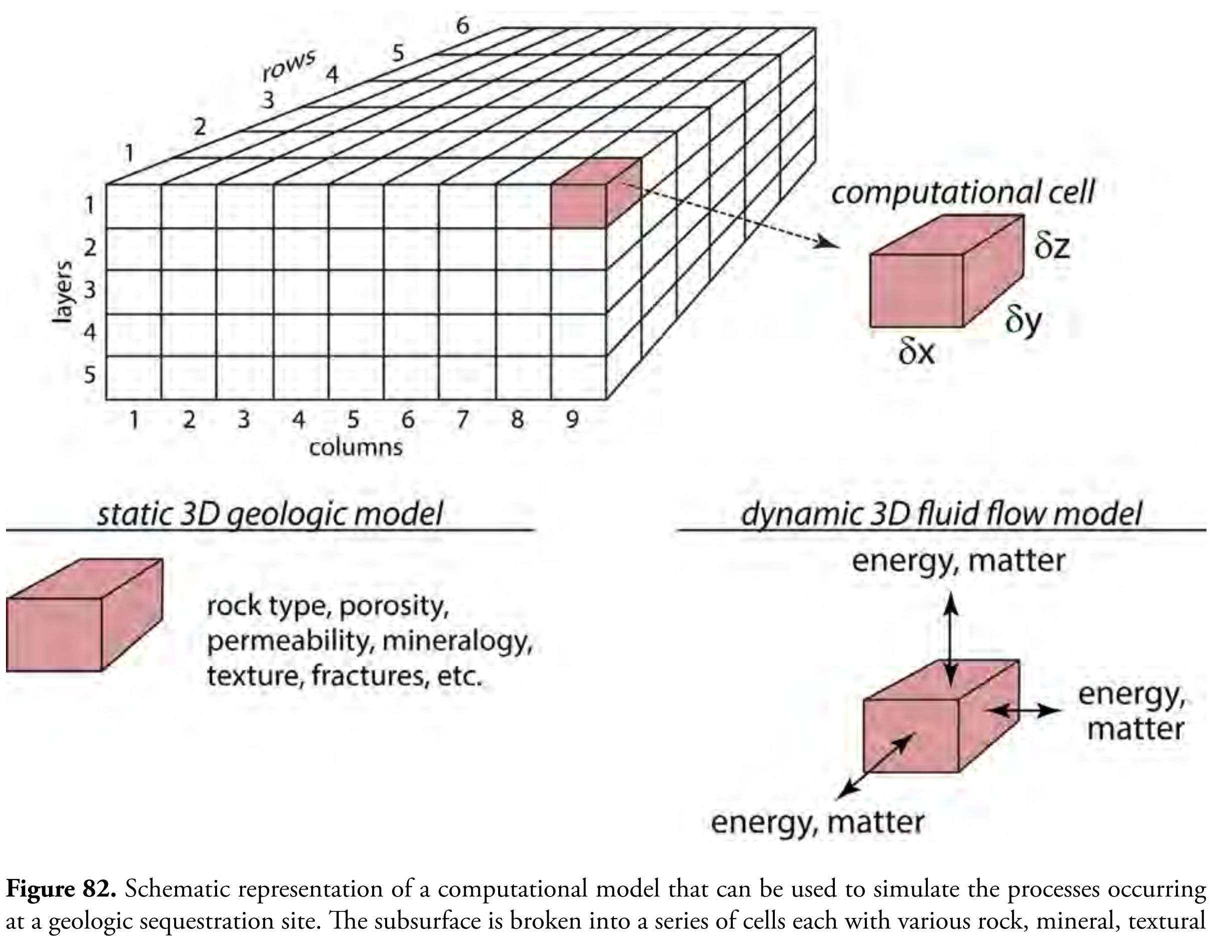

Figure 82. Schematic representation of a computational model that can be used to simulate the processes occurring at a geologic sequestration site. The subsurface is broken into a series of cells each with various rock, mineral, textural and structural attributes. For homogenous units, the numerical values for these parameters would be the same, whereas they will vary from cell to cell for heterogeneous geologic formations.

By feeding the resultant temperature and pressure combinations into a second set of equations, i.e., *equations of state*, the physical and chemical state of the fluid in each cell is computed.

Computational modeling is critically dependent on the numerical values chosen for the various model parameters. A *parameter* is a variable in the mathematical equations and computer code. It approximates the physical properties of the real world. For example, the porosity and permeability of the rock comprising a cell or the temperature and pressure of a cell are all parameters. Parameters at the beginning of the modeling reflect the initial conditions at the start of the simulation. Hence, they are called *initial conditions*. *Boundary condition*s reflect the value of parameters at the boundaries of the model. For a sequestration site, these correspond to the edges of the block of crust being modeled and at the locations of the injection well and/or extraction well. Site characterization provides the information necessary to determine the appropriate numerical values for the model parameters. Whenever possible, parameter values are assigned based on actual, measured data. When site data are unavailable, data from similar geologic environments or known physical relationships are used. EPA (2013d) divides the parameters important in GCS modeling into five categories (hydrogeologic properties, fluid properties, chemical properties, fluid injection and withdrawal rates, and system orientation and simulation controls). It also lists 27 separate model parameters that are important for site modeling.

Delineating the Area of Review (AoR)

The AoR of a GCS project is defined using two calculated parameters: the lateral extent of the CO_2 plume and the pressure front. Both of these must be calculated using a computational model that simulates the sequestration site. AoR delineation is an interactive process that depends on site characterization, model development, and during later stages of the project, monitoring and operational data. The computational model used to define the AoR as well as the preliminary AoR itself must be submitted with the original well permit application as part of the Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13)]. On completion of site characterization, injection well construction, and pre-injection testing, a finalized AoR must be submitted with the application for a permit to inject [40 CFR 146.82(c)(1)]. Thus, AoR delineation is an iterative process. As knowledge of the site grows through operational experience, the AoR must be periodically reviewed, by rule at least every five years [40 CFR 146.82(a)(13)].

Requirements: The AoR, the region around the GCS project where USDWs might be endangered, must be based on computational modeling that encompasses all physical and chemical properties of all injected CO_2 phases [40 CFR 146.84(a)]. Based on computational modeling using site, operational, and monitoring data, the lateral and vertical movement of the CO_2 plume and formation fluids must be predicted. This modeling must extend temporally from the start of injection until one of three conditions are met: 1) the CO_2 plume ceases to move, 2) injection zone fluid pressure has fallen to values that can no longer drive formation fluid into USDWs, or 3) at the end of a fixed time period (set by the UIC Program Director) [40 CFR 146.82(c)(1)]. The timeframes defined by these conditions cover hundreds to thousands of years. To accurately prediction injection, the computational model of the site must include geologic heterogeneities and possible migration pathways such as faults, fractures, and artificial penetrations. It must characterize the confining and injection zones geologically and account for projected operational conditions, e.g., injection rates and pressures and total injected volume.

Data Acquisition: The Class VI Rule requires the operator to collect a variety of data about the site [40 CFR 146.82 and 146.83]. These data are designed to show that the site is a good candidate for sequestration. In particular, the data must show that the injectivity of the proposed injection zone can accommodate the planned injection rate and pressure. The storage capacity of the zone must be sufficient to accept the cumulative volume of CO_2 that will be injected over the lifetime of the project. The data must also demonstrate the existence of a confining zone that will prevent the upper migration of the CO_2 stream. The data acquisition phase must also assemble baseline geochemical and physical data against which future monitoring results can be compared.

Model Development: There are three stages to developing a site model: conceptual model design, computational model creation, and model parameterization. The conceptual model is a mental sketch of all the major features of the project site. It includes the geologic components of the subsurface, physical and chemical processes occurring in the model domain, the location of USDWs, potential fluid conduits, and model boundary conditions. The conceptual model is generally represented by one or more diagrams (Fig. 83).

To move from the conceptual to the computational model, it is necessary to determine which physical processes will be included in the code. The Class VI Rule only mandates modeling multiphase flow involving CO_2 and formation fluid [40 CFR 146.84(a) and 40 CFR 146.82(c)(1)]. However, site conditions may suggest other processes should be included in the modeling. For example, if the migrating CO_2 interacts with the minerals of the host rock, it could precipitate new mineral phases. Such reactions have, at least, two important consequences for sequestration. First, porosity and permeability may be impacted both negatively and positively depending on whether mineral precipitation or dissolution is the dominant process. Secondly, these mineralogical changes can have important ramifications for long-term CO_2 storage. Increased mineral trapping will provide much greater storage stability than a mobile, buoyant supercritical fluid. Regardless of outcome, inclusion of reactive transport into the computational model in this case would be beneficial to predict the long-term behavior of the sequestration site. In some instances, the computational model should also simulate geomechanical processes.

Pressure front: The *pressure front* is defined as the minimum injection zone pressure that will cause fluid to flow from the injection zone through a hypothetical conduit into a USDW. Regions of

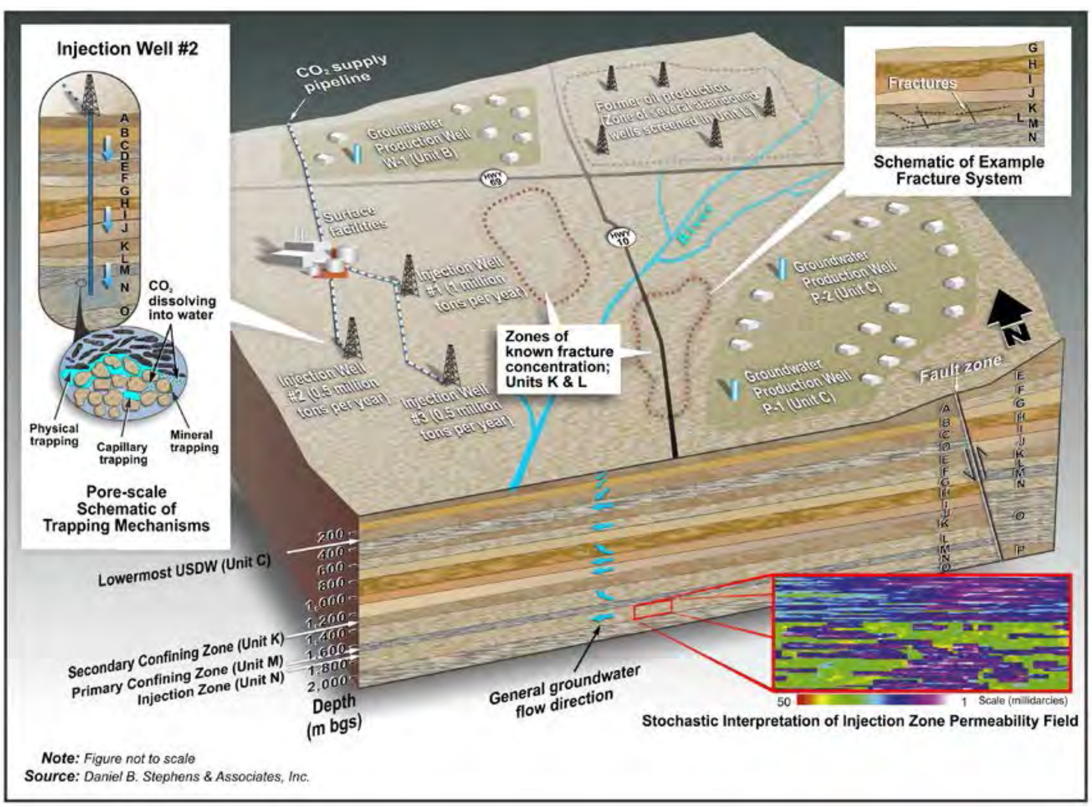

Figure 83. Conceptual model for a hypothetical geologic sequestration site. This stage of model development identifies all of the key components that must be accounted for in the subsequent computational model. (Source: EPA, 2013c)

the injection zone with formation pressures less than the threshold pressure will not endanger USDWs even if a natural or human created pathway exists between the injection zone and the USDW (Bandilla and others, 2012). Conversely in portions of injection zones where fluid pressure is greater than the threshold pressure, fluid in the injection zone can follow any open vertical pathway into the USDW.

For Class VI, as well as Classes I, II, and III, wells, EPA requires delineation of a pressure front to determine the region where care must be taken to identify potential pathways between USDWs and the injection zone. In defining the pressure front, EPA postulates the existence of a hypothetical conduit between the injection zone and lowermost USDW (Fig. 84). The conduit is isolated from all other zones except these two zones, which are perforated. If the fluid pressure in the USDW is greater than that in the injection zone, fluid will be forced out of the formation, up the conduit, and into the USDW. The pressure front is the minimum pressure necessary to move formation fluid into the USDW. Regions in front of the pressure front, i.e., away from the injection well, are under-pressurized relative to the USDW. Injection zone pressures in this region may move brine or injectate out of the formation into, and perhaps up, the conduit, but cannot force it all the way to the USDW (Fig. 84). If the region between the pressure front and the injection well is over-pressurized, that is, the initial injection zone pressure is greater than of the USDW, fluids from the injection zone will be forced up the conduit and into the USDW (Fig. 84). Thus, any potential pathway between the two zones in this region could cause the contamination of the USDW and must be checked to ensure they are not open to fluid flow or, if they are, must be remediated to prevent such flow.

The manner in which the pressure front is calculated differs between over- and under-pressurized regions (EPA, 2013c). Likewise hydrostatic conditions also require a different mathematical approach (Nicot and others, 2009). In all cases, the pressure front is a function of the elevations of the injection zone and USDW above some reference datum, the initial pressure in the USDW, and the density of the fluid in the injection zone. For under-pressurized injection zones, the pressure front ($P_{i.f}$) is given by:

$$P_{i,f} = P_u + \rho g \left(e_u - e_i \right) \tag{7}$$

where P_u is the initial pressure in the USDW, e_u is the USDW elevation, e_i is the injection zone elevation, r_i is the density of injection zone fluid, and g is acceleration due to gravity (EPA, 2013c). From Eq. 7, the critical pressure increase in the injection zone that will not cause fluid to invade the USDW is:

$$\Delta P_{i,f} = P_u + \rho g \left(e_u - e_i \right) - P_i \tag{8}$$

where P_i is the initial pressure in the injection zone. With this expression, a quantitative criterion can be placed on injection zone pressurization (Fig. 84). An injection zone that has a pressure less than the USDW, i.e., it is under-pressurized, has $\Delta P_{i,f}$ of less than zero, whereas over-pressurized injection zones have positive values. To accurately calculate $\Delta P_{i,f}$, EPA (2013c) recommends measurements of P_i, P_u, and r_i in the injection zone. Given the variables that determine the pressure front threshold are likely to vary spatially, $P_{i,f}$ is also likely to vary over the injection site.

In a region with a hydrostatic pressure gradient, the density of any fluid in the borehole will vary with depth. Thus, fluid entering the borehole from the injection zone will be more dense than fluid in the borehole. For small amounts of leakage, this will displace some fluid in the borehole into the USDW. However, below a certain pressure increase, fluid displaced from the injection zone will only move higher up in the borehole, not into the USDW. According to Nicot and others (2009), this critical pressure increase for hydrostatic conditions and a linear borehole fluid density increase is:

$$\Delta P_c = \frac{1}{2} f \frac{\left(\rho_i - \rho_u \right)}{\left(e_u - e_i \right)} \left(e_u - e_i \right)^2 \tag{9}$$

Similarly, $P_{i,f}$ for a region with hydrostatic pressure gradient, the pressure front threshold can be calculated from:

$$P_{i,f} = P_u + \frac{1}{2} f \frac{\left(\rho_i - \rho_u \right)}{\left(e_u - e_i \right)} \left(e_u - e_i \right)^2 \tag{10}$$

where the terms are as defined earlier (Nicot and others, 2009). In regions where actual site conditions

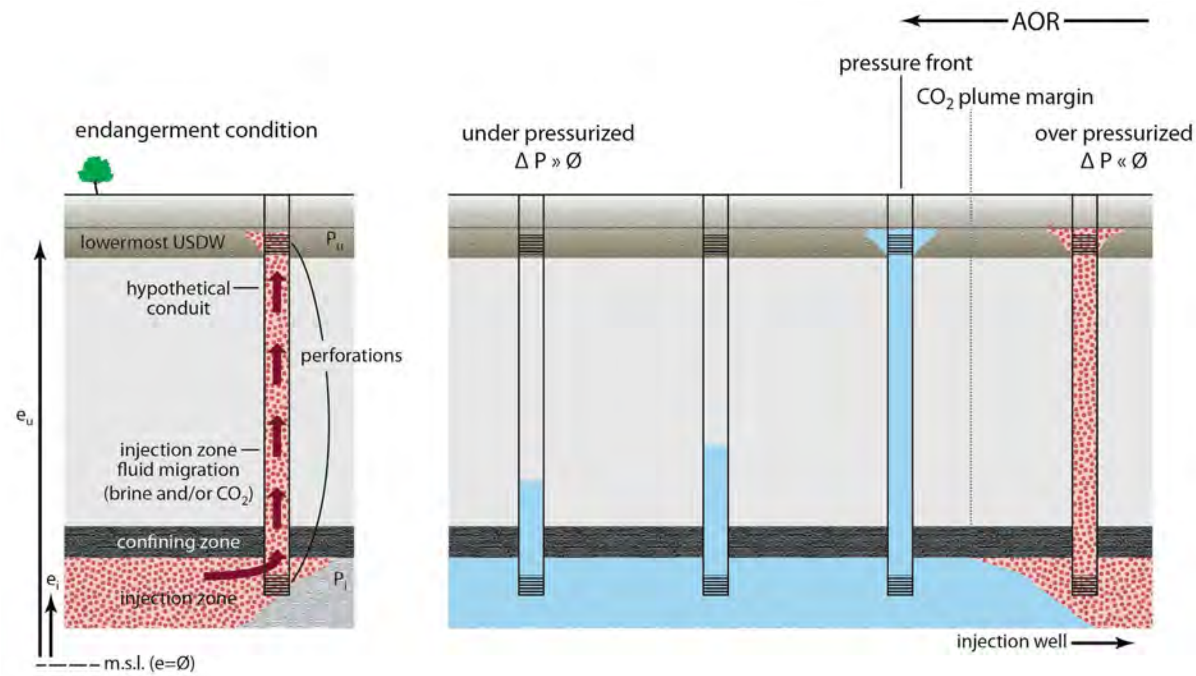

Figure 84. Schematic illustration of the pressure front concept. Left: The pressure front is the injection zone pressure necessary to force liquid from the injection zone up a hypothetical conduit into the lowermost USDW. Right: In front of the pressure front, injection zone pressure can move formation fluids into and up the conduit, but not to the height necessary to reach the USDW. This region is under-pressurized. In contrast, behind the pressure front, the injection zone is over-pressurized relative to the USDW. That is, the pressure in the injection zone is sufficient to drive formation fluid up the conduit and into the USDW against the latter's hydraulic head. Depending on the groundwater hydrology and geologic stratigraphy, the pressure front may be outside or inside the AoR.

are not available during initial site characterization, an assumption of hydrostatic conditions is probably useful for initial AoR characterization.

In regions of over-pressurization, injection zone fluid will flow into the USDW through the hypothetical borehole even if there is no CO_2 injection. Thus, such zones must have very competent cap rocks to prevent contamination of USDWs. Determining the pressure front threshold in these situations will require more complex mathematical formulations than for under- or over-pressurized zones (EPA Region 5, 2008; Birkholzer and others, 2011).

AoR Boundaries: Once the computational model of the injection site is developed, calibrated, and tested, the final delineation of the AoR involves a four step process. The first step is to define the critical pressure at which fluid would flow from the injection zone through a hypothetical conduit into the lowermost USDW (Fig. 85).

Step 2 in the AoR delineation process is to run the computational model for injection over the lifetime of the project. From these results, contour maps of the pressure at various time steps are constructed. Using the minimum pressure calculated in Step 1, the contour corresponding to this value is determined and highlighted on the various pressure maps (Fig. 86). This contour represents the maximum extent of the pressure front at the contoured time interval. To determine the maximum AoR for the project, EPA recommends using the time interval with the maximum lateral pressure front extent.

For Step 3, the computational model calculates the position of the edge of the CO_2 plume at different times throughout the lifetime of the project. The edge of the plume is contoured by year and plotted on a map of the project site (Fig. 87). The plume boundary with the maximum areal extend is selected for use in the final AoR delineation.

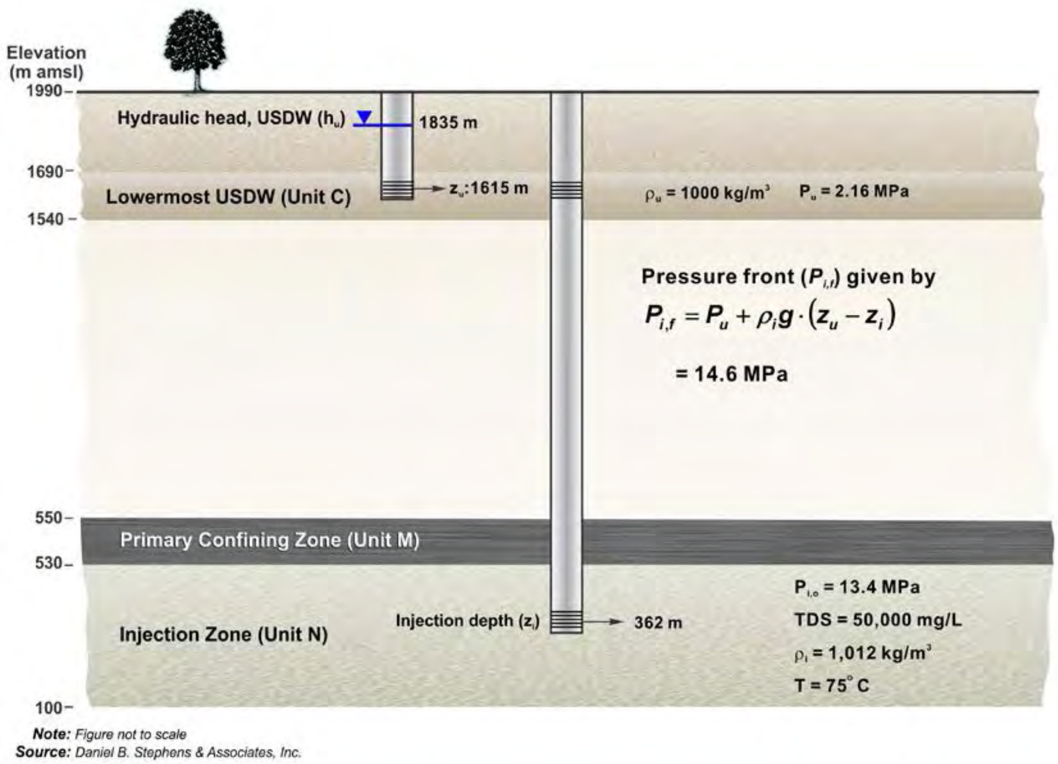

Figure 85. Calculation of the minimum injection zone pressure for a hypothetical sequestration site that will move fluid from the injection zone through a hypothetical borehole to the lowermost USDW, i.e., endangerment of the USDW. (Source: EPA, 2013c)

The fourth and final step in defining a project's AoR is to superimpose the largest pressure front contour and the CO_2 plume boundary on a map of the project site. The AoR is drawn using the two curves (Fig. 88). Perhaps surprisingly, the margin of the CO_2 plume is not always inside the pressure front edge (Bandilla and others, 2012). This situation arises because the pressure front tracks the minimum pressure necessary to force fluid from the injection zone to the lowermost USDW. It is not tracking the region of formation pressure build-up or fluid displacement.

AoR Reporting: The original well permit application must have an AoR and Corrective Action Plan with a tentative AoR based on current site and operational knowledge [40 CFR 146.82(a)(13)]. On completion of injection well construction and testing, a finalized AoR must be submitted prior to being granted a permit to inject [40 CFR 146.82(c)(1)]. In support of the permit request, the permit application must include a conceptual model of the site (Fig. 83) along with a description of the region's geologic stratigraphy and other supporting data. The code used to generate the computational model must be fully described, e.g., code name, scientific basics, assumptions, developer, etc. An accounting of the model's lateral and vertical dimensions as well as information on grid size and formation thicknesses are also necessary. This information should be presented using maps and geologic cross-sections. The equations of state used to model fluid, (CO_2 and formation fluid) behavior must be included. The manner in which the model was parameterized must also be described. This discussion should include a description of how site characterization informed model parameter assignment, initial and boundary conditions used, as well as a tabulation of all model parameters. If these parameters vary over time during modeling, they must be shown as a function of time. Contour maps showing the movement of the CO_2 plume and pressure front throughout the lifetime of the project must be included. The procedure for calculating the

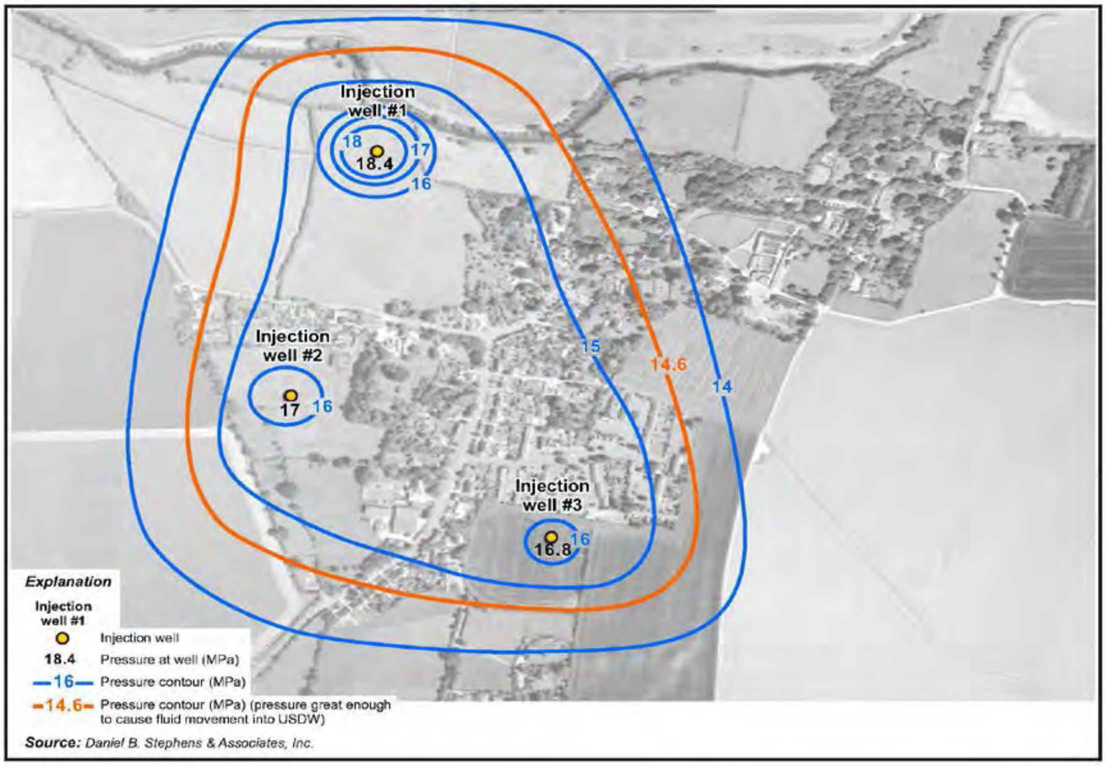

Figure 86. Formation fluid pressure contour maps are used, in conjunction with the minimum pressure, to define the lateral extent of the pressure front. EPA recommends choosing the time period in the project lifetime for AoR delineation. (Source: EPA, 2013c)

minimum pressure for the pressure front must be described as well as the AoR delineation process.

Artificial Penetrations and Corrective Action

The AoR is defined to provide a means of identifying any geologic or artificial penetration, e.g., wells or mines, which may permit the flow of fluid out of the injection zone and endanger USDWs. For all Class VI wells, an Area of Review and Corrective Action Plan must be prepared, maintained, and implemented [40 CFR 146.84(b)(2)(iv)]. The plan must describe any corrective actions that will be performed on deficient wells in the AoR. In particular, the Class VI Rule requires the plan to:

- identify all artificial penetrations (active and abandoned wells, mines) in the AoR [40 CFR 146.84(c)(2]. For each well, the well type, construction, date drilled, location, depth, and record of plugging and/or completion must be reported. At his/her discretion, the UIC Program Director may require additional information
- determine those abandoned wells that have been improperly plugged and may endanger USDWs [40 CFR 146.84(c)(3)]
- describe corrective actions to be performed on those wells that may endanger USDWs [40 CFR 146.84(c)(d]
- revise periodically the Area of Review and Corrective Action Plan whenever the AoR is re-evaluated [40 CFR 146.84(e)(4]
- identify all wells in a revised AoR that may require corrective action [40 CFR 146.84(e)(3]

Identifying Artificial Penetrations: Depending on when they were drilled and abandoned, wells may be difficult to find. The first step in finding these wells is to search historical records. For oil and gas industry, wells are typically permitted by a state agency that keeps detailed records of the well, e.g., when it was drilled, how it was constructed, the procedures used to abandon it, etc. Most of these records are

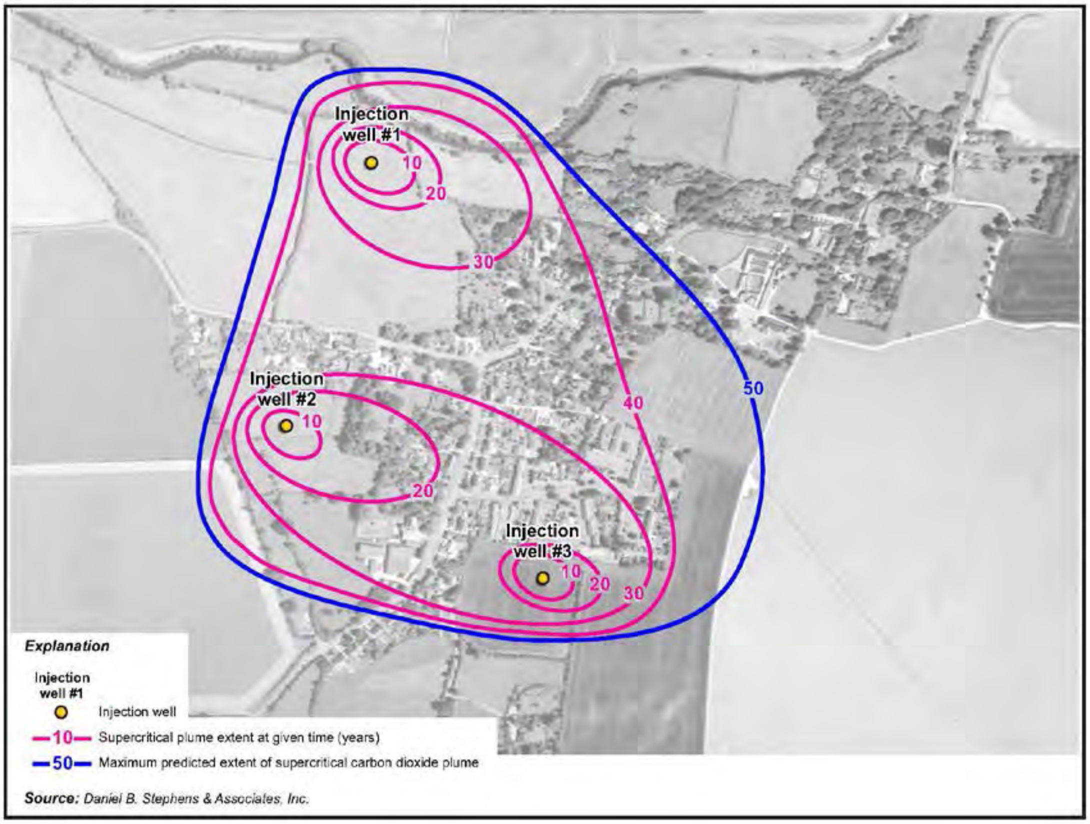

Figure 87. Boundaries of the CO_2 plume at different times during the lifetime of a hypothetical sequestration project. This project consists of three Class VI wells injecting into the same injection zone. Their respective CO_2 plumes merge 50 years after injection commenced. The boundary with the largest spatial extent (the 50 year contour in this case) is selected to aid in defining the project AoR. (Source: EPA, 2013c)

publicly available and maintained in accessible, online electronic databases. Oil and gas wells are of primary interest when permitting a Class VI well site, because they are generally the deepest and most likely to penetrate a confining zone. Very old wells may not be in a state's electronic database, but can be often found in archived paper records. Conversely, the oldest wells may have been drilled before permitting and are unlikely to have records. Historical record search should be followed up by site reconnaissance. These can be conducted by examining current aerial and satellite imagery of the proposed injection site. When present, surface features, such as well pads, brine or mud pits, access roads, etc., can be used to identify locations of abandoned wells. Historic aerial photographs may also be useful in identifying historic oil and gas drilling operations.

Geophysical field surveys are another means of locating abandoned wells. Most of these methods use a signal generated by the presence of iron or steel casing to locate wells. Unfortunately, a large number of casings were removed for recycling during World War II (Gochioco and Ruev, 2006) and may not be visible to these geophysical surveys. Magnetic, electromagnetic, and ground penetrating radar (GPR) can all be used to find abandoned wells. These methods can identify wells when all surface expressions are gone. They are also useful for finding wells for which no documentation exists. Best results are likely to be achieved by running at least two of these surveys, because they rely on complimentary information to locate wells.

Magnetic surveys are a standard, established means of finding abandoned wells (Fig. 89). These surveys measure components of the Earth's magnetic field. Because abandoned wells may

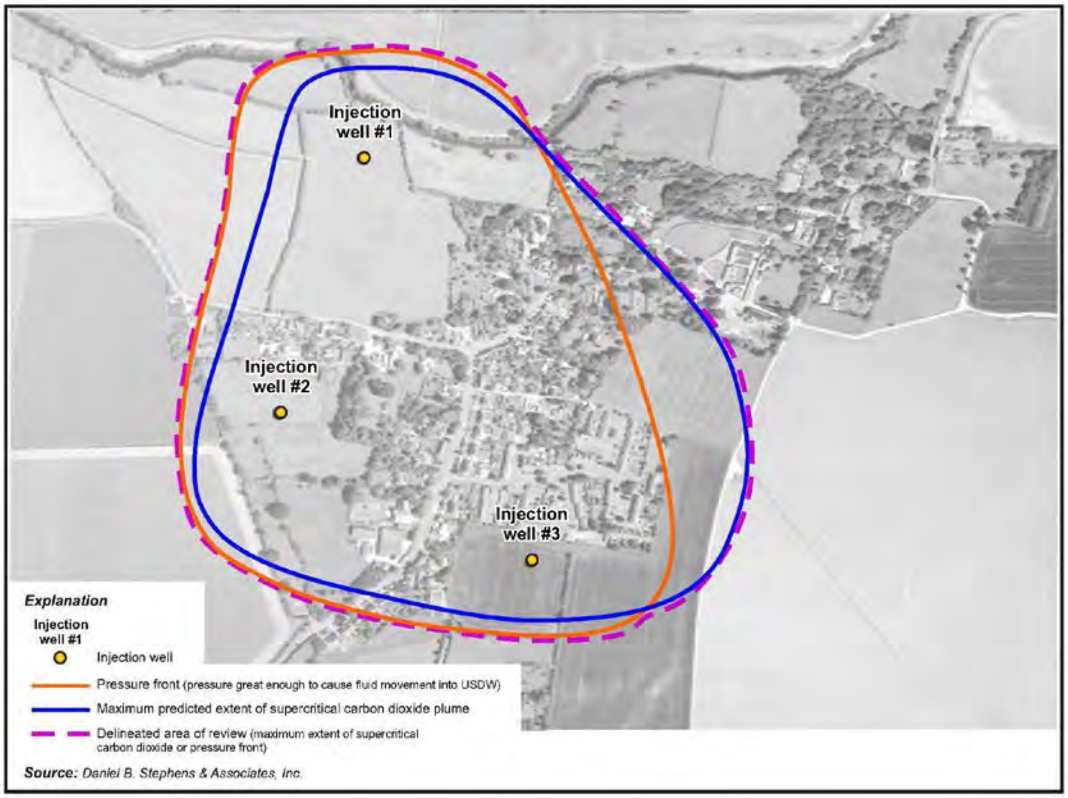

Figure 88. Determination of the AoR for a hypothetical sequestration project. The AoR is drawn using both the maximum critical pressure contour and the CO_2 plume margin. (Source: EPA, 2013c)

have steel or iron casing that are magnetic, they can cause anomalies in the background magnetic field. Magnetic surveys can be conducted from the air or on the ground. Aerial surveys are likely to discover wells with 200 feet (61 meters) or more of 8 inch (20 centimeters) casing (Frischknecht and others, 1983; Frischknecht and others, 1985). However, open holes, wells with severely corroded casing, or wells that were cased with plastic casing will not be detected by this type of survey. Well positions will be marked by positive magnetic anomalies superimposed on the background magnetic field (Fig. 89). Electromagnetic surveys are conducted using a transmitter that produces an electromagnetic field. Based on its greater conductivity than soils, well casing impacted by electromagnetic field may experience an induced electrical current. This current will, in turn, generate a secondary electromagnetic field that can be detected by various receivers. Frequency-domain surveys detect this field directly. In contrast, time-domain surveys measure the decay of the secondary electromagnetic field (EPA, 2013c).

Ground penetrating radar (GPR) may be able to detect open boreholes, wells with casing removed, and wells cased with non-metallic material. The depth of penetration depends on radio wave frequency and ground conductivity (EPA, 2013c). Given the small size of casing, GPR is limited to depths of only a few meters (Jordan and Hare, 2002). GPR investigations are also much slower than other types of geophysical surveys. Consequently, EPA (2013d) recommends using GPR to investigate smaller areas at greater resolution within a larger area originally surveyed using one of the larger scale survey techniques.

Abandoned Well Assessment: Each identified abandoned well in the AoR must be evaluated to ensure that it will not allow the migration of fluids into USDWs [40 CFR 146.84(c)(3)]. This means that the well must have been plugged properly with cement plugs across the confining

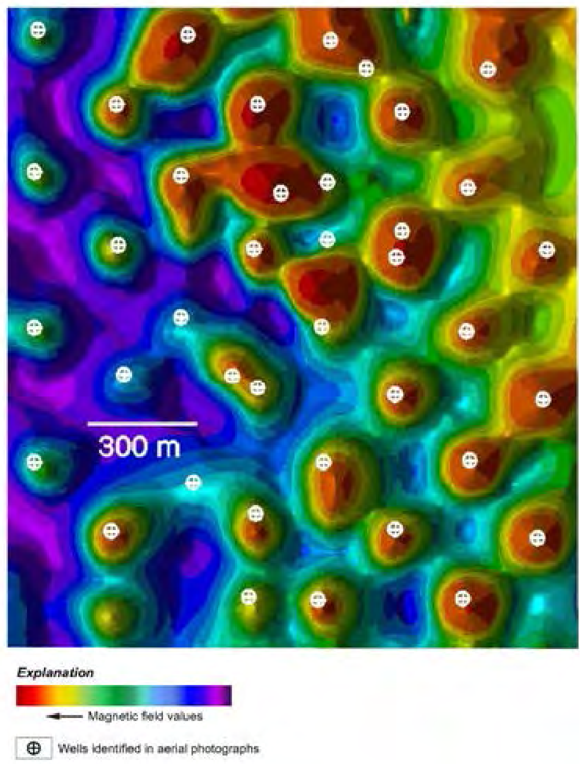

Figure 89. Magnetic survey of the Cook Creek Oil Field, Arcadia, Oklahoma. The white crosses represent wells identified by examination of aerial photos, whereas the high magnetic anomalies mark the position of detected casing. Magnetic surveys will only locate wells with iron or steel casing that is in good condition, of sufficient length and diameter, and not badly corroded. (Source: USGS, 1995).

zone and/or the injection/confining zone contact. A surface plug is also important (Fig. 90). Any plugs set must also be compatible with exposure to CO_2. Assessing the integrity of abandoned wells involves reviewing historic records on well construction and abandonment, and for wells without records or with integrity concerns, conducting field tests to evaluate the mechanical integrity of the well.

Historic records in public databases are an excellent source of information on how a well was drilled, completed, and ultimately abandoned. They will also provide a record of the nature of the construction materials used and any problems encountered. Some key pieces of information about a well that can be gleaned from historical records include:

- well depth and completion: indicates if the well penetrated the confining zone (if not, no further action is necessary)
- well abandonment date: identifies the regulatory scheme under which the well was plugged and abandoned
- open or cased hole: indicates how susceptible a well is to invasion by formation fluids or loss of wellbore fluids
- plug location: suggests the level of zonal isolation achieved during plugging; the plugs must still be evaluated to determine the quality of plugging [40 CFR 146.84(c)(3)]
- MIT records: assists in determining the mechanical integrity of existing casing [40 CFR 146.84(c)(3)]
- well orientation: vertical wells are of less leakage risk that deviated wells (Watson and Bachu, 2008)

Since casing failure is most likely to occur at joints, across weak formations, or where casing has been damaged or stressed during setting and cementing, well construction reports can provide valuable information about the potential state of casing and where along the wellbore weaknesses may exist. Examination of mud and open-hole caliper logs can provide information about the locations of weak formations. MITs can reveal if leaks were detected in the wellbore and how, and if, they were repaired. Logs (cement evaluation, temperature) run at completion can give an indication of the initial quality of primary cementing. Subsequently, the potential for casing corrosion can be evaluated by reviewing caliper, electromagnetic thickness and downhole video log reports of cased wells.

If an abandoned well's historic record cannot show adequate zonal isolation through proper plug placement, it must be evaluated physically to determine the quality and positions of its plugs [40 CFR 146.84(c)(3)]. Alternatively with UIC Program Director approval, an owner/operator may choose to replug a well without physically evaluating it. When the integrity of a well's plugs and/or casing is in doubt EPA (2013c) recommends drilling out the existing plugs and testing the well itself. If corrective action on deficient wells is to be carried out in phases, the

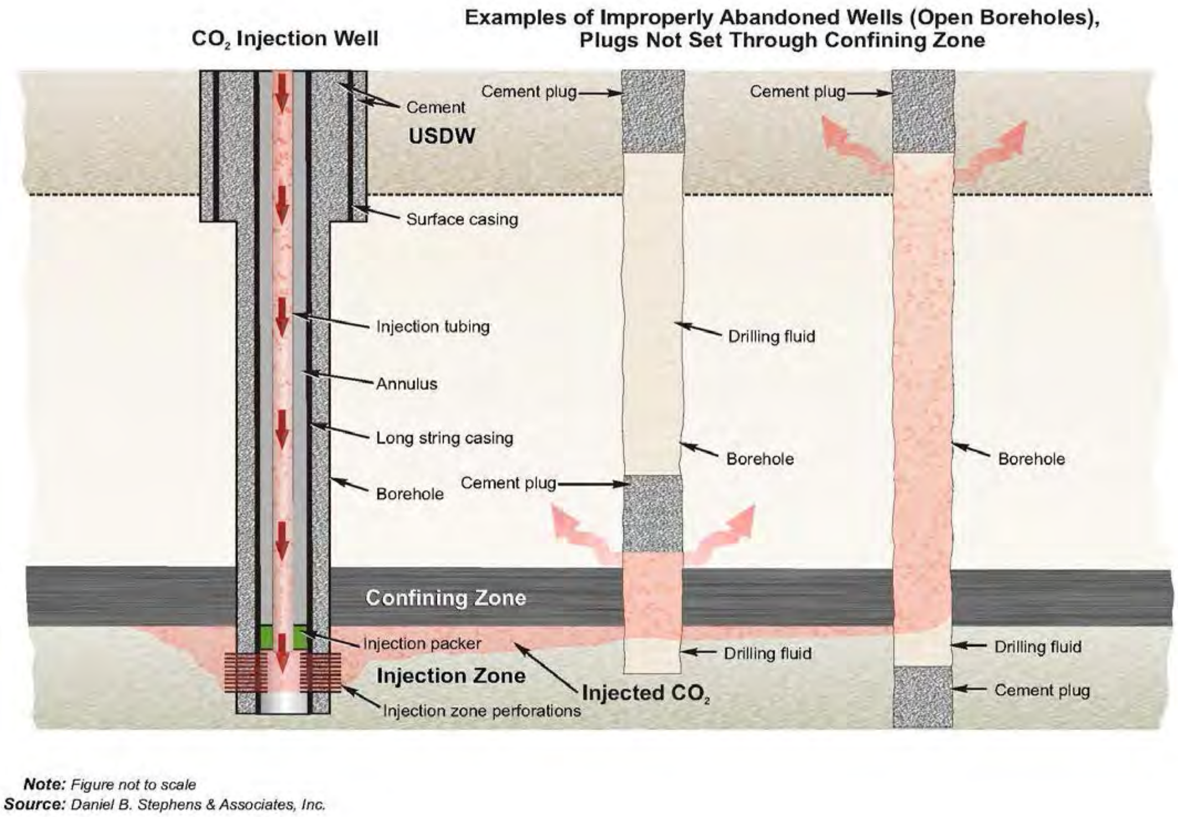

Figure 90. Impacts of improperly plugged and abandoned wells on USDW endangerment. Improper plugging of these two abandoned wells have endangered the USDW overlying the injection zone by permitting vertical migration of the buoyant CO_2 out of the injection zone. (Source: EPA, 2013c)

owner/operator must demonstrate that site access has been granted for such future activities [40 CFR 146.84(b)(iv)].

When evaluating a well, EPA (2013d) recommends investigating both cement plugs and casing. A wide variety of techniques are available to evaluating the condition of a well (Table 5). These tests vary from simple and non-destructive to complex and destructive (see Chapter 6 for a discussion of the various logging methods). By running the tests from simplest and least costly to more complex and costly, deficiencies identified early in the testing sequence will alleviate the need for more complex tests. The typical sequence for testing might be caliper, sonic and ultrasonic, cased hole leak tests, and sidewall coring.

Corrective Action: The Class VI Rule requires corrective action on all abandoned wells that penetrate the confining zone and that lack adequate plugging to prevent fluid migration into USDWs [40 CFR 146.84(d)]. The purpose of corrective action is to ensure that the wellbore will not allow injected fluids to migrate out of the injection zone and potentially to USDWs. Whether or not a well needs corrective action can be objectively assessed by following a decision tree (Fig. 91). The primary mechanisms of corrective action are cement plugging and/or remedial cementing. EPA (2013d) also recommends increased monitoring in the areas around remediated wellbores.

There are a number of circumstances that will require the setting of new plugs under the Class VI Rule. These include: absence of evidence for plugging, lack of a plug across the primary confining zone, plugs that show evidence of cracking, channeling, and annuli formation, or plugs that have been corroded due to contact with corrosive fluids. In addition, EPA recommends replacing plugs that have records suggesting they were constructed of materials not compatible with

Tool	Target	Advantages	Disadvantages
multifinger caliper	casing	non-destructive, relatively simple	only examines interior, only detects casing damage
sonic logs	cement	non-destructive, yields information on cement bond	results averaged over well circumference, can't indicate reasons for poor quality bond
ultrasonic logs	casing, cement	non-destructive, can detect flaws in casing and cement, provides three dimensional images	sensitive to well fluids
cement evaluation log	cement	non-destructive, yields information on quality of cement bond	results averaged over well circumference
tracers	leak detection	can pinpoint routes of leaks, channeling	radioactive tracers require specialhanding and may have negative public perception
dynamic cased hole tester	cement	can determine porosity of cement	semi-destructive, untested in low porosity conditions
sidewall coring	cement	can give detailed analysis of cement condition	destructive

Table 5. Methods for field testing the integrity of zonal isolation in an abandoned well. (Source: EPA, 2013c)

CO_2. Locations for positioning new plugs include across the confining zone, at the base of any casing string, across USDWs, and at the surface.

Another zone of potential fluid migration in abandoned wells is at the contact between cement and geologic formations. If deficiencies exist in this bond, the placement of cement plugs within the casing will not remediate this problem. Where tests indicate a poor cement-formation bonding, e.g., the existence of annuli cracks or channels, a remedial cement job should be performed. The primary locations along the borehole for remedial cementing include the injection zone and any permeable zone the wellbore encountered. Remedial cementing can be performed using packers, cement retainers, or bradenhead squeezes (packer set only below depth of cement job). The type of cement to use will depend on the nature of the repair and must be compatible with contact with CO_2 [40 CFR 146.84(d)].

Reporting: When submitting the Area of Review and Corrective Action Plan with the well permit application, the manner in which wells are identified and how they will be assessed for zonal isolation must be fully described [40 CFR 146.84(b)(2)(iv)]. On approval by the UIC Program Director, this plan becomes part of the permit [40 CFR 146.84(b)]. Owner/operators are required to describe all wells that may penetrate the confining zone. For each well, well type, construction, date drilled, location, depth, and well completion or plugging record must be reported [40 CFR 146.84(a)(4)]. Reports from all field tests of potentially deficient wells must also be included in the application. A list of wells for which corrective action will be performed must accompany the application [40 CFR 146.84(b)]. Prior to the issuance of a permit to inject, a report detailing the corrective actions taken must be submitted [40 CFR 146.84(c)(6)]. For each well, the number, type, and location of plugs placed must be documented. Remedial cementing activities should also be reported.

AoR Re-evaluation

The Class VI Rule requires a re-evaluation of the AoR, at least, every five years [40 CFR 146.84(e)] or sooner if conditions warrant. Re-evaluation tests the computational model by comparing predicted positions of the CO_2 plume edge and pressure front with those determined by monitoring. If the comparison of the two datasets necessitates a revision of the AoR, the Area of Review and Corrective Action Plan as well as other project plans must also be reviewed. This process of re-evaluation continues throughout the injection and PISC phases of the project.

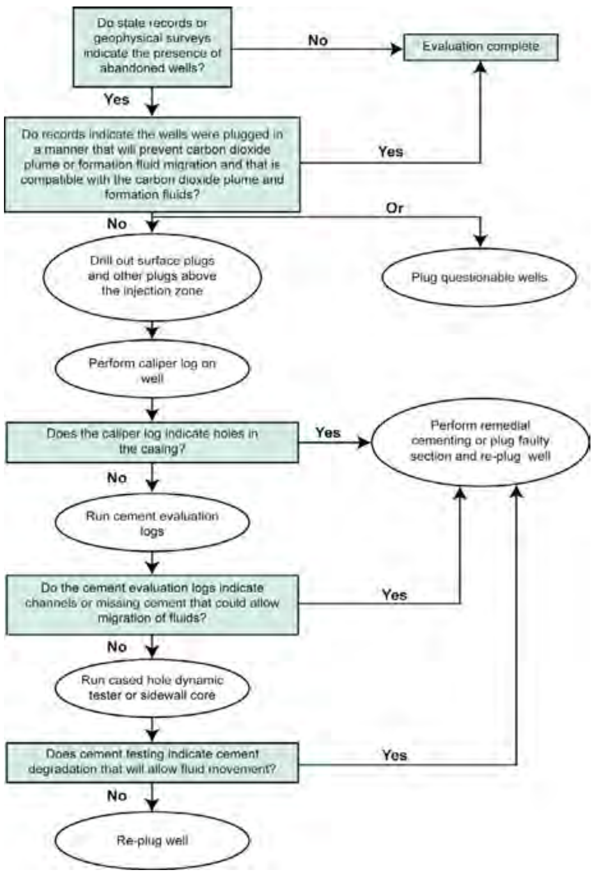

Figure 91. Decision tree flowchart for deciding whether or not an abandoned well in the AoR that penetrates the confining zone will require corrective action. (Source: EPA, 2013c)

During a re-evaluation, the owner operator must identify all the wells in the new AoR that require corrective action [40 CFR 146.84(c)(1)], perform any required corrective action [40 CFR 146.84(d)], and submit an amended AoR and CA Plan. Major changes in site operation, divergence of modeling predictions and monitoring results, and new site characterization data are all conditions that might mandate an early AoR review. The AoR and CA Plan must include the threshold operational changes and model prediction-monitoring result differences that will automatically trigger an AoR review [40 CFR 146.84(b)(2)(ii)].

The initial step in an AoR re-evaluation is to compare predicted to actual plume and pressure front location (Fig. 92). If the two agree, the AoR need not be revised and the results are submitted to the UIC Program Director for approval. An adjustment of the AoR will necessitate revising the site conceptual model, model calibrations, and presentation of the adjustments and new AoR to the UIC Program Director.

Revisions will require amendments to the AoR and Corrective Action Plan and possibly other project plans [40 CFR 146.84(e)(4) and (f)]. The newly defined AoR must be presented on maps in the AoR and Corrective Plan amendment (Fig. 93).

Testing and Monitoring

Overview

A GCS project poses various levels of risk to USDWs at different stages throughout a project's lifetime (Fig. 94). To ensure safe and long-term storage of CO_2 and that USDWs are not endangered, the Class VI Rule mandates a rigorous program of testing and monitoring throughout all stages of a project's lifetime [40 CFR 146.90]. The data collected under these programs are used to evaluate site performance and compare observed behavior to that predicted by computational modeling. For example, monitoring data can show when plume behavior is unlike that predicted by modeling. The testing and monitoring program for the site is described in one of the five plans that must be submitted with the original GCS application. The testing and monitoring program for a Class VI well is based on those for other UIC injection well classes, but is more comprehensive. It covers the project's injection phase as well as PISC (Fig. 94) The plan must incorporate the unique geologic and physical characteristics of the site to identify the most appropriate tests.

Testing and Monitoring Plan

The Class VI Rule specifies specific information that must be compiled by the testing and monitoring program. These include characterizing the chemical nature of the injected CO_2 stream, continuous recording of operational data, monitoring of injection well corrosion, periodic groundwater monitoring, annual injection well external MI testing, pressure fall-off testing (every five years at least), and tracking of the injected CO_2 plume and associated pressure front (Fig. 93). At

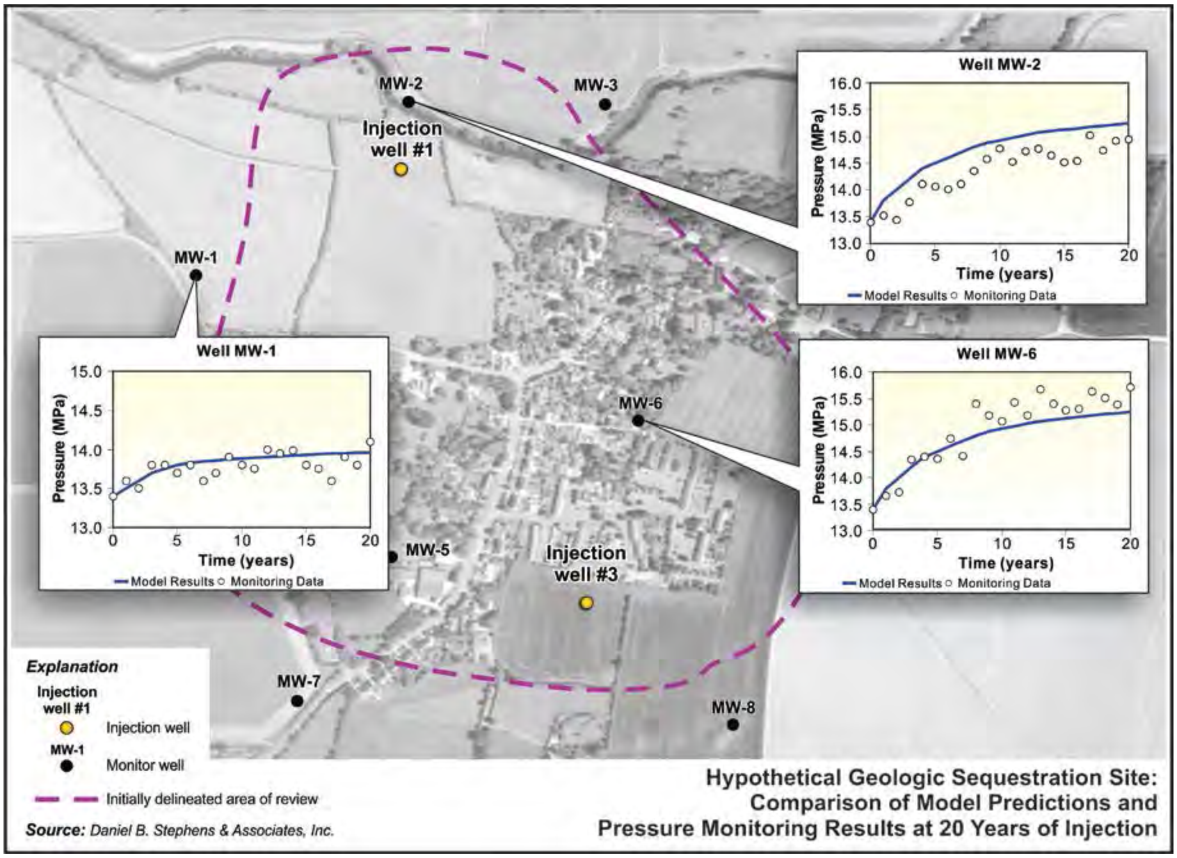

Figure 92. Hypothetical re-evaluation of an AoR. This map compares predicted pressure values to monitoring results for three monitoring wells. The differences for wells MW-2 and MW-6 indicate a revision of the AoR is warranted. (Source: EPA, 2013c)

his/her discretion, the UIC Program Director may also require air and soil gas monitoring as well as additional testing and monitoring. All of these activities must be described in detail in the Testing and Monitoring Plan.

As with the other site plans, the rule requires periodic review of the Testing and Monitoring Plan to ensure its adequacy. These reviews are to be conducted in the context of any AoR re-evaluation that is done and in light of operational and monitoring results. These and other events may trigger the need to conduct a Monitoring and Testing plan review [40 CFR 146.90(j)]. For example, AoR reevaluations that require an adjustment to the sites computational model would likely require a reexamination of the Monitoring and Testing Plan. Likewise departures in the shape or extent of the AoR from those predicted would require a re-evaluation. A rise in metals or organic constituents in analyzed groundwater might suggest the need to increase the frequency of sampling and number of locations at which sampling is conducted.

Mechanical Integrity Testing

EPA specifies that Class VI (as well as other class) wells must maintain mechanical integrity to ensure that accidental injection into unauthorized formations or leakage into USDWs does not occur. The agency mandates two types of integrity tests (Fig. 94). Internal integrity refers to the internal components of the well and ensures there is not leakage in tubing, casing, or packers. Conversely, external integrity specifies the absence of fluid movement in vertical channels adjacent to the wellbore that may result in fluid movement between formations or into USDWs.

There are a number of ways that the mechanical integrity of an injection well can be compromised (Fig. 95). Internal integrity

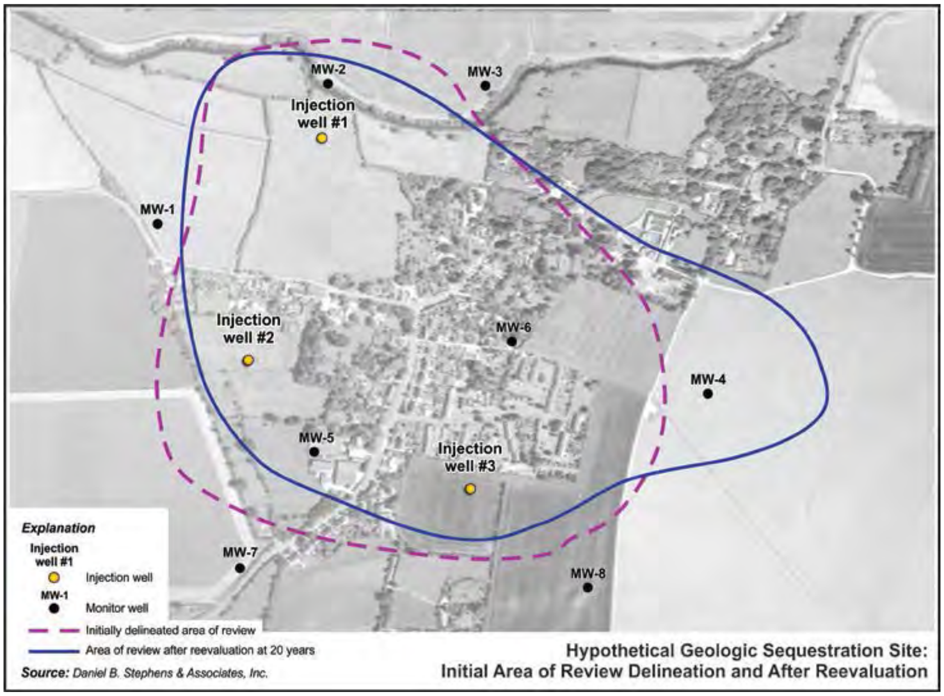

Figure 93. Hypothetical sequestration project demonstrating map comparison of original AoR to revised AoR that would be submitted with an AoR and Corrective Action Plan amendment. (Source: EPA, 2013c)

is lost when injectate from the tubing leaks into the annulus or if corrosion or mechanical failure of the casing permits fluids to leak out of or into the tubing-long string annulus. If the formation pressure is greater than the annulus pressure, formation fluid would enter the annulus, whereas the opposite pressure configuration would result in annulus fluid entering the formation. In either case, the annulus pressure would change, a condition detectable by annulus pressure monitoring. Carbon dioxide leakage to unauthorized zones due to loss of internal mechanical integrity would require simultaneous failure of tubing and casing integrity, a presumably rare event. External mechanical integrity is compromised when channels develop in the cement sheath of the outermost casing or when channels open up along the cement-borehole interface (Fig. 95). These channels can allow the upward migration of CO_2 out of the injection zone and through the confining zone. Class VI well construction requirements, approved operational plans, and monitoring protocols are designed to ensure mechanical integrity and to identify when it might have been compromised.

At all times during injection operations, the owner/operator must maintain both internal and external well integrity. To ensure MI, the operator must perform periodic tests as approved by the UIC Program Director and specified in the well permit. Alternative tests sanctioned in writing by the EPA Administrator can be used if approved by the UIC Program Director.

Internal MIT: To monitor internal mechanical integrity, the Class VI Rule requires continuous monitoring of a variety of operational parameters during injection [40 CFR 146.89(b)]. Parameters that must be measured and recorded include injection pressure, rate and volume, and tubing-long string annulus pressure and fluid volume. To provide a baseline against which to compare the monitoring data, the rule requires an initial annulus pressure test. To conduct this test, the pressure in the annulus is increased to some specific value and the annulus shut-off. The pressure of the annulus is monitored for any changes for a specified time interval. For other classes of injection wells, the specific parameters of this test vary by region. The only internal MIT approved by EPA as an alternative to the annulus pressure test is the radioactive tracer survey.

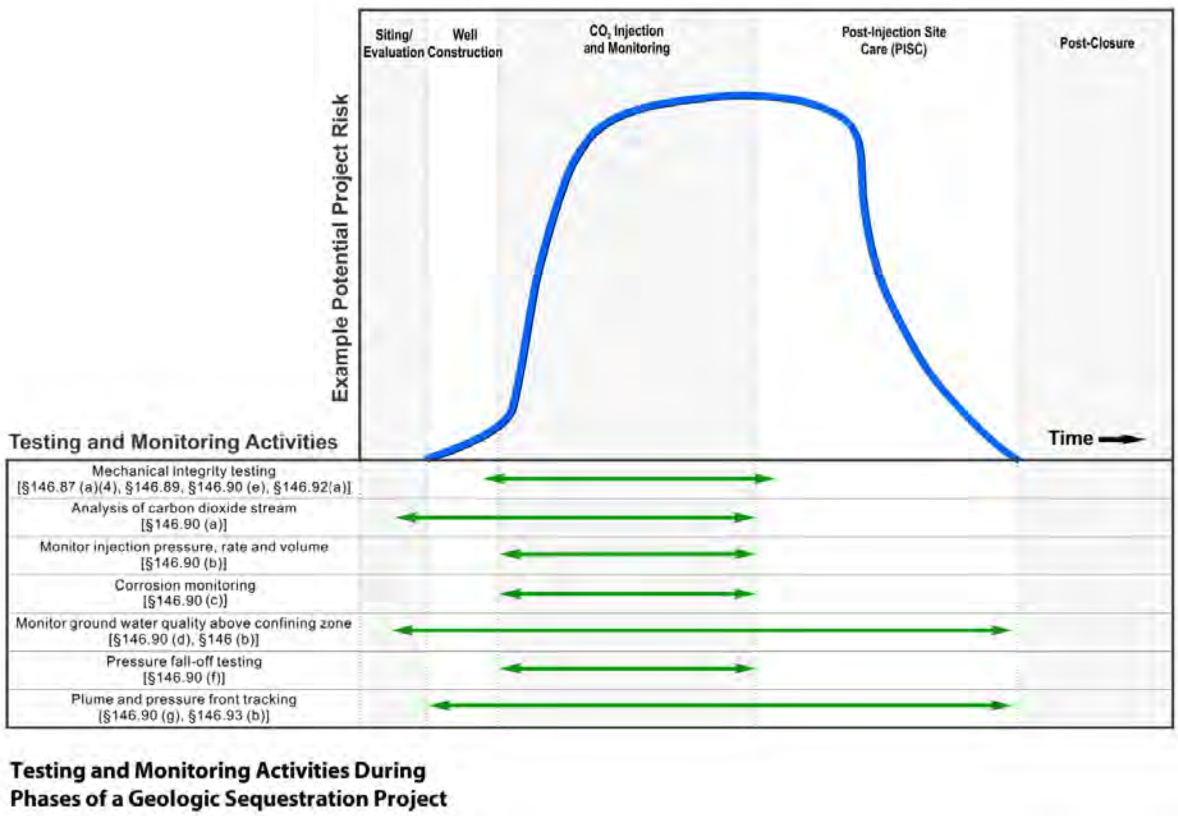

Figure 94. Approximate risk level during different phases of a GCS project. To ensure the injected CO_2 stream and mobilized formation fluids do not pose a risk to USDWs, the Class VI Rule specifies an extensive and comprehensive testing and monitoring program.(Source: EPA, 2013d)

External MIT: To establish a baseline for subsequent monitoring and to ensure the well does not threaten USDWs, the Class VI Rule mandates that a Class VI well be certified to have external MI before injection commences [[40 CFR 146.87(A)(4)]. During the injection phase, a well must be tested for external mechanical integrity annually. The approved tests for mechanical integrity of a Class VI well are oxygen activation, temperature, or noise logs [40 CFR 146.89(c)]. These tests provide information that is complimentary, but not duplicative. (See Chapter 6 for descriptions of these logs).

The owner/operator must submit electronically the results of all required MITs to EPA [40 CFR 146.91(e)]. The results of the continuous monitoring of annulus pressure must be reported to the UIC Program Director in semi-annual operational reports [40 CFR 146.9(a)]. EPA specifies a long list of information that must be included in these reports (EPA, 2013d). MIT results must be reported within 30 days of when the test was conducted [40 CFR 146.91(b)]. However, a failed MIT must be reported within 24 hours to the UIC Program Director [40 CFR 146.91(c)].

Operational Testing and Monitoring

There are two areas of interest for the operational testing and monitoring program mandated by EPA: 1) the nature of the injected CO_2 and 2) the status of the well itself. The stream must be analyzed at sufficient detail to characterize its physical and chemical nature. In addition to chemistry, continuous recording devices must record injection rate, pressure, and volume [40 CFR 146.88(e) and 146.90(b)]. At least once every five years, a pressure fall-off test must be conducted

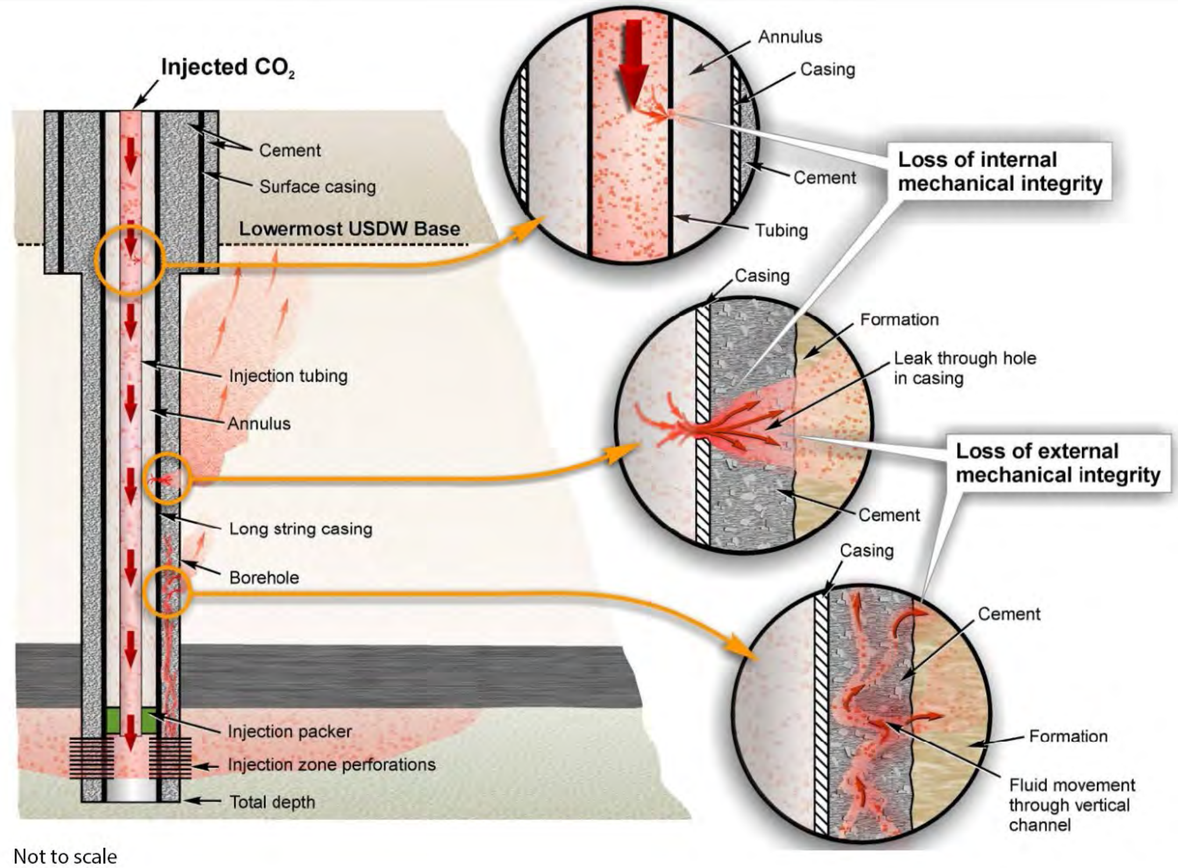

Figure 95. Class VI wells must maintain mechanical integrity throughout the lifetime of the GCS project. Mechanical integrity consists of two components: internal and external. Internal integrity is maintained when casing, packers, and tubing are leak free. The absence of fluid movement between cement and formation means a well has external mechanical integrity. (Source: EPA, 2013d)

[40 CFR 146.90(f)]. The testing and monitoring protocols must be described in the Testing and Monitoring Plan.

Carbon Stream Analysis: An understanding of how the injectate will interact with formation and formation fluids is important in evaluating the danger injection might pose to USDWs. In addition, it is important to determine the corrosivity that the well itself will be subject to. To provide this knowledge, the Class VI Rule mandates analysis of the injectate stream at a frequency that ensures the stream is well characterized physically and chemically. To this end, EPA requires measuring fluid composition including CO_2 and other constituents, as well as pressure and temperature. Other constituents that might be monitored include sulfur dioxide, nitrogen oxides, hydrocarbons, carbon monoxide, methane, water vapor, nitrogen, oxygen, mercury, and arsenic (EPA, 2013d). The manner and frequency in which the stream will be sampled, as well as the analytical techniques and equipment that will be used for chemical analysis must be described in the Testing and Monitoring Plan.

Continuous Monitoring: Injection Rate, Volume, and Pressure: In addition to monitoring the nature of the CO_2 stream, the Class VI Rule mandates the use of monitoring devices to record the injection rate and volume or mass [40 CFR 146.88(e)]. These must be recorded by continuous recording devices and reported in semi-annual operational reports to the UIC Program Director. The reports must report monthly averages, maximum and minimum injection pressure, flow rate, and volume [40 CFR 46.91(a)(2)]. With this data, the UIC Program Director can determine if the project is operating within its permitted conditions.

Similarly, injection pressure must be continuously monitored [40 CFR 146.90(b)]. This pressure can be measured at the wellhead or at the injection zone (bottomhole pressure). This monitoring is to ensure injection pressures do not exceed the burst pressure of the tubing or the fracture pressure of the injection zone (EPA, 2013d). The semi-annual reports must be submitted to EPA [40 CFr 145.91(a)(2)]. The type of data to include in the reports and their reporting format are specified in the rule [40 CFR 146.91(a)]. Any non-compliance with permit conditions identified by the monitored operational data must be reported to the UIC Program Director within 24 hours [40 CFR 146.91(c)(2)].

Corrosion Monitoring: The environment that a GCS injection well operates in is potentially much more corrosive than that commonly experienced by many oil and gas production wells. This means that the material used to construct a well is at risk for increased corrosion, which can result in the compromise of a well's internal as well as external mechanical integrity. Thus, the Class VI Rule mandates a corrosion monitoring plan for the injection well (EPA, 2013d). Corrosion is the loss of metal by chemical or electromechanical reactions. This loss of metal can result in well component loss of mass or thickness, pitting, or cracking. Given this potential threat to MI, the Class VI Rule requires quarterly monitoring of well material corrosion [40 CFR 146.90(c)]. At his/her discretion, the UIC Program Director can order the project to require periodic use of casing inspection logs (CILs) to check for downhole corrosion [40 CFR 146.89(d)].

A common industry method of monitoring well corrosion is the use of *corrosion coupons* (EPA, 2013d). Coupons consist of small pieces of well construction material that are exposed to injectate at well temperatures and pressures for a pre-determined time period. Before exposure, the coupons are carefully weighted and measured. After exposure, the coupons are cleaned and re-characterized to determine the rate of corrosion. This approach is simple and a direct measure of general corrosion, crevice corrosion, pitting, stress corrosion cracking, embrittlement, galvanic corrosion, and structural corrosion (EPA, 1987). Corrosion coupons can be deployed downhole using wireline techniques and in different parts of the wellbore, thereby matching those conditions well material are exposed to at that depth. One of the downsides of coupon testing is the time required to generate meaningful corrosion. Depending on where the coupons are deployed in the well, there may be differences in the conditions the coupons experience and bottomhole conditions, e.g., geologic environment, temperatures, pressures, injectate flow velocities, etc. (EPA, 1987).

The second means of monitoring corrosion is through corrosion loops. A corrosion loop consists of a section of tubing connected to the injectate stream via a valve. The loop is constructed of the same material as that of the injection tubing. Loops are generally of smaller diameter than the injection tubing and deployed at the surface. Surface deployment means, however, that the temperature and pressure in the loop is considerably less than that downhole (EPA, 1987). Simply opening the valve of the corrosion loop exposes the loop materials to the injection stream.

A direct means of measuring well corrosion is provided by CILs. The use of these methods and their deployment frequency can be mandated by the UIC Program Director. Potential CILs include caliper log and electromagnetic thickness, pipe analysis, and ultrasonic imaging surveys. Losses in well thickness of an inch or greater can be detected using an electromagnetic thickness survey. This tool has a low-frequency emitter coil that generates a magnetic field. The field interacts with the casing, thereby producing a shift in the phase of the magnetic field. This shift is detected by a receiver coil and proportional to casing thickness and casing magnetic susceptibility. To provide an accurate measurement, a baseline survey has to be run when the well is first put into service (EPA, 2013d). Disturbances in the magnetic-flux produced when an artificially generated magnetic field interacts with casing constitute a *pipe analysis survey*. Anomalies in tubing or casing can also be measured by sound waves emitted from a high frequency transducer, which is deployed on a wireline. This tool provides a circumferential image of the tubing or casing (EPA, 2013d).

Regardless of how corrosion is monitored, results from the tests must be reported quarterly [40 CFR 146.91(a)(7)]. The data are reported electronically to EPA and are then available to the UIC Program Director and other EPA offices. Some of the information required in the report includes corrosion monitoring techniques, measurement of mass and thickness loss, results of other corrosion losses, losses measured by CIL, CIL measurements, and comparison to base logs. The report must also discuss and explain any data gaps and how the Testing and Monitoring Plan might have to be modified to better protect USDWs. Based on the reported data, the UIC Program Director will assess the mechanical integrity of the injection well.

Pressure Fall-off Testing: Once every five years, a pressure fall-off test of the injection well is required [40 CFR 146.90(f)]. This test measures the formation properties in the area around the well. Its purpose is to monitor how changes near the wellbore may have impacted injectivity and pressure. To conduct the test, injection is halted and the pressure is monitored for a fixed period of time. Once the well is shut-in, pressure is continuously measured. Ideally, pressure would be measured by bottomhole gauges. Interpreting pressure fall-off test for GCS wells will be complicated by the two fluids present in the formation.

Within 30 days of the test, the results must be reported to the UIC Program Director [40 CFR 146.91(e) and 40 CFR 146.91(b)(3)]. The location, name of the well, and the date and time of the well test should be included in the report. Likewise, bottomhole pressure and temperature gauge records must be included. The gauges used to measure the pressure must be described as well as their calibrations. From the data collected, injectivity, permeability, and formation skin are calculated and must be provided in the test report.

Groundwater Water Quality and Geochemical Monitoring

To determine if formation fluid or injection has moved through the confining layer(s), groundwater above the confining formation must be monitored for quality and geochemical changes [40 CFR 146.90(d)]. Although EPA recommends collecting fluid samples from the first formation above the confining layer with sufficient permeability to permit collection and analysis of fluid, the decision where to sample above the confining layers is made on site-specific information and in discussion with the UIC Program Director. To support this monitoring, the owner/operator must construct a network of monitoring wells positioned based on site-specific conditions. These decisions are strongly influenced by AoR modeling results [40 CFR 146.84(c)]. The Testing and Monitoring Plan must describe the rationale behind the positioning of monitoring wells as well as reasons for the formation chosen for sampling. The operational plan for the monitoring, e.g., sampling frequency and analyses performed, must also be described in the plan. Direct groundwater monitoring must be complimented by direct measurement of pressure in the injection zone [40 CFR 146.90(g)].

Monitoring Well Network: The monitoring well network must be designed to detect leakage from the injection zone that may endanger USDWs. It is site- and project-specific. Parameters such as injection rate and volume, site geology, and artificial penetrations, as well as other relevant information, must be used to design this network [40 CFR 146.90(d)(1) and (2)]. In addition to describing the positioning of the wells, the Testing and Monitoring Plan must describe the depth and formation(s) in which the wells will be perforated. All of these decisions will be strongly influenced by the computational modeling and the resultant AoR [40 CFR 146.90(d)(2)]. Consequently, revisions to the AoR will necessarily require a re-evaluation of the Testing and Monitoring Plan [40 CFR 14.90(j)]. These wells must be constructed so that they only sample fluids in the targeted formation. Depending on the anticipated rate of plume and pressure front movement, the Testing and Monitoring Plan can propose building the monitoring well network in stages if approved by the UIC Program Director.

Well Construction: During drilling, fluids must be prevented from moving between formations. Thus, drilling mud weight must be carefully chosen to prevent formation fluids from entering the well. Prior to cementing, the mud should be thoroughly cleaned from the hole to permit proper cement bonding. Various methods are available for cleaning mud from the borehole (Shryock and Smith, 1981). If while preparing the Testing and Monitoring plan, the owner/operator decides not to remove the mud before cementing, he/she should discuss this decision with the UIC Program Director. As with the injection well itself, monitoring wells must be constructed to maintain zonal isolation and to be compatible with the fluids with which they may come in contact with. Thus, they must have good cement jobs and be constructed of corrosion-resistant materials. Well design for monitoring of the injection zone should also consider the possibility that the well will experience elevated pressures and temperatures. In contrast, pressures in the zone above the confining zone may be lower. When choosing tubing diameters, care must be taken to select tubing that will permit the use of the various tools required for monitoring. To maintain strict zonal isolation, perforations should not cross injection-confining zone boundaries. To ensure proper placement, the perforations should also be logged. If a well is perforated in multiple zones, packers must be installed to separate the zones.

Pre-existing production or injection wells may be converted to monitoring wells. Such wells must be evaluated to ensure they have mechanical integrity and will not allow fluid movement along the borehole. At the least, they should be logged to evaluate casing and cement status. Any defects identified must be remediated. Plans to repurpose pre-existing wells to monitoring wells must be fully described in the Testing and Monitoring Plan.

Groundwater Sampling and Analysis: Groundwater above the confining zone must be analyzed [40 CFR 146.90(d)] and compared to baseline data [40 CFR 146.82(a)(6)] to determine if leakage out of the injection zone has occurred. The constituents analyzed, sampling frequency and methodology, and analytical procedures must be described in detail in the Testing and Monitoring Plan. TDS, specific conductivity, temperature, pH, CO_2, and density are the minimum recommended constituents. The UIC Program Director may also require analysis for major anions and cations, trace metals, tracers, hydrocarbons, and any other constituents. If the CO_2 stream contains any impurities, the Testing and Monitoring Plan should consider analyzing for these as well. For a minimum, EPA recommends quarterly sampling at the beginning of the testing and monitoring phase. As the project progresses, monitoring data can be used to refine the sampling frequency. The sampling protocols EPA has established for shallow groundwater monitoring apply also to deep injection GCS wells (EPA, 2013d). Given the difference in shallow versus deep environments, there may be the need to modify some protocols to account for the high-pressure and high-temperature conditions of the sampling depth. These sampling programs are subject to established EPA chain of custody records management requirements.

Reporting and Evaluation: Results from the monitoring program must be reported semi-annually to EPA in electronic form [40 CFR 146.91(a)(7)]. The UIC Program Director and other EPA offices will have access to this data after submittal. The report should include original complete laboratory reports, interpretation of changing trends, evaluation of leakage likelihood, monitoring well network map, descriptions of all sampling equipment and analytical procedures, calibration records of field sampling equipment, date, time, location and depth of groundwater samples, and identification of any data gaps.

Plume and Pressure-Front Tracking

Regions most at risk of USDW endangerment are those overlying the CO_2 plume and the region of elevated formation pressure. Thus, understanding the position of both of these areas is crucial in protecting USDWs. Knowledge of the plume and pressure front positions also key to validating the computational model predictions and assessing the adequacy of the AoR. Thus, the Class VI Rule requires owner/operators to track the position of the CO_2 plume and pressure front both directly and indirectly. The suite of procedures selected for this tracking must be chosen on site- and project-specific data and must be described in the Testing and Monitoring Plan [40 CFR 146.90]. These procedures, in turn, must be approved by the UIC Program Director. Potential means of tracking these entities include: 1) in-situ pressure monitoring, 2) indirect geophysical modeling, 3) groundwater geochemical monitoring, and 4) computational modeling (EPA, 2013d).

Rather than mandating the specific technologies to use, the Class VI Rule allows the owner/operator great flexibility in choosing the most appropriate plan using site- and project-specific information. The rule does, however, mandate the use of, at least one direct ([40 CFR 146.90(g)(1)] and one indirect [40 CFR 145.90(g)(2)] monitoring method. If the UIC Program Director deems them unsuitable for the proposed site, he/she may waive the requirement for using an indirect monitoring technique. Instead, the UIC Program Director may require direct monitoring of injection zone pressure by use of monitoring wells perforated in the injection zone.

The information provided by the different monitoring techniques provides complimentary data that together should provide a better estimate of the location of the plume and pressure front. Direct methods provide explicit observations constrained at a single point, and do not rely on modeling or assumptions. Conversely, indirect methods provide information over a broad area, but require extensive processing of data. Finally, computational modeling allows predictions into the future, which neither direct nor indirect monitoring can provide. Such modeling requires, however, making simplifying assumptions and are marked by various levels of uncertainty, which can never be completely eliminated. The monitoring requirements of the Class VI Rule are summarized in Table 6.

Direct Methods: One of the requirements of the testing and monitoring program is direct measurement of fluid pressure in the injection zone [40 CFR 146.90(g)(1)]. These in-situ measurements provide real-time evaluation of fluid pressure at a particular position within the injection zone. Pressure can be measured by bottomhole pressure gauges, fluid depth in the wellbore, or measurements made at the wellhead. Although EPA recommends monitoring of pressure changes on a monthly basis for all wells, the exact scheduling frequency is determined by the owner/operator and must be thoroughly described in the Testing and Monitoring Plan, which has to be approved by the UIC Program Director [40 CFR 146.90].

The rule permits owner/operators to use a single monitoring well to monitor pressure in both the injection zone as well as in a formation above the confining zone. Monitoring wells should be positioned predominantly in the down-dip direction from the injection well, but there should be, at least, one well sited up-dip. The positioning and placement wells should be determined based on the projected migration of the plume and pressure front. Time series graphs of pressure should be generated for each well to document any changes over time in formation fluid pressure. Likewise, area variation in pressure should be documented using maps of the AoR and project site. Finally, it is recommended that measured pressures be compared to predicted pressures to determine how well the computational model predicts changes in the injection zone induced by CO_2 injection.

Semi-annual reports of pressure monitoring must be submitted to EPA electronically [40 CFR 146.91(a)(7)]. These reports are then available to the UIC Program Director as well as other EPA offices. For each well, raw pressure, temperature, and density data should be reported along with records of calibration of pressure transducers used to make measurements. If data are recorded at the wellhead, the records of wellhead surveying and point elevations must be included. The data must be interpreted and results conveyed visually through maps and graphs. Predicted pressures must be compared to measured pressures and any necessary changes to the Testing and Monitoring Plan discussed. To provide context for the most recent monitoring data, the data should be synthesized and interpreted in light of the entire historical monitoring dataset. With this information, the owner/operator must assess whether or not there is evidence for leakage from the injection zone. Within 24 hours, the owner/operator must report to the UIC Program Director any movement of CO_2 plume or pressure front that may exceed permit conditions and endanger USDWs.

Indirect Methods – Geophysical: In addition to direct monitoring, the Class VI Rule requires monitoring of the CO_2 plume and pressure front by at least one indirect method [40 CFR 146,90(g)(2)]. These types of approaches use the propagation of a signal (e.g., seismic or electromagnetic) through the subsurface and record the signals

Technology	Description	Class VI Rule Requirement	Class VI Rule Citation
direct pressure monitoring	in-situ fluid pressure measurement can be done with transducers in monitoring wells in injection zone	required to track presence/absence of elevated pressure within injection zone	40 CFR 146.90(g)(1)
indirect geophysical monitoring	seismic, electrical, gravity or electromagnetic techniques	track presence/absence of elevated pressure within injection zone and extent of carbon dioxide plume (UIC Program Director can decide methods not appropriate)	40 CFR 146.90(g)(2)
direct carbon dioxide plume monitoring	use of monitoring wells in injection zone to substantiate presence/ absence of carbon dioxide by geochemical analysis	track extent of carbon dioxide plume UIC Program Director determines indirect methods inappropriate	40 CFR 146.90(g)(1)
computational modeling	inform development of field monitoring strategies and incorporation of measured data in comprehensive, mathematical model of site	computational modeling required as component of AoR delineation and reevaluation	40 CFR 146.84

Table 6. Various monitoring methods and the Class VI monitoring requirements they fulfill. (EPA, 2013d)

reflected or transmitted. The recorded data are processed and interpolated to provide an image of a subsurface volume. These geophysical techniques can be deployed from the surface or through wellbores. They provide information about fluid state, e.g., aqueous versus supercritical, as well as fluid pressure. Thus, they provide the broad area view of the plume and pressure front not available from monitoring wells.

There are three primary geophysical signals that can potentially be used for monitoring GCS sites: seismic, gravity, and electrical. Given that geologic sequestration is a new application of technology, the utility of these techniques in monitoring CO_2 plume and pressure front are still being assessed. A study of possible GCS indirect monitoring techniques rated various technologies as primary, secondary, or potential based on their usefulness at this time (NETL, 2009a). Regardless of technology, all these monitoring approaches require a pre-injection baseline against which to identify any changes that may have occurred since injection began. For this purpose, it is crucial that surveys are carefully spatially referenced so differences in subsequent surveys can be assigned to changes in fluid behavior and not errors introduced by imaging different subsurface volumes. Ideally, a permanent deployment of survey instruments would limit positioning errors and reduce uncertainty in the interpretation of sequential surveys.

Seismic Methods: The highest resolution imaging of all geophysical techniques is seismic surveying, which measures the arrival of seismic waves after they have passed through a portion of the Earth's crust. Surveying can be used to determine the position of the plume as well as fluid movement. Secondary technologies include two- and three-dimensional surveys, as well as time sequences (four dimensional) and microseismic surveys. Vertical seismic profile and crosswell seismic methods are currently viewed as potential monitoring methods (NETL, 2009b).

A seismic survey measures the time a seismic wave, either artificially or naturally produced, takes to reach a receiver. Because seismic waves travel through CO_2-saturated rock slower than ones containing water, the displacement of formation fluid by CO_2 will slow seismic waves and alter the resultant seismic image. This difference arises because CO_2 is less dense and more compressible than brine. If sources and receivers are deployed on the surface, the resultant survey it is termed a surface survey, whereas deployment in the subsurface is denoted as a borehole seismic method. The surface methods image a large area and have the potential to capture the entire spatial extent of the plume and pressure front. Conversely, borehole methods only reveal if the plume or pressure front has reached the position of the borehole. Borehole methods are therefore less likely to detect fingering or movement along faults that are off-plane. They do, however, provide higher resolution images that can pick up thin or complex shapes near the borehole. They also suffer less from positioning errors because the borehole location is fixed.

There are three main variations of surface seismic surveying: 2D, 3D and 4D. *Two dimensional (2D) seismic surveys* are conducted by aligning sources and receivers along a linear trend. They produce a vertical subsurface image (x vs. z) along that trend. Anything to either side of the trace is not imaged by the survey. In terms of GCS monitoring, they will provide only a vertical slice through the plume and pressure front, not a three dimensional view. In contrast, a three-dimensional or 3D survey (x and y vs. z) positions the receivers and sources in a two dimensional grid on the Earth's surface. One arrangement is a line of receivers at right angles to a line of sources. The receivers record data from different sources, angles, and directions and not just along a line as in a 2D survey. Once processed, the data provide a three-dimensional image of the subsurface under the receiver-source grid pattern. A 4D seismic survey adds time as the fourth dimension (x,y,x vs. t). Thus, a 4D survey consists of multiple 3D surveys of the same crustal volume, but at different times. A time-series of this type allows tracking of fluid movement over time.

Unlike surface surveys, borehole seismic surveys image the subsurface around a well by deploying receivers or sources in the subsurface. The most common is the vertical seismic profile or VSP. In this procedure, the receiver (geophone) is positioned downhole and the source is positioned on the surface (Fig. 96). During recording, the surface receiver can be stationary or moving. The borehole may be vertical or deviated and onshore or offshore, but is generally limited to depths of 3,000 meters or less. The image produced is along a line from the well to the surface source, so although it is a 2D survey, its greater resolution allows detection of thin plumes intersecting the survey trace that might be hard to detect with a surface survey.

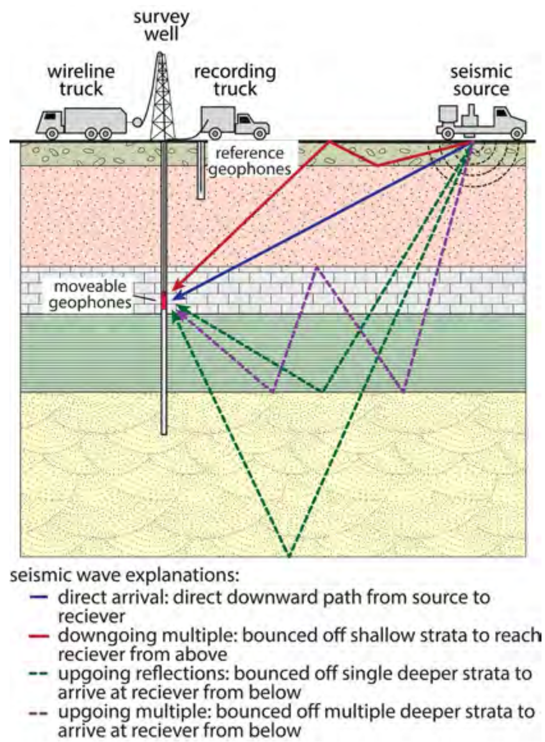

Figure 96. Schematic representation of vertical seismic profiling (VSP). VSP combines a surface deployed component with a downhole component. The surface component may be stationary or moving. This produces a vertical subsurface image along the trace between the borehole and the surface component. It has greater resolution that a surface survey so it may be good at detecting fingering of the plume and pressure front, if they intersect the survey trace. (Modified from EPA, 2013d)

Crosswell seismic surveys place a source in one well and receivers in a second well. The survey produces a subsurface image of the plane between the two wells. Generally, the wells are less than 1,640 feet [500 meters] apart and are dedicated monitoring wells. Other survey techniques can use several wells to produce a 3D survey (Washbourne and Bube, 1998). The seismic methods described to this point all use artificially induced seismic waves. A *borehole microseismic profile* uses geophones deployed down a wellbore for an extended period to record the microseismic events (magnitudes -3 to -1) within one kilometer of the well. This is a passive source method. Hypocenters for the earthquakes are plotted in a three-dimensional volume to provide an image of the area being deformed. This technique cannot image or detect the CO_2 plume, but it may provide information about the pressure front because seismicity is often related to pressure changes.

Electromagnetic: Electromagnetic surveys measure changes in formation electrical resistivity. An electrical survey passes a current through the subsurface, whereas electromagnetic surveys use an electromagnetic field or current to generate another current or field (induction), that is then measured. Because CO_2 is less electrically conductive than brine, displacement of brine by CO_2 will result in a change in resistivity. The major advantage of this type of survey is it is entirely dependent on formation fluid composition and saturation and independent of rock properties. Because the primary means of conducting such surveys is from permanently installed monitoring equipment, such approaches are ideal for 4D surveying. As of now, NETL (2009b) classifies electromagnetic surveys as potential GCS monitoring technologies.

The two EM survey methods most likely to prove useful in the future are long electrodes and electrical resistance tomography (ERT) (EPA, 2013d). The *long electrode method* uses long probes or electrodes inserted into the ground to send and receive electric pulses. The electrodes can be made of any conducting material that contacts the surface and region of interest. With a grid of electrodes deployed, some act as sources and others as receivers. The differences between emitted and received signals are used to calculate formation resistivity. The probes can be the surface casing of a well, which allows for the use of both vertical and horizontal wells. The addition of horizontal wells to the survey provides a vertical resolution that would be absent if only vertical wells are used. *ERT* surveys are similar to crosswell seismic surveys in that the sources and receivers are positioned in different wells. However, the casing of the well must be non-conductive plastic or fiberglass, and point sources and receivers are distributed along their lengths. Receiver/source deployment may be either permanent or temporary. An electrical pulse is generated in one well and the resultant electrical currents measured in another. Thus, the resistivity of the formations along the plane between the two wells can be calculated. With the resistivity measured at multiple depths, ERT surveys provide both vertical and horizontal resolution.

Gravity: Gravity surveys are used to detect differences in the acceleration due to gravity at different points on the surface. Variations in measured gravity indicate changes in the density of materials directly below the measurement point. Because of the density difference between CO_2 and brine, gravity surveys have the to potential to detect the displacement of brine by CO_2, provided baseline surveys were established during site characterization. Gravity surveys work best for injection formations that are thick, horizontal, and have high permeability and porosity. Such formations are likely to produce anomalous gravity signals strong enough to be detected at the surface. Time gravity surveys will show a decrease in gravity as CO_2 displaces brine. Gravity surveys can be land-based or aerial, although the former will yield better resolution. A gravity survey can be conducted by lowering a gravimeter down a well and measuring gravity as it is raised through a series of different positions. In this manner, the survey can detect the appearance of the CO_2 plume even if the well does not penetrate to the injection zone.

Reporting and Recordkeeping

Results of the monitoring and testing program are to be reported semi-annually [40 CFR 146.90(b)-(c)]. Data to be included in these reports include monthly average minimum and maximum injection pressures, CO_2 stream flow rate and volume, and annular pressure and volume. If an event results in an exceedance of allowed annulus or injection pressures, the report must describe these events. Given the corrosivity of CO_2 injection streams, well corrosion monitoring is critical to ensuring well MI and addressing problems early. Thus, well corrosion must be monitored using coupons, corrosion loops or other methods approved by the UIC Program Director [40 CFR 146.90(b) and (c)]. This testing must focus on all the major components of the well, e.g., casing, tubing, packers, that ensure mechanical integrity. Mechanical integrity is to be periodically checked using the testing methods outlined and approved in the original permit, e.g., radioactive tracer, temperature or noise logs. Another well test that must be conducted is a pressure drop-off test. As with other tests, the type of test when, and how it will be conducted, and how results will be reported must all be described and approved in the original permit application and the subsequently approved operational plan.

Another important focus of monitoring is the groundwater above the confining zone. Changes in the quality of this groundwater may indicate the confining zone has been compromised. Some of the geochemical parameters to be monitored routinely include pH, specific conductivity, temperature, CO_2 content, major cations and anions, total dissolved solids, metals, and hydrocarbons.

The other major focus of monitoring is the fluids in the injection zone, i.e., the CO_2 plume and the formation fluid. In particular, the positions of the plume and pressure front most likely must be tracked using geophysical surveys. In addition, pressure measurements in the first formation above the confining zone or results from indirect surveys of this region must be submitted with the report on the fluids in the injection zone. Results of this monitoring is important in establishing that the fluids in the injection zone are behaving as predicted by the computational modeling. It will also show if CO_2 is moving laterally or vertically in a manner that might result in compromising long-term storage.

The Class VI Rule has special directives about the responsibility of an owner/operator for reporting and recording keeping. These are mandated under the authority of the SDWA. All GCS projects, whether permitted by state or federal UIC programs, must submit reports to EPA via a new electronic reporting system that is being developed specifically for Class VI wells. Specific classes of reports that must be submitted include semi-annual reports, 24-hour emergency notification, and 30-day reports. The semi-annual reports must describe changes or deviations of the carbon stream from that which was designated in the original permit. These reports will be used by UIC Program Directors to ensure well MI has been maintained, there are no significant leaks, and to show that injection and operation are within the parameters of the original application. Any event that results in the possible endangerment of USDWs will trigger the reporting of this event within 24 hours of its occurrence. Events that might trigger such a report could be changes in pressure front, the loss of mechanical integrity, or the initiation of a well shut-off system. Whenever the well is subject to a workover, MIT or other injection tests, the owner/operator must submit a report to the UIC program within 30 days of the change or test. All reports are designed to ensure the UIC program that the GCS project is not placing any USDW at risk.

In addition to reporting requirements, the Class VI Rule lays out specific responsibilities for recordkeeping [40 CFR 146.91(f)]. All the data collected for the original project application must be maintained during the operational lifetime of the project and for ten years after site closure. Likewise, information from well plugging operations and post-injection site care, as well as the site closure report, must be maintained for the same period of time. After the record retention period, records must be given to the UIC Program Director who will designate a means for storing the information for longer periods. In contrast, monitoring data must be kept for ten years after the time of collection.

Injection Well Plugging

Purpose

When a Class VI injection well is no longer needed as an injector or monitoring well, it must be properly plugged and abandoned to ensure that it does not provide a means for fluid movement into USDWs [40 CFR 146.88]. By specifying proper abandonment and plugging procedures and materials, the Class VI Rule ensures that the abandoned injection well will maintain mechanical integrity and preserve the zonal isolation that characterized the operational phase. The rule does not specify when the well should be plugged, but EPA recommends plugging soon after injection stops unless the well will be repurposed as a monitoring well.

Injection Well Plugging Plan

An Injection Well Plugging Plan is one of the five planning documents that must be submitted with the original well permit application [40 CFR 146.92(b)]. Unlike the other plans, it is not mandatory to review this plan during the operational phase of the well since plugging will occur only after injection ceases. The UIC Program Director will review this plan to ensure it provides adequate protection to USDWs. A well plugging plan must specify the types of tests that will be used to measure bottomhole reservoir pressure before plugging [40 CFR 146.92(b)(1)], test(s) that will be used to assess external mechanical integrity [40 CFR 146.92(b)(2)], type and number of plugs to be set [40 CFR 146.92(b)(3)], the position of the top and bottom of each plug [40 CFR 146.92(b)(4)], the type, grade and quantity of plugging material [40 CFR 146.92(b)(5)], and the method for plug emplacement [40 CFR 146.92(b)(6)]. Although the owner/operator can specify the types of plugging material to be used, he/she must provide evidence they are compatible with exposure to CO_2. When developing the plugging plan, stratigraphic information including the depths and thicknesses of the injection and USDW-containing formations are critical (EPA, 2013b). Operational information describing the nature of the proposed injected CO_2 stream and the geochemistry of formation fluids should be consulted when developing the plan. When approved by the UIC Program Director, the Injection Well Plugging Plan becomes part of the Class VI permit.

A Notice of Intent (NOI) to plug must be submitted to the UIC Program Director at least 60 days before plugging is planned [40 CFR 146.92(c)]. The date and time of plugging, well name and location, and parties performing the plugging must be included in the NOI. If changes have been made to the Well Plugging Plan, they must be approved by the UIC Program Director and added to the permit before operations begin.

Plugging is envisioned as multistep process (Fig. 97). Prior to plugging, the well is flushed with a buffer fluid that displaces injectate out of the tubing and completion fluid from the tubing-casing annulus. The bottomhole pressure is measured and an external mechanical integrity test performed. After removal of the tubing and packers, a bridge plug is placed to isolate the perforated segment of the long-string casing. Often this is a cement retainer with cement squeezed into the perforations below the retainer and a cement plug placed on top of the retainer. A plugging fluid is used to fill the unplugged portion of the long-string. In the final stage, a number of cement plugs are placed in the long-string casing at strategic positions (Fig. 74).

Preparation for Plugging

Once the injection well is ready for plugging it must first be prepared (EPA, 2013b). This process involves a number of steps. First, the condition of the well is determined through a series of tests. Once the tests are complete, the well is flushed to remove residual injectate and completion fluid. After flushing, injection equipment is removed and any objects or debris that may have fallen into the well over time are also removed. Defects in the well construction that might endanger long-term mechanical integrity are repaired. Finally, a plugging fluid is circulated into the wellbore and static equilibrium attained.

Well Testing: Before an injection well can be properly plugged, its physical state must be thoroughly assessed. The first step is to determine bottomhole pressure at the position of the perforations [40 CFR 146.92(a)] using the test originally identified in the Injection Well Plugging Plan [40 CFR 146.92(b)(1)]. Bottomhole pressure must be known in order to: 1) determine the density needed for the workover fluid, 2) establish the proper density of the plugging fluid to ensure static equilibrium is achieved, and 3) provide pressure measurements for subsequent pressure decay modeling. In shallow wells with a single fluid phase in the wellbore, measurement of the fluid pressure at the surface can be corrected to bottomhole pressure through a simple calculation (EPA, 2013b). For deeper wells and wells with multiphase fluids, actual bottomhole pressure should be measured with downhole pressure gauges or a pressure gauge lowered into the hole.

Before plugging, a final external mechanical integrity test must be conducted on the well [40 CFR 146.92(a)]. These tests are specified in the Injection Well Plugging Plan. Approved tests include tracer survey, e.g., oxygen activation, temperature, or noise logs [40 CFR 146.89(c)]. Alternative tests can be approved by the UIC Program Director [40 CFR 146.89(e)]. The external MIT is designed to reveal any leaks in the long-string casing that might allow significant fluid movement along the wellbore. Should the well fail

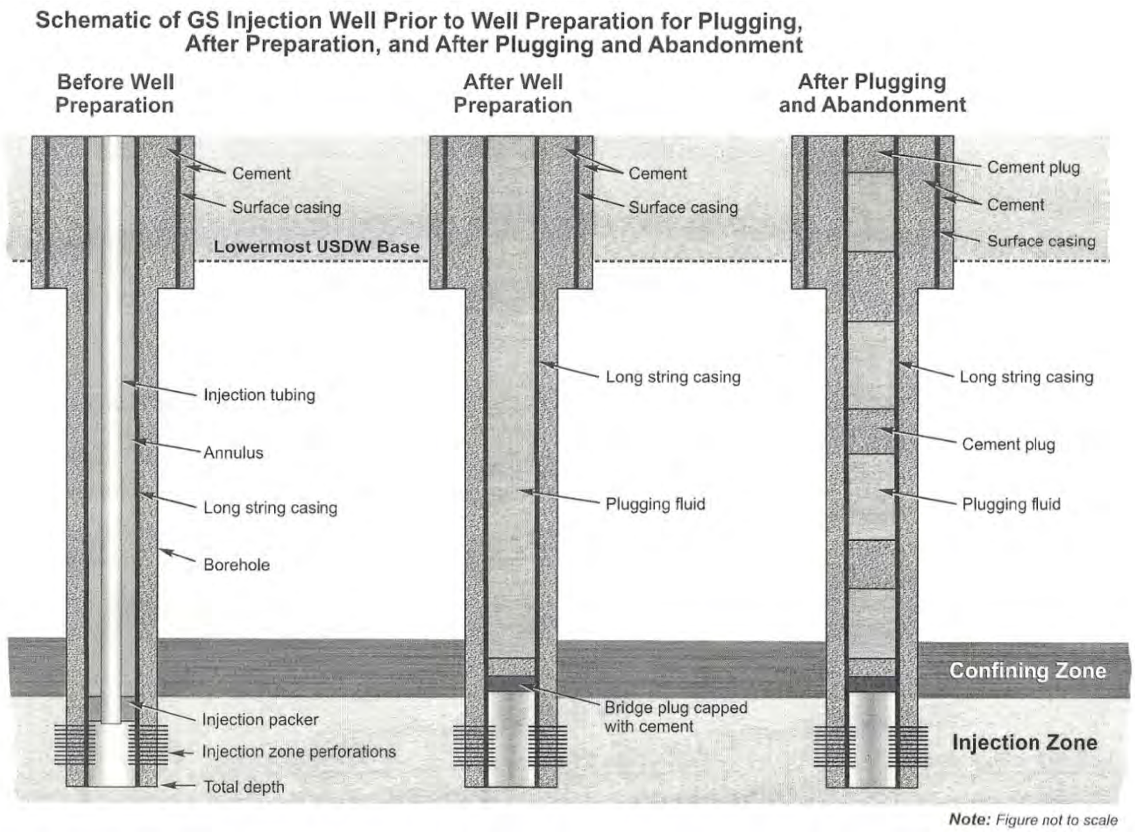

Figure 97. Plugging a Class VI injection well is a multistep process. First, the state or condition of the well at the end of the operation phase is assessed (left). The well is then prepared for plugging by flushing, extracting lost equipment (fish) and emplacement of a plugging fluid (middle). Finally, plugs are set at various locations within the wellbore (right). (Source: EPA, 2013b)

the MIT, the problem must be corrected before proceeding with plugging [40 CFR 146.88(f)(4)].

Well Preparation: With the successful completion of the well tests, the well is ready to be prepared for plugging. This process includes flushing the well, pulling the injection tubing and any monitoring equipment, removing (fishing) lost objects from the wellbore, and remediating any deficiencies that exist in well construction. Workover fluids are used to flush the well before tubing and packers are removed [40 CFR 146.92(a)]. A workover fluid is a designed brine or mud that is circulated through the wellbore to remove residual drilling mud or small particles like sand (EPA, 1982). The annular space, long-string casing, perforated zone, and possibly the injection packer, that is, anything that will be left in the well and that contacted injectate during operation, must be flushed.

With the well flushed, the well equipment can be removed. This involves pulling the tubing string with a workover rig and removing any downhole equipment, e.g., pressure transducers, shut-off systems, etc. With the wellbore clear, any large debris that might interfere with plugging must be removed from the well. These may be 'fished out' using a junk basket or a fishing magnet (Johnson and others, 2013). Those pieces of debris that cannot be successfully fished may have to be milled or drilled out to ensure successful plugging.

Any deficiencies found in the casing and cementing during well testing must be fixed before the well can be plugged [40 CFR 146.88(f)]. In addition to the final external MIT, operational data, historic MIT data, and past remedial work can all be used to identify potential trouble spots. Buckled or collapsed casing can be opened using a casing roller or swaging tool (EPA, 1989). Leaks in casing or cement missing behind casing are generally repaired using a squeeze cement job. Cement retainers are set in the wellbore above and below the damaged section of casing and cement pumped at higher pressure between them. The high pressure forces the cement into the openings in the casing. If the absence of cement is detected behind casing, but no openings are present in the casing, the casing will have to be perforated so a squeeze cement job can be performed.

When flushed and repaired, the wellbore is ready to be filled with plugging fluid. Plugging fluid is designed to produce a static environment in the wellbore to facilitate successful placement of cement plugs. It must be of uniform weight, the right density and capable of maintaining physical and chemical stability for long time intervals (EPA, 1989). The physical properties of the plugging fluid ensure that it will move little during plug emplacement and subsequent setting and hardening (Fig. 74). This allows the plug to set properly and minimizes possible cement contamination. The placement of the plugging fluid in the well should enable the establishment of a static equilibrium throughout the wellbore with minimal to no fluid motion. Plugging fluids can be brines or freshwater, bentonite (gel or clay), attapulgite (a type of clay), or lost circulation fluids (EPA, 1989).

Well Plugging

Locations: Plugs, usually cement, placed throughout the wellbore are the primary means of ensuring zonal isolation during plugging. Primary locations for plug placement are 1) above the lowermost injection zone, 2) across or above and below USDWs, 3) at the bases of the surface and intermediate casings, 4) across cut-off and pulled casing terminations (casing stubs), and 5) at the surface (EPA, 1989). For horizontal wells and wells with multilaterals, plugs should be set at the appropriate kickoff points. In addition to plugs above injection zones, squeeze cement jobs across the perforations should be considered.

Cement: As with all aspects of the plugging plan, the grade, type, and quantity of cement to be used in plugging, must be specified in the Injection Well Plugging Plan submitted with the well permit application [40 CFR 146.92(b)(5)]. To be effective, cement must bond strongly to the casing and tubing and not react with the completion fluid. Cement must be pumpable, and should set and harden in a reasonable amount of time (Calvert and Smith, 1994). The choice of plugging fluid will also impact the cement selected for plugging. Relative to the plugging fluid, cement should have a higher yield strength and plastic viscosity. It should have a density as close to that of the plugging fluid as possible to minimize cement movement and allow the plug to be set at the proper depth (EPA, 1989). Downhole conditions, e.g., temperature and pressure, will determine, in part, the additives mixed with the cement (see Cementing section in Chapter 6). EPA (1982) suggests API Class A, G, or H cements are well suited for injection well plugging. Whatever cement grade is selected for plugging, it must be resistant to corrosion caused by reaction with carbonic acid [40 CFR 146.92(b)(5)].

In addition to cement plugs, there are also bridge and inflatable plugs that can be used to isolate different zones of the wellbore. Bridge plugs are mechanical devices used to seal off high-pressure portions of a well or as cement retainers (Fig. 98). Bridge plugs are similar to packers in that they enter the hole with an outside diameter less than that of the casing. When in position, they are activated so that the diameter of a portion of the plug increases until it presses up against the casing sealing the well to fluid movement. Bridge plugs can be permanent or temporary. Temporary plugs should be strong enough to resist fluid pressures in the wellbore, but should be brittle enough that they can be drilled out if it is necessary to re-enter the bottom of the well. In Class VI wells, plugs for abandonment must be permanent so it is likely cement would be set on top of them. Bridge plugs of the proper design can also be used as cement retainers.

Methods: The last factor in plugging an injection well is to determine how the cement will be emplaced, which also must be specified in the Injection Well Plugging Plan [40 CFR 146.92(b)(6)]. There are three plug emplacement methods that are acceptable for GCS plugging: balance, retainer, and the two plug methods (EPA, 2013b). Depending on where plugs are set in the well, a

Figure 98. A typical bridge plug used for isolating high pressure zones and setting cement plugs. The plug is shown in its unexpanded form. When set, the black portion of the plug is squeezed by compressive force applied by the movement of the metal plates above and below the segment. The segment increases in diameter until it presses against the casing, thereby sealing off the lower portion of the well. (Source: EPA, 2013b).

combination of the different methods may be used through the length of the well.

Balance Method: In the balance method, cement slurry is pumped down tubing that has been centralized in the well. The name comes from the fact that emplacement 'balances' the cement-plugging/displacement fluid interfaces inside and outside the tubing (Fig. 99). Successful placement of a plug using the balance method requires a near match in cement slurry and plugging fluid density (Fig. 75). To set a balance plug, drill pipe or tubing is run into the well to the desired depth of the plug (EPA, 2013b). Cement slurry is slowly pumped into the casing and rises up around the tubing. With the tubing centralized, the cement slurry will form a uniformly thick sheath around the tubing. When the correct volume of cement has been pumped into the tubing, a displacement fluid is used to displace the slurry downhole. When the level of the cement slurry-fluid interface in the tubing equals that outside the tubing, pumping ceases and the tubing is slowly withdrawn from the cement slurry (Fig. 99). Excess cement and displacement fluid are reverse circulated out of the well. The cement slurry is left in place to set and harden before setting the next plug. In balance plug setting, fluid movement must be kept to a minimum so there is no mixing of plugging fluid and cement slurry. Smaller diameter tubing, low pumping rates, deflection jets, and slow tubing withdrawal all contribute to successful plug emplacement by the balance method. Successful plug emplacement is also critically dependent on properly calculating the necessary volumes of cement slurry, water, and displacement fluid (EPA, 1989).

Retainer Method: The retainer method combines a cement plug and bridge plug to set a plug (Fig. 100). It is particularly useful for open (uncased) holes (not a possibility with Class VI wells) and across perforated zones (EPA, 1982; EPA, 2013b). With this method, a bridge plug is included in the tubing string (Fig. 100). Tubing is run to the top of the desired plug position above the bottom of the well. Cement slurry is pumped down the tubing through the retainer and into the well and rises above the retainer for 50–100 feet

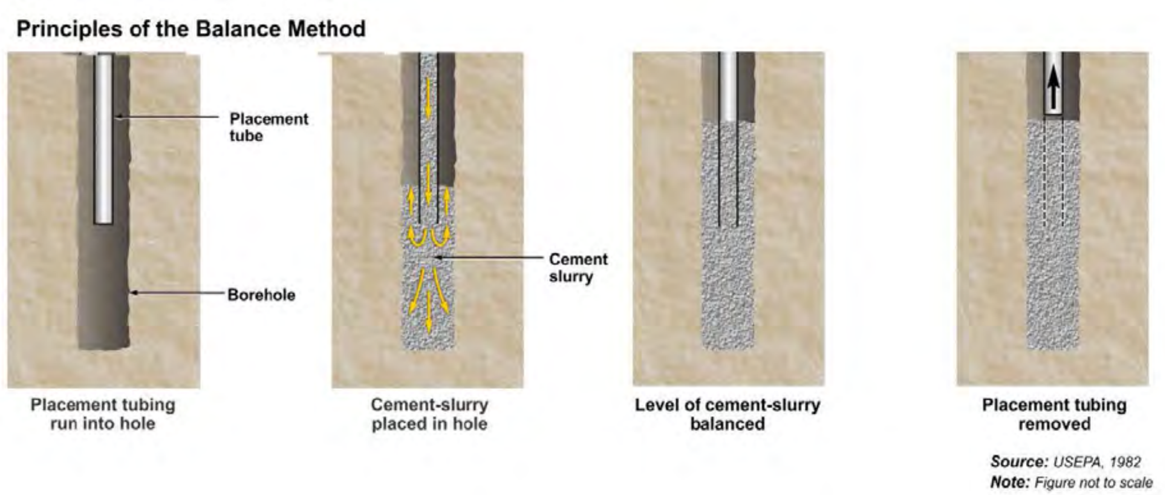

Figure 99. The balance method of plug emplacement requires considerable operator skill. The diagram shows plugging at the bottom of the well, but as long as cement and plugging fluid densities are close it can be used to place plugs anywhere along the wellbore. (Source: EPA, 1982, 2013b)

Example of the Retainer Method

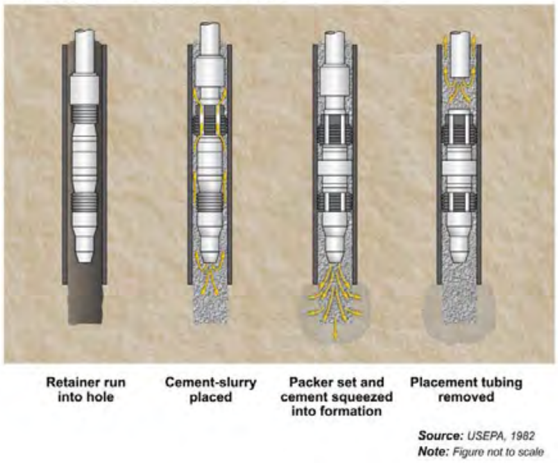

Figure 100. The retainer method is used to set plugs in barefoot completions and across perforated zones in cased and cemented wells. The method uses a bridge plug to isolate the portion of the well in the injection zone. Cement pumped into this zone at high pressure enters the producing formation in barefoot completions and plugs perforations in cased and cemented wells. (Source: EPA, 1982, 2013b)

(15–30 meters). At this point, the bridge plug is activated and set, thereby sealing off the bottom of the well (Fig. 100). Cement slurry under pressure is pumped into the well below the retainer. The rising pressure in the lower part of the well forces the cement slurry into the formation in open holes and through the casing and cement perforations into the formation in cased and cemented wells. When the proper amount of cement slurry has been pumped into the bottom of the well, the retainer valve is closed and the tubing withdrawn. The cement slurry above the retainer fills in the void left by tubing removal creating a solid cement plug above the retainer. For Class VI injection wells, the retainer used for plugging must be drillable (EPA, 2013b).

Two Plug Method: To minimize cement contamination, the two plug method uses a top and bottom plug to isolate the cement slurry in the tubing from the plugging fluid (Fig. 101). At the start of plugging, tubing is run into the well until the location for the plug is reached. The bottom plug is dropped into the tubing and cement slurry pumped in behind. After the proper amount of cement slurry has been pumped, the top plug is

Principles of the Two-Plug Method

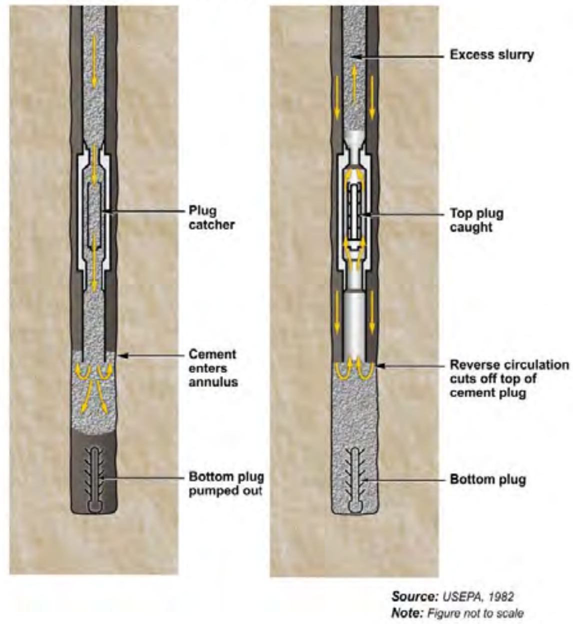

Figure 101. The two plug method of plugging uses top and bottom plugs to separate cement slurry from displacement or plugging fluid. This ensures a good cement setting and hardening. Because the technique allows precise positioning of the top of a plug it is well-suited for use in deep wells. (Source: EPA, 1982, 2013b)

released, thereby separating it from displacement or from plugging fluid pumped into the tubing to displace the cement slurry downhole. The top plug is caught in the tubing by a plug-catcher that prevents it from exiting the tubing and entering the well. The plug is latched in place preventing further displacement of fluid from the tubing. This method of emplacement allows improved control over the depth of placement, a factor important in deep wells (EPA, 2013b).

Plugging Report

Within 60 days of plugging, a plugging report certified by the owner/operator and the plugging party, must be submitted for review [40 CFR 146.92(d)]. This report must describe the activities that occurred during plugging and identify any deviations from the initial plugging plan. Specific information required for the report are well location, plug date, plug emplacement method(s), plug materials, and depth of plugs. This report must be kept for ten years after site closure. The plugging report confirms that plugging operations were carried out in the manner specified in the Injection Well Plugging Plan. At minimum, the report should also include the bottomhole pressure and mechanical integrity test results, the type and number of plugs set, plug type, grade, weight and quantities, plug emplacement method, as and the top and bottom locations of each plug set. The report should also document the steps that were taken to prepare the well for plugging, including, description of flushing, inventory of debris removed, documentation of downhole equipment removed, description of tubing pulling, type and volume of plugging fluid used, and notes on if and how plugs were tagged, e.g., plug position directly measured by drillstring, tubing, or wireline (EPA, 2013b).

Post-Injection Site Care (PISC) and Site Closure

One of the unique features of a Class VI well is the Post-Injection Site Care and Site Closure requirements. During this time period, the CO_2 plume and the associated pressure front are monitored after injection has ceased. This phase of the GCS project, which is described by the PISC and Site Closure Plan that is submitted with the original permit application, ensures USDW protection after injection operations have ended. It ensures that prior to injection the owner/operator has clearly defined the methods and data that will be necessary to ensure that CO_2 plume and pressure front do not endanger USDWs [40 CFR 146.93(b)]. When this monitoring phase indicates that USDWs are no longer at risk, the PISC period ends and site closure can occur. The minimum duration of the PISC is fixed at 50 years, but the Director may approve an alternative timeframe. The actual timeframe is determined by the characteristics of the specific sequestration site. The PISC and Site Closure plan must cover this entire time period.

PISC

The PISC-SC plan must include basic information about the facility itself. In addition, the Class VI Rule requires the plan to include differences in pre- and predicted post-injection pressure, predicted plume and pressure front position at site closure, proposed post-injection monitoring locations, methods and frequencies, PISC monitoring reporting schedule, PISC duration, and site closure plan [40 CFR 146.93(a)]. During operations, the PISC-SC plan does not need to be reviewed (similar to the Plugging Plan). However, when operations cease the owner/operator must review the original plan in light of the now-known injection volume and pressure increases. The review must show the original plan is still appropriate or result in the submission of a revised PISC-SC plan. Some of the guidelines that can be used to determine the adequacy of the original plan is include: 1) the original monitoring plan sufficient are the proper types and amounts of data being collected to allow a non-endangerment decision; or 2) will the site care plans protect USDWs from endangerment by migration of CO_2 or formation fluid?

The default duration for the PISC phase of a GCS project is 50 years. However, the UIC Program Director can either shorten or extend this time period should monitoring require such adjustment [40 CFR 146.93(b)(10)(2)]. To justify this change, the owner/operator must submit documentation of a list of 11 items [40 CFR 146.93(c)(1)]. Records from the PISC phase must be kept for ten years following closure. At this time, they must be provided to the Director who will determine where the records will be retained.

The PISC ends when it can be demonstrated that there is no further endangerment to USDWs from either the injected plume or the pressure front. The owner/operator must submit a report detailing how risks have changed over time [40 CFR 146.93(b)]. This information must be supported by monitoring data and modeling results. Monitoring data derived from direct and indirect techniques must show the position and rate of motion of the plume and pressure front. Modeling can be used to estimate the phase-state and the degree of carbon trapping that has occurred over time, as well as the future migration of the plume. Based on monitoring, operational data, and site characterization, modeling must show that future movement of the plume is insignificant.

Monitoring: One of the major requirements of the PISC is to continue to monitor the site for the CO_2 plume and pressure front migration. This is important because CO_2 will remain mobile for a while, and elevated pressures are likely in the injection zone and possibly in overlying zones as well (EPA, 2013b).

Wells: During the PISC period, the Class VI Rule requires in-situ measurements of fluid pressures [40 CFR 146.90(g)(1)] as well as collection of groundwater samples above the confining zone for geochemical analysis [40 CFR 146.90(d)]. During initial stages of the PISC, wells used for monitoring during the injection phase may still be used. If the plume continues to migrate, but in directions different from those originally predicted by computational modeling, new monitoring wells may have to be drilled and constructed (Fig. 102). The need for new monitoring would trigger a PISC and Site Closure Plan review and resubmission to the UIC Program Director for approval [40 CFR 146.93(a)(4)]. Groundwater samples must be analyzed for CO_2, major anions and cations, organics, total dissolved solids, pH, temperature, mobilized or injected drinking water contaminants, and displaced formation fluids. If the UIC Program Director mandated the injection of tracers, the monitoring program must analyze for these as well. In addition, the reservoir pressure must be measured. EPA (2013b) suggests use of pressure transducers for measuring pressure. Because elevated pressure is a prime driver of USDW endangerment, EPA (2013b) recommends PISC monitoring focus primarily on pressure.

Geophysical Surveys: During injection, both direct and indirect methods are to be used to monitor plume and pressure front movement. If indirect surveys were used during the injection phase, EPA (2013b) recommends continuing the same indirect monitoring program in the PISC phase. Other possible indirect monitoring methods include seismic, electromagnetic, and gravity and ground displacement surveys. Seismic surveys repeated at the same locations over time provide time-lapse documentation of subsurface changes.

Frequency: Because the frequency of monitoring is tied to site-specific conditions and which change during the PISC, monitoring the frequency of monitoring and reporting will also change. Initially, a schedule similar to that used during injection would be appropriate. With time, this frequency can be changed in light of evolving subsurface conditions.

Results Reporting: The original PISC and Site Closure Plan requires a proposed schedule for reporting monitoring results [40 CFR 146.93(a)(2)(iv)]. All reports should including the following information: 1) monitoring events and dates during the reporting period, 2) identification of gaps in the monitoring data, 3) discussion of any changes in the monitoring plan, 4) use of entire, historical monitoring dataset to interpret results, and 5) any changes in the PISC and Site Closure Plan that are deemed necessary. In addition, the rule requires detailed and specific information describing groundwater geochemistry monitoring.

Monitoring Timeframe: By rule, the PISC monitoring time period is set at 50 years [40 CFR 146.93(d)]. This timeframe may be changed with the approval of the UIC Program Director [40 CFR 146.93(c)]. When submitted, either the default or an alternative timeframe may be proposed in the PISC and Site Closure Plan [40 CFR 146.93(a)(2)(v)]. Any alternative PISC timeframe must be extensively justified and approved by the UIC Program Director.

Site Closure

A minimum of 120 days before site closure and the end of PISC, the owner/operator must submit a Notice of Intent for Site Closure report for review. This document must describe any changes to the PISC and Site Closure Plan [40 CFR 146.93(d)]. Once approved, site closure would proceed according to this plan. Activities that might occur in this time period might include plugging and abandoning of all monitoring wells [40 CFR 146.93(e)], submission of site closure report, and recording of relevant documents and deeds that the site is underlain by sequestered CO_2. Although not required, EPA recommends that monitoring wells are plugged using the same procedures, methods, and materials as the injection well. Within 90 days of site closure approval, a site closure report must be submitted to ensure proper procedures were followed during closure [40 CFR 146.93(f)]. In part, this document will inform future land owners

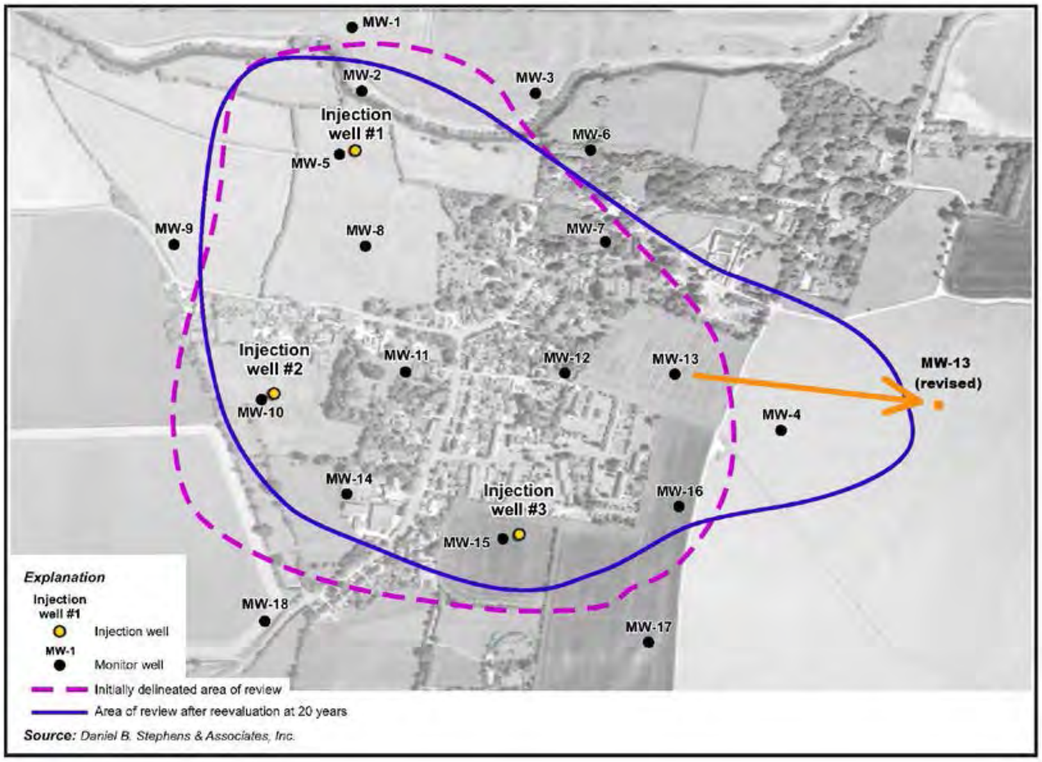

Figure 102. Map of a hypothetical GCS project with revised AoR and new monitoring well. In this example, monitoring data has revealed that the plume is moving in a direction (orange arrow) other than that predicted by the original computational modeling. Thus, the original AoR (dashed line) was revised and a new monitoring well (MW-13) added to the PISC and Site Closure Plan. Both of these changes would require permit amendments to the respective plans and UIC Program Director approval (Source: EPA, 2013b).

and planners of the activities that occurred at the site. The report must also indicate the nature, composition, and volume of CO_2 that was injected [40 CFR 146.93(f)(3)]. It must document plugging procedures for the injection well and monitoring wells, indicate the nature, composition, and volume of the carbon stream injected, and contain a survey plat that has been submitted to the local zoning authority. The notation on the title must include a statement that the land has been used for GCS, name of state agency, local authority, and/or tribe the survey plat was filed with, the regional EPA to which it was submitted, and the volume and dates of CO_2 injection [40 CFR 146.93(g)]. As mentioned previously, all records produced during the PISC must be kept by the owner/operator for ten years after closure. A copy of the site closure report will be submitted to EPA and retained in EPA's electronic reporting system [40 CFR 146.93(f)].

After closure, the owner/operator is responsible for remedial action necessary to protect USDWs from endangerment resulting from injection. In short, the owner/operator is still financially liable for the site. When the UIC Program Director approves closure, the owner/operator is no longer subject to regulatory enforcement. Should a contaminant enter or threaten a public water system or USDW, the UIC Program Director under the authority of Section 1431 of the SWDA may require the owner/operator to take appropriate action to protect public health.

Emergency and Remedial Response

To ensure that all parties are prepared to address any emergencies that arise during well construction, injection, and PISC, an Emergency and Remedial Response (ERR) Plan must be submitted with the Class VI well permit application and approved by the UIC Program

Director. This plan must be site- and project-specific and account for regional geology, USDW depths, injection well operating conditions, the nature of the CO_2 stream, and any activities taking place within the AoR [40 CFR 146.91(a)]. Adverse events, which could occur during well construction, injection, or PISC, might include loss of injection well MI or CO_2 plume or formation fluid movement that endangers USDWs. In the event of such emergencies, an ERR plan ensures a process is in place to deal with such adverse conditions quickly and effectively. Actions taken in response to an adverse event and outlined by the ERR Plan must ensure that USDWs are protected. When such events occur, the UIC Program Director must be notified within 24 hours of the event.

An adequate ERR Plan must include basic information describing the facility as well as a list of resources and infrastructure that lie within the AoR. Descriptions of planned staffing training and exercise procedures must be included. There must be a communications plan and a procedure for notifying relevant agencies and individuals when adverse events occur. Attachments describing a safety and health plan and an AoR map identifying relevant resources and infrastructure must accompany the plan.

As with most of the other plans required by a CO_2 injection well permit, an ERR Plan must be periodically reviewed and if necessary, revised [40 CFR 146.94(d)]. A number of factors could suggest or require an ERR review. For example, departure of monitoring data from model predictions might trigger an ERR Plan review. When monitoring data suggest emergency events are more likely than originally estimated, the ERR Plan should be reviewed. MIT results that suggest potential well failure should also trigger an ERR review. The development of new infrastructure or resources adjacent to or within an AoR might warrant a review. In the event that emergency procedures were triggered, the ERR should be reviewed in light of lessons learned. In contrast, an AoR review and/or revision requires, by rule, an ERR review.

In the event of an emergency, the owner/operator must immediately cease injection, characterize the nature of the release, and implement the ERR Plan. Within 24 hours of the event, the UIC Program Director must be notified. If USDWs are not endangered, the UIC Program Director can allow the resumption of injection before remedial action is actually taken [40 CFR 146.94(c)].

Other Permit Requirements

Well Construction and Mechanical Integrity

One of the key safety features of a GCS project is the injection well itself. Like all UIC injection wells, it must ensure efficient injection operations while protecting USDWs by ensuring mechanical integrity and zonal isolation. Because CO_2 is more corrosive than many injected fluids, Class VI wells must be constructed using materials that will stand up to chemical attack for the duration of an GCS project [40 CFR 146.86(a)-149.86(c)]. Thus, the Class VI Rule describes well construction in detail. In the permit application, the design of the well must be described and accompanied by schematics. Before construction begins, this plan must be approved by the UIC Program Director. Any construction changes must have prior approval of the director. Before the well is authorized to inject CO_2, the construction records are reviewed by the UIC program staff who determines if it was constructed in a manner that will prevent migration of fluids out of the injection zone.

Well Design: Compared to Class II injection wells, Class VI wells will inject CO_2 at higher rates and pressures. They are also likely to have considerably longer lifetimes (EPA, 2012a). For these reasons, the construction of a Class VI is more highly regulated than for Class II wells. Elements of the Class VI well that are of particular concern are the casing, cement, tubing, and packers (Fig. 103). Materials used to construct these elements must prevent movement of fluid into or between USDWs or any other unauthorized subsurface zone. Secondly, they must be constructed in a manner that will permit any of the subsequent well operations that will be required by the Class VI permit, e.g., testing and monitoring [40 CFR 146.86(a)(2)]. In addition, all materials used in well construction must be compatible with the fluids they will come in contract with during the lifetime of the GCS project [40 CFR 146.86(b)(1)].

By rule, the surface casing of a Class VI well must extend to below the base of the lowermost USDW and be cemented all the way to the surface [40 CFR 146.86(b)(2)]. Where USDWs are particularly deep, multiple casing strings can be set to function as surface casing, but each must be cemented up to the surface (EPA, 2012a). Intermediate casing(s) may or may not be used, but the UIC Program Director can mandate the use of such casing as geologic subsurface conditions warrant. If intermediate casing is used, each string must be cemented up to the surface (Fig. 103) [40 CFR 146.86(b)(3)]. The long-string casing (i.e., the equivalent of the production casing in an oil and gas well) must extend to the injection zone and be cemented along its entire length [40 CFR 146.86(b)(3)]. Although liners can be used in place of casing strings, EPA (2012a) cautions they might not provide the mechanical integrity of an equivalent casing string.

Before surface casing and the long-string casing are set, the Class VI Rule mandates running a caliper log [40 CFR 146.87(a)(2)(i) and 40 CFR 146.87(a)(3)(i)]. A caliper log measures the internal diameter of the borehole or casing. The caliper tool consists of centralizers and a set of retractable mechanical arms (Fig. 104). To run a caliper log, the tool is lowered to the bottom of the hole, the mechanical arms extended until they contact the borehole, and the tool pulled up slowly. As the tool rises, the arms are forced inward wherever the hole narrows and expand outward where the diameter widens. In this manner, a continuous depth record of hole diameter is obtained. Caliper logs ensure a uniform borehole diameter and detect wash-out and collapse zones. It is used to calculate the amount of cement needed to cement the casing. When run inside the casing, this method identifies casing breaks, distortions, and corrosion (EPA, 2012a).

The Class VI Rule has some very specific requirements for setting and cementing casing. It requires centralizers be used on the long-string casing [40 CFR 146.86(b)(3)]. Although not required on surface or intermediate casing, EPA suggests the use of centralizers on these strings as well. The use of centralizers ensures a uniform

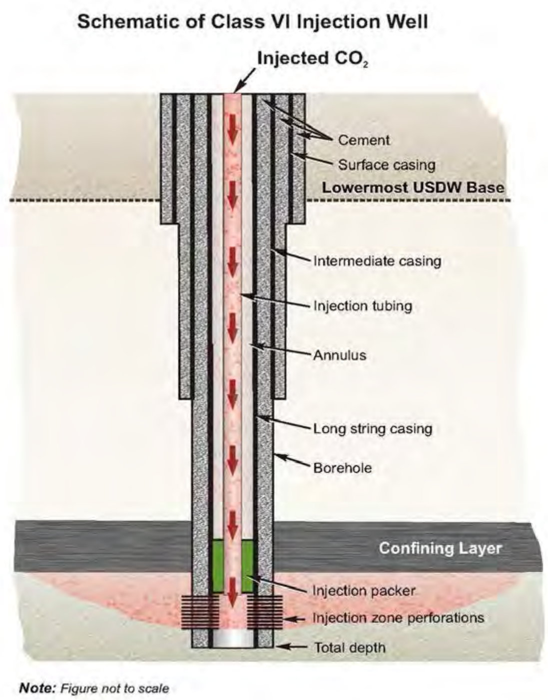

Figure 103. Schematic cut-away of a Class VI injection well. The key elements of the well are its casing, cement, tubing, and packers. By rule, all of these materials must be selected to withstand downhole stresses and to be compatible with fluids they may come in contact. (Source: EPA, 1982, 2012a)

sheath of cement around the casing string. This is particularly important through the injection and confining zones EPA (2012a). Proper cement-formation bonding is critically dependent on displacement of drilling mud before cementing. Therefore, EPA (2012a) suggests flushing of drilling mud using a displacement fluid and using scratchers on the casing to remove mudcake from the borehole wall as the casing is rotated down into the hole. Given the tendency of casing to sit on the bottoms of horizontal wells, EPA (2012a) recommends closer spacing of centralizers along horizontal well segments.

Although EPA prefers single stage cementing, it may not be possible to cement the long-string casing in a single stage in very deep injection wells or wells intersecting weak formations or unconsolidated zones EPA (2012a). For the former, the height of the required cement slurry column may exceed the pressures that the cement pumps can deliver. In the latter case, weak shallow

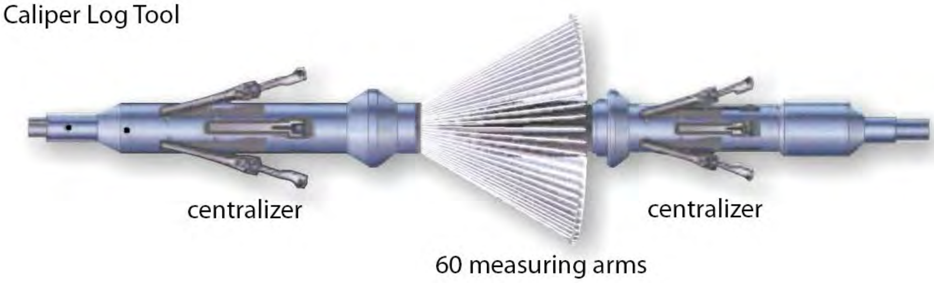

Figure 104. A caliper log tool with two centralizers and a set of measuring arms. The Class VI Rule requires running a caliper log before surface and long-string casing are set and cemented. (Source: EPA, 2012a)

formations may be fractured by the pressure of the cement slurry. In these cases, multistage cementing may be used to cement the entire length of the casing if approved by the UIC Program Director [40 CFR 146.86(b)(4)]. In two-stage cementing, the casing is fitted with a cement collar with cement ports (Fig. 105). The ports allow placement of cement slurry into the annulus at some intermediate point along the casing string. The first stage delivers cement slurry to the lower portion of the well as in a single stage primary cement job. When a predetermined amount of cement slurry has been pumped into the casing, a displacement fluid forces the rest of the cement slurry out of the casing. At this point, a plug, called a bomb, is dropped down the casing (Fig. 105). When it encounters the cement collar, the bomb closes a valve, thereby isolating the lower part of the casing. When it hits the collar, a second plug opens the cement ports. Cement slurry is then pumped down the casing and out the ports into the annulus (Fig. 105). If designed properly, the top of the cement from the first stage is at some distance below the cement ports. The cement slurry fills this section and is circulated to the surface. On completion of cementing, a third plug closes the cement ports. Three-stage cementing uses two cement collars and is useful in situations where there are two weak formations along the borehole or it is very deep. Reverse circulation cementing is an alternative method that pumps cement directly down the annulus from the surface EPA (2012a). Because of the shorter cement slurry column, bottomhole pressure is reduced. This type of cementing often uses less dense cement and it is more difficult to ensure proper cementing than with standard methods.

After setting and cementing of the surface and long-string casings, cement bond and variable density logs must be run [40 CFR 146.87(a)(2)(ii) and 40 CFR 146.87(a)(3)(ii)]. These two logs use sonic signals to produce complementary information about the quality of the cementing job (Fig. 72). They are typically run simultaneously and indicate the presence or absence of cement behind the casing and the quality of the cement-formation bond (see Chapter 6).

The Class VI Rule requires CO_2 injection through tubing with a packer set opposite a cemented interval [40 CFR 146.86(c)(1)]. The depth at which the packer is set must be approved by the UIC Program Director [40 CFR 146.86(c)(2)]. The packer must be constructed of materials compatible with the injected CO_2 stream [40 CFR 146.86(c)(1) and (2)]. The burst strength of the tubing must exceed that of the planned injection pressure, whereas its collapse strength must be greater than the anticipated annulus pressure. Details of the tubing set-up that must be provided in the well permit application include depth of setting, tubing size, maximum injection pressure, maximum annulus pressure, and tubing tensile, burst, and collapse strengths. The nature of injection (continuous or intermittent) as well as the volume of injection must also be specified. The tubing-long string annulus must be filled with a non-corrosive fluid [40 CFR 146.88(c)].

The proposed well design must permit use of required logging tools and for well workovers (see Testing and Monitoring section in this chapter).

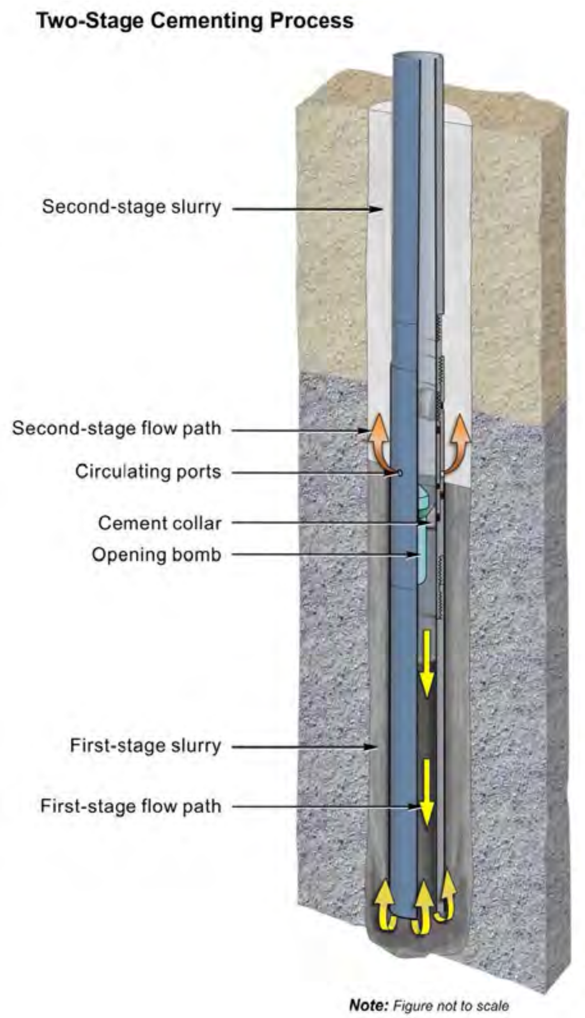

Figure 105. A caliper log tool with two centralizers and a set of measuring arms. The Class VI Rule requires running a caliper log before surface and long-string casing are set and cemented. (Source: EPA, 2012a)

Thus, the well diameter must be larger than that of the largest instrument/tool that will pass through the well [40 CFR 146.86(a)(2)]. Likewise, for horizontal wells, the radius of curvature of the well must allow the required logging tools to enter the horizontal segment of the well. Tubing diameter must also be selected to accommodate all required logging tools.

Detailed well construction schematics and drawings showing casing points must be included in the permit application along with detailed construction procedures. These must include details about casing, cementing, tubing, and packers. A well schematic must include depth to injection zone, hole size, size and grading of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material), number and spacing of centralizers (to ensure adequate cementing), type or grade cement, and cement additives to be used. To evaluate the suitability of the casing and cementing plan, proposed injection pressure, external formation pressure, internal annular pressure, tubular loading, downhole temperatures as well as the composition, temperature, and quantity of the injection stream must be specified in the construction plan [40 CFR 146.86(b)(1)(i)-(ix)]. The corrosiveness of the CO_2 stream and formation fluids must also be specified. For the tubing, the permit application must indicate depth of setting; CO_2 stream characteristics (chemical content, corrosiveness, temperature, density), nature of formation fluids, maximum proposed injection pressure, maximum proposed annulus pressure, proposed (intermittent or continuous) injection rate, volume and mass of CO_2 stream, size of tubing, and tubing tensile, burst, and collapse strengths. The permit application must also describe the lithologies of the confining and injection zones [40 CFR 146.86(c)(3)(i)-(vii)].

Pre-injection Requirements: On approval of the construction plan by the UIC Program Director, construction of the injection well can begin. Once the well is constructed, a series of tests on the well and the formations it intersects are required. These tests are designed to ensure the computational parameters (depth, thickness, porosity, permeability, etc.) are known accurately, to establish baseline data against which to compare future monitoring data, and to verify well construction parameters. A report of the well logs acquired, core and formulation fluids analyzed, as well as the results of the formation tests must be submitted to the UIC Program Director for approval to inject [40 CFR 146.87(a)].

Both uncased and cased logs must be run on the borehole during construction. Before casing, resistivity, spontaneous potential, and caliper logs must be run [40 CFR 146.87(a)(1)-(4)]. Cement bond, temperature, and variable density logs must be run after surface casing is set and cemented. Once the hole has been drilled to the injection zone and before the long-string casing is set, the hole must be logged for resistivity, spontaneous potential, caliper, gamma ray, and fractures (i.e., a fracture finder log). The integrity of the cementing of the long-string casing must be confirmed by re-running cement, temperature, and variable density logs.

On well completion, a series of tests to ensure external and internal mechanical integrity are required. These may include pressure tests with liquid or gas, tracer surveys, oxygen-activation logging, temperature or noise logs, casing inspection logs, or alternative tests approved by the UIC Program Director. The UIC Program Director must have the ability to observe all of the logging and testing done on the well. Thus, the owner/operator must provide a schedule of these activities 30 days before the first test. Changes to the testing schedule must be conveyed to the UIC Program Director 30 days before the next test is scheduled. The UIC Program Director may suggest changes to the schedule as well as approve/disapprove it.

Regulations require the submission of information about formation and formation fluid properties after well construction and before injection [40 CFR 146.82(c)]. These data are in addition to and supplement data originally submitted with the pre-construction permit application [40 CFR 146.86(a)]. This report summarizes information from cores, either whole or sidewall, collected from the confining and injection zones. Data must include permeability, porosity, and mineralogical descriptions. Coring must be adequate to fully characterize these zones. Formation fluid samples from the injection zone must be analyzed for temperature, pH, conductivity, reservoir pressure, and static fluid levels in the well. Based on conductivity, the UIC Program Director will certify that the injection zone is not a USDW. These data provide a baseline for subsequent monitoring results, as well as input parameters for injection computational modeling. Regulations also require fracture pressure and injectivity testing to establish the hydrogeologic and physical nature of the confining and injection zones [40 CFR 146.87(e)].

Operational Plan

In the well permit application, the owner/operator must detail the proposed operational parameters of the proposed injection well [40 CFR 146.82(a)(7), (9) and (10)]. The plan must provide sufficient information that assures the UIC Program Director that USDWs will be protected. Once approved, the operational plan becomes part of the injection permit. The UIC Program Director must also approve any proposed stimulation of the injection zone. Stimulation is any operation carried out to improve formation transmissivity/injectivity around the borehole by increasing the size and number of pre-existing fractures or by creating new ones. Some of the operational data to be included in the permit application are the proposed injection and annulus pressures, the types of continuous recording devices to be used, surface shut-off devices proposed, and the type of non-corrosive fluid that will fill the long-string tubing annulus. If required by the UIC Program Director, the type of downhole shut-off devices to be used must also be identified. This information is designed to allow the UIC Program Director to evaluate the likelihood that the proposed operational plan will ensure that injection along the outermost casing and wellbore is not likely to happen.

A number of operational parameters are specified by the rule [40 CFR 146.88 and 146.82]. For example, injection pressure must be less than 90 percent of the formation fracture pressure, a parameter determined during site characterization. During any approved stimulation plan, this value can be exceeded. During operation, injection pressure and rate as well as CO_2 stream temperature and volume must be continuously monitored and recorded. Annulus pressure, as specified in the permit, must be greater than injection pressure to prevent leaking from the long-string tubing to the annulus. As with the injection parameters, annulus pressure and volume must be continually monitored and recorded for reporting purposes. Except during approved stimulation operations, injection operations must not hydraulically fracture the injection formation. All stimulation programs must be pre-approved by the UIC Program Director and the owner/operator must provide advance notice before such a program is initiated. At all times during injection operations, well mechanical integrity must be maintained. The only times mechanical integrity is not required is during pre-approved well maintenance activities.

To assist in tracking the CO_2 plume, the UIC Program Director may require that a tracer be added to the injection stream. The presence of a trace would make it easier to determine the position of the plume in the subsurface. The Program Director can also specify the type of tracer to use.

Class VI regulations require alarms and automatic surface shut-off systems for all onshore wells. At his/her discretion, the UIC Program Director can also require downhole shut-off systems. These systems are required for offshore injection wells within state territorial waters. The systems installed must warn the operator when operating parameters are exceeded and automatically shut off the well. When closed, these systems prevent fluid flow out of the well. In the event an automatic shut-off system is triggered or the well loses mechanical integrity, injection operations must immediately cease and the operator must determine if injectate was released to any unauthorized zones. Within 24 hours of such an event, the owner/operator must notify the UIC Program Director with a written report. Injection can re-commence only when it has been proven to the UIC Program Director that full mechanical integrity has been restored or the malfunction remediated. When the resumption of injection is approved, the UIC Program Director must be notified when normal operations resume.

Depth Waiver

Although the Class VI Rule normally requires injection below the lowermost USDW, the rule does allow for an exception to this requirement [40 CFR 146.95]. This provision permits injection above and/or between USDWs under certain conditions. While part of the federal Class VI Rule, states seeking primacy over Class VI need not include this option in their own programs. To request this waiver, an owner/operator must submit a supplemental report with their initial well permit application. If the state allows such waivers, the UIC Program Director will forward the depth waiver request to the EPA Regional Administrator (RA), who will make the final decision on whether or not to grant the waiver.

In the supplemental report, the injection zone must be shown to be appropriate for injection and by demonstrating confining zones bracket the injection zone. In addition, injection well construction, operation, and monitoring will have to be conducted so as not to endanger the upper or lower USDWs [40 CFR 146.95(a)]. The supplemental report must contain a geologic/hydrogeologic map and two cross-sections (like the standard application) that show the proposed injection zone is laterally continuous, is not hydraulically connected to the USDWs, does not crop out in the AoR, has injectivity, porosity, and volume adequate to accommodate the proposed CO_2 volume, is bounded above and below by confining zones without transmissive faults or fractures, and is geochemically compatible with the proposed CO_2 injectate [40 CFR 146.95(a)(1) and (2)]. The Testing and Monitoring Plan must incorporate monitoring both above the upper confining zone and below the lowering confining zone [40 CFR 146.95(a)(3)-(7)]. The supplemental report must also include a water treatment plan or identify alternative water sources in the event USDWs are contaminated. It must also document alternative injection sites [40 CFR 146.95(b)(1)(iii)-(iv) & (viii)].

Before a waiver can be granted, two additional stakeholders must be involved in the decision making process [40 CFR 146.95(b)(2) and (3)]. One is the state's Public Water System Supervision (PWSS) Director or similar agency. The other stakeholder to be notified of the depth waiver request is the general public. To this end, the UIC Program Director must provide public notification of the waiver request. This notification must identify the depth of the injection zone, injection well location, name/depth of USDWs in AoR, any public water supplies affected or supplied by USDWs in AoR, and results of the UIC-PWSS Directors consultations [40 CFR 146.95(c)]. It must also include a map of the AoR. On completion of the public notification process, the UIC Program Director will forward all relevant information to the EPA Regional Administration for his/her acceptance/rejection of the depth waiver request [40 CFR 146.95(d)-(e)]. If a waiver is issued, the EPA-RA will notify the UIC Program Director in writing and within 30 days EPA Headquarters will post on the Office of Water's website the proposed injection zone depth, injection well location, name and depth of all

USDWs in AoR; AoR map, and names of public waters affected, likely to be affected, or served by USDWs in the AoR [40 CFR 146.95(d) and (e)].

State Primacy

As with the main UIC program, EPA has created a procedure whereby states, tribes, or territories can acquire primacy over Class VI well programs. To be granted primacy, an entity must demonstrate they have jurisdiction over underground injection, their regulations are as strict as federal regulations, and they have the necessary administrative, civil and criminal authority to punish non-compliance. For states, tribes or territories seeking Class VI well primacy there are two possibilities: either managing the entire program or just Class VI wells. This flexibility represents a change in EPA policy. Under the new regulations a state, tribe, or territory can have independent control of only Class VI wells. In the past, there was, except for Class II wells, no flexibility about which well classes could be administered. Since states can have different authorities for the UIC program, there are two potential paths the state can pursue in gaining primacy. This difference is because Class VI wells are authorized under SDWA 1422, not 1425. For states with full UIC program control, i.e., acting under SDWA 1422, they merely have to revise their existing program to include Class VI wells. Other states independent of whether or not they have Class II authority, must develop a new UIC Class VI program. If an entity does not submit an application for Class VI primacy, EPA will administer that UIC class in the state.

For a state applying for a new Class VI primacy, the application to EPA has six core elements: letter from the Governor, complete program description, Attorney General's statement, Memorandum of Agreement with the appropriate regional EPA administrator, copy of all applicable state statutes and regulations, and demonstration of compliance with the public participation rules for drafting the new Class VI regulations. Once EPA receives the application, it conducts a completeness review and if this is satisfactory begins a statutorily required review. There is a notice and 30-day comment period, which provides an opportunity for the public to comment on the pending program. After review, the application is either approved or disapproved. If it is approved, EPA announces the fact through its rulemaking process and publishes their findings in the Federal Register. The program becomes effective on the Register publication date.

For states, tribes, and territories wanting to modify their UIC programs to include Class VI wells, the application process is significantly different. First, these entities need to conduct a review of their program to determine if changes to other well classes are required. Once this review is complete and the guidelines for the new class established, these entities must submit an application to EPA. The application must include a UIC program description, an Attorney General's statement, and a Memorandum of Agreement with the state's regional EPA administrator. In the UIC program description, the state must note any aquifer exemptions, waivers on injection depth, and required financial responsibilities. On receipt of an application, EPA conducts a review, including public notice, of the application including summary of revisions, 30-day public comment period, and the opportunity for the public to request that a public hearing be held. The notice of the public comment period is to be published in state newspapers and published in the Federal Register, as well as mailing a notice to interested parties. After review and comment, the application is approved or disapproved. If approved, the approval is announced by the EPA through its normal rulemaking process and published in the Federal Register. It becomes effective on the Register publication date.

Summary

EPA created the new UIC Class VI well to address the unique characteristics of injected CO_2, e.g., mobility, buoyancy, corrosivity, large volumes, and large spatial footprints of proposed GCS operations. None of these characteristics were properly addressed by any of the existing UIC well classes. In creating the new well class, EPA started with the basic components of the other classes and either modified these components or added new ones. Well class components carried over to Class VI are site characterization, area of review, well construction and operation, site monitoring, post injection site care, site closure, and public participation in the permitting process.

Discussions about how the UIC program would handle geologic carbon sequestration began in 2005 with a series of technical workshops on the subject. These workshops engaged technical stakeholders from various industries, other governmental agencies, and academia. In September, 2007, EPA announced their intention to create a new well class. The draft rule was published in 2008 and finalized in 2010. In support of the rule's implementation, EPA has created a series of guidance documents aimed at both regulators and owner/operators. States can apply for Class VI primacy as part of their larger UIC program or they can manage the well class by itself. To date, no state has been granted primacy over Class VI by EPA.

Unlike the other well classes, Class VI permits are issued for the lifetime of the project and do not require periodic permit re-filing and re-issuance. To accommodate this change, a Class VI well permit application consists of five separate, but interrelated, project plans: Area of Review and Corrective Action, Testing and Monitoring, Injection Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response. If the permit application is approved, these plans become part of the permit and the project must be run according to the programs they describe. Another unique characteristic of the Class VI well application process is the manner in which the AoR is delineated. For this new class, computational modeling of the injected CO_2 plume and the formation pressure front are used to define the AoR. The AoR must also be periodically reviewed as new site, operating, and monitoring data become available. The maximum time between AoR reviews is five years. If changes are required to the AoR, the Area of Review and Corrective Action, Testing and Monitoring, and Emergency and Remedial Response Plans must be reviewed as well. Amendments to these plans must be approved by the UIC Program Director and on approval become part of the permit. Given the varied geologic settings anticipated for geologic carbon sequestration, the Class VI Rule is not overly prescriptive. Rather, project plans are site- and project-specific. Because of this feature, development of a Class VI permit requires an extensive site characterization phase.

Chapter 8
Summary

Carbon capture and storage (CCS) has been proposed as a means of reducing anthropogenic emissions of CO_2 while permitting continued use of the Earth's abundant fossil fuel resources. CCS is a three stage process that would integrate a number of proven industrial technologies into a new type of industrial chain involving massive material and energy flows. The first stage of CCS involves capturing CO_2 from stationary sources such as power plants, refineries, cement plants, etc. The captured CO_2 is transported to a storage site by pipeline or, depending on location, ship. Three commonly discussed storage options are ocean, geologic, and mineral. Ocean storage would pump CO_2 either into the water column to form CO_2 plumes or depressions on the seafloor to produce CO_2 lakes. If CO_2 is injected at water depths below approximately 1,640 feet (500 meters), it will form a gaseous plume that will rise and ultimately be dispersed in the water column. Below this depth, the injected CO_2 will be in liquid form. Between 1,640 and approximately 8,200 feet (500 to 2,500 meters) the injected CO_2 liquid will be less dense than seawater and rise to shallower depths while dissolving and dispersing into seawater. However, at deeper depths the denser liquid CO_2 would sink toward the ocean floor and either dissolve into seawater or pool on the seafloor. All ocean sequestration scenarios would sequester CO_2 from the upper ocean thereby avoiding the ocean acidification associated with the equilibration of the upper ocean and an increasingly CO_2 rich atmosphere.

Geologic sequestration injects supercritical CO_2 into suitable, porous subsurface geologic formations where it would remain sequestered for hundreds to thousands of years. Both ocean and geologic storage approaches involve CO_2 in fluid form, a physical state that is readily mobile and, therefore, difficult to prevent from migrating in the ocean or subsurface. In contrast, mineral carbonation reacts CO_2 with various chemical constituents, i.e., divalent cations of metals such as calcium, magnesium, and iron, to produce carbonate minerals. To significantly reduce anthropogenic emissions, these metals would have to be mined, processed, and transported on a scale that would be similar to that of the modern mining industry. In addition, a vast quantity of newly produced carbonate minerals would have to be disposed of safely, efficiently, and economically.

The CO_2 storage option closest to wide scale deployment is geologic carbon sequestration (GCS). This process involves injecting CO_2 into geologic formations for sequestration on the time scale of hundreds to thousands of years. To reduce significantly the volume of CO_2 that must be stored, injection is anticipated to be at depths greater than 2,625 feet (800 meters) where temperatures and pressures are such that CO_2 will be a supercritical fluid, i.e., a fluid with a combination of gas- and liquid-like physical and chemical properties. The four primary GCS targets are: depleted oil and gas reservoirs, producing oil and gas fields, unmineable coal seams, and saline formations. In the United States, CO_2 is routinely injected into aging oil and gas fields as a means of enhanced oil recovery (CO_2-EOR). This approach to sequestration has the benefit of an economic justification for CO_2 sequestration, i.e., the recovery of additional petroleum. CO_2-EOR has been successfully conducted in the United States for over 30 years, and an extensive pipeline system for moving CO_2 has been constructed in the mid-portion of the country. Depleted oil and gas fields have the same geologic features that make active oil and gas fields likely targets for GCS, e.g., proven injection and confining strata and significant geologic datasets. In addition, their subsurface geology is well-known, thereby reducing the cost of site characterization. Because all depleted oil and gas fields contain significant amounts of residual oil, sequestration in these fields may also allow the recovery of additional oil, thereby reducing the economic costs of building a sequestration project using these reserviors. Saline formations are porous geologic formations containing groundwater with greater than 10,000 mg/l total dissolved solids, i.e., brine. These units are widespread in the United States and globally, and have been estimated to have a significant storage capacity, e.g., enough to store several hundred years of anthropogenic fossil fuel combustion emissions. Because coal has a greater affinity for CO_2 than methane, gaseous CO_2 injected into unmineable coal seams above 2,625 feet (800 meters) is adsorbed onto coal surfaces, releasing methane. Thus, geologic carbon sequestration in coal seams can also lead to enhanced coalbed methane (ECBM) recovery, which like CO_2-EOR provides an economic incentive for sequester CO_2. The biggest drawbacks to coal seam sequestration is the possibility that future advances in mining technology may render the coal seam a viable mining target, and seams that are likely candidates for GCS are often sources of drinking water. At injection depths greater than 2,625 feet (800 meters), injected CO_2 will be in a supercritical state and the CO_2 is absorbed into the coal itself, not adsorbed onto its surfaces.

In the long-term, storage in deep, porous saline formations is viewed as the most likely target for storing large volumes of anthropogenic CO_2. Because CO_2 and brine are immiscible, injection into these formations will produce two fluid phases, i.e., brine and supercritical CO_2. Supercritical CO_2 is less dense and viscous than brine, so it will be more mobile than brine and have a tendency to rise within the storage formation due to buoyancy. Given this behavior, CO_2 must be prevented from migrating out of the injection zone by various physical and chemical processes, i.e., *trapping mechanisms*. *Structural* or *stratigraphic trapping*, also known as physical trapping, occurs when buoyant CO_2 fluid is trapped beneath an impermeable rock formation. During *residual* or *capillary trapping*, pockets of CO_2 become disconnected or isolated from the main CO_2 plume and trapped in the storage formation pore space. With time, CO_2 in contact with brine dissolves into the formation fluid producing a single fluid phase, a process known as *solubility* or *dissolution trapping*. This process consumes the buoyant phase, thereby eliminating upward fluid migration. On a longer time scale, injected CO_2 once dissolved in formation water reacts with the minerals in the storage formation and caprock to form new carbonate minerals, i.e., *mineral trapping.* This chemical process renders CO_2 solid and immobile. Residual and capillary trapping are the result of physical processes, whereas solubility and mineral trapping occur because of chemical reactions. As these processes proceed, injected CO_2 becomes less mobile over time and storage security naturally increases.

As with any industrial activity in developed nations, GCS will be regulated by a variety of environmental laws. The three U.S. environmental laws with the most direct impact on GCS are the Clean Air (CAA), Clean Water (CWA), and Safe Drinking Water (SDWA) acts. The CAA impacts GCS both directly and indirectly. First, it will impose reporting requirements on any sequestration project through Subpart RR of the Clean Air Act. The second impact will be more indirect, but possibly of greater consequence. This impact relates to the prevention of significant deterioration and Title V permitting requirements with regards to CO_2 emissions. These regulations have already taken effect, but at this time EPA has not mandated reductions in CO_2 emissions as they have for other air pollutants regulated by the CAA. However, future enforcement of the regulation may mandate lowering GHG emissions from industrial sources. For those industrial facilities using fossil fuels, GCS may be the only technically viable technology available for lowering their GHG emissions.

When injected into a saline formation, supercritical CO_2 displaces formation brine and causes a pressure increase within the storage formation. If too much CO_2 is injected, fluid pressures may ultimately exceed fracture pressure and fracture of the injection and confining formations may occur, thereby compromising storage integrity. It has been suggested that one means of managing formation pressure is by extracting or producing some of the brine originally in the storage formation. Because this produced brine would have total dissolved solids greater than 10,000 mgle, its improper disposal or discharge would violate the CWA. Disposing of it to any surface water would, therefore require a discharge permit under the NPDES program of CWA. Of the three relevant environmental laws, the SDWA is the law most directly impacting GCS projects. Through its Underground Injection Control (UIC) Program, it will regulate CO_2 injection so as not to endanger underground sources of drinking water (USDW). Thus, the UIC program will control how, and ultimately if, CO_2 can be injected into a particular geologic formation.

As part of the SDWA, the UIC Program regulates underground injection of nearly all fluids, i.e., liquid, gas, or slurry, in the United States. It defines six classes of injection wells that cover a range of activities and industries. Classes I through III regulate the injection of fluid below the deepest USDWs in a region. Class IV, which was originally designed to regulate injection of hazardous or radioactive fluids into or above USDWs, has been banned nationally and can now be used only for approved remediation projects. Class V regulates injection of non-hazardous materials into or above USDWs. The new Class VI manages the injection of supercritical CO_2 for the purpose of long-term geologic storage, generally at depths below the lowermost USDW.

The UIC well classes are designed to ensure that injection wells are sited, constructed, operated, tested, monitored, and closed in a manner that protects underground sources of drinking water. However, when considering the commercial scale deployment of geologic carbon sequestration, EPA concluded that the unique characteristics of GCS could not be handled through any of the existing UIC well classes. Some of the unique characteristics of GCS that EPA considered in making this decision included the new application of existing technology (underground injection), the large volumes of CO_2 likely to be injected, the buoyancy and mobility of CO_2 in the subsurface, the corrosivity of CO_2 in the presence of water, and the possibility of impurities in the injected carbon stream. In addition, the likely acidification of formation waters may lead to mobilization of trace elements as well as other subsurface contaminants. All of these factors led EPA to propose the creation of a new UIC well class.

To develop the Class VI Rule, EPA started with the basic components of the other UIC well classes, i.e., site characterization, area of review, well construction and operation guidelines, site monitoring, post-injection site care, public participation, financial responsibility, and site closure. As a means of accommodating the unique characteristic of the injected carbon stream, these components were modified, often significantly. In this manner, the new Class VI well class incorporates proven regulatory approaches while accounting for the unique nature of GCS. In addition, EPA attempted to make the new well class regulations adaptive and not prescriptive. Thus, many aspects of a Class VI well permit are site- and project-specific to accommodate the many varied geologic settings anticipated for GCS selection. In addition, the relatively young nature of GCS industry also led EPA to adopt an adaptive process for the Class VI rulemaking. Thus, in six years the rule will be reviewed in light of operational experience, new industry practices, and additional academic and industry research.

Despite many common fundamental concepts and components, the Class VI well class is markedly different from other UIC well classes (Table 7). Unlike other well classes, Class VI permits are issued for the lifetime of the project and do not require periodic permit re-filing and re-issuance. To accommodate this change, a Class VI well permit application consists of five separate, but interrelated project plans: Area of Review and Corrective Action, Testing and Monitoring, Injection Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response Plans. Given the varied geologic settings anticipated for geologic carbon sequestration, the Class VI Rule is not overly prescriptive. Rather, the required project plans are to be tailored to site- and project-specific conditions. Because of this feature, development of a Class VI permit requires an extensive site characterization phase. If the permit application is approved, the project plans become part of the permit and the project must be run according to the programs they describe.

Another significant change characteristic of Class VI is the manner in which the AoR is delineated. For this new class, computational modeling of the injected CO_2 plume and formation pressure front are used to define the AoR. The AoR must also be periodically reviewed as new site, operating, and monitoring data become available. The maximum time allowed between AoR reviews is five years. If changes are required to the AoR, the Area of Review and Corrective Action, Testing and Monitoring and Emergency and Remedial Response Plans must be reviewed as well. Amendments to these plans must be approved by the UIC Program Director and on approval become part of the permit.

					Injection well								
					MITs				other tests		monitoring		
			AoR		external		internal						report
well class	permit/rule	duration	size	tasks	type	freq	type	freq	what?	freq	what?	recordings	frequency
Class I-NH	permit	≤10 years	0.25 mi	construction info for wells penetrating injection zone, corrective action	pressure/ alternative	every 5 years	temperature, noise, other approved	every 5 years			• injection pressure, injection flow rate, injection volume, temperature, annulus pressure • fluid chemistry, PFT	• continuous • annually	quarterly
Class I-H	permit + land ban petition	≤10 years	2 mi minimum	construction info for wells penetrating injection zone, corrective action	pressure	initially, after each workover	temperature, noise, other approved	at least, every 5 years	• RTS • PFT • CIL • CT	• annual • annual • after each workover • continuous	• injection pressure, injection flow rate, injection volume, temperature • annulus pressure, fluid chemistry, groundwater monitoring	• continuous • annually	quarterly
Class II	permit; existing EOR - rule	specific time, may be project lifetime	0.25 mi or RoE	construction info for wells penetrating injection zone, corrective action	cement records may be used in place of logs		pressure	at least, once every 5 years	fluid chemistry, other tests	annually or as required	• injection pressure, flow rate, cumulative volume	• disposal well – weekly • EOR well – monthly	annual
Class III	permit	specific time, may be project lifetime	0.25 mi or RoE	construction info for wells penetrating injection zone, corrective action	cement records and RTS, noise or temperature	as required by permit	pressure	salt wells: initially and every 5 years	as required by permit		• injection pressure, injection flow rate, injection volume, fluid chemistry • groundwater monitoring	• continuous • as required by permit	quarterly
Class IV	banned except in special cases	banned											
Class V	mostly by rule, but some require a permit		mostly no		32 different classes with very different requirements								permitted wells must report
Class VI	permit	lifetime	model dependent and based on CO_2 plume and pressure front	construction info for wells penetrating injection zone, corrective action, review at least every 5 years	• OA, noise and temperature • PFT	• annually • once every 5 years	injection pressure, rate, and volume annulus pressure and volume	continuous	as required by permit		• ground water quality and chemistry above confining zone, injected CO_2 stream chemistry, track CO_2 plume and pressure front with indirect and direct methods	• semi-annually and as required by permit	depending on report semi-annually within 30 days, or 24 hours; reports submitted electronically to EPA; must keep records for 10 years after site closure

Abbreviations: CIL – casing inspection log; CT – corrosion testing; H – hazardous; NH – non-hazardous; OA – oxygen activation log; PFT – pressure fall-off test; RoE – radius of endangerment; RTS – radioactive tracer survey

Table 7. Comparison of the technical requirements of the six UIC well classes. (Sources: EPA, 2002; Koplos and others, 2006; Class VI Rule)

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APPENDIX A: ACRONYMS

AoR – Area of Review
APD – Application for Permit to Drill
API – American Petroleum Institute
BACT – Best Available Current Technology
BAU – Business as Usual
BHA – Bottomhole Assembly
BOD – Biological Oxygen Demand
CA – Corrective Action
CAA – Clean Air Act
CBL – Cement Bond Log
CC – Carbon Capture
CCS – Carbon Capture and Storage
CCUS – Carbon Capture, Utilization and Storage
CEL – Cement Evaluation Log
CERCLA – Comprehensive Environmental Response, Compensation and Liability Act
CFC - ClouroFluroCarbon
CFR – Code of Federal Regulations
CIL – Casing inspection log
CNPC – Chinese National Petroleum Company
CO_2-EOR – CO_2 Enhanced Oil Recovery
COE – Corps of Engineers (Army)
CWA – Clean Water Act
DOE – Department of Energy
DNV – Det Norske Veritas
ECBM – Enhanced Coalbed Methane
EIA – Energy Information Administration (DOE)
ENGR – Enhanced Natural Gas Recovery
EOR – Enhanced Oil Recovery
EPA – Environmental Protection Agency
ERD – Extended Reach Drilling
ERR - Emergency and Remedial Response
ERT – Electrical Resistance Tomography
ESA – Endangered Species Act
ESP – Electrical Submersible Pump
FDA – Food and Drug Administration
FR – Financial Responsibility
FRAC – Fracturing Responsibility and Awareness of Chemicals Act
GHG – Greenhouse Gas
GCS – Geologic Carbon Sequestration
GPR – Ground Penetrating Radar
GWPC – Ground Water Protection Council
HAP – Hazardous Air Pollutant
HCFC - HydroChloroFluroCarbon
HSP – Hydraulic Submersible Pump
HWDP – Heavy Weight Drilling Pipe
IEA – International Energy Agency
IOGCC – Interstate Oil and Gas Compact Commission
IPCC – Intergovernmental Panel on Climate Change
ISL – In-situ Leaching
LNG – Liquefied Natural Gas
LPG – Liquid Propane Gas
LWD – Logging while Drilling
MACT – Maximum Achievable Control Technology
MCL – Maximum Contaminant Level (enforceable)
MCLG – Maximum Contaminant Level Goal (non-enforceable)
MEA – MonoEthanolAmine
MI – Mechanical Integrity
MIT – Mechanical Integrity Test
MMV – Monitoring, Measurement, and Verification
MRV – Monitoring, Reporting, and Verification (for Subpart RR)
MWD – Measurement while Drilling
NAAQS – National Ambient Air Quality Standards
NETL – National Energy Technology Laboratory
NPC – National Petroleum Council
NPDES - National Pollutant Discharge Elimination System
NEPA – National Environmental Policy Act
NGCC – Natural Gas Combined Cycle
NIMBY – Not-In-My-Backyard
NODA – Notice of Data Availability
NOI – Notice of Intent
NO_X – nitrogen oxides
NSPS – New Source Performance Standards
OAL – Oxygen Activation Log
OOIP – Original Oil in Place
OSHA – Occupational Safety and Health Administration
P&A – Plug and Abandon
PC – Pulverized Coal
PDC – polycrystalline diamond compact
PES – Primary Energy Source
PIG – Pipeline Inspection Gauge
PISC – Post-injection Site Care
POTW - Publically Owned Treatment Works
PSD – Prevention of Significant Deterioration
PWS – Public Water System
PWSID – Public Water System Identification
PWSS – Public Water System Supervision

RA – Regional Administrator (EPA)
RC – Request for Comment
RCRA – Resource Conservation and Recovery Act
RT – Radioactive Tracer
RTS – Radioactive Tracer Survey
SAPT – Standard Annulus Pressure Test
SAMT – Standard Annulus Monitoring Test
SC – Site Closure
SDWA – Safe Drinking Water Act
SO_x – Sulfur Oxides
SPCC – Spill Prevention and Control Countermeasures
SRA – Subsequent Report of Abandonment
SSDA – Special Sodium Drilling Areas
STP – Standard Temperature and Pressure (25°C, 1 bar)
SWPP – Storm Water Prevention Plan
TCR – Total Coliform Rule
TDS – Total Dissolved Solids
TRC – Texas Railroad Commission
TSS – Total Suspended Solids
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
USGS – United States Geological Survey
VSP – Vertical Seismic Profile
WAG – Water Alternating Gas
WDEQ – Wyoming Department of Environmental Quality
WOC – Waiting on Cement
WOGCC – Wyoming Oil and Gas Conservation Commission

APPENDIX B: EPA TERM DEFINITIONS

EPA definition sources:

1. Class VI Rule Preamble.
2. EPA's UIC website (http://water.epa.gov/type/groundwater/uic/glossary.cfm).
3. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Construction Guidance.
4. 40 CFR 146.81(d).
5. 40 CFR 144.6(f) and 144.80(f).
6. 40 CFR 144.3.
7. Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure
8. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance
9. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance

Annulus: the space between the well casing and the wall of the borehole; the space between concentric strings of casing; the space between casing and tubing.[1]

Area of Review: the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is required to be delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in 40 CFR 146.84 of the Class VI regulations. Note that this is different from AoR in other well classes which allow for a fixed radius from the well to be delineated.

Buoyancy the upward force on one phase (e.g., a fluid) produced by the surrounding fluid (e.g., a liquid or a gas) in which it is fully or partially immersed, caused by differences in pressure or density.[1]

Burst Strength: pressure, when applied normal to the surface, that will cause a mechanical well component to rupture.[3]

Carbon Dioxide Plume: the extent underground, in three dimensions, of an injected carbon dioxide stream.[4]

Carbon Dioxide Stream: carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. This Class VI definition does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under 40 CFR 261.[4]

Casing: the pipe material placed inside a drilled hole to prevent the hole from collapsing. The two types of casing in most injection wells are (1) surface casing, the outermost casing that extends from the surface to the base of the lowermost USDW and (2) long-string casing, which extends from the surface to or through the injection zone.[1]

Cement: the material used to support and seal the well casing to the rock formations exposed in the borehole. Cement also protects the casing from corrosion and prevents movement of injectate up the borehole. The composition of the cement may vary based on the well type and purpose; cement may contain latex, mineral blends, or epoxy.[1]

Class II Wells: wells that inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons. Class II well types include salt water disposal wells, enhanced oil recovery wells, enhanced gas recovery wells, and hydrocarbon storage wells.[2]

Class VI Wells: wells that are not experimental in nature that are used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at 40 CFR 146.95; 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 40 CFR 146.4 and 144.7(d).[5]

Collapse Strength: pressure which will cause a mechanical well component to collapse.[3]

Capillary Pressure: the difference of pressures between two phases existing in a system of interconnecting pores or capillaries. The difference in pressure is due to the combination of surface tension and curvature in the capillaries.[8]

Computational Code: series of interrelated mathematical equations solved by computer to represent the behavior of a complex system. For the purposes of GS, computational models represent, at a minimum, the flow and transport of multiple fluids and components in varying phases through porous media. Computational codes offer the ability to predict fluid flow in the subsurface using scientifically accepted mathematical approximations and theory. The use of computational codes is necessary because the mathematical formulations describing fluid flow are complicated and in many cases, non-linear. Several codes have been specifically developed or tailored for injection activities similar to GS, and can be used for this purpose.[8]

Computational Model: a mathematical representation of the injection project and relevant features, including injection wells, site geology, and fluids present. For a GS project, site specific geologic information is used as input to a computational code, creating a computational model that provides predictions of subsurface conditions, fluid flow, and carbon dioxide plume and pressure front movement at that site. The computational model includes all model input and predictions (i.e.,, outputs).[8]

Confining Zone: a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement. For Class VI wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically *overlying and underlying* the injection zone(s), i.e., both above and below, since the injection zone is not below the lowermost USDW. Note: Injection depth waivers are for western United States deep USDWs.[4]

Corrective Action: the use of UIC Program Director-approved methods to assure that wells within the AoR do not serve as conduits for the movement of fluids into USDWs.[4]

Corrosive: having the ability to wear away a material by chemical action. Carbon dioxide mixed with water forms carbonic acid, which can corrode well materials.[1]

Drilling Mud: heavy suspension used in drilling an "injection well," introduced down the drill pipe and through the drill bit.[6]

Enhanced Oil or Gas Recovery (EOR/ EGR): the process of injecting a fluid (e.g., water, brine, or carbon dioxide) into an oil or gas bearing formation to recover residual oil or natural gas. The injected fluid thins (decreases the viscosity) and/or displaces extractable oil and gas, which is then available for recovery. This is also used for secondary or tertiary recovery.[1]

Fluid: any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas or other form or state.[5]

Formation or **Geological Formation**: layer of rock that is made up of a certain type of rock or a combination of types.[1]

Geologic Sequestration: the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport.[4]

Geologic Sequestration Project means an injection well or wells used to emplace a carbon dioxide stream 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 40 CFR 146.95; 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 40 CFR 146.4 and 144.7(d). It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region.[4]

Geophysical Surveys: the use of geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys or well logging methods such as gamma ray and spontaneous potential) to characterize subsurface rock formations.[1]

Groundwater: water below the land surface in a zone of saturation.6

Heterogeneity: the spatial variability in the geologic structure and/or physical properties of the site.[8]

Immiscible: the property wherein two or more liquids or phases do not readily dissolve in one another.[8]

Injectate: the fluids injected. For the purposes of the Class VI Rule, this is also known as the carbon dioxide stream.[1]

Injection Depth Waivers: provisions at 40 CFR 146.95 that allow owners or operators to seek a waiver from the Class VI injection depth requirements for GS to allow injection into non-USDW formations while ensuring that USDWs are protected from endangerment.[8]

Injection Interval: the portion of the injection zone in which the injection well is screened, perforated, or otherwise allows for movement of injectate into the formation.

Injection Zone: a geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a geologic sequestration project.[4]

Logging: the measurement of physical properties in or around the well. [3]

Mechanical Integrity: the absence of significant leakage within the injection tubing, casing, or packer (known as internal mechanical integrity), or outside of the casing (known as external mechanical integrity).[1]

Mechanical Integrity Test: a test performed on a well to confirm that a well maintains internal and external mechanical integrity. MITs are a means of measuring the adequacy of the construction of an injection well and a way to detect problems within the well system.[1]

Model: a representation or simulation of a phenomenon or process that is difficult to observe directly or that occurs over long time frames. Models that support GS can predict the flow of carbon dioxide within the subsurface, accounting for the properties and fluid content of the subsurface formations and the effects of injection parameters.[1]

Model Calibration: adjusting model parameters to minimize the difference between model predictions and monitoring data at the site.[8]

Mud: a generic term for a wide range of drilling fluids, usually water or oil but occasionally synthetically based with high concentrations of suspended solids.[3]

Multiphase Flow: flow in which two or more distinct phases are present (e.g., liquid, gas, supercritical fluid).[8]

Parameter: a mathematical variable used in governing equations, equations of state, and constitutive relationships. Parameters describe properties of the fluids present, porous media, and fluid sources and sinks (e.g., injection well). Examples of model parameters include intrinsic permeability, fluid viscosity, and fluid injection rate.[8]

Owner or Operator: the owner or operator of any facility or activity subject to regulation under the UIC Program.[5]

Packer: a mechanical device that seals the outside of the tubing to the inside of the long-string casing, isolating an annular space.[1]

Plug: a watertight, gastight seal installed in a borehole or well to prevent movement of fluids that may be mechanical or composed of cement or other material that are capable of zonal isolation.[7]

Portland Cement: a hydraulic cement made by reacting a pulverized calcium silicate hydrate material (C-S-H), which in turn is made by heating limestone and clay in a kiln, with water to create a calcium silicate hydrate and other reaction products. [3]

Post-injection Site Care (PISC): appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered, as required under 40 CFR 146.93.[4]

Pressure Front: the zone of elevated pressure that is created by the injection of carbon dioxide into the subsurface. For the purposes of this subpart, the pressure front of a carbon dioxide plume refers to a zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW.[4]

Radius of Curvature: the radius of a circle whose arc represents the curvature in a given well bore.[3]

Separate-phase Carbon Dioxide: carbon dioxide that is present in a free, or non-aqueous, gaseous, liquid, or supercritical phase state.[3]

Site Closure: the specific point or time, as determined by the UIC Program Director following the requirements under 40 CFR 146.93, at which the owner or operator of a GS site is released from PISC responsibilities.[4]

Shoe: a rounded collar that is screwed onto the bottom of the casing. It has a check valve in it to prevent backflow of cement slurry. During installation it guides the casing toward the center of the well bore. During cementing cement flows through the shoe and into the space between the casing and formation.[3]

Shut-off Device: a valve coupled with a control device which closes the valve when a set pressure or flow value is exceeded. Shut-off devices in injection wells can automatically shut down injection activities when operating parameters unacceptably diverge from permitted values.[2]

Site Closure: the specific point or time, as determined by the UIC Program Director following the requirements under 40 CFR 146.93, at which the owner or operator of a GS site (Class VI injection well) is released from PISC responsibilities.[3]

Stochastic Methods: use of probability statistical methods in development of one or more possible realizations of the spatial patterns of the value(s) of a given set of model parameters.[8]

Supercritical Fluid: a fluid above its critical temperature (31.1oC for carbon dioxide) and critical pressure (73.8 bar for carbon dioxide).[1]

Tensile Strength: the maximum force an element can take in tension before it breaks.[3]

Total Dissolved Solids (TDS): the measurement, usually in mg/L, for the amount of all inorganic and organic substances suspended in liquid as molecules, ions, or granules. For injection operations, TDS typically refers to the saline (i.e.,, salt) content of water-saturated underground formations.[1]

Transmissive Fault or **Fracture**: a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.[4]

Tubing: small-diameter pipe installed inside the casing of a well. Tubing conducts injected fluids from the wellhead at the surface to the injection zone and protects the long-string casing of a well from corrosion or damage by the injected fluids.[2]

Underground Injection Control Program: the program EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act (SDWA) that is responsible for regulating the underground injection of fluids by injection wells. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.[3]

Underground Injection Control Program Director: the chief administrative officer of any state or tribal agency or EPA Region that has been delegated to operate an approved UIC program.[2]

Underground Source of Drinking Water (USDW): an aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer.[1]

Wellbore: the hole that remains throughout a geologic (rock) formation after a well is drilled.[3]

Well Plugging: act of sealing off a well so that all USDWs and producing zones are zonally isolated and the well bore, casings, and annulus can no longer act as a conduit for fluids. Plugging typically involves the injection of alternating layers of mud and cement into the well bore, casings, and annulus.[7]

Workover: to any maintenance activity performed on a well that involves ceasing injection or production and removing the wellhead.[9]

APPENDIX C: NON-EPA TERM DEFINITIONS

absorption: a physical or chemical process by which one fluid substance (absorbate) permates or dissolves into a solid or liquid (absorbent or solvent), it is a volume of bulk process.

adsorption: adhesion of gas, liquid or dissolved solid to a surface generally solid, a surface process

anthropogenic: caused or produced by human activities

API gravity: a unitless measure of how heavy or light a particular type is compared to water. Petroleum with API gravity greater than 10 floats on oil, whereas oil with API gravities of less than 10 will sink through water. Most crude oil has API gravities between 10 and 70.

carbon cycle: the geobiochemical cycle by which carbon, in different physical states and chemical forms, moves through the various Earth system's including the atmosphere, biosphere, hydrosphere, lithosphere and pedosphere.

cleats: natural open fractures in coal consisting of face and butt cleats.

CO_2e: equivalent carbon dioxide or CO_2e is the concentration of carbon dioxide necessary to produce the same level of radiative forcing as a specific type and concentration of greenhouse gas, typically expressed as parts per million by volume, ppmv.

desorption: reverse of adsorption.

fishing: oil and gas operations designed to recover items left or lost in a wellbore than can impede future operations, such items, i.e., fish, include drilling, production, and logging equipment, typical fish might be hand tools, drill bits, piece of drill pipe, logging tool, etc.

flue gas: the exhaust gas the combustion of a fuel in an industrial facility, e.g. power plant, cement plant, etc. It is a mixture of a number of different gases.

GW: a gigaWatt, one billion Watts.

GtC: a gigatonne carbon, one billion tonnes carbon.

Gt: a gigatonne, one billion tonnes.

impermeable: not permitting the passage of a fluid.

lithosphere: the rigid, solid outermost shell of the Earth encompassing the crust and upper part of the mantle.

maceral: an organic component of coal that forms the building blocks of coal, a maceral is equivalent to a mineral in a rock, different macerals have different physical and chemical characteristics and their combinations define how coal behaves chemically and physically, macerals are classified into three groups: inertinite, vitrinite and liptinite

mineral carbonation: reaction of CO_2 with metal oxide materials to form insoluble carbonate minerals such as calcite, magnesite, dolomite and siderite, two of the most common metals that are involved are calcium and magnesium.

$MtCO_2$: a megaton carbon, one million tonnes CO_2

MW_e: the electrical output of a power plant measured in megaWatts electric (MWe), a megaWatt is one million (106) Watts

plat: a scale map of a section of land showing the locations of individually owned land parcels, streets, alleys, easements, the various estates associated with each land parcel is often shown as well

primary energy source (PES): new energy derived by excavating/extracting a natural resource stock, e.g. coal, petroleum, natural gas, uranium, etc, or capturing/harnessing a natural energy flow, e.g. wind, solar, tidal, water.

solvent: the part of a solution that comprises that largest mass and into which another component dissolves or permeates. For example, nitrogen is the solvent for air, whereas water is the solvent for seawater.

sorbent: a material that traps another material by either absorption or adsorption.

stoichiometry: ratios or relationships between two or more substances involved in a chemical or physical change, in a chemical reaction, it is the ratio between constituents in the products and reactants.

tagging: checking the depth of a cement plug by running pipe or tubing into the well to determine accurately the depth of a plug.

van der Waals forces: weak attractive force between electrically neutral molecules, it results from the slight attraction between electron-poor regions with slight positive charge and electron-rich parts with a slight negative charge, it is much weaker than a chemical bond. These forces cause liquid and solid molecules to adhere and produce surface tension and capillary action.

watt: a measure of power, that is energy/time, its SI units are Joules per second (J/s).

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