United States Environmental Protection Agency

Geologic Sequestration of Carbon Dioxide

Draft Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance

January 2012

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Office of Water (4606M)
EPA 816-D-10-009
January 2012
http://water.epa.gov/drink

Disclaimer

The Class VI injection well classification was established by the *Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (The Class VI Rule) (75 FR 77230, December 10, 2010).

The Safe Drinking Water Act (SDWA) provisions and EPA regulations cited in this document contain legally-binding requirements. In several chapters this guidance document makes recommendations and offers alternatives that go beyond the minimum requirements indicated by the Rule. This is done to provide information and recommendations that may be helpful for UIC Class VI Program implementation efforts. Such recommendations are prefaced by the words "may" or "should" and are to be considered advisory. They are not required elements of the Class VI Rule. Therefore, this document does not substitute for those provisions or regulations, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA, states or the regulated community. The recommendations herein may not be applicable to each and every situation.

EPA and state decision makers retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Any decisions regarding a particular facility will be made based on the applicable statutes and regulations. Mention of trade names or commercial products does not constitute endorsement or recommendation for use. EPA is taking an adaptive rulemaking approach to regulating Class VI injection wells, and the Agency will continue to evaluate ongoing research and demonstration projects and gather other relevant information as needed to refine the Rule. Consequently, this guidance may change in the future without public notice.

While EPA has made every effort to ensure the accuracy of the discussion in this document, the obligations of the regulated community are determined by statutes, regulations or other legally binding requirements. In the event of a conflict between the discussion in this document and any statute or regulation, this document would not be controlling.

Note that this document only addresses issues covered by EPA's authorities under the SDWA. Other EPA authorities, such as greenhouse gas (GHG) reporting requirements for facilities that inject carbon dioxide underground promulgated under authority of the Clean Air Act (CAA),[1] are not within the scope of this manual.

[1] Information can be found at http://www.epa.gov/climatechange/emissions/subpart/rr.html and http://www.epa.gov/climatechange/emissions/subpart/uu.html.

Executive Summary

EPA's *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells* are now codified in the U.S. Code of Federal Regulations [40 CFR 146.81 et seq.], known as the Class VI Rule. This Class VI Rule establishes a new class of injection well (Class VI) and sets federal minimum technical criteria for Class VI injection wells for the purposes of protecting underground sources of drinking water (USDWs). This document is part of a series of technical guidance documents that EPA is developing to support owners or operators of Class VI wells and the UIC Program permitting authorities.

The Class VI Rule requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to ensure that the injection well maintains its mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that USDWs are not endangered. These monitoring activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of ground water quality in several zones, tracking of the carbon dioxide plume and associated pressure front, and, at the discretion of the UIC Program Director, soil gas and surface air monitoring. This guidance provides information regarding how to perform these testing and monitoring activities.

The introductory section reviews the Class VI regulations related to testing and monitoring. The rest of the document covers technical issues as follows:

- Section 2 addresses Mechanical Integrity Tests
- Section 3 addresses Operational Testing and Monitoring During Injection
- Section 4 addresses Ground Water and Pressure Monitoring
- Section 5 addresses Geophysical Methods for Plume and Pressure-Front Tracking
- Section 6 addresses Soil Gas and Surface Air Monitoring
- Section 7 presents several Testing and Monitoring Case Studies

For each section, this guidance:

- Explains how to perform activities necessary to comply with testing and monitoring requirements (e.g., ground water monitoring, MITs). Illustrative examples are provided in several cases.

- Provides references to comprehensive reference documents and the scientific literature for further information.

- Explains how and when to report to the UIC Program Director the results of activities related to testing and monitoring.

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Acronyms and Abbreviations

ACZ	Above the confining zone
AoR	Area of review
ASTM	American Society of Testing and Materials
CASSM	Continuous active seismic source monitoring
CATS	Capillary adsorption tube samplers
CEM	Continuous emission monitoring
CIL	Casing inspection log
CVAFS	Cold vapor atomic fluorescence spectrometry
DC	Direct current
DOE	Department of Energy
DTF	Depth to fluid
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERT	Electroresistive (or electrical resistive) tomography
FID	Flame ionization detector
FL	Fluid level
GS	Geologic sequestration
GSE	Ground surface elevation
InSAR	Interferometric synthetic aperture radar
IPA	Isopropyl alcohol
IR	Infrared
IZ	Injection zone
LBNL	Lawrence Berkeley National Laboratory
MI	Mechanical integrity
MIT	Mechanical integrity test
MWD	Measurement while drilling
NDIR	Non-dispersive infrared
NETL	National Energy Technology Laboratory
NMR	Nuclear magnetic resonance
PFPD	Pulsed flame photometric detector
PTE	Pressure transducer elevation

QA	Quality assurance
QC	Quality control
RCSP	Regional Carbon Sequestration Partnership
MRCSP	Midwest Regional Carbon Sequestration Partnership
Mt	Megatonne
SFC	Supercritical fluid chromatography
SP	Spontaneous potential
SPE	Supercritical fluid extraction
SWP	Southwest Regional Partnership
TDS	Total dissolved solids
TSD	Technical Support Document
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
UV	Ultraviolet
VSP	Vertical seismic profiling

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Definitions

Key to definition sources:

1: Class VI Rule Preamble
2: 40 CFR 146.81(d)
3: EPA's UIC website (http://water.epa.gov/type/groundwater/uic/glossary.cfm)
4: 40 CFR 144.3
5: This definition was drafted for the purposes of this document

Annulus means the space between the well casing and the wall of the bore hole; the space between concentric strings of casing; space between casing and tubing.[1]

Area of Review (AoR) means the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is 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.[2]

Confining zone means 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.[2]

Formation or geological formation means a layer of rock that is made up of a certain type of rock or a combination of types.[1]

Geologic sequestration (GS) means 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.[2]

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.[2]

Ground water means water below the land surface in a zone of saturation.[4]

Injection zone means 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.[2]

Mechanical integrity (MI) means 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 (MIT) refers to 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 means 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]

Post-injection site care means appropriate monitoring and other actions (including corrective action) needed following cessation of injection to assure that USDWs are not endangered, as required under 40 CFR 146.93.[2]

Pressure front means the zone of elevated pressure that is created by the injection of carbon dioxide into the subsurface. For [GS projects], the pressure front of a carbon dioxide plume refers to the zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW.[2]

Separate-phase carbon dioxide means carbon dioxide that is present in a free, or non-aqueous, gaseous, liquid, or supercritical phase state.[5]

Supercritical fluid means a fluid above its critical temperature (31.1^{o}C for carbon dioxide) and critical pressure (73.8 bar for carbon dioxide). Supercritical fluids have physical properties intermediate to those of gases and liquids.[1]

Total dissolved solids (TDS) refers to the total dissolved (filterable) solids as determined by use of the method specified in 40 CFR part 136.[4]

Underground Injection Control Program Director refers to the chief administrative officer of any state or tribal agency or EPA Region that has been delegated to operate an approved UIC program.[3]

Underground Source of Drinking Water (USDW) means 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]

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1. Introduction

Testing and monitoring of geologic sequestration (GS) sites refers to a suite of activities that are used to detect any fluid migration or risk factors that may lead to fluid migration, which potentially could endanger underground sources of drinking water (USDWs). Therefore, testing and monitoring activities are integral to the protection of USDWs. Testing generally refers to those activities that assess the properties and integrity of the injection well. Monitoring generally includes those activities used to track the carbon dioxide plume and pressure front, changes in the injection operation, or fluid properties at the GS site, over time.

The United States Environmental Protection Agency (USEPA) rulemaking *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* [40 CFR 146.81 et seq.], hereafter referred to as the Class VI Rule, introduces testing and monitoring requirements tailored to the unique circumstances of GS projects. These activities are necessary to verify the integrity of the injection well and to track any changes in ground water quality or pressure that may lead to endangerment of a USDW. In addition, monitoring results are needed to inform reevaluation of the area of review (AoR) for the GS project, as required at 40 CFR 146.84(e). The purpose of this guidance is to identify appropriate methods for testing and monitoring of GS projects. The intended primary audiences of this guidance document are Class VI injection well owners or operators, contractors performing testing and monitoring activities, and UIC Program Directors.

1.1. Review of Class VI Monitoring Regulations

The Class VI Rule requires various testing and monitoring activities during the different phases of a GS project to verify the integrity and construction specifications of the injection well, detect any fluid leakage that may endanger USDWs, and inform ongoing area of review (AoR) delineation modeling and subsequent corrective action [40 CFR 146.87, 146.89, 146.90, 146.92, 146.93]. Figure 1-1 presents an example “risk diagram” for the stages of a GS project and the accompanying required Class VI Rule testing and monitoring requirements. Note that the relative risks to USDWs during the stages of a GS project are site and project specific. Figure 1-1 presents a simple example for explanatory purposes.

Mechanical integrity testing (MIT) is required prior to commencement of injection [40 CFR 146.87(a)(4)], during the injection phase [40 CFR 146.89], and prior to well plugging [40 CFR 146.92(a)]. During injection, the owner or operator must also characterize the injectate, monitor injection rate and pressure, monitor for corrosion of the well, monitor ground water quality, and track the movement of the carbon dioxide plume and pressure front [40 CFR 146.90]. The Underground Injection Control (UIC) Program Director has the discretion to require additional monitoring of carbon dioxide in soil gas and surface air, if necessary, to protect USDWs [40 CFR 146.90(h)]. During post-injection site care (PISC), monitoring is required to continue to ensure USDWs are not endangered and to track the migration of the plume and pressure front [40 CFR 146.93(b)].

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The owner or operator must submit, as part of the permit application, a Testing and Monitoring Plan that explains the anticipated monitoring methodology and frequency for the lifetime if the project [40 CFR 146.90]. The risk-based, flexible approach adopted by EPA allows development of site-specific monitoring programs based on individual site geology and other unique factors. This approach relies, in part, on ongoing communication between the owner or operator and UIC Program Director. The plan is subject to UIC Program Director approval and, once approved, is enforceable as a condition of the permit. The plan is also to be reviewed periodically following AoR reevaluations at least once every five years. Changes to the plan are subject to UIC Program Director approval and must be based on updated monitoring data, site operations and the most recent AoR reevaluation [40 CFR 144.39 and 144.41].

Additionally, the Class VI Rule includes provisions for owners or operators of Class VI carbon dioxide injection wells seeking to inject into non-underground sources of drinking water (non-USDWs) that lie above or between USDWs. These owners or operators must apply for and receive injection depth waivers and meet additional requirements to ensure the protection of USDWs above and below the permitted injection zone. These additional requirements largely are based on the need to monitor additional zones below the lower confining zone. The Testing and Monitoring Plan that meets the requirements under 40 CFR 146.90 must also demonstrate that additional monitoring will be performed to ensure the protection of UDWs below the injection zone and will be approved by the UIC Program Director. For more detailed information about the additional considerations for testing and monitoring at projects operating under injection depth waivers, see the *UIC Program Class VI Injection Depth Waiver Application Guidance.*

Importantly, Class VI permits are issued for the lifetime of the GS project [40 CFR 144.36(a)]. Periodic AoR reevaluation and subsequent reevaluation of plans, including the Testing and Monitoring Plan, are the primary vehicle for communication between the owner or operator and the UIC Program Director. Requirements related to the Testing and Monitoring Plan are discussed in depth in the *UIC Class VI Program Project Plan Development Guidance.*

1.2. Organization of this Guidance

This guidance is organized to cover the testing and monitoring activities that will occur during the injection phase (Figure 1-1). Complementary guidance documents provide detail on additional activities that will occur during site characterization, AoR determination and PISC. Site characterization procedures are discussed in detail in the *UIC Program Class VI Well Site Characterization Guidance*. Recommended procedures and materials for designing and constructing injection wells that address the unique nature of carbon dioxide injection for GS are discussed in detail in the *UIC Program Class VI Well Construction Guidance.* Delineation of the AoR and performance of corrective action are covered in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*. Monitoring activities during PISC are discussed in the *UIC Program Class VI Well Plugging, Post-Injection Site Care (PISC) and Site Closure Guidance*. Development of the Testing and Monitoring Plan is discussed in more detail in the *UIC Class VI Program Project Plan Development Guidance*.

Section 2 of this guidance focuses specifically on MITs. Section 3 discusses operational testing and monitoring during injection. Section 4 discusses monitoring of ground water quality and geochemistry, and Section 5 discusses tracking of the plume and pressure front. Section 6

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discusses monitoring of surface air and soil gas. Finally, Section 7 presents several case studies of testing and monitoring at early GS pilot projects.

Throughout this guidance, a wide variety of testing and monitoring techniques are discussed. Discussion of these techniques is organized into four major parts:

- General Information: Requirements in the Class VI Rule regarding this technique for Class VI owners or operators, the objective of the monitoring technique and the fundamental principles on which the technique is based.

- Application: Fundamental information pertaining to collection of data using the technique, and references to more detailed manuals and guidance documents.

- Interpretation: The format the collected data will take, and how to interpret data collected by the technique to characterize the measured system.

- Reporting and Evaluation: The recommended format and required reporting frequency of collected data and interpretation to the UIC Program Director, the information and data that should be included in all submittals and the factors that the UIC Program Director may evaluate.

This document has been written to help guide owners or operators as they fulfill the testing and monitoring requirements of the Class VI Rule. Table 1-1 lists the Class VI Rule sections addressed by each of the section of this guidance document.

Table 1-1. Crosswalk of guidance document sections to the related Class VI Rule section(s).

Section of Testing and Monitoring Guidance	Relevant Section(s) of Rule
2. Mechanical integrity tests (MITs)	
2.1 Internal MITs	40 CFR 146.87(a)(4) 40 CFR 146.89(a)(1) 40 CFR 146.89(b)
2.2 External MITs	40 CFR 146.87(a)(4) 40 CFR 146.89(a)(2) 40 CFR 146.89(c) 40 CFR 146.92(a)
2.3 Reporting results of MITs	40 CFR 146.91(a)(7) 40 CFR 146.91(b)(1)

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Section of Testing and Monitoring Guidance	Relevant Section(s) of Rule
3. Operational testing and monitoring during injection	
3.1 Analysis of carbon dioxide stream	40 CFR 146.90(a) 40 CFR 146.91(a)(1) 40 CFR 146.91(a)(7)
3.2 Continuous monitoring of injection rate and volume	40 CFR 146.88(e) 40 CFR 146.90(b) 40 CFR 146.91(a)(2)
3.3 Continuous monitoring of injection pressure	40 CFR 146.90(b) 40 CFR 146.91(a)(2)
3.4 Corrosion monitoring	40 CFR 146.90(c) 40 CFR 146.91(a)(7)
35 Pressure fall-off testing	40 CFR 146.90(f)
4. Ground water quality geochemistry and pressure monitoring	
4.1 Design of monitoring well network	40 CFR 146.90(d) 40 CFR 146.90(g)(1)
4.2 Monitoring well construction	40 CFR 146.90
4.3 Collection and analysis of ground water samples	40 CFR 146.90(d) 40 CFR 146.90(g)(1) 40 CFR 146.91(a)(7)
5. Plume and pressure-front tracking	
5.1 Class VI Rule requirements regarding plume and pressure-front tracking	40 CFR 146.90(g)(1) 40 CFR 146.90(g)(2)
5.2 Pressure-Front Tracking	40 CFR 146.90(g)(1) 40 CFR 146.91(a)(7)
5.3 Plume tracking using indirect geophysical techniques	40 CFR 146.90(g)(2) 40 CFR 146.91(a)(7)
5.4 Use of geochemical ground water monitoring in plume tracking	40 CFR 146.90(d) 40 CFR 146.90(g)(2)
6. Soil gas and surface air monitoring	
6.1 Soil gas monitoring	40 CFR 146.90(h)(1) – (2) 40 CFR 146.91(a)(7)
6.2 Surface air monitoring	40 CFR 146.90(h)(1) – (2) 40 CFR 146.91(a)(7)

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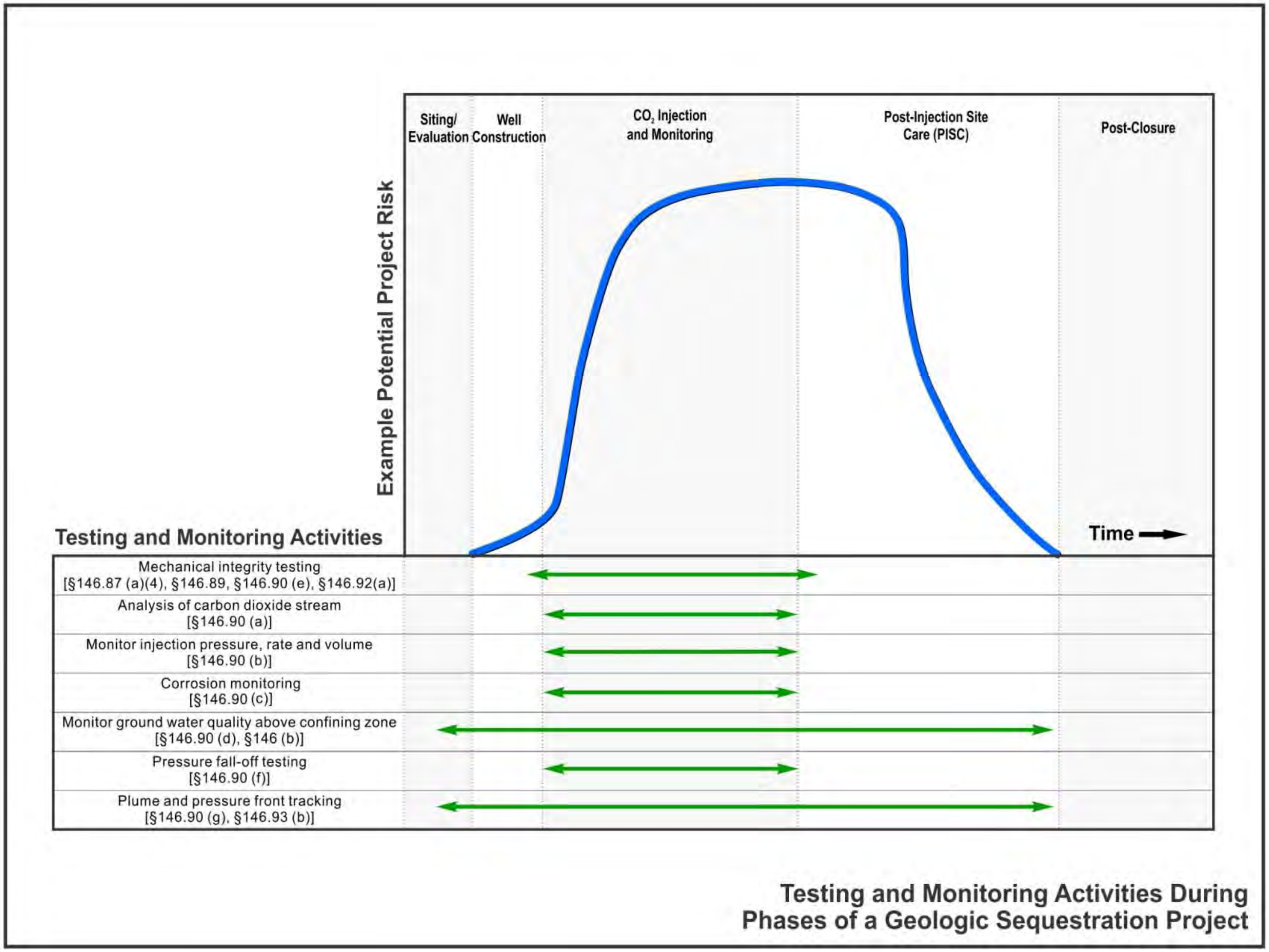

Figure 1-1. Testing and monitoring activities during different phases of a GS project in relation to potential project risk.

2. Mechanical Integrity Tests (MITs)

MITs are required by the Class VI Rule prior to injection in a Class VI well [40 CFR 146.87(a)(4)], during the injection phase [40 CFR 146.89], and prior to well plugging after injection [40 CFR 146.92(a)] (Table 1-1). The objective of MITs is to assess integrity of the injection well and detect leakage through or around well components, including fluid movement in channels between the cement and the formation. Additionally, the UIC Program Director may require casing inspection logs be conducted periodically during injection [40 CFR 146.89(d)]. Casing inspection logs complement MITs by providing additional information regarding any corrosion within the long-string casing and are discussed in Section 3.4.3. Because induced formation pressures will be greatest at the injection well, and the well penetrates USDWs, the injection zone and intervening zones, the well is a possible conduit for fluid movement and USDW endangerment. This section discusses the well logging and testing methods that are acceptable methods of MIT for a Class VI well. The MIT methods discussed herein are standard practices in the UIC Program, and are not unique to the Class VI Rule. Additional specific details regarding the execution of MITs can be found in USEPA Region 5 (2008), USEPA (1982) and McKinley (1994).

As set forth in the Class VI Rule, internal mechanical integrity of an injection well refers to the absence of any leaks in the injection tubing, packer or casing [40 CFR 146.89(a)(1)], and external mechanical integrity refers to the absence of any leaks through channels adjacent to the wellbore that results in significant fluid movement into a USDW [40 CFR 146.89(a)(2)]. Figure 2-1 illustrates three scenarios in which internal or external mechanical integrity has been lost, and therefore the example well is operating in violation of Class VI requirements.

- The top example in Figure 2-1 shows a leak in the tubing. In a properly functioning well system, the pressure will normally be higher in the annulus than in the tubing [40 CFR 146.88(c)], causing annular fluid to move into the tubing through a leak. In a situation where either the UIC Program Director has approved a lower relative annular pressure or the normal annular pressure has been lost, injectate may instead move from the tubing into the annulus, as shown.

- In the middle example in Figure 2-1, mechanical integrity has been lost through a leak in the casing, allowing annular fluid to leak outside the casing and potentially into the formation (loss of external mechanical integrity). In cases where the formation opposite the casing leak was of a higher pressure than the annulus pressure, formation fluid could instead enter the annulus. Annular pressure is required to be monitored continuously [40 CFR 146.88(e)(1)], and loss of internal mechanical integrity must trigger a shut-off system [40 CFR 146.88(e)(2)], which would halt injection quickly and limit the amount of leakage. This mechanism provides an additional protective barrier to USDW contamination. Failure of the shut-off system to engage, however, would permit greater movement of annular fluid or injectate, potentially endangering USDWs.

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- The bottom example in Figure 2-1 illustrates loss of external mechanical integrity through channels in the cement, which may allow injectate to migrate upwards and potentially reach a USDW. The goal of annual external mechanical integrity testing is to identify fluid movement through such channels. If a loss of mechanical integrity is verified, the owner or operator must take immediate corrective action to protect USDWs [40 CFR 146.94].

Separate tests are conducted to verify internal and external mechanical integrity. For internal MITs, specific tests are required for Class VI wells, unless alternative tests are allowed by the UIC Program Director and EPA Regional Administrator. For external MITs, the owner or operator may use one of several acceptable MITs to comply with Class VI requirements. If a well fails an MIT (or if a loss of mechanical integrity is detected), the Class VI Rule requires that immediate action be taken by the owner or operator to remediate the well and prevent endangerment of USDWs [40 CFR 146.88(f)].

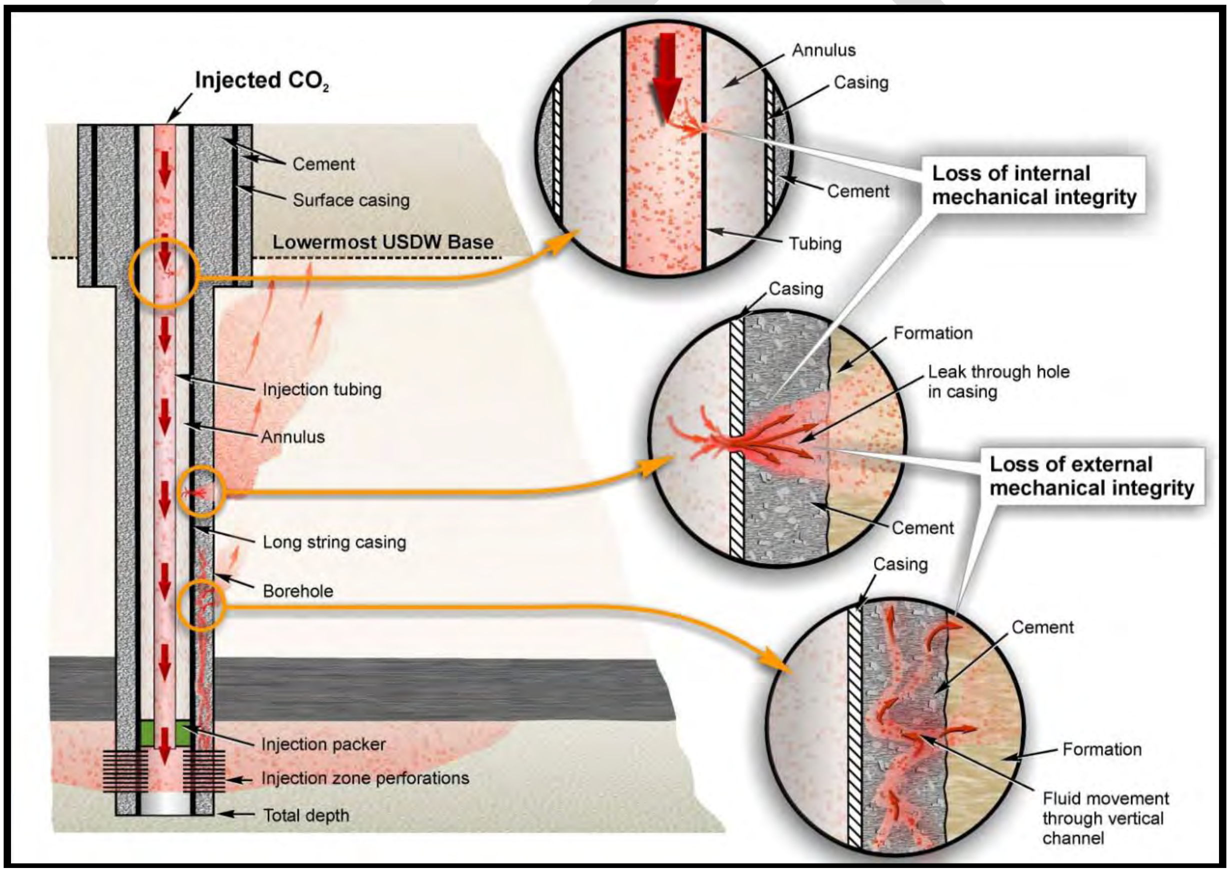

Figure 2-1. Diagram of an improperly operated injection well showing examples of loss of mechanical integrity and resulting fluid leakage (not to scale).

2.1. Internal MITs

Internal MITs are used to test for any possible leaks in the casing, tubing and packer [40 CFR 146.89(a)(1)]. The Class VI Rule requires an initial internal MIT prior to injection [40 CFR 146.87(a)(4)(i) and 146.89(b)]. Unless an alternative test is allowed by the EPA Regional Administrator and UIC Program Director [under 40 CFR 146.89(e)], the annulus pressure test must be used as the initial internal MIT. Currently, the only acceptable alternative internal MIT that is available is the radioactive tracer test, which can be used under specific conditions. EPA expects approval of the radioactive tracer test as an alternative for internal MIT to be rare for Class VI wells (see section 2.1.3). However, the radioactive tracer test may provide supplementary information to verify or further characterize loss of internal mechanical integrity.

The Class VI Rule also requires that internal mechanical integrity be demonstrated continuously during injection [40 CFR 146.89(b)]. Specifically, owners or operators must continuously monitor injection pressure, rate, injected volumes, pressure on the annulus between the tubing and long-string casing, and annulus fluid volume during injection for all Class VI wells.

2.1.1. Annulus Pressure Test

General Information

The annulus pressure test is required prior to commencing injection in a Class VI well [40 CFR 146.89(b)]. The standard annulus pressure test is the most common means used to demonstrate internal mechanical integrity within the UIC Program and consists of increasing the pressure of the annulus to a specified level and subsequently monitoring the annular pressure for a set period of time. The test is based on the principle that pressure applied to fluids filling a sealed vessel, in this case the annular space, will persist. The test provides an immediate demonstration of the internal mechanical integrity of the well. If loss of internal mechanical integrity is detected, action may be required to remediate leakage pathways in the injection tubing packer or casing prior to the commencement of injection [40 CFR 146.88(f)].

Application

The annulus pressure test is conducted after the well has been fully constructed and all well logs have been conducted (see the *UIC Program Class VI Well Construction Guidance*). Prior to conducting the test, the injection tubing and annulus are completely filled with liquid and temperature stabilization is achieved within the well. The addition of any unapproved substances to the annulus liquid that might affect the outcome of the test may constitute falsification of the test procedure and invalidate the test. In order for the test to be effective, the pressure applied to the annulus system needs to be transmitted through the entire wellbore. Therefore, no mechanical plug may be placed above the packer in a well during the annulus pressure test.

After temperature stabilization, the annulus is pressurized to the test pressure. The appropriate test pressure is dependent on several factors such as well depth, formation pressure, fluid densities and injection pressure. For Class II wells, regional requirements vary from 300 to 2,000 psi gauge (psig) (Nielsen and Aller, 1984). A common requirement is for the test pressure to be set based on the maximum allowable injection pressure. EPA Region 8 (1995) sets a level of the maximum allowable injection pressure or 1,000 psig, whichever is less. EPA Region 5 (2008) requires a pressure 100 psi greater than the maximum allowable injection pressure or 300 psig, whichever is greater. Another common requirement is for the annulus test pressure to exceed the tubing pressure by 100 to 200 psi (Texas Railroad Commission, 2006; EPA Region 8, 1995). EPA recommends that the test pressure be determined in consultation with the UIC Program Director and be informed by previous practices in the applicable state and/or EPA regional office.

Following pressurization, the annular space is isolated from the source of pressure by a closed valve, or by disconnecting the pressure source entirely. The test consists of isolating the annular space and measuring any pressure changes. The appropriate test period is long enough to allow the pressure to stabilize, but short enough to minimize temperature changes. Typical test times are between 15 minutes and one hour (Nielsen and Aller, 1984). To be effective, the gauge used to make the annular pressure measurements must be sensitive enough to detect any pressure changes that would result in a failure of the test. For example, if the test pressure is 300 psig, then the precision of an appropriate gauge for the test would be 5 psi or greater. Pressure gauge apparatuses are described in Section 3.3. During isolation, measurement of pressure is best made at regular intervals (e.g., every 10 minutes). After the test period, the valve to the annulus should be opened and liquid returned from the annulus should be caught in a container and measured. This can indicate whether the full length of the annulus has been tested.

Interpretation

Pressure measurements taken during isolation of the annulus are analyzed for any change in pressure, which may indicate leakage and failure of the well to pass the test. Because the annulus exchanges heat with its surroundings, small pressure changes that are not indicative of leakage may occur during the test. Failure of the pressure to stabilize during the test period or a change above a UIC Program Director-approved minimum value indicates a failure to demonstrate mechanical integrity. Typical pressure changes used to indicate a failure to demonstrate mechanical integrity vary between three and 10 percent (USEPA, 2008; Nielsen and Aller, 1984). A common criterion is 5 percent (GWPC, 2005).

In addition, the amount of liquid returned after the isolation period may indicate a blockage at shallow depth, and the entire wellbore may not have been tested adequately. The amount of liquid to be returned in a given test can be calculated based on the size of the annulus and the test pressure (see USEPA Region 5, 2008). If several gallons of liquid are returned, it is fairly certain that the entire length of the casing and tubing have been tested.

2.1.2. Annulus Pressure Monitoring

General Information

The Class VI Rule requires continuous monitoring of the pressure on the annulus to verify internal mechanical integrity during injection [40 CFR 146.89(b)]. Significant changes in annulus pressure measured during injection may indicate a loss of internal mechanical integrity. Pressure monitoring also verifies that the annulus pressure is greater than injection pressure

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(within the injection tubing), which is required by the Class VI Rule unless the UIC Program Director determines that such a requirement might harm the integrity of the well or endanger USDWs [40 CFR 146.88(c)]. Annulus pressure monitoring to demonstrate internal mechanical integrity is performed in concert with continuous monitoring of injection pressure, rate, and annulus fluid volume, all of which are required by 40 CFR 146.89(b) to achieve this demonstration. See Sections 3.2 and 3.3 for additional information on this continuous monitoring.

<u>Application</u>

Similar to the annulus pressure test, to be effective, continuous annulus pressure measurements need to be made using a gauge sensitive enough to detect any pressure changes that would result in a failure of the tests (e.g., a change of three percent). Pressure gauge apparatuses are described in Section 3.3.

<u>Interpretation</u>

Figure 2-2 presents a flow chart explaining the interpretation of the results of annulus pressure monitoring. Continuous monitoring of the annulus is similar in methodology to the initial pressure test. However, interpretation is complicated by operational effects such as injection tubing expansion or contraction, wellbore temperature changes, changes in injection rate or temporary cessation of injection, and changes in the injectate temperature. In the event of a casing leak opposite a permeable zone, the pressure will normally fall to atmospheric pressure; if not, the range of pressure change will be much diminished because the aquifer in communication with the leak will buffer volumetric changes in the annulus. In the event of a tubing or packer leak, the annulus pressure will track injection pressure. These two pressures will probably not be equal because of a pressure loss due to friction in the injection tubing and density differences.

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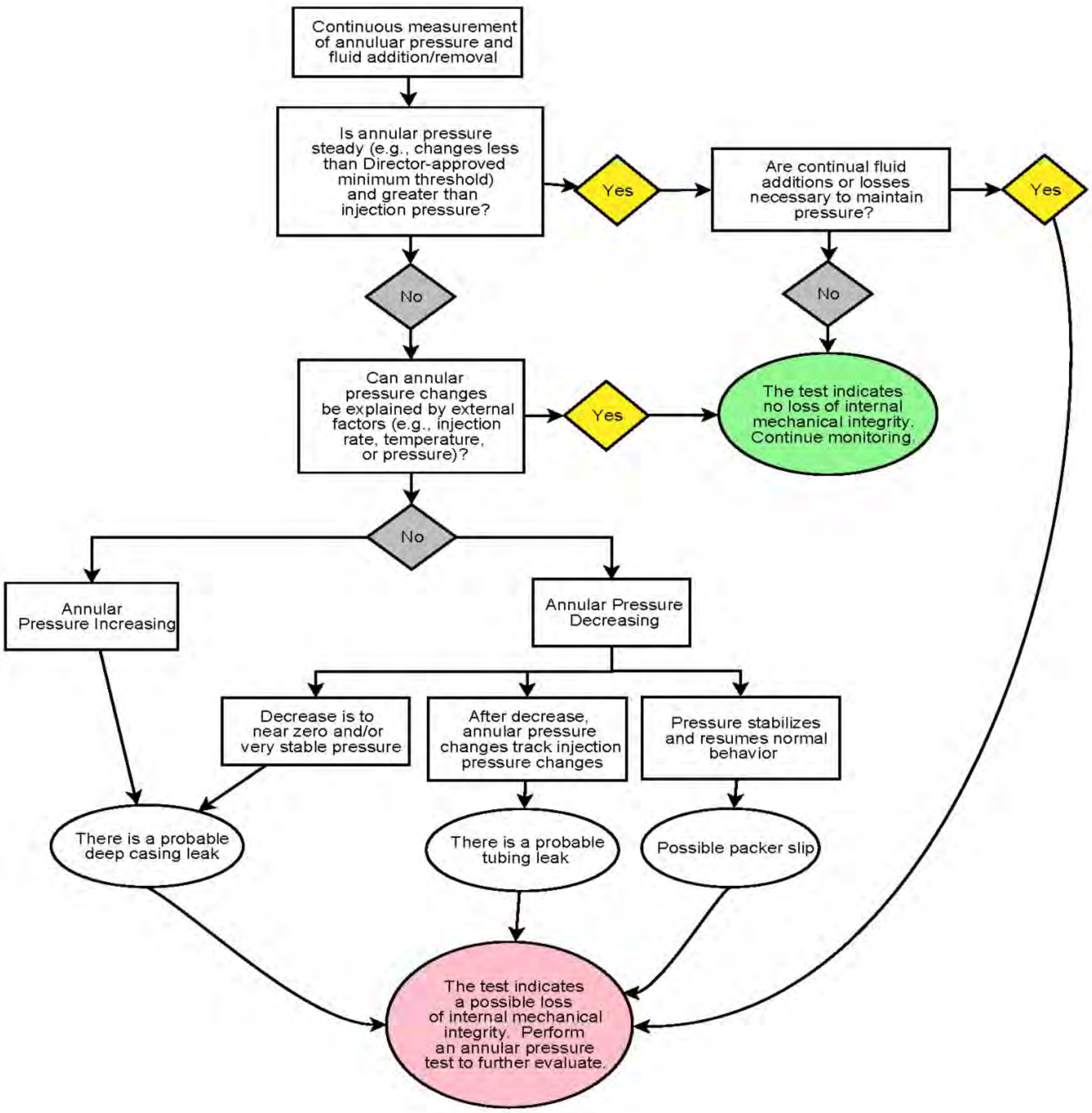

Figure 2-2. Interpretation of annulus pressure monitoring.

A leak that does not result in an unimpeded pressure change might not be evident. To enhance the value of maintaining a positive pressure differential, and the likelihood of detecting a leak, the Class VI Rule requires volume measurement of all liquid additions from the annulus system [40 CFR 146.89(b)]. The results of these measurements are accumulated, and a continuing need to add or remove fluid to maintain a set pressure is evidence of a leak in the well.

The standard used for evaluating continuous pressure measurement is typically similar to the minimum value used during the annulus pressure test. For example, a three percent pressure loss in a 60-minute interval may indicate a potential loss of internal mechanical integrity. However, it is only possible to apply the minimum pressure change standard when external factors that might affect the annulus pressure are stable. Otherwise, liquid property changes occurring in response to changes in ambient conditions make determination of a leak-induced pressure change impossible. To provide an effective, real-time demonstration of internal mechanical integrity, frequent review of pressure records is necessary. This review would focus on the pressure in the annulus relative to atmospheric pressure, injection pressure as measured at the surface, and pressure in formations adjacent to the wellbore.

Continual addition or removal of fluids to maintain annular pressure, or annular pressure changes greater than the UIC Program Director-approved minimum change that cannot be explained by changing operational conditions (e.g., injection rate, pressure or temperature), indicate a possible loss of internal mechanical integrity. Under these circumstances, EPA recommends that injection be ceased and an annulus pressure test (Section 2.1.1) be conducted. A radioactive tracer survey may also be conducted to determine the depth of the leak (Section 2.1.3). If the annulus pressure test indicates no loss of internal mechanical integrity, injection may resume. If a loss of mechanical integrity is identified, the Class VI Rule requires that the owner or operator take appropriate action to repair the well and investigate any impairment of a USDW [40 CFR 146.88(f)].

2.1.3. Radioactive Tracer Survey

General Information

The Class VI Rule specifically requires annulus pressure tests and monitoring to verify internal mechanical integrity. However, if approved by the UIC Program Director and EPA Regional Administrator, alternative MIT methods may be used [40 CFR 146.89(e)]. Currently, the only available alternative internal MIT is the radioactive tracer survey, which is used under specific conditions. EPA expects that approval of the radioactive tracer survey as an alternative internal MIT will be rare. The radioactive tracer survey is expensive compared to the annulus pressure test and may require long periods of investigation. Furthermore, the radioactive tracer survey cannot feasibly be conducted continuously during injection, and therefore cannot be used to comply with the continuous monitoring requirements. However, the radioactive tracer survey provides supplementary information regarding internal fluid leakage, and therefore may be conducted in addition to annular pressure monitoring. Importantly, the radioactive tracer survey may be used to locate the depth of a leak within the wellbore, unlike annulus pressure tests. As discussed below (Section 2.2.4), in very specific circumstances, radioactive tracer surveys may also be used as an external MIT.

Application

The radioactive tracer survey uses a wireline tool that consists of an injector stage, one or more gamma radiation detector devices and a collar locator (i.e., a logging tool used to detect the threaded collar used to connect two joints of casing). The relative positions of the injector and detectors are variable. Three detectors are sometimes used, with two below the injector. This allows for very accurate measurement of the speed of the injectate. It also simplifies the location of the upward limit of leaking by eliminating some repositioning of the tool. The purpose of the collar locator is to pinpoint the location of leaks in reference to permanent markers. This may also be done by means of correlation to a gamma ray log that is scaled to show lithologic effects (see the *UIC Program Class VI Well Site Characterization Guidance*). Using a collar locator immediately lets the analyst know whether an identified leak is at a collar, while using a gamma ray correlation log clarifies the stratigraphic location of the leak. The radioactive tracer is usually iodine-131 because of its short (eight-day) half life. An anionic tracer material should be used to minimize molecular attraction to well and rock materials.

The test consists of releasing the radioactive tracer above the interval to be tested and subsequent measurement of gamma radiation as it moves vertically. The demonstration can be effective for locating leaks in both the tubing and the casing. However, the test is useful for demonstrating an absence of leaks only in tubing strings through which the tracer material may flow. A demonstration that there are no leaks in the tubing requires that the test be conducted within the tubing. To test the casing, the tubing may be removed. Testing is always conducted while injecting. It is best to maintain an injection rate as close to the maximum injection rate as practical. See USEPA Region 5 (2008) for detailed instructions on conducting a radioactive tracer survey as an internal MIT.

Interpretation

After a slug of radioactive material is injected, that slug will move with the injectate into the injection zone. If a measureable leak is present, the gamma ray detector will identify an area of increased radioactivity after the slug has passed. Importantly, in order to distinguish the impact of lithologic features, the gamma ray log needs to be compared to a baseline (see the *UIC Program Class VI Well Site Characterization Guidance*). Figure 2-3 presents an example radioactive tracer survey log conducted to test leakage through casing (i.e., the tubing has been removed). If, compared to the baseline gamma ray log, no additional radiation is observed after the slug has passed, the well has demonstrated internal mechanical integrity at the depth tested.

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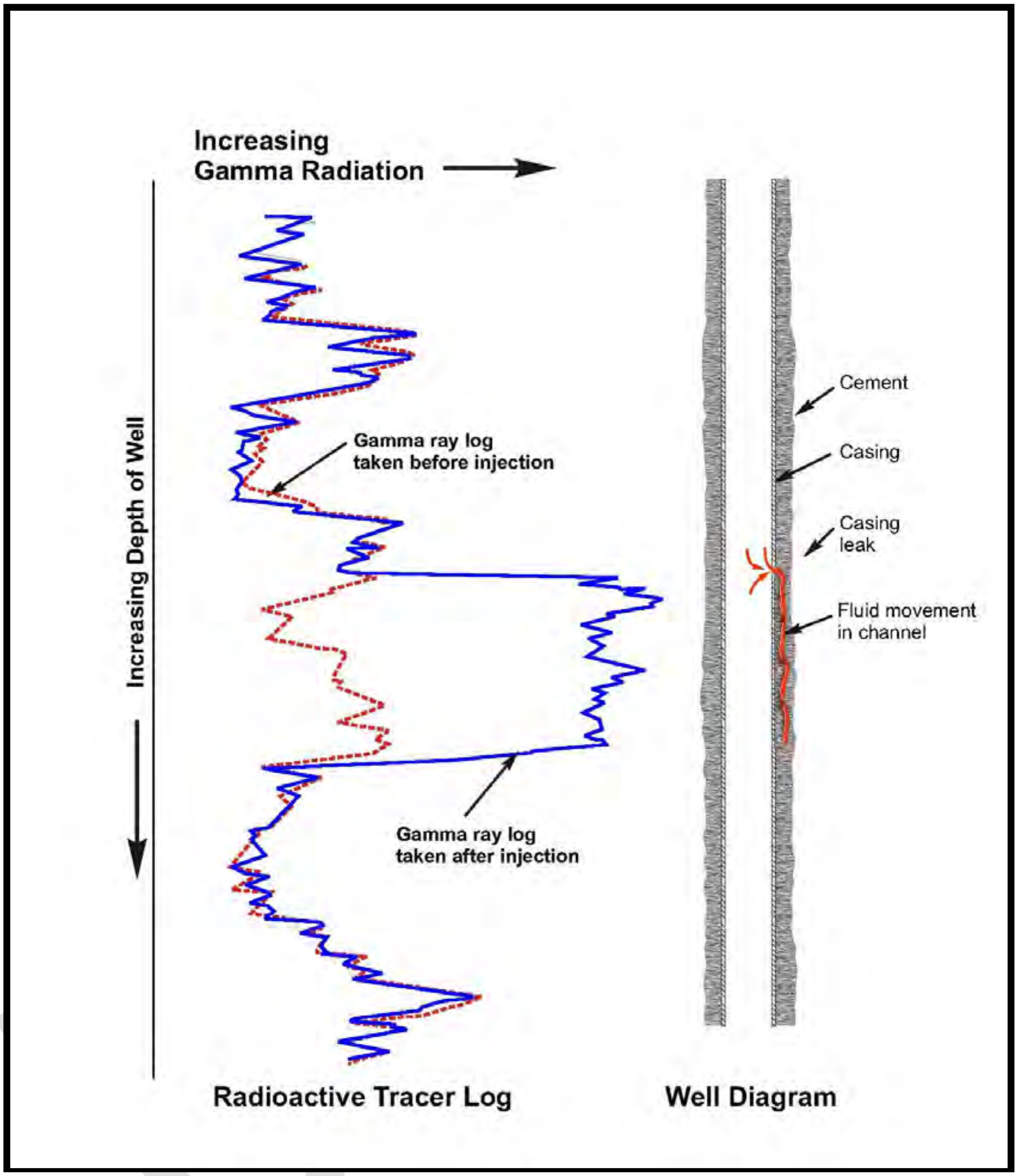

Figure 2-3. Radioactive tracer log showing the detection of a leak in the casing and subsequent fluid movement in a channel behind the casing (USEPA, 1982; not to scale).

2.2. External MITs

As set forth in the Class VI Rule, external mechanical integrity refers to the absence of any significant fluid movement into a USDW through channels adjacent to the wellbore [40 CFR 146.89(a)(2)]. Therefore, external MITs are designed to detect any leakage through channels adjacent to the wellbore that may result in significant fluid movement into a USDW. The Class VI Rule requires an external MIT be conducted prior to injection [40 CFR 146.87(a)(4)], at least once per year during the injection phase [40 CFR 146.89(c)], and prior to injection well plugging after the cessation of injection [40 CFR 146.92(a)] (Figure 1-1). If loss of external mechanical integrity is detected, the Class VI Rule requires that immediate action be taken by the owner or operator to remediate the well and prevent endangerment of USDWs [40 CFR 146.88(f)].

Unless an alternative test is allowed by the EPA Administrator and UIC Program Director under 40 CFR 146.89(e), the owner or operator must use at least one of the following methods for external MITs: an oxygen activation log, temperature log or noise log [40 CFR 146.89(c)]. The choice of MIT(s) to use is dependent on conditions of the site and well, operator preferences and the approval of the UIC Program Director. As described below, the separate MITs provide complementary, but not entirely duplicative, information regarding the well. In cases where one test indicates the potential loss of mechanical integrity, follow-up tests can verify and further characterize the potential leakage pathway. In addition, the UIC Program Director may require more than one test, as there have been cases where the loss of external MIT was not detected by a certain method but was found using other methods.

2.2.1. Oxygen Activation Log

General Information

The oxygen activation method is based on the ability of a wireline tool to convert oxygen into nitrogen-16 (N^{16}) within a short distance. This is accomplished by emitting high-energy neutrons from a neutron source. N^{16} is an unstable isotope of nitrogen that is referred to as activated oxygen. The half life of activated oxygen is just 7.13 seconds, and the release of gamma rays as the activated oxygen decays into oxygen can be measured. If the tool is stationary and oxygen is activated, detectors placed near the activator device will detect increased gamma radiation. The intensity of the additional radiation will be inversely proportional to the square of the distance of the activated oxygen from the detector. Much of the oxygen near the tool occurs in water. If water containing activated oxygen moves, the measured intensity of radiation will be greater if the slug of activated oxygen moves closer to the detector, and less if it moves away. By comparing the intensity of gamma radiation measured as a result of activation at two detectors, the direction and velocity of water movement can be determined. Studies under controlled conditions have shown that water velocities between two and 120 feet per minute can be measured.

The results of oxygen activation logs are relatively simple to interpret. Compared to temperature logs (Section 2.2.2), little or no shut-in (i.e., temporary cessation of injection) time is necessary. The test also does not require a liquid-filled wellbore. One disadvantage of this method is that it detects flow in a broad, but fixed, velocity range. The method also has a very small range of investigation and cannot be used to demonstrate the absence of liquid movement through confining layers. Studies have shown that the method is prone to false positives and has missed MIT failures confirmed by one or more other methods.

Application

The wireline logging tool consists of a high-energy neutron generator and gamma ray detectors. By spacing several detectors at increasing distances from the oxygen activation area, interpretational accuracy is increased. Although the activated oxygen may be present in water potentially moving along the wellbore, oxygen is also present in rock and cement. Some of this oxygen in rocks and adjacent cement may also be activated, and the oxygen's decay products would create a level of background radiation that needs to be accounted for in order to obtain a valid measurement of the movement of activated atoms in the fluid passing along the wellbore. Accounting for the background radiation caused by oxygen in rocks and cement that is not in flowing water can be addressed in either of two ways: (1) by making calibration measurements in a representative area of the wellbore in which there is thought to be no flow behind the casing, or (2) by extending the measurement period at each station beyond the time during which the activated oxygen in flowing water has been carried away. The rate of decay indicated by the late measurements is used to calculate the theoretical levels of gamma radiation that would have been measured if there were no water movement. The difference between the calculated and measured values is assumed to be the effect of the decay of activated oxygen carried to the vicinity of the detectors as part of moving water.

To be effective, injection pressure needs to be maintained during the test to ensure identification of fluid flow near the injection zone. EPA recommends that all measurements be taken for periods of at least five minutes with the well injecting at the maximum normal rate. A total of at least 15 minutes of measurement time is recommended at each station. This total time may be accumulated in one, two or three episodes. EPA also recommends that all readings be taken at depths where the wellbore is in gauge, based on open-hole caliper logs (see the *UIC Program Class VI Well Construction Guidance*). Measurements are best taken at least 10 feet above the injection interval, at the top of the confining zone, at two or three formation interfaces between the confining zone and the base of the lowermost USDW (based on previous lithologic logs; see the *UIC Program Class VI Well Site Characterization Guidance*), and within 50 feet of the base of the lowermost USDW. If anomalies are found, additional readings made above and below the depth of the anomaly will confirm the anomalous reading and discover the extent of fluid movement.

Interpretation

Measurements from two or more gamma-ray detectors may be used to calculate water flow direction and velocity. If water flow outside of the casing is detected, this indicates the potential loss of external mechanical integrity. Indicated water-flow velocities of less than two feet per minute may be false positives. To minimize false positives, it is recommended that all measurements be confirmed at several nearby depths and/or that measurements be taken under a minimum of three varying injection rates: 75 percent, 50 percent and 25 percent of maximum permitted injection rate. If a failure of an external mechanical integrity test occurs, the Class VI Rule requires that the owner or operator notify the UIC Program Director within 24 hours in order to determine appropriate next steps [40 CFR 146.91(c)(4)].

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2.2.2. Temperature Log (for External MIT)

General Information

Temperature logs are an acceptable external MIT, and they are based on the principle that fluid leaking from the well will cause a temperature anomaly adjacent to the wellbore. Temperature logs are run after the well has been shut in (i.e., after injection has ceased) to allow for temperature equilibration and after heat radiation from well cement hydration has ended. The Class VI Rule requires that temperature logs be conducted immediately after well cementing to evaluate the presence of cement behind the casings [40 CFR 146.87(a)(2)(ii) and 146.87(a)(3)(ii)] (see the *UIC Program Class VI Well Construction Guidance*). If temperature logs are to be used for external MITs, several logs will be run prior to injection to comply with both cement evaluation and external MIT requirements.

Fluid that leaks from the wellbore will, in most cases, be of a different temperature than native fluids at that depth. Given sensors of sufficient sensitivity, it is possible to identify the change in temperature resulting from heating or cooling by leaking fluid. In addition, it is possible to identify the original zone of the water if flow is continuing. Temperature logs can also confirm that there is no flow of injectate through the rock surrounding the wellbore and will often identify small casing leaks.

During injection, the ability of the injectate flowing through the well to maintain its own temperature dominates all other effects; therefore, to be effective for the purpose of establishing mechanical integrity, the well needs to be shut in during temperature logging. The principal requirement for running temperature logs is that the well be shut in long enough that temperature effects can dissipate, leaving a relatively simple temperature profile. Experience has shown that 36 hours is usually a sufficient shut-in period. During the shut-in period, the temperature within the wellbore will typically increase toward static geothermal conditions. If there has been a leak of fluid out of the well, the temperature within the wellbore at this location will change to a lesser extent and be measured as an anomaly because the temperature of the surrounding formation will have been modified by the leaking fluid (Figure 2-4).

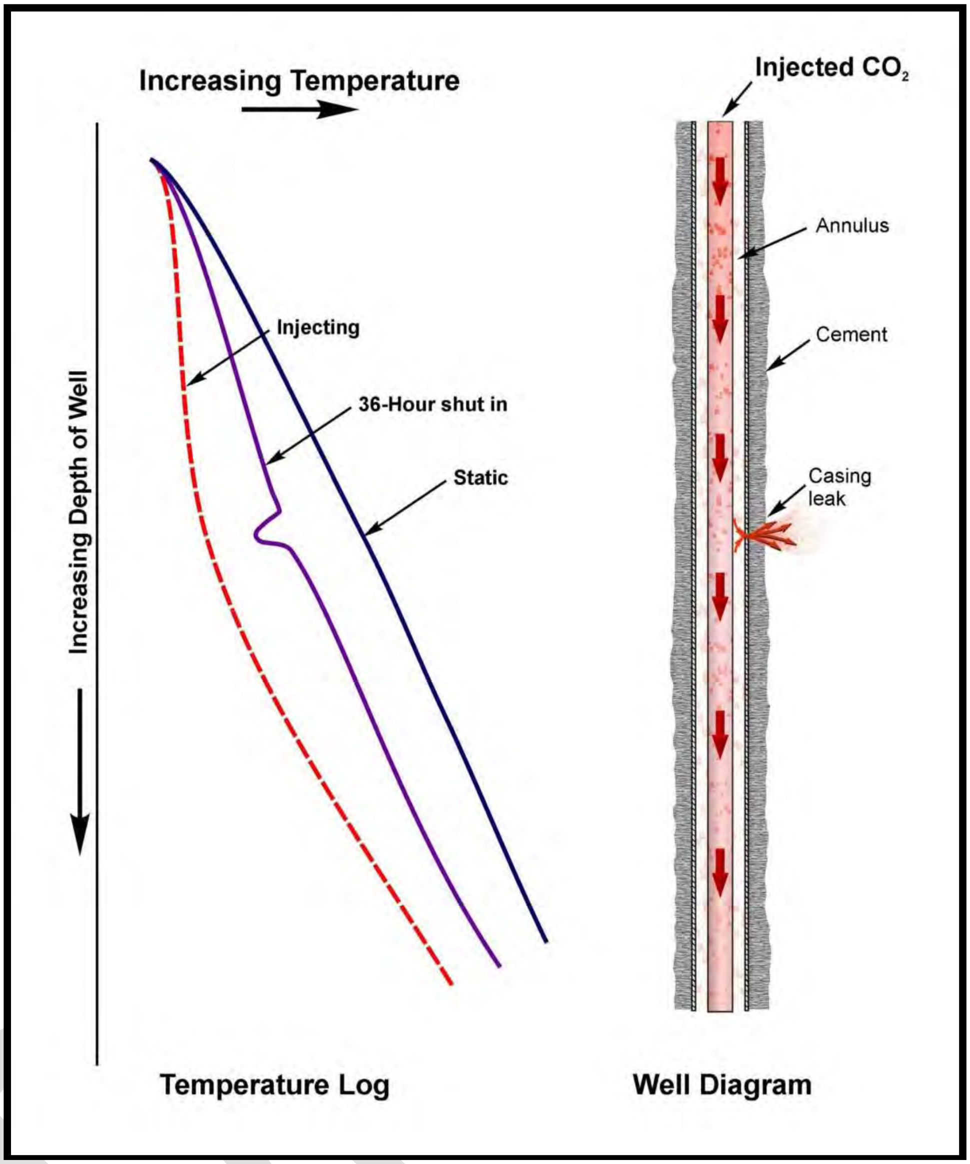

Figure 2-4. Temperature log showing the detection of a leak in the casing (USEPA, 1982; not to scale).

Application

In new wells, EPA recommends that baseline temperature logs for external MIT be made as long as possible after drilling the well but before injection begins (see the *UIC Program Class VI Well Site Characterization Guidance*). Temperature effects due to circulation and infiltration of drilling fluid will persist for several weeks or months after drilling is completed. Although these anomalies can mark permeable zones, the existence of a temperature log that reflects the natural geothermal gradient can be of great value in evaluating later analyses and for understanding other geophysical effects.

The wireline temperature logging tool consists of circuitry that responds to temperature change by changing resistance to current flow. The response is linear, and temperature logs can distinguish very small changes in temperature. To be effective, temperature logging tools should have good thermal coupling to the borehole environment, which means that they are generally not useful in gas-filled holes. Newer temperature measurement technologies, such as the use of fiber optic cables, may be more applicable to carbon dioxide-filled holes. Sampling is done at short intervals as the tool is lowered into the well, producing a record of the entire wellbore. Because the tool does not react to temperature change instantaneously and is continuously moving, the measured temperature changes lag behind actual wellbore temperature changes by a consistent amount. The more slowly the tool moves, the closer the measured temperatures are to actual temperatures. If the tool speed is erratic, the recorded temperature profile will also be irregular. Despite the possible inaccuracies due to poor calibration and tool response time, the absolute values recorded can generally be compared with some confidence.

If there are frequent changes in the temperature of the injectate or if process changes have caused a significant change in the temperature of the injectate, it is important to record the average temperatures of the injectate before existing logs were made, as well as the date of the change in injectate temperature and the volume of liquid injected before and since that time. The scaling of logs is very important. Features of significance are emphasized by compressing the depth scale and expanding the temperature scale. A depth scale of one or two inches per 100 feet and a temperature scale of one inch to two degrees Fahrenheit are appropriate in almost every case. If multiple logs are run while the well is shut in, it is helpful to display them on the same axes (depth scale) for comparison. Gamma ray logs may be run simultaneously with the temperature log. Gamma ray logs provide depth control and important information about the rock types along the wellbore. Additional detailed instructions for conducting temperature logs for external MIT are available in USEPA Region 5 (2008).

Interpretation

EPA recommends that the temperature log be compared to a baseline log taken prior to injection or to another log taken at the same site. When lithology and injectate characteristics are similar, the thermal effects along the wellbore are expected to be very similar. After the temperature effects caused by casing joints, packers, well diameter, casing string differences and cement have dissipated, the temperature profiles are expected to be similar, although not identical. If the thermal effects of construction features are evident in the temperature log, a longer shut-in period may be needed.

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Identification of flow is based on relative differences between the collected temperature log and the baseline log or the logs of nearby wells, if such logs exist. Although the gradients may be quite different as a result of differing injection history, their relative positions would be consistent. Lithologic effects that appear on one log are expected to appear similarly in other wells at the same site. Anomalies are revealed by inconsistencies among logs made at the same site under conditions that should result in thermal stability. If there are no logs suitable for comparison, then deviations from a predictable geothermal gradient, modified by the effects of injection, indicate anomalies. These anomalies may take the form of nearly constant temperatures between reservoir strata.

When more than one log is run sequentially in the same well, anomalies are likely to become more prominent as the profile returns toward the natural geothermal gradient. Areas with active flow will also reach a stable temperature more quickly than other areas. An example temperature log, showing an anomaly indicative of leakage, is shown in Figure 2-4.

Anomalies may indicate a failure of mechanical integrity. In such a case, an additional log may be necessary to show whether forms apparent on the original log are evolving toward the forms established on the log from another well. Comparison of these two new logs is expected to show increasing parallelism along the cased wellbore; if not, then there may be flow along a channel adjacent to the wellbore. In the event that there are unresolved anomalies that might indicate the absence of mechanical integrity, another approved method could be used to confirm the absence of flow into or between USDWs. Depending on the nature of the liquid movement, radioactive tracer, noise, oxygen activation or other logs approved by the UIC Program Director may be used to further define the nature of the fluid movement.

2.2.3. Noise Log

General Information

Channels along wellbores are very rarely uniform. When flow is occurring through these channels, irregularities in channel cross section usually result in the generation of some turbulence, which occurs in audible ranges. Sonic energy travels for considerable distances through solids, allowing sensitive microphones to detect the effects of turbulent fluid flow at sizeable distances. In addition, different types of turbulence result in sounds with different frequencies. Single phase turbulence results in low-frequency sounds, while two phase turbulence usually results in high-frequency sounds. High pass filters are used to determine the intensity of detected noise within various frequency ranges.

Application

Noise logging tools are wireline tools that are essentially sensitive microphones. Sampling is done in a stationary mode and the time required at each station is approximately three to five minutes. Any sounds detected are transmitted to recorders that measure the amount (loudness) of sonic energy received over a period of time. A cumulative measure of the sound energy that has been received is recorded. Because sonic energy travels for considerable distances through solids, sampling can be done in a reconnaissance mode, with additional stations run where increases in energy are detected to identify the exact locations of conditions

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that cause sonic events. Similarly to temperature logs, sonic logs are more effective in liquid-filled holes because of improved coupling.

Noise logging may be carried out while injection is occurring in many wells because flow restriction caused by the logging tool is often insufficient to cause turbulence. It is especially desirable to log while injecting when looking for flow resulting from pressure increases near the top of the injection zone. EPA recommends that noise measurements be made at intervals of 100 feet to create a log on a coarse grid. If any anomalies are evident on the coarse log, EPA recommends constructing a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels. EPA also recommends that noise measurements be made at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within 100 feet of the base of the lowermost bleed-off zone above the injection interval, the base of the lowermost USDW, and, in the case of varying water quality within the zone of USDWs, at the top and base of each interval with significantly different water quality from the next interval. Additional measurements may be made to pinpoint the depths at which noise is produced.

Interpretation

When the level of sound is low, a linear scale is used for reporting noise logs, and when there are intervals with higher sound, a logarithmic form is used. Regardless of whether data are presented in linear or log form, a vertical scale of one or two inches per 100 feet is recommended. The interpretation of noise logs for the purpose of demonstrating external mechanical integrity is straightforward. Departures from base noise level in the log indicate an anomaly. Figure 2-5 shows a noise log indicating leakage through a cement channel adjacent to the wellbore. Ambient noise while injecting that produces a signal greater than 10 mV may indicate leakage and potential loss of external mechanical integrity. If a lack of external mechanical integrity is identified, the Class VI Rule requires that action be taken to remediate the well [40 CFR 146.88(f)]. If the log measurements are ambiguous, another testing method may be used for confirmation.

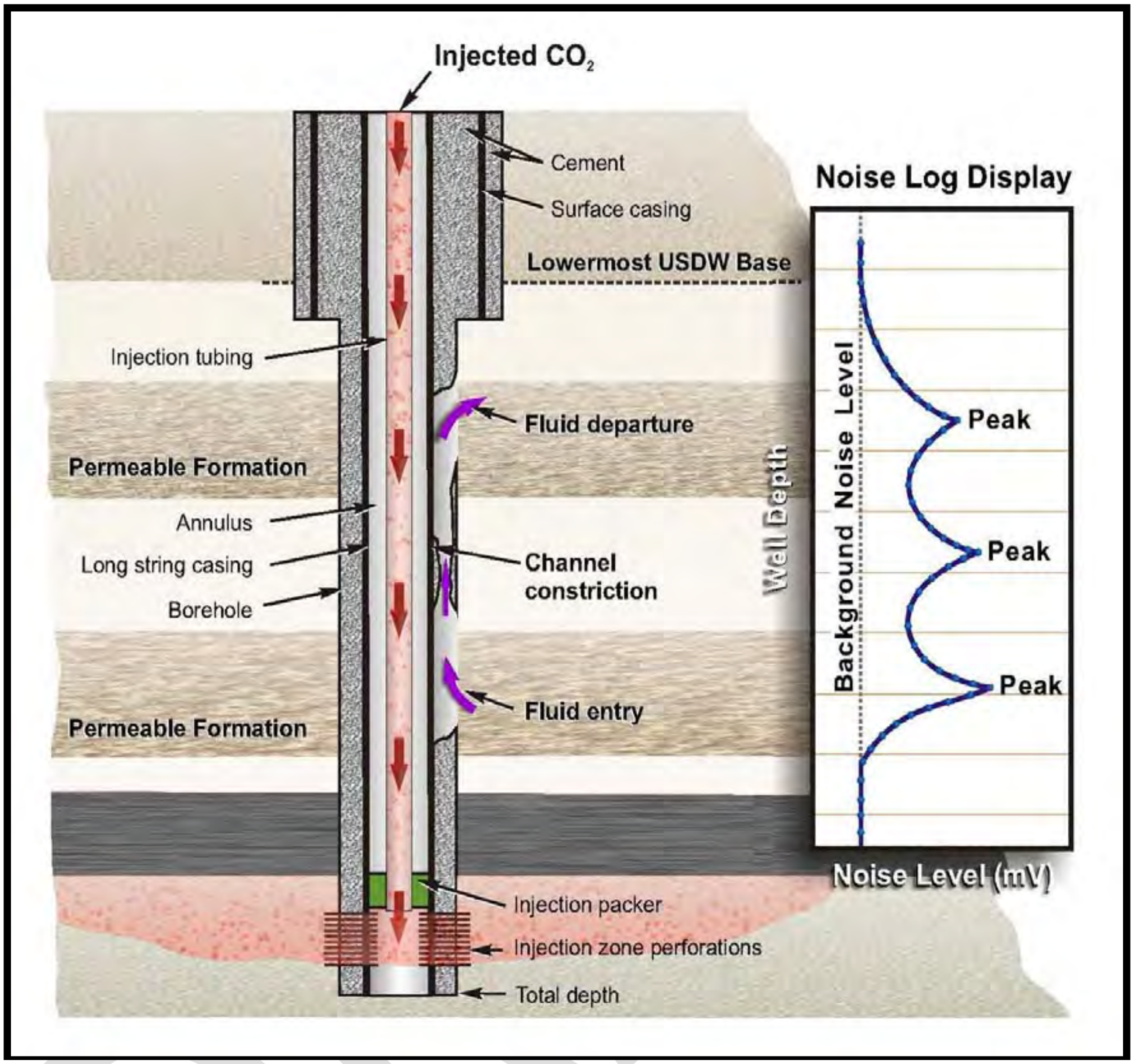

Figure 2-5. Diagram of fluid leakage through channel in cement and corresponding noise log (not to scale).

2.2.4. Alternative Methods for External MIT

The Class VI Rule requires that an oxygen-activation log or other tracer survey, a temperature log or a noise log be conducted to comply with external MIT requirements [40 CFR 146.89(c)]. However, alternative methods beyond those listed may be used if approved by the UIC Program Director and EPA Regional Administrator [40 CFR 146.89(e)]. A request for using alternative methods other than those currently approved by EPA requires an additional EPA approval process and publication of the alternative method approval in the *Federal Register*, as required at 40 CFR 146.89(e). Currently, there are no alternative methods that may feasibly be used for external MIT beyond those listed here, except under very limited circumstances. The Class VI Rule does not preclude the use of methods that may be developed in the future, as long as use of these methods is approved by the UIC Program Director and the EPA Regional Administrator.

Radioactive tracer surveys have been used previously as an external MIT. Radioactive tracer studies, although expensive, can be very sensitive. There are two potential methods for performing radioactive tracer studies for external mechanical integrity: the velocity shot method and the slug tracking method. The instrumentation used is the same as that used for radioactive tracer studies to test internal mechanical integrity as described in Section 2.1.3. The sensitivity used for external MITs is typically lower than would be used for gamma logs or velocity profiling because, at high sensitivities, small amounts of tracer that are not indicative of an integrity problem may be detected (McKinley, 1994). In the velocity shot method, the instrument is placed just above the packer and a slug of tracer material is released. The tool is kept stationary and the detectors are monitored to see if the radioactive material passes upward by the detectors after the initial injection. If a radioactive slug passes the lower detector and then the upper detector, upward flow of the tracer is occurring.

If upward movement of the tracer is detected, it is recommended to use the slug tracking method to determine the cause and limits of the upward flow (McKinley, 1994). In the slug test, a slug of tracer is released and the tool is lowered up and down the well while the position of the slug(s) is tracked. If any portion of the slug moves upward, it should be tracked until the upward motion stops. Sometimes it will be necessary to release a larger slug to be able to track the upward motion to its end point. If the upward motion does not extend above the casing then the cement is likely intact and the upward motion is from vertical permeability within the formation. If the upward movement extends above the casing, then there is likely a flaw in the cement. While it is fairly easy to recognize upward fluid movement using the radioactive tracer test, the cause of the movement and its precise location can require additional tests or analysis. McKinley (1994) provides more information on radioactive tracer tests and their interpretation.

By regulation, use of radioactive tracer surveys as the sole test for external MIT is limited to cases where there are no permeable formations between the injection zone and the lowermost USDW (USEPA, 1987b). Essentially, a single confining layer would need to be present that separates the injection zone from the lowermost USDW. Given the depths of Class VI wells and the significant siting requirements, it is unlikely that this condition will be met for Class VI wells. However, radioactive tracer tests may be used to complement the external MITs discussed above.

Evaluation of cementing records and cement evaluation tools (see the *UIC Program Class VI Well Construction Guidance*) have previously been used in isolated circumstances for external MIT. These methods, however, do not directly detect fluid leakage and do not identify any potential leakage pathways in the cement. Therefore, the use of cement evaluation tools and cementing records is not an acceptable form of demonstrating external mechanical integrity for Class VI wells.

2.3. Reporting the Results of MITs

The Class VI Rule requires that the owner or operator submit to the UIC Program Director a descriptive report of all MITs conducted at the site in an electronic format [40 CFR 146.91(e)]. EPA recommends that the result of initial MITs, performed prior to injection, be submitted to the UIC Program Director prior to the commencement of injection. The results of continual monitoring to demonstrate internal mechanical integrity must be submitted in semi-annual operational reports [40 CFR 146.91(a)]. The results of periodic external MITs must be reported within 30 days of the test [40 CFR 146.91(b)]. Any failure of an MIT must be reported to the UIC Program Director within 24 hours of the failure [40 CFR 146.91(c)]. It is recommended that the submittal to the UIC Program Director include:

- Chart and/or tabular results of each log or test
- The interpretation of log results provided by the log analyst(s)
- Description of all tests and methods used
- Records and schematics of all instrumentation used for the test(s) and the most recent calibration of any instrumentation
- Identification of any loss of mechanical integrity, evidence of fluid leakage, and corrective action taken
- The date and time of each test
- The name and professional certification of the logging company and log analyst(s)
- For any tests conducted during injection, operating conditions during measurement, including injection rate, pressure, and temperature (for tests run during well shut-in, this information needs to be provided relevant to the period prior to shut-in)
- For any tests conducted during shut-in, the date and time of the cessation of injection, and records of well stabilization

The UIC Program Director may evaluate the results and interpretations of MITs to independently assess the integrity of the injection well.

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3. Operational Testing and Monitoring during Injection

The Class VI Rule requires that the owner or operator of a Class VI well monitor several aspects of the GS project during the injection phase, including analysis of the injected carbon dioxide stream; monitoring of injection rate, pressure and volume; and corrosion monitoring (Figure 1-1) [40 CFR 146.90(a), (b), (c)]. Additionally, the owner or operator must conduct continuous monitoring to demonstrate internal mechanical integrity, perform an external MIT at least once per year [40 CFR 146.89(c)], and conduct a pressure fall-off test at least once every five years [40 CFR 146.90(f)]. As discussed below, the objective of these activities is to ensure the Class VI project is operating as intended by the owner or operator, to ensure that the project is operating within the limits of the UIC permit, and to confirm that USDWs are not endangered. Furthermore, these activities are designed to detect factors that may lead to fluid leakage and endangerment of a USDW. All of these methods must be described in the Testing and Monitoring Plan submitted with the permit application, per 40 CFR 146.82(a)(15) and approved by the UIC Program Director. This section discusses operational monitoring activities performed during the injection phase, other than MITs, which are discussed in Section 2.

3.1. Analysis of Carbon Dioxide Stream

The Class VI Rule requires that the injected carbon dioxide stream be analyzed with sufficient frequency to yield data representative of its chemical and physical characteristics [40 CFR 146.90(a)]. Chemical characteristics include the fluid composition, including carbon dioxide purity (percent) and the concentrations of impurities in parts per million by volume (ppmv) or percent. Physical characteristics include temperature and pressure and are discussed below (Section 3.3). Monitoring the chemical composition of the injectate is conducted to verify that the injectate does not qualify as hazardous waste with regard to corrosivity or toxicity, as well as to ensure that the delivered carbon dioxide stream meets the specifications outlined in the UIC permit.

This section discusses analysis of chemical impurities, which may include sulfur dioxide, hydrogen sulfide, nitrous oxides (NO_x), hydrocarbons, carbon monoxide, methane, water vapor, nitrogen, oxygen, mercury and arsenic. Methods for analysis of the injectate stream can be adapted from available methods for flue gas analysis in industrial settings as well as from analytical methods for verification of the purity of carbon dioxide used for supercritical fluid applications or the food industry. EPA notes that flue gas methods (Section 3.1.1), which use in-situ sensors that may provide nearly continuous monitoring of the composition of the fluid within a pipeline, may not be necessary for many GS projects; rather, periodic fluid sampling and ex-situ laboratory analysis (Section 3.1.2) may be sufficient. GS project owners or operators are encouraged to consult with the UIC Program Director to establish a carbon dioxide stream characterization protocol that is tailored to the specifics of the GS project. The methods used to characterize the stream must be specified in the Testing and Monitoring Plan, which must be approved prior to authorizing injection. An owner or operator that is also subject to requirements under Subpart RR of the Mandatory Reporting of Greenhouse Gases Rule may note that the carbon dioxide composition samples must be collected from a point immediately upstream or downstream of the flow meter [40 CFR 98.440-98.449]. Additional information may also be found in the Subpart RR General Technical Support Document (TSD). A copy of the Subpart RR TSD can be downloaded here: http://www.epa.gov/climatechange/emissions/downloads10/Subpart-RR-UU_TSD.pdf.

Analyses of flue gas and food-grade carbon dioxide are performed in the gas phase. Because carbon dioxide for GS will in most cases be transported and injected in the supercritical phase, samples may need to be extracted from the pipeline or wellhead via a valve and permitted to decompress into a gaseous phase within a sample holder or other device for analysis by one of the methods below. If samples are allowed to decompress to the gas phase for chemical analysis, temperature and pressure will both drop and will no longer represent carbon dioxide conditions in the pipeline or as injected.

3.1.1. Flue Gas Analysis Methods

<u>General Information</u>

Flue gas monitoring in industrial settings is conducted both for determining the optimal operating conditions for equipment and for compliance with federal and state emissions standards. Monitoring can be conducted with hand-held analytical units or with dedicated in-situ stationary gas monitoring systems called continuous emission monitoring (CEM) systems.

CEMs employ a probe, a filter, a sample line, a gas conditioning unit and a series of gas analyzers that can detect a wide range of constituents, including carbon dioxide, sulfur dioxide, nitrous oxides, carbon monoxide, hydrochloric acid (HCl), particulate matter, mercury, volatile organic compounds (VOCs), oxygen and moisture. Several types of instruments may be used, such as infrared (IR) and ultraviolet (UV) absorption detectors, photoionization or flame ionization detectors, or chemiluminescence detectors. Because CEMs are installed permanently, they require a housing and protection from environmental conditions. Portable flue gas analyzers may be a viable option for periodic ex-situ chemical analysis of the injectate stream. These instruments use infrared and electrochemical sensors to detect a variety of gas constituents.

<u>Application</u>

Infrared sensors use non-dispersive infrared (NDIR) technology, which is based on Beer's Law. Beer's Law states that, at a given wavelength, the amount of absorbed light is directly proportional to the concentration of a particular gas that absorbs the light (Ingle and Crouch, 1988). NDIR techniques use a broad wavelength IR source and monochromatic (single wavelength) filters to detect specific gases and quantify gas concentrations. Different gaseous constituents absorb different wavelengths, and the concentrations of the desired analytes can be determined by measuring the light intensity at the appropriate wavelengths by using the appropriate filter. A multi-wavelength beam of IR light of known intensity is sent a known length across a gas sample where some of the light is absorbed. The transmitted light, at a lower intensity, passes through a filter allowing only a chosen wavelength to reach the detector. The absorbance is calculated as the log of the ratio of initial to final intensity. The absorbance is then used to calculate the concentration.

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IR sampling methods require that the gas sample first be dried because wet samples can fog the sensing lenses. Also, the absorption wavelength for water is very close to those for nitric oxide (NO) and sulfur dioxide. Allowing water to remain in the sample will result in significant measurement error for these compounds, particularly if the compounds are only present at low concentrations. Because of the physics governing the interactions between light and gas molecules, certain gases such as oxygen and nitrogen cannot be measured with IR (Clarke, 1998).

Electrochemical sensors amplify and measure the current generated when gases react on an electrode. A sample of gas can be tested in situ using a probe or collected and transported to the measurement device. Grab samples are often collected for analyses where it is not practical or safe to insert a probe (Fegen, 2005). The gas stream may need to be heated to prevent certain constituents from condensing (e.g., nitrous oxides, sulfur oxides, hydrochloric acid and water vapor) before being measured. When long-term analyses (several hours) of flue gases are required, the sample may require conditioning with a Peltier Cooler before entering the analyzer. This prevents condensation and corrosive gases from accumulating near the analyzer and distorting results over the course of the test.

Electrochemical sensor methods are subject to cross-sensitivity. This occurs when two gases both absorb the same or similar wavelengths, making discrimination between the two gases difficult or impossible. The risk of such an interaction increases with the number of gases included for analysis (Kleine, 2012). Usually alternate methods can be found to measure cross-sensitive compounds (for example, different wavelengths can be used). An additional source of error is a potentially corrosive operating environment. Compounds such as hydrogen sulfide, hydrochloric acid and sulfur dioxide may cause wear on sensors, which can affect measurement quality. Furthermore, the electrodes for electrochemical techniques may be consumed by reduction/oxidation reactions during measurement. As a result, IR sensors are increasingly used; however, particulates and fog on lenses can negatively impact the performance of IR devices (Fegen, 2005).

Portable flue gas analyzers do not measure mercury, but CEMs can monitor for mercury using atomic absorption spectrophotometry, atomic fluorescence spectroscopy or plasma atomic emission spectroscopy. Some models measure total vapor phase mercury, while others allow for speciation of elemental and oxidized mercury. Analysis of arsenic in gases appears to be less frequently performed than mercury analysis, but it is likely to be accomplished by similar methods.

Interpretation

The data from flue gas analyzers are reported either as ppmv or milligrams per cubic meter (mg/m^3). The conversion of mg/m^3 to ppmv for each component requires converting milligrams to moles then to cubic meters with an equation of state. CEMs provide nearly continuous data that are usually sent to a remote computer, removing the necessity of sampling the injectate line.

3.1.2. Laboratory Chemical Analysis

General Information

In addition to on-site and in-situ analysis, carbon dioxide injectate samples may be collected at the wellhead or transmission line and transported to an approved testing laboratory for analysis. Carbon dioxide is used for laboratory applications in supercritical fluid extraction (SFE) and supercritical fluid chromatography (SFC), which require the carbon dioxide to be high-quality. Accordingly, the American Society of Testing and Materials (ASTM) has developed a standard guide for the purity of carbon dioxide intended for such applications (ASTM, 2005), which includes descriptions of analytical methods such as gas chromatography and the use of a total hydrocarbon analyzer. These methods may be considered for adoption in analyzing the carbon dioxide stream or injectate for certain types of impurities. For example, an adsorbent concentration method followed by gas chromatography may be used for the analysis of contaminants in carbon dioxide, such as hydrocarbons and halocarbons. A method published by the South Coast Air Quality Management District (2008; Method S.C. 10.1, alternative to EPA Method 10) analyzes carbon dioxide in a gas sample by gas chromatography (GC) with detection performed by a non-dispersive infrared detector.

Some equipment manufacturers have developed similar methods suitable for the analysis of impurities in carbon dioxide. These methods use gas chromatography for separation of the various constituents in the sample, followed by detection with any of several possible instruments. Gas chromatographic methods have much lower detection limits than the IR and electrochemical detectors used in portable flue gas analyzers or CEMs. The descriptions below are intended to provide examples of the analytical approaches available for various constituents that may be present in a carbon dioxide stream. Owners or operators may contact commercial laboratories that handle gas samples to discuss their site-specific analytical needs.

Application

Gas chromatography with a pulsed flame photometric detector (PFPD) and flame ionization detector (FID) can be used for measuring trace sulfur and hydrocarbon contaminants in carbon dioxide intended for beverages (e.g., Agilent, 2010). This method permits highly sensitive analyses of sulfur gases (hydrogen sulfide, sulfur dioxide, carbonyl sulfide (OCS)) and some hydrocarbons (e.g., acetaldehyde, benzene and light hydrocarbons). Detection levels are reportedly 0.1 ppm for sulfur gases and <100 parts per billion by volume (ppbv) for hydrocarbons. In addition, gas chromatograph analyzers have been specifically designed for detection of impurities in beverage grade carbon dioxide. These units use a sulfur chemiluminescence detector (SCD) for sulfur compounds (hydrogen sulfide, carbonyl sulfide, sulfur dioxide, mercaptans, aromatic sulfur compounds). A photo ionization detector (PID) is used for aromatic hydrocarbons (benzene, toluene, xylenes, ethylbenzene), and an FID is used for certain other hydrocarbons (Arnel, 1999). Detection limits are in the ppb range. A nitrogen chemiluminescence detector can be used for measurement of nitrous oxides.

Because of the very low concentrations in emissions, very sensitive methods employing preconcentration are needed for mercury analysis. Mercury in flue gases is generally measured by one of several forms of spectroscopy. ASTM Method D5954 (ASTM, 2006) describes a method for measurement of both inorganic and organic mercury in natural gas. The mercury is pre-concentrated by adsorption onto gold-coated beads, resulting in the capacity to detect very low concentrations (as low as one ng/m^3). Analysis is conducted by atomic absorption spectrophotometry. Another method, cold vapor atomic fluorescence spectrometry (CVAFS), uses a sorbent trap that is inserted into a natural gas stream, with a metered amount of gas passed through it. The mercury is detected by fluorescence spectrometry (EPA Method 1631 Revision E; USEPA, 2002a).

Interpretation

The detection methods that are coupled to gas chromatography generally produce output in the form of concentrations in micrograms per liter (µg/L) or the equivalent (at the same analyte density) ppbv. Gas chromatographic methods can produce concentrations when calibration data are provided to the controlling software. Output can also take the form of chromatograms with peak areas, which are usually provided in the lab report.

3.1.3. Reporting and Evaluation of Carbon Dioxide Stream Analysis

The Class VI Rule requires that the owner or operator submit data on analysis of the carbon dioxide stream in semi-annual reports [40 CFR 146.91(a)(7)]. The data are required to be submitted to EPA in an electronic format [40 CFR 146.91(e)], and it is recommended that the submission include:

- A list of chemicals analyzed, including carbon dioxide and other impurities (e.g., sulfur dioxide, hydrogen sulfide, nitrous oxides)
- A description of the sampling methodology, including schematics of the monitoring equipment if using flue-gas methods
- Any laboratory analytical methods used and the name of the certified laboratory performing analysis
- All sample dates and times
- A database of all available carbon dioxide stream analyses, including any quality assurance/quality control (QA/QC) samples
- Interpretation of the results with respect to regulatory requirements and past results
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs

The UIC Program Director will evaluate the submittal to ensure that the purity of the injected stream is consistent with permit conditions, and that the concentration of any impurities does not result in the injectate being classified as a hazardous waste.

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3.2. Continuous Monitoring of Injection Rate and Volume

General Information

The Class VI Rule requires the installation and use of continuous recording devices to monitor injection rate and volume [40 CFR 146.88(e)]. The monthly average, maximum, and minimum values must be reported by the owner or operator to the UIC Program Director in the semi-annual reports [40 CFR 146.91(a)(2)]. This information is used to verify compliance with the operational conditions of the permit and to inform AoR reevaluation. Flow rate data are also used to determine the cumulative carbon dioxide injected, which is not measured directly. If flow rate is measured on a mass basis, pressure and temperature measurements are also used to determine fluid density and convert values to volumetric measurements. EPA recommends that injection rates also be reported as mass per unit time (e.g., kg/sec) because carbon dioxide is compressible; mass can be used in conjunction with downhole pressure and temperature data to constrain the volume of the injectate at depth. Additional information may also be found in the Subpart RR TSD.

Injection rate can be continuously monitored using a flow metering device. Flow metering is a common practice in most industrial processes. There are many different types of flow meters depending upon the intended application. The applications most similar to geologic sequestration include metering of natural gas and carbon dioxide in the petroleum industry. The types of meters used in these practices include differential pressure meters (orifice plates, venturi meters); velocity meters (turbine meters, ultrasonic meters), which measure the velocity of the fluid; and mass meters (thermal meters, Coriolis meters), which measure the mass of fluid flow past the meter.

These approaches are discussed in more detail in the following sections, and schematics of common flow meters are given in Figure 3-1. Because continuous measurement of injection rate and volume are important for verifying that the well is operated as stipulated by the UIC permit, the UIC Program Director may require redundant monitoring systems (i.e., multiple flow meters for each well).

Application

Differential pressure meters and velocity meters are dependent upon the properties of the fluid, especially temperature, pressure and density. If the fluid properties are known and constant, they can be programmed into the meter, which can calculate flow rate. Density can either be measured directly or it can be calculated using equations of state and pressure and temperature readings. Otherwise, these values will need to be measured and input to a separate computational device. Measurements from mass flow meters do not depend on the pressure and temperature of the gas, and these meters do not require additional instrumentation. Thermal meters do require knowledge of the heat capacitance of the fluid. If the heat capacitance is expected to change because of variations in fluid composition, then fluid composition will need to be measured. In all cases, signals from the flow meter will be input into a device that will calculate the flow rate. The flow rate can then be recorded and stored electronically.

Orifice plate differential meters are one of the most common meter types used to measure gas flow. They are considered standard in natural gas pipelines and carbon dioxide pipelines (McAllister, 2005). Orifice plates use Bernoulli's equation to determine flow by measuring the pressure drop across a plate with a hole. The plate is placed in the pipe, and the diameter of the hole is typically 0.2 to 0.75 times the pipe diameter (Maxiflo, 2009). Orifice meters are simple to use, inexpensive, have no moving parts and are not as sensitive to density changes as some other meter types. They typically achieve an accuracy of two to four percent of the full scale reading. Disadvantages include a limited range and less accuracy than other meters. Wear or corrosion of the plates can also reduce the accuracy of the meter.

Venturi differential meters use the same principle as orifice plates, but the pressure differential is measured across a constriction in a long tube. The constriction gradually widens out to the original pipe diameter, and this slow widening allows some recovery of pressure and results in a lower pressure drop than in an orifice plate. The advantages of a venturi meter are similar to those of an orifice plate; they are simple and have no moving parts. They are more accurate than orifice plates, typically achieving 0.5 to two percent of full scale. They produce a slightly lower pressure drop and have a range that is larger than that of orifice plates but still significantly less than other meters. Disadvantages include high cost and sensitivity to fluid properties.

Turbine velocity meters operate by placing a multiple-blade rotor in the flow path, perpendicular to the flow direction. The flow moves the rotors and, by measuring the speed of the blades, the flow rate can be calculated. Turbine movement can be measured by magnetic pickup, photoelectric cells, gears or tachometers. The advantages of turbine meters are high accuracy and applicable range of flow. They typically achieve an accuracy of 0.25 percent of full scale and can operate at flows 20 times smaller than full scale flow. Disadvantages include high pressure drop, high cost, dependence on fluid properties and potential wearing of moving parts.

Ultrasonic velocity meters operate by measuring ultrasonic waves as they travel through the fluid. There are two types of ultrasonic meters: Doppler meters and transit time meters. Doppler meters measure the change in frequency of reflected ultrasonic waves. They require entrained particles or bubbles to reflect the ultrasonic waves and are, therefore, not appropriate for measuring gases. Transit time instruments measure the time it takes for ultrasonic waves to travel between sensors both with and against the flow. The difference between the measurements is proportional to the flow. The advantages of ultrasonic meters are that they do not cause a pressure drop and are available in clamp-on varieties that can be retrofitted to pipes without cutting the pipe or stopping flow. They also have a good operating range, able to operate at flow rates 20 times less than maximum scale. They typically achieve an accuracy of one to five percent of full scale. Disadvantages include high cost and the fact that carbon dioxide strongly attenuates ultrasound waves. Therefore, specially designed instruments are required for carbon dioxide applications to offset the attenuation caused by carbon dioxide (van Helden et al., 2009).

Thermal mass meters use a heating element that is isolated from the flow. The amount of heat conducted away from the element is proportional to the mass flow. Built-in calibrations allow the unit to convert the temperature change to a flow rate. An advantage of thermal mass meters is that they operate independently of pressure, temperature, density and viscosity. They are intermediate in accuracy (typically one percent of full scale). Their operating range is less

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than those of turbine and ultrasonic meters but greater than those of orifice plates and venturi meters. They cause a lower pressure drop than most meters with the exception of ultrasonic meters. Disadvantages include high cost and a high dependence on accurate calibration.

Coriolis mass meters are based on the Coriolis force experienced by the fluid as it passes through a vibrating tube. The flow passes through a bent tube that is vibrated using a magnetic device. The flow in the tube resists the motion caused by the vibration and causes the tube to twist. The twist is proportional to the mass flow rate. Sensors measure the speed of the vibration and use it to calculate the mass flow rate. The advantage of Coriolis meters is that they are independent of fluid properties such as temperature, pressure, density and viscosity. They are also very accurate (typically 0.4 percent of full scale). They can measure an intermediate range of flow rates and produce an intermediate pressure drop. A disadvantage is high cost.

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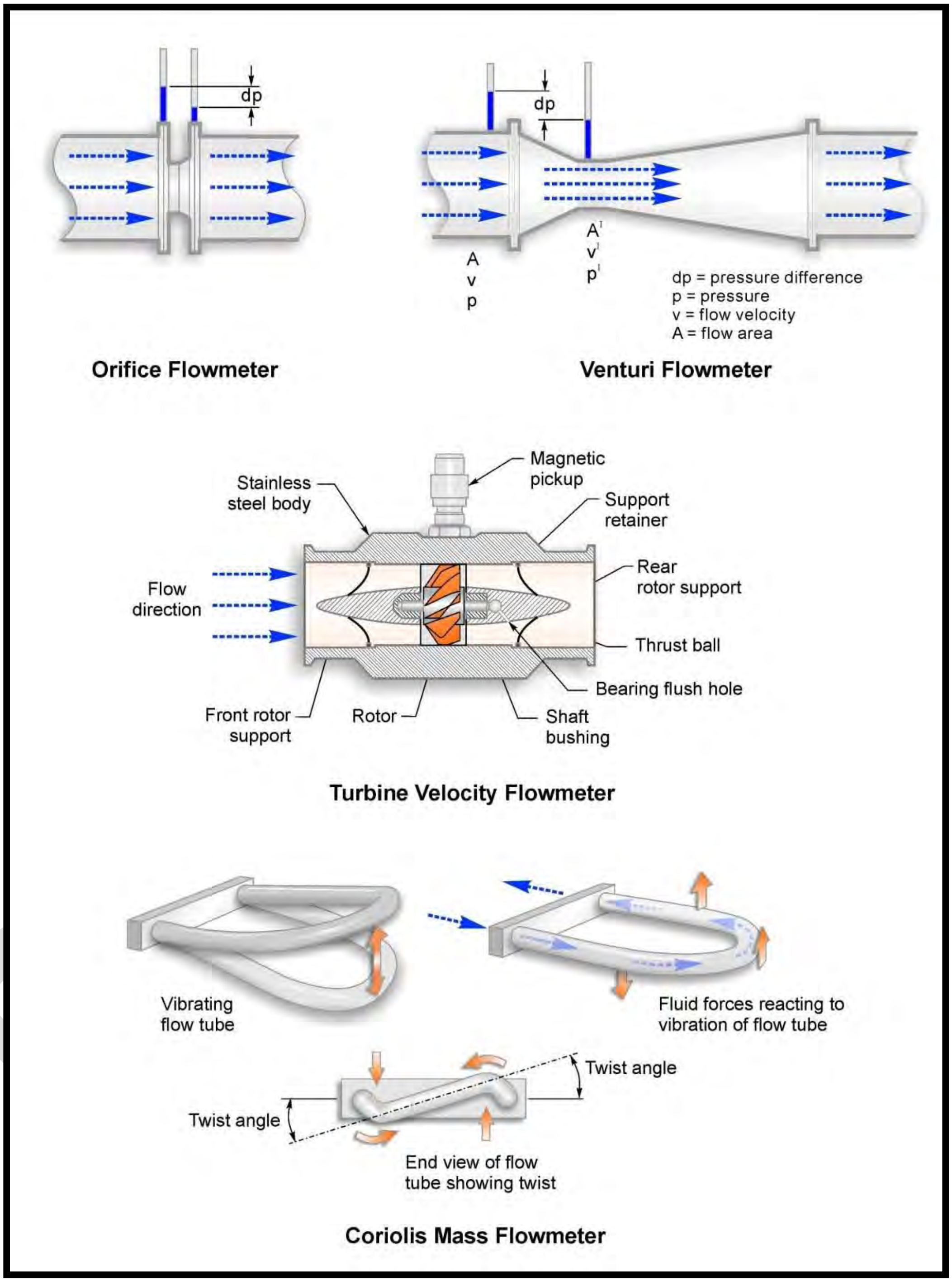

Figure 3-1. Schematic of common flow meters (not to scale).

Industry standards for flow meter applications should be consulted during selection, installation and use. Relevant industrial standards include:

- AGA Report No. 11 – Measurement of Natural Gas by Coriolis Meters
- AGA Report No. 9 – Measurement of Gas by Multipath Ultrasonic Meters
- AGA Report No. 3 – Orifice Metering of Natural Gas
- AGA Report No. 7 – Measurement of Natural Gas by Turbine Meter
- ASME – MFC-3M-2004 – Measurement of Fluid Flow in Pipes Using Nozzle, Orifice, Venturi Meters
- ASME – MFC-4M-1986 – Measurement of Gas Flow by Turbine Meter
- ASME – MFC-11M-2006 – Measurement of Fluid Flow by Coriolis Mass Flow Meters

Interpretation

The various meters discussed above will provide either flow rate data in units of volume or mass per time, or fluid velocity data in units of length per time. Injection flow rates may be calculated from velocity data by multiplying measured values by the cross-sectional area of the pipe or tubing at the measurement point. An example of a plot of measured injection rate over time is provided in Figure 3-2. Injection volumes are calculated by multiplying measured flow rates by the length of time for which the flow rate measurement is valid. Cumulative injection volume may be continuously calculated over the life of the project, and the term of the reporting period. In addition, if volume measurements are taken, it is recommended that the total mass of the injectate be calculated based on density as determined by pressure and temperature.

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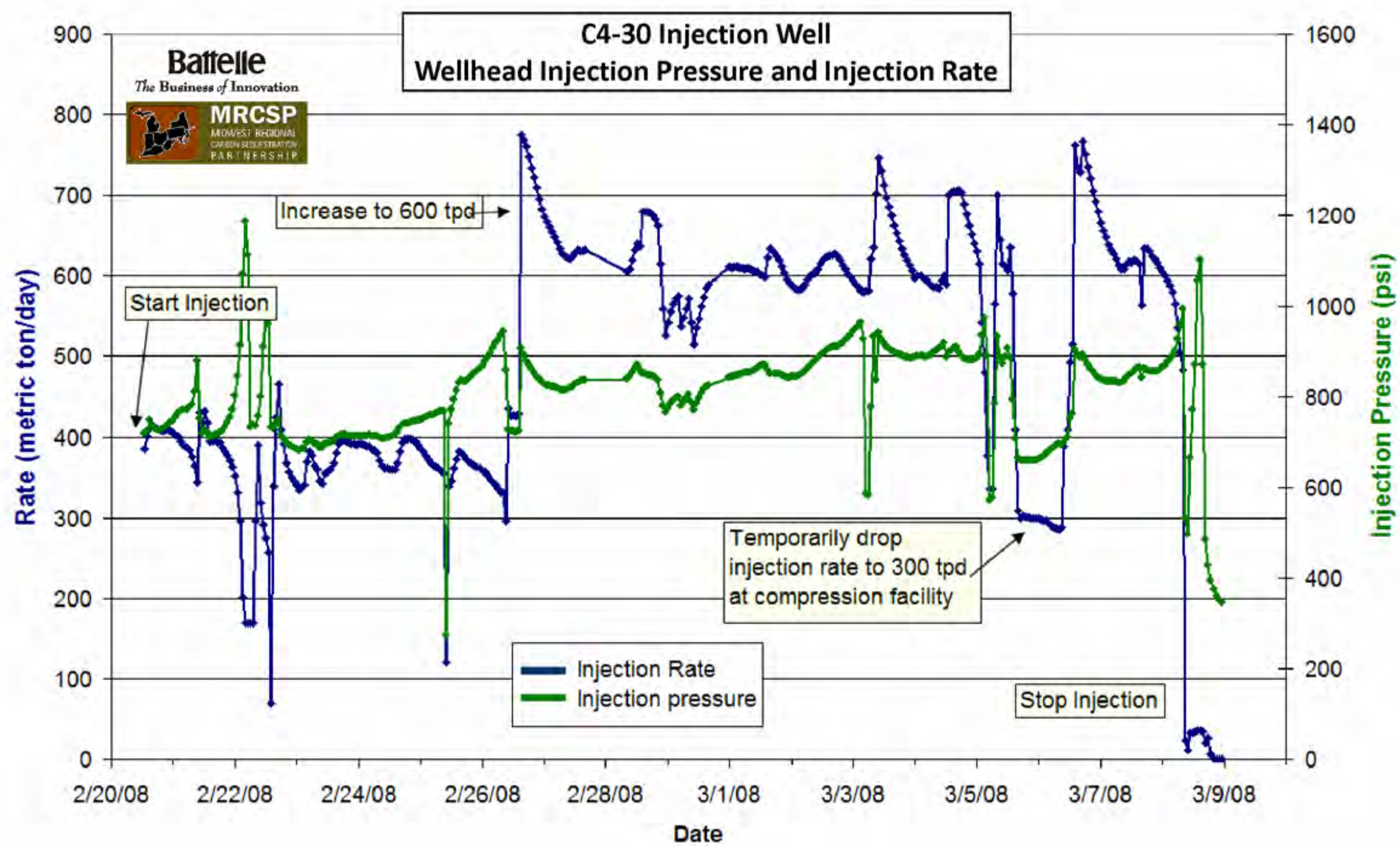

Figure 3-2. Example plot of measured injection rate and pressure measured at wellhead, Midwest Regional Carbon Sequestration Partnership (MRCSP) Michigan Basin Validation Test (image provided by Battelle Memorial Institute).

Reporting and Evaluation

Injection rate data must be submitted to EPA and the UIC Program Director in the semi-annual reports [40 CFR 146.91(a)(2)]. Data will be submitted in electronic form directly to EPA's database where they can then be accessed both by the UIC Program Director and other EPA offices. Monthly data submissions are expected for each of the six months covered in the report. The Class VI Rule requires certain information to be included in these reports [40 CFR 146.91(a)], and it is recommended that all of the information below be included:

- Tabular data of all flow rate measurements
- Monthly average for flow rate
- Monthly maximum and minimum values
- Total volume (mass) injected each month
- Cumulative volume (mass) for the project
- If flow rate exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion and response to the excursion
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs

The UIC Program Director will evaluate the data to determine compliance with permit conditions. If the pressure or flow exceeded the permit conditions, the UIC Program Director will evaluate the causes and determine if the permit needs to be modified or if changes are needed in any of the plans (e.g., the emergency and remedial response plan). The UIC Program Director will also likely review injection volume and compare it to the original plan.

3.3. Continuous Monitoring of Injection Pressure

General Information

The Class VI Rule requires the installation and use of continuous recording devices to monitor injection pressure [40 CFR 146.90(b)]. Injection pressure may be defined either at the wellhead (i.e., wellhead pressure), or at the center of the perforations into the injection zone (i.e., bottomhole pressure). Bottomhole pressure is equal to wellhead pressure plus the hydrostatic pressure that exists due to the weight of the fluid column between the wellhead and bottomhole, minus frictional losses. Injection pressure is monitored to ensure that the fracture pressure of the formation and the burst pressure of the well tubing are not exceeded and that the owner or operator is in compliance with the permit. If these pressures are exceeded, the formation may

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fracture or the tubing may burst. An example of a plot of measured injection pressure over time is provided in Figure 3-2.

<u>Application</u>

During operation, with an accurate knowledge of fluid density, bottomhole pressure can generally be estimated from wellhead pressure measurements. Due to temperature effects, measuring bottomhole pressure with a dedicated downhole pressure gauge is a more reliable approach. Pressure gauges are commonly-used instruments that have been developed for a wide range of applications. There are several types of pressure gauges (described below), and they can be broadly classified as mechanical or electronic devices. Mechanical gauges are generally considered less accurate but can withstand more severe conditions. Electronic gauges are more accurate but may not be able to handle extreme temperatures and pressures. Electronic gauges also require a power source. For additional information regarding pressure monitoring, see Shepard and Thacker (1993), USEPA (1998) and ASTM (2009).

Amerada gauges are mechanical devices that consist of a helically wound Bourdon tube that bends in response to the pressure differential between the inner and outer surfaces. As the tube moves, it moves a stylus, which records the pressure on a chart. This gauge is relatively accurate, but not as accurate as most electronic gauges. It is used mainly if the temperature is expected to be greater than 175˚ C.

Strain gauges are electronic devices bonded to a pressure transducer. The transducer can consist of wires wrapped around the inside of flexible tubing or a plate attached to a diaphragm. The resistance of the transducer changes as it is stretched by the pressure. The transducer is connected to a Wheatstone bridge, which can determine the resistance in the transducer. The resistance is related back to pressure by means of a calibrated curve showing pressure versus resistance. These gauges are rugged, have a long life span and have a high pressure range. They have a larger drift than other gauges and are more affected by temperature changes.

Capacitance gauges are electronic gauges that consist of two plates set a very small distance apart (0.001 to 0.002 inches) that act as the capacitor in a circuit. Deflections in one plate caused by pressure change the capacitance of the circuit. A reference curve relates the changes in capacitance to pressure. These gauges are among the more common types. They are rugged, sensitive, accurate and simple. They can exhibit slower response times if the oil used to fill the device leaks. In addition, their use is limited to environments where the temperature is less than 220˚ C.

Vibrating crystal transducers are electronic gauges consisting of a quartz crystal wired to an electrical circuit. The crystal oscillates with a frequency that is pressure dependent. A second crystal that is not exposed to pressure is often used to correct for temperature. These gauges are highly accurate, but they are not as robust as other gauges and have a slow dynamic response. A variation on the vibrating crystal transducer uses a sapphire crystal instead of a quartz crystal. It is not as accurate as the quartz version, but it works at higher pressures (20,000 psi) and temperatures (190˚ C).

Fiber optic transducers are a relatively new category of electronic gauges. They generally measure the changes in either phase modulation or polarization rotation of light in the fiber optic cable caused by pressure changes. Advantages include their immunity to electromagnetic interference, small size and good dynamic response. However, they are not as robust as other types of gauges, are more sensitive to temperature changes and perform poorly with static pressure measurements.

Reporting and Evaluation

Measured pressure data must be submitted to EPA and the UIC Program Director in the semi-annual reports [40 CFR 146.91(a)(2)]. Data will be submitted in electronic form directly to EPA's database where they can then be accessed both by the UIC Program Director and other EPA offices. The Class VI Rule requires that certain information be included in these reports [40 CFR 146.91(a)], and it is recommended that all of the information below be included:

- Tabular data of all pressure measurements
- Monthly average for injection pressure
- Monthly maximum and minimum values
- If pressure exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion, and response to the excursion
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs

The UIC Program Director will evaluate the data to determine compliance with permit conditions. If the pressure exceeded the permit conditions, the UIC Program Director will take the necessary enforcement actions, evaluate the causes and determine if there is any endangerment to the well and/or any USDWs. He or she will also determine if the permit needs to be modified or if changes are needed in any of the plans (e.g., the Emergency and Remedial Response Plan).

3.4. Corrosion Monitoring

The Class VI Rule at 40 CFR 146.90(c) requires quarterly monitoring of well materials for corrosion. The objective of corrosion monitoring is to detect any deterioration of well components (i.e., casing, tubing, packer) that may cause loss of mechanical integrity. Corrosion may refer to loss of mass or thickness, cracking or pitting, and monitoring is required to provide early indication of well integrity problems. Historically, corrosion of well materials has been a primary reason for failures related to well structure in carbon dioxide injection wells. Because carbon dioxide in the presence of water will lead to the formation of carbonic acid, Class VI

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injection wells may be exposed to a more corrosive environment than wells that do not inject carbon dioxide.

General corrosion refers to the uniform, or near uniform, thinning of metal. If the rate of general corrosion is tolerable, an adequate lifespan can be built into the injection well materials by adding a corrosion allowance to the design thickness. Localized corrosion consists of several forms of attack that lead to failure of the equipment before the corrosion allowance is spent. Mechanical integrity loss may result from the development of a leak, from mechanical failure caused by localized thinning or from crack propagation in the well components.

The Class VI Rule requires that well components be monitored for corrosion using at least one of the following methods: coupons; a flow loop; or an alternative method approved by the UIC Program Director [40 CFR 146.90(c)]. These methods are described in the subsections below. Additionally, the UIC Program Director may require the use of casing inspection logs on a periodic basis [40 CFR 146.89(d)] to monitor for corrosion. Because monitoring wells will also be susceptible to corrosion, especially if they are installed in the injection zone, EPA recommends that operators consider corrosion monitoring for monitoring wells in addition to injection wells.

3.4.1. Use of Corrosion Coupons

General Information

The most common of all corrosion rate measurement tests involves exposing pieces of metal, similar to those in the injection system, to the corrosive environment. Small, pre-weighed and measured coupons made of the construction materials are exposed to well fluids for a defined period of time, then removed, cleaned and weighed to determine the corrosion rate (Allen and Roberts, 1978). Coupons are very simple to use and analyze, and they give a direct measurement of material lost to corrosion. Coupons can predict the following types of corrosion when correctly emplaced in the well to ensure appropriate exposure: general corrosion, crevice corrosion, pitting, stress corrosion cracking, embrittlement, galvanic corrosion and metallurgical structure-related corrosion (USEPA, 1987a). However, coupons have several limitations. An extended period of time is required to produce useful data, and coupons can only be used to determine average corrosion rates. The inevitable differences in the size and thermomechanical history of coupons compared with the actual well materials mean that the corrosion rate measured on a coupon cannot exactly match the corrosion rate experienced by the well (USEPA, 1987a).

Application

A coupon is a small, carefully manufactured piece of metal (such as a strip or ring) placed in the injection well to measure corrosion (Figure 3-3). The coupon is made from the same material as the well's casing or tubing. It is weighed before it is inserted into the well, subjected to the well environment for a period of time and then removed and weighed again. The average corrosion rate in the well can be calculated from the weight loss of the coupon (Jaske et al., 1995).

The placement and removal of coupons in the well can be done with standard wireline equipment (USEPA, 1987a). Racks that hold one or more coupons have been developed in the oil and gas industry to monitor corrosion in production wells. These may be considered if the dimensions of the carriers are compatible with the injection well design. Coupons might also be placed in a valved loop through which the injection stream passes. In a Class VI well, coupons deployed either downhole or in a loop near the wellhead will register the effects of the carbon dioxide on the material on the inside of the tubing. It is important to bear in mind that corrosion coupons can only measure corrosion in the part of the well in which they are placed. For example, Smith and Pakalapati (2004) described a production scenario where extensive corrosion caused joints to collapse although coupons at the wellhead of the same well indicated minimal corrosion rates. In addition, the coupon material needs to match the material of concern as closely as possible. When not in use, coupons need to be stored in a non-corrosive environment. Specialized envelopes and other containers are available for coupon storage.

The National Association of Corrosion Engineers (NACE) Recommended Practice RP-0775 (NACE, 2005) provides technical information and best practices for coupon use in oil and gas applications, including more detailed technical information on preparing, analyzing and installing corrosion coupons. ASTM Standards G1 (ASTM, 2003) and G4 (ASTM, 2008) provide additional technical information on preparing and evaluating corrosion coupons.

Figure 3-3. Example of corrosion coupons (image of Rohrback Cosasco System coupons, reprinted with permission).

<u>Interpretation</u>

Corrosion rates are commonly reported in mils per year (mpy) of penetration or metal loss, where a mil is equal to a thousandth of an inch. Target corrosion rates of one mpy (approximately 25 μm/year) or less are common in the oil industry. A low corrosion rate may not be acceptable if localized corrosion (such as pitting) is occurring, whereas a higher rate with a general area type of metal loss may be, in certain cases, a relatively insignificant problem (USEPA, 1987a). Inspection of the coupon's surface can yield information about the nature of the corrosion that is taking place (e.g., localized or general attack, presence of pitting or cracking).

Weight loss coupon tests are only comparative. The difference in the size and thermomechanical history of a coupon compared with actual items of equipment means that the corrosion rate measured on a coupon will not exactly match what is experienced by the actual equipment. Nevertheless, coupons provide the simplest and most useful guide to corrosion, particularly localized corrosion effects. When suitably fabricated and exposed, coupons predict general corrosion, crevice corrosion, pitting, stress corrosion cracking, embrittlement, galvanic corrosion and metallurgical structure-related corrosion.

3.4.2. Use of Corrosion Loops

General Information

Another method of determining the corrosion potential of injection fluids is the use of a corrosion loop. A corrosion loop is a section of casing that is valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. Because the composition of this pipe is the same as the well casing, it acts as a small-scale version of the well; the only differences are that the loop pipe has a smaller diameter and its temperature (due to its shallower depth) is generally lower (USEPA, 1987a). Although not as commonly used in the field as coupons, use of flow loops is a viable corrosion monitoring option.

Application

In a field setting, the loop would consist of a section of casing that is valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. The pipe can then be analyzed for corrosion. When the valves are open, some of the injection stream passes through the loop. When the valves are closed, the corrosion loop can be removed from the system and analyzed for corrosion. Corrosion rates can be calculated in a similar fashion to the corrosion coupon method.

Interpretation

If corrosion is observed in the loop, corrosion is likely occurring in the well tubing. Because the dimensions and temperature of the loop are different than that of the well, conditions in the loop do not exactly match the conditions in the well, and the loop may be subject to more or less corrosion than the well itself. For example, temperature usually increases with depth, and therefore the temperature in the loop is generally less than the temperature of the well. Because corrosion rates increase with temperature, this may lead to an artificially low estimate of corrosion. In addition, loops cannot measure the corrosion experienced by specific features of the well (such as joints) that may have corrosion-enhancing properties (USEPA, 1987a).

3.4.3. Casing Inspection Logs

General Information

If required by the UIC Program Director, the owner or operator of a Class VI well must run a casing inspection log (CIL) at a frequency specified in the Testing and Monitoring Plan [40 CFR 146.89(d)]. The purpose of the casing inspection log is to determine the presence or absence of corrosion in the long-string casing. Casing inspection logs measure casing thickness.

One of several available logs may be used for a casing inspection log, including physical measurement with a caliper, electromagnetic phase shift in the magnetic field passing through the tubing or casing, electromagnetic flux leakage due to variations in the tubing or casing, and ultrasonic images of reflected sound waves. Each of the methods provides data that, along with the physical characteristics of the well, will yield the thickness of the casing and the location of anomalies, such corrosion pits, scratches and splits. The choice of appropriate test is based on operator preferences and subject to approval by the UIC Program Director.

<u>Application</u>

All casing inspection log tools are wireline based and identify and measure variances, referred to as defects, in the thickness of the casing wall. Examples of defects are pits or ruts (formed by corrosion, substandard welds at casing couplings, wear from centralizers or collar locators, etc.) and splits that open gaps in the casing.

Caliper logs measure the internal radius of the casing (see the *UIC Program Class VI Well Construction Guidance*). A loss of thickness of the casing is evident from a caliper log because the internal radius increases in the area of corrosion. Baseline caliper surveys may be used for comparison. An example of a caliper log showing significant casing corrosion is provided in Figure 3-4.

An **electromagnetic thickness survey** measures large defects on the order of one inch (USEPA, 1982; Neilsen and Aller, 1984). The tool has an emitter coil (low frequency) used to create a magnetic field that passes through the tubing or casing and a receiver coil that measures the shift in the returning magnetic field. The receiver coil is set at a distance where it intercepts magnetic field lines that pass outside the coil. The phase shift is proportional to the thickness of the metal and the casing's magnetic permeability. Properties of the casing affect the log, so properties such as the material and density of the casing need to be known before the base log is run. The results are relative and need to be compared to a baseline log. The baseline log may be generated when the well is first installed so the resulting log corresponds to the initial casing thickness.

One commercially available electromagnetic scanner offers the advantage of not requiring the tubing to be pulled if the inner diameter is large enough (at least 2.875 inches) to accommodate the instrument. Qualitative results can be obtained for tubing and casing together. If metal loss is indicated, the tubing would then be removed to determine if the loss is in the casing or tubing.

The **pipe analysis survey** is a form of magnetic flux-leakage test that measures disturbances in an artificially created magnetic field (USEPA, 1982). The logging tool consists of an electromagnet, two arrays of pads, two cartridges of electronics and centralizers (Neilsen and Aller, 1984). Each pad contains upper and lower electric coils used to measure flux leakage and eddy currents and an eddy coil to produce eddy currents along the inner wall. The coils collect data in the form of induced currents that are converted to casing variations on the log. The pads are set around the tool to give circumferential coverage for the survey.

The **ultrasonic imaging survey** uses a very high transducer frequency to measure anomalies in the tubing or casing (Schlumberger, 2009). The emitter/detector is on the end of the wireline tool, with centralizers located above. The emitter sends out sound waves and the detector measures the reflected response. The survey can measure anomalies as small as 0.3 inches and measures anomalies both on the inner and outer surfaces of the tubing or casing. The tool rotates but the electronics keep track of a reference point, and it can therefore produce an accurate circumferential image of the tubing or casing. The data are analyzed and yield the thickness and inner and outer surface conditions. The survey response is attenuated by the fluid in the casing and the best results are produced with oils, brines and light muds.

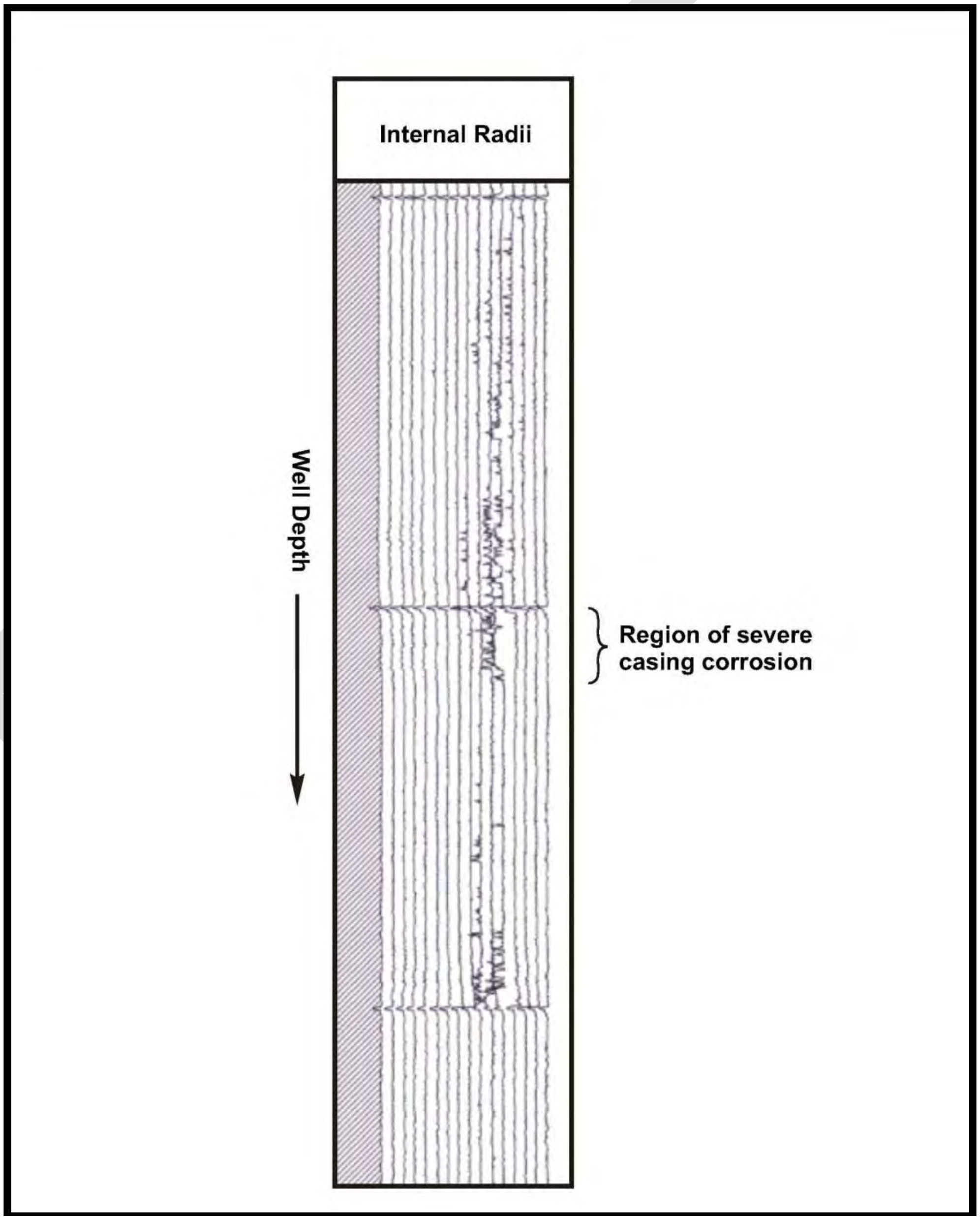

Figure 3-4. Example casing inspection log (caliper log) showing significant corrosion (Brondel et al., 1994).

Interpretation

The data from each of the surveys are displayed as vertical logs (e.g., Figure 3-4). Defects in the long-string casing will be displayed as anomalies on the log that cannot be attributed to casing joints or other construction features. Loss of thickness may be determined from comparison to baseline logs. For any of these tests, time series logs can be used to gauge the growth of defects and predict eventual loss of mechanical integrity.

The caliper log is generally reported as internal diameter, nominal wall penetration or average remaining thickness, depending on the logging company. Some logs can even show the variation detected by each arm as side by side traces like a seismograph (see Figure 3-4). The pipe analysis survey generates logs with either two or four curves. The ultrasonic imaging survey produces images of the surfaces and a log of the thickness.

Knowledge of the casing properties is needed to properly interpret casing inspection logs. The information used in interpreting the log consist of dimensions, weights and alloys, locations of couplings, locations of wall scratches or other abrasions, locations of perforations and locations of centralizers. The same inner diameter casing with different weights and alloys will have different initial thicknesses. Couplings will show an increase in thickness and are usually spaced at regular, but always known, intervals (e.g., Figure 3-4). Perforations will show as defects but typically yield a regular output. Variation within the perforated sections can show corrosion in the perforations.

3.4.4. Reporting and Evaluation of Corrosion Monitoring Data

Owners or operators are required to submit the results of corrosion monitoring in the semi-annual reports [40 CFR 146.91(a)(7)]. Data will be submitted in electronic form directly to EPA's database where they can then be accessed both by the UIC Program Director and other EPA offices. Certain information is required to be included in these reports [40 CFR 146.91(a)], and it is recommended that all of the information below be included:

- A description of the techniques used for corrosion monitoring
- Measurement of mass and thickness loss from any corrosion coupons or loops used
- Assessment of additional corrosion, including pitting, in any corrosion coupons or loops
- Measurement of thickness loss of corrosion detected in any casing inspection logs
- All measured casing inspection logs, and comparison to previous logs
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs

The UIC Program Director will independently assess the results of corrosion monitoring to assess the integrity of the injection well.

3.5. Pressure Fall-Off Testing

General Information

The Class VI Rule requires pressure fall-off testing of the injection well at least once every five years, or more frequently if required by the UIC Program Director [40 CFR 146.90 (f)]. Pressure fall-off tests are used to measure formation properties in the vicinity of the injection well (e.g., transmissivity). The objective of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity and pressure increase. Anomalous pressure drops during the test may also be indicative of fluid leakage through the wellbore. For additional information regarding pressure fall off tests, see the USEPA Region 6 UIC Pressure Falloff Testing Guideline (USEPA, 2002c), or the USEPA Nuts and Bolts of Falloff Testing (USEPA, 2003). Information is also available in publications such as Schlumberger (2006), Kamal (2009) or Lee et al. (2003). Some portions of this section have been adopted from USEPA (2002c).

Application

Pressure fall-off tests are conducted by ceasing injection for a period of time (i.e., shutting in the well) and monitoring pressure decay at the well. The results of the pressure fall-off test are dependent upon the injection conditions previous to shutting in the well. Therefore, prior to the test, it is recommended that injection rate and pressure be kept constant and continuously recorded (Sections 3.2 and 3.3).

Upon shutting in the well, pressure measurements are taken continuously. Temperature measurements taken during the test may assist in data interpretation. Bottomhole reservoir pressure measurements may be less subject to data scatter, but surface (i.e., wellhead) pressure measurements may be sufficient if a positive pressure is maintained at the surface throughout the test. The use of two pressure gauges is recommended, with one serving as a backup, or for verification in cases of questionable data quality. It is recommended that the duration of the shut-in period be long enough to observe a straight line of pressure decay on a semi-log plot (i.e., radial flow is achieved). A general rule of thumb is to run the test for three to five times the time required to reach radial flow conditions.

For projects with multiple injection wells within the same zone, special considerations may be made for pressure fall-off testing, as injection at one well will influence the pressure fall-off curve at other wells. For the offset wells (i.e., those not being tested), injection should cease prior to the test for a period of time exceeding the planned shut-in period, or injection rates may be held constant and continuously recorded during the test. It is recommended that multiple wells not be shut in and tested simultaneously. Following the fall-off test, owners or operators are encouraged to send at least two pulses to the test well by the way of rate changes in the offset well. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain inter-well reservoir parameters.

Interpretation

Pressure fall-off tests measure the change in pressure over time at the test well, and results are plotted as a function of time. Several graphs aid in interpretation of test results. Observed bottomhole pressure and recorded temperature may be plotted as a function of time for the time period prior to the shut-in and the duration of the test. This plot is used to confirm pressure stabilization prior to the test. Any pressure changes may be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution. Any data collected after reaching resolution of the gauge are suspect. Pressure gauges typically auto-correct for temperature fluctuations. However, if temperature anomalies are not accounted for correctly, this may lead to erroneous results. Any temperature anomalies observed during the test may be noted to determine if they correspond to pressure anomalies. Computational models may be used to aid in interpretation of pressure fall-off tests if there are large temperature fluctuations.

Log-log and semi-log diagnostic plots of observed pressure and time are used for further data interpretation. Unique flow regimes can be identified on these plots, corresponding to the region(s) governing pressure fall off during a certain phase of the test. Early data correspond to flow within the wellbore and immediate surrounding area, and later data correlate to distances further from the well. Later-time data, representative of reservoir conditions, are used for quantitative data analysis. Observations of anomalous pressure decay at greater rates than previous tests may be indicative of fluid leakage. See USEPA (2002c) for further interpretation of the diagnostic plots as they relate to detection of reservoir geologic features and leakage pathways.

Quantitative analysis of the measured data is used to estimate formation characteristics, including transmissivity, and the well skin factor. Analytical solutions of Darcy's Law are fit to the measured data to estimate these parameters. The well skin factor accounts for changes in the permeability of the formation at or near the wellbore as a result of drilling, completion and injection practices (e.g., van Everdingen, 1953). Changes in permeability are also expected due to the presence of a multi-phase system and possibly due to mineral precipitation near the wellbore. Commercial software programs are often used to analyze pressure fall-off tests. Parameters determined in pressure fall-off tests may be compared to those used in site computational modeling and AoR delineation. Changes in formation permeability values as measured during pressure fall-off tests may also be required by the UIC Program Director to be reflected in AoR reevaluation.

Reporting and Evaluation

The Class VI Rule requires that the results of pressure fall-off tests be submitted to EPA electronically within 30 days of the test [40 CFR 146.91(e) and 146.91(b)(3)]. EPA recommends that submittals include:

- The location and name of the test well, and the date/time of the shut-in period
- Well completion diagrams
- Depths of bottomhole pressure and temperature

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- Records of gauges (if they are lowered and raised)
- Raw data collected during the fall-off test in a tabular format
- Measured injection rates and pressures from the test well and any off-set wells in the same zone
- Information on any pressure gauges used, and demonstration of gauge calibration according to manufacturer specifications
- Diagnostic curves of test results, noting any flow regimes
- Description of quantitative analysis of pressure-test results, including use of any commercial software
- Calculated parameter values from analysis, including transmissivity and skin factor
- Comparison of calculated parameter values to previously measured values (using any previous methods), and to values used in computational modeling and AoR delineation
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs

The UIC Program Director will evaluate the pressure-test results to assess any changes in characteristics of the near-wellbore environment, and any indication of fluid leakage during the test.

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4. Ground Water Quality and Geochemistry Monitoring

The Class VI Rule requires periodic monitoring of ground water quality and geochemical changes above the confining zone(s) [40 CFR 146.90(d)]. Periodically analyzing ground water quality above the confining layer serves to identify injectate migration and/or native fluid displacement from the injection zone. This monitoring of ground water can also identify geochemical changes due to leaching or mobilization of heavy metals and organic compounds that can result from the presence of injectate migration or native fluid displacement above the primary confining zone. If the injected or displaced fluids migrate into a USDW, they may cause degradation of drinking water quality by contamination with highly saline fluids or leached or mobilized drinking water contaminants.

This section discusses how owners or operators will design and construct a monitoring well network, collect and analyze ground water samples from above the primary confining zone, and interpret and submit the results of the ground water sample analysis. The Class VI Rule also requires owners or operators to use direct methods to monitor for pressure changes in the injection zone at 40 CFR 146.90(g)(1); this is discussed in Section 5. Section 5 also discusses the use of monitoring wells in tracking the extent of the carbon dioxide plume within the injection zone, which is not a Class VI Rule requirement but may be requested by the UIC Program Director in certain cases.

For GS projects operating under an injection depth waiver, the requirements for ground water quality and geochemistry monitoring will necessitate measuring pressure and sampling fluids in at least one additional formation (the first USDW below the injection zone) and possibly other formations if specified by the UIC Program Director [40 CFR 146.95]. More detailed information is available for such project in the *UIC Program Class VI Well Injection Depth Waiver Application Guidance*.

4.1. Design of the Monitoring Well Network

Monitoring of ground water geochemistry above the confining zone(s) to detect fluid leakage [40 CFR 146.90(d)] is predicated on direct contact between a monitoring instrument and in-situ fluids at depth. Monitoring wells are therefore necessary to meet this requirement. The design of the monitoring well network is a key component of a monitoring system that serves to detect any leakage through the confining zone that may endanger USDWs. Therefore, the owner or operator must consider all relevant site data, including injection rate and volume, geology, the presence of artificial penetrations and other factors, as required at 40 CFR 146.90(d)(1), in planning monitoring well placement (i.e., both the depth of the wells and their geographic location with respect to the injection well(s) and anticipated injectate plume and pressure front movement). The proposed monitoring well placement is to be described and technically justified in detail in the Testing and Monitoring Plan, and it is subject to UIC Program Director approval. This section provides guidelines for design of the monitoring well network, based on site characteristics and computational modeling performed for AoR delineation. Development of the

Testing and Monitoring Plan is discussed in the *UIC Class VI Program Project Plan Development Guidance*.

4.1.1. Perforated Interval of Monitoring Wells

The perforated interval of a monitoring well refers to the depth at which openings or slots are present in the casing, allowing for native ground water at that interval to flow into the casing for sample collection. The monitoring well is designed to sample ground water only in the perforated interval (the hydrostratigraphic section of interest). As discussed above, the Class VI Rule requires geochemical monitoring above the primary confining zone [40 CFR 146.90(d)]. However, the owner or operator, or the UIC Program Director, may determine that monitoring ground water quality (or pressure) within additional zones is a necessary component of a monitoring network that serves to protect USDWs. For example, monitoring the ground water geochemistry of the lowermost USDW may be required by the UIC Program Director to detect potential fluid leakage into the USDW. Based on site-specific criteria, the UIC Program Director may also determine that geochemical monitoring within the injection zone is necessary for tracking of the carbon dioxide plume (see Section 5). Therefore, at a minimum, the owner or operator is required to construct monitoring wells perforated above the confining zone in a suitable formation for collection of ground water samples [40 CFR 146.90(d)].

The UIC Program Director may also require that monitoring wells be constructed in additional water-bearing formations. EPA recommends that monitoring wells above the confining zone be perforated in the first reasonably permeable formation above the confining zone (i.e., the first formation from which fluids can be extracted at appreciable volumes for sampling and analysis), unless otherwise approved by the UIC Program Director to perforate the well in a shallower zone. Placing wells as close to the confining zone as possible will allow for earlier detection of leakage through the confining zone.

For GS projects operating under an injection depth waiver, the monitoring will be needed both above and below the injection formation [40 CFR 146.95(f)(3)(i)]. Therefore, owners or operators may wish to install monitoring wells with multi-level samplers. See the *UIC Program Class VI Well Injection Depth Waiver Application Guidance* for more information.

4.1.2. Monitoring Well Placement

Similar to injection wells, improperly constructed monitoring wells at a GS site may present a potential conduit for fluid movement to USDWs. EPA recognizes that monitoring well construction will also be a relatively expensive component of total monitoring costs at a GS facility. Therefore, EPA recommends that monitoring wells be placed strategically in order to maximize the ability of the monitoring well network to detect potential leakage and track the migration of the plume, if necessary, and pressure front while minimizing the number of wells. The Class VI Rule requires that the placement of monitoring wells used for geochemical monitoring above the confining zone be based on available site characterization data and AoR delineation modeling [40 CFR 146.90(d)(2)].

The general sequence of site characterization, modeling and monitoring at a GS project is shown in Figure 4-1. Initial computational modeling predictions of fluid movement and pressure changes are based on site characterization data and proposed operating data. The AoR is delineated from computational modeling results, and as discussed below, these results should also be used in design of the proposed monitoring system. After initial monitoring data are collected at the site, the data should inform refinement of the model (i.e., model calibration). The improved model is then used to revise the AoR and monitoring system design if necessary.

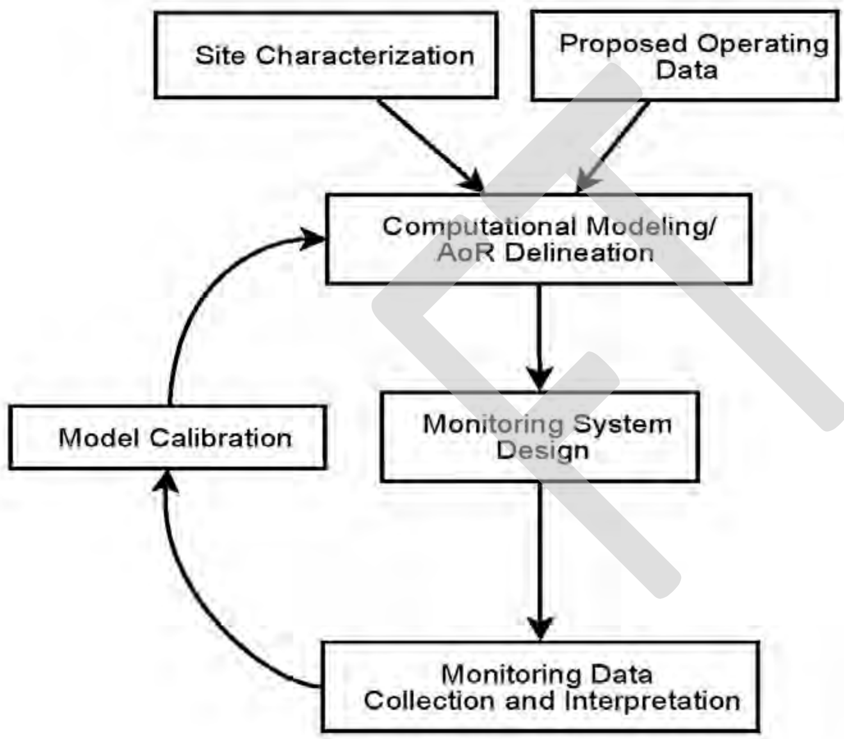

Figure 4-1. Flow chart of modeling and monitoring at a Class VI project.

Model calibration and revision of the AoR are facilitated for GS projects by periodic AoR reevaluation. Revision of the monitoring system design after model calibration is facilitated by periodic revision, and UIC Program Director approval, of the Testing and Monitoring Plan. The reader is referred to the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for discussion of generating model results and delineation of the AoR.

EPA is providing the following recommended guidelines for determining the number and placement of monitoring wells above the confining zone(s) at a Class VI project based on available site characterization data and the results of computational modeling. These recommended guidelines are intended to provide a reference for owners or operators during the design of the monitoring well network, and for UIC Program Directors in evaluating the proposed Testing and Monitoring Plan. The objective of these recommended guidelines is the development of a monitoring network with a sufficient yet minimal number of monitoring wells that are strategically located to provide site monitoring that meets the requirements at 40 CFR 146.90(d)(1) and (2). The guidelines are as follows:

- As displayed in Figure 4-1, monitoring network design will ideally build upon site characterization and computational modeling information, which will then be used to instruct placement of monitoring wells that will enable collection of baseline site data.

- The number of required monitoring wells will generally be greater for projects with larger predicted areas of elevated pressure and/or plume movement, or in cases of more complex or heterogeneous injection/confining zone hydrogeology. If the predicted area of impact of a given project increases in size due to AoR reevaluation, additional monitoring wells may be necessary.

- For projects with a separate-phase plume and/or pressure front predicted to move in a more narrow and well-defined path, well placement should be more numerous in the down-gradient direction.

- Well placement should be based on the predicted rate of migration of the separate-phase plume and/or pressure front.

- Wells sited above the confining zone(s) should be preferentially placed in the vicinity to the injection well(s), as this will be the region of greatest pressure increase and greatest risk of fluid leakage. However, EPA recommends that monitoring wells not be placed too close to the injection wells because the monitoring wells themselves can introduce some potential for risk of fluid leakage through the annular space of the monitoring well. Owners or operators can work with the UIC Program Director to determine the ideal distance between monitoring wells and injection wells.

- Wells sited above the confining zone(s) should also be preferentially placed in regions of concern for potential risk of fluid leakage and USDW endangerment. These regions may include identified faults, fractures or abandoned wellbores that may represent a pathway for fluid leakage into a USDW. Additionally, regions that are predicted to overlie the maximum thickness and saturation of the separate-phase plume, and/or elevated pressures, constitute regions for potential concern.

- All monitoring wells do not need to be completed prior to commencement of injection operations. This allows for changes to the overall monitoring system design and changes to plans for specific well placement based on a revised and improved understanding of project operations.

- For projects with multiple Class VI injection wells, EPA recommends that the monitoring well system design address all injection wells together in a unified plan, even though the multiple wells are permitted separately.

- The number of monitoring wells placed above the confining zone should be determined such that any leakage through the confining zone that may endanger a USDW will be detected in sufficient time to implement corrective action measures. The number of monitoring wells above the confining zone may be determined based on a modeling and/or statistical analysis, which may be documented in the Testing and Monitoring

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Plan. Considerations that may be included in this analysis are the regional hydraulic gradient, flow paths, transmissivity and baseline geochemistry.

- If approved by the UIC Program Director, previously existing wells perforated in the appropriate zone may be converted to use as a monitoring well for the GS project. These wells should to be constructed to appropriate specifications, as discussed below.

- Revision of the site computational model and delineated AoR associated with reevaluation of the AoR may trigger a revision of the Testing and Monitoring Plan [40 CFR 146.90(j)]. Design of the monitoring well network, including steps taken to determine the placement of monitoring wells should be reviewed during revision of the Testing and Monitoring Plan. If revision of the site computational model has resulted in changes to the size and shape of the AoR, the monitoring well placement may require revision. See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for discussion of AoR reevaluation; also see the *UIC Class VI Program Project Plan Development Guidance* for additional information on updating the Testing and Monitoring Plan.

4.1.3. Use of Phased Monitoring Well Installation

If approved by the UIC Program Director, monitoring wells may be installed on a phased basis during the lifetime of the project. Allowing for phased monitoring well installation will allow for monitoring well placement design to be changed based on monitoring results and revision of the site computational model. Phased monitoring well installation will also spread the cost of monitoring well construction across several years. If phased monitoring well installation is allowed by the UIC Program Director, the phasing plan should be described and technically justified (e.g., the timing of monitoring well construction for each well) in detail in the Testing and Monitoring Plan. EPA recommends that all planned monitoring wells predicted to come into contact with the carbon dioxide plume and/or significantly elevated pressure within five years be constructed prior to the commencement of injection. All monitoring wells constructed after the commencement of injection should be installed at least five years prior to the predicted movement of the separate-phase plume or pressure front into that location.

4.2. Monitoring Well Construction

The construction of monitoring wells is very similar to the construction of injection or production wells. The Class VI Rule injection well construction requirements are listed at 40 CFR 146.86. As with all wells, improperly constructed wells can serve as conduits for fluid movement. This guidance will not cover areas common to all well construction, but will focus on topics that may be of particular interest or concern for monitoring wells for GS. If more details on well construction are desired, there are many documents that can provide more detailed descriptions and recommendations. For example, the *UIC Program Class VI Well Construction Guidance* discusses aspects of construction for Class VI injection wells, including the precautions necessary to address the injection of supercritical carbon dioxide streams. There are many other sources that provide detailed recommendations and guidelines for well construction: both the American Petroleum Institute (API) and the American Society for Testing and Materials (ASTM) have published standards for various aspects of well construction. Furthermore, the *UIC*

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Program Class VI Injection Depth Waiver Application Guidance includes information on construction of wells in areas where the injection zone is located above the lowermost USDW. Topics that may be of special concern for monitoring wells include materials, drilling techniques, well completion, zonal isolation and recompletion of existing wells for use as monitoring wells. These are described below.

Materials

As with injection wells, monitoring well materials should be selected to withstand downhole conditions. In a GS project, monitoring wells will encounter elevated pressures, temperatures and stress from the rock column. They will also be exposed to deep formation fluids that will likely contain high total dissolved solids (TDS), sulfate or possibly hydrogen sulfide. Monitoring wells in the injection zone may also encounter separate-phase carbon dioxide and carbon dioxide-rich fluids. These conditions can accelerate the degradation of well materials, including metals, cements and plastics. Any monitoring equipment installed in the monitoring well will also need to be compatible with subsurface fluids. The *UIC Program Class VI Well Construction Guidance* contains specific information on materials that are compatible with carbon dioxide streams as well as native brines. It also includes details on designing materials for the stresses likely to be encountered in the downhole environment. Monitoring wells completed above the injection zone will likely face lower pressures than injection wells, but they will face other conditions such as corrosive brines. Wells completed in the injection zone will eventually be exposed to the pressure front as the plume enters the vicinity of the well. Although the pressure will be somewhat lower than the injection pressure, the well should be designed for pressures greater than the initial reservoir pressure. Wells completed below the injection zone because of an injection depth waiver will be subjected to even higher temperatures and pressures than in the injection zone.

Well Drilling

Well drilling should be conducted using practices that prevent movement of fluids between formations. In addition to allowing fluid movement during drilling, improper drilling can weaken or damage formations in the immediate vicinity of the wellbore and lead to poor cement bonding, which can compromise the well after construction. Under- and over-pressurized zones present particular challenges in drilling and completing the well. An under-pressurized zone might be encountered when drilling through a depleted reservoir. Elevated pressure in an over-pressurized zone may be encountered if drilling to place a new monitoring well in the injection formation. For example, if an AoR reevaluation indicates that the plume has moved into an unanticipated area, it might be desirable to place a new monitoring well within the pressure front to better track the plume. In drilling such a well, care would be needed to prevent migration of fluids and/or carbon dioxide out of the injection zone.

The choice of drilling fluid (mud) is important for maintaining zonal isolation and for producing a good wellbore. The mud must be appropriate for the subsurface conditions and allow hydraulics to be properly maintained with respect to the formation. Depleted reservoirs may have formations or zones with poor integrity; an inappropriate mud may further degrade the rock, plug the pore space and/or widen the wellbore. High pressure zones, on the other hand, necessitate the use of high density mud to help maintain well control (i.e., control of high downhole pressure during drilling) (Wray et al., 2009). Muds come in several classes or types, including water-based and oil-based fluids, those with and without solids, and high performance muds, which can include synthetics. It is possible to test the compatibility of the mud with the rock in the lab using core samples, although field experience is often also used (Brufatto et al., 2003).

During drilling, the pressure or weight of the mud needs to be correctly controlled. If the pressure/weight is too high, the mud will infiltrate the formation. It may fracture the formation and can be difficult to remove, causing pore spaces to clog. If the pressure/weight is too low, native fluids from higher pressure zones can flow into the wellbore, potentially causing the driller to lose control of the well. Infiltration of fluids from the formation into the wellbore can cause delays in drilling, possibly damage equipment and, with infiltration during well cementing, a poor cement job (poor bonding and/or development of channels in the cement) can be the result. If a well is being drilled through an injection zone, loss of control could result in movement of carbon dioxide out of the injection zone. The mud weight is determined by a combination of mud density, mud flow rate, friction losses and pressure at the wellhead (Medley and Reynolds, 2006). Mud density is the easiest and most common way to alter mud weight and can be changed by altering the type of mud and through additives. More sophisticated equipment is capable of controlling flow rate, pressure and friction losses as well.

After drilling, the mud must be properly removed to clean and prepare the wellbore so that a good bond and seal can be achieved between the cement and casing, and between the cement and the formation. If there is mud on the casing or formation, channels or microannuli could form in the cement and/or along the cement/casing contact or the cement/formation contact. These microannuli or channels could enable formation fluid or injectate movement outside the casing in the wellbore. The optimal strategy for mud removal depends upon borehole characteristics and the rheology of the drilling fluid (Brufatto et al., 2003). Options include displacing the mud using another fluid called a spacer, using metal attachments called scratchers attached to the casing and either rotating or reciprocating the casing, or using special chemicals such as acid washes (Shryock and Smith, 1981).

Well Completions

Well completion involves installing well tubular materials and other equipment to prepare the well for operation. Some equipment may be "dedicated" (permanently deployed), such as temperature gauges, pressure sensors or geochemical sampling devices. Other monitoring equipment, such as crosswell sonar devices, MIT instruments and logging equipment may be deployed periodically and will need adequate access for lowering into the well. To plan for all monitoring equipment, the well diameter, any deviations of the well from vertical, and any significant curvature or bends in the well should be taken into consideration. Other factors to consider in designing the monitoring well and planning for completion include the number and locations of perforated zones.

Most permanent downhole equipment requires cables or sample tubing for the transmission of collected data or samples to the surface. These can, however, interfere with other monitoring equipment lowered into the well. The cables and sample tubing can be coated and placed in metal or other hard conduits to protect against damage during installation. Another way to protect cables and sample tubing is to run them along the exterior of the tubing and hold them in place using clamps to prevent them from interfering with other equipment. In some cases, devices have been run along the outside of the casing and cemented in place. In this case, the sensors must be rugged and reliable as there is no way to replace them once they are installed. Dual sensors (i.e., two sensors performing the same function, a primary and a backup) are also often used for this reason.

In some cases, aggressive downhole environments can interfere with sensor functioning. For example, fiber optic sensors have been known to drift in high temperature and pressure environments. Carbon- or metal-based coatings can sometimes prevent these problems (Omotosho, 2004). Coatings can also protect cables from aggressive chemical environments as well as elevated temperature and pressure.

Because there is cement between the casing and the wellbore to prevent fluid migration along the wellbore, both the casing and cement will need to be perforated in areas where monitoring will occur so that the monitoring equipment can access the formation fluids to be sampled. Perforations are not required where equipment is installed on the exterior of the casing. However, geochemical sampling will always require perforations. The perforated intervals should be designed to monitor the appropriate zones and to be wholly located within the desired zones. Perforated zones should not cross injection zone/confining zone boundaries or confining layers. Depths of perforated layers should be verified using logs to ensure they have been emplaced properly.

Zonal Isolation

In some cases, it may be desirable to monitor in multiple zones (e.g., the injection zone, the first permeable zone above the injection zone, and underlying formations if the project operates under an injection depth waiver). Using multiple completions in one well can reduce costs and minimize the number of penetrations through the confining layer. In this case, care must be taken to ensure proper zonal isolation during the entire life of the well.

Monitoring wells perforated in multiple zones should first be equipped with packers to isolate the zones. The packers should be placed above and below each perforated area to prevent flow of fluids between formations. The lowermost perforated zone, however, only needs a packer above the perforations. Packers should be made of materials capable of withstanding any corrosive effects from formation fluids such as wet carbon dioxide, supercritical carbon dioxide or brine saturated with carbon dioxide. Packers will also need to be constructed to allow cables and tubing to pass through, and they should be pressure tested at the anticipated downhole pressures to ensure that they are sealed and will not allow fluid to pass through them.

One option to help preserve zonal isolation is to install equipment on the exterior of the casing and cement it in place. Running the required cables and tubes down the outside of the casing provides fewer openings in the packer and, therefore, fewer opportunities for leakage. This was done with fiber optic distributed temperature sensors and electric tomography equipment in a monitoring well in the CO_2SINK project in Ketzin, Germany (Giese et al., 2009).

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Re-completion of Existing Wells as Monitoring Wells

The cost of drilling new wells can make the use of existing wells as monitoring wells an attractive option. GS projects may involve the use of old production or injection wells for monitoring purposes. If such wells are recompleted for monitoring, there are special considerations necessary to ensure the integrity of the well and to prevent fluid migration along the borehole. These considerations include logging of the well (see the *UIC Program Class VI Well Construction Guidance*), determining the integrity of the cement and casing, conducting any necessary cement squeezes to repair any defects and determining whether the existing well materials are adequate for the new function of the well.

The diameter of the hole, any deviations from vertical, and any significant curvature or bends in the well should be compared with the size of the proposed monitoring equipment. Existing well materials should be checked to ensure that they are compatible with carbon dioxide and carbon dioxide-rich brines if they are completed in the injection zone. Any flaws in the casing or cement will need to be repaired. Cement defects such as cracking, channels or annuli detected through a logging program can be repaired by performing a cement squeeze. Procedures for repairing defects in wells can be found in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*. Also, if monitoring is not necessary below the injection formation (as it would be in the case of an injection depth waiver), plugging the well below the injection formation is recommended.

Although monitoring wells are constructed for observational and sampling purposes, in most cases, the design and construction will be similar to that of injection or production wells. Consideration of a few key issues will allow monitoring wells to be used without serving as conduits for fluid movement or endangering USDWs. These critical issues include: (1) well drilling through over-pressurized areas; (2) proper accommodation of necessary monitoring equipment; (3) zonal isolation during well construction and completion; and (4) proper evaluation and use of existing wells for use as monitoring wells.

4.3. Collection and Analysis of Ground Water Samples

<u>General Information</u>

Ground water geochemistry monitoring refers to collection of ground water samples via monitoring wells, as well as chemical analysis of the ground water samples to quantify the concentration of dissolved and suspended chemicals. The Class VI Rule requires ground water geochemistry monitoring above the confining zone to detect changes in aqueous geochemistry resulting from fluid leakage out of the injection zone [40 CFR 146.90(d)]. The results of ground water monitoring may be compared against baseline geochemical data collected during site characterization to obtain evidence of fluid movement that may impact USDWs. In addition, the owner or operator, directed by the UIC Program Director, may periodically collect fluid samples, in a manner that would not endanger any USDWs, within the injection zone as a component of tracking the extent of the carbon dioxide plume, as discussed in Section 5.

The proposed sampling methodology and frequency for all constituents should be described and technically justified in the Testing and Monitoring Plan. At a minimum, EPA

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recommends that all wells initially be sampled on a quarterly basis for all relevant constituents during the early years of the injection phase. Sampling frequency may be reduced based on project-specific benchmarks, such as generally stable conditions observed in several successive sampling rounds. Likewise, sample frequency may need to be increased if the results of monitoring indicate possible fluid leakage or endangerment of USDWs at a particular location. Certain constituents may be monitored near-continuously using dedicated downhole sensors, such as pH and conductivity. In such cases, fluids may be collected and analyzed less frequently for those specific constituents.

Application

Sample Collection

Appropriate protocols consistent with existing EPA guidance should be followed for collection of ground water samples to maintain sample integrity. Some aspects of common ground water sampling protocols typical for shallow ground water investigations are applicable to deep-well sampling at GS sites, while other protocols will need to be adapted to high-pressure, high-temperature conditions. This section briefly describes appropriate protocols for collection of ground water samples for GS projects. For further guidance, refer to existing EPA guidance (USEPA, 1991; USEPA, 1992); some portions of the section have been adopted from these existing documents).

Fluid collection from monitoring wells at depths typical of GS projects is complicated by elevated pressure and temperature of the sampled zone. If not controlled, multiple fluids may separate as pressures decrease moving upwards through the wellbore. Partitioning relationships (e.g., carbon dioxide dissolution into the aqueous phase) are also temperature and pressure dependent. Commercial sampling systems have been developed that are lowered into the wellbore using a wireline or slickline. These samplers maintain sample integrity by collecting samples at formation pressure and temperature (Freifield, 2009).

The U-tube sampling system is one example of a sampling system that has been developed specifically for deep well sampling, such as at GS sites. EPA notes that the U-tube sampling system may not be appropriate or feasible for all GS sites, and is provided as one example of a pertinent deep well sampling system. The U-tube sampler can collect large volumes of multiphase samples into high pressure cylinders for real-time field analysis and/or laboratory analysis (Figure 4-2). The U-tube sampling device utilizes a positive fluid displacement pump that uses high pressure gas. The sampler includes a loop of tubing that terminates at surface and forms a “U” and a ball check-valve beneath the junction at the base of the U that permits fluid to enter based on gas pressure. A sintered stainless steel filter terminates the inlet below the check valve to prevent it from plugging. A sample is collected by venting the U to the atmosphere and allowing fluid to rise to hydrostatic level. The sample is recovered by supplying high pressure nitrogen gas (or inert gas) which closes the check valve and forces fluid out of the sample leg.

The general protocol for deep well sampling at GS sites consists of the following steps:

1. Fluid Level or Pressure Measurement. Prior to well purging and sample collection, it is important to measure and record the fluid level and/or pressure in the well. These

measurements may be needed to estimate the amount of water to be purged prior to sample collection, and also may be used for calculation of in-situ pressure (Section 5.2). Pressure measurements may be obtained by application of a downhole pressure transducer (Section 5.2).

2. Decontaminating Sample Equipment. When dedicated equipment is not used for sampling (or well purging) or when dedicated equipment is stored outside of the well, the sampling equipment needs to be cleaned between each sampling event. See USEPA (1992) for recommended cleaning procedures, as well as manufacture guidelines for the particular system used.

3. Well Purging. Stagnant water within the well is removed prior to sampling, in order to obtain a sample representative of the formation. See USEPA (1991) for guidance on how to determine the volume of fluid to be flushed prior to sample collection. During purging, pH, specific conductance and temperature are recommended to be field measured periodically. EPA recommends that samples not be collected until the value of these parameters have stabilized.

4. In-situ or field analyses. Physically or chemically unstable analytes are recommended to be measured in the field, rather than in the laboratory. Examples include pH, redox potential, dissolved oxygen, temperature and specific conductivity. An in-line flow cell, field kit or downhole probes may be used for this analysis. All field and downhole equipment should be properly calibrated according to manufacturer specifications.

5. Sample Collection and Handling. The following recommended guidelines pertain to collection of ground water samples (for additional guidance, see USEPA, 1991 and USEPA, 1992):

    a. Samples should be collected at tubing outlets and placed into containers as close as possible to the wellhead.

    b. Separate containers are typically used for different types of target analytes. Samples should be collected and containerized in order according to the volatility of the target analytes. The preferred order is: (1) volatile organics, (2) dissolved gases, including carbon dioxide, (3) semivolatile organics, (4) metals and cyanide, (5) major anions and cations, and (6) radionuclides.

    c. Samples should be transferred to sample containers in a controlled manner that minimizes sample agitation and aeration.

    d. Ground water samples should be collected as soon as possible after the well is purged. Water that has remained in the well casing for more than about two hours should not be sampled.

    e. The rate at which the well is sampled should not exceed the rate at which the well was purged.

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f. Generally, the only samples that should be filtered in the field include major anions and cations and TDS.

g. QA/QC procedures should be adhered to, as discussed below.

6. Sample Containers and Preservation. Refer to USEPA (1991) for the appropriate sample container and preservation method depending on the analyte. Exposure of the samples to ambient air should be minimized.

7. Chain of Custody and Records Management. A chain-of-custody procedure should be designed to allow the owner or operator to reconstruct how and under what circumstances the sample was collected, stored and transported including any problems encountered. The chain-of-custody procedure is intended to prevent misidentification of samples, to prevent tampering, and allow easy tracking of possession.

8. Sample Storage and Transport. Transport should be planned so as not to exceed sample holding time before laboratory analysis. Every effort should be made to inform the laboratory staff of the approximate time of arrival so that the most critical analytical determinations can be made within recommended holding periods.

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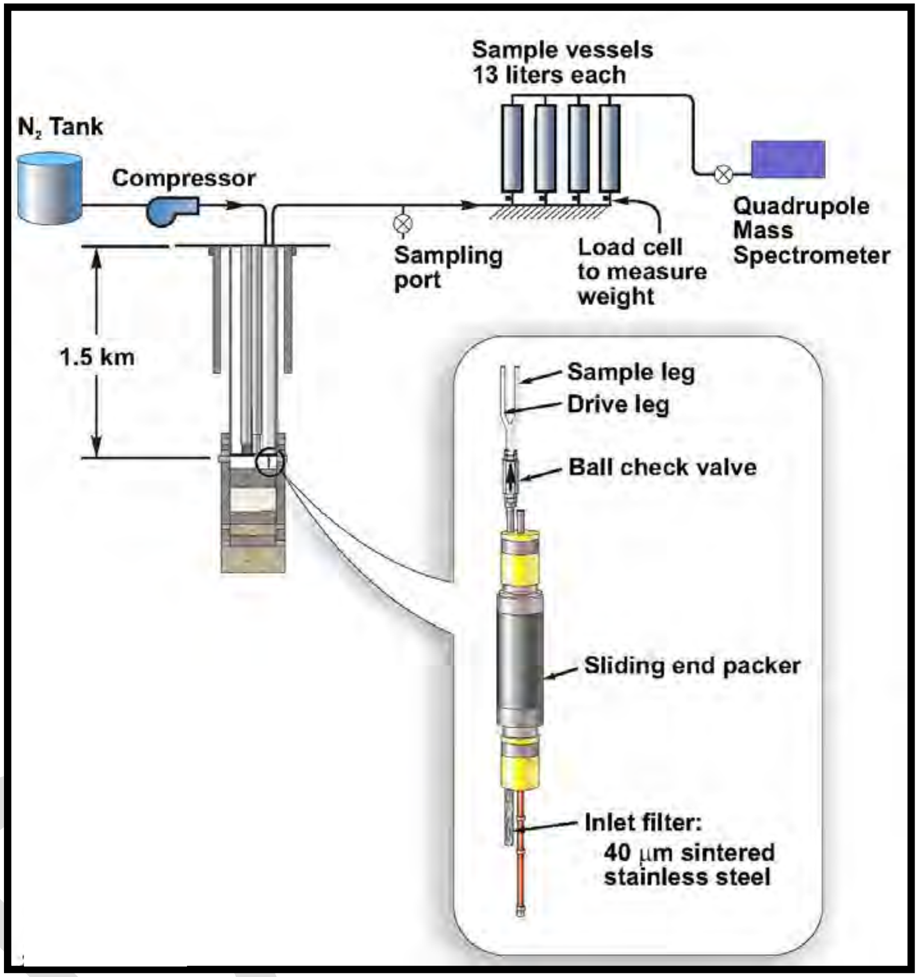

Figure 4-2. Schematic of the U-tube fluid sampling system (adapted from Freifeld et al., 2009; not to scale).

Quality Assurance/Quality Control

The owner or operator is encouraged to follow accepted QA/QC procedures for collection and analysis of ground water samples (USEPA 1991; USEPA 1992). The purpose of QA/QC samples is to ensure that the sampling protocol supports accurate laboratory analyses by eliminating cross contamination of samples and evaluating the repeatability of the laboratory analyses. The following QA/QC samples are recommended to be analyzed, as a minimum, with each batch of collected samples (a batch should not exceed 20 samples):

- One field duplicate
- One equipment rinsate
- One matrix spike (when appropriate for the analytical method)
- One trip blank (when analyzed constituents include volatile organics or dissolved gases)

All field QA/QC samples should be prepared exactly as regular investigation samples with regard to sample volume, containers and preservation. EPA recommends that the results of QA/QC samples be evaluated to ensure that data quality is within acceptable limits. The owner or operator may define acceptable data evaluation criteria in the Testing and Monitoring Plan. QA/QC procedures may also be described and technically justified in a Quality Assurance Project Plan (QAPP), following EPA protocol (USEPA, 2002b).

Sample Analysis

Once the sample has been collected, it is analyzed using an approved method for the constituents of interest. EPA recommends that fluid collected be monitored for, at a minimum, TDS, specific conductivity, temperature, pH, carbon dioxide and density. In addition, the UIC Program Director may require regular monitoring of major anions and cations, select trace metals, tracers, hydrocarbons, and any other constituents identified by the owner or operator, or the UIC Program Director. If hazardous substances are present in the injectate (e.g., mercury, hydrogen sulfide), it is recommended that these be included in routine ground water monitoring. Owners or operators of GS projects located in former or ongoing oil and gas reservoirs may also monitor for hydrocarbons. EPA recommends that owners or operators of projects located in formations containing appreciable levels of arsenic or other metals that may be mobilized by the injection activity routinely monitor for those metals.

Acceptable analytical methods for relevant parameters are provided in Table 4-1. It is recommended that an EPA-certified laboratory be used for all sample analysis. EPA's Office of Water implements the Drinking Water Laboratory Certification Program in partnership with EPA regional offices and states. Laboratories are certified by EPA or the state to analyze drinking water samples for compliance monitoring. In order to be certified by EPA, laboratories are required to successfully analyze proficiency testing samples annually, use approved methods and successfully pass periodic on-site audits.

Table 4-1. Analytical methods for common constituents in ground water.

Monitoring Parameter	EPA Method(s)	ASTM Method(s)	Standard Methods
Carbon dioxide		D513	4500
Dissolved metals	200.8, 200.9, 7010	D3919-08	3112, 3113
Arsenic		D2972	3114, 3500
Mercury	245.1, 245.2	D3223	
Lead		D3559	3500
Hydrogen sulfide		D4658	4500
Petroleum hydrocarbons	8260B		
TDS		D5907	2540C
Major anions	300.1	D4327-03	4110, 4140
Major cations	6020A, 6020C, 700B	D5673-05, D4691-02(2007), D1976-07	3125, 3111
Fluid density		D1429-08	

<u>Interpretation</u>

The analytical laboratory will provide the owner or operator with electronic and/or physical reports. The reports will provide all sample results in appropriate units (e.g., mg/L), method detection limits, the results of all QA/QC samples and an evaluation of the resulting data quality. The results of field-measurement analysis (e.g., pH, temperature) is typically then compiled with the laboratory-supplied data. EPA recommends that the owner or operator maintain an electronic database of all monitoring well sample results that lists the resulting sample concentration, and supplementary information, including sample data/time, analysis date/time, analytical detection limit and data quality flags.

Prior to use, collected data from monitoring wells are to be evaluated for quality and correctness. EPA recommends standard methods to be used to ensure that sample results are consistent with the project data quality objectives. Interpretation of samples also relies on comparison to baseline samples collected from the formation prior to injection, or upon construction of the monitoring well. See the *UIC Program Class VI Well Site Characterization Guidance* for discussion of baseline samples.

The primary objective of ground water monitoring is to detect geochemical changes that are indicative of fluid leakage and migration. EPA recommends that the owner or operator evaluate the collected data in comparison to previously collected data and baseline data. Trends that are indicative of fluid leakage include:

- Changing TDS: An increasing TDS trend may indicate that native brines have migrated into the monitored zone. A change in the overall TDS trend may indicate fluid exchange between adjacent formations.

- Changing signature of major cations and anions: A change in the signature of dissolved ground water constituents in the monitored zone to that of the injection zone, or confining zone, indicates leakage. The anion/cation signature may be evaluated through construction and use of ion diagrams, including trilinear Piper diagrams and Stiff diagrams (Figure 4-3).

- Increasing carbon dioxide concentration: An increase in the concentration of dissolved carbon dioxide indicates leakage of the dissolved phase plume into the monitoring zone. Increasing carbon dioxide concentrations may also be observed due to other factors, including increasing ground water recharge. These other factors may be evaluated to ascertain if the observed increasing carbon dioxide concentrations are due to leakage from the injection zone.

- Decreasing pH: A decreasing pH trend may indicate migration of carbonic acid and fluid leakage into the monitoring zone. Similar to increasing carbon dioxide concentrations, other factors may be evaluated that would additionally cause an observed decrease in pH.

- Increasing concentration of injectate impurities: An increase in concentration of any impurities in the injectate (e.g., hydrogen sulfide) is indicative of injectate leakage into the monitoring zone.

- Increasing concentration of leached constituents: The presence of carbon dioxide may leach certain inorganics (e.g., lead, arsenic, iron, manganese) from the formation matrix. Additionally, if petroleum hydrocarbons are present, carbon dioxide may increase the concentration of these constituents. Increasing trends may be indicative of fluid leakage.

- Increased reservoir pressure and/or static water levels (see Section 5.2).

Reduced sample fluid density and the presence of separate-phase carbon dioxide in the sampled fluid are results that indicate the presence of the separate-phase plume at the monitoring location.

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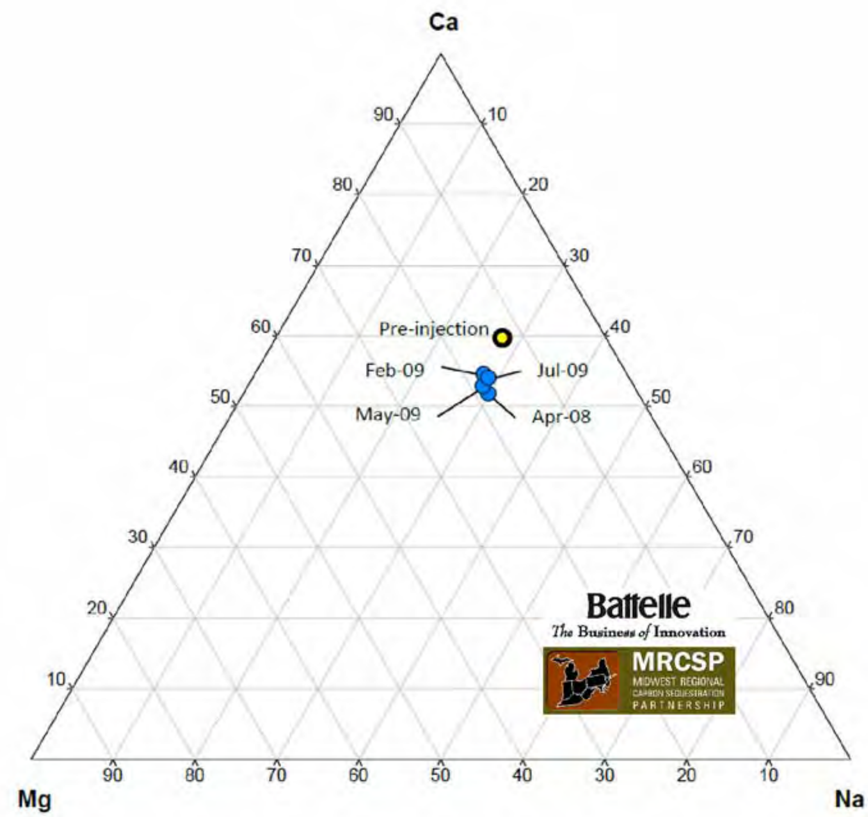

Figure 4-3. Example ternary plot showing proportion of major cations for injection well C4-30 (yellow circle) and Monitoring Well C3-30 (blue circles) – MRCSP Michigan Basin Validation Test (image provided by Battelle Memorial Institute).

Reporting and Evaluation

The owner or operator is required to submit the results of ground water monitoring in the semi-annual reports [40 CFR 146.91(a)(7)]. Data will be submitted in electronic form directly to EPA's database where they can then be accessed both by the UIC Program Director and other EPA offices. EPA recommends that the following information be submitted with all reports:

- The most up-to-date historical database of all ground water monitoring results and QA/QC monitoring results
- Interpretation of any changing trends and evaluation of fluid leakage and migration. This may include graphs of relevant trends and interpretive diagrams (e.g., Piper diagrams)
- A map showing all monitoring wells, indicating those wells that are believed to be in the location of the separate-phase carbon dioxide plume
- The date, time, location, and depth of all ground water sample collection and analysis

- An evaluation of data quality for each sampling event
- If required by the UIC Program Director, copies of all laboratory analytical reports
- A description of all sampling equipment used
- Records of calibration of all field sampling instruments
- Sample chain of custody records
- The name and contact information for the EPA-certified laboratory conducting the analysis
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs
- Presentation, synthesis and interpretation of the entire historical data set
- Documentation of the monitoring well construction specifications, sampling procedure, laboratory analytical procedure and QA/QC standards

The UIC Program Director will evaluate the ground water monitoring data to independently assess data quality, and the resulting interpretation of fluid leakage and plume migration. Furthermore, the UIC Program Director will assess the concentration of all potential ground water contaminants to ascertain if corrective action is necessary to protect USDWs.

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5. Plume and Pressure-Front Tracking

Identification of the position of the injected carbon dioxide plume and the presence or absence of elevated pressure (i.e., the pressure front) is integral to protection of USDWs for Class VI projects. Regions overlying the separate-phase (i.e., liquid, gaseous or supercritical) carbon dioxide plume and area of elevated pressure are at enhanced risk for fluid leakage that may endanger a USDW. Monitoring the movement of the carbon dioxide and the pressure front is necessary to both identify potential risks to USDWs posed by injection activities and to verify predictions of plume movement. Monitoring results from all of these methodologies can also provide necessary data for comparison to model predictions, and inform reevaluation of the AoR. The owner or operator will use a site-specific, complementary suite of methods to track the position of the carbon dioxide plume and area of elevated pressure. Available methods for plume and pressure-front tracking include: (1) in-situ fluid pressure monitoring; (2) indirect geophysical monitoring; (3) ground water geochemical monitoring; and (4) computational modeling. These methods must be described, by the owner or operator, in the Testing and Monitoring Plan approved by the UIC Program Director [40 CFR 146.90].

EPA recognizes that these four methods include a range of specific technologies that may be used to monitor and track a carbon dioxide plume and pressure front. Therefore, in the Class VI Rule, EPA does not prescribe specific technologies (e.g., geophysical techniques, water sampling apparatuses) that must be used to achieve these goals. The suite of methodologies used will be site specific and vary based on project details. Additionally, the flexibility of these requirements allows for deployment of new technologies as they are developed. This section discusses available methods used for tracking the carbon dioxide plume and the pressure front. Computational modeling is discussed in detail in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

The various methods for identification of the location of carbon dioxide, mobilized fluids (see Section 4) and elevated pressure provide complementary types of data. Ground water geochemistry and direct pressure monitoring do not rely on theoretical assumptions or data processing to the extent of other methods (e.g., indirect geophysical methods). However, ground water geochemistry and pressure monitoring only provide point measurements (i.e., measurements at discrete locations). Indirect geophysical monitoring, discussed in Section 5.3, provides broad, non-point measurements, but data collection requires extensive pre-processing and in some cases results may be ambiguous compared to ground water monitoring. Computational modeling (discussed in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*) provides a prediction of future conditions, but these predictions rely on simplifying assumptions and are prone to uncertainty. The most comprehensive understanding of plume and pressure-front behavior will follow from an integrated interpretation of information collected from all of these methods. For example, interpretation of geophysical monitoring results is improved by consideration of available monitoring well data during data processing. The predictive capability of computational models is improved by model calibration to ground water geochemistry, pressure and geophysical monitoring data. For Class VI projects, this process is conducted during AoR reevaluation.

5.1. Class VI Rule Requirements Regarding Plume and Pressure-Front Tracking

The Class VI Rule requires the use of 'direct' methods for tracking the presence or absence of elevated pressure (e.g., the pressure front) within the injection zone [40 CFR 146.90(g)(1)]. In this context, the term 'direct methods' pertains to the in-situ measurement of fluid pressure using transducers placed in the injection zone. Additionally, the Class VI Rule requires the use of indirect geophysical techniques for the purpose of tracking the extent of the carbon dioxide plume, unless the UIC Program Director determines that such methods are not appropriate [40 CFR 146.90(g)(2)] and/or results from such methods do not track the carbon dioxide plume at a sufficient level of accuracy. As discussed below, on a site-specific basis, where the UIC Program Director determines that indirect methods do not track the carbon dioxide plume sufficiently, he or she may require the use of direct methods for the purpose of tracking the carbon dioxide plume by using monitoring wells that are perforated within the injection zone. Table 5-1 provides a summary of the Class VI Rule monitoring requirements related to tracking the position of the carbon dioxide plume and pressure front.

Table 5-1. Summary of Class VI Rule requirements and recommendations for identifying the position of the carbon dioxide plume and associated pressure front.

Technology	Description	Class VI Rule	
		Requirement	Citation
Direct pressure monitoring	Measurement of in-situ fluid pressure using transducers placed within monitoring wells in the injection zone (see Section 5.2)	Required to track the presence or absence of elevated pressure within the injection zone	40 CFR 146.90(g)(1)
Indirect geophysical monitoring	Seismic, electrical, gravity or electromagnetic techniques (see Section 5.3)	Required to track the position of the carbon dioxide plume, unless the UIC Program Director determines that such methods are not appropriate	40 CFR 146.90(g)(2)
Geochemical monitoring for carbon dioxide	Use of monitoring wells in the injection zone to infer the presence or absence of carbon dioxide (see Section 5.4)	Recommended to augment required carbon dioxide and pressure monitoring	N/A
Computational modeling	Incorporation of site data into a comprehensive mathematical model of the site	Computational modeling is required as a component of AoR delineation and reevaluation	40 CFR 146.84

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5.2. Pressure-Front Tracking

The Class VI Rule requires that fluid pressure be directly monitored within the injection zone. This type of monitoring provides observations of increases in formation pressures and support tracking the migration of the pressure front [40 CFR 146.90(g)(1)]. In addition, EPA recommends that owners or operators also monitor pressure above the confining zone, as this information is necessary for correct fluid sample collection (see Section 4), and also may be used to detect potential leakage through the confining zone. Increased pressure within the injection zone is the primary driver for fluid movement that may endanger USDWs. Furthermore, pressure measurements will inform reevaluation of the AoR.

The pressure front is defined as the boundary of the extent of pressure great enough within the injection zone to cause fluid movement through an open conduit from the injection zone into the lowermost USDW. The value of reservoir pressure that defines the pressure front is calculated based on static pressure within the injection zone and the lowermost USDW, and the elevations of both zones. The *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* includes an illustrative example of calculation of the threshold pressure that defines the pressure front.

The proposed pressure monitoring frequency for all wells must be described and technically justified in the Testing and Monitoring Plan. At a minimum, EPA recommends that all wells be monitored for pressure changes on a monthly basis during the injection phase. Monitoring frequency may need to be increased if the results of monitoring indicate pressure increases greater than modeling predictions or indicate fluid leakage. For many GS projects, pressure may be monitored near continuously from dedicated downhole pressure transducers.

<u>Application</u>

For most monitoring wells at GS sites, pressure will be directly monitored from dedicated downhole pressure transducers. In some cases, fluid pressure may be inferred from measurements of the depth to fluid. In the absence of a packer, fluid pressure within the perforated interval of the monitoring well can cause fluid movement upwards through the well. Measurement of the depth to fluid in the well from the surface can be used to determine bottomhole pressure with knowledge of the density of the fluid and the surveyed elevations above a common datum of the well perforated interval and ground surface. Fluid-level measurements may be obtained by use of an electric depth gauge lowered on a wireline.

Considerations related to monitoring well placement and design of the monitoring well network for tracking of the pressure front are similar to those for ground water geochemical monitoring above the confining zone discussed in Section 4. Specifically, EPA recommends the following considerations for design of the monitoring well network for pressure-front tracking:

- Wells used to track the migration of the pressure front are required to be designed to allow in-situ measurements within the injection zone [40 CFR 146.90(g)(1)]. EPA recommends that pressure measurements be conducted at the same depth intervals in the injection zone at which injection occurs.

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- For projects predicted to have a separate-phase plume and/or pressure front that moves preferentially in one direction due to known subsurface heterogeneity, more wells should be placed in that direction to capture as much information as possible on the movement of the plume and/or pressure front.

- Well placement should be based on the predicted rate of migration of the separate-phase plume and/or pressure front.

- The number of monitoring wells placed within the injection zone should be determined such that the migration of the area of elevated pressure may be tracked sufficiently to detect any pressure increase that differs from modeled predictions. The determination of the number of injection zone wells may be based on a modeling and/or statistical analysis, which must be documented in the Testing and Monitoring Plan.

Interpretation

Fluid-level data obtained from electric gauges lowered into the well on a wireline will consist of depth to fluid measurements, in units of feet or meters. These measurements will be converted to values of the elevation of the fluid column relative to a common datum, most commonly mean seal level (msl). This is achieved from the following equation:

$$FL = GSE - DTF \qquad [1]$$

where *FL* is the elevation of the top of the fluid column within the well, *GSE* refers to the surveyed ground surface elevation at the wellhead or measurement point and *DTF* refers to the measured depth to fluid. Data collected from downhole pressure transducers will consist of pressure readings (units psi, Pa). With knowledge of the elevation of the pressure transducer measurement device, *FL* may be obtained using the following equation:

$$FL = PTE + \frac{P_t}{\rho g} \qquad [2]$$

where *PTE* refers to the known elevation of the pressure transducer (measured when the pressure transducer was emplaced), P_t refers to the measured pressure at the transducer, ρ refers to the density of fluid within the well and g refers to the acceleration due to gravity. Lastly, the *FL* within the well is used to calculate the pressure (P) at the depth of the screened interval of the well using the following equation:

$$P = (FL - Z) \cdot \rho g \qquad [3]$$

where Z is the elevation of the center of the screened interval of the well. If using data from a pressure transducer set at the center of the screened interval of the well, the above calculations are unnecessary, and the measured pressure is representative of the in-situ pressure.

Once the in-situ pressure at all wells has been determined, temporal changes should be analyzed by comparing the new data to past readings. Time series graphs for each well may be useful. An example plot of the temporal trend of measured pressure for an injection and monitoring well are presented in Figure 5-1. It is recommended that spatial patterns be analyzed by constructing maps that present contours of pressure and/or hydraulic head. Increases in pressure in wells above the confining zone (if such monitoring is performed) may be indicative of fluid leakage, and measurements should be used to complement fluid monitoring data in assessing leakage. It is recommended that increases in pressure within the injection zone be compared to modeling predictions to determine if the AoR is consistent with monitoring results. Pressure increases at a monitoring well location greater than predicted by the current site AoR model, or increases at a greater rate, may indicate that the model needs to be revised. In this case, the UIC Program Director should be consulted to determine whether an AoR reevaluation is necessary.

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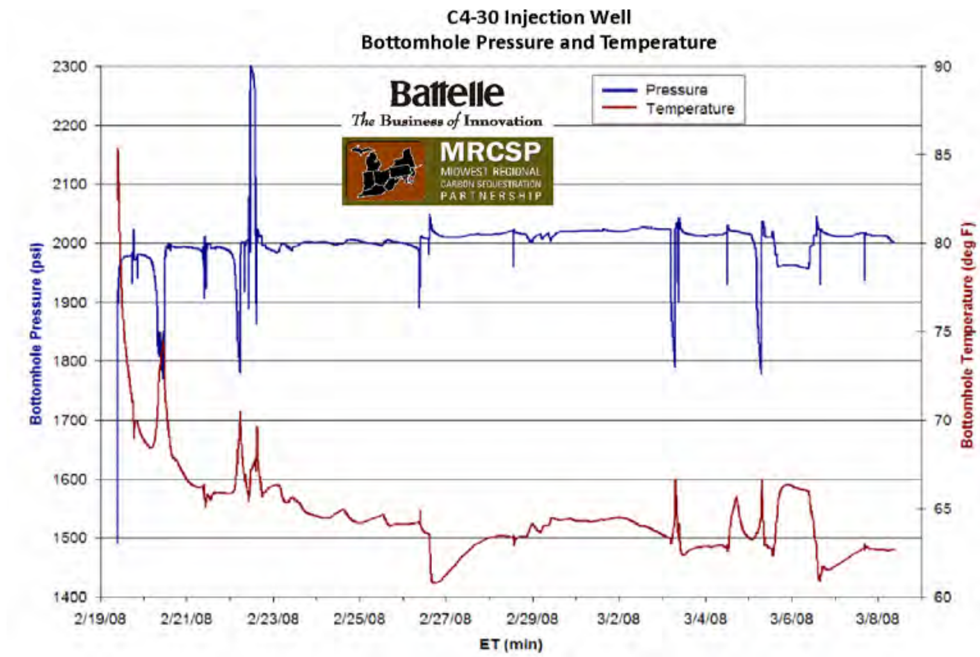

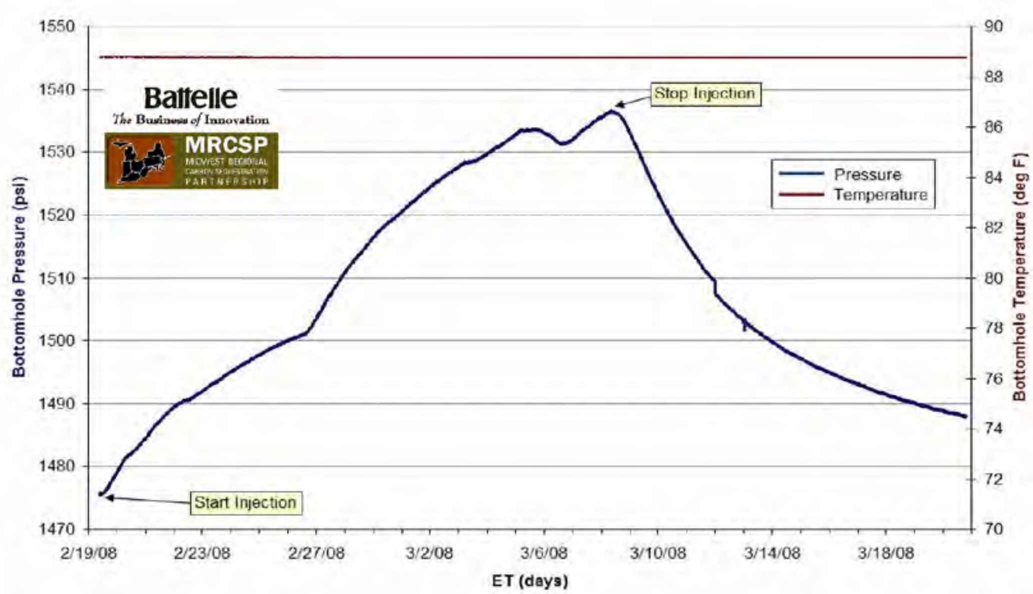

Figure 5-1. Example of temporal plots showing change in pressure and temperature at the injection well (a) and monitoring well (b) during initial testing at the MRCSP Michigan Basin Validation Test (images provided by Battelle Memorial Institute).

Reporting and Evaluation

The Class VI Rule requires that the owner or operator submit the results of pressure monitoring in the semi-annual reports [40 CFR 146.91(a)(7)]. Data will be submitted in electronic form directly to EPA's GS data system where they can then be accessed both by the UIC Program Director and other EPA offices. EPA recommends the following information be submitted with all reports:

- Measured depth to fluid or pressure transducer readings in all wells, fluid density, fluid temperature and the depth of all casing collars
- If using pressure transducers, records of the most recent calibration or verification of the measurement instrument
- Records of the surveying of wellhead and measurement point elevations
- Calculated pressure in all wells
- Time-series graphs and pressure or head maps used in interpretation of pressure data
- Comparison of measured pressures and model predictions for the same time period after commencement of injection
- The date and time of all water level measurements
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs
- Presentation, synthesis, and interpretation of the entire historical data set

The UIC Program Director will evaluate the submitted data to independently assess if pressure increases within the injection zone are consistent with predictive modeling, and if pressure measurements from wells above the confining zone are indicative of fluid leakage.

5.3. Plume Tracking using Indirect Geophysical Techniques

The Class VI Rule at 40 CFR146.90(g)(2) requires the use of indirect (i.e., geophysical) methods for monitoring the carbon dioxide plume except in cases where the UIC Program Director determines, based on site-specific considerations, that indirect methods are not suitable. This section will cover the use of geophysical methods, which can be used to image the carbon dioxide plume and, in the case of seismic profiling, may also be used to derive fluid pressure. Geophysical methods include several technologies used to indirectly monitor subsurface conditions over a relatively large area using surface and/or several wellbore measurements. These techniques typically work by initiating the propagation of a signal (e.g., sonic, electromagnetic) and measuring the reflection or transmission of that signal. Resulting data can

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be processed and interpolated to provide estimates of fluid phase-state (e.g., aqueous versus supercritical) and fluid pressure (if seismic profiling is used). Geophysical techniques provide advantages over use of monitoring wells in that results are interpreted over a broad area, whereas monitoring wells only provide a discrete point measurement. Geophysical techniques have been widely deployed in petroleum exploration and monitoring and in early GS projects (e.g., USDOE NETL, 2009).

There are three main types of geophysical methods that can be used for monitoring at GS projects: seismic, gravity and electrical. In addition to plume and pressure-front tracking, geophysical methods are also used for site characterization (see the *UIC Program Class VI Well Site Characterization Guidance*). Baseline geophysical surveys, conducted during site characterization, are necessary for evaluation of changes in the subsurface induced by the injection operation. For detailed information regarding conducting of baseline geophysical surveys, see the *UIC Program Class VI Well Site Characterization Guidance*. This section focuses on those methods applicable to surveys collected during the injection phase (Figure 1-1).

In a preliminary evaluation of GS monitoring technologies, the U.S. Department of Energy (USDOE) National Energy Technology Laboratory (NETL) has assessed the applicability of several technologies (USDOE NETL, 2009). In this evaluation, technologies were rated as primary, secondary or potential in their ability to provide useful information for subsurface monitoring of injection well integrity and the fate of the injectate and mobilized fluids. Primary technologies are considered proven. Secondary technologies are considered to be currently available and appropriate for complementing the use of the primary technologies in tracking of the injectate and understanding carbon dioxide behavior. Potential technologies are considered to be not yet mature but possibly having some benefit as a monitoring tool in the future after additional testing in the field.

The primary technologies identified by NETL (USDOE NETL, 2009) included geophysical well logging (see the *UIC Program Class VI Well Site Characterization Guidance*), annulus pressure monitoring (Section 2), and ground water geochemistry and pressure monitoring using wells (Section 4). Of the geophysical techniques discussed herein for plume and pressure front tracking that are discussed in this section, certain seismic methods were rated as secondary technologies. The remaining methods, as discussed below, are considered to be potential technologies that have not yet been proven in commercial-scale projects. Before using any technology considered “potential” in the NETL evaluation system, EPA recommends that the owner or operator consult with the UIC Program Director. Unproven technologies prone to a great deal of uncertainty may not be acceptable for monitoring.

In addition to geophysical techniques, the NETL evaluation also discusses certain promising technologies, such as tiltmeters, synthetic aperture radar, and interferometric synthetic aperture radar (InSAR), which can indicate crustal deformation associated with elevated pressure due to carbon dioxide injection. These methods are at an early stage of development in their applicability to GS and are not discussed in detail in this guidance document. The reader is referred to USDOE NETL (2009) and references therein for more information, and owners or operators may consider use of these techniques in consultation with the UIC Program Director.

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In addition to the advantages and disadvantages common to most geophysical surveys (see the *UIC Program Class VI Well Site Characterization Guidance*), an additional challenge facing deployment of these technologies for plume and pressure-front monitoring is ensuring proper time-lapse (also called four-dimensional) deployment. To facilitate comparison between sequential surveys, it is essential that each survey is carefully georeferenced. Changes in subsurface conditions between surveys can be linked to changes in the location of the plume or pressure front only if the exact location of every survey is known. Otherwise, anomalies between surveys may be the result of comparing two different subsurface locations. Installing infrastructure such as survey markers or measurement stations is one method to ensure repeatability. A permanent deployment array is another method that can limit positioning error between repeat surveys. Changes in near-surface conditions may also need to be taken into consideration. For example, research suggests that near-surface conditions such as soil water saturation may have a large effect on comparability between seismic surveys (Urosevic et al., 2007). If possible, near-surface variables should be limited by taking repeat surveys during periods of similar soil water saturation and other near-surface variables. Because the information gathered from geophysical surveys is indirect and subject to processing that can introduce error, it is recommended that the results of any survey also be compared to additional site data (e.g., monitoring well data) where available.

5.3.1. Seismic Methods

General Information

Seismic profiling methods measure the arrival of seismic waves that travel through the earth. Seismic surveys can be used to track the separate-phase plume and the migration of formation fluids. Of the types of geophysical monitoring discussed in this guidance, these methods are the only option for estimating pore pressure. Seismic methods are generally recognized to have the highest resolution of all geophysical remote imaging techniques in a variety of geologic situations (Benson and Myer, 2002). A large variety of seismic techniques are available with different capabilities that can be targeted to deliver greater detail near the borehole, between wells, or in another targeted location. Because seismic monitoring is an established method, data collection and processing methods are well known, numerous and can be easily tailored to site-specific requirements.

However, seismic imaging may be difficult when imaging through certain types of geologic formations including salts, basalts, coal seams, carbonates and non-sedimentary units (Cooper, 2009; Hyne, 2001). If such lithologies are present, seismic data may need to be supplemented with additional data to ensure accuracy (e.g., geochemical monitoring in the injection zone). Seismic methods also perform poorly for detecting carbon dioxide in depleted gas reservoirs and do not work well for imaging through shallow, dry natural gas reservoirs. Seismic methods can also be affected by anthropogenic noise and are hard to deploy in populated areas. Data quality can also vary widely for seismic surveys.

Of the seismic methods, two- and three-dimensional surface surveys, including time-lapse surveys, and microseismic surveys are considered secondary technologies according to the NETL evaluation system. Vertical seismic profiling (VSP) and crosswell seismic methods are considered to be potential monitoring technologies (USDOE NETL, 2009).

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Application

Data collection procedures for specific seismic methods vary widely, but there are several common fundamentals. All methods require a natural or man-made source of seismic waves that are detected by receivers (geophones or hydrophones) that log information about the wave. Sources and receivers can either be on the surface (i.e., surface methods) or in the subsurface (i.e., borehole methods). Seismic sources include natural earthquakes (including microseismic events as small as -3 magnitude), explosives, vibroseis trucks, air guns and piezoelectric sources.

All seismic methods rely on different subsurface materials having different seismic velocities and varying likelihoods of reflecting seismic waves based on characteristics such as saturation and compaction. For example, seismic waves travel much more slowly through carbon dioxide-saturated rock because supercritical carbon dioxide is less dense and more compressible than aqueous fluids. Therefore, depending on the material, both the transmission time and the number of reflections vary. In some methods, the recorded time is the two-way travel time (from the source, to the subsurface reflector, and back to the receiver).

Surface seismic methods (including two- and three-dimensional seismic) are suitable for plume and pressure front monitoring because they can image a large area and will be able to capture the entire extent of the plume or front. Borehole methods are only able to verify if the plume has reached a certain point. Additionally, if the carbon dioxide plume develops narrow protrusions (i.e., fingers) or migrates along faults or other narrow linear features, borehole methods may fail to detect the movement of carbon dioxide.

Borehole methods (crosswell, vertical-seismic profiling, borehole microseismic) produce higher resolution images than surface methods because seismic waves only pass through weathered surface horizons once, minimizing distortion. The higher resolution provided by this technique may be useful where the carbon dioxide plume is predicted to be thin or complex in shape. Additionally, because wells are stationary, repeatability and georeferencing between surveys in a time-lapse sequence is not a problem. However, borehole methods are less than ideal for plume and pressure-front monitoring because they can only image a small region close to the wellbore. Borehole seismic methods may use monitoring wells installed for ground water monitoring.

Two-dimensional seismic surveys are used to collect an image that represents a vertical cross section though the earth. Data is collected by a linear arrangement of geophones and seismic sources positioned along the surface trace of the slice. Two-dimensional seismic surveys were considered state of the art through the 1980s and are still commonly used today. Because of their linear nature, two-dimensional surveys do not image features that are out-of-plane. For this reason, two-dimensional surveys are less applicable for plume and pressure-front tracking compared to three-dimensional surveys.

Three-dimensional surveys use a grid of multiple sources and receivers to generate a mix of source-receiver combinations. The most basic arrangement is a linear array of geophones and a linear array of seismic sources intersecting at a right angle (McFarland, 2009). The resulting data set represents signal data received from a variety of sources, angles and distances at each geophone, eliminating problems caused by out-of-plane features. Advanced computer processing is able to account for these geometries and create a three-dimensional model of the subsurface. Three-dimensional seismic methods replaced two-dimensional seismic methods as the state-of-the-art standard in the 1990s. Resolution and spatial coverage can be high, and, under the right conditions, this method is ideal for imaging carbon dioxide in the subsurface.

Time-lapse seismic surveys (also referred to as four-dimensional surveys) generally consist of the periodic repetition of three-dimensional surveys to image changes to the subsurface over time. The exact same methodology needs to be used in the same location during the repeated surveys in order for data to be comparable. Performing a time series survey allows subsurface features such as fluid saturation to be tracked over time. The ability to accurately determine the exact position of individual seismic surveys has been assumed to exert the strongest influence on the overall quality of the time-lapse composite. However, research at the Otway pilot project in Australia (Urosevic et al., 2007) suggests that near-surface conditions such as soil saturation may also have a significant effect on seismic repeatability and comparability between surveys. An example of tracking the evolution of a carbon-dioxide plume in the subsurface using time-lapse seismic surveys is provided in Figure 5-2.

Vertical seismic profiles (VSPs) are the most common borehole seismic methods. They obtain an image of the plane between the wellbore and the surface. A VSP is conducted with one component located on the surface (usually the source) and the remaining component placed downhole (Figure 5-3). The surface component may be stationary or moved during the survey. VSPs can be conducted on land or at sea in vertical or deviated wells to a depth of at least 3,000 m (Balch et al., 1982). The source may be directly adjacent to the borehole or located at a fixed distance away (an offset VSP). A "walkaway" VSP results when the source is moved away from the well over the course of the survey.

Crosswell seismic methods deploy sources and receivers in several different wells, producing a survey that images the plane between the wells. Equipment is generally deployed in dedicated monitoring wells not more than 500 m apart (Hoversten et al., 2002), although deployment down active injection wells is also possible (Daley et al., 2007). A seismic source is deployed down one well and seismic recorders are deployed down additional wells. A typical problem with crosswell surveys is difficulty in matching profiles taken at a common well. These failures often result from processing techniques that assume simple geology and vertical wells and that fail to allow for out-of-plane structure. However, newer data processing techniques have made progress at remedying these problems. Crosswell surveys using several wells are now able to generate three-dimensional crosswell surveys (Washbourne and Bube, 1998). Multiple wells are needed for crosswell seismic surveys, potentially limiting deployment in regions with few subsurface penetrations.

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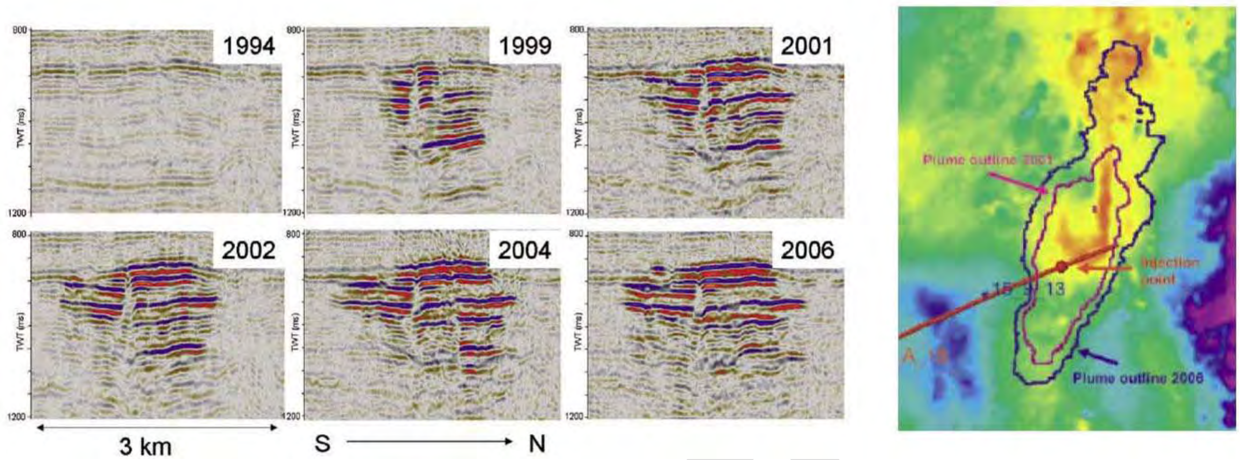

Figure 5-2. Time-lapse three-dimensional seismic was used to track the spread of the carbon dioxide plume at the Sleipner project (Arts et al., 2008): surface view of the plume (right) and slices through the plume (left). (images of EAGE/First Break, reprinted with permission).

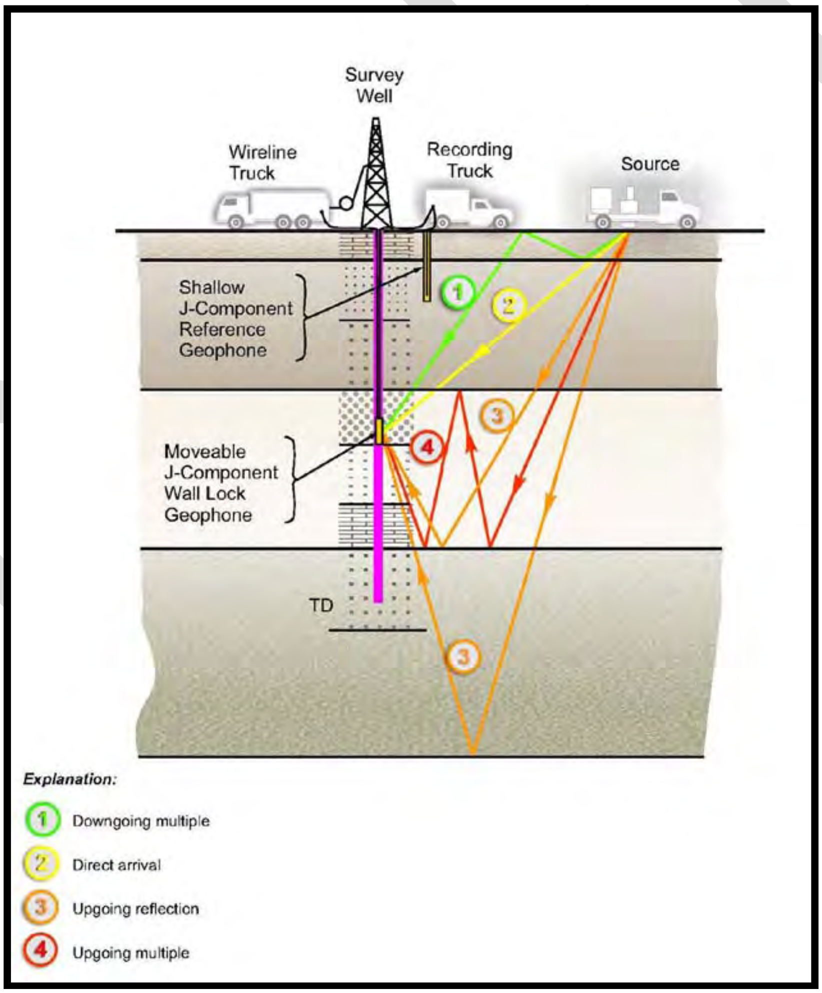

Figure 5-3. Schematic of the VSP process (adapted from Sah, 2003).

Borehole microseismic profiling uses a string of geophones deployed down a monitoring well for weeks to months. Microseismic events (typically on the order of -3 to -1) are detected by the geophones. On average, microseismic events can be detected up to 1 km from the well (Downie et al., 2009). After collection, the hypocenters of the microseismic events are plotted onto a three-dimensional subsurface projection to image subsurface areas undergoing deformation. Microseismic events occur in all environments and in all regions of the United States, but are not detectable without sophisticated equipment. For example, movements smaller than a magnitude 3—an event releasing more than 500 million times more energy than a -3 event—cannot be felt by a person standing on the surface directly above the hypocenter at the time of the event. Borehole seismic profiling cannot be used for imaging fluids, and therefore it will not be useful for plume tracking. However, the method may be useful for tracking of the pressure front because changes in seismicity are often related to changes in subsurface pressure.

<u>Interpretation</u>

Seismic surveys produce a two-dimensional cross-section or a three-dimensional image of the subsurface. However, after collection, seismic data require extensive post-collection processing to convert the data into interpretable images. For example, due to source/receiver geometry and physics, uncorrected seismic reflections from dipping layers appear in the wrong location and at an incorrect dip. Layers that terminate against a fault may appear to cross the fault. Depending upon the method, more than thirty different filtering and processing steps can be applied. These data processing steps inherently introduce error and uncertainty. Direct data collected from monitoring wells may be used to constrain data processing and improve data confidence.

Resolution varies greatly depending on the seismic setup used. Generally, crosswell seismic has the best resolution, followed by VSP, then surface seismic methods. Three-dimensional methods are usually higher resolution than two-dimensional methods. There is a tradeoff with resolution and depth: high-frequency waves yield a greater resolution because the wavelength is smaller but they cannot penetrate as deeply. Traditional rules of thumb limit the resolution to between 1/4 and 1/8 of the wavelength (Rubin 2005; Wilson and Monea, 2004). It is generally recognized that seismic methods have the best resolution of all geophysical methods (Benson and Myer, 2002).

Although seismic waves are sensitive to low saturations of carbon dioxide, the relationship between saturation and sensitivity is not linear (IEA, 2006). Therefore, while it is relatively easy to determine if separate-phase carbon dioxide is present using seismic methods, it much harder to constrain the volume present on a seismic survey. Additionally, temperature uncertainties in the reservoir can introduce large errors into carbon dioxide volume calculations because temperature has a strong effect on carbon dioxide phase and volume. The range of carbon dioxide saturation that can be imaged will depend upon several site-specific conditions. Lumley et al. (2008) have discussed this issue and draw some general conclusions: (1) seismic techniques are an excellent monitoring tool for detecting areas with and without carbon dioxide (i.e., with a bird's eye view); (2) in typical situations, seismic techniques may or may not be able to reasonably image the three-dimensional distribution of carbon dioxide; and (3) it will be extremely challenging to quantitatively invert seismic data to accurately estimate carbon dioxide saturations and injected volumes of carbon dioxide due to fundamental physical limitations.

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Seismic surveys can be processed to yield subsurface pressure data and used to track the pressure front. Any seismic survey that yields an accurate acoustic seismic velocity can be used, but multi-component data are especially useful in improving the resolution of seismic pore pressure determinations. Seismic velocity data are coupled with an estimate of the overburden pressure (usually from gravity data or bore logs) and further processed to produce pressure estimates. This step may introduce error because subjective correction factors may be needed. Pore pressure estimation tends to work best in basins filled with shales and sands where significant investigations have already occurred and local correction factors have already been developed (see Sayers et al., 2005; Young and Lepley, 2005; Sayers et al., 2000). Under optimal conditions, pore pressure analysis can resolve pressure data for strata 30 to 60 m thick at medium depth in clastic basins with relatively simple stratigraphy (Huffman, 2002).

5.3.2. Electric Geophysical Methods

General Information

Electromagnetic and electric geophysical methods measure changes in the resistivity of the formation due to changes in the electrical conductivity and saturation of formation fluids. Electric methods transmit current into the subsurface, while electromagnetic methods measure the induction effect (generation of current and electric fields) in the subsurface caused by another electromagnetic field or electric current. Electric methods are more appropriate for the purposes of monitoring, and they may be used to track the injected carbon dioxide plume. Because carbon dioxide is relatively less conductive to electric current and brines are highly conductive, displacement of brine by carbon dioxide will result in a change in the resistivity of the formation to current flow.

Although many different methods are available, two electric methods are common and likely to be useful for monitoring purposes: long electrodes and electrical resistance tomography (ERT). The long-electrode method uses long electrodes, either the well casings themselves or specially inserted metal poles. ERT operates similarly to crosswell seismic imaging and uses arrays of sources and receivers deployed down wellbores to collect data. These methods are described more fully in the *UIC Program Class VI Well Site Characterization Guidance*.

One advantage of electric techniques is that they are not dependent on rock type, rock strength or formation depth but are influenced almost solely by fluid composition and saturation (Wynn, 2003), making them good candidates for tracking the progress of carbon dioxide plumes in a wide range of environments. Electrical conductivity is also more directly influenced by carbon dioxide saturation and other changes in reservoir fluid properties than seismic variables, which are more influenced by changes in density (Wilt et al., 1995). Additionally, site locations do not have to be re-surveyed between tests because monitoring hardware will likely be permanently installed. This advantage makes four-dimensional comparisons easier than with other methods. However, because hydrocarbons are also resistive, electrical surveys are harder to conduct in hydrocarbon reservoirs. Resistivity methods are also not recommended for dry gas reservoirs (Benson and Myer, 2002).

Time lapse surveys can be complicated by changes in soil saturation, fluid pH and temperature. Also, most electrical/electromagnetic deployments are better for measuring bulk changes in resistivity than for identifying thin fingers or small regions of anomalously resistive material, similar to what may occur along leakage paths. Potential imaging planes for borehole methods are also limited to planes between wells or other subsurface protrusions. Electric geophysical methods for plume and pressure tracking are considered potential monitoring technologies according to the NETL evaluation system (USDOE NETL, 2009).

Application

The **long electrode** method shows promise for GS; owners or operators may wish to consider this method as its utility becomes more firmly established. The method consists of a controlled-source electric method that uses electrodes inserted into the subsurface to emit and receive electric pulses. Long electrodes are a conducting material that is in contact with both the region of interest and the surface. Specially deployed metal probes can be installed or, in some cases, the well casings themselves can be used as long electrodes. Even when wells are used, additional probes may be needed to improve resolution (Newmark et al., 2002). If metal probes are used, they will represent penetrations into the confining zone, because the probe needs to be in contact with pore fluids in the region of interest (i.e., the injection zone). Such probes, however, are generally permanently deployed, so the risk of leakage may be minimal as long as the probes themselves do not degrade.

During the survey, some long electrodes are used as receivers and measure the electric signal from charging of other electrodes with an electric current. The resistivity of the formation is calculated from the difference between the strength of the emitted and received signal and contoured on a surface map. A variety of source/receiver combinations is usually used to maximize the amount of data gathered and the number of different views of the targeted area (Daily and Ramirez, 2000). Both vertical and horizontal wells can be used as long electrodes. If only vertical wells are used, the resulting survey will have no vertical resolution. Additionally, when using long electrodes, the signal is the average over the entire length of the electrode. Therefore, small changes that only contact a small part of the electrode may be difficult to detect.

Crosswell ERT surveys have a similar deployment to crosswell seismic surveys and image a plane between the two wells. Point electrodes are deployed at set distances along a non-conductive well-casing such as plastic or fiberglass (Newmark et al., 1999). Deployment can be either temporary or permanent. As an electric source is raised in one well, the resistivity of the formation between the wells is recorded. Ideally, the distance between wells is not more than a few hundred meters (Christensen et al., 2005), although successful ERT studies have occurred with wells spaced up to 850 m apart (Marsala et al., 2008). Because resistivity measurements are taken at different depths, this type of survey can determine both the horizontal and vertical extent of electric anomalies. This deployment produces results with greater detail than other electrical methods. However, it requires a greater capital investment in specialized hardware, costs more per survey, and requires dedicated monitoring wells and/or stoppages in production/injection.

Interpretation

Resistivity measurements are highly sensitive to the brine saturation within a reservoir. Measured resistivity values will increase when gas or supercritical fluid invades the pore space in the monitored location. In reservoirs without the presence of other gases, increased resistivity

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measurements are interpreted as the arrival of the separate-phase carbon dioxide plume (e.g., Schilling et al., 2009). Resistivity changes on the order of 30 percent can generally be detected, although under optimal conditions resistivity changes are little as 10 percent can be measured. The resolution of the survey is highly dependent upon the arrangement of the electrodes. When low electromagnetic frequencies are used, resolution is fairly low and the measurements are strongly affected by the conductivities of structures near the source and receiver (Wynn, 2003). Resolution is low for most methods when compared to seismic methods, although some methods may provide higher resolution for small areas.

Depending upon the exact deployment, electrical methods require various amounts of post-collection processing. Raw data are corrected for the effect of steel casings and obvious outliers are excluded. The data are then inverted and color-coded to produce either two- or three-dimensional resistivity maps (Schuett et al., 2008). Depending upon the method, results can be presented either as surface maps or depth sections. Like seismic methods, results are interpreted visually. Electrical changes in the subsurface are also caused by changes in soil saturation and the pH of the fluids and the temperature. Such changes can complicate time-lapse surveys. Several non-unique reconstructions of electrical survey data are possible, complicating data interpretation. Interpretation can be improved by considering other types of data (e.g., monitoring well data, other geophysical surveys). Furthermore, instrument calibration in a laboratory using in-situ conditions can improve data quality and interpretability (e.g., Schilling et al., 2009).

5.3.3. Gravity Methods

<u>General Information</u>

Gravity-based methods use a gravimeter to detect the force due to gravity at a given point. Measurements may be used to track the carbon dioxide plume because carbon dioxide has a different density than the formation fluids it displaces and will have a different gravity signal strength. The contact between carbon dioxide and formation fluids might be determined both laterally with surface measurements and vertically with borehole measurements (Alshakhs et al., 2008). Gravity methods cannot be used to measure the pressure front. Further discussion of geophysical gravity methods can be found in the *UIC Program Class VI Well Site Characterization Guidance*.

Gravity measurements for plume tracking will work best in horizontal, thick formations with high porosity and permeability where brine is being replaced by carbon dioxide. Such settings will produce large density contrasts between original and post-injection conditions. Gravity monitoring may be especially useful for monitoring upward movement of gaseous carbon dioxide plumes, which will occur at relatively shallow depths (i.e., less than approximately 800 m).

Carbon dioxide is difficult to detect with gravity measurements when it occurs in thin layers. Therefore, gravity methods are likely to work better in thick saline formations than in hydrocarbon reservoirs, which are often thin (Hoversten and Gasperikova, 2003). Depleted gas reservoirs pose a challenge for gravity monitoring because residual gas trapped within pores in the reservoir can decrease the density contrast with injected carbon dioxide (Sherlock et al., 2005).One advantage of gravity methods, particularly compared with seismic methods, is that the data are collected from a robust signal and transformed with simple equations that introduce a minimum of interpretive error. However, like electromagnetic data, the measurements are not unique to certain lithologies or features, and complementary data are helpful in interpreting the results. Gravity methods for plume monitoring are considered to be potential monitoring technologies according to the NETL evaluation system (USDOE NETL, 2009).

Application

Data are collected using a gravimeter, which measures the elongation of a wire suspending or attached to a mass. As gravity increases, the mass is pulled downward and the wire lengthens. The deformation is measured and transformed into a gravity reading. Relative gravimeters compare the gravity measurement at one point with another. They should be calibrated at a location where the gravity is known accurately and subsequently transported to another location where the gravity is to be measured. The gravimeters then measure the ratio of the gravity at the two points; the deformation is measured and transformed into a gravity reading. Absolute gravimeters, which measure gravity by dropping a mass a short distance (several centimeters) and using a laser to measure the acceleration, are also available. Absolute gravimeters are thought to produce higher quality data than other types of gravimeters (Cooper, 2009).

Land-based and aerial gravity methods are both used to collect gravity surveys on a large scale. Land-based surveys will generally have a higher resolution than aerial data. Aerial data may not be sufficiently resolved for plume detection. For surface deployments, measurements are typically taken at discrete stations across the area of interest.

Borehole gravity surveys are similar to borehole seismic surveys. A gravimeter is lowered down the borehole and measurements are taken as the device is raised. Borehole surveys have been conducted in wells 2,000 m deep and inclined up to 60˚ (Seigel et al., 2009). Gravity gradiometry, a slightly different data collection technique, needs to be used in regions with non-horizontal strata. Borehole gravity data can be used to monitor the carbon dioxide plume by detecting the interface between formation fluids, even if wellbores do not intersect it. The gas/brine interface can be detected for hundreds of meters. With a permanently installed gravimeter, the detection distance for these interfaces could be detected at over one km away (Alshakas et al., 2008). However, when using a single well it is only possible to know the radial distance of a feature from the well, but not the direction.

Interpretation

After collection, gravity data are corrected for instrument drift, elevation differences and other corrections dependent upon deployment specifics. For monitoring purposes, gravity data will most likely be contoured and displayed on a surface map. Like other geophysical monitoring techniques, data are usually interpreted and cross-referenced with cross-sections, stratigraphy and regional geologic information to help constrain the most logical interpretation of the data.

Time-lapse gravity surveys would be expected to show a decrease in gravity values as carbon dioxide migrates into a location (USDOE NETL, 2009). The method can detect mass changes and, possibly, surface deformations induced by the injection activity. The detection threshold is site specific, and it depends on reservoir depth and physical properties and the distance between the target location and the survey. A common problem in interpretation of gravity surveys is the need to account for other sources of gravity variations and instrument drift.

5.3.4. Reporting and Evaluation of Geophysical Survey Results

The Class VI Rule requires that the owner or operator submit the results of any indirect geophysical monitoring that has been done in the semi-annual reports required under 40 CFR 146.91(a)(7). Data will be submitted in electronic form directly to EPA's data system where they can then be accessed both by the UIC Program Director and other EPA offices. The following information should be submitted with all reports:

- A description and technical justification of all survey techniques and methodologies used
- A map showing the location of all survey equipment positions during the test
- The date and time of collection of all geophysical data
- If required by the UIC Program Director, all raw data collected by the survey equipment, a description of all data processing steps taken and the major assumptions used during data processing that may affect the interpretation of the data
- An interpretation of all geophysical surveys relating to the position of the plume and/or pressure front and fluid leakage, including any available information on method sensitivity and any out of zone anomalies that require follow up
- Maps showing the interpreted location of separate-phase carbon dioxide in the injection zone and its location in any additional zones in which it was detected
- A comparison of the measured position of the carbon dioxide plume with modeled predictions corresponding to the time of the survey
- Identification of data gaps, if any
- Any identified necessary changes to the project Testing and Monitoring Plan to continue protection of USDWs
- Presentation, synthesis, and interpretation of the entire historical data set

The UIC Program Director will evaluate the submitted data to independently assess if the position of the carbon dioxide plume and/or pressure front are consistent with predictive modeling.

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5.4. Use of Geochemical Ground Water Monitoring in Plume Tracking

Ground water geochemical monitoring from wells perforated within the injection zone may be used to infer the presence or absence of carbon dioxide at a location, and therefore they may be used to augment the required activities at 40 CFR 146.90(g) for tracking the extent of the carbon dioxide plume. The Class VI Rule does not require the use of monitoring wells for the purposes of tracking the extent of the carbon dioxide plume in all cases. Rather, indirect methods are required for plume tracking, unless they are determined to be inappropriate based on site-specific criteria [40 CFR 146.90(g)(2)]. In certain cases, the owner or operator, collaboratively with the UIC Program Director, may determine that the use of geochemical ground water monitoring may be necessary to track the carbon dioxide plume sufficiently. The decision whether to use geochemical ground water monitoring for plume tracking will be highly site-specific, and the owner or operator is encouraged to consult the UIC Program Director.

Criteria for Evaluation of Plume Tracking Using Ground Water Geochemical Monitoring

EPA recommends the following criteria be evaluated in determining whether to use ground water geochemical monitoring as a component of plume tracking:

- In cases when the UIC Program Director has determined that geophysical techniques are not appropriate for a given site for plume tracking, EPA recommends the use of geochemical ground water monitoring for plume tracking. Section 5.3 discusses geologic formations that may not be suitable for indirect geophysical methods. For example:
    - Seismic imaging may not be appropriate in salts, basalts, coal seams, carbonates, non-sedimentary units, depleted gas reservoirs and shallow natural gas reservoirs. Seismic methods can also be affected by anthropogenic noise and are hard to deploy in populated areas.
    - Time-lapse electrical/electromagnetic methods can be complicated by changes in soil saturation, fluid pH and temperature, and they are not favorable for imaging of thin fingers of carbon dioxide fluid that may occur along preferential pathways.
    - Carbon dioxide is difficult to detect with gravity measurements when it occurs in thin layers. Therefore, gravity methods are likely to work better in thick saline formations than in hydrocarbon reservoirs, which are often thin. Depleted gas reservoirs pose a challenge for gravity monitoring because residual gas trapped within pores in the reservoir can decrease the density contrast with injected carbon dioxide.
- Geophysical techniques are capable of imaging the separate-phase carbon dioxide plume, but not the larger "dissolved-phase" carbon dioxide plume that is created by dissolution of carbon dioxide into native fluids. In cases where there may be risks associated with the dissolved-phase plume, geochemical ground water monitoring is recommended.
- If geophysical methods will be deployed, but are prone to a significant amount of uncertainty, ground water geochemical monitoring may be used to complement

geophysical surveys (see site-specific factors discussed above). For example, geochemical data may be used to reduce uncertainty with interpretation of geophysical results during data processing.

- In some cases, it may be cost-effective to conduct relatively frequent ground water geochemical monitoring for plume tracking (e.g., every six months), with less frequent repeat geophysical surveys to complement the geochemical monitoring (e.g., every five years). A complementary program of geochemical monitoring and geophysical surveys may be designed to optimize costs, while providing sufficient tracking of the carbon dioxide plume.

Application

Considerations related to collection and analysis of ground water samples within the injection zone will be similar to those for wells perforated above the confining zone (see Section 4). EPA recommends similar sampling protocols, QA/QC and analytical procedures as those discussed for ground water geochemical monitoring above. For the purposes of plume tracking, EPA recommends that fluids collected from the injection zone be monitored for carbon dioxide, at a minimum. If available, downhole probes may be used to estimate carbon dioxide concentrations in lieu of sample collection and laboratory analysis.

Wells constructed in order to directly monitor pressure within the injection zone may also be used for geochemical monitoring. In some rare cases, particularly when indirect geophysical techniques are not used, additional monitoring wells may be necessary within the injection zone in order to track the carbon dioxide plume. Specifically, EPA recommends the following considerations for design of the monitoring well network for plume tracking:

- For the purpose of plume tracking, EPA recommends that monitoring wells be perforated at a similar interval to the injection well(s) if sited near injection wells. For those wells sited further from the injection wells, the owner or operator may consider perforating wells at a higher elevation (closer to the injection zone/confining zone interface), to account for vertical buoyant flow as carbon dioxide migrates laterally.

- For projects predicted to have a separate-phase plume and/or pressure front that moves preferentially in one direction, EPA recommends that more monitoring be placed in that direction.

- Well placement should be based on the predicted rate of migration of the separate-phase plume and/or pressure front.

- The number of monitoring wells placed within the injection zone should be determined such that the migration of the carbon dioxide plume may be tracked sufficiently to detect any pressure increase that differs from modeled predictions. The determination of the number of injection zone wells may be based on a modeling and/or statistical analysis, which may be documented in the Testing and Monitoring Plan.

Interpretation

The objective of ground water monitoring within the injection zone is to track the extent of the carbon dioxide plume. EPA recommends that the owner or operator evaluate the collected data in comparison to previously collected data and baseline data. Trends that are indicative of the presence of the carbon dioxide plume at a particular location are:

- An increase in the concentration of dissolved carbon dioxide indicates the presence of separate-phase or dissolved-phase carbon dioxide. The concentration of carbon dioxide may be used to ascertain if separate-phase carbon dioxide may be present, based on accepted mass-transfer relations and equilibrium constants.

- Results indicative of the presence of the separate-phase plume at the monitoring location also include reduced sample fluid density and the presence of separate-phase carbon dioxide in the sampled fluid.

EPA recommends that, where possible, data collected from monitoring wells within the injection zone be compared to indirect geophysical data regarding the extent of the separate-phase plume. Comparison and interpretation of the two data sets may be used to elucidate uncertainties related to either monitoring technology.

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6. Soil Gas and Surface Air Monitoring

At the discretion of the UIC Program Director, the owner or operator may be required to monitor surface air and soil gas for carbon dioxide leakage that may endanger USDWs [40 CFR 146.90(h)]. Under the Class VI Rule, all surface air and/or soil gas monitoring required for compliance with UIC regulations must be based on potential risk to USDWs [40 CFR 146.90(h)(1)]. The objective of soil gas/surface air monitoring under the Class VI UIC Program is to provide an additional line of evidence if carbon dioxide has leaked from the injection zone and potentially endangered USDWs.

If the UIC Program Director requires surface air/soil gas monitoring pursuant to requirements at 40 CFR 146.90(h) and an owner or operator demonstrates that monitoring employed under Subpart RR of the GHG Reporting Program [40 CFR 98.440 to 98.449] meets the requirements at 40 CFR 146.90(h)(3), the Director may approve the use of monitoring employed under Subpart RR. Subpart RR, promulgated under the authority of the Clean Air Act, complements UIC requirements with the added monitoring objectives of verifying the amount of carbon dioxide sequestered, as well as collecting data on any carbon dioxide surface emissions. The Subpart RR General TSD describes a suite of monitoring technologies available for soil gas and surface air monitoring (section 4 of the Subpart RR General TSD) and provides considerations for reporters in developing their Monitoring, Verification and Reporting (MRV) plans for Subpart RR (section 5 of the Subpart RR General TSD).

Soil gas and/or surface air monitoring may also be required to meet additional monitoring objectives by other state or federal regulations. EPA recommends that when soil gas/surface air monitoring is conducted in compliance with multiple regulatory programs, the owner or operator design a monitoring strategy that efficiently meets all monitoring objectives. In some cases, separate technologies (e.g., eddy covariance towers versus soil gas probes) may be used to meet specific monitoring objectives. However, it is likely that data collected from multiple techniques will be complementary and useful in data analysis and interpretations for all regulatory programs.

Carbon dioxide detection above background levels in soil gas or at the surface does not necessarily indicate that USDWs have been endangered, but rather that a leakage pathway or conduit exists at some point in the operation. For example, the carbon dioxide delivery system or ancillary wellhead equipment may be another leakage source. Carbon dioxide leakage into the unsaturated zone or surface air from the injection zone may occur from a non-point or point source or a combination of both. Non-point sources include leakage of injectate through the confining zone and overlying zones through a diffuse network of high-permeability pathways, including micro-fractures. Point sources include leakage through artificial penetrations (e.g., wells), individual fractures, fault zones and surface equipment. In either case, leaking carbon dioxide at these depths will be in the gaseous phase, and it will mix with resident gases (e.g., soil gas, surface air). Carbon dioxide leakage may be detected by observation of concentrations elevated above background levels. Detection of leakage is more likely for point sources, because the resulting carbon dioxide concentrations will likely be greater. Common to soil gas and surface air monitoring is the need to account for background natural carbon dioxide

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concentrations, which fluctuate seasonally. In addition to monitoring for carbon dioxide concentration, soil gas and/or surface air may also be monitored for tracer gases or carbon dioxide isotopic signatures, which may aid in evaluating carbon dioxide sources. A detailed discussion of monitoring for tracer gases and carbon dioxide isotopes is included in the Subpart RR General TSD.

The Class VI Rule, at 40 CFR 146.91(h)(2), requires that monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring be determined using baseline data, and the Testing and Monitoring Plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under 40 CFR 144.12. Information regarding determination of baseline is given in the *UIC Program Class VI Well Site Characterization Guidance.* In addition, EPA recommends that the location of soil gas and/or surface air sampling points be based on the following considerations:

- Avoiding areas of highly fluctuating background concentrations, based on previously recorded data.
- Near obvious point-sources, including wellheads, artificial penetrations, and fault or fracture zones. A transect-profiling approach may be used for linear features, such as faults (see ASTM, 2006).
- If intended to monitor for non-point source leakage, monitor throughout the AoR, using a grid methodology in areas of potential leakage. Grid cell spacing may range over several orders of magnitude, depending on site specific factors. See ASTM (2006) for discussion of establishing a soil sampling grid.

6.1. Soil Gas Monitoring

<u>General Information</u>

Soil gas monitoring at a Class VI GS project refers to sampling of vapors within the unsaturated zone (i.e., the zone from the ground surface to the capillary fringe above the water table), or across the ground surface, and analysis for the vapor-phase concentration of carbon dioxide. Unsaturated-zone samples may be collected from soil gas probes. Soil flux chambers are used to collect vapors across the ground surface. As described below, collected gas samples may be analyzed using portable gas analyzers. Soil gas monitoring is a relatively common technology, used in characterization of contaminated sites and for exploration of natural resources, including petroleum, natural gas and precious metals.

<u>Application</u>

Soil gas is traditionally sampled using whole air or sorbent methods. Whole air methods collect a sample of soil gas for vapor-phase analysis. Sorbent methods collect non-polar chemicals on a sorbent material that is put in place at the site for an extended period of time. For Class VI projects, EPA recommends use of whole air sampling methods because data collection and interpretation are comparatively straightforward.

Soil gas probes are borehole sampling devices that are driven into the unsaturated zone. The tip of the sampling probe contains a sampling tube that runs to the surface (Figure 6-1). During sample collection, a vacuum is applied to the sampling tube on the surface, and soil gas from the sampled depth is collected. For GS projects, EPA recommends that soil gas probes are driven to a depth as close to the potential leakage point as possible. In most cases, it is recommended that soil gas probes be driven as deep as possible while remaining above the water table capillary fringe, accounting for seasonal and long-term fluctuation. In any case, it is recommended that soil vapor samples be collected at depths great enough to be out of the zone of influence of atmospheric chemical concentration and temperature fluctuations; in addition, the probe should not be terminated in a low-permeability (e.g., clay) zone. During installation, it is recommended that the probe tip be emplaced midway within a sand pack (minimum of one foot; e.g., CalEPA, 2003). The borehole may then be grouted to the surface with hydrated bentonite or a cement/bentonite mixture.

Prior to sample collection from a soil gas probe, the probe is purged, similar to ground water monitoring wells (Section 5.2). Purge tests are conducted on each typical lithologic unit into which soil vapor probes are installed to determine the appropriate purge volume (CalEPA, 2003). In general, it is recommended that purging and sampling rates not be greater than 100 to 200 mL per minute. Leakage of surface air through the borehole during sampling, and concomitant sample dilution, is of potential concern during sample collection. During sampling, a leakage test may be conducted by placing a tracer compound, such as isopropyl alcohol (IPA), at the surface. A leakage test sample would then be analyzed using appropriate analytical methods for detection of the tracer. Samples may be collected in reusable containers, such as glass syringes, as long as appropriate decontamination procedures are adhered to between sample collections. Samples may be analyzed in the field for carbon dioxide using a standard handheld gas analyzer, such as a portable infrared detector. The portable analyzer should be calibrated regularly to a gas standard according to manufacturer specifications.

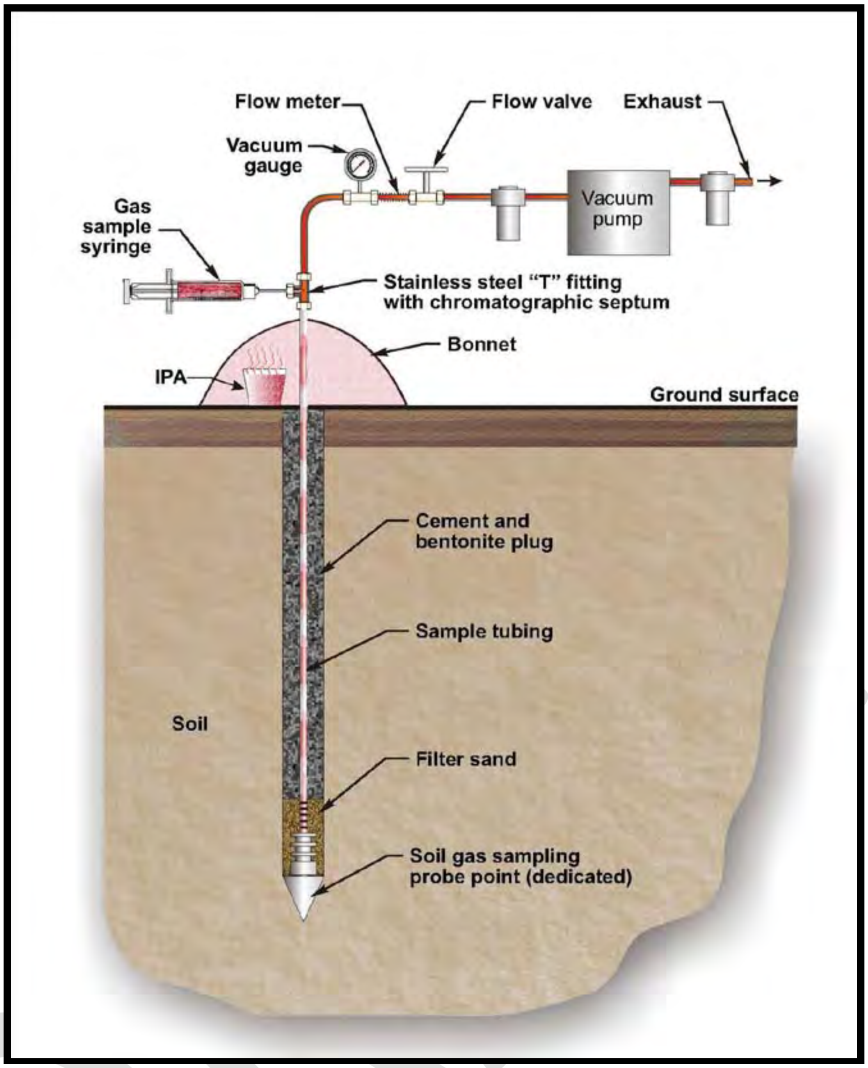

Figure 6-1. Schematic of a soil gas sampling system (adapted from Wilson et al., 1995; not to scale).

Soil flux chambers, also referred to as accumulation chambers, are installed at the ground surface and are used to measure the flow and composition of gases at the soil surface (Figure 6-2). The chamber is swept by injection of a carrier gas, and the resulting mixture is collected for analysis (ASTM, 2006). The flux of carbon dioxide out of the soil surface into surface air may be calculated if flow rates of the injected gas are known. Compared to soil gas probes, soil flux chambers are more limited in their ability to detect carbon dioxide leakage. Samples are diluted by use of the carrier gas, decreasing method sensitivity. Vapor flux from deeper zones near the USDW to the soil surface may be reduced due to soil characteristics such as high water saturation and the presence of low permeability lenses. However, the use of soil flux chambers may be preferred because borehole installation is not necessary, and equipment may be reused at several sites. The use of soil flux chambers may also be complementary to soil gas probes; whereas probes identify a zone of leakage, chambers may be used to estimate the flow and composition at the surface. Additional information regarding soil flux chambers that pertains to quantification of leakage rates is available in the Subpart RR General TSD.

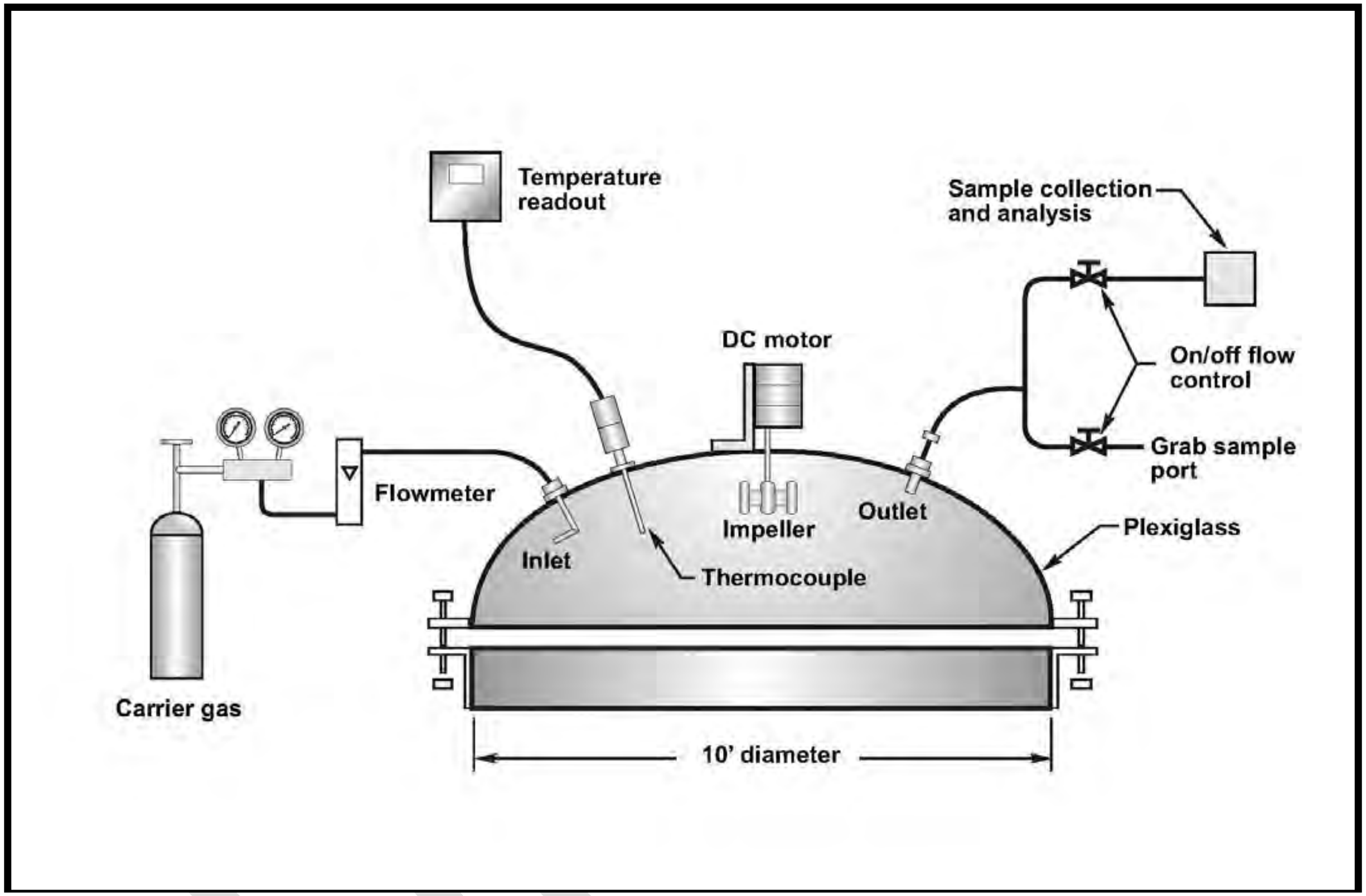

Figure 6-2. Schematic of a soil flux chamber (adapted from ASTM, 2006; not to scale).

Interpretation

Subsurface gases are relatively less affected by surface environmental forces (e.g., atmospheric dispersion) and associated dilution. Therefore, monitoring soil gas concentrations of carbon dioxide may be preferable over surface air monitoring for early detection of leakage. It is recommended that carbon dioxide concentrations observed in soil gas measurements be compared to background levels to identify potential anomalies which may be indicative of leakage of carbon dioxide from the intended storage formations [40 CFR 146.90 (h)(2)]. When required to conduct soil gas and surface air monitoring, owners or operators need to include a strategy for effectively conducting such monitoring in the Testing and Monitoring Plan for the UIC Program Director's approval. Background soil carbon dioxide fluxes, concentrations and isotopic compositions show large variations and are dependent on exchange with the atmosphere, organic matter decay, uptake by plants, root respiration, deep degassing, release from ground water due to depressurization and microbial activities (Oldenburg and Lewicki, 2004). Therefore, EPA recommends that baseline studies be carried out prior to injection of carbon dioxide to characterize the background spatial trends and variability (see the *UIC Program Class VI Well Site Characterization Guidance*). Such studies would include repetitive measurements over time taken at several fixed representative sites to capture diurnal to seasonal variations (Oldenburg et al., 2003). EPA particularly recommends that such monitoring include areas with geologic and artificial structures (e.g., faults, artificial penetrations) that may potentially create conduits for leakage to occur. During these measurements, soil temperature and moisture are recommended to be monitored along with the collection of records of atmospheric temperature, pressure, and wind speed and direction measured at a weather station. Ideally, robust (e.g., multi-year) background (i.e., pre-injection) carbon dioxide data will be available from the locations monitored during the GS project. Importantly, collected gas composition data using different methods (e.g., different types of soil gas probes, different depths) are not directly comparable. If pre-injection data are not available, local soil gas data collected outside of the region of influence of the project may be used for comparison. Identification and quantification of leakage is also an integral part of the Subpart RR requirements and more information can be found in Subpart RR General TSD. See also the *UIC Program Class VI Well Site Characterization Guidance* for additional information on collecting baseline data.

Carbon dioxide concentrations in soil gas that exceed above background levels may be indicative of carbon dioxide leakage and USDW contamination. It is recommended that seasonal fluctuations in background levels be considered during this comparison. If a sampling grid has been established, data collected during a sampling event may be plotted on a site map and contoured. Sampling locations with the greatest carbon dioxide concentrations may be in the vicinity of a leakage pathway. However, leakage pathways may be circuitous within the subsurface, in which case it may not be straightforward to determine the leakage source strictly from soil gas data. Furthermore, non-point leakage sources may result in large carbon dioxide plumes in soil gas without a discernible central location. If soil gas data indicate potential leakage, USDWs in the vicinity may be monitored for any geochemical changes and impairment.

Multi-level soil vapor data collection points are typically necessary to provide the basis for making three-dimensional interpretations (i.e., lateral and vertical extent) of carbon dioxide concentrations in soil gas. Like other monitoring techniques, data are usually interpreted and

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cross-referenced with cross-sections, stratigraphy and regional geologic information to help constrain the most logical interpretation of the data.

Reporting and Evaluation

If required by the UIC Program Director, soil gas data must be submitted in the semi-annual reports [40 CFR 146.91(a)(7)]. EPA recommends that submittals be in an electronic format and include the following:

- Records, schematics and technical justification for all soil gas probe or soil flux chamber equipment installation
- A database of all available soil gas data from each sampling location and depth, including any background data and QA/QC samples
- Interpretive maps and/or graphs of carbon dioxide trends
- Records of the calibration of any analytical equipment, including handheld portable gas analyzers
- Records of all field activities, including vacuum-volume purge tests, sample probe purging and sampling rates

6.2. Surface Air Monitoring

General Information

Surface air above the GS project may be analyzed for elevated levels of carbon dioxide. Collection and analysis of surface air samples is relatively straightforward. Similar to soil gas sampling, EPA recommends that collected data be compared to background levels in order to assess leakage [40 CFR 146.90(h)(2)]. Surface air monitoring is complicated by other carbon dioxide sources, including soil and vegetation, industrial processes and surface carbon dioxide delivery and processing equipment. Additionally, the atmosphere is well mixed, and the leakage signals may be diluted such that they cannot be detected (USDOE NETL, 2009). As with soil flux chambers, carbon dioxide leaking through USDWs may not emanate at appreciable rates to the surface due to retardation in the unsaturated zone. For these reasons, surface air monitoring will likely only be useful for detecting large point-source leaks. Surface air monitoring, however, is relatively low cost and may be required by other state or federal regulations, including Subpart RR. The Subpart RR General TSD discusses surface air monitoring techniques as they pertain to quantification of leakage from a GS project.

Application

The simplest application of surface air monitoring is the use of portable or stationary **carbon dioxide detectors**. Infrared detectors, also used for soil gas sampling (Section 6.1), may be used for field-analysis of surface air. Stationary monitors may be used to continuously collect and record ambient carbon dioxide concentrations. Handheld portable analyzers may be used to spot check carbon dioxide concentrations at given times. Alternatively, sampling devices may be left at the surface to collect air samples over a given time, such as a 24-hour interval (e.g., Summa canisters). **Advanced leak detection systems**, often used along pipelines, consist of a portable gas analyzer mounted to a GPS-referenced ground or airborne vehicle. The Subpart RR General TSD further discusses carbon dioxide detectors, including detection of tracers and carbon dioxide measurements.

Eddy covariance towers may be used to monitor carbon dioxide concentrations at a height above the ground surface. These towers use an infrared gas analyzer to continuously monitor carbon dioxide concentrations. They also use additional equipment to measure wind velocity, relative humidity and temperature. Primarily, these towers would be used to detect carbon dioxide flux of large areas in real time (USDOE NETL, 2009). Interpretation of atmospheric data from eddy covariance towers requires significant data processing and may be complicated by local weather patterns and precipitation.

Interpretation

EPA recommends that measured carbon dioxide concentrations in surface air be compared to locally collected background data, as described in Section 6.1 [40 CFR 146.90(h)(2)]. The average carbon dioxide concentration in surface air is currently 0.038 percent (NOAA, 2011). Carbon dioxide levels that are significantly higher than background levels may be indicative of leakage. However, for reasons discussed above, surface air data is not ideal for detecting the source or location of leakage that may impact a USDW. If carbon dioxide leakage is suspected based on surface air data, additional monitoring may be conducted in order to elucidate the source of the leak and assess any impairment of USDWs. This may involve further sampling using soil gas probes and ground water monitoring within surficial USDWs.

Reporting and Evaluation

If required by the UIC Program Director, surface air data should be submitted electronically in the semi-annual reports [40 CFR 146.91(a)(7)]. EPA recommends that submittals include the following:

- Records and technical justification of the location and time intervals of all surface air sampling
- A database of all available surface air data from each sampling location, including any background data and QA/QC samples
- Interpretive maps and/or graphs of carbon dioxide trends
- Records of the calibration of any analytical equipment, including gas analyzers
- Records of all field activities

7. Testing and Monitoring Case Studies

GS is an emerging technology, and few commercial-scale projects have begun operation. However, several field-scale pilot projects have been initiated in the United States and internationally. One objective of these projects has been testing and evaluation of different monitoring techniques. EPA believes that learning from early projects will be integral to developing effective testing and monitoring programs and protecting USDWs. The case studies presented here provide examples of the application of several of the technologies discussed in this guidance. The reader is referred to references cited within the case studies for further information and guidance regarding use of these techniques. Importantly, the projects discussed here are not mature commercial-scale projects that use monitoring techniques, but rather research-oriented pilot projects. As additional data are collected from larger-scale GS projects, EPA is committed to collecting and evaluating new data and information as a component of the Class VI Rule adaptive approach.

7.1. Cranfield Oil Field

The Cranfield oil field, located in Natchez, Mississippi, hosts a Southeast Regional Carbon Sequestration Partnership (SECARB) test project combining enhanced oil recovery (EOR) and GS. Injection activities at the site target an 18 m thick sandstone layer in the Lower Tuscaloosa unit, 3,117 m below the surface (Meckel and Hovorka, 2009). The thick sedimentary sequence at the site underlies several Gulf Coast states. SECARB conducted a stacked test using eleven existing wells dating from the 1960s as injection wells and an additional existing well as a monitoring well. Both the injection zone and an overlying formation have been monitored. Injection of carbon dioxide for the stacked test began in July 2008.

Baseline measurements of temperature and pressure were gathered in spring 2008, and monitoring began in July 2008. The monitoring well allowed for continuous downhole monitoring in two zones: the injection zone and a sandstone unit in the Upper Tuscaloosa Formation that serves as a monitoring horizon above the confining zone. Pressure and temperature data from both zones were collected on a near-continuous basis and uploaded to the Internet (Meckel and Hovorka, 2009). Additional monitoring included daily tracking of wellhead pressures, pressure memory gauges, and dip-in pressures. Wireline geophysical methods were used to detect gas saturations in monitoring wells (SECARB, 2009a). To track potential impacts on near-surface aquifers, researchers obtained time-lapse measurements of soil gas at plugged and abandoned wells to monitor for shallow leakage.

A one-year initial monitoring period was completed in the spring of 2009. Monitoring results from the first year of injection indicated increased pressure in the injection zone (SECARB, 2009a), and subsequent monitoring has detected pressure increase above the injection zone. Results from the soil gas study show no changes in soil gas composition between the pre- and post-injection stages (SECARB, 2009a).

Activities at Cranfield continued after the end of the stacked test with the initiation of four distinct sub-projects: a high volume injection test, a “detailed area of study” well-based monitoring test, a geomechanical test and a surface monitoring program at the “P” area (for “plants, pad and pit”). Monitoring for these projects began in 2009 and was scheduled to continue through 2011, followed by post-injection monitoring.

Monitoring activities for the new projects include geophysical plume tracking, pressure monitoring and ground water monitoring. To monitor the carbon dioxide plume, researchers are using ERT arrays. The 10,400 ft deep array is one of the deepest applications of ERT to date (Carrigan et al., 2009). Continuous active seismic source monitoring (CASSM) also tracks the plume. Researchers will continue to monitor pressure using continuous downhole sensors, and downhole temperature will be recorded with a distributed temperature sensor. Downhole fluid samples will be retrieved using a U-tube sampler and analyzed both in the field and in the lab. Researchers will continue to use wireline geophysical tools to monitor for fluid composition changes. Data were not yet available for the current tests at the time this document was developed, but preliminary results confirm the integrity of the seal (SECARB, 2009b). Data are also being incorporated into models to better understand the long-term behavior of injected carbon dioxide.

7.2. In Salah Natural Gas Fields

The In Salah project is a commercial-scale project centered on a group of active natural gas production fields at Krechba, in central Algeria. Carbon dioxide is separated from produced gas to meet market requirements for natural gas purity. The carbon dioxide is reinjected to meet the operator’s environmental sustainability standards (BP, 2008; Wright, 2007). The operator’s plan is to inject 17 megatonnes (Mt) of carbon dioxide over 15 to 20 years (BP, 2008; Michael et al., 2009; Riddiford et al., 2004). The target formation is a heterogeneous, low-permeability sandstone that is approximately 20 m thick and 1,800 m deep (BP, 2008; Wright, 2007; ISG, 2008; Ringrose et al., 2009). The sandstone is part of a gas-containing anticline, and the carbon dioxide is injected through three horizontal injection wells (BP, 2008). Monitoring efforts began with baseline seismic surveys taken in 2004 just prior to the start of injection.

Remote satellite imaging of surface deformation is the main technology used to track the plume at In Salah. Investigations focus on a 20 km by five km area defined by the gas leg of the reservoir anticline. During the initial planning phase, researchers expected that satellite tracking would be of little use at In Salah because of the depth and thinness of the target formation. However, modeling conducted by Lawrence Berkeley National Laboratory (LBNL) using the TOUGH-FLAC simulator indicated that injection at the site could potentially result in several centimeters of surface elevation change (Rutqvist et al., 2010). Results of this magnitude are sufficient for satellite monitoring. The site is also ideally suited for satellite monitoring because the land surface is hard and has little vegetation. Between 2004 and 2007, 17 passes were made to collect satellite data. Data collection is ongoing at a rate of one image with a pixel size of three square meters every 26 days (Mathieson et al., 2008). Tiltmeter and differential global positioning system data are also collected for calibration purposes.

Satellite images show an excellent correlation between areas of injection and uplift. Elevation increases of up to 30 mm were observed near the injectors, enough for successful imaging. There is also good correlation between areas of extraction and subsidence. The images indicate a northwest/southeast elongating plume, which suggests that carbon dioxide is traveling along a fracture network not previously expected to control carbon dioxide movement. Satellite imaging also alerted site operators to rapid migration of the carbon dioxide plume towards an abandoned well on the site. Later monitoring at the abandoned well revealed that carbon dioxide was reaching the surface and more detailed investigations led to the detection of a previously uncharacterized fracture near the well (Ringrose et al., 2009; Statoil, 2009). Tracers co-injected with carbon dioxide were used to verify that the leaking carbon dioxide at the abandoned well originated from a nearby injector (Ringrose et al., 2009). Subsequently, the leaking well was permanently sealed.

Three-dimensional seismic surveys are also considered a key technology in the In Salah monitoring plan and are used to help track the spread of the carbon dioxide plume (Wright, 2006). A baseline seismic survey was conducted in 2004, and a repeat survey was conducted in 2009 at the same location (BP, 2008). Data from the repeat survey were not yet available when this document was developed. To track the subsurface pressure, the eight active injection and production wells are continually monitored for pressure at the wellhead, and seven additional monitoring wells at the site are monitored every few weeks (ISG, 2009). Ground water is monitored by sampling wellhead fluids (BP, 2008).

Soil gas monitoring has also been conducted at In Salah. One test sampled six locations: three locations near injection wells, one location near a shut-in existing well, one location near the top of the anticline and one background area. All sites had methane values that were slightly higher than expected, but all sites also shared a similar range of concentrations for all detected gases. A larger baseline soil gas survey in 2000 and a repeat survey in 2004 monitored soil gas at 100 locations across the field using shallow (one meter) sampling methods. Results of the 2004 survey were comparable to those from the 2000 survey. The survey results also indicated that the dry, permeable, nearly sterile soil at the site allowed for quick downward migration of atmospheric gases and that deeper (five meter) sampling might improve results. Additionally, in 2009 laser equipment was deployed to monitor near-ground atmospheric gases. Tools to measure radon (a natural tracer gas) and activated charcoal sorbent samplers to test for a broader range of gases were also deployed. In addition, gas has been sampled from some wellheads. Results for these studies were not yet available at the time this document was developed, but it is expected that the dusty environment will complicate laser measurement. Finally, two shallow monitoring wells were drilled in 2009 to monitor the potable aquifer 950 m above the injection zone (Dodds, 2009). No results on the shallow aquifer wells were available at the time this document was developed.

7.3. Ketzin Project

The Ketzin Project, in the German state of Brandenburg, is a pilot scale project designed to store 0.06 Mt of carbon dioxide (MIT, 2010) in a 650 m deep, 80 m thick sandstone saline aquifer (Schilling et al., 2009; MIT 2010). A consortium of universities, research institutes and industry representatives oversees the project, which also receives support from the European Union. Injection at the project began in June 2008.

At Ketzin, researchers use both seismic and electrical methods to track the carbon dioxide plume. The monitoring focus area was defined as a one kilometer deep block covering a 14 km^2 area around the injection well (CO_2SINK, 2010). Several types of seismic imaging were tested at

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the site to determine the most appropriate method for longer-term monitoring. Baseline three-dimensional seismic, VSP and crosswell seismic surveys were taken prior to injection (Giese et al., 2009). In addition, existing two-dimensional seismic data were verified with repeat surveys (Schilling et al., 2009). Crosswell surveys made use of two new monitoring wells. Due to the formation conditions, carbon dioxide may be stored in a gaseous state and not a supercritical state at Ketzin, which makes seismic detection easier (Kazemeini, 2009). All of the preliminary seismic methods successfully imaged the target formation. Two subsequent crosswell surveys were able to image the injected carbon dioxide plume. Results from a follow-up three-dimensional seismic survey have yet to be released.

Researchers at Ketzin also used ERT to track the carbon dioxide plume. To minimize costs, increase repeatability and minimize disruption to injection activities, all three boreholes at the site were equipped with a permanent vertical electrical resistance array when they were cased. Each array has 15 electrodes spaced 10 m apart (CO_2SINK, 2010). As of 2009, one baseline survey and two follow-up surveys have been conducted. The follow-up surveys yielded good lateral and vertical definition of the plume in the regions near the borehole (CO_2SINK, 2010). One of the downhole arrays is also equipped with a permanent fiber-optic downhole sensor to provide continuous pressure measurements (Giese et al., 2009; CO_2SINK, 2010).

The Ketzin team has also taken several measures to monitor both deep and shallow ground water at the site. Existing studies provided background information on deep ground water properties (Forster et al., 2006). Baseline water samples were taken from the injection formation, and three shallow wells (35 to 55 m deep) were drilled to monitor the near-surface hydrology and to deploy electrochemical carbon dioxide detection methods. To monitor the fluids in the injection zone, permanent downhole gas membrane sensors have been deployed in two wells. These sensors use a gas-permeable silicone membrane to separate dissolved gases from formation fluids. A continuous loop of injected argon gas acts as a carrier to transport the separated gases to the surface where they are analyzed by a portable mass spectrometer or collected for further study (Giese et al., 2009). Researchers also monitor for changes in microbiology that may occur with changes in the pH of the formation fluids (Schilling et al., 2009).

7.4. Paradox/Aneth Project

Aneth Field is an active hydrocarbon production field in the Paradox Basin near Bluff, Utah. The Southwest Regional Partnership (SWP) operated the pilot-scale Paradox/Aneth EOR/GS project in conjunction with field operators. SWP injected a minimum of 0.14 Mt of carbon dioxide per year for two to three years (USDOE NETL, 2009; SWP, 2008). Carbon dioxide flooding for EOR has occurred in other parts of Aneth field since 1985. However, the fate of the injected carbon dioxide was poorly understood (Chidsey et al., nd).

Baseline studies were completed prior to the beginning of carbon dioxide flooding in 2007 (SWP, 2012). Although the flood will last for five to eight years to maximize potential oil recovery, monitoring by the SWP only lasted for the first two years of the commercial flood. Aneth Field is typical of many Western hydrocarbon fields; the site was picked to develop criteria that can be used to identify other storage sites in the western United States as well as to develop a risk assessment framework for such sites (SWP, 2012).

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The targets of the carbon dioxide flood were the Desert Creek and Ismay members of the hydrocarbon-bearing carbonate Paradox Formation. The injection zone is located at a depth of approximately 1,930 m (USDOE NETL, 2009) and has an average thickness of 17 m, although the thickness is highly variable. Shale, anhydrite and halite layers act as upper and lower confining zones, and unfractured mudstones and wackestones seal the injection zone laterally (Chidsey et al., nd).

Seismic methods were used to track the injected carbon dioxide plume. A permanent 60-level, 96-channel geophone array was installed in a monitoring well to allow for high quality, repeatable VSPs at low cost (Huang et al., 2008). One zero-offset and seven offset VSPs were completed prior to injection to provide baseline data. After 0.01 Mt of carbon dioxide was injected, researchers completed a follow-up VSP survey in July 2008. Results indicate that time-lapse VSPs coupled with high resolution migration and scattering analysis can provide reliable imaging of carbon dioxide migration within a target formation (Huang et al., 2008).

Microseismic monitoring was also used continuously since injection began in 2007 (Huang et al., 2008; SWP, 2012). The 60-level geophone string used in the VSP surveys was repurposed for microseismic monitoring. Following injection, the number of microseismic events increased. According to poroelastic stress models, the likely cause for the increase in seismicity is an increase in fluid pressure (Rutledge et al., 2008) within the target formation. In addition to the carbon dioxide plume, subsurface pressure was also tracked at the site (SWP, 2012).

To monitor ground water chemistry, researchers collected baseline measurements of injection zone fluids (USDOE NETL, 2009). Results from repeat measurements are not currently available. Surface air carbon dioxide flux monitoring was implemented to detect leaks reaching the surface (USDOE NETL, 2009). Baseline surface flux data were taken in 2006 prior to conversion to carbon dioxide flooding.

7.5. West Pearl Queen Project

The West Pearl Queen project is a completed pilot-scale project that injected 0.002 Mt of carbon dioxide into the West Pearl Queen oil field in Hobbs, New Mexico during 2002 and 2003 (Pawar et al., 2006). Carbon dioxide was injected via a single well into a 12 m thick depleted sandstone target formation. The unit, which is at a depth of 1,372 m, is overlain by dolomite and shale confining formations (Westrich et al., nd; Wells et al., 2007). Four existing wells were repurposed for the project, one for use as an injection well and three for monitoring. The injection well had been shut in since 1998, and the monitoring wells had previously been used as two produced water injection wells and one production well. The carbon dioxide was vented from the injection well six months after injection was completed. Monitoring studies were limited to a one square mile region surrounding the injection well. Laboratory and numerical modeling were also completed to support the field testing program.

At West Pearl Queen, researchers used seismic methods and tracer/atmospheric monitoring to track the carbon dioxide plume. A baseline three-dimensional seismic survey was followed with a repeat survey six months after injection (just prior to venting) to image the carbon dioxide plume (Pawar et al., 2006). P-waves imaged a feature that was interpreted, along with other data, to be the carbon dioxide plume. Analysis of the S-wave data may improve the

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resolution of the imaging and confirm the anomaly as the carbon dioxide plume. The seismic results also suggested that the majority of the carbon dioxide had not migrated out of the target formation. Microseismic monitoring was also deployed at the site. No significant microseismic events were detected.

Tracers were also used to track the carbon dioxide plume. Three unique perfluorocarbon tracers were co-injected sequentially with the carbon dioxide (Wilson et al., 2005). Following injection, 40 capillary adsorption tube samplers (CATS) were deployed in a radial pattern surrounding the injection well. The CATS were collected and redeployed several times. Within a few days of injection, tracers were detected at sampling locations 50 m away from the well, and they continued to be detected for several years after venting, indicating that injected carbon dioxide continuously escaped from the injection zone (Wilson et al., 2005; Wells et al., 2007). Although many leakage pathways are possible, investigation targeted leakage along the injection well casing as the most likely leakage path given the timing, size and distribution of the detected carbon dioxide (Wells et al., 2007). The volume of leakage was estimated to be 0.0085 percent of the total amount of carbon dioxide sequestered per year, an amount too small to be detected on a seismic survey.

Researchers also monitored injection zone pressure at the site. Following the injection phase, a downhole pressure sampler was deployed at the bottom of the injection well. Pressure measurements were taken intermittently over a 6 month period (Pawar et al., 2006). For the first month after shut-in, pressure readings decreased, suggesting that the formation was accommodating the injected carbon dioxide (Wells et al., 2007). After 30 days, equilibrium pressure was reached. The equilibrium pressure was much higher than modeled predictions (Pawar et al., 2006).

Ground water quality was also monitored at the site. Samples of formation brines were analyzed for cations, anions and pH prior to injection as part of a baseline study. Subsequent samples of injection zone fluids were taken six months post injection as well as during the carbon dioxide venting process. In addition to sample collection, the volume of produced fluid during venting was also recorded.

At West Pearl Queen, geochemical models did not match bench-scale experiments; in addition, the injection rate was much lower than predicted by models based on baseline and site characterization data (Pawar et al., 2006). Migration of injected fluids between wells through a heterogeneous injection zone was also incorrectly predicted, and injectate failed to appear at a monitoring well as predicted. These results indicate that more baseline data are likely needed from more diverse sources to correctly understand the response of a receiving formation to carbon dioxide injection and to plan monitoring strategies that correctly site and select the most effective, properly resolved monitoring technologies.

7.6. Weyburn Oil Field

The Weyburn project in Saskatchewan, Canada injects more than 1.8 Mt of carbon dioxide annually into the Weyburn oil field for EOR. The target layers are the 24 m thick, 1,400 m deep hydrocarbon-bearing carbonate beds of the Midale Formation, which are sealed by numerous thick shales (Wilson and Monea, 2004; Riding and Rochelle, 2005). Regional investigations were conducted over a 200 km by 200 km by four km deep block centered on Weyburn Field, while more detailed studies were focused on an area extending 10 km beyond the limits of the planned carbon dioxide flood. Baseline monitoring began in 2000 prior to injection. Over 30 Mt are predicted to be stored at the site (PTRC, 2007) over the next 25 years (Riding and Rochelle, 2005).

Researchers at Weyburn have successfully used time-lapse three-dimensional surface seismic profiling to image the injected carbon dioxide plume (Wilson and Monea, 2004) even though the thickness of the reservoir is at the limit for seismic resolution and the total injection volume was initially small (approximately 2,500 tonnes). Although plume extent could be accurately detected at relatively low saturations, results also suggested that quantitative estimation of plume volume will be considerably more difficult (IEA, 2006). The time-lapse seismic surveys using shear wave splitting showed the potential for imaging mineral dissolution and precipitation along fracture networks, which influenced carbon dioxide distribution within the reservoir (Wilson and Monea, 2004). Along with other monitoring efforts, seismic results indicated that the plume distribution was most strongly influenced by the geologic features (e.g., faults, fractures, porosity) of the reservoir (Wilson and Monea, 2004).

Monitoring at Weyburn also includes a passive microseismic monitoring array. Seismic events detected during the monitoring period ranged from -4 to -1 in magnitude (Wilson and Monea, 2004). Such events are similar to or smaller in magnitude than events detected during periods of pure water flooding. Monitoring also indicated that seismic events within the field area were more closely related to production activities than injection (Wilson and Monea, 2004). In addition to passive seismic monitoring, downhole pressure measurements collected regularly as part of production activities from a sparse subset of production wells were also used to track subsurface pressure. Data were plotted and contoured to create a map of the reservoir pressure field (Wilson and Monea, 2004).

The carbon dioxide plume was also tracked using isotopic and geochemical methods. Produced fluid with the greatest isotopic anomalies corresponded to regions with the highest injection volume (Wilson and Monea, 2004). A geochemical baseline survey was conducted in 2000, and sampling of reservoir fluid every four months from the same forty wells continued for the next four years. Fluids were analyzed for total alkalinity, pH, calcium, magnesium, resistivity, chlorine, sulfate, aluminum, barium, beryllium, chromium, iron, arsenic, copper, nickel and zinc (Wilson and Monea, 2004). Samples were also analyzed for the following dissolved gases: carbon monoxide, carbon dioxide, helium, hydrogen, hydrogen sulfide, methane, neon, nitrogen and oxygen. Results from the geochemical sampling program indicated dissolution trapping of the carbon dioxide within reservoir brines and the dissolution of reservoir carbonates. Due to the lengthy reaction time, geochemical sampling cannot confirm mineral trapping (Czernichowski-Lauriol, 2006). Metal concentrations were difficult to interpret. Concentrations of aluminum, barium, beryllium, chromium and iron increased over the sampling period, but arsenic, copper, nickel and zinc concentrations fell. These trends have not yet been explained. Good correlation was observed between seismic anomalies, geochemical changes and areas of the field undergoing the most intense injection (Wilson and Monea, 2004).

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