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January 12, 2026

Ms. Jessie Chmielowski
Commissioner
Alaska Oil and Gas Conservation Commission
333 West Seventh Avenue
Anchorage, AK 99501

Mr. Greg Wilson
Commissioner
Alaska Oil and Gas Conservation Commission
333 West Seventh Avenue
Anchorage, AK 99501

Dear Commissioners Chmielowski and Wilson

Subject: Alaska Oil and Gas Conservation Commission UIC Class VI Wells Proposed Regulation Changes

The Alaska Railbelt Carbon Capture and Storage (ARCCS) project is a study funded by the U.S. Department of Energy through its CarbonSAFE program and by the State of Alaska. The project evaluates the storage capacity and technical feasibility of permanently storing carbon dioxide (CO_2) deep underground in the northwestern Cook Inlet region. Specifically, ARCCS is screening deep geologic formations, including depleted natural gas reservoirs and adjacent deep saline aquifer formations near the Beluga River Field, for their potential as commercial-scale CO_2 storage sites. While the evaluated storage capacity is not currently dedicated to a specific project, ARCCS is also assessing potential CO_2 pipeline transportation routes from a proposed Terra Energy Center biomass–coal power plant in the West Susitna area and from two existing Chugach Electric Association natural gas–fired power plants in Anchorage.

The ARCCS project team is led by the University of Alaska Fairbanks Institute of Northern Engineering in partnership with the University of North Dakota's Energy and Environmental Research Center (EERC), Advanced Resources International (ARI), Belowich Coal Consulting, Explor Geoscience USA, Friends of West Susitna, Northern Land Use Research Alaska, the State of Alaska Division of Geological and Geophysical Services and Division of Oil and Gas, Terra Energy Center, as well as industry partners and state and local community organizations.

As part of the ARCCS project, the project team has reviewed the proposed regulatory changes to Title 20, Chapter 25 of the Alaska Administrative Code and believes the proposed rules meet or exceed the stringency of the federal Underground Injection Control (UIC) Class VI regulations. The project team also supports the flexibility incorporated into the proposed regulations, which appropriately mirror the federal regulatory framework with respect to Area of Review (AOR) delineation methodologies.

Furthermore, as allowed under both the proposed Alaska regulations and the corresponding federal UIC Class VI regulations, the project team recommends that the Alaska Oil and Gas Conservation Commission (AOGCC) accept AOR delineations developed using the methodologies outlined in the U.S.

Environmental Protection Agency's 2013 guidance document entitled Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. This includes, as explicitly stated in the guidance, the use of "more sophisticated methods than the analytical equations described" in cases involving over-pressured reservoirs.

One such example is the risk-based Area of Review methodology developed by the EERC through its Plains CO_2 Reduction (PCOR) Partnership. This methodology is described in Burton-Kelly et al. (2021) and has been successfully used to support the approval of nine UIC Class VI CO_2 storage projects to date. Both the 2013 EPA guidance document and Burton-Kelly et al. (2021) are included as attachments to this letter for reference. For reference, projects successfully employing the risk-based Area of Review methodology are shown in Table 1.

Applicant Name	Storage Facility (ND) / Project Name (WY)	Case No. (ND) / Permit No. (WY)
Blue Flint Sequester Co.	Blue Flint Underwood Broom Creek Storage Facility #1, ND	29888
Dakota Gasification Co.	DGC Beulah Broom Creek Storage Facility #1, ND	29450
DCC East	Minnkota Center MRYS Broom Creek Storage Facility #1, ND	29029
DCC West	DCC West Center Broom Creek Storage Facility #1, ND	30122
Summit Carbon Storage #1	TB Leingang Broom Creek Storage Facility #1, ND	30869
Summit Carbon Storage #2	BK Fischer Broom Creek Storage Facility #1, ND	30873
Summit Carbon Storage #3	KJ Hintz Broom Creek Storage Facility #1, ND	30877
Tallgrass	Eastern Wyoming Sequestration Hub (Juniper), WY	2024-0911
Tallgrass	Eastern Wyoming Sequestration Hub (Azalea, Barberry, Cypress, Old Barberry, Spirea), WY	2024-1030

Table 1: Approved UIC Class VI Projects That Have Used Risk-Based AOR Approach

Thank you for the opportunity to comment on the proposed UIC Class VI wells regulation changes for the State of Alaska. If you have any questions or need any additional information about these comments, please contact me by email at FPaskvan@alaska.edu.

Sincerely,

Frank Paskvan

Affiliate Professor
University of Alaska Fairbanks
College of Engineering and Mines
Institute of Northern Engineering

United States Environmental Protection Agency

Geologic Sequestration of Carbon Dioxide

Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance

Office of Water (4606M) EPA 816-R-13-005 May 2013

Disclaimer

The *Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (75 FR 77230, December 10, 2010), known as the Class VI Rule, establishes a new class of injection well (Class VI).

The Safe Drinking Water Act (SDWA) provisions and U.S. Environmental Protection Agency (EPA) regulations cited in this document contain legally-binding requirements. In several chapters this guidance document makes suggestions and offers alternatives that go beyond the minimum requirements indicated by the Class VI Rule. This is intended to provide information and suggestions that may be helpful for implementation efforts. Such suggestions are prefaced by "may" or "should" and are to be considered advisory. They are not required elements of the 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 a formal notice and comment period.

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 Clean Air Act (CAA) requirements to report carbon dioxide injection activities under the Greenhouse Gas Mandatory Reporting Rule (GHG MRR), are not within the scope of this document.

Executive Summary

EPA's *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells* has been codified in the U.S. Code of Federal Regulations (40 CFR 146.81 *et seq*.), and is referred to as the Class VI Rule. This rule establishes a new class of injection well (Class VI) and sets minimum federal technical criteria for Class VI injection wells for the purposes of protecting underground sources of drinking water (USDWs). This guidance is part of a series of technical guidance documents that EPA is developing to support owners or operators of Class VI wells and UIC Program permitting authorities in the implementation of the Class VI Rule. The Class VI Rule and related documents are available at http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.

The Class VI Rule requires owners or operators of Class VI injection wells to delineate the area of review (AoR) for the proposed Class VI well, which is the region surrounding the proposed well where USDWs may be endangered by the injection activity [40 CFR 146.84]. The Class VI Rule requires that the AoR be delineated using computational modeling and the AoR must be reevaluated periodically during the lifetime of the geologic sequestration (GS) project [40 CFR 146.84]. Within the AoR, the owners or operators must identify all potential conduits for fluid movement out of the injection zone, including both geologic features and artificial penetrations [40 CFR 146.84(c)(1)(iii)]. The owner or operator must then evaluate those artificial penetrations that may penetrate the confining layer(s) of the injection project for the quality of casing and cementing, and in the case of abandoned wells, for the quality of plugging and abandonment, and perform corrective action on any identified artificial penetrations that could serve as a conduit for fluid movement [40 CFR 146.84(c)(2), 146.84(c)(3), and 146.84(d)]. The Class VI Rule allows, at the discretion of the UIC Program Director, the use of "phased" corrective action, where certain regions of the AoR are addressed prior to injection and other regions of the AoR are addressed during the injection phase of the project [40 CFR 146.84(b)(2)(iv)].

This guidance provides information regarding modeling requirements and recommendations for delineating the AoR, describes the circumstances under which the AoR is to be reevaluated, and describes how to perform an AoR reevaluation. In addition, the guidance presents information on how to identify, evaluate, and perform corrective action on artificial penetrations located within the AoR.

The introductory section reviews the definition of the AoR and regulations pertaining to AoR and corrective action in the Class VI Rule. Following that section:

- Section 2 addresses computational modeling of GS;
- Section 3 addresses AoR delineation using computational models;
- Section 4 addresses identification, evaluation, and performing corrective action on artificial penetrations within the AoR; and
- Section 5 addresses AoR reevaluation.

For each section, the guidance:

- Explains how to perform activities necessary to comply with AoR and corrective action requirements (e.g., performing computational modeling). Illustrative examples are provided in several cases;
- Provides references to comprehensive reference documents and the scientific literature for additional information; and
- Explains how to report to the UIC Program Director the results of activities related to AoR and corrective action.

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Acronyms and Abbreviations

AoR	Area of review
API	American Petroleum Institute
CAA	Clean Air Act
CFR	Code of Federal Regulations
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
GHG MRR	Greenhouse Gas Mandatory Reporting Rule
GPR	Ground penetrating radar
GS	Geologic sequestration
LBNL	Lawrence Berkeley National Laboratory
MAE	Mean-absolute error
mD	Millidarcies
ME	Mean error
MIT	Mechanical integrity test
MPa	Megapascals
PISC	Post-injection site care
RCSP	Regional Carbon Sequestration Partnership
RMSE	Root-mean squared error
SDWA	Safe Drinking Water Act
UIC	Underground Injection Control
USDW	Underground source of drinking water
USGS	United States Department of the Interior, United States Geological Survey

Definitions

Key to definition sources:

1: 40 CFR 146.81(d).
2: Definition drafted for the purposes of this document.
3: Class VI Rule Preamble.
4: 40 CFR 144.3.

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.[1]

Boundary condition parameters refers to the parameters that describe fluid flow rates and/or pressures at the edges of the model domain and in the location of injection/extraction wells.[2]

Capillary Pressure refers to the difference of pressures between two phases existing in a system of interconnecting pores or capillaries. The difference in pressure is due to the combination of surface tension and curvature in the capillaries.[2]

Computational code refers to a series of interrelated mathematical equations solved by computer to represent the behavior of a complex system. For the purposes of GS, computational models represent, at a minimum, the flow and transport of multiple fluids and components in varying phases through porous media. Computational codes offer the ability to predict fluid flow in the subsurface using scientifically accepted mathematical approximations and theory. The use of computational codes is necessary because the mathematical formulations describing fluid flow are complicated and in many cases, non-linear. Several codes have been specifically developed or tailored for injection activities similar to GS, and can be used for this purpose.[2]

Computational model means a mathematical representation of the injection project and relevant features, including injection wells, site geology, and fluids present. For a GS project, site specific geologic information is used as input to a computational code, creating a computational model that provides predictions of subsurface conditions, fluid flow, and carbon dioxide plume and pressure front movement at that site. The computational model includes all model input and predictions (i.e., outputs).[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.[1]

Constitutive relationship typically means, empirically based approximations used to simplify the system and estimate unknowns in cases where the parameters of the governing equations are not readily available for use in the equation because necessary information is not typically measurable, and thus not directly input into the model. An example of a constitutive relationship is relative permeability-saturation functions. These functions estimate the relative permeability of a particular fluid in a porous media as a function of its saturation at a given location and time. This permeability is then used in the governing equation to predict flow.[2]

Equation of state refers to an equation that expresses the equilibrium phase relationship between pressure, volume and temperature for a particular chemical species.[2]

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.[1]

Geophysical surveys refers to the use of geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys or well logging methods such as gamma ray and spontaneous potential) to characterize subsurface rock formations.[3]

Governing equation refers to the mathematical formulae that form the basis of the computational code are termed governing equations. For GS modeling, they govern the predicted behavior of fluids in the subsurface provided by the code. Governing equations are mathematical approximations for describing flow and transport of fluids and their components in the environment.[2]

Ground Penetrating Radar (GPR) refers to a geophysical method that utilizes microwave technology in order to characterize features found in the subsurface.[2]

Heterogeneity refers to the spatial variability in the geologic structure and/or physical properties of the site.[2]

Hysteresis means the phenomenon where the response of a system depends not only on the present stimulus, but also on the previous history of the medium. For example, in a GS project, relative permeability, capillary pressure, and residual trapping will depend upon the saturation history of the formation.[2]

Immiscible refers to the property wherein two or more liquids or phases do not readily dissolve in one another.[2]

Initial conditions refers to parameter values at the start of the model simulation.[2]

Intrinsic permeability refers to a parameter that describes properties of the subsurface that impact the rate of fluid flow. Larger intrinsic permeability values correspond to greater fluid flow rates. Intrinsic permeability has units of area (distance squared).[2]

Model calibration means adjusting model parameters in order to minimize the difference between model predictions and monitoring data at the site.[2]

Multiphase flow refers to flow in which two or more distinct phases are present (e.g., liquid, gas, supercritical fluid).[2]

Numerical Artifacts refers to model results that are created erroneously based on computational limitations of the model, which may result from improper model development.[2]

Parameter means a mathematical variable used in governing equations, equations of state, and constitutive relationships. Parameters describe properties of the fluids present, porous media, and fluid sources and sinks (e.g., injection well). Examples of model parameters include intrinsic permeability, fluid viscosity, and fluid injection rate.[2]

Relative permeability refers to a factor, between 0 and 1, that is multiplied by the intrinsic permeability of a formation to compute the effective permeability for a fluid in a particular pore space. When immiscible fluids (e.g., carbon dioxide, water) are present within the pore space of a formation, the ability for flow of those fluids is reduced, due to the blocking effect of the presence of the other fluid. This reduction is represented by relative permeability.[2]

Sensitivity Analyses refers to the study of how the output of a model varies based in changes to an input variable or model parameter over a specified range of values. The results of a sensitivity analysis determine the which input variable and model parameter variability have the greatest effect on the model results.[2]

Stochastic Methods means the use of probability statistical methods in development of one or more possible realizations of the spatial patterns of the value(s) of a given set of model parameters.[2]

Underground Injection Control Program refers to the program EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act (SDWA) that is responsible for regulating the underground injection of fluids by wells injection. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.[2]

Underground Source of Drinking Water (USDW) means an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer.[4]

Unit Conversions

Imperial/Non-Metric Unit	Metric Unit
1 Foot	0.3048 Meters
1 Mile	1.609 Kilometers
1 Pound per Square Inch (psi)	0.006895 Megapascals (MPa)
Temperature in Degrees Fahrenheit (ºF)	Temperature in Degrees Celsius = (ºF – 32) x 0.56
1 Pound (lb)	0.4536 Kilograms
1 Megatonne (Mt)	1 x 10^6 Tonnes
1 Metric Ton (tonne; t)	1,000 kg
1 Cubic Foot	0.0283 Cubic Meters

1. Introduction

Area of review (AoR) evaluations and corrective action are long-standing permit requirements of the Underground Injection Control (UIC) Program of the U.S. Environmental Protection Agency (EPA). The AoR refers to the delineated region surrounding the injection well(s) wherein the potential exists for underground sources of drinking water (USDWs) to be endangered by the leakage of injectate and/or formation fluids. Typically, for injection well classes other than Class VI, the AoR is defined either as a fixed radius around the injection well or by a relatively simple radial calculation. Owners or operators of injection wells are required to identify any potential conduits for fluid movement, including artificial penetrations (e.g., abandoned well bores) within the AoR, assess the integrity of any artificial penetrations, and perform corrective action where necessary to prevent fluid movement into a USDW [40 CFR 144.55, 146.84(d)].

The Class VI Rule introduces enhanced AoR and corrective action requirements for Class VI injection wells that are tailored to the unique circumstances of geologic sequestration (GS) of carbon dioxide projects [40 CFR 146.84]. The purpose of this guidance is to identify appropriate methods for delineating the AoR and performing corrective action for Class VI injection wells. The intended primary audiences of this guidance document are Class VI injection well owners or operators and their representatives conducting AoR delineation modeling or performing artificial penetration identification, assessment, and corrective action activities. The UIC Program staff who are responsible for reviewing and approving Class VI injection well permit applications and related reports concerning AoR delineation and corrective action are another intended audience of this guidance document.

This document is one of a series of technical guidance documents intended to provide information and possible approaches for addressing various aspects of permitting and operating a Class VI injection well. Three of these companion guidance documents focus on site characterization, well construction, and testing and monitoring:

- The *UIC Program Class VI Well Site Characterization Guidance*;
- The *UIC Program Class VI Well Construction Guidance*; and
- The *UIC Program Class VI Well Testing and Monitoring Guidance.*

These guidance documents are intended to complement each other and to assist owners or operators in preparing permit applications that satisfy the requirements of the Class VI Rule. Class VI injection well regulations are tailored to the characteristics of individual sites. For example, the required site characterization data collected will inform the model development for AoR delineation, and AoR models will be reevaluated, and perhaps change, based on the results of site testing and monitoring data (Figure 1-1). Cross-linkages between guidance documents are noted in the text where appropriate. Additional guidance on developing, presenting, and using the required Class VI project plan information as part of a Class VI injection well permit application is provided in the *UIC Program Class VI Well Project Plan Development Guidance*.

1.1. Overview of the Class VI Rule AoR and Corrective Action Requirements

The Class VI Rule defines the AoR as the region surrounding the GS project where USDWs may be endangered by the injection activity [40 CFR 146.84(a)]. The purpose of the AoR and corrective action requirements of the Class VI Rule is to ensure that the areas potentially impacted by a proposed GS operation are delineated, all wells that need corrective action receive it, and that this process is updated throughout the injection project. While the details of all of the requirements are presented in later sections of this guidance, the basic requirements that owners or operators of GS projects must meet include:

- Prepare, maintain, and comply with an AoR and Corrective Action Plan that includes all of the required elements of the plan [40 CFR 146.84(b)];
- Delineate the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Perform all required corrective action on wells in the AoR [40 CFR 146.84(d)];
- Reevaluate the AoR throughout the life of the project [40 CFR 146.84(e)];
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)]; and
- Retain modeling inputs and data used to support AoR reevaluations for 10 years [40 CFR 146.84(g)].

If a vertical leakage pathway out of the injection zone is present, USDWs in the vicinity of a proposed Class VI injection well may be endangered by (1) movement of carbon dioxide into the USDW, impairing drinking water quality through changes in pH, contamination by trace impurities in the injectate (e.g., mercury, hydrogen sulfide), and leaching of metals and/or organics; and (2) movement of non-potable water (e.g., brine) out of the injection formation into a USDW as caused by elevated formation pressures induced by injection. Therefore, the AoR encompasses the region overlying the separate-phase (e.g., supercritical, liquid, or gaseous) carbon dioxide plume and the region overlying the pressure front where fluid pressures are sufficient to force fluids into a USDW. While it may often be the case that the AoR will encompass the boundary of the GS project, within which all project activities will occur, the Class VI Rule does not require that the AoR and overall project boundary be equivalent in all cases.

The Class VI Rule requires that "the AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data" [40 CFR 146.84(a)]. As discussed below, GS computational modeling for Class VI injection wells is complex and requires advanced methods. Additionally, the AoR must be reevaluated at a minimum fixed frequency not to exceed five years, or when monitoring and operational conditions warrant [40 CFR 146.84(e)]. The purpose of Class VI well AoR reevaluations is to ensure that site monitoring data are used to update modeling results, and that the AoR delineation reflects any changes in operational conditions. The general relationship between site characterization, modeling, and monitoring activities at a GS project is shown in Figure 1-1.

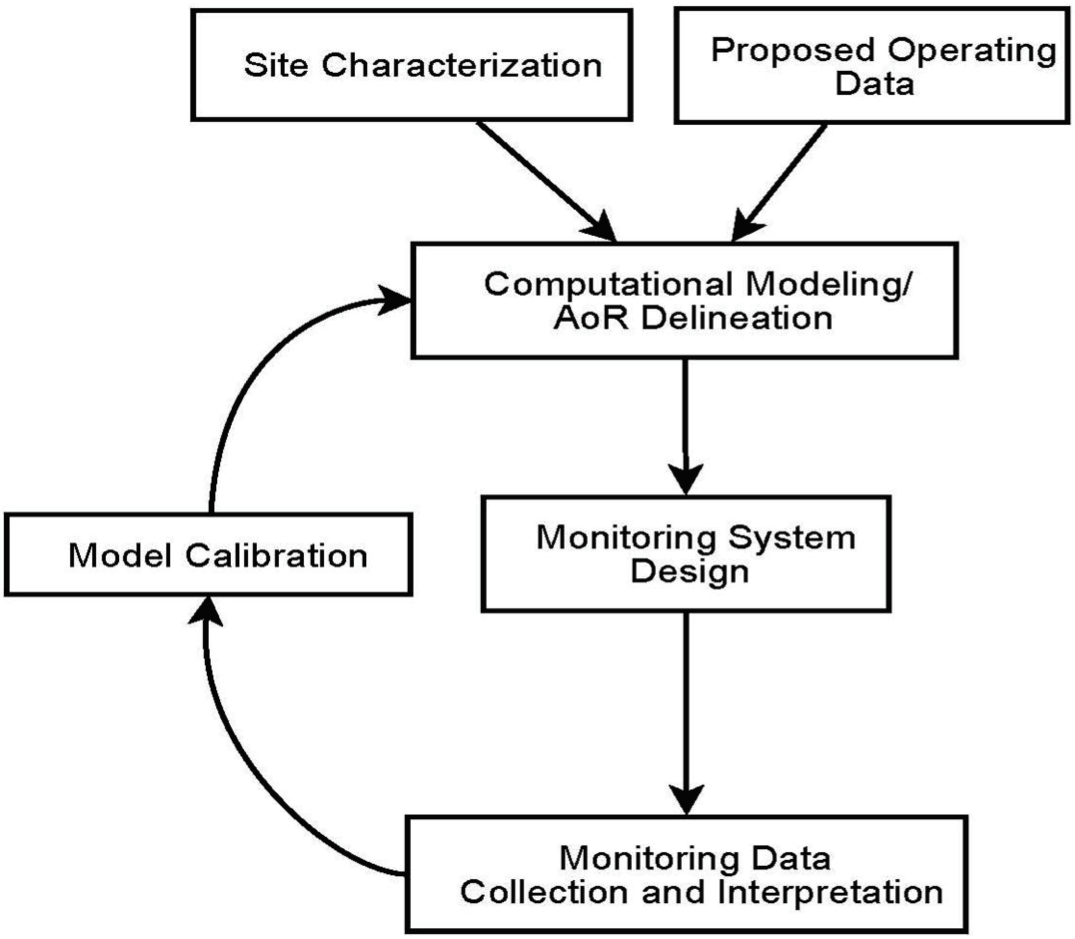

Figure 1-1: Flow Chart of Monitoring and Modeling at a GS Project.

An individual Class VI permit must be obtained separately for each injection well, as area permits are not allowed under the Class VI Rule [40 CFR 144.33]. However, EPA anticipates that, in many cases, multiple injection wells will be operated within a single GS project. If approved by the UIC Program Director, AoR delineation and corrective action activities may be performed collectively for all wells included within a single project. All required submittals (e.g., maps of the delineated the AoR and the AoR and Corrective Action Plan) must be submitted separately for each well, however, so that they may be incorporated into each well's Class VI permit. In all cases, EPA recommends that AoR delineation models account for all wells injecting into (including any injection wells associated with other UIC well classes or other Class VI operations) or pumping from the injection zone or any other zones that are hydraulically connected to the injection zone.

The corrective action requirements for Class VI wells are generally similar to those for other injection well classes. However, due to the potentially large AoR of GS projects, EPA has allowed the use of phased corrective action, if approved by the UIC Program Director [40 CFR 146.84(b)(2)(iv)]. If phased corrective action is approved by the UIC Program Director, owners or operators would be allowed to perform corrective action only on the subset of artificial penetrations located within the AoR prior to injection that are located in regions nearest the injection well(s). Corrective action would continue during injection in the remaining regions of the AoR prior to carbon dioxide migration or pressure elevation in that area. EPA encourages owners or operators to perform all necessary corrective action on deficient wells identified during the initial AoR delineation or AoR reevaluations before the end of the injection phase.

As a part of a Class VI permit application, the owner or operator must submit an AoR and Corrective Action Plan that describes the anticipated activities that will be performed to comply with these requirements [40 CFR 146.84(b)]. The AoR and Corrective Action Plan must be approved by the UIC Program Director prior to submittal of the initial AoR delineation and issuance of a permit [40 CFR 146.84(b)]. This plan will facilitate dialogue between the owners or operators and the UIC Program Director to ensure that the UIC Program Director understands and agrees early in the project lifetime with the methods necessary to delineate the AoR and complete all required corrective action. A Class VI AoR and Corrective Action Plan must include the following information [40 CFR 146.84(b)]:

1. The method for delineating the AoR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;
2. The minimum fixed frequency, at least once every five (5) years, that the owner or operator proposes to reevaluate the AoR;
3. The site- and project-specific monitoring and operational conditions that would warrant a reevaluation of the AoR prior to the next routinely scheduled reevaluation;
4. How specific monitoring and operational data (e.g., injection rate and pressure) will be used to inform an AoR reevaluation;

5. How corrective action will be conducted, including what corrective action will be performed prior to injection and what, if any, portions of the AoR will have corrective action addressed on a phased basis and how the phasing will be determined;
6. How corrective action will be adjusted if there are changes in the AoR; and
7. How site access will be guaranteed for future corrective action.

The requirements related to the AoR and Corrective Action Plan are discussed in depth in the *UIC Program Class VI Well Project Plan Development Guidance*.

1.2. Organization of this Guidance

This guidance document is organized to generally follow the sequence of AoR delineation and corrective action activities that an owner or operator will perform over the life of a proposed and later permitted Class VI injection project. These activities will generally proceed as described below.

Prior to the issuance of a permit for the construction of a new Class VI well (or the conversion of an existing well):

1. Collection of relevant site characterization and operational data [40 CFR 146.82(a)(3), 146.82(a)(5), 146.82(a)(6), and 146.83];

2. Determination of relevant operational data that will inform the AoR modeling [40 CFR 146.82(a)(7), and 146.82(a)(10)-(11)];

3. Development of an AoR and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b)];

4. Performing AoR modeling and delineation [40 CFR 146.82(a)(2)]; and

5. Identification and assessment of artificial penetrations within the AoR [40 CFR 146.82(a)(4)].

Prior to granting approval for injection:

6. Collection and/or updating of relevant site characterization and operational data that will inform AoR modeling [40 CFR 146.82(c)(2)-(5), 146.82(c)(7), and 146.83];

7. Identification of any needed updates to the AoR and Corrective Action Plan [40 CFR 146.82(c)(9)];

8. Finalizing AoR modeling and delineation [40 CFR 146.82(c)(1)]; and

9. Performing corrective action on those penetrations that may serve as a conduit for fluid movement [40 CFR 146.82(c)(6) and 146.84(d)].

During injection and post-injection site care (PISC):

10. Reevaluation of the AoR periodically, at least once every five (5) years [40 CFR 146.82(c)(9) and 146.84(e)], and updating the AoR and Corrective Action Plan; and

11. If phased corrective action is approved or when additional corrective action is warranted based on AoR reevaluations, performing corrective action [40 CFR 146.82(c)(6) and 146.84(d)].

Activities (1) through (5) must be performed prior to receiving approval to construct a Class VI injection well and activities (6) through (9) must be performed prior to receiving approval to inject carbon dioxide, and their results must be submitted to the UIC Program Director as part of the Class VI injection well permit application [40 CFR 146.82(a)]. The remaining activities will be performed after a permit application has been approved by the UIC Program Director and the Class VI injection well is actively operating.

This guidance document generally focuses on activities (4), (5), (8), (9), (10), and (11), as follows:

- Section 2 provides background on computational modeling of GS activities;
- Section 3 discusses performing computational modeling to delineate the AoR and comply with permit requirements (activities 4 and 8);
- Section 4 focuses on abandoned well identification, assessment, and corrective action on all artificial penetrations within the AoR (activities 5, 9, and 11); and
- Section 5 focuses on reevaluation of the AoR (activity 10).

Site characterization activities (activities 1 and 6) are discussed briefly in this guidance (Section 3.2), and are covered in more detail in the *UIC Program Class VI Well Site Characterization Guidance*. Preparation of the AoR and Corrective Action Plan (activity 3) and identification of any updates (activity 7) are also discussed briefly herein, and in more detail in the *UIC Program Class VI Well Project Plan Development Guidance*.

2. Computational Modeling for Geologic Sequestration

This section discusses the fundamentals of computational modeling for GS to provide the necessary background for owners or operators, and to assist in understanding and complying with the Class VI Rule. While computational modeling for GS may entail a vast amount of complex information, the purpose of this section is to provide a brief introduction to the modeling techniques and fundamentals that may be necessary or significant for satisfying the specific rule requirements. Following an introduction that explains the use of modeling in the context of meeting the requirements of the Class VI Rule:

- Section 2.1 discusses the processes that can be modeled;
- Section 2.2 presents a discussion of the parameters that are included in AoR models;
- Section 2.3 presents available computational approaches, including numerical, analytical, semi-analytical, and hybrid approaches;
- Section 2.4 discusses model uncertainty and sensitivity analyses;
- Section 2.5 discusses model calibration; and
- Section 2.6 provides an overview of existing codes used for development of GS models.

The AoR for a Class VI injection project must be delineated using a computational model that accounts for the physical and chemical properties of all phases of the injected carbon dioxide [40 CFR 146.84(a)]. A computational model is based on available data, and it is a mathematical representation of the GS project and relevant features, including injection wells, site geology, and fluids present. As described below, a site-specific computational *model* is designed by incorporating the GS site and operational characteristics into a computational *code*, which is a computer program that has been designed to simulate multiphase flow and other pertinent processes in geologic media based on scientific principles and accepted mathematical (i.e., governing) equations.

Computational codes that may be used for modeling of GS are necessarily more technically complex than commonly used ground water flow codes because GS modeling considers multiphase (e.g., gas, liquid, supercritical fluid) flow of several fluids (i.e., ground water, carbon dioxide, hydrocarbons), phase changes of carbon dioxide, heat flow, and significant pressure changes. Furthermore, in some cases models consider reactive transport (e.g., chemical reactions between constituents) and geomechanical processes (e.g., induced fault activation). As discussed below, the Class VI Rule requires that the AoR be delineated using models that include multiphase flow [40 CFR 146.84(a)], but not necessarily reactive transport or geomechanical processes. However, inclusion of these processes in the AoR delineation model may be important in some cases and may be required by the UIC Program Director.

Several codes are available that are capable for use in development of adequate models for delineation of the AoR at a GS site and for complying with Class VI injection well permit requirements (Section 2.6). Although available codes are sophisticated and based on the best-available scientific understanding, computational models are approximations and are never perfect representations of reality, and they cannot provide a completely accurate prediction of fluid movement at a GS site. Therefore, the characterization of model uncertainty, using sensitivity analyses, and conducting model calibrations are very important parts of many computational approaches.

Research studies have provided valuable information on the capabilities of available models, what information may be collected in order to properly inform model development, and how the model results may be presented. Importantly, the information and guidance provided here is based on currently available data, scientific research, and project experience. EPA recognizes that data collected from future GS projects may advance GS computational modeling and AoR delineation. EPA is committed to an adaptive approach for regulation of GS projects and may revisit aspects of Class VI federal regulations, and guidance, as new data becomes available.

There is a long history of simulating multiphase flow and transport in porous media using computational models. Comprehensive reviews of multiphase flow in porous media and modeling are provided elsewhere (e.g., Pinder and Gray, 2008; Miller et al., 1998; Gerritsen and Durlofsky, 2005; Finsterle, 2004). These models solve a series of governing equations to predict the composition and volumetric fraction of each phase state (e.g., liquid, gas, supercritical fluid) as a function of space and time for a particular set of circumstances. Governing equations are formulated to describe the flow and transport of several chemical species in several phases, in which interphase mass transfer may be important. Typically, flow equations are derived by substituting a multiphase form of Darcy's Law into continuum balance expressions.

The solution of the continuum balance equations requires that they be supplemented with closure relations that express unknowns in terms of accessible parameters. These include equations of state and constitutive relationships. Equations of state express the equilibrium phase relationship between pressure, volume, and temperature for a particular chemical. Accepted equations of state for carbon dioxide are presented in Figure 2-1, and are discussed in Section 2.2.4. Constitutive relationships are typically empirically based approximations used to simplify the system and estimate unknowns. Examples of constitutive relationships are saturation-relative permeability relationships, interphase mass transfer relations, and solution reaction relations.

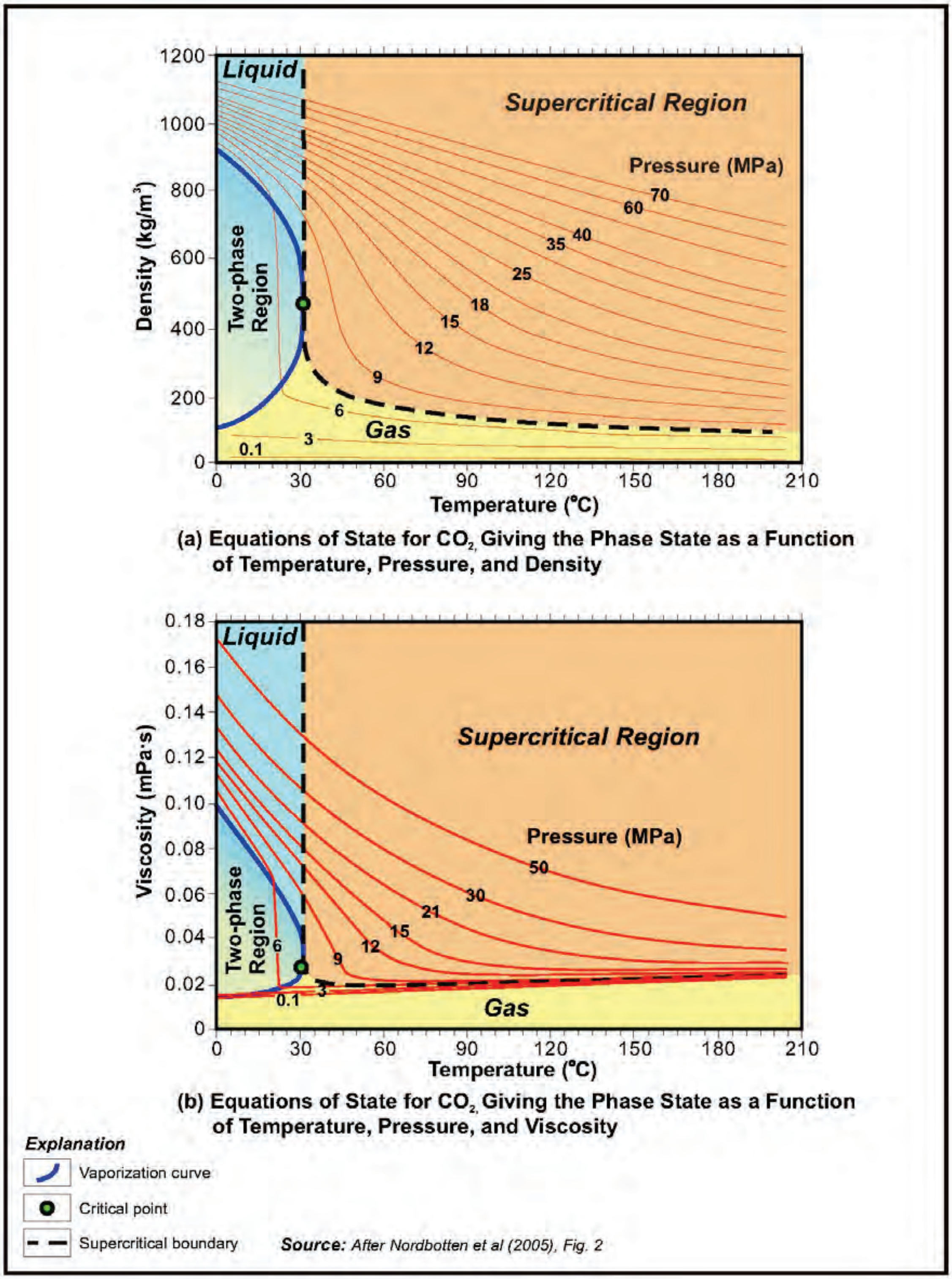

Figure 2-1: Equations of State for Carbon Dioxide.

2.1. Modeled Processes

Computational codes used for GS vary in complexity and may include routines for multiphase flow, reactive transport, and geomechanical processes. Traditionally, codes have been developed as separate entities to simulate these processes. Present-day simulators typically address and couple multiphase flow with geomechanical processes or geochemical processes. However, depending on site-specific characteristics, where the geochemical and geomechanical processes are significant, robust simulation of GS may require interactive coupling of all three processes. The Class VI Rule only requires that multiphase flow be included in computational modeling. However, the owner or operator, or the UIC Program Director, may determine that reactive transport and/or geomechanical modeling should also be included for a particular proposed project. For example, reactive transport could be relevant if permeability and/or porosity are predicted, based on previous testing, to change as a result of precipitation/dissolution reactions. Geomechanical processes could be relevant if previous testing has indicated that pressure and stress changes hydrogeologic properties and/or affects confining unit integrity.

Codes used to simulate multiphase flow generally incorporate some or all of the following processes: phase transition behavior of carbon dioxide (gas, liquid, supercritical fluid) and associated buoyancy; dissolution of carbon dioxide in brine and oil and associated increased density; dissolution of water in carbon dioxide; variable viscosity and density of brine and carbon dioxide phases; thermal effects such as cooling or freezing due to carbon dioxide expansion from supercritical and liquid phases; and reduced fluid permeability due to the presence of several immiscible fluids within a pore space.

Codes used to simulate reactive transport generally incorporate rate-limited intra-aqueous reactions, mineral dissolution and precipitation, changes in porosity and permeability due to these reactions, and multi-component gas mixtures. Reactive transport models can be used to determine the impact of carbon dioxide and its co-injectates (e.g., hydrogen sulfide, sulfur dioxide) on aquifer acidification, the concomitant mobilization of metals, and any mineral trapping of carbon dioxide (e.g., precipitation of carbonate minerals). Reactive transport models can also be used to assess corrosion of well construction materials as influenced by carbon dioxide.

The length scales associated with interfacial geochemistry are very small (e.g., micrometers to millimeters) compared to multiphase flow simulation (meters to kilometers). Small grid spacing around these regions may imply associated small time steps, so that the overall problem becomes computationally demanding when trying to couple these reactions to multiphase flow. Data related to geochemical rate parameters are generally lacking (e.g., Knauss et al., 2005; Xu et al., 2006), and have to be estimated for a wide range of possible environmental conditions and mineralogical interfaces. Several common codes that may be used for AoR delineation, such as ECLIPSE, normally do not include routines for reactive transport.

Geomechanical codes can be used to evaluate the effect of reservoir pressurization and buoyancy on the integrity of geologic confining units, reactivation of existing fractures and faults, and rock properties such as porosity and permeability. The amount and spatial distribution of pressure buildup in a geologic formation will depend on the rate of injection, the permeability and thickness of the injection formation, the mechanistic properties of the rock matrix, the permeability of the confining units, and the presence or absence of permeability barriers, and boundary conditions of the system. Models used to simulate geomechanical processes generally incorporate effective stress/strain relationships, aperture stiffness and associated closing and widening, and variation in porosity and permeability. Geomechanical modeling may require simulation on both a large and small scale (individual fractures), which can be computationally challenging (i.e., require long model processing times on the order of days). When individual fractures are considered, the spatial grid resolution may need to be on the order of meters or less. Therefore, smaller-domain models may be necessary to investigate migration through individual fractures. Generally, simulation of flow through a fractured reservoir requires codes that have been designed for this purpose.

2.2. Model Parameters

A parameter is a variable in the governing equations of the model that may be of uniform value throughout the domain, or may vary in space and time. While maintaining salient features of the hydrogeologic system, some system aspects are often lumped together in simulation models and described by effective parameters that are estimated or averaged from several data sources. Relevant parameters for multiphase flow modeling of GS are summarized in Table 2-1, and include hydrogeologic characteristics, fluid properties, chemical properties, fluid injection and withdrawal rates, initial and boundary conditions, system orientation (e.g., model domain, grid cell size), and simulation control parameters. Initial conditions describe parameter values at the start of the model run. Boundary condition parameters describe conditions of the system (e.g., fluid flow rates and/or pressures) at the edges of the model domain and at the location of injection and/or extraction wells. While fluid injection and/or withdrawal rates and simulation control parameters are project specific, other particularly important site- and project-specific parameters for GS include formation intrinsic permeability, porosity, relative permeability, compressibility, fluid viscosity, and fluid density. These parameters are discussed in the following subsections.

Parameter values are to be based on site data to the extent possible. However, as discussed below, in cases where detailed site geologic characterization data are unavailable (i.e., if formation testing is not complete or core samples are not available), parameter values may be estimated from standard values or relationships in the scientific literature. Model calibration, which may occur during AoR reevaluation, consists of adjusting a subset of the estimated parameter values to minimize the difference between model simulations and observed monitoring data. Model parameters may also be adjusted based on newly acquired site characterization data. For example, data gathered during well logging may inform updates to parameter values. See the *UIC Program Class VI Well Site Characterization Guidance* for more information.

Table 2-1: Model Parameters for Multiphase Fluid Modeling of Geologic Sequestration.

Parameter	Description	Estimation Methods	Dimensions
Hydrogeologic Properties			
Intrinsic Permeability	Represents properties of the subsurface that impact the rate of fluid flow.	See the *UIC Program Class VI Well Site Characterization Guidance*, and Section 2.2.1 of this guidance	L^2
Porosity	The relative volume of void space within a formation. Controls the volume of carbon dioxide that may be stored.	See the *UIC Program Class VI Well Site Characterization Guidance*	Dimensionless
Capillary Pressure	The pressure difference across the interface of two immiscible fluids (e.g., carbon dioxide and water)	Calculated based on fluid saturations (see Section 2.2.2 of this guidance)	M/LT^2
Relative Permeability	Factor that determines the decrease in permeability for a fluid due to the presence of other immiscible fluids	Calculated based on fluid saturations (see Section 2.2.2 of this guidance)	Dimensionless
Fluid Pressure	Force acting on a unit area, measure of the potential energy per volume of fluid	See the *UIC Program Class VI Well Site Characterization Guidance*	M/LT^2
Temperature	Measure of the internal energy of a fluid	See the *UIC Program Class VI Well Site Characterization Guidance*	Temperature
Formation Compressibility	Measure of change in aquifer volume with a change in fluid pressure	See the *UIC Program Class VI Well Site Characterization Guidance*	LT^2/M
Water Saturation	The percent of system void space occupied by aqueous fluids	See the *UIC Program Class VI Well Site Characterization Guidance*	Dimensionless
Carbon Dioxide Saturation	The percent of system void space occupied by carbon dioxide	Calculated by the computational model	Dimensionless
Storativity	The volume of fluid released from storage per unit decline in head per unit area of the formation	See Standard References, e.g., Fetter, 2001	Dimensionless
Fluid Properties			
Viscosity	Measure of the internal resistance to flow	Calculated based on equations of state, also influenced by fluid composition (see Section 2.2.4 of this guidance)	M/LT

Parameter	Description	Estimation Methods	Dimensions
Density	The mass of a fluid per unit volume	Calculated based on equations of state, also influenced by fluid composition (see Section 2.2.4 of this guidance)	M/L^3
Composition	Molecular makeup, by volume or mass, of a fluid. Measurement of salinity, concentration of trace compounds	See the *UIC Program Class VI Well Site Characterization Guidance*	M/L^3
Fluid Compressibility	The change in volume of a fluid from a unit change in pressure	See Standard References, e.g., Perry and Green, 1984	LT^2/M
Chemical Properties			
Aqueous Diffusion Coefficient	The rate of chemical transport due to a concentration gradient	See Standard References, e.g., Tamimi et al., 1994	L^2/T
Aqueous Solubility	The maximum concentration of a chemical (e.g., carbon dioxide) dissolved in the aqueous phase	Salinity, temperature and pressure dependent (see Spycher et al., 2003; Spycher and Pruess, 2005)	M/L^3
Solubility in Carbon Dioxide	The maximum concentration of a chemical (e.g., water) dissolved in separate-phase carbon dioxide.	Temperature and pressure dependent (see Spycher et al., 2003; Spycher and Pruess, 2005)	M/L^3
Fluid injection and withdrawal rates			
Injection Rates	Injection rates at each well	Planned site operational data	L^3/T
Withdrawal Rates	Any fluid withdrawal rates within model domain	Measure rates for wells conducting pumping within the AoR	L^3/T
Boundary Conditions	Fluid pressures and/or flow rates at the edges of the model domain	Tested in conjunction with model extent, to ensure no artificial influence on model results	Varies
Fluid injection and withdrawal rates (Continued)			
Initial Conditions	Fluid pressures and/or flow rates within the domain at the beginning of the model run	Based on pre-injection site characterization data, see the *UIC Program Class VI Well Site Characterization Guidance*	Varies

Parameter	Description	Estimation Methods	Dimensions
System Orientation and Simulation Controls			
Model Extent (domain)	The lateral extent of the model in all directions	Tested in conjunction with boundary conditions, to ensure no artificial influence on model results	L
Number of Model Layers	Model vertical discretization	Based on conceptual site model of site stratigraphy, see the *UIC Program Class VI Well Site Characterization Guidance*	Dimensionless
Layer Thickness	Vertical extent of each model layer	See the *UIC Program Class VI Well Site Characterization Guidance*	L
Grid Cell Size	Lateral size of each model cell	May vary throughout domain, as dictated by conceptual model and computational necessities	L^2
Model Timeframe	The complete duration of the model run	Tested to ensure long enough to allow for pressure decline to pre-injection conditions	T
Time Step Size	The duration of each temporal interval during the model timeframe	Often controlled by code, tested to ensure small enough to not artificially influence results	T

L = Length; M = Mass; T = Time

2.2.1. Intrinsic Permeability

Intrinsic permeability is a property of the solid phase (i.e., porous medium) in the subsurface that impacts the rate of fluid flow. Larger intrinsic permeability values correspond to greater fluid flow rates. Intrinsic permeability has units of length squared and is often reported in the units of millidarcies (mD); one mD is equal to $9.9 \cdot 10^{-16}$ square meters (m^2). Typical permeability values for an injection zone at a GS project range from 1 to 10^2 mD (e.g., Sorensen et al., 2005; Fischer et al., 2005; MGSC, undated; ISGS, 2009). Typical permeability values for a confining unit (e.g., shale) range from 10^{-7} to 10^{-4} mD (e.g., Soeder, 1988).

Intrinsic permeability incorporates the effects of formation porosity, pore structure, such as pore-size distribution and connectivity, and the presence of fractures or faults. The spatially heterogeneous nature of subsurface materials results in a heterogeneous intrinsic permeability distribution in most formations. Additionally, intrinsic permeability is an anisotropic parameter, in that lateral intrinsic permeability is often significantly larger than vertical intrinsic permeability due to depositional layering. Anisotropy in intrinsic permeability, both vertical and horizontal, may also be an effective property of fractured rock media. Intrinsic permeability is typically estimated from a combination of hydrogeologic field tests (e.g., aquifer tests, pressure fall-off tests), laboratory core analysis, and geophysical well logging. The *UIC Program Class VI Well Site Characterization Guidance* provides details regarding estimation of formation intrinsic permeability. Intrinsic permeability values are often adjusted during model calibration. See Box 2-1 for more information.

During the development of the computational model, the model developer determines how to estimate values of intrinsic permeability within the entire model domain based on results of site characterization activities at discrete locations. For modeling purposes, the simplest description of intrinsic permeability is a homogenous distribution, which incorporates a single value for the entire subsurface domain based on an average of available data. A model that assumes a homogeneous permeability distribution, however, will not account for heterogeneity (if it exists) that causes preferential flow paths or confining strata, or for the depth dependence of permeability in an updipping formation. Another option is to incorporate a layered distribution, which incorporates a single permeability value for each geologic stratum in the domain, and can be constructed by using geologic maps and cross-sections of the proposed project site.

Alternatively, geostatistical and stochastic methods are available to create a statistical ensemble of possible permeability distributions that incorporate both lateral and vertical heterogeneity based on available site characterization data. Spatial variability of permeability is thus described by a relatively small number of geostatistical parameters. Considering the large areas that are anticipated to be modeled for AoR delineations of proposed Class VI injection well project sites, techniques are among the best methods for incorporating realistic heterogeneity distributions into the computational model with limited data (see inset, Box 3-1).

Compared to homogeneous or layered permeability distributions, depending on the available data, intrinsic permeability fields developed with geostatistical techniques may provide a more realistic representation of conditions within the formation, and resulting models may better represent carbon dioxide migration through high-permeability channels. Commercial software packages are available for use in the development of heterogeneous intrinsic permeability distributions based on available site data (e.g., T-PROGS; Carle, 1999). See Doughty and Pruess (2004), Juanes et al. (2006), Obi and Blunt (2006), and Flett et al. (2007) for examples of the development of heterogeneous profiles based on geostatistical techniques. For more information regarding the use of geostatistical methods, see the *UIC Program Class VI Site Characterization Guidance*.

Several previous studies have evaluated the impact of permeability values on computational modeling results, through the use of parameter sensitivity analyses. Law and Bachu (1996) and Lindeburg (1997) demonstrated that for a homogeneous system, carbon dioxide mobility increases with increased formation permeability. Comparing homogeneous formations and those with layered heterogeneities, Lindeberg (1997) showed that the presence of thin shale layers increases sweep and thus carbon dioxide dissolution. For systems that are heterogeneous in three dimensions, Flett et al. (2007) illustrated that increased heterogeneity resulted in increased lateral migration and therefore dissolution. However, increasing heterogeneity also decreased the rate of residual phase trapping by delaying water imbibition into previously carbon dioxide-filled pore space. Overall, increased heterogeneity resulted in slower carbon dioxide migration and decreased accumulation at the confining layer compared to a homogeneous case. Pruess (2008) showed that for discharge through a fault, decreased fault permeability resulted in delayed leakage to the surface and an increased maximum leakage rate.

Simulations by Zhou et al. (2008) indicate that patterns of formation pressure increase induced by carbon dioxide injection are sensitive to permeability. Larger formation permeability values resulted in less localized pressure increase surrounding the injection well. In addition, larger confining layer permeability resulted in less pressure buildup throughout the formation due to pressure dissipation and associated brine leakage.

2.2.2. Relative Permeability and Capillary Pressure

When immiscible fluids (e.g., carbon dioxide, water) are present within the pore spaces of a geologic formation, the ability for flow of one of those fluids is reduced, due to the blocking effect of the presence of the other fluid. Note that under any reservoir conditions, ground water and carbon dioxide will be immiscible, and ground water and hydrocarbons will be immiscible. Carbon dioxide and hydrocarbons, however, may be miscible or immiscible based on reservoir conditions. The relative permeability is a scaling factor that represents the reduction in the capacity for fluid flow due to the presence of other phases in porous media, with a value between 0 and 1. This value is multiplied by the intrinsic permeability of a geologic formation in order to compute the effective permeability for a fluid in a particular pore space. The relative permeability of a fluid is based on the properties and amounts of all fluids present within the system. The greater the amount of pore space occupied by a particular fluid or phase (measured as fluid saturation), the greater the relative permeability will be for that fluid. Because fluid saturations change over time and location, relative permeability values typically vary during model simulations.

The relative permeability for each fluid is typically calculated as a function of fluid saturations at each location and time within a model. This is achieved via a relative permeability-saturation function. The relative permeability-saturation function shape is based on properties of the porous media and fluids present at a particular site. Residual fluid saturation also impacts the shape of the relative permeability function, and describes the minimum fluid saturation within the porous medium following immiscible fluid displacement. An example relative permeability-saturation function is given in Figure 2-2. Note that this example function has been developed for a specific site (Doughty, 2007) and may not be applicable to other GS sites. Capillary pressure-saturation relationships (also known as characteristic curves) are also of importance because capillary pressure gradients provide a driving force for fluid movement under unsaturated conditions.

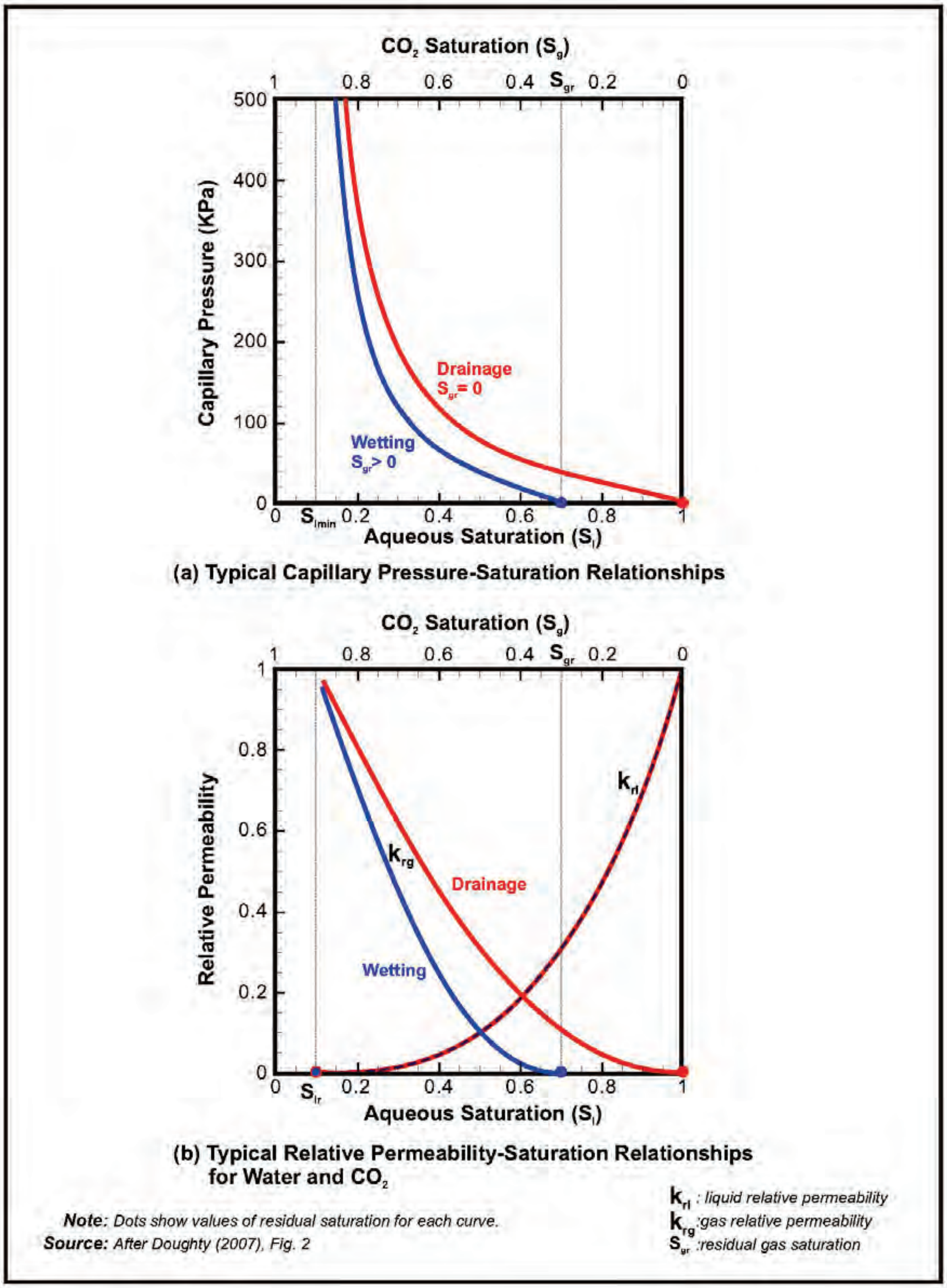

Figure 2-2: Example Relative Permeability-Saturation and Capillary Pressure-Saturation Relationships for Water and Carbon Dioxide.
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Previous research has shown that model predictions are very sensitive to the shape of the relative permeability-saturation functions used. The *UIC Program Class VI Well Site Characterization Guidance* provides details regarding measurement of relative permeability. Ideally, laboratory core-analysis techniques will be used for experimental measurement of the relative permeability-saturation and capillary pressure-saturation functions for a particular site at reservoir conditions, with carbon dioxide and representative native fluids (e.g., Perrin et al., 2008; Bachu and Bennion, 2008; Plug and Bruining, 2007). If this is not feasible, relative permeability-saturation relationships may be estimated from core analysis using other immiscible fluids (e.g., Doughty et al., 2007). Alternatively, previously reported functions may be used, such as those presented in Figure 2-2, if the experimental system was very similar to the site conditions for which the model will be applied. Relative permeability-saturation relationships are also commonly adjusted during model calibration.

Doughty and Pruess (2004) compared site-specific characteristic curves to "generic" curves at the Frio, TX GS pilot project site and found that the choice of characteristic curves had a significant impact on plume size, shape, and mobility. The authors point out that the differences in plume behavior for different sets of characteristic curves had important implications for operation and monitoring of the pilot test. Similarly, Doughty et al. (2007) found that model results were very sensitive to characteristic curve parameters. The authors constrained the value of characteristic curve parameters by calibration to monitoring data.

Pruess (2008) compared the effect of using three-phase characteristic curves developed for organic liquid-water-air systems (Stone, 1970) and simple linear characteristic curves. The choice of characteristic curves was found to have a significant impact on the observed leakage rate of carbon dioxide through a fault system. The linear characteristic curves resulted in simulated earlier leakage of carbon dioxide to the surface and lower leakage rates. Use of three-phase relationships resulted in small fluid permeability at intermediate saturations due to phase-interference effects.

The impact of using hysteretic versus non-hysteretic characteristic curves has also been compared. Hysteresis refers to the dependence of the shape of the characteristic curve on the history of fluid flow within the formation. For example, characteristic curves are often observed to have a different shape when non-wetting fluids (e.g., supercritical carbon dioxide) are displacing wetting fluids (e.g., formation water), than when wetting fluids are displacing non-wetting fluids. Juanes et al. (2006) showed that consideration of hysteresis and capillary trapping resulted in the carbon dioxide being spatially distributed over a larger area with less accumulation at the confining layer. Doughty (2007) found that results from simulations with non-hysteretic curves did a poor job of matching simulations with hysteretic curves in homogeneous and heterogeneous media. Relative to non-hysteretic cases, simulations including hysteresis exhibited a more mobile plume leading edge (where there is no water imbibition) and a slower trailing edge with a significant amount of residual trapping (due to water imbibition).

2.2.3. Injection Rate

The carbon dioxide injection rate at proposed Class VI injection wells is incorporated into the model by assigning the injection rate parameter at a constant or variable-rate boundary condition, or by defining various source terms for specific nodes that correspond to injection location. However, it is important to note that calculated pressure values where injection rates are applied may need to be monitored to identify flow-controlled or pressure-limited cases. Several researchers have reported that increasing the carbon dioxide injection rate results in increased migration rates (e.g., Law and Bachu, 1996; Saripalli and McGrail, 2002; Juanes et al., 2006). Juanes et al. (2006) considered capillary trapping in highly heterogeneous media, and found that increased injection rate resulted in more simulated residual trapping due to invasion of carbon dioxide into a wider range of pore sizes. Therefore, in the long term, increased injection rates actually decreased the final simulated extent of carbon dioxide migration, as more mass was immobilized through capillary forces. Pruess (2008) modeled leakage to the ground surface through a fault system, and simulations indicated that larger injection rates resulted in increased maximum surface discharge rates relative to injection rates.

2.2.4. Fluid Properties and Equations of State

The density, viscosity, and phase-state of the carbon dioxide injectate, ground water, and any other fluids that may be present (e.g., hydrocarbons), are important model input parameters. However, these properties change significantly across the temperature and pressure range that will be encountered at GS projects, and they are also affected by salinity. The equations of state describe these fluid properties and the existence of phases as a function of pressure and temperature; they are used by the model to calculate properties at conditions encountered in the simulation as they change with location and time. Graphs developed from accepted equations of state for carbon dioxide are depicted in Figure 2-1. Previous studies have shown that model results are sensitive to the equations of state used (Pruess et al., 2004; Han and McPherson, 2008).

The composition of the injectate will be reflected in several chemical and physical parameters assigned to the carbon dioxide fluid in the model simulations. Several studies have evaluated the impact of common carbon dioxide stream impurities hydrogen sulfide and sulfur dioxide on geochemical reactions and mineral trapping. Both Knauss et al. (2005) and Xu et al. (2007) showed that the addition of hydrogen sulfide had little impact, whereas the addition of sulfur dioxide resulted in a lower pH in the injection zone, less carbon-bearing mineral precipitation, and more formation-mineral dissolution.

2.2.5. Mass-Transfer Coefficients

Mass transfer coefficients describe the equilibrium concentration of chemical constituents (e.g., water, carbon dioxide) between separate phases. For example, the equilibrium aqueous concentration of carbon dioxide dissolved in ground water in contact with separate-phase (e.g., supercritical) carbon dioxide is described by a partitioning coefficient. Other mass-transfer coefficients describe the distribution of constituents between the gaseous, aqueous, separate-phase carbon dioxide, and solid phases. For the case of reactive transport modeling, mass-transfer coefficients describe equilibrium concentration of constituents between mineral and dissolved phases. Similar to fluid properties, mass-transfer coefficients are in many cases temperature and pressure dependent. Mass-transfer coefficients may also be dependent on properties of the formation and fluids present, such as ground water salinity. Reference documents are available that provide many necessary mass-transfer coefficients (e.g., Green and Perry, 2008), and several commonly used codes include necessary mass-transfer coefficients (e.g., TOUGH2-ECO2N; Pruess and Spycher, 2007).

2.2.6. Mineral Precipitation Kinetic Parameters

Mineral precipitation is a subset of reactive transport problems and represents a trapping mechanism for carbon dioxide as well as a mechanism for permeability modification. As noted above, the Class VI Rule does not stipulate that reactive transport be considered in AoR delineation modeling. However, the owner or operator, or the UIC Program Director, may determine that reactive transport modeling should be considered for a particular project.

Studies accounting for mineral precipitation typically include precipitation kinetic (i.e., rate) parameters. Although precipitation rates have a large impact on mineral trapping, there is a great deal of uncertainty related to these parameters (Knauss et al., 2005; Xu et al., 2006). Furthermore, complex interrelationships exist between the rates of separate mineral species in a formation. For example, a sensitivity analysis for trapping through dawsonite [$NaAl(CO_3)(OH)_2$] precipitation showed that decreasing dawsonite kinetics resulted in increased formation of other trapping minerals calcite [$CaCO_3$] and magnesite [$MgCO_3$] (Knauss et al., 2005). Izgec et al. (2008) showed that changes in formation permeability resulting from mineralization reactions were very sensitive to kinetic rate parameters. Several modeling studies have indicated that geochemical equilibrium following injection may not occur for thousands of years (e.g., Xu et al., 2006; Gaus et al., 2005).

2.2.7. Model Orientation and Gridding Parameters

Numerical modeling requires the developer to define the spatial and temporal domains, grid spacing and gridding routine, and domain boundaries. These features of the model are typically designed with an effort to minimize computational demand and therefore processing time. However, there is potential for erroneous results based on grid features of the model (i.e., numerical artifacts), which can mask or enhance the effects of physical processes. A few studies have focused on evaluating the impacts of numerical artifacts for models of GS.

Doughty and Pruess (2004) tested the impact of varying grid cell sizes for a model of the Frio formation pilot GS project site in Texas. They found that the overall pattern of plume movement was similar for different grid sizes, but overly coarse grids were not able to simulate buoyancy-driven flow within individual sand channels. The authors also observed that the choice of grid block sizes and gridding routine could result in preferential flow in the grid axis direction and numerical dispersion. Similarly, Juanes et al. (2006) observed that overly coarse grid block sizes that did not capture specific migration pathways overestimated carbon dioxide movement and the amount of capillary trapping. Doughty et al. (2007) note that higher-resolution models are needed for understanding of near well-bore effects. Yamamoto and Doughty (2009) demonstrate that grid refinement may have a substantial effect on overall simulated plume extent. Methods have been developed to establish numerical grids with high resolution in areas of interest (e.g., near well bores and fractures), and lower resolution in other areas, such as near the model area boundaries.

2.3. Computational Approaches

Computational codes consist of the set of interrelated mathematical equations (i.e., governing equations, constitutive relationships, and equations of state) that are solved simultaneously in order to predict fluid movement, pressure changes, and other changes, as a function of both location and time. These equations include complex partial differential equations that cannot be easily solved, and require complex estimation techniques. In most cases, numerical approximation methods, discussed below, will be needed to adequately represent the several physical processes necessary to delineate the AoR and comply with the Class VI Rule.

In certain circumstances, simpler analytic and semi-analytic approaches may be used to complement numerical efforts in delineating the AoR. As discussed below, analytic and semi-analytic approaches are not capable of representing several processes and features that are important for predictions of fluid movement, and they often assume simple geometry and homogeneity.

2.3.1. Numerical Approaches

Computational models used for practical applications typically consist of a numerical formulation of the governing equations applied over a spatially discretized model domain that defines the spatial extent and resolution of the problem (i.e., the model grid). This formulation is solved by a numerical method, such as finite element or finite difference approximation. The model grid is partitioned into grid cells, smaller spatial sub-units within the model. Fluid and heat flow is then solved between adjoining grid cells, while maintaining a mass and energy balance within the model. Phase changes, mass transfer, and chemical reactions can also be calculated for phases and constituents within a cell. Each cell can be assigned unique parameter values for physical properties (i.e., intrinsic permeability, porosity), allowing for three-dimensional, detailed representations of physical heterogeneity. Numerical models may be used for steady-state problems (in which injection and withdrawal rates are constant and the solution is obtained only for infinite time when system variables become constant and the solution becomes independent of the initial condition) and transient problems (in which injection and withdrawal rates may vary in time, and the solution is obtained at several discrete times during the model timeframe while the system variables exhibit change in time and depend upon the initial condition).

In addition to detailed geologic heterogeneity, numerical models are typically capable of representing density-driven fluid flow (e.g., the buoyancy of carbon dioxide) and the dissolution of carbon dioxide into ground water. Numerical models can also represent irreducible (i.e., residual) fluid saturations (i.e., the amount of fluid being "trapped" in geologic formation pore space even after another immiscible fluid has passed through that area), multiphase flow effects, and the concomitant reduced permeability.

The scale of spatial and temporal discretization of the model affects the accuracy of the solutions to these numerical formulations. Finer scales of time and space reduce numerical solution error. However, computational demand increases as the length scale (e.g., grid cell size) and time scale (e.g., time-step size) decrease, and as additional processes are simulated. Methods have been developed to mitigate increases in computational demand, while focusing on regions and times of interest, such as adaptive grid block size (i.e., mesh) refinement. Another possibility is the use of parallel computing, in which a single problem is broken up and distributed among many processors (e.g., Zhang et al., 2007).

2.3.2. Analytical, Semi-Analytical, and Hybrid Approaches

Analytical and semi-analytical models may be used to complement numerical modeling efforts in AoR delineation for Class VI wells. Compared to numerical models, analytical models have much lower computational requirements and therefore lower processing times. Analytical and semi-analytical codes may also be particularly useful for assessing the transport of carbon dioxide through abandoned well bores, which is difficult in numerical models due to the disparity in spatial scales. Analytical and semi-analytical models also may be used as screening tools to quickly assess potential storage sites, or as a relatively simple comparative check on numerical modeling results. Celia and Nordbotten (2009) suggest the use of hybrid numerical-analytical models for cases where a large-scale numerical model could be combined with local analytical models (e.g., describing wells), or the use of semi-analytical solutions where analytical solution is used in the spatial dimension and finite-stepping is used for temporal changes.

However, strictly analytical and semi-analytical models are not able to explicitly account for detailed physical and chemical characteristics of carbon dioxide injected as required under the Class VI Rule. They are also not able to simulate other important processes, such as capillary trapping, or account for varying injection rates or formation heterogeneity. The applicability of these models is limited to simplified cases where an exact function can be found to satisfy the governing equation and boundary and initial conditions. For example, in most cases, these models assume homogenous aquifers (i.e., no variability in physical structure, porosity, or intrinsic permeability). For most formations this is an unrealistic assumption, and it neglects preferential fluid movement through heterogeneous channels within geologic formations.

2.4. Model Uncertainty and Sensitivity Analyses

As discussed above, computational models are an approximate representation of reality, and thus predictions exhibit some degree of uncertainty. Model uncertainty is a result of the uncertainties related to the underlying science of the governing equations and the uncertainty in the parameter values input to represent the actual system (USEPA, 2003). Uncertainty in governing equations and model framework may arise from incomplete scientific data or lack of knowledge, as well as the necessary simplifications that translate scientific concepts into mathematical equations. Parameter uncertainty results from poor data quality (e.g., measurement errors, analytical imprecision, limited sample size), lack of data, and the inherent variability in natural systems. Model predictions depend largely on the values input for a number of key parameters and thus may be significantly impacted by incomplete knowledge, or they may be process and scale dependent. The predictive accuracy of a model improves with improved data quality, increased data quantity, realistic assumptions that reflect observed conditions and scientific knowledge, and a modeling domain (extent and resolution) that sufficiently and accurately represents the GS project.

Significant uncertainty exists in modeling predictions of GS due to the difficulty in determining the geological formation structure and permeability field throughout the extensive area likely to be impacted by proposed large injection volumes, a relative lack of data on the behavior of supercritical carbon dioxide in the subsurface, the drastic changes in transport behavior of carbon dioxide caused by changes in pressure and/or temperature, and the buoyant nature of carbon dioxide relative to native formation ground water.

The impact of parameter uncertainty on modeling results can be characterized through a model sensitivity analysis, which consists of sequentially varying a single parameter in successive model simulations while keeping all other model features constant. Sensitivity analyses provide an indication of those modeling parameters that are most sensitive (i.e., that most impact predictions of carbon dioxide migration, trapping, and pressure changes), and provide guidance for what parameters to focus on during data collection, parameter estimation, and model calibration. Accepted guides to environmental modeling (e.g., NRC, 2007) recommend the use of sensitivity analyses in submission of modeling results. Parameters that are sensitive for a particular model will be based on case-specific circumstances, and will be identified via sensitivity analyses.

2.5. Model Calibration

Model calibration consists of using the computational model to simulate a past time period for which monitoring data are available and adjusting relevant model parameters to reduce differences between model results and the observed monitoring data. For example, during initial model development, in-situ pressure data of the injection zone may be available for comparison to model predictions of pre-injection fluid pressures. After the initiation of carbon dioxide injection, monitoring data may be available regarding changes in reservoir pressure and fluid properties that may be used to calibrate the model. It is generally understood that model calibration reduces model error in prediction of future conditions.

Examples of observed data that may be used for model calibration include carbon dioxide saturation values and fluid pressures. Model calibration involves adjustment of model parameters, termed “calibration parameters,” in order to minimize the difference between simulated and observed data values. Calibration parameters for a particular model will be site specific, but they will commonly include intrinsic permeability and relative permeability-saturation function parameters. Calibration may involve incorporating additional heterogeneities or highly-permeable pathways. A case study of model calibration to monitoring data at an early GS research site, the Frio Brine Pilot in Texas, is provided in Box 2-1 of this guidance document.

Model calibration is never perfect, in that simulated and observed values for a computational model will not agree exactly. Calibration statistics are often used to characterize the error difference between model simulations and observed data values. The objective of model calibration is to minimize the value of the calibration statistics to the extent possible, using model parameters values consistent with site data or realistic estimates.

Common calibration statistics include the mean error (ME), mean-absolute error (MAE), and the root-mean squared error (RMSE). The ME is a simple average of the residual error between observed and simulated values and, therefore, positive values will offset negative values. The ME therefore provides an indication of the net bias (positive or negative) of the model simulated values. MAE is similar to the ME, with the important distinction that the sum of the absolute values of the residuals is calculated, thereby eliminating the offset that occurs by adding positive and negative values. The MAE, therefore, is always positive and represents the average difference between observed and simulated values. The RMSE is similar to the MAE, although negative values of the residual between observed and simulated values are eliminated by squaring the difference, and then the square root of the sum is determined prior to computing the average.

Model calibration may be conducted by use of computer programs designed for this purpose (i.e., automated calibration, see Finsterle, 2004), and/or adjusted manually based on best professional judgment. In practice, the automated programs can be cumbersome; therefore, manual parameter adjustment is a more standard practice in the calibration of complex models.

Box 2-1. Model Calibration Case Study: Frio Brine Pilot Project

Pilot projects of GS can provide valuable insight into modeling predictions and monitoring results comparison. The Frio Brine Pilot Project, in Dayton, TX, is an early experimental project conducted primarily by researchers at the Texas Bureau of Economic Geology and Lawrence Berkeley National Laboratory (LBNL). Two carbon dioxide injection and monitoring experiments (Frio I and Frio II) have been conducted at Frio, supplemented by numerical modeling. In this text box, separate-phase carbon dioxide data from monitoring wells, pressure monitoring data, and geophysical monitoring data are presented. These figures and discussion are taken from Doughty et al. (2007) and Ajo-Franklin et al. (2008).

A geologic schematic of the Frio pilot site is shown in Figure 2-3. For the Frio I pilot, 1,600 metric tons of carbon dioxide were injected over 10 days into a steeply dipping brine-saturated later at a depth of 1,500 m. For the Frio II pilot, approximately 350 metric tons of carbon dioxide was injected at a depth of 1,600 m. A number of pre-injection site characterization, and operational and post-injection monitoring activities were conducted along with both injections.

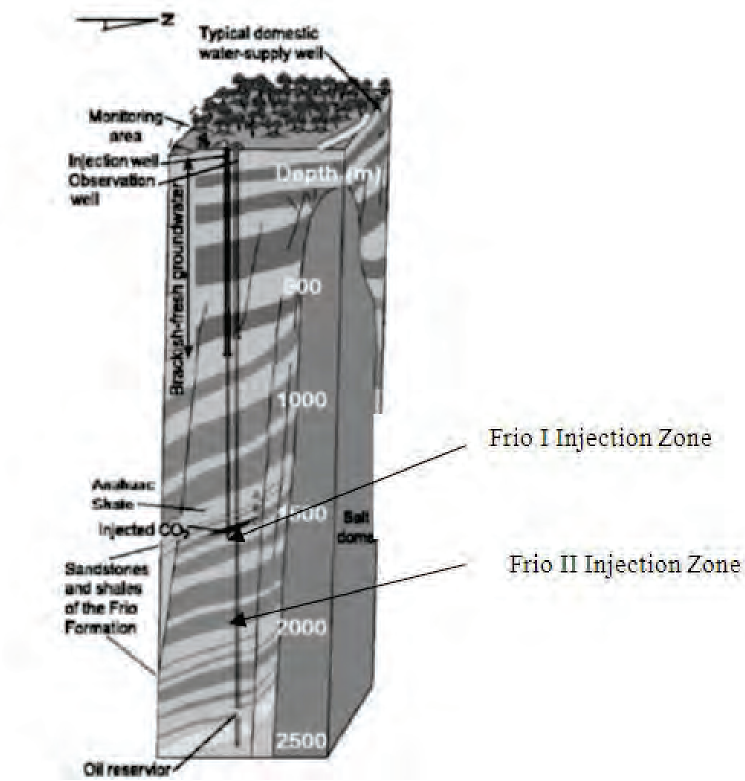


Figure 2-3: Geologic Schematic of Frio Brine Pilot Project. The arrow at top indicates the north direction.
From: Doughty et al. (2007).Reproduced with permission of Springer Science + Business Media.

For the Frio I pilot, a numerical model was calibrated by constraining the value of several parameters to a variety of monitoring data. Key calibration parameters were determined to be multi-phase flow parameters that describe the relative permeability-saturation relationship

Box 2-1. Model Calibration Case Study: Frio Brine Pilot Project, *continued*

(referred to in the study as the irreducible liquid saturation, S_{lr}) and the van-Genuchten (i.e., characteristic curve) parameter (m). The value of these parameters was constrained by several types of monitoring data (see Doughty et al., 2007). The researchers focused on calibration to the arrival time of carbon dioxide at the monitoring well, and pressure monitoring at the injection and monitoring wells. The arrival time of carbon dioxide at the injection well was determined based on a reduction of fluid density collected at the observation well using a U-tube sampling apparatus. The observed arrival time was compared to a series of model runs, varying S_{lr} and m (Figure 2-4). In addition, the observed pressure increase at both the monitoring and the injection wells were compared to model predictions (Figure 2-5). Based on these results, the value of the parameter S_{lr} was constrained to a range of 0.15 to 0.30, and the value of m was constrained to 0.9.

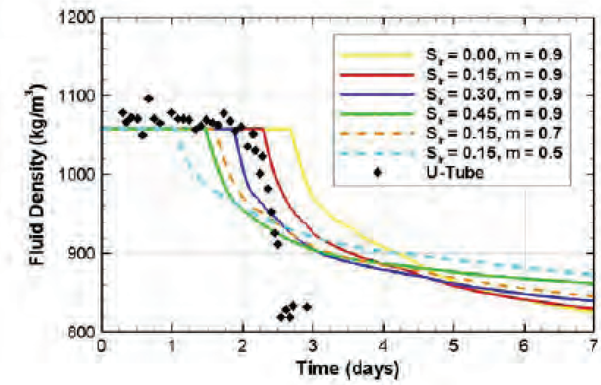


Figure 2-4: Observed and Modeled Carbon Dioxide Arrival at the Observation Well Based on Change in Fluid Density. From: Doughty et al. (2007). Reproduced with permission of Springer Science + Business Media.

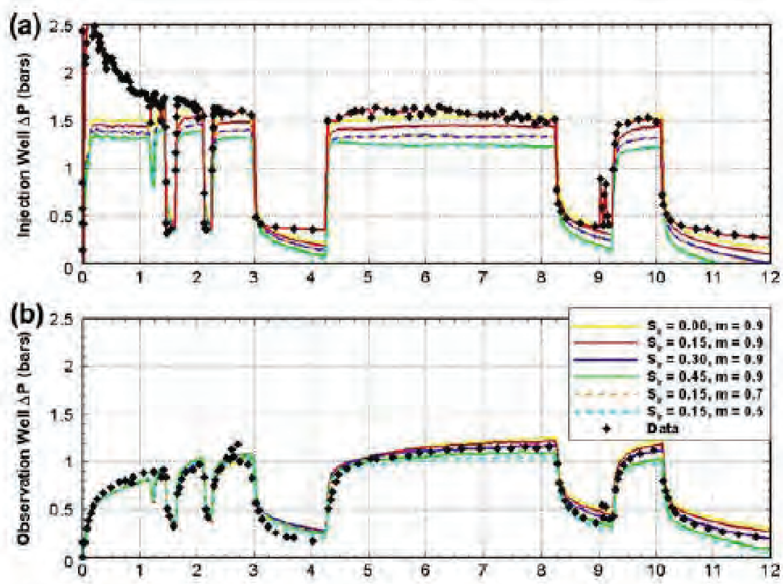
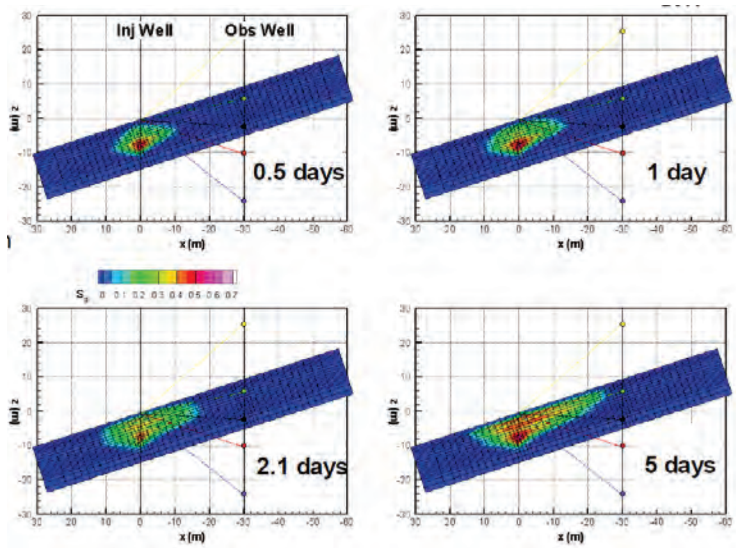


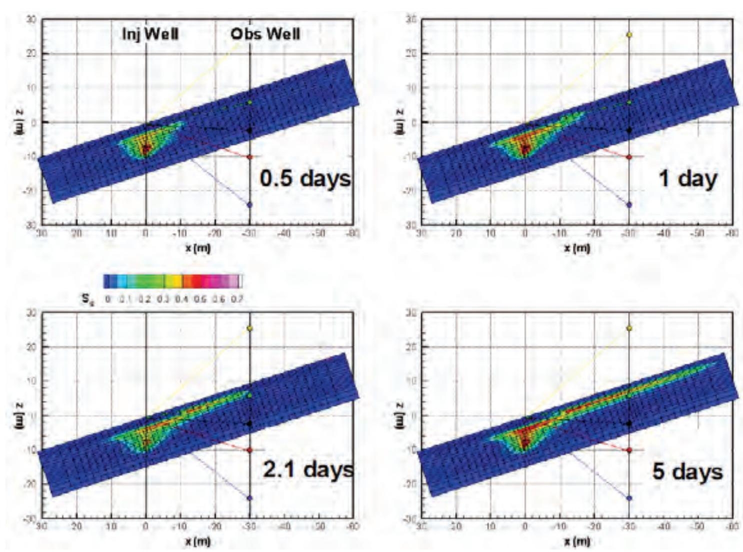
Figure 2-5: Observed and Modeled Pressure Increase at (a) the Injection Well and (b) the Monitoring Well (from Doughty et al., 2007). Reproduced with permission of Springer Science + Business Media.

Box 2-1. Model Calibration Case Study: Frio Brine Pilot Project, *continued*

Frio II used an initial numerical model to predict the evolution of the carbon dioxide plume over time. Observed seismic geophysical data of plume migration showed that a thin finger of carbon dioxide moved further up-dip than initially predicted by the model. The model was calibrated to the seismic monitoring results by, among other changes, increasing the value of the intrinsic permeability throughout the model, and increasing the thickness of a high-permeability channel at the confining zone-injection zone interface. The initial and data-calibrated model results are shown in Figure 2-6.



(a)



(b)

Figure 2-6: Comparison of (a) Initial and (b) Post-Calibration Model Predictions of Carbon Dioxide Plume Evolution. From: Ajo-Franklin et al. (2008).

2.6. Existing Codes used for Development of GS Models

A wide variety of modeling exercises have been reported in the peer-reviewed literature for GS and have been reviewed previously (Schnaar and Digiulio, 2009). Several computational codes have been developed for multiphase flow and transport problems, and a number of these codes are publicly or commercially available for the owners or operators of a GS project to use in AoR delineation modeling. Codes reported in the literature used for modeling of GS include petroleum reservoir codes (STARS, Law and Bachu, 1996; GEM, Kumar et al., 2004; ECLIPSE, Zhou et al., 2004; Juanes et al., 2006; CHEARS, Flett et al., 2007) and codes that have been developed at U.S. Department of Energy (DOE) national laboratories for a range of multiphase flow and transport problems (STOMP, CRUNCH, Knauss et al., 2005; TOUGH-series, Finsterle, 2004; Xu et al., 2006; Doughty and Pruess, 2004; Doughty, 2007). Additionally, DOE provides a summary of available models that have been used to model processes associated with injection for GS at the Regional Carbon Sequestration Partnership (RCSP) project sites. The document presents the types of data that are needed for various models and how to obtain such information (NETL, 2011). These codes vary not only in the physical processes considered, but also in numerical techniques such as the spatial discretization method, iteration approach, and gridding routines. The codes mentioned above are provided as examples that may be used for GS modeling, and the lists given are not meant to include all available codes, or to suggest preference for certain codes over others.

Codes used for modeling GS consider multiphase flow of carbon dioxide in supercritical, liquid, and gaseous phases including miscible and immiscible displacement, dissolution of carbon dioxide in ground water, density-driven flow, and flow of ground water as impacted by injection. Available codes may also be further categorized based on their ability to consider, or to be adjusted to consider, complex three-dimensionally heterogeneous formations, residual phase trapping and characteristic-curve hysteresis, mineral precipitation/dissolution reactions and subsequent mineral phase trapping and leaching of heavy metals, carbon dioxide sorption in coal-bed methane problems, and leakage through abandoned well bores. Models based on the TOUGH-series codes have been widely reported in the literature and are capable of considering three-dimensional heterogeneous formations, carbon dioxide dissolution, residual phase trapping and characteristic-curve hysteresis, coupled fluid flow and geomechanical processes, and mineral precipitation (e.g., Finsterle, 2004; Doughty, 2007; Xu et al., 2006; Rutqvist et al., 2008).

Several codes were compared for identical GS problems in an LBNL study (Pruess et al., 2004) in order to evaluate code comparability. Ten research groups representing six countries participated in the study. The codes evaluated included TOUGH-series codes (LBNL, CSIRO Petroleum, Industrial Research Limited), ECLIPSE 300 (Los Alamos National Laboratory), and STOMP (Pacific Northwest National Laboratory), among others. The problems considered varied in complexity and included mixture of gases in an open system, radial flow from an injection well, discharge along a fault zone, injection with mineral trapping, and injection with enhanced-oil recovery. For the most part, model results for the different codes were found to be in good agreement. Most discrepancies were traced to differences in the calculation of fluid properties (e.g., viscosity). These results emphasize the need for accurate descriptors of carbon dioxide transport properties and equations of state.

The use of proprietary codes (i.e., codes not available for free to the general public) may prevent full evaluation of model results (e.g., NRC, 2007). There are several aspects of a model that can be proprietary, and some may be more important than others for computational model evaluation. For example, use of a proprietary user interface with a publicly available code may not present a significant problem. Several popular codes in the petroleum-reservoir engineering discipline are proprietary (e.g., ECLIPSE). However, these codes have been used in peer-reviewed studies to model GS, and operators of particular GS sites may prefer to use these codes as they have previous experience with them. As discussed below, when using a proprietary model for AoR delineation, site operators of GS projects are encouraged to clearly disclose to the UIC Program Director the code assumptions and, if necessary, governing equations and equations of state with the permit application.

3. AoR Delineation Using Computational Models

Determination of the AoR for proposed Class VI wells will consist of data collection and compilation, development of the site computational model, delineation of the AoR based on model results, and submission of the model results and AoR delineation to the UIC Program Director with the Class VI permit application. The AoR and Corrective Action Plan must describe how the owner or operator plans to conduct these activities and is subject to UIC Program Director approval [40 CFR 146.84(b)].

The AoR delineation model must be submitted with the Class VI permit application—i.e., with the proposed AoR and Corrective Action Plan, as required at 40 CFR 146.82(a)(13)—and the modeled AoR will be finalized after all site data are collected and pre-injection testing is complete, per 40 CFR 146.82(c)(1). Therefore, the submittal, evaluation, and approval of the AoR, as part of the AoR and Corrective Action Plan, may be an iterative process, involving multiple drafts, until all the information required is submitted at the appropriate level of detail as determined by the UIC Program Director. See the *UIC Program Class VI Well Project Plan Development Guidance* for more information on the AoR and Corrective Action Plan. Also see the *UIC Program Class VI Implementation Manual* for additional information on how permitting authorities will review the information submitted by owners or operators.

This section describes the AoR delineation process and provides several quantitative examples revolving around a hypothetical GS site. EPA recommends that model development in all cases be conducted by a professional expert with the understanding of multiphase flow processes and experience with application of sophisticated computational models.

3.1. AoR Delineation Class VI Rule Requirements

The following Class VI Rule requirements pertain to AoR delineation:

- 40 CFR 146.84(a): The AoR is the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

- 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:
    (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data,

including injection pressures, rates, and total volumes over the proposed life of the GS project;

(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

3.2. Data Collection and Compilation

Computational modeling utilizes the required site characterization data for a proposed Class VI injection well site and applies scientifically accepted principles to estimate the carbon dioxide plume and pressure front migration. The extent to which site and operational conditions are realistically represented determines the validity of the resulting model predictions. Site characterization data inform model parameterization and the development of the model and, therefore, adequate data collection, analysis, and compilation are integral components of model development. Table 2-1 of this guidance provides a summary of important model parameters, many of which are determined based on site characterization data.

A variety of site characterization data are required to be collected for proposed GS projects [40 CFR 146.82 and 146.83]. These data are required to verify that the proposed injection zone at the characterized site has adequate injectivity to accept the injected carbon dioxide at the proposed rate and adequate volume to store the injectate over the lifetime of the project. Furthermore, site characterization data verify that suitable confining zone(s) are present to restrict the upwards movement of carbon dioxide. Additional features of the site, such as baseline geochemistry and pre-injection fluid pressures, inform the interpretation of future monitoring results and support reactive transport modeling if it is chosen to be used. As discussed below, much of the site characterization data collected at the proposed Class VI injection well site are also necessary to inform computational model development and AoR delineation. Site characterization requirements and methods are discussed in more detail in the *UIC Program Class VI Well Site Characterization Guidance*.

3.2.1. Site Hydrogeology

Regional and site-specific geology provide the foundations of the computational model used to delineate the AoR. This includes site stratigraphy, including formation elevation and thickness, as presented in cross sections and/or topographic maps. It is recommended that any data regarding structural geology (including folding, and fracture and fault systems) be identified and used when creating the computational model. For each geologic formation at the proposed injection site, hydrogeologic information, including initial fluid pressure, horizontal and vertical gradients, and ground water flow direction and velocity, should be considered. Other important characteristics include intrinsic permeability and porosity of all formations ranging from the uppermost USDW to beneath the injection zone. Where injection depth waiver applications are considered, EPA recommends that these parameters be determined for all formations down to and including the first USDW below the injection zone. See the *UIC Program Class VI Well Injection Depth Waivers Guidance* for additional information. EPA recommends that the heterogeneity of these characteristics within each formation also be evaluated. Data regarding the heterogeneity of these parameters are of particular importance in representing the injection and confining zone(s). The Class VI Rule requires that AoR computational modeling take into account any geologic heterogeneities and other discontinuities [40 CFR 146.84(c)(1)(ii)].

Thorough characterization of multiphase flow parameters is also recommended to properly inform the computational modeling. These include parameters describing the capillary pressure-saturation and relative permeability-saturation relationships of each formation, with the injection and confining zones being of particular importance. See Figure 2-2 of this guidance for more information. EPA recommends that accepted formulations of these relationships be defined that are as specific to the site and fluids of interest (e.g., brine, carbon dioxide) as possible.

The quantity of data used to inform model development is recommended to be, at least, based on the Class VI Rule site characterization requirements, as discussed in the *UIC Program Class VI Well Site Characterization Guidance*. For pertinent data types, as discussed above, all data collected to comply with site characterization requirements may be considered in the AoR delineation. Furthermore, EPA recommends that any additional pertinent data available in the vicinity of the site, for example from the U.S. Geological Survey (USGS) or other sources, also be included in model development.

Additionally, EPA recommends that the lateral and vertical extents of all formations predicted to exhibit contact with supercritical carbon dioxide or elevated pressure over the lifetime of the proposed GS project be characterized for hydrogeologic properties. This may be an iterative process because initial model estimates of plume and pressure front migration may indicate further migration than previously assumed. In these cases, some additional site characterization in these regions may be requested by the UIC Program Director before a permit is approved.

EPA recommends that adequate data be collected to reasonably estimate site heterogeneity. Collection of sufficient data is always a challenge in geologic studies, and this is compounded by the large areas that may be impacted by GS projects. Use of geophysical site characterization techniques may reduce the burden of site characterization over large areas. See the *UIC Program Class VI Well Site Characterization Guidance* for more information on using geophysical methods to assist with collecting the required site characterization data for a Class VI injection well permit application.

3.2.2. Operational Data

The Class VI Rule requires that the AoR computational modeling for a Class VI injection well be based on existing or proposed operational data including injection pressures, rates, and total volumes over the lifetime of the GS project [40 CFR 146.84(c)(1)(i)]. EPA recommends that operational data also include the location and number of injection wells, and the injection well construction details (e.g., total depth, perforated interval). In the case of GS projects with multiple Class VI injection wells, it is important to note that each Class VI well is required to be permitted separately, as area permits are not allowed [40 CFR 144.33(a)(5)]. However, EPA strongly encourages potential Class VI injection well owners or operators to account for all injection wells associated with the proposed project, or any other injection or extraction wells in the area, when developing the AoR model. EPA recommends that a single AoR delineation model be used for all Class VI injection wells for a single GS project, and that the model include the influences of all relevant wells. EPA also recommends that overlapping pressure perturbations be evaluated for a given basin or hydraulically connected formations to determine any combined risk to USDWs. The owner or operator may consult the UIC Program Director regarding any existing or planned projects in the vicinity of the proposed well.

3.3. Model Development

Once adequate data are collected, model development consists of the formation of a conceptual site model, design of the mathematical framework and grid, and parameterization (i.e., determination of input parameter values) (USEPA, 2003). The model is then executed to provide predictions of fluid movement and pressure perturbations during the lifetime of the project.

A Note Regarding Hypothetical Examples

Several informative boxes are included within this guidance that provide examples of the AoR delineation and reevaluation process based on a hypothetical site (Box 3-1, Box 3-2, Box 5-1, and Box 5-2). The hypothetical site presented is not intended to be representative of all GS projects. Assumptions and methods used in hypothetical examples may not be valid in all cases. A length scale has not been included on hypothetical site figures, such that an allowable size of the AoR, or distance between wells, is not unintentionally inferred from the figures.

3.3.1. Conceptual Model of the Proposed Injection Site

A conceptual site model is a schematic representation of the proposed GS project, including all major geologic elements present in the flow system and any relevant physical processes. In the delineation process, the conceptual model is translated mathematically into a numerical model to be solved for pressure and saturation. The conceptual site model is informed primarily by the collected site characterization data and the proposed operational conditions, such as well-field configuration and injection rates. EPA recommends that descriptions of the conceptual site model present a clear statement and description of each element of the site, as well as any assumptions and hypotheses related to the proposed injection site and the reasoning behind them (e.g., lab experiments, empirical data, or peer-reviewed literature). The conceptual site model also identifies the modeling region in three dimensions. Geologic stratigraphy, any other relevant geologic features, all physical processes that will impact migration of carbon dioxide and ground water, chemical species of interest, location of USDWs and potential conduits, conditions at site boundaries that may inform model boundary conditions, and areas of sparse site characterization data are also identified in the conceptual site model. See Box 3-1 for more information about the conceptual site model.

Box 3-1. Hypothetical Example of a Conceptual Site Model

A conceptual site model describes the general features of the anticipated Class VI project, using one or several schematics and diagrams. EPA recommends that schematics be used to show the general project orientation, both at the surface and at depth, important site features, and known processes that will impact plume and pressure front evolution at the site. Report text accompanying the conceptual site model schematic describes the relevant features at the site. A hypothetical example conceptual site model schematic is shown in Figure 3-1, and the example accompanying text is below.

For this hypothetical project, three injection wells are planned to inject a total of two million tons of carbon dioxide per year for 30 years. The source of carbon dioxide is a coal-fired power plant located approximately 200 miles to the north of the injection site. The injectate will be supplied via pipeline to the site, delivered to a surface facility, and then supplied separately to each of the injection wells. The injectate will be greater than 99% pure carbon dioxide at all times, containing trace amounts of sulfur dioxide and nitrogen oxides.

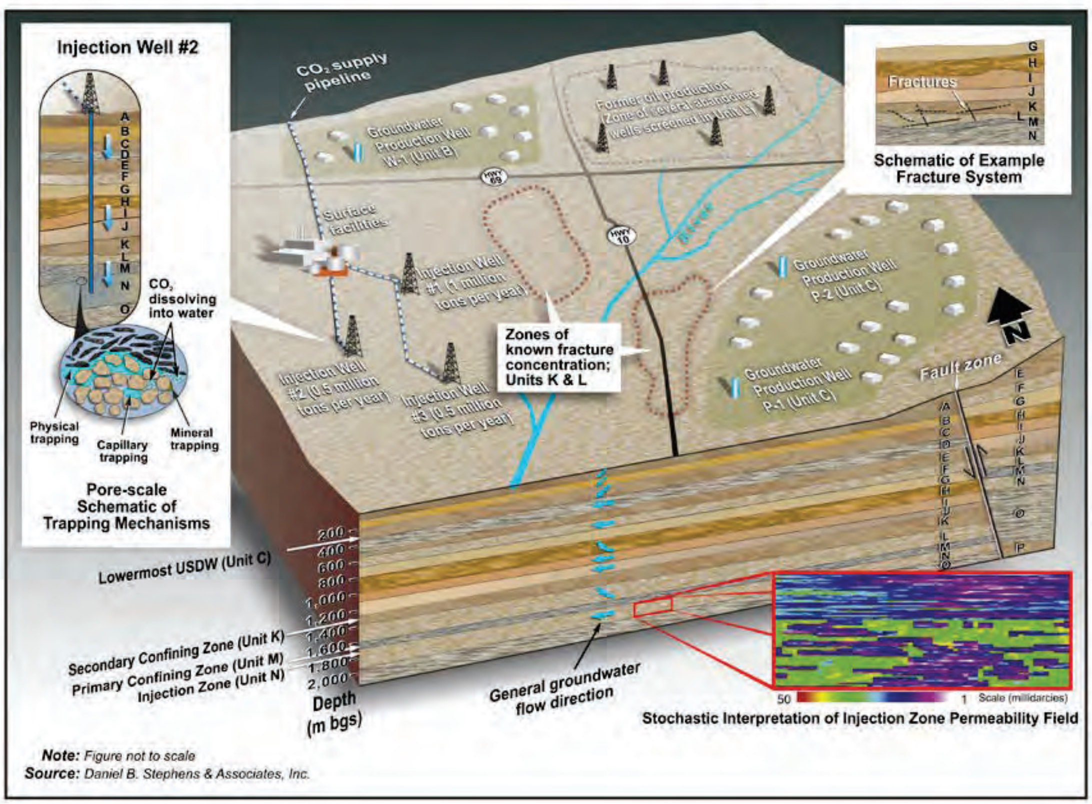


Figure 3-1: Hypothetical Conceptual Site Model for Geologic Sequestration.

Box 3-1. Hypothetical Example of a Conceptual Site Model, *continued*

Injection will occur into a saline formation (Unit N), with a measured salinity of 50,000 mg/L, at a depth of approximately 1,800 meters below ground surface. The formation dips slightly, and carbon dioxide and pressure front movement are expected to be generally greater in the up-dip direction. The permeability of the injection zone has been measured to range from 1 to 50 mD, with lower permeabilities generally at higher elevations and at the contact between the confining and injection zones.

A shale unit, at least 20 meters thick throughout the vicinity, serves as the primary confining unit (Unit M). The depth of the lowermost USDW (Unit C) varies somewhat throughout the vicinity, but it is generally from 200 to 500 meters below ground surface. Intervening layers of sand, shale, and clay units exist between the confining layer and lowermost USDW. A secondary confining zone (Unit K) has been identified.

The majority of carbon dioxide is expected to migrate upwards through the zones of higher permeability until encountering lower permeability zones within the injection zone, or the injection zone/confining zone contact, and be physically trapped. Capillary trapping, mineral trapping, and dissolution of carbon dioxide into ground water will also occur; however, at this point the rate and total amount expected to be sequestered via the different mechanisms has not been quantified. Currently, ground water in all subsurface formations flows generally to the west. It is expected that pressure increases within the injection zone induced by the project will cause ground water to generally flow radially away from the injection wells.

Two relevant geologic zones with a concentration of fractures are located in the vicinity of the project, as shown on Figure 3-1. Fractures exist primarily in Unit K, the secondary confining unit, but also are potentially identified in the primary confining zone, Unit M. Geologic studies of the fractures and preliminary modeling have indicated that due to the orientation and fracture widths, they will not serve as a leakage pathway during carbon dioxide injection. However, these two relevant geologic zones will likely be locations for enhanced monitoring during the lifetime of the project, based on consultation with the UIC Program Director.

A former oil and gas field is located to the northeast of the project. Further analysis, including modeling, is used to determine if carbon dioxide may migrate into this area. If migration is detected, enhanced corrective action and monitoring will occur within the area of the former oil and gas field in consultation with the UIC Program Director. A fault zone exists far to the east of the proposed site. Carbon dioxide is not expected to migrate as far as the fault zone. However, this feature may also be further evaluated over the course of project, along with the potential for brine migration through the fault zone as a result of pressure buildup in the formation.

3.3.2. Determination of Physical Processes to be Included in the Computational Model

Prior to developing the computational model for a proposed Class VI injection well AoR delineation, the owner or operator will need to determine what physical processes will be considered in the computational model. This determination is based on the most significant processes identified in the conceptual model, as well as those processes that can be realistically included in the computational model. At a minimum, the Class VI Rule requires that the model include multiphase flow of carbon dioxide and formation fluids [40 CFR 146.84(a) and (c)(1)]. Additional processes may be necessary for certain projects. For example, reactive transport could be relevant if permeability and/or porosity are predicted, based on previous testing, to change as a result of precipitation/dissolution reactions. In addition, geomechanical processes could be relevant if pressure and stress may change hydrogeologic properties. If the aqueous carbon dioxide plume is a potential risk factor, carbon dioxide dissolution into ground water may also be considered in the AoR delineation model.

For some model applications, including reactive transport and geomechanical processes may be impractical. Complications can arise from increases in computational demands (i.e., extremely long computer processing times), lack of meaningful data on mineral precipitation/dissolution kinetics, or the inability of preferred computational code. Furthermore, including these processes may be unnecessary in many cases because the impact on plume and pressure front migration may be relatively minor. The Class VI Rule does not require including reactive transport and geomechanical processes in the AoR delineation modeling. However, the UIC Program Director may request that the owner or operator include these additional processes in AoR delineation modeling in cases where doing so would improve the understanding of plume and pressure migration for the project.

3.3.3. Computational Model Design

After a conceptual site model has been developed, and the processes that will be considered have been determined, the next step is to develop the site computational model. This includes the determination of an appropriate computational code, and parameterization (i.e., populating the code with the selected site-specific parameters) in order to develop the model.

3.3.3.1. Computational Code Determination

To create the computational model, EPA recommends that a code be used that includes routines for the relevant physical processes at the site based on peer-reviewed theory and equations, including equations of state for carbon dioxide and other chemical species of interest. EPA recommends that the code also include accurate mass-transfer coefficients, including solubility of carbon dioxide, as a function of primary thermodynamic variables (e.g., temperature, pressure, phase saturations). If using an independently developed or untested code, EPA also recommends that the developer model test cases found in the literature to verify the accuracy of the model before submitting the Class VI injection well permit application to the UIC Program Director (e.g., see Pruess et al., 2004).

3.3.3.2. Model Spatial Extent, Discretization, and Boundary Conditions

The computational model will be designed by determining the spatial boundaries of the problem and spatial discretization. It is recommended that lateral grid spacing be fine enough to resolve heterogeneities, as discussed above (e.g., Doughty and Pruess, 2004). Vertically, the model is recommended to include the injection zone, with sufficient vertical resolution to properly account for buoyant plume migration, and a sufficient section of the primary confining zone to demonstrate to the satisfaction of the UIC Program Director that no leakage is expected to occur through the confining zone. In some cases, the UIC Program Director may require that additional zones be included in the computational model, such as overlying USDWs. Inclusion of additional zones may allow for estimation of vertical leakage rates and pressure changes above the primary confining zone, which may aid in performing risk assessments and designing the Class VI testing and monitoring program.

Boundary conditions are typically based on hydrogeologic conditions in locations corresponding to the edges of the model domain where the domain extends beyond the pressure front and/or plume. Model testing may be conducted to ensure that grid spacing, gridding routine, and boundary conditions do not result in numerical artifacts that impact the model results. If results of such testing indicate artificial impacts, then adjustment of the model may be necessary prior to running the model for a proposed Class VI injection well AoR delineation.

3.3.3.3. Model Timeframe

The Class VI Rule requires that the model used to delineate the AoR for a proposed Class VI injection well be run from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director [40 CFR 146.84(c)(1)]. In order to meet these conditions, it may be necessary for the model simulation of the GS project to extend for several hundred or thousands of years (e.g., Flett et al., 2007).

3.3.3.4. Parameterization

Parameterization is the final step in the initial development of the computational model, and it consists of populating the computational code with the selected site-specific parameters. Key parameters include formation intrinsic permeability, porosity, phase-partitioning coefficients, and relative permeability-saturation parameters. Parameter values are based on the site-specific data as much as possible, but may also be based on values and relationships from the scientific literature. Geostatistical techniques can also be used to create a representation of realistic, three-dimensionally heterogeneous conditions in the subsurface. See Section 2.2 of this guidance for more information on model parameters. In some cases, a reasonable range of parameter values may be identified for the purposes of later sensitivity analyses.

3.3.4. Executing the Computational Model

The computational model is executed (i.e., solved) after parameterization, and this consists of using the code to calculate phase saturations and composition, fluid pressures, and other system aspects within the model domain for each point in time and space separated by specified intervals (i.e., time step, grid spacing). Model results are typically text files that contain modeled data for each grid cell, during each time step. In some cases, the model results will need to be post-processed following execution of the model before they can be easily visualized and interpreted. For example, model results may need to be transformed to produce site coordinates. Model results of particular interest for Class VI injection well AoR delineation include estimation of the extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the injection zone over time. See Section 3.4 for more information on AoR delineation.

The use of an *a priori* AoR delineation based on computational modeling predictions highlights the need for uncertainty and sensitivity analyses for the initial prediction. Conservative predictions will be needed prior to the commencement of injection and the availability of any site-specific data on carbon dioxide migration paths and rates. EPA recommends conducting sensitivity analyses as the principal evaluation tool for characterizing the most and least important sources of error in computational models (USEPA, 2003). Based on these results, maximum-risk scenario simulations can be conducted considering plume extent and pressure perturbation predictions that account for uncertainties in the model.

3.4. AoR Delineation Based on Model Results

The planned or predicted AoR submitted with the permit application for a proposed Class VI injection well is required to be based on a delineation of the area where the GS project may cause endangerment of USDWs, which in turn is required to be based on the results of computational modeling [40 CFR 146.84(a) and 40 CFR 146.84(c)(1)]. The boundaries of the AoR are based on simulated predictions of the extent of the separate-phase (i.e., supercritical, liquid, or gaseous) plume and pressure front. As such, EPA recommends that the AoR encompass the maximum extent of the separate-phase plume or pressure front over the lifetime of the project and entire timeframe of the model simulations. The pressure front, as described below, is the extent of pressure increase of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW.

In the case of GS projects with multiple Class VI injection wells, the owner or operator must apply for and obtain a Class VI injection well permit for each individual well [40 CFR 144.33(a)(5)]. However, as discussed previously, a single AoR modeling exercise may be conducted for all wells within a single project at the discretion of the UIC Program Director. In all cases, EPA recommends that the AoR delineation boundaries for the cumulative GS project be based on modeling that accounts for the anticipated injection rates from all planned Class VI injection wells.

Box 3-2 provides a hypothetical example of an AoR delineation based on computational modeling results, including the calculation of the threshold pressure that defines the pressure front. The determination of the pressure front in Box 3-2 (Step 2) is consistent with existing standard practices for other well classes of the UIC Program (e.g., Thornhill et al., 1982) and is applicable to any Class VI injection well for which, prior to injection, the injection zone is under-pressurized compared to the lowermost USDW (i.e., Method 1, Section 3.4.1). Determination of the pressure front is discussed in more detail in Section 3.4.1.

3.4.1. Determination of Threshold Pressure Front

The pressure front may be defined as the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals. Several methods, as described below, are available to estimate the value of the pressure front, and are based on various assumptions. The owner or operator is encouraged to consult with the UIC Program Director to determine which method is appropriate for the proposed GS project. For instance, if an existing aquifer exemption is proposed to be expanded for a GS project, the pressure front may be determined based upon the pressure increase necessary for formation fluids to be displaced into portions of aquifer that are not exempted.

Method 1. Pressure front based on bringing injection zone and USDW to equivalent hydraulic heads (applicable to under-pressurized case only).

As stated by Thornhill et al. (1982), the pressure-front component of the AoR is "the area around an injection well where, during injection, the [hydraulic] head of the formation fluid in the injection zone is equal to or greater than the [hydraulic] head of USDWs." Defined this way, the pressure-front ($P_{i,f}$) may be calculated by the following equation:

$$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) \qquad \text{[Eq-1]}$$

where P_u is the initial fluid pressure in the USDW, ρ_i is the injection-zone fluid density, g is the acceleration due to gravity, z_u is the representative elevation of the USDW, and z_i is the representative elevation of the injection zone. Similarly, the increase in pressure that may be sustained in the injection zone ($\Delta P_{i,f}$) is given by:

$$\Delta P_{if} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq-2]}$$

where P_i is the initial pressure in the injection zone. Eq-1 and Eq-2 are subject to the assumption that the hypothetical open borehole is perforated exclusively within the injection zone and USDW.

A positive value of $\Delta P_{i,f}$ (Eq-2) corresponds to an injection reservoir that is under-pressurized relative to the USDW and can accommodate an increase in pressure equal to $\Delta P_{i,f}$ prior to potential fluid migration into the drinking water reservoir. A $\Delta P_{i,f}$ value of zero corresponds to the hydrostatic case, and a negative value of $\Delta P_{i,f}$ relates to a situation where the injection zone is already over-pressurized and thus subject to potential fluid leakage from the injection reservoir to the drinking water aquifer even prior to the planned GS project. Eq-1 and Eq-2 are only applicable for calculating the allowable pressure increase for the under-pressurized case (i.e., positive value of $\Delta P_{i,f}$). Alternative methods may be applicable for the hydrostatic case or over-pressurized cases (see below).

EPA recommends that Eq-1 and Eq-2 be applied using values of pressure and fluid density (i.e., P_u, P_i, and ρ_i) based on direct measurement of fluid properties in the direct vicinity of the proposed project (i.e., see the *UIC Program Class VI Well Site Characterization Guidance*). Notably, the results of Eq-1 and Eq-2 are sensitive to the injection-zone fluid density (ρ_i), which is influenced by the pressure, temperature, and salinity of the injection zone. Salinity, pressure, and temperature tend to increase with depth below the ground surface. If site-specific fluid density values at reservoir conditions are not available, injection zone fluid density may be estimated based on measured salinity, temperature, and pressure. Figure 3-2 presents fluid density as a function of depth below ground surface for several different salinities, based on the method of Peng and Robinson (1976).

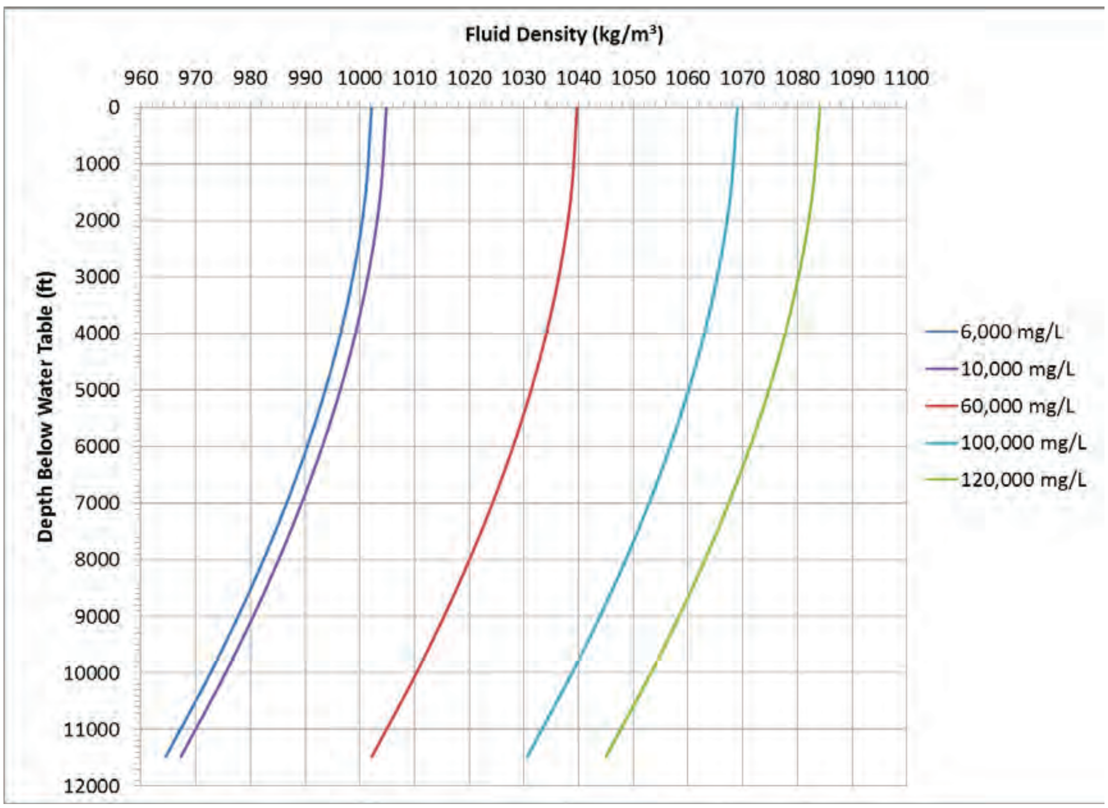


Figure 3-2: Fluid Density Functions for Varying Salinities.

Note also that, in using this method, $P_{i,f}$ is a function of the fluid density of the injection zone, the elevation of both formations, and the fluid pressure within the USDW. To the extent that these parameters vary spatially in the vicinity of the project, the value of $P_{i,f}$ may also vary throughout the region of the AoR.

Method 2. Pressure front based on displacing fluid initially present in the borehole (applicable to hydrostatic case only).

Under hydrostatic conditions, a pressure increase within the injection zone may be allowable due to the fact that water entering a hypothetical borehole from the injection zone will be more dense than the fluid initially present in that borehole. Fluid from the injection zone will displace the fluid in the borehole, which will flow into the USDW. However, below a calculated threshold pressure, a new pressure equilibrium will be established, and fluid from the injection zone will not intrude into the USDW.

As given by Nicot et al. (2008) and Bandilla et al. (2012), assuming (1) hydrostatic conditions and (2) initially linearly varying densities in the borehole and constant density once the injection-zone fluid is lifted to the top of the borehole (i.e., uniform density approach), the threshold pressure increase (ΔP_c) may be calculated:

$$\Delta P_c = \frac{1}{2} \cdot g \cdot \xi \cdot (z_u - z_i)^2 \qquad \text{[Eq-3]}$$

where ξ is a linear coefficient defined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Eq-4]}$$

and where ρ_u is the fluid density of the USDW.

Nicot et al. (2008) also present a solution subject to the assumption of linearly varying densities in the borehole both initially and when the injection zone fluid is lifted to the top of the borehole (i.e., equilibrium approach), rather than the uniform density approach (assumption #2) used to derive Eq-3 (see Nicot, 2008 and Bandilla, 2012). Birkholzer et al. (2011) state that the value of ΔP_c calculated using the uniform density approach (Eq-3) may be less precise than the equilibrium approach, but it is easier to apply and also more conservative for protection of the USDW.

At pressure increase less than ΔP_c, the fluid originally present in the borehole will leak into the USDW. This fluid leakage from the borehole may be acceptable and not cause degradation of water quality within the USDW, as the volume of water in the borehole may be minor and quickly diluted by water in the surrounding aquifer.

Calculation of the allowable threshold pressure increase using these methods (Eq-3 and Eq-4) is applicable only to the hydrostatic case. In some instances, site-specific fluid pressure and density measurements may not be available at the time of preparing the permit application and initial AoR delineation in order to evaluate if the injection reservoir is over- or under-pressurized. If warranted by previous site knowledge (i.e., no previous large-scale fluid withdrawal or injection from the injection zone), it may be acceptable to initially assume hydrostatic conditions. The owner or operator may choose to use these methods (Eq-3 and Eq-4) for an initial estimate of the threshold pressure allowable for delineation of the AoR. However, once site-specific data are available for the proposed injection zone following construction of injection or monitoring wells, EPA recommends reevaluation of the hydrostatic assumption. If the reservoir is under-pressurized, the allowable threshold pressure increase may be greater than calculated using Eq-3 (see Method 1, above). However, if the injection reservoir is actually over-pressurized, the allowable pressure increase will be less than calculated using Eq-3.

Methods for over-pressurized cases.

In some instances, the desired injection zone may already be over-pressurized relative to the USDW prior to the injection project (i.e., $\Delta P_{i,f}$ value is negative using Eq-2). In this situation, fluid leakage would occur from the injection zone to the USDW through a borehole perforated within both zones even prior to commencing injection. Additional pressure increase within the injection zone owing to the injection associated with the GS project may increase fluid leakage rates. Determination of the allowable pressure increase to be used in AoR delineation for the over-pressurized case may require more sophisticated methods than the analytical equations described above for Methods 1 and 2.

Possible methods to estimate an acceptable pressure increase for over-pressurized reservoirs include:

1. Using similar methods as described in Nicot et al. (2008), some over-pressurization within the injection zone may be allowable without causing sustained fluid leakage, owing to the density differential between the injection zone and USDW. If the value of ΔP_c using Eq-3 is greater than the absolute value of $\Delta P_{i,f}$ using Eq-2, the difference in magnitude between the two may be used as an estimate of the allowable pressure increase, subject to the assumptions used to derive Eq-3 (see Method 2, above). To date, peer-reviewed research papers on this topic have developed analytical solutions only for the hydrostatic case. Future publications may address the initially over-pressurized case and, if so, these methods may be used to calculate an allowable pressure increase in an over-pressurized reservoir.

2. A multiphase numerical model may be designed to model leakage through a single well bore, or through multiple well bores in the formation (see e.g., Birkholzer et al., 2011). Additional pressure increases up to a certain point within an already over-pressurized injection zone may not cause an appreciable increase in fluid leakage rates through a hypothetical borehole. A sensitivity analysis may be conducted to bound the modeled leakage rates.

3. In conjunction with item #2 above, numerical or analytic ground water modeling may be conducted for the USDW to estimate how additional fluid leakage caused by the injection project is diluted within the USDW and attenuated. Dilution of fluid leakage from a borehole is impacted by the natural background flow rate of water within the USDW, which is turn a function of the hydraulic gradient, aquifer thickness, and hydraulic conductivity. An additional pressure increase may be allowable if it can be demonstrated

to the UIC Program Director that negligible degradation of the USDW would result from increased fluid leakage rates.

Box 3-2. Hypothetical Example of an AoR Delineation

The AoR is based on the results of computational modeling and encompasses the predicted maximum extent of the separate-phase plume or pressure front over the lifetime of the project. The pressure front is defined as the pressure, within the injection zone, great enough to force fluids from within the injection zone through a hypothetical open conduit into any overlying USDW. This box provides a hypothetical example of an AoR delineation using a stepwise approach. The example scenario is based on the conceptual site model described above (see Box 3-1). First, the threshold pressure that defines the pressure front is determined. Next, maps showing the maximum extent of the plume and pressure front are overlaid and the AoR is delineated.

Step 1. Determine the Pressure Front

A cross-sectional schematic of the hypothetical scenario is shown in Figure 3-3, which also presents values for fluid density, and pressure (units of megapascals, MPa, equal to $1 \cdot 10^6$ Pa) for each formation.

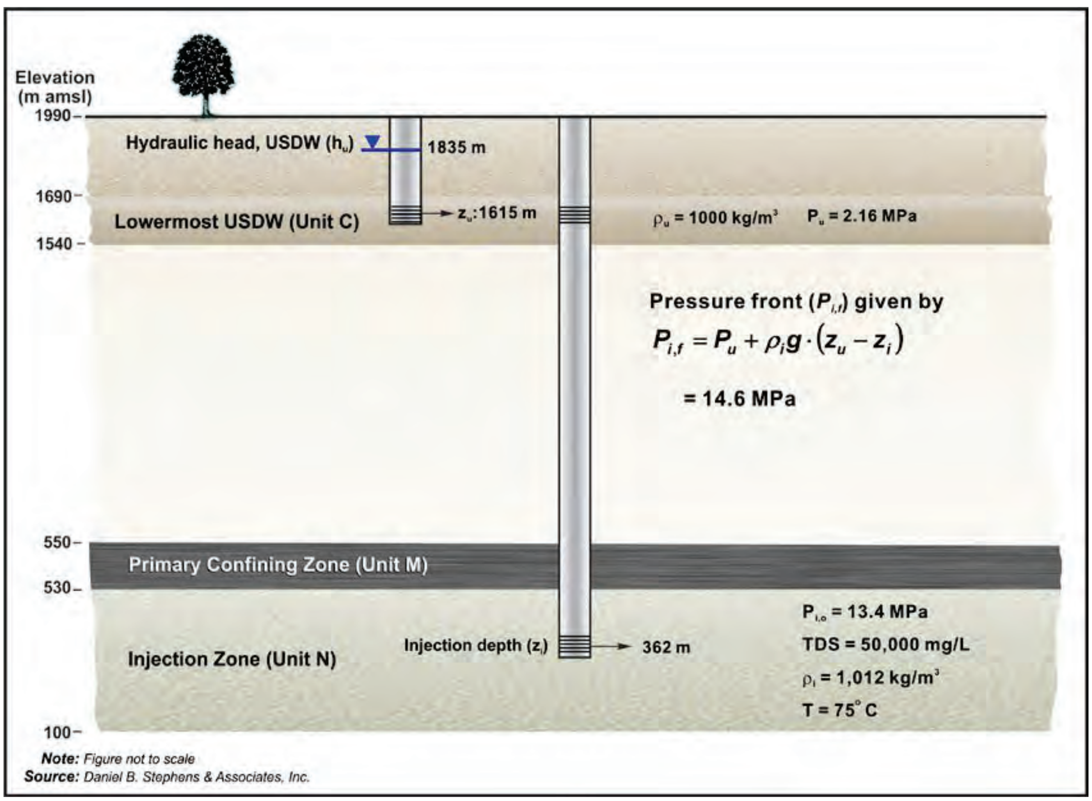


Figure 3-3: Hypothetical Geologic Sequestration Site: Cross Sectional Schematic and Calculations.

Box 3-2. Hypothetical Example of an AoR Delineation, *continued*

The methodology used here is consistent with the determination of the pressure front for other well classes within the UIC Program (e.g., USEPA, 2002). As explained above, in Section 3.4 of this guidance, this methodology is applicable to any proposed Class VI injection well for which, prior to injection, the injection zone is not over-pressurized compared to the lowermost USDW (i.e., the injection zone has a lower or equal hydraulic head as compared to the lowermost USDW).

The pressure front is determined by calculating the minimum pressure within the injection zone ($P_{i,f}$) necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals. $P_{i,f}$ is calculated using Eq-1 (Section 3.4.1). In this example, $P_{i,f}$ is 14.6 MPa.

Step 2. Inspect Model Results to Determine the Maximum Extent of the Pressure Front (P_f)

The computational model will provide a prediction of the pressures within the injection zone over time. For the purpose of AoR delineation, EPA recommends using the pressure distribution corresponding to the time of maximum lateral extent of the pressure front ($P_{i,f}$). This will likely correspond to a time of maximum injection rates during the operational phase of the project or to the end of a long injection period.

EPA recommends contouring these predictions of pressure increase and providing the predictions on a base map of the proposed project area (Figure 3-4). In this recommended contour map, EPA also recommends highlighting the pressure equivalent to $P_{i,f}$. In the hypothetical example provided here, the region encompassed by $P_{i,f}$ includes the three planned Class VI injection well locations and a significant distance surrounding the area of the proposed injection wells.

<u>Box 3-2. Hypothetical Example of an AoR Delineation, *continued*</u>

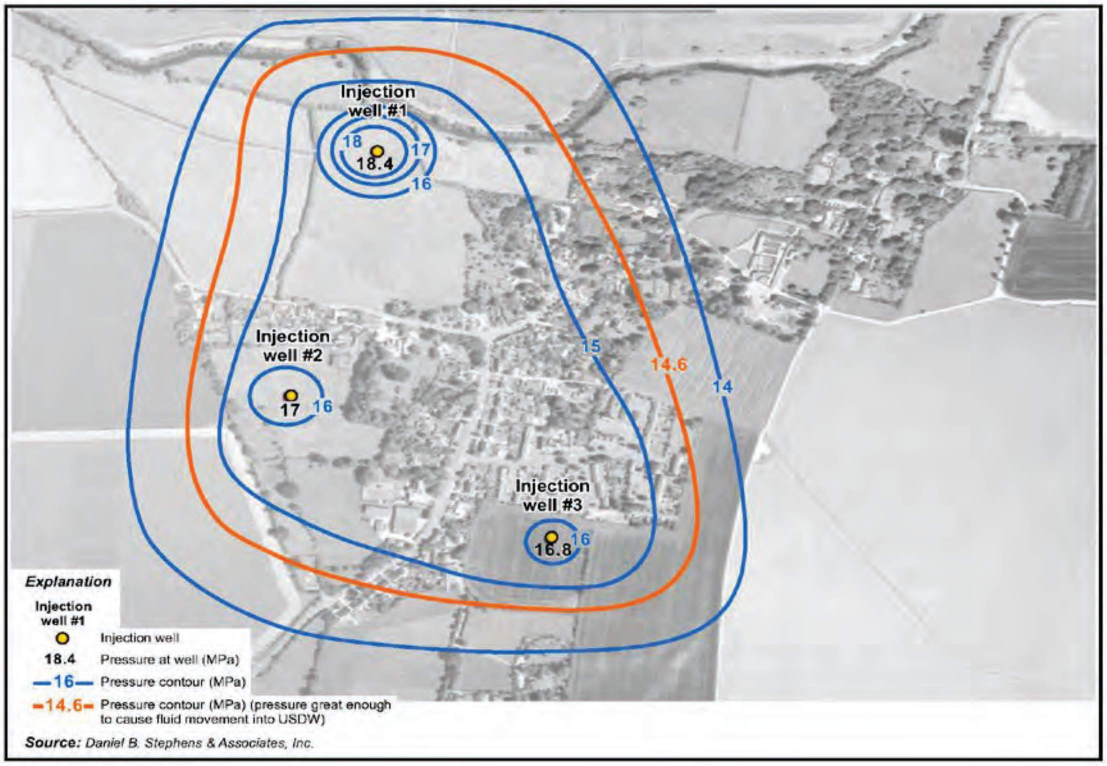


Figure 3-4: Hypothetical Geologic Sequestration Site: Model Predicted Maximum Pressure Within the Injection Zone.

<u>Step 3. Inspect Model Results to Determine the Maximum Extent of the Separate-Phase Plume</u>

The computational model will also provide a prediction of the extent of the separate-phase plume as it evolves over time. EPA recommends that these data be also contoured and provided on a base map (Figure 3-5). In the example provided here, the maximum extent of the supercritical plume, as predicted by the model, exists at 50 years after carbon dioxide injection commences.

<u>Box 3-2. Hypothetical Example of an AoR Delineation, *continued*</u>

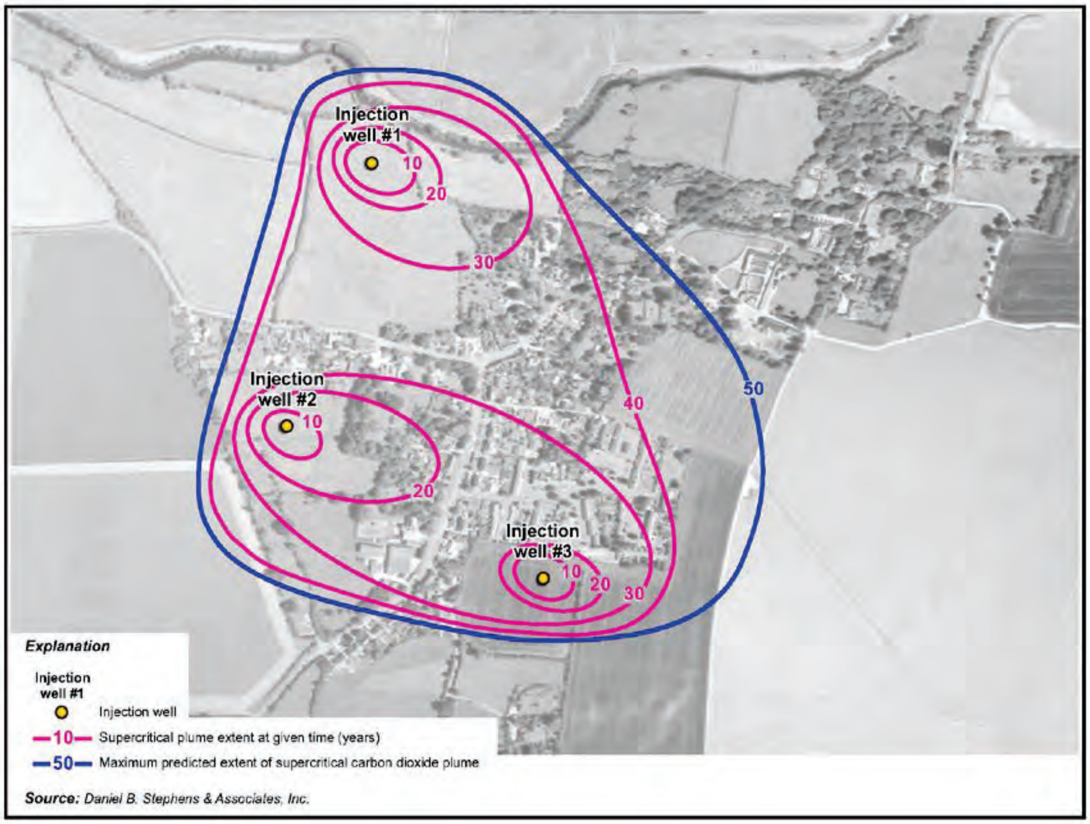


Figure 3-5: Hypothetical Geologic Sequestration Site: Model Predicted Extent of Supercritical Carbon Dioxide Plume Over Time.

<u>Step 4. Delineate the AoR</u>

Lastly, the maximum extent of the separate-phase plume and pressure front is compared and overlaid on the base map (see Figure 3-6). The AoR is delineated by drawing the contour line that encompasses the maximum extent of the separate-phase plume or pressure front (Figure 3-6).

<u>Box 3-2. Hypothetical Example of an AoR Delineation, *continued*</u>

It is important to note that the region encompassed by the pressure front will not in all cases be larger in all directions than the extent of the separate-phase plume. This is because the pressure front does not include all areas exhibiting any increase in pressure, only pressure great enough to cause fluid movement into a USDW. Therefore, pressure differentials may still exist outside of the pressure front, and separate-phase fluids may migrate beyond the extent of the pressure front. For this reason, it is necessary to calculate the extent of both the plume and pressure front to delineate the AoR for a proposed Class VI injection well and to submit these separate delineation results to the UIC Program Director with the permit application.

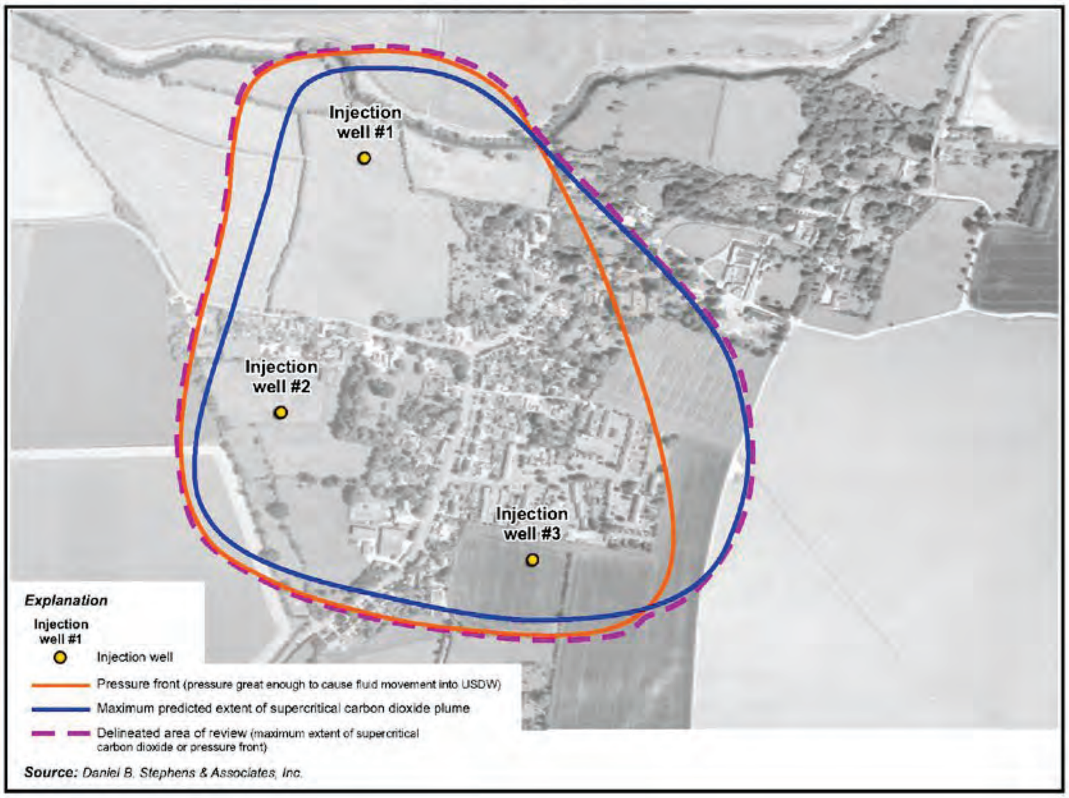


Figure 3-6: Hypothetical Geologic Sequestration Site: Initial Area of Review Based on Model Results.

3.5. Reporting AoR Delineation Results to the UIC Program Director

The owner or operator is required to submit the AoR and Corrective Action Plan with the initial permit application [40 CFR 146.82(a)(13)]. Information pertaining to how this plan should be submitted is provided in the *UIC Program Class VI Well Project Plan Development Guidance*. The final delineated AoR based on computational modeling is submitted to the UIC Program Director prior to receiving authorization to inject [40 CFR 146.82(c)(1)].

EPA recommends that this permit application submittal include all necessary information for the UIC Program Director to evaluate the AoR delineation results and replicate the computational modeling exercise if he or she elects to do so, as well as all model input and output data and files. This may include providing inputs for the UIC Program Director to use in their verification modeling effort. The owner or operator and the UIC Program Director should discuss the specific needs as the permit application is submitted. For additional information on submitting information to support Class VI permit applications, please see the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators.*

EPA recommends that the permit application submittal include the following in support of the AoR delineation:

- The conceptual site model and all supporting data on which the model is based, including the description of geologic stratigraphy and any relevant geologic features. See Box 3-1 of this guidance document for more information;

- Attributes of the code used to create the computational model, including the code name, name of developing organization, a full accounting of or reference to the model governing equations, scientific basis, and any simplifying assumptions;

- A description of the model domain, i.e., the model’s lateral and vertical extents, geologic layer thickness, and grid cell sizes, as presented on maps and cross-sections;

- An accounting of all equations of state used for all fluids modeled (e.g. ground water, carbon dioxide);

- Any constitutive relationships, such as relative-permeability saturation relationships, and how they were determined;

- Values of all model parameters, as detailed in Table 2-1 of this guidance document, throughout the entire model domain, as a function of time if necessary, including initial conditions and boundary conditions, and a description of how model parameters were determined based on site characterization data. This information may be submitted in tabular or graphical/map formats;

- If required by the UIC Program Director, the owner or operator must also include raw model input and output files [40 CFR 146.82(a)(21)]. These files may be useful in model verification, or if the UIC Program Director wishes to run alternative simulations/scenarios with the model;

- Model results, including predictions of carbon dioxide and pressure-front migration over the lifetime of the project. EPA recommends that the model results be presented in the form of contour maps, cross sections, and/or graphs showing plume and pressure front migration as a function of time, and that the permit application submittal include the outcome of parameter sensitivity analyses;

- A description of pressure front calculation and delineation of the AoR; and

- If required by the UIC Program Director, the relevant qualifications and professional experience of any individuals and/or consulting firms responsible for model development, AoR delineation, and reevaluation, including examples of previous multiphase modeling studies conducted.

4. Identifying Artificial Penetrations and Performing Corrective Action

The purpose of AoR delineation for a proposed GS project is to determine the area where any geologic features or artificial penetrations (e.g., wells) may become conduits for fluid movement out of the injection zone, or additional zones, and potentially cause endangerment to a USDW. Artificial penetrations include any man-made structures, such as wells or mines, which provide a flow path out of the injection zone. The Class VI Rule requires that the owner or operator prepare, maintain, and implement a AoR and Corrective Action Plan that includes a description of how corrective action will be performed on any artificial penetrations through the confining zone and whether such action will be phased [40 CFR 146.84(b)(2)(iv)].

This section discusses the identification and evaluation of artificial penetrations and the performance of required corrective action (if necessary). Monitoring activities necessary for detection of fluid leakage into USDWs are discussed in the *UIC Program Class VI Well Testing and Monitoring Guidance*.

4.1. Rule Requirements

The following rule requirements pertain to corrective action within the AoR:

- 40 CFR 146.84(c)(2): Using methods approved by the UIC Program Director, identify all penetrations, including active and abandoned wells and underground mines, in the AoR that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the UIC Program Director may require;

- 40 CFR 146.84(c)(3): Determine which abandoned wells in the AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream;

- 40 CFR 146.84(d): Perform corrective action on all wells in the AoR that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate;

- 40 CFR 146.84(e)(2): During the AoR reevaluation process, identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

- 40 CFR 146.84(e)(3): Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d);

- 40 CFR 146.84(e)(4): Revise the AoR and Corrective Action Plan as necessary whenever the AoR is reevaluated.

4.2. Identifying Artificial Penetrations within the AoR

The Class VI Rule requires potential Class VI injection well owners or operators to identify all artificial penetrations located within the delineated AoR, including active and abandoned wells and underground mines, that may penetrate the confining zone, and provide a description of each well's type, construction, date drilled, location, depth, and if applicable, the record of plugging and/or completion, and any additional information the UIC Program Director may require [40 CFR 146.84(c)(2)]. If the identified abandoned wells have been improperly plugged or not plugged at all, such penetrations can provide unimpeded flow conduits out of the injection zone. As such, they must be properly plugged in order to prevent endangerment of USDWs [40 CFR 146.84(d)].

A variety of types of abandoned wells may exist within the delineated AoR of a proposed GS project, including wells constructed prior to federal or state regulation (i.e., in the late 1800s or early 1900s) and any recently decommissioned wells. Wells constructed during early oil exploration, including cable-tool drilled wells, pose the largest risk because these wells may be relatively deep and often consist of an open (i.e., non-cased) well bore over much of their length. These older wells may also not have been documented in state or local records.

Historically, wells no longer in use may not have been plugged and abandoned by today's common standards. Prior to the early 1900s, there were no regulations concerning well abandonment and it is unlikely that those wells were abandoned properly. Even in states regulating well abandonment, it is likely that any wells abandoned before 1952 may have inadequate plugs (Ide et al., 2006). In 1952, the American Petroleum Institute (API) published its standards for cements for oil and gas wells. Prior to that, cement often lacked sufficient additives to achieve the proper cement setting in the conditions experienced in oil and gas wells. As a result, the plugs in many of these older wells failed to set properly and may have experienced channeling and/or cement failure because of fluid intrusion into the improperly set cement. The potential also exists for more recently constructed wells to have been decommissioned improperly. For example, owners or operators may have gone bankrupt and failed to plug their wells or used substandard materials.

Depending on site conditions and corrosion, "properly" plugged wells may also contain zones (i.e., annular spaces) that could serve as a conduit for fluid movement. In other cases, the well plugs may have degraded over time because of a poor cement job and/or corrosive conditions. Even properly plugged wells may have been plugged with types of cement that could degrade when in contact with a carbon dioxide plume. See the *UIC Program Class VI Well Construction Guidance* for information on compatibility of different materials with a carbon dioxide stream.

Detecting abandoned wells can be very challenging in certain locations because of the variety of wells that may exist. In addition, steel casings, the primary detectable portion of the well, were often removed from abandoned wells for recycling and use during World War II (Gochioco and Ruev, 2006). These challenges are compounded by the potentially large AoR delineation determined for a proposed Class VI injection project, and therefore the greater surface area that will have to be evaluated for the presence of artificial penetrations. However, as discussed below, several methods and sources of information are available to identify those artificial penetrations in a relatively efficient manner. The primary stages of an abandoned well investigation within the AoR include historical research, site reconnaissance, review of aerial and satellite imagery, and one or more geophysical surveys. The reader is referred to additional standard references regarding identification of artificial penetrations for further information (Jordan and Hare, 2002; Frischknecht et al., 1985; ASTM, 2005).

4.2.1. Historical Research

Most deep wells that may penetrate the primary confining zone of a proposed GS project site are related to oil and gas exploration and production. Deep well drilling for oil and gas exploration dates back to the 1870s. State and local databases of well exploration may include locations of abandoned wells, and EPA recommends conducting a records review as the first step in abandoned well identification within the delineated AoR for a proposed Class VI injection well. In addition, state and local records will provide information on the time period and types of exploration that have been conducted in an area, and they may also provide information on typical completion and abandonment methods in a given field. This records search will provide a list of known abandoned wells, and it may inform additional stages of abandoned well identification.

State well databases will, in most cases, provide valuable information for assistance with the identification of abandoned wells. Prior to well construction, a government permitting authority requires owners or operators to seek a permit to drill from a specific agency, such as a state natural resources agency, environmental quality agency, or geological survey. Most states maintain records of drilled wells, including location, construction, operating, and plugging information. Although these records can take many forms, many states now have comprehensive databases of these well records that have been digitized and made available online. However, when conducting this historical records search, owners or operators of proposed Class VI injection wells should be aware that older well records may not have been entered into databases. In some cases, the records from different time periods may be filed in separate locations or on separate types of media.

For example, the Wyoming Oil and Gas Conservation Commission maintains a digital database, accessible online, of wells within the state. (See http://wogcc.state.wy.us for more information on this database.) Basic information is available to the public regarding each well, including geophysical survey results where available. The database can be searched by location, well name, and well number, among other fields. The state also has a "well book" available online, which contains records of older wells not entered in the database.

In addition, county records, including survey maps, ownership records, and chain-of-title and property lease history, maintained by local tax assessors and county clerks, list abandoned wells in many cases. Such records may also indicate land use and indicate areas and timeframes in which drilling activities likely occurred. Private data compilation services often maintain detailed databases for the purpose of oil and gas exploration, including information regarding well locations, plugging, and abandonment. Often these services will maintain maps of known well locations. While these maps can be out of date, most private services have been known to update their database for a fee.

4.2.2. Site Reconnaissance

Site reconnaissance includes interviewing local residents and property owners, as well as conducting a physical search for features indicative of abandoned wells. Initial site reconnaissance may be informed by the historical database research. For example, the records search may indicate that, with a great deal of confidence, certain regions of the AoR have never been subject to oil and gas exploration, deep well injection, or any other activity that may result in deep well penetration. In this case, the owners or operators may choose to exclude those areas from any additional well identification efforts.

Local residents that may be well informed regarding abandoned wells include oilfield workers and service company employees, including consultants, and property and drilling-rights ownership brokers. Such informed residents may be able to provide information on the areas and timeframes where past drilling occurred. They may also be able to give additional details in response to specific questions and provide information on locations, completion methods, and plugging of wells.

Surface features that may be indicative of abandoned wells include abandoned well derricks, access roads, brine pits, or vegetation stress associated with brine leakage. Detection of these features at a site indicates the possible likelihood of one or more wells in the area. EPA recommends that, because the AoR is likely to cover a large area, a surface review for such features is most effectively supplemented by use of aerial surveys or photos.

4.2.3. Aerial and Satellite Imagery Review

EPA recommends that historical aerial photographs and satellite imagery be used in the identification of abandoned wells. Aerial photographic surveys, taken from airplanes, were conducted beginning in the 1930s and are available from a variety of governmental and private information services. All historical aerial photos within the AoR are recommended to be reviewed for evidence of past drilling activity. Surface features that provide a “signature” of drilling activity include drill derricks, rig platforms, brine pits, power sources, and access roads.

Depending on the resolution of the image, satellite (i.e., remote sensing) images may be used to detect wellheads, derricks, and surface features indicative of abandoned wells. These include spatial patterns indicative of a well site, brine pits, modified topography, and vegetation stress associated with brine leakage.

4.2.4. Geophysical Surveys

Geophysical surveys, including magnetic, ground penetrating radar (GPR), and electromagnetic methods, can be used in the detection of abandoned wells. EPA recommends conducting geophysical surveys throughout regions of the AoR that may have been subject to oil and gas exploration, deep well injection, or any other activity that may result in deep well penetration. Geophysical methods will supplement other identification methods, discussed above. Geophysical methods can help to pinpoint locations of known wells where surface evidence of the well has been removed or can help to identify abandoned wells that are undocumented. The type(s) of geophysical surveys conducted at a proposed Class VI injection well site are based on known site subsurface and surface conditions. In general, at least two different types of geophysical surveys are recommended in order to parse data background noise and to inform the interpretation of survey results. As discussed below, ground or aerial (e.g., aeromagnetic) surveys may be conducted, depending on the size of the area of interest.

4.2.4.1. Magnetic Methods

The magnetic method is one of the oldest and most well developed geophysical techniques, and it is the standard method used for abandoned well detection. Magnetic surveys measure a component of the magnetic field near the land surface. Any anomalies in the magnetic field are caused by subsurface features, which could include abandoned well bores with iron or steel casings. Anomalies associated with well casings are typically distinguishable from the background magnetic field.

Magnetic surveys are applicable to abandoned wells with iron or steel casings or to wellheads in areas with relatively low background magnetic signatures. Areas with significant cultural development on the surface or in the shallow subsurface may have high interferences. Airborne magnetic surveys can detect most wells constructed with approximately 200 feet or more of at least 8-inch casing, and in some cases, very large cavities (Frischknecht et al., 1985). However, open well bores, non-steel casings, or severely corroded casings cannot typically be detected with a magnetic survey.

Ground or aerial (i.e., aeromagnetic) surveys may be conducted, depending on the size of the area of interest. Aeromagnetic surveys will likely be more practical for most GS projects due to the anticipated size of the delineated AoR, as they can collect large amounts of data in a relatively short amount of time. Both ground and aerial surveys are conducted along straight-line transects. EPA recommends that that ground survey transect spacing be no larger than 20–30 feet, and aerial survey transect spacing be no larger than 50–100 feet (Jordan and Hare, 2002).

Magnetic surveys may be conducted to measure the total magnetic field, or the vertical or horizontal field gradients. For the purpose of locating abandoned well bores, the total magnetic field measurement type is recommended. During these surveys, EPA recommends that the operator periodically return to a common point to ensure instrument repeatability, continuously measure diurnal variation in the magnetic field, and avoid high magnetic gradients. Data processing of magnetic surveys includes incorporation of spatial positioning data, correction for diurnal variation, and data filtering.

Figure 4-1 compares aeromagnetic survey results for the Coon Creek oil field in Oklahoma to abandoned wells identified from aerial imagery (USGS, 1995). As shown in the figure, magnetic anomalies associated with well casings are typically apparent. However, this figure also reveals some of the typical challenges that may be faced by owners or operators in abandoned well bore identification. One challenge is that, due to the presence of other buried infrastructure (e.g., pipes), certain regions exhibit larger magnetic field values even if wells are not present. Additionally, some wells may not be identified in the aeromagnetic survey, most likely because of well casing removals. These challenges demonstrate the benefits of using multiple survey techniques in order to properly identify abandoned wells.

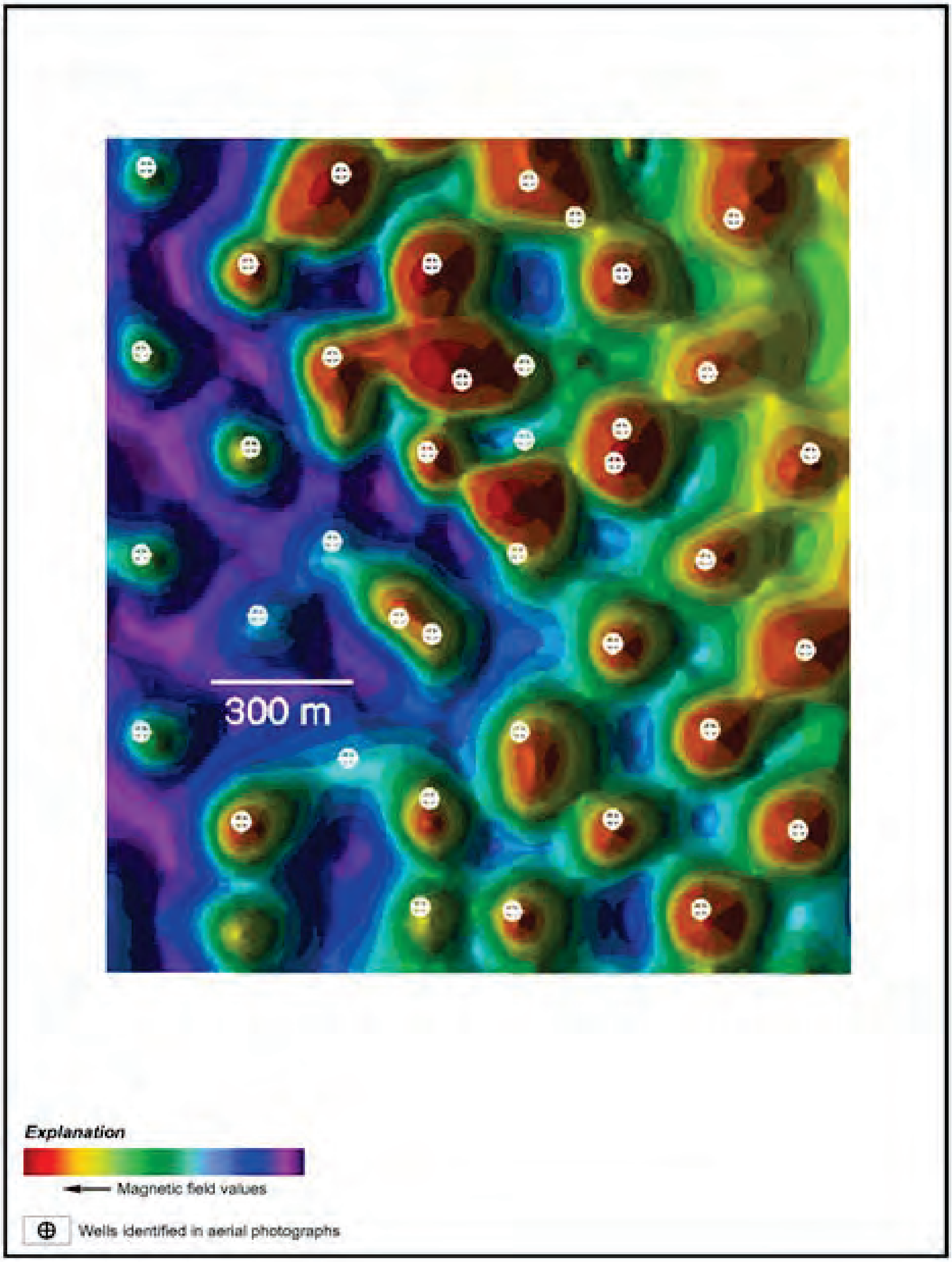


Figure 4-1: Total Field Aeromagnetic Map, Cook Creek Oil Field, Arcadia, Oklahoma.
From: USGS (1995).

4.2.4.3. Electromagnetic Methods

Electromagnetic methods used for abandoned well bore detection include frequency-domain and time-domain electromagnetic surveys. These surveys consist of an electromagnetic transmitter that establishes an electromagnetic field measured by a receiver. Similar to magnetic surveys, electromagnetic surveys are non-invasive, as both the transmitter and receiver are positioned above the ground surface. Both surface and aerial electromagnetic surveys are possible. The depth at which these instruments are able to detect objects depends on the size and geometry of the sensor, the size and conductivity of the target, and the potential interference from other sources, such as fences and pipelines. Generally, object detection at depths ranging from a few meters to several hundred meters is possible. Larger and more complex arrays are required at greater depths. Aerial surveys are not likely able to detect small objects, such as well casings, but may detect brine plumes, which may indicate the presence of abandoned wells (Jordan and Hare, 2002).

Abandoned well bore detection using electromagnetic methods is based on the larger conductivity of steel casings and other well materials compared to surrounding soils and geologic formations. These methods may detect anomalous fluids associated with leakage from an abandoned well. Frequency-domain electromagnetic methods can measure current induced in the subsurface by the electromagnetic field established by the transmitter. Induced current establishes a secondary electromagnetic field detected by the receiver. The magnitude of the induced current is a function of subsurface conditions, including conductivity. Time-domain electromagnetic methods measure the decay of the secondary magnetic field created by the induced current, and they can be especially useful for detection of brine leakage.

4.2.4.4. Ground Penetrating Radar

GPR may be used in abandoned well bore detection and in finding other artificial penetrations. Unlike other geophysical methods, GPR does not rely on the presence of a steel or iron well bore, so it may be able to detect open boreholes and non-metallic materials. GPR uses high frequency radio waves to measure the transmission of electromagnetic energy. The investigation depth possible depends on the frequency of the radio waves and the conductivity of the ground. The greater the depth, the less resolution the instrument will have. For small objects, such as well casings, depths are limited to a few meters (Jordan and Hare, 2002). This depth limitation may lessen the value of GPR in areas with large topographical changes. GPR is also slower than magnetic or electromagnetic methods. GPR is likely not as practical to use throughout the delineated AoR as an initial larger scale survey method because the distance between transect lines for sufficient resolution is too small. Instead, EPA recommends using GPR to determine the exact location of abandoned well bores within a given area that have already been identified by earlier, larger scale surveys.

4.3. Assessing Identified Abandoned Wells

After all artificial penetrations within the AoR that may penetrate the confining zone have been identified, the owners or operators of a proposed Class VI injection well must evaluate the potential for each artificial penetration to serve as a conduit for fluid movement. In particular, owners or operators must establish which abandoned wells in the AoR, if any, have not been plugged in a manner that would prevent the movement of carbon dioxide or other fluids that may endanger USDWs [40 CFR 146.84(c)(3)]. To prevent fluid movement, abandoned wells should include a cement plug through the primary confining zone, and/or across the injection zone/confining zone contact, with sufficient integrity to contain separate-phase carbon dioxide and elevated pressures. The type of plugging that is sufficient to contain carbon dioxide and formation fluids from the injection zone will be site specific and should be reviewed with the UIC Program Director. In the absence of an adequate plug across the confining zone, cross-migration may occur where fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone. See Figure 4-2 for more information. EPA recommends cement surface plugs (typically required by well abandonment regulations), and the UIC Program Director may require additional plugs based on site-specific circumstances.

Evaluation of the wells in the AoR requires a two-step approach. The first step is to review whatever records are available, as outlined in Section 4.3.1, for information relevant to proper plugging. The second step is to perform physical tests on wells that are suspect or for which no records are available.

4.3.1. Abandoned Well Plugging Records Review

A records review can aid in reducing the number of identified wells that may need to be evaluated by future field testing. Records of wells that have been recently abandoned, have no mentions of any difficulties experienced during the abandonment procedure, are cased holes, and have plugs and cement situated to isolate the injection zone from other fluid containing zones may be used to justify reduction in the number of follow-up field investigations. If records are incomplete or indicate that the well has not been plugged or was inadequately plugged, follow-up field investigations should be performed. Identified undocumented wells will have no records and will require field investigation in order to determine the quality of plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. The owner or operator may also choose to plug any questionably abandoned wells rather than go through the expense of evaluating the plugs.

There are many elements in existing reports that can help in determining the adequacy of abandonment procedures for identified wells located within the AoR. Some key elements to review include, but are not limited to:

- Well depth and completion;
- Well abandonment date;
- Open hole or cased hole;
- Location of plugs;
- Casing and cementing records;
- Records of mechanical integrity tests (MITs) or logs performed; and
- Well deviation.

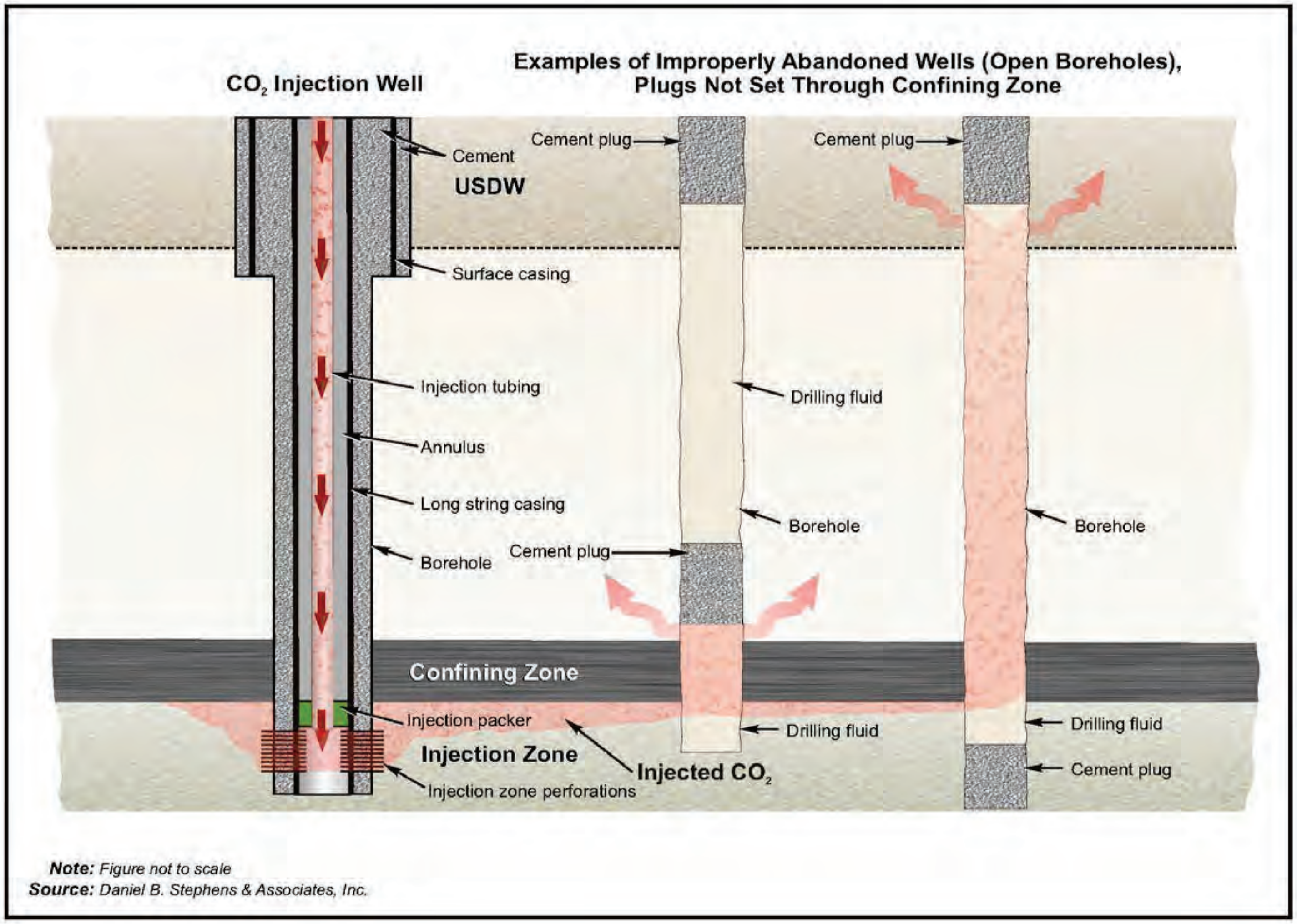


Figure 4-2: Examples of Carbon Dioxide Leakage Through Improperly Abandoned Wells.

The well completion depth is important in determining if the identified abandoned well may penetrate the proposed confining zone(s). If the well completion depth is above the confining zone(s), no further action would likely need to be taken. The date of abandonment may also provide information as to the adequacy of the abandonment procedure. Whether the well was abandoned with casing or as an open hole is an important consideration in determining the likelihood that the well might act as a conduit for fluid movement. Open holes are susceptible to cross-migration between aquifers. If the hole is open and there is not a proper plug located at a depth corresponding to the primary confining zone, fluids may migrate out of the injection zone and into a USDW. For cased holes, EPA recommends that integrity of the casing be evaluated.

The location and type of plugs are also important factors, especially in open-hole wells. The plug locations must be reviewed in order to determine the quality of plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. For example, EPA recommends that the injection zone be isolated from all other formations with plugs. This may be especially important if a well was completed in a formation deeper than the proposed injection zone. EPA recommends that any length of the well in the proposed injection zone be properly isolated by means of plugs and casing. Mechanical plugs and cemented casing are not sufficient for the long-term isolation of carbon dioxide, as eventually the metal is likely to corrode and the plug will fail (Randhol et al., 2007). Therefore, cement plugs are considered superior to mechanical plugs for preventing the movement of fluids into or between USDWs. EPA recommends that cement plugs be located across the bottom of any casings, at the base of the lowermost USDW, and that plugging fluid (i.e., composition, specific gravity) characteristics be considered, as drilling fluid of sufficient weight may resist displacement by the injectate or mobilized fluids.

The integrity of any existing casing and cement must be determined in order to assess the quality of well construction and plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. EPA recommends reviewing the casing and cement quality through the proposed injection zone in order to ensure that they are appropriate for contact with carbon dioxide, as well as reviewing any additional well records that may indicate unusual conditions experienced during casing and cementing. Events such as a loss of circulation, well bore stability problems, lack of the use of centralizers, and/or improper removal of drilling mud before cementing can all lead to premature cement or casing failure. Reviewing load calculations, if available, and comparing them to actual events recorded in the drilling log may give the owners or operators an indication of an under-designed casing that may be susceptible to failure. For example, if the casing had a low axial loading stress and stuck pipe was experienced during casing placement, it is possible that the casing may have experienced damage. The materials used for the well casing and cement must also be assessed to see if they are compatible with carbon dioxide, in order to comply with Class VI Rule requirements [40 CFR 146.84(c)(3)]. See the *UIC Program Class VI Well Construction Guidance* for more information on compatibility of different materials with a carbon dioxide stream.

Any tests performed on the well prior to its abandonment can also be useful information. An MIT such as a pressure test, noise log, temperature log, or cement evaluation log can provide information on any known or suspected leaks. If leaks were encountered, EPA recommends determining if the source of the leak was found and repaired. If the leaks were not sealed, corrective action would be required to be taken to plug the leaks as discussed below [40 CFR 146.84(d)]. Drilling records can yield clues as to areas that might be susceptible to failure. Mud logs and open-hole caliper logs can show areas of weak formations. Weak formations are susceptible to well bore instability and subsequent cement failure. Cement evaluation logs and temperature logs taken at the time of completion can also give an idea of the condition of the cement, although degradation is always possible after well completion. Any corrosion logs will help provide information on the condition of the casing. Results from mechanical caliper logs, electromagnetic thickness logs, or down-hole video can show the casing condition when the well was abandoned. For more information regarding these logs and tests, see the *UIC Program Class VI Well Testing and Monitoring Guidance*.

Evaluation of well records for deviation during drilling may also identify wells more likely to be in need of corrective action, as deviated wells are far more likely to fail than wells with no deviation (Watson, 2009). Events such as well bore collapse during drilling or conditions that placed unusual loads on the casing may also indicate a higher chance of failed well bore integrity. EPA recommends that the design casing load also be checked to ensure adequacy for the actual loads faced by the well.

4.3.2. Abandoned Well Field Testing

After all the available records have been reviewed, any wells located within the AoR that cannot be proven to have plugs adequate to prevent migration of carbon dioxide or formation fluids out of the injection zone must be evaluated by field tests in order to determine the quality of plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. Evaluation and corrective action for wells which the plume is not expected to reach in the near future may be phased. If the owner or operator chooses and the UIC Program Director agrees, the evaluation may be omitted and the wells re-plugged. If the integrity of the bottom plug or cement is in question, and records cannot prove that the plugging is adequate, EPA recommends that the surface plug and possibly additional plugs down-hole be drilled out and tests conducted to determine the adequacy of abandonment. There are numerous field tests available to evaluate the integrity of abandoned wells. Several of these tests are discussed in detail in the *UIC Program Class VI Well Testing and Monitoring Guidance*. Additionally, the owner or operator must demonstrate guaranteed site access to wells potentially needing corrective action in the future [40 CFR 146.84(b)(iv)]. The owner or operator is encouraged to consult the UIC Program Director regarding any difficulties in gaining site access in order to evaluate and perform corrective action on any identified improperly plugged abandoned wells.

EPA recommends that both the casing and the cement plugs be evaluated. Casing failure is most common at joints and in weak formations where instability around the well bore can lead to failed cement and to casing buckling. Weak formations are also common areas for cement failure, as are high pressure formations, due to fluid intrusion. Tools used to evaluate the cement and casing include, but are not limited to:

- Multi-finger caliper log;
- Sonic scanner;

- Ultrasonic imaging tool;
- Cement evaluation log;
- Radioactive tracer;
- Cased hole dynamic tester;
- Modular sidewall coring tool; and
- Cased hole fluid test.

Multi-finger caliper logs measure the radius of the borehole in a non-destructive way. They can give a 360-degree picture of the inside of the casing and identify any defects caused by corrosion, erosion, or other events (e.g., dropped tools).

A sonic scanner sends out sound waves and measures the returned waves in receivers. The log provides information on the quality of the casing-cement bond and the cement-formation bond. The sonic scanner averages the results for the entire radius and therefore cannot provide three-dimensional pictures of the cement bond, or determine the reasons for a poor quality cement bond. An ultrasonic imaging tool is another non-destructive tool that uses ultrasonic transmitters and receivers to determine information about the casing and cement. The ultrasonic imaging tool can return 360-degree information on casing thickness, cement thickness, and cement bond. More information on these tools can be found in Duguid and Crow (2007) and Close et al. (2009).

A cement evaluation log is another tool used and log results include information on both the cement and the bond quality. This log provides results that are averaged over the circumference of the well, and testing is typically conducted in combination with an ultrasonic imaging tool to provide more complete information on the three-dimensional picture of the well. In some cases, the cement hardens while the well casing is under pressure and, when pressure is released, microannuli can form between the casing and cement. If unconnected to other cracks, these microannuli cannot transmit fluid, but they will appear in logging results as a potential poor bond. This artifact can be evaluated by performing the cement evaluation log under pressure (Randhol et al., 2007). Radioactive tracers also can be used to detect leaks in casing and cement and fluid leaking along channels in the well bore. Radioactive tracers are injected down the well, and gamma detectors are used to detect any fluid flow.

Cased-hole dynamic testers measure mobility or porosity. They can be used to determine the porosity of the cement. They are semi-destructive tests as they do create a small hole in the casing and cement; however, the hole is patched after the test is run. The instrument works well in highly permeable formations or in cement, while performance in lower porosity formations is still under investigation.

Modular sidewall coring tools take small cores of the casing and cement for analysis in the laboratory. Laboratory analyses can include scanning electron microscopy, X-ray diffraction, and measurements of permeability and density. This is a more destructive test that leaves approximately 1-inch diameter holes in the side of the well, which is then patched with a remedial cement squeeze after testing is completed. Cased-hole fluid testers can be run with the cased-hole mobility tool, using optical instruments to determine what fluids are present in the formation outside the well bore.

In general, EPA recommends that these tests be run sequentially, from the simplest and least destructive tests to the more complicated and destructive tests. This way, if a flaw is found with a simpler test that determines that the well should be plugged or otherwise remediated, the more expensive and destructive tests may be avoided. The typical order of running the tests is caliper log, sonic and ultrasonic tools, cased-hole mobility and fluid tests, and then sidewall cores (Duguid and Crow, 2007). This set of tools can be used to determine the quality of the casing and cement; if flaws such as degraded cement porosity, casing corrosion, microannuli in the cement, channels between the cement and casing or cement and formation, or missing cement are found, the Class VI Rule requires that corrective action be performed on the well [40 CFR 146.84(d)]. A brief summary of the main methods for evaluating cement and casing condition along with major benefits and disadvantages are included in Table 4-1 below.

Table 4-1: Tools for Assessment of the Integrity of Abandoned Wells.

Tool	Target	Advantages	Disadvantages
Multifinger calipers	Casing	Non-destructive, relatively simple	Only examines interior, only detects casing damage
Sonic Logs	Cement	Non-destructive, yields information on cement bond	Results averaged over well circumference, can't indicate reasons for poor quality bond
Ultrasonic Logs	Casing, Cement	Non-destructive, can detect flaws in casing and cement, provides three-dimensional images	Sensitive to well fluids
Cement evaluation log	Cement	Non-destructive, yields information on quality of cement bond	Results averaged over well circumference
Tracers	Leak detection	Can pinpoint routes of leaks, channeling	Radioactive tracers require special handling and may have negative public perception
Dynamic Cased Hole Tester	Cement	Can determine porosity of cement	Semi-destructive, untested in low porosity conditions
Sidewall coring	Cement	Can give detailed analysis of cement condition	Destructive

4.4. Performing Corrective Action on Wells Within the AoR

The Class VI Rule requires that owners or operators of Class VI injection wells perform corrective action on all artificial penetrations in the AoR that may penetrate the confining zone and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement and endanger USDWs [40 CFR 146.84(d)]. In performing corrective action, owners or operators must use methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate [40 CFR 146.84(d)]. Figure 4-3 presents a decision tree that illustrates how the various evaluation tools can be used together to evaluate abandoned wells in an efficient and logical manner.

As described above, the Class VI Rule allows owners or operators to perform corrective action on a phased basis, if approved by the UIC Program Director. If a phased approach is approved for performing corrective action for a GS project, EPA recommends that all required corrective action on wells identified as deficient during the permit application process (or AoR reevaluations) receive corrective action prior to the end of the injection phase.

It is possible that some corrective action may be performed during the post-injection phase. For example, if the plume and pressure front movement were to deviate from predictions, this may necessitate corrective action for newly identified artificial penetration during the post-injection phase.

Performing corrective action on improperly abandoned wells is intended to prevent the movement of carbon dioxide or other mobilized fluids into or between USDWs. Acceptable forms of corrective action include well plugging and/or remedial cementing of the improperly abandoned well. In addition to corrective action, EPA recommends performing enhanced monitoring in the vicinity of improperly abandoned wells, including ground water monitoring and using indirect geophysical techniques for obtaining monitoring results. Appropriate monitoring for Class VI injection wells is discussed in the *UIC Program Class VI Well Testing and Monitoring Guidance*.

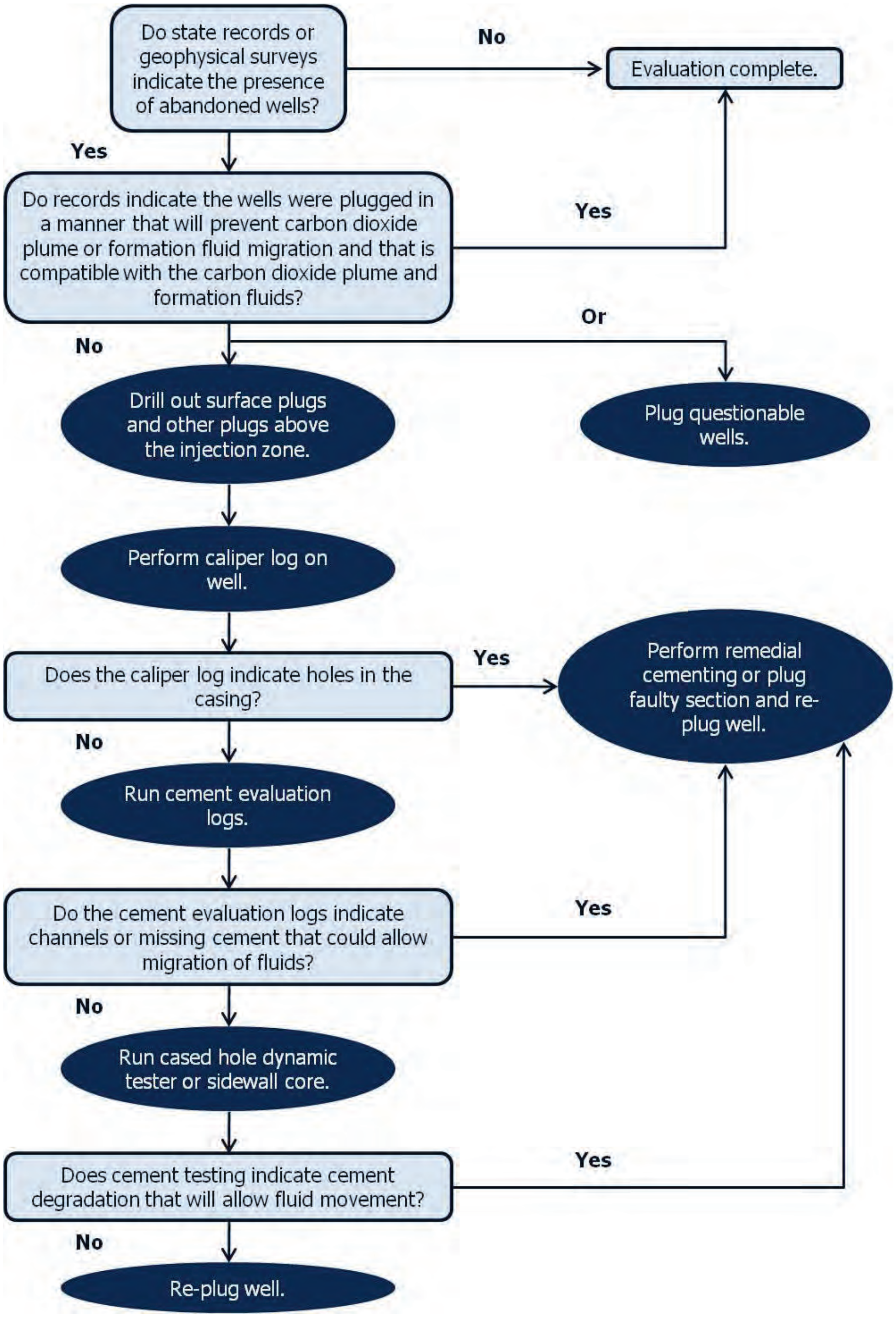


Figure 4-3: Well Evaluation Decision Tree.

4.4.1. Plugging of Wells within the AoR

Plugging of Class VI injection wells at the cessation of the injection phase of the project is discussed in detail in the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure*. This section focuses on the plugging of improperly abandoned wells within the AoR prior to the commencement of injection. However, because similarities exist in plugging techniques for abandoned wells and former injection wells, the reader should refer to the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure* for further detail regarding well plugging techniques for Class VI injection wells.

A well requires plugging if records indicate that an abandoned well was not plugged, was plugged and abandoned improperly, or has not been plugged in a manner that prevents movement of carbon dioxide or other fluids that may endanger USDWs [40 CFR 146.84(c) and (d)]. In addition, where records indicate that a well plug does not exist at a depth corresponding to the primary confining layer of the GS project, EPA recommends that the well have an additional plug set at this depth to meet the requirements of the Class VI Rule. Where records indicate that there are no well plugs below USDWs or other permeable formations that may exhibit cross flow of mobilized fluids, additional plugs may be required by the UIC Program Director for proper corrective action in these zones. Also, in wells that were plugged but the evaluation techniques discussed in Section 4.3 of this guidance document reveal cracks, channels, or annuli in the plug that would allow fluid migration, EPA recommends drilling out and replacing the plug. In addition, if the plug material may corrode in a carbon-dioxide rich environment, EPA recommends replacing it. For wells where casing exists at depths corresponding to the injection and/or confining zone and the annular space may serve as a conduit for fluid movement if not properly cemented, remedial cementing may be necessary or the casing may need to be removed and replaced with a cement plug. See Section 4.4.2 of this guidance document for more information on remedial cementing.

For the plugging of improperly abandoned wells within the AoR, EPA recommends that a plug be set at a depth interval corresponding to the primary confining zone overlying the injection zone of the Class VI injection well. In the absence of an adequate plug across the confining zone, cross-migration may occur wherein fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone. See Figure 4-2 of this guidance document for more information. However, in order to supplement the confining-zone plug, ideal additional plugging zones include the bottom of any casings and across any USDWs. A surface plug would also typically be required by local well abandonment regulations to ensure that there is no risk of anyone physically falling into the well bore.

To provide the best possible barrier to carbon dioxide migration out of the injection zone, EPA recommends that corrective action be conducted in a manner to provide multiple barriers to carbon dioxide migration and avoid underground cross-flow. Materials that are compatible with the carbon dioxide must be used where appropriate [40 CFR 146.84(d)]. Material compatibility with carbon dioxide is discussed further in the *UIC Program Class VI Well Construction Guidance*.

4.4.2. Remedial Cementing

Properly cementing improperly abandoned wells located within the delineated AoR between any existing well casing and the geologic formation, especially through the injection zone, provides an important fluid migration barrier. EPA recommends performing remedial cementing in order to meet the corrective action requirements of the Class VI Rule if a well has been properly plugged but the records, or any testing such as that described in Section 4.3 of this guidance, indicate that the cement surrounding the well bore has failed or has cracks, channels, or annuli that could allow migration of carbon dioxide. Key areas on which to focus remedial cementing include depths corresponding to the injection zone and through any other permeable zones.

Remedial cementing is performed through squeeze cementing, where the cement is emplaced into the affected area. For more information on cement squeezes, refer to Reynolds and Kiker (2003). Increased pressure on the cement forces water out of the cement slurry leaving behind the partially dehydrated cement. Cement squeezes can either be low pressure or high pressure. Low pressure squeezes are used to set a small amount of cement in a given area and operate at a pressure lower than the fracture pressure of the formation. Higher pressure squeezes are used when channels or disconnected microannuli are to be cemented. The higher pressure squeezes may fracture the formation and then allow the cement to flow into disconnected channels.

Cement squeezes can be performed using either a packer or a bradenhead squeeze. The methods differ in how the treated section is isolated from the rest of the well. In the packer squeeze, packers isolate the area to be treated, and a bridge plug isolates the area below the area to be cemented, while a modified packer with a bypass valve isolates the area above the treated area. Cement retainers are used if significant back pressure is expected. A bradenhead squeeze only isolates the area below the area to be cemented. It is typically used only if the casing above the treated area is strong enough to withstand the squeeze pressure. In cement squeezes, either drillable packers or retrievable packers can be used. Drillable packers allow less freedom in placement but better control of the cement. They are preferred if high pressures are maintained on the cement after the squeeze.

Cements used in squeeze cementing can vary depending on the nature of the defect. The Class VI Rule requires that all materials used for cementing of abandoned wells be compatible with the carbon dioxide stream, where appropriate [40 CFR 146.84(d)]. Traditional cements may be supplemented with or replaced by materials such as polymer gels and acrylic grouts. Acrylic grouts can be used for small casing leaks or cases where pressure leak off is detected. High concentration low molecular weight polymers can be used for small to moderate leaks. High molecular weight polymers are typically used for channeling and lost circulation applications. Cement or cement/polymer blends are typically used for severe leaks (Randhol et al., 2007).

4.5. Reporting Well Identification, Assessment, and Corrective Action to the UIC Program Director

As discussed in the *UIC Program Class VI Well Project Plan Development Guidance*, the AoR and Corrective Action Plan, submitted with the initial stage of the permit application, must indicate what well identification and assessments will be used and how corrective action will be conducted [40 CFR 146.84(b)(2)(iv)]. The plan is a condition of the permit and is subject to UIC Program Director approval [40 CFR 146.84(b)].

Owners or operators seeking a Class VI injection well permit are required to report the following information regarding abandoned wells within the AoR that may penetrate the primary confining zone: the well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information required by the UIC Program Director [40 CFR 146.82(a)(4)]. This information may be found in acceptable public and private databases, where available. See Section 4.2.1 for more information. In cases where available records do not provide the necessary information or indicate that the well was plugged improperly, in a questionable manner, or with materials inappropriate for contact with carbon dioxide, then site investigations must be performed to establish the condition of the well, as discussed previously [40 CFR 146.84(c)(3)].

The UIC Program Director will review the submitted well information to ensure completeness and may consult with officials at oil and gas or water agencies to ensure that the well search was thorough. The UIC Program Director will also review well completion records to determine those wells that may penetrate the primary confining zone and will likely compare this list to wells scheduled for corrective action and submitted with the Class VI injection well permit application. For those identified abandoned wells that have been determined by the owner or operator to not require corrective action, the UIC Program Director will likely review the records of plugging and any field testing conducted, to verify that the well does not require corrective action. If information on the depth or condition of the plug(s) is missing, the UIC Program Director may request additional tests or require the well to be re-plugged.

Reports of any tests done on abandoned wells must be submitted to the UIC Program Director with the permit application along with a list of wells for which corrective action will be conducted, as part of the AoR and Corrective Action Plan required at 40 CFR 146.84(b). Before receiving authorization to inject, the owner or operator must submit a report on the status of corrective action [40 CFR 146.82(c)(6)], indicating the number, type, and location of the plugs. EPA recommends that owners or operators also submit any records of remedial cementing with the Class VI injection well permit application, along with cement logs showing the methods used and the results of the remedial cementing. Testing and remedial cementing records for wells which are part of a planned later stage of corrective action may be submitted after that phase is completed.

5. AoR Reevaluation

The Class VI Rule requires owners or operators of permitted Class VI injection wells to reevaluate the AoR delineation on a regular basis, at a frequency of at least once every five (5) years [40 CFR 146.84(e)]. The purpose of AoR reevaluation is to ensure that the initial model predictions are adequate for predicting the extent of the separate-phase carbon dioxide plume and pressure front. To this end, AoR reevaluation consists of a comparison of modeling predictions and the required site monitoring data [40 CFR 146.90] and a revision of the model used to delineate the AoR when necessary. Because Class VI injection well permits are granted for the lifetime of the project, AoR reevaluation is the primary opportunity for the owner or operator and the UIC Program Director to assess the project's operation and take additional appropriate actions, if necessary, to protect USDWs. If a revision of the AoR delineation is necessary, a revision of the AoR and Corrective Action Plan is also required [40 CFR 146.84(e)(4)], along with other related project plans that may be dependent on the extent of the delineated AoR, including the Testing and Monitoring Plan [40 CFR 146.90(j)]. It is important to note that a change in the AoR and/or the AoR and Corrective Action Plan after the permit is issued may constitute a modification of the Class VI permit, and would be subject to public notice [40 CFR 144.39(a)(5)(i)].

Reevaluations of the AoR must continue throughout the life of the GS project, including the post-injection phase [40 CFR 146.84(e)]. It is likely that, following cessation of injection, the area of increased pressure will reduce in size as pressures dissipate; therefore, EPA expects that the reviews will entail an examination of monitoring data and confirmation and communication to the UIC Program Director that no modifications to the AoR or amendments to any plans are needed. However, this step is necessary to ensure that USDWs are not endangered and that all of the plans in force (including the PISC and Site Closure Plan and the Emergency and Remedial Response Plan) remain protective of USDWs.

5.1. Class VI Rule Requirements Related to AoR Reevaluation

The following Class VI Rule requirements pertain to reevaluation of the AoR:

- 40 CFR 146.84(e): At the minimum fixed frequency, not to exceed five years, as specified in the AoR and Corrective Action Plan, or when monitoring and operational conditions warrant, owners or operators must:

    (1) Reevaluate the AoR in the same manner specified in 40 CFR 146.84(c)(1);

    (2) Identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

    (3) Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d); and

    (4) Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments

to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

5.2. Conditions Warranting an AoR Reevaluation

AoR reevaluation is required at a minimum fixed frequency of at least once every five years, or when monitoring and operational conditions warrant [40 CFR 146.84(e)]. EPA recommends that monitoring and operational conditions that may warrant a reevaluation of the AoR include:

- Significant changes in site operations that may alter model predictions and the AoR delineation;
- Monitoring results for the injected carbon dioxide plume and/or the associated pressure front that differ significantly from model predictions; or
- New site characterization data obtained that may significantly change model predictions and the delineated AoR.

Any site-specific criteria that will trigger an AoR reevaluation for a particular project must be included in the AoR and Corrective Action Plan [40 CFR 146.84(b)(2)(ii)].

5.2.1. Minimum Fixed Frequency

As stated above, the owners or operators of permitted Class VI injection wells must reevaluate the AoR delineation at least once every five years [40 CFR 146.84(e)]. The planned fixed frequency for reevaluation must be included in the AoR and Corrective Action Plan [40 CFR 146.84(b)(2)(i)]. The AoR may need to be reevaluated more frequently than the previously scheduled timeframe based on other factors. In these cases, the schedule for AoR reevaluation may be updated appropriately. At no time may AoR reevaluation occur less than once every five years [40 CFR 146.84(e)].

5.2.2. Significant Changes in Operations

Significant changes in operation of the GS project and/or individual Class VI injection wells mandate an AoR reevaluation [40 CFR 146.84(e)]. The UIC Program Director may require an AoR reevaluation prior to approving any operational changes. If allowed by the UIC Program Director, operational changes may occur prior to reevaluation of the AoR. In these cases, EPA recommends that the AoR reevaluation be submitted to the UIC Program Director within an agreed-upon timeframe of instituting such changes, as described in the AoR and Corrective Action Plan.

EPA recommends that proposed operational changes warranting an AoR reevaluation may include, but are not limited to, a change in the location or number of Class VI injection wells injecting into the same injection zone and/or a change in carbon dioxide injection rates, volumes, or pressures outside of the limits of the original permit and AoR delineation. Additional operational changes that may warrant an AoR reevaluation, if required by the UIC Program Director, include a change in the composition of the injectate or changes in fluid production rates from the injection or overlying zones. Based on the discretion of the UIC Program Director, short-term routine operational changes (e.g., temporary well shut-ins) may not warrant reevaluation of the AoR.

In addition, the owner or operator may choose to perform an AoR reevaluation based on other operational changes, with the approval of the UIC Program Director. Specific operational triggers for an AoR reevaluation for a particular Class VI injection well must be included in the AoR and Corrective Action Plan submitted with the permit application for that particular injection well [40 CFR 146.84(b)(2)(ii)]. Operational changes that trigger a reevaluation may be associated with the GS project under which the permitted Class VI injection well operates or with separate projects that inject carbon dioxide into the same injection formation.

5.2.3. Results from Site Monitoring that Differ From Model Predictions

EPA recommends that collection of any monitoring data (required under 40 CFR 146.90) that indicate carbon dioxide and/or pressure front migration significantly different than that predicted by the current AoR delineation model warrant an AoR reevaluation. Specific criteria for differences in monitoring data and model predictions that may trigger an AoR reevaluation for a particular project must be included in the AoR and Corrective Action Plan [40 CFR 146.84(b)(2)(ii)]. In such cases, when monitoring data and modeling predictions differ, the owner or operator is encouraged to notify the UIC Program Director and submit an AoR reevaluation within timeframes that have been established in the AoR and Corrective Action Plan. Methods for monitoring the evolution of the carbon dioxide plume and associated pressure front are discussed in more detail in the *UIC Program Class VI Well Testing and Monitoring Guidance.* An example of evaluation of monitoring results during AoR reevaluation is provided in Box 5-1.

The owner or operator is required to perform monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure [40 CFR 146.90(g)]. Pressure monitoring is required using direct methods (e.g., pressure transducers) within the injection zone, and indirect methods for plume tracking are also required unless the UIC Program Director determines, based on site-specific geology, that such methods are not appropriate [40 CFR 146.90(g)(1) and (2)]. Additionally, the owner or operator is required to perform periodic monitoring of ground water quality and geochemical changes above the primary confining zone that may be a result of carbon dioxide movement through the confining zone [40 CFR 146.90(d)]. On a site-specific basis, the UIC Program Director may require additional geochemical monitoring within the injection zone as a component of carbon dioxide plume tracking [40 CFR 146.90(i)].

EPA recommends that pressure measurements indicative of pressure-front migration further than that predicted by the current computational model warrant an AoR reevaluation. In practice, this would be indicated by an observed increase in pressure at monitoring wells greater than predicted by the computational model. In some cases, pressure measurements may fluctuate, and short-term temporary pressure increases (e.g., spikes) may not warrant an AoR reevaluation. EPA recommends that the specific pressure monitoring results that would trigger an AoR reevaluation be included in the AoR and Corrective Action Plan. For example, the owner or operator may specify the magnitude and duration of increased pressure that would trigger an AoR reevaluation for each monitoring well.

Results of carbon dioxide plume and pressure-front tracking using indirect methods, such as periodic geophysical surveys, may also be used for comparison to model predictions. Geophysical survey results provide information over relatively large areas, as opposed to "point" measurements provided by monitoring wells. Geophysical survey results are intended to provide an estimate of the extent of the separate-phase carbon dioxide plume and, in some cases, pressure changes. EPA anticipates that results of indirect monitoring that indicate carbon dioxide migration (1) outside of the boundaries of the current AoR delineation, or (2) at rates significantly greater than current model estimates would also warrant an AoR reevaluation.

EPA also recommends performing an AoR reevaluation if the results of the ground water geochemical sampling indicate separate-phase (i.e., supercritical, liquid, or gaseous) carbon dioxide migration outside of the boundaries of the current AoR delineation, or at rates significantly greater than predicted by the computational model. The presence of separate-phase carbon dioxide in the sampled fluids above the confining zone is evidence of carbon dioxide/fluid migration out of the injection zone and is cause to notify the UIC Program Director pursuant to 40 CFR 146.91(c)(1). In addition, elevated carbon dioxide aqueous concentrations may indicate the presence of separate-phase carbon dioxide in the immediate vicinity of the monitoring well.

5.2.4. Ongoing Site Characterization

Site characterization is not a one-time exercise at GS project sites. As additional site characterization data are collected via geophysical surveys, the drilling of new injection or monitoring wells, or from other sources, the data must be subsequently incorporated into the existing computational model used for AoR delineation [40 CFR 146.84(c)(1) and (e)(1)]. Types of data that may be incorporated into a reevaluation include newly identified potential conduits for fluid movement, updated information regarding injection or confining zone extent and thickness, or further characterization of formation heterogeneity. The UIC Program Director may also require an AoR reevaluation based on any newly available site characterization data that may impact current modeling predictions.

5.3. Performing an AoR Reevaluation

The first step in performing an AoR reevaluation for a Class VI injection well is a comparison of the available monitoring data and the model predictions. If Class VI owners or operators believe that monitoring and modeling data are consistent and that revision of the model is not necessary, they must demonstrate this to the UIC Program Director in lieu of revising the computational model [40 CFR 146.84(e)(4)]. However, if monitoring data and modeling predictions differ significantly, then the Class VI owner or operator must submit an amended AoR and Corrective

Action Plan and revise both the computational model and the AoR delineation results [40 CFR 146.84(e)(1) and (4)].

Box 5-1. Hypothetical Example of an AoR Reevaluation

An AoR reevaluation consists of comparing monitoring results of plume and pressure-front movement to model predictions. In this hypothetical example, a continuation of the scenario presented earlier in Boxes 3-1 and 3-2, the AoR reevaluation required after 20 years of injection is illustrated below. In this example, the previously required AoR reevaluations at 5, 10, and 15 years did not result in any AoR delineation modifications.

Comparison of Plume Monitoring Data

In this hypothetical scenario, monitoring data are available from eight monitoring wells screened within the injection zone and from an indirect geophysical monitoring technique. Monitoring well data are used to assess the potential presence of separate-phase carbon dioxide at each location. The data indicate that separate-phase carbon dioxide is present at one of the monitoring wells. These data are compared to initial model predictions of plume evolution for 20 years after the commencement of injection (Figure 5-1). Carbon dioxide is detected at MW-6, outside of the areas predicted by the model to exhibit carbon dioxide.

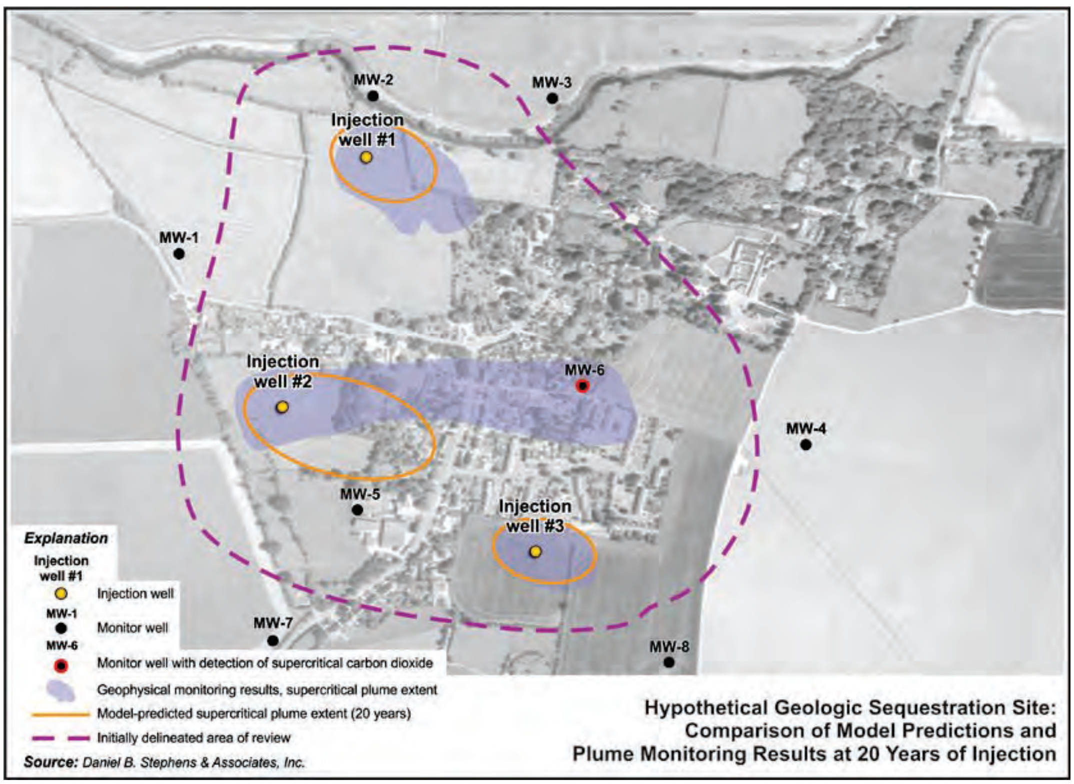


Figure 5-1: Hypothetical Geologic Sequestration Site: Comparison of Model Predictions and Plume Monitoring Results at 20 Years of Injection.

Box 5-1. Hypothetical Example of an AoR Reevaluation, *continued*

Compared to monitoring well data, geophysical data provide a larger-area estimate of the extent of separate-phase carbon dioxide. The geophysical and monitoring-well data are consistent in their general evaluation of where separate-phase carbon dioxide is present. Geophysical data and model results are generally consistent for the plume emanating from Injection Well #3, and inconsistent for Injection Wells #1 and #2. The carbon dioxide plume may have migrated differently than originally predicted for several reasons, as discussed below.

<u>Comparison of Pressure Monitoring Data</u>

Bottom-hole pressure data are collected at all of the eight monitoring wells. This example focuses on data collected at three of the wells, MW-1, MW-2, and MW-6. For actual projects, EPA recommends that data from all monitoring wells be considered. Graphs of pressure monitoring data over the first 20 years of the project, compared to modeling results, are presented in Figure 5-2.

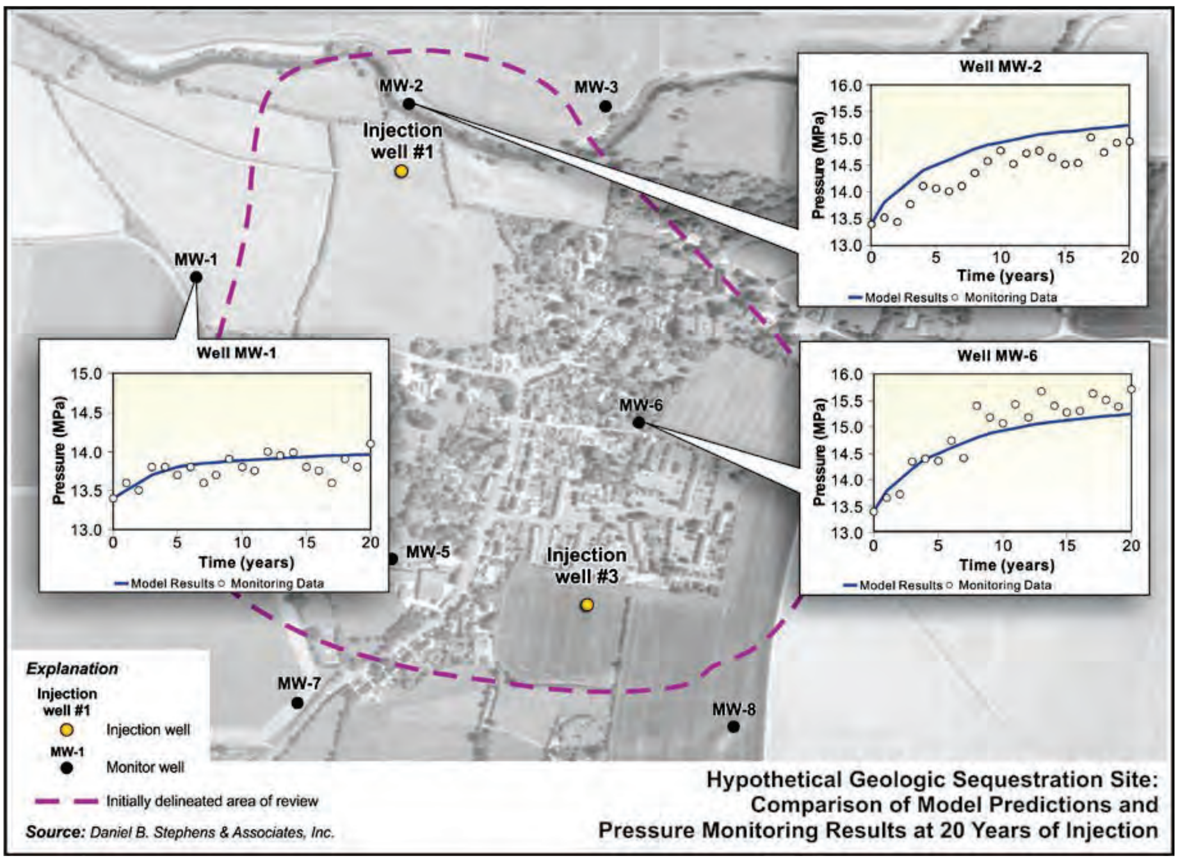


Figure 5-2: Hypothetical Geologic Sequestration Site: Comparison of Model Predictions and Pressure Monitoring Results at 20 Years of Injection.

Box 5-1. Hypothetical Example of an AoR Reevaluation, *continued*

Pressure monitoring data are consistent with modeling predictions on the western edge of the project (MW-1). The general scatter in the monitoring data are expected, and there is no significant bias (i.e., less than, greater than) in comparing the monitoring data and modeling results. Data from the northern portion of the project (MW-2) indicate that actual pressure increases in the injection zone are lower than model predictions. This area has exhibited less of a pressure perturbation caused by injection than originally predicted. In contrast, data from the eastern portion of the site (MW-6) indicate that there has been a larger pressure increase than originally predicted. These data are generally consistent with the plume migration data, presented above, which showed that the plume has migrated further east than originally predicted.

<u>Outcome of Monitoring Data and Model Comparison</u>

This comparison indicates that, after 20 years of injection, modeling results and monitoring data compare favorably in some regions of the site. However, the plume and pressure front appear to have migrated further to the east than initially predicted. This disparity may be due to several factors. Examples include the presence of a high-permeability pathway within the injection zone that had not been fully characterized during initial site characterization, or the dip angle at the injection zone/confining zone interface being larger than originally assumed. Based on this comparison, the operator of the project site, in consultation with the UIC Program Director, decided to calibrate the AoR model and re-delineate the AoR. See Box 5-2 for more information.

5.3.1. Demonstrating Adequate Existing AoR Delineation

An AoR reevaluation does not necessarily need to result in revisions or updates to the site computational model. If the owner or operator determines that no changes are necessary, the required reevaluation may consist of demonstrating this to the UIC Program Director [40 CFR 146.84(e)(4)]. EPA recommends that demonstrating the adequacy of the current AoR delineation includes verification that existing operational and site characterization data have been incorporated into the model and that existing monitoring data agree with the modeled predictions.

EPA recommends that the Class VI injection well owners or operators submit any new operational, monitoring, or site characterization data that have been received since the last AoR reevaluation to the UIC Program Director. EPA also recommends that details regarding how this information has been incorporated into the site computational model be presented, as newly received operational or site characterization data may impact model input parameter values.

Integral to demonstrating that the current AoR delineation is adequate is the comparison of monitoring data and model predictions. EPA recommends that this comparison take the form of graphics and informative maps showing the general agreement between monitoring results and model predictions, and that all available monitoring data be considered, including fluid geochemistry monitoring, pressure monitoring, and geophysical surveys.

5.3.2. Modifying the Existing AoR Delineation

Any significant differences between operational monitoring results and the existing model predictions that are the basis for the AoR delineation, for example as discussed in Section 5.2.3 of this guidance document, warrant a modification to the existing AoR delineation [40 CFR 146.84(e)]. The steps in revision of the AoR delineation include adjusting the site conceptual model, model calibration (i.e., adjusting model parameters), and presentation of adjusted model results and the newly delineated AoR to the UIC Program Director.

EPA recommends that the site conceptual model be revised based on new site characterization, operational, and, in some cases, monitoring data. The new conceptual site model schematic may be provided to the UIC Program Director along with the AoR reevaluation information, with any changes highlighted. Examples of changes to the conceptual model include new injection wells, newly elucidated geologic features (e.g., stratigraphic layers), or a revised permeability field.

Following revision of the site conceptual model, revision of the existing AoR delineation may require model calibration in order to minimize the differences between monitoring data and model simulations (see Section 2.5 of this guidance). EPA recommends that the relative error difference between monitoring data and model predictions be quantified via the use of calibration statistics (e.g., ME, MAE, RMSE). To the extent possible, the value of the calibration statistics should be minimized during model calibration. The value of the model calibration statistics also informs the expected uncertainty and error in model predictions of future conditions. Following model calibration, the AoR delineation may be revised using methods described in Section 3.4 of this guidance.

In reporting an AoR computational model and delineation revision, EPA recommends that all model attributes, as given in Section 3.5 of this guidance document, be re-submitted to the UIC Program Director. In addition, EPA recommends that the model calibration process and final AoR delineation results be presented in detail as part of the submission with:

- Adjusted input parameter values listed;
- Graphs comparing observed and modeled values of carbon dioxide migration and fluid pressure;
- Model results showing carbon dioxide and pressure front migration over time included; and
- The value of the model calibration statistics.

The newly delineated AoR may be presented on maps which would highlight similarities and differences in comparison with previous AoR delineations. See Box 5-2, below, for an example of a hypothetical AoR reevaluation.

If a revision of the AoR delineation is necessary, an amendment to the AoR and Corrective Action Plan is also required, along with possible amendments to other related project plans [40 CFR 146.84(e)(4) and (f)]. EPA recommends that the amended AoR and Corrective Action Plan explain any differences in corrective action activities that result from AoR revision, including a demonstration of adequate surface access rights in order to perform the required corrective action activities. See Section 4 for more information on performing corrective action. Furthermore, in some cases, GS project attributes that are outside the scope of the Class VI Rule and the UIC Program, such as pore-space ownership rights, may be related to the size of the AoR. In these cases, the owners or operators are encouraged to consult with the UIC Program Director, or another applicable regulatory agency, following a revision of the AoR in order to proceed.

Box 5-2. Hypothetical Example of a Presentation of the Revised AoR

After the site computational model has been revised through model calibration to monitoring data, and/or updating with new operational or site characterization parameters, the AoR must be re-delineated [40 CFR 146.84(e)]. See Box 3-2 for more information on AoR delineation; the same general methods should be used during the reevaluation. Once the AoR has been revised, it may be presented on a site base map in comparison to the former AoR delineation (Figure 5-3).

In this hypothetical example, the AoR reevaluation has resulted in an AoR delineation that extends generally farther toward the east than previously. This is consistent with the monitoring data (Box 5-1) indicating further plume and pressure front migration toward the east. The model was revised to match monitoring data by adjusting intrinsic permeability values within the injection zone and the dip angle at the injection/confining zone interface.

The region newly identified as located within the delineated AoR (between the purple and blue contour lines) must be subjected to the artificial penetration identification, assessment, and corrective action procedures as discussed in Section 4 of this guidance document [40 CFR 146.84(e)(2) and (3)]. Furthermore, the revision of the AoR requires revisions to the AoR and Corrective Action Plan and other project plans, as discussed in the *UIC Program Class VI Well Project Plan Development Guidance*. Changes to the AoR and Corrective Action Plan may demonstrate a need to secure new surface access rights for the newly included area. The owner or operator may also contact the applicable regulatory agency for other project attributes (e.g., new pore space ownership rights) that are outside the scope of the Class VI Rule and the UIC Program.

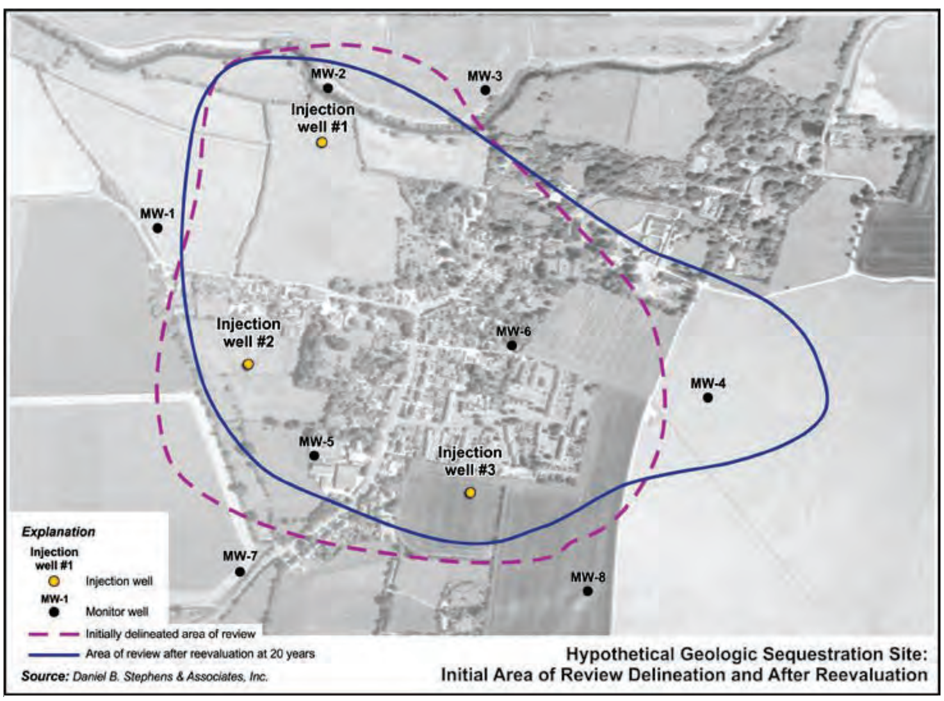


Figure 5-3: Hypothetical Geologic Sequestration Site: Initial AoR Delineation and Delineation after Reevaluation.

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Original Research Article

GREENHOUSE GASES SCIENCE AND TECHNOLOGY

Risk-based area of review estimation in overpressured reservoirs to support injection well storage facility permit requirements for CO_2 storage projects

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Abstract: This paper presents a workflow for delineating a risk-based area of review (AOR) to support a US Environmental Protection Agency (EPA) Class VI permit for a carbon dioxide (CO_2) storage project. The approach combines semianalytical solutions for estimating formation fluid leakage through a hypothetical leaky wellbore with the results of physics-based numerical reservoir simulations. The workflow is demonstrated using a case study for a hypothetical 180,000-metric-ton-per-year storage project located in the Plains CO_2 Reduction (PCOR) Partnership region, which includes all or part of 10 states in the United States and four Canadian provinces. Under the scenario where the leaky wellbore is open to a saline aquifer (thief zone) between the overlying seal (cap rock) and the underground sources of drinking water (USDW), the risk-based AOR is no larger than the areal extent of the CO_2 plume in the storage reservoir because the pressure buildup in the storage reservoir beyond the CO_2 plume is insufficient to drive formation fluids up a hypothetical leaky wellbore into the USDW. However, even under the conservative assumption that the leaky wellbore is not open to a thief zone, the incremental leakage beyond the areal extent of the CO_2 plume is less than 400 m^3 over 20 years. The approach outlined in this paper is designed to be protective of USDWs and comply with the Safe Drinking Water Act requirements and provisions for the EPA Class VI Underground Injection Control (UIC) Program (Class VI Rule) and North Dakota Administrative Code Chapter 43-05-01. © 2021 Society of Chemical Industry and John Wiley & Sons, Ltd.

Additional supporting information may be found online in the Supporting Information section at the end of the article.

Keywords: area of review (AOR); class VI rule; storage facility permit; CCS

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Introduction

Carbon capture and storage (CCS) is a process that captures carbon dioxide (CO_2) from an industrial facility, preventing its release to the atmosphere, and injects it via one or more injection wells into a deep geologic reservoir for permanent storage. CCS is a key technology option to mitigate CO_2 emissions while allowing the full range of economic and societal benefits derived from fossil fuels. The Plains CO_2 Reduction (PCOR) Partnership, funded by the US Department of Energy (DOE), the North Dakota Industrial Commission (NDIC), and participating member organizations, is fostering the deployment of CCS in the PCOR partnership region. The PCOR partnership region covers the central interior of North America and includes all or part of 10 US states (Alaska, Iowa, Minnesota, Missouri, Montana, Nebraska, North Dakota, South Dakota, Wisconsin, and Wyoming) and four Canadian provinces (Alberta, British Columbia, Manitoba, and Saskatchewan). The Energy & Environmental Research Center (EERC) at the University of North Dakota leads the PCOR partnership, with support from the University of Wyoming and the University of Alaska at Fairbanks.

In the United States, the US Environmental Protection Agency (EPA) regulates the construction, operation, permitting, and closure of injection wells used to place fluids underground for storage. The federal regulations for the Underground Injection Control (UIC) Program are found in Title 40 of the Code of Federal Regulations. The Safe Drinking Water Act (SDWA) establishes requirements and provisions for the UIC Program.[1] Regulations for CCS fall under the Class VI Rule of the UIC Program – *Wells Used for Geologic Sequestration of CO_2*. The Class VI Rule requirements are designed to protect underground sources of drinking water (USDWs). On April 24, 2018, EPA approved an application from the state of North Dakota under the SDWA to implement a UIC Program for Class VI injection wells located within the state, except within Indian lands. Therefore, in the state of North Dakota, Class VI injection wells and the associated storage facility permit for the storage project are managed under the North Dakota Century Code (Chapter 38-22, *Carbon Dioxide Underground Storage*) and the North Dakota Administrative Code Chapter 43-05-01 (*Geologic Storage of Carbon Dioxide*). Any state such as North Dakota is said to have primacy if EPA has delegated it the responsibility for implementing a regulatory framework equivalent to the federal Class VI UIC Program.

In North Dakota, a CO_2 storage project (hereafter '*storage project*') comprises a *storage facility* (an area on the ground surface, defined by the operator and/or regulatory agency, which is occupied by CO_2 injection facilities and storage activities, including monitoring, take place) and a *storage complex* (a subsurface geologic system comprising a storage unit and primary and possibly secondary seal(s), which extend laterally to the defined limits of the CO_2 storage operation or operations).[2] The primary regulatory permit for a *storage project* in North Dakota is the *storage facility permit*, a major technical component of which is the delineation of the *area of review* (AOR). The AOR is defined as the region surrounding the *storage project* where USDWs may be endangered by the injection activity (40 CFR 146.84 and North Dakota Administrative Code Section 43-05-01-05.1. *Area of review and corrective action*). EPA[3] guidance for delineation of the AOR includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a 'critical pressure' that could potentially drive higher salinity formation fluids from the storage reservoir up an open conduit to the lowermost USDW. The methods described in EPA[3] for estimating the AOR under the Class VI Rule were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and around the United States, some storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW even prior to the planned storage project.[4] Consequently, applying the assumed-equilibrium methods of EPA[3] to these geological situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for delineating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer *et al.*[5] described the unnecessary conservatism in EPA's definition of the critical pressure, which could lead to a heavy burden on storage facility permit applicants. As an alternative, the authors proposed a risk-based reinterpretation of this framework that would allow for

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a reduction in the AOR while ensuring protection of drinking water resources. As described by Birkholzer *et al.*,[5] brine requires a pressure gradient to move upwards along a leakage pathway and impact a USDW. The mere presence of saline fluids at the location of a permeable pathway is not sufficient to pose a risk of contamination to the USDW. Thus, leakage of brine is a concern for drinking water resources only if the pressure increase due to injection is large enough to drive brine from the injection formation to the elevation of the lowermost USDW. In the current document, 'risk-based' refers to quantifying the potential impacts to the USDW resulting from the flow of brine from the storage reservoir to the USDW under different input assumptions, accounting for the storage reservoir, leaky wellbore, and aquifer properties. This risk-based approach contrasts with the default EPA[3] assumptions, which presume that all locations above the critical pressure pose a potential leakage risk and must therefore be included in the AOR. While a site-specific risk assessment would include well failure modes, their likelihood over the performance period, and the likely permeability of each of these failure mechanisms, the approach described herein uses representative leaky wellbore effective permeability values to illustrate the risk-based AOR process that could be further adapted to address site-specific conditions.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg *et al.*,[6,7] who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur during CO_2 injection. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven *et al.*[8] and Avci,[9] which were creatively solved, coded, and compiled in FORTRAN under the name ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described in Cihan *et al.*[10,11] (hereafter ASLMA Model'). Recently, White *et al.*[12] outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, the NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

The current work applies the ASLMA Model to an anonymized potential storage project ('storage project example') in the PCOR partnership region to illustrate how the workflow described by Oldenburg *et al.*[6,7] can be used for risk-based AOR estimation to support a Class VI storage facility permit. The proposed workflow leverages the ASLMA Model by incorporating custom scripting to more easily include broader uncertainty quantification and by combining it with the results from physics-based numerical reservoir simulations to estimate the risk-based AOR. In addition, this work examines the effect of an intermediary saline aquifer between the storage reservoir and USDW, which is designated as a 'thief zone' because vertically migrating fluid is lost to this saline aquifer thereby lowering the vertical hydraulic head gradient with increasing vertical location in a leaky wellbore and thereby decreasing, or nearly eliminating, vertical fluid migration above the saline aquifer to the USDW. The thief zone phenomenon was described by Nordbotten *et al.*[13] as an 'elevator model,' by analogy with an elevator full of people on the ground floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The workflow and tools described in this paper provide a detailed workplan for delineating the AOR for a proposed storage project and to periodically reevaluate the delineation.

Methods

This section describes the ASLMA Model in general and how it is applied (Risk-based AOR workflow Section); describes the required output from compositional reservoir simulation (Compositional reservoir simulation Section); describes how results from multiple ASLMA runs are combined for AOR delineation (Model analysis Section); and describes calculation of the site-specific ASLMA parameters for the storage project example used to demonstrate this workflow (Site-specific model parameters Section). The scripts used for the workflow are introduced in the customized R code for multiple model runs Section.

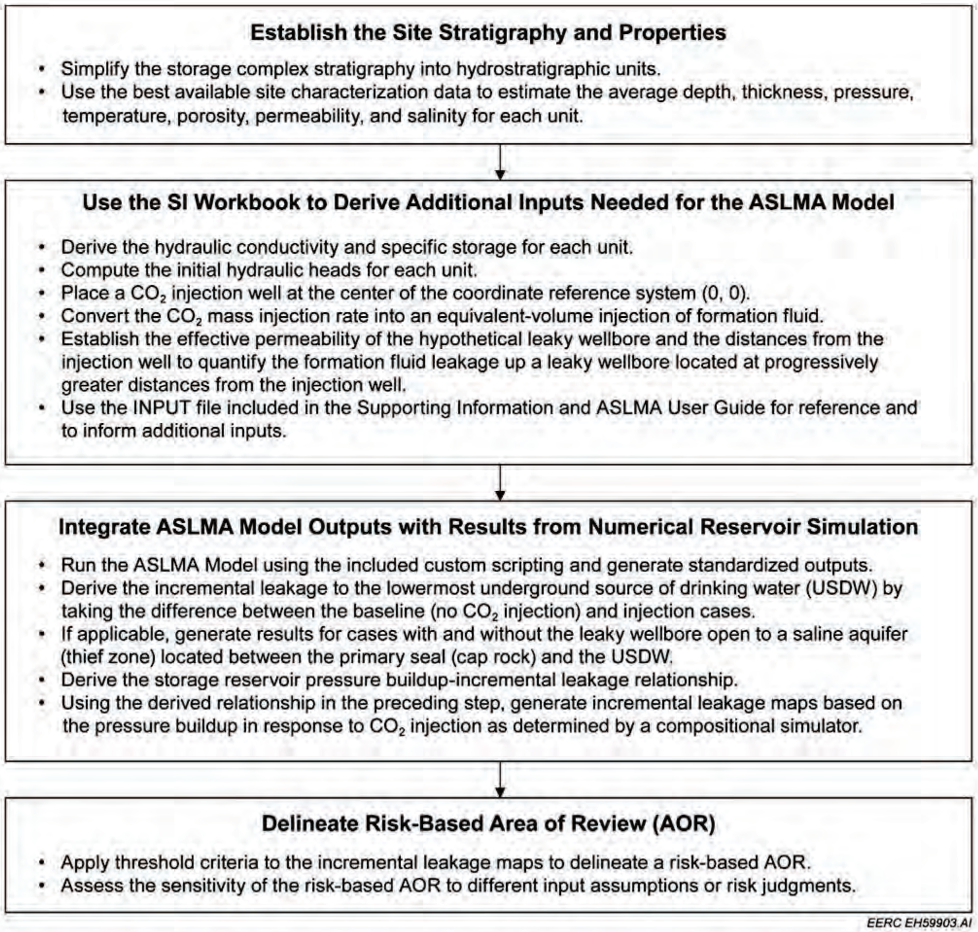

Figure 1. Workflow for delineating a risk-based AOR for a storage facility permit.

Risk-based AOR workflow

The workflow presented here extends the work of Oldenburg *et al.*[6,7] by combining the results of numerical reservoir simulation with results from an ensemble of ASLMA runs to incorporate pressure buildup heterogeneity that may occur in the simulated reservoir during injection. To delineate a risk-based AOR based on the amount of potential leakage along a hypothetical conduit into the lowest USDW, the ASLMA ensemble defines potential leakage as a function of reservoir pressure increase over the injection period. In areas near an injection well, pressure increase and potential leakage are greater than in areas far from the injection well. This relationship between reservoir pressure increase and leakage into the USDW is applied to a map of pressure buildup from reservoir simulation to translate reservoir pressure increase at the end of simulation to potential leakage into the USDW over the simulated period of injection. As a result, for a given injection scenario, an anisotropic risk map is produced where relative leakage risk can be assessed according to the volume of potential brine leakage into the USDW.

Figure 1 summarizes the workflow used in this study to develop a risk-based AOR for a storage facility permit. The methods described in the remainder of this section describe each step in the workflow and refer to Supporting Information for additional details.

ASLMA Model

The storage facility permit requires that the operator 'predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the CO_2 plume and its associated pressure front in the subsurface from the commencement of injection activities until the plume movement ceases, or until the end of a fixed time period as determined by the commission' (North Dakota Administrative Code Section 43-05-01-05.1 *Area of review and corrective* *action*). However, the associated pressure front (pressure buildup in the storage reservoir) caused by CO_2 injection typically extends beyond the CO_2 plume (and 0.5-mile buffer region) and, consequently, drives the delineation of the AOR. Therefore, delineation of the AOR typically focuses on pressure buildup in the storage reservoir during a given period of time.

Building a geologic model using a commercial-grade software platform like Schlumberger Petrel and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform like Computer Modelling Group's compositional simulator, GEM (CMG-GEM), provide the 'gold standard' for estimating pressure buildup in response to CO_2 injection.[14] However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that is unwarranted given the amount of uncertainty that may be present if only a few nearby wells are present and/or can be used for characterization activities.

This work uses a reduced-order model (ROM) for simulating reservoir injection and pressure that was developed by Lawrence Berkley National Laboratory called 'ASLMA'. The ASLMA Model has been extensively described in Cihan *et al.*[10,11] A brief overview of the solution approach is described below. The analytical solution assumes single-phase flow in a multilayered system of aquifers and aquitards, which has been shown to be applicable for far-field pressure changes beyond the CO_2 plume.[10,11,15–17] The version used in the current study does not account for diffuse brine leakage (i.e., flux through aquitards) and only accounts for focused brine leakage (i.e., flow through wells).[11] Because the ASLMA Model is a single-phase model, multiphase processes are not incorporated into the solution. However, injection of a single-phase fluid (brine) with an equivalent volume of CO_2 compared well with the numerical model, TOUGH2-ECO$_2$ N, and provided accurate results for pressures beyond the CO_2 plume and brine leakage zone.[10,11,16] These results show that multiphase processes inside the CO_2 plume may be assumed negligible for prediction of far-field pressure buildup. However, because the analytical solution does over-predict pressure build-up within the CO_2 plume, this study restricts the ASLMA modeling outputs to distances of greater than 2 km from the injection location.[11] All aquifers and aquitards are assumed to be homogeneous, with uniform thickness and infinite radial extent. Fluid flow is horizontal in the aquifers and vertical in the aquitards. Leaky wells are represented as Darcy-type flow pathways, and the user may specify well *X*- and *Y*-coordinates, the hydraulic conductivity of well-aquifer segments, and the radius of the well.[11] The equations of horizontal groundwater flow in the aquifers are coupled to the vertical-flow equations in the aquitards and the flow-continuity equations in the leaky wells. The governing partial differential equations for single-phase flow in aquifers and aquitards are transformed into the Laplace domain, and the resulting coupled system of ordinary differential equations are solved using the eigenvalue analysis method.[11] The ASLMA Model is compiled in FORTRAN, and the model output includes pressure buildup in the different geologic units with time and the cumulative leakage of brine from the storage reservoir (Aquifer 1) into the overlying aquifers (i.e., Aquifer 2 [thief zone and Aquifer 3 [USDW] in the storage project example).

The proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and the resultant effects of this buildup on the vertical migration of formation fluid via a (single) leaky wellbore. Multiple ASLMA runs are needed to define a general solution for the relationship between reservoir pressure increase and potential USDW leakage at a specific site. After establishing the site stratigraphy (Fig. 2) and average properties (Table 1), the next step in the risk-based AOR workflow is to generate the set of input parameters needed to implement the ASLMA Model. A macro-enabled Microsoft Excel workbook with built-in visual basic application (VBA) functions, which is included in Supporting Information of this paper, provides the calculations needed to determine ASLMA Model (SI Workbook).

Hypothetical leaky wellbore

In our storage project example, no wellbores are known to exist that penetrate the primary seal (cap rock) within the study area. However, for heuristic, what-if scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA

Table 1. Average hydrostratigraphic properties for the storage project example.

Hydrostratigraphic Unit	Depth (m)*	Thickness (m)	Pressure (MPa)	Temperature (°C)	Porosity (%)	Permeability (m^2)	Salinity (ppm)	Total Head (m)
Overlying Units to Ground Surface (not directly modeled)		473						
Aquifer 3 – USDW (Fox Hills Fm)	473	88	5.2	21.2	34	2.76×10^{-13}	1 800	759
Aquitard 2 – Additional Seals (Pierre–Inyan Kara Fms)	562	900	10.0	35.6	10	9.87×10^{-17}	5 800	759
Aquifer 2 (thief zone – Inyan Kara Fm)	1 462	142	15.1	50.8	20	3.95×10^{-13}	10 000	761
Aquitard 1 – Primary Seal or Cap Rock (Swift-Broom Creek Fms)	1 604	334	17.5	57.7	10	9.87×10^{-17}	40 000	728
Aquifer 1 – Storage Reservoir (Broom Creek Fm)	1 938	96	22.0	64.0	25	3.33×10^{-13}	65 000	936

*Ground surface elevation 750 m amsl.

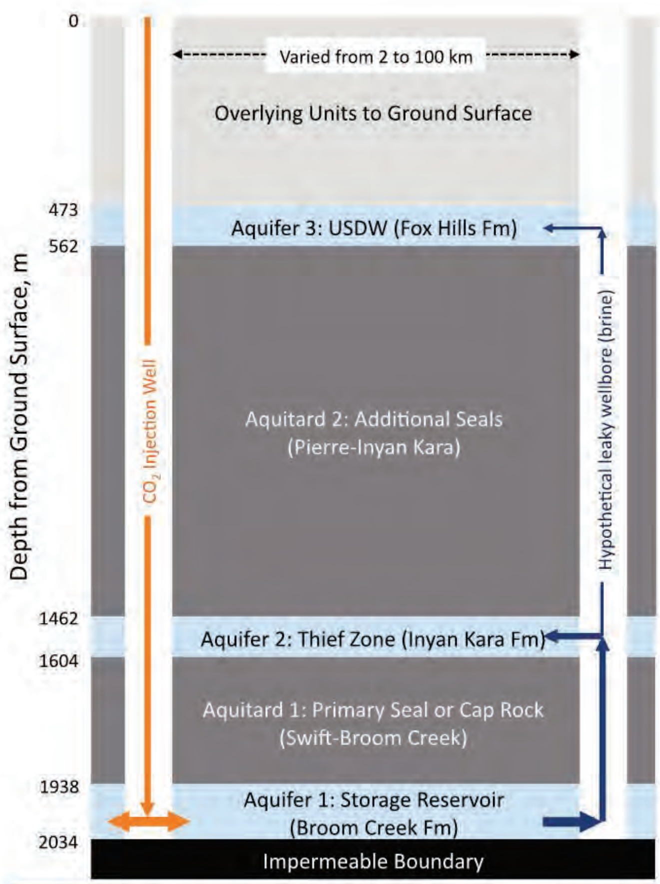

Figure 2. Simplified stratigraphy and well relationships used to represent the storage complex. See Table 1 for average properties of each unit shown.

model for each of multiple runs. The leaky well is located at incrementally larger distances of 2, 3, …, 100 km from the CO_2 injection well ('leaky well distance'). The pressure buildup in the storage reservoir at each leaky well distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 20-year injection period, provide the data set needed to derive the risk-based AOR. As described above, both reservoir pressure increase and potential USDW leakage decrease as leaky well distance increases.

ASLMA case matrix and results

All ASLMA runs for a given site scenario are set up using consistent hydrostratigraphic parameters, but parameters describing the injection well (injection rate) and hypothetical leaky wellbore (distance from injector) are varied to produce raw results that are postprocessed to generate curves representing the relationship between reservoir pressure buildup and leakage into the USDW. For each hydrostratigraphic scenario, one ASLMA run is performed with no injection ('baseline case') and an arbitrary distance (e.g., 2 km) between the injector and the leaky well. This case represents the system without CO_2 injection, to determine the amount of leakage from the reservoir

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into overlying aquifer(s) under the assumption of an overpressurized reservoir. For each leaky well distance (e.g., 2, 3, …, 100 km), an additional ASLMA run is performed with CO_2 injection. ASLMA runs at multiple leaky well distances are a requirement of this method.

If a single thief zone aquifer is present in the hydrostratigraphic framework as in the storage project example, two ASLMA runs are performed for each leaky well distance, one with the thief zone open to the leaky wellbore ('thief zone on') and one with the thief zone closed to the leaky wellbore ('thief zone off'). Additional thief zones can be considered individually or in combination. For example, if two thief zones ('A' and 'B') are present, ASLMA can be run with the following combinations: A on, B off; A off, B on; A on, B on; and A off, B off, for each leaky well distance. Thief zones are recognized as a special case of sensitivity analysis because they must be described in the hydrostratigraphic scenario, regardless of on/off status for a given run.

Each ASLMA run gives a single-point pressure buildup in and flow to/from each aquifer (reservoir, thief zone, or USDW) according to the case matrix. The compositional reservoir simulation Subsection describes the postprocessing steps to combine output data from ASLMA runs to determine potential leakage over a range of reservoir pressure increase values.

Compositional reservoir simulation

Previous work by Oldenburg *et al.*[6,7] used ASLMA to estimate potential leakage from a CO_2 storage reservoir into a USDW as a function of injection duration and distance from injector. The current efforts extend previous work by directly relating reservoir pressure increase to potential leakage volume over the period of injection. Benefits of this approach include the ability to use compositional reservoir simulation of a heterogeneous geologic model as a source of pressure buildup, rather than a homogeneous model generated in ASLMA or other analytical software, and the ability to generalize results to account for more than one injector without needing to build each injector location into the ASLMA Model.

Compositional reservoir simulation to support the current workflow can be performed in any software that can produce a map of the change in pressure in the reservoir over the injection period. Maps may be of average or maximum change in pressure per location or change in pressure at a single grid layer, depending on representativeness (as judged for each project) and amount of pressure heterogeneity in the simulation results.

Model analysis

Calculating the potential incremental leakage to the USDW

As previously noted, several candidate storage reservoirs within North Dakota (and likely elsewhere around the world) are already overpressurized relative to overlying aquifers and thus subject to potential vertical fluid migration from the storage reservoir to the lowermost USDW prior to the planned storage project. Stated differently, were a hypothetical leaky wellbore to exist that connected the storage reservoir to the USDW, then even in the absence of CO_2 injection, there would be an existing flow of formation fluids from the storage reservoir to the USDW. This pressure situation is important since the relative change in the storage reservoir pressure buildup and formation fluid flow to the USDW (incremental leakage) between the baseline scenario (no CO_2 injection) and the CO_2 injection scenario are critical inputs for assessing endangerment for the purpose of defining a risk-based AOR.

The following approach to determine these inputs is adapted from Oldenburg *et al.*[6] and the sequence of steps is as follows:

1. Run the baseline case (no CO_2 injection) ASLMA Model to estimate the cumulative flow (leakage) of formation fluid from the storage reservoir to overlying aquifers via hypothetical wellbores. Multiple leaky wellbores at progressively greater distances are not needed for the baseline case because there is no injection occurring and storage reservoir pressure is laterally uniform. Record the pressure in the storage reservoir and cumulative flow of formation fluid into the USDW. For the baseline case with the leaky wellbore open to Aquifer 2 (thief zone), record the pressure in the storage reservoir and cumulative flow of formation fluid into both the thief zone and the USDW at each leaky wellbore distance. The outputs from this step are the storage reservoir pressure buildup and cumulative flows attributable to the intrinsic relative overpressure condition and not to CO_2 injection. The storage project example in the current study writes outputs for 20 years of CO_2 injection;

however, the time steps should mirror the site-specific CO_2 injection plans.

2. Run the CO_2 injection case ASLMA Model to estimate the cumulative flow (leakage along leaky wellbores) of formation fluid from the storage reservoir to overlying aquifers under CO_2 injection. Record the reservoir pressure and cumulative flow of formation fluid into the USDW at each leaky wellbore distance. For the CO_2 injection case with the leaky wellbore open to Aquifer 2 (thief zone), record the pressure in the storage reservoir and cumulative flow of formation fluid into both the thief zone and the USDW at each leaky wellbore distance. The outputs from this step are the storage reservoir pressure buildup and cumulative flows attributable to both the intrinsic relative overpressure condition and CO_2 injection for leaky wells at different distances from the injector.
3. Calculate the ratio and difference between the cumulative flow of formation fluid for each aquifer/leaky wellbore distance under the CO_2 injection case (Step 2) to the cumulative flow of formation fluid for each aquifer/leaky wellbore distance under the baseline (no CO_2 injection) case (Step 1) to quantify the relative change in cumulative flow attributable to CO_2 injection (i.e., the incremental leakage that occurs as a result of the storage project). This approach is analogous to Normalization Method 2 in Oldenburg *et al.*,[6] which does not account for the additional cumulative leakage into the USDW that may have occurred along any hypothetical leaky wellbore that existed prior to the start of CO_2 injection and provides a more conservative estimate, that is, results in a larger incremental leakage due to the CO_2 injection. Steps 1, 2, and 3 use the cumulative flow rather than the leakage rate because the leakage rate does not provide an overall indication of total impact to the USDW over the injection period.
4. Calculate the incremental storage reservoir pressure buildup for each aquifer/leaky wellbore distance by subtracting the reservoir pressure buildup in the baseline (no CO_2 injection) case from the reservoir pressure buildup under the CO_2 injection case. The incremental reservoir pressure buildup rather than the absolute pressure buildup under the CO_2 injection case is used because, under some combinations of input parameters, there may be a reduction in pressure in the reservoir at the leaky well location in both the baseline and CO_2 injection cases. Relate the incremental pressure buildup in the storage reservoir at the end of the injection period to the incremental leakage to the USDW at the end of the injection period using derived functions or linear interpolations for both the case with and without the leaky wellbore open to Aquifer 2 (thief zone). The mathematical relationship derived in this step informs the subsequent mapping in Step 6.
5. Simulate the pressure buildup within the storage reservoir in response to the same CO_2 injection using a compositional simulator (e.g., CMG-GEM). The reason for using CMG-GEM is to better accommodate the temporospatial evolution of pressure buildup within the storage reservoir that is more accurately modeled using a heterogeneous geologic model and a compositional simulator that accounts for the multiphase flow processes within the CO_2 plume.
6. Using the compositional simulator output, apply the incremental pressure buildup-incremental leakage relationship derived in Step 4 to an aerial map of reservoir pressure buildup from the compositional simulator to produce a map of potential incremental leakage to Aquifer 3 (USDW).
7. Delineate a risk-based AOR, the two-dimensional (2D) extent of which encompasses a specified threshold incremental leakage (see Discussion).
8. Quantify the sensitivity of the incremental leakage (and, by extension, the risk-based AOR) to variation in petrophysical properties of the storage reservoir and overlying units, wellbore properties, and the presence of a thief zone between the primary seal (cap rock) and the USDW.

Site-specific model parameters

Storage complex stratigraphy and properties

The risk-based AOR workflow begins with simplifying the storage complex stratigraphy into hydrostratigraphic units and using the best-available site characterization data to estimate the average properties of each unit. Figure 2 illustrates the stratigraphy and average properties used to represent the storage complex in this study. These properties are averaged from available wireline log and drill core data from regional oil and gas wells and project-specific characterization wells. The storage project example model is based on a scenario in which CO_2 is injected into the Pennsylvanian–Permian Broom Creek Formation of North Dakota, United States. The Broom

Creek Formation consists of coastal eolian dunes overlain by high-energy, shallow marine beach or offshore bar deposits and has been identified as a primary CO_2 storage target with high porosity and permeability.[18–21] Individual geologic members are grouped to simplify the stratigraphy into hydrostratigraphic units with similar hydrologic characteristics related to fluid flow. The resultant stratigraphy (Table 1) consists of a deep saline formation storage reservoir (Aquifer 1 – Broom Creek Formation, 1938 m deep and 96 m thick), an overlying aquitard that serves as the primary seal or cap rock (Aquitard 1–top of Swift Formation to top of Broom Creek Formation, 1604 m deep, 334 m thick), an intermediate saline aquifer and potential thief zone (Aquifer 2 – Inyan Kara Formation, 1462 deep and 142 m thick), a second set of aquitards that act as additional seals (Aquitard 2 – top of Pierre Formation to top of Inyan Kara Formation, 562 m deep and 900 m thick), and a shallow USDW (Aquifer 3 – Fox Hills Formation, 473 m deep and 88 m thick). The units from the Fox Hills Formation to the ground surface are not directly modeled; however, the thicknesses of these units are implicit in the baseline pressures for the underlying units. The average properties for each hydrostratigraphic unit define the reference case for the ASLMA Model.

Aquifer- and aquitard-derived properties

For each unit shown in Fig. 2, pressure, temperature, porosity, permeability, and salinity (Table 1) are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). VBA functions included in the SI Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are 0.576, 0.606, and 0.240 m d^{-1}, respectively, and the estimated SS for these units is 5.50×10^{-6}, 5.17×10^{-6}, and 5.60×10^{-6} (1/m), respectively. Details regarding the HCON and SS derivations are provided in Supporting Information.

Saline aquifer thief zone parameters

As shown in Fig. 2, a saline aquifer (Aquifer 2) exists between the primary seal above the storage reservoir and the USDW (Aquifer 3). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, reducing the continued flow up the wellbore and into the USDW. Therefore, the presence of Aquifer 2 acts as a thief zone and reduces the potential for formation fluid impacts to the USDW. The term 'thief zone' is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. As described in Supporting Information, models with and without opening the leaky wellbore to Aquifer 2 are run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

Initial hydraulic head parameters

The original ASLMA model[11] initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers.[6] The initial hydraulic heads are calculated using force potential theory to calculate the total hydraulic potential for each unit (total head) using the sum of the gravity potential and pressure potential based on the unit-specific elevations and pressures.[22] The total heads are entered into the ASLMA model and establish the initial pressure conditions for the storage complex prior to CO_2 injection. The initial reference case total heads for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are 936, 761, and 759 m, respectively, which illustrates the state of overpressure in the storage complex, as both Aquifers 1 and 2 have a greater initial total head relative to Aquifer 3. Therefore, the storage complex requires different treatment than the default AOR calculations described in EPA.[3] Details on the calculations of initial hydraulic head are provided in the Supporting Information.

CO_2 injection parameters

The storage project modeled in the reference case has a relatively small target CO_2 injection rate of 180 000 metric tons CO_2 per year for 20 years. A single injector is placed at the center of the ASLMA model grid at an *x*,*y*-location of (0,0) in the coordinate reference system. The ASLMA model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. VBA functions included in the SI Workbook are used to estimate the CO_2 density from the storage reservoir pressure and temperature, which results in an estimated density of 730 kg m^{-3} in the reference case. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate of approximately 675 m^3 per day. Details of these calculations are provided in Supporting Information and the SI Workbook.

Hypothetical leaky wellbore parameters

Published ranges for the effective permeability of a leaky wellbore have included an 'open wellbore' with an effective permeability as high as 10^{-5} m^2 to values more representative of leakage through a wellbore annulus of 10^{-10} to 10^{-12} m^2.[23–25] Carey[26] provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-10} to 10^{-20} m^2. As previously discussed, a site-specific risk assessment would include an assessment of well failure modes, their likelihood over the performance period, and the likely permeability of each of these failure mechanisms. However, for illustration purposes, the effectively permeability of the leaky wellbore is set to 10^{-10} m^2 for the reference-case ASLMA model, which is a relatively conservative (highly permeable) value near the maximum of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites. Additional cases are evaluated to quantify the sensitivity of the effect of the leaky wellbore effective permeability on the risk-based AOR. Details regarding the leaky wellbore properties are provided in Supporting Information.

The current work uses the ASLMA model Type 1 feature (focused leakage only) for the injection-case model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards and yields a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of focused rather than diffuse leakage provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir and, therefore, a greater leakage of formation fluid up the leaky wellbore to the USDW.

Case matrix

Table 2 summarizes the set of four ASLMA Model cases (case matrix) for the storage project example. Each case includes multiple ASLMA runs as detailed above.

Sensitivity analysis

There is uncertainty associated with any understanding or prediction of geologic systems. For example, uncertainty exists in both the random and systematic errors used to measure fundamental rock properties, as well as in the assumptions used to estimate the parameters from theoretical models, such as estimating permeability from well test data.[27,28] However, there is also environmental variability over space for these parameters. This variability is inherent to the storage complex, and unlike uncertainty, it cannot be reduced through additional measurements.[28,29] In this paper, the hydrostratigraphic unit properties shown in Table 1 and the ASLMA Model inputs derived in the SI Workbook represent the *average values*. Therefore, the ASLMA Model results using these average values represent the reference-case response, and the risk-based AOR derived from the reference-case response represents the most likely outcome (i.e., the best estimated value of the output, incremental leakage, corresponding to the best estimated values of the inputs). A sensitivity analysis is necessary to examine the effect that the ASLMA Model input variables have on the calculation of the incremental leakage to the USDW and, therefore, the estimated risk-based AOR of the reference-case response.

While each of the input variables contributes to the output, the sensitivity analysis focuses on the variation in four inputs: HCON of Aquifer 1 (storage reservoir) and Aquifer 2 (thief zone), SS of Aquifers 1 and 2, hydraulic conductivity of the leaky wellbore, and CO_2 injection rate. HCON and SS for each aquifer depend on the underlying properties used to derive them and are not independent. Therefore, a one-at-a-time sensitivity analysis holding one of the two inputs constant while varying the other would be invalid. Instead, the sensitivity analysis approach derives a joint-probability region for HCON and SS and then explores the ASLMA Model outputs as the input variables move from lower to higher HCON/SS, covering the region between approximately the 30th and 70th percentiles of the joint distribution.

The sensitivity analysis for the leaky wellbore assumes that the quality of materials in each well is

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Table 2. ASLMA model case matrix showing reference case parameters for estimating the risk-based AOR.

Case number	Case name	Injection rate (metric tons per year)	Thief zone (Aquifer 2)
Case 1	Baseline (no CO_2 injection)	0	Off
Case 2	Baseline (no CO_2 injection)	0	On
Case 3	Injection	180 000	Off
Case 4	Injection	180 000	On

uniform along the entire well, which means that the effective permeability values for each wellbore–aquifer and wellbore–aquitard segment are completely correlated. In other words, one value of effective permeability is chosen, and that value is assigned to all leaky wellbore segments.[25] The sensitivity analysis explores a range of leaky wellbore effective permeabilities from 10^{-9} to 10^{-13} m^2, using log-order increments (i.e., 10^{-9}, 10^{-10}, 10^{-13} m^2), or one order-of-magnitude higher permeability than the reference case to three orders-of-magnitude lower permeability than the reference case.

The injection-case CO_2 mass injection rate is 180 000 metric tons per year, which reflects the expected injection rate of the example storage project. However, two additional injection rates are included in the sensitivity analysis: 500 000 and 1 000 000 metric tons per year.

Varying the HCON and SS of Aquifers 1 and 2, the hydraulic conductivity of the leaky wellbore and the CO_2 mass injection rate, provides a sensitivity analysis test matrix (Table S1) of 16 additional ASLMA Model cases (one reference case [Test Case No. 1] plus 16 additional cases, i.e., 17 cases total). Details about the formulation of the sensitivity analysis test matrix are provided in Supporting Information (Table S-1).

Customized R code for multiple model runs

A custom wrapper written in the software environment, R,[30] was developed to perform the multiple runs of the ASLMA Model needed for each case using given ranges for one or more input parameters. The input text file for the ASLMA Model was modified to include an '@R-variable-name' token for the inputs that were going to vary across model runs. While all inputs could be programmed to accept variable ranges, the current work focuses on those

```
Figure 3 ASLMA Model input file with variable tokens - Notepad
File  Edit  Format  View  Help
*TITLE: ASLMA MODEL FOR R
*------------------------------------------------------------------*
* Model Selection
* Model Type=1 : Focused Leakage Only
* Model Type=2 : Diffuse Leakage Only
* Model Type=3 : Coupled Focused and Diffuse Leakage
* Enter Model Type
   1

*------------------------------------------------------------------*
* 1- RESERVOIR DESCRIPTION
* 1.1. Layer types at bottom and top
* AQUIFER = 1,  AQUITARD = 0
* BOTTOM OF THE DOMAIN, BL
  1

* TOP OF THE DOMAIN; TL
  1

* 1.2: Number of Aquifers, NAQ
  3

* 1.3: Aquifer Properties
* Listed from bottom (aquifer 1, top line) to top (aquifer 6, bottom line)
* BAQ   HCONX       ANSR    SS    HEAD_INIT
* Aquifer 1 (Storage Reservoir, Broom Creek)
  96    @aq1_hconx    1.  @aq1_ss    1010
* Aquifer 2 (Thief Zone, Inyan Kara)
  142   @aq2_hconx    1.  @aq2_ss    762
* Aquifer 3 (USDW, Fox Hills)
  88    2.40E-01    1.  2.70E-06    760

Ln 32, Col 1    100%    Unix (LF)    UTF-8
```

EERC EH59905.AI

Figure 3. Example portion of ASLMA Model input file with variable tokens.

parameters listed in site-specific model parameters Section.

The custom R wrapper consists of two parts: (1) an R package containing the ASLMA Model FORTRAN code and R functions to read tokenized input files (Fig. 3), replace tokens with given parameter values, write new input files, call the ASLMA Model executable, and capture the resulting 'BUILDUP_AQ' and 'FLOW_LW' output files as R data frames and (2) a script that calls the functions in the R package and handles parameter preprocessing and output data postprocessing. Inputs to the R script are the tokenized ASLMA Model input file, parameter token names, and values with which to replace those token names in the input file.

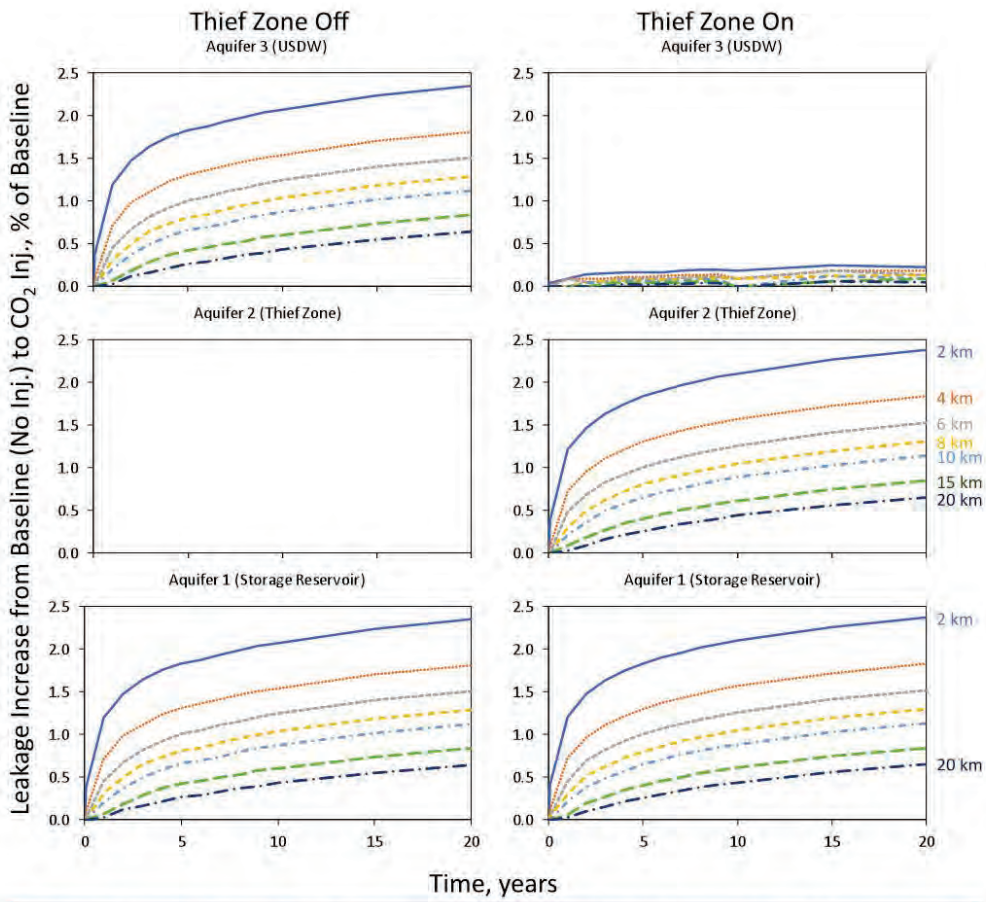

Figure 4. Results of the ASLMA Model for leaky well distances from 2 to 20 km with the incremental total cumulative leakage expressed as an increase in percent of the baseline leakage. The left-hand column of panels shows the scenario where the leaky wellbore is closed to Aquifer 2 (thief zone), and the right-hand column of panels shows the scenario where the leaky wellbore is open to Aquifer 2.

In addition, to generate multiple runs more readily, the customized R code standardizes the ASLMA Model outputs across multiple runs, expediting the analysis and allowing easier graphing within the R programming environment or other software programs.

Results

The workflow described above produces three sets of results: (1) an isotropic prediction of potential incremental total cumulative leakage based on distance from a single injection well using only the ASLMA Model, (2) a predicted relationship between reservoir pressure increase and leakage into the USDW derived from the ASLMA Model, and (3) an anisotropic prediction map of potential incremental total cumulative leakage using a combination of the relationship between reservoir pressure buildup and leakage and reservoir pressure buildup results from compositional simulation of the geocellular model.

Incremental total cumulative leakage from ASLMA model

Figure 4 shows the results of the reference-case ASLMA Model results with the incremental leakage expressed as a percent for both the scenario with and without the leaky wellbore being open to Aquifer 2 (thief zone). Figure 5 shows the incremental leakage results expressed as a volume (m^3). The incremental leakage is a function of both distance from the injection well and time, as a leaky wellbore located closer to the injection well is subjected to greater pressure buildup over the injection period and, therefore, commensurately greater incremental leakage.

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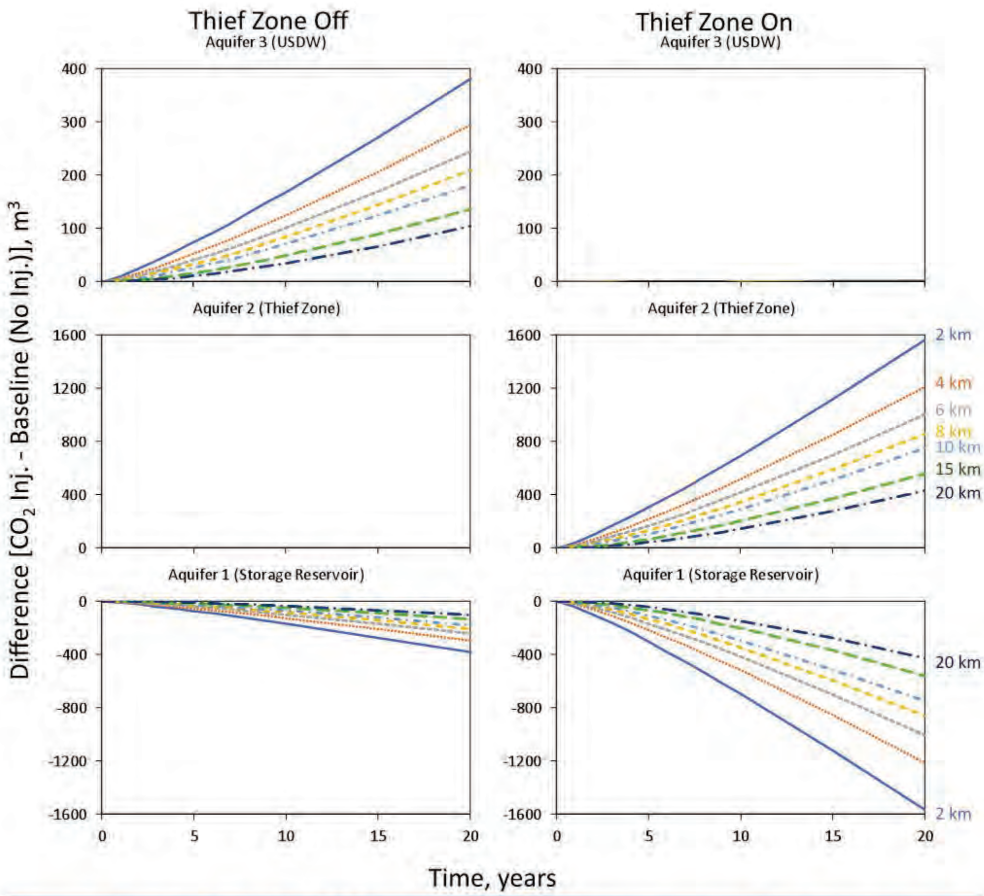

Figure 5. Results of the ASLMA Model for leaky well distances from 2 to 20 km with the incremental total cumulative leakage expressed as a volume. The left-hand column of panels shows the scenario where the leaky wellbore is closed to Aquifer 2 (thief zone), and the right-hand column of panels shows the scenario where the leaky wellbore is open to Aquifer 2.

For a leaky wellbore located 2 km from the injection well and the case when the leaky wellbore is closed to Aquifer 2 (thief zone), the incremental leakage to Aquifer 3 (USDW) at the end of 20 years is approximately 2.4% above the baseline (no CO_2 injection) (Fig. 4, top left panel). However, when the leaky wellbore located 2 km from the injection well is open to Aquifer 2, the incremental leakage to Aquifer 3 at the end of 20 years is essentially zero (0.2%, Fig. 4, top right panel). Thus, the presence of a thief zone significantly reduces the incremental leakage, which is consistent with the 'elevator model' described by Nordbotten *et al.*[13] and other published modeling studies that have included a thief zone.[5,11,31]

At leaky wellbores located farther from the injection well, the incremental leakage at the end of 20 years decreases substantially. For example, for leaky wellbores located 4, 8, and 15 km from the injection well, the incremental leakage into Aquifer 3 at the end of 20 years is approximately 1.8, 1.3, and 0.8%, respectively, above the baseline (no CO_2 injection) case when the leaky wellbore is closed to Aquifer 2. When the leaky wellbore is open to Aquifer 2, the incremental leakage to Aquifer 3 at the end of 20 years for these distances is essentially zero (all less than 0.2%).

Relating pressure buildup to incremental leakage using ASLMA model and compositional simulations

Figure 6 shows the relationship between pressure buildup in the storage reservoir (Aquifer 1) at the end of injection and the incremental leakage to the USDW (Aquifer 3) at each hypothetical leaky wellbore location at the end of 20 years for both the cases with and without the leaky wellbore open to Aquifer 2 (thief

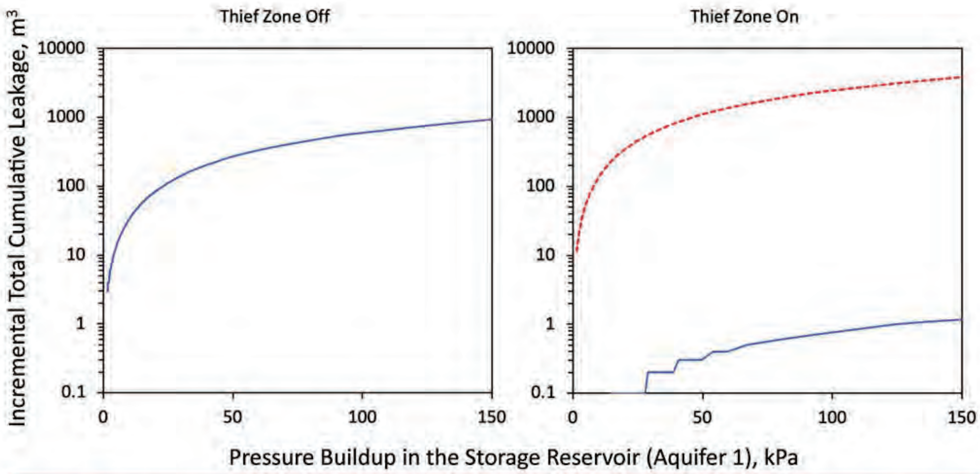

Figure 6. Relationship between pressure buildup in the storage reservoir (*x*-axis, kPa) and incremental total cumulative leakage (*y*-axis, m^3) for Aquifer 3 (USDW, blue line) and Aquifer 2 (thief zone, red dashed line, right-hand panel only). The left-hand panel shows the scenario where the leaky wellbore is closed to Aquifer 2, and the right-hand panel shows the scenario where the leaky wellbore is open to Aquifer 2.

zone). In the case where the leaky wellbore is closed to Aquifer 2 (thief zone = off), there is no incremental leakage to Aquifer 2 (the incremental leakage to Aquifer 2 is not used for delineating the risk-based AOR and is provided only for reference). The curvilinear relationship between pressure buildup in the storage reservoir and the incremental leakage to Aquifer 3 is used to predict incremental leakage from the pressure buildup map produced by compositional simulation of a geocellular model. The maximum simulated pressure buildup in the reservoir (mean, maximum, or chosen layer) is represented by a raster map of pressure buildup values. For each raster value, the relationship between pressure buildup and incremental leakage is used to predict incremental leakage using linear interpolation between the points making up the USDW curve, both with and without a thief zone. As shown in Fig. 6 when the leaky wellbore is open to Aquifer 2, it decreases the incremental total cumulative leakage to Aquifer 3 by one to two orders of magnitude for any given pressure.

Incremental leakage maps

The pressure buildup–incremental leakage relationships in Fig. 6, when applied to the mean change in pressure in the reservoir at the end of compositional simulation, result in the incremental leakage maps shown in Fig. 7, which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the planned 20-year injection period. For the case where the leaky wellbore is closed to Aquifer 2 (thief zone), the areal extent of the CO_2 plume in the storage reservoir plus half-mile buffer (as determined using a compositional simulator and the site-specific geologic model) corresponds to an incremental leakage potential contour of approximately 350 m^3 (Fig. 7a). In contrast, when the leaky wellbore is open to Aquifer 2, there is essentially no incremental leakage to Aquifer 3, and the areal extent of measurable incremental leakage is less than the extent of the CO_2 plume in the storage reservoir plus half-mile buffer (Fig. 7b). The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR (see discussion Section).

Sensitivity analysis results

Figure 8 shows the results of the sensitivity analysis for the four sets of input parameters. The horizontal lines are provided for reference and show the maximum incremental leakage to Aquifer 3 (USDW) at the end of 20 years for the reference case with the leaky wellbore closed to Aquifer 2 (thief zone off – 1340 m^3) and open to Aquifer 2 (thief zone on – 2 m^3), respectively (Fig. 8e).

Lowering HCON/SS of Aquifer 1 (storage reservoir) from the reference case increases the pressure buildup in response to CO_2 injection and, therefore, increases

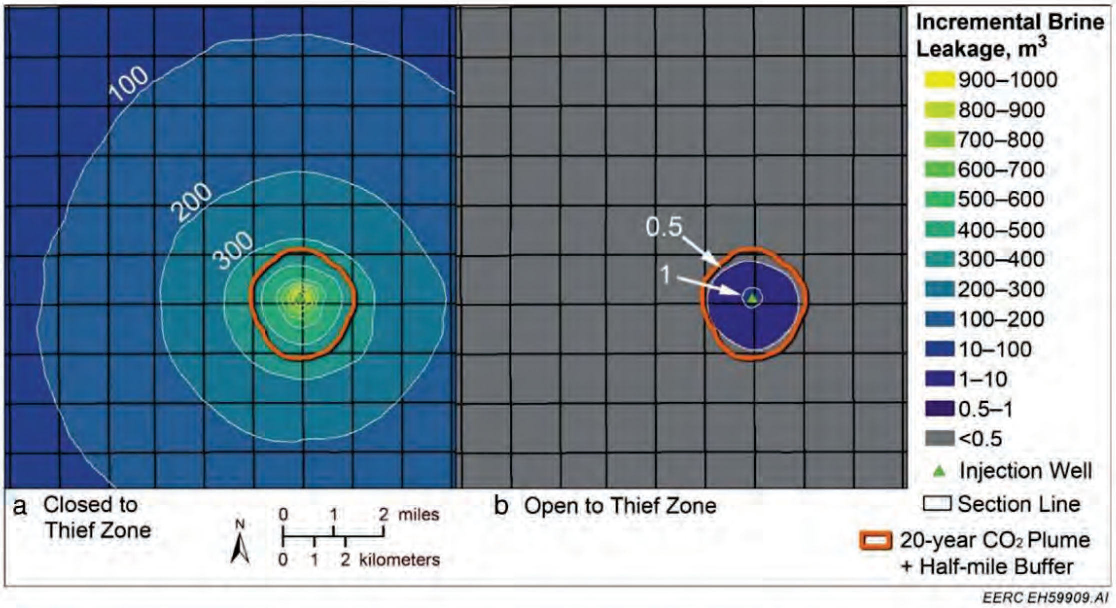

Figure 7. Incremental leakage maps based on average reservoir pressure increase at the end of 20 years of CO_2 injection for the scenario where the leaky wellbore is closed to Aquifer 2 (thief zone) (a) or open to Aquifer 2 (b). The orange polygon in both panels denotes the areal extent of the CO_2 plume in the storage reservoir plus half-mile buffer at the end of 20 years of CO_2 injection as determined using a compositional simulator and the site-specific geologic model.

the incremental leakage of formation fluids up the leaky wellbore to Aquifer 3. For example, for the same CO_2 injection rate as the reference case, the lower HCON/SS of Aquifer 1 results in a maximum pressure buildup of 2760 kPa (1210% increase from the reference value of 210 kPa) and a maximum incremental leakage of 17 330 m^3 (1190% increase from the reference value of 1340 m^3). The result is slightly less pronounced for the case when the leaky wellbore is open to Aquifer 2, which results in a maximum pressure buildup of 2720 kPa (1200% increase from the reference value of 201 kPa) and a maximum incremental leakage of 22 m^3 (1000% increase from the reference value of 2 m^3) (Fig. 8a).

Modifying the HCON/SS of Aquifer 2 from the reference case has no effect on the case when the leaky wellbore is closed to Aquifer 2. However, when the leaky wellbore is open to Aquifer 2, lowering HCON/SS of Aquifer 2 from the reference case increases the incremental leakage to Aquifer 3. For example, the maximum incremental leakage when the leaky wellbore is open to Aquifer 2 is 80 m^3 (3900% increase from the reference value of 2 m^3) (Fig. 8b). Therefore, the lower HCON/SS of Aquifer 2 prevents the flow of formation fluids into Aquifer 2 from the leaky wellbore, and results in a greater incremental leakage to Aquifer 3. Conversely, increasing the HCON/SS of Aquifer 2 from the reference case decreases the incremental leakage to Aquifer 3, as shown in the bottom set of data points in Fig. 8b.

The effect of increasing the CO_2 mass injection rate from the reference case is analogous to lowering HCON/SS of Aquifer 1: the higher injection rate increases the pressure buildup in

Aquifer 1 in response to CO_2 injection and, therefore, increases the incremental leakage of formation fluids up the leaky wellbore to Aquifer 3. The maximum incremental leakage with the leaky wellbore closed to Aquifer 2 is 7430 m^3 (450% increase from the reference value of 1340 m^3) and maximum incremental leakage with the leaky wellbore open to Aquifer 2 is 10 m^3 (400% increase from the reference value of 2 m^3) (Fig. 8c).

Lastly, the effect of increasing the leaky wellbore effective permeability increases the incremental leakage to Aquifer 3; conversely, decreasing the leaky wellbore effective permeability decreases the incremental leakage to Aquifer 3 (Fig. 8d). For example, the case with the greatest leaky wellbore effective permeability when the leaky wellbore is closed to Aquifer 2 results in a maximum incremental leakage of 13 250 m^3 (900% increase from the reference

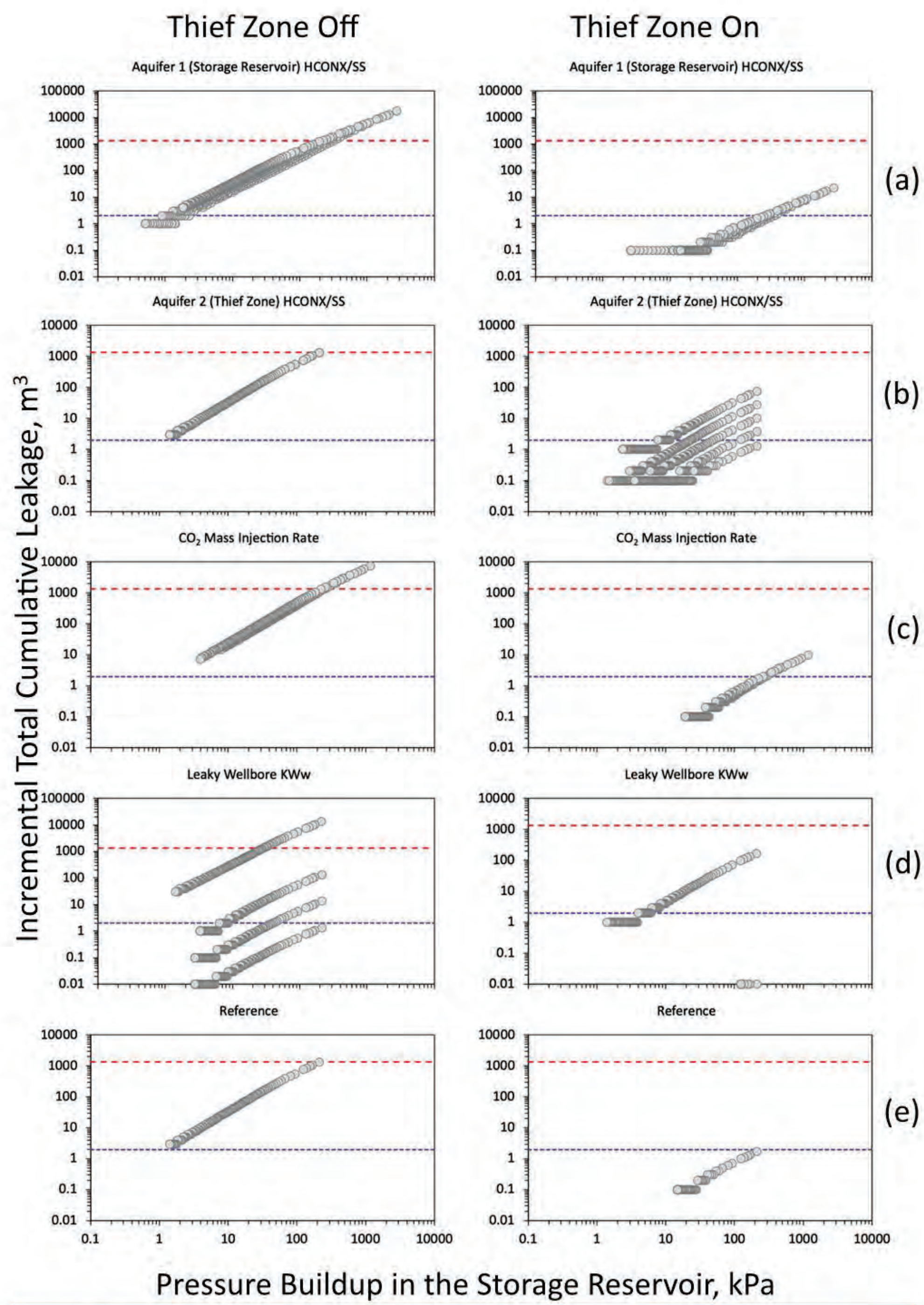

Figure 8. Results of the sensitivity analysis showing pressure buildup in the storage reservoir (*x*-axis [$\log_{10}$-scale]) and the estimated incremental total cumulative leakage to Aquifer 3 (USDW) at the end of 20 years of CO_2 injection (*y*-axis [$\log_{10}$-scale]; varies between rows) as a function of varying four sets of input parameters: (a) HCON/SS of Aquifer 1, (b) HCON/SS of Aquifer 2, (c) CO_2 mass injection rate, and (d) leaky wellbore effective permeability, as compared to the reference case (e). The horizontal lines at 1340 m^3 and 2 m^3 are provided for reference and show the maximum incremental leakage for the reference case with the thief zone off and on, respectively.

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value of 1340 m^3), while the case with the lowest leaky wellbore effective permeability when the leaky wellbore is closed to Aquifer 2 results in a maximum incremental leakage of 1 m^3 (100% decrease from the reference value of 1340 m^3). Similarly, the case with the greatest leaky wellbore effective permeability when the leaky wellbore is open to Aquifer 2 results in a maximum incremental leakage of 170 m^3 (8400% increase from reference), while the case with the lowest leaky wellbore effective permeability when the leaky wellbore is open to Aquifer 2 results in a maximum incremental leakage of 0 m^3 (no measurable incremental leakage) (Fig. 8d).

The sensitivity analysis results show the importance of site characterization data to the delineation of the risk-based AOR, as the measurements of depth, pressure, temperature, salinity, porosity, and permeability affect the subsequent estimates of HCON and SS for the hydrostratigraphic units. In addition, well integrity surveys provide invaluable data that can inform the potential wellbore leakage risk within the AOR.

DISCUSSION

The method presented herein provides a defensible approach for generating a potential incremental leakage map for an overpressurized CO_2 storage reservoir using the combined results of the ASLMA model and compositional simulation. These methods translate ASLMA model-based pressure increase in the storage reservoir into expected potential incremental leakage into overlying aquifers according to average geometry and petrophysical properties. The approach builds upon well-established research and underlying hydrogeological principles. For example, the semianalytical solutions included in the ASLMA model are extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven *et al.*[8] and Avci,[9] which have been upheld for nearly three decades. In addition, the ASLMA Model[10,11] has been broadly applied to an array of storage projects. However, to use this information to delineate a risk-based AOR requires a the final step, which is to define a threshold criterion to the incremental leakage maps which reflects an acceptable impact to the USDW. Ultimately, defining a site-specific threshold criterion is a matter of risk judgment under uncertainty.[32]

For the example storage project evaluated here, under the scenario where the leaky wellbore is open to a thief zone between the overlying seal and the USDW, the risk-based AOR essentially collapses to the areal extent of the CO_2 plume in the storage reservoir because the pressure buildup in the storage reservoir beyond the CO_2 plume is insufficient to drive formation fluids up a hypothetical leaky wellbore past the thief zone and into the USDW. However, even under the conservative assumption that the leaky wellbore is not open to the thief zone, at distances beyond the areal extent of the CO_2 plume, the incremental leakage is less than $\sim$400 m^3 over 20 years (Fig. 6). Therefore, a risk-based AOR could be delineated based on a no-impact threshold (i.e., no incremental leakage) or a low- or nondetectable threshold (i.e., a leakage volume so small that it either would not be detected by conventional analytical methods or otherwise have no measurable impact on the salinity of the USDW). The threshold criterion is site-specific and should be informed by the results of the sensitivity analysis, available site characterization data, discussion with regulators, and input from third-party stakeholders.

The example storage project presented in this paper represents a relatively small CO_2 injection rate of 180 000 metric tons per year. While the differences in reservoir pressure and potential leakage into the USDW under the baseline no-injection versus CO_2 injection comparisons are evident, they would be much more dramatic under larger injection volumes, such as those anticipated for a typical coal-fired power plant (1 million metric tons of CO_2 or more injected per year).

The approach outlined in this paper is designed to be protective of USDWs and, therefore, comply with SDWA requirements and provisions for the EPA Class VI UIC program (Class VI Rule) and North Dakota Administrative Code Chapter 43-05-01. The described risk-based approach combining compositional reservoir simulation and the results from the ASLMA Model are meant to help delineate AOR in overpressurized reservoirs, for which a specific method is not described by EPA.[3] This particular method may also provide a similar risk-based result to other recently published approaches in reducing AOR for reservoirs in hydrostatic equilibrium with or underpressurized relative to the USDW. Continued attempts to engage regulatory bodies on the usefulness and applicability of risk-based AOR delineation methods for specific sites are warranted.

CONCLUSIONS

This paper presents a workflow and modeling approach for delineating a risk-based AOR to support an EPA Class VI storage facility permit for a CO_2 storage project. The approach combines semianalytical solutions for estimating the formation fluid leakage through a hypothetical leaky wellbore with the results of numerical reservoir simulations to define the AOR. The modeling approach that is presented improves AOR delineation of overpressurized reservoirs in three ways, (1) by incorporating the potential for one or more potential thief zones between the reservoir and the USDW; (2) by defining a site-specific relationship between reservoir pressure increase and potential leakage volumes into the USDW over the injection period, regardless of the number and arrangement of injection wells; and (3) by combining the reservoir pressure increase–potential leakage relationship with the results of compositional reservoir simulation to produce an anisotropic map of potential leakage into the USDW.

For the example storage project evaluated here, under the scenario where the leaky wellbore is open to a saline aquifer (thief zone) between the overlying seal (cap rock) and the USDW, the risk-based AOR essentially collapses to the areal extent of the CO_2 plume in the storage reservoir because the pressure buildup in the storage reservoir beyond the CO_2 plume is insufficient to drive formation fluids up a hypothetical leaky wellbore into the USDW. However, even under the conservative assumption that the leaky wellbore is not open to a thief zone, the incremental leakage beyond the areal extent of the CO_2 plume is less than $\sim$400 m^3 over 20 years (Fig. 6). The approach outlined in this paper is designed to be protective of USDWs and, therefore, comply with SDWA requirements and provisions for the EPA Class VI UIC program (Class VI Rule) and North Dakota Administrative Code Chapter 43-05-01. The described risk-based approach combining compositional reservoir simulation and the results from the ASLMA model are meant to help delineate AOR in overpressurized reservoirs, for which a specific method is not described by EPA.[3] This particular method may also provide a similar risk-based result to other recently published approaches in reducing AOR for reservoirs in hydrostatic equilibrium with or underpressurized relative to the USDW. Continued attempts to engage regulatory bodies on the usefulness and applicability of risk-based AOR delineation methods for specific sites are warranted.

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