BEST PRACTICES:

Operations for Geologic Storage Projects

2017 REVISED EDITION

DOE/NETL-2017/1848

NATIONAL ENERGY TECHNOLOGY LABORATORY

Albany, OR • Anchorage, AK • Houston, TX • Morgantown, WV • Pittsburgh, PA

U.S. DEPARTMENT OF ENERGY | Office of Fossil Energy

DISCLAIMER

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ACRONYMS AND ABBREVIATIONS

Acronym/ Abbreviation	Definition
2D	Two-Dimensional
3D	Three-Dimensional
4D	Four-Dimensional
^{14}C	Radiogenic Carbon
AAPG	American Association of Petroleum Geologists
AFE	Authority for Expenditure
AoR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AZMI	Above-Zone Monitoring Interval
BHP	Bottomhole Pressure
BPM	Best Practice Manual
BSCSP	Big Sky Carbon Sequestration Partnership
CX	Categorical Exclusion
CBL	Cement Bond Log
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CH_4	Methane
CO_2	Carbon Dioxide
Corps	U.S. Army Corps of Engineers
CSLF	Carbon Sequestration Leadership Forum
CSRMS	Carbon Dioxide Storage Resource Management System
CWA	Clean Water Act
DOE	U.S. Department of Energy
DST	Drill Stem Test
EA	Environmental Assessment
ECBM	Enhanced Coalbed Methane
ECOF	East Canton Oilfield
EDX	Energy Data eXchange™

Acronym/ Abbreviation	Definition
EERC	Energy and Environmental Research Center
EGR	Enhanced Gas Recovery
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESD	Emergency Shutdown Valves
FE	The Office of Fossil Energy
FEED	Front-End Engineering Design
FTP	File Transfer Protocol
FWU	Farnsworth Unit
GHG	Greenhouse Gas
GIS	Geographical Information System
GS	Geologic Storage
HSE Plan	Health, Safety and Environment Plan
IBDP	Illinois Basin – Decatur Project
IZ	Injection Zone
km^2	Square Kilometer
LWD	Logging While Drilling
m^2	Square Meter
MASIP	Maximum Allowable Surface Injection Pressure
MCOF	Morrow Consolidated Oilfield
mD	Millidarcies
MDT	Modular Dynamic Tester
MGSC	Midwest Geological Sequestration Consortium
MIT	Mechanical Integrity Tests
MRCSP	Midwest Regional Carbon Sequestration Partnership
MVA	Monitoring, Verification, and Accounting
MWD	Measurement While Drilling
N_2	Nitrogen

Acronym/ Abbreviation	Definition
NATCARB	National Carbon Sequestration Database and Geographic Information System
NEPA	National Environmental Protection Agency
NETL	National Energy Technology Laboratory
NPSHR	Net positive suction head required
NRC	National Resource Council
O_2	Oxygen
ODNR	Ohio Department of Natural Resources
O&M	Operating and Maintenance
OOIP	Original Oil in Place
OSHA	Occupational Safety and Health Administration
P&A	Plug and Abandon
PCOR	The Plains CO_2 Reduction Partnership
PFT	Perfluorocarbon Tracers
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIIP	Petroleum Initially in Place
PNNL	Pacific Northwest National Laboratory
POGO	Production of Oil and Gas in Ohio Database
ppm	Parts per million
P&R	Production and Recycle
PRMS	Petroleum Resources Management System
PSI	Pounds per Square Inch
PTRC	Petroleum Technology Research Center
QA	Quality Assurance
QC	Quality Control

Acronym/ Abbreviation	Definition
RBDMS	Risk-based Data Management System
RCSP	Regional Carbon Sequestration Partnerships
ROW	Right-of-Way
SCADA	Supervisory Control and Data Acquisition
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SEMs	Static Earth Models
SET	Spectra Energy Transmission
SP	Spontaneous Potential
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRO	Surface Read-Out
SWP	Southwest Regional Partnership on Carbon Sequestration
TDS	Total Dissolved Solids
TORIS	Tertiary Oil Recovery Information System Database
U.S.	United States
UIC	Underground Injection Control
UNEP	United Nations Environment Programme
USDW	Underground Source of Drinking Water
VDL	Variable Density Waveform
VOI	Value of Information
VSP	Vertical Seismic Profile
WAG	Water–Alternating Gas
WHP	Wellhead Pressure
WPC	World Petroleum Council

TERMINOLOGY

Area of Review: The region around an injection well which may be endangered by the injection activity. This endangerment could come from either the increased pressure in the storage reservoir, or the presence of CO_2.

Caprock: A low-permeability sedimentary layer, which immediately overlies the reservoir and serves as a physical barrier to upward migration of CO_2 or brine from the top of the reservoir.

Confining Zone: One or more geologic barriers, typically low-permeability rock units that overlie or enclose a storage reservoir and are capable of preventing upward and/or lateral migration of CO_2 or brine out of the reservoir. A confining zone may contain multiple geologic seals.

Environmental Assessment: A study which determines whether or not a federal action has the potential to cause significant environmental effects.

Geologic Seal: A low-permeability sedimentary or structural unit, such as shale or a sealing fault, which provides a physical barrier to upward or lateral migration of CO_2 or brine out of the reservoir.

Injection Interval: The perforated interval through which CO_2 injectate is pumped into the storage reservoir.

Injection Zone: Specific sedimentary layers, within a storage reservoir, that are targeted for current or future CO_2 injection.

Pore Space: The void space in formation rocks that can contain fluids.

Site Characterization: The process of evaluating Potential Sites to identify one or more "Qualified Sites" which are viable for storage and ready to permit. Technical and non-technical data is used and data sampling/analysis is site-specific. Site Characterization involves two stages: (1) Initial Characterization involves analysis of available site-specific information and (2) Detailed Characterization involves site-specific field acquisition and analysis of new data.

Site Screening: The process of evaluating Sub-Regions within basins or other large geographic regions and identifying "Selected Areas" within those regions which warrant additional investigation for storage. Available technical and non-technical data is used and data sampling / analysis is coarse.

Site Selection: The process of evaluating Selected Areas and identifying "Potential Sites "within those areas, which warrant additional investigation for storage. Available technical and non-technical data is used and data sampling/analysis is necessary and sufficient to identify individual sites.

Storage Complex: A geologic entity that is physically suitable for long-term storage of CO_2. It consists of: (1) one or more storage reservoirs, with permeability and porosity that allow injection and storage of CO_2; and (2) one or more low-permeability seals, which enclose the reservoir(s) and serve as barriers to migration of CO_2 out of the reservoir units.

Storage Formation: An established, named geologic formation that contains known or potential CO_2 storage reservoirs.

Storage Reservoir: Layers of porous and permeable rock, within a geologic formation, which are confined by impermeable rock, characterized by a single pressure system, and suitable for long-term storage of CO_2.

Supercritical CO_2: CO_2 that is at or above its critical temperature and pressure, or 31.1 °C and 7.39 MPa. In this state it has densities approaching liquid but viscosity approaching gas. This is a very efficient state for transportation and storage.

EXECUTIVE SUMMARY

Geologic Storage of anthropogenic carbon dioxide (CO_2) has gained recognition in recent years as a necessary technology approach for ensure environmental sustainability by reducing greenhouse gas emissions. The U.S. Department of Energy (DOE) Office of Fossil Energy's (FE) National Energy Technology Laboratory (NETL) are developing technologies that will enable widespread commercial deployment of geologic storage of CO_2 by 2025-2035.

DOE has engaged with technical experts in the Regional Carbon Sequestration Partnership (RCSP) Initiative to update its Best Practice Manuals (BPMs) for geologic storage projects. The BPMs are intended to disseminate knowledge gained through the RCSP Initiative and to establish uniform approaches for carrying out successful projects.

The first editions of the BPMs were completed between 2009 and 2013 and incorporated findings from RCSP Characterization Phase and small-scale Validation Phase field projects. The 2017 Revised Editions of the BPMs include lessons learned in more recent years, as the RCSPs have progressed to large-scale Development Phase field projects.

The five 2017 Revised Edition BPMs are:

- *BEST PRACTICES: Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects*
- *BEST PRACTICES: Public Outreach and Education for Geologic Storage Projects*
- *BEST PRACTICES: Risk Management and Simulation for Geologic Storage Projects*
- *BEST PRACTICES: Operations for Geologic Storage Projects*
- *BEST PRACTICES: Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects*

The BPMs are interconnected, and together they are intended to provide a holistic approach to carrying out a geologic storage project, from inception to completion. While there is no set order to these manuals, the above list follows the logical progression of a carbon storage project and would be a sensible order to review them. That said, if the reader is only interested in operational details, for instance, there is no reason to not start with this manual. Overlapping topics that are covered in detail in other manuals will be summarized here and referenced accordingly.

The purpose of this Operating Carbon Storage Projects Best Practices Manual (BPM) is threefold:

- Provide stakeholders with a compilation of best practice guidelines for Operating Carbon Storage Projects
- Communicate the experience gained, to date, through the U.S. Department of Energy's (DOE) Regional Carbon Sequestration Partnership (RCSP) Initiative
- Develop a consistent industry-standard framework, terminology, and set of guidelines for communicating project-related storage resources and risk estimates associated with the project

This manual is not intended as a guide to comply with regulations, nor is the discussion limited to the operational phase of a carbon storage project. It is intended as a guide to considering the broader set of factors relating to the operations of a carbon storage project.

The primary audience for this BPM is future storage project developers, carbon dioxide (CO_2) producers, and transporters. It will also be of use in informing local, regional, state, and national governmental agencies, policy makers and regulatory officials regarding best practices in operating carbon storage projects. In addition, it will inform the general public on the compliance and operational procedures necessary to conduct carbon storage projects.

This manual encompasses all facets of field operations related to planning, designing, implementing, and executing a carbon storage project— from project development to post-injection monitoring. The field site development planning, permitting, well drilling and completion operations, injection operations, and post injection operations are discussed in depth, with emphasis on detailing the components necessary to initiate and operate a large scale carbon storage project.

Field development planning is the first step for operating a carbon storage project. The focus is placed on finalizing the operational details of the project, such as the field execution project team, injection facilities, monitoring installations, and project economics. The culmination of this planning effort leads to a Front-End Engineering and Design (FEED) study, which ultimately determines whether a project should proceed.

Permitting wells for the carbon storage project follows the developmental planning and FEED study, which is one of the most important and time consuming steps in the process. In the U.S., underground injection wells are regulated under the Safe Drinking Water Act (SDWA) through the Underground Injection Control (UIC) Program administered by the U.S. Environmental Protection Agency (EPA), which were designed to protect Underground Sources of Drinking Water (USDW) from any potential contamination caused by the geologic storage of CO_2. Obtaining the necessary UIC permits and all tangential permits are integral to the commencement of project operations.

After permits have been obtained, the well drilling and completion operations can commence. All phases of drilling and developing wells for the injection and monitoring of CO_2 for carbon storage activities are discussed: preparation of the well pad, equipment needed, materials handling, drilling operations, formation testing and sampling, and the completion and construction of wells. These sections in the BPM outline the drilling considerations necessary for the successful execution of a carbon storage project.

The injection operations encompass all operational processes to successfully inject and geologically store CO_2. The critical operations are comprised of pre-injection baseline monitoring system installation, injection system completion, injection, closure, and post-injection monitoring. This provides an assessment of how to plan for, start, maintain, and cease injection operations. In addition, generalized monitoring, verification, and accounting (MVA) protocols linked to the injection operations necessary for successful accounting of CO_2 storage are detailed.

The post-injection operations include three main activities following the cessation of injection. These include: post-injection MVA, well closure, and site closure. These activities will take place over several years, possibly decades, until the operator collects and reports all necessary monitoring data to demonstrate the integrity of the storage complex.

1.0 INTRODUCTION

Geologic Storage of anthropogenic carbon dioxide (CO_2) has gained recognition in recent years as a necessary technology approach for ensure environmental sustainability by reducing greenhouse gas emissions. The U.S. Department of Energy (DOE) Office of Fossil Energy's (FE) National Energy Technology Laboratory (NETL) are developing technologies that will enable widespread commercial deployment of geologic storage of CO_2 by 2025-2035.

As an important step in meeting this objective, DOE/FE/NETL established the Regional Carbon Sequestration Partnership (RCSP) Initiative (see Appendix I). This national Initiative, launched in 2003, includes seven regional partnerships tasked with developing and testing technologies and approaches for safe and permanent storage of CO_2 in different geologic and geographic settings across the United States. An important outcome of the RCSP Initiative is the publication of a series of topical BPMs for geologic storage projects. The BPMs are intended to disseminate knowledge gained through the RCSP field efforts and to establish effective methods, reliable approaches, and consistent standards for carrying out successful geologic storage projects.

The first editions of the BPMs were completed between 2009 and 2013 and presented salient findings of the RCSPs' Characterization and Validation Phase field projects. Since that time, the RCSPs have progressed to large-scale Development Phase field projects. For the 2017 Revised Editions of the BPMs, DOE/FE/NETL has worked closely with technical experts from the RCSPs to incorporate new findings and lessons learned from these Development Phase projects.

The five 2017 Revised Edition BPMs are:

- *BEST PRACTICES: Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects*
- *BEST PRACTICES: Public Outreach and Education for Geologic Storage Projects*
- *BEST PRACTICES: Risk Management and Simulation for Geologic Storage Projects*
- *BEST PRACTICES: Operations for Geologic Storage Projects*
- *BEST PRACTICES: Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects*

Taken separately, each BPM can serve as a stand-alone guide for conducting specific activities related to Characterization, Public Outreach, Risk Management, Operations, or MVA. Taken together, the five BPMs are interconnected—each linked to the others by the interdisciplinary nature of a geologic storage project. They are intended to provide a holistic approach to carrying out a multifaceted geologic storage project, from inception to completion.

This document is designed to be a best practice manual on field operations for Carbon Storage Projects, and a collection of lessons learned from field projects by the seven Regional Carbon Sequestration Partnerships (RCSPs). It is intended for those involved in the development and implementation of carbon capture and storage (CCS) projects, governmental agencies, project developers, regulatory officials, national and state policy makers, and the general public. This manual provides guidance on site-specific management activities for carbon storage sites.

This BPM specifically examines the following subjects pertinent to operating an injection project:

- Project and Site Development Operations Planning
- Permitting
- Drilling and Completion Operations
- Injection Operations
- Post Injection Operations

Where there is crossover between subjects covered by the BPMs listed above, the reader will be referred to the appropriate BPM for more information after a brief summation.

Throughout the manual, examples and lessons learned are provided as "case studies" from the RCSP Large-Scale Development Phase field projects. Figure 1-1 and Table 1-1 provide the fundamental information on these RCSP projects, including project name, project type, geologic basin, amount of stored CO_2, and geographic location. Some additional context for the RCSP Development Phase field projects is provided in Appendix I.

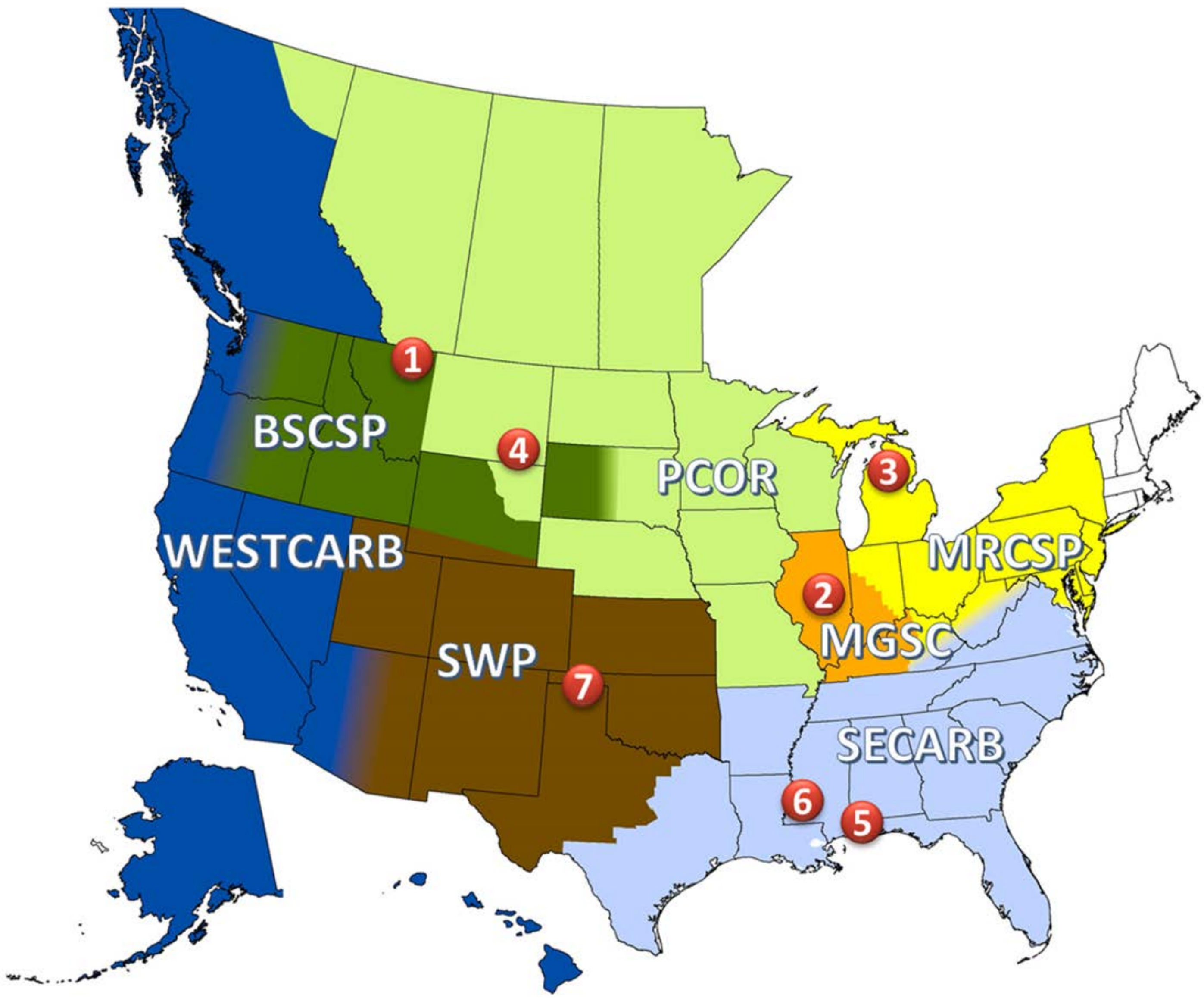

Figure 1-1: Locations of RCSP Large-Scale Development Phase Projects
(Numbers correspond to Table 1-1)

Table 1-1: RCSP Large-Scale Development Phase Projects

(See Figure 1-1 for project locations)

RCSP Development Phase Projects				
Number on Map	**Project Name**	**Project Type**	**Geologic Basin**	**Metric Tons of CO_2 Stored**
1	**Big Sky Carbon Sequestration Partnership–Kevin Dome Project**	Saline Storage	Kevin Dome	N/A (no injection date)
2	**Midwest Geological Sequestration Consortium–Illinois Basin Decatur Project**	Saline Storage	Illinois Basin	999,215 (final stored, and project in post-injection monitoring phase)
3	**Midwest Regional Carbon Sequestration Partnership–Michigan Basin Project**	Enhanced Oil Recovery	Michigan Basin	596,282 (as of Sept. 30, 2016)
4	**The Plains CO_2 Reduction Partnership–Bell Creek Field Project**	Enhanced Oil Recovery	Powder River Basin	2,982,000 (final stored, and project in post-injection monitoring phase)
5	**Southeast Regional Carbon Sequestration Partnership–Citronelle Project**	Saline Storage	Interior Salt Basin, Gulf Coast Region	114,104 (final stored, and project in post-injection monitoring phase)
6	**Southeast Regional Carbon Sequestration Partnership–Cranfield Project**	Saline Storage	Interior Salt Basin, Gulf Coast Region	4,743,898 (final stored, and project in post-injection monitoring phase)
7	**Southwest Carbon Sequestration Partnership–Farnsworth Unit Project**	Enhanced Oil Recovery	Anadarko Basin	490,720 (as of Sept. 30, 2016)

1.1 ESSENTIAL GEOLOGIC STORAGE PROJECT DEVELOPMENT COMPONENTS

A key lesson and common theme reiterated throughout the five DOE BPMs is that each project site is unique. Practical geologic storage projects are designed to address specific site characteristics and involve an integrated team of experts from multiple technical (e.g., scientific and engineering) and nontechnical (e.g., legal, economic, communications) disciplines. Project management should be well delineated with an organized structure in place. It is recommended that prior to starting project operations, a team who are familiar with the permitting, injection operations, and the local geology and other specialties be engaged. Each of the five BPMs discusses in greater detail the decision process and associated data gathering for these specialties.

As with the associated BPM's, many technical and nontechnical aspects of geologic storage projects discussed here are interdependent. Geologic storage projects are implemented through an iterative process, so new information affects decisions in several different areas. For example, early site screening efforts inform decisions to drill test wells, and information from test wells feeds back to inform site selection and injection and monitoring well designs.

1.1.1 SITE SCREENING, SELECTION AND CHARACTERIZATION

Field operations for any carbon storage site will commence only upon satisfactory completion of the operator's due diligence in properly selecting and characterizing a site. For a thorough discussion of these tasks, see the Best Practices manual titled *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects*.

1.1.2 GEOLOGIC MODELING AND RISK ASSESSMENT

Geologic modeling and risk assessment is an integral component that runs in tandem with all project phases over the entire course of a geologic storage project, evolving as the project progresses. Modeling is used to understand and assess reservoir storage capacity, inform operations and address future planning, as collection of project data will augment modeling actions. Results of modeling may be applied to risk assessments to evaluate if the benefits of the project outweigh the risks as well as serve as a basis for understanding the location of the CO_2 plume in the subsurface. For further details on modeling and risk assessment, the reader is encouraged to see the associated *Risk Management and Simulation for Geologic Storage Projects* Manual.

1.1.3 SURFACE ACCESS AND SUBSURFACE/PORE SPACE STORAGE RIGHTS

Establishing surface access with the land owner is critical to the development of a geologic storage project, and the conditions must allow access during all phases of a project. The land owner should be provided with extensive plan details prior to negotiations to maintain positive owner relations. Conditions of access might include clauses such as repairing any roads damaged by trucks, replanting vegetation, and mitigating any damages to the property. The landowner should be released from any liabilities, including injury, damage, or loss incurred in connection with activities under the agreement. Establishing a good relationship with the land owner will facilitate the smooth advancement of a project.

In addition to surface access, the successful implementation of a geologic storage project requires access to the subsurface pore space or mineral rights. In the United States, the subsurface mineral and pore space rights may be severed from the surface rights. The complexity of mineral and pore rights is well documented, and in some instances, minerals in a single geologic unit may be subject to different ownership, as is the case for some coal formations and the methane adsorbed to the coal seam.[1] Thus, surface owners may own the formation but not the pore space or mineral

[1] Amoco Production Co. v. Southern Ute Indian Tribe, 526 U.S. 865, 880 (1999) (holding reservation of coal estate under the Coal Lands Acts does not include reservation of coal bed methane); Newman v. RAG Wyoming Land Co., 53 P.3d 540, 550 (Wyo. 2002) (holding deed from landowner conveying coal but reserving oil and gas did not convey ownership of coal bed methane).

rights. It is therefore prudent to assess the ownership of a specified project area, i.e. identify all lands or subsurface mineral and pore rights that may require negotiation in a lease or purchase agreement pursuant to state and federal regulations to move a project forward.

Both stakeholder engagement and the development of good relations with landowners are critical to the success of implementing and executing a geologic storage project. A project can be held up indefinitely or ultimately prevented from moving forward if an attempt to establish a good affiliation with members of the community and landowners is unsuccessful. For more detail on landowner relations and stakeholder engagement, the reader is encouraged to consult the associated *Public Outreach and Education for Geologic Storage Projects* Manual.

Case Study 1.1 describes the Plains CO_2 Reduction (PCOR) Partnership's approach to landowner relations.

▶ See page 21

1.1.4 PERMITTING PATHWAYS

Permitting, which is critical to launching a geologic storage project, is broken into two broad categories: operational permits and environmental permits. The operational permits needed for a project will include well drilling and injection permits. Operational permits, which allow a project to commence, are integral to a project's viability. Planning for operational permits should begin early in the development of a geologic storage project to ensure that information needed for permitting is developed as part of characterization activities (see *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* BPM for more detail).

Required environmental permits may include National Pollutant Discharge Elimination System (NPDES) permits and archeology and historical permits. Required environmental permits can be determined from conducting an environmental assessment of the potential project site. Environmental assessments are typically performed to locate wetlands, water features, endangered species, and other environmental features of concern within a potential project site that may require permitting. NPDES permits are designed to ensure that surface waters are not degraded by pollutant and contaminant runoff from any industrial activities. Regulatory requirements may also include a review by the State Historic Preservation Office (SHPO) and any Native American tribes where any proposed work may cause surface disturbances. Local officials may require formal environmental assessments if the site receives Federal funds (the National Environmental Policy Act [NEPA]), or is located on Federal or tribal land (NEPA), or if the state has additional requirements (e.g., the California Environmental Quality Act [CEQA] in California). The project should check with local officials to determine the need for any additional requirements.

Case Study 1.2 describes the way PCOR plans operations with consideration of wildlife in mind.

▶ See page 22

It is important to note that each permit type may require substantial collection of unique and detailed information to commence the development of a project, so ample time should be allocated to the permitting process.

1.1.5 ENVIRONMENTAL REVIEW

The level of environmental review necessary for a project may depend on the scale and the scope of a project. These are typically performed to locate wetlands, water features, endangered species, and other environmental features of concern relative to a proposed project site.

For a project that requires a federal action to be taken, there are three levels of environmental review to be carried out and documented under the NEPA. These do not extend to private projects, however, which may need to follow other regulations. The NEPA classes of action include: 1) Categorical Exclusions (CXs); 2) Environmental Assessments (EAs); and 3) Environmental Impact Statements (EIS). Each ranges in scope of environmental consideration depending upon project requirements and are detailed below.

A CX is the least intensive compliance documentation that a project may involve. This requires the environmental documentation to demonstrate that a project's actions pose no significant effect on the human environment. The assessment determines the impact on: 1) planned growth or land use; 2) natural, cultural, recreational, and historic or other resources; 3) air, noise or water quality; and 4) the relocation of people. Where the significance of environmental impact(s) cannot clearly be established for any of these criteria, preparation of an EA is necessary.

EAs are prepared to establish the significance of environmental impact of a proposed project. During the EA process, the environmental analysis receives an interagency review to determine if the project qualifies for a Finding of No Significant Impact. This will comprise a concise public document that provides sufficient evidence and analysis that the project will bear no significant impact on the human environment, and will institute any compliance protocol. If the findings of an EA at any point establish that a project poses a significant impact to the quality of the human environment, then an EIS will be required.

An EIS is a full disclosure document that details the probable environmental impacts of the project. The document discusses the purpose and need of the project, includes a range of reasonable alternatives, provides a delineation of the affected environment and the consequences, and is then subject to an interagency review. It should be noted that this process requires ample time to conduct all salient assessments to produce a report for review, which may take several years.

The course of action taken for NEPA compliance will depend upon a host of project parameters. Where no project activities are impacting the environment, a CX may be issued, such as for a desktop injection modeling study. In the case of a small scale pilot injection project, an EA may be most appropriate action since there will be minimal impact on the environment. However, a commercial scale project involving a federal agency may require a full EIS for NEPA compliance. Conducting any environmental assessment will detail all pertinent environmental components to obtain permits and determine if any cost of site remediation outweigh the economics of a project.

Case Study 1.3 details SECARB's efforts to protect the habitat of the Gopher Tortoise, a threatened species.

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1.2 PROJECT DECISION POINTS

For any commercial venture, the project viability must be assessed at several key decision points as the project timeline develops to ensure that a project can commence as planned. Three decision points have been identified for project continuation: 1) satisfactory data and technological ability; 2) secured financing; and 3) public support. Any disruption in these major decision points may be cause for a project to be cancelled.

The first key decision point is to determine if the technology is available and whether the data collected from the initial site characterization supports the goals of the proposed development. If the relevant information and data collected suggest that the proposed project site is amenable to the project goals, then the project can commence and a detailed engineering plan may be devised. However, if the storage complex is found to be sub-par or uneconomical during supplemental site characterization, or the technology is deemed incapable of achieving the project objectives, then the project must re-evaluate its goals or cease further development.

Another key decision point pivotal to project development is when financing is sought. Obtaining project financing for the total extent of the project timeline is essential to advancing the development of a project. If financing is soundly secured over the entire project duration, then a project can proceed provided that the other crucial decision points are also deemed favorable. However, if the financing of the project falls through at any point along the project timeline, the project may face postponement to secure new financing or be forced to halt all operations. It is important to note that there are significant financial requirements imposed by the EPA on an operator for a Class VI permit.

A third key decision point relies on stakeholder engagement. To continue into the project development phase, the project must engage with stakeholders to discuss risks and benefits, which requires strong public outreach and clearly stated goals and provides appropriate lines of communication. An additional concern may be to obtain landowner's permission for site access and pore space rights. If the project at any point faces enough backlash from the community, or public support wanes, the project may have to abandon its goals. It is therefore advised to be continually observant of public opinion (see *Public Outreach and Education for Geologic Storage Projects* BPM for more detail.

1.3 DOCUMENT ORGANIZATION

This manual provides the reader with an overview of the management activities typically associated with geologic storage projects. It is not intended to provide the detailed information necessary to develop a project, but rather to assist those involved in projects to develop an understanding of what to expect as a project unfolds and the types of expertise that need to be included in the project team. **Figure 1-2** presents a brief overview of these activities by stage, starting with pre-injection planning and spanning the life of a project through post-injection operations. Each of these boxes represents a section in this document. To the side of each box is a brief indication of the activities involved at each stage; these are discussed in further detail in the remaining chapters of this manual.

- **Chapter 2**, **Project and Site Development Planning** outlines the major elements that need to be considered before site work begins, including project design, budget management, and permitting
- **Chapter 3**, **Permitting** details the application process to get regulatory permission for construction, injection and operation of a geologic storage project
- **Chapter 4**, **Drilling and Completion Operations** includes a summary of typical drilling equipment, well installation and materials, well completion, and further well development
- **Chapter 5**, **Injection Operations** includes an overview of standard equipment, operating procedures, and data collection
- **Chapter 6, Post-Injection Operations** describes activities that relate to the closure of a project, from cessation of injection, plugging and abandonment of both injection and monitoring wells, and any long term monitoring and closure of the site

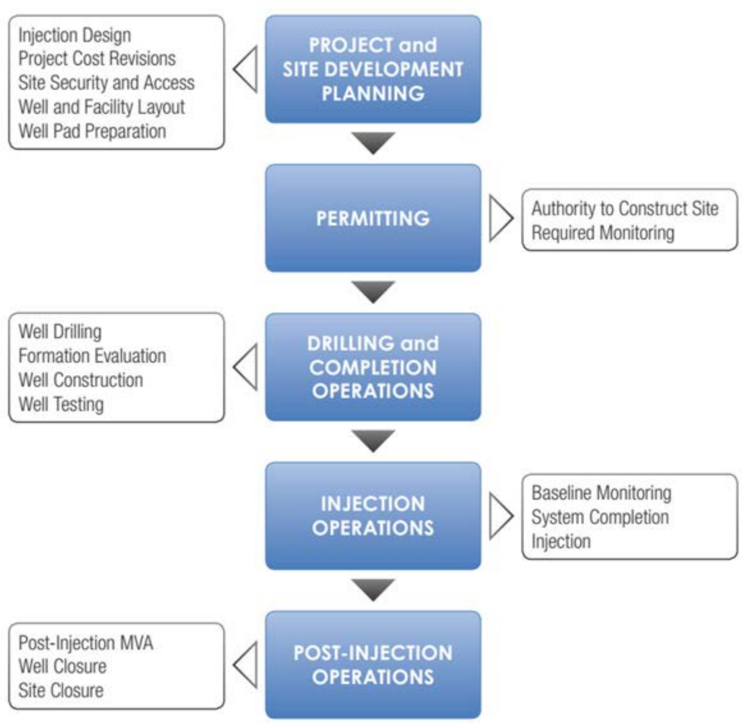

Figure 1-2: Overview of Major Well Management Activities by Stage of Project Development

The **Appendices** include more detailed information on the following topics:

A. Project Site And Development Planning
   1. Project Development Planning List
   2. Communications Plan
   3. Sample HSE Plan
   4. CO_2 Quality Report

B. Permitting
   1. UIC Program and Well Classes
   2. US EPA Guidance Documents
   3. Regulatory Summary
   4. UIC Permit Contact Information by State (Nov. 2011)

C. Drilling and Completion Operations
   1. References for Different Aspects of Well Drilling and Construction
   2. Oil and Gas Contact Information by State (Nov. 2011)
   3. Sample Authority for Expenditure (AFE) Form from Petroleum Industry

D. Injection Operations
   1. Seal types
   2. Valves
   3. Flow Meters
   4. Waste Disposal

As mentioned, this BPM builds on decades of petroleum industry commercial practices with oil and gas exploration and production. As additional geologic storage-specific knowledge is gained through the Development Phase of the RCSP Initiative, the best practices described here will continue to be refined in later versions of this manual.

1.4 RCSP CASE STUDIES

CASE STUDY 1.1 — **PCOR**

PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP

Landowner Relations

Developing and maintaining positive landowner relations are essential to the success of a geologic storage project and the associated MVA activities. At the Bell Creek CO_2 EOR project, much of the land's surface acreage is privately owned by farming and ranching landowners. PCOR and Denbury Resources Inc. have engaged in forging positive relationships with the landowners to ensure the protection of the land and water resources, and to monitor the CO_2 storage and incremental oil recovery. This partnership is critical to help ensure the long-term viability of this project.

Initial contact with landowners in the Bell Creek project area began in July 2011 with a phone conversation followed by an on-site meeting to distribute informational materials and to address any questions or concerns. Landowners signed site access agreements once satisfied that the research personnel would be respectful users of their property, and that the project's intended use would have minimal impact. These agreements granted the PCOR Partnership access to their property to perform MVA and other project-related activities over the course of the project. In return, the agreement allowed the landowners to receive the sampling results from their property.

The PCOR Partnership has been able to successfully cultivate positive relationships with landowners at Bell Creek by initiating contact early in the project, sharing test results and maintaining a two-way flow of information.

CASE STUDY 1.2 — **PCOR**

PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP
Considerations of Wildlife During Project Planning

A key monitoring, verification, and accounting (MVA) activity at the PCOR Partnerships Bell Creek demonstration project is the collection of periodic 3-D surface seismic surveys. Because land disturbance is inherent to these types of surveys, it is necessary to avoid the nesting areas of local wildlife as well as timing the seismic survey to avoid the key mating and nesting seasons for the species in the area. An environmental assessment at the beginning of the project revealed a significant presence of sage grouse and raptor birds. Bureau of Land Management (BLM) staff conducted a survey of nesting locations in the area, and the mating and nesting seasons were documented. The information derived from the environmental assessment and BLM survey played an important role in planning the timing of the seismic surveys.

Knowledge gained through the early project planning and coordination with local wildlife authorities allowed the PCOR Partnership and the project partners to effectively plan field activities while minimizing disturbance of wildlife in the area.

Prairie Grouse

Photo courtesy of Energy & Environmental Research Center

CASE STUDY 1.3 — **SECARB**

SOUTHEAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (SECARB)

Threatened Species and Habitat Considerations for Pipeline Construction

Transportation of the CO_2 captured from the coal-fired power plant source to the SECARB Citronelle Project site necessitated the construction of approximately 12 miles of pipeline. Environmental surveys conducted during the pipeline design phase identified several potential impacts to threatened species and fragile habitats.

The habitats of federally threatened gopher tortoise (Gopherus Polyphemus) were reported by The Alabama Natural Heritage Program within the Project area. To ensure that the project did not impact the gopher tortoises, the SECARB Team followed avoidance and minimization measures recommended by the U.S. Fish and Wildlife Service. These procedures consisted of conducting additional gopher tortoise surveys, gopher tortoise relocation, worker training, the installation of barrier fencing, and directional drilling.

One-hundred-and-ten gopher tortoise burrows were detected along the easement for pipeline construction. Where gopher tortoises or active burrows were encountered in the pipeline construction path, the tortoises were temporarily relocated. Directional drilling was then conducted to depths between 30 and 60 feet under the tortoise burrows/colonies to avoid damaging the habitat, and tortoises were reestablished to their dwelling following construction activities.

Directional drilling was also used to install the pipeline under 15 acres of wetlands. This allowed the project to bypass any “open-cutting” of wetlands and any mitigation required by the Army Corps of Engineers wetlands impacts permit. In total, 18 pipeline sections were directional drilled to avoid infrastructure (e.g., roads, utilities, and railroad tracks), tortoise colonies, and wetlands.

Gopher Tortoise (Gopherus Polyphemus)

Photo courtesy of Southern Company

2.0 PROJECT AND SITE DEVELOPMENT PLANNING

This chapter details the operational proceedings necessary to coordinate and plan geologic storage project field activities for successful execution. The emphasis is on outlining the details of the project from establishing a project operational team, planning the injection and facility layout to monitoring and economics. The culmination of this planning leads to a Front-End Engineering and Design (FEED) study, which ultimately determines whether a project should proceed. The *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* BPM Chapter 2 has a detailed discussion of the earlier steps that would have been performed in project analysis, scope, evaluation criteria, resource definition and scheduling. This manual picks up where operational planning would begin.

2.1 PROJECT MANAGEMENT

A well-structured management team is key to actualizing successful projects. The typical management team's duties include the development and tracking of the project objectives, timelines, budget, and approval of any changes to contracts or scope-of-work. The management team is usually formed at the early stages of planning a geologic storage project which commonly includes a project director, project managers, and a wide range of people with technical expertise and financial control. A project director should be accountable for the roles and responsibilities of all team members and establish who has decision making authority. The management team typically has a supervisory role over the contractors hired for all facets of the project, from initial planning to project closure. The management team is also responsible to help develop and implement policies and procedures related to Health, Safety and Environment (HSE), risk management, communications and public engagement. Please see the *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* BPM for more details on setting up the project management team.

2.1.1 DEVELOPMENT OF SCHEDULE

Figure 2-1 is the Gantt chart sequencing all of the major activities performed by one of the Development Phase field projects. After site characterization and selection of a site, the first objective of the management team should be to develop a schedule to align all facets of the project, from planning, obtaining permits, drilling and completing wells, operations, and monitoring protocols. Development of the schedule may include the following: identifying and sequencing activities, estimating the duration of each task or activity, assigning resources (materials, equipment, and labor) and responsibilities for each task, and determining who will manage and control the schedule and any changes to it. The management team should consult with their field site consultants on the availability of service companies to establish an operations timeline. It can be helpful to use commercial software to develop and track the schedule. An extensive list of items to consider when developing a project schedule can be found in **Appendix B-1.**

2.1.2 DEVELOPMENT OF PROJECT TEAM

Assembling a strong project team is accomplished by selecting members with appropriate expertise to plan all operational phases. Individuals on the team should have clearly defined roles, responsibilities and accountabilities. The team may include members from multiple organizations, likely comprised of project managers, engineers, geologists, drilling operators, service companies, outreach, and finance, legal, and administrative staff. The structure of the team should be displayed in an organizational chart similar to the example shown in **Figure 2-2**. It is beneficial to have a document that summarizes each involved organization, the responsibilities of team members, and how they will interface with one another. A contact list with each member's organization, name, position, phone number, and email should also be included in the document, which is often called a Project Management Plan (PMP), and updated regularly.

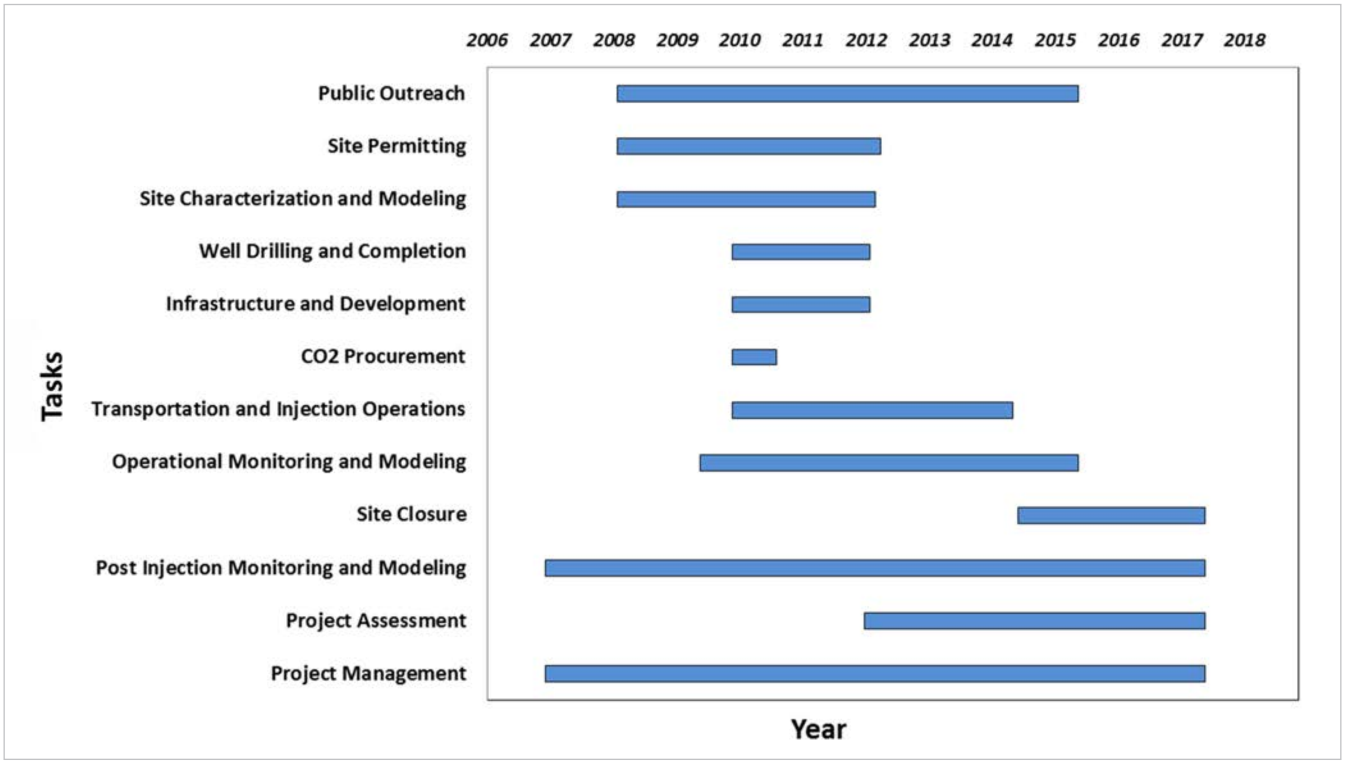

Figure 2-1: A Gantt Chart for the SECARB Citronelle Project Site

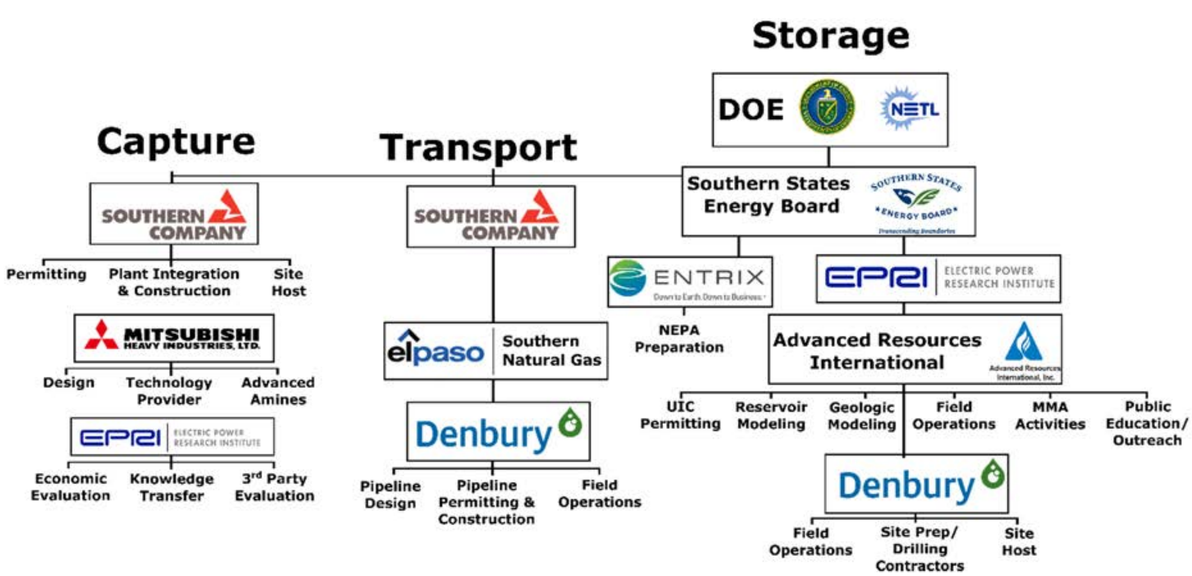

Figure 2-2: Citronelle Project Organization Chart

2.1.3 CHAIN-OF-COMMAND AND COMMUNICATIONS

Establishing a chain-of-command is essential to the operations of a project. A chain-of-command informs the team who has the authority to approve changes and make decisions that will affect the scope-of-work, budget, and timeline. A well delineated chain-of-command streamlines communications and reduces logistical uncertainties.

Internal operations communication efficiency is also critical to project success. The details of the project's communication structure and approach should be well documented in a communications plan or other document. Communication logistics should also be considered when developing a communications plan to ensure a well-organized and successful program. Such logistical questions may include:

- Is there reliable cell service at the site or is there a land line?
- Is there internet service and how fast does it need to be?
- What type of power is there and what is in place for backup communications?
- Are two-way radios needed for operations?

Several types of communications will be necessary over the course of geologic storage projects, which include: routine team communications, feedback, change management, regulatory body and stakeholder communications, and emergency (or crisis) communication. Communications may be either internal or external and may need to conform to reporting requirements if applicable. Each of these communication types are described in **Appendix B-2** and discussed in greater detail in the *Public Outreach and Education for Geologic Storage Projects* BPM**.**

2.1.4 HEALTH, SAFETY AND ENVIRONMENT PLAN

To ensure a safe work environment and promote a strong safety culture, a Health, Safety and Environment (HSE) Plan should be developed. An HSE plan is a document that establishes safety guidelines and outlines procedures to comply with all applicable laws and best practices. It is designed to protect employees, the public, and the environment by establishing protocols to reduce chances for adverse effects that may result during normal operating conditions and the prevention of incidents or accidents that might result from irregular operating conditions. The HSE Plan will outline the program's HSE objectives and identify who in the organization is in charge of safety and compliance on-site.

An HSE Plan should identify and cover all health, safety, and environmental policies and procedures that will be followed by all personnel involved in daily operations. The plan should also cover any other project requirements, such as policies to protect natural and cultural resources, respect private property, and/or reduce noise or other impacts for local stakeholders. The plan should also address all risks identified during risk analysis and outline the measures to reduce and control these risks. The following topics should be addressed in detail by the plan:

- Site access and security
- Weapons, alcohol, smoking and drugs
- Driving hazards
- Fire prevention and protection
- H_2S or other hazardous atmospheric exposures and safety
- Personal Protective Equipment (PPE) requirements
- Required trainings and site access limitations for personnel and visitors
- Standard Operating Procedures
- Proposed tasks, associated risks, and measures to avoid, control or minimize risks
- Safety reference materials such as material safety data sheets and physical agent data sheets

The HSE Plan is necessary for compliance with all local, state, and federal regulations. The HSE Plan is commonly an output of a more thorough risk management process. The Occupational Safety and Health Administration (OSHA) also has multiple guidance documents that describe the development of an HSE program as well as development of a site specific HSE plan. A sample HSE Plan can be found in **Appendix B-3.** More information on risk identification, assessment and mitigation may be found in the *Risk Management and Simulation for Geologic Storage Projects* Best Practices Manual.

2.2 INJECTION DESIGN

This section details the operational considerations, source, and equipment needed for injection design. Most data needed for this section will have been defined and acquired as detailed in the *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* BPM.

Design of the injection systems is established based on several parameters:

- Pre-existing areal constraints
- Volumes of CO_2
- Phase of CO_2
- Quality of CO_2

The injection system design is largely predicated on the areal constraints of a field and the petrophysical parameters present in the storage formation. This can include topographic, geologic and/or pre-existing infrastructure limitations. These features can determine the volume and the rate at which CO_2 can be stored. Additionally, depending on the distribution pipelines needs, booster pumps may be required.

The volumes, phase, and quality of CO_2 that will be stored are also integral to the design of the injection system. Systems must be designed to handle a volume of CO_2 as specified by project requirements or contractual obligations. Since CO_2 for injection is commonly compressed to a supercritical state, the infrastructure must consider the phase into the design. Additionally, depending on the CO_2 quality from the source, or in the case of recycled CO_2 from EOR/ECBM, purification infrastructure may be necessary.

The injection system design utilizes models that incorporate the site characterization analyses and all of these data to enhance the design architecture.

2.2.1 INJECTION FACILITY LAYOUT

The layout of the injection facility will depend upon any preexisting infrastructure, areal constraints, and necessary infrastructure to be installed. Facilities will be comprised of injection well(s) and all associated infrastructure, which may include a separator, pump, climate controlled buildings, a well pad, access roads, and any on-site office or laboratory (trailer). The facility may also include storage tanks for fluids, a pipeline transfer station, safety monitoring equipment, a compressor station or gas handling facility, storage for wastes, and a generator for power. Monitoring wells and associated infrastructure should also be integrated into the facility layout.

2.2.2 INJECTION SYSTEM INPUTS

The inputs of the injection system include the state and quality of the incoming injectate. Incoming CO_2 will be at a specific phase (commonly supercritical) and pressure depending upon the source, which is metered at the custody transfer point. CO_2 quality should be agreed upon between the source and storage operator and based on the permitting standards for the injection well class and operational requirements. The CO_2 quality must be maintained over the life of the project. Enough samples must be taken to assess the overall quality and contaminant load in the stream to determine if any mitigation strategies are needed to clean the CO_2 prior to injection. An example of CO_2 contamination is water in the incoming stream, which has the potential to corrode infrastructure. Therefore, a project must not compromise on the materials since the metallurgy of the well completion is designed for certain impurities to accommodate corrosion resistance. A sample report of CO_2 quality and contaminants is given in **Appendix B-4**.

Case Study 2.1 describes MRCSP's annulus pressurization system to comply with Class VI operation requirements for injection wells.

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2.2.3 NEED FOR PRESSURE BOOSTING/ PUMPING

Any need for increasing pressure to deliver and inject the CO_2 into the well(s) should be evaluated and will depend upon several aspects of the project:

- Length and diameter of the pipeline
- Field configuration
- Pressure and phase of the CO_2
- Depth of injection interval and reservoir pressure
- Reservoir injectivity
- Injection well(s) tubing size and restrictions

This requires assessment of the appropriate bottomhole pressure necessary for a well(s) to overcome frictional losses for injection. Field and reservoir modeling is a key element in making such determinations, which are explained in further detail in the *Risk Management and Simulation for Geologic Storage Projects* Manual. If there is possibility for site expansion, it is prudent to plan accordingly (e.g. pipeline diameter sized to accommodate a larger operation). Where a project requires compression, the operator is directed to look for vendors who specialize in low pressure gas compression design.

2.2.4 MANNED OR REMOTE OPERATION

Whether a project is manned or operated remotely should also be considered during the design phase of a project, which may be largely determined by a project's location. Permitting and operating requirements and safety protocols may necessitate a specific frequency and type of monitoring. Regulatory requirements may also dictate the type of monitoring necessary.

2.2.5 WELLS

The number and type of wells involved in a geologic storage project is dependent upon the project's objectives. For example, projects strictly focused on geological storage commonly have one or more injection wells and at least one monitoring well, whereas projects associated with EOR may have many injection, production, and monitoring wells. A project may also employ multiple monitoring wells, each designed for a unique purpose. Such wells can be equipped with downhole sensors to continuously measure temperature, pressure, and other metrics in addition to being designed to allow samples to be taken at subsurface conditions. The monitoring wells can be used for downhole seismic programs such as cross-well, vertical seismic profiling (VSP), or microseismic monitoring. The objectives of the project and permitting requirements should guide the number and location of the monitoring wells as well as sampling and monitoring frequency. Water samples from the lowermost underground source of drinking water (USDW) are required. These samples may be pulled from a monitoring well or an existing well drilled to the lowermost USDW. Most data needed for this section will have been defined and acquired as detailed in the *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* BPM, and monitoring system designing is detailed in the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* BPM.

2.2.5.1 EXISTING WELLS

During the site characterization phase of a geologic storage project, a thorough inventory of all of the existing wells in the region will have been completed. The team should acquire all available data from these wells including drilling procedures, well logs, completion reports, production records, testing data, and plugging reports. Existing wells may be assets to the project if they can be utilized for geochemical monitoring, downhole geophysical surveys or CO_2 injection. This data is highly useful for geologic modeling and other geologic analyses. Information related to water quality or gases encountered during the drilling of potential injection and monitoring zones is also extremely useful when developing waste management and site safety plans. Existing wells can be used (or recompleted) for injection wells as part of EOR, ECBM in developed oil and gas reservoirs, or they can be used as part of a monitoring system.

Conversely, existing wells can be a concern if they are within the Area of Review (AoR) for an EPA Class VI permit (EPA, 2013). All existing wells should be thoroughly evaluated for their current state of mechanical integrity, whether still operating or plugged and abandoned. The effects and impacts of well leakage have been extensively studied to minimize risk (Celia and Bachu, 2003; Pacala, 2003; Longworth et al., 1996; Bachu and Celia, 2006). **Figure 2-3** highlights the potential leakage pathways in a CO_2 injection well as detailed by Celia et al. (2004). Corroded well casing or cement could result in loss of zonal isolation for the CO_2 plume or formation fluids. Loss of zonal isolation could result in CO_2 or other fluids migrating into overlying formations or to the surface. Wells that have compromised integrity are required to be addressed as part of the project permit. If there is insufficient data to support well integrity, then the well needs to be reentered and evaluated, which may require remediation, adding costs to the project.

Case Study 2.2 describes SECARB's use of existing wells to reduce the cost of an injection operation.

▶ See page 36

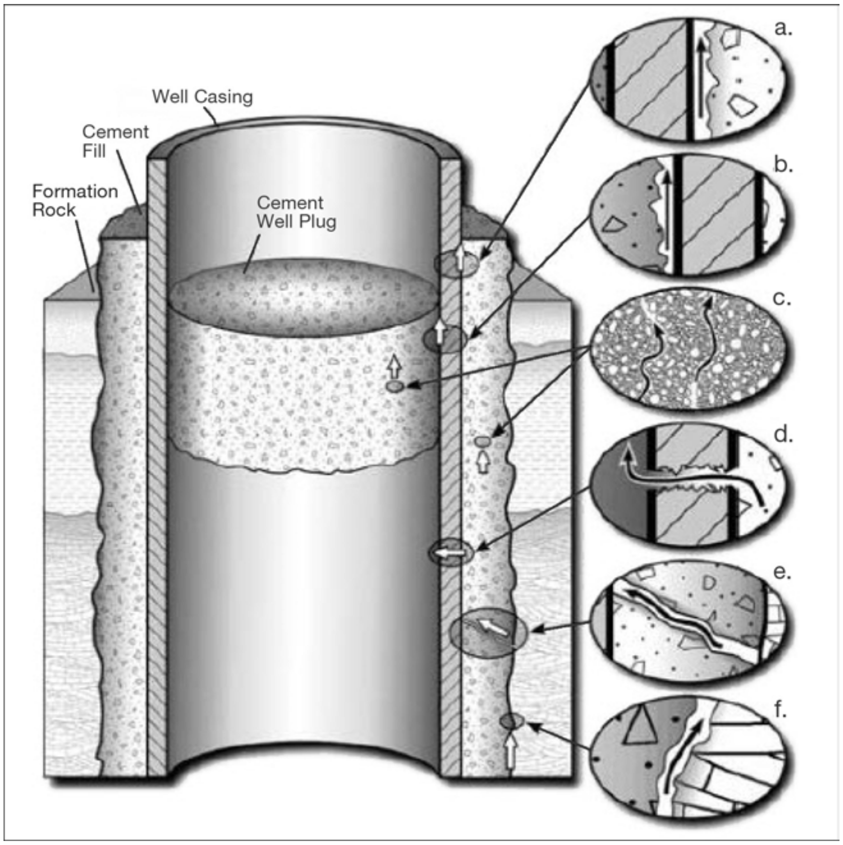

Figure 2-3: Potential leakage pathways for CO_2 in a well: the casing-cement interface (paths a and b), within the cement (c), through the casing (d), through fractures (e), cement-formation interface (f)

(from Celia et al., 2004)

2.2.5.2 NEW WELLS

Recent improvements in technology have expanded the options for drilling wells. Today, there are two different types of wells that can be drilled: vertical wells, also known as conventional wells and horizontal wells, a type of directional well.

A vertical well is drilled from the surface straight down to the target formation. These are the most common types of wells employed by the oil and gas industry. Vertical wells are significantly less expensive than horizontal wells and take less time to complete.

Horizontal wells, however, can be directed to drill horizontally in the subsurface following vertical drilling. Horizontal wells may include multiple laterals (i.e. multi-lateral) from one well, or multiple horizontal wells drilled from the same well pad. While horizontal wells are more expensive to drill than conventional or deviated wells, they can have several advantages. They typically have significantly more contact with the formation because formations tend to be longer and wider laterally compared to their vertical thickness. The horizontal design allows the well to run the length of the formation versus just penetrating it vertically, providing greater access to the reservoir. This can be especially beneficial in thin formations. However, horizontal wells can be challenging to drill because of geologic uncertainty, requiring more sophisticated engineering requirements, and higher risks.

Multi-lateral wells are wells that originate in a single borehole and then branch out into multiple horizontal wellbores. These types of wells can access multiple formations at different depths. A multi-lateral well can be more cost effective than if the wells were drilled individually and are typically employed for oil and gas extraction purposes. However, these are extremely expensive and completion is complicated. While there are many tradeoffs that need to be considered, this technology is not being widely utilized for geologic storage at this time.

To date, most projects have employed conventional wells for injection of CO_2 largely due to cost. Each project will need to evaluate the geologic setting, the project's finances, and objectives to determine what well type and configuration will be most appropriate. In the case of EOR, existing infrastructure will dictate which wells can be used. When making this assessment, it is imperative to closely review the EPA's UIC Class specification requirements to ensure the new well configuration can address these strict requirements.

2.2.5.3 WELLFIELD CONFIGURATION AND DEVELOPMENT PLAN

Each project will have a unique configuration for wells. In a project requiring all new wells, the injection well location is usually decided first following site characterization. From there, the project team will use geologic models, risk, uncertainty, and cost analyses along with regulatory requirements to determine where to place the remaining monitoring and injection wells. The monitoring well placement will vary depending on the purpose of the well. For example, at the Southeast Regional Carbon Sequestration Partnership Citronelle Project, two in-zone monitoring wells were placed at 870 ft and 3,500 ft distance from the injection well to conduct in-reservoir pressure and CO_2 monitoring.

2.3 WELL PAD AND FACILITY LAYOUT

In designing a well pad and layout, is important to evaluate site needs throughout all of the program phases. A pad design unique to geologic storage will likely necessitate facilities for sampling, storage of data, computers and telecommunications equipment, fiber optic equipment, microseismic, and insulation because of the unusual nature of CO_2. Additionally, the operator should consider metering equipment to account for volumes necessitated by regulatory permitting. As in previous operational planning sections, most data needed for this section will have been defined and acquired as detailed in the *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* BPM.

Prior to designing and developing the well pad and facility, the team should assess what is available for transportation access, power, water, waste management and any sensitive environmental or stakeholder concerns in the area. The facility should be designed to utilize existing infrastructure; minimize impacts for the landowners; adhere with all local, state and federal regulatory permitting requirements; and facilitate efficient and safe work operations while accomplishing all of the project objectives.

If existing infrastructure will be used, it should be determined whether upgrades are needed. The location should adhere to all regulatory and permitting requirements for well spacing and setbacks. It is a good idea to confirm with the regulatory agency the legal location of the well prior to staking and surveying the well. If the well pad or other facilities have potential to impact wetlands, waters, sensitive biological species or cultural resources, it is important to consult with the appropriate regulatory agencies about applicable permits and requirements (refer to permit list in Section 2.1.1 and Chapter 3 Permitting for more details).

The well pad should be large enough to accommodate all activities related to operations, from drilling, construction, maintenance, and monitoring. The well pad should be located in an area that has good drainage, minimizes impacts to natural resources, and has year-round access by heavy trucks and equipment. Given the longevity of most geologic storage projects, the pad should be covered with gravel to prevent rutting and soil erosion. If the project location is in a winter climate, there will likely be accommodations to ensure that lines and other equipment does not freeze. Once the well is drilled and completed, the well pad may be partially reclaimed to a smaller size. At the end of the project, the well pad and facility should be fully reclaimed back to its original state as much as possible. All permitting requirements and reporting should be complete and any agreements with the landowner should be fulfilled at the end of the project.

Site security and overall safety are also factors that should be considered in the facility layout. Some projects will have a locked or gated access to prevent unauthorized visitors from going on-site. The well or wells may need to have a shack or fencing around them for protection and security. Site security is important both from a safety perspective and the security of equipment and data.

Case Study 2.3 describes MGSC's modifications to surface equipment for operation in cold weather climates.

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2.4 MONITORING

It is imperative that the team design and plan a monitoring program in conjunction with planning and drilling wells for a carbon storage project. This is necessary for both permitting and public assurance. The monitoring program will have three key stages: 1) Pre-injection; 2) Injection; and 3) Post-injection.

The first phase of monitoring will occur prior to the commencement of injection to establish baseline conditions. Background monitoring carried out during the pre-injection stage could include sampling groundwater, surface water bodies, atmospheric conditions, soil chemistry, reservoir fluid sampling, aquifer sampling and other environmental measurements over time. USGS or other regional agencies may have historical water quality data that could enhance baseline monitoring dataset. It is also helpful, when possible, to sample over several seasons or years prior to injection to observe baseline seasonal variability for the project site.

The next phase of monitoring occurs throughout injection to detect any changes as a result of project activities and ensure CO_2 storage security.

The final stage of monitoring is the post-injection monitoring period to ensure that there is no unintended CO_2 migration or any chemical or environmental changes as a result of the project.

During implementation of the Illinois Basin – Decatur Project (which involved injection of 1 million metric tons into a saline reservoir), MGSC observed that coordinating the acquisition, distribution, use, and interpretation of MVA data in a large, complicated project requires a great deal of time and effort. In addition to developing a comprehensive, risk-based MVA plan that addresses risks and clarifies roles of responsibility, the operator should consider expanding the MVA plan to cover IT, hardware, telecommunications, and lifetime data management. Establishing a database manager who is responsible for receiving, archiving, and distributing monitoring data to the rest of the technical team is recommended to improved project efficiency. Furthermore, the creation of a data monitoring and interpretation plan that outlines specific report generation and intended recipients would ensure that information is targeted and distributed effectively.

For more information on monitoring design, tools, frequency and practices, please refer to the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* BPM.

2.5 RISK MANAGEMENT

Risk management for geologic storage is designed to take place over the entire project duration. Assessment of risk involves conducting a risk profile to identify potential scenarios that would prevent the project from achieving commerciality and determine risks acceptable to the project development team. This may include a wide variety of factors such as financial, public acceptance, political, technical, various types of liability, and uncertainties. Such potential project risks may include: selecting a reservoir that proves to be technically or economically unsuitable; mechanical failure in equipment; failing to secure sufficient pore space or surface rights; significant public opposition; changing legal and regulatory regimes as they become more defined; etc. The initial risk assessment during Project Definition must ascertain, with a high degree of confidence, that the initial project plan is capable of evaluating each of the defined elements in sufficient depth to allow proper technical and economic decisions to be made and establish public confidence. To do this, the risk assessment must ensure that the project's scope, staffing and competence levels, funding levels, schedule, and criteria are all sufficiently robust to accomplish the required evaluations. For more information on Risk Management, please see the *Risk Management and Simulation for Geologic Storage Projects* BPM.

2.6 PROJECT ECONOMICS

Economics are very important to analyze in advance of decision-making to begin any project and should be revisited throughout the life of the project. A major obstacle for geologic storage is the sub-economic nature of most saline reservoir projects due to lack of revenue or savings associated with carbon storage. To make a project economical, offsets or credits for CO_2 may need to be implemented. Associated recovery of oil or methane in EOR or ECBM applications, respectively, also provides many economic benefits such as increased product/ revenue and savings from use of existing infrastructure.

Regardless of the economic projection, a detailed project budget should be developed at the onset of the project, and financing will need to be secured. **Table 2-1** details the major cost elements by project stage that should be considered when developing a budget. Bids should be collected from all contractors, which will include the rigs and service companies that are intended to be employed on the project. Due to geologic and other uncertainties, there is considerable risk of budget overruns for a geologic storage project. The project design should be well developed to accurately determine costs and factor in an ample contingency budget. It is recommended that costs from the characterization phase be reviewed to help develop a more realistic budget. To determine the costs to drill a well and construct supporting infrastructure, the team should request an Authority for Expenditure (AFE) from the drilling manager. This is a document that is prepared to estimate the costs to drill a well to a specified depth and to meet geologic objectives. The AFE typically includes costs for the site development, daily rig rental rates, fuel, cement, pipe, tubing, drilling mud and fluids, wellhead, engineering and geologists, supervision, equipment rentals, and other expected expenses to drill the well. The AFE may also include the completion and testing expenses if those plans are provided to the operator. Bids for other infrastructure needed such as pipelines, gas handling facilities, roads, and power should also be solicited. The financial security requirements for a Class VI permit are significant and should also be considered as part of the economic analysis.

Table 2-1: Major Cost Elements by Project Stage

	Site Preparation	Well Drilling and Completion	Injection Operation	Post-Injection Operations
• Permitting and bonding • Well cost estimates (including exploration wells, if needed) • Acquisition of data for site characterization • Modeling • Detailed cost estimates for site-specific equipment modifications, rental equipment, construction (and related temporary) costs • Scheduling impacts and developing contingencies	• Site grading • Surface infrastructure (roads, pipelines, fences, security) • Well pad construction and preparation • Weather constraints • Water supply	• Drilling rig costs (including scheduling) for site-specific conditions • Weather constraints • Injection and monitoring well drilling • Injection and monitoring well completions • Drill casing and tubing, cement, wellheads, downhole safety shutoff valve, packer(s), and all other associated equipment • Injection pumps and other associated equipment • Fluid and cuttings disposal	• Well pad maintenance • Mechanical integrity and testing • Pressure falloff testing • Injection data monitoring and management • Evaluation of integrity of abandoned/plugged wells that penetrate the confining zone – mitigation if necessary • Equipment maintenance and replacement • Power • Labor • Well development • Weather constraints • Waste management • Monitoring well O&M • Injection well O&M	• Monitoring equipment maintenance and replacement • Well plugging and reporting • Equipment and facilities removal • Site restoration • Closure activities

2.7 FRONT-END ENGINEERING AND DESIGN

Following the assessment of all major facets of a potential project, a Front-End Engineering and Design (FEED) study should be performed to assess all expenses and the project feasibility. This will include the project scope (engineering, modeling, equipment layout, and installation, etc.), process flow, project timeline, and fixed-quote bids, etc. This will provide the foundation for making the key go/no go decision(s) of whether to pursue a particular project. The FEED takes into account the technical requirements and high level financial considerations for the project, serving as the basis of design and all tendering and bidding for the project. During the FEED there needs to be good communication between the various project partners and contractors ensure that all the project requirements are incorporated into the study. These studies can take up to a year to complete for large projects since they need to incorporate all the project's requirements.

2.8 RCSP CASE STUDIES

CASE STUDY 2.1 — **MRCSP**

MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (MRCSP)

Annulus Pressurization System

The U.S. EPA UIC Class VI regulation specifies operating requirements for injection wells, including the need to maintain pressure on the annular fluid in excess of injection pressure. This implies that the pressure of the annular fluid must be greater than the pressure of the CO_2 inside the tubing at all depths. This requirement necessitates having an engineered system (e.g., a system of tanks, pumps, piping, valves, instrumentation, controls, and alarms) capable of applying pressure to the annular fluid. The system must be fabricated of materials suitable for high pressures and corrosive fluids. In some areas, appropriate measures must be incorporated into the design of the system to prevent freezing (e.g., heat tape, insulation, heated enclosure). The engineered system must be capable of adjusting the pressure on the annular fluid to ensure it is always higher than the injection pressure, which typically fluctuates. One way to achieve this is to design the system to automatically increase or decrease the annular fluid pressure to maintain a constant pressure difference above the injection pressure. Another way is to design the system to maintain a constant annular fluid pressure that is greater than the maximum (or allowable) injection pressure.

Within the MRCSP region, Battelle designed, constructed and operated a well-annulus pressurization system for a pilot-scale project at the American Electric Power (AEP) Plant in West Virginia. The major mechanical components of the system that regulated annular fluid pressure are described and illustrated below.

125-gal annular fluid tank (top left) and annular fluid pumps (bottom left)

- Six vessels, each with a capacity of 30 to 35 gallons, were mounted on a pre-fabricated, skid-mounted hydraulic system.
  - Two vessels (accumulators) functioned as storage for the annular fluid system. These vessels were filled with annular fluid and pressurized nitrogen. The annular fluid and nitrogen were separated by a movable piston, the location of which indicated the annular fluid volume in the accumulator tanks.
  - Four vessels were pressurized nitrogen bottles that provided additional vapor space for the accumulators. This extra volume allowed for minimal venting of CO_2 during daily temperature fluctuations.
- ½-inch-diameter buried stainless steel pipeline connected the three vessels containing annular fluid to the injection well and allowed annular fluid to move from the accumulator to the well's annular space or vice versa.
- One 125-gal stainless steel tank contained a reserve supply of annular fluid.

30-gal accumulator tanks for annular fluid (top right) and four 35-gal cylinders for nitrogen (middle bottom right)

CASE STUDY 2.1 — **MRCSP** (continued)

- One polyethylene tank to hold water that was pumped into and bled off from the pressurized water side of the accumulators.
- Two high-pressure piston pumps that pumped reserve annular fluid from the 125-gal tank into the accumulators when the pressure in these accumulators reached a low set point.
- A system of valves to control fluid and nitrogen flow.

Fluid system valves mounted on skid (Nitrogen system valves are monitored on back side and not visible in this photo)

Assembly of skid-mounted pressurization system in progress (left and right sides)

Building for housing annular pressurization system under construction

½-inch diameter stainless-steel line connecting well annulus to pressurization system

CASE STUDY 2.2 — **SECARB**

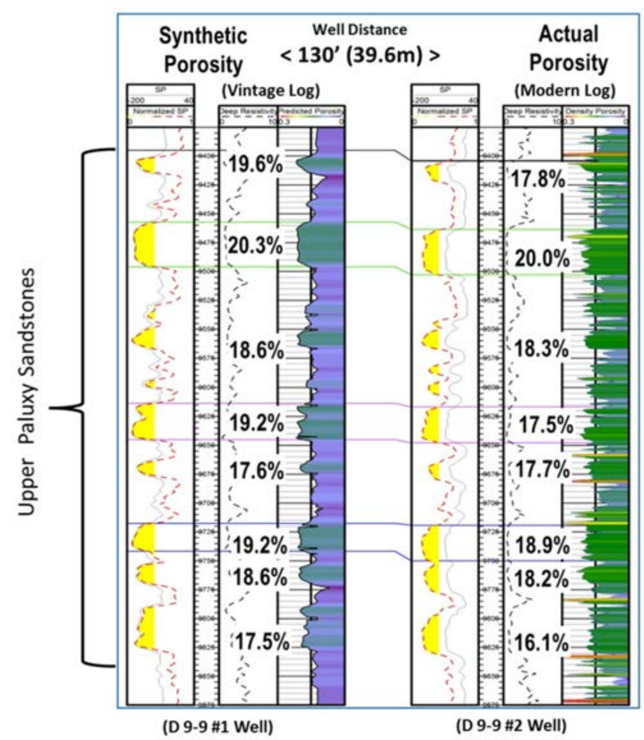
SOUTHEAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (SECARB)

Use of Existing Wells and General Project Design for Citronelle

The SECARB Citronelle Project's storage site is located within the Citronelle oilfield, the largest oilfield in the state of Alabama. The field was discovered in 1955 and contains over 400 active and shut-in wells drilled at 40-acre spacing. The oil-producing reservoir (the Jurassic 'Donovan Sand' of the Rodessa formation) at the test site lies beneath the injection zone (the Cretaceous Paluxy formation), therefore, geophysical well logs obtained from the drilling operations were utilized for the characterization of the injection zone and the overlying confining zone.

At the test site, over 80 existing oilfield well logs were used to evaluate the porosity, thickness and vertical and horizontal reservoir architecture of the storage formation for the southeast portion of the field. Neural networks were applied to the vintage data from existing wells to forecast porosity with the application of data derived from the newly drilled wells. These data were then used to extrapolate porosity and permeability estimates over the field (see figure below).

Existing oilfield well pads were utilized for locating the project's injection and observation wells. This resulted in cost savings associated with construction and needing to mitigate potential wetland impacts. Two temporarily abandoned wells were re-worked as monitoring wells. These wells were plugged back to the monitoring zones, perforated in the zones of interest and had tubing and packers installed. The wells were then able to be utilized for pressure monitoring, deep fluid sampling via slickline and cased-hole saturation logging.



Comparison of Neural Network Porosity Interpolation for the Paluxy Sandstone Injection Zone with the Logged Interval from The Newly Drilled Well

CASE STUDY 2.3 — **MGSC**

MIDWEST GEOLOGICAL SEQUESTRATION CONSORTIUM (MGSC)
Climate-Based Surface Equipment Considerations

At the IBDP, winter climate conditions had unintended impacts on the geologic storage operations, necessitating minor revisions to the infrastructure.

The pipeline transporting CO_2 from the final stage of compression to the injector wellhead was losing a significant amount of heat during winter due to the large temperature contrast between the CO_2 stream and the atmosphere. Therefore, CO_2 had to be injected at a lower pressure, which caused problems controlling pressure in the pipeline and at the wellhead. To counter this, the 6-inch transportation pipeline was insulated to help minimize heat loss. The insulation stabilized the pressure and temperature of the CO_2 arriving at the wellhead and in the pipeline.

An additional winter climate challenge detected was that the brine used to keep the well's annular space pressurized is in danger of freezing at the wellhead, which would cause the annular pressure to fall below the regulatory limit. Therefore, a nitrogen gas source was hooked up to the well's annulus to keep the pressure above the regulatory requirements when required.

Local extreme temperature considerations should be given to annular pressure maintenance systems, and future CO_2 injection projects operating in cold regions should have any above-ground pipeline insulated to prevent such an occurrence.

Configuration of pipeline near wellhead (no insulation)

Insulated pipeline at wellhead

Partial insulation of pipeline during construction

3.0 PERMITTING

Permitting for a geologic storage project is one of the most important, and time consuming, steps in the process. In the U.S., underground injection wells are regulated under the Safe Drinking Water Act (SDWA) through the Underground Injection Control (UIC) Program administered by the U.S. EPA. The UIC regulations are designed to protect Underground Sources of Drinking Water (USDWs) from CO_2 plume infiltration, brine intrusion caused by the increased pressures from the CO_2 injection, and from mobilization of any potential subsurface contaminants (i.e. trace metals and organics) caused by geochemical reactions due to geologic storage of CO_2. The UIC Program is responsible for regulating the permitting, siting, construction, monitoring and testing, closure, and post-closure care of injection wells that place fluids (liquids, gases, semi-solids, or slurries) underground for storage or disposal (U.S. EPA, 2015d)

3.1 OVERVIEW OF EPA INJECTION PERMIT CLASSES

Six classes of wells are recognized by the EPA program, with each class subject to siting, construction, operating, monitoring, and closure requirements that address the types of fluids injected and the use of the wells. The existing well classes under the UIC Program are:

- **Class I—**Wells injecting hazardous and/or non-hazardous industrial and municipal wastes below USDWs
- **Class II—**Wells related to oil and gas production, mainly injecting brine and other fluids (includes CO_2 for EOR)
- **Class III—**Wells injecting fluids associated with solution mining of minerals, such as salt (sodium chloride [NaCl]) and sulfur (S)
- **Class IV—**Wells injecting hazardous or radioactive wastes into or above USDWs; generally only used for groundwater remediation
- **Class V—**Injection wells not included in Class I through Class IV that are typically used as experimental technology wells. These wells are typically permitted with Class I requirements
- **Class VI—**New class of injection wells specific for CO_2 geologic storage in saline aquifers

Previously, wells for the geologic storage of CO_2 were permitted as Class I non-hazardous, Class II, and Class V. A more detailed discussion of the six existing UIC well classes is available on EPA's UIC website: https://www.epa.gov/uic

3.2 CLASS VI DRILLING AND OPERATIONS PERMITTING

The regulations for Class VI wells are developed under the EPA's UIC program, which is established under the SDWA. **Appendix C-1** of this manual describes the UIC program and the Class VI regulations. They are published in the Code of Federal Regulations (CFR) in 40 CFR 146.82. It should be noted that the amount of lead time required for permitting can be significant.

Case Study 3.1 describes MGSC's permitting process for the IBPD Large Scale Carbon Storage Project.

See page 45

Unlike Class I, no area permits are allowed for Class VI storage projects. A separate application is required for each planned injection well. However, all information gathered for the permit application may be leveraged and used as efficiently as possible, minimizing differences between each separate application, assuming each of the injection wells is in a similar geologic setting.

The Class VI permit does not provide a permit for a stratigraphic test well or for any of the project required monitoring wells (in-zone monitoring wells, above zone monitoring wells, shallow monitoring wells for USDWs, or any other types of monitoring wells). These permits are to be obtained from the local, State, or Tribal natural resources agency or oil and gas agency.

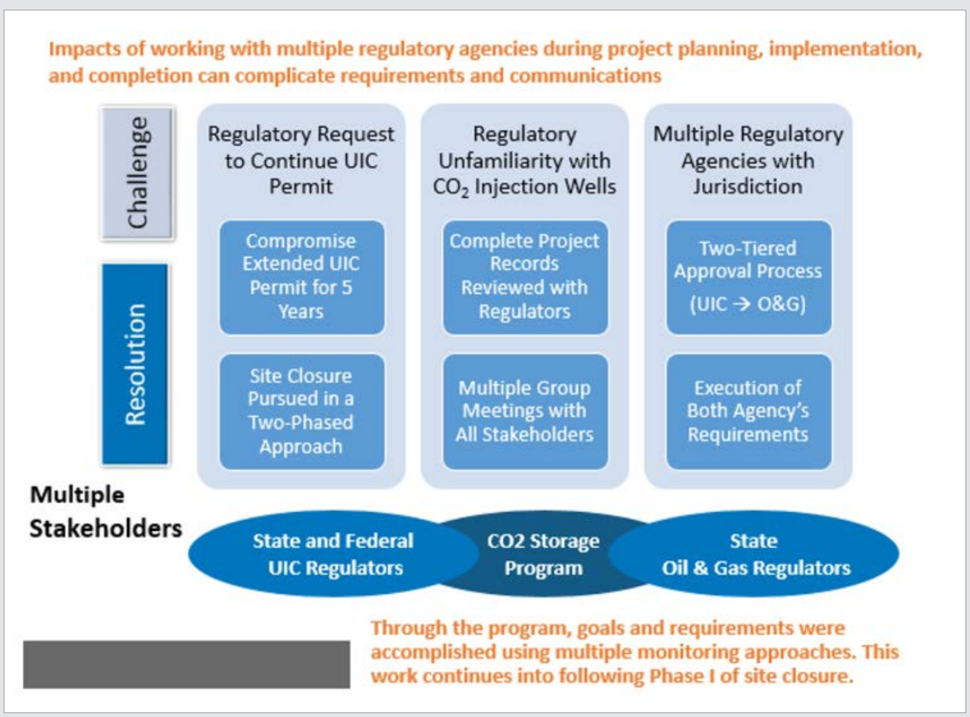
The Class VI permit is issued in two stages. The first stage provides the owner/operator the authority to drill and test the well in accordance with the permit. Once the well has been drilled and tested, the owner/operator must prepare a completion report which includes the test data and interpreted results. Any significant differences from the site characterization presented in the application should be noted. The major part of this project iteration is to update the static and dynamic site models and make any adjustments to the AoR as determined from computational models and field data (EPA, 2013). Upon submission, the regulatory agency will review the completion report and the associated data. If the report findings are satisfactory, the regulatory agency will then issue the second stage of the permit to allow the operation of the injection well.

Maintain Awareness of all Regulatory Stakeholders and Bridge the Gap between Regulatory Agencies that Govern the CO_2 Storage Program

For one geologic storage project, located at a coal-fired power plant in the Midwest U.S., three regulatory agencies were involved—The U.S. EPA, the state Office of Oil and Gas (OOG), and the state Division of Water and Waste Management (DWWM). The OOG was responsible for oversight of drilling, construction, plug and abandonment, remediation permits, and environmental responsibility releases, and the state DWWM was responsible for the issuance and maintenance of the Class V UIC permit. Since the project was conducted before Class VI regulation was issued, the DWWM consulted the U.S. EPA UIC regional office in order to draft a permit that would be compliant with the impending Class VI UIC regulations.

During the initial phases of the project, the injection and monitoring well designs needed to satisfy both UIC requirements and the OOG well construction requirements. OOG well construction requirements mandated wells to be constructed in such a way that the inner casing strings are able to be cut and removed during the plug and abandon process. DWWM, on the other hand, required the wells to be constructed with the injection casing string cemented to surface to comply with proposed UIC Class VI regulations. These conflicting requests were resolved by the project team by holding discussions and presenting technical information about the proposed well design. The well design was adjusted until the plan was acceptable to all parties.

During project operations and closure, a number of challenges were raised as shown in the figure below. In addition to unfamiliarity with CO_2 injection wells, other challenges included a request by the state DWWM to continue the UIC permit after meeting site closure requirements and a need to obtain approval from both agencies for site closure. Open channels of communication among the regulatory stakeholders helped to develop satisfactory resolutions. It is recommended that during the permitting and design phases, a review of all of the permit requirements through site closure be performed with all regulatory stakeholders to mitigate conflicting issues that may arise in later project stages. Since the regulatory agencies involved in permitting CO2 monitoring wells vary by state, efforts are required to maintain awareness of all regulatory requirements and to bridge the gap between agencies when conflicting requirements arise.



Overview of the Challenges and Resolutions to the Involvement of Multiple Agencies in the Regulator Process for the Project Approaching Site Closure

3.2.1 COMPONENTS OF PERMIT APPLICATION

The Class VI Permit Application includes six key components:

- General administrative project and contact information—Facility name, location, mailing address, etc.; operators' contact information; a brief summary of the proposed permitted activities, CO_2 source, quantity, etc.; and list of contacts for states, tribes and territories within the AoR
- Site Characterization Data—Fluid chemistry, geologic, and depth data on both the injection and confining zones and information on all USDWs in the area
- Map—showing the planned injection well location and preliminary AoR; location of the AoR boundary and all artificial penetrations (wells, boreholes) that breach the injection or confining zones; known or suspected faults and fractures in the AoR; and other surface features such as waste site locations (landfills, cleanup sites) surface water features, springs, mines, quarries, drinking water wells, roads, buildings, property and political boundaries like townships, counties and state lines (if non-public site-specific data is available, such as information from a stratigraphic test well or seismic survey, it should be included in the permit records and noted on the AoR map)
- Tabulations—Wells in the AoR that penetrate the confining zone and/or the injection zone; location of wells on the AoR map including well record ID numbers, location (latitude/longitude); well type (oil gas, test); depth; deepest formation penetrated; completion date; current status (active, inactive, plugged or unknown); and information about whether the well is in need of corrective action
- Project Plans (see plan descriptions in Section 3.2.2)—Plans that will eventually become a part of the permit to drill and operate the well
- Provision for financial responsibility—Requirements established in 40 CFR 146.85 and in US EPA guidance (See Appendix B-1)

Additional discussion and detail in the permit application includes proposed operating conditions, proposed well stimulation, and steps for conducting the injection operations. A summary of the formation testing program should also be provided.

3.2.2 PROJECT PLANS

The permit applicant must prepare project plans and submit them along with all other components of the Class VI permit application to the regulatory agency. The plans must include:

- AoR and Corrective Action Plan—Describes how an owner or operator intends to delineate the AoR for the Class VI injection well and ensure that all identified deficient artificial penetrations (wells that are improperly plugged or completed) will be addressed by correction action techniques so that they will not become conduits for fluid movement into USDWs
- Testing and Monitoring Plan—Describes how the owner or operator intends to perform all necessary testing and monitoring associated with the storage project, including injectate monitoring, performance of mechanical integrity tests (MITs), corrosion monitoring, tracking of CO_2 plume and area of elevated pressure, monitoring of geochemical changes above the confining zone, and, at the discretion of the UIC Program Director, surface, air, and/or soil gas monitoring for CO_2 fluctuations and any additional tests necessary to ensure USDW protection from endangerment
- Injection Well Plugging Plan—Describes how, following cessation of injection, the owner or operator intends to plug the Class VI injection well using the appropriate materials and methods to ensure that the well will not become a conduit for fluid movement into USDWs in the future
- Post-Injection Site Care (PISC) and Site Closure Plan—Describes how the owner or operator intends to monitor the site after injection has ceased, to ensure that the CO_2 plume and pressure front are moving as predicted and USDWs are not endangered. PISC monitoring must continue until it can be demonstrated that the site poses no further endangerment to USDWs (the default duration for PISC, as stated in the Rules, is 50 years)
- Emergency and Remedial Response Plan—Describes the actions that the owner or operator intends to take in the event of movement of the injectate or formation fluids in a manner that may cause danger to a USDW, including the appropriate people to contact

Table 3-1 highlights the typical injection permit information provided by the RCSP's. The required project plans are based on available site-specific information. The owner/operator should note that if a stratigraphic test well is required, the well could be used in the future as an injection or monitoring well with proper design and planning.

When the plans are approved, they become an enforceable part of the Class VI permit (US EPA Project Plan Guidance, EPA, 2012a). The project plans may need to be updated as additional project data are accumulated from the site characterization, well construction, and operation phases. The regulations require that the Class VI well owner/operator periodically review and update the plans, incorporating operational and monitoring data. The periodic reviews will also include an update of the site modeling and AoR boundaries. **Figure 3-1** depicts an AoR determined for the SECARB Citronelle Project site.

For more information on project plans, the EPA offers project plan guidance (EPA, 2012a; EPA, 2015c). In addition, US EPA has published a series of guidance documents to assist the permitting agency and the well owner/operator. The full list of guidance documents is included in **Appendix C-2**, and Regulatory Summary in **Appendix C-3**.

Table 3-1: Typical Injection Permit Information Provided by RCSPs

Information Typically Provided by RCSPs*

Geologic Information

- Injection Depth and Formation
- Lithological Description
- Lower-Most USDW
- Testing of Multiple Sources of Groundwater
- Model of Potential Plume Development

Well Design and Construction

- AoR Detailed Schematic and Proposal
- Legal Description of Land Ownership
- Proof of Notification of Injection Intent to Affected Parties in the Region
- Third Party Certifications for Injection and Construction
- Construction details on all wells within the AoR and remediation action taken to improve these wells, if necessary

Description of Surface Equipment

- Proposed Equipment to be Installed
- Equipment Sizing and Location Calculations
- Proposed Average and Maximum Daily Rate of Fluids to be Injected
- Proposed Average and Maximum Surface Injection Pressure
- Potential Fracture Pressure Determination

Monitoring Systems

- Continuous Sampling of Multiple Neighboring Drinking Water Wells
- Proposed Injection Monitoring Plan Equipment
- Post-Injection Long-Term Monitoring Plan and Equipment

Logging and Testing Results

- Geophysical Data Supporting Location of Injection Zone and Caprocks and Absence of Resolvable Faults
- Modeling of AoR Throughout Pre-Injection, Injection, and Long-Term Post-Injection

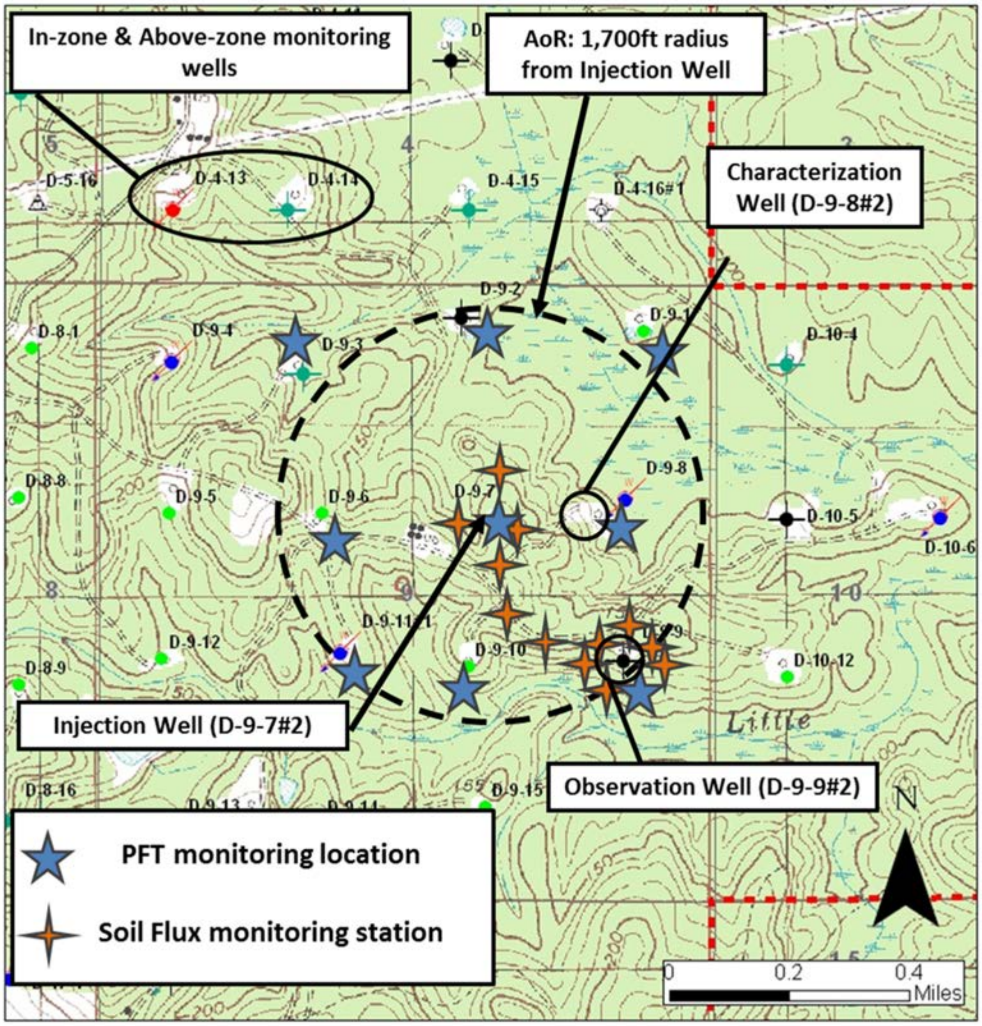


Figure 3-1: Area of Review for the SECARB Citronelle Project Site. Figure shows the location of the injection well, observation wells, and all monitoring locations.

Guidance documents (EPA, 2015b) pertinent to Class VI construction and operations include:

- Class VI Well Site Characterization Guidance—Covers discussions of the type of site characterization data that should be collected during drilling and installation of the injection well and may also be used as a guide for planning stratigraphic test wells
- Class VI Well Testing and Monitoring Guidance—Describes tools and methodologies available to the owner/operator to collect subsurface data and complete well tests that can be used to fulfill requirements
- Class VI Well Construction Guidance—Recommends how to meet injection well drilling, construction, testing, and operating requirements and describes requirements for the permit application including well materials descriptions that address suitability for proposed injection conditions, compatibility with the injectate and reservoir conditions, well schematics and details, and well construction procedures
- Class VI Well Plugging, Post-injection Site Care, and Site Closure—Provides guidance on well plugging requirements that should be considered during well design and construction

Construction procedures for Class VI wells require that surface casing be set through the base of the lowermost USDW and cemented to the surface. The casing which covers the injection zone should be cemented in place along its entire length. Geological sequestration wells should be constructed with a packer set at a depth above the injection interval, and the use of corrosion-resistant materials compatible with the injectate and subsurface fluids is required. The regulations also require automatic downhole shut-off mechanisms (a subsurface safety valve [SSSV], which is a requirement in all offshore wells) in the event of a mechanical integrity loss. The owners or operators of CO_2 injection wells are required to demonstrate mechanical integrity (accomplished through the use of casing imaging tools, cement bond logs, and casing caliper logs or pressure tests designed to detect leaks [**See Chapter 4**]) prior to injection of CO_2 and at least once annually during the operation phase of the project.

3.2.3 WELL MAINTENANCE AND PLUGGING

3.2.3.1 WORKOVERS AND INTERVENTION

Class VI well mechanical integrity requirements (EPA, 2015c) are established in 40 CFR 146.89 and require regular episodic monitoring to demonstrate internal mechanical integrity and annual external mechanical integrity tests. Well workovers and intervention may be completed either as routine preventive maintenance, in response to the results of annual mechanical integrity testing, or in response to a sudden loss or reduction of mechanical integrity. Maintenance activities will be established in the permit and should be clearly delineated in the Testing and Monitoring Plan in the permit application. Following a workover, or if a loss of mechanical integrity has occurred, the injection well must remain off line until mechanical integrity has been restored, the well tested in accordance with the permit, and the EPA agency director has authorized injection operations to resume.

3.2.3.2 CLOSURE

The requirement for plugging an injection well (US EPA 2015c) is established by 40 CFR 146.92. The requirements for plugging the well, including materials to be used, the order of plugging operations, and verification are established in the permit as part of the Injection Well Plugging Plan (see reference above). The key objective of the plugging operation is to provide assurance that the well does not become a conduit for fluid movement into a USDW.

3.2.4 CLASS II PERMIT COMPONENTS

In some instances, Class II UIC permitted wells may be converted to Class VI injection wells. Class II UIC permits are primarily obtained for the injection of brine and other fluids related to oil and gas production. These in general are less complex than the permits required for Class VI. A major difference is a simple radius of influence calculation is acceptable in lieu of a detailed AoR developed through complex computer modeling. As a result, the burden for site characterization data is less extensive for Class II. In addition, the permit application is simpler and does not require development of the numerous plans necessary for Class VI. A Class II permit application requires:

- General administrative and contact information
- A discussion of the source, composition and phase of the CO_2
- A well design schematic and a discussion of well construction methods and materials (to demonstrate compatibility with the injectate)
- A discussion of methods and plans for any well testing, including MITs and well stimulation
- A discussion of, and demonstration of, protection of USDWs
- A well plugging plan
- Financial assurance (such as a bond) to cover the costs of well plugging

If the primary purpose of the project is CO_2 storage rather than EOR, then the suppliers (under joint and severable liability) and/or the EOR operators, will be responsible for demonstrating and quantifying “permanent storage” as set out in the Class VI regulations. The key elements that become effective from the Class VI program are that the Class II wells may be grandfathered but must meet Class VI design standards and mechanical integrity once the well is transitioned. The Class VI monitoring requirements and the post-injection site care also apply.

US EPA has prepared two (draft) documents for the transition from a Class II to Class VI project:

- Geologic Sequestration of Carbon Dioxide Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II wells to Class VI Wells (EPA, 2013)
- Key Principles in EPA’s Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI (EPA, 2015a)

The Class VI regulations describe the requirements (US EPA 2015b) for owners or operators seeking to re-permit existing Class II wells to Class VI wells for the purpose of geologic storage at 40 CFR 146.81(c). Owners or operators planning to convert existing Class II wells to Class VI wells must, per 40 CFR 146.81(c), demonstrate to the Class VI UIC Program Director that the wells were engineered and constructed to meet the requirements at 40 CFR 146.86(a). The owner or operator must also demonstrate that the wells will ensure protection of USDWs in lieu of the requirements for casing and cementing of Class VI wells at 40 CFR 146.86(b) and the requirements for logging, sampling and testing prior to injection well operation at 40 CFR 146.87(a). For further information on well construction to meet these Class VI requirements, see the UIC Program Class VI Well Construction Guidance. If an owner or operator seeking to grandfather an existing Class II well to a Class VI well cannot make this demonstration, then re-permitting of the constructed well will not be allowed. The owner or operator may discuss with the Class VI UIC Program Director whether remedial activities will enable the well to meet Class VI requirements or if construction of a new Class VI well or selection of an alternative well for conversion is needed.

Case Study 3.2 describes SECARB's plan for converting an injection well to a production well for post-injection operation.

▶ See page 46

3.2.5 MISCELLANEOUS PERMITTING

In addition to Class VI, other permits are required to construct monitoring wells not authorized under the Class VI permit. As noted, a Class VI permit is only for drilling and operating an injection well. Although a variety of monitoring wells are required by the permit (via the Monitoring, Verification, and Accounting Plan), authorization for construction of those wells is to be incorporated into the permit by reference and obtained through the local oil and gas agency if applicable.

Oil and gas wells are regulated at the state level either within a department of natural resources or a separate agency. Stratigraphic test boreholes and test wells require a permit from the oil and gas regulatory agency. Similarly, any deep monitoring wells, stratigraphic test boreholes, test wells and production wells (for EOR) must be permitted by that agency. In some cases they may be incorporated into the permit by reference. Most states recognize "deep wells" as any well that extends into or below the shallowest known hydrocarbon producing zone.

For any deep well, including the injection well, it is prudent to consult with the regulatory agency and review the site characterization data for known or potential drilling issues such as lost circulation zones, over-pressured zones, unstable geologic conditions, or other drilling hazards such as the presence of hydrogen sulfide (H_2S) or methane.

Shallow wells, such as groundwater monitoring wells, also require a permit. Typically, these permits are administered and issued by a state or local agency responsible for all freshwater wells (private or municipal water supply, irrigation, and monitoring wells).

Although not directly related to drilling or injection well operations, a variety of other permits or regulatory approvals may be required for successful implementation of a project. These include consideration of environmental impact, which if using Federal funding or operating on Federal lands, must conform to the National Environmental Policy Act (NEPA) and work through escalating levels of approval:

- Categorical Exclusion (or CX), which determines, based on readily available data, that the project would not have an impact on the environment or cultural features (occupied structures, historical sites, etc.) included within or immediately adjacent to the project work area
- Environmental Assessment (EA), which is a more detailed review of available information and may be required if the CX does not resolve regulatory or public concerns
- Environmental Impact Statement (EIS), which is the most detailed assessment of the project impacts on the environment and may require collection of new data (e.g., wildlife inventories) and the project owner to address and develop a mitigation plan for impact on the natural environment, cultural features, environmental justice issues

The U.S. Army Corp of Engineers may need to be involved in the project if the surface site will disturb or impact any wetlands, waterbodies, or streams.

In terms of drilling, construction, and operations, the project owner should also review other local and state requirements such as:

- Pipeline and surface facilities construction permits
- Handling and disposal of produced water
- Transportation permits (frost laws, road and bridge weight limits, oversized loads)
- Noise restrictions
- Utilities (temporary or permanent)
- Construction permits

3.3 RCSP CASE STUDIES

CASE STUDY 3.1 — **MGSC**

MIDWEST GEOLOGICAL SEQUESTRATION CONSORTIUM (MGSC)

Permitting for Large-Scale Carbon Storage Projects: The Illinois Basin – Decatur Project (IBDP)

Permitting the injection well was a critical path activity for the MGSC's IBDP. In the United States, underground injection wells are regulated as part of the Safe Drinking Water Act (SWDA, 1974). The SDWA includes protection of underground sources of drinking water (USDWs). Up until 2010, five classes of underground injection control (UIC) wells were regulated by US EPA or by individual states that had received approval for regulatory primacy from the federal agency. Primacy varies from state to state and within regions for Classes I to V.

The State of Illinois holds primacy for Classes I to V. In 2007, the IBDP began preparing the injection permit application. In 2009, the project received a Class I - Non-hazardous UIC permit issued by the Illinois Environmental Protection Agency. The permit holder is the Archer Daniels Midland Company (ADM).

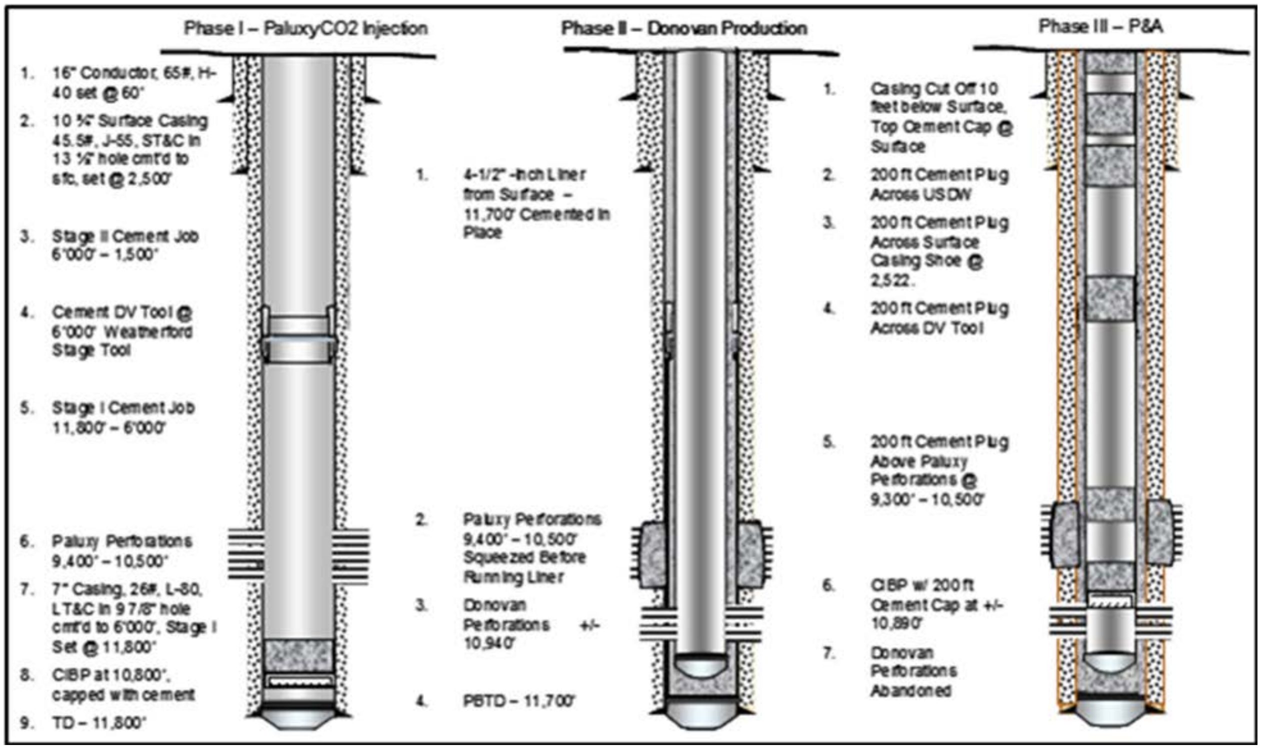
Coincident with the IBDP permitting process (2010), the US EPA promulgated final regulations for a new class of injection well (Class VI) specific to the injection of CO_2 in the subsurface. These regulations became effective in September 2011. They required that Class I CO_2 UIC well permit holders apply by December 2011 to US EPA to convert the existing Class I permit to Class VI. The IBDP ADM Class VI permit was issued in 2014 as the injection phase of the project was nearing completion. Post-injection site care (PISC) and well plugging will be completed under the Class VI UIC permit. The permit for IBDP links monitoring in the PISC with a second larger-scale industrial CCS project hosted by ADM.

CASE STUDY 3.2 — **SECARB**

SOUTHEAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (SECARB)

Post-Injection Well Conversions – Class V to Class II Operations

The SECARB Citronelle Project injection and storage site is located within an oilfield operated by Denbury Onshore, LLC. Following the conclusion of the project's post-injection site care period, Denbury Onshore, LLC anticipates that the injection well will be transitioned for use in oil field operations. Conversion of the well will consist of removing the injection tubing and packer, sealing all perforations with cement, and testing the well casing integrity. A robust steel casing liner will then be run into the well and cemented in place, and a cement bond log will then be obtained to assess the quality of the cement seal. Following this, the well will be pressure tested and integrity tested. This procedure is designed to effectively seal off the open perforations in the injection zone, thereby protecting the USDW from fugitive migration of CO_2. Once the well is effectively sealed, it will then be converted to Class II for oilfield operations. After oilfield operations, the wells will be plugged and abandoned. A cast iron bridge plug and a series of cement plugs will be employed to officially seal off and abandon the well. The figure below exhibits the well schematics depicting the proposed UIC completion, the proposed oilfield completion and the proposed abandoned wellbore.



Well Plugging and Abandonment Plan

4.0 DRILLING AND COMPLETION OPERATIONS

Drilling and completion operations for geologic storage wells are based on more than a century of experience by the petroleum industry. The lessons learned and best practices devised are directly applicable to the drilling and completion phases of projects. This material provides an underpinning for the comprehensive guide outlining all phases of drilling and developing wells for the injection and monitoring of CO_2 storage.

4.1 SITE PREPARATION

Site preparation encompasses preparation of the well pad and establishment of site security and access. These activities ensure creation of a safe, well laid out construction and work site and help minimize operational delays. It is important to note that although site preparation activities are presented in a linear fashion, many of these tasks may occur in parallel with each other.

4.1.1 ESTABLISHING SITE SECURITY AND ACCESS

A secure site during all active phases of operation is essential to ensure the safety of the public and site workers. Because well drilling and construction involves many safety hazards, access should only be granted to essential personnel. Site security typically consists of enclosing the work area with fences, gates, and signs. If necessary, bollards may be installed for the protection of equipment and pedestrians from vehicle traffic to and from the site. Video surveillance may also be installed to monitor the critical areas of the site (wellhead, injection equipment, etc.).

When planning a site, the operator should consider how equipment and materials will be transported both to and within the site. It is advantageous to utilize existing infrastructure (e.g. public roads) whenever feasible to reduce costs and limit disturbance to the environment. Road usage is typically required through all phases of the injection project to transport equipment and materials to the site. The degree of usage is likely to vary over the course of the project with the heaviest use during the construction and drilling phases. Operators then work with permitting agencies and local municipalities to determine if the specific roads used necessitate additional requirements such as highway occupancy permits, road bonding, or weight and usage restrictions.

Case Study 4.1 discusses site planning around existing infrastructure.

▶ See page 68

Over the life of a project, road requirements are expected to change within the site boundary. During the installation and construction phases, roads may typically be constructed of gravel, which is engineered to handle heavy equipment loads like drilling rigs and well completion equipment. When the project moves into the injection operation stage, the need for routine, heavy vehicular access is likely to decrease. For large-scale projects, however, delivery of CO_2 will most likely be via pipeline. Therefore roads would only need to be designed to handle occasional heavy equipment like workover rigs, logging trucks, or Vibroseis (seismic acquisition) trucks.

In some instances, new roads may require construction. A new road must be designed in accordance with federal, state, and local regulations and to industry standards. When siting and constructing a new road, consideration of environmental impact is important. Factors of concern include: erosion, excessive site disturbance, fugitive dust and air pollution, and impacts to wetlands, natural waters, cultural resources, and the proximity to sensitive pieces of equipment. The design, layout, construction, and maintenance practices should be tailored to minimize any negative potential impacts.

4.1.2 WELL PAD PREPARATION

Surface pads at prospective well locations are required to accommodate all drilling, completion, and injection operations. Consideration of project scale is an essential component of site prep. Well pads are typically designed to support the space requirements of the drilling rig and well casing pipe, and pad size and orientation will vary by project. These components depend on the type of rig used, plans for source water and produced water management, the proposed layout of the site, topographical, geotechnical and environmental constraints, and future maintenance and access needs. As a project site is developed, the size of the affected area, or "footprint," will likely change. This can be due to both staging the pad during operations or if any unforeseen circumstances necessitate a change in the well pad layout.

Breaking ground on well pad construction requires the operator to have performed all necessary surveying, testing, and permitting to initiate construction. The first step of well pad construction typically consists of clearing vegetation. Next, the top soil should be stripped and stockpiled for use in reclamation after the operations are complete. The area is then leveled, which may require excavation or fill. The geotechnical requirements of the anticipated drilling operations and injection facilities will dictate the specifics of the required excavation/fill plan.

Once the pad area is leveled, it should be graded to divert water into drainage ditches and/or dedicated holding ponds. A typical pad has a dedicated pond, pit, or lagoon to store water for drilling mud and drill cuttings. The design of the well pad and associated pits and ponds shall be consistent with pertinent state and federal regulations and drilling permit requirements. They are designed to accommodate any drainage and fluid collection during drilling operations. In many cases, precipitation or fluids generated on the pad are treated as waste products and should be collected and stored in onsite ponds or tanks. A good practice is to divert all off-pad precipitation and runoff away from the pad to prevent the collection of any unnecessary waste.

MGSC constructed a drilling pad that was 200 feet by 150 feet at the Decatur Site because it was to hold both an injection well and an observation well with a permanent geophone array. However, the SECARB Black Warrior Site was able to use a pad that was 100 feet by 100 feet. The ideal well pad would not take up any extra space than is required by the operations and would require little excavation or fill to construct. Following these guidelines should help to protect the environment while keeping construction costs to a minimum (Lyons & Plisga, 2005).

4.2 WELL DRILLING

Well drilling activities commence with the mobilization and installation of the drill rig and supporting equipment at the site. A variety of drill rigs and drill methods are designed to address the site-specific conditions. It should be noted that different drilling stages may require separate drilling methods, personnel, and equipment depending on the pre-injection plans and schedule.

It is essential to review state licensing laws for drilling operations, since some states require drillers to be licensed as a company and/or as individuals, and some states require individuals with certifications to man the rigs. To assure safe operations, optimize data collection, and minimize the risk of cost overruns, it is advantageous to work with experienced drillers and associated service companies. The RCSP experience demonstrated that the involvement of qualified professionals with specific expertise in drilling and familiarity with the specific region and the local subsurface geology was an important factor to smooth drilling operations. Using local experts and companies with knowledge of the region was highly useful in optimizing drilling, determining depths of storage formations, and avoiding/anticipating and preparing for potential drilling hazards. A list of reference material concerning several aspects of the drilling and completion process has been provided in **Appendix D-1** to further assist operators in selecting drilling support. **Appendix D-2** provides a list of Oil and Gas Contact Information by State.

Drilling Through Zones of Lost Circulation

A potential concern while drilling deep wells is encountering zones of lost circulation – the reduced or total absence of fluid flow up the annulus when fluid is pumped through the drill string. Lost circulation can occur when the drill bit encounters natural fissures, fractures, or caverns in a formation, allowing mud to flow into the newly available space. Lost circulation may also result from applying more hydrostatic mud pressure than the formation can withstand. At a minimum, the loss of fluid to the formation represents potential environmental issues in the formation and/or a financial loss, which is directly tied to the per barrel cost of the drilling fluid. Lost circulation also increases the chances of the drilling assembly becoming stuck in the well. In severe cases, lost circulation can result in lost well control.

Significant zones of lost circulation were encountered in the Potosi formation while drilling all of the deep wells at the Illinois Basin – Decatur Project (IBDP) site. The formation was heavily karsted and the void spaces were inches to feet in diameter. Standard oilfield methods of increasing aggressiveness were used until circulation was restored. During the drilling of CCS1, the first well on location, this added days and thousands of dollars in cost to the well drilling operations. Subsequent wells were able to anticipate and mitigate for potential risk associated with the expected lost circulation zone.

Several options exist for drilling though lost circulation zones, including; 1) mixing a high-viscosity “pill” of drilling mud and circulating it into the interval, 2) mixing lost circulation (plugging) materials in the drilling mud, and 3) circulating cement across the lost circulation interval.

A high-viscosity pill is the easiest solution and will work on very fine fractures that are leaking the drilling mud into the formation.

Mixing lost circulation materials in the drilling mud is usually successful on wells exhibiting seepage but not in instances of a severe loss of circulation. A drawback is that the lost circulation materials can be flushed out of the zone by circulating the drilling fluid, causing a return of lost circulation. Common materials used include nut hulls, cottonseed hulls, ground corncobs, mica flakes, cedar bark, and other fibrous, flaky or granular materials.

In severe cases, such as at IBDP, the voids are so large that plugging must be done with cement. Several cement plugs will be pumped with time allowed between for the cement to set. The goal is to build up a solid wall around the well that will be able to hold back future hydrostatic pressure. Once circulation is restored, this cement plug will need to be drilled through. This method is the most time intensive and is thus the option of last resort. A constant worry is that a new severe lost circulation interval will be encountered and the process will need to be repeated several times before the formation is completely drilled. In the case of IBDP, after the CCS1 experience with lost circulation, all subsequent wells opted to start with this method to address lost circulation, which helped to keep the project on schedule and within budget.

Prior planning is very important to mitigate the cost and time lost to circulation issues. Offset well drilling records are the best place to look, if available. Regional and site geology are key points of knowledge. Having a good wellsite geologist that can pick the markers previously identified, and that can work with the drilling engineer to anticipate lost circulation before it happens, is very important. A contingency plan should be agreed and in place long before the lost circulation event occurs.

4.2.1 DRILLING METHODS

The same drilling methods developed by the petroleum industry are applied to the development of geologic storage wells. Several unique well drilling methods have been developed depending upon reservoir parameters and the application of the well. **Table 4-1** provides an overview of some of the most common methods and their applications, advantages and challenges. In some instances, a combination of more than one drilling method may be used for a well. However, only the most commonly applied method, rotary drilling, is discussed here. It is advantageous for the operator to consult regional drilling experts to know when one or more drilling method can be implemented.

Some of the drilling methods listed in **Table 4-1** are more common than others. The most common drilling method applied is rotary drilling. Several major factors contribute to the selection of site-specific drilling methods including:

- Borehole depth
- Expected lithologies and their associated properties
- Anticipated borehole diameters
- Project budget/schedule

Core drilling is usually performed in the formations of interest. However, core drilling could be cost effective to drill to T.D. where many formations would warrant stratigraphic and petrographic assessment. Further discussion on core drilling is discussed in more detail in **Section 4.4.2**.

Table 4-1: Common Drilling Methods

Method		Comments	Application
PERCUSSION	Cable Tool	Very simple process, but limited by equipment and formation.	Shallow water wells. Could be utilized for shallow monitoring wells.
	Air Hammer		
ROTARY	Air	Fast, can overcome most drilling conditions. Most common method for wells several thousand feet and deeper.	Shallow to deep well drilling, vertical or horizontal. Injection and monitoring wells.
	Direct Mud		
	Reverse Circulation		
	Directional		
	Core Drilling		

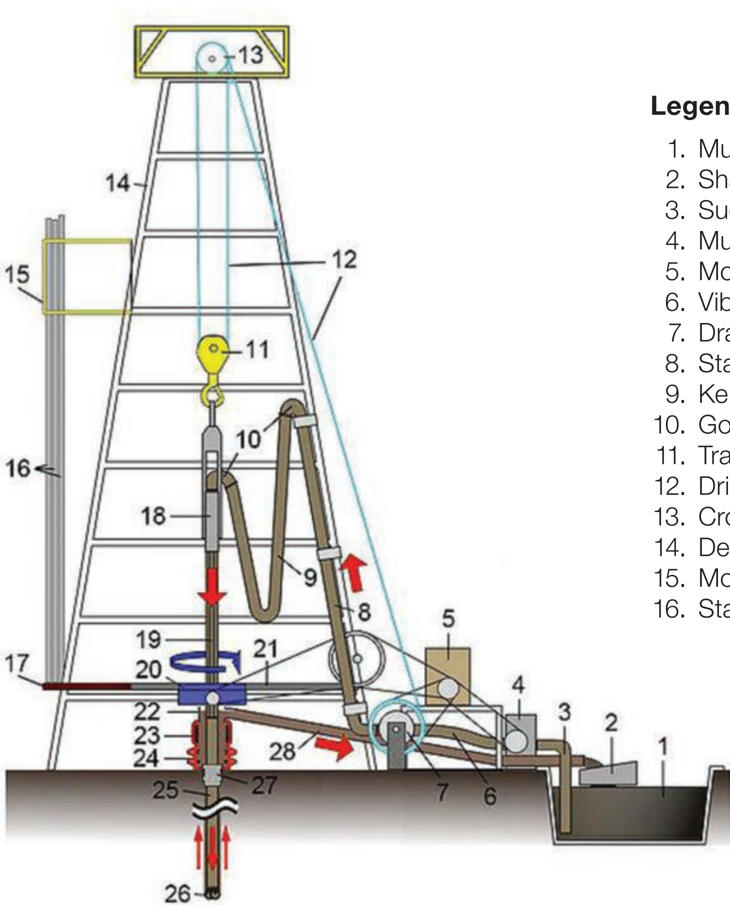
(Modified from a TetraTech table)

4.2.2 EQUIPMENT

A drill rig and a host of supporting equipment are necessary during all phases of drilling operations. The drill rig and equipment must be suited to the site and the anticipated geology to optimize drilling, completion, and operation of the well. The type of drill rig selected is determined by a series of site-specific factors, such as the layout of the drilling pad, drilling method, depth of well, rock type to be encountered, and well casing requirements. A sample Authority for Expenditure Form from the petroleum industry is shown in **Appendix D-3**.

As indicated in **Figure 4-1**, the supplementary equipment and support structures required to maintain drilling operations could include:

- Fuel sources (diesel, electricity)
- Drilling mud and additives
- Water supply
- Recirculation pit (mud pit)
- Cuttings handling equipment
- Support trucks
- Trailers for personnel work space



Legend

1. Mud tank
2. Shale shakers
3. Suction line (mud pump)
4. Mud pump
5. Motor or power source
6. Vibrating hose
7. Draw-works
8. Standpipe
9. Kelly hose
10. Goose-neck
11. Traveling block
12. Drill line
13. Crown block
14. Derrick
15. Monkey board
16. Stand (of drill pipe)
17. Pipe rack (floor)
18. Swivel (on newer rigs this may be replaced by a top drive)
19. Kelly drive
20. Rotary table
21. Drill floor
22. Bell nipple
23. Blowout preventer (BOP) Annular
24. Blowout preventers (BOPs) pipe ram & shear ram
25. Drill string
26. Drill bit
27. Casing head
28. Flow line

Figure 4-1: Example of a Mud Rotary Drilling Rig

(List created by TetraTech based on: http://en.wikipedia.org/wiki/File:Oil_Rig_NT8.jpg)

The layout of the support equipment will vary based on the size and shape of the drilling pad and should comply with individual project needs. The rig should be placed so that support equipment and support structures can be accessed easily without obstruction to the drilling operations. The layout should also include considerations for health and safety of the drilling and support staff.

For mud rotary drilling, a lined mud pit may need to be constructed near the drill rig to contain the drilling mud for recirculation through the drilling string. The size of the mud pits varies based on factors such as depth of well, borehole size, volume of mud, cutting volume, etc. For example, a 35-foot by 100-foot pit was used at MGSC's Illinois Basin-Decatur test site, and a 10-foot by 20-foot pit was used at SECARB's Black Warrior test site. Alternatively, temporary storage tanks may be used—and may be mandated—for a closed-loop drilling fluid system so that the drilling fluid and cuttings can be contained for offsite disposal. Depending on the volume of water needed to support drilling operations (e.g., for drilling mud), source water and flowback water, impoundments may also be necessary.

4.2.3 MATERIALS HANDLING

Four areas of materials handling are necessary during drilling operations: 1) drilling fluids, 2) wastewater, 3) produced water, and 4) drill cuttings. These materials must be properly managed and disposed of during and after the completion operations. **Table 4-2** presents several recommendations for material/waste reduction, disposal, and potential re-use based on industry best practices. Regulatory agencies typically approve material handling plans and can aid in determining specific reduction, disposal, and potential reuse procedures for a specific site.

4.2.3.1 DRILLING FLUIDS

Large volumes of drill cuttings are generated in the wellbore during drilling operations. To remove these cuttings, drilling fluids are used to carry cuttings up and out of the wellbore during drilling operations. Application of drilling fluids additionally acts to lubricate and cool the drill bit, and create filtercake on the formation, which separates formation fluids from the drilling fluids by choking back the well. Choice of drilling fluid is dependent upon the pressure regime of the formations drilled, drilling depth, fluid compatibility and lithology.

Drilling fluids fall into four groups: 1) air and mist, 2) water-, 3) oil-, and 4) synthetic fluids (Lake, 2006). The most common drilling fluid is water-based, but the other fluids offer characteristics that work better in certain applications or with certain geologic units.

Case Study 4.2 details SWP's use of drilling fluids to meet geological challenges at the Farnsworth site.

▶ See page 69

4.2.3.2 AIR / MIST

Air and mist systems are useful for drilling shallow wells up to approximately 6,000 ft. Air is the least expensive option which requires little to no fluids for cleanup and can extend the life of drill bits relative to other drilling fluids. Air systems, however, are not effective against reservoir formation fluid influxes during drilling. The addition of mist can be applied to both continue drilling where some water influx occurs and to improve downhole cleaning. However, if a fluid influx is encountered during drilling that is too great to continue mist drilling, another fluid must be utilized.

4.2.3.3 WATER-BASED FLUID

Fresh water, sea water, or brine can be used as a drilling fluid. Depending on the borehole and geologic conditions, bentonite may be added to the water to help lift the cuttings to the surface, to reduce fluid loss, or to help maintain the hydrostatic pressure in the borehole to prevent cave-in.

4.2.3.4 OIL-BASED FLUIDS

Oil-based fluids can include a mixture of oils or oils and water. The oils may include diesel fuel, mineral oil, or low-toxicity linear paraffins (Lake, 2006). These fluids were designed to control clay swelling and slough into the hole when drilling with water-based fluids. Oil-based fluids can act as a lubricant which assists in removal of stuck tools and increases penetration rates. Typically, the oil-based fluids include 10 to 20 percent fresh water, sea water, or brine. For long intervals of shale, an all-oil fluid may be used.

A disadvantage of oil-based drilling fluids is the potential for environmental impacts to water supplies in the subsurface and at the surface. As a result, oil-based fluids should not be used near potential potable water aquifers, and the cuttings and drilling fluids must be properly handled and disposed of in an approved manner. In general, oil-based fluids are not preferred for geologic storage injection or monitoring wells, but may be necessary under certain conditions.

4.4.3.5 SYNTHETIC FLUIDS

To reduce the potential environmental impacts caused from oil-based fluids, a synthetic fluid may be used. Like oil-based fluids, synthetic fluids are used to maximize penetration rate, increase the lubricating qualities in directional wells, and minimize wellbore stability problems associated with certain formations (Lake, 2006).

4.2.3.6 CHOOSING AND REDUCING FLUIDS

Choosing the appropriate drilling fluid or fluids for a project is necessary for successful, timely and cost-effective operations. Maintaining the permeability of the formation is a critical component of any project when drilling into the injection zone. Certain drilling fluids could potentially cause precipitates to form when the geochemical make-up of the formation and the formation water comingle with the drilling fluids. The production of precipitates could cause a significant reduction of the permeability of the injection zone. Therefore, a proper drilling fluid should be selected that will not react with the formation.

Reduction of fluids used during operations is useful for reducing drilling and disposal costs. There are several strategies to reduce the necessary volume of drilling fluid, which includes opting for smaller boreholes, using air drilling methods, and employing advanced drilling mud formulas and recovery options. Once collected, some spent drilling mud may be reusable if collected and processed using advanced recovery equipment. If drilling mud cannot be reused, then it must be disposed of or treated in an approved manner.

4.2.3.7 WASTEWATER AND PRODUCED WATER

In general, all water involved with drilling operations is considered wastewater. Wastewater is usually disposed of in disposal wells, allowed to evaporate, or moved offsite for commercial treatment and/or disposal. This includes produced water that is generated as a result of drilling activities. Wastewater can be managed through one of three broad approaches: waste minimization, beneficial reuse, and disposal. It is important to note, however, that legal liability remains with the company that produced the waste initially, regardless of its final disposition (ANL, 2009a).

4.2.3.8 DRILL CUTTINGS

Significant drill cutting volumes are commonly generated during drilling operations, particularly in deep- and large diameter boreholes. Therefore, it is necessary to calculate the expected volume of drill cuttings to plan accordingly for their handling and disposal. It is important to note that the volume of drill cuttings will not necessarily be equal to the volume of the hole drilled. The volume generated is a function of the chosen drilling method and the geologic material encountered. Air rotary methods typically produce large volumes of dust which has to be handled to prevent dispersal (usually with a misting system). Fluid-based drilling typically produces larger volumes of cuttings than air rotary methods because the cuttings are captured by the drilling fluids.

An efficient handling system is necessary to minimize disruption of the drilling progress. In an open system, drill cuttings may be stored in pits. Cuttings are separated and removed from drilling fluids using a “Shale Shaker,” where they are dried while the drilling fluid is re-circulated into the borehole. During this process, course and fine cuttings are produced. Since the coarse cuttings are comprised of ground rock with some coating of drilling fluid, they can be of beneficial use such as road base or fill material. However, analytical testing of the material may be required to ensure that any environmental contaminations present are below regulatory levels. If no specific beneficial onsite use can be established, the cuttings may be transported offsite to a landfill or used as backfill at other sites. Local and state requirements and restrictions may place restrictions on offsite use and should be investigated during site planning.

4.2.3.9 CLOSED LOOP SYSTEMS

A closed loop drilling system is a mud pit alternative, which utilizes a series of storage tanks and separation equipment (such as screen shakers, hydrocyclones and centrifuges) to separate liquids and solids from the drilling mud. Closed loop systems maximize drilling fluid recycle during the drilling process which reduces overall waste. The benefits of a closed loop drilling system include elimination of potential hazardous waste escaping into the environment, and a reduction in both surface disturbances and the drilling pad’s space requirements.

Table 4-2: Residual Waste Management Considerations

Water Category	Reduction Strategies	Disposal Options	Beneficial Reuse Potential
DRILLING FLUIDS	Smaller Diameter Wellbores	Burial	Recycling/Reprocessing Oil- and Synthetic-Based Muds
	Multiple Bores from Single Wellhead	Land Application	Enhanced Mud Recovery from Drilling Equipment
	Use Air	Bioremediation	
	Advanced Mud Processing Equipment Technology	Salt Cavern Disposal	
	Advanced Mud Formulas	Thermal Treatment	
		Commercial Disposal	
WASTE WATER	Grading to Divert Rain Water Around and Away from Pad	Injection Well Disposal	Underground Injection for Future Use
		Evaporation	Underground Injection for Increased Oil Recovery
		Offsite Commercial Disposal	
PRODUCED WATER		Discharge (Generally Prohibited Except Under Effluent Limitation Guidelines for Agriculture and Wildlife Subcategory)	Underground Injection for Hydrological Purposes (i.e., Controlling Subsidence, Blocking Salt Water Intrusions, Augmenting Ground Water/Stream Flows)
		Underground Injection	Underground Injection for Increased Oil Recovery
		Evaporation	Industrial Use
		Offsite Commercial Disposal	Agricultural Use
			Domestic Use
			Road De-icing
			Erosion Control (Following Separation and Treatment)
DRILL CUTTINGS	Smaller Diameter Wellbores	Onsite Burial	Fill Material
	Closer Spacing of Consecutive Casing Strings	Landfill Disposal	Daily Cover of Landfills
	Slimhole Drilling	Slurry Injection	Concrete and Brick Filler/Aggregate
	Coiled Tubing Drilling	Commercial Disposal Options – Including Salt Cavern Disposal	Encapsulation and Use as Road Foundation

4.3 FORMATION EVALUATION

Formation evaluation is conducted to test the physical and chemical properties of the formations encountered in the borehole. These tests include a suite of logging tools and coring of the formations to confirm the suitability of the geology at the site. The span and complexity of the logging and testing program is site-specific and the types of data gathered are dependent on locally available geologic information, regulatory mandates, and project specific needs.

Geologic data is collected at various points over the duration of the drilling process and after. This includes mud logs to collect formation and fluid characteristics of the subsurface and core samples to collect information on the injection and confining zones. Laboratory analysis of samples is an important component that can be used to assess formation water chemistry, permeability and porosity, and other information useful to a project. Drill stem tests (DSTs), reservoir tests, openhole tests, and logging operations are also used to determine downhole conditions and collect the critical geologic and fluid information as discussed below.

4.3.1 WELL LOGGING

Formation logging may occur in two stages, during and after drilling. There are two technologies that can be employed to log during drilling: mudlogging and logging while drilling (LWD) or measurement while drilling (MWD). Mudlogging is a passive mode of assessing drill cuttings in real time of the depths and formations encountered. LWD/MWD is a newer technology that occurs synchronous with drilling which can replace openhole logging, and is a normal practice in highly deviated wells and horizontal wells. Post drilling logging provides a more in depth look at the formations encountered and a variety of their petrophysical parameters.

4.3.1.1 MUD LOGGING

Mud logging and fluid characterization analyses are commonly performed during drilling. These techniques allow a near real-time observation of the formation being drilled via the cuttings recovered from the circulated drilling fluid. The analysis is also used to confirm the presence and depth of the various expected lithologies within the confining and injection zones.

4.3.1.2 GEOPHYSICAL LOGGING

Once a borehole has been drilled, additional data can be collected using downhole logging tools. This data is then interpreted to provide an understanding of formations and reservoir properties. Data yielded from these analyses provides the basis for the identification of depths and analysis of properties of potential storage complexes.

Logging packages developed by the petroleum industry for geological characterization are applicable to CO_2 storage projects. A standard log suite commonly includes Gamma Ray, Resistivity, Density, Neutron Porosity, Caliper, Spontaneous Potential, and in some cases, a Sonic log. In addition to the standard logging suite, several logging companies offer advanced logging packages which serve more specific purposes, which may include:

- A magnetic resonance log which may serve to determine permeability and usable pore space within a formation
- A formation imaging tool to identify faults, fractures, and sedimentary features
- A capture spectroscopy log to detect subsurface elemental concentrations to analyze formation mineralogy

These provide an assortment of valuable information on various geologic and petrophysical parameters of the storage complex. However, advanced logging packages may require additional processing and/or supplementary information for interpretation. **Table 4-3** shows several examples of logs performed by RCSP pilot projects and **Figure 4-2** illustrates an example of an openhole wireline log. More detailed information regarding these logging methods can be found in the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* Manual and in Strickland et al., 2014. While many logging service providers offer similar technologies, specific measurement applications can vary between individual geophysical tools and among service providers.

Case Study 4.3 describes the wireline logging tools and data used by SWP at the Farnsworth site.

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Table 4-3: Some Examples of Openhole Logs Performed by RCSP Projects

Logging Data Channels	Common Applications*, #
Density	Formation Density, Calculated Porosity
Neutron	Compensated Total Porosity
Caliper	Borehole Diameter and Rugosity
Sonic	Primary and Secondary Porosity, Seismic Calibration
Micro Imaging	Fractures, Faults and Stratigraphy
Resistivity	Deep Formation Resistivity
Magnetic Resonance	Pore size, effective porosity
Elemental Capture	Presence of Multiple Elements Within Formation
Gamma Ray	Formation Natural Gamma Ray

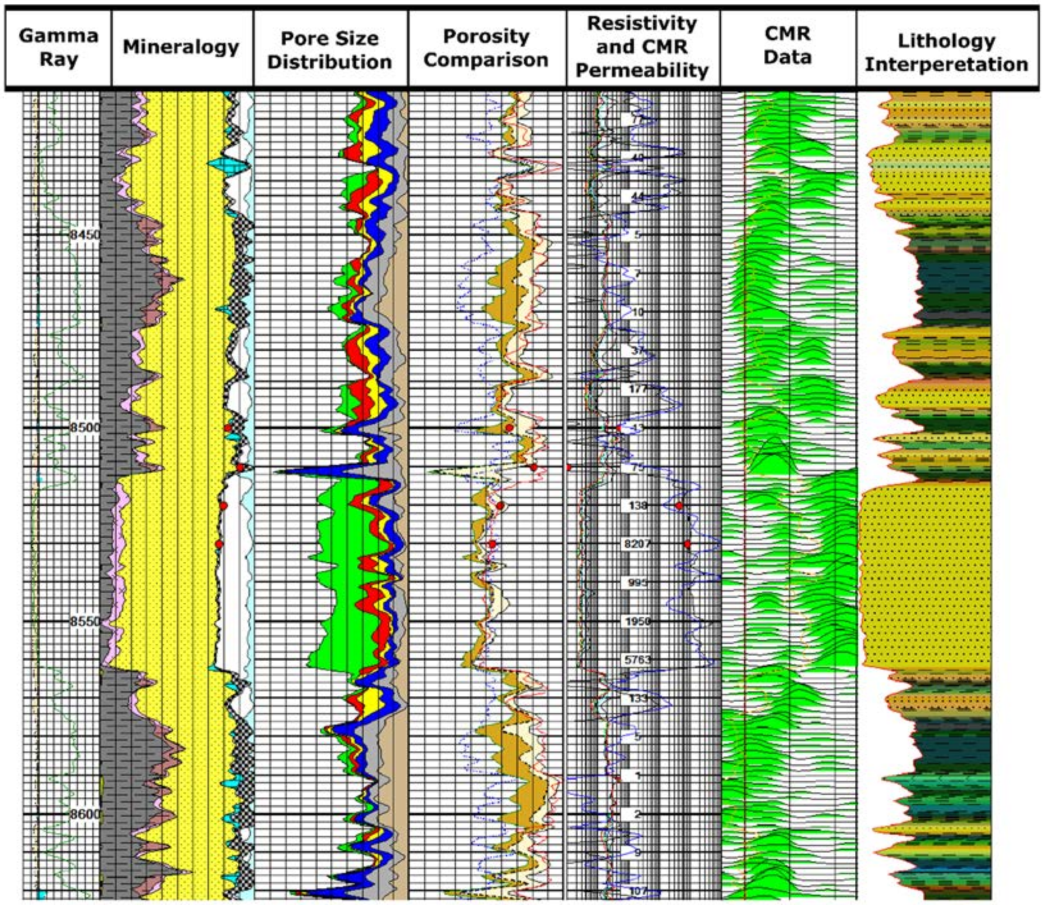


Figure 4-2: Example of an Open-Hole Wireline Log

(SECARB, Final Report: Plant Daniel Project Closure Report, Volume 1 of 2, 2010)

4.3.2 CORING

Downhole core sampling provides essential lab-based petrophysical data on confining and injection zones in geologic storage projects. There are three methods of collecting rock cores: 1) conventional coring; 2) wireline retrievable coring; and 3) sidewall coring. Cores allow for physical and chemical analyses of key properties in potential storage formations and the associated caprocks. In the case of geologic storage, the two most important things to core are the storage reservoir to best understand and assess the reservoir properties, such as permeability, porosity and injectivity, and the caprock to ascertain the integrity of the seal. Analyses of the physical properties of core provide potential storage volume data and details on the ability of a caprock to restrict migration, while chemical analyses may help predict the potential for long-term reactions to mineralize injected CO_2.

It is important to note that a provision in the U.S. EPA Class VI UIC permit indicates that regulators can request information about the geologic properties of sealing formations. Therefore, it is recommended that regulators be contacted during the development of a coring program. It is also recommended that volume of sample needed for laboratory analysis also be factored into the decision on the specific type of coring method to be used.

4.3.2.1 CONVENTIONAL CORING

Conventional coring utilizes a core barrel attached to the end of the drill string and lowered to the bottom of the well. A typical core ranges from 10 to 30 feet in length (but can be up to 60 feet), and from one to six inches in diameter. The core barrel is hollow in the center and equipped with a diamond studded bit (**Figure 4-3**). As the drill string is rotated, fluid is circulated through the center of the drill pipe and core barrel to cool the bit and remove the cuttings. As the drill string is advanced, it cuts the rock and the core sample slides up the center of the barrel into an inner barrel, or sleeve with a retaining device. Once the run has been completed (the length of the core barrel has been drilled), the drill string is removed from the borehole and the core is extracted from the barrel assembly either onsite or at the core analysis laboratory. This type of coring method may require additional rig time because the drill string must be removed from the well to retrieve each interval of drilled core.

4.3.2.2 WIRELINE RETRIEVABLE CORING

Wireline retrievable coring is similar to conventional coring, except that the inner core barrel is retrieved without removing the entire drill string. Once the run has been completed, a wire cable is sent down the interior of the drill string, which unlocks and attaches itself to the inner barrel when it reaches the top of the core barrel. The wire is retrieved and the inner barrel is brought to the surface. Once the core has been extracted, the inner barrel can be sent back down the drill string to collect another sample. This method is effective in deep boreholes where several consecutive runs are required. This method can significantly reduce drilling times because the drill stem does not need to be removed to retrieve each core.

4.3.2.3 SIDEWALL CORING

The third method, sidewall coring, can target specific intervals for coring. This method involves a rotary bit or percussion coring tool that is lowered into the borehole after the borehole has been drilled. A small core (typically around one-inch diameter) is collected from the side of the borehole and the core sample is stored in the tool so multiple samples can be collected from each run. A benefit of this method is that it allows for the economical collection of rock samples from multiple levels in the well after a basic logging suite has been collected. For example, the Midwest Regional Carbon Sequestration Partnership (MRCSP) collected 48 sidewall core samples at the R.E. Burger Site in two sampling runs.

Sidewall coring has several limitations, however. The main drawback is that the core is not continuous, so small-scale changes in lithology may not be observed. Additionally, the small sample size can increase the uncertainty in some laboratory measurements of rock properties. Therefore, it may be beneficial to run a microimaging log to supplement sidewall core data.

Figure 4-3: Core Bits

(**http://en.wikipedia.org/wiki/File:Diamondcorebits.jpg**)

4.3.3 HYDROLOGIC AND GEOMECHANICAL TESTING

Hydrologic and geomechanical testing are essential to constraining the full suite of reservoir properties necessary for completing a geologic storage project. These tests include: 1) openhole testing; 2) cased hole testing; 3) reservoir fluid sampling; and 4) seismic applications. To expedite the well completion process, the well may be cased and cemented and then tested for mechanical integrity while waiting for core analyses to be conducted.

4.3.3.1 OPENHOLE TESTING

Openhole tests are used to assess the geologic parameters of the well bore and the potential injection parameters. Common methods include wireline formation tests, drill stem tests (DSTs), and injection and production tests. DSTs and wireline formation tests can be utilized to calculate the reservoir pressures in potential injection zones.

4.3.3.2 WIRELINE FORMATION TESTS

Openhole wireline formation tests are run prior to and after casing and cementing the well, where logging tools measure the formations directly. This allows the logging equipment to generate strong signals to provide robust data for interpretation of reservoir parameters. An example of an openhole test includes Modular Dynamic Tester (MDT) a useful tool for getting a fluid sample for geochemical analysis, and to assess reservoir pressures, fluid density, fluid contacts and intercommunication among reservoirs.

4.3.3.3 DRILL STEM TESTS

DSTs are performed to determine formation fluid types and to estimate potential production, injectivity, formation pressure, permeability, and relative formation damage. These are conducted while the drill string remains in the well, using temporary downhole packers to isolate the zone of interest, and valves to control the production of reservoir fluids into the drill pipe and to control the flow time. Test results may be analyzed on readily available software packages or standard methods published in reservoir engineering textbooks[1].

Running DST's provide several key benefits to well analysis. For example, data collected can be used to standardize and correlate with logs that are run in the wellbore, and DST's have minimal environmental impacts at the surface because there is little or no release of fluids. However, the main benefit of DST's is the ability to evaluate the formations of interest before casing and completing the well. This helps reduce costs in the event that a storage formation yields unsatisfactory properties. For example, WESTCARB used this approach at the Cholla well in northeastern Arizona. A DST showed that the storage formation had negligible permeability, so the well was abandoned without incurring most of the casing and completion costs (Myer, et al., 2010). However, it is worth noting that there is a risk associated with DST's getting stuck in the well, which must be taken into consideration when devising a drilling strategy.

4.3.3.4 PRODUCTION AND INJECTION TESTS

Production and injection tests are applied to wells to determine a host of reservoir parameters including potential production rates, reservoir injectivity, and the mechanical failure pressure of a reservoir (Matthews and Russell, 1967). Assessment of the injection/production potential of a reservoir enables an operator to address mechanical issues in a wellbore, analyze fluids, and build a comprehensive assessment of a reservoir in combination with adjacent wells. Conducting production tests may entail a pressure buildup and pressure drawdown analysis. A production test may detail the flow rate of a reservoir, pressure, temperature, skin (a measure of formation damage), and detail fluid properties.

In an injection test, a fluid is injected into a reservoir for a set period and halted. The pressure decline is then measured as a function of time to determine the maximum potential injection rate of a storage reservoir. Step-rate injection tests can be employed to determine the mechanical formation failure pressures. In this approach, brine or a native formation fluid is injected at increasing rates while corresponding pressure increases are monitored in the well and injection lines (and possibly nearby monitoring wells). Monitoring changes in formation backpressure may also help to determine formation permeability parameters, and the point of fracture initiation. For additional information, see Matthews and Russell (1967) and/or Earlougher (1977).

4.3.3.5 CASED HOLE TESTING

Cased hole tests are run after the well is cased and cemented, where logging measurements are gathered on the formations through the well casing and cement. While these may hinder some reservoir assessments, they provide useful data and help determine the state of cement and perforations.

Cement Bonding Logs (CBL) are conducted after the casing is cemented in place to assess the cement-to-formation and cement-to-casing bond quality. These logs will be discussed further under the Well Evaluation section. Formation and cement imaging, and CBLs are several types of data used to confirm that the casing and cement are properly set. Other logging instruments are designed to identify fluid flow pathways behind the casing or to assess the integrity of the casing itself.

4.3.3.6 RESERVOIR FLUID SAMPLING

Reservoir fluid sampling is conducted to assess the characteristics of storage reservoirs. Fluid samples collected from a well are typically retrieved and maintained under in-situ conditions and then analyzed at the laboratory. Some tools have built-in downhole fluid analysis capabilities such as optical spectrometry, resistivity measurements, and fluorescence (which has the ability of compositional analysis and hydrocarbon typing). Some of these tools are limited in scope relative to laboratory testing. However, some advanced downhole tools allows for near laboratory-quality fluid analysis directly in the formation. Typical properties of interest are fluid density/viscosity, chemical composition (TDSs, presence of CO_2, sulfur, etc.), fluid pressure, and temperature. The subject of reservoir fluid chemistry has received considerable attention given its impact on the efficacy of EOR operations (Mullins, 2008).

Essential fluid testing for potential storage reservoirs includes fluid-compatibility effects, the products of reactions (e.g., emulsions and scales), and the precipitation of the dissolved solids (e.g., salt). The testing of the reservoir fluids is crucial for determining potential workovers and treatments that may be required to maintain the operating efficiency of injection wells. In some instances, precipitates could act to reduce the porosity and permeability of the formation reducing the injectivity over time. Additionally, fluid analysis results can be utilized by models to better determine injection and post-injection scenarios. Potential issues with injection pressure, CO_2 dissolution, and plume distribution can be assessed and mitigated prior to injection operations based on the results of fluid testing.

Field service companies may also provide field laboratory equipment for more immediate results. MGSC contracted a field service company to run a DST in a formation above the storage reservoir to determine the order-of-magnitude for total dissolved solids (TDSs).

4.3.4 SEISMIC APPLICATIONS

Seismic acquisition and analysis is conducted to analyze subsurface formations. Acquisition consists of generating and recording seismic data by using a seismic source. The seismic source operates by creating acoustic or elastic vibrations (by a vibrator unit, air gun, or dynamite shot) that travel through the earth. The response of the seismic signal is altered by passing through different rock types producing unique responses that detail the structures encountered in the subsurface. The signal returns to the surface and is then recorded as seismic data by the seismometers or geophone arrays which may be deployed at surface or at depth in a borehole depending upon the goal of seismic acquisition.

Seismic acquisition of the reservoir may be beneficial data for a project to establish potential capacity for CO_2 storage volumes and to create a baseline of reservoir acoustic impedance to be used for plume monitoring. There has been some success in tracking injected CO_2 plumes using seismic techniques. Seismic applications are discussed in further detail in the *Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects* and the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* BPMs.

4.4 WELL CONSTRUCTION

Well construction practices in geologic storage are based upon standard practices in the petroleum industry, however, different regulatory requirements apply. The new EPA UIC Program construction requirements include standard construction and performance requirements for Class VI wells for injection of CO_2. A detailed discussion of the six existing UIC well classes is found in **Appendix C-1.** **Table 4-4** presents a summary of some American Petroleum Institute (API) and American Society for Testing and Materials (ASTM) Well Construction Specifications. API specifications cover all aspects of well construction, but ASTM only covers a specification for the type of well cement.

Several private companies have developed guidelines and manuals for well construction and intervention. In general, materials selected for the construction of CO_2 injection wells (e.g., casing, tubing, cement, completion hardware) need to be non-reactive to native groundwater or brines. In addition, they must also be non-reactive to the CO_2 stream or any acid-gas impurities being injected, and to the CO_2-saturated reservoir fluid. The following section describes some of the common well materials.

Well construction consists of: 1) the casing program; 2) cementing; 3) wellhead construction; 4) completion and stimulation; and 5) well integrity testing.

Table 4-4: API and ASTM Well Construction Specifications

API Specification	ASTM Specification	Construction Application
5CT		Casing and Tubing
5L		Line Pipe
6A		Wellhead and Christmas Tree Equipment
6D		Pipeline Valves
10A	C150	Well Cement
10D		Bow-Spring Casing Centralizers

4.4.1 CASING PROGRAM

The installation of casing strings occurs at discrete points during the well construction process. Casing strings are used to maintain borehole integrity during drilling, assist in the drilling process, and protect against unwanted migration of fluids and gases (e.g., into shallow groundwater). Casing strings are installed in a telescoping fashion, from the largest diameter at the surface to the smallest diameter at the greatest depth. The number of required casing strings is dependent on the geologic formations penetrated, the depth of the well, and by state and federal regulations. It is important to have accurate geological information so that the proper number of casing strings can be included in the well design prior to drilling.

While the construction of CO_2 injection wells is similar to the construction of oil and gas wells, CO_2 injection wells face additional regulations under the EPA UIC Program. For example, the casing strings should contain suitable casing materials and the inner casing in and near the injection zone must be constructed with corrosion-resistant material (e.g., chrome alloy steel, stainless steel). **Figure 4-4** presents an illustration of an injection well with surface and injection casing strings set to various depths.

The first casing is known as the conductor casing, which is set to a shallow depth, has a large diameter, and prevents the collapse of the loose soil near the surface during initial drilling operations. This prevents surface erosion caused by drilling fluids, and provides strength for installation of wellhead equipment. The conductor casing needs to have a large enough diameter to accommodate the additional concentric casing strings that will be installed as the well is completed.

The surface casing is the second casing in the well, which has the primary purpose of isolating USDWs from deeper formations. Surface casing is set from hundreds to thousands of feet deep once the borehole is advanced through the overburden material. The casing is placed in the well and cemented in place from the bottom to top in the annular space between the casing and the borehole. Once the cement has cured, drilling with a smaller diameter bit can continue through the surface casing.

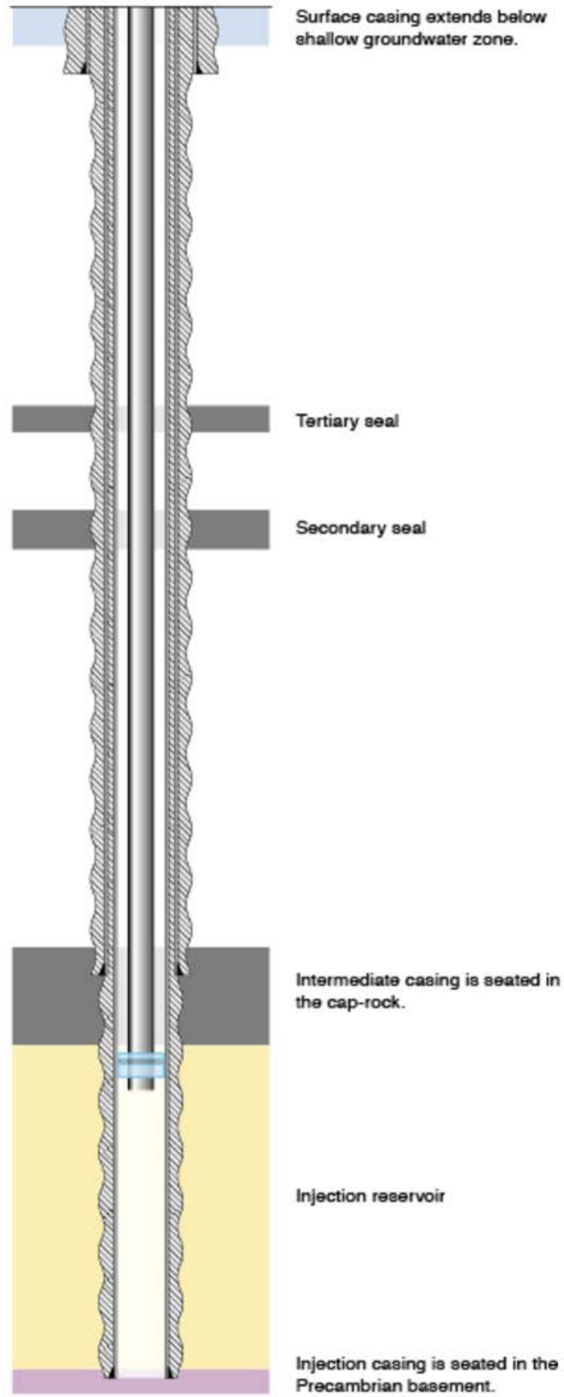


Figure 4-4: Example of a Well Built per Class VI Regulations

Intermediate casing is used to prevent well collapse in weak formations, isolate zones that may have different pressures and water chemistry, and to allow changing drilling fluid density to control lower formations. Although EPA establishes casing material requirements as part of its groundwater protection efforts, the casing grade should be carefully selected by a drilling engineer based on geologic conditions. A variety of materials, alloys, and coatings are available to address corrosion of well casings and tubing. Injection casing and tubing are classified by API type of steel (H-Q) and minimum yield pressure (40-125+ thousand pounds per square inch). In general, higher grades of steel are designed for deeper wells, higher temperatures, higher pressures, and corrosion resistance. Many grades of steel are designed to be more ductile to prevent brittle failure from hydrogen sulfide (H_2S) gas, also known as “sour gas.” Each successive casing interval is cemented in place as described above and drilling continues with progressively smaller bits. Centralizers are installed around the casing, particularly at depth, to keep the casing string centered in the well. If centralizers are not used, the casing string could rest along the borehole walls and prevent a proper seal with cement. The lack of centralizers may also result in difficulties with insertion and retrieval of the drilling tools.

The final string of well casing, the injection casing, inner casing string, or “long string casing,” is run into the wellbore and set at or near the bottom of the borehole. The final string is equipped with centralizers to center the casing in the borehole and maintain a sufficient annulus for cement placement around the casing. Cement is placed in the annular space using the displacement method commonly used in the completion of oil and gas wells. The casing and surrounding cement can then be perforated at the injection interval to establish communication between the casing and the formation. In addition to casing, the well will likely be fitted with tubing. Tubing fits within well casing and is used for injection or production purposes. The tubing string attaches to the wellhead and is designed to provide a continuous bore from the wellhead to the injection zone. This acts to protect the wellbore casing from corrosion and wear and tear.

4.4.2 CEMENTING

Cementing requirements set by the EPA UIC vary by well type. Typically, a cement design for a specific well is developed prior to starting the well installation. The design is commonly based on information from nearby wells and information collected during the drilling of the well. It should be emphasized that a good cement job is crucial to prevent out-of-zone migration.

Several key elements have been identified for proper cementing. Primarily, the wellbore should be prepared for cementing by circulating drilling mud in the well to condition the wellbore. The casing string should be properly centralized to assure complete cement coverage of the annular space between the casing and wellbore. Additionally, the cement should comply with the appropriate API and ASTM specifications. Cement used for Class VI wells must be compatible with CO_2 and the formation fluids encountered in the well. As part of the Class VI permit requirements, cement must be brought to the surface to ensure non-endangerment and seal leakage pathways. Typically, Class A cement is used in most applications. However, other API class cements have been designed specifically for use in wells with elevated temperatures and acidic environments, where cement is designated as CO_2-resistant. Given that cement slurry is prepared on site, it is crucial that the water used for mixing and displacement be clean and free of organic materials such as leaves or agricultural wastes. There should also be no free water within the cement slurry which may form voids. Typically, these details are managed by the company providing the cementing services; the operator should be aware of these requirements and may want to ensure that the cement service company is assessing the impact of formation fluids on the cement being used.

Challenges with Cementing Casing Back to Surface

UIC Class VI regulations for injection wells require the casing to be cemented from total setting depth back to surface. Although this concept is a good idea, the practice can lead to some challenges in achieving effective seals and in the future operation and closure of the wells. As discussed below, significant planning and wellbore preparation procedures are necessary to achieve a successful job.

Washouts in the borehole and drilling mud on the formation face can cause poor bonding between the cement and the borehole. Pumping spacers and mud flush chemicals ahead of the cement slurry can help remove the mud cake from the formation face. Pumping at a high rate to achieve turbulent flow of the annular fluid is also very important.

A long cement slurry column produces a high hydrostatic pressure on the lower formations. If the hydrostatic pressure of the cement column exceeds the fracture gradient of the formation, the formation can break down and the cement slurry can invade the formation, causing formation damage and loss of cement slurry. The operator should estimate the fracture gradient for formations open in the borehole and ensure that the hydrostatic pressure of the column of cement slurry does not exceed the minimum fracture gradient.

Many operators use a lightweight lead cement slurry on the upper part of the cement column to reduce the hydrostatic weight of the cement column on the formation. Light weight cements generally require more mix water and have less compressive strength than regular cement slurries. The additional mix water can separate as the cement slurry sets, causing free water voids in the cement which can impair the integrity of the cement bond. Light weight cement slurries need to be designed for maximum compressive strength and minimum free water. Operators also might use multiple stage cement tools to reduce the hydrostatic weight of the cement column on the formation.

At the IBDP site, a combination of the above methods were used to successfully cement all strings of casing in all of the wells. Since the intermediate casing was across a very problematic lost circulation zone, a stage tool was placed above this zone and two independent stages of cementing were performed. The upper stage was placed with a lighter cement to reduce the risk of breaking down the lost circulation seal. The long casing string was cemented in one stage using a lighter lead cement and a special CO_2-resistant cement across the injection formation and the caprock. Careful planning utilizing experiences documented in offset wells, caliper and rock strength data from the openhole logs, and lab experiments run using various cement formulations were key to wellbore integrity success in all wells.

4.4.3 WELLHEADS

The wellhead consists of components installed on the top of the casing strings at the surface and will vary depending on the well's function (e.g., injection or monitoring). For injection wells, the wellhead allows the regulation and monitoring of the injected CO_2 into the well. It also prevents migration of CO_2 out of the top of the well, and prevents blowouts due to high pressures that may be present in the reservoirs. A monitoring wellhead can be similar to the injection wellhead, which may include perforations and fluid sampling ports to accommodate the planned monitoring techniques. **Figure 4-5** illustrates a standard monitoring wellhead assembly minus the tubing and packer.

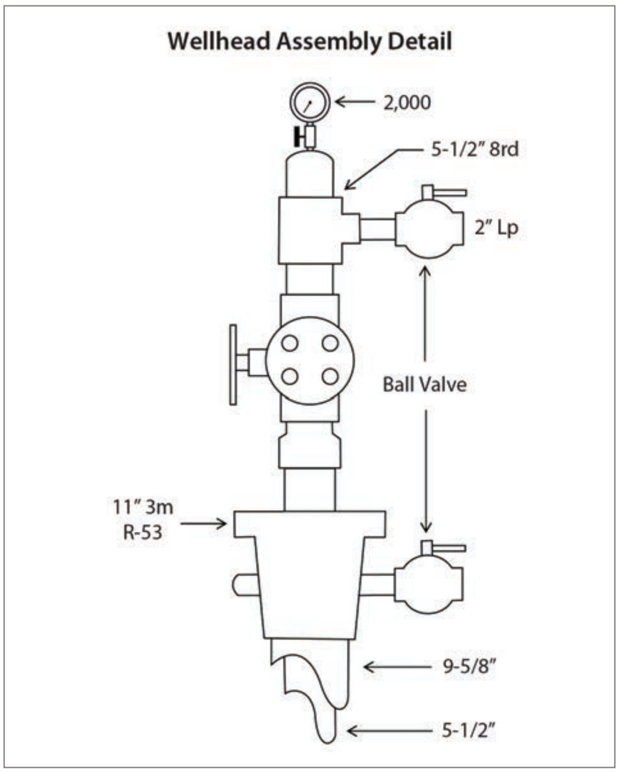


Figure 4-5: Example of a Monitoring Wellhead Assembly

(SECARB, Summary Sheet, SECARB, Mississippi Test Site – Plant Daniel, 2010)

A wellhead is typically designed to withstand pressures up to 10,000 psi or more, and is made up of two "heads," a casing head and a tubing head. The configurations shown in **Figure 4-6** is representative of a typical injection wellhead design. The casing head is a flanged fitting that is connected to the surface casing and provides a seal between the casing annulus and the atmosphere. The tubing head is also a flanged fitting. It is used to support the tubing and to seal off pressure between the casing and the outside of the tubing.

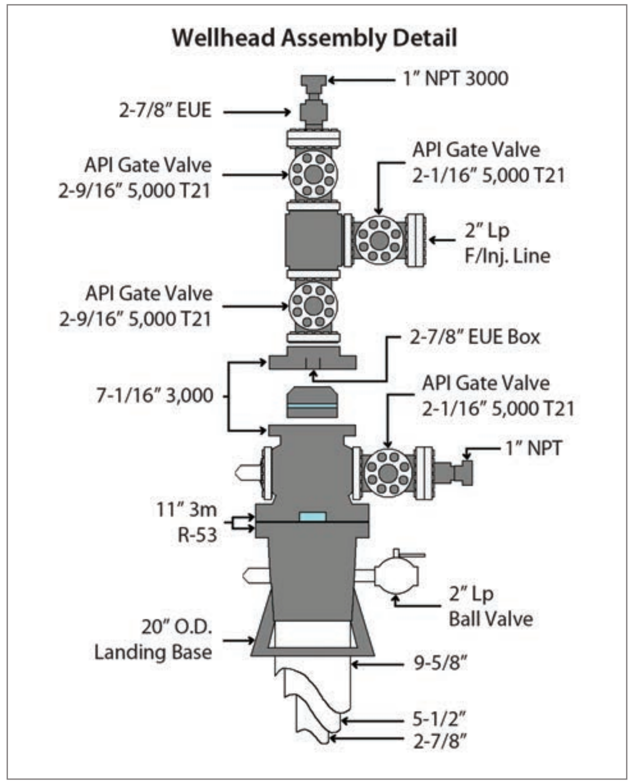


Figure 4-6: Example of an Injection Wellhead Assembly

(SECARB, Summary Sheet, SECARB, Mississippi Test Site – Plant Daniel, 2010)

Construction of both wellheads should conform to the API specifications listed on **Table 4-4**, as well as any other regional requirements. Care must be exercised in selecting the API grade of tubing given the potential for acid formation when CO_2 and water mix. Typically, the lower the carbon content of steel used, the longer the life of the tubing string used for the injection of CO_2. For this reason, careful consideration must be given to the pipe grade.

In a typical installation the tubing is set in a retrievable packer which permits the tubing to be under tension and allows its removal if problems or wear appear during use. This type of packer is common to the oil and gas industry and is used in both injection and production wells.

4.4.4 WELL COMPLETION AND STIMULATION

Once a well has been drilled, cased, and cemented, it must be evaluated and prepared for injection or monitoring. This involves preparing the bottom of the well to the required specifications, running tubing and perforating and stimulating the well.

4.4.4.1 WELL COMPLETION

A well completion involves several steps to permit injection. Tubing must be installed in the well down to the reservoir being targeted for injection. The production casing must then be perforated in the intended injection and monitoring zones. Explosive shape charges are set off to perforate the casing to allow the wellbore to communicate with the formation. Design of the perforation interval and spacing will be project specific.

4.4.4.2 WELL STIMULATION

Following perforation, a well may be stimulated to enhance the formations ability to flow near the wellbore. Several methods may be applied to enhance fractures depending upon lithology, which may include acidizing carbonate formations to enhance injectivity. To date, intentional fracturing of formations for geologic storage has not been widespread. Besides most likely requiring permission from EPA, the public outreach aspects of this simulation method should also be considered prior to any fracturing of a reservoir.

4.4.5 WELL INTEGRITY TESTING

Prior to injection, it is necessary to assess the quality of the well construction. Several tests are performed to determine if casing conditions are optimal for injection or if any re-working is required to fulfill regulatory well requirements. This relies primarily on a cement bonding evaluation to identify and evaluate the quality of the cement sheath around the casing and the bond between the casing and the formations. A high-quality cement bond in and above the injection zones is essential to prevent the migration of CO_2 or formation fluids into other formations or a USDW.

4.4.5.1 LOGGING TECHNIQUES

Several logging techniques may be employed to assess the integrity of the well for injection of $CO_{2,}$ which includes cement bond log (CBL) and variable density waveform (VDL) plot. These logs operate by recording transit time and attenuation of an acoustic wave propagated into the formations through the borehole fluid, casing, and cement to be assessed for the robustness of the cement bonding. **Figure 4-7** is an example of a processed cement bond log and variable density waveform (VDL) plot. The percent bond estimation is graphically shown on the first track (CBL-BI). Amplitude (CBL) and attenuation (CBL-ATTN) are shown in the third track. High signal amplitude indicates poor cement bond, as much of the energy is retained by the casing. The variable density waveform (VDL), displayed in the fifth track, helps to detect the presence of channels between cement and bedrock. The calculated cement compressive strength (CBL-COMP) is shown on the last track.

The CBL-VDL log in this example is interpreted as having intermittent or partial cement in the top half (mid to high amplitude, no clear formation signals in VDL, suggesting a mid- to low-calculated bond index), while the bottom half shows good cement bond (low amplitude, clear formation signals in VDL, suggesting a mid-high bond index).
Note that additional factors may be needed to properly interpret a CBL-VDL log (including well/formation pressure, formation composition, etc.).

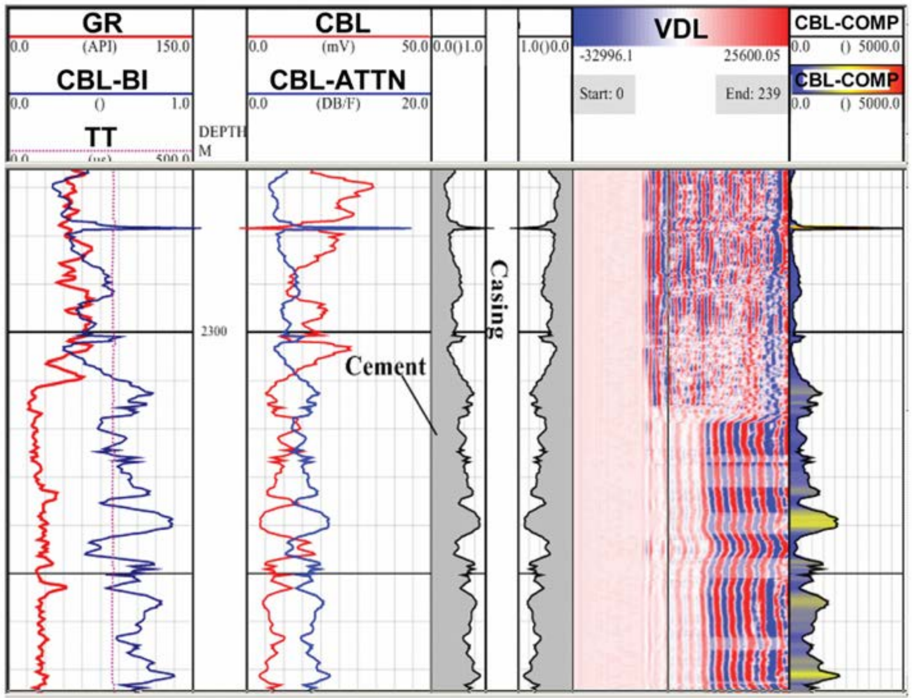


Figure 4-7: Example of a Processed CBL-VDL Log,

Courtesy of Petrolog.net
(http://www.petrolog.net/webhelp/Graphics/Plots_Misc/Sonic_Array.htm)

4.4.5.2 INTEGRITY TESTING

Another set of tests conducted after the well is completed to demonstrate that it has satisfactory internal and external integrity is referred to as Mechanical Integrity Tests (MITs). Internal MITs are used to detect any penetrations in the well tubing, casing, and/or packer. External MITs are used to determine if there is significant movement of fluids, possibly to a USDW, through vertical channels adjacent to the wellbore. For Class VI wells, EPA requires an initial annulus pressure test and then continuous monitoring of injection pressure, rate, injected volumes, pressure on the annulus between tubing and long-string casing, and annulus fluid volume as specified in the regulations under 40 CFR Part 146.88 (e). Additionally, the operator must use an approved method, such as a tracer survey, an oxygen-activation log, or a temperature or noise log, to demonstrate mechanical integrity on an annual basis. Other potential MITs include a casing inspection log or an alternative method that provides equivalent or better information and that is approved of by the EPA Director.

Once it has been demonstrated that the well has been completed properly, integrity issues have been resolved, and the well is deemed suitable for injection, it can be incorporated into the project. If a well evaluation indicates that there are concerns, however, the operator must consider whether the well can be reworked or if the injection zone can be repositioned to a different interval within the wellbore. If this is not possible, the wellbore may possibly be reconfigured as a monitoring well, or be abandoned. Throughout the lifespan of a well, the operator should conduct tests and checks to determine that the well's integrity is still suitable for the planned use.

4.5 RCSP CASE STUDIES

CASE STUDY 4.1 — MGSC

MIDWEST GEOLOGICAL SEQUESTRATION CONSORTIUM (MGSC)

Planning Around Road Use Restrictions

Though it is advantageous to utilize existing road infrastructure, it may not always be feasible to do so. In the case of the MGSC EOR pilot project located at the Owens #1 site in Illinois, the CO_2 for injection was delivered by truck. Bulk delivery by truck is often the only feasible option for small-scale test projects. The nearest roads, however, were not rated to handle the weight of the delivery truck on the access road leading to the Owens #1 site located approximately a quarter-mile (400 meters) from the paved township road. Therefore, the injection equipment was located adjacent to the township road and a 1,280-foot (391-meter) pipeline was constructed to transport the CO_2 to the well (Midwest Geological Sequestration Consortium, 2009).

CASE STUDY 4.2 — **SWP**

SOUTHWEST REGIONAL PARTNERSHIP ON CARBON SEQUESTRATION (SWP)

Drilling Fluids: Example at SWP's Farnsworth Site

Water-based (aqueous) drilling fluids are commonly used in drilling. They are effective, allow the widest range of logging measurements and are cost effective. Although oil-based mud (nonaqueous) is typically more costly than water-based drilling fluids, oil-based muds often provide superior wellbore stability, reduce the potential for sticking the drill pipe, and reduce non-productive time.

At the SWP's Farnsworth Unit, both types of drilling fluids were used. Water-based mud was used to drill the surface and intermediate portion of the well. The water-based muds consist of bentonite clay and additives such as barite to increase the weight of the fluid to prevent the influx of formation fluids or, in extreme cases, blowouts.

Drilling Fluid Engineered in Laboratory

Image Provided Courtesy of Schlumberger

The hydrocarbon reservoir portion was drilled using an oil-based mud. In oil-based muds the water is replaced with a mixture of diesel and heavier hydrocarbons. This is most commonly used when drilling rock formations that are water-sensitive and may become unstable when coming in contact with water-based mud.

Historically, FWU wells were drilled with only water-based drilling fluids. After encountering hole stability problems, stuck pipe, and hydrocarbon influx in the deeper section of the well, they determined the most prudent drilling practice was to set an intermediate string of casing just above the problem area and then convert to oil-based mud to drill the remainder of the well.

CASE STUDY 4.3 — **SWP**

SOUTHWEST REGIONAL PARTNERSHIP ON CARBON SEQUESTRATION (SWP)

Wireline Logging Applied to the Farnsworth CO_2-EOR Field

Wireline logs are acquired to obtain a suite of data used to evaluate the critical petrophysical parameters of the storage complex, which includes porosity, permeability and fluid saturations. At the Farnsworth CO_2 EOR project, logs were collected for three wells, as illustrated in the figure below.

The openhole wireline logging evaluation consisted of the following tools:

- **Platform Express*** integrated wireline logging tool includes density, neutron porosity, resistivity, gamma ray, and caliper measurements with real-time speed correction and depth matching of the sensors
- **Sonic Scanner*** is an array sonic tool used to provide 3-D acoustic characterization for geomechanics, geophysics and fracture evaluation
- **Combinable Magnetic Resonance tool** provides a lithology independent porosity and pore size distribution used to determine the formation porosity, permeability and irreducible water
- **Hostile Environment Natural Gama Ray Spectrometry** provides natural gamma ray spectroscopy to aid in the analysis of the clay quantification, type and special minerals containing potassium, thorium and uranium
- **Elemental Capture Spectrometry*** is a neutron induced spectroscopy measurement used to identify the type and abundance of elements in the formation. The spectroscopy measurement is used to develop a detailed formation lithology model and improve formation porosity and permeability estimates
- **Ultrasonic Borehole Imager*** provides high resolution images of the borehole with 100% circumferential coverage. Borehole images are used to identify structure, depositional environment and fractures and faults that may be present in the formations as well as aiding in mechanical properties modeling

The cased hole wireline logging consisted of:

- **RST*** pulsed neutron tool is used to monitor formation fluids saturations (formation oil, water and CO_2), and verify well mechanical integrity
- **Isolation Scanner*** utilizes a ultrasonic and sonic flexural measurements to provide casing and cement inspection

Routine Core Analysis allows for validation and calibration of the petrophysical model. Core measurements of porosity, water saturation and permeability are compared to the petrophysical model.

Logging Operators Working on a Rig Floor

Image Provided Courtesy of Schlumberger

5.0 INJECTION OPERATIONS

All operational stages encompassing geologic storage injection processes, from pre- through post-injection monitoring, are described in this chapter. The critical operations are comprised of four steps:

- Pre-injection baseline monitoring
- Injection system completion
- Injection
- Closure and post-injection monitoring

This section provides a generalized assessment of some MVA protocols linked to the injection operations. However, a more thorough investigation can be found in the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* Manual.

5.1 PRE-INJECTION MONITORING FOR BASELINE ESTABLISHMENT

Prior to injection of CO_2 into the storage formation, a pre-injection baseline monitoring dataset is established to compare against data acquired during injection and post-injection monitoring activities. Baseline data are typically acquired for surface, near-surface, and subsurface environments. Atmospheric baseline data may also be beneficial. It is recommended that the baseline monitoring program collect multiple samples over a chosen length of time to account for seasonal variations. The accurate assessment of baseline conditions is paramount to ensuring the integrity of the project and measuring the progress of project objectives.

Some of the key baseline data acquisition activities include, but are not limited to:

- Collection of groundwater samples from wells drilled near CO_2 injection wells, and characterization of the samples based on pH, alkalinity, total dissolved solids, concentrations of metals identified by EPA as groundwater contaminants, and numerous other geochemical parameters
- Analyses to establish the composition and variability of reservoir fluids, including dissolved gases, via the use of pressurized fluid samples taken from the injection zone
- Quantification of CO_2 levels near well penetrations via the use of seismic and/or pulsed neutron logging techniques
- Injection zone and shallower pressure and temperature data
- Surface monitoring of areas around injection wellbores for the presence of perfluorocarbon tracers (PFTs) that may be periodically injected along with CO_2 as a means of detecting possible CO_2 migration. Because these PFTs are almost insoluble in water and can be detected at multiple-orders-of-magnitude-lower concentrations than CO_2, their detection (at levels exceeding baseline) following CO_2 injection would represent a high probability of CO_2 migration

It is important to note that baseline data requirements are project-specific since each CO_2 injection project is associated with a unique set of objectives and site considerations. Therefore, the above list is not intended to represent a universally applicable set of baseline data acquisition activities. Monitoring techniques (for acquisition of baseline, injection, and post-injection data) are continually evolving as new technologies are developed. **Figure 5-1** highlights several of the field monitoring techniques employed. Detailed discussion of monitoring tools and techniques is provided in the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* BPM.

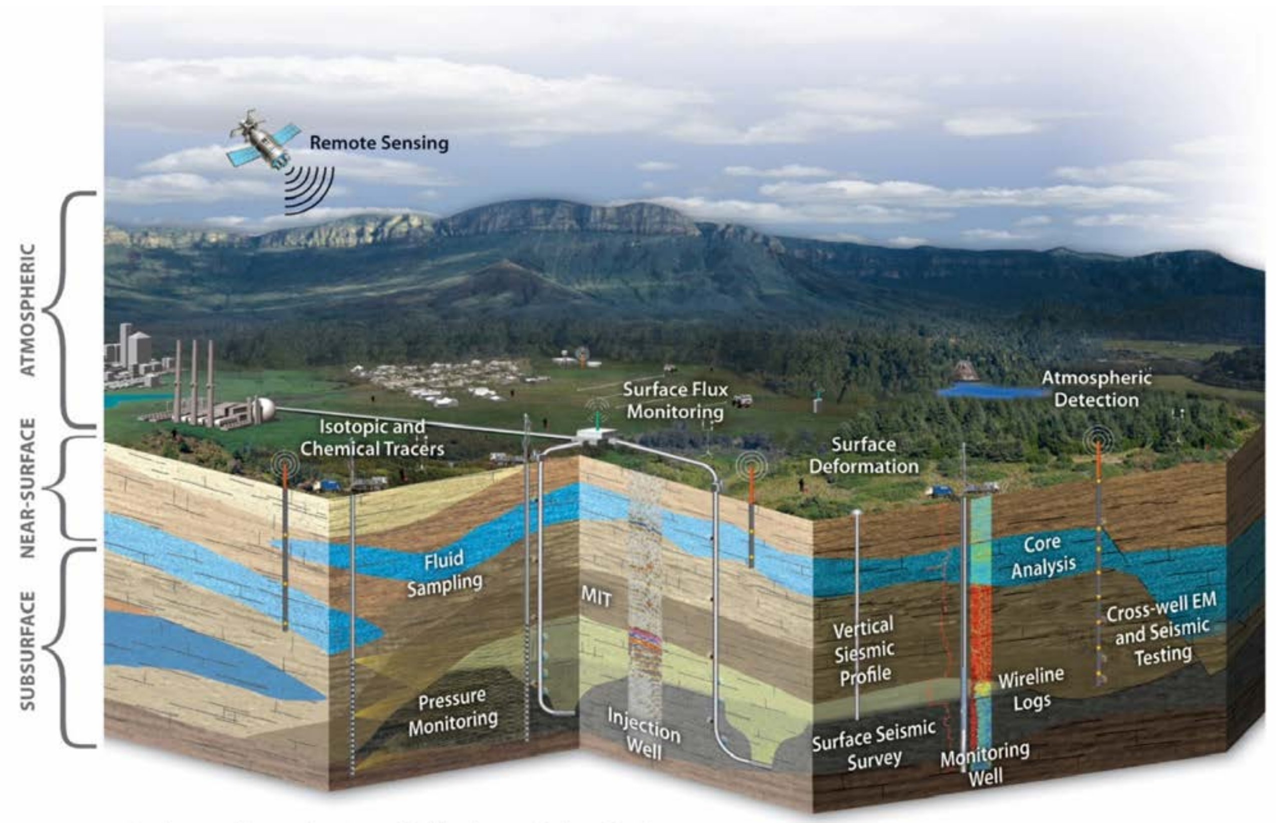


Figure 5-1: Examples of Various Field Monitoring Techniques

Backround Image Courtesy of Schlumberger Carbon Services

5.2 INJECTION SYSTEM COMPLETION

All injection projects share a common core of operational components, regardless of the project objectives. This includes CO_2 supply, pipelines, compressors, injection header(s), and injection well(s). The design and completion of injection systems for a geologic storage project are largely predicated upon the geologic storage resource, the source of the CO_2, and individual requirements of the project. Each project will comprise a unique suite of equipment, capacity, and design requirements based upon the geology, CO_2 supply, infrastructure, and financial considerations based on project-specific objectives.

The two types of injection systems discussed are storage systems and value added (EOR, ECBM) storage. A CO_2 storage only project (e.g. targeting a saline reservoir) typically comprises the most straightforward and basic equipment and operations, shown in **Figure 5-2**. Injection operations for CO_2 EOR and ECBM, however, are more complex in design and operation because of their need to handle and process produced fluids and gases (**Figure 5-3**). EOR and ECBM projects necessitate additional equipment for oil and/or methane recovery and purification, CO_2 recovery and recycle (possibly including steps for CO_2 dehydration, desulfurization, and other purification techniques), and may include equipment for recovery and purification of gas condensate and other products. The equipment selected must be cost-effective and capable of safely achieving the injection pressures and flow rates necessary to meet project objectives.

CO_2 injection system design begins with a source of captured and compressed CO_2. Captured CO_2 is commonly compressed to a supercritical state (typically between 1200-2200 psi) which has high density but flows readily like a gas, and transported via pipeline to the injection site. The chosen transportation pressure will vary depending on pipeline design and client specifications. Dehydration of the CO_2 prior to transport may be necessary if the water content consistently exceeds a threshold of approximately 50 ppm to prevent potential for downstream corrosion throughout the CO_2 distribution system.

Following compression and dehydration, the CO_2 is mobilized to the project site. Depending on topography, between the CO_2 source and injection site, the transport pipeline may require one or more booster pumps to keep the CO_2 moving along the system. As opposed to compressors, which are designed to pressurize gases and can also—as in the case of CO_2—effect transformation of a gas to a liquid with sufficient pressurization, booster pumps are designed to take a relatively incompressible fluid (such as supercritical CO_2) to a higher level of pressure or "head."

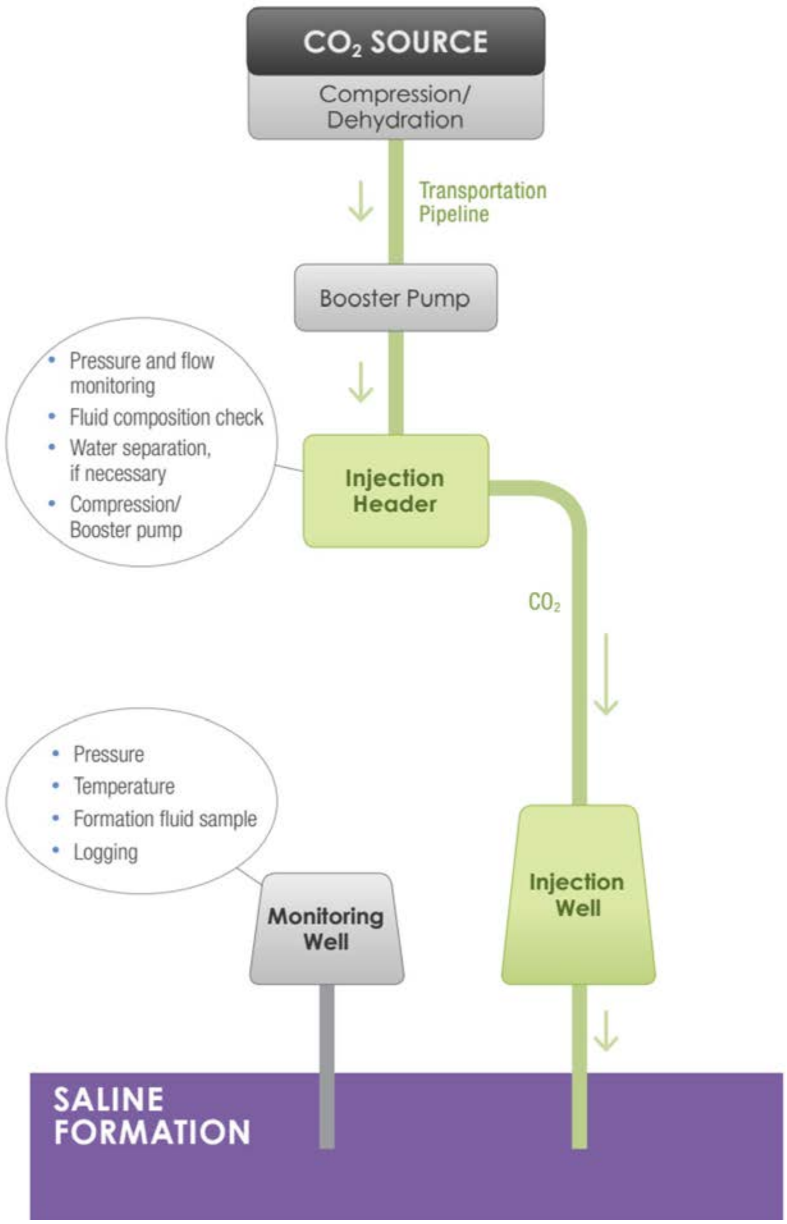


Figure 5-2: Basic Flow Diagram of a Storage-Only CO_2 Injection Project

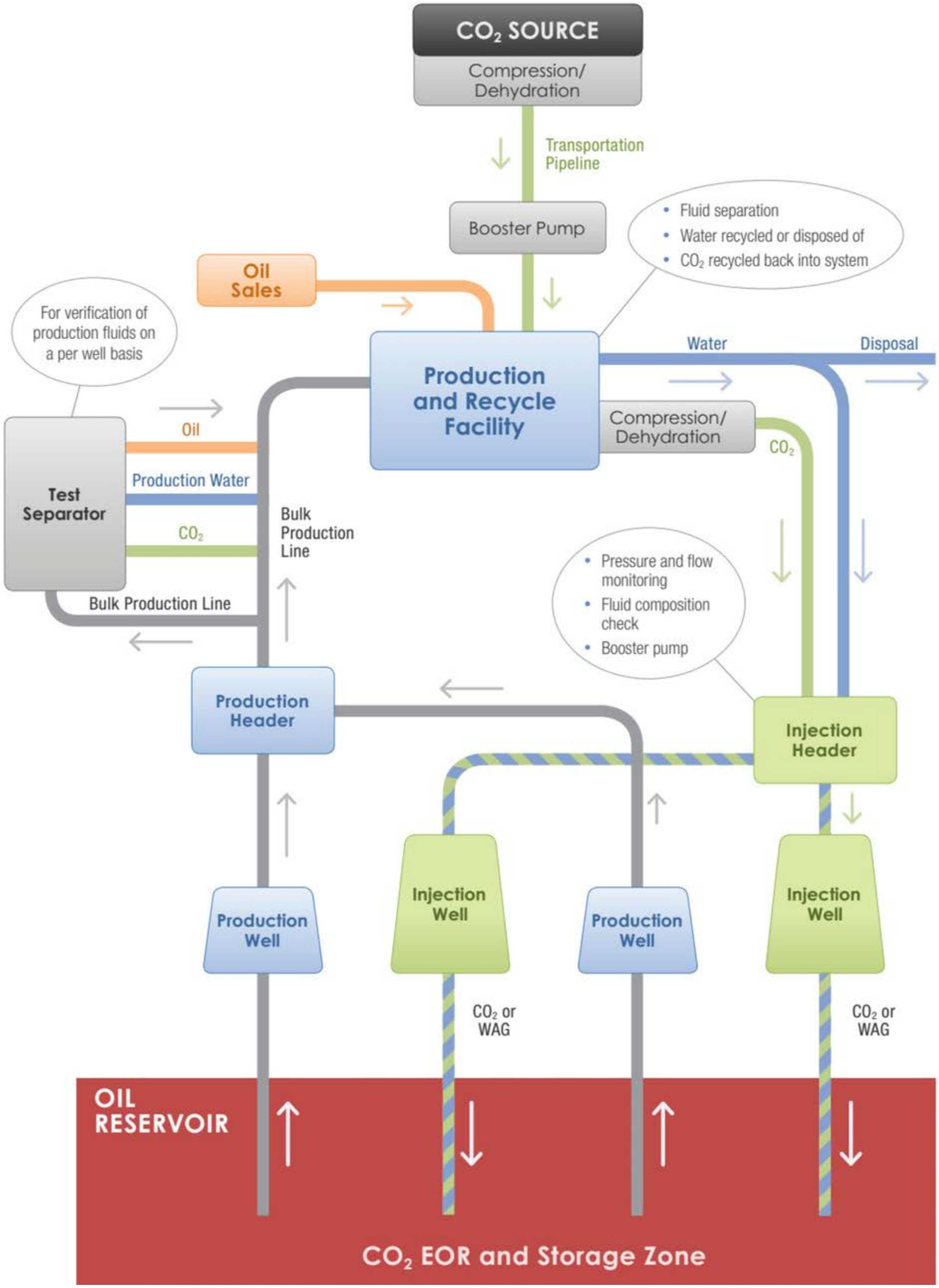


Figure 5-3: Basic Flow Diagram of an EOR-Based CO_2 Injection Project

5.3 STANDARD EQUIPMENT AND LAYOUT FOR EOR-BASED CO_2 INJECTION PROJECTS

For a typical EOR project, “fresh” CO_2 is routed to a production and recycle (P&R) facility to determine and record the pressure, flow, and composition. This ensures that the CO_2 quality meets the project requirements for injection. Following this step, the CO_2 received can be blended with any recycled CO_2 for injection.

EOR operations commonly involve a period of alternating injections of water and CO_2 (referred to as a “water–alternating gas” [WAG] operation). WAG injection is designed to improve the sweep efficiency for improved oil recovery, which is critical to EOR project viability. This, however, increases the volume of produced water which must be treated along with any other produced fluids.

Any fluids produced through the EOR process can be routed through a test separator to monitor the proportion of oil, water, and gas from an individual well or group of wells prior to arriving at the P&R facility. When the produced fluids arrive at the P&R facility, they undergo separation and purification as needed. Once purified, recovered CO_2 is compressed/dehydrated and recycled back into the CO_2 injection stream, the oil may be shipped for sale and water is treated as needed for recycle, other uses, or disposed of as shown in the **Figure 5-3**.

ECBM operations are similar to EOR operations, with two key distinctions. WAG is not performed, and production comprises primarily methane and CO_2, so processing primarily involves gas separation and purification to meet pipeline standards. In some cases, coalbed methane reservoirs produce coal fines that are light enough to travel through the piping system. Sock and cartridge filters for fines removal can be placed before the reinjection plant as well as before any CO_2 injection pumps. Filters may also be used in other injection projects if aging transmission pipelines carrying CO_2 have corroded, causing rust and other debris to collect in the system.

5.3.1 CO_2 PIPELINES

The CO_2 pipeline is a key component to move the CO_2 from source to sink. The pipeline infrastructure for geologic storage is analogous to the infrastructure for natural gas pipelines. Three primary types of pipelines used to transport CO_2 include:

- Gathering lines
- Trunklines
- Distribution lines

Gathering lines are used to transport CO_2 from multiple point sources over an area, which connect into a main trunkline. The trunkline is the main pipeline that transports CO_2 collected from various gathering lines which connects to the distribution lines. The distribution lines are used to transport CO_2 to the storage fields and wellheads.

Prior to introducing CO_2 to the pipeline, dehydration of the CO_2 is highly recommended to reduce the risk of corrosion since CO_2 mixed with water forms corrosive carbonic acid. As an additional safeguard, CO_2 pipelines can be constructed of or coated with non-corrodible materials, which include an array of metals, polymers, and fiberglass. The petroleum industry has developed significant expertise in the use of dehydration and/or pipeline construction and maintenance approaches to address carbonic acid corrosion. It is important to note that in addition to corrosion, water accumulation within the system can result in damage to monitoring and other sensitive equipment. To safeguard against water accumulation, water dropout traps or “legs” can be installed where appropriate to enable collection and drainage of excess fluids.

External corrosion of pipelines is an additional risk faced by pipelines. The most common defense against external corrosion is cathodic protection, often in combination with external coatings. The application of crack arrestor techniques is recommended since CO_2 pipelines are not self-arresting in terms of longitudinal failure, which includes periodic wrapping of the pipeline with nonmetallic materials, and/or the use of periodically spaced pipe sections with greater wall thickness and improved hoop stress properties. Additionally, pipelines exposed to the surface may be wrapped in insulation to protect against, or minimize, phase changes and pressure issues resulting from changes in atmospheric conditions.

For CO_2 distribution lines at the injection site, carbon steel may be acceptable if the CO_2 is consistently and reliably dry, ideally containing less than 50 ppm of water (Meyer, 2007). The distribution system should include check and isolation valves (see **Figure 5-4**), metering equipment, control valves, pressure sensors and switches, gauges, and pressure relief valves, all of which must be selected based on the characteristics of the CO_2 to be injected. API standards for CO_2 valves can be useful for planning.[2] Additionally, pipelines near the surface or above ground may necessitate the use of insulation to resolve any potential phase and pressure issues.

5.3.2 COMPRESSION/DEHYDRATION SYSTEM

Depending on the condition of the CO_2, from the source or recycle facilities, a compression and/or dehydration system may be required to remove water and compress the CO_2 immediately prior to injection. The size and type of the compressor(s) will depend on the scale of the injection. The two primary types of compressors for consideration are reciprocating and centrifugal compressors. High-speed reciprocating compressors are ideally suited for smaller

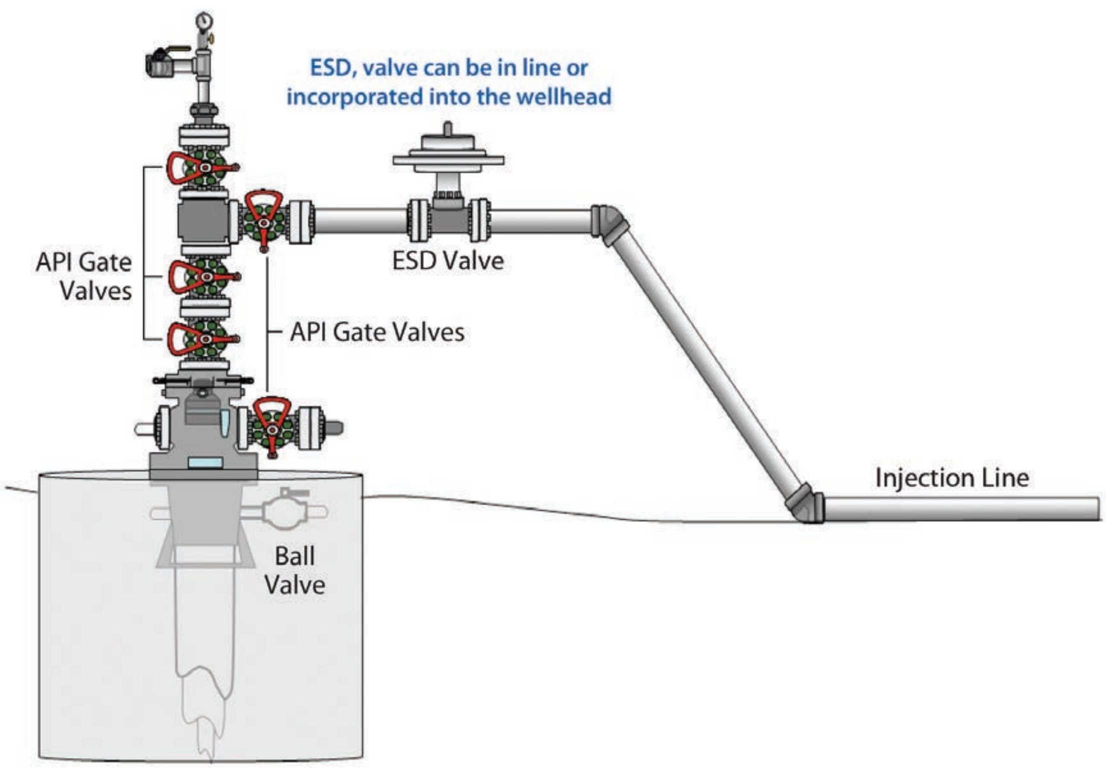


Figure 5-4. Close-Up Illustration of an Injection Wellhead

[2] Spec 6D/ISO 14313.

commercial and pilot-scale operations since they efficiently achieve high CO_2 discharge pressures. These, however, are not commonly used for large-scale CO_2 injection operations because of capacity (throughput) limitations (see **Figure 5-5**). Centrifugal compressors are more commonly used to accommodate the high-volume CO_2 throughput needed for larger injection projects. Centrifugal compressors utilize multiple incremental compression stages (each one operating at a specific compression ratio) packaged together in a single unit to achieve a required pressure (Jensen et al., 2011).

5.3.3 BOOSTER PUMPS – SELECTION AND OPERATIONAL CONSIDERATIONS

CO_2 injection facilities use pumps to inject CO_2 into the reservoir. While horizontally mounted centrifugal-style pumps similar to electric submersible pumps are commonly used in large-scale injection operations (see **Figure 5-6**), rotary gear turbine pumps are frequently used in low-injection-rate (up to 50 gallons/minute) applications where a centrifugal pump is not practical. Key advantages of rotary gear turbine pumps are low "net positive suction head required" (NPSHR) and relatively low cost. However, they are not designed for continuous service at high speed,

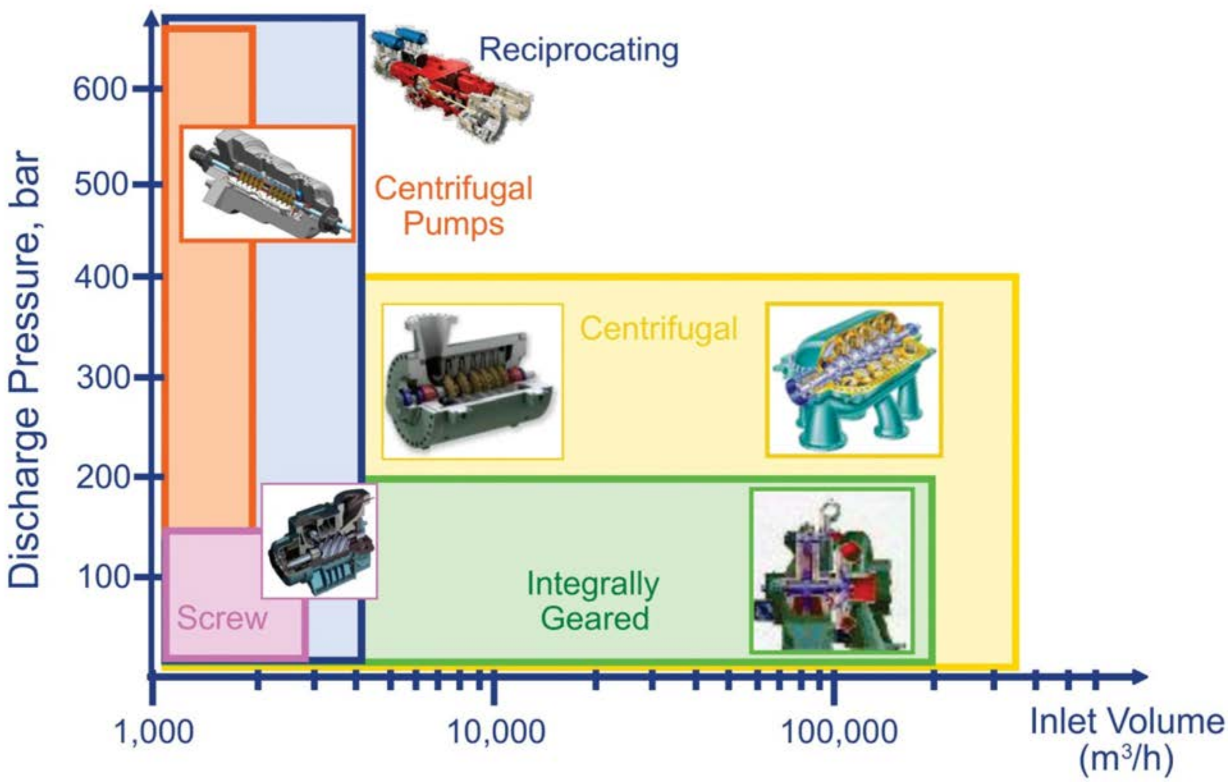


Figure 5-5. Types of compressors and the approximate ranges of inlet volumetric flow rates and pressures at which they are used *(taken from Wadas, 2010)*. It should be noted that 500 bar = 50 MPa = 7252 psi and 100,000 m3/hr = 3.53 MMcfh.

and are recommended to be operated at no greater than 1,800 rpm. In some applications, a line heater may be required to maintain the fluid at an acceptable temperature to prevent freezing of residual water in surface equipment. An important design consideration is freeze prevention since CO_2 pumped through meter runs and other pipeline restrictions cause pressure drops of sufficient intensity to cool the line, resulting in internal ice build-up.

The two most commonly experienced problems when injecting CO_2 are cavitation and seal failure. Cavitation occurs when vapor bubbles form in the suction line, suddenly collapse, and move along the vane of an impeller. Cavitation can be prevented by ensuring that the net positive suction head at the pump suction is well above the vapor pressure of the liquid CO_2. Ways of achieving this can include one or a combination of the following actions:

- Moving the pump to a lower elevation.
- Decreasing the length of the suction piping
- Reducing the temperature of the process liquid
- Increasing suction diameter
- Reducing flow rate and pump speed

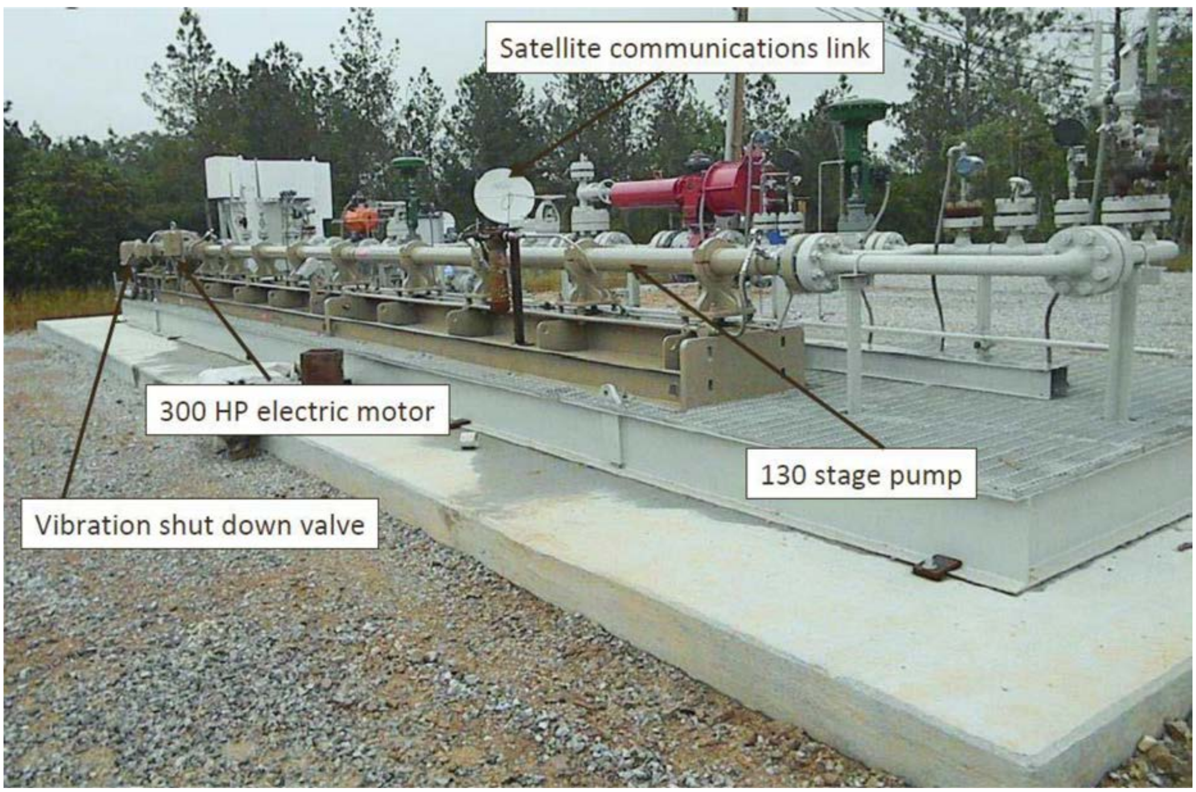


Figure 5-6: Horizontal ESP-Type Booster Pump for CO_2 Injection

Image from Koperna et al., 2013

Additional recommendations for avoidance of cavitation include:

- installing vent valves on the pump case (or discharge flange) and on the suction header to vent accumulated vapor
- insulating the system to minimize exposure to atmospheric influences
- pipe minimum flow bypass back to the suction vessel
- properly size piping
- Elevating the suction vessel (if possible)

Selecting appropriate seals is also critical for CO_2 pumps since CO_2 surface tension is lower than the surface tension of most hydrocarbons by approximately an order of magnitude (Campbell, 1994). In addition, CO_2 viscosity is about 25% less than that of comparable-size/weight hydrocarbons such as propane. In some cases, escaping CO_2 may solidify when it exits to the atmosphere (i.e., depressurizes). The importance of seals is therefore paramount to maintaining the integrity of pipelines against any potential leakage. More information on seals can be found in **Appendix E-1**.

5.3.4 VALVES

The valves for a CO_2 injection operation come in different types and can be manually or electronically operated. Correct valve placement is critically important to successful and safe injection operations. Valves should be placed to assist in equipment operation and to help gate and control the injection flow rate. Additionally, they should be easily accessible so that during emergencies, the system can be quickly, easily, and safely deactivated. Emergency relief valves are needed to enable automatic venting of pressures exceeding prescribed safe levels (via safe channels), to prevent damage to the system and risk to system operators. Emergency relief valves need to be placed in safe locations where personnel will not be exposed if the valves are activated. Valves should also be placed where their operation will not be adversely affected by weather (especially temperatures sufficiently cold to freeze valve mechanics). The injection wellhead assembly illustrated in **Figure 4-6** shows some typical valves that may be used. Most operators follow API recommendations for valve selection. A list of common valves used for CO_2 injection operations can be found in **Appendix E-2**.

Operators should be aware that a sudden unexpected drop in pressure is likely indicative of a leak. To deal with sudden-onset leaks, CO_2 pipelines are typically equipped with emergency shutdown (ESD) valves to enable isolation of the affected section. Spacing of ESD valves is dependent upon factors such as population density and local and/or federal/state regulations, generally, spacing intervals of between 10 and 20 kilometers.

5.3.5 INJECTION CONTROL AND MONITORING EQUIPMENT

The monitoring performed during injection operations is necessary for regulatory compliance to ensure that the CO_2 enters the intended injection zones at the appropriate injection rates, and to validate that reservoir pressures do not exceed established limits. Control and monitoring equipment for CO_2 injection wells typically focuses on injection pressure in the injection wells and reservoir pressure in monitoring wells. For pilot-scale projects, injection rates and schedules can be controlled from the CO_2 source via the use of control valves or automated control systems. This approach, however, may not be adequate for commercial-scale projects that utilize large CO_2 volumes, involve long pipeline distance, and/or require additional downstream process equipment and multiple injection points. For these reasons, pipelines are sized to provide some buffer capacity (to accommodate expected swings in CO_2 supply or offtake) and the capability for venting if the CO_2 supply should exceed the site injection rate limit.

Monitoring systems based on “supervisory control and data acquisition” (SCADA) technologies are often used to track the key operational parameters of CO_2 pressure, temperature, water content, and flow rate. For example, an advanced monitoring system based on proprietary software is used in the Weyburn–Midale CO_2 Monitoring and Storage Project to monitor for and determine the size and location of leaks every 5 seconds. In situations where monitoring indicates significant potential for leakage or flow disruption, or as part of a regular maintenance program, a “smart pig” can be utilized to inspect the interior of pipelines and other tubulars, measure wall thickness, acquire numerous other data, and locate leaks and corrosion.

Wellhead pressure is monitored to prevent injection pressure from reaching or surpassing the maximum allowable limits as determined via the state or federal underground injection control (UIC) permitting process. Downhole pressure is calculated based on wellhead pressures and periodically confirmed with bottomhole pressure logs and shut-in tests. The intent is to avoid fracturing the injection and confining zones. Pressure gauges are commonly used to collect these measurements. The gauges should be properly placed in the system so that critical areas can be continuously monitored and allow for some redundancy. In more advanced systems, pressure and temperature gauges are placed in the borehole ("downhole") near the injection zone to provide direct measurement and avoid the need to calculate an estimated bottomhole pressure.

5.3.6 METERING

Flowmeters are devices used to track CO_2 movement from the source to the storage reservoir. They are useful for custody transfer purposes, detection of leaks, document control and distribution of the CO_2 to injection wells and record the quantity of fluids produced by each production well (for EOR). Meters used for CO_2 injection operations are designed to operate on the basis of either flow rate or pressure. These need to be compatible with the CO_2 and able to handle the anticipated flow and pressures documented in the injection plan while providing accurate flow measurements. Calibration of metering equipment should be conducted regularly as designated in the injection permit and manufactures specifications. The recording and reporting of flow data at certain points in the system may also be required by the regulator. Metering devices that can be calibrated for CO_2 flow rate measurement include: 1) Orifice meters, 2) Turbine meters, and 3) Coriolis meters. For further information on the distinction between these, please see **Appendix E-3.**

5.3.7 SURFACE EQUIPMENT AND OPERATOR SAFETY ALERTS

The presence of large, concentrated quantities of atmospheric CO_2 is hazardous to health since it is an asphyxiant and heavier than air. For public and worker safety, the installation of sensors that monitor the concentration of CO_2 in the atmosphere near pipes, valves, compressors, and storage tanks that contain CO_2 is necessary. These sensors are intended to sound alarms to alert the operator of an equipment malfunction and set to trip if pressure levels, temperatures, or vibrations, for example, exceed a set limit. If a problem occurs during the injection operation, employees need to be alerted immediately to initiate corrective measures. Alarms may include lights, audio, text messages, and e-mail notifications, which may be triggered by either an automated control system or a manual system.

5.3.8 SUPPORT BUILDINGS

Support buildings may be installed to provide operations personnel office space and a safe environment. The buildings offer a degree of working comfort and safety for personnel by reducing exposure to weather conditions and noise. Support buildings also provide weather protection for injection equipment, particularly important for sensitive electronic equipment. At one Midwest Regional Carbon Sequestration Partnership Phase II project site, two buildings were used. One housed the compressors (for a project where the CO_2 source and injection site were the same), and the other housed the blower, glycol regeneration unit, and post-compression pump. These buildings protected the equipment from weather damage and reduced ambient noise levels. For any project, the number, size, and configuration of support buildings would vary based on necessity and the size and type of operation.

Proper operating and maintenance (O&M) of the injection system is vital to a project. A detailed O&M plan should be prepared in the pre-injection planning activities. The O&M plan should contain diagrams and supplier-specific information for each component, which includes the supplier, part number, specifications, maintenance procedures, and maintenance schedules. The O&M plan should adequately address standard operating procedures for start-up, operating mode, normal shutdown and emergency shutdown, and use of operating logs to track equipment performance trends. In addition, safety meetings and formal classes can be held to properly train personnel to identify critical process temperatures, pressures and rates, and also understand all controls, monitoring systems, and alarms of the injection facility. Safe zones and muster points should be clearly defined and marked in case of an emergency, and these should be discussed in daily safety meetings, with each muster point numbered. For example, because of wind direction, Muster Point 2 will be the primary safe zone and Muster Point 1 will be the secondary zone. All health and safety documentation should be maintained on-site within easy access of all personnel.

5.4 INJECTION

Methods and operations utilized for CO_2 injections are project-specific and developed based on project requirements and objectives. For EOR projects, injection patterns are set up strategically to maximize oil or gas production, with the associated benefit of CO_2 storage in the reservoir at the conclusion of the project. For CO_2 injection into a saline reservoir, the goal is simply to store the CO_2 underground. Regardless of project type and objectives, all injection projects share many operational activities and all need to monitor injection rates, CO_2 plume migration, well integrity, and subsurface conditions.

Each active CO_2 injection project involves the two basic operational stages: start-up operations and standard operations. Initial start-up involves pressuring up the well by gradually increasing the injection rate to the planned operating level. The injection rate is dependent on the properties of the injection formation, and injection pressure is not to exceed the permitted maximum pressure, which is normally set by the regulating authority to minimize the potential for unintended fracturing of the injection zone. The planned injection rate might not be achieved for an extended period of time as the entire system comes online and equilibrates. The standard operations stage involves injection that can continue for weeks to years, depending on site-specific conditions and the planned injection program. Key aspects of both start-up and standard operations are monitoring activities to ensure well and reservoir integrity and to assess injection performance.

5.4.1 STARTUP OPERATIONS

Prior to initiation of planned injection operations, the system should undergo start-up and shakedown procedures to certify proper operating conditions within the design specifications. Appropriate site readings are collected to ensure that initial injection rates are within acceptable operating limits. Typically, during system start-up, an increased-intensity system monitoring regimen is employed to allow for any necessary system adjustments. The engineer of record also usually visits the site to inspect the final connections during this time. Testing, modifications, and adjustments must occur until the system is operating according to design and manufacturer specifications.

Once a system meets design specifications, CO_2 injection into the storage formation can commence. As injection initially proceeds, the wellbore begins to pressure up. During this time, the operator must closely monitor injection pressure, generally stepped up over a certain length of time, to confirm it does not exceed the permitted pressure. For a specific injection pressure level, start-up injection flow rates are typically lower than steady-state operational rates, a result of the early fluid displacement mechanisms associated with pressurized CO_2 starting to move through the near-wellbore environment prior to establishing a stable flow regime. Pressure propagation will cause increasing pressure in the near-wellbore reservoir until a steady-state flow regime is established. If injection pressures are sustained at a higher level or beyond what is perceived to be a normal pressure equilibration period, the injection zone would typically be reevaluated. The start-up period can last several days or months, depending on formation injectivity, volume of CO_2 being injected, and number of integrated systems brought online.

5.4.2 STANDARD INJECTION OPERATIONS

Once a well/system has completed system start-up, it is considered to be in the injection stage until closeout. CO_2 injection procedures will likely vary depending on the size and scale of the project. During injection, operators must continuously monitor all facets of the operation.

5.4.2.1 MONITORING

Monitoring conducted for a geologic storage project refers to several different components. This includes the prescribed set of parameters to be measured relative to the established pre-injection baseline, and the CO_2's quality, properties, and volume injected. Monitoring of the parameters established for the baseline describes the conditions that existent in the injection site surface, near-surface, subsurface, and atmospheric environments during and after injection activities.

The monitoring element focused on ensuring the CO_2's quality, properties, and volume injected ensures that the correct amount and composition of CO_2 is being injected into the storage reservoir. This helps account for the CO_2 and informs monitoring efforts focused on detection of any injection-driven changes to the storage complex. Multiple checkpoints in the system are usually set up to monitor flow, pressure, and composition of the CO_2 as described earlier in the injection system equipment section of this chapter.

These monitoring activities are required to verify that injected CO_2 is behaving, and being retained as expected in the storage reservoir. Application of this monitoring data is used to link project risk assessment profiles and simulation (modeling) activities in an iterative process that incorporates the use of earlier monitoring results (in conjunction with risk and modeling projections) as the basis for taking corrective actions or dictating the location and frequency of subsequent monitoring activities. Monitoring results can be used as the basis for go/no-go decisions. Lower-cost monitoring activity results can be used as a basis for designing higher-cost, more definitive monitoring events. Similarly, high-cost monitoring events may determine that subsequent lower-cost alternatives can be justified.

Case Study 5.1 describes SECARB's experience with using bottom hole pressure data as a monitoring tool.

▶ See page 85

5.4.2.2 WASTE DISPOSAL

During injection operations wastes are commonly generated as a byproduct. These may include produced water, CO_2 (primarily for ECBM and EOR operations), and other wastes. Several methods to handle and/or dispose of produced water are available. Ideally, operators will be able to find a beneficial use for produced water. Some of these uses may require intensive and expensive treatment programs. Reuse applications that have been employed include:

- Use in EOR applications
- Domestic use
- Industrial use
- Agricultural use
- Discharge under a National Pollution Discharge Elimination System (NPDES) permit into approved waterways
- Reinjection of treated water to replenish the potable groundwater supply

If no acceptable applications for the beneficial use of produced water can be found, the operator will likely need to find a disposal or treatment option. These might include:

- Underground injection into UIC-approved disposal wells
- Evaporation from collection ponds (to enhance evaporation, some regulators will allow produced water to be sprayed over collection ponds but residual material would be disposed of or, if allowed, reused)
- Off-site disposal in commercial treatment or disposal facilities

CO_2 produced in EOR and ECBM fields may be recycled and used in continuing operations. Further disposal and mitigation strategies are discussed further in **Appendix E-4**.

5.4.2.3 SUPPORT OPERATIONS – WELL FIELD OPTIMIZATION

Well field optimization involved with geologic storage depends upon the project goals. In the case of CO_2 disposal into saline reservoirs, well field optimization involves a series of procedures and strategies to allow the injection system to operate at peak efficiency by maximizing the volume/rate of CO_2 injected into the subsurface. EOR and ECBM operations, however, are designed to maximize economic recovery of hydrocarbons. In this case, optimization strategies include minimizing the quantity of purchased CO_2, while still operating the injection system at peak efficiency.

For stacked injection intervals with multiple injection zones, field optimization may include balancing the injection stream among multiple injection wells and injection intervals. This requires that the injection wells be designed and constructed to allow the division of the injection stream into separate isolated injection intervals. It should be noted that the reservoir pressure may vary among individual injection intervals. Each individual injection interval has its own unique distribution of porosity, permeability, and injectivity. Additionally, the entire injection zone has an associated confining zone. The vertical hydraulic interconnection of the stacked zones should be considered to estimate the ultimate fate of the CO_2.

Controlling the distribution of CO_2 with engineered perforation placement and size can optimize use of the storage volume, both in terms of lowering the maximum pressure and decreasing the area of the CO_2 plume footprint. By knowing the injection rate of CO_2 and the properties of each individual well and/or injection interval, the CO_2 can be diverted into one or more injection zones to maximize injection rate and minimize the induced pressure on each individual zone. The use of several stacked zones can also result in a smaller plume footprint. Pressure minimization can reduce the potential for geomechanical impacts due to injection, which include the risk of induced seismicity. Additionally, wellhead temperature has an impact on flow rates through pressure–density coupling. Seasonal temperature variation of CO_2 arriving at the wellhead affects injection performance, with higher temperature associated with higher wellhead pressure and/or lower injection rate. Therefore, balancing wellhead pressure and temperature can also help to optimize the system. Thermal stress can also have an impact on the strength of the rock and well materials.

5.4.2.4 SUPPORT OPERATIONS – WELL INTEGRITY MONITORING AND MAINTENANCE

Well integrity monitoring and well maintenance is an important component of injection operations. Integrity issues may be revealed if injection or reservoir pressures become too high, or during geophysical logging and testing of the well. Loss of well integrity may occur over time because of degradation of a well. Mechanical integrity tests can help detect a loss of integrity, but it should be noted that a failure in integrity does not necessarily mean a leak to the surface, but rather indicates leakage pathways between the well and unintended formations.

Mitigation strategies for CO_2 injection well integrity issues may utilize several procedures developed by the oil and gas industry. For instance, a cement squeeze job can be implemented to rectify fractures, leaks, and zonal isolation problems caused by cement integrity issues. During a cement squeeze, a hole is cut into the casing and a cement slurry is forced through the hole into potential leakage pathways. Following this procedure, a pressure test can be performed to confirm if well integrity has been restored. In cases where cement slurries are ineffective, other alternatives could be explored, such as sealing polymers or gels. Further details on remedial actions can be found in oil industry publications.

In some instances, an individual well might need to undergo maintenance to restore optimal operating conditions. In cases where injection rates and pressures are diminished, a well may require cleaning, need to be stimulated, or additional casing sections perforated. Once a well has reached the end of its active life, the operator may begin a series of activities to close the well. In the case of projects with multiple wells, the operator can begin activities to close the well, and subsequently close down the project or part of the storage complex. It is important to recognize that closure activities gradually increase in intensity and take place in a series of stages. These activities and stages are discussed in the next chapter.

All of the procedures used to rectify well integrity issues need to be compliant with state/provincial and federal regulations. In the event of the detection of a compromised well, the operator must perform an assessment and determine the type and scope of the potential problem. The result of this assessment will determine the corrective operation to perform at the well. EPA UIC Federal Reporting System Part III: Inspections Mechanical Integrity Testing (MIT) Form 7520 Section VII specifically requires documentation of remedial actions(s) taken based on MIT failures.

Case Study 5.2 describes SECARB's process for deploying MVA tools in one of their injection wells at the Citronelle Project site.

▶ See page 86

Well and Reservoir Maintenance During a Two-Year CO_2 Injection Operation

In 2009 and 2010, a CO_2 capture and storage demonstration project was conducted at a coal-fired power plant, utilizing two injection wells. Each injection well was constructed with multiple casing strings and injection tubing comprised of carbon-steel casing, with the exception of the casing string over the injection interval being completed with stainless-steel, corrosion resistant casing. A corrosion-resistant, nickel-plated packer assembly was used to isolate the injection zones. The wells were equipped with real-time downhole pressure and temperature gauges attached to the outside of the tubing, and each with a downhole safety valve hydraulically operated from units at the surface.

After the first year of injection, the power plant supplying the CO_2 for injection shut down for annual maintenance, so workovers were performed on each injection well. A suite of well tests were conducted to verify each well's mechanical integrity through a visual inspection of the tubing, geophysical logging, and annular pressure testing. This included:

- Cement bond logs confirmed hydraulic isolation in the annular space of the injection casing string, indicating no leakage pathways were present between the injection zone and the surface
- The perforations were acidized and tested for flow enhancement, showing improved injectivity following acidization
- Repeat pulsed neutron capture logs and temperature logs indicated that injected CO_2 had not migrated vertically in the near wellbore region
- A radioactive tracer test performed on one injection well demonstrated the mechanical integrity of the well and identified which perforations were accepting fluid
- Visual inspection of the tubing and downhole components resulted in the replacement of some components, including the injection packers
- After all checks and tests had been completed, an annular pressure test was performed to verify the well's mechanical integrity prior to restarting operations

Replacement of the Wellhead Valve Assembly on One of the Injection Wells during the Post-Injection Monitoring and Maintenance Period

The injection demonstration then resumed for the final six months of the project's operational phase. As the project entered the post-injection site care monitoring and maintenance period, a host of well maintenance needs arose. Pressure readings from the downhole and surface gauges indicated a tubing blockage, so the tubing was cleared several times using a methanol treatment and mechanical cleaning tools. In addition, the post-injection removal of the pneumatic controls from the capture and injection operations triggered the need to replace the automated pneumatic wellhead valves with manual valves (see figure below). After 18 months of frequent cycling the valves open and closed, the seals and lubricants were in need of maintenance. The real-time downhole gauges used during injection proved to be problematic and were replaced with memory gauges. Through regular well observation and maintenance of the injection wells during 4 years of post-injection site care, all project objectives were met, leading to the successful plugging and abandoning of the both injection wells.

5.5 RCSP CASE STUDIES

CASE STUDY 5.1 — SECARB

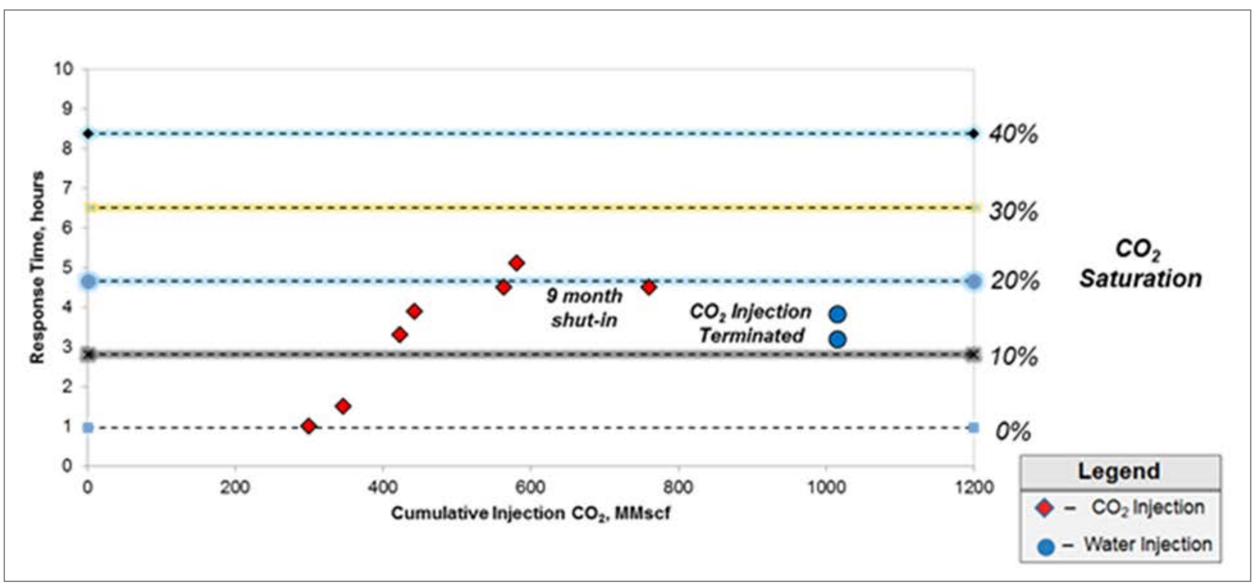
SOUTHEAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (SECARB)

Bottom Hole Pressure Gauge Data Behaves as Well Test

An extensive suite of monitoring activities was conducted at the SECARB Citronelle Project site, which included the collection of bottom-hole pressure data from two in-zone observation wells. Data generated during the injection project was collected from pressure and temperature gauges deployed within the injection zones in the perforated wells over the injection and post-injection periods.

Multiple injection interruptions occurred during the injection period as a result of disruptions at the CO_2 capture unit. Empirical pressure transient times were determined from the delay between the startup of the onsite CO_2 injection booster pump and the onset of the pressure response at the observation wells during these periods. In addition, several small scale water pulses were periodically injected into the formation to create an observable pressure transient to gather post-CO_2 injection data.

Theoretical transient response times were calculated using reservoir properties for several CO_2 saturations to place constraints on changes in CO_2 saturation in the system. An increase in pressure transient time was observed to correlate with an increase in cumulative volume of CO_2 injected. This suggests that the introduction of a compressible fluid into a relatively incompressible system acts to increase the system's overall compressibility, yielding longer transient times with increasing saturations of CO_2. However, after a long period of non-injection and during the post injection site care period, the transient time decreased. The figure below shows pressure response times observed at the observation well versus cumulative injection volume. Horizontal lines represent predicted response times at various CO_2 saturations. This may suggest that the CO_2 saturation in the system decreased during the shut in period, which may be explained by CO_2 dissolution into the brine.



Pressure Response Times versus Cumulative Injection Volume. Horizontal Lines Represent Predicted Response Times at Various CO_2 Saturations.

CASE STUDY 5.2 — **SECARB**

SOUTHEAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (SECARB)

Injection Well Workover for Monitoring, Verification and Accounting

One MVA tool deployed at the SECARB Citronelle Project Site was a time-lapse cross-well seismic survey. This was designed to observe any injection induced seismic velocity anomalies in the storage reservoir, which may indicate the buildup of CO_2 saturation between wells. A baseline cross-well profile was collected prior to installing the downhole injection and monitoring assemblies in 2012 after the injection well and observation wells were cased and cemented. A second cross-well survey was conducted during a hiatus in the CO_2 injection operations in 2014.

Repeating the cross-well seismic profile necessitated the removal of the tubing string in the injection well due to the physical size of the acoustic source tool used for the procedure. Operations to pull the injection string required the well to be hydrostatically stabilized to maintain well control and prevent any unintended release of CO_2 from the well during the work over. A heavy, solids-based drilling mud was used to provide the hydrostatic gradient necessary to push CO_2 out of the wellbore and into the perforations and to generate filter cake to prevent fluid loss into the formation. Once the well was effectively stabilized, the injection tubing was able to be pulled and the acoustic source was run in.

Following the completion of the cross-well survey, the injection tubing was re-run into the well. Mud thinner was pumped into the wellbore and across the perforations to mix with the mud that remained below the packer. A mixture of mud thinner, drilling fluid, and CO_2 returned to the surface, indicating that at least some of the perforations had cleaned up. CO_2 injection operations re-commenced shortly thereafter, however, wellhead pressure was higher than observed prior to the shut-in. A subsequent well flow survey indicated that post-workover CO_2 was only distributed in the top-most perforated interval in the injection zone. A second cleanup of the perforations was planned, however, the injection phase of the project ended prior to implementation.

6.0 POST-INJECTION OPERATIONS

Post-injection operations encompass all areas of a storage site, from specific wells up to the entire project. In projects with a small number of wells, post-injection operations may occur simultaneously for wells and the overall project. In larger projects with many wells, injection will likely cease in some parts of a field as it begins in another. In these cases, post-injection activities may be phased in over time. This section describes the three main activities that take place after injection ceases:

- Post-Injection MVA
- Well Closure
- Site Closure

The relationship of these post injection activities is illustrated in **Figure 6-1,** which may take place over several years, possibly decades, until the operator collects and reports all necessary monitoring data, demonstrating the integrity of the storage complex.

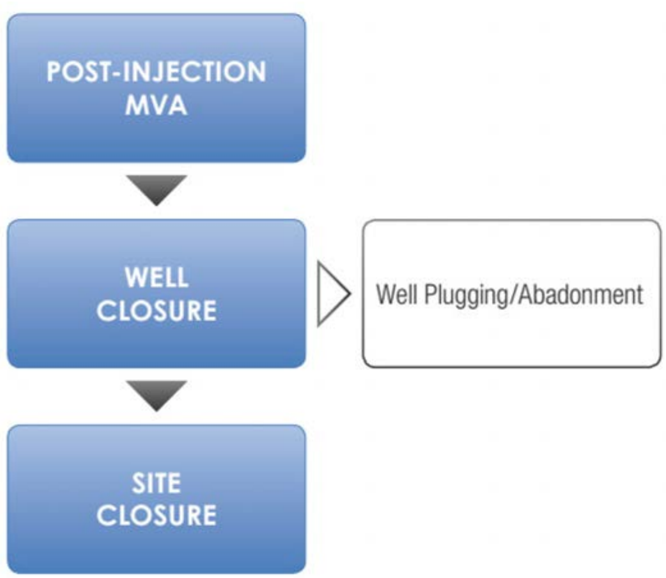


Figure 6-1: Process Diagram of Post-Injection Operations for a CO_2 Injection Project

In addition to injection well plugging, activities relevant to post-injection operations, particularly for Class VI permitted wells, include:

- Demonstrating and maintaining financial responsibility for corrective action on wells in the AoR, maintaining emergency and remedial response capabilities, post-injection site care (PISC) and site closure
- Implementing the PISC and Site Closure Plan to ensure that the CO_2 plume and pressure front are moving as predicted and USDWs are not endangered. PISC monitoring continues until the operator or owner can demonstrate that the site poses no further endangerment to USDWs
- Taking action in the event of movement of the injectate or formation fluids that endanger a USDW

Elements of a post-injection MVA plan, such as monitoring duration, monitoring well locations, and specific equipment, are site-specific and directly related to the risk assessment conducted for the site. MVA consists of various project-specific tests that are implemented to track the movement and stabilization of the CO_2 plume. The monitoring methods used during injection operations may be continued, discontinued, or replaced with other applicable methods. The injection well can be plugged and abandoned, or it can continue to be used as a monitoring well. Any injection well(s) and monitoring well(s) that are not needed should be properly plugged and abandoned in accordance with previous plans [e.g., PISC and Site Closure Plan], Federal, state, and local regulations. The injection system can be dismantled, except for any MVA equipment that is necessary to support the post-injection MVA program. If possible, the equipment should be removed in such a manner that would allow reuse. Unusable equipment should be recycled or disposed of properly.

The length of time required for post-injection monitoring and well closure will be project-specific, based upon operational data collected during injection, ongoing risk assessments, modeling results, and regulations. **Figure 6-2** illustrates the stages in a geologic storage project, with permitted operations terminating after the operator achieves site closure. Site closure activities may include cessation of injection and production operations, removal of surface equipment, site closeout reports, final permitting, and delivery of project records to the permit authority for their retention.

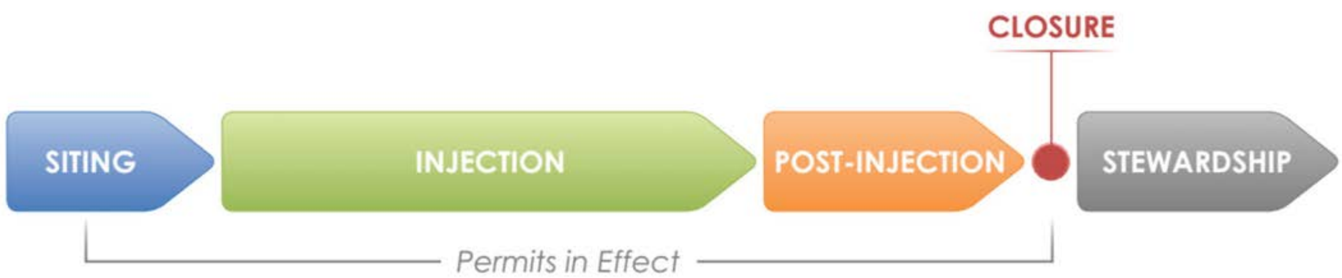


Figure 6-2: Stages in a geologic storage project

6.1 POST-INJECTION MVA

The post-injection MVA plan should conform to the requirements of the regulations under which the operations are being permitted. The EPA UIC Class VI rules require the operator to develop a PISC and Site Closure Plan that describes how the owner or operator intends to monitor the site after injection has ceased. The post-injection MVA plan should be site-specific and designed with the objectives of verifying that the plume is stabilizing and pressures are equilibrating, and detecting migration of the CO_2 before it reaches an identified receptor to allow for early corrective measures. The level of effort is based on the risk and assessment of migration pathways as defined by the EPA guidelines (EPA, 2013; **Appendix C-1**). The nominal time period in the Class VI rule is 50 years, unless the operator demonstrates that an alternative post-injection site care timeframe should be implemented. It is important to consider and plan, if necessary, for the financial requirements of a monitoring program for an extensive length of time. For more details on the MVA protocols, the reader is directed to the *Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects* BPM.

Case Study 6.1 presents some information pertaining to SWP's PISC plan for the Farnsworth Project.

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The operator will remain responsible for maintenance, monitoring and control, reporting, and corrective measures pursuant to a post-injection plan until the site meets the applicable closure requirements.

6.2 WELL CLOSURE

Following all injection and monitoring activities, the remaining project wells should be plugged and abandoned using best practices to prevent communication of fluids between the storage reservoir and the overlying underground sources of drinking water. The process of permanently closing wells is commonly referred to as "plugging and abandoning" (P&A) a well.

Prior to plugging the well, the operator will need to notify the appropriate regulatory agencies. In the case of a Class VI permitted well, the operator will have already filed an injection well plugging plan to ensure there is agreement on the process prior to commencement of injection. This plan should be updated to reflect any new circumstances or conditions requiring a change in the plan.

The operator may temporarily abandon a well if there is a chance the well will be used in the future. "Temporarily abandoned" wells are inactive wells in which the completion interval has been isolated from the interior of the casing. The process should follow the appropriate standards (International Organization for Standardization, API, etc.) and regulations mandated by the regulatory agency or agencies overseeing the temporary well abandonment (each state has a different standard). The injection interval may be isolated using the bridge plug method, the cement squeeze method, or the balanced cement plug method. If a packer is installed in the well, isolation of the injection interval may also be achieved by installing a plug in the packer or tailpipe (API, 1993).

Once a well no longer has a potential future need, the operator plugs and abandons the well in accordance with Federal, state, and local regulations. The Class VI Rule presents the required elements of an Injection Well Plugging Plan [40 CFR 146.92(b)]. Developing a plugging plan is also required of Class I and Class II injection well operators. Many of the plugging procedures used by Class I and Class II well operators may be acceptable for Class VI injection wells. However, one important consideration is that Class VI injection wells must be plugged using methods and materials that are compatible with the composition of the CO_2 stream and formation fluid geochemistry (EPA, 2012a).

Prior to injection well plugging, the Class VI Rule requires that the owner or operator flush each Class VI injection well with a buffer fluidand perform a final external MIT [40 CFR 146.92(a)]. In addition, the operator needs to determine bottomhole pressure and mechanical integrity to plan any remedial activities and to ensure that plugging materials and procedures are selected correctly. Bottomhole pressure should be measured using a downhole pressure gauge. Integrity of the well may be examined by an approved tracer survey, a temperature log, or noise log. Wells with perforations may be plugged using the cement retainer method to cement the perforated intervals and the balanced plug method to cement the well above the perforated zones and the cement retainer. A plugging plan should explain the depth in the well that plugs placement is planned, method of placement of the plugs (e.g., balance method, retainer method, or two-plug method), and the type, grade, and quantity of materials to be used in plugging. The cement and other materials in the injection zone must be compatible with the CO_2 and water mixtures, so acid resistant cement is recommended (EPA, 2013).

Methodologies to properly plug and abandon wells may be found in state-specific guidance documents or regulations. According to the *UIC Program Class VI Well Project Plan Development Guidance* (2012), the U.S. EPA recommends that the owner or operator consider the following information: well depth and construction; the location, type, and depth of subsurface formations penetrated; and how the composition of the CO_2 stream and formation fluid geochemistry may impact plugging materials. State plugging and abandonment methods may differ based on the region's geology, proximity to aquifers or populated areas, and the construction of the well, among other conditions. If the state provides specific guidelines, they should be followed. If the state does not provide any guidelines for abandonment, the project should consider developing a plan consistent with the best practices from the oil and gas industry and comply with any existing Federal regulations. The following are some basic steps that should be considered during abandonment. Well closure requirements are discussed further in *Geologic Sequestration of Carbon Dioxide Draft Underground Injection Control (UIC) Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure* (2013).

- Prepare well prior to plugging by performing well cleaning, remedial operations, and establishment of static equilibrium within the well (injection zone pressure must be controlled at all times)
- Remove all obstructions, including and monitoring equipment, from the wells. Casing cemented to the formation will generally not be removed; sections of uncemented casing should be removed or the operator may need to squeeze cement behind portions of the casing to isolate and prevent fluid migration
- Establish static equilibrium within the well bore by circulating a plugging fluid of appropriate weight and viscosity
- Set plugs sequentially from bottom of the well to the top, with adequate time between to allow setting. EPA recommends that owners or operators emplace plugs:
  - above the lowermost production and/or injection zone
  - above, below, and/or through each USDW
  - at the bottom of intermediate and surface casings
  - across any casing stubs (pulled casing sections)
  - at the surface (US EPA, 1989)
- Use accepted and established methods for the emplacement of cement plugs. These include the balance method; the retainer method; and the two-plug method (US EPA, 2013)

Reports should be prepared that describe the procedures and results of the well closure process and submitted within 60 days to the UIC Program Director [40 CFR 146.92(d)]. Although a well plugging report is not explicitly required for monitoring wells, EPA encourages owners or operators to submit such reports (US EPA, 2013). All wells will have to be plugged and abandoned before the overall project can complete site closure.

Class VI well closure requirements are not required for Class II CO_2 injection operations. A Class II well that has been operated within its permit conditions can be closed as a Class II well (US EPA, 2015). However, operators reporting under subpart RR may have additional reporting requirements in accordance with its monitoring plan compared to Class II CO_2 injection operations that do not report associated storage of CO_2.

Case Study 6.2 describes MRCSP's process for plugging and abandoning a CO_2 injection well under a Class V permit.

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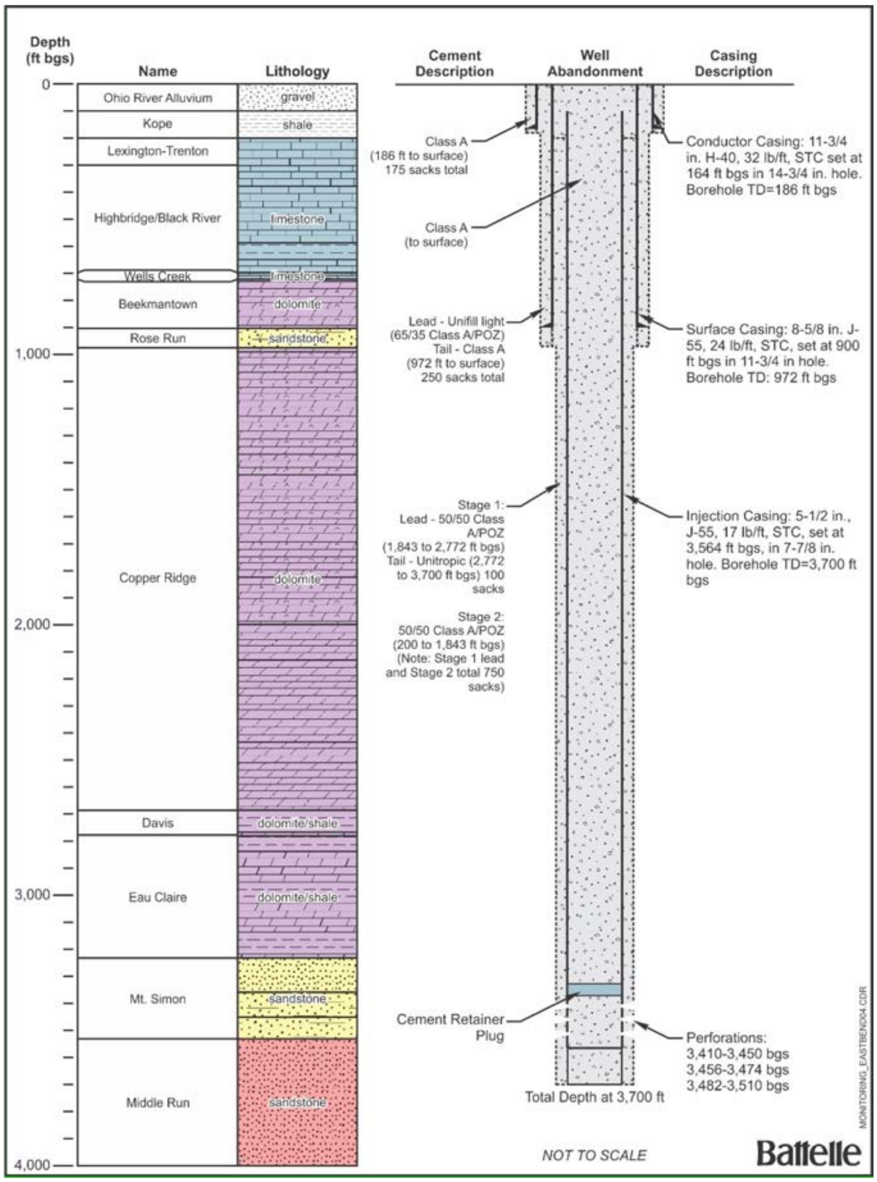

Figure 6-3: Depiction of MRCSP Phase II Test Well Following Plugging and Abandonment

6.3 SITE CLOSURE

The owner or operator must submit information to demonstrate non-endangerment [40 CFR 146.93(b)(3)] to USDWs before the UIC Program Director will authorize site closure. Once the non-endangerment demonstration is approved by the UIC Program Director and site closure has been authorized, 120 days' notice of intent must be submitted [40 CFR 146.93(d)]. Following site closure, a site closure report must be sent to the UIC Program Director within 90 days [40 CFR 146.93(f)]. The types of documentation to be included in the notifications (e.g., well plugging, notification to authorities, records regarding the injectate) are described at 40 CFR 146.93(f).

EPA recommends that owners or operators describe in their PISC and Site Closure Plan how they plan to close the site following the conclusion of the PISC period. Activities described in the plan may include: cessation of injection operations, plugging all monitoring wells, removing all surface equipment, restoring the site to its prior condition (e.g., planting vegetation), site closeout reports, and final permitting and documentation. The primary environmental concerns are protection of freshwater aquifers from fluid migration and isolation of hydrocarbon production and fluid injection intervals. Additional issues include protection of surface soils and surface waters, future end use, and permanent documentation of plugged and abandoned wellbore locations and conditions. *UIC Program Class VI Well Project Plan Development Guidance* (2012) includes guidance on providing the necessary information that the UIC Program Director will need to make a decision regarding site closure, as well as guidance on completing requirements for the site closure report.

The owner or operator of a Class VI permitted well must retain the records collected during the post-injection site care period for 10 years following site closure. The owner or operator must deliver the records to the UIC Program Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the UIC Program Director for that purpose (40 CFR 146.93(h)).

As mentioned previously, Class VI closure requirements are not required for Class II CO_2 injection operations where a Class II well has been operated within its permit conditions. However, EOR operators reporting under subpart RR will have additional requirements compared to Class II CO_2 injection operations that do not report associated storage of CO_2. Site closure activities may include cessation of injection and production operations, removal of surface equipment, site closeout reports, final permitting, and documentation of the storage zone in oil and gas records.

6.4 RCSP CASE STUDIES

CASE STUDY 6.1 — SWP

SOUTHWEST REGIONAL PARTNERSHIP ON CARBON SEQUESTRATION (SWP)

PISC Plan of the Farnsworth CO_2 EOR Project

For its Phase III CO_2 injection project at the Farnsworth Unit, Texas, an EOR site, the SWP will be focused primarily on the efficiency of a combined EOR/sequestration site and validation of CO_2 storage permanence. The tools and methods employed in the injection phase will be 1) the construction of detailed geologic models, 2) multiphase transport/reactive transport simulations to determine oil/brine/CO_2 fate and their combined effect on the reservoir and seal units, and 3) a comprehensive MVA plan and toolkit (e.g., seismic, tracers, pressure, temperature, geochemistry) to iteratively populate and refine models/simulations, and spatially and temporally monitor for CO_2 migration within and beyond the storage reservoir. Data and results gathered during the CO_2 injection phase will be applied to the post-injection period to refine the Area-of-Review and better define any areas (risks) needing additional monitoring scrutiny. For example, surface/near-surface CO_2 and geochemical/tracer data will be collected to monitor for CO_2 and/or brine migration beyond the injection zone.

To date, the project has injected four unique naphthalene sulphonate tracers that track the aqueous-phase (brine) and two unique perfluorocarbon tracers that track the vapor-phase (CO_2). These tracers are considered conservative (non-reactive) and each is significantly detectable to the sub-parts per billion level, allowing for high-resolution inter-well fluid flow rate/path determinations, EOR-specific attributes such as drawdown curves for reservoir characteristics (heterogeneity, fluid saturation, sweep efficiency), and potential detection of spatial and temporal fluid migration beyond the injection zone (surface and/or USDW).

The long life-span of tracers within the environment and their use as sub-surface, near-surface and surface analogs for the interpretation of fluid migration and detection of potential CO_2 migration make them useful MVA tools for the post-closure phase of the SWP project. Because all of the injection wells within the Farnsworth Unit are Class II, any mandated PISC monitoring period for the field operator is effectively undefined. However, the SWP will continue PISC monitoring at the Farnsworth Unit for the remainder of the DOE-funded project (FY 2022) or as additional funds become available.

CASE STUDY 6.2 — **MRCSP**

MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP (MRCSP)

Plugging and Abandoning the MRCSP Well

As part of one of its Validation Phase projects, MRCSP installed a 3,564-foot well in July 2009, under an EPA Class V Experimental Well Permit. This well included an 11 3/4-inch diameter conductor casing set to a depth of 164 feet, an 8 5/8-inch diameter intermediate casing string set to a depth of 900 feet, and a 5 1/2-inch diameter deep casing string set to a depth of 3,564 feet. The well was perforated in three intervals as follows: 3,410 to 3,450 feet; 3,456 to 3,474 feet; and 3,482 to 3,510 feet.

Approximately 1,000 tons of commercial CO_2 was injected into the injection intervals in September, 2009. Following the test, the well was shut in with the injection tubing and packer in place. The tubing was sealed at the surface with a valve and a plug. After the project was complete, MRCSP plugged and abandoned the well in accordance with the EPA UIC Class V permit.

The well was opened and allowed to flow water for approximately six hours to release pressure in the well caused by gasification of CO_2 in the tubing. After allowing the well to depressurize, 20 barrels of 10.1 lb/gallon brine were pumped into the tubing to kill the well. Once the well was controlled, the tubing and packer assembly was removed.

Next, mechanical integrity of the well was confirmed by running a CBL across the entire length of the deep casing string. Plugging entailed filling the deep casing (5 1/2-inch) with Class A cement from total depth (3,564 feet) to approximately three feet below ground surface using a cement retainer method. This method involved setting a cement retainer at a depth of approximately 3,350 feet (60 feet above the perforated interval), pumping cement through the tubing below the retainer plug into the perforated zones, and then pumping cement into the casing to fill the remainder of the well above the retainer plug.

Prior to placing the cement, the deep casing string was cut off approximately 100 feet below ground to allow cement to flow between the 5 1/2-inch and 8 5/8-inch casing strings. The other casing strings were cut off approximately three feet below ground surface and a steel plate was welded to the top of the 8 5/8-inch casing string. The remaining hole was backfilled to the ground surface with soil and a concrete marker, flush with the ground surface, was emplaced above the well. The concrete marker included a brass tag with UIC permit number and other identifying information. See the figure below for an illustration of the plugged well.

The well site was restored to pre-operational conditions, which included two major activities: (1) removal of the stone aggregate that was laid down before drilling commenced, replacement of the top soil, and final grading of the site; and (2) reseeding of the site with grass.

7.0 SUMMARY

Carbon Capture and Storage (CCS) is a method to help mitigate CO_2 emissions and its associated effects on climate change. The Department of Energy has developed five Best Practice Manuals (BPMs) on activities associated with performing safe and successful CCS projects. Care must be taken to closely integrate these lessons learned to help ensure successful projects. This manual focuses on best practices developed for field operations related to planning, designing, implementing, and executing a carbon storage project from project development to post-injection monitoring. This BPM discusses preparation of the site and well pad(s), drilling and completing wells for injection and monitoring of CO_2, equipment needs, materials handling, formation testing and sampling, monitoring and injection operations, and post injection monitoring and site closure.

Field development planning is the first step for operating a carbon storage project once site screening, selection and characterization has been performed. If the results from this phase indicate that select location(s) are viable for CCS, then initial plans are developed for the project. These plans should include negotiating surface and subsurface access concurrently or prior to preliminary development of well and construction designs, budgets, and schedules. Additionally, if there are any data gaps that were identified in the preceding phases, a plan should be developed to obtain the needed information. The full project execution team is assembled and contractor selection criteria are developed. The culmination of this planning effort leads to a Front-End Engineering and Design (FEED) study, which ultimately determines whether the project should proceed.

Once the FEED evaluation indicates that the project is feasible, information developed from the characterization phase and the field development phase should be used to complete permit applications. Permitting for carbon storage projects can take a lot of time and effort that should be accounted for in the project schedule and budget. Many of the field activities can't proceed without the necessary permits being approved. After approved permits are received, construction activities usually commence.

Operations during injection are focused on collecting monitoring data and limiting the risks of working around a dynamic, high-pressure system. Monitoring includes the entire storage complex, (the reservoir, confining layers, near subsurface environment, and surface environment) to ensure the CO_2 is where it is supposed to be, and that there are no negative impacts to underground sources of drinking water, human health, and the environment. Large amounts of monitoring data will be generated and interpreted, usually with the help of static and dynamic models. All CO_2-handling pumps, pipelines and wells will require frequent inspection and maintenance.

The focus of post-injection operations includes continued monitoring of the storage complex, well closure, and site closure. These activities will take place over years, possibly decades, until the operator can demonstrate the integrity of the storage complex and stability of the CO_2 plume to the satisfaction of regulators.

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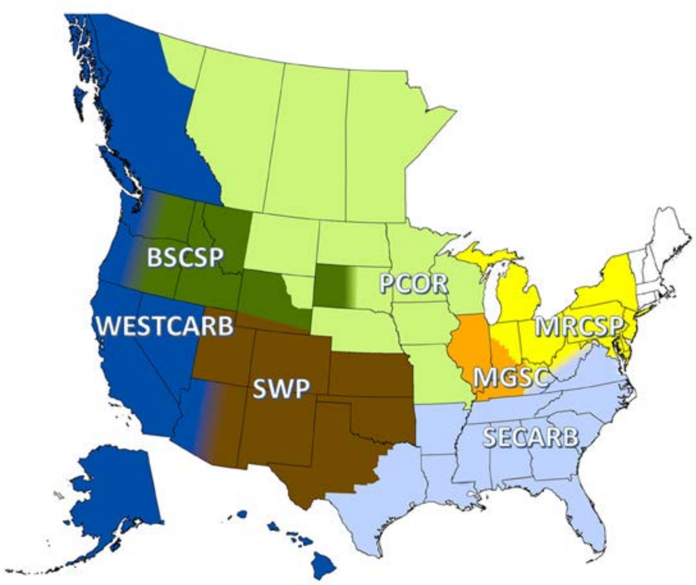
APPENDIX A. RCSP INITIATIVE

In 2003, the DOE launched the RCSP Initiative, by establishing a network of seven RCSPs distributed across the U.S. The overarching objective of this national initiative is to develop the knowledge base, infrastructure, and technology needed to achieve large-scale storage of CO_2 in geologic reservoirs. The RCSPs contribute to this goal through Characterization, Validation, and Development Phase projects in their respective geographic regions.

The seven partnerships are:

- Big Sky Carbon Sequestration Partnership – http://www.bigskyco2.org
- Midwest Geological Sequestration Consortium – http://www.sequestration.org
- Midwest Regional Carbon Storage Partnership – http://www.mrcsp.org
- Plains CO_2 Reduction Partnership – http://www.undeerc.org/pcor
- Southeast Regional Carbon Sequestration Partnership – http://www.secarbon.org
- Southwest Regional Partnership on Carbon Sequestration – http://www.southwestcarbonpartnership.org
- West Coast Regional Carbon Storage Partnership – http://www.westcarb.org



Characterization Phase Projects: The RCSP's Characterization Phase projects began in 2003. These projects focused on collecting data on CO_2 sources and sinks and developing the resources to enable CO_2 storage testing in the field. By the end of this phase, each partnership had succeeded in establishing its own regional network of organizations and individuals working to develop the foundations for CO_2 storage deployment. Characterization Phase projects culminated in the development of a standard, consistent methodology for estimating geologic storage resource, which has been applied in a series of widely acclaimed Carbon Storage Atlases for the United States and portions of Canada.[3]

Validation Phase Projects: Validation Phase projects began in 2005, with a shift in focus to small-scale field projects to validate the most promising regional storage opportunities. Nineteen small-scale field projects were successfully completed, resulting in more than 1.0 million metric tons of CO_2 safely injected and monitored. Eight projects were carried out in depleted oil and gas fields, 5 in unmineable coal seams, 5 in clastic and carbonate saline formations, and 1 in basalt. These small-scale tests provide the foundation for larger volume, Development Phase field projects.

Development Phase Field Projects: The Development Phase projects of the RCSP Initiative began in 2008, with large-scale field projects in different geologic settings (Table 1-1; Figure 1-1). The aim of these projects is to confirm that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically. Results will provide a more thorough understanding of plume movement and permanent storage of CO_2 in a variety of geologic storage formations. Experience and knowledge gained from these projects will also help support regulatory development and commercial deployment of geologic storage. The formations being tested are considered regionally significant and are expected to have the potential to store hundreds of years of CO_2 from stationary source emissions. To date, more than 8 million metric tons of CO_2 have been stored in geologic formations via large-scale field projects being developed by the RCSPs.

NATCARB Atlas: Additional information on the large-scale Development Phase field projects can be found in the *DOE/FE/NETL Carbon Storage Atlas, Fifth Edition (2015)*.

[3] See: http://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas

APPENDIX B. PROJECT SITE AND DEVELOPMENT PLANNING

APPENDIX B-1. PROJECT DEVELOPMENT PLANNING LIST

1. Development of Project Team, Scope, Objectives
2. Development of Safety Program and Policies
3. Development of Communications and Outreach Program and Policies
4. Risk Identification and Management
5. Development and review of the Drilling Prognosis and Program
    a. Identification of services companies and consultants involved
6. Site Selection:
    a. Subsurface – geologic, review of nearby wells, logs, seismic data, development of preliminary models, mineral ownership, groundwater and USDW information, other subsurface data
    b. Surface – evaluation of topography, natural resources (i.e. wetlands/waters, vegetation, wildlife, sensitive habitats, etc.), cultural features, viewsheds, landownership, transportation networks, noise abatement
7. Landowner negotiation
    a. Signed agreements with agencies and/or private owners
8. Staking the well and other pertinent infrastructure
    a. Surveys and map generation
9. Permitting (some or all may apply, see Chapter 3 Permitting for more details)
    a. NEPA analysis and state equivalent analysis
    b. Infrastructure Construction and Operational Permits (i.e. includes wells, pads, roads, pipelines, etc.)
        i. Well drilling permits
        ii. Pipeline permits
        iii. Storm water protection permits
        iv. Wetlands/surface waters related permits
        v. Groundwater related permits
        vi. Air quality related permits
        vii. Landowner permits or agreements (i.e. private property access agreement or public lands lease agreement)
        viii. Mineral right permits or agreements
        ix. Other permits or approvals related to federal- and state-listed species, cultural resources, noise, migratory birds, waste disposal and handling, transportation of rigs, seismic surveys and local stipulations may apply
    c. Well Injection permit (EPA UIC Class VI permits could take ~2 years for approval)
10. Pre-Construction Technical Meetings (i.e. Drill the Well on Paper meeting)
    a. Allow time for changes to be made to drilling/construction program and permits after the meeting
11. Well pad and access road construction
12. Mobilization of rig and services
13. Well drilling program
14. Logging, testing, sampling programs
15. Well completion and testing programs
16. Demobilization
17. Enter into agreements with CO_2 sources
18. Infrastructure development (sighting, design, permit, construct and post-construction reclamation)
    a. Access roads and pads
    b. Pipelines
    c. Gas Handling and compression Facilities
    d. Power infrastructure
    e. Buildings
20. Data Analysis and Report Generation
21. Post Work Debriefing and Capturing of Lessons Learned

22. Filing of Information with Permitting Agencies
23. Injection Phase
24. Monitoring Period
25. Data Analyses & Report Generation
26. Post-Injection Site Reclamation and Restoration

APPENDIX B-2. COMMUNICATIONS PLAN

ROUTINE COMMUNICATIONS FOR DRILLING OPERATIONS

Routine communications maintain open communication between the management team and the field location. Most modern drilling operations use real-time drilling management systems such as Pason® DataHub or Live Rig View to allow remote, log-in access to real-time drilling information. These systems can be extremely useful for managers and scientists and aid in efficient decision making.

Communication tools that are commonly used for routine communications:

- Daily reports from on-site engineers and geologists
- Daily calls with rig team
- Risk Identification Reports / Job Hazard Analyses (JHAs)
- Near miss and injury reporting
- Emergency response drills
- Daily tailgate safety meetings
- Pre-tour safety meetings for shift changes
- Log books
- Daily planning meetings
- Tool box safety meetings prior to non-routine operations
- Weekly project progress reports
- Weekly conference calls with technical team members
- Monthly performance reports

FEEDBACK COMMUNICATIONS

Open lines of communication are critical in ensuring that the field team and the project management team are working together as efficiently as possible. Feedback in the form of suggestions for improvement is encouraged from the rig crews and service personnel during daily tailgate safety meetings and daily operations. Feedback can also be received via Hazard Identification cards, near miss and injury reporting, daily reports and other daily communications. Feedback can be incorporated into daily operations and shared with the management team. The management team can also provide feedback to the field team to communicate project updates and ensure that on-the-ground activities are compliant with project commitments.

MANAGEMENT OF CHANGE

Management of Change is the process used to review all proposed changes to materials, technology, equipment, procedures, personnel, and facility operations before they are implemented to determine their effects on scope, objectives, budget and safety. All proposed modifications to operational plans should be subjected to a review process whereby change requests are submitted to management and analyzed for project impact. Technical experts should be consulted during the review process when necessary. If the team approves of the change, it is implemented, documents are updated, and all employees whose job tasks will be affected by the change should be informed and retrained prior to resumption of work.

For example, standard operating procedures generally describe the acceptable operating ranges of tasks and process parameters. A knowledgeable person should evaluate any proposed changes in these process tasks or parameters to ensure safe operation. If the proposed change is determined to be safe, operators should be informed about the parameter change and trained to respond with the appropriate actions if the parameter should fall outside of its acceptable range (e.g., notify supervisors, change process settings, shut down process) in order to maintain a safe working environment.

After the change is made, it should be monitored and evaluated to ensure it accomplished the intended purpose. If not, the team should re-initiate the change process to find a more suitable solution to the unresolved issue.

REGULATORY BODY AND STAKEHOLDER COMMUNICATIONS

Persons should be identified who have the authority to communicate with any local, county, state or Federal government agencies, landowners or other stakeholders. Communications with these entities should be documented and the management of change process should be initiated if the communication results in any changes to operations. Special care should be made to designate spokespersons with the authority to speak to the press or media. Everyone on the team should be aware of who has the authority to speak with stakeholders or the media and who does not.

EMERGENCY COMMUNICATION & PROCEDURES

The management team, assisted by the designated project Safety Supervisor, should agree on the key measures required in the event of loss of control/release of a significant hazard, medical emergency or environmental incident. Measures should be put in place for:

- Medical Emergencies
- Environmental Incidents
- Regulatory Reporting Protocols

It is also important to have emergency contacts, emergency call trees and routes to emergency facilities established, documented on-site and provided to each service company.

APPENDIX B-3. SAMPLE HEALTH, SAFETY, AND ENVIRONMENT PLAN

NATIONAL ENERGY TECHNOLOGY LABORATORY

CARBON CAPTURE AND STORAGE PROJECT WELL #1 WELL CONSTRUCTION HEALTH, SAFETY, AND ENVIRONMENT BRIDGING DOCUMENT

Project Manager

18 April, 2016

U.S. DEPARTMENT OF ENERGY | NATIONAL ENERGY TECHNOLOGY LABORATORY

APPENDIX B-3. SAMPLE HSE PLAN (continued)

DOCUMENT INFORMATION:

Issue/Revision	1.0
Project Director	TBD
Sub awardee	TBD
Funding Entity	TBD
Well Name	Well#1
Drilling Contractor	Driller
Rig	TBD
Field	TBD
Well Location	TBD
Well Coordinates	X° Y' Z"N Latitude Q° R' S"W Longitude

Prepared by: TBD, Project Manager

____
(Signature)

____
Date:

Agreed by: TBD Service Company Well Engineering Manager ____________________________ (Signature) ____________________________ Date:	Agreed by: TBD Service Company Wellsite Coordinator ____________________________ (Signature) ____________________________ Date:
Agreed by: TBD Drilling Manager ____________________________ (Signature) ____________________________ Date:	Agreed by: TBD CLIENT Project Director ____________________________ (Signature) ____________________________ Date:

APPENDIX B-3. SAMPLE HSE PLAN (continued)

INTRODUCTION

Client (CLIENT), Service Company, and Driller (DRILLER) are jointly involved in the drilling of an injection well bore near City, State. Each of these parties operates its own Health, Safety, and Environment (HSE) management system (MS). For drilling operations to proceed efficiently and safely, it is necessary to integrate these systems. This is particularly critical for the management of activities. Many of the activities present significant risk to one or more of the parties. The adoption of a single party's HSE-MS for all activities would not provide adequate risk control.

HSE management systems bridging arrangements should ensure that HSE standards achieved by any one party through the application of its HSE-MS are not compromised by another party while undertaking shared activities.

The purpose of this HSE Bridging Document is to integrate the HSE management systems of CLIENT, Service Company, and DRILLER by clearly defining the interfaces and by assigning responsibilities to individuals in each of the three organizations. The document provides the reference point for all involved companies during the drilling and borehole testing operations phase of the WELL#1 well between the CLIENT, Service Company, and DRILLER as well as other core services that occasionally might offer services in the Project and gives evidence to the senior management of all parties that operations will be conducted within the envelope of the respective HSE management systems. This approach promotes open lines of communication among all parties.

The company HSE management systems involved in the process are documented in detail in the respective HSE management system manuals:

- Service Company – as described in their Quality, Health, Safety, and Environment (QHSE) Management System,
- DRILLER – as described in their Safety Manual (available on request)
- CLIENT – as described in their Contractor Safety Training documentation
- Service Company contractors – as described in their individual HSE Management System documents
- Management of contractors and third parties by CLIENT and DRILLER is in accordance with each company's respective HSE management systems (Ref. 1.10.1 and Ref. 1.10.2)

HSE OBJECTIVES

General HSE objectives are summarized within the HSE corporate statements and policies of the different members of the project team. This bridging document defines which company's policies take precedence for HSE issues under what conditions and/or in which physical space.

The overall objective of this document is to ensure the effective management of risks to the environment, to the health and safety of people and assets, and to the reputation of all parties involved in the project. Risks should be reduced and managed to the level called "as low as reasonably practical" (ALARP). By defining all interface issues, potential sources of conflict among the companies' HSE management systems can be removed. This HSE Bridging Document supports the companies' HSE policies. This helps to ensure that health, safety and environmental objectives can be treated in an equal manner to all other business objectives, and are not compromised in the pursuit of other goals, such as efficiency or financial targets.

MANAGEMENT STRUCTURE, RESPONSIBILITIES, AND ACCOUNTABILITIES MANAGEMENT STRUCTURE

A management organization chart is given in Figure 1. This chart summarizes the companies involved in the project, key positions for personnel in land offices and at the well site, and the primary lines of reporting and communication.

ROLES, INDIVIDUAL RESPONSIBILITIES, AND ACCOUNTABILITIES

The roles of the principal companies involved in the drilling operations of the Service Company, CLIENT and DRILLER campaign are summarized as follows:

- **CLIENT:** Overall control of and responsibility of the Carbon Capture and Storage (CCS) well construction campaign (i.e., permitting, drilling, well services, logistics, transportation, communications, HSE)
- **Service Company:** Responsible for the day-to-day supervision of drilling operations, service providers, logistics, administration of services, and execution of operations
- **DRILLER:** Provision of the rig including crew, medical First Aid Kit for rig personnel, and rig HSE management system

APPENDIX B-3. SAMPLE HSE PLAN (continued)

On the Rig

The roles and responsibilities of the management team on the rig are summarized below:

- The CLIENT Project Director and the Service Company Project Manager are responsible for giving overall direction to the project. They are the interface between other CLIENT/Service Company and the drilling operations team.
- The Service Company Contract Well Site Supervisor (WSS) has overall responsibility for all day-to-day drilling operations. He/she is accountable to the Service Company Well Engineering Manager and receives direction and input from the CLIENT Project Director. The primary duty of the WSS is to ensure that drilling operations are conducted in a safe, environmentally responsible, and cost effective manner. He/she is responsible for the direction of the DRILLER Tool Pusher. In the case of a well control emergency, the Service Company Contract Well Site Supervisor takes overall responsibility of all operations in close liaison with the Service Company Project Manager and the Service Company Well Engineering Manager, Service Company Project Coordinator, and the DRILLER Tool Pusher.
- The DRILLER Tool Pusher is responsible for the direction and supervision of the drill crew, for analyzing and overseeing all rig operations and for regular rig inspections. He/she also has a responsibility to ensure that all drill crewmembers are trained in, and comply with, HSE procedures. The Tool Pusher is accountable to the DRILLER Drilling Manager to ensure that rig operations are conducted in a safe and environmentally responsible manner. The DRILLER Drilling Tool Pusher takes directions for execution of operations from the Service Company Contract WSS assisted by Service Company Well Engineering Manager. In the case of a well control emergency, the Tool Pusher takes the responsibility of executing all operations, under the direct direction of the Service Company Contract Well Site Supervisor.
- If a DRILLER Night Pusher is on staff, the Night Pusher assumes responsibility for the Tool Pusher's duties whenever the Tool Pusher is off duty. He is also responsible for providing training in well control, fire prevention, firefighting and emergency response to work crews. He is also charged with the responsibility for organizing pre-operational safety meetings.
- The DRILLER on tour is responsible for operating and maintaining drilling and safety related equipment. The DRILLER oversees rig floor operations to ensure compliance with HSE procedures.

In the Office

The roles and responsibilities of the office management team are summarized below:

- The **Service Company Project Manager** is accountable to the CLIENT Management and Management staff. He is responsible for overseeing the execution of the drilling program in the geologic storage project drilling campaign in a safe and efficient manner. The Service Company Project Manager works closely with the DRILLER's drilling management at all times. He/she is directly responsible for ensuring that the WSS understands all the policies in place and carries out the work program, policies, and procedures as required.
- The **Service Company Well Engineering Manager** reports to the Service Company Project Manager of the STATE geologic storage project (PROJECT). His/her main responsibilities are to ensure that the day to day operations are carried out as per the well plans. He/she is responsible for the appropriate technical integrity of the designs for the wells. He/she is responsible for the in-depth analysis and implementation of new technology and lessons learnt. He is responsible for the implementation of new processes and procedures that will impact the performance of the drilling at the Well#1 well site.
- The **Service Company Project Coordinator** reports to the Service Company Project Manager of the CLIENT geologic storage project. His/her main responsibilities are to coordinate the day to day operations at the direction of the Service Company Well Engineering Manager in the CLIENT Project. Among his/her responsibilities will be documentation of HSE issues, complying with the reporting requirements of Service Company Project Management and other tasks as assigned by the Service Company Project Manager or Service Company Well Engineering Manager.
- The **DRILLER Drilling Manager** is the primary point of contact for the Service Company for all matters related to the rig, and oversees all the DRILLER's Drilling operations on the rig. The DRILLER Manager works closely with the Service Company Well Engineering Manager and/or Project Manager to ensure the operations are carried out in an efficient manner.
- The **CLIENT HSE Manager**, located in City, State is responsible for supporting the project as needed and providing day-to-day HSE advice, environmental incidents and CLIENT facility-specific HSE compliance.

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Management of Well Control Incidents

The parties have agreed that the Service Company Well Control Procedures for the CLIENT Well#1 drilling campaign with the DRILLER Drilling Rig # (Appendix C) will be followed for all well control incidents. In case of a kick, the parties have agreed to the use of a hard shut-in of the well using either the ram or annular preventers.

For any Well Control Incident it will be the responsibility of the DRILLER's Driller on duty (or authorized delegate) to initiate communication with the DRILLER's Drilling Tool Pusher and the WSS. Responsibility for shutting-in the well lies with the DRILLER's Driller, or his/her authorized delegate. DRILLER will ensure that the Driller or his/her authorized delegate is aware that he/she is empowered to perform this task.

The ultimate responsibility for any well-kill decision rests with the WSS with consultation with the Service Company Well Engineering Manager and in consultation with DRILLER and CLIENT.

Well killing procedures and procedural changes

The DRILLER's Driller is responsible to ensure that well killing procedures (as defined in Appendix C) are followed if circumstances should arise such that a change to procedures may be advisable; the Driller shall follow decision procedure as below:

- If there is sufficient time, such change must be approved in writing by the Service Company Project Manager and Well Engineering Manager and the DRILLER Drilling Manager in City, State.
- If there is not sufficient time to coordinate with the individuals cited above, such change must be approved by the CLIENT Contract Well Site Supervisor, the Well Engineering Manager and the DRILLER's Drilling Rig Tool Pusher.

At all times there will be a minimum of one DRILLER drilling employee on the rig floor who is competent in well control, demonstrated by holding a current Blowout Prevention (BOP) certificate, which must be to the either the International Association of Drilling Contractors (IADC) Well Cap or International Well Control Forum (IWCF) standard. Additionally, there must be at least one DRILLER Drilling Tool Pusher or Tool Pusher on site with a well control certificate for one of these two standards. Also the Service Company Well Engineering Manager and the Service Company Contract Well Site Supervisors must hold a well control certificate to one of these two standards. Training will be provided if any of the certifications have expired. All certificates will be filed at the well site in one of the project files.

COMMUNICATION

COMMUNICATION INTERFACE

Good communication between CLIENT, Service Company, Service Company contractors, and DRILLER is vital to ensure safe, environmentally responsible, and effective operations. It is important that communication links be re-defined following any organizational changes within or among the parties.

There are five main areas of communication among the parties:

- Routine Communications
- Feedback
- Management of Change
- Emergency Communication
- Regulatory Body Communication

Routine Communications

A variety of communication tools will be utilized on a routine basis to establish and maintain effective lines of communication between the rig and office management teams and on the rig itself. The tools to be used include but are not limited to:

- Risk identification reports
- Weekly project progress reports
- Monthly performance reports
- Near miss and injury reporting
- Emergency response drills
- Weekly rig crew safety meetings
- Pre-tour safety meetings
- Log books
- Daily planning meetings
- Pre-operations safety meetings
- Tool box safety meetings prior to non-routine operations
- Office/well site communications

Where appropriate, regular meetings are held with employee representatives to communicate and encourage participation and involvement in HSE issues.

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Feedback

Feedback in the form of suggestions for improvement is also encouraged from the DRILLER Drilling Rig # crews and service personnel during daily pre-tour HSE meetings.

Management of Change

Significant changes to the Drilling Program must be approved in writing by CLIENT, Service Company Well Engineering Manager and DRILLER management teams. Such changes will be issued by the CLIENT Contract WSS in written communications between the Service Company office management team and the Service Company Contract Well Site Supervisor. The changes must be distributed to the DRILLER management team and the office employees of each company. If such changes affect this HSE Bridging Document, then its custodian, the Service Company Project Manager, will make any updates required.

Changes in the personnel roster at the rig will be notified as part of the normal reporting procedures from the rig to the office. All new personnel to the rig will receive an initial HSE briefing, which will be provided by designated DRILLER personnel and which is briefly outlined in the attached Appendix B.

Emergency Communication

Details of the communication requirements for an emergency situation are contained in Section 6.5 of this bridging document, Emergency Response Procedures, and are summarized in the Figure 2.

Contact numbers for the Project Well#1 well are also shown in listed Figure 2.

Regulatory Body Communication

Any communications required to be made with any local, state, or Federal USA government agencies or regulatory bodies will be made solely by authorized parties within CLIENT, DRILLER and Service Company. As a general rule, when feasible CLIENT will take the lead on these communications. This communication will have to be coordinated with assistance from the Service Company Contract Well Site Supervisor and the Service Company Well Engineering Manager.

HAZARD IDENTIFICATION, ANALYSIS, AND RISK MANAGEMENT

Prior to the start of operations, the office and well site management teams, assisted by the Service Company Project Coordinator, systematically identify and assess the HSE hazards in the shared activities. For those hazards which are considered to pose a significant risk to operations, the Service Company Project Coordinator will specify control measures.

Hazard controls are contained primarily in the Work Program, Operational Procedures and the Permit to Work System, as detailed in Section 1.6. Additional controls relating to health, the environment, security and safety are detailed following.

HEALTH ARRANGEMENTS

To protect the health of everyone involved in the project all parties agree to a number of medical requirements. All DRILLER personnel are to adhere to the employment requirements of DRILLER, including but not limited to the drug testing policy, routine medical physicals(if any), and other employment requirements. DRILLER and Service Company are responsible for ensuring that all their own personnel and contractor staff meet these requirements.

In the case of an emergency or a severe operational problem, these requirements may be waived for temporary visitors to the well site. This waiver requires the written approval of the Service Company Project Manager and DRILLER Drilling Manager. The provision of medical facilities and the upkeep of the medical records on the DRILLER Rig # (if any) is the responsibility of DRILLER.

The DRILLER Drilling Rig Tool Pusher is responsible for regular hygiene and medical care for their personnel and areas such as any rig toilets, bathrooms, and crew change rooms (if any).

WASTE MANAGEMENT

Arrangements and individual responsibilities for waste management shall conform to the recommendations specified by CLIENT. The objective is environmental compliance and world class performance in the drilling campaign with respect to waste management. CLIENT is the owner of all surface and sub-surface wastes, and the rig team will manage such wastes on behalf of CLIENT.

APPENDIX B-3. SAMPLE HSE PLAN (continued)

In addition, solids control environmental monitoring with regards to discharged water from drilling fluids, sewage, cuttings disposal, gas emissions, and sample analyses shall be maintained in compliance with all local, state, and federal government official hydrocarbon decrees or permit criteria. Service Company Contract Well Site Supervisor shall keep a copy of this permit in the WSS trailer at all times.

SECURITY

If such notifications are required, CLIENT is responsible for informing the appropriate government authorities of the location of the rig, and for providing copies of the certificates issued by the various local, state or Federal authorities to the Service Company Project Manager. The Service Company Project Manager will keep these certificates on file at the well site in the WSS's trailer.

WEAPONS, ALCOHOL, AND DRUGS

Service Company, DRILLER, and CLIENT maintain a policy of no weapons, alcohol, and/or non-prescription drugs on the project site. All personnel working on the rig are subject to this policy. Each third party (DRILLER and Service Company) will comply with their own policies and practices in regards to weapons, drugs and alcohol.

USE OF "STOP" OR EQUIVALENT PROGRAM

All parties at the well site agree to the use of a Safety Training and Observation Program (STOP) or equivalent to reduce unsafe acts and conditions, identify and record near miss accidents and incidents, and reduce the risk of lost time injuries and environmental incidents to ALARP. DRILLER uses their own equivalent system of constructive, positive reinforcement HSE system, and this system will be utilized during the drilling campaign.

All well site employees and Service Company contractor employees will undergo training in the proper use of this proactive, positive reinforcement system of DRILLER.

RECOVERY MEASURES

The office and well site management teams, assisted by the Service Company Well Engineering Manager, agree on the key recovery measures required in the event of loss of control/release of significant hazardous material. Recovery measures are in place for:

- Well control incident
- Medical evacuations
- Environmental incident

Well Control Incident

Refer to Section 3.2.3: Management of Well Control Incidents.

Medical Evacuations

Medical evacuations (Medevac) from the well site are initiated by the Service Company WSS or DRILLER Drilling Tool Pusher with prior approval and assistance from an onsite Paramedic, if available.

Arrangements for ambulance, hospital, notification of next of kin, etc. are the responsibility of Service Company or DRILLER as appropriate.

Environmental Incident

Environmental incidents are controlled in the same manner as other emergency responses and are dealt with as specified in the CLIENT Environmental Impact Statement (Ref. 1.10.9) and the Operations Emergency Response Plan (Ref 1.10.8).

APPENDIX B-3. SAMPLE HSE PLAN (continued)

WORK PROGRAM AND PROCEDURES

WORK PROGRAM

The contracted scope of work for each of the parties involved in the CLIENT geologic storage drilling campaign is primarily defined by the respective contracts and by the Drilling Program.

Prior to the commencement of drilling operations Service Company will organize a pre-spud meeting. Disagreements and questions regarding program content, hazard identification, assessment and control, or HSE management will be addressed, and amendments to the Drilling Program made as required.

Additionally, it is the responsibility of all key office and Well Site Managers and Supervisors from Service Company, CLIENT, and DRILLER to continually assess the suitability of this drilling program and recommend any alterations that may be required to maintain a risk level that is ALARP.

WORK PROGRAM

Any significant changes to the Drilling Program are covered in Section 4.1.3 Management of Change.

OPERATIONAL PROCEDURES

All work is to be carried out in accordance with the written Drilling Program. No work is to be performed which in any way conflicts with Service Company or DRILLER HSE objectives, policies or procedures. If such conflict arises or if an unsafe condition occurs, work is to be stopped until conditions are once more safe to continue as determined by the relevant person in charge, (i.e. the Service Company Contract Well Site Supervisor or DRILLER Tool Pusher). Each person who is authorized to work on the drilling program is also authorized and is responsible to stop work if he/she observes an unsafe condition. The Drilling Program will be re-assessed and amended as required.

PERMIT TO WORK SYSTEM

All rig operations are subject to the DRILLER Permit to Work (PTW) System. The PTW system covers:

- Confined space entry
- Welding and cutting
- Electrical and mechanical isolation (lockout-tag out)

The PTW system is supplemented by the DRILLER Job Safety Analysis (JSA) Program. This program requires analysis of the hazards associated with a particular activity (or sub-activity) and hence identification of the required safe working practices. The DRILLER JSA Program is developed on the rig and is therefore rig-specific. It is developed by rig-based personnel, including the crews and supervisors and third party personnel when relevant. Development of the JSA Program is a training exercise for these staff as well as a risk mitigation measure. The file containing previous DRILLER JSA program activities, remains with the rig at all times. All personnel new to the rig will receive induction training in the PTW and DRILLER JSA program systems. Appropriate personnel receive formal training.

Personnel are issued personal protective equipment (PPE) as required by the relevant Service Company, CLIENT or DRILLER policy. Where such PPE is rig specific, it is provided by DRILLER. All other PPE is the responsibility of the individual companies. At a minimum all personnel must wear proper PPE per CLIENT Policy (safety boots/shoes, safety gloves where /when needed, safety goggles/glasses, and hard hat).

EMERGENCY RESPONSE PROCEDURES

Emergency response arrangements for the well site are the responsibility of Service Company, as defined in Emergency Response Plan (ERP) and shown here in Figure 2.

The initial declaration of an emergency is made by the Service Company Contract WSS or DRILLER Tool Pusher. Should escalation occur such that resources on the rig are unable to manage the incident, the WSS is notified to initiate call-outs of the duty personnel forming the initial Emergency Response Team. This team convenes at the location indicated in the ERP and co-ordinates responses from there. Additional support will be made available from, Service Company or DRILLER management support teams.

Copies of the Emergency Response Plan are held at the well site and in the Service Company local office.

A schedule of emergency exercises and drills will be planned and implemented by the DRILLER Tool Pusher. Emergency exercises will be monitored and supervised by Service Company Contract WSS. Results of the exercises will be reported to the WSS, HSE, the Service Company Project Manager and Well Engineering Manager as well as the DRILLER Manager. They also will be reviewed in daily pre-tour meetings.

APPENDIX B-3. SAMPLE HSE PLAN (continued)

PERSONNEL MANAGEMENT, COMPETENCE, AND TRAINING

CREWING LEVELS

Crewing levels for the CLIENT, Well#1 drilling campaign should be held to a minimum. Additional personnel may be required at various stages throughout the campaign to provide maintenance skills, specialist assistance, and training and to conduct audits. However, the use of such personnel is governed by rig operations and space availability. It is the responsibility of the DRILLER Tool Pusher or Service Company Contract WSS to assess the space availability for the utilization of additional personnel.

Crewing levels are monitored by the Service Company Contract WSS and are notified to the office management team via the daily reports. This is in the format of total numbers on the rig and total numbers by company. The DRILLER Tool Pusher is responsible for maintaining a well site personnel breakdown by name and company.

COMPETENCE, SELECTION, AND TRAINING

The Service Company should operate a Quality Management System (QMS). A major element of this QMS is a program which in assesses and utilizes the competence assurance programs of contractors.

The required competencies of key DRILLER personnel are detailed in the CLIENT and DRILLER Drilling Agreement. All DRILLER personnel are trained throughout the contract and are subject to performance competence checks by their supervisors. Any ‘site specific’ training requirements are provided by CLIENT or the Drilling Contractor.

EQUIPMENT FITNESS FOR PURPOSE

DESIGN AND CONSTRUCTION STANDARDS AND CERTIFICATION

The DRILLER Rig # was constructed in accordance with the standards described in the DRILLER Quality Assurance (QA) Procedures. The mast and superstructure were certified by a manufacturer’s representative. All overhead string components are inspected as per API-RP8B. All BOP equipment is hydrostatically tested upon installation and at no more than 14 day intervals. Drill string components are routinely inspected as per API-RP7G. Relative to the above-listed equipment, fulfillment of all certification and inspection requirements and recordkeeping thereon are the responsibility of DRILLER.

The Service Company QMS should assure the fitness for purpose of all Service Company contractor well service equipment. Only certified well services equipment is approved for use. Appropriate certifying documentation will be provided by each vendor or subcontractor to enable this to be verified. If this documentation does not arrive with the equipment, the equipment is not to be put into service until such time as verification can be made, unless approval in writing is obtained from the Service Company Contract WSS and the Service Company Project Manager.

Individual Service Company product lines and third party contractors ensure fitness for purpose of their equipment through control of design and construction standards and certification.

Any additional HSE-critical equipment manufactured elsewhere outside the USA or on the rig requires appropriate certification prior to use, e.g. pressure vessels and lifting equipment/pad-eyes, etc. It is the responsibility of the Service Company Contract WSS to ensure that any such additional equipment is fit for purpose and safe to use prior to entering service.

All lifting equipment (i.e. slings, harnesses, pad-eyes, etc.) will be inspected and certified prior to use by DRILLER or the respective service company providing the equipment and are/will be re-certified annually for continued use.

The parties recognize and agree that reliance on ISO 9000 certificates alone is not sufficient to reduce operational risk of equipment design and construction to ALARP, and that this requires the personal, active, and visible involvement of management at all levels.

Modification Procedures Minor modifications to the DRILLER RIG structure or layout will be subject to agreement by the DRILLER Tool Pusher and the WSS in consultation with the Service Company Well Engineering Manager. For any significant modifications, notification and approval from the office management team is also required. Major changes to the mast, sub-structure, or lifting equipment of the rig DRILLER RIG # must be notified to DRILLER headquarters in City, State for prior approval. Depending upon the degree of modification requested, DRILLER headquarters and the manufacture’s approval is also required.

In all cases it is the responsibility of the DRILLER Drilling Manager to confirm DRILLER Headquarters office HSE or Engineering Department approval of any such rig modifications.

APPENDIX B-3. SAMPLE HSE PLAN (continued)

If necessary, Field technical equipment of Service Company Service Segments shall be modified in accordance with standard instructions (Modification Recaps) issued to the product center responsible for its design and manufacture. Modifications shall be performed only in accordance with such instructions and by suitably trained personnel. All such modifications shall be recorded in the tool/equipment history cards and are stamped on the tool identification plate.

MONITORING, AUDITING, AND REVIEW

HSE performance is monitored by means of agreed performance indicators such as:

- "STOP" Cards or equivalent positive reinforcement card system
- HSE Training Hours per Employee per Year
- % of Action Items Complete (from "STOP" Audits or other safety audits)
- Lost Time Injury Frequency Rate

HSE statistics will be collated on the rig by the DRILLER Tool Pusher and are forwarded to the DRILLER HSE Manager and the WSS and then compiled for all personnel by the Contract WSS and presented to both HSE Management and the Service Company Project Manager every week. The Service Company Contract Well Site Supervisor will prepare a monthly report and send it to the DRILLER Drilling Manager, Service Company Project Manager, Well Engineering Manager, and the Service Company Project Coordinator

The Service Company Project Manager or Project Coordinator will design and implement appropriate controls to ensure the implementation of corrective actions identified by the monitoring, auditing, and review processes. The Service Company Project Manager or Project Coordinator and DRILLER Drilling Manager will jointly ensure that all corrective actions are implemented and closed out on a timely basis. All corrective items should be reported to the Service Company Project Manager.

INCIDENT INVESTIGATION AND REPORTING

CLIENT's reporting system has primacy for the reporting of all accidents and incidents. Additionally, all accident/incident reporting is in accordance with DRILLER incident and investigation reporting procedures. In parallel, the Service Company QHSE Incident/Injury investigation system is also followed if the incident affects the Service Company or its contractor staff.

All action items resulting from investigations by the Service Company, CLIENT and DRILLER are incorporated into a remedial work plan. Each action item is assigned an action party, verification party and a target close-out date. (An example can be furnished on request)

CONCURRENCE STATEMENT

The HSE management system detailed in this document is to remain in place for the duration of the project or until such time as this Bridging Document is re-issued.

It is the responsibility of the Service Company Project Manager to ensure that this Bridging Document is subject to detailed review and revision on a routine basis or upon significant changes in the work program (or if/when additional work scope is planned or another well is planned).

This HSE Bridging Document is acceptable to the respective companies, as acknowledged by the signatures on page 3.

REFERENCES

- Schlumberger HSE Management System
- Driller Drilling Co. HSE or Safety Management System
- Well Control Bridging Document for the project with DRILLER
- Emergency Response Plan for the drilling campaign – Figure 2 of this document
- Schlumberger Environmental Contingency Plan
- Schlumberger Quality Management System
- Job Descriptions for Field Personnel – Appendix C of this document and available from each company
- Operations Emergency Response Plan
- CLIENT Environmental Impact Statement – Available from CLIENT upon request
- Schlumberger Spill Contingency Plan

APPENDIX B-3. SAMPLE HSE PLAN (continued)

EMERGENCY RESPONSE PLAN

CLIENT : CLIENT

JOB NAME: PROJECT

DATE : January, 2015

WELL SITE ADDRESS : ADDRESS | VERSION

DIRECTIONS FROM PROJECT TO WELLSITE	G.P.S. COORDINATES
	Well site COORDINATES
	X° Y' Z"N Latitude
	Q° R' S"W Longitude

DIRECTIONS FROM WELLSITE TO NEAREST MEDICAL FACILITY (Clinic and Hospital)

PROJECT IS A 911 AREA

Company	Contact / Position	Phone 1	Phone 2	EMERGENCY CONTACT
	Project Manager -			YES
	Well Engineering Manager -			YES
	Project Coordinator -			YES
	Well Engineering Manager -			YES
	Geologist -			NO
	President -			NO
	Communications -			NO
	Geologist -			NO
	Wellsite Supervisor -			YES
	Principal Investigator -			YES
				NO
				NO
				NO
				YES
				NO
				NO
				NO
				NO
	FIRE, AMBULANCE, POLICE & HELICOPTER MEDIVAC	911		
	Security -			
	Fire Department -		911	
	Sherriff's Department - County Sheriffs Department		911	

CLOSEST HOSPITAL	PHONE #	LOCATION
Hospital		Address

EMERGENCY EVACUATION PLAN

In the event of any life threatening emergency, an immediate sounding of the "General Alarm" is necessary.
All workers will immediately stop what they are doing and report to a muster station if not rendering first aid.
The Driller, WSS, Paramedic or Tool Pusher will call 911 if needed. ADM Security can also help if they are notified.
If the scene is safe, administer emergency first aid. The AED, Oxygen kit and First aid kit are located in the HSE trailer.
The "All Clear" signal will be given only when safe to do so by the Driller, WSS, Paramedic or Tool Pusher.

SUBMIT NEAR MISSES & HAZARD CARDS!!!

APPENDIX B-3. SAMPLE HSE PLAN (continued)

SAMPLE APPENDIX – INTERFACE MATRIX

Section	Interface Issues to be Addressed	CLIENT	Service Company	DRILLER	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
1	**INTRODUCTION**		X			
	Bridging Document Objectives		X			
	Contractor Qualification and Selection		X			
	Contractor Interfacing					
	Control of Contractor Activities					
	Interface Matrix Issues	X	X	X		
2	**HSE OBJECTIVES**	X	X	X		
3	**MANAGEMENT STRUCTURE, RESPONSIBILITIES AND ACCOUNTABILITIES**					
3.1	HSE Management Organization Chart for Drilling Campaign, HSE Representatives, HSE Committee Structure	X	X	X		
3.2	Roles and Individual Responsibilities and Accountabilities	X	X	X		
3.2.3	Management of Well Control Incidents		X	X		
	Operational Support and Interface Resources		X	X		
	Reward and Recognition Schemes, Incentive Schemes		X	X		
4	**COMMUNICATION**		X			
4.1	Communication of Interface Arrangements	X	X	X		
4.1.1	Routine Communications	X	X			
4.1.2	Feedback Mechanisms, Workforce Involvement		X			
4.1.3	Change Management	X	X			
4.1.4	Emergency Communication	X	X	X		
4.1.5	Communication with Regulatory Bodies					
5	**HAZARD IDENTIFICATION, ANALYSIS AND RISK MANAGEMENT**					
	QRA/HAZOP/HAZID studies if applicable	X	X	X		
	Task/Activity/Specific Risk Assessments:		X	X		
	Identification and Analysis of Hazards, Assessment of Significant Risks, Hazard Controls, Plan and Set Standards for Identified Hazards:		X	X		
	Passenger and Freight Transportation	X				
	Adverse Weather Working Policy	X		X		
	Scaffolding/Access/Working Environment			X		
	Tools and Equipment			X		
	Electrical		X	X		
	Ignition Sources			X		
	Housekeeping		X	X		
	Personal Protective Equipment		X	X		
	Equipment Procurement Standards		?	?		
	Equipment Certification			X		

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Section	Interface Issues to be Addressed	CLIENT	Service Company	DRILLER	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
	Equipment QC System		X	X		
	Manual Handling			X		
	Hazardous Substance/Materials		X	X		
	COSHH/OCNS					
	Dangerous goods Declaration - IATA Regulations	X		X		
	Noise and Vibration			X		
	Thermal Radiation			X		
	Ionizing/Non-Ionizing Radiation		X	X		
	Pressure		X	X		
5.1	Identification and Management of Occupational Health Hazards, Hazard Controls, Plan and Set Standards for Identified Hazards:		X	X		
	Drug and Alcohol Abuse Policy	X	X	X		
	Health and Fitness Screening and Monitoring		X	X		
	Smoking Hygiene and Welfare	X	X	X		
	Medical Treatment			X		
	Display Screen Equipment		X			
	Food Hygiene			X		
	Potable Water, Legionella Sampling	X		X		
5.2	Identification of Environmental Hazards and Waste Management Arrangements, Hazard Controls, Plan and Set Standards for Identified Hazards	X	X	X		
5.3	Identification and Management of Security Hazards, Hazard Controls, Plan and Set Standards for Identified Hazards	X	X	X		
5.4	Additional Policies, Weapons/Firearms, etc.	X	X	X		
5.5	Program for the Identification and Feedback of Unsafe Acts, e.g. "STOP", Observation of Work/Behavior	X	X	X		
5.6	Recovery Measures for Well Control Incident, MEDEVAC, Environmental Incident, etc.	X	X	X		
6	**WORK PROGRAM AND PROCEDURES**					
6.1	Work Program, Work Instructions		X	X		
6.3	Operational Procedures		X	X		
6.4	Permit to Work System, Job Safety Analysis (JSA)		X	X		
	PTW System Formal Training		X	X		
	Job and Task Training		X	X		
6.5	Emergency Response Procedures, Exercises and Drill Schedules		X	X		
7	**PERSONNEL MANAGEMENT, COMPETENCE AND TRAINING**					
7.1	Crewing Levels		X	X		

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Section	Interface Issues to be Addressed	CLIENT	Service Company	DRILLER	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
7.2	Competence, Selection, Training, and Reviews		X	X		
	Well Control Training		X	X		
	Onshore Induction		X	X		
	Hazardous Substances Training		X	X		
	Occupation Health and Hygiene Training		X	X		
	Emergency Response Training		X	X		
	Defensive Driving / Commentary Drives		X			
8	**EQUIPMENT FITNESS FOR PURPOSE**					
8.1	Design and Construction Standards and Certification		X	X		
8.2	Modification Procedures, Engineering Hardware Modifications			X		
	Materials and Spares Procurement			X		
	Preventive Maintenance Procedures			X		
9	**MONITORING, AUDIT AND REVIEW**					
	Active Monitoring of HSE Performance	X	X	X		
	HSE Performance Measures		X	X		
	Structured HSE Monitoring Program (vs HSE Plan)		X	X		
	Worksite/Plant/Equipment Inspections			X		
	General Housekeeping Inspections		X	X		
	Joint Management Visits	X	X	X		
	Quality Improvement Process		X	X		
	Workforce Surveys		X	X		
	HSE Performance Reports (Review of performance against plans)		X	X		
	Involvement of Staff in Performance Monitoring		X	X		
	Structured HSE Audit Program	X	X	X		
	Audits of Third Parties		X			
	HSE Management System Audits		X	X		
	Audits to Check Compliance with Standards	X	X	X		
	Audits to assist the Implementation of HSE Plans	X	X	X		
	Final review of the HSE Management System Interface Arrangements before Start of Operations		X			
	Pre-Execution Audits		X	X		
	Periodic Reviews for HSE Performance Reports, including reviews of Incident Reports and statistics		X	X		
	Joint Audits to Verify Compliance with HSE Management System Interfacing Arrangements	X	X	X		
	Demobilization and Close Out reviews	X	X	X		
	Schedule and Format of Joint Management HSE Performance Reviews		X			

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Section	Interface Issues to be Addressed	CLIENT	Service Company	DRILLER	**Notes on Interface Agreement/Comments/Document Reference** (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
	Joint Management Review of Effectiveness of HSE Management System Interfacing Arrangements	X	X	X		
	Communications/Tracking/Follow-up of Audit and Review Recommendations - Share Learning Lessons from Reviews		X	X		
10	**INCIDENT INVESTIGATION AND REPORTING**					
	Incident Notification (Internally and Externally to Authorities)	X	X	X		
	Incident Investigation, Reporting and Review	X	X	X		
	Communication/Tracking/Follow-Up of Incident Corrective Actions - Shared Learning		X	X		
11	**CONCURRENCE STATEMENT**					
Fig 1.0	Integration of HSE management systems and organizational chart		X	X		
Fig 2.0	Emergency Communication	X	X	X		

APPENDIX B-3. SAMPLE HSE PLAN (continued)

SAMPLE APPENDIX – BRIEFING RECORD

To be completed by the party receiving the briefing.

SECTION No.	SECTION	COMMENTS (See Below)
1.1	Introduction	Yes / No
1.2	HSE Objectives	Yes / No
1.3	Management Structure, Responsibilities and Accountabilities	Yes / No
1.4	Communication	Yes / No
1.5	Hazard Identification, Analysis and Risk Management	Yes / No
1.6	Work Program and Procedures	Yes / No
1.7	Personnel Management, Competence and Training	Yes / No
1.8	Equipment Fitness for Purpose	Yes / No
1.9	Monitoring, Audit and Review	Yes / No
1.10	Incident Investigation and Reporting	Yes / No
1.11	Concurrence Statement	Yes / No
Appendix	Interface Matrix	Yes / No
Appendix	Well Control Bridging document	Yes / No

I have read the detailed arrangements defined in the Interface Document and I understand and accept my accountabilities for the above mentioned Contract/Project.

NAME (please print)	FUNCTION	COMPANY	SIGNATURE	DATE

APPENDIX B-3. SAMPLE HSE PLAN (continued)

SAMPLE APPENDIX – WELL CONTROL BRIDGING DOCUMENT

General API System of units to be used

WELL CONTROL

- All supervisory personnel for the rig contractor (Drillers, Tool Pusher), Service Company Well Engineering Manager and the Service Company WSS will hold a current Well Control certification to Well-cap or IWCF standards
- Well control drills will be held at a minimum of weekly with all crews. DRILLER Drilling Tool Pusher is responsible for carrying out the drills
- BOP´s with a minimum of Annular, pipe rams, and blind rams will be installed below the 20" /13-3/8". They will be tested upon rig up and at no more than 14 day intervals thereafter
- The choke manifold will be installed and tested prior to drilling out the 20"/13-3/8" casing
- Casing pressure tests will be carried out prior to drilling out any string as per the well plans
- Should there be excessive metal shavings, a casing wear log should be run and a repeat of casing pressure test should be carried out.
- Formation integrity test will be carried out immediately after drilling out the shoe of each casing string.
- A minimum of 0.5 ppg Kick tolerance will be maintained at all times while drilling
- Drilling will be suspended after all drilling breaks exceeding 5 feet and investigated
- Flow check shall be done any time an unusual situation occurs
- A minimum of 50 psi overbalance will be maintained during static conditions
- The flow show and PVT will be working at all times when drilling in the 17 1/2" hole section and below.
- An inventory of barite sufficient to raise the MW 1 ppg will be maintained at the well site at all times
  - When drilling below the 20"/13-3/8" shoe, slow pump rates will be carried out at the beginning of each tour and whenever there is a change of MW, BHA
- The well will be shut in using the hard shut in method using the annular preventer
- Responsibilities in the event of a kick
  - The CLIENT WSS will be responsible for preparing the well control plan. The CLIENT WSS will make the plan in conjunction with DRILLER Tool Pusher and Service Company Well Engineering Manager
  - DRILLER Tool Pusher will execute the plan
  - DRILLER has the authority to shut in the well anytime he feels that there is a well kick in progress. The driller will immediately inform the Tool Pusher

DISTRIBUTION: THE FINAL WELL CONTROL BRIDGING DOCUMENT SHALL BE:

- Distributed to key office and well site personnel by the CLIENT, Service Company, Service Company contractors, and DRILLER as appropriate
- Reviewed in detail during the pre-spud meeting

REPORTING AND RESPONSIBILITIES

SERVICE COMPANY CONTRACT WELL SITE SUPERVISOR

Reporting:

- Directly reports to Service Company Project Manager or the Service Company Well Architect on a daily basis
- Accepts advice from CLIENT and DRILLER personnel

Responsibilities:

General:

- The Service Company WSS is responsible for all well site operations and QHSE of all persons at the well site
- The Service Company WSS is the representative of CLIENT and Service Company on the rig. He/she is the local manager of all CLIENT and Service Company assets and personnel on-site
- The Service Company WSS is responsible for planning, co-ordination, supervision, execution, and evaluation of all work performed by DRILLER, Service Company, and other third parties on the rig

APPENDIX B-3. SAMPLE HSE PLAN (continued)

HSE:

- Shows leadership in all HSE matters by actively participating in all safety meetings and actively promotes the use of the “STOP” (or equivalent) program through his participation on a daily basis
- Authority for all HSE related activities for all personnel on well site
- Ensures a permit to work system is in place and working according to Service Company policies and/or those of DRILLER, depending on the higher standard
- Ensures the rig operations are conducted in accordance with CLIENT and Service Company policies and procedures
- Ensures that all personnel follow the HSE policies and procedures of CLIENT, Service Company and DRILLER
- Ensures that all Service Company and Service Company sub-contractor’s personnel have received and are up to date in the relevant HSE training for their position
- Ensures that all Service Company and Service Company sub-contracted personnel attend the relevant safety meetings for their position and furthermore play an active part in these meetings
- Ensures that all accidents and incidents are reported to the project office in City, State in a timely manner (immediately for serious accidents or incidents), next report for minor accidents or incidents
- Leads accident/incident investigation and reporting
- Monitors compliance with applicable rules, regulations and other program constraints
- Ensures that all programs are in compliance with policies and procedures
- Ensures that all personnel attend “STOP” training or equivalent, rig-based, positive reinforcement system and actively participate in the program

Planning and Control:

- Co-ordinates and supervises well site activities with DRILLER, third party contractors to ensure compliance with work program and optimum efficiency in job execution
- Prepares daily the 72-hour forecasts and sends to town each afternoon by 1800 hours
- Prepares equipment checklists for each hole section and sends to town prior to starting each hole section
- Provides feedback to Service Company Well Architect regarding changes to well plan.

Operations:

- Summarizes and researches offset data for well optimization
- Responsible for monitoring well parameters and drilling trends
- Assists in evaluation of potential improvements to well design and execution of operations
- Ensure suitable operational procedures are followed
- Leads recommendations and decisions regarding Stuck Pipe and Fishing Operations
- Final authorization of down hole and equipment installation (Tallies, space-outs, etc.)
- Overall responsibility for quality control of construction of the well
- Responsible for witnessing wire line logging when no CLIENT or Service Company representative is onsite

Emergency Duties:

- Directs well control operations and supervises the application of appropriate well control measures.
- Makes decisions to evacuate the rig
- Focal point for implementation of Emergency Response Procedures

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Management:

- Overall management of well site team
- Onsite management and interpretation of contracts and terms
- Cost control and monitoring for the well site operations
- Responsible for compliance with Environmental Management Plan requirements

Communication:

- Holds daily co-ordination meeting with companies and service contractors
- Prepares daily morning report and cost report, sends reports to town by 07:00 each morning
- Communicates daily with Service Company Project Management, CLIENT Operations Manager, and Service Company Well Architect
- Prepares weekly report and sends to Service Company Project Manager and Well Engineering Manager's offices by 08:00 each Monday morning
- Prepares monthly report and sends to Service Company Project Manager and Well Engineering Manager's offices by 08:00 hrs. on the first of each month or as agreed to by Project Manager/CLIENT and CLIENT

Administration:

- Final authorization of the rig contractors Morning Report (IADC)
- Final responsibility for the daily drilling report
- Approval of job tickets
- Chairs daily meetings with service contractors and ensures that actions are followed up
- Contributes comments for End of Well reports (EOWR)

DRILLER DRILLING TOOL PUSHER

Reporting:

- Reports functionally to the Rig Superintendent
- Reports operationally and with regard to QHSE matters to the Service Company WSS
- Reports contractually to the CLIENT Operations Manager

Responsibilities:

General:

- The Tool Pusher is the representative of DRILLER on the rig and is the local manager of DRILLER´s assets and personnel
- The Tool Pusher manages DRILLER´s interest at the well site in respect to CLIENT, the well program and all personnel on the rig

HSE:

- Shows leadership in all HSE matters by actively participating in all safety meetings and actively promotes the use of the “STOP” or equivalent program thru his participation on a daily basis
- Ensures the rig operations are conducted in accordance with DRILLER´s policies and procedures and the HSE case
- Ensures that all personnel follow the DRILLER´s and CLIENT HSE policies and in particular that DRILLER and all other services´ personnel follow these policies
- Ensures that all DRILLER´s and DRILLER´s subcontracted personnel have received and are up to date in the relevant HSE training for their position
- Participates in accident/incident investigation and reporting
- Co-ordinates the Permit to Work system
- Enforces the use of the “STOP” program covering all operations on site
- Trains crew in emergency response procedures (fires, evacuation, spills, etc.)
- Ensures that all personnel are trained in well control procedures

APPENDIX B-3. SAMPLE HSE PLAN (continued)

Operations:

- Supervises drilling equipment and operation of same
- Supervises the use and operation of the BOP and other associated equipment, and ensures subordinates know, understand and follow the guidelines of applicable well control policies and other general operating policies and procedures
- Supervises and plans DRILLER´s aspects of rig moves

Equipment:

- Directs the application of the DRILLER´s preventive and planned maintenance programs
- Ensures drill string and lifting equipment inspections are performed as per schedule.
- Keeps equipment and systems operational by setting priorities on equipment repairs and ensuring that PMR (or equivalent) system is being followed
- Monitors rig equipment and systems´ usage by ensuring operational parameters and limits are observed
- Ensures diesel tanks are appropriately monitored and if/when needed, advise CLIENT of additional fuel required (CLIENT to furnish the diesel)

Emergency Duties:

- Secures the well in emergency situations and handles primary controls during well control emergency operations
- Makes decisions to evacuate or abandon the rig in conjunction with CLIENT and Service Company
- Directs the crew in other emergencies such as fires, spills etc.

Management:

- Plans work for crews
- Ensures rig personnel are being trained to meet DRILLER, Service Company, and CLIENT training requirements
- Supervises adherence to safety policies and procedures
- Controls the budget and warehouse inventory at the well site
- Safeguard the physical presence of fixed assets and inventories

Administration:

- Maintains appropriate logs and records
- Administers and approves the IADC Drilling Report and assists preparation of the Daily Drilling Report
- Receives visitors and keeps track of personnel onsite

Technical/Diagnostic Skills:

- Researches information on parts, equipment, data and/or operations procedures as required
- Interprets and responds to downhole conditions and provides his particular expertise to the Service Company Contract WSS

APPENDIX B-4. CO_2 QUALITY REPORT

Airborne Labs International, Inc.

22C World's Fair Drive Somerset, NJ 08873 Voice: 732-302-1950 Fax: 732-302-3035
Email: airbornelabs@aol.com Website: www.airbornelabs.com

Carbon Dioxide (CO_2) Analysis
Feed Gas Characterization Program©

Denbury Onshore LLC
2929 Layfair Dr.; Suite 200
Flowood, MS 39232
Phone: 601-503-6823, (Fax: 601-718-6250)
Attn.: Mr. James Cauthen
E-Mail: james.cauthen@denbury.com
Sample ID.: Gaseous CO_2: "Plant Barry Seal # 0201909 + 0201910"
Sample ID.: Received in 2L *True Blue* MLB Polybag 1.2 + MiniCyl 1.0 *No-Haz* Feed Gas Kits

ALI Track No.: 12-0267
Received On: 03/13/12
Report Date: 03/20/12
Payment Mode: PO/CC/Wire

Sample Date: 03/08/12
Process Stage: Feed

Test Description/Units:	Result	MDL	Spec
CO_2 Identification (% v/v by [DT]):	99+	5	report
Comments: All Polybags tested & found to contain 99+% CO_2			
CO_2 Purity (% v/v, [GC]):	99.6+	5	report
Comments: Obtained by NCG + target list impurity subtraction method using Minicyl sample			
Hydrogen (H_2, ppm v/v, [GC]):	trace	50	report
Helium (He, ppm v/v, [GC]):	--*	50	report
Comments: **Not a std feed gas test = special add-on test requiring 2nd minicyl.			
Oxygen + Argon (O_2 + Ar, ppm v/v, [GC]):	880	10	report
Comments: Result represents Total O_2 + Ar ppm v/v.			
Nitrogen (N_2, ppm v/v, [GC]):	2,700	10	report
Carbon Monoxide (CO, ppm v/v, [DT]):	nd	2	report
Ammonia (NH_3, ppm v/v, [DT]):	nd	0.5	report
Oxides of Nitrogen (NO_x, ppm v/v,[DT]):	nd	0.5	report
Comments: *Speciation performed if NO_x is above 2.5 ppm v/v			
Nitric Oxide (NO, ppm v/v, [DT]):	nd	0.5	report
Nitrogen Dioxide (NO_2, ppm v/v, [DT]):	nd	0.5	report
Phosphine (PH_3, ppm v/v, [DT]):	nd	0.25	report
Comments:			
Total Hydrocarbons (THC, ppm v/v as CH_4, [THA]):	12	0.1	report
Comments:			
Total Non-Methane Hydrocarbons (TNMHC, ppm v/v as CH_4, [GC]):	12	0.1	report
Methane (CH_4, ppm v/v, [GC]):	trace	0.1	report
Acetaldehyde (AA, ppm v/v, [GC]):	12	0.05	report
Aromatic Hydrocarbon Content (ppb v/v as Benzene, [GC/MS]):	nd	2	report
Benzene (ppb v/v [GC/MS]):	nd	2	report
Toluene (ppb v/v, [GC/MS]):	nd	2	report
Ethyl Benzene (ppb v/v, [GC/MS]):	nd	2	report
m,p Xylenes (ppb v/v [GC/MS]):	nd	2	report
o Xylene (ppb v/v [GC/MS]):	nd	2	report
Comments:			
Total Sulfur Content* (TSC* ppm v/v as S, [GC]):	nd	0.01	report
Comments: Obtained by summation of all speciated VSC target impurities <u>less</u> SO_2			
Sulfur Dioxide (SO_2, ppm v/v, [GC]):	nd	0.05	report
Hydrogen Cyanide (HCN, ppm v/v, [GC]):	nd	0.2	report
Vinyl Chloride (VCl, ppm v/v, [GC]):	nd	0.1	report
Radon (Rn^{222}, pCi/L, [Lucas Cell]):	--*	0.1	report
Comments: *Not a std feed gas pgm test = specialized add-on test requiring an Rn222 sampling kit.			
Ethylene Glycol (ppm v/v, [GC]):	--*	2	report
Comments: *Not a std feed gas pgm test = specialized add-on test requiring a Sorbent tube sampling kit.			

Figure B.1 Initial CO_2 characterization report required for ADEM

Sample ID: Denbury Onshore LLC **ALI Track No.:** 12-0267

Speciated Volatile Hydrocarbons (VHC, ppm v/v)	Result	MDL	Spec.
Ethane:	0.1	0.1	report
Ethylene:	nd	0.1	report
Propane:	nd	0.1	report
Propylene:	nd	0.1	report
Isobutane:	nd	0.1	report
n-Butane:	nd	0.1	report
Butene:	nd	0.1	report
Isopentane:	nd	0.1	report
n-Pentane:	nd	0.1	report
Hexanes+:	1.1	0.1	report

Comments: Pk ID based upon tr match against target analyte std. CH_4 result on pg 1.

Speciated Volatile Sulfur Compounds (VSC, ppm v/v)			
Hydrogen Sulfide (H_2S):	nd	0.01	report
Carbonyl Sulfide (COS):	nd	0.01	report
Methyl Mercaptan:	nd	0.01	report
Ethyl Mercaptan:	nd	0.01	report
Dimethyl Sulfide:	nd	0.01	report
Carbon Disulfide:	nd	0.01	report
t-Butyl Mercaptan:	nd	0.01	report
Isopropyl Mercaptan:	nd	0.01	report
n-Propyl Mercaptan:	nd	0.01	report
Methyl Ethyl Sulfide:	nd	0.01	report
2-Butyl Mercaptan:	nd	0.01	report
i-Butyl Mercaptan:	nd	0.01	report
Diethyl Sulfide:	nd	0.01	report
n-Butyl Mercaptan:	nd	0.01	report
Dimethyl Disulfide:	nd	0.01	report
Unknown VSC:	nd	0.01	report

Comments: Peak ID based upon t_r match against target analyte standards. Note: SO_2 + TSC* results reported on pg. 1.

Speciated Volatile Oxygenates (VOX, ppm v/v)			
Dimethyl Ether:	nd	0.1	report
Ethylene Oxide:	nd	0.1	report
Diethyl Ether:	trace	0.1	report
Propionaldehyde:	nd	0.1	report
Acetone:	0.2	0.1	report
Methanol:	nd	0.1	report
t-Butanol:	nd	0.1	report
Ethanol:	nd	0.1	report
Isopropanol:	nd	0.1	report
Ethyl Acetate:	nd	0.1	report
Methyl Ethyl Ketone:	nd	0.1	report
2-Butanol:	nd	0.1	report
n-Propanol:	nd	0.1	report
Isobutanol:	nd	0.1	report
n-Butanol:	nd	0.1	report
Isoamyl Alcohol:	nd	0.1	report
Isoamyl Acetate:	nd	0.1	report
Unknown VOX:	0.1	0.1	report

Comments: Peak ID based upon t_r match against target analyte standards. AA & Ethylene Glycol results reported on pg. 1.

MDL = method detection limit (for quantitation). **tr** = Trace amount less than the MDL was observed. **nd** = indicates the impurity was not detected (below the report detection limit). -- = test not performed. **na** = not available. **LT** = less than the amount specified. **GT** = greater than the amount specified. **%** = percent. **ppm** = parts per million **ppb** = parts per billion. **v/v** = volume analyte/volume sample. **w/w** = weight analyte/weight sample. **(result)** indicates the result was obtained by the method listed within brackets. **TSC*** = ISBT Total Sulfur Content exluding SO_2. **Unit Conversions**: 1ppm v/v = 1µL/L = 1000 ppb = 0.0001% v/v. Date format MM/DD/YY.

Report Summary:

Customer request for a std CO_2 feed gas test pgm.

Reviewed by / Date:

Nicole James 03/20/12

Nicole James - CO_2 Laboratory Manager

Attachments: none

Addendum: Signatures, Instrument & Notebook data on-file

F-21.3v1 (3/12)

PJLA Testing

Accreditation # 68099

Figure B.1 Initial CO_2 characterization report required for ADEM (continued)

Emissions Summary

Test Performed For: **Southern Company - Plant Barry**
Bucks, Alabama

Testing Performed By:
Birmingham Division

Source(s) Tested: **CO2 Metering Station Line**
Test Condition: **Particulate and Metals Testing**
Test(s) Performed: **Methods 4, 5 and 29**

Project Manager:
Mr. Lynn Beane

Run Number		Run 2	Run 3	Run 4	Average
Date of Run		3/8/12	3/8/12	3/8/12	***3 Runs***
Times, Pollutant Runs (Began - Ended)		1734-1834	1901-2001	2046-2153	-
Molecular Weight Of Stack Gas	% (dry basis)	44.00	44.00	44.00	44.00
Molecular Weight Of Stack Gas	% (wet basis)	43.32	43.72	43.49	43.51
Moisture Content	%, v / v	2.60	1.07	1.98	1.88
Particulate Concentrations @ STP	gr / dscf	**0.00282**	**0.00454**	**0.00141**	**0.00293**
Antimony Concentrations @ STP	gr / dscf	**3.30E-04**	**1.03E-03**	**4.11E-05**	**4.67E-04**
Arsenic Concentrations @ STP	gr / dscf	**7.83E-08**	**7.70E-08**	**7.64E-08**	**7.72E-08**
Beryllium Concentrations @ STP	gr / dscf	**4.48E-05**	**4.40E-05**	**4.37E-05**	**4.42E-05**
Cadmium Concentrations @ STP	gr / dscf	**1.21E-07**	**8.37E-08**	**7.64E-08**	**9.37E-08**
Chromium Concentrations @ STP	gr / dscf	**2.33E-06**	**1.40E-06**	**3.12E-06**	**2.28E-06**
Lead Concentrations @ STP	gr / dscf	**5.19E-07**	**2.16E-07**	**2.17E-07**	**3.17E-07**
Mercury Concentrations @ STP	gr / dscf	**1.96E-07**	**1.92E-07**	**1.91E-07**	**1.93E-07**
Nickel Concentrations @ STP	gr / dscf	**3.26E-03**	**2.85E-03**	**2.33E-03**	**2.81E-03**
Total Metals Concentrations @ STP	gr / dscf	**5.56E-06**	**5.58E-06**	**5.11E-06**	**5.42E-06**
Antimony Concentrations	ppm	**6.52E-05**	**2.03E-04**	**8.12E-06**	**9.23E-05**
Arsenic Concentrations	ppm	**5.76E-05**	**5.66E-05**	**5.61E-05**	**5.68E-05**
Beryllium Concentrations	ppm	**1.20E-04**	**1.18E-04**	**1.17E-04**	**1.18E-04**
Cadmium Concentrations	ppm	**5.93E-05**	**4.10E-05**	**3.74E-05**	**4.59E-05**
Chromium Concentrations	ppm	**2.47E-03**	**1.48E-03**	**3.30E-03**	**2.42E-03**
Lead Concentrations	ppm	**1.38E-04**	**5.74E-05**	**5.78E-05**	**8.43E-05**
Mercury Concentrations	ppm	**5.38E-05**	**5.28E-05**	**5.24E-05**	**5.30E-05**
Nickel Concentrations	ppm	**1.34E-03**	**1.17E-03**	**9.53E-04**	**1.15E-03**
Selenium Concentrations	ppm	**4.29E-04**	**1.66E-04**	**2.14E-04**	**2.70E-04**

Figure B.1 Initial CO_2 characterization report required for ADEM (continued)

APPENDIX C. PERMITTING

APPENDIX C-1. UIC PROGRAM AND WELL CLASSES

In the U.S., underground injection wells are regulated under the Safe Drinking Water Act (SDWA) through the Underground Injection Control (UIC) Program administered by the U.S. EPA. The UIC regulations are designed to protect Underground Sources of Drinking Water (USDWs)—in the case of CO_2 geologic storage—from plume infiltration into the USDWs, from brine intrusion caused by the increased pressures from the CO_2 injection, and from mobilization of any potential subsurface contaminants (i.e. trace metals and organics). The UIC Program is responsible for regulating the permitting, siting, construction, monitoring and testing, closure, and post-closure care of injection wells that place fluids (liquids, gases, semi-solids, or slurries) underground for storage or disposal (U.S. EPA, 2015d)

The program recognizes six classes of wells. Each injection well class is subject to siting, construction, operating, monitoring, and closure requirements that address the types of fluids injected and the use of the wells. For example, injection wells must be sited in geologically suitable areas, and a study must be conducted to determine whether any conduits (e.g., abandoned wells) for fluid movement into USDWs exist. Injection wells are constructed of materials that can withstand exposure to injected fluids; following operating requirements and testing throughout injection helps ensure that the well remains in proper working order and that no unintended movement of injected fluids occurs. Finally, injection wells must be closed in a manner that prevents the well from inadvertently serving as a conduit for fluid migration.

In December 2010, US EPA promulgated final regulations for Class VI wells for States and at the Federal level. The rules ensure that proper criteria and standards will be applied through the permit, construction, operating, recordkeeping, and closeout of commercial-scale geologic storage projects.

The UIC Program provides standards, technical assistance, and grants to State governments for regulating injection wells and protecting drinking water resources. At present, EPA defines six classes of wells (Class I to Class VI) according to the type of fluid they inject and where the fluid is injected. EPA's most recent change to the rules created Class VI wells, a new category of injection wells under its existing UIC Program with new Federal requirements to allow for permitting of the injection of CO_2 for the purpose of geologic storage. The program builds on existing UIC regulatory components for key areas for injection wells, including siting, construction, operation, monitoring and testing, and closure that address the pathways through which USDWs may be endangered. The new well class also recognizes the large fluid volumes involved, relative to other well classes, and the potential formation pressure stresses that would occur (say in comparison to Class II CO_2 injection wells where formation pressures are managed through injection and production). In addition to protecting USDWs, the proposed rule provides a regulatory framework to promote consistent approaches to permitting geologic storage projects across the United States.

As of 2015, EPA has primary enforcement responsibility (primacy) for Class VI wells; only one state has a pending application for Class VI primacy. US EPA has primacy for all other well classes in 33 states, shares primacy for some well classes in another 7 states and 2 Tribes, and directly implements a federal UIC Program in 10 states and all other Tribes.

A detailed discussion of the six existing UIC well classes is available on EPA's UIC website: https://www.epa.gov/uic. The following are existing well classes under the UIC Program:

- **Class I**—Wells injecting hazardous and/or non-hazardous industrial and municipal wastes below USDWs
- **Class II—**Wells related to oil and gas production, mainly injecting brine and other fluids (including CO_2 for EOR operations)
- **Class III**—Wells injecting fluids associated with solution mining of minerals, such as salt (sodium chloride [NaCl]) and sulfur (S)
- **Class IV—**Wells injecting hazardous or radioactive wastes into or above USDWs; generally only used for groundwater remediation
- **Class V—**Injection wells not included in Class I through Class IV that are typically used as experimental technology wells. These wells are typically permitted with Class I requirements
- **Class VI**—New class of injection wells specific for CO_2 geologic storage

Previously, wells for CO_2 geologic storage were permitted as Class I non-hazardous, Class II, and Class V.

The construction, permitting, operating, and monitoring requirements are more stringent for Class I hazardous wells than for the other types of injection wells, including Class I non-hazardous. Class II wells inject fluids associated with oil and natural gas production. Most of the injected fluid is salt water (brine), which is brought to the surface in the process of producing (extracting) oil and gas. However, many Class II wells are installed specifically for CO_2 injection for EOR or enhanced gas recovery (EGR).

Class V wells, which encompass a variety of uses and injected fluids, have been used for early test wells. Class V wells are, at a minimum, subject to the non-endangerment standard, which states that operators may not site, construct, operate, or maintain any injection activity that endangers USDWs. However, permitting authorities may, at their discretion, require operators of Class V wells to meet specific standards to assure protection of USDWs and human health. This classification may be desirable because of the flexibility it would offer. One subclass of Class V wells is the experimental technology well; this subclass is designated for injection wells used to test new or unproven technologies.

With the promulgation of the Class VI well category and rules, CO_2 injection wells are likely to be permitted only as Class II or Class VI. To date, five projects have applied for Class VI permits to US EPA Region V. At the time of this publication, the Taylorville Energy Center applications (two injection wells) have been withdrawn prior to issuing the permit. The FutureGen 2.0 project permits to drill four injection wells were issued. However, the project has been suspended by the owner. Two other permits have been issued and are active including the Illinois Basin—Decatur Project (conversion from Class I Non-hazardous) and the Illinois Industrial Carbon Capture and Storage Project at Archer Daniels Midland (both in Decatur, Illinois). The Illinois Basin—Decatur Project injection phase was completed under an Illinois EPA Class I permit. Post-injection site care is being completed under the US EPA Class VI permit. The Industrial Carbon Capture project injection well has been drilled. However, under the staged Class VI permitting program, the permit to inject is pending. The draft permit for the Kansas geologic storage project is pending with US EPA Region 7.

CLASS II WELLS – INJECTION OF PRODUCED WATER AND OTHER WASTE STREAMS

As discussed above, the SDWA of 1974 (Part C, Sections 1421-1426) gives EPA the authority for UIC regulation. Of the six UIC well classes, Class II is, by far, the most heavily used. The class is exclusively for the injection of brines and other fluids associated with oil and gas production (produced water) and for injection related to hydrocarbon storage. A recent count by the EPA listed approximately 185,000 Class II wells in the United States (http://www.epa.gov/uic/underground-injection-well-inventory).

Class II includes two subdivisions: Class II R for enhanced recovery wells and Class II D for water disposal wells. Enhanced recovery wells recycle produced water or inject CO_2, from natural and/or anthropogenic sources. The fluid is pumped into the producing formation where it displaces or mobilizes hydrocarbons to producing wells.

In water flooding, this use of produced water has increased production significantly from pressure-depleted fields. When water cannot be recycled in a water flood, it is stored in an underground formation other than the formation from which it was produced. Generally, oil and gas producers are prohibited from onshore surface discharge of produced waters without treatment.

In CO_2 floods, depending on formation pressures and conditions, the flood may be either miscible or immiscible. In either case, the CO_2 serves to mobilize the hydrocarbons where they can be extracted via a production well. The CO_2 is then stripped from the produced hydrocarbons and reused in the operation. The primary purpose of the activity is to produce hydrocarbons. However, some of the CO_2 becomes trapped (stored) in the formation. If an operator were to shift the primary purpose of the operation from hydrocarbon production to CO_2 storage, the injection wells would need to be transitioned to Class VI permits and the storage operations, monitoring, and closure of the site would be regulated through the Class VI rules (including post-injection site care).

Class II CO_2 and produced water injection wells share many site selection criteria with Class VI CO_2 injection site criteria. Among them are requirements for providing to regulators specific information including:

- Injection volume and rate
- Geology
- Hydrology
- Geochemistry of injected fluid and its compatibility with reservoir fluids
- Injection and confinement zone geo/hydrological properties
- Injection and confinement zone geomechanical properties
- In situ stress profile in the various layers
- Location, age, depth, and condition of nearby wells
- Location, orientation, and properties of nearby faults or fractures
- Rigid well construction requirements

From US EPA https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2:

> "The Class VI Rule describes the requirements for owners or operators seeking to re-permit existing Class II wells to Class VI wells for the purpose of geologic storage at 40 CFR 146.81(c). Owners or operators planning to convert existing Class II wells to Class VI wells must, per 40 CFR 146.81(c), demonstrate to the Class VI UIC Program Director that the wells were engineered and constructed to meet the requirements at 40 CFR 146.86(a). The owner or operator must also demonstrate that the wells will ensure protection of USDWs in lieu of the requirements for casing and cementing of Class VI wells at 40 CFR 146.86(b) and the requirements for logging, sampling and testing prior to injection well operation at 40 CFR 146.87(a). For further information on well construction to meet these Class VI requirements, see the UIC Program Class VI Well Construction Guidance. If an owner or operator seeking to grandfather an existing Class II well to a Class VI well cannot make this demonstration, then re-permitting of the constructed well will not likely be allowed. The owner or operator may discuss with the Class VI UIC Program Director whether remedial activities will enable the well to meet Class VI requirements or if construction of a new Class VI well or selection of an alternative well for conversion is needed."

The EPA has determined that the source of the CO_2 is not a determining factor in whether the well must be permitted as Class II or Class VI. That is, an operator may use CO_2 from natural or anthropogenic sources (or may alternate between the supplies) for EOR without triggering Class VI regulations.

CLASS VI WELLS – GEOLOGIC STORAGE OF CO_2

In December 2010, U.S EPA published the final rules for Class VI wells (Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration Wells Final Rule (Class VI Rule). The regulations are designed to protect USDWs and address siting, construction, operation, testing, monitoring, and closure of geologic storage sites. The regulations recognize that CO_2 has some unique issues in regards to its relative buoyancy, mobility, corrosively (in the presence of water) and the anticipated large injection volumes of a commercial project.

EPA developed specific criteria for Class VI wells (EPA, 2012):

- Extensive site characterization requirements
- Injection well construction requirements for materials that are compatible with and can withstand contact with CO_2 over the life of a project
- Injection well operation requirements
- Comprehensive monitoring requirements that address all aspects of well integrity, CO_2 injection and storage, and ground water quality during the injection operation and the post-injection site care period
- Financial responsibility requirements assuring the availability of funds for the life of a geologic storage project (including post-injection site care and emergency response)
- Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection

The rule includes provisions for:

- Permitting
  - Geologic site characterization
  - Area of review (AoR) and corrective action
  - Financial responsibility
- Well construction
- Operation
  - Mechanical integrity testing (MIT)
  - Monitoring
- Well plugging
- Post-injection site care (PISC)
- Site closure

More specifically, injection for geologic storage requires geologic site characterization to ensure that wells are appropriately sited. Requirements for the construction and operation of the wells includes construction with injectate compatible materials and automatic shutoff systems to prevent fluid movement into unintended zones. The rules require the development, implementation, and periodic update of a series of project-specific plans to guide the management of storage projects:

- The owner/operator must periodically re-evaluate of the area of review around the injection well to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface. This also means that the project plans must be updated as data are gathered and variances from predicted conditions are observed.
- The MVA program requires rigorous testing and monitoring of each project that includes testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 using direct and indirect methods. Baseline and periodic measurements are required.
- Extended post-injection monitoring and site care is required to track the location of the injected CO_2 and monitor subsurface pressures until it can be demonstrated that USDWs are no longer endangered. The rules also clarified and expanded financial responsibility requirements to ensure that funds will be available for corrective action, well plugging, post-injection site care, closure, and emergency and remedial response.
- The rules and (draft) guidance) also consider permitting wells that are transitioning from Class II enhanced recovery (ER) to Class VI. The guidance helps to clarify the point at which the primary purpose of CO_2 injection transitions from ER (i.e., a Class II well) to long-term storage (i.e., Class VI).

APPENDIX C-2. US EPA GUIDANCE DOCUMENTS

(http://epa.gov/uic/class-vi-guidance-documents):

- Geologic Sequestration of Carbon Dioxide - Underground Injection Control (UIC) Program Class VI Primacy Manual for State Directors (US EPA 2014)—This manual is intended to provide procedural support to UIC Program Directors preparing the required UIC primacy application materials to submit to EPA for approval.
- Geologic Sequestration of Carbon Dioxide - Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance (US EPA 2013a)—This document is part of a series of technical guidance documents designed to support owners or operators of Class VI wells and the UIC Program permitting authorities.
- Geologic Sequestration of Carbon Dioxide - Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance (US EPA 2013b)—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.
- Geologic Sequestration of Carbon Dioxide - Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance (US EPA 2013c)—The purpose of this guidance document is to describe the technologies, tools, and methods available to owners or operators of Class VI wells to fulfill the Class VI Rule requirements related to developing and implementing site- and project-specific strategies for testing and monitoring. The intended primary audiences of this guidance document are Class VI injection well owners or operators, contractors performing testing and monitoring activities, and UIC Program Directors.

- Geologic Sequestration of Carbon Dioxide - Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance (EPA, 2012a)—This guidance describes, for Class VI injection well owners or operators, the required elements of each plan and the site-specific elements of each geologic storage project that may be considered when developing the plans. This document also describes the process by which the UIC Program Director will evaluate and approve each plan and how EPA recommends that the plans be reviewed and amended, if necessary, throughout the lifecycle of the project.

- Geologic Sequestration of Carbon Dioxide - Underground Injection Control (UIC) Program Class VI Well Construction Guidance (US EPA 2012b)—This guidance describes, for Class VI injection well owners or operators, the construction, testing, and operating requirements for an approved Class VI injection well. It includes guidance and recommendations on how to meet these requirements. This document also describes the information that the UIC Program Director will evaluate when reviewing a permit application for a Class VI injection well.

- Research and Analysis in Support of UIC Class VI Program Financial Responsibility Requirements and Guidance (US EPA 2010)—This document provides some of the supporting research and analysis for the financial responsibility requirements (40 CFR 146.85) and guidance (EPA 816-D-10-010) for the UIC Class VI Program.

- Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects (US EPA 2007)—this guidance provides information for states and EPA regions to consider when permitting pilot projects designed to evaluate the technical issues associated with carbon dioxide injection as Class V experimental technology wells. Please note that EPA in some instances has required Class VI permitting for geologic storage pilot testing.

- DRAFT Geologic Sequestration of Carbon Dioxide Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells (US EPA 2013d)—This guidance also provides information regarding Class VI regulations that may be of interest to owners or operators of Class II wells and Class II UIC Program Directors.

- DRAFT Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI (US EPA 2015b)—This Memorandum from the Director of the Office of Ground Water and Drinking Water to the EPA Regional Water Division Directors identifies key principles related to the transition of ER wells that store CO_2 from Class II operations to the Class VI program.

- DRAFT Geologic Sequestration of Carbon Dioxide Draft Underground Injection Control (UIC) Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure (US EPA 2013e)—This guidance document includes considerations and recommendations to help owners or operators petition for an alternate PISC timeframe (i.e., other than the 50-year default) during permitting; revise the PISC timeframe during the injection operation; and make a non-endangerment demonstration for revision to the PISC and Site Closure Plan.

- Geologic Sequestration of Carbon Dioxide Draft Underground Injection Control (UIC) Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Permitting Authorities (US EPA 2013f)—Information on how the reporting, recordkeeping, and data management activities will ensure USDW protection; and a description of EPA's central data system used for the purpose of reporting, recordkeeping, and data management by permitting authorities.

APPENDIX C-3. REGULATORY SUMMARY

SITE CHARACTERIZATION GUIDANCE DOCUMENT (US EPA 2013A):

The Class VI Rule, at 40 CFR 146.83, establishes minimum criteria for the siting of Class VI wells. Specifically, Class VI wells must be located in areas with a suitable geologic system, including:

- The presence of an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream

- The presence of confining zones that are free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the carbon dioxide stream and displaced formation fluids and allow injection without initiating or propagating fractures [40 CFR 146.83(a)]

Additionally, at the UIC Program Director's discretion, owners or operators may be required to identify and characterize additional confining zones to ensure USDW protection, impede vertical fluid movement, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation [40 CFR 146.83(b)].

Owners or operators must demonstrate that a proposed site is suitable for geologic storage by performing detailed site characterization and submitting extensive geologic data to the UIC Program Director. These data, described at 40 CFR 146.82(a), are necessary to demonstrate that the well will be sited in an area with a suitable geologic system that will ensure USDW protection and meet the requirements of 40 CFR 146.83. The Class VI Rule specifies distinct requirements for information to be submitted with the permit application and before well construction is approved at 40 CFR 146.82(a), and information to be submitted before operation of the well is authorized at 40 CFR 146.82(c).

Site characterization is an iterative process. Site characterization data are submitted to the UIC Program Director to fulfill the requirements for a Class VI permit application [40 CFR 146.82(a)] before well construction is approved. Pursuant to the requirements at 40 CFR 146.82(c), the data must be updated and refined before operation of the well is authorized based on the results of the formation testing program required at 40 CFR 146.82(a)(8) and 146.87 that is executed during injection well drilling and completion.

The types of site characterization information specified by the Class VI Rule that must be provided with a Class VI well permit application include:

- Maps and cross sections of the area of review (AoR) [40 CFR 146.82(a)(3)(i) and 146.82(a)(2)]
- The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR, along with a determination that they will not interfere with containment [40 CFR 146.82(a)(3)(ii)]
- Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes [40 CFR 146.82(a)(3)(iii)]
- Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)]
- Information on the seismic history of the area, including the presence and depths of seismic sources, and a determination that the seismicity will not interfere with containment [40 CFR 146.82(a)(3)(v)]
- Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)]
- Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s), and the direction of water movement (where known) [40 CFR 146.82(a)(5)]
- Baseline geochemical data on subsurface formations, including all USDWs in the AoR [40 CFR 146.82(a)(6)]

The types of site characterization information specified by the Class VI Rule for the operation of a Class VI well that must be provided for the UIC Program Director to review and approve include:

- Any relevant updates to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, based on data obtained during logging and testing of the well [40 CFR 146.82(c)(2)]
- Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) [40 CFR 146.82(c)(3)]
- The results of formation testing [40 CFR 146.82(c)(4)]
- All available logging and testing program data on the well required by 40 CFR 146.87 [40 CFR 146.82(c)(7)]

Owners or operators are expected to take full advantage of existing site characterization data to fulfill the requirements at 40 CFR 146.82. However, a stratigraphic well may need to be drilled in some cases (e.g., if adequate data are not already available). If owners or operators need to drill a stratigraphic well, they may consider ultimately using it for injection or monitoring.

Owners or operators should keep in mind that if the AoR delineation or any of the project plans require significant changes based on the final site characterization data, the Class VI permit would have to be modified to incorporate these changes before injection can be authorized [40 CFR 144.39]. Depending on the extent of the modifications, the UIC Program Director may need to re-initiate the public notice process. To avoid any potential delays associated with the permit modification process, EPA encourages owners or operators to collect as much site-specific data as possible before submitting the initial Class VI permit application. Additional information on the Class VI permitting process and how UIC Program Directors may evaluate the site characterization submittals is presented in the UIC Program Class VI Implementation Manual for State Directors.

PROJECT PLAN DEVELOPMENT GUIDANCE (US EPA 2012A):

Owners or operators of Class VI wells must prepare project plans and submit them to the UIC Program Director for approval with their Class VI permit application. When the plans are approved, they become an enforceable part of the Class VI permit. The required project plans, which must be based on site-specific information, include the following:

- Area of Review (AoR) and Corrective Action Plan—Describes how an owner or operator intends to delineate the AoR for the Class VI injection well and ensure that all identified deficient artificial penetrations (i.e., wells that are improperly plugged or completed) will be addressed by corrective action techniques so that they will not become conduits for fluid movement into underground sources of drinking water (USDWs)
- Testing and Monitoring Plan—describes how the owner or operator intends to perform all necessary testing and monitoring associated with a project, including injectate monitoring, performing mechanical integrity tests (MITs), corrosion monitoring, tracking the carbon dioxide plume and area of elevated pressure, monitoring geochemical changes above the confining zone, and, at the discretion of the UIC Program Director, surface air and/or soil gas monitoring for carbon dioxide fluctuations and any additional tests necessary to ensure USDW protection from endangerment
- Injection Well Plugging Plan—describes how, following the cessation of injection, the owner or operator intends to plug the Class VI injection well using the appropriate materials and methods to ensure that the well will not become a conduit for fluid movement into USDWs in the future
- Post-Injection Site Care (PISC) and Site Closure Plan—describes how the owner or operator intends to monitor the site after injection has ceased, in order to ensure that the carbon dioxide plume and pressure front are moving as predicted and USDWs are not endangered. PISC monitoring must continue until it can be demonstrated that the site poses no further endangerment to USDWs
- Emergency and Remedial Response Plan—describes the actions that the owner or operator intends to take in the event of movement of the injectate or formation fluids in a manner that may cause an endangerment to a USDW, including the appropriate people to contact.

These detailed, site-specific project plans are necessary to ensure that management of the project is based on the most up-to-date site characterization, modeling, operational, and monitoring data to protect USDWs from endangerment. The plans also afford the flexibility needed to address the variety of types of geologic formations in which geologic storage will occur, while also facilitating dialogue between the Class VI injection well owner or operator and the UIC Program Director.

Class VI well permits are issued for the operating life of the project (i.e., from authorization of injection through site closure, which may occur many decades later). Thus, unlike some other injection well classes regulated under the UIC Program, there is no periodic reapplication for, or reissuance of, a Class VI permit. Instead, these five project plans, which are reviewed as part of the Class VI permit application review and approval process and incorporated into the Class VI permit, must be amended periodically, as specified in the Class VI Rule. The iterative process of developing and executing the project plans described in this guidance is tailored to the unique aspects of geologic storage and is intended to ensure that time and resources are committed to the most critical aspects of managing Class VI injection well operations.

The project plans must be submitted with the permit application for each Class VI well. While area permits are not an option for permitting of Class VI wells per 40 CFR 144.33(a)(5), owners or operators can realize some efficiencies in developing and implementing project plans where certain aspects of multiple wells in an area are common. For example, owners or operators may develop Testing and Monitoring Plans or PISC and Site Closure Plans that include ground water monitoring or carbon dioxide plume and pressure front tracking over an area that would satisfy the requirements for several permits simultaneously. Additionally, if several wells in a field have similar construction, owners or operators may plan to plug each well in a similar manner; however, a separate Injection Well Plugging Plan is required for each well (i.e., tailored to its depth and any other unique characteristics of the well).

In addition to providing permitting efficiency, collectively considering all wells in a field will ensure that the site is evaluated and operated in a holistic manner and that all aspects of the project that may impact USDWs have been evaluated and addressed. The owner or operator should discuss the implications of combining common elements and activities associated with multiple wells/permits with the UIC Program Director to ensure that every well is constructed, operated, monitored, plugged, and closed in a manner that is protective of USDWs.

APPENDIX C-4. UIC PERMIT CONTACT INFORMATION BY STATE (NOV. 2011)

Organization	UIC Well Class Primacy	Website	Phone Number
Alabama			
AL Oil and Gas Board	Class II	http://www.ogb.state.al.us/ogb/gw_prot.html	205-247-3575
AL Department of Environmental Management	Class V	http://www.adem.state.al.us/default.cnt	334-270-5655
EPA Region 4		http://www.epa.gov/aboutepa/region4.html	404-562-9345
Alaska			
EPA Region 10	Classes I and V	http://www.epa.gov/aboutepa/region10.html	206-553-1200
AK Oil and Gas Conservation Commission	Class II	http://doa.alaska.gov/ogc/	907-279-1433
Arizona			
EPA Region 9	Classes I, II, and V	http://www.epa.gov/aboutepa/region9.html	415-947-8000
Arkansas			
AR Oil and Gas Commission	Class II and V (bromine related)	http://www.aogc.state.ar.us/	501-683-5814
AR Department of Environmental Quality	Class I and V	http://www.adeq.state.ar.us/	501-682-0629
EPA Region 6	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region6.html	800-887-6063
California			
EPA Region 9	Classes I and V	http://www.epa.gov/aboutepa/region9.html	415-947-8000
CA Department of Conservation	Class II	http://www.conservation.ca.gov/Index/	
Pages/Index.aspx	916-323-1777		
Colorado			
EPA Region 8	Classes I and V (incl.		
Class II in Tribal Lands)	http://www.epa.gov/aboutepa/region8.html	303-312-6312	
CO Oil and Gas Conservation Commission	Class II	http://cogcc.state.co.us	303-894-2100
Connecticut			
CT Department of Environmental Protection	Classes I, II, and V except when in Tribal Lands	http://www.ct.gov/dep/site/default.asp	860-424-3018
EPA Region 1	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region1.html	617-918-1111
Delaware			
DE Department of Natural Resources and Env. Control	Classes I, II, and V	http://www.dnrec.delaware.gov/Pages/Portal.aspx	302-739-9948
EPA Region 3		http://www.epa.gov/aboutepa/region3.html	215-814-5000

Organization	UIC Well Class Primacy	Website	Phone Number
District of Columbia			
EPA Region 3	Classes I, II, and V	http://www.epa.gov/aboutepa/region3.html	215-814-5000
Florida			
EPA Region 4	Class II	http://www.epa.gov/aboutepa/region4.html	404-562-9345
FL Department of Environmental Protection	Classes I and V	http://www.dep.state.fl.us/	850-245-8336
Georgia			
GA Department of Natural Resources	Classes I, II, and V	http://www.gadnr.org/	404-675-6232
EPA Region 4		http://www.epa.gov/aboutepa/region4.html	404-562-9345
Hawaii			
EPA Region 9	Classes I, II, and V	http://www.epa.gov/aboutepa/region9.html	415-947-8000
Idaho			
MO Department of Natural Resources	Classes I, II, and V	http://dnr.mo.gov/env/wpp/index.html	573-751-1300
Montana			
EPA Region 8	Classes I and V (incl. Class II in most Tribal Lands)	http://www.epa.gov/aboutepa/region8.html	303-312-6312
MO Board of Oil and Gas Conservation	Class II	http://bogc.dnrc.state.mt.us	406-656-0040
MO Fort Peck Office of Environmental Protection	Class II Wells within Fort Peck Tribal Contract Area	http://www.fortpeckoep.org/	406-768-5155
Nebraska			
EPA Region 7	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region7.html	913-551-7003
NE Oil and Gas Conservation Commission	Class II	http://www.nogcc.ne.gov/	308-254-6919
NE Department of Environmental Quality	Classes I and V wells	http://www.deq.state.ne.us/	402-471-2186
Nevada			
EPA Region 9	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region9.html	415-947-8000
NV Division of Environmental Protection	Classes I, II, and V	http://ndep.nv.gov/	775-687–4670
New Hampshire			
NH Department of Environmental Services	Classes I, II, and V	http://des.nh.gov/	603-271-3503
EPA Region 1		http://www.epa.gov/aboutepa/region1.html	617-918-1111

Organization	UIC Well Class Primacy	Website	Phone Number
New Jersey			
EPA Region 2	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region2.html	877-251-4575
NJ Department of Environmental Protection	Classes I, II, and V	http://www.state.nj.us/dep/	609-633-7021
New Mexico			
NM Oil Conservation Division	Oil and Gas Related Injection Wells	http://www.emnrd.state.nm.us/ocd/	505-476-3460
NM Environment Department	All Other Injection Wells	http://www.nmenv.state.nm.us/	505-827-2855
EPA Region 6	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region6.html	800-887-6063
New York			
EPA Region 2	Classes I, II, and V	http://www.epa.gov/aboutepa/region2.html	877-251-4575
North Carolina			
NC Department of Environment and Natural Resources	Class V	http://portal.ncdenr.org/web/guest	919-715-3060
EPA Region 4		http://www.epa.gov/aboutepa/region4.html	404-562-9345
North Dakota			
EPA Region 8	Classes II and V when in Tribal Lands	http://www.epa.gov/aboutepa/region8.html	303-312-6312
ND Department of Health	Classes I and V	http://www.ndhealth.gov/wq/gw/gw.htm	701-328-5213
ND Industrial Commission	Class II	https://www.dmr.nd.gov/oilgas/	701-328-8020
Ohio			
EPA Region 5	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region5.html	312-353-2000
OH Environmental Protection Agency	Classes I and V (in partnership w/ OH DNR)	http://www.epa.state.oh.us/	614-644-3020
Oklahoma			
OK Corporation Commission	Oil and Gas Related Injection Wells	http://www.occ.state.ok.us/	405-521-2211
OK Department of Environmental Quality	All Other Injection Wells	http://www.deq.state.ok.us/	405-702-0100
EPA Region 6	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region6.html	800-887-6063
Oregon			
EPA Region 10		http://www.epa.gov/aboutepa/region10.html	206-553-1200
OR Department of Environmental Quality	Classes I, II, and V	http://www.oregon.gov/DEQ/	503-229-5696

Organization	UIC Well Class Primacy	Website	Phone Number
Pennsylvania			
EPA Region 3	Classes I, II, and V	http://www.epa.gov/aboutepa/region3.html	215-814-5000
Rhode Island			
RI Department of Environmental Management	Classes I, II, and V	http://www.dem.ri.gov/	401-222-6800
EPA Region 1		http://www.epa.gov/aboutepa/region1.html	617-918-1111
South Carolina			
SC Department of Health and Environmental Control	Classes II and V (State prohibits Class I wells)	http://www.scdhec.gov/	803-898-4300
EPA Region 4		http://www.epa.gov/aboutepa/region4.html	404-562-9345
South Dakota			
EPA Region 8	Classes I and V (incl. Class II in Tribal Lands)	http://www.epa.gov/aboutepa/region8.html	303-312-6312
SD Department of Environment and Natural Resources	Class II	http://denr.sd.gov/des/gw/UIC/UIC.aspx	605-773-4589
Tennessee			
EPA Region 4	Class II	http://www.epa.gov/aboutepa/region4.html	404-562-9345
Department of Environment & Conservation	Classes I and V	http://www.tn.gov/environment/permits/injetwel.shtml	615-532-0109
Texas			
Railroad Commission of Texas	Oil and Gas Related Injection Wells	http://www.rrc.state.tx.us/	877-228-5740
TX Commission on Environmental Quality	All Other Injection Wells	http://www.tceq.state.tx.us/	512-239-1000
EPA Region 6	Classes I, II, and V when in Tribal Lands	http://www.epa.gov/aboutepa/region6.html	800-887-6063
Utah			
EPA Region 8	Classes II and V when in Tribal Lands	http://www.epa.gov/aboutepa/region8.html	303-312-6312
UT Department of Environmental Quality	Classes I and V	http://www.waterquality.utah.gov	801-536-4352
UT Department of Natural Resources	Class II	http://dogm.nr.state.ut.us	801-538-5338
Vermont			
VT Department of Environmental Conservation	Classes I, II, and V	http://www.anr.state.vt.us/dec/dec.htm	802-241-3800
EPA Region 1		http://www.epa.gov/aboutepa/region1.html	617-918-1111

Organization	UIC Well Class Primacy	Website	Phone Number
Virginia			
EPA Region 3	Classes I, II, and V	http://www.epa.gov/aboutepa/region3.html	215-814-5000
Washington			
EPA Region 10		http://www.epa.gov/aboutepa/region10.html	206-553-1200
WA Department of Ecology	Classes I, II, and V	http://www.ecy.wa.gov/ecyhome.html	360-407-6143
West Virginia			
WV Division of Environmental Protection	Classes II and V	http://www.dep.wv.gov/Pages/default.aspx	304-926-0499
EPA Region 3		http://www.epa.gov/aboutepa/region3.html	215-814-5000
Wisconsin			
WI Department of Natural Resources	Classes I, II, and V	http://dnr.wi.gov/	888-936-7463
Wyoming			
EPA Region 8	Class II and V when in		
Tribal Lands	http://www.epa.gov/aboutepa/region8.html	303-312-6312	
WY Oil and Gas Conservation Commission	Class II	http://wogcc.state.wy.us	307-234-7147
WY Department of Environmental Quality	Class I and V	http://deq.state.wy.us/	307-777-7937
UIC Class VI Wells			
UIC Class VI Well regulations were finalized in December 2010. EPA and state authorities are currently in the process of evaluating primacy responsibilities for the newly finalized well class. As of November 2011, all Class VI applications being submitted to the state will be sent to and evaluated by the regional EPA authorities.			

APPENDIX D. DRILLING AND COMPLETION OPERATIONS

D-1. A LIST OF REFERENCE MATERIAL CONCERNING SEVERAL ASPECTS OF THE DRILLING AND COMPLETION PROCESS HAS BEEN PROVIDED TO FURTHER ASSIST OPERATORS IN SELECTING DRILLING SUPPORT (NOVEMBER 2011).

Sources	Document / Series Title	Description	Subject
Occupational Health and Safety Administration (OSHA)	SIC 131	Safety Requirements specific to Crude Petroleum and Natural Gas Activities	Safety
	SIC 138	Safety Requirements specific to Oil and Gas Field Services	Safety
	29 CRF 1910	General Industrial Safety and Emergency Standards	Safety
CA State Standards	CA OSHA Regulations, Title 8, Chapter 4, Subchapter 14	Petroleum Safety Orders - Drilling and Production	Drilling / Safety
AL State Standards	State Statutes and Regulations Related to Oil and Gas. Department of Natural Resources, Division of Oil and Gas	State Specific Regulations for Oil and Gas Activity	Drilling / Safety
TX State Standards	Title 16, Economic Regulation; Part 1, Railroad Commission of Texas Chapter 3, Oil and Gas Division	State Specific Regulations for Oil and Gas Activity	Drilling / Safety
UT State Standards	Rule R614-2	State Specific Rules for the Drilling Industry	Drilling / Safety
	Title R649	Natural Resources; Oil, Gas and Mining	Drilling
WY State Standards	Oil and Gas Conservation Commission Standards	State Rules and Statutes for Oil and Gas Projects	Drilling
American National Standards Institute (ANSI)/American Society of Safety Engineers (ASSE)	Z41	Personal Protection - Protective Footwear	Safety
	Z49.1	Safety in Welding and Cutting and Allied Processes	Safety
	Z87.1	Practice for Occupational and Educational Eye and Face Protection	Safety
	Z88.2	Respiratory Protection	Safety
	Z89.1	Requirements for Industrial Head Protection	Safety
	Z117.1	Safety Requirements for Confined Spaces	Safety
	Z359.1	Safety Requirements for Personal Fall Arrest Systems, Subsystems and Components	Safety

Sources	Document / Series Title	Description	Subject
U.S. Research and Special Programs Administration (RSPA)	49 CFR 171	General Information, Regulations, and Definitions	Safety
	49 CFR 172	Hazardous Materials Table, Special Provisions, Hazardous Materials Communications, Emergency Response Information and Training Requirements	Safety
	49 CFR 173	Shippers – General Requirements for Shipments and Packaging	Safety
	49 CFR 177	Carriage by Public Highway	Safety
	49 CFR 178	Specifications for Packaging	Safety
American Petroleum Institute (API)	Exploration and Production Publications	Standards including Oilfield Equipment and Material Standards, Offshore Structures, Valves and Wellhead Equipment, Drilling Equipment, Oil Well Cements, Production Equipment, Drilling Fluid Materials, Offshore Safety and Anti-Pollution, etc.	Equipment
	Health and Environmental Issues Publications	Standards for Plant Emissions during Construction, Exploration and Production, Marketing, Transportation, etc. Pollution Prevention and Air/Soil/ Water Testing and Research	Equipment / Construction
	Pipeline Publications	Standards on Pipeline Transportation, Installation, Welding, Maintenance, and Third Party Connectivity	Equipment / Construction
	Safety and Fire Protection Publications	Standards for Safety and Fireproofing for Oil and Gas Locations	Equipment / Safety
	Valve Publications	Standards for Wellhead Equipment Installation, Testing, Maintenance, and Replacement	Equipment

Sources	Document / Series Title	Description	Subject
International Association of Drilling Contractors (IADC)	IADC Drilling Manual	Recommended Industry Practices	Drilling / Equipment
	Drilling Technology Series	Covering the many aspects of Drilling	Drilling / Equipment
	Formulas and Calculations for Drilling, Production and Workover		Drilling
	High Pressure High Temperature (HPHT) Wells		Drilling
	Introduction to Well Control		Drilling
	Offshore Fire Prevention		Drilling
	Oil and Gas Exploration & Production		Drilling
	Principles of Drilling Fluid Control		Drilling
	IADC Guideline for MODUs	Guidelines for Mobile Offshore Drilling Units	Drilling
Society of Petroleum Engineers (SPE)	Drilling and Completion Publications	Papers covering horizontal and directional drilling, drilling fluids, bit technology, sand control, perforating, cementing, well control, completions, and drilling operations	Drilling
	Economics and Management Publications	Covers resource and reserve evaluation, portfolio and asset management, project valuation, strategic decision-making and processes, uncertainty/risk assessment and mitigation, systems modeling and forecasting, etc.	Construction
	Production and Operations Publications	Papers on production operations, artificial lift, downhole equipment, formation damage control, multiphase flow, workovers, and stimulation	Construction
	Projects, Facilities & Construction Publications	Covers all aspects of onshore and offshore surface facilities design, project management, operations, and abandonment, including subsea, fixed and floating production systems; pipelines; mid-stream natural gas (LNG, CNG, GTL plants, terminals and transportation); carbon capture and storage; project valuation; integrated asset modeling; remote monitoring and control; safety, human factors and environmental management.	Construction

Sources	Document / Series Title	Description	Subject
Further Publications	Well Cementing	By Erik B. Nelson, Schlumberger Educational Services, 5000 Gulf Freeway, Houston, Texas 77023 (1990)	Drilling/Construction
	Petroleum Well Construction	By Economides, Michael J., Watters, Larry T. and Dunn-Norman, Shari, John Wiley & Sons, West Sussex, England (1998)	Construction
	Applied Drilling Engineering - SPE Textbook Series Volume 2	Bourgoyne, A.T., Millheim, Keith K., Chenevert, Martin E. and Young, Farrile S., Society of Petroleum Engineers, Richardson, Texas (1986)	Drilling

D-2. OIL AND GAS CONTACT INFORMATION BY STATE (NOV. 2011)

Organization	Purpose	Website	Phone Number
Alabama			
AL State Oil and Gas Board - Tuscaloosa	Drilling Permits and Mineral Rights	http://www.gsa.state.al.us/ogb/ogb.html	205-349-2852
AL State Oil and Gas Board - Mobile	Regional Office	http://www.gsa.state.al.us/ogb/ogb.html	251-438-4848
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Alaska			
AK DNR Division of Oil and Gas	State Land Leasing, Resource Evaluation, & Geophysical Exploration Permits	http://dog.dnr.alaska.gov/	907-269-8800
AK Oil and Gas Conservation Commission	Drilling Permit	http://doa.alaska.gov/ogc/	907-279-1433
US DOI Bureau of Land Management AK	Leasing of Federal Lands	http://www.blm.gov/ak/st/en.html	907-271-5960
Arizona			
AZ Oil and Gas Conservation Commission	Drilling and Exploration Permit	http://www.azogcc.az.gov/	520-770-3500
AZ State Land Department	State Land and Mineral Rights	http://www.land.state.az.us/	602-542-4621
US DOI Bureau of Land Management AZ	Leasing of Federal Lands	http://www.blm.gov/az/st/en.html	602-417-9200
Arkansas			
AR Oil and Gas Commission	Drilling and Exploration Permit, Land Leasing	http://www.aogc.state.ar.us/	501-683-5814
AR Geological Survey	Mining and Mineral Resources & Oil and Gas/Fossil Fuel Resources	http://www.geology.ar.gov/home/ index.htm	501-296-1877
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
California			
CA Dept. of Conservation, Division of OGGR	Drilling Permits	http://www.conservation.ca.gov/dog/	
Pages/Index.aspx	916-323-1777		
US DOI Bureau of Land Management CA	Federal Land and Resources Mgmt.	http://www.blm.gov/ca/st/en.html	916-978-4400
Colorado			
CO DNR Oil and Gas Conservation Commission	Drilling Permits & Oil and Gas Location Assessment	http://cogcc.state.co.us/	303-894-2100
US DOI Bureau of Land Management CO	Leasing of Federal Lands	http://www.blm.gov/co/st/en.html	303-239-3600

Organization	Purpose	Website	Phone Number
Connecticut			
CT Department of Environmental Protection	Drilling Permits	http://www.ct.gov/dep/site/default.asp	860-424-3000
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Delaware			
DE Department of Natural Resources and Env. Control	Drilling Permits	http://www.dnrec.delaware.gov/ Pages/ Portal.aspx	302-739-9000
District of Columbia			
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Florida			
FL Department of Environmental Protection - Oil and Gas	Drilling Permits	http://www.dep.state.fl.us/water/ mines/ oil_gas/index.htm	850-488-8217
FL Department of Environmental Protection - State Lands	Leasing of State Lands	http://www.dep.state.fl.us/mainpage/ programs/lands.htm	850-245-2555
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Georgia			
GA Department of Natural Resources		http://www.gadnr.org/	404-656-3500
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Hawaii			
HI Department of Land and Natural Resources - Land Division		http://hawaii.gov/dlnr/land/	808-587-0433
Idaho			
ID Department of Lands	Land/ Mineral Rights for Oil & Gas Exploration	http://www.idl.idaho.gov/	208-334-0200
ID Department of Water Resources	Drilling Permits	http://www.idwr.idaho.gov/	208-287-4800
US DOI Bureau of Land Management ID	Leasing of Federal Lands	http://www.blm.gov/id/st/en.html	208-373-4000
Illinois			
IL Department of Natural Resources - Oil and Gas Division	Drilling Permits	http://dnr.state.il.us/mines/dog/	217-782-6302
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600

Organization	Purpose	Website	Phone Number
Indiana			
IN Department of Natural Resources - Division of Oil and Gas	Drilling Permits & State Land/Mineral Lease Rights	http://www.in.gov/dnr/dnroil/	317-232-4055
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Iowa			
IA DNR Geological and Water Survey	Drilling Permits & State Land/Mineral Lease Rights	http://www.igsb.uiowa.edu/	319-335-1575
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Kansas			
KS Corporation Commission - Oil and Gas Conservation Div.	Drilling Permits & State Land/Mineral Lease Rights	http://www.kcc.state.ks.us/ conservation/ index.htm	316-337-6200
US DOI Bureau of Land Management NM/OK/TX/KS	Leasing of Federal Lands	http://www.blm.gov/nm/st/en.html	505-954-2000
Kentucky			
KY EEC Division of Oil and Gas	Drilling Permits & State Land/Mineral Lease Rights	http://oilandgas.ky.gov/Pages/ Welcome. aspx	502-573-0147
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Louisiana			
LA Department of Natural Resources - Oil and Gas Division		http://dnr.louisiana.gov/	225-342-4500
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Maine			
ME Department of Environmental Protection		http://www.maine.gov/dep/	207-287-7688
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Maryland			
MD Department of the Environment		http://www.mde.state.md.us/Pages/ Home.aspx	410-537-3000
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Massachusetts			
MA Department of Environmental Protection		http://www.mass.gov/dep/	617-292-5500
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600

Organization	Purpose	Website	Phone Number
Michigan			
MI Dept. of Natural Resources and Environment - Env. Quality	Land and Mineral Rights, Drilling Permits, & Office of Geological Survey	http://www.michigan.gov/deq	517-373-7917
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Minnesota			
MN DNR - Division of Minerals	Land and Mineral Rights	http://www.dnr.state.mn.us/ lands_ minerals/index.html	651-259-5959
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Mississippi			
MS State Oil and Gas Board	Well Records &Drilling Permits	http://www.ogb.state.ms.us/	601-576-4900
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Missouri			
MO DNR Division of Energy	Drilling Permits	http://www.dnr.mo.gov/energy/	573-751-3443
MO DNR Division of Environmental Quality	Quality Conservation	http://www.dnr.mo.gov/env/index.html	573-751-0763
MO DNR Division of Geology and Land Survey	Land and Mineral Rights	http://www.dnr.mo.gov/geology/ index.html	573-368-2100
Montana			
MT Board of Oil and Gas Conservation	Drilling Permit Processing	http://bogc.dnrc.mt.gov/	406-656-0040
MT DNR Trust Land Managements Division	Leasing of Mineral Rights	http://dnrc.mt.gov/trust/default.asp	406-444-2074
US DOI Bureau of Land Management MT/ND/SD	Leasing of Federal Lands	http://www.blm.gov/mt/st/en.html	406-896-5000
Nebraska			
NE Oil and Gas Conservation Commission	Drilling Permits & State Land/Mineral Lease Rights	http://www.nogcc.ne.gov/	308-254-6919
Nevada			
NV Commission on Mineral Resources - Div. of Minerals	Drilling Permits and Mineral Rights	http://minerals.state.nv.us/	775-684-7040
US DOI Bureau of Land Management NV	Leasing of Federal Lands	http://www.blm.gov/nv/st/en.html	775-861-6400
New Hampshire			
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
New Jersey			
NJ Department of Env. Protection - Div. of Water Supply	Drilling Permits	http://www.nj.gov/dep/watersupply/	609-777-3373
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600

Organization	Purpose	Website	Phone Number
New Mexico			
NM Energy, Minerals and Natural Resources Dept. - Oil & Gas	Drilling Permits	http://www.emnrd.state.nm.us/ocd/	505-476-3460
NM State Land Office - Oil, Gas, and Minerals Division	Land and Mineral Rights	http://www.nmstatelands.org/ Overview_6.aspx	505-827-5760
US DOI Bureau of Land Management NM/OK/TX/KS	Leasing of Federal Lands	http://www.blm.gov/nm/st/en.html	505-954-2000
New York			
NY Department of Environmental Conservation	Drilling Permits & Leasing of State Land	http://www.dec.ny.gov/	518-402-8056
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
North Carolina			
NC Department of Environment and Natural Resources		http://portal.ncdenr.org/web/guest	877-623-6748
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
North Dakota			
ND State Land Department - Minerals Management Division	Leasing and Mineral Rights	http://www.land.nd.gov/minerals/ minerals.htm	701-328-2800
ND Industrial Commission - Oil and Gas Division	Drilling Permits	https://www.dmr.nd.gov/oilgas/	701-328-8020
US DOI Bureau of Land Management MT/ND/SD	Leasing of Federal Lands	http://www.blm.gov/mt/st/en.html	406-896-5000
Ohio			
OH Department of Natural Resources	Drilling Permits	http://www.ohiodnr.com/	614-265-6610
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Oklahoma			
OK Corporation Commission	Drilling Permits	http://www.occ.state.ok.us/	405-522-2211
US DOI Bureau of Land Management NM/OK/TX/KS	Leasing of Federal Lands	http://www.blm.gov/nm/st/en.html	505-954-2000
Oregon			
OR Dept. of Geology and Mineral Industries	Drilling Permits & Mineral Land Regulation	http://www.oregongeology.org/sub/ default.htm	971-673-1555
US DOI Bureau of Land Management OR/WA	Leasing of Federal Lands	http://www.blm.gov/or/st/en.html	503-808-6002
Pennsylvania			
PA Department of Environmental Protection, Oil & Gas Management	Drilling Permits and State/Land Leasing	http://www.dep.state.pa.us/dep/ deputate/ minres/oilgas/oilgas.htm	717-772-2199
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600

Organization	Purpose	Website	Phone Number
Rhode Island			
RI Department of Environmental Management		http://www.dem.ri.gov/	401-222-6800
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
South Carolina			
SC Department of Health and Environmental Control	Drilling Permits	http://www.scdhec.gov/	803-898-3432
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
South Dakota			
SD Department of Environment and Natural Resources	Drilling Permits	http://denr.sd.gov/	605-773-3151
US DOI Bureau of Land Management MT/ND/SD	Leasing of Federal Lands	http://www.blm.gov/mt/st/en.html	406-896-5000
Tennessee			
TN Dept. of Env. & Conservation - Div. of Water Control	Drilling Permits	http://www.tn.gov/environment/wpc/	615-532-0625
Tennessee Oil and Gas Board		http://www.tn.gov/environment/boards/og/	615-532-0998
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Texas			
Railroad Commission of Texas	Drilling Permits and State Land Leasing	http://www.rrc.state.tx.us/	877-228-5740
US DOI Bureau of Land Management NM/OK/TX/KS	Leasing of Federal Lands	http://www.blm.gov/nm/st/en.html	505-954-2000
Utah			
UT DNR Division of Oil, Gas, and Mining - Oil & Gas Program	Drilling Permits	http://oilgas.ogm.utah.gov/	801-538-5340
US DOI Bureau of Land Management UT	Leasing of Federal Lands	http://www.blm.gov/ut/st/en.html	801-539-4001
Vermont			
VT Dept. of Env. Conservation - Agency of Natural Resources	Permit Coordination	http://www.anr.state.vt.us/dec/dec.htm	802-241-3808
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Virginia			
VA Dept. of Mines, Minerals, and Energy - Division of Gas & Oil	Drilling Permits	http://www.dmme.virginia.gov/divisiongasoil.shtml	276-415-9700
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600

Organization	Purpose	Website	Phone Number
Washington			
WA DNR Division of Geology and Earth Resources	Drilling Permits and State/Land Leasing	http://www.dnr.wa.gov/Publications/ger_division_fact_sheet.pdf	360-902-1450
US DOI Bureau of Land Management OR/WA	Leasing of Federal Lands	http://www.blm.gov/or/st/en.html	503-808-6002
West Virginia			
WV Dept. of Environmental Protection - Office of Oil & Gas	Drilling Permits	http://www.dep.wv.gov/oil-and-gas/Pages/default.aspx	304-926-0499
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Wisconsin			
WI Department of Natural Resources	Drilling Permits	http://dnr.wi.gov/	888-936-7463
US DOI Bureau of Land Management - Eastern States	Leasing of Federal Lands	http://www.blm.gov/es/st/en.html	703-440-1600
Wyoming			
WY Oil and Gas Conservation Commission	Drilling Permits	http://wogcc.state.wy.us/	307-234-7147
U.S. DOI Bureau of Land Management WY	Leasing of Federal Lands	http://www.blm.gov/wy/st/en.html	307-775-6256

Offshore U.S. Territories and Natural Resources Jurisdiction

Within State Jurisdiction

Region	Entity	Distance from Shore	Standard miles from Shore
Texas	Railroad Commission of Texas	9 nautical miles (3 marine leagues)	10.36
Florida Gulf Coast	FL Department of Environmental Protection	9 nautical miles (3 marine leagues)	10.36
Louisiana	LA Department of Natural Resources	3 imperial nautical miles	3.45
Other U.S. Coastal States	Respective State Organizations	3 nautical miles	3.45

Beyond State Jurisdiction

Entity	Distance of Jurisdiction	Phone Number
DOI - Bureau of Ocean Energy Management, Regulation and Enforcement - Minerals Management Service	The seaward limit is defined as the farthest of 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured or, if the continental shelf can be shown to exceed 200 nautical miles, a distance not greater than a line 100 nautical miles from the 2,500-meter isobath or a line 350 nautical miles from the baseline. Outer Continental Shelf limits greater than 200 nautical miles but less than either the 2,500 meter isobath plus 100 nautical miles or 350 nautical miles are defined by a line 60 nautical miles seaward of the foot of the continental slope or by a line seaward of the foot of the continental slope connecting points where the sediment thickness divided by the distance to the foot of the slope equals 0.01, whichever is farthest.	202-208-3985

D-3. SAMPLE AUTHORITY FOR EXPENDITURE (AFE) FORM FROM PETROLEUM INDUSTRY

Project Title

AUTHORIZATION FOR EXPENDITURES - Est Cost DRILLING ONLY

In US $ **$0**

BUDGET SCHEDULE NO.__

Operator:
Contract Area:
Contract Area #:

Project Type :
Well Name :
Well Type :
Platform/Tripod :
Field/Structure :
Basin :

AFE #:
Date:

Location ____________ **Surface Coordinate** ____________
Surface Elev. ____________ **Elevation** ____________

	PROGRAM	ACTUAL
Spud Date		
Compl Date		
In Service		
Drilling Days		

	PROGRAM	ACTUAL
Rig Days	0	
Total Depth	0	
Well Cost $/Ft.		
Well Cost $/Day		

Close Out Date: ________ **Completion Type:** ____________ **Well Status:** ____________

	Description	Dry Hole Budget	Completed Budget	Total Budget	Actual Expenditure	Actual Over/Under	% Over/Under
1	**TANGIBLE COSTS**						
2	Casing			0		0	
3	Casing Accessories; Float Equip & Liners			0		0	
4	Tubing			0		0	
5	Well Equipment - Surface			0		0	
6	Well Equipment - Subsurface			0		0	
7	Other Tangible Costs			0		0	
8	Contingency			0		0	
9	**Total Tangible Costs**	$0	$0	$0	$0	0	
10	**INTANGIBLE COSTS**						
11	**PREPARATION & TERMINATION**						
12	Surveys			0		0	
13	Location Staking & Positioning			0		0	
14	Wellsite & Access Road Preparation			0		0	
15	Service Lines & Communications			0		0	
16	Water Systems			0		0	
17	Rigging Up/Rigging Down/ Mob/Demob			0		0	
19	**Total Preparations/MOB**	$0	$0	$0	$0	0	
20	**DRILLING - W/O OPERATIONS**						
21	Contract Rig			0		0	
22	Drlg Rig Crew/Contract Rig Crew/Catering			0		0	
23	Mud, Chem & Engineering Servs			0		0	
24	Water			0		0	
25	Bits, Reamers & Coreheads			0		0	
26	Equipment Rentals			0		0	
27	Directional Drlg & Surveys			0		0	
28	Diving Services			0		0	
29	Casing & Wellhead Installation & Inspection			0		0	
30	Cement, Cementing & Pump Fees			0		0	
31	Misc. H2S Services			0		0	
32	**Total Drilling Operations**	$0	$0	$0	$0	0	
33	**FORMATION EVALUATION**						
34	Coring			0		0	
35	Mud Logging Services			0		0	
36	Drillstem Tests			0		0	
37	Open Hole Elec Logging Services			0		0	
39	**Total Formation Evaluation**	$0	$0	$0	$0	0	
40	**COMPLETION**						
41	Casing, Liner, Wellhead & Tubing Installation			0		0	
42	Cement, Cementing & Pump Fees			0		0	
43	Cased Hole Elec Logging Services			0		0	
44	Perforating & Wireline Services			0		0	
45	Stimulation Treatment			0		0	
46	Production Tests			0	$0	0	
48	**Total Completion Costs**	$0	$0	$0	$0	0	
49	**GENERAL**						
50	Supervision			0		0	
51	Insurance			0		0	
52	Permits & Fees			0		0	
53	Marine Rental & Charters			0		0	
54	Helicopter & Aviation Charges			0		0	
55	Land Transportation			0		0	
56	Other Transportation			0		0	
57	Fuel & Lubricants			0		0	
58	Camp Facilities			0		0	
59	Allocated Overhead - Field Office			0		0	
60	Allocated Overhead - Main Office			0		0	
61	Allocated Overhead - Overseas			0		0	
62	Technical Services From Abroad			0		0	
64	**Total General Costs**	$0	$0	$0	$0	0	
65	**TOTAL INTANGIBLE COSTS**	$0	$0	$0	$0	0	
	TOTAL TANGIBLE COSTS	$0	$0	$0	$0	0	
66	**TOTAL WELL COST**			**$0**	**$0**	**0**	
67	**Timed Phased Expenditures**						
68	**-This Year**						
69	**-Future Years**						
70	**Total**						

Operator	Approved By:		**Remarks**
	Position		
	Date		
Operator Approval	Approved By:		
	Position		
	Date		

APPENDIX E. INJECTION OPERATIONS

E-1. SEAL TYPES

For high-speed centrifugal pumps, mechanical seals are normally specified. The types of seals include:

- single seal
- tandem seal
- double seal
- triple seal

Proper seal flush in the outer cavity can be achieved via a pressurized closed loop using a seal pumping ring or American Petroleum Institute (API) Plan 614. With a pressurized closed loop, the entire outer seal oil system is at higher (than pumpage) pressure, resulting in less operating cost, but capital cost is increased because of needed seal oil auxiliaries. API Plan 614 allows the seal fluid to be depressurized when it leaves the cavity, which means that power is required to re-pressurize the fluid for it to circulate and reenter the seal. Both of these seal arrangements have been used successfully with turbine oil (e.g., Shell Turbo 32) as the seal flush fluid.

For reciprocating pumps in high-pressure CO_2 service, improper and/or deficient packing is the most common cause of failure. The low surface tension and viscosity of CO_2 require special attention to packing specifications. To overcome packing problems, a nitrile/dacron cloth-fiber tetrafluoroethylene (TFE) material is recommended by many manufacturers. Lubrication can be provided by an oil drip system on the heel of the plunger, or can be force-fed through a lantern ring. Adhering to proper packing procedures will help avoid packing failures, which can lead to pump cavitation.

E-2. VALVES

Common valves used for CO_2 injection operations include:

- A pressure relief valve—A control valve that can be used between pipeline sections to protect against excessive pressure in the flow line, including rapid pressure build-ups that can occur even at the low temperatures typically maintained within the pipeline
- An isolation valve, or shutoff valve placed in the system to isolate a portion of the system for repair, inspection, or maintenance—A common type of isolation valve is a gate valve, which is useful when straight-line CO_2 flow and minimum CO_2 flow restriction are needed
- Ball valves that are stop valves that use a ball to stop or start CO_2 flow—They perform the same function as the disk in other valves (standard ball valves should also be ported)
- Flow control valves—Used to regulate either pressure or temperature in a CO_2 flow line, keeping them close to a specified preset level

E-3. FLOW METERS

Three types of flow meters are used for CO_2 injection operations and consist of the following types:

- Orifice meters are generally the preferred meter of choice for measuring CO_2 flow rates. They are simple, reliable, and readily available on the market. They work by measuring pressure changes of flowing fluid in a pipe, and deriving a flow rate based on the pressure differential as the fluid passes through an orifice or nozzle of known size. A discharge (or nozzle) coefficient developed by the American Society of Mechanical Engineers (ASME) is then factored into computing flow rate. One disadvantage of orifice meters is significant friction head loss, which is why the ASME coefficient factor is needed.
- A turbine meter uses the mechanical energy of a flowing fluid to effect rotation of the meter rotor. Key advantages of turbine meters are moderate cost and high accuracy with clean, low-viscosity fluids moving at moderately high and steady flow rates. Disadvantages include pressure drops that can occur in a gravity flow system, less accuracy at low flow rates, and a tendency to experience rotor bearing wear issues. Because of flow-rate verification difficulties, the acceptance of turbine meter use for custody transfer applications is fairly limited. They are recommended to operate above approximately 5 percent of maximum flow.[4]
- Coriolis meters comprise two main components: a sensor and a transmitter. These sensors measure the gas mass flow rate by sensing the force on a vibrating tube(s). During flow, the vibrating tube(s) and mass flow rate couple together, because of Coriolis force, causing twisting of the flow tube(s) from inlet to outlet, and a phase shift in the signals is produced indicating a difference of

[4] www.flowmeters.com/turbine-technology

time. The phase shift is directly proportional to the mass flow rate. A key advantage of Coriolis meters is that they eliminate the need to quantify gas at flowing conditions as well as the need to measure flowing temperature and flowing pressure, and the need to calculate a flowing compressibility. These meters also have the ability to bi-directionally measure almost any gas-phase fluid from −400° to +400°F without error or damage due to flow profile disturbances, pulsations, regulator noise, surges, compressibility change, and density change.[5]

E-4. WASTE DISPOSAL

Disposal of wastes may comprise a large component of a geologic storage project, especially in the case of EOR. Typically, more than half of the volume of CO_2 injected into an EOR reservoir will return in the production stream, requiring separation (**Figures E-1 and E-2**) from the main product and recycle injection. Other produced gases can include methane and other hydrocarbons as well as sulfides, which can affect product separation, particularly

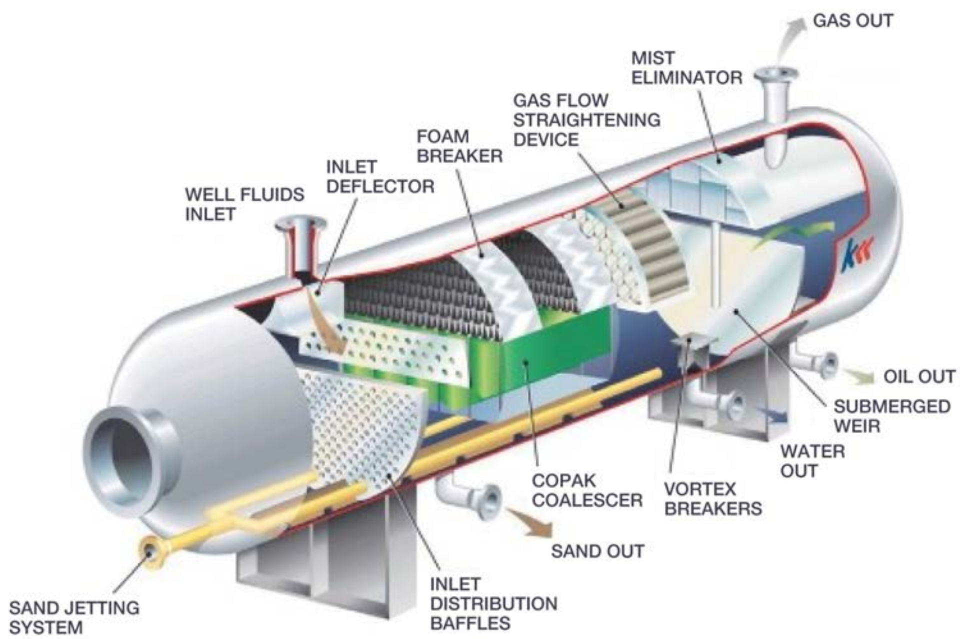


Figure E-1: Schematic of a production separator

Figure E-2: Image of multiple production separators

[5] http://asgmt.com/wp-content/uploads/pdf-docs/2007/1/030.pdf

for ECBM projects. Coal fines can also be generated from ECBM. Produced gases from CO_2 EOR contain mostly CO_2, with small amounts of methane, other hydrocarbons, and possibly trace amounts of sulfides, depending on the composition of the incoming CO_2 stream. Composition of the produced gas should be monitored periodically to ensure any potential presence of sulfides will not affect equipment. Although the presence of sulfur can negatively impact the overall performance of injection operations because sulfur species (especially H_2S and other sulfides) are corrosive, polar, reactive, and absorptive, equipment can be designed to accommodate sulfur and enable acid gas injection. Depending on a variety of factors including specific gravity of oil, injection depth, and reservoir temperature, acid gas injection can provide benefits to some EOR operations such as increasing CO_2-oil miscibility. In addition, the cost savings realized by elimination of sulfur removal operations can be significant. If sulfur removal is required for the project, the ability to analyze for sulfur species at low concentrations is essential to ensure against their presence at actionable levels.

Gas processing options for CO_2 recycle (with or without H_2S removal as required) vary based on economic and site-specific conditions (e.g. CO_2 minimum miscibility pressure [MMP]). The following charts (**Figures E-3 through E-5**) show the three common tactics used.

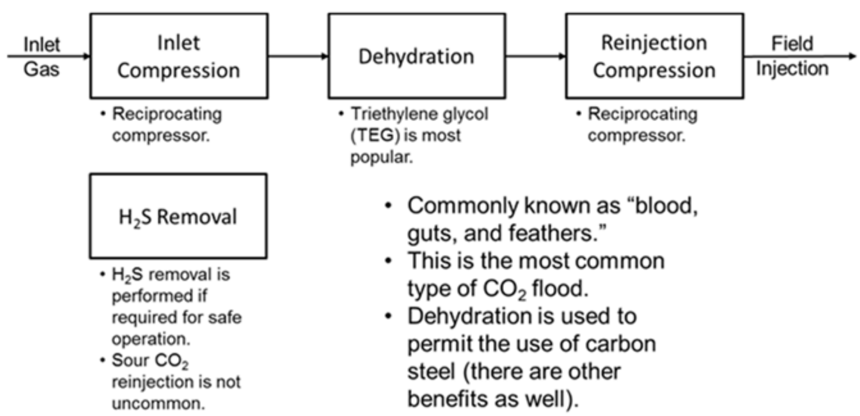


Figure E-3. Full-stream reinjection produced gas option consists of dehydration and compression

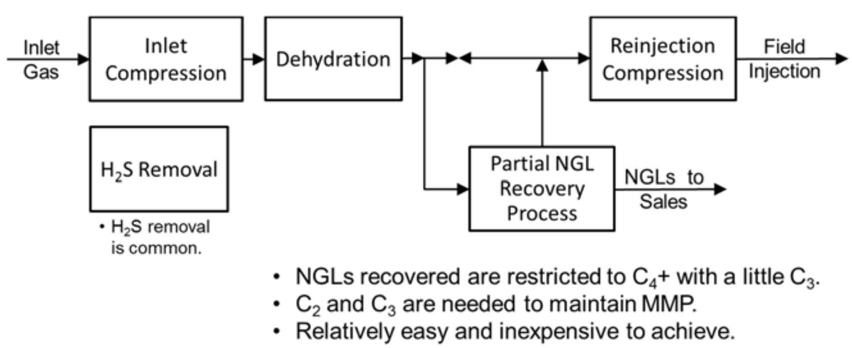


Figure E-4. Partial processing produced gas option (recovery of C_4+ hydrocarbons) adds partial hydrocarbon recovery to full-stream reinjection

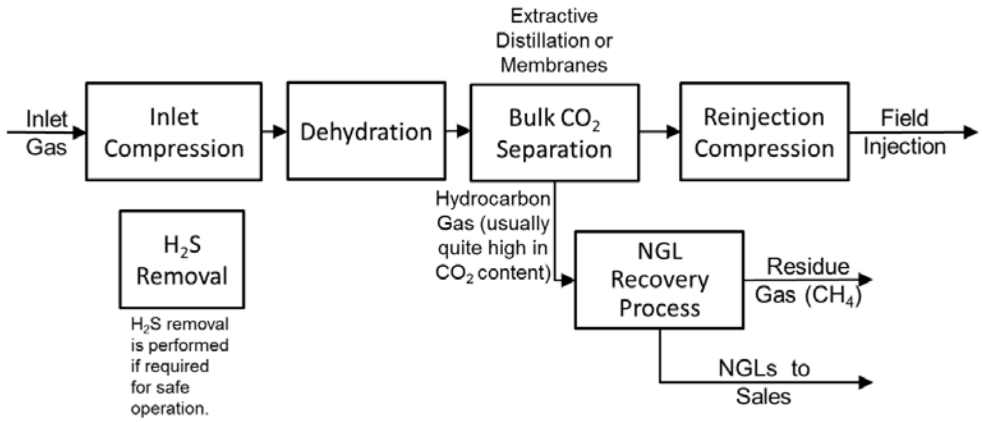


Figure E-5. Full processing produced gas option (recovery of NGLs and methane) adds purification of CO_2 to partial processing

If necessary, removal of H_2S and other corrosive sulfur species can be accomplished by four basic methods: recirculating solvent systems, direct REDOX (reduction–oxidation) conversion systems, regenerative adsorption systems, and throw-away solid and liquid scavengers. Recirculating solvent systems can be used on the front end of the plant to treat the inlet gas stream, and they are used to treat hydrocarbon product streams such as natural gas liquids. The solvent is used by contacting the gas stream to strip out H_2S; the remaining gas stream is recycled back through the process. Amine systems are the most common gas-stripping systems, have the advantage of being relatively simple, and are most familiar to operators.[4]

REDOX systems use a solvent (many available choices are on the market) to convert H_2S directly to elemental sulfur. REDOX systems have a high conversion rate of H_2S to sulfur, but the disadvantages include the complex chemistry and the high chemical costs that accrue because of solvent degradation.

Regenerative adsorption and solid and liquid scavenger systems are used for smaller gas volumes. Regenerative adsorption systems are generally expensive to install and used for treating final products. The H_2S-contaminated gas passes through a vessel containing a mole sieve. Once the gas is adsorbed onto the mole sieve, the sieve can be regenerated through a chemical, temperature, or mechanical process.[6] A mole sieve can be regenerated a limited number of times before needing replacement. Solid and liquid scavenger systems are limited to treating small volumes of gas when a continuous process is not justified. Batch treatment is a fairly common application for this type of approach.

For ECBM operations, produced contaminants include water, nitrogen, CO_2, carbonates, sulfates, sodium, potassium, calcium and magnesium. These require separation before pipeline compression of sales gas. Typical pipeline standards require that methane gas be purified (a common standard is less than 2 percent CO_2 or 7 pounds of CO_2 per thousand cubic feet [mcf]), so the project should check with the pipeline carrier for the applicable standards. The recovered CO_2 can be recycled similarly to the CO_2 EOR process.

[6] Jarrell, P.M, Fox, C.E, Stein, M.H., and Webb, S.L., Practical aspects of CO_2 flooding: Monograph v. 22 SPE Henry L. Doherty Series, Chapter 5 Surface Facilities Design, p. 111–112, Richardson, Texas, 2002.

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