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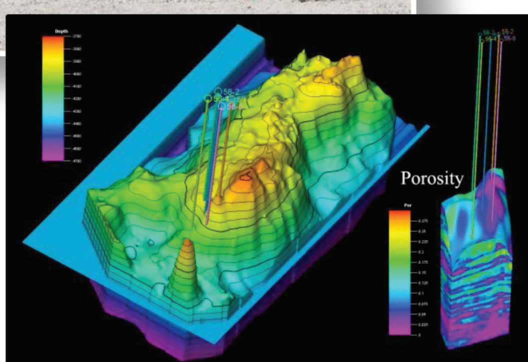
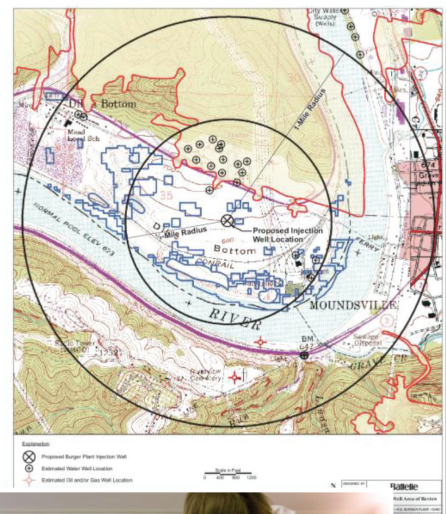
BEST PRACTICES for:

Site Screening, Site Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations





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NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

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Site Screening, Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations

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List of Acronyms and Abbreviations

Acronym/Abbreviation	Definition
2D	Two-Dimensional
3D	Three-Dimensional
4D	Four-Dimensional
AAPG	American Association of Petroleum Geologists
AC	Accumulation Chamber
ANWR	Arctic National Wildlife Refuge
AoR	Area of Review
ARI	Advanced Resources International, Inc.
Bcf	Billion Cubic Feet
BIG SKY	Big Sky Carbon Sequestration Partnership
BLM	Bureau of Land Management
CBL	Cement Bond Log
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
CO_2 GS	Geologic Storage of CO_2
Corps	U.S. Army Corps of Engineers
CRBG	Columbia River Basalt Group
CSLF	Carbon Sequestration Leadership Forum
CWA	Clean Water Act
daf	Dry-Ash Free
DOE	U.S. Department of Energy
DST	Drill Stem Test
ECBM	Enhanced Coalbed Methane
EC	Eddy-Covariance
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EUR	Estimated Ultimate Recovery
FEHM	Finite Element Heat & Mass numerical simulator
FERC	Federal Energy Regulatory Commission
FRACGEN	Fracture Network Generators
GHG	Greenhouse Gas
GIS	Geographical Information System
GS	Geologic Storage

H_2S	Hydrogen Sulfide
IRGA	Infrared Gas Analyzers
km^2	Square Kilometer
LANL	Los Alamos National Laboratory
m^2	Square Meter
MGSC	Midwest Geological Sequestration Consortium
MIT	Mechanical Integrity Test
MRCSP	Midwest Regional Carbon Sequestration Partnership
MVA	Monitoring, Verification, and Accounting
MW	Molecular Weight
N_2O	Nitrous Oxide
NaCl	Sodium Chloride
NatCarb	National Carbon Sequestration Database and Geographic Information System
NCCI	National Carbon Cyberinfrastructure
NETL	National Energy Technology Laboratory
NEPA	National Environmental Protection Agency
NSF	National Science Foundation
O_2	Oxygen
OOIP	Original Oil in Place
PCOR	The Plains CO_2 Reduction Partnership
PNNL	Pacific Northwest National Laboratory
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSI	Pounds per Square Inch
R&D	Research and Development
RCSP	Regional Carbon Sequestration Partnerships
RHOB	Bulk Density
ROW	Right-of-Way
S	Sulfur
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
STB	Surface Transportation Board
SWP	Southwest Regional Partnership on Carbon Sequestration
TDS	Total Dissolved Solids
U.S.	United States
UIC	Underground Injection Control

UNEP	United Nations Environment Programme
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
VSP	Vertical Seismic Profiling
WAG	Water Alternating Gas
WESTCARB	West Coast Regional Carbon Sequestration Partnership
WPC	World Petroleum Council

Executive Summary

The contribution of greenhouse gases to global warming continues to be a growing concern. One of the most common greenhouse gases is carbon dioxide (CO_2). A number of methods to lower CO_2 emissions are under investigation. One of the promising technologies for near- to medium-term CO_2 emissions reduction is geologic storage of CO_2 (CO_2GS) in deep geologic formations. It is estimated that the storage potential for assessed U.S. and Canadian geologic formations is sufficient to store CO_2 equivalent in the amount that would be emitted to the atmosphere from large stationary sources in these two countries for several hundred years.[1]

The purpose of this document is to establish a framework and methodology for Site Screening, Site Selection, and Initial Characterization of CO_2 GS sites that:

- Provide stakeholders with a compilation of best practices for Site Screening, Site Selection, and Initial Characterization.
- Communicate the experience gained through DOE's Regional Carbon Sequestration Partnership Initiative through the Characterization and Validation Phases.
- Develop a consistent industry-standard framework, terminology, and set of guidelines for communicating project related storage resources and risk estimates associated with the project.

The primary audience for this manual is future storage project developers, CO_2 producers, and transporters. It will also be of use in informing local, regional, state, and national governmental agencies regarding best practices in exploration for CO_2 GS sites. Furthermore, it will inform the general public on the rigorous analyses conducted for potential CO_2 GS sites.

Although there is large potential for storing CO_2, the process of identifying suitable sites with adequate storage involves methodical and careful analysis of the technical and non-technical features of promising areas. This process is largely analogous to one in the petroleum industry through which a project matures from an exploration project to a producing project. This manual uses a set of terms that includes storage classes and project status sub-classes to categorize projects. Petroleum industry evaluations begin with an exploration model when evaluating projects for Prospective Resources. Once a discovery has been made, the project is further evaluated and classified as Contingent Resources. To complete the process, a project will need to be evaluated based on commercial conditions so it can then be classified as Reserves. This manual describes the evaluation process site screening, site selection and initial characterization used to classify a potential CO_2 storage project into a project subclass. It then integrates these processes into a classification framework, comparable to that of the petroleum industry, for CO_2 Storage Resources and capacity as seen in Figure ES-1.

Petroleum Industry		CO_2 Geological Storage
Reserves	Implementation	**Storage Capacity**
On Production		Active Injection
Approved for Development		Approved for Development
Justified for Development		Justified for Development
Contingent Resources	Site Characterization	**Contingent Storage Resources**
Development Pending		Development Pending
Development Unclarified or On Hold		Development Unclarified or On Hold
Development Not Viable		Development Not Viable
Prospective Resources	Exploration	**Prospective Storage Resources**
Prospect		Qualified Site(s)
Lead		Selected Areas
Play		Potential Sub-Regions

	Prospective Storage Resources	
Exploration	**Project Sub-class**	**Evaluation Process**
	Qualified Site(s)	Initial Characterization
	Selected Areas	Site Selection
	Potential Sub-Regions	Site Screening

Figure ES-1. Comparison of Petroleum Industry Classification and Proposed CO_2 Geologic Storage Classification. Adapted from SPE/WPC/AAPG/SPEE Resource Classification System. (© 2007 Society of Petroleum Engineers, Petroleum Resources Management System.)
(Note: this table should be read from the bottom to top)

[1] http://www.natcarb.org

The proposed classification framework for geologic storage is divided into three storage classes that correspond to three Phases of evaluation: Exploration, Site Characterization, and Implementation. The Exploration Phase is the focus of this manual and is further divided into three project sub-classes: Potential Sub-Regions, Selected Areas, and Qualified Site(s). These sub-classes correspond to three stages of evaluation during the Exploration Phase: Site Screening, Site Selection, and Initial Characterization. The most important objectives of the Exploration Phase are to lay the groundwork to ensure safe storage of CO_2 and compliance with the Underground Injection Control (UIC) program requirements.[2] This manual describes the evaluations involved in the Exploration Phase and provides best practice guidelines for project developers.

Project Definition is an important step that is conducted at the start of a project and revisited throughout the Exploration Phase as Project Management. During Project Definition, the project developer establishes an overall management plan for the project with a detailed focus on the Exploration Phase. It is important in Project Definition to plan for the full range of activities encompassed in Exploration including recognition of the high potential for contingencies. As part of Project Definition, the developer establishes a set of technical and economic criteria that can be used to help guide the Exploration Phase.

Site Screening involves the evaluation of Potential Sub-Regions that are potentially suitable for CO_2 GS. The analysis in this step relies on readily accessible data that can be obtained from public sources such as state geological surveys, groundwater management districts, departments of natural resources, published and open-file reports and atlases, academic research, previous injection or storage permits and the U.S. National Carbon Sequestration Database and Geographic Information System (NatCarb). It may also be determined that some data should be acquired from private firms such as oil and gas, coal, mineral companies, and private vendors of related industry data. Existing data can be coupled with mapping software such as geographic information systems (GIS) or NatCarb's mapping program to assess sub-regions that meet the criteria identified in Project Definition. This process will highlight the most promising Potential Sub-Regions for geologic sequestration, while eliminating from consideration those that do not meet a developer's criteria.

During Site Selection, identified Selected Areas are evaluated using previous studies and new data to determine if a potential storage site can be identified. Most of the data necessary to complete this evaluation could be readily accessible; however, the quantity and quality of this data may vary depending on a site's location and may need to be supplemented by site-specific data. Technical information to be considered include data from existing core samples, available seismic surveys, well logs, records and sample descriptions from existing or plugged/abandoned wells, and other available geologic data (some of which must be purchased). During this stage, an initial estimate of area of review (AoR) will be developed. The size of the AoR is a function of both the planned injection volumes and the target reservoir characteristics. The size of the AoR can have a significant impact on the nontechnical factors of a project, such the location of CO_2 emission sources in relation to planned storage locations, property and pore space ownership, land use, and available infrastructure. It must be emphasized at this stage that the initial AoR may have significant uncertainty due to the quality and availability of subsurface data to properly ascertain the potential AoR size. As part of this analysis, it is recommended that for each Selected Area, the developer should outline a Site Development Plan that includes an economic feasibility analysis. At the completion of this stage, the developer will have a list of the most promising Qualified Site(s) to be evaluated during Initial Characterization.

In the final step, Initial Characterization, the project developer continues the evaluation of one or more of the higher ranked Qualified Site(s). During this

[2] The UIC program, authorized under the Safe Drinking Water Act (SDWA), is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids (liquids, gases, and semi-solids) underground for storage or disposal. This program is administered by the U.S. Environmental Protection Agency.

stage, a developer assesses all the baseline, geological, regulatory, site, and social issues for the Qualified Site(s) and either confirms or rejects a site as having sufficient data and analysis to be classified as Contingent Storage Resource. While the analysis in Site Screening and Site Selection relies primarily on existing data, Initial Characterization involves the acquisition of new, site-specific data by employing investigative tools and techniques. Initial Characterization tools include both data collection (e.g., seismic and well logging, core analysis, injectivity tests) and development of three-dimensional (3D) mathematical models of the selected injection and confining zone(s). The successful characterization of a site is the most important step in ensuring the safe and economic operation of a CO_2 GS site. To this end, it is recommended that AoR size development assumptions should be validated before full site storage commitment.

This manual presents a systematic approach for selecting suitable locations for CO_2 GS projects based on an evolving set of science and engineering best practices as well as practical experience. A graphical representation of this approach is seen in Figure ES-2—the process begins with Potential Sub-Regions, identifies Selected Areas, and yields a prioritized list of Qualified Site(s). The approach draws on a number of existing reports and documents as well as industry practices. The manual is not intended as a guide to compliance with regulations but rather as a guide to considering the broader set of factors that determine the commerciality of a potential CO_2 GS site. Future editions are anticipated as experience-gained through real-world commercial development of large, integrated CCS projects will help to inform and improve this manual and the proposed classification.

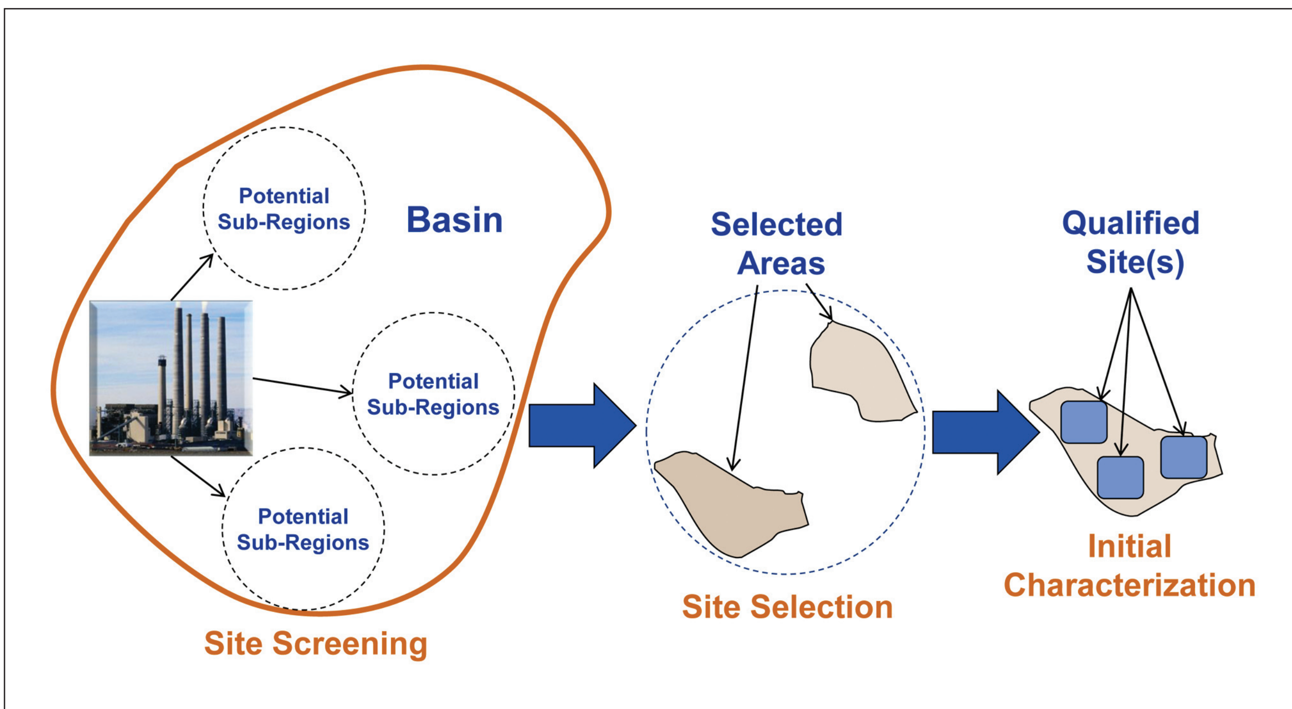

Figure ES-2. Graphical representation of “Project Site Maturation” through the Exploration Phase.

NETL

1.0 Introduction

The U.S. Department of Energy (DOE) is actively developing and demonstrating practical, safe, and effective carbon emissions reduction technologies. One of the promising technologies under development is carbon capture and storage (CCS), whereby carbon dioxide (CO_2) is captured at a source, transported to a suitable location, and injected into deep geologic formations for long-term storage. In this manual, geologic storage of CO_2 is referred to as CO_2 GS. The goal of DOE's Sequestration Program is to demonstrate that CO_2 can be successfully and securely stored over extended periods of time in a manner that is compliant with the best engineering and geological practices; Federal, State, and local regulations; and the best interests of local and regional stakeholders. This will directly link the national interest in reducing greenhouse gases with regional and local economic, environmental, and social interests.

As part of the DOE Sequestration Program, the Regional Carbon Sequestration Partnership (RCSP) Initiative established seven partnerships tasked with determining the most suitable technologies for carbon storage. An objective of the RCSP Initiative is to develop the foundation for demonstration and commercialization of CCS technologies. The RCSP Initiative is being conducted in three phases. During the first phase, called the Characterization Phase, the Partnerships characterized the potential geologic storage opportunities within each of their respective regions. In the Validation Phase, each Partnership implemented a series of small-scale CO_2 GS projects in a variety of geologic and geographic settings. Building on the knowledge developed during the Validation Phase, the Partnerships are implementing large scale (e.g., 1 million metric tonnes or greater) CO_2 GS projects during the third phase of the program, termed the Development Phase. By conducting the pilot and larger scale projects, the RCSPs are addressing regulatory and policy issues while developing technical expertise within their respective areas of the United States and portions of Canada.

During the first phases of the RCSP Initiative, the Partnerships collected and integrated data on geologic formations into a national database known as the National Carbon Sequestration Database and Geographic Information System (NatCarb). This database has the capability to graphically represent the distribution of the assessed storage formations and includes a method for estimating a basin-scale assessment of the potential storage volumes. According to the NatCarb estimates, potential volumetric storage resource is on the order of magnitude of 3,600 billion metric tonnes of CO_2—enough to accommodate injection of the existing output of CO_2 from major stationary sources within the United States for hundreds of years.[3] Although NatCarb documents large storage volumes across the United States and parts of Canada as reported by the partnerships, additional work is required to qualify potential commercial storage sites that have sufficient size, geology, and pressure characteristics to contain the area of elevated pressure and the active and ultimate plume of injected CO_2, while allowing potentially for multiple wells.

The process to qualify sites is largely analogous to the one in the petroleum industry in which a project matures through resource classes and project status sub-classes until the project begins producing hydrocarbons. Petroleum industry evaluations begin with an exploration model that qualifies appropriate projects as Prospective Resources. Once a discovery has been made, the project is further evaluated and, if qualified, can be classified as Contingent Resources, which is a sub-commercial status. To complete the process, a project will need to be justified based on technical and economic criteria in order to become classified as Reserves.

This manual builds on the experience of the RCSP Initiative as well as the body of literature and best practice guidelines developed by the research community and private industry from around the world. It proposes a standardized framework for classifying CO_2 Storage Resources and Capacity. Classification is proposed with the understanding that it will evolve with the geologic storage industry. The initial classification is presented in Figure 1.1.

[3] Source: Carbon Sequestration 2008 Atlas, second edition, numbers cited are low estimates for the combined saline formations, oil and gas formations and unmineable coal seams.

Petroleum Industry		CO_2 Geological Storage
Reserves	Implementation	**Storage Capacity**
On Production	Implementation	Active Injection
Approved for Development	Implementation	Approved for Development
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Development Not Viable	Site Characterization	Development Not Viable
Prospective Resources	Exploration	**Prospective Storage Resources**
Prospect	Exploration	Qualified Site(s)
Lead	Exploration	Selected Areas
Play	Exploration	Potential Sub-Regions

	Prospective Storage Resources	
	Project Sub-class	**Evaluation Process**
Exploration	Qualified Site(s)	Initial Characterization
Exploration	Selected Areas	Site Selection
Exploration	Potential Sub-Regions	Site Screening

Figure 1.1. Comparison of Petroleum Industry Classification and Proposed CO_2 Geologic Storage Classification. Adapted from SPE/WPC/AAPG/SPEE Resource Classification System. (© 2007 Society of Petroleum Engineers, Petroleum Resources Management System.)

(Note: this table should be read from the bottom to top)

The geologic storage classification framework includes three progressively commercial storage classes—Prospective Storage Resources, Contingent Storage Resources, and Storage Capacity—each with a set of sub-classes. The classes correspond to three phases: Exploration, Site Characterization, and Implementation. The Exploration Phase involves the process of classifying Prospective Storage Resources and has the increasingly mature project status sub-classes of Potential Sub-Regions, Selected Areas, and Qualified Sites. The Site Characterization Phase involves the process of defining Contingent Storage Resources and has the increasingly mature project status sub-classes of Development not Viable, Development Unclarified or on Hold, and Development Pending. The Implementation Phase involves the process of developing sites into Storage Capacity and has the increasingly mature project status sub-classes of Justified for Development, Approved for Development, and Active Injection.

A classification framework like the one proposed for CO_2 storage provides a roadmap in the form of standard expectations for data collection and analysis for the process of identifying suitable storage sites. This manual focuses on the first phase of that process called Exploration for Prospective Storage Resources. The three project sub-classes—Potential Sub-Regions, Selected Areas, and Qualified Site(s)—correspond to three stages of evaluation during the Exploration Phase: Site Screening, Site Selection and Initial Characterization. The most important objective of the Exploration Phase is to qualify a suitable site to ensure safe storage of CO_2 and compliance with the Underground Injection Control (UIC) program requirements.[4] This manual describes the steps involved in Exploration and provides best practice guidelines for project developers; it includes the high level structural framework and processes to evaluate a site.

Each stage in the Exploration Phase builds on the previous one, paring down a large region into a select few sites based on identified component evaluations. It is a process that is designed to:

- Establish that the site has the resources to accept and store safely the anticipated quantity of CO_2 at the desired injection rate for the storage project.
- Provide input data to models required to predict site performance in terms of pressure change and CO_2 plume evolution.
- Minimize the probability of adverse effects on the environment.
- Identify and address any potential regulatory, subsurface ownership, site access and pipeline issues.
- Ensure the site has the capability to meet the performance standards established for the project, such as operational efficiency, reliability, and safety.
- Ensure alignment of national, regional, and local social, economic, and environmental interests.

[4] The UIC program, authorized under the Safe Drinking Water Act (SDWA), is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids (liquids, gases, and semi-solids) underground for storage or disposal.

The evaluation process at each stage in the Exploration Phase is divided into components that undergo an analysis. Each of the components contains several elements to consider during the analysis. It should be understood that the process is fluid; individual components may be evaluated simultaneously and the data generated should be integrated between the components throughout the evaluation process.

The manual is organized into eight chapters.

- Chapter 1 orients the reader to the classification framework used throughout the manual and describes the purpose of the Exploration Phase.
- Chapter 2 describes Project Definition, which should be conducted prior to beginning the Exploration Phase, to establish the initial plan for overall project management and a detailed plan for the stages of the Exploration, including the high potential for contingencies. As part of Project Definition, the developer establishes a set of technical and economic criteria that can be used to help rank potential candidates identified through Exploration. Project Definition should be re-evaluated at the beginning of each stage as Project Management.
- Chapters 3, 4, and 5 describe each of the three stages of the Exploration Phase used for identifying and qualifying Prospective Storage Resources for potential elevation to Contingent Storage Resource Status:

  The first stage, Site Screening, involves three component analyses: regional geologic data, regional site data, and social data, used to develop and rank a list of Selected Areas. Most of the analyses in this stage rely on readily accessible data. These analyses highlights the most promising areas for CO_2 GS, while eliminating from consideration those that do not meet a developer's criteria.

  The second stage, Site Selection, involves analyzing the most promising Selected Areas in more detail to define Qualified Site(s) that meet critical technical and economic criteria for further evaluation. Most of the data necessary to complete this evaluation will be readily accessible; however, depending on the quantity and quality of these data, additional data may be acquired to complete the analyses. This stage includes five component analyses: subsurface geologic data, regulatory requirements, model data, site data, and social data. For each potential Qualified Site(s), the developer would outline a Site Development Plan and conduct an economic feasibility analysis. At the completion of this stage, the developer will have a list of ranked Qualified Site(s) that can be assessed during the next stage.

  In the final stage, Initial Characterization evaluates one or more sites from the higher ranked Qualified Site(s). This stage builds on the previous work and involves several component analyses including: baseline data, regulatory requirements, model data, social data, and a site development plan. Included in this evaluation is a decision point to acquire more data, for example from drilling a characterization well and/or acquiring seismic data to aid in the spatial analysis away from the prospective section. The results of this process should provide enough information to classify appraised storage at the site as Contingent Storage Resources.

- Chapter 6 integrates the information into a proposed framework to classify a site into a storage class and project sub-class. The project-based classification system for CO_2 GS proposed in this manual is similar to the classification system for petroleum resources/reserves. It attempts to provide developers with a guide that can be used to address projects in the field using a standard terminology.
- Chapter 7 presents a detailed case study of the Illinois Basin-Decatur Project. This case study is included to illustrate the site evaluation process for an "active project"through the Exploration Phase to the Site Characterization Phase.
- Chapter 8 provides a conclusion for the document and is followed by several apendicies with additional details on certain topics touched on in this manual.

The work entailed in the Exploration Phase described in this manual is based on the experience gained in the RCSP Initiative, other DOE projects, academia, and industry. Each stage includes the component analyses of various elements to determine whether a given sub-region, area, or site is suitable to move through a decision gate to a more mature project status. Each evaluation builds on previous work conducted in the Exploration Phase. The following table presents a number of the reports that were consulted in developing this manual.

Table 1.1. Consulted Sources

Document	Author*	Main Areas of Focus	Target Audience	Best Pract.	Important Themes
Best Practices for: Public Outreach and Education for Carbon Storage Projects (2009)	NETL	Outreach and education planning for storage projects	Project developers	No	Iterative planning; importance of preparation, tailored approaches
Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations (2009)	NETL	Monitoring techniques, application by strata and project phase, MVA planning	Project developers	No	Methodology and design of flexible MVA systems
A Technical Basis for Carbon Dioxide Storage (2009)	CCP	Technical aspects and technological innovations used in CO_2 GS; case studies	Project developers, regulators, the general public	Yes	Site characterization, wells, MVA, operations, closure, risk management
Guidelines for Carbon Dioxide Capture, Transport and Storage (2008)	WRI	Background and preliminary discussion of technical issues related to capture, transport, and storage	Introduction for interested parties; general information	Yes	Source/transport/sink interactions; iterative planning; importance of site selection process in reducing risk
Storage Capacity Estimation, Site Selection and Characterization for CO_2 Storage Projects (Report No: RPTD8-1001) (2008)	CO_2CRC	Estimation of storage capacity by formation type; classification for storage capacity; methods for site characterization	Storage developers and contractors. Focus on Australia, New Zealand	Yes	Technical discussions of engineering and environmental aspects of injection and long-term storage
Policy Brief: Regulation of Carbon Capture and Storage (2008)	IRGC	Current issues with emerging CCS legislation and regulations; focus risk assessment	General stakeholders, legal community	No	Significant change underway on policy front; importance of addressing risk
GEO-SEQ Best Practices Manual, Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation (2004)	LBNL	Site selection and characterization for CO_2EOR (oil and gas) sequestration projects; recovery optimization by active well control and use of solvent	Technical experts involved in CCS operation and regulation	Partial	Sequestration through CO_2EOR requires careful site characterization; rigorous monitoring is required to confirm integrity of storage
Risk Assessment and Remediation Options for Geologic Storage of CO_2 (2003)	LBNL	Presents lessons learned from natural gas analogues to the storage of CO_2	Technical experts involved in CCS operation, risk assessment, and regulation	No	Highlights a probabilistic methodology that could be used for risk assessment; outlines options for risk management, mitigation and remediation

Document	Author*	Main Areas of Focus	Target Audience	Best Pract.	Important Themes
Health, Safety, and Environmental Risk Assessment for Leakage of CO_2 from Deep Geologic Storage Sites (2005)	LBNL	Presents a coupled framework for HSE risk assessment for geologic storage of CO_2	Storage developers and the HSE, legal and regulatory communities	No	Description and simulation of CO_2 subsurface migration and surface dispersion and the implications for HSE
Long-term CO_2 Storage Using Petroleum Industry Experience (2005)	NMINT	Study of over 135 reservoirs in the U.S. into which CO_2 is being injected, plans to be injected or has been injected	Storage developers, geologists, and reservoir engineers	No	In projects where anthropogenic CO_2 has been injected containment has been secure
Development of Storage Coefficientis for CO_2 Storage in Deep Saline Formations (2009)	IEA	Includes a series of storage coefficients for use in improving estimates of storage resources in deep saline formations	Storage developers, regulators, independent verifiers	No	Assists in converting theoretical resources in realistic or viable capacities at a regional level
CO2QUALSTORE: Guideline for Selection and Qualification of Sites and Projects for Geological Storage of CO_2 (DNV Report: 2009-1425) (released 2010)	DNV	A systematic approach to selection and qualification of sites and projects for CO_2 geological storage	Storage developers, regulators, independent verifiers	Yes	Site selection and management tailored to unique characteristics of each site in order to demonstrate that inherent or engineered risk can be controlled and managed
CCS Site Characterization Criteria - December (2009)	IEA	Reviews site charcterization literature since IPCC report and provides synthesis and classification criteria for saline formations and hydrocarbon reservoirs	Storage developers and policy makers	Yes	Focus on three main characteristics: capacity, injectivity, and containment

* NETL: National Energy Technology Laboratory, U.S. Department of Energy
WRI: World Resources Institute
CCP: CO_2 Capture Project
CO_2CRC: Cooperative Research Centre for Greenhouse Gas Technologies
IRGC: International Risk Governance Council
GTI: Gas Technology Institute
LBNL: Lawrence Berkeley National Laboratory
NMIMT: New Mexico Institute of Mining and Technology
IEA: International Energy Agency
DNV: Der Norske Veritas

This manual is not intended to be prescriptive but rather introduces a framework for evaluating and classifying potential geologic storage sites. The specific plans for data collection, acquisition, and analysis will need to be determined for each site based on the nature of the site and the extent to which there are readily accessible data. This framework is designed to help developers identify qualified sites that contain the necessary elements for successful CO_2 GS, including a subsurface injection zone capable of holding CO_2 indefinitely, confining zone, confining mechanisms that ensure leakage will not occur, and appropriate monitoring devices and programs to continually assess the state and security of the stored CO_2.

2.0 Project Definition and Management

Planning and managing the characterization of a project through each of the three evaluation stages, Site Screening, Site Selection and Initial Characterization, is critical to the successful maturation of a potential storage site. Prior to initiating any evaluations, an analysis of a project's needs, organization, management structure and resources should be conducted. Understanding that a project needs will evolve as the project matures, the project developer should attempt to envision the entire characterization process, develop an initial plan and create a framework for addressing any future contingencies. The initial plan should then be revisited at each stage to better manage the project's needs.

2.1 Project Analysis

A storage site is an area that has suitable area, geology, and pressure characteristics to contain the area of elevated pressure and the active and ultimate plume of injected CO_2, while supporting the potential use of multiple injection wells. Depending on these characteristics, it is likely to be a large area, and therefore should be thoroughly evaluated and characterized. However, prior to any technical evaluation, the developer should perform a project analysis on the Project Definition component consisting of at least six elements (i) Scope, (ii) CO_2 Strategy, (iii) Evaluation Criteria, (iv) Resources, (v) Schedule and (vi) Risk Assessment. Once the initial Project Definition has been completed, the componential analysis will be revisited at the beginning of each stage and referred to as Project Management. The steps involved in Project Definition are contained in Figure 2.1 and the Best Practice Guidelines are contained in Table 2.1

i. Project Scope

The project scope should address the entire Exploration Phase. It needs to anticipate increasing costs as the level of detail increases throughout the three stages of evaluation in the Exploration Phase. The plan should focus on understanding and reducing the uncertainties that could arise as the project matures including issues related to geology, community, modeling, or the site in general. During each of the three stages within the Exploration Phase, a number of potential sub-regions, areas, and sites might be examined. This would necessitate a project scoping exercise for each in-depth study. It is crucial that the scope of the project be determined and planned for correctly. The Project Definition plan should be dynamic; at this stage, it provides a static baseline from which changes can be planned as the project matures and circumstances change. Failure to correctly scope each aspect of the project could result in unforeseen delays and potential cost overruns, potentially leading to failure of the project.

ii. CO_2 Management Strategy

Prior to beginning the Exploration Phase of a project, a CO_2 management strategy should be developed that addresses the planned source or sources of CO_2 intended for injection; the expected number of injection sites; maximum and minimum volumes of CO_2 over project lifetimes; reliability, namely the potential need for backup capacity; pressure and temperature of CO_2 throughout the systems; planned years of operation; the chemical properties of the potential CO_2 gas stream; and other issues directly related to CO_2 that will be used in a project. Delivery system options, such as pipeline routes, should also be evaluated and considered during this evaluation. The CO_2 management strategy should be used to inform the ranking criteria discussed below. For example, the CO_2 management strategy will have a bearing on the preference for injectivity and potential storage volume required for each specific project developed.

iii. Evaluation Criteria

As part of Project Definition, developers should establish criteria to be used in qualifying and ranking potential CO_2 GS sub-regions, areas, and sites identified within the three stages of evaluation. These criteria will include primary factors leading to a go/no-go decision, as well as factors that may lead to a contingent set of analyses. For example:

Primary factors might include:

- The site can be permitted under all relevant federal, state, and local regulations.
- For projects with federal funding, assuring NEPA requirements can be met.
- Mechanisms for obtaining access from surface and subsurface owners for storage, surface facilities, and pipelines can be established.

Table 2.1. Guidelines for Project Definition.

Component		Element	Guidelines for Project Definition
Project Definition/Management	Project Analysis	Scope	Conduct a scoping review of the overall project and a detailed review of the three sub-processes (Site Screening, Site Selection and Initial Characterization) involved in selecting a site for a carbon storage project. Scoping should include a definition of project objectives and criteria to evaluate project success or failure.
		CO_2 Strategy	Develop a CO_2 strategy that identifies the characteristics of the CO_2 intended for storage (e.g., source(s), volume(s), rates of delivery—target injection rates). It may be useful to assess the feasibility of several implementation options, risks, and mitigation options.
		Evaluation Criteria	Establish criteria for qualifying and ranking potential sites identified through the Site Screening, Site Selection and Initial Characterization processes. Criteria could include technical, economic and social parameters.
		Resources	Identify the personnel, equipment and funding resources necessary to complete the entire Site Screening, Site Selection and Initial Characterization processes. This assessment should identify necessary areas of expertise, financial thresholds, potential contingencies and other resource risks.
		Schedule	Develop a project schedule for the Site Screening, Selection and Initial Characterization processes, addressing the potential need to assess multiple sites. The schedule should include milestones and contigency plans to mitigate schedule delays.
		Risk Assessment	Conduct a risk assessment to identify potential scenarios that would prevent the project from achieving commerciality. Define mitigation options and develop a potential implementation plan that could include go/no-go decision gates.

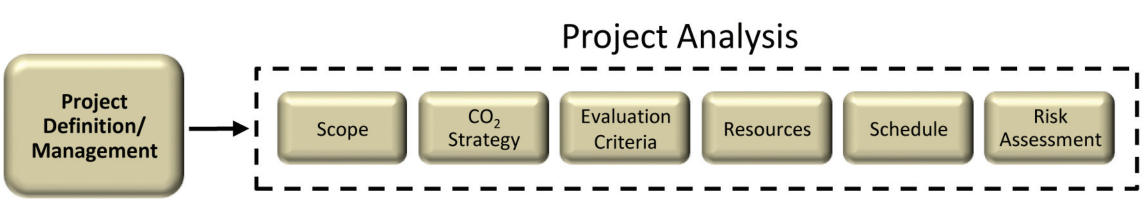

Figure 2.1. Process Flowchart for Project Definition.

- The risk profile (including a wide variety of factors such as financial, public acceptance, political, technical, various types of liability, uncertainties, etc.) is acceptable to the project development team.
- Availability of risk management options.
- Ability to conduct expected or required monitoring.
- Costs including all of the above elements are within project budget.

Factors to be considered that might lead to contingent evaluation could include:

- Prospective Storage – does the evaluated site have sufficient storage for the planned volume of CO_2 or would multiple sites and/or multiple wells need to be developed.
- Formation Type and Depositional Environment – in the case of a large saline formation, is there a single depositional environment within a continuous vertical column of connected flow units or does a series stacked or amalgamated depositional compartments exist that may or may not be in flow communication.
- Structural Setting – potential faults that compartmentalize the injection zone or create closed or partly closed flow boundaries.
- Pipeline Issues - does one site require fewer miles of pipeline or have less rugged terrain for pipeline installation.

Numerous ranking criteria may be relevant for each specific site or project developer, so each project will likely establish its own set of ranking criteria. It is essential to develop a good ranking scheme to ensure the systematic selection of sites. Developers should also consider explicitly ranking risk factors. Some teams will high rank one set of risks, others will be more concerned about another set, which will lead to different site selection approaches. For example, one developer might assign a high rank to protected areas; this could lead to siting preferences such as extensive buffer zones around parks. Another team might more highly rank the uncertainty about injectivity; this could lead to a preference for projects that could demonstrate a high rate of injectivity.

iv. Resources

The Project Definition needs to identify and plan for resource needs, including skilled personnel and funding, that will be necessary for the Exploration Phase and generally for the entire project. Sufficient manpower must be employed to meet the planned scope and schedule for the project. Cross-functional teams consisting of appropriate skill sets should be created needs to be for each evaluation step; at various points this will include geoscientists; engineers; modeling experts; and those with business, legal, social characterization, regulatory, and environmental expertise. It is important to create a project management hierarchy and management communications network to ensure that each person understands his or her role in the project and that there is clear communication of the project goals, data, and findings.

Adequate funding is essential; therefore, a funding-needs analysis should be completed for each component within the three evaluation stages, and it should recognize that a number of decision points may require repetition of a just-completed analysis or that unavoidable delays may be encountered. As is usually found in any major project, for planning purposes, contingency funding may be needed to complete the Exploration Phase and should be identified.

v. Schedule

Based on an assessment of planned activities and available resources, the Project Definition should include a realistic schedule that includes the time requirements to fully complete each evaluation component. As with the funding assessment, tasks that may need to be repeated or requirements for unanticipated data collection, analysis, and modeling, may alter a project's schedule. Contingency timing should be allotted for repeating analyses of more than one region, area, or site in the initial project schedule.

vi. Risk Assessment

The final element in Project Definition is a risk assessment that identifies potential project risks and a mitigation plan. Project risks are different than those included in a regulatory analysis; they include those events or circumstances that would result in a project not maturing to the status of Contingent Storage Resource and potentially on to commercially available Storage Capacity. The following are potential project risks: the CO_2 source or pipeline do not develop as planned, 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, and others. These risks share analogous characteristics with the upstream oil and natural gas industry. 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.

3.0 Site Screening

The purpose of the Site Screening stage of the Exploration Phase is to evaluate sub-regional basinal data sets and assess storage potential within a defined sub-region. This stage utilizes primarily existing data and resources for this assessment which classifies storage potential as Prospective Storage Resources. The initial evaluation conducted during this stage, evaluates a Potential Sub-Region through each component analysis resulting in a set of Selected Areas. These areas are then ranked based on criteria established during Project Definition and the highest ranking Selected Area advances to the next evaluation stage. This process is analogous to the maturation of a petroleum project from "play" to "lead". The Site Screening evaluation performed on Potential Sub-Regions includes three components for analysis: (1) Regional Geologic Data; (2) Regional Proximity Data; and (3) Social Data. Elements within these components can be evaluated simultaneously while working towards answering the questions posed at the decision gates; "no" responses move the analysis to a new Potential Sub-Region, and a "yes" response leads to inclusion on the list of Selected Areas to be ranked and further evaluated during Site Selection.

Prior to initiating each component analysis, a multi-disciplinary team should be assembled and define the analysis to be conducted incorporating each of the elements. Similar to the Project Analysis described in Chapter 2, when defining the analysis, the team should consider scope, evaluation criteria, resources and schedule. Again, this process should be conducted, for each of the components within the evaluation stage to ensure the project needs and resources are adequately planned for to properly complete all the analyses.

In order to keep costs to a minimum when evaluating numerous large sub-regions of a basin, developers should rely on readily accessible data sources including the National Carbon Sequestration Database and Geographic Information System (NatCarb)[5], RCSP websites[6], state geological surveys, groundwater management districts, oil and gas commissions, and state departments of natural resources. The Site Screening evaluation will identify those Potential Sub-Regions with the highest potential for storage, and help eliminate from consideration those that are less preferable. The most promising areas within the Potential Sub-Regions would then proceed to the second stage of the Exploration Phase and be classified as Selected Areas. Figure 3.1 provides a more detailed overview of the entire Site Screening evaluation stage and Table 3.1 provides recommended guidelines for the types of data and analyses necessary to complete the Site Screening evaluation.

3.1 Subsurface Data Analysis

The main objective in evaluating the Regional Geologic Data component is to screen potential storage regions for at least four elements:

i. *Injection Formation* – identify regional and sub-regional formations that have geologic characteristics that are suitable for storage.

ii. *Adequate Depth* – ensure that formations have regional extent with sufficient depth to maintain injected CO_2 in the supercritical state.

iii. *Confining Zone* – ensure adequate confining zone is present and have lateral extent to contain injected CO_2 and avoid vertical migration of brine into a USDW.

iv. *Prospective Storage Resources* – calculate the prospective storage resource to ensure that formations have sufficient pore volumes and can accept the change in pressure to accommodate planned injection volumes.

[5] NatCarb is a GIS database that integrates carbon sequestration data from the RCSPs and various other sources (NatCarb, 2008). The purpose of NatCarb is to provide a national view of the CCS potential in the United States and Canada. The digital spatial database allows users to estimate the amount of CO_2 emitted by sources, such as power plants, refineries, and other fossil fuel-consuming industries, in relation to geologic formations that can provide safe CO_2 GS over long periods of time (DOE, 2008).

[6] Most of the RCSPs have websites with interactive layers populated with the results of their Characterization Phase mapping activities. Websites can be accessed through NETL's RCSP Website: http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html.

Table 3.1. Guidelines for Site Screening.

COMPONENT		ELEMENT	GUIDELINES FOR SITE SCREENING
Regional Geologic Data	Subsurface Data Analysis	Injection Formation(s)	Identify regional and sub-regional injection formation types. Utilize readily accessible data from public sources (e.g., state geological surveys, NATCARB, the Regional Sequestration Partnerships, published and open-file literature, academic sources) or acquired from private firms. Data gathered should include regional lithology maps, injection zone data (thickness, porosity, permeability), structural maps, information about structure closure and features that might compartmentalize the reservoir such as stratigraphic pinch outs, regional type logs, offset logs, petrophysical data, and regional seismicity maps.
		Adequate Depth	Assessment of minimum depth of the injection zone to protect USDWs is required; in addition depths greater than 800 m generally indicate CO_2 will be in a supercritical state and may be more cost-effectively stored. Shallow depths (generally < 800 m) may add to the risk profile because (1) CO_2 could be in gas phase and (2) the injection zone may be closer to USDW.
		Confining Zone	Candidate injection zones should be overlain by a confining zone comprised of one or more thick and impermeable confining intervals of sufficient lateral extent to cover the projected aerial extent of the injected CO_2. Confining zones can be identified on a regional basis from the same types of information used to identify injection formations. Wells that penetrate potential confining zones should be identified and included in the risk assessment; this information can be obtained from state oil and gas regulatory agencies. Faulting and folding information that may impact confining zone integrity should be mapped along with potential communication pathways. Confining zone integrity may be validated by presence of nearby hydrocarbon accumulations.
		Prospective Storage Resources	Candidate CO_2 storage formations should contain enough Prospective Storage Resources beneath a robust confining zone for the volume of CO_2 estimated during Project Definition and the displaced fluids. Prospective Storage Resources (and injectivity if permeability data is available) should be estimated at the sub-regional scale utilizing existing data (e.g., NATCARB, and state geological surveys) to populate basic numerical models.
Regional Site Data	Regional Proximity Analysis	Protected and Sensitive Areas	Identify environmentally sensitive areas using U.S. Environmental Protection Agency, U.S. Department of Interior, U.S. Forest Service and U.S. Bureau of Land Management GIS systems. Assess the potential for conflicts with siting of pipeline routes, field compressors and injection wells. In addition, evaluate potential for other surface sensitivities utilizing maps for other hazards (e.g., flood, landslide, tsunami).
		Population Centers	Identify population centers using state and federal census data. Assess the potential for conflicts with siting of carbon storage projects .
		Existing Resource Development	Identify existing resource development, including wells that penetrate the confining zone, using data from state and federal oil and gas, coal, mining and UIC and natural resource management offices. Assess the potential for conflicts between siting of carbon storage projects and existing or prospective mineral leases as well the availability of complementary or competing infrastructure.
		Pipeline ROWs	Identify all pipelines and gathering lines/systems. Assess potential for conflicts in routing of pipelines to carbon storage projects as well as the potential for use or access to existing pipeline right-of-ways (ROWs). Identify other ROWs (e.g., powerlines, RR's highways) and assess potential for synergies or conflicts in siting carbon storage projects. This data can be found through commercial and government sources.
Social Data	Social Context Analysis	Demographic Trends	Describe communities above and near candidate Sub-Regions by evaluating readily available demographic data and media sources. To the extent possible, assess public perceptions of carbon storage and related issues; develop an understanding of local economic and industrial trends; and begin to identify opinion leaders.
		Land Use: Industrial and Environmental History	Describe the trends in land use, industrial development and environmental impacts in communities above or near candidate Sub-Regions by evaluating sources such as online media sites, regulatory agencies, corporate websites, local environmental group websites, and other sources. Begin to assess community sensitivities to land use and the environment.
Complete Site Screening		Selected Area	Develop a list of potential Selected Areas and rank based on criteria established in Project Definition.

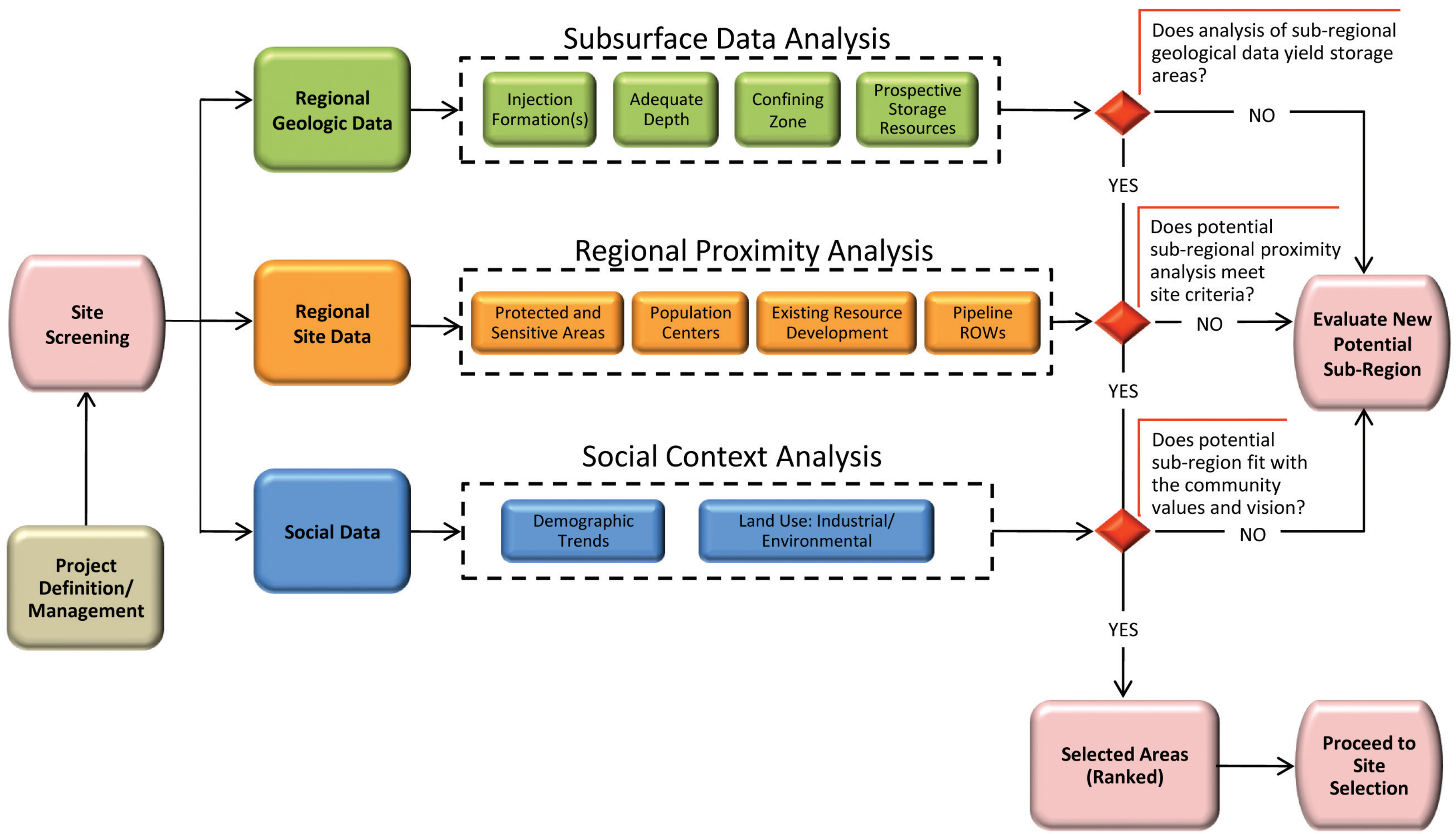

Figure 3.1. Process Flowchart for Site Screening.

A brief description of each of these elements is provided below, the reader should also refer back to Figure 3.1 and Table 3.1 to chart the process flow and find the suggested guidelines for assessing these elements. The guidelines should be considered the minimum for data collection and analyses completed through the Site Screening evaluation.

i. Injection Formation

The RCSP Initiative has mapped three primary geologic types within their regions as potentially suitable for CO_2 GS: oil and natural gas reservoirs, deep saline formations, and unmineable coal seams. In addition, two other formation types, organic-rich shale and volcanic and mafic rocks, principally basalt, are being further studied. While these formations are focused primarily onshore, the RCSP Initiative is beginning to identify and map potential offshore sub-seabed formations. Each geologic type has its own opportunities and challenges. As illustrated in Figure 3.2, formations with potential storage sites are found throughout the United States near numerous large sources of CO_2.

Most CO_2 storage resources across the United States are present in major depositional basins. Within these basins, the rock units are complex amalgamations of homogeneous and heterogeneous rocks whose properties are dependent on their depositional and diagenetic history. The five formation types currently evaluated or studied for CO_2 GS are described below.

Oil and Natural Gas Reservoirs

Mature fields that have in the past or are currently producing oil or natural gas contain geologic characteristics that make them excellent target locations for CO_2 GS. Typically oil and natural gas reservoirs have held hydrocarbons for millions of years. The geologic conditions that trap oil and gas are also conducive to CO_2 GS. In addition, because these fields have been extensively studied, a large amount of production history, well-log, and other data are available. Typically, there is also significant field infrastructure already in place. In some cases, this infrastructure could be utilized for CO_2 GS.

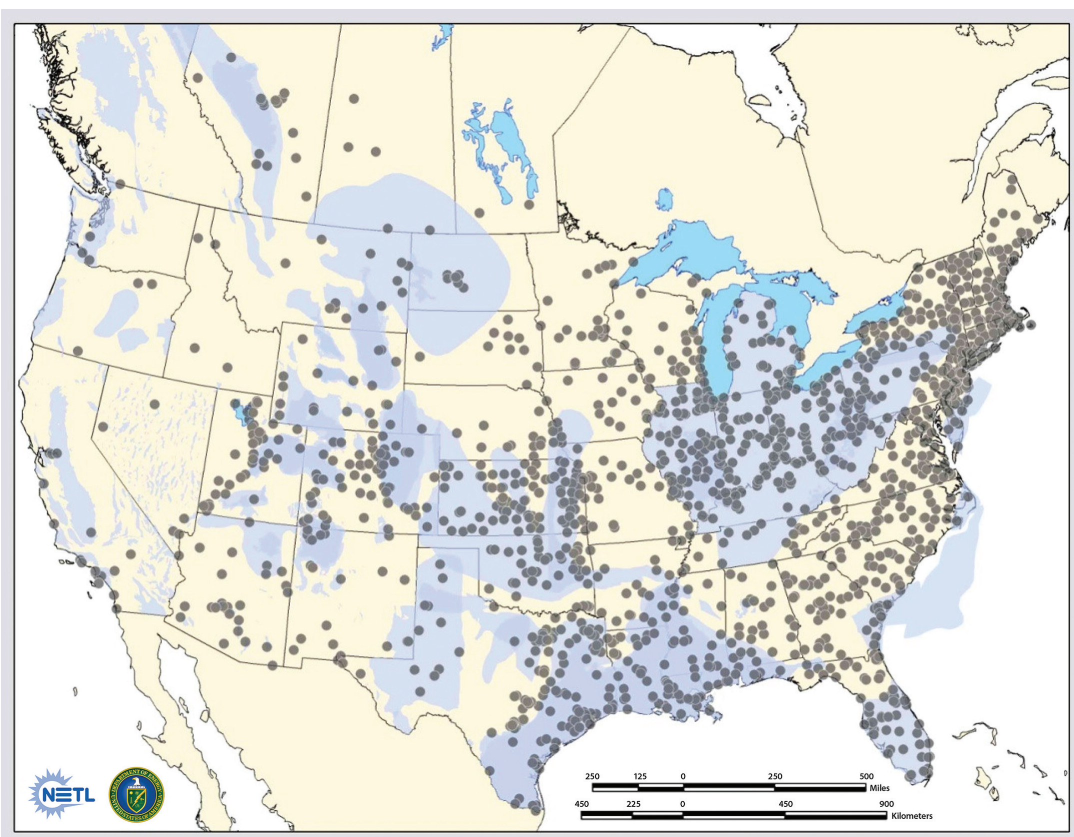

Figure 3.2. An overlay of the geologic storage options and power plant locations to provide an image of the distribution and source-to-sink proximity for potential storage locations and major CO_2 point sources as reported by the RCSPs.

As a benefit, when CO_2 is injected into a mature oil field, it may produce additional oil through a process known as CO_2 enhanced oil recovery (EOR).

Potential storage formations in mature oil and gas fields are characterized by sedimentary rocks that include one or more layers of clastics (coarse, medium and fine grained), or carbonates (dolomite and limestone) with sufficient porosity and permeability for adequate injection and storage. These porous formations must be overlain by one or more layers of low-permeability rock called a confining zone(s), such as an evaporite or shale, to form a physical barrier that kept the hydrocarbon trapped and will keep the CO_2 from migrating out of the injection zone. Prospective storage resource in mature oil and gas fields is estimated in the 2008 National Carbon Atlas to be 140 billion metric tonnes (DOE, 2008).

Deep Saline Formations

Deep saline formations are layers of porous rock that contain formation waters whose salinity is greater than 10,000 mg/L total dissolved solids (TDS). This water is generally unsuitable for drinking or agriculture.[7] Saline formations are very promising as potential CO_2 GS sites because they are often thicker and more areal extensive than oil and natural gas reservoirs or coal seams and therefore represent an enormous potential for storage. Suitable saline CO_2 GS sites may be in close proximity to CO_2 sources, minimizing pipeline transport distance.

Like oil and natural gas reservoirs, potential storage sites in deep saline formations are characterized by sedimentary rocks that could include one or more layers of clastics (coarse, medium, and fine grained), or carbonate (dolomite and limestone) with sufficient porosity and permeability for adequate storage and injectivity. These potential formations are typically overlain by one or more layers of low-permeability rock called a confining zone, that form a physical barrier that prevents upward migration of the CO_2. Deep saline formations must be shown to effectively trap CO_2 as well as any pressurized brine. Trapping is needed to avoid escape of fluids into a USDW or to the surface and atmosphere. Trapping can be in a structural or stratigraphic closure analogous to those that trap hydrocarbons. Alternatively, effective trapping by a combination of capillary processes and dissolution over a long flow path can be considered.

Despite the large potential for storage capacity, it is important to note that deep saline formations are less extensively characterized than oil and gas fields and many coal seams. Therefore, more effort is required to complete the Exploration Phase evaluations. The 2008 National Carbon Atlas estimates 3,300 to 13,000 billion metric tonnes of prospective storage resource in saline formations throughout North America (DOE, 2008). NETL's work in this area is focused on improving our understanding of the fate and safety of long-term CO_2 GS in deep saline formations.

Unmineable Coal Seams

CO_2 could potentially be stored in unmineable coal seams through the process of adsorption. Coal seams that are too deep or too thin to be economically mined are considered unmineable. CO_2 injected as a gas into a coal seam will adsorb onto the coal surface and be stored. All coal seams have varying amounts of methane adsorbed onto pore surfaces. Coalbed methane (CBM) production recovers natural gas or methane by drilling wells into coal seams. The concept of enhanced coalbed methane (ECBM) recovery is based upon the fact that coal has a greater affinity for CO_2 than methane. Thus, when CO_2 is injected into the coal seam, methane is liberated and produced, depending on the hydrostatic pressure, while the CO_2 is retained. It is important to note that coal permeability decreases with depth, such that injectivity is not possible below about 3000 feet without fracturing, and that coal "swells" in the presence of CO_2, which further reduces permeability, hence injectivity. NETL's work in this area is focused on increasing the amount of CO_2 that remains in the coal, while minimizing the negative effects of CO_2 on the seam's properties. A range of approximately 160 to 180 billion metric tons of prospective storage resource is available in unmineable coal seams in North America (DOE, 2008).

[7] Average seawater is 33,000 mg/L TDS - http://www.ruf.rice.edu/~cbensa/Salinity/index.html

Organic Shale

Shale is characterized by horizontal layers of typically clay-rich rock with low permeability, especially in the vertical direction. For this reason organic shale functions currently as a confining zone. Many shale units contain one to two percent organic material, which provides an adsorption substrate for CO_2 GS similar to that of coal seams. Organic shale has recently emerged as a current and future source of natural gas in the United States. With the prospects of producing shale gas, the issue of CO_2 storage in shale becomes much more complex and needs further examination. To date, little research has been done on achieving economically viable CO_2 injection rates or enhanced gas recovery in organic shale, given the extremely low permeability. The technical and commercial feasibility is unknown, but should it prove feasible, organic shale may represent a CO_2 GS resource.

Basalt and Other Volcanic and Mafic Rocks

A number of volcanic and associated rock types have a chemical composition making them highly reactive with CO_2 that could potentially convert the injected CO_2 to a solid mineral form, thus permanently isolating it from the atmosphere. Basalt research is focused on enhancing the mineralization reactions and increasing CO_2 flow within a basalt formation. Basalt flows, such as those of the Columbia River Basalts in the Pacific Northwest, are believed to have a large potential for permanent CO_2 GS. These flow intervals have generally high permeability and porosity, and their confinement ability has to be demonstrated. Although research is being carried out on CO_2 GS in basalt, further validation and development injection tests are anticipated before this formation is used for commercial injection.

ii. Adequate Depth

Compliance with the Safe Drinking Water Act requires that injection occur below USDW, although EPA may grant exemptions in some cases of very deep fresh water. A project developer should map all USDWs and their depths.

In addition, to increase storage security and confidence, injection at depths where CO_2 will be supercritical are favored. To maximize CO_2 GS potential, the entire injection formation should be deep enough to store CO_2 under supercritical conditions that are at least 800 meters below the surface, at or above 88.3 degrees F temperature, and at or above 1,071.3 psi pressure. At this combination of temperature and pressure, the CO_2 has a liquid-like density of approximately 31 to 50 pounds per cubic foot (500 to 800 kg per cubic meter) and the volume of the CO_2 is significantly reduced compared to gas phase at shallower depths. This ensures efficient utilization of underground storage space. At supercritical conditions, the density of CO_2 ranges from 50 to 80 percent of the density of water and is close to the density of some crude oils. Therefore, supercritical CO_2 is less dense than saline water, and, as a result, buoyant forces will tend to drive CO_2 upwards within the formation. Consequently, the presence of an effective confining zone over the selected injection zone is necessary to ensure that CO_2 remains trapped underground. Sites that are isolated in this way typically possess pressure and temperature conditions that maintain CO_2 in a supercritical condition, depending on the regional geothermal gradient. Storing CO_2 as a supercritical fluid with liquid-like density allows for efficient utilization of underground storage space.

It is important to note that some opportunities may be available at shallower depths not favorable to supercritical conditions. For example, the German Ketzin project is located at a depth that is right at the phase boundary. In addition, some additional attractive settings are depressurized gas reservoirs. The low pressure provides a lot of storage under conditions of high isolation; however the CO_2 will be in agaseous state when it first enters the reservoir.

iii. Confining Zone

Candidate CO_2 GS regions, areas, and sites must possess a suitable confining zone. A confining zone is defined as one or more confining intervals that limit the vertical flow of CO_2 into other formations, underground sources of drinking water (USDWs), and the atmosphere. Examples of suitable confining interval(s) include shale and thick deposits of evaporite, such as gypsum or salt (WRI, 2008). Analyzing existing geologic data can provide insight into the presence of confining zone(s) in the region, including formation type, depth, thickness, and lateral extent. This level of analysis can be sufficient for Site Screening; however, significantly more detailed analysis of the confining zone(s) will be necessary in the subsequent Site Selection and Initial Characterization stages.

iv. Prospective Storage Resources

In the Site Screening stage, Prospective Storage Resource estimates are simply based on the geologic characteristics of the target formation. Key factors influencing calculations include the areal extent, thickness average porosity of the injection formation, density of the CO_2 at reservoir conditions, and the efficiency factor as defined in Appendix 1. Initial estimates of the Prospective Storage Resources should be established and then further refined as new data are acquired throughout the Exploration Phase. A detailed description of the procedures used to estimate Prospective Storage Resources for oil and natural gas reservoirs, saline formations, and unmineable coals seams are available in Appendix 1.

Completion of the regional geologic evaluation leads to a decision gate. To move forward in the evaluation, identified injection formation(s) have to be located at an adequate depth to maintain supercritical conditions, have an extensive regional confining zone and a calculated Prospective Storage Resources volume sufficient to store the planned volume of CO_2 and the initial estimate for extent of the plume. After all these elements have been analyzed for the region, the results of the regional geological analysis should identify several regions of interest that will also be evaluated with the remaining two components, Regional Site Data and Social Data to yield a ranked list of Selected Areas to be evaluated further in the Site Selection stage.

3.2 Regional Proximity Analysis

The second component of the Site Screening stage includes an analysis of Regional Site Data to determine any potential regional or sub-regional proximity issues. At a minimum, four potential site features could have an impact on the attractiveness of a sub-region: (i) Protected and Sensitive Areas, (ii) Population Centers, (iii) Existing Resource Development, and (iv) Pipeline Right-of-Ways (ROWs). While the presence of any of these features does not constitute a technical reason to eliminate a site, their presence could require additional analyses, contingencies, project delays and increased project costs. Careful evaluation of any potential issues concerning land access and use should also be carefully evaluated during this process.

i. Protected and Sensitive Areas

Actions must be taken to protect the land, air, and water in the vicinity of the well during siting, development, operation, and closure. During the Site Screening evaluation, thoughtful consideration should be given to environmentally sensitive features in or near a region being evaluated. Protected and sensitive areas such as wetlands, national or state parks, protected or historical areas, Native American tribal lands, and species-sensitive areas may require additional measures to protect them. As a result, it may be advisable to exclude them during Site Screening or to consult the corresponding regulatory authorities about additional requirements. This is especially important if federal funds will be used, as this triggers National Environmental Policy Act (NEPA) requirements, which specifically consider these factors.

Wetlands

Any modifications to wetlands in the United States will likely be regulated, in some capacity, by federal, state, and/or local governing authorities. Section 404 of the Clean Water Act (CWA) (EPA, 2009b) provides the regulatory framework for the Federal government's role in regulating activities that impact wetlands. The Federal program is administered by the U.S. Army Corps of Engineers (Corps) with oversight by the U.S. Environmental Protection Agency (EPA). Section 404 of the CWA regulates the discharge of dredged and fill material into U.S. waters, including wetlands. The regulations under Section 404 of the CWA may be applicable if a project requires disposal of fill material into waterways. Wetland replacement regulations, similar to "mitigation banking," are commonly active on the state level with the goal of replacing any lost wetland acreage with constructed wetlands. Potential site development in or near wetlands (including possible transportation through a wetland) that impact wetland integrity may require alternative wetland be set aside to replace the impacted acreage. In Pennsylvania, for example, the Department of Environmental Protection governs wetland replacement regulations and requires the replacement of lost wetland acreage with constructed wetlands, with a ratio currently set at 1:1 with a permit, and 2:1 without a permit. EPA guidance on wetlands is available at (EPA, 2009c).

Source Water Protection Areas[8]

Source water is untreated water from streams, rivers, lakes or underground aquifers that is used to provide public drinking water and wells for private consumption. Although this water usually requires treatment before being consumed, these waters are protected to the extent possible from contamination. The Safe Drinking Water Act requires that the states develop EPA-approved programs to carry out assessments of all source waters in the state. The source water assessment is a study that defines the land area contributing water to each public water system, identifies the major potential sources of contamination that could affect the drinking water supply, and then determines how susceptible the public water supply is to this potential contamination. There may be local or federal requirements relating to activities that take place nearby, or that have the potential to impact these waters. Notably, Sole Source Aquifers might trigger additional project reviews as part of the permitting process.

Protected Areas

A protected area is defined as an area of land and/or sea where protection and maintenance of biological diversity, natural resources, and cultural effects are required through legal or other effective means. Examples of protected areas include national or state parks, national monuments, or areas with important historical or cultural significance. In the United States, protected areas are managed by an assortment of different federal, state, local, and tribal authorities. As of July 2009, the United States had 6,770 nationally designated (Federal) protected areas, according to the United Nations Environment Programme (UNEP, 2008). These protected areas cover 27 percent of the land area of the United States (1,006,619 mi^2 [2,607,131 km^2]).

Species Protection

In the United States, CO_2 GS projects cannot pose a threat to the well-being of protected wildlife, flora, or fauna in the region or the habitat in which they live. There are a number of methods for successfully developing oil and natural gas infrastructure in such areas, but these operations are carefully planned and in some cases incur additional project time and costs. During Site Screening, project developers should identify, evaluate, and prepare a mitigation plan to address the protected species in the region being evaluated. Project schedule and costs should also be modified to account for protected species and wildlife migration patterns in the region being evaluated.

ii. Population Centers

In order to obtain permits, a CO_2 GS project must be able to demonstrate that injected CO_2 will remain contained in the subsurface. The fact that there are a number of analogous injection practices, such as natural gas storage, located in densely populated areas suggests that the presence of a population center near a candidate site is not a reason, per se, to reject that site. However, a number of issues must be carefully examined when considering a site in a densely populated area. These include the challenges associated with acquiring permission for site characterization activities, rights to pore space, and access right-of-ways. These concerns could lead to project delays and increased costs in the future; therefore, a project developer may prefer sites that are not near population centers. In addition, costs of developing a project increase where land is more valuable and both cost of accommodating dual uses.

iii. Existing Resource Development

Locating a CO_2 GS project near existing hydrocarbon resource developments can lead to benefits and concerns. Existing upstream oil and natural gas developments, for example, may provide valuable information about the potential reservoir with minimal investment. However, every deep well through the candidate injection zone is a breach of the potential confining zone and the cement and casing integrity of those wells needs

[8] This section draws extensively on information provided by US EPA's Source Water Protection program website: http://cfpub.epa.gov/safewater/sourcewater/sourcewater.cfm?action=Basic&view=general

to be understood if the site is later qualified for injection and storage. Production wells (Class II wells under the UIC program) generally do not have cement between the production zone and the surface casing; this may cause wells to provide unacceptable pathways from the one zone to another above the reservoir. For this reason, careful analysis should be made of all existing infrastructure—subsurface and surface, industrial and non-industrial—to determine the extent to which their presence might impact proposed injection and storage operations as potential leakage pathways.

Furthermore, as the petroleum industry evolves, new technologies are enabling resources once considered not technically feasible to become economic sources of hydrocarbons (e.g., producing shale reservoirs). In some instances, a shale formation that was being considered a confining zone for geologic storage may also be considered an economic reservoir for the petroleum industry. Regional analysis of the existing and competing resource developments needs to be considered against the ranking criteria.

iv. *Pipeline Right-Of-Ways (ROWs)*

During Site Screening, proximity to CO_2 pipelines and existing right-of-ways should be evaluated. The construction of pipelines can be capital intensive. A preliminary screening should evaluate a CO_2 GS project's pipeline needs and the existing CO_2 pipeline network in the candidate project regions, and if any exist, to rate the size, capacity and age of the pipelines. It may be possible to utilize existing pipeline right-of-ways or infrastructure. Furthermore, if no pipeline infrastructure exists, the developer may prefer a region with potential injection formations that are located closer to the CO_2 source because they would not need extensive pipelines. If pipelines will be constructed, then the ability to store large volumes of CO_2 will help to reduce pipeline cost per unit volume stored, thus indicating a preference for injection formations with large Prospective Storage Resources. Regardless, the existence, condition, and availability of access to any existing pipelines in acceptable proximity to the regions of interest should be carefully evaluated. It should be noted, however, that many existing pipelines are unlikely to be suitable for conversion to supercritical CO_2 service due to pressure limitations and, possibly, due to materials utilized. This type of data may be available from state public utility regulators or obtained from oil and gas data vendors.

The initial regional proximity analysis will contribute to the ranking of potential sub-regions by identifying those sub-regions that may require extensive operations (including transportation) in or near environmentally sensitive or densely populated areas, or that may require extensive transportation systems.

3.3 Social Context Analysis

The 2009 Public Outreach and Education Best Practices Manual published by the RCSP Initiative highlights the imperative of integrating outreach into overall project planning and management starting with Site Screening. During this stage of Site Screening, the objective is to open lines of communication and develop an understanding with the communities under consideration as potential locations for CO_2 GS projects. In addition, it is important to consider the public outreach implications based on the land ownership patterns around candidate parcels of land, pore-space issues, local and regional governance structures, and the necessary permits and approvals. The project developer should review readily accessible sources of information for (i) Demographic Trends, and (ii) Land Use–Industrial and Environmental. These insights can be used to begin to understand how a community may view CO_2 GS, the strategies for community engagement that may be appropriate, and the potential perceived benefits and risks from the project for the community. This information feeds into a preliminary social characterization that will be expanded during the Exploration Phase. Further, it may be useful to review back issues of local and regional newspapers to get a better understanding of community perspectives on energy, climate, the economy, and other related issues.

i. *Demographic Trends*

Demographic trends can be used to help develop an understanding of the social context across the region being considered. Data collection can be done through online sites focused on demographic data (e.g., U.S. Census database or State economic development websites), academic journals and reports, and local media; interviews with project team members who may have direct experience in the candidate location; reviews of economic and industrial activity databases; and reviews of historic environmental trends through permitting, regulatory, and other databases. The purpose of this research is to develop a preliminary understanding of the communities in which a project may be located. This can help to answer questions about how well a project may fit in a community.

ii. Land Use: Industrial and Environmental

It is important to assess the land use and environmental history in regions being considered for a CO_2 GS project. This history can give insights to questions such as: Is the land primarily industrial? Are communities used to seeing well-drilling operations, seismic acquisitions, or pipeline construction and use? Is there a strong agricultural presence in the region? Are there environmentally sensitive areas of concern in the region? Understanding the land use in a region will aid in assessing the potential perceived risks and benefits from a project.

An evaluation of the social context in regions of interest should be used to identify the public outreach efforts that will be necessary to support a CO_2 GS project in a given sub-region. This can lead to a better understanding of potential project costs and timelines.

3.4 Develop List of Selected Areas and Rank

Site Screening involves a broad review of potentially suitable Potential Sub-Regions within a basin. The Site Screening process results in identification of Selected Areas that meet geologic screening, proximity, and social context criteria as well as suitability for injection based on criteria established during Project Definition. The identified and ranked selected areas will be evaluated further during Site Selection. Some identified areas will not be able to go forward because they either do not meet the criteria or could meet the criteria but the costs incurred to meet the criteria might yield an uneconomic project.

4.0 Site Selection

The purpose of Site Selection is to further evaluate previously Selected Areas and develop a short list of Qualified Sites suitable for Initial Characterization. Site Selection utilizes the existing data and analyses from Site Screening and augments them with new, proprietary or other purchased data to evaluate characteristics of the Selected Areas. Prior to initiating the analyses of the Selected Areas, similar to Site Screening, a multi-discipline team should define the analysis to be conducted at each of the components. The analysis should include at minimal the elements described in Figure 4.1 and consider scope, evaluation criteria, resources and schedule. This stage, analogous to the second project status of an oil exploration program called a "Lead," includes evaluation of five technical and nontechnical components: (1) Subsurface Geologic Data; (2) Regulatory Requirements; (3) Model Data; (4) Site Data; and (5) Social Data. These components can be evaluated simultaneously while working towards answering the questions posed at the decision gates indicated in the Site Selection process chart in Figure 4.1. Accordingly, "no" responses would shift the analysis to a new Selected Area, and "yes" responses would lead to inclusion on the list of potential Qualified Sites for further ranking and evaluation. A site development plan should be outlined for each Qualified Site and used to assess their economic feasibility. Based on their economic feasibility and fit with the project goals, the project developer can establish a rank order of Qualified Site(s) for Initial Characterization. Table 4.1 includes the guidelines for each element necessary to satisfy the project status as Site Selection.

Table 4.1. Guidelines for Site Selection.

COMPONENT		ELEMENT	GUIDELINES FOR SITE SELECTION
Subsurface Geologic Data	Subsurface Data Analysis	Injection Zone (Reservoir)	Define injection zones (reservoirs) based on public and acquired regional well data. Analysis should include at minimum the development of a regional stratigraphic column identifying potential storage types and injection and confining zone(s), and potential USDWs; structure and isopach maps of injection and confining zone(s); regional cross-sections; regional tectonic maps, reservoir dip, and analog well data such as lithology, porosity, permeability, pressure, temperature, and dynamic formation evaluation data (DST, well test, production/injection data).
		Confining Zone	Establish the areal extent, thickness, lithology, porosity, permeability, capillary pressure data, and other factors that might affect integrity of the confining interval(s) within the confining zone. Perform a faulting and folding analysis based on tectonic history and analogs. Utilize existing well bore, core, outcrop and regional analog data to identify and map confining interval(s) tops, bases and thicknesses within the confining zone.
		Trapping Mechanisms	There are several mechanisms that effectively "trap" injected CO_2, including physical barriers, as well as physical and geochemical processes. Evaluation of trapping mechanism should be based on the local well, outcrop and any available regional reservoir analyses including analogs in similar formations.
		Potential Injectivity	Utilize collected data and analyses to estimate potential permeability-thickness of targeted injection zone and identify boundary conditions that will affect injection estimates; assess well stimulation and completion scenarios to achieve target injection rates .
		Evaluate Existing Seismic	Existing regional seismic data could be used to validate the regional stratigraphic and structural framework. All available seismic attribute data should be integrated with the injection zone, structure, confining zone and capacity evaluations. If existing seismic data is not available, it is recommended that a project developer wait to acquire data during the Initial Characterization stage—unless regional geology warrants information earlier in process.
		Prospective Storage Resources	Prospective storage volumes should be calculated utilizing acquired data, reporting resource volume ranges (low/medium/high) with identification of uncertainties in calculations. The reservoir evaluation should be used in calculation of prospective storage with all parameters and sources defined, such as "efficiency" calculations. It is recommended, if no other methodology is preferred, to begin with DOE 2010 resource calculation methodology in Appendix 1. Calculations should be reported assuming a maximum storage pressure and either an open or a closed system for brine displacement as endpoints.
Regulatory Requirements	Regulatory Issue Analysis	Well Classification	Review state and federal rules and UIC well classes and requirements for Area of Review (AoR), well construction and MVA. For the AoR, understand well construction, and monitoring requirements. Develop an understanding of the process for well permitting operations, maintenance and eventual closure. Consider proposed regulatory requirements for the operation, maintenance and eventual abandonment of wells.
		Corrective Action	Review UIC requirements for corrective action in the AoR and initiate an analysis of wellbore integrity for existing wellbores in the Selected Area by utilizing existing data and identifying data needs for further evaluation.
		Injection Pressure	Review the regulatory requirements for establishing maximum injection pressures for the formation.
		Containment Mechanisms	Review the regulatory requirements for demonstrating the long term integrity of containment mechanisms. Utilize collected data and the reservoir analysis to identify potential containment risks and potential mitigation actions.
		Liability	Review the provisions for addressing financial assurance and liability that pertain to the project in the relevant state and federal regulations. As necessary, incorporate requirements into the project plan and budget.
Model Data	Model Development	Modeling Parameters	Identify type of model(s) (static and dynamic) and modeling parameters. Parameters should be defined by the results of the subsurface geologic evaluation, including injection zone characteristics, confining zone mechanisms, and available rock and fluid properties. The model should be based on subsurface data; grid dimensions and layering definition based on the reservoir analysis and likely plume extent. Analog data should be utilized to populate parameters with data gaps.
		Data Requirments and Cost	Identify data requirements to reduce model uncertainty ; construct cost analysis to determine the value of acquiring data. Data acquisition should balance the benefit of reducing uncertainty against cost of acquiring it at this stage.
		Boundary Conditions/ Uncertainty	Uncertainties related to boundary conditions should be identified, documented, and communicated to project stakeholders to avoid over extrapolation of the model results and creation of non-relevant or incorrect data. Modeling sensitivities should include both open and closed boundaries for brine flux and future pressure estimates.
		Existing Seismic Data	If available, integrate existing seismic data in development of model.

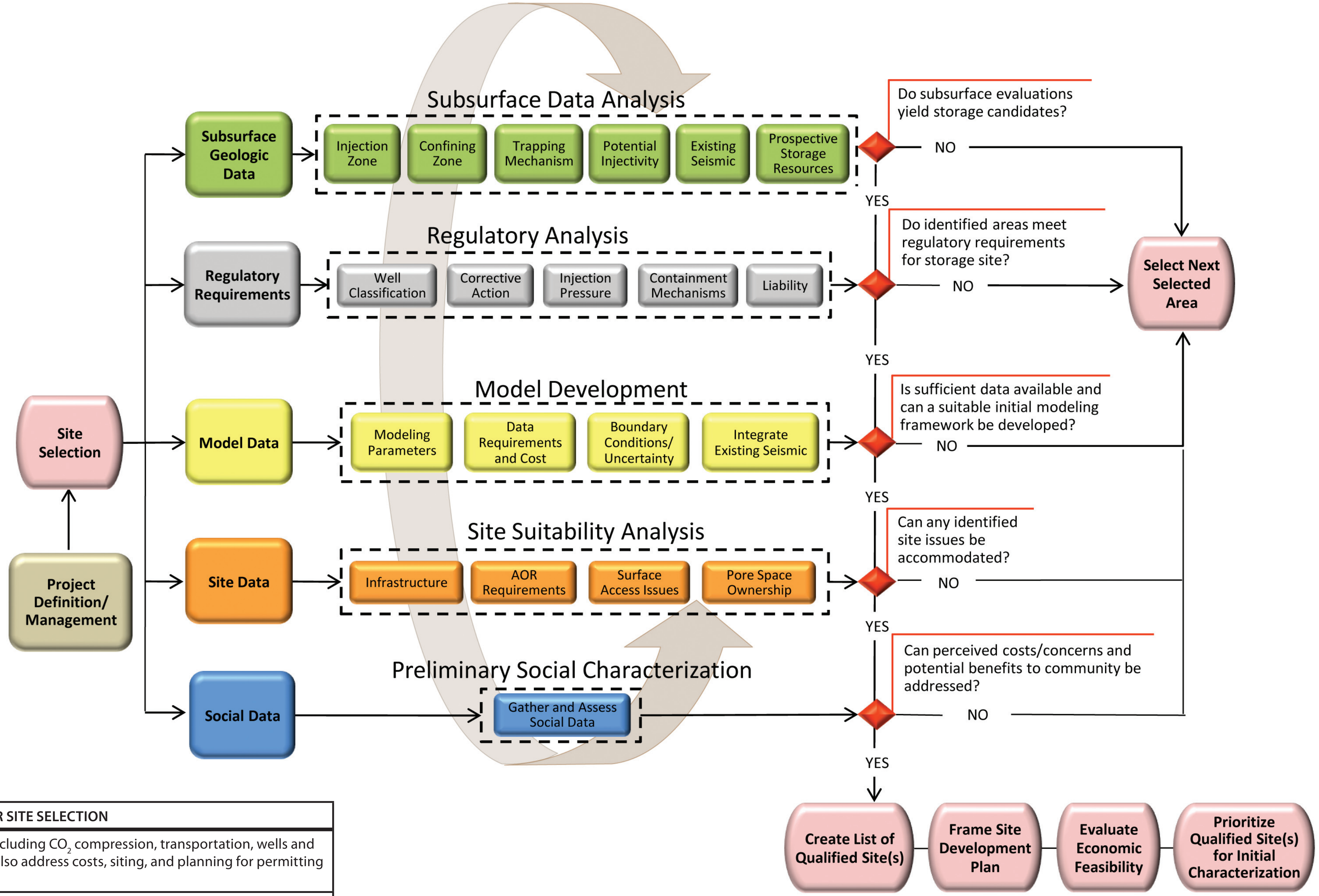

Figure 4.1. Process Flowchart for Site Selection.

COMPONENT	ELEMENT	GUIDELINES FOR SITE SELECTION
Site Data	Infrastructure	Include the evaluation of necessary infrastructure including CO_2 compression, transportation, wells and monitoring. A feasibility study for pipelines should also address costs, siting, and planning for permitting pipeline right of ways.
	AoR Requirements	Evaluate the AoR to assess potential surface and pore space ownership issues. There are several methods for determining the AoR; it is recommended that the developer use a range of methods to determine the area to be covered in this analysis. Model results should be examined for both pressure and plume migration impacts on AoR.
	Surface Access	Evaluate potential surface access issues. This should include identification of and a mitigation plan for potential access and environmental issues. An assessment of project impacts (e.g., economic, schedule and social) should also be conducted and the results incorporated into ranking criteria.
	Pore Space Ownership	Evaluate the pore space ownership rules for Selected Areas, including mineral rights and unitization provisions. Utilize a range of AoR outcomes to assess the number of pore space owners potentially impacted by plume migration.
Social Data	Gather and Assess Social Data	Conduct a more detailed evaluation of data to begin to develop an understanding of potential perceived concerns and benefits, opinion leaders and stakeholder groups. At this point, it may be useful to conduct some stakeholder interviews.
Complete Site Selection	Qualify Site(s)	Frame the Site Development Plan and complete an economic feasibility analysis across a range of carbon prices for each site to be included on the short list of Qualified Sites. Rank Qualified Site(s) for Initial Characterization.

4.1 Subsurface Data Analysis

The Site Selection process builds on the geologic evaluation conducted during Site Screening in order to improve the project developer's understanding of the complex nature of the subsurface. At this stage, the Subsurface Geologic Evaluation component will consider six primary elements that will be addressed in this section: (i) Injection Zone (Reservoir); (ii) Confining Zone; (iii) Trapping Mechanisms (both structural and non-structural or open systems that rely on CO_2 dissipation); (iv) Potential Injectivity; (v) Existing Seismic; and, (vi) Prospective Storage Resources. The results of these evaluations will be used to determine if Selected Areas within the Screened Sub-Regions have the subsurface characteristics necessary to proceed to the next stage.

i. Injection Zone (Reservoir)

The injection zone is an interval that includes the injection formation in which CO_2 will be injected and stored over the lifetime of the project, including the post injection period. An injection zone may have multiple injection intervals. The project developer should develop an initial stratigraphic and structural framework of the given area the heterogeneity of the subsurface–these initial frameworks will be developed on a coarse level. This framework will be further segmented into specific injection intervals for correlation if a site is promoted to the project status of Initial Characterization.

At the coarse level, a stratigraphic and structural framework correlates well log data within the region surrounding areas of interest in order to map the top and base of known regional formations. Purchase and analysis of available seismic data should be considered and cost/benefit analysis performed. The project developer's level of confidence in the accuracy of the stratigraphic and structural framework will depend on the density of available data within the area. The initial stratigraphic framework should highlight any structures such as faults, folds and stratigraphic pinch-outs that control the flow system and provide an understanding of the regional geology, thickness, and lateral extent of the targeted injection zone. In some instances, multiple target injection zones may occur at different depths and should also be mapped and assessed. Injection zone thickness maps (isopachs) can be layered onto the initial framework. As in the petroleum industry, the initial understanding of complex subsurface geology begins with the integration of this data. Once the stratigraphic and structural frameworks have been completed, if available, rock property (porosity) and formation test data (permeability and brine injection volumes) can be integrated to determine geologic storage potential.

ii. Confining Zone

At supercritical conditions, as it will be at most sites, CO_2 is lighter than saline water and oil, but heavier than natural gas. In addition, unless an injection zone is strongly depressurized, CO_2 will be injected at pressure higher than hydrostatic, giving both CO_2 and associated saline water and other fluids energy to move outward from the injection area, including upward (referred to as buoyancy). If a stream of CO_2 begins to move upward, expansion of the volume and decrease in density provides increasing energy to drive flow upward, which can result in gas lift, a process for moving fluid upward. It is essential that injection occur beneath a confining zone comprised of one or more confining intervals that are capable of preventing upward migration of ambient fluids and injected CO_2.

All rocks have some permeability, however many rock types have such low permeability that fluid flow occurs only over geologic time frames. Confining intervals within a confining zone are relatively impervious layers that overlie the injection zones and act to prevent movement of CO_2 and other fluids beyond the injection interval or immediate buffer zones. These layers typically have extremely low permeability and/or porosity, which aides in the ability to prevent transmission of fluids and gases. They are typically are composed of fine grained rocks, such as shales and mudstones, or of crystalline rocks in which the crystals are closely intergrown, such as well-cemented carbonate, bedded salt, or anhydrite rocks. The small pore throats of these rocks provide a capillary barrier, which does not allow entry of the CO_2 into the pore system. Flow through such rocks is limited to diffusion.

A confining zone must be regional in scale and separate the CO_2 injection zones from both the surface and USDWs over both the area where pressure is elevated such that saline water could be lifted to USDW and the area which will at some point in plume evolution be occupied by free-phase CO_2.

The confining intervals and zone(s) can be assessed by utilizing the well logs that were used for the subsurface analysis. Project developers should map the tops, bases, and isopach of local individual confining interval(s) within the confining zone. This will provide a more thorough understanding of the lateral extent of local and regional confining zone(s). Also, the level of confidence in the assessment of the individual confining interval(s) capacity can be improved by evaluating the rock properties of any available core through the confining interval formation.

iii. Trapping Mechanisms

Trapping mechanisms that will further assure permanence fall into two major categories: (1) traps that limit lateral flow of fluids (stratigraphic and structural traps) effectively forming a container to hold the CO_2 in place, and (2) mechanisms occurring during flow that attenuate CO_2 mobility over distance.

Features that form traps include structural traps such as anticlines, faulted compartments and stratigraphic traps, such as pinch out of permeable facies. Typically, the bottom of the traps are connected to a larger rock saline formation volume. This connection forms a water drive during hydrocarbon production, so that the volume of oil or gas removed by production is partly or wholly replaced by water, and therefore pressure is not permanently decreased. During injection, the reverse occurs, and saline water is displaced, so that pressure increase is reduced in magnitude and duration. Traps for buoyant fluids are common in saline formations also. In these areas, the features are similar to those that trap oil and gas in reservoirs, the main difference is that these saline formations did not receive hydrocarbon charge.

Figure 4.2 illustrates several ways in which structural and stratigraphic traps can be formed. For example, the left image shows an initial deposition of porous rock that is pinched off by layers of impermeable rock (known as stratigraphic thinning). The middle image in Figure 4.2 illustrates a trap formed by a fold that forms a structure. And the image to the far right shows a sealing fault.

Mechanisms occurring during flow that attenuate CO_2 mobility over distance are important to consider if the site does not contain traps, or if the risk model prefers stabilization by attenuation. These mechanism are often called secondary trapping mechanisms; they do not impede CO_2 movement through a physical trap. During stabilization, the CO_2 will move outward under pressure gradient and upward under buoyancy forces. During this

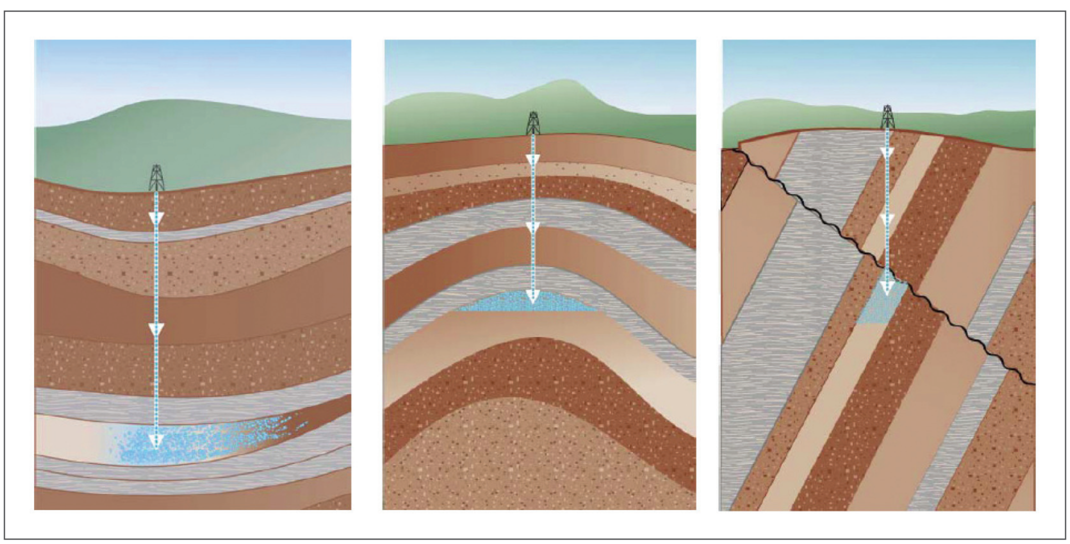

Figure 4.2. Models of stratigraphic trapping resulting from depositional thinning of a porous unit (left), structural trapping by a fold (middle), and confining zone(s)ing fault (right). (*Source: CO2CRC.)*

movement, it fills additional pore spaces. The ability of CO_2 to drain out of pore spaces is limited by capillary entry pressure, and significant volumes of 20% to 50% will be permanently stored as immobile phase CO_2. This capillary trapping is well known from oil and gas production, leaving large volumes of resource in the reservoir at the end of primary production. The advantage of this storage mechanism over a physical trap is that large volumes of such storage are available, and at the end of stabilization the CO_2 is immobile. Sleipner and the Frio Test are examples of storage occurring in an open volume in which movement is attenuated over distance. However, it is important to calculate the eventual flow path during siting.

Two other kinds of secondary trapping may take place over time. In solubility trapping, otherwise known as dissolution trapping, some of the injected CO_2 dissolves in the saline water; this is similar to the effect when CO_2 is dissolved into a carbonated beverage. Solubility (dissolution) trapping forms a fluid that is denser than saline water and it will not rise in the storage formation. And, in mineral trapping, the CO_2 may react chemically with the surrounding rocks to form minerals. Mineral trapping can be fast in reactive rocks such as basalt, but is slow in most sedimentary rocks.

iv. Potential Injectivity

An understanding of the potential injectivity is needed in project development for planning purposes. Some parameters affected by injectivity include planned rate of CO_2 captured, number of wells, and well design (vertical, horizontal, enhanced diameter, multi-lateral, etc.). Injection pressure and well number/design are key cost parameters. Injectivity can be estimated from production history in oil or gas reservoirs, from hydrologic tests (with water), or from analysis of core plugs. It is important to remember that this is only an estimate of the injectivity into a CO_2-brine system. Maximum pressure at which injection can occur is an important component determining injectivity and is regulated by the U.S. EPA through the UIC program. The maximum allowable surface injection pressure (MASIP) is calculated from the pressure in the injection zone that would risk mechanical failure of a subsurface component. Typically, such failure is determined by calculation of the pore pressure that would fracture the injection or confining zone, cause critical stress on a fault or fractures, or exceed the strength of engineered features (e.g., mud weight in existing wells). The maximum pressure is typically set at a specified fraction of the pressure that would lead to failure. MASIP also considers the density of the injectate and friction of flow though the wellbore. In later stages of site assessment, field tests of rock and fluid properties are needed to refine the estimates made at early stages.

v. Existing Seismic

Existing regional seismic data could be used to validate the regional stratigraphic and structural framework. All available seismic attribute data should be integrated with the reservoir, structure, seal, and storage resource evaluations. If existing data is not available due to cost of data acquisition, it is recommended that a project developer wait to acquire data in the field until a Selected Area matures to the Initial Characterization stage.

vi. Prospective Storage Resources

Finally, the last element to address in the geologic evaluation during Site Selection is updating the Prospective Storage Resource calculations. As more information is gathered and the potential injection formation is better understood, the confidence in the resource calculation should improve. Prospective Storage Resource calculations should be routinely updated, utilizing the DOE methodology outlined in Appendix 1 unless some other method is deemed more appropriate, to determine if the potential volume is reasonable for the CO_2 management strategy established in Project Definition. The project developer should also consider the volume of calculated storage that will potentially be occupied by brine. At this stage, the storage resource estimate is more certain than the one developed in Site Screening, but will be further refined as more data is incorporated into the evaluation. Storage resource calculations are continuously updated through the life of the project. This process is used in classifying the status of the storage site and will be further discussed in Chapter 6 on Geologic Storage Classification.

4.2 Regulatory Analysis

The second component of Site Selection involves an analysis of the potential regulatory requirements facing the project. The evaluations focus on five elements: (i) Well Classification; (ii) Corrective Action; (iii) Injection Pressure; (iv) Containment Mechanisms; and (v) Liability.

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 GS—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, 2009a). As of 2010, EPA has approved primary enforcement responsibility (primacy) for UIC Programs for all 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. See Appendix 3 for a more complete overview of the UIC program, the description of existing and proposed well classes, and insight into UIC jurisdiction across the United States.

During Site Selection, the project developer can assess the likely well classification applicable to the areas of interest and determine what siting characteristics are likely to be required by the UIC Program and other state and regional agencies. This information can be obtained by reviewing regulatory language that is typically posted on websites and contacting regulatory entities to develop an understanding of data needs and the steps involved in the permitting process. At this stage, it is a good idea to begin discussions with appropriate regulatory agencies. Regulatory and permitting requirements vary from state to state; the project developer should be sure to review the provisions that apply in the state where a potential project may be located. This initial review may be more helpful in identifying areas that may not meet regulatory requirements, rather than providing a definitive sense that a project will be permitted. If this is the case, a new Selected Area should be selected. If the site appears to meet the requirements, it can continue through remaining component analysis.

i. Well Classification

Under the UIC Program, injection wells are classified based on similarity in the fluids injected, activities, construction, injection depth, design, and operating techniques.[9] To date, CO_2 GS injection well permits have been issued under Class I, Class II, and Class V. In 2009, U.S. EPA published regulations for a new Class VI for CO_2 geologic sequestration wells; this rule is expected to be promulgated in 2010. If this rule is promulgated, it is likely that future CO_2 GS wells may be classified as Class II (if involving EOR) or Class VI. The draft Class VI requirements have significant differences from the Class II requirements. The UIC requirements are described in more detail in Appendix 3.

ii. Corrective Action

UIC requirements should be reviewed for correction in the Area of Review (AoR) and existing wellbores in the Selected Area should be analyzed for wellbore integrity. To complete the analysis, existing data should be evaluated and future data needs should be identified.

iii. Injection Pressure

The siting requirements for Class I and Class II (and likely Class VI) UIC wells under 40 CFR § 146.14 include demonstration of the presence and adequacy of injectivity by presenting information on local geologic structures, faults, and other relevant geomechanical information, plus maps and cross-sections of site lithology and USDWs. The project developer should ensure that the subsurface geologic evaluation will meet the regulatory requirements likely to face the project.

iv. Containment Mechanisms

Class I and Class II (and likely Class VI) UIC wells under 40 CFR § 146.14 require project developers to demonstrate the presence and adequacy of a containment mechanism. The demonstration must

[9] Source: US EPA website, UIC Program, accessed on 3/1/2010: http://www.epa.gov/ogwdw000/uic/wells.html

include information on local geologic structures, faults, and other relevant geomechanical information. It must also include maps and cross-sections of site lithology and USDWs. The project developer should ensure that the ranking criteria address the UIC containment mechanism requirements and any additional permitting requirements as defined by state and regional agencies. Anticipating these needs up front should help to streamline the permitting process, in turn helping to keep a project on schedule, limiting potential scheduling delays and cost overruns.

v. Liability

Liability for the CO_2, once it has been injected into the subsurface, is a currently debated issue. Uncertainty in long-term liability and responsibility for the injected CO_2, could affect the forward progress of a project. There is currently no clearly defined, widely accepted framework for the assignment of liability in CO_2 sequestration, although several states have adopted or are considering legislative approaches to address this issue. For example, Montana places liability for CO_2 GS with the CO_2 injection developer during the injection phase and for 30 years following cessation of injection. The liability may then be transferred to the State of Montana after the developer has met compliance standards and obtained the approval of Montana's Board of Oil and Gas Conservation. If liability is not transferred, it may remain with the developer indefinitely, with the possibility of later transfer after a review period. This is just one example of a state approach to liability. Project developers must review and understand any liability statutes in states where potential sites are being considered. Developers may want to discuss the implications with potential financiers or internal risk officers.

In addition to the regulatory issues discussed, several other regulatory issues should also be considered at this stage:

- Local requirements for obtaining approvals or permits and which agencies are responsible for oversight of these programs.
- Determine if there are other state or federal regulatory programs that might impact projects located in the areas being considered.
- Review the costs of obtaining permits (in terms of both time and budget) based on previous experience in a region and ensure that this information is integrated into the project plan.

4.3 Model Development

During the third component of Site Selection, Model Data, initial model(s),will be developed to be used for later numerical simulations. Several elements should be addressed when developing an initial model including (i) Modeling Parameters, (ii) Data Requirements and Cost, (iii) Boundary Conditions and Uncertainty, (iv) Existing Seismic Data. Models and numerical simulations are used to predict the movement of injected CO_2 and the magnitude and extent of pressure front(s). Modeling is used to test assumptions about the suitability of the injection zone to accept and retain CO_2 within the targeted injection zone. In addition, models used for sensitivity analysis are useful in assessing the importance of uncertainty in data. The stratigraphic and structural framework and the analysis of the depositional environment developed during the subsurface data analysis provide the subsurface understanding necessary to construct the initial models. At this stage, it is likely that the models are reasonably simple, and even analytical models can be useful; they will be further refined if a site matures to the stage of Initial Characterization.

Mathematical models and numerical simulations serve several important roles. They are used in evaluating the feasibility of CO_2 storage in the subsurface; designing, implementing, and analyzing field tests; and, engineering and operating geologic CO_2 storage systems (Pruess et al., 2001). Once a project is in operation, measurements gained through monitoring can be used to verify that the project is performing as predicted by models. Therefore, tracking changes between the initial and the updated model through time is critical for long-term validation.

The linkage between model results and monitoring data can be complicated if monitoring, verification, and accounting (MVA) programs are not designed to assess and acquire data for the same parameters (including the timing of measurements, location, spatial scale, and resolution of measurements) that are generated from modeling outputs. It is particularly important that the MVA and modeling efforts be coordinated in the early stages of a project, when the opportunity exists to alter operations to ensure long-term storage and improve efficiency. Therefore, data management and project integration through time becomes a critical requirement of the project process. During Site Selection, it is useful to determine the magnitude of the pressure front that is likely to result from injection and determine if this pressure front can be measured via available monitoring strategies. Follow-on studies can be designed to collect additional data that are important for updating models.

Site Selection activities are designed to obtain the geologic and hydrologic information needed to develop a predictive model for areas of interest. Although modeling has applications across all phases of a CO_2 GS project, modeling activities specific to Site Selection are aimed at identifying suitable candidate sites that have sufficient storage resource, confining formations, and the capability to retain the injected CO_2 over hundreds of years. Modeling results are also used to assist several additional activities including: calculation of the AoR (a requirement under proposed UIC Class VI Well Regulations); determination of the most advantageous injection intervals and operation parameters; assessment of potential leakage pathways; mitigation options; and risk evaluation.

i. Modeling Parameters

Project developers can select or reject potential sites based onthe results of modeling. The first tenet in developing a model is to identify the model parameters that will be used as inputs. Model type (static and dynamic) and parameters necessary to populate the models should be planned to reflect the subsurface system behavior, including confining and injection zones. The parameters to be modeled should be established early on in the Site Selection process because large amounts of data will have to be modeled beginning in the early phases of this stage. The subsurface analysis should be used to identify appropriate modeling parameters and these should be integrated into the models.

ii. Data Requirements and Cost

Once the modeling parameters are established, the project developer should undertake careful analysis of the data and data format required to develop the model. At this point, it is important to assess the costs and benefits of acquiring additional data to reduce uncertainty in the modeling results. Generally, the more data that is acquired and incorporated into the model, the more confidence and certainty will reside in the results. However, additional data can be costly to acquire. Therefore, a project developer should determine the critical modeling parameters and determine the value of needed information: how much and what kind of data is sufficient to lower uncertainties yet keep the project economic?

iii. Boundary Conditions and Uncertainty

Models are used to simulate the behavior of injected CO_2 in geologic storage reservoirs. Since these reservoirs are complex, models will have a certain level of uncertainty during this stage of development. This uncertainty will decrease as a potential site matures and more data acquired. Also, it should be understood that all models bear certain capability restrictions. Project developers should evaluate the model uncertainties and restrictions against a set of acceptability confidence levels for the parameters in order to better understand the model outputs. Model results, uncertainty, and confidence in results should be thoroughly communicated with stakeholders, especially those who are not familiar with modeling, uncertainties, and confidence parameters developed for the model, or who are not familiar with the role of additional geologic evaluation in decreasing uncertainty.

Boundary conditions of the injection zone define whether stratigraphic or structural features limit flow on the bottom and one or more sides. Such no-flow or low-flow boundaries will increase the rate of pressure build-up and influence the size and symmetry of the plume. They are key factors in determining how long injection can continue before pressure builds regionally to limit injection rate. Examples of no- or low-flow boundaries include faults that compartmentalize the reservoir, regional facies changes that limit the extent of injectable facies, and heterogeneity such as channel geometries that limit lateral flow. The boundary conditions are identified, characterized, and evaluated during subsurface analysis and then incorporated into the model(s). During this stage, they may need to be simplified to be incorporated into the dynamic model(s).

iv. Existing Seismic Data

During this stage of development, a model is based on stratigraphic and structural frameworks developed during the subsurface analysis. Some potential sites being evaluated might exist in areas that have existing 2D seismic data. Under these circumstances, available seismic data over the AoR should be considered to supplement and validate the initial developed models.

4.4 Site Suitability Analysis

In the Site Selection process, the site suitability analysis focuses on four primary elements: (i) Infrastructure; (ii) AoR Requirements; (iii) Surface Access; and (iv) Pore Space Ownership. The purpose of the analysis is to determine if there are any identified site issues for the local setting and feasible mitigating actions given the criteria established in the Project Definition. For example, even though a site may have favorable geologic and other characteristics, it may not be suitable because of infrastructure needs, pore space ownership issues, or for other reasons. These issues should be considered and analyzed during Site Selection.

i. Infrastructure

When considering promising areas, a site-specific infrastructure analysis should be conducted to plan for the future injection operations. The analysis should be based on site specific characteristics such as storage type, potential plume migration and source/injection site distance. Types of infrastructure to be considered should include injection and monitoring wells, compression equipment, transport pipelines, and various types of monitoring devices. Potentially, the most capital-intensive infrastructure costs could be transport of CO_2 to the project site; this is a major factor to consider when selecting a CO_2 GS site.

CO_2 can be moved via truck, railroad, ship, and pipeline, although pipeline is currently the only economically feasible transport for commercial-scale projects. Consequently, it is expected that CO_2 for geologic storage will nearly always be transported to the injection site by pipeline. CO_2 has been transported through commercial pipelines in the United States since 1972; currently, the CO_2 pipeline network is more than 3,600 miles in length (see Figure 4.3). The system predominantly carries naturally occurring CO_2 to oilfields for CO_2 EOR. The ability to transport CO_2 to the site is critical to project success. Access to an existing CO_2 pipeline may be a positive factor in selecting a particular site. If such access is not available, a pipeline will have to be constructed and

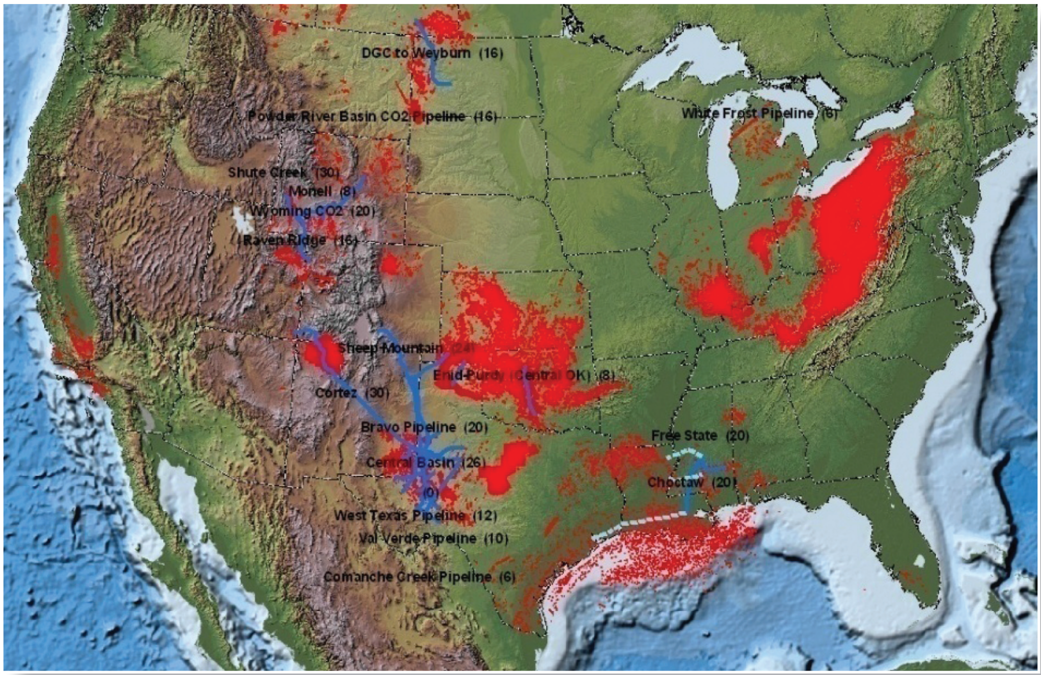

Figure 4.3. Existing CO_2 Pipelines (blue) with Oil and Natural Gas Fields (red).
(Source: NatCarb, 2008)

the costs for building the pipeline and permitting of a pipeline ROW will have to be figured into the capital costs and schedule of the project. The distance between the CO_2 source and storage site, the injection volume, pressure, rate, and location of the pipeline ROW will influence overall pipeline design and cost.

CO_2 pipelines are operated at ambient temperature and high pressure, with primary compressor stations located at the pipeline inlet and booster compressors located as needed along the pipeline. In overall construction, CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas (IPCC, 2005). See Appendix 4 for details on pipeline regulations and ROWs.

ii. Area of Review (AoR) Requirements

The proposed Class VI GS well regulations require developers to calculate and re-calculate the AoR using sophisticated computational models in order to assure that it addresses the full extent of plume migration and pressure propagation. The AoR should encompass all surface and subsurface area enclosed by the boundaries of the injection zones being evaluated for potential injection and storage.

iii. Surface Access to Develop CO_2 Infrastructure

The ability to gain surface access needs to be considered in the site suitability analysis. Factors that should be consideredin the analysis include: the location of geologic storage sites in relation to CO_2 emissions sources, competing land uses, impact on environmentally sensitive areas and availability of infrastructure. Considerations should also be given to geographic terrain and population density which may restrict access for drilling and characterization activities. Surface easements for pipelines and injection facilities will be necessary for the operation of a large-scale CO_2 GS project. For CO_2 pipelines, surface and near-surface competition may come from other industries that require the same zoning, easements, and ROWs. This may include utility transmission lines, oil and natural gas pipelines, water pipelines, fiber optic lines, and sewers. There may also be roads, rivers, and railroads to traverse, requiring special easements or ROWs. Proper planning is necessary to address these kinds of potential issues with surface access. Surface competition for well sites may occur at CO_2 EOR sites, where well spacing may play a key role in injection and recovery rates. Many oil and natural gas fields are located in agricultural areas, so there may be surface competition from agriculture as well. CO_2 injection wells may also compete with subsurface uses, such as mineral extraction and other underground injection applications. Mineral extraction includes oil and natural gas production, solution mining for salt or uranium, and coal and mineral mining. Coal, oil, and natural gas companies often hold leases on marginally economic prospects in case the commodity price escalates. In these cases, surface access may be denied until the leases expire.

iv. Pore Space Ownership

The fourth element to be addressed in the site suitability analysis is pore space ownership and ownership of the injected CO_2. The jurisdiction for pore space ownership resides with the States. However, the legal treatment of pore space at the state level varies significantly. The project developer needs to develop an early understanding of the state rules governing promising areas being considered in the Site Selection stage. Using modeling results to assess the extent of the predicted subsurface CO_2 movement, the developer can begin to determine how many pore space owners may be impacted and the potential implications for project costs.

Although laws differ by state, it appears that several states are converging on a consistent model that would vest ownership of the subsurface pore space to the owners of the surface above the storage space. This concept is consistent with the legal framework governing subsurface mineral rights. Wyoming adopted this approach in legislation enacted in 2009. North Dakota and Montana recently adopted similar legislation. Some states have created provisions for unitization of storage formations, an approach that is grounded in oil and natural gas conservation.

4.5 Preliminary Social Characterization

Social characterization is an important part of the Exploration Phase; during Site Selection, it involves more direct investigation into the socio-cultural factors that could influence how the project is viewed in Selected Areas of interest. The element for this evaluation requires the project developer to (i) Gather and Assess Social Data. The community assessment should be used to frame an outreach plan. The evaluation begins with readily accessible information such as local media and websites. In certain communities, data gathering could involve more direct contact through interviews with key stakeholders, use of focus groups, and possibly other community discussions. At this stage it may also be useful to initiate discussion with regulators or other officials. Once all the pertinent information is collected, information can be used to begin to understand the potential benefits to a community, potential concerns that will need to be addressed through project design, and to identify aspects that will need to be considered in an outreach plan.

i. Gather and Assess Social Data

At this stage, data collection focuses on a specific set of potential communities within the most promising Selected Areas. The existing data collected during the subregional analysis are enhanced by gathering information about the communities in which they are located. If conditions warrant, more intensive research might be initiated at this stage. This might include a review of the positions and record of regulatory and elected officials to develop a better understanding of their familiarity with the scientific concepts in CO_2 GS, and their stated positions on development or views for community growth. It would be worthwhile to begin understanding land ownership structures; for example, what kind of land use exists directly adjacent to the potential sites—is it residential or industrial? If residential, is it agricultural or more densely populated? If there are current land uses in practice, such as mining or natural gas activities, what companies are involved and what is their local history? Does the community have a strong local government and/or business development community? Do those groups have stated positions on economic development, environmental protection, climate change, or other issues that might influence perceptions of a carbon storage project? If deemed appropriate, a project team might begin very preliminary discussions or interviews with key stakeholders to learn more about the community and also to begin sharing information about geologic storage. At this time, focus group interviews might be useful to develop a better understanding of community views on related issues. The intensity of this research should match the state of the Exploration Phase. For example, if there are a dozen potential sites, then the level of effort would necessarily decrease and focus on identifying key areas of potential concern or benefit. If the potential list of sites is narrowed to a few, then more intensive research might be warranted. Social characterization is described more fully in the Department of Energy's Public Outreach and Education Best Practices Manual (2009).

4.6 Qualification of Site for Initial Characterization

Projects that successfully meet the ranking criteria throughout Site Screening and Site Selection processes should be included on a short list of potential Qualified Site(s) for Initial Characterization. These sites must then be weighed against two further criteria, (i) Frame Site Development Plan and (ii) Evaluate Economic Feasibility.

i. Frame Site Development Plan

A preliminary site development plan should be outlined for all candidate sites within the most promising Selected Areas considered for promotion to the Initial Characterization. This plan should be used to determine the economic feasibility based on various parameters of the project including deliverable volumes of CO_2, transportation infrastructure, surface equipment for injection and monitoring, number of wells, well construction, storage volumes, anticipated operational time, and contingency plans for site interruption or shutdown, which could include a spare injection-ready site for operation reliability.

ii. Evaluate Economic Feasibility

The initial site development plans should be used to conduct an initial economic analysis of each candidate site to determine if the site can meet the project economic hurdles established during Project Definition. Each site development plan should be weighed and ranked for economic feasibility. The site that best meets all criteria with the most favorable economics should be the first site elevated to the next stage.

5.0 Initial Characterization

Upon completion of the Site Selection stage, the most promising Selected Areas are assessed and result in a list of ranked Qualified Site(s). These Qualified Site(s) are then assessed in greater detail during Initial Characterization stage; however, their storage resource is still reported as Prospective Storage Resources.

The Initial Characterization process, analogous to processes utilized in the petroleum industry for a project sub-class "Prospect", is the last step in the Exploration Phase. During this evaluation stage, five technical and nontechnical components should be analyzed: (1) Baseline Data, (2) Regulatory Requirements, (3) Model Data, (4) Social Data, and (5) Site Development. As with the previous two stages, prior to initiating any analyses a team should be assembled and plan the analysis to be completed at each component. The multi-discipline team should consider scope, evaluation criteria, resources and schedule to ensure the project needs and resources are adequately planned for to properly complete the analysis.

Also, as with the previous two stages, analyses are evaluated and integrated simultaneously while working towards answering the questions posed at each component decision gate indicated in the Initial Characterization process chart in Figure 5.1. Accordingly, "no" responses would shift the analysis back to the list of Qualified Site(s) and "yes" responses would lead to the decision to acquire more data or to elevate the site to Site Characterization Phase. At this time, the outreach program would have commenced and the determination would need to be made if the site required more information such as a characterization well or acquisition of seismic data to complete the evaluation. If the site needed a new test well, the project developer would begin notifying the stakeholders in the area and determine if the acquisition of seismic data would be necessary prior to drilling and characterizing the test well. Table 5.1 includes the guidelines for each element assessed during the Initial Characterization evaluation.

Once a Qualified Site has successfully completed the analysis at this stage, it can elevated to the Site Characterization Phase (Contingent Storage Resources). Additional analyses and capital investment would be necessary for the project as it moves upward through the geologic storage classification. The level of funding and detailed analyses required to advance the site to a commercial storage site is several magnitudes greater than what could be required for a site in the Exploration Phase, as a Qualified Site. Several Qualified Sites could be elevated to the Site Characterization Phase and further evaluated as Contingent Storage Resources; however, due to the level of capital investment, this should be limited to only site(s) with commercial potential.

5.1 Subsurface Data Analysis

Building on the previous subsurface analyses conducted during the Site Selection stage, the subsurface data analysis is expanded to integrate elements of the Baseline Data component: (i) Geological, (ii) Geochemical, (iii) Geomechanical, (iv) Hydrogeologic and (v) Flux Baselines in order to improve the project developer's understanding of the complex nature of the subsurface. Sources used to characterize the injection zone include, but are not limited to existing geological and seismic data, offset well logs, offset well cores and offset well production data. Existing data might not be adequate to characterize the injection zone with sufficient confidence. Therefore, the decision might be made to drill and characterize a new test well, acquiring new data such as well logs and cores, drill stem tests (DSTs), reservoir fluid samples, and pressure and temperature data. Baselines conducted at this stage on the identified five elements can also be used later to monitor a project. A detailed description of monitoring technologies can be found in the DOE's Best Practices Manual "Monitoring, Verification, and Accounting of CO_2 in Deep Geologic Formations" (DOE 2009).

Table 5.1. Guidelines for Initial Characterization.

COMPONENT		ELEMENT	GUIDELINES FOR INITIAL CHARACTERIZATION
Baseline Data	Subsurface Data Analysis	Geological	Develop site specific geologic baseline of Qualified Site(s) including type log/stratigraphic column; detailed correlation of reservoir architecture including injection intervals within the injection zone and potential confining intervals within confining zone; detailed structural maps; interpreted depositional model and facies distribution; porosity maps for potential injection and confining intervals and zones; and porosity/permeability log transforms. This evaluation should be updated as additional information is acquired (seismic and well data). During Initial Characterization any additional data from a new well test should also be integrated into previous analyses.
		Geochemical	Develop baseline of groundwater in all overlying aquifers using fluid and fluid level data collected in shallow aquifer formations in offset wells. If available, collect rock and fluid property data (composition, geochemistry, pH, conductivity, mineralogy) from the injection zone to model formation fluid-CO_2- rock reactions in the injection zone and at confining zone interfaces.
		Geomechanical	Develop baselines for injection rates and pressures utilizing drilling data on formation strength and modeling. Analyze advanced logging suites from offset wells and characterization wells (if any exist) to identify faults and fractures. Analyze new or existing core to determine the existing stress state and assess the impact of changes in pore pressure on stress.
		Hydrogeological	Determine fluid compositions and injection zone flow units from new or offset well data, fluid samples, and hydrologic and other tests; integrate into dynamic injection zone models and compare to the existing hydrological model. Conduct multi-well tests where possible. Injection zone fluids and hydraulic tests should be further investigated during the Site Characterization Phase and fluid samples should be collected if a new well is drilled or an existing well(s) is further tested.
		Flux Baselines	Plan a monitoring system to establish baseline readings of near surface, ground level, and shallow subsurface fluxes. Baseline monitoring could be conducted during Initial Characterization and conducted for at least a year to account for changes in flux reading due to seasonal changes. Nearby urban, industrial or agricultural expansions and developments may require re-establishing a baseline prior to injection.
Regulatory Requirements	Regulatory Issue Analysis	Determine Applicable Regulations	Review the current state, regional and federal regulatory requirements for Initial and Site Characterization activities including permitting and acquiring seismic data; permitting stratigraphic, injection, or monitoring wells. Identify data gaps requirements, lead agencies and timelines for permitting process; update project timelines accordingly. Review all requirements for carbon storage (e.g., pipeline development, land access, pore rights) in site area, plan for compliance and understand cost implications to project.
		Develop Well Plan	Develop plan for well design, construction, testing, injection and monitoring in compliance with current and anticipated state, regional and federal regulations for all types of wells being planned. Update cost estimates for wells and booster compressors, if needed.
		UIC Permit Planning	Collaborate with identified agencies for initial approval for both the well plan and any potential development plans to confirm that assessments are in alignment with UIC and other regulations. Identify and assess existing well bores (locally and regionally) within the planned AoR for well integrity.
Model Data	Model Refinement	Test Model	Model should be optimized to allow for numerous model runs with varying parameters and boundary conditions; tested for mode functionality; and assumptions, uncertainties and impact parameters of model should be documented.
		Input Data / Scenario Analysis	Continue to integrate new data and analyses into the static and dynamic models this should include offset well data parameters such as porosity, permeability, and potential baffles in the reservoir . Develop and run various modeling scenarios for a range of parameters in order to test the injection design, optimize plume migration, and verify the expected definition of AoR, subsurface processes, and prospective storage estimates. Assess cost and benefit of brine withdrawals.
		Compare Outputs	Compare results of previous models runs with newly modeled data to ensure consistency and model functionality. Update the preliminary modeled AoR, if necessary.
Social Data	Assess Outreach Needs	Critical Path Analysis	A critical path analysis should be carried out to determine requirements for an outreach program.
		Outreach Team	An outreach team should be established with personnel proficient in the implementation of an outreach plan.
		Identify Stakeholders	Identify stakeholders and continue to assess their concerns and perceptions of carbon storage.
		Social Characterization	Evaluate community data to develop an appropriate public outreach program. The plan should identify stakeholders, key messages, planned activities, timing, resource needs and other relevant information.
Site Development	Site Development Plan	Initial Plan	Develop initial Site Development Plan that was framed at the completeion of the Site Selection Process. Address all aspects of a commercial site based on surface, subsurface and modeling analyses and the criteria established in Project Definition. Plan should be site specific and include for example(1) data acquisition plan for the Site Characterization Phase (2) required infrastructure - number of wells (injection, monitoring, and reliability, and water production if needed), compression, pipelines, (3) MVA and reporting plans, (4) operational issues and mitigation plans, and (5) outreach plans. Update analysis of project economics and review results with investors and regulators.
		Commission FEED Study	Conduct a front end engineering and design (FEED) study in alignment with the initial Site Development Plan to identify any engineering or design issues. Update project costs and economics based on FEED and review results with investors and regulators.
		Develop Tender Requirements	If project is still viable, tender requirements to implement the Site Development Plan should be written and potential contractors asked to qualify for tender. This will aid in further defining the total costs associated with specific sites and validate that the site meets project defined economic thresholds.

If the site being characterized meets all Initial Characterization—technical and nontechnical criteria for carbon storage—it should be elevated to the Site Characterization Phase. If further information is required, additional project data must be collected via additional seismic or other survey acquisition and, possibly, a test well.

	COMPONENT	ELEMENT	GUIDELINES FOR INITIAL CHARACTERIZATION
Complete Initial Site Characterization	Engage Outreach Program		Prior to making any announcements or beginning additional site data collection, the appropriate outreach program should be engaged.
	Notify Stakeholders		Seismic acquisition and drilling of a test well require access to the site. Therefore, if planned at this stage leases should be obtained and interested parties notified prior to the beginning of either activity.
	Evaluate Existing Data		Evaluate existing seismic data (e.g., 2D, 3D, well VSP) in area that could be reprocessed and resultant data input into models to qualify site. If it is determined new data will need to be acquired, collaborate with acquisition experts to optimize this process. Also, assess existing wellbores in the region for potential re-entry for formation evaluation and/or well testing. Additional wellbore data should also be integrated into models.
	Drill Characterization Well	Well Design	Prior to drilling a test well, the well design should be solidified and measured against appropriate UIC regulations and industry best standards.
		Formation Evaluation	Formation evaluation in new characterization wells should be based on the level of certainty needed, and could include coring (standard whole core and rotary side-wall) of potential injection and seal zones, standard and advanced logging suites; mechanical and hydrological data, and fluid sampling for geochemical analysis.
		Well Testing	Project developer could conduct geomechanical, hydrological and formation testing to further determine and reduce uncertainty in capacity, injectivity, and injection and confining zone properties before proceeding to well completion.
		Injection Tests	Injection tests (brine or CO_2) should be undertaken to validate permeability, storage capacity, boundary conditions, and to identify compartmentalization or other permeability barriers for proposed injection rates and pressures. Formation breakdown tests in the reservoir and overlying seals will establish fracture initiation pressures of the formations.
Complete Initial Characterization		Qualified Site(s)	Rank Qualified Site(s) and then elevate to Site Characterization Phase.

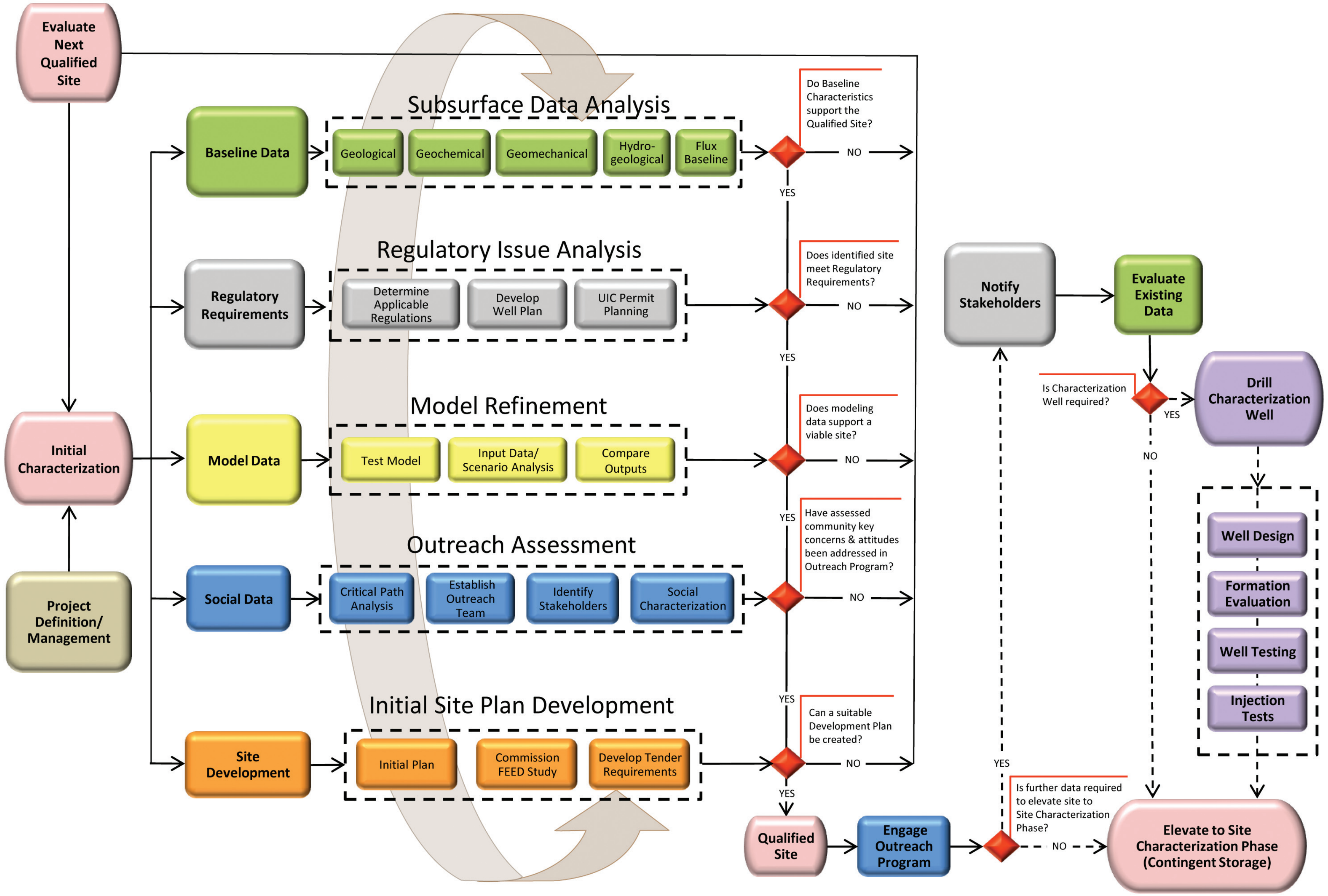

Figure 5.1. Process Flowchart for Initial Characterization.

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i. Geological Data Evaluation

The project developer should establish a thorough subsurface geologic baseline of the candidate injection zone. The baseline evaluation will be used as the foundation for models developed and should include, at a minimum, a site-specific type log/stratigraphic column; detailed correlation of subsurface architecture including site-specific injection intervals within the injection zone and confining interval(s) within the confining zone; structural maps of at least the injection and confining zone(s); a depositional model; facies distribution; and, porosity maps for potential injection and confining intervals and injection and confining zone(s). This evaluation should be updated as additional information is acquired (seismic and well data) and integrated into the updated stratigraphic and structural models. Any offset data parameters from well log data and tests, such as porosity, permeability and potential baffles in the reservoir, should be used to update parameters in the static and dynamic reservoir models developed for candidate sites. During Initial Characterization, any additional data from a new well test should be integrated into previous analyses. During this stage, the project developer should collect additional geologic information required for an injection permit; for example, developer may be required to list all penetrations into and/or through the injection zone.

General and detailed subsurface data should have been gathered during Site Screening and Site Selection from existing well logs, cores, DSTs, production histories, and seismic surveys. Additional data can be obtained from vendor sources to complement the existing data. This additional data can be useful to Initial Characterization and will generally be incorporated into the various modeling programs to further refine site-specific models and reduce subsurface uncertainties..

ii. Geochemical Data Evaluation

Understanding and accounting for brine-CO_2-formation interactions is essential to the development of a robust subsurface analysis. Effects of chemical reactions induced by CO_2 include changes in porosity and permeability of the injection zone; an overall drop in formation fluid pH, which might affect the stability of the target confining zone; and, reactions to form CO_3^{-2} precipitates (solid carbonates involving ions such as Ca^{2+}, Mg^{2+}, or Fe^{2+}), which chemically trap CO_2 in place (Gunter et al., 1997). However, carbonate build up could reduce porosity, permeability, and overall injectivity. Additional compounds that might occur as the result of reaction between carbonates (bicarbonates) and monovalent cations (Na^+ or K^+) are typically more soluble and tend to remain sequestered by solubility trapping through dissolution.

Geochemical monitoring during Initial Characterization establishes the baseline groundwater quality and composition in selected fresh and saline aquifers (injection and non-injection/prior CO_2 injection). This analysis can be accomplished using data collected in targeted formations in offset wells. If available, fluid property data (composition, geochemistry, rock mineralogy, pH, conductivity) from the injection zone could be used to model any brine-CO_2-formation rock reactions in the injection zone and at confining zone(s) interface. To establish the baseline goundwater characteristics of shallower aquifers fluids can be sampled from existing water wells near the potential site.

Groundwater sources of interest include USDWs around the injection site, saline formation fluids (brine), and production well water from EOR and ECBM projects. Groundwater quality monitoring can be used to identify USDWs in the vicinity of the project, establish groundwater quality, and confirm whether target formation fluids meet the criteria outlined in 40 § CFR 146.4 that would exempt them from USDW status.

Baseline groundwater samples may be part of the MVA design and should be collected to ensure data availability prior to first injection of CO_2. This will provide the basis against which further sampling and analytical work can be compared. In addition, permitting requirements often include reporting annual formation fluid analysis and quarterly analysis of the physical characteristics of the injected fluid; baselines established during Initial Characterization can inform this requirement.

It is important to note that a vast majority of well files may not contain geochemistry data that can be associated with any specific aquifer other than the formation that was being tested for hydrocarbons. There is typically minimal geochemistry data for formations above or below the oil- and natural gas-containing zones. Also, the collection of truly representative fluid samples from previously unsampled formations within existing wells will be logistically and technically challenging, at best, and impossible, at worst. In short, developing baseline geochemical data on all aquifers in a study area will be very difficult in most sedimentary basins; however, the developer should develop baseline geochemistry data on all formations in a study area known to contain USDW.

iii. Geomechanical Data Evaluation

Thorough evaluation using modeling and simulation of the mechanical effects of CO_2 storage on the injection zone is essential to ensure integrity of the confining zone. During the Exploration Phase, the project developer should account for geomechanical properties in models in order to assess the integrity of the confining zone under various injection andinjection zone pressures, and forecast the pressure propagation front for any size CO_2 injection over an extended time period. Geomechanical forces that affect the subsurface are a result of a pressure increase due to both the injection rate and volume of CO_2 and buoyancy forces. Proper characterization and management of pressure will ensure that inevitable deformations in the surrounding rock matrix are acceptable. It is required for an injection permit to establish the maximum injection pressure prior to injection. Currently, by regulation, the maximum injection pressure cannot exceed the fracture pressure of the injection formation.

Geomechanical baselines can be established by analyzing advanced logging suites from offset wells through injection and confining zone(s) to identify faults and fractures. Evaluating existing or new core data in injection and confining zone(s) for rock properties, stress fields, and pressure regimes can also aid in establishing the baseline. Information collected on geomechanical parameters should be regularly updated when available to refine developed models.

The project developer should be able to use baseline data developed during Initial Characterization to prepare for permitting requirements. For example, siting requirements for Class I, Class II, and proposed Class VI UIC wells under 40 CFR § 146.14 require demonstration of the presence and adequacy of injection and confining zones by presenting information on local geologic structures, faults, and other relevant geomechanical information.

iv. Hydrogeological Data Evaluation

A thorough understanding of the hydrogeological environment within the injection zone is necessary for accurate characterization. Hydrogeological analysis focuses on three sets of reservoir data: (1) location(s) of water and other fluids, (2) properties of water and other fluids (especially chemical properties), and (3) existing or potential flow patterns of water and other liquids. During Initial Characterization, prior to any planned test well, the location of any liquid within the reservoir and potential flow paths may be estimated from processed seismic data and reservoir modeling.

Prior to injection of CO_2 project developers should assess the hydrologic performance of the injection zone and the confining zone through a designed series of observationn tests of pressure responses to injected or extracted fluids. These tests provide assurance that the selected injection interval can accept the planned fluid volumes without exceeding pressure limits and that the confining zone(s) are limiting vertical flow at acceptable levels. A number of types of tests can be conducted. Initial tests can be conducted by extraction of small volumes of fluid under open-hole conditions; these can be useful in determining where to set perforations (if in the well completion design) to conduct larger scale tests. Larger scale hydrologic tests increase confidence in the injection zone response and should be conducted at a sufficient scale to demonstrate reservoir continuity (e.g., hours to multiple days). Single well tests conducted by either pumping fluids from a well or injecting fluids into a well while observing pressure response in that same well provides direct evidence of injectivity (pressure build-up, fall-off tests). These tests can be conducted with any fluid, however use of native formation brine can be low cost and informative prior to availability of CO_2. Multi-well tests where injection or extraction occurs in one well while observations of pressure response in nearby wells completed in the same zone can be used to increase confidence in suitability of the injection zone to accept the design injection rates, especially if sustained. Confidence in the performance of the confining zone can be tested through measurement of stable pressure above the confining zone(s) as fluids are injected or extracted from the injection zone. This test requires a design with access for a pressure measurement in a permeable zone above the confining zone, which can be accomplished through various approaches, including pressure gages on the outside of casing, multiple perforated intervals separated by packers, or by a dedicated well perforated in an above zone monitoring interval.

v. Flux Baselines

By assessing baseline CO_2 concentrations within the site's vicinity, a developer may be able to use any subsequent elevated CO_2 fluxes as an indicator of possible CO_2 leakage. The magnitude of CO_2 seepage fluxes will depend on a variety of factors, such as the mechanism of emission (e.g., focused CO_2 flow along a near-surface fault or more diffuse emission through sediments), wind, and density-driven atmospheric dispersion.

Although this analysis is currently not required under the existing UIC regulations, it could potentially be required in the future and it could be a very useful tool for the project developer. If developing flux baseline, the project developer should plan a monitoring system to establish baseline readings of atmospheric, ground level, and shallow subsurface fluxes. Available techniques are further described in the DOE Best Practice Manual "Monitoring, Verification and Acct..."DOE, 2009.

5.2 Regulatory Issue Analysis

In the Site Selection stage, the project developer should have assessed the potential regulatory requirements facing projects. During the Initial Characterization stage, the project developer should further analyze the Regulatory Requirement component to further understand the resources and timing necessary to complete requirements. Although there are many other regulatory issues, this section focuses on UIC planning and potential permitting preparation. It is extremely important to understand the data requirements for UIC regulations to make certain the project is acquiring the data necessary to meet those regulations. There are three elements in this analysis: (i) Determining Applicable Regulations, (ii) Develop Well Plan, and (iii) UIC Permit Planning.

i. Determine Applicable Regulations

The project developer should consider the appropriate state, regional, and federal regulatory requirements for activities to characterize a site including acquiring seismic data and permitting a stratigraphic test, injection well, or monitoring well. This includes at a minimum identification of the data requirements, lead agencies, and timelines for the various permitting processes. Based on this information, the project timelines and resource plans developed in Project Definition should be updated. The developer should also review any additional requirements for carbon storage (e.g., pipeline development, land access, pore rights) in most promising site areas. This information will be used to assess the feasibility of the Qualified Site.

Although the proposed Class VI GS injection well regulations have not been finalized and these provisions may change, it is worth noting the additional siting requirements, AoR estimation methods, well design and construction specifications, and mechanical integrity testing (MIT) may be required.

Additional siting requirements to the existing UIC regulations include providing extensive data on target formation porosity; information on the seismic history of the site and in-situ fluid pressures, maps and cross-sections of USDWs near the injection zone;

notification of any faults or fractures transecting confining zones, and extensive geochemical data on fluids in the injection zone, confining zones, overburden layers, and USDWs. The additional siting requirements can be fulfilled by implementing a variety of site characterization tools.

The proposed rules for the AoR calculation for Class VI GS wells require the use of sophisticated computational models. Such modeling is linked to specific site conditions and to the scope of the injection project (volume, rate, formation depth, pressures, and duration of injection) in order to fully assess the extent of plume migration and pressure propagation. For other well classes, the UIC program has relied on fairly uncomplicated formulae for calculating a zone of endangering influence (ZEI) or has simply required a fixed radius around the injection well, dependent on well classification. The computational models for Class VI GS wells should be based on the analysis of site characterization data collected from the injection zone and confining zones, taking into account any geologic heterogeneities, and potential migration pathways through faults, fractures, and artificial penetrations such as unplugged abandoned wells. In addition, the proposed rule would require that the owner/operator periodically re-evaluate the AoR during the injection operation as site conditions may change from the baseline (pre-injection state) and the monitoring data required to be collected during project operation will help inform any changes for the AoR model in the future. This proposed AoR re-evaluation will require running the model again and basing the outcome on new data as CO_2 injection progresses throughout the project's life. The timing and number of re-evaluations will be determined between the operator and the UIC Director. GS project operators will have to revise both their AoR and Corrective Action Plans each time a re-evaluation is conducted on the computational model.

Construction procedures for proposed Class VI wells would require that surface casing be set through the base of the lowermost USDW and cemented to the surface. The long-string casing should be cemented in place along its entire length. GS wells should also be constructed with a packer set at a depth above the injection interval. Also, the use of corrosion-resistant materials compatible with the injectate and subsurface fluids is required. The proposal would also require automatic downhole shut-off mechanisms (a subsurface safety valve [SSSV], a requirement in all offshore wells) in the event of a mechanical integrity loss. The proposal would require owners or operators of CO_2 wells to demonstrate injection well external mechanical integrity (accomplished through the use of CBL and casing caliper logs or pressure tests designed to detect leaks) at least once annually (during the operation phase of the project) and prior to injection of CO_2.

ii. Develop Well Plan

During Initial Characterization, the developer should determine what type of wells will be drilled and plan for well design, construction, testing, injection, and monitoring in compliance with current and anticipated state, regional, and federal regulations for all types of wells being planned. It is important to note whether the wells will be vertical or horizontal and to address specific planning issues accordingly. This plan should incorporate best practices in well design and construction. When the EPA proposed Class VI rule is promulgated, storage wells will potentially need to meet the new requirements. In the meantime, a well plan should be evaluated against existing Class I and II requirements as well as developing UIC Class VI well requirements.

iii. UIC Permit Planning

Early consultation with regulators can assist the project developer, to avoid unanticipated permit costs and project delays. Project developers should contact identified agencies to obtain feedback on initial well plans and site development plans to confirm that assessments are in alignment with UIC and other regulations. In addition, developers should identify and assess existing well bores (locally and regionally) within the planned AoR for well integrity. For example, existing wells (water, disposal, and oil and natural gas production and injection) within the AoR must be screened for integrity, because each wellbore through the confining zone could be a potential leak point. If a well is producing within the AoR boundary, confirmation should be acquired indicating that tubing and casing pressures are continually monitored and recorded and not operated outside of the permitted ranges. GS project developers should ensure that abandoned wells within the AoR have been abandoned in accordance with regulations and are not a risk as a leakage pathway. Wells that may be of concern as potential leakage pathways (older wells, noticeable structural damage, etc.) can be pressure tested for mechanical integrity. If the pressure test fails, both cement bond and casing caliper logs could be used to determine the overall integrity of the casing and cement and provide insight as to possible remedial action.

5.3 Model Refinement

During Initial Characterization the project developer will be collecting information from subsurface analysis needed to test and refine the models being used to predict reservoir behavior at the site(s) being considered. It should be noted that currently no single model is capable of simulating all the coupled processes at once. Typically, a combination of models is used. See Appendix 5 for additional information. This modeling can also be used to optimize the design of the injection plan and forecast risks that may be encountered during the project, including unanticipated reservoir failure, leakage through faults or abandoned wells, and potential contamination of other resources, such as USDWs. Specific modeling applications for CO_2 GS projects include, but are not limited to, the following (Gupta et al., 2008):

- Evaluation of subsurface processes, including CO_2 phase behavior, advective forces, solubility, temperature and pressure effects, chemical reactions, and geomechanical effects
- Injection system design, well design, and pressure profiles
- AoR estimation
- Optimization of spatial and temporal monitoring strategies
- Risk assessment and MVA plan design
- Prediction of post-closure CO_2 plume behavior
- Site closure decisions

To accurately and reliably apply models, multiple physical and chemical considerations must be included in the model's development. Detailed data related to these phenomena can be acquired from Initial Characterization activities. Reactive transport modeling integrates all of the thermal, hydrogeological, and geochemical processes that are associated with dynamic geologic systems.

The project developer can account for flow, chemical reactions, and geomechanics by combining multiple models. Proper simulation of CO_2 GS requires incorporating interdependent processes that must be modeled simultaneously to simulate the behavior of the injection formation. These processes include chemical reactions, molecular transport and diffusion, fluid flow, heat transfer, and mechanical stress and strain. This stage of Model Refinement involves three elements, (i) Testing Model, (ii) Input Data and Scenario Analysis, and (iii) Compare Outputs. A comprehensive discussion of modeling is presented in Appendix 5.

i. Test Model

As indicated earlier in this manual, the modeling process is iterative. During Initial Characterization, model frameworks should be completed and should be populated with subsurface data from subsurface analyses conducted. The models should be designed for optimization; allow for numerous model runs with varying parameters then tested for model functionality; they should be properly calibrated, and, sensitivity analyses should be used to assess uncertainties and impact parameters. The developer should fully document the model(s) and uncertainties and communicate results to the entire team.

ii. Input Data and Scenario Analysis

Project developers should continue to integrate new data and analyses into the static and dynamic models. This involves developing and running various modeling scenarios for a range of parameters in order to test the injection design, optimize plume migration, and verify the expected definition of AoR, subsurface processes, and prospective storage estimates.

For example, data from subsurface analyses could be integrated into a numerical model of geochemical processes to investigate long-term consequences of CO_2 injection due to slow reactions between dissolved CO_2 and the host rock. A numerical model that can successfully predict the fate of CO_2 and its transport over extended periods must be able to couple hydrogeologic, geomechanical, and geochemical reactions. Uncoupled fluid flow simulation and batch geochemical modeling are not sufficient to account for all the complexities and interactions expected to occur from geologic sequestration of CO_2 (Tsang et al., 2007). Several models are discussed in Appendix 5.

iii. Compare Outputs

The results of previous model runs should be compared with newly modeled data to ensure consistency and model functionality. Anomalies should be investigated and if necessary, the model should be refined.

5.4 Outreach Assessment

At this point, a project team has narrowed its focus to a single or just a couple of potential sites. More in-depth characterization is undertaken to assure that the site is suitable for a project.

The Social Data component is now analyzed to further assess the outreach needs for each potential site. There are four elements that are addressed in this analysis: (i) Critical Path Analysis, (ii) Outreach Team, (iii) Identify Stakeholders, and (iv) Social Characterization. Similar to the characterization efforts of the subsurface, the same thorough characterization should be conducted for the community; this is what is referred to as social characterization.

It is important in doing social characterization to develop a real sense of the level of effort that will likely be needed to implement a project. This involves developing a timeline for major activities and mapping public interaction to this timeline. For example, what kind of public process is involved in obtaining the permissions to conduct characterization and to permit a project? "Best Practices for Public Outreach and Education for Carbon Storage Projects" outlines the steps involved in conducting the evaluations necessary to assess the likely level of effort needed for outreach.

In some cases, Initial Characterization will involve extensive field work, even though the site may not have been qualified. This fieldwork might include doing visual assessments of the community and conducting seismic surveys, as well as drilling boreholes and test wells. If the site characterization activities include these steps, then a preliminary outreach plan needs to be developed and implemented based on the four elements of the Social Data component described above before going out into the community to do fieldwork.

i. Critical Path Analysis

The assessment of outreach needs should begin with a critical path analysis that clearly identifies goals for the outreach plan.

ii. Outreach Team

Once the outreach plan is created, the team should be staffed with individuals whose capabilities match the structure, work schedule, and goals of the program.

iii. Identify Stakeholders

Following the creation of the outreach plan and its staffing, local and regional stakeholders must be identified. The definition of stakeholders is fluid. Social science theory defines them as anyone who perceives that they have a direct interest in the outcome of a project. Stakeholders are also those who will have a strong interest in the project and may be influential in a community. At a minimum, key stakeholders for a CO_2 GS project will include local land owners/pore-space owners, local contractors who might tender for work, local government and regulatory agencies, the local environmental community, and concerned citizenry. To the extent possible, it may be productive to provide stakeholders with an opportunity to share their concerns and input during the Initial Characterization stage. Information gained from stakeholders can help to improve the project and can also help to build relationships that can be used during the course of a project's life to share information back and forth.

iv. Social Characterization

Based on knowledge of the critical path elements, the strengths and weaknesses of the outreach team, and stakeholder identification, the project developer should evaluate community data to develop an appropriate public outreach plan. The plan should identify stakeholders, key messages, planned activities, timing, resource needs, and other relevant information. This plan will aid in further defining total project timing and costs.

5.5 Initial Site Plan Development

During Initial Characterization, the project developer should build on the preliminary framework of the site development plan outlined in the Site Selection stage. The development of the Initial Site Development Plan will include three elements of the Site Development Component: (i) Initial Plan, (ii) Commission FEED Study, and (iii) Develop Tender Requirements. This plan should be similar to a field development plan that the petroleum industry would develop for each field. The plan should include, but not be limited to (1) an update of the Prospective Storage Resources calculations based on all completed subsurface analyses conducted to ensure that the project continues to meet the economic threshold; (2) updated risk assessment that should include an update of the assessment of the confining zone(s) to ensure the project has containment that is adequate to account for the volume of CO_2 established in the Project Definition; and, (3) development scenarios for planned injection that includes number of wells, alternative sites for reliability, monitoring wells, amount of CO_2 to be injected, economic analysis, etc.

i. Initial Plan

The project developer should update the Initial Site Development Plan framed at the completion of the Site Selection stage. This would include addressing all aspects of a commercial site based on surface, subsurface and modeling analyses, and the criteria established in the Project Definition. The site development plan should be site-specific and include aspects such as (1) required infrastructure – number of wells (injection, monitoring, and reliability), compression, pipelines, (2) MVA and reporting plans, and (3) operational issues and mitigation plans.

ii. Commission FEED Study

Using the updated site development plan as a basis, the equivalent of a Front End Engineering and Design (FEED) study should be commissioned by a licensed design firm. The FEED study should identify any developmental or design issues that would result in project delays. Identified issues should be further addressed in future updates to the site development plan.

iii. Develop Tender Requirements

In anticipation of site injection and storage, a set of tender requirements (like a request for contracts) should be established. These should include demonstrations by all potential vendors of well-developed technical competencies, viable safety and project management capabilities, and financial capabilities and stability. The project developer should contact potential contractors to ask them to qualify for tender. This will aid in further defining the total costs associated with specific sites and validate that the site meets project defined economic thresholds.

5.6 Completion of Initial Characterization

Based on the outcome of all previous analyses, the project developer will reach a decision point to determine if further data is required to complete the Qualified Site evaluation to determine if storage resources can be classified as Contingent Storage Resource. In some instances, a site being assessed will occur in an existing oil or natural gas producing area with multiple wells having data already acquired to establish permeability and injection potential for a reservoir. In that case, new reservoir data might not be required at this time to elevate the storage resources to Contingent Storage Resource class. However, in most cases additional reservoir data, such as a characterization well or seismic data, will be required to complete the evaluation and validate injection potential.

This section describes the final steps that determine if a project is elevated into Contingent Storage Resource class. Regardless if new data will be required or not, if the site is to be a potential storage site, the public outreach program should be engaged because visible activities are likely to begin. From this point forward, the outreach plan should be implemented.

5.7 Conduct Additional Characterization

If it was decided previously that there were insufficient data to qualify the site for potential injection, additional characterization should include collecting more data to qualify the site. This involves several steps including (i) Engage Outreach Program, (ii) Notify Stakeholders, (iii) Evaluate Existing Data, (iv) Drill Characterization Well and (v) Complete Initial Characterization.

i. Engage Outreach Program

As previously discussed, prior to making final selection or beginning additional site data collection, the appropriate outreach program should be fully engaged.

ii. Notify Stakeholders

Preceding the collection of any new data, stakeholders within the site's area should be notified and the project team should communicate with local communities on process, timing, and potential impacts. Stakeholders could include city officials who will provide important information on the process for property access. A communication plan developed by the outreach team will be used to notify stakeholders.

iii. Evaluate Existing Data

Review thoroughly any significant existing data such as 2D/3D geophysical data and evaluate existing wellbores that potentially could be re-entered for further evaluation. Determine if data could provide enough information to characterize the area. This type of data would need to be purchased and potential costs assessed; however cost could be significantly less than new seismic acquisition or driling a characterization well.

In some instances, an older version of 2D or 3D data can be reprocessed, using new parameters and the results interpreted. If the results do not provide additional information that qualifies the site, at minimum new 2D data should be acquired prior to completion of this stage. Following additional seismic acquisition, the seismic data should be processed and interpreted; resultant data should be integrated into the model. New seismic should also be correlated or "tied" to any existing seismic data in the area (e.g., 2D, 3D, well VSP). Due to cost associated, it is recommended that a comprehensive 3D survey not be conducted until the Site Characterization Phase. Other geophysical approaches should be evaluated and integrated to get the best quantitative estimate of CO_2 that can be stored, such as electro-magnetic (EM) surveys that could be conducted prior to drilling a test well. Results of these types of geophysical evaluations can be compared to subsequent monitoring data during the injection and post-closure phases to observe time-lapse changes resulting from injection.

Existing wellbores might exist within the region and penetrate the potential injection and confining zone(s). In this instance, it could be more cost effective to re-enter the wellbore and conduct a formation evaluation, well testing, or injection test instead of drilling a new well. The project developer should consider all data, including the vintage of the well and perform a cost and risk analysis to determine if utilization of existing wellbore would provide the data needed to elevate the site to Contingent Storage Resources.

After all available data are reviewed, acquired, and interpreted, it should be determined if sufficient additional data exists to qualify the site. If the site cannot be qualified with existing well information then a characterization well should be drilled.

iv. Drill Characterization Well

There are four steps involved in this activity, including: (i) Well Design, (ii) Formation Evaluation, (iii) Well Testing, and (iv) Injection Tests.

Well Design

Prior to drilling a characterization well, the developer should determine the ultimate use of the well. If the well is to be considered as a future injection well, the appropriate permit should be acquired, well design should be solidified and approved by the appropriate regulatory agency. The well should be constructed by a reputable and competent company in line with industry best standards of the petroleum industry.

Requirements under the relevant UIC regulations indicate that injection pressures must be monitored and not cause fracturing into the confining zone or cause fluid movement into USDWs.

Step-rate tests conducted prior to injection can indicate the maximum allowable injection pressure without inducing failure or formation parting pressures. Usually, injection pressure will be some fraction of estimated formation pressure, with maximum injection pressure capped by regulation. Downhole pressure sensors can be used to obtain pressure readings inside the well casing. Step-rate tests only need to be conducted once for each project injection well drilled during the pre-operation period. Refer to the EPA step-rate testing procedure for additional details on conducting a step-rate well test (U.S. EPA, 2009d).

A mechanical integrity test (MIT) is needed to satisfy relevant UIC requirements by ensuring the absence of leaks in the tubing, packer, or casing and ensuring that no fluid movement into a USDW through vertical channels adjacent to the injection wellbore will occur. No specific MIT is required for Class V wells; however, permit conditions will likely require developers to demonstrate internal and external integrity during the lifetime of the project, and this may require more frequent testing (Class V wells for CO_2 injection are typically permitted to Class I requirements). Initial MITs are required prior to CO_2 injection to verify well integrity.

The three following methods are considered suitable MITs according to 40 CFR § 146.8(b): (1) conduct an initial pressure test and monitor the tubing casing annulus pressure with sufficient frequency to be representative while maintaining an annulus pressure different from atmospheric pressure measured at the surface; (2) pressure test with liquid or gas; or (3) monitoring record showing stability in the relationship between injection pressure and injection flow rate for certain existing Class II enhanced recovery wells. The MIT should be conducted once the well is complete. Acoustic logs and cement bond logs (CBL) can be used to assess the integrity of the cement component of the well. Cement records are required for new and existing Class II injection wells in all EPA regions except Region 6 (Arkansas, Louisiana, New Mexico, Oklahoma, and Texas), where State or Bureau of Land Management (BLM) records are used (unless a State has primacy over UIC regulations). CBLs are also required for new and existing Class II injection wells in all EPA regions[10] except Region 5 (Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin).

Formation Evaluation

A number of data gathering activities, or tests, are performed on a new wellbore to characterize the injection and confining zones. Tests conducted should be tailored to a specific site based on the level of certainty already achieved during the Initial Characterization. Activities at this stage may include whole cores of potential injection and confining), standard and advanced logging suites; side-wall cores to complement whole cores taken; and fluid sampling for geochemistry analysis. Analysis of cores, formation fluids, pressure readings, and logs should be directed towards better delineation of both the confining and injection zone(s) properties.

Well Testing

The project developer may want to conduct tests, such as a drill-stem test, to further determine reservoir properties and permeability before proceeding to well completion. Drill-stem tests are commonly used in the oil and natural gas industry to acquire additional information about fluids, pressures, areal extent of the reservoir, and pressure boundaries.

Injection Tests

Injection tests (brine or CO_2) could be undertaken to validate existence of permeability and identify any potential permeability barriers for required injection rates and pressures in a potential reservoir. This might include a series of step-rate injection tests to confirm that the reservoir can support the planned injection regime. Refer to the EPA step-rate testing procedure for additional details on conducting a step-rate well test (http://www.epa.gov/region8/water/uic/INFO-StepRateTest.pdf). Any

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10 The U.S. EPA has nine regional offices throughout the U.S. Under the UIC program, a state may obtain primacy to implement certain classes of wells, if a state does not obtain such primacy for a certain well class, the regional EPA office that serves that state will implement the program. See http://www.epa.gov/safewater/uic/whereyoulive.html for a listing of state and federal contacts for each class of well.

type of injection test should be compliant with the well design and permitting requirements. The team should make certain to coordinate with the appropriate permitting agencyprior to drilling the well, again to ensure that these tests can be completed with the permit granted.

v. Complete Initial Characterization

Qualified site should be elevated to Site Characterization Phase and classified as Contingent Storage Resources.

5.8 Site Characterization Phase

The intent of this manual was to provide some guidance and begin to formalize the process of evaluating future geologic storage sites within the Exploration Phase of the classification framework. The next phase, Site Characterization, classifies storage resources as Appraised but Sub-Commercial and builds on the previous studies to develop a more detailed characterization of the subsurface similar to what would be expected of a commercial project. The large-scale detailed characterization conducted at a site could include additional drilling and testing of wells to understand the geomechanical and geochemical properties of the rocks, as well as testing of stimulation techniques to enhance injectivity. Also, additional 2D/3D seismic data should be acquired, processed, and integrated with rock property data from existing and new wells drilled. Subsurface mapping should then be conducted on the survey to further understand the subsurface architecture of the injection area; define the areal extent of a project site; validate contingent storage resource estimates for future financial investments; establish continuity of injection zones and confining zone; and identify potential leakage issues that could be created by regional small-scale reservoir faulting or juxtaposition of injection or confining zone(s). Furthermore small- and large-scale brine injection tests could potentially provide the opportunity to study interference and pressure pulse between two wells; and potentially ground truth dynamic models. The costs associated with detailed characterization in this phase are expensive and should be conducted only for sites being planned for commercial project status.

6.0 Carbon Dioxide Storage Classification Framework

Companies within the petroleum industry have differences in the methodologies they use to characterize resources in the Petroleum Resources Management System (PRMS) framework. They tend to use a rigorous probability framework coupled with cross-disciplinary decision analysis to move prospects through resources and to reserves. These methodologies and criteria are proprietary and often represent significant competitive advantage for a company. In the analogy for the CO_2 GS framework, there will be a potential for competitiveness issues to arise as well, because there will also be differences in processes to evaluate and mature projects from Prospective Resources to Contingent Resources to Storage Capacity. Therefore, the CO_2 GS framework should leave a lot of flexibility in place so that competitive forces can improve finding Qualified Site(s) and turning them into "CO_2 Storage Capacity" ultimately. Over the years, the Securities and Exchange Commission (SEC) also laid out requirements and criteria, in terms of reserves accounting and impacts on financial statements, and industry compliance. Perhaps a future CO_2 industry would have the same oversight.

This chapter proposes a classification framework for CO_2 storage to be used at each stage in the process of maturing a site from Prospective Storage Resource to useable Storage Capacity. The framework is based on a similar classification framework used in the petroleum industry. It will be valuable in communicating the rigor involved in appraising for and developing a suitable storage site. Further, establishing standards for data acquisition, analysis, and interpretation for project statuses within the classes of CO_2 Storage Resources and Capacity helps to reduce the uncertainty associated with estimates. This will facilitate use of storage estimates for a variety of purposes including:

- Assessments by governmental agencies to define available storage
- Management of business processes to achieve efficiency in appraisal and injection
- Documenting the value of Storage Capacity in financial statements of publicly traded companies

Several classification approaches have been proposed for CO_2 GS. Adaptation of the Petroleum Resources Management System has the advantage of an exploration and development design similar to that required to appraise and develop CO_2 storage. It is a classification system that has worldwide acceptance and is already familiar to the technical experts such as geologists and reservoir engineers, companies, investors, financial institutions, and government regulators most likely to be involved in the CCS industry. This proposed framework is intended as a starting point. It recognizes that the analogous framework in the oil and gas industry evolved over a long period of time, allows for companies to develop their own competitive approaches to resource estimates, and has also been influenced by the SEC. These steps have not taken place in the CCS industry and as such, it is expected that the terms proposed in this CO_2 storage framework will also evolve over time and with experience. The CO_2 storage framework is intended for use from a commercial perspective, not a regulatory one.

6.1 Petroleum Resources Management System as an Analog for CO_2 Storage

The Petroleum Resources Management System (PRMS) was sponsored by several prominent petroleum associations including the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE) and published in 2007 (PRMS, 2007). It is currently widely used to standardize the definitions of reserves and classify resources in the petroleum industry. Three major classifications of resources in the PRMS are based on degree of certainty as to their existence: 1) Prospective Resources—undiscovered (no wellbores or inadequate tests of existing wellbores); 2) Contingent Resources—most of all necessary data are available but commerciality not established; and 3) Reserves—commercially established sources of petroleum. Subclasses under each major class express the stage in the exploration and development process the project has achieved.

This is an indication of project status risk as a function of the likelihood the project will move into commercial operation. The PRMS classification framework is shown in Figure 6.1. Definition of terms within the PRMS classification framework can be found in Figure 6.3 Comparison of Petroleum and CO_2 Storage Classification Framework.

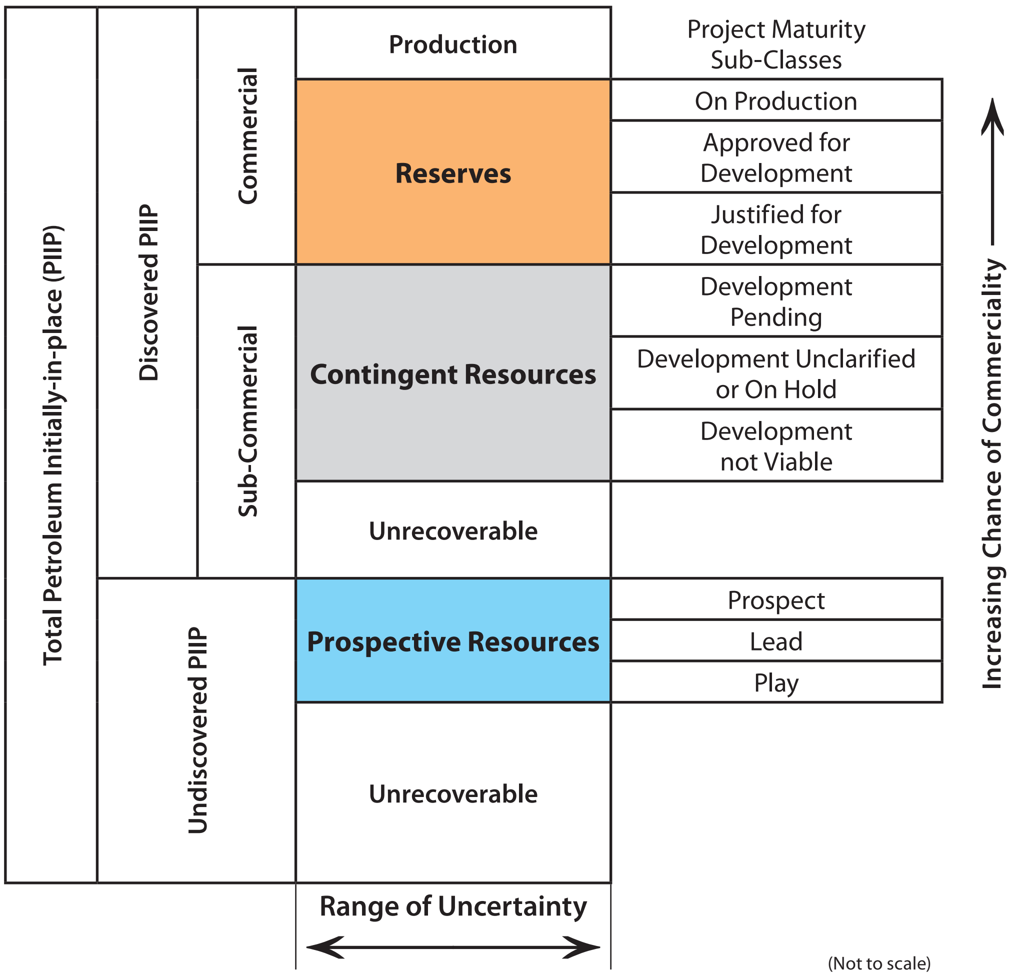

Figure 6.1. SPE/WPC/AAPG/SPEE Resource Classification System.
(© 2007 Society of Petroleum Engineers, Petroleum Resources Management System.)

6.2 Development of the CO_2 Storage Classification Framework

The process of identifying suitable CO_2 storage sites is analogous to the exploration for and development of oil and natural gas accumulations. A major similarity lies in the effort to characterize connected pore space and the fluids within the pore space. For the upstream oil and natural gas industry, the ultimate goal is to locate hydrocarbon accumulations that contain a sufficient volume of recoverable oil and natural gas to support commercial development. Similarly for the CCS industry, the goal is to identify formations with pore space of sufficient size and injectivity to support commercial storage projects. The stages of the petroleum exploration process (Play-Lead-Prospect) involve the same kinds of data acquisition and analyses that are involved in identifying prospective storage sites (Potential Sub-Regions-Selected Areas-Qualified Site).

The analogies between the two efforts are strong but not every aspect of geologic CO_2 storage is fully equivalent to the exploration, development, and production of hydrocarbons. There are distinct differences between injecting CO_2 and producing hydrocarbons. The main difference is that the discovery of a hydrocarbon accumulation is proof that a containment trap exists, while the identification of injectable pore space does not establish that CO_2 can be permanently contained at that site until it has been established that the confining zone can prohibit the vertical flow of CO_2. Another difference is that the petroleum industry "produces" hydrocarbons from a formation thus evacuating fluids from known pore volume, while CO_2 injection displaces existing saline fluids which increases pressure in the affected pore volume. Finally, there is virtually no experience in the CCS industry in defining commerciality. Since the CCS industry is just emerging, markets for projecting the value of CO_2 storage currently do not exist and the legal, regulatory, environmental, and political issues to be addressed are not fully defined. For example, states are just now starting to address the issue of pore space ownership. Currently, it would be nearly impossible for most proposed geologic CO_2 storage projects to be called commercial until development has actually started. This will change rapidly as the CCS industry matures and should not affect the development of the proposed classification framework.

The petroleum industry has developed a resource classification that has evolved over many decades to meet industry and regulatory requirements, which are essentially the same requirements that are evolving for the emerging CCS industry. An adapted version of the PRMS for the classification of geologic CO_2 storage resources is shown by Figure 6.2. The proposed classification system provides a framework for defining storage resources and storage capacity. It also contains a subclass definition for project maturity. With a standardized classification system, project status could be compared consistently between projects throughout the World with a common understanding of the level of detail in the evaluations completed to achieve each project status. This proposed classification system is similar to the petroleum classification system that was developed over decades of active oil production. It is anticipated that a storage classification will evolve in to a more robust framework as the CCS industry itself matures and several commercial projects are started.

Due to the infancy of carbon sequestration, there are some caveats to proposing this classification system at this time. The structural foundation can be developed into classes and sub-classes with general definitions and we can fully describe the Exploration Phase; however, completing the definitions and constructing guidelines for Site Characterization and Implementation Phases is premature at this time. This level of detail will evolve with experience as commerciality is further defined by commodity price of CO_2, value for stored CO_2 in pore space, and established "cost of doing business" expenses for power plant operators and other industries involved in CCS. Regardless of these caveats, development of the geologic storage classification system is necessary bring standardization to worldwide geologic storage assessments similar to the standardization brought to the petroleum industry.

The CO_2 storage framework includes the Total Geologic Storage that is then subdivided into Un-Appraised and Appraised storage potential (Figure 6.2, left-most column). The primary difference between the two categories is that for Un-Appraised Storage there are not sufficient formation evaluation data (injection test, DST or pressure tests, or a wellbore) to confirm an injectable reservoir. Once the reservoir has been determined injectable, it is termed Appraised. The dynamic classification system, similar to the petroleum classification, further divides Total Geologic Storage into three distinct classes. The Un-Appraised Storage is classified as Prospective Storage Resources and the Appraised potential is classified as Sub-Commercial Contingent Storage Resource and commercial Storage Capacity. The movement between classes from the Sub-commercial Contingent Storage Resource to commercial Storage Capacity would require an established forecast of revenue from carbon dioxide injection and defined regulatory framework.

To better understand the framework, a comparison of general definitions of both classification systems is shown below in Figure 6.3 followed by more thorough discussion of each class and subclass.

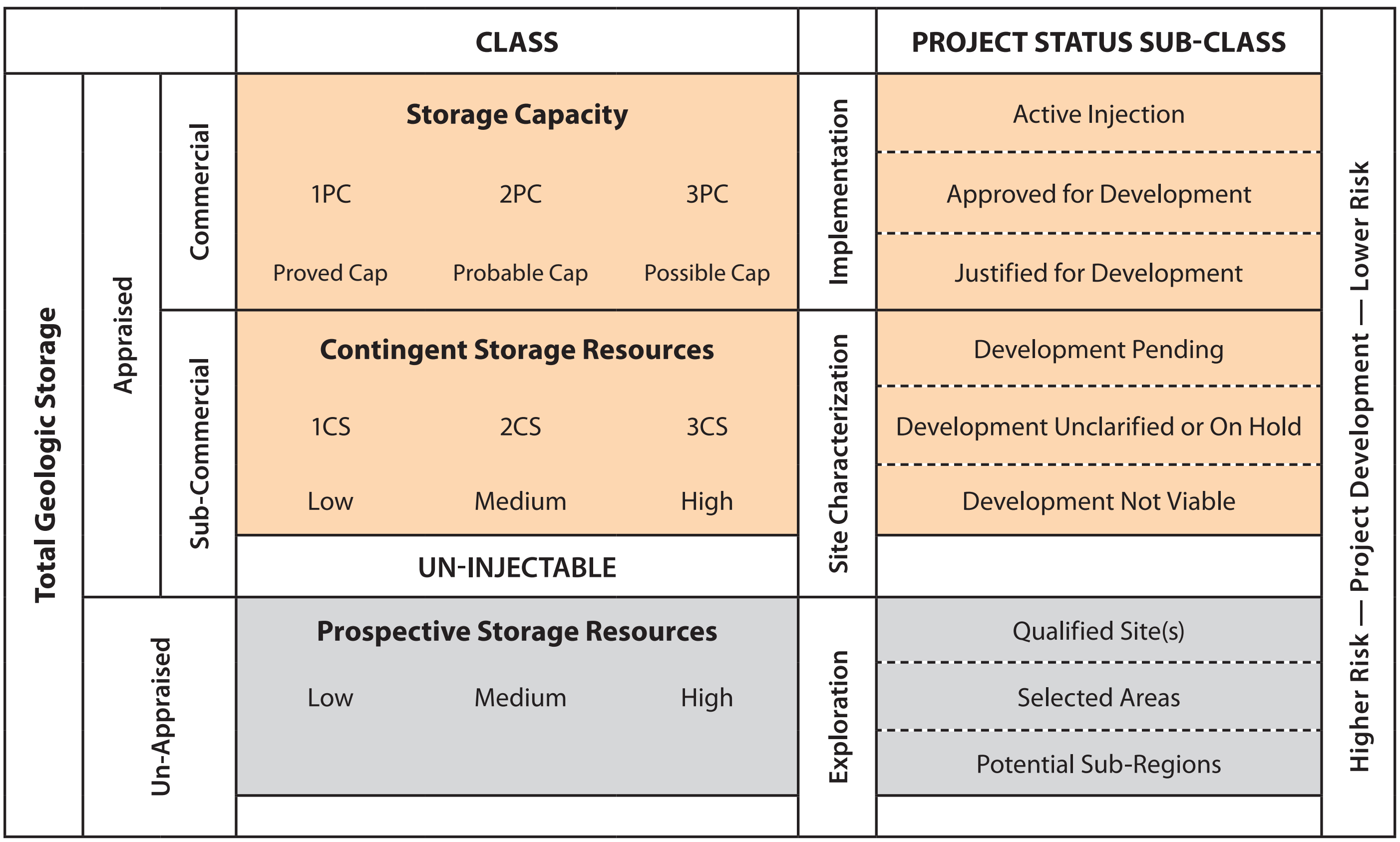

Figure 6.2. Proposed CO_2 Storage Resource and Storage Capacity Classification. Adapted from SPE/WPC/AAPG/SPEE Resource Classification System. (© 2007 Society of Petroleum Engineers, Petroleum Resources Management System.)

Petroleum Industry			CO_2 Geologic Storage			
Class	**Sub-Class**	**Definition**	**Class**		**Sub-Class**	**Definition**
Reserves		Quantities of petroleum anticipated to be commercially recoverable by application of development projects to know accumulations from a given date forward.	**Storage Capacity**			Quantities of CO_2 anticipated to be commercially stored into formations with known injectable pore space by application of development projects from a given date forward.
	On Production	Development project is currently producing and selling petroleum to market.		**Implementation**	**Active Injection**	Commercial scale development project currently injecting and storing CO_2.
	Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway.			**Approved for Development**	All necessary approvals and permits have been obtained, capital funds have been committed, and implementation of the development project is underway.
	Justified for Development	Implementation of development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and reasonable expectations that all necessary approvals/contracts will be obtained.			**Justified for Development**	Implementation of development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources		Quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by applications of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	**Contingent Storage Resources**			Quantities of estimated CO_2, as of a given date, to be potentially stored into known pore space, by applications of development projects, but which are not currently considered to be commercial projects due to one or more contingencies.
	Development Pending	Discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.		**Site Characterization**	**Development Pending**	Discovered pore space for CO_2 storage, where project and site characterization activities are ongoing to justify commercial development in the foreseeable future.
	Development Unclarified or On Hold	Discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.			**Development Unclarified or On Hold**	Discovered pore space for CO_2 storage, where site characterization and project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
	Development Not Viable	Discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.			**Development Not Viable**	Discovered pore space for CO_2 storage, which there are no plans for further site characterization and no current development plans at the time due to limited storage potential.
Prospective Resources		Quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	**Prospective Storage Resources**			Quantities of CO_2 which are estimated, as of a given date, to be potentially stored in undiscovered pore space.
	Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.		**Exploration**	**Qualified Site(s)**	A project associated with potential pore space for CO_2 storage that is sufficiently well defined to represent a viable storage option.
	Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.			**Selected Areas**	A project associated with potential pore space for CO_2 storage that is currently poorly defined and requires more data acquisition and further evaluation to be defined as Qualified Site.
	Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.			**Potential Sub-Regions**	A project associated with a sub regional trend of potential CO_2 storage project sites, but requires more data acquisition and/or evaluation to define Selected Areas.

Figure 6.3. Comparison of Petroleum and CO_2 Storage Classification Frameworks. Adapted from SPE/WPC/AAPG/SPEE Resource Classification System. (© 2007 Society of Petroleum Engineers, Petroleum Resources Management System.)

Prospective Storage Resources

Prospective Storage Resources are the pore volume estimates within characterized geologic formations that could potentially be used for CO_2 injection and have been identified through work being conducted by RCSPs. The quantity and complexity of analyses associated with each project status is in the guidelines from the previous chapters. These guidelines should be used to highlight the certainty of analyses results for classifying projects as they mature from Potential Sub-Regions through Qualified Site(s). The results from analyses conducted can decrease project risk but in turn can increase project costs through the maturation process. Added value of information (VOI) assessments should also be considered for each project site to determine if the data and analysis being collected will influence decisions being made on the project.

Storage resource estimates have a range of certainty within individual parameters used in the calculations as well as risk of both pore space and project development. Prospective Storage Resource estimates can use analog regional estimates of parameters that are calculated either deterministically or probabilistically. They should be reported as estimates – low, medium, and high. The Prospective Storage Resources' Project Status is defined into three sub-classes:

Potential Sub-Regions – The project site associated with a sub-regional trend of potential storage sites, similar to the level of data and analysis needed for an exploration "play." Projects in this category need acquisition of more data and/or additional evaluation. The Site Screening process evaluates these potential Sub-Regions to select a specific Selected Area for continued consideration and further definition of pore space.

Selected Areas – During this evaluation of the project, subsurface evaluation of the potential storage reservoir is poorly defined and requires more data acquisition and further analyses to consider drilling a new well or retesting an existing well. Similar to the "Lead" in the petroleum classification system, during Site Selection, further evaluation of data is incorporated into the initial geologic model framework and Prospective Storage Resources is revised with more confidence and greater certainty with a narrower range of parameter values.

Qualified Site(s) – The evaluations that have taken place up to this point, including Initial Characterization, will sufficiently define potential pore space for CO_2 storage. The pore space could represent a viable candidate for drilling a characterization well or well testing of an existing wellbore to collect data to sufficiently characterize the injectivity of the reservoir.

Contingent Storage Resources

Contingent Storage Resources is the CO_2 storage volume estimated in geologic formations. This estimate is typically based on an assessment using data from existing wellbore(s) in the area of the site that could potentially be used for CO_2 injection. Contingent Storage Resources are not yet commercial due to one or more contingencies. Example contingencies could include lack of CO_2 market, regulatory framework, and liability. However, site specific contingencies could include the need for more data such as seismic acquisition, development of CO_2 pipeline/infrastructure, securing pore volume rights, or awaiting approval of injection permits. During this stage project development risk decreases, but some risk remains due to the defined contingencies. During this stage, all necessary approvals and contracts for long-term injection will be solidified, capital funds will be identified, and implementation will be justified.

Contingent Storage Resources estimates are calculated either deterministically (1CS, 2CS, 3CS) or probabilistically (low, medium, high). Contingent Storage Resources is reported similar to Storage Capacity because the primary difference between the Contingent Storage Resource and Storage Capacity is the commerciality of the project. Based on the petroleum resource classification in PRMS, the resource should be developed within a reasonable timeframe (usually five years). However, carbon capture and injection technologies are not planned for broad deployment of commerciality until the 2020 timeframe. Therefore, it may be premature to finalize guidelines during the start-up periods.

The Contingent Storage Resources, within the Site Characterization Phase, are divided into three sub-classes that focus on development of a commercial project:

Development Not Viable – There are no current plans to develop or to acquire additional data due to limited storage or injection potential. Storage potential is not adequate for the project being developed, for example, due to low injection rate forecasts, or the potential geologic storage is too far from the CO_2 emission source that drilling is not justified.

Development On Hold – The discovered pore space is of adequate size, but commercial development could be significantly delayed and project activities are on hold. This could be due to lack of developed capture facilities, or other technical, environmental, political, or economical contingencies.

Development Pending – Project is proceeding with project and site characterization activities moving forward towards commercial development in the foreseeable future at this specific site. It is during this phase of the project that a final "Project Development Plan" is completed and submitted.

Storage Capacity

Storage Capacity is the quantity of CO_2 anticipated to be commercially storable by available technology applied to known formations from a given date forward under defined conditions. Storage Capacity must further satisfy four criteria: it must be appraised, injectable, commercial, and remaining (as of the evaluation date) based on the development technology applied. Storage Capacity is further categorized in accordance with the level of certainty associated with the calculated capacity estimates (Proved, Probable, Possible) and may be sub-classified based on the following development and injection statuses:

Justified for Development – Project has been justified on the forecast of commercial conditions, and there is a firm intent (contract) to develop capacity. The project is moving forward on the development plan with the expectation that all necessary approvals and contracts will be finalized (because all necessary approvals and contracts are largely unknown at this time, it will be nearly impossible to place a project in this subclass until development has started).

Approved for Development – All necessary approvals and permits have been obtained, capital funds have been committed, and development of the project is underway. The Development Plan is being implemented and on schedule for injection.

Active Injection – The project is currently injecting and storing CO_2.

It is likely that a framework similar to the PRMS classification will be used, but, due to lack of clear understanding of attributes that will be required to establish CO_2 geologic storage commerciality, a discussion of Proved, Probable, and Possible Storage Capacity for this guideline document is considered too speculative. Nevertheless, additional details on Storage Capacity is available (Frailey and Finley [2009], and Frailey, Finley, and Hickman [2006]).

7.0 Case Study – Siting a Phase III RCSP Project in the Illinois Basin

Note: The following case study provides an example of the effort that goes into siting a project. It is important to note that the requirements faced by this project may not be the same for other projects. Not every project may need to submit all data indicated here, and some projects may have to submit more or less information, depending on the particular situation.

7.1 Introduction

The Regional Carbon Sequestration Partnership (RCSP) Initiative was begun in 2003 to help determine the best approaches for capturing and permanently storing CO_2. The key lessons learned from these projects are being captured in technical reports and Best Practices Manuals like this one. The RCSP projects are proving invaluable in providing future project developers, regulators, and the general public with lessons learned and expectations for project development.

The work conducted in the RCSP projects provides the basis for these Best Practices, however, it should be recognized from the outset that the objectives of a research project differ from commercial objectives. The primary objectives of the RCSP Development Phase are to:

- Demonstrate the ability of various formations, in this case the Mount Simon Sandstone, to accept and retain at least one million metric tonnes of injected CO_2, and,
- Achieve a more comprehensive understanding of the science, technology, regulatory framework, risk factors, and public opinion issues regarding large-scale injection operations.

This Best Practices Manual documents the methods used by the RCSPs through what is the equivalent of the Exploration Phase and the early Site Characterization Phase of the process to identify Prospective and Contingent Resources. The steps involved in this process, illustrated by the following case study, are formalized in the flow charts for Site Screening, Site Selection, and Initial Characterization.

7.2 The Illinois Basin-Decatur Phase III Project

The Illinois Basin-Decatur Phase III injection site characterization process proceeded from the Exploration Phase activities of basin-scale mapping and assessment through detailed site-specific data collection before moving into the Site Characterization Phase. This case study describes that progression. During Phase I of the RCSP Initiative, the Midwest Geological Sequestration Consortium (MGSC) conducted regional and sub-regional site screening that involved identifying existing well logs and core data; mapping regional structure and thickness; and, using existing site studies, such as those for natural gas storage, in the same formation. During Phase II of the RCSP Initiative, MGSC conducted pilot projects in the Illinois Basin and continued to assess the most promising potential storage areas, including the Decatur site that was elevated to Qualified Site Project status and then to the Site Characterization Phase. DOE's announcement for Phase III of the RCSP Initiative was made during Phase II and the ensuing Request for Proposals (RFP) served, in effect, as a foundation for Project Definition for the Decatur project and the other Phase III projects. The RFP outlined major objectives and criteria for evaluating proposals.

The Phase III Illinois Basin - Decatur Project targets storage in the Mount Simon Sandstone (injection zone) in the central and southern Illinois Basin, a sandstone reservoir that has also been used for natural gas storage in the northern Illinois Basin. Data on the Eau Claire Shale, the potential primary confining zone immediately above the Mount Simon injection zone, has also been collected.

7.3 Site Screening and Site Selection

Initial mapping in the Site Screening and Site Selection stages focused on the structure of the top of the Mount Simon to determine drilling depth and its thickness. Data available from a number of existing wells were used for the structure map; however relatively few of these wells penetrated the entire Mount Simon, hence the isopach map was data-limited. Likewise, there were a limited number of available wells with porosity logs because producible hydrocarbons have never been encountered in the Mount Simon. Outside of natural gas storage fields, there has never been any commercial interest in Mount Simon porosity and permeability, especially for the lower half of the formation. Fortunately, a few deep wells were located in the central Basin area. A key well was found at Manlove Gas Storage Field and another at Loudon Oil Field that had a log for the entire Mount Simon interval. Interpolation between these wells allowed prediction of a porous zone related to secondary porosity development in the lower Mount Simon at the Illinois Basin-Decatur site. Structural complexity was not an issue at the site, since the central Illinois Basin is characterized by several regional uplift features but not an abundance of faulting, as in the far southern part of the Basin.

Regional isopach and structure contour maps were prepared during the Site Screening and Site Selection stages and a composite type log was developed to illustrate the anticipated Mount Simon stratigraphy. A limited number of sidewall cores were available from the Manlove field that indicated that feldspar dissolution was likely responsible for development of secondary porosity low in the formation. The feldspar is derived from the underlying granitic basement in the Cambrian source areas generally to the north. This was a reasonable inference based on the porosity indications from deep in the Mount Simon in the few locations where the complete formation had been logged. Further, the Eau Claire Shale was observed to be a functioning confining zone at Manlove field over an area of more than 25 square miles where natural gas has been stored since the early 1970s. Manlove is located approximately 40 miles northeast of Decatur, Illinois.

Some regional screening was carried out for a secondary injection aone, St. Peter Sandstone, but that unit lacks an immediately overlying confining zone(s) and anecdotal information was obtained suggesting that some shallow gas storage operations attempted in the St. Peter had leakage issues. While drilling depths could be 2,000 feet less for the St. Peter, knowledge of gas storage operations called into question the ability of the St. Peter to retain CO_2 absent much more extensive, site-specific investigations. Thus, the St. Peter did not appear to meet the highest requirements for confining zone integrity, especially for an early project, and so it was not considered for further analysis.

Once it was determined that the regional geology was favorable in the east-central Illinois area for a Phase III project, in other words the site had reached the status of a Selected Area within the Prospective Storage Resources class, discussions were held with Archer Daniels Midland Company (ADM) in Decatur, Illinois, about one of the more promising locations. ADM was amenable to developing a project and determined that it had CO_2 at a high-enough purity for the project. A site on open land owned by ADM and adjacent to the north margin of its facility was elevated to Qualified Site and MGSC began further evaluation of the components discussed in the Initial Characterization stage. Presentations were made to ADM executives and outreach was extended to ADM staff through an in-house video posted to the employee web site. Also, presentations were made to the community at large through local TV stations and the Decatur newspaper with the support of ADM's media relations team. The MGSC matured the potential Sub-Region to Selected Area and then a Qualified Site for further detailed evaluations. The initial site development plan and economic feasibility assessment were developed as part of the RCSP Phase III project application, to complete the site selection process.

7.4 Initial Characterization

Given the geologic data and the cooperation of ADM, the Illinois Basin-Decatur site was believed to be suitable for a Phase III Deployment Test in the Mount Simon Sandstone and additional data collection was deemed appropriate; the site had reached Initial Characterization status. In October 2007, a 2D seismic survey was conducted consisting of two lines, each about 3 miles long, running north-south and east-west adjacent to the site. The data were difficult to collect because of ambient noise, electrical interference in an industrial environment, and because the vibrator source trucks available were not capable of the highest possible energy output. The 2D data indicated that the site had the integrity desired for a storage site and the decision was made to proceed with the drilling of the injection well to confirm reservoir and confining zone(s) quality. A UIC Class I Nonhazardous injection permit was filed for in January 2008 and received in January 2009. Illinois has primacy (authority from EPA) to implement the UIC program, so the permit was issued by the Illinois Environmental Protection Agency. Given ADM's ownership of the site and responsibility for 24/7 operations once injection began, it was determined that ADM would be the permit holder on behalf of the project.

The injection well was spudded on February 14, 2009, and the rig released on May 4, 2009; total depth of the well is 7,230 feet. Reservoir quality came in as expected with a total thickness of the Mount Simon of about

1,650 feet with sufficient injectivity at the base of the unit. Figure 7.1 shows the stratigraphic column at the well location. Porosities ranged from 20 to 28 percent in the potential injection zones with permeabilities of tens to more than 1,000 md. A total of 55 feet of perforations have been opened for initial injection and additional zones are available above where the injection packer has been set. The relationship between plume size and land ownership will be addressed by modeling CO_2 distribution using parameters derived from well logs and

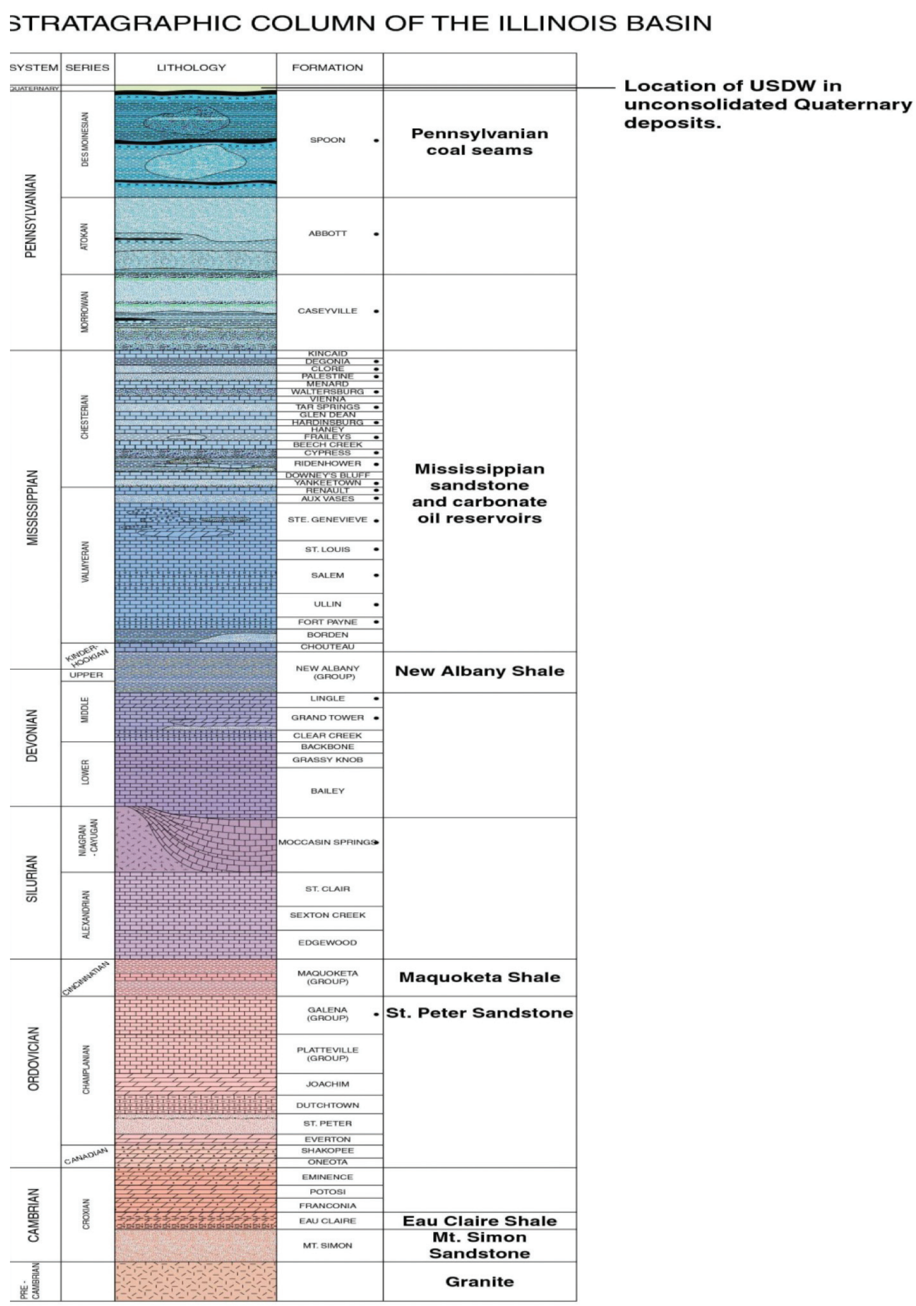

Figure 7.1. Stratigraphic Column of the Illinois Basin.

(Courtesy of Finley, R. at MGSC, 2009)

sidewall cores in the injection well. For example, opening multiple zones sequentially has been shown to result in a more compact plume with more vertical development of the plume shape and the CO_2 remaining on-site. Two 30-foot cores were collected in the Mount Simon, but neither was deep enough in the unit to cover the interval now being configured for injection. Given the lack of nearby well control, the risk of not coring and hitting the underlying granite prematurely without collecting core made targeting the core a difficult task. Some 400 feet of reservoir core are now planned for the verification well, a 7,200-foot deep observation and sampling well is expected to be drilled in fall 2010, and that core can be easily and specifically targeted given the proximity of the verification and injection wells on the site.

With the 2D data and the injection well completed, the next major effort was the collection of a 3D seismic survey. The survey was designed to update injection zone structure, determine internal architecture to the extent that vertical bed resolution will allow, and carry out special attribute processing that could reveal faults or fractures not resolvable in the 2D data. Simultaneously with the collection of the 3D data, vertical seismic profiles (VSPs) were obtained using an array of 31 geophones permanently cemented into a 3,500-foot-deep monitoring well approximately 200 feet northwest of the injection well. The geophone well was drilled following perforation and injectivity testing of the injection well, confirming that the Mount Simon would accept fluids at the required rate. At this point, the site achieved Qualified Site status. The VSPs are designed to be the ongoing monitoring tools to determine position of the CO_2 plume front as injection occurs. The permanent geophone array will allow monitoring while injection occurs simply by bringing a vibrator source to the site and will avoid ambiguity in position of the geophones in the well as may occur with a wireline array. Microseismic sensors have been installed in the injection well on special mandrels made up in the tubing string. A fiber optic temperature sensor has been installed over the length of the injection tubing, and fluid pressure and temperature sensors have been installed at the packer.

7.5 Contingent Storage Resources: Site Characterization

With completion of well testing and the full 3D survey, the Illinois Basin-Decatur project is considered well into the Site Characterization Phase Contingent Storage Resource class. Given the knowledge of the regional geology prior to drilling, and the data from the 2D lines, there is little expectation that the 3D would set the project back to where development and injection were not considered viable. This was particularly true because the Illinois Basin-Decatur site has a confining zone with both secondary and tertiary confining zones in the form of the Maquoketa and New Albany Shales, respectively. These confining zones are regional in extent and considered backups to the primary Eau Claire Shale confining zone.

Completion of the 3D data collection and subsequent processing and interpretation should allow important assessment of the internal architecture of the Mount Simon reservoir. Well log data and sidewall cores from the injection well indicated low permeability baffles within the Mount Simon that will constrain vertical migration of supercritical CO_2 and should enhance retention in the reservoir. These baffles are lower permeability zones related to the diagenesis of the sandstones. Also present are depositional heterogeneities believed related to the original depositional system as a bedload-rich, probably braided fluvial system that may incorporate sand-on-sand boundaries with some capability to impact internal fluid flow. Numeric simulations of 1 million metric tonnes injected indicate that this volume of CO_2 would remain in the lower half of the Mount Simon even 100 years after the three-year injection period was completed.

Verification of the distribution of CO_2 in a sequestration reservoir and the associated pressure front are considered important aspects of validating geological sequestration, especially for early projects. Further, the Area of Review may need to be modified as a project proceeds depending on distribution of the pressure perturbation. The Illinois Basin-Decatur project is scheduled to drill one verification well through the Mount Simon reservoir to verify the distribution of CO_2 relative to geophysical observations, obtain reservoir pressure measurements, and sample chemical changes in the brine prior to the CO_2 plume arriving at the verification well. Baseline data will be collected from this well prior to commencing injection and the well will be an important part of post-injection monitoring. Because internal heterogeneity of the Mount Simon from its original depositional systems may control any preferential flow directions of injected CO_2, it is important to interpret the 3D survey before locating the verification well. Fold coverage up to 80 fold and high input frequencies are desirable for maximizing the ability to image sand body geometry within the Mount Simon, however the minimum mapping unit may still be on the order of 40 feet in thickness. The Mount Simon is interpreted to be an alluvial fan to braided stream deposit in the proximal to middle parts of its depositional systems tract, thus some channeling of CO_2 and depositionally controlled preferential flow may be expected. The extent of this influence on CO_2 flow direction will also depend on the nature of the sand body contacts and any preferential diagenesis at those boundaries.

As more data became available, project researchers were able to confirm to ADM the suitability of the site. Additional outreach involved a company-hosted event for local and regional officials and corporate leaders in central Illinois. Additional media coverage initiated by ADM with support by project staff provided more information to the general public. A public information meeting was held prior to shooting the 3D seismic to which all landowners in the area of the shoot were invited to attend. Teachers in the Decatur school district have had opportunities to hear about the project and visit the site, and involvement has been extended to the community college near the north boundary of the site.

7.6 Case Study Conclusion

In summary, the development of a Phase III storage site at Decatur, Illinois, proceeded from Potential Sub-Region to Selected Area and then Qualified Site through increasingly detailed and more costly site-specific assessments. In oil field terms, the injection well was a "rank wildcat" with very limited nearby well control and limited velocity information for time-to-depth conversion of the initial 2D seismic survey lines. However, confidence in the regional distribution of the Mount Simon and the early, but limited, understanding of reservoir quality controls made the drilling of the injection well an acceptable risk. Further, without the well data, initial planning, and subsequent interpretation, of the much more costly 3D survey would have been difficult. The final characterization step prior to injection will be locating the verification well based on 3D seismic interpretation and recovering core, well logs, pressure data, and fluid samples. Following the success of that drilling, sampling, and testing program, and with a comprehensive data set in hand from two on-site wells, a high degree of confidence will exist in the suitability of the site for extensive storage of CO_2.

The Phase III research project is slated to continue for 10 years. If this were a commercial project, it would likely have the current project sub-class status of "Development Pending" in the Contingent Storage Resource class. The site characterization activities have confirmed the site suitable, however as a research project, there is no commercial benefit—or impetus—in maturing the site to the Storage Capacity class. The RCSP large-scale development projects, as well as other large-scale demonstration projects being planned, are subsidized by federal funding to develop and demonstrate the capability to safely and permanently store CO_2 in deep geologic formations. Future projects developed by industry will require some resolution of current issues such as definition of commerciality and reasonable forecast of commercial conditions, regulatory framework, and liability. These issues will need to be resolved before storage capacity estimates can be determined for geologic storage projects. Consequently, all storage estimates will be classified as Prospective Storage or Contingent Storage Resources until the CO_2 geologic sequestration process costs are included as operating expenses to an existing business or become a revenue generating business.

8.0 Conclusion

Geologic storage of CO_2 is an important technology in the emerging portfolio of options to cost-effectively reduce CO_2 emissions. The technical underpinning for carbon storage is found in more than a century of experience gained in the petroleum industry and dates even further to early drilling experience for water and other resources. It is commonly agreed that the process of identifying and fully characterizing potential storage sites is fundamental to ensuring the safety and integrity of a CO_2 GS project.

This manual introduces a set of processes and guidelines to aid in identifying and selecting a suitable site for geologic storage. The processes and guidelines are integrated into a proposed CO_2 geologic storage framework designed to classify storage resources and storage capacity into classes and project-status sub-classes. The proposed CO_2 geologic framework, and adaptation from the petroleum industry, consists of three phases: Exploration, Site Characterization, and Implementation. The emphasis of this manual was on the Exploration Phase and provided a set of process flowcharts and guidelines for thorough evaluation for potential CO_2 geologic storage through the three stages of the Exploration Phase: Site Screening, Site Selection, and Initial Characterization respectively classifying projects as Potential Sub-Region, Selected Areas, and Qualified Site(s).

Each stage's Process Flowcharts and detailed Guidelines are meant to help project developers plan for and implement comprehensive site identification procedures. Further, it will help other stakeholders to gain a better understanding of the rigorous steps involved in the characterization process. This manual is a companion to several other carbon sequestration best practices documents either recently published or under development within Department of Energy. Subjects for these companion documents include: monitoring, verification, and accounting; simulation and risk assessment; well construction and closure; public outreach and education; and terrestrial sequestration.

For more information on the Sequestration Program or to download a copy of the existing Department of Energy Best Practice Manuals from our Reference Shelf, please visit our website at www.netl.doe.gov/technologies/carbon-seq/index.html.

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Appendix 1—CO_2 Storage Resources and Storage Capacity Estimates

The scale of CCS necessary to have a major impact on GHG emissions from stationary sources vastly exceeds the historical use of CO_2 injection practiced for CO_2 EOR. If legislation is enacted to limit GHG emissions, commercial-scale CCS projects are likely to be extensive. Because CO_2 GS estimates will be important in site selection, there is a major need for robust procedures for estimating the CO_2 storage potential in deep geologic formations.

CO_2 storage resource is the calculated volumes of resource estimated in geologic formations, subdivided into Prospective and Contingent Storage Resources. Whereas, the CO_2 storage capacity is an estimate of the amount of CO_2 that can be stored in a given geologic formation based on the specific geologic, economic, and regulatory characteristics associated with the target formation. Governments worldwide depend on reliable estimates of CO_2 storage, as well as evaluations of the viability of geological storage operations in their respective regions. Similarly, the private sector requires reliable estimates to make important business decisions regarding site selection and development. If decisions are based on poor information due to an unreliable estimate, valuable resources and time could be wasted, public health and safety, and the environment could be at risk, and policies that have been developed and implemented to address CO_2 emissions could be compromised. Estimates of CO_2 storage resource and storage capacity should include clear identification of all limitations in the information available at the time the assessment was made, as well as indications of the scope and future applications to which the estimate applies. A concrete set of guidelines for estimation of storage resource and capacity can greatly assist future deliberations by government and industry on the appropriateness of CO_2 GS in different geological settings and regions (Bradshaw et al., 2007).

To some extent, all geologic subsurface characterization is inherently uncertain, regardless of the level of characterization effort and the precision and sophistication of the characterization tools. Carbon dioxide storage resource and capacity estimates are, therefore, at best an approximation of the amount of CO_2 that can be stored and not a measure of the exact amount. These estimates rely on the skill and judgment of the evaluator and are directly affected by the stage of exploration and development, geologic complexity, volume of CO_2 already stored, temperature, pressure, the rate of chemical reactions that are sequestering the CO_2, and available geologic data. Although it is a challenge to develop the best estimate for a given target reservoir, it is critical to identify, with the highest level of accuracy possible, key geologic and environmental factors that directly influence CO_2 storage potential.

Key factors influencing CO_2 GS estimates include the density of CO_2 at subsurface reservoir conditions (pressure and temperature), the nature of existing formation fluids, the presence of an open or closed system, and the interconnectedness of the pore volume of the reservoir rock. Potential CO_2 storage resource and storage capacity should be assessed in terms of available interconnected pore space, accounting for factors such as injection rate, rate of CO_2 migration, the dip of the reservoir, the heterogeneity of the reservoir, and geologic structures encountered along the migration path. Due to the flow behavior of CO_2 (and other formation fluids) in the subsurface, not all potentially available reservoir pore volume may be occupied during injection and migration. Preferential flow pathways may occur upward due to buoyancy forces or laterally because of low permeability zones (spreading effect beneath confining zone) (Kaldi and Gibson-Poole, 2008). These phenomena can make CO_2 storage resource and capacity difficult to estimate, particularly in reservoir rocks at depths below defined structural or stratigraphic closures, where much of the available rock pore volume can be bypassed by CO_2 preferentially following higher permeability zones (Gibson-Poole, 2008).

Those assessing CO_2 storage resource and storage capacity have used a range of approaches and methodologies, including data sets of various sizes and quality, resulting in widely varying storage estimates of inconsistent values and reliability. Of the various methods to estimate CO_2 storage, few take into account commercial or engineering feasibility limitations. Two examples of major works providing methodologies for the estimation of storage potential of CO_2 in geological formations are (1) DOE's "Methodology for Development of Geologic Storage Estimates for Carbon Dioxide," in preparation for NETL's Carbon Sequestration Program (DOE, 2010) (this document was originally published in the first edition of the Atlas in 2006, republished in the second edition in 2008, and will be republished in the third edition in 2010), and (2) CSLF's "Estimation of CO_2 Storage Capacity in Geological Media—Phase II," prepared by the Task Force on CO_2 Storage Capacity Estimation (Bachu et al., 2007).

CSLF (2007) and DOE (2010) studies do not incorporate commercial perspectives related to GS into storage estimation and are aimed at identifying total pore volume. Both studies include equations specifically for volumetric calculation of pore volume for a given formation thickness and areal extent. The DOE (2010) study provides volumetric equations for calculations in the three main storage systems (oil and gas reservoirs, saline formations, and coal seams). A Monte Carlo approach is used to estimate probability limits on the efficiency factor for CO_2 storage resource from a combination of trapping mechanisms. The DOE (2010) CO_2 storage estimation method uses an equation that employs a storage efficiency factor to account for all corrections, such as net-to-gross volume, gravity effects, and displacement efficiency.

Methods available for estimating subsurface volumes are widely and routinely applied in petroleum, ground water, underground natural gas storage, and the Underground Injection Control (UIC) disposal-related estimations. In general, subsurface volume estimation methods can be divided into two categories: static and dynamic. While both categories are applicable after active CO_2 injection, only the static methods are applicable before injection or the collection of field-measured injection rates. These models rely on parameters that are directly related to the geology of the area (areal extent, thickness, porosity, permeability, pore volume interconnectedness, etc.). Dynamic models are applicable after CO_2 injection has begun. For the purpose of this document, estimation of resource and capacity will be based primarily on DOE's methodology outlined in the Atlas (DOE, 2010).

DOE estimation methodologies are specifically designed to provide a resource estimate for a given target formation. A CO_2 storage resource estimate is the available pore volume of a given formation that will be occupied by CO_2 injected through drilled and completed wellbores. As described herein, CO_2 storage resource estimates are based upon the assumption that *in-situ* fluids will either be displaced by the injected CO_2 into distant parts of the same formation or neighboring formations, or managed by means of fluid production, treatment, and disposal in accordance with current technical, regulatory, and economic guidelines. CO_2 storage resource assessments omit economic and regulatory constraints and take into account only physical constraints to define the accessible part of the subsurface. Examples of physical constraints include isolation from potable water, solubility of CO_2 in water, gravity segregation, caprock (confining zone(s)) capillary entry pressure, fracture propagation pressure, and displacement efficiency. Additional geologic-based physical constraints include vertical thickness, proportion of porosity available for CO_2 storage, and fraction of the total area accessible to injected CO_2. Economic and regulatory constraints are, however, included in CO_2 capacity estimates.

Factors affecting economics include CO_2 injection rate and pressure, the number of wells drilled into the formation, type of well (horizontal versus vertical), the number of injection zones completed in each well, operating expenses, and injection site proximity to the CO_2 source. For the development of specific commercial-scale geologic storage sites, economic and regulatory constraints must be considered to determine the portion of the CO_2 storage resource that is available under various development scenarios. Under the most favorable and ideal economic and regulatory scenario, 100 percent of the estimated CO_2 resource may be considered to be CO_2 capacity (DOE, 2010).

Types of Geologic Environments

Typical subsurface storage formations can be categorized into several storage types, including: oil and gas reservoirs, saline formations, coal seams, and interflow zones in basalt formations. These formations are defined in DOE's Carbon Sequestration Atlas (2010), along with parameters for CO_2 storage resource calculations. This appendix provides an overview of the methodology for oil and gas reservoir, saline formation, and coal seam storage resource estimation.

Oil and Natural Gas Reservoir CO_2 Storage Resource Estimation

Typical mature oil and gas reservoirs in North America have held crude oil and natural gas for millions of years. They consist of a layer of permeable rock with a layer of impermeable rock (caprock) above the reservoir, such that the impermeable layer forms a trap holding the oil and gas in place. Oil and gas fields have many characteristics that make them excellent target locations for geologic storage of CO_2, as the geologic conditions (e.g., impermeable caprocks) that trap oil and gas are also conducive to long-term CO_2 storage. The main mechanisms for storing CO_2 in oil and gas reservoirs are structure trapping and solubility trapping.

Major criteria for oil and gas reservoirs as CO_2 storage sites are the capacity, injectivity, lithology, and caprock integrity. Estimation of CO_2 storage is more straightforward for oil and gas than saline formations and unmineable coal seams. Oil and gas reservoirs are better characterized as a result of exploration and production. Oil and gas field CO_2 resource estimates are based on recoverable reserves, reservoir properties, and in-situ CO_2 characteristics. As a value-added benefit, CO_2 injection into a mature oil reservoir can enable incremental oil to be recovered. A small amount of CO_2 will dissolve in the oil, increasing its bulk volume and decreasing its viscosity, thereby facilitating flow to a production wellbore. Typically, primary oil recovery and secondary recovery via a water flood produce 30–40 percent of a reservoir's original oil-in-place (OOIP). EOR via a CO_2 flood allows recovery of an additional 10–15 percent of the OOIP.

Estimating CO_2 Storage Resources in Oil and Gas Fields

The general form of the volumetric equation used for oil and gas fields is as follows:

$$G_{CO2} = A\, h_n\, \phi_e\, (1\text{-}S_w) B\, \rho\, E$$

The area (A),net thickness (h_n), and average effective porosity (ϕ_e) terms account for the total volume of pore space available. The oil and gas saturation (1-water saturation as a fraction [Sw]), formation volume factor (B), and CO_2 density (ρ) terms account for the fluid and fluid-rock interaction properties and define the mass of CO_2 that can fit into the total available pore space. The CO_2 storage efficiency factor (E) reflects the fraction of the total pore volume that can be filled by CO_2 and is derived from local experience or reservoir simulation. Terms in this equation are described in the following table.

Table A1.1. Description of Terms in the Volumetric Formula for Oil and Natural Gas Fields

Parameter	Units	Description
G_{CO2}	Mass	Mass estimate of oil and gas reservoir CO_2 storage resource.
A	Length Squared	Area that defines the oil or gas reservoir that is being assessed for CO_2 storage.
h_n	Length	Net oil and gas column height in the reservoir.
$Ø_e$	Dimensionless	Porosity in volume defined by the net thickness.
S_W	Dimensionless	Average water saturation within the total area (A) and net thickness (h_n).
B	Dimensionless	Reservoir volume factor; converts standard oil or gas volume to subsurface volume (at reservoir pressure and temperature). B = 1.0 if CO_2 density is evaluated at anticipated reservoir pressure and temperature.
ρ	Mass/Length Cubed	Density of CO_2 evaluated at pressure and temperature that represents storage conditions in the reservoir averaged over h_n and A.
E	Dimensionless	CO_2 storage efficiency factor that reflects the fraction of total pore volume from which oil and/or gas has been produced and that can be occupied by CO_2.

Saline Formation CO_2 Storage Resource Estimation

Saline formations are composed of saturated porous rock and capped by one or more regionally extensive impermeable rock formations. A saline formation (injection zone) assessed for CO_2 storage is defined as a porous and permeable body of rock containing water with TDS greater than 10,000 ppm. A saline formation can include more than one named geologic system or be defined as only part of a system. Mechanisms for CO_2 storage in saline formations include structural trapping, hydrodynamic trapping, residual trapping, dissolution, and mineralization. Structural and hydrodynamic trapping are initially the dominant trapping mechanisms. Over time, the contributions of residual, dissolution and mineral trapping mechanisms become important. The CO_2 storage resource estimates produced by this methodology do not account for dissolution and mineralization. (DOE, 2010).

Saline formations assessed for storage are restricted to those meeting the following basic criteria: (1) pressure and temperature conditions in the saline formation are adequate to keep the CO_2 in dense phase (liquid or supercritical); (2) a suitable confining zone is present to limit vertical flow of the CO_2 to the surface; and (3) a combination of hydrogeologic conditions isolates the CO_2 within the saline formation. These criteria also apply to existing UIC and other regulations and are relevant to capacity assessment as well, but the criteria are first incorporated into resource assessments.

The storage of CO_2 in saline formations is limited to sedimentary basins with vertical flow barriers and depth exceeding 800 meters. Sedimentary basins include porous and permeable sandstone and carbonate rocks. The 800-meter cutoff is an attempt to select a depth that reflects pressure and temperature that yields high density liquid or supercritical CO_2. This is arbitrary and does not necessarily designate a lower limit of depth conducive to CO_2 storage. Several natural gas reservoirs exist at shallower depths, which suggests that CO_2 gas may be stored at shallower depths but only at pressure and temperatures most likely to sustain gas-phase CO_2 density. Because of the large difference in density between liquid-phase and gas-phase CO_2, the additional storage of shallow saline formations is not anticipated to provide any substantial increase in resource estimates for the United States, but a shallow formation could be considered for a site-specific assessment.

All sedimentary rocks included in the saline formation resource estimate should have confining zone(s) consisting of intervals of shale, anhydrite, or evaporites. Thickness of these seals is not considered in the assessment. To increase confidence in storage estimate effectiveness, other criteria including seal effectiveness (e.g., salinity and pressure above and below the confining zone), minimum permeability, minimum threshold capillary pressure, and fracture propagation pressure of specific seal layers should be considered. (DOE, 2010).

Estimating CO_2 Storage Resource in Saline Formations

The volumetric method is the recommended basis for CO_2 storage resource calculations in saline formations. The volumetric formula is:

$$G_{CO_2} = A_t h_g \phi_{tot} \rho E$$

The total area (A_t), gross formation thickness (h_g), and total porosity (ϕ_{tot}) terms account for the total volume of pore space available. The CO_2 density (ρ) term accounts for the fluid and fluid-rock interaction properties. The storage efficiency factor (E) reflects the fraction of the total pore volume that will be occupied by the injected CO_2. The terms in this equation are defined in the following table.

Table A1.2. Description of Terms in the Volumetric Formula for Saline Formations

Parameter	Units	Description
G_{CO_2}	Mass	Mass estimate of saline formation CO_2 storage resource.
A_t	Length squared	Geographical area that defines the basin or region being assessed for CO_2 storage resource estimate.
h_g	Length	Gross thickness of saline formation for which CO_2 storage resource is assessed within the basin or region defined by A_t.
φ_{tot}	Dimensionless	Total porosity in volume defined by the net thickness.
ρ	Mass/Length cubed	Density of CO_2 evaluated at the pressure and temperature that represents storage conditions anticipated for a specific geologic unit, averaged over h_g and A_t.
E	Dimensionless	CO_2 storage efficiency factor that reflects the fraction of the total pore volume that is occupied by CO_2.

A variety of approaches for obtaining the geologic properties are needed for this equation. Geologic information from existing wells or geologic exploratory efforts can be used to provide insight into the lithology and geophysical properties of a geologic region for which a resource assessment will take place. If existing data are not available, or extensive geologic characterization is needed, several geophysical tools are available that can be used during characterization activities to obtain the geologic properties needed for storage estimation. Porosity can be determined from sample cores of the target formation, wireline logging techniques like pulsed neutron capture, sonic (acoustic) logging, density (RHOB) logging, gamma ray logging, or seismic surveying (calibrated based on results from other geophysical tests). Additionally, seismic surveying (primarily 2D or 3D) can provide insight to both the areal extent and thickness of the target formation. The capabilities and applications of site characterization tools are described in Section 5.B.

CO_2 Storage Efficiency Factor Calculation

The following equation is used to estimate the CO_2 storage efficiency factor (E) for saline formations:

$$E = (A_n/A_t)\,(h_n/h_g)\,(\phi_e/\phi_{tot})\,E_v\,E_d$$

Terms included in the CO_2 storage efficiency factor equation are defined in the following table.

Table A1.3. Description of Terms in the Equation Used to Estimate CO_2 Storage Efficiency Factor for Saline Formations

Term	Symbol	P_{10}/P_{90} Values by Lithology*			Description
		Clastics	Dolomite	Limestone	
Geologic terms used to define the entire basin or region pore volume					
Net-to-Total Area	A_n/A_t	0.2/0.8	0.2/0.8	0.2/0.8	Fraction of total basin or region area with a suitable formation.
Net-to-Gross Thickness	h_n/h_g	0.21/0.76	0.17/0.68	0.13/0.62	Fraction of total geologic unit that meets minimum porosity and permeability requirements for injection.
Effective-to-Total Porosity	ϕ_e/ϕ_{tot}	0.64/0.77	0.53/0.71	0.64/0.75	Fraction of total porosity that is effective, i.e., interconnected.
Displacement terms used to define the pore volume immediately surrounding a single well CO_2 injector.					
Areal Sweep Efficiency	E_A	N/A	N/A	N/A	Fraction of total planar area contacted by CO_2.
Vertical Sweep Efficiency	E_I	N/A	N/A	N/A	Fraction of vertical cross-sectional area contacted by CO_2.
Gravity Efficiency	Eg	N/A	N/A	N/A	Buoyancy of CO_2.
Volumetric Displacement Efficiency	E_V	0.16/0.39	0.26/0.43	0.33/0.57	Combined fraction of immediate volume surrounding an injection well that can be contacted by CO_2 and fraction of net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and in-situ water. ($E_V = E_A E_L E_g$)
Microscopic Displacement Efficiency	E_d	0.35/0.76	0.57/0.64	0.27/0.42	Fraction of pore space unavailable due to immobile *in-situ* fluids.

*Values obtained from Gorecki, C. D. et al. Development of storage coefficients for carbon dioxide storage in deep saline formations (North Dakota Energy and Environmental Research Center (EERC) 2009). Terms labeled N/A (not/applicable) refer to terms used in the 2006 and 2008 Atlases.

Monte Carlo simulation was performed using the indicated ranges for the above five factors to estimate the overall efficiency factor. As shown in the table below, these simulations estimated efficiency factors between 0.40 to 5.5 percent at the 10th and 90th percent probability range.

Table A1.4. Saline Formation Efficiency Factors

Saline Formation Efficiency Factors for Geologic and Displacement Terms $E_{saline} = (A_n/A_t)(h_n/h_g)(\phi_e/\phi_{tot}) E_v E_d$			
Lithology	P_{10}	P_{50}	P_{90}
Clastics	0.51%	2.0%	5.4%
Dolomite	0.64%	2.2%	5.5%
Limestone	0.40%	1.5%	4.1%

Coal Seam CO_2 Storage Resource Estimation

Carbon dioxide storage within coal seams normally involves displacement of coalbed methane (CBM) originated through biogenic bacterial activity (in lower rank coals) or thermogenic coalification (in higher rank coals). Initial CBM recovery methods, such as dewatering and depressurization, leave a portion of methane in the formation. CO_2 sequestration in economically unmineable coal seams can provide the added benefit of enhanced coalbed methane (ECBM) recovery controlled by the relative affinity of the two gases to the sorption sites, their relative mobility, and sorption-desorption kinetics. Recovery of displaced CH_4 is mandated by the fact that it is a much more potent greenhouse gas than CO_2.

The vertical intervals included are between a minimum and maximum depth. The minimum depth was dictated by a water-quality standard to ensure that potentially potable water-bearing coals are not included; only coal seams with a water TDS concentration of 10,000 ppm and higher are included. Where water quality data are scarce or unavailable, analogy to other basins was used to estimate the minimum depth criteria.

Within the depth intervals selected for a particular basin, a determination is being made as to which coals are unmineable, based upon today's standards of technology and profitability. This criteria implies the use of economic constraints for this coal storage assessment; however, use of this constraint is necessary because of safety and regulatory concerns for mining coal used to store CO_2. While there will clearly be advancements in mining technology and changes in the value of the commodity in the future, which will enable some of the coal seams deemed unmineable today to be mineable in the future, it is beyond the scope of this effort to forecast those developments and their impact. Depth, thickness, and coal quality (e.g., coal rank, sulphur content, etc.) criteria are established for each basin for this purpose. Only those coals deemed unmineable (with today's technology) are included in this CO_2 resource estimate. If such data are available, any coal reserve is also excluded.

Estimating CO_2 Storage Resources in Coal Seams

The volumetric equation for CO_2 storage resource estimate potential in unmineable coal seams is as follows:

$$G_{CO2} = A\, h_g\, C_s\, \rho_{s,max}\, E$$

The total area (A) and gross seam thickness (h_g) terms account for the total volume of pore space available. The fraction of sorbed CO_2 (C_s) and CO_2 density ($\rho_{s,max}$) terms account for the fluid and fluid-rock interaction properties. The storage efficiency factor (E) reflects the fraction of the total pore volume that will be occupied by the injected CO_2. As discussed below, E factors range between 21 and 48 percent at the 10 to 90 percent probability range. Terms in this equation are described in the following table.

Table A1.5. Description of Terms in the Volumetric Equation with Consistent Units Applied for Coal CO_2 Storage Resource

Parameter	Units*	Description
G_{CO2}	Mass	Mass estimate of CO_2 resource of one or more coal beds.
A	Square Length	Geographical area that outlines the coal basin or region for CO_2 storage resource calculation.
h_g	Length	Gross thickness of coal seam(s) for which CO_2 storage resource is assessed within the basin or region defined by A.
C_s	Percent	Fraction of sorbed CO_2 per unit of coal under reservoir conditions as opposed to under ideal (maximum) pressure conditions (e.g., as defined by Langmuir volume constant or alternative)
$\rho_{s,max}$	Mass/ Cubic Length	Density of sorbed CO_2 averaged over coal bulk volume; assumes 100% CO_2 saturated coal conditions.
E	Cubic Length/Cubic Length	CO_2 storage efficiency factor that reflects a fraction of the total coal bulk volume that is contacted by CO_2.

The maximum CO_2 sorption capacity of coal (at saturation), which depends on the coal characteristics and, to a certain extent, on temperature, is traditionally reported on per unit-of-coal-mass basis ($n_{s,max}$). Conversion into per unit-volume basis (ρ_s,max) requires the knowledge of coal bulk density (ρ_c) as well as moisture and/or ash content, depending on reporting format (such as dry, ash free). The average density of sorbed CO_2 in coal under saturation conditions is described as follows:

$$\rho_{s,max} = n_{s,max}\, \rho_{c,dry}\, (1 - f_{a,dry})$$

where $f_{a,dry}$ is the ash weight fraction of the dry coal bulk density ($\rho_{c,dry}$). For consistency with the distinction between the micropore sorption and hydrodynamic trapping due to fracture porosity, the coal bulk density should be measured as inclusive of micropore volume (e.g., mercury density of coal). However, the helium density of coal, which is the most readily available data, is a good approximation as long as the micropore volume is accounted for in the fracture porosity.

Rather than using the density of CO_2 fluid integrated over the pore volume, computation of CO_2 sorbed in coal involves integration of the sorbed amount over the entire coal volume. The in-situ fraction of CO_2 (C_s) that is stored per unit of coal under reservoir conditions as opposed to under ideal (maximum) pressure conditions depends on reservoir pressure after injection, moisture content and the amount of gas in place. There is not sufficient field data to allow complete quantification of this parameter. However, the pressure effect can be approximated by a standard (e.g., Langmuir) isotherm equation. For lower rank coals, care should be taken to perform laboratory testing under reservoir (especially, moisture and pressure) conditions as there is an increasing difference in accessible micropore volumes between wet and dry coals, observed at low pressure (low surface coverage) due to chemical heterogeneity. If data are available, different isotherms for different coal ranks are used. If no CO_2 isotherm is available, isotherms from similar rank coals in analog basins can be used. (DOE, 2010).

CO_2 Storage Efficiency Factor Calculation

The following equation is used to estimate the CO_2 storage efficiency factor (E) for coal seams:

$$E = (A_n/A_t)\,(h_n/h_g) E_A\, E_L\, E_g\, E_d$$

Terms included in the CO_2 storage efficiency factor equation are defined in the table below:

Table A1.6. Description of Terms in the Equation Used to Estimate CO_2 Storage Efficiency Factor for Coal Seams

Term	Symbol	P_{10}/P_{90} Values	Description
Geologic terms used to define the entire basin or region pore volume			
Net-to-Total Area	A_n/A_t	0.6/0.8	Fraction of total basin or region area that has bulk coal present.
Net-to-Gross Thickness	h_n/h_g	0.75/0.90	Fraction of coal seam thickness that has adsorptive capability.
Displacement terms used to define the pore volume immediately surrounding a single well CO_2 injector.			
Areal Displacement Efficiency	E_A	0.7/0.95	Fraction of the immediate area surrounding an injection well that can be contacted by CO_2.
Vertical Displacement Efficiency	E_L	0.8/0.95	Fraction of the vertical cross section (thickness), with the volume defined by the area (A) that can be contacted by a single well.
Gravity	Eg	0.9/1.0*	Fraction of the net thickness that is contacted by CO_2 as a consequence of the density difference between CO_2 and the in-situ water in the cleats.
Microscopic Displacement Efficiency	E_d	0.75/0.95	Reflects the degree of saturation achievable for in-situ coal compared with the theoretical maximum predicted by the CO_2 Langmuir Isotherm.

*0.999 used due to inability to divide by zero when using Log Odds Method.

Monte Carlo simulation was performed using the indicated ranges for the above six factors to estimate the overall efficiency factor. As shown in the following table, these simulations estimated efficiency factors between of 21 to 48 percent at the 10th and 90th percent probability range.

Table A1.7. Coal Seam Efficiency Factors

Coal Seam Efficiency Factors $E_{coal} = (A_n/A_t)\ (h_n/h_g) E_A\ E_L\ E_g\ E_d$		
P_{10}	P_{50}	P_{90}
21%	37%	48%

Appendix 2—NatCarb

NatCarb provides a national coverage across DOE's RCSPs. Currently, the partnerships cover 43 states, and 4 Canadian provinces. The RCSPs are responsible for generating geospatial data for the maps displayed in the *Carbon Sequestration Atlas of the United States and Canada*. NatCarb is a GIS relational database that assists by bringing together key geospatial data (carbon sources, potential storage sites, transportation, land use, etc.) generated by the RCSPs that are required for the Atlas, and for efficient evaluation of carbon sequestration on a national and regional scale.

NatCarb uses advanced distributed computing solutions to link database servers across the partnerships and other publicly accessible servers (e.g., the United States Geological Survey [USGS], Google Map™) into a single system where data are maintained and enhanced at the local level, but are accessed and assembled through a single Web portal (Figure A2.1). It extends the concept of cyberinfrastructure, first defined by the National Science Foundation (NSF), to address CCS. Cyberinfrastructure refers to an integrated computing environment that provides access to information, problem solving capabilities, and communication. A well-formulated National Carbon Cyberinfrastructure (NCCI) design, incorporating advances in informatics and GIS, is essential for a national approach to carbon sequestration science and technology efforts. The NatCarb project improves the flow of data across servers and increases the amount and quality of available carbon sequestration information at national, regional, and local scales.

NatCarb consists of an online accessible and distributed computing environment that provides paths to the acquisition, storage, and distribution of critical geospatial and tabular data from multiple sources, and information services for search, visualization, and analysis. Geological sequestration data, focused on the assessment of large-scale geological sequestration, include measurements of potential storage volumes and the monitoring and verification of ongoing demonstration projects, such as those undertaken as part of the RCSPs, and efforts of other public and private entities. The data are gathered in participating data warehouses and linked with online analysis, visualization, and modeling tools to form a knowledge base. Information is accessed and assembled through a Web portal and provided to the decision-makers and the general public. In order to successfully design a successful NCCI, on-going reliable access to a comprehensive set of data libraries, model simulations, and associated tools must be provided.

The NatCarb project organization is unique in that it is distributive, geographic, and overlapping. The organization is structured along both geographic boundaries and broad functions. The geographic focus of the RCSPs provides strong local expertise to characterize both CO_2 sources and potential geologic sequestration targets. The interaction between computing and domain teams at the local level provided unique solutions to address challenges and advance both areas. The flexibility provided by the distributive structure of the NatCarb system allows for local experiments in data type, structure, and display. Successful "experiments" can be propagated across the RCSPs.

NatCarb is a functional, first-step demonstration of cyberinfrastructure as an effective federation of both distributed resources (data and facilities) and distributed multidisciplinary expertise (RCSPs). The system links together data from the RCSPs concerning sources, sinks, and transportation within a spatial database that can be queried online. Information that addresses CO_2 sequestration is provided through a single interface that accesses the coverages and data from servers in each participating partnership and other servers providing national coverages. The NatCarb system is scalable and can be expanded to access, query and display CO_2 sequestration data on any accessible server at a participating site. NatCarb provides complete distributed management of the system (i.e., data and GIS layers can be edited and loaded from anywhere in the NatCarb system). The complexity and volume of data required to address CO_2 sequestration on a national and international basis rapidly increases the demands on any system to display the information, integrate the data with models for analysis, and manage the system. A distributed environment is required to address the complex challenges of creating a nationwide network of partnerships to bring the technical and policy expertise together with sufficient data to determine the most suitable technologies, regulations, and infrastructure for CCS in different areas. Access to high quality and up-to-date data related to CO_2 sequestration can assist decision-makers by providing access to common sets of high-quality data in a consistent manner in order to minimize the negative economic impact and maximize the possible value of the CO_2 sequestration, while addressing issues of health, safety, and the environment.

Figure A2.1. NatCarb Homepage (http://www.natcarb.org/) Showing Various Links to Access Information on Sources and Sinks Across the United States and Canada.

Appendix 3—UIC Program

UIC Program and Well Classes

A critical issue in site selection is ensuring that the injection wells will meet UIC Program requirements. Existing regulations in the United States relevant to CO_2 GS involve protection of groundwater from brine intrusion and CO_2 plume infiltration by meeting USDW standards under the SDWA. The UIC Program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids (liquids, gases, and semi-solids) underground for storage or disposal (http://www.epa.gov/safewater/uic/index.html). Once EPA promulgates final regulations for GS wells for States and at the Federal level, proper criteria and standards will be in place to ensure a consistent and effective permitting system for commercial-scale GS projects.

The UIC regulations and program elements are intended to protect USDWs. 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.

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 five classes of wells (Class I to Class V) according to the type of fluid they inject and where the fluid is injected. EPA is proposing to create 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 GS. The proposal 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. In addition to protecting USDWs, the proposed rule provides a regulatory framework to promote consistent approaches to permitting GS projects across the United States.

A detailed discussion of the five existing UIC well classes is available on EPA's UIC website (http://www.epa.gov/safewater/uic/wells.html). 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.
- **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**—Proposed new class of injection wells specific for CO_2 GS.

Currently, wells for CO_2 GS all fall under Class I, Class II, and Class V. The proposed EPA rulemaking, when finalized, would establish a new class of injection well—Class VI—for GS projects based on the unique challenges of preventing potential endangerment to USDWs and subsurface leakages from these operations (Federal Register, July 25, 2008, p 43502).

Currently, more than 550 Class I wells exist in the United States. 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 I wells for CO_2 GS are typically 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, has been considered as an option for GS 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.

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 five 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 listed 143,951 Class II wells in the United States (http://www.epa.gov//safewater/uic/wells.html).

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. It is pumped into the producing formation where it displaces hydrocarbons to producing wells. Commonly called 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 sequestered 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.

Class II produced water injection wells share many site selection criteria with proposed CO_2 injection site selection criteria. Among them are requirements for providing to regulators specific information concerning the following (International Association of Oil & Gas Producers, 2000):

1. Produced water volume and rate
2. Geology
3. Hydrology
4. Geochemistry of injected water and its compatibility with reservoir fluids
5. Injection and confinement zone geohydrological properties
6. Injection and confinement zone geomechanical properties
7. In-situ stress profile in the various layers
8. Location, age, depth, and condition of nearby wells
9. Location, orientation, and properties of nearby faults or fractures
10. Rigid well construction requirements

Water flooding and water disposal by injection have been employed for more than 50 years to handle produced water. The injection volumes are impressive, as indicated by the disposal rates of three major hydrocarbon producing States in 2000:

1. California had nearly 25,000 produced-water injection wells. The annual injected volume was approximately 1.8 billion bbl, with about 20 percent injected for disposal.
2. New Mexico had 903 permitted disposal wells, with 264 of them active. Approximately 190 million bbl of produced water were injected for disposal.
3. Texas had 11,988 permitted disposal wells, with 7,405 of them active. In 2000, approximately 1.2 billion bbl of produced water were injected into nonproducing formations, and 1 billion bbl were injected into producing formations. (http://www.netl.doe.gov/technologies/pwmis/techdesc/injectdisp/index.html).

In summation, operators in these three States injected more than 4 billion bbl of produced water for disposal and EOR in 2000. Although the exact figure is unknown, it is reasonable to estimate that between 350 and 400 billion bbl of produced water have been injected in the United States.

Injection permits are either issued by the EPA, state agencies, or jointly (Figure A3.1). EPA has provided UIC Program guidance to assist State and EPA-regional UIC programs in processing permit applications for these projects. This guidance applies only to near-term geologic sequestration pilot projects prior to full-scale deployment. Regulations now in development will address full-scale projects. Pilot geologic sequestration projects around the country are assessing the success of CO_2 injection for the purpose of geologic sequestration. They will provide information about how CO_2 behaves in the subsurface and will address proper well construction and operational procedures.

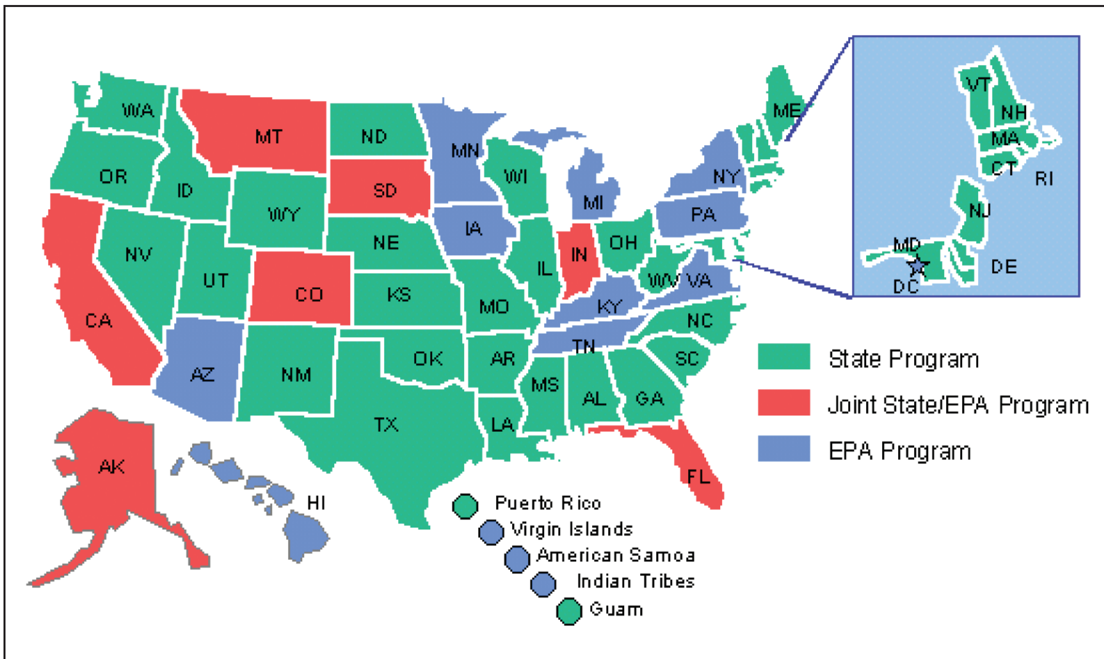

Figure A3.1. Map Showing Agencies Issuing UIC Permits (2010).

Appendix 4—Pipeline Regulatory and Right-of-Way (ROW) Issues

Pipeline Regulatory Issues: Site selection will be greatly influenced by the regulation of CO_2 pipelines, which is currently unclear. Regulation of interstate pipelines by the Federal government is generally intended to ensure pipelines fulfill "common carrier" obligations as in the case of oil and gas pipelines (GAO, 1998). If interstate CO_2 pipelines for carbon sequestration are developed, it will raise important regulatory questions because Federal jurisdiction over hypothetical interstate CO_2 pipeline siting and rate decisions is not clear. Based on their current regulatory roles, two of the more likely candidates for Federal jurisdiction over interstate pipelines transporting CO_2 for purposes of CCS are the Federal Energy Regulatory Commission (FERC) and the Surface Transportation Board (STB). However, both agencies have taken the position that interstate CO_2 pipelines are not within their purview. Issues relating to the safe and environmentally acceptable operation of CO_2 pipelines are covered under the 2001 Code of Federal Regulations, Parts 190 through 199, which classify CO_2 pipelines as High Volatile/Low Hazard and Low Risk. Currently, regulations delegate authority to individual States.

An organization wishing to construct a CO_2 pipeline has to obtain a ROW and negotiate with landowners for permission to site the pipeline. For CO_2 pipelines, siting authority is held at the state level (generally by a public utility commission or a public service commission). This is in contrast to natural gas pipelines for which interstate siting authority is held at the Federal level by FERC. A governmental entity could obtain land for ROW by eminent domain. However, no States currently have provisions to apply eminent domain towards the development of CO_2 pipelines. If a major multi-state backbone project is to be constructed, expansion of Federal authority for interstate CO_2 pipelines may be required.

Legislation on CCS has been more focused on the capture and storage of CO_2 than on its transportation, which reflects a perception that transporting CO_2 via pipelines does not present a significant barrier to implementing large-scale CCS and site selection. Even though regional CO_2 pipeline networks already operate in the United States for CO_2-EOR, developing a more expansive national CO_2 pipeline network for CCS will likely yield new regulatory and economic challenges. There are important unanswered questions about pipeline network requirements, economic regulation, utility cost recovery, regulatory classification of CO_2 itself, and pipeline safety. Federal classification of CO_2, as both a commodity (by BLM) and as a pollutant (by EPA), could potentially create an immediate conflict if the regulations become Federal because CO_2 pipelines for EOR are already in use today.

Right-of-Ways: ROW agreements typically specify the rights of the pipeline operator relative to property, as well as the ongoing above-ground use rights of the landowner. A ROW is ordinarily sufficient for day-to-day operations of a pipeline but is often insufficient for situations where pipeline repairs or expansions are planned. In such cases, the pipeline operator often has to renegotiate with a property owner for additional permanent and/or temporary work space. Pipeline operators generally try to keep the ROW as free of physical encumbrances as possible in order to assure reasonable and frequent visual inspections of the pipeline from the air and ground. In addition, a clear ROW helps ensure ease of access for repairs. These concerns must be balanced with the wishes of the landowner to maintain options for the ROW, including using the land for crops, grazing, parking, and other uses. Limitations sometimes imposed on the landowner can include prohibitions against the installation of buildings, pools, trees, and other structures.

Residential and commercial development in once-rural areas is encroaching on pipeline ROWs with increasing frequency. Encroachment implies safety concerns for local residents and for the physical integrity of the pipeline itself. To help prevent encroachment and excavation-related damage to pipelines, operators are required to post pipeline markers clearly and frequently along the length of the ROW. They must also communicate with residents along the ROW and establish liaison with local government and emergency officials (NETL, 2007).

Appendix 5—Mathematical Modeling of CO_2 Injection and Storage

This appendix provides additional information about the use of mathematical modeling to predict the behavior of injected CO_2. As indicated in the manual, no single model provides sufficient information to predict CO_2 fate in the subsurface, rather this is based on the integration of different models. This appendix reviews fundamental considerations for selecting and using different models and then provides a case study.

For convenience, the models described in this appendix are organized by Code and Use in Table A5.1, they are presented again at the beginning of the case study. References that describe these and other available simulation codes are cited by Schnaar and Digiulio (2009), Pruess et al. (2004), and by articles cited in these papers.

Table A5.1. Classification of Selected Model Simulation Codes Available and Used by RCSPs

Type of Code	Names	Main Sequestration Application
Non-isothermal multiphase flow processes in porous media	Eclipse, GEM-GHG, NUFT, FEHM, TOUGH2	Simulate plume migration and dispersion
Non-isothermal multiphase chemically reactive flow and transport in porous media	TOUGHREACT, VIP Reservoir, FEHM, PFLOTRAN, STOMP	Simulate plume migration and chemical interaction of CO_2 with reservoir rock and fluids (reactions and CO_2 trapping)
Geomechanical Processes	FLAC, GMI-SFIB, ABACUS, FEHM	Simulate stress and strain induced in reservoirs during and after injection
Non-isothermal multiphase flow in porous media with geomechanical coupling	TOUGH-FLAC, FEHM	Model plume dispersion and impacts of stress and strain due to CO_2 injection
Flow in fractured media	TOUGH2, NFFLOW-FRACGEN	CO_2 flow through fractured networks

Development of Initial and Boundary Conditions Based on Site Characterization Data

Effective flow simulation is an accurate representation of the geologic features of the injection site and incorporates site-specific data obtained through site characterization activities, including pre-injection monitoring (World Resources Institute, 2008). Section 5.B provides an overview of the available site characterization specific monitoring considerations and tools typically included in any MVA protocol. Site characterization data can be combined with existing data, gathered within the site's vicinity, to develop initial and boundary conditions for the reservoir simulation model and to establish baseline geochemical and geophysical conditions prior to CO_2 injection.

Based on factors, such as injection location, injection depth, total injection volume, and injection duration, the "observed area" (3D section of earth around the injection site determined by boundary conditions that will be included in the simulation) can be defined. Typical model development involves a 3D grid with potentially millions of grid-blocks (depending on available computational resources) or cells that represents the site. Cells (the size of the cells is determined by the modeler and will vary by GS project) in the modeling framework represent a 3D section of the Earth within the observed area. Geologic properties (e.g., porosity, permeability, pressure, and temperature) acquired during site characterization or from existing data are assigned to corresponding cells in the 3D grid. The vertical order and thickness of model cells are chosen to represent geologic profiles inferred from well logs. Geostatistics, or another form of 3D data interpolation, can be used to assign geologic properties to each cell when field data are not available.

Relevant governing equations that represent the thermal, physical, chemical, geomechanical, and hydrogeological phenomena associated with subsurface storage of CO_2 are incorporated into the model so that it will predict CO_2 behavior and transport based on the initial and boundary conditions incorporated in the model. Over time, as additional data are gathered during site selection, characterization, and monitoring of the GS project, the model parameters can be updated (World Resources Institute, 2008), as outlined in Figure A5.1.

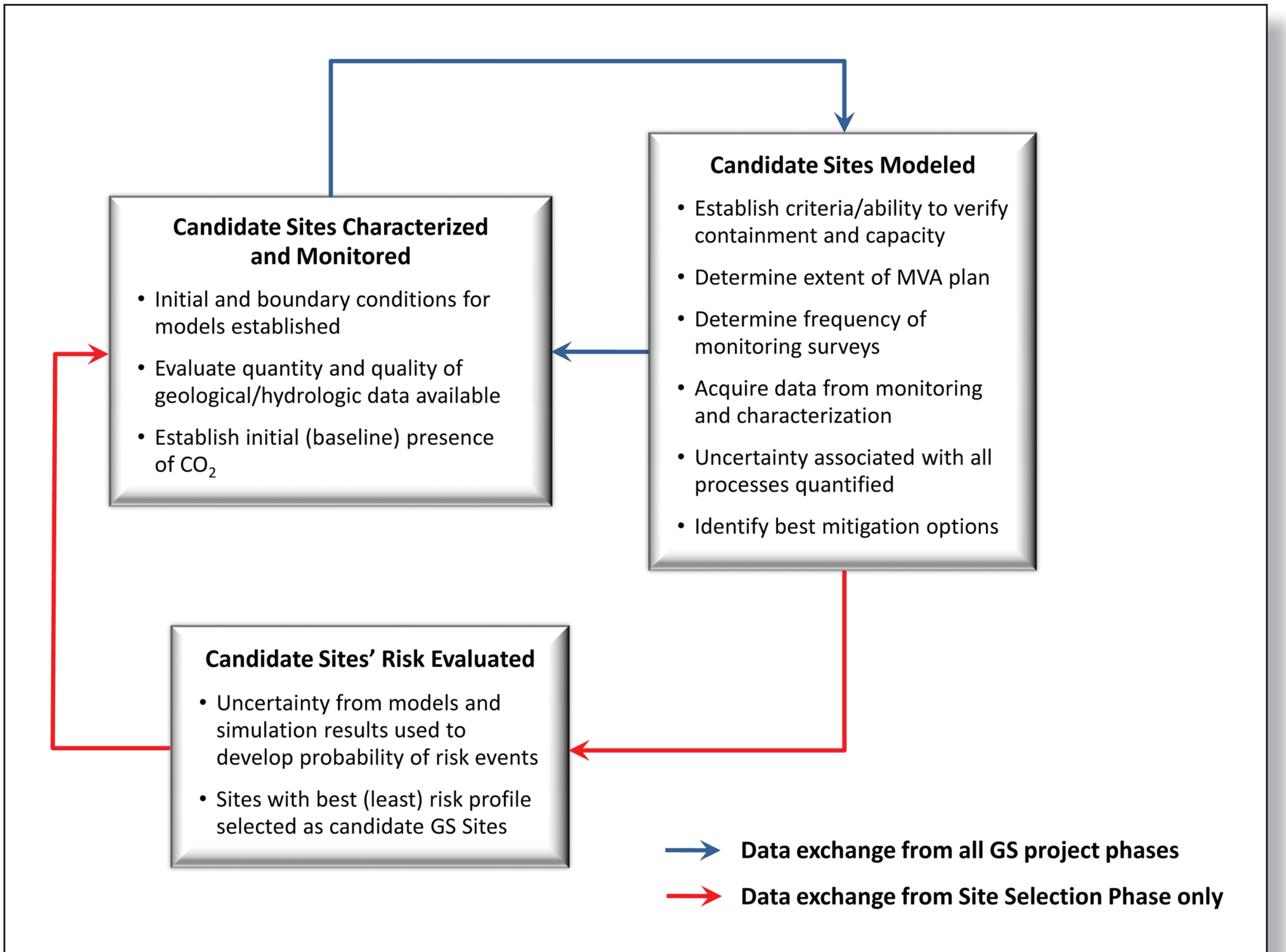

Figure A5.1. Flowchart for Updating Models based on Newly Acquired Data.

(Figure Adapted and Modified from "Ensuring Integrity of Geologic Sequestration: Integrated Application of Simulation, Risk Assessment, and MVA."—Presented at the December 2008 AWWA Meeting, Author: B. McPherson.)

Initial/boundary conditions need to be updated depending on observations and history matching that occur during the GS project. While some assumptions can be made about certain initial/boundary conditions, the validity of the assumptions is established (or refuted) based on how well model results compare with observations.

Figure A5.1 outlines how modeling input data are collected during the characterization phase and used in predictive model runs based on anticipated injection volume, rate, and duration to assess storage capacity, determine acceptable MVA plans, identify strategic areas for monitoring, and identify potential risks that may influence site selection/rejection decisions. Once a site has been deemed suitable for geologic storage, newly acquired site data from pre-operational, operational, or monitoring activities can be incorporated into the model. Monitoring data collected early in the project are often used to refine and calibrate the predictive model, including the initial and boundary conditions, improving the basis for predicting longer-term performance. The updated model can be used to generate improved simulation results, allowing for a more representative prediction of CO_2 plume and pressure front locations, which can be valuable in reassessing monitoring plans, mitigation options, and post-closure care. Periodic modeling reassessment, as site conditions change from the baseline, pre-injection state, will be a required practice for the proposed UIC Class VI wells. This will require adjusting model conditions based on newly generated site data as CO_2 injection progresses throughout the project.

Modeling CO_2 and Pressure Propagation, and Saturation of CO_2

In contrast to underground liquid injection for waste disposal, CO_2 injected into a deep saline formation will exist in multiple forms over time, including a dense supercritical phase, a dissolved phase, and an immobile solid phase, due to reactions between CO_2 and in situ minerals (Hendricks and Blok, 1993). The dissolved proportion varies depending on the properties of the formation fluids. Dissolved CO_2 is estimated to be anywhere from two percent by weight in sodium chloride brines to seven percent in groundwater. Immobilization of CO_2 due to mineralization is a relatively slow process and varies significantly with the target formation properties, including pressure, temperature, and specific formation rock type. Carbon dioxide that has precipitated into a solid state through mineralization is no longer a threat to breaching confining zone, contaminating a USDW, or entering the atmosphere. In a deep (greater than 2,625 feet) saline target formation, the majority of CO_2 will exist in the supercritical state due to pressure and temperature conditions (Tsang et al., 2007). The partitioning of CO_2 among phases will gradually change over time, as depicted in Figure A5.2.

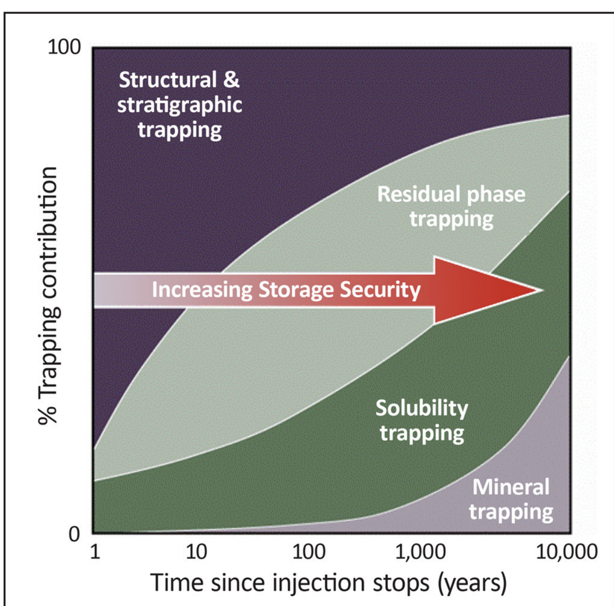

Figure A5.2. The Fate of Injected CO_2 as a Function of Storage Time. *(Source: IPCC, 2005)*

Accounting for CO_2 distribution among different phases in a reservoir model is critical to predicting the fate and transport of CO_2 over extended periods, as well as assessing the integrity of the target formation and confining layers. For instance, supercritical CO_2 is typically less dense and viscous than brine. The lower density of the injected supercritical CO_2 will cause buoyant flow of CO_2 to the top of the target formation. Further upward flow will be prevented by lower-permeability confining zone. As a result, the areal extent of injected CO_2 will be larger than that of a buoyancy-neutral injectant (for the same amount of injectant). However, a buoyancy-neutral fluid will likely have a larger vertical extent in the reservoir (Tsang et al., 2007). Furthermore, buoyant driving forces can push CO_2 through potential leakage pathways, such as faults and fractures in confining zone or abandoned wells and boreholes. Accounting for buoyant forces in modeling and simulation is critical in predicting potential leakage through these pathways within the AoR. The basic phenomena that need to be considered in reservoir modeling of CO_2 injection into brine are outlined in Figure A5.3.

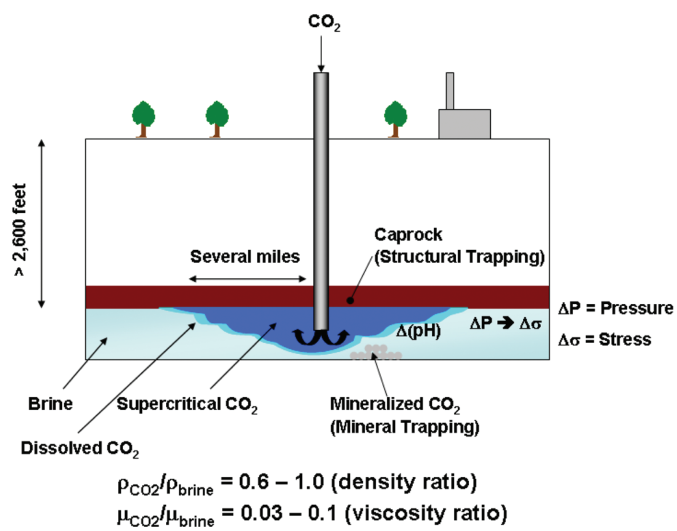

Figure A5.3. Factors to be Considered in Modeling CO_2 Injection and Storage in a Brine Formation.

Fundamental processes that must be accounted for in modeling a basic CO_2 GS scenario in a brine formation are (1) hydrological processes, (2) thermal processes, (3) geomechanical processes, and, (4) geochemical processes. In the geological literature, this suite of processes is often referred to as "THMC," for thermal-hydrologic-mechanical-chemical.

Hydrogeologic Modeling Considerations

Hydrologic effects on CO_2 sequestration in brine formations involve the overall trapping mechanisms of the formation, flow path influenced by specific subsurface geological characteristics (rock type, porosity, pore-connectivity, permeability, etc.), storage capacity, and buoyancy forces. Hydrologic processes provide basic principles upon which a successful GS model is built. Hydrogeological processes affecting CO_2 in a brine formation include the lower density CO_2 compared to brine and an order of magnitude lower viscosity. As a result, a plume of injected CO_2 migrates up (to the confining zone) and spreads out from the injection well (under a homogenous geologic structure with no "fingering" effects) (Tsang et al., 2007).

CO_2 sequestration projects in brine formations are typically at depths greater than 2,625 feet (800 meters) where the injected CO_2 exists primarily as an immiscible, supercritical liquid phase. CO_2 in this state is much denser than atmospheric CO_2 and can be stored more efficiently by occupying less volume than gas-phase CO_2. The supercritical CO_2 is less dense and less viscous than the brine it displaces, resulting in upward buoyant forces. Trapping mechanisms for injected CO_2 for model consideration can be divided into four categories, depending on the state and phase of the CO_2: (1) structural or stratigraphic trapping, (2) capillary trapping, (3) dissolution trapping, and (4) mineral trapping. These mechanisms are described in detail in Section 3.4, and correct modeling of these mechanisms is critical to estimating CO_2 distribution among phases and preferential flow paths for the CO_2 plume (Tsang et al., 2007).

Understanding subsurface heterogeneity and buoyancy flow relationships is critical in determining the effectiveness of structural and stratigraphic traps and how the CO_2 plume is distributed spatially. Low-permeability structures dispersed throughout the target formation act as barriers to uniform flow. Should discontinuities in low-permeable structures occur, buoyant CO_2 can migrate through them, resulting in a sinuous CO_2 plume distribution. The opposite effect occurs in a homogenous subsurface structure in which buoyant forces drive the plume to the confining zone, where it may collect or spread out (Tsang et al., 2007). Plume shape (sinuous or uniform) influences the mobility of the plume, as well as the amount of CO_2 available to dissolve into the formation fluids. Dissolution of CO_2 increases under circumstances in which CO_2 contacts more brine as a result of an increased surface-to-volume ratio.

Plumes that are sinuous and variable in shape as a consequence of a heterogeneous flow path typically have a higher surface-to-volume ratio than a plume of similar mass under a uniform, homogenous flow regime. As a result, more CO_2 is likely to dissolve into brine under a sinuous plume shape due to a greater CO_2 surface area. In summary, the flow path of the plume, dictated by the surrounding flow field, will influence the effectiveness of trapping mechanisms and the phase state of CO_2. Accurate understanding of these phenomena is critical to the development of a reliable CO_2 multiphase flow model.

Quantitative hydrologic evaluation of CO_2 sequestration can be conducted using a multi-component, multiphase simulator for flow in porous media. Specific modeling codes include: FEHM, NUFT, PFLOTRAN, STOMP, and TOUGH2. For a description of these codes and/or references related to these codes, see Schnaar and Digiulio (2009), Pruess et al. (2004), and references cited in these papers.

Geomechanical Modeling Considerations

Thorough evaluation through modeling and simulation of the mechanical effects on the target formation associated with geologic sequestration of CO_2 is essential to ensure integrity of the confining zone so that a breach of CO_2 does not occur. Geomechanical forces that affect the subsurface are a result of a pressure increase due to both the injection rate and volume of CO_2 and buoyancy forces. These effects, should there be too high a pressure increase, can cause advective forces to direct the CO_2 plume away from the injection location through a path of least resistance (fingering effect), as well as creating deformations in the surrounding rock matrix that directly influence porosity, permeability, and the overall flow field. Carbon dioxide injection results in an increase in formation fluid pressure that can cause changes in the effective stress field; depending on the extent of the pressure increase, mechanical deformations may occur and a direct increase in porosity and permeability (which reduces fluid pressures) can result (Tsang et al., 2007). Elevated pressure in the target formation can also lead to permanent integrity failure of the confining zone and trigger hydraulic fracturing (Figure A5.4). For site screening, selection, and characterization, accounting for geomechanical properties in model estimates will allow the user to (1) assess the integrity of the confining zone intervals under various injection and target formation pressures and (2) forecast the pressure propagation front for any amount of CO_2 injection over an extended period of time.

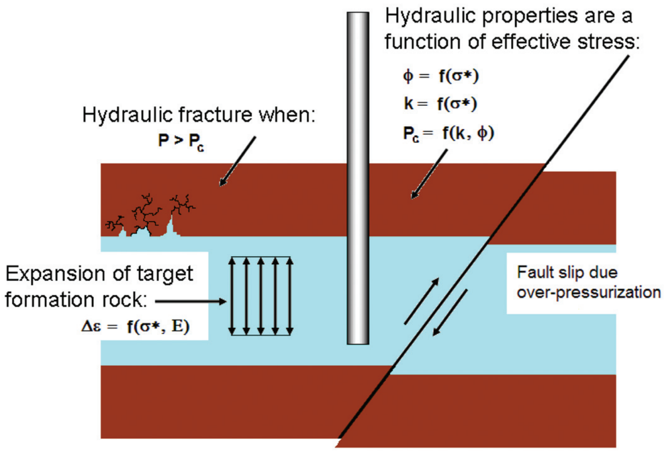

Figure A5.4. Geomechanical Processes Associated with CO_2 Injection. *(Adapted from Tsang et al., 2007.)*

In Figure A5.4, ϕ represents porosity of the confining zone, k represents confining zone permeability, P_c represents the minimum pressure that would induce confining zone fracture, P represents the current formation pressure, E represents rock compressibility, $\Delta\varepsilon$ represents the expansion of the target formation rock, and σ^* represents shear stress. Values for these variables can be determined through a combination of laboratory and field-generated data. The geomechanical variables in the model should be regularly updated, as in situ monitoring data from the project becomes available.

Interactions occur between hydraulic and mechanical processes in geologic media and should be considered when building a GS model. In porous geological formations, coupled hydraulic and mechanical processes can occur (e.g., deformation and pore-fluid pressure changes) that can be complex, nonlinear, and difficult to model appropriately. The numerical modeling code TOUGH-FLAC (Table A5.1) has been used to model coupled processes, such as the interactions between hydraulic and geomechanical phenomena (Tsang et al., 2007). In addition, FEHM has also been applied to simulate coupled non-isothermal flow and stress processes taking place during CO_2 injection (Zyvoloski and Pawar, 2008). It is important to study coupled hydraulic and geomechanical processes to properly assess the integrity of the confining zone and its potential for leakage. Hydraulic fracturing and shear slip of existing faults (outlined in Figure A5.4) are potential consequences of over pressurizing the system beyond P_c, or inducing excessive shear stress (σ^*) on existing faults.

In summary, elevated pressure caused by injection of CO_2 into the target formation may affect the stability and integrity of the confining zone intervals and may lead to hydraulic fracturing or possible slippage of existing faults. Faults and fractures may become pathways for CO_2 leakage (all faults are not open and slippage may not lead to opening up the faults and leakage). Incorporating geomechanical processes may be necessary to the development of a reliable multiphase flow model including CO_2.

Geochemical Modeling Considerations

Accounting for brine-CO_2-rock interactions is essential to the development of a robust model. When CO_2 dissolves in brine, solubility trapping occurs and the brine chemistry changes. Dissolved CO_2 could react with minerals in the geologic formation. Mineral trapping may occur as a result of precipitation of carbonates due to chemical reactions between dissolved CO_2 and metal ions (like Fe^{2+}, Ca^{2+}, Mg^{2+}) or solubility trapping with formation of soluble carbonates (Na^+, K^+).

Effects of chemical reactions induced by CO_2 include changes in porosity and permeability of the target formation; an overall drop in formation fluid pH, which can directly affect the stability of the target reservoir confining zone; and reactions to form CO_3^{-2} precipitates (solid carbonates involving ions like Ca^{2+}, Mg^{2+}, or Fe^{2+}), thus chemically trapping CO_2 in place (Gunter et al., 1997). Mineral trapping is a useful technique in permanently sequestering injected CO_2; however, carbonate buildup in the target reservoir can greatly reduce porosity, permeability, and overall injectivity.

Relevant geochemical reactions are described below. The first reaction involves CO_2 dissolving in water to produce weak carbonic acid where K is the equilibrium constant:

$$CO_2(g) + H_2O = H_2CO_3 \qquad (K = 10^{-1.5}\ mol/atm\ liter)$$

H_2CO_3 is the dominant carbonate system species when the pH of the solution (brine) is below approximately 6.3. H_2CO_3 ionizes to form bicarbonate ion (HCO_3^-), which is the most abundant form of dissolved CO_2 in the pH range from 6.3 to 10.3 Readers are refered to Gaus et al. (2008) for a comprehensive discussion of CO_2 sequestration geochemical processes of interest.

$$H_2CO_3 = HCO_3^- + H^+ \qquad (K = 10^{-6.3}\ mol/atm\ liter)$$

Increased acidity induces dissolution of many of the primary host-rock minerals, resulting in complexation of dissolved cations and the bicarbonate ion, such as:

$$M_2+ + 2HCO_3^- = M(HCO_3)_2 \downarrow$$

where M represents a divalent cation. Dissolved bicarbonate species can react with different divalent cations and form solids that precipitate out of the brine solution. Formation of calcium, magnesium, and ferrous carbonates are expected to be the primary means by which CO_2 is immobilized (Gunter et al., 1997). However, products of reaction between dissolved bicarbonate and monovalent cations (Na^+ or K^+) are typically more soluble and tend to remain sequestered by solubility trapping through dissolution.

Numerical modeling of geochemical processes is necessary to investigate long-term consequences of CO_2 injection due to slow reactions between dissolved CO_2 and the host rock. A numerical model that can successfully predict the fate of CO_2 and its transport over extended periods must be able to directly or indirectly couple hydrogeologic, geomechanical, and geochemical processes. Uncoupled fluid flow simulation and batch geochemical modeling are not sufficient to account for all the complexities (physical and chemical) and interactions expected to occur from CO_2 GS (Tsang et al., 2007). TOUGHREACT is a chemical transport code that is capable of hydro-chemical coupling by inserting a reactivity chemistry code into the existing TOUGH2 multiphase and heat flow code (Pruess et al., 1999). NUFT, PFLOTRAN, and FEHM are other codes available for chemical transport/hydro-chemical coupling. Other codes that focus on geomechanical properties (GMI-SFIB, ABCUS, FEHM, or TOUGH and FLAC in tandem) may possibly be used in tandem with geochemical and hydrological-based codes to simulate all potential coupled processes in a GS project. References that describe these and other available simulation codes are cited by Schnaar and Digiulio (2009), Pruess et al. (2004), and by articles cited in these papers.

Examples of Numerical Modeling in Practice

The practice of numerical modeling for CO_2 sequestration is relatively new and is still being advanced and further developed as more knowledge and experience is gained through conducting and modeling GS projects worldwide. Model development and advancement is providing better estimates of physical and chemical processes and improved predictions given in situ conditions and properties (Tsang et al., 2007). Several DOE supported sequestration projects are taking place all over the world. They are employing modeling and simulation as part of the site screening and characterization process to predict plume transport and assess reservoir integrity based on data generated from site characterization.

Since 1999, DOE's Core R&D Program has directly supported a limited number of GS field tests (both nationally and internationally) to contribute towards gaining the knowledge necessary to employ GS of CO_2 commercially across various geologic and regional settings. The program's core R&D agenda focuses on increased understanding of CO_2 GS, MVA technology and cost, and regulations through field-testing of GS technologies. A major portion of DOE's Core R&D is aimed at using site characterization data to build reservoir simulation models of locations of interest. These models are used to (1) assess the consequences of CO_2 injection at candidate project sites, (2) provide input to the accept/reject process of candidate sites based on model forecasting results, and (3) contribute "lessons-learned" to the GS scientific community based on project performance and results obtained.

Simulations have been used in Core R&D test projects, including Weyburn in Canada, and others in the United States including Frio Brine Pilot, West Pearl Queen, Deerlick Creek, and Marshall County, West Virginia, for ECBM. Several modeling programs have been used by the RCSPs for the Verification

Phase (small-injection tests) and Development Phase (large-scale greater than 1 million tons CO_2) field injection tests. For example, the Southeast Regional Carbon Sequestration Partnership (SECARB) has used Comet3, a reservoir simulator, to determine optimal locations for observation/monitoring wells for a CBM project in the Black Warrior Basin. The West Coast Regional Carbon Sequestration Partnership (WESTCARB), working with the Arizona Utilities CO_2 Storage Pilot demonstration, will conduct preliminary computer simulations (by LBNL) using TOUGH2/ EOS7C in support of the pilot tests. The simulations will be used to:

- Determine CO_2 quantity and rate of injection.
- Estimate the pressure and temperature changes in the reservoir associated with CO_2 injection.
- Provide insight into the monitoring and sampling that should be conducted in the injection well.

Carbon dioxide storage simulations for the Mt. Simon formation in west-central Ohio near the TAME Ethanol site were carried out earlier by members of the Midwest Regional Carbon Sequestration Partnership (MRCSP) team. While these early models did not simulate the exact proposed project location, the results are expected to be similar at locations across the region, as the intended target formation is the regionally extensive Mt. Simon sandstone. Key input parameters in the simulations were based on best available regional data. The parameters are not site-specific, but they are fairly reasonable for the Mt. Simon formation in the area. These initial model studies indicate that injection rates of more than 1 million tons of CO_2 per year may be sustained in the Mt. Simon formation at the TAME site without breach of the confining zone.

Several types of reservoir simulators exist that are being used by the RCSPs' large-scale field projects for sequestration of CO_2 in brine-saturated formations or in formations that contain both brine and oil. An overview of the simulation codes used by the RCSPs for large-scale field projects is briefly described in Table A5.1. These include simulators for multiphase flow through porous media, geomechanical simulators, simulators for "leakage" of CO_2 from wells or from deep underground to the atmosphere, and simulators for flow through fractured geologic formations. For historical reasons, the phrases "reservoir simulator" and "reservoir simulation" often refer only to computer codes and calculations that treat the flow of fluids deep underground.

Table A5.1. Classification of Selected Model Simulation Codes Available and Used by the RCSPs.

Type of Code	Names	Main Sequestration Application
Non-isothermal multiphase flow processes in porous media	Eclipse, GEM-GHG, NUFT, FEHM, TOUGH2	Simulate plume migration and dispersion
Non-isothermal multiphase chemically-reactive flow and transport in porous media	TOUGHREACT, VIP Reservoir, FEHM, PFLOTRAN STOMP	Simulate plume migration and chemical interaction of CO_2 with reservoir rock and fluids (reactions and CO_2 trapping)
Geomechanical Processes	FLAC, GMI-SFIB, ABACUS, FEHM	Simulate stress and strain induced in reservoirs during and after injection
Non-isothermal multiphase flow in porous media with geomechanical coupling	TOUGH-FLAC, FEHM	Model plume dispersion and impacts of stress and strain due to CO_2 injection
Flow in fractured media	TOUGH2, NFFLOW-FRACGEN	CO_2 flow through fractured networks

In general, three key areas of simulation—focusing on faults and fractures, subsurface behavior and fate of CO_2, and geomechanical/mechanical/flow models—demonstrate how simulation technology is critical to sequestration evaluation and risk assessment.

NETL is also committed to model development through the Core R&D Program that is not associated directly with the RCSP Program, but rather is to develop and test models "in-house" prior to large-scale deployment. NETL has developed a state-of-the-art fractured reservoir model, FRACGEN/NFFLOW, that consists of two key components. First, a series of fracture network generators (FRACGEN) provides detailed 2D or 3D representations of reservoir fracture networks. Second, a flow model (NFFLOW) estimates the interaction of the fractures with the rock matrix and simulates the flow of gas through the fracture network to one or more boreholes. FRACGEN implements four stochastic models of increasing complexity that sample fitted distributions of fracture length, aperture, spacing, etc., for up to 10 fracture sets. The selection of which model to use is driven by the amount of data available. Examples of a FRACGEN-NFLOW modeling network and resultant output are shown in Figure A5.5.

The three most complex models allow the fracture termination and intersection frequencies among the different sets to be controlled by the user. Two of the models also generate fracture swarms. Clustering can be random or parallel to sub-parallel. In addition, the user can condition the network to known fracture locations as observed in a borehole. Recent work allows the modeling of multi-layered networks, in which fracture networks are generated for several layers that are then stacked, with a user-specified percentage of fractures in each layer extending into the overlying layer.

NFFLOW computes flow rates or bottom-hole pressures according to user-specified pressure or rate schedules. Single, multiple, or multi-branched wells may be used, and the wells may be vertical, inclined, or horizontal. Flow is single phase and gravity effects are neglected. Fracture-bound matrix blocks drain to, or recharge from, the midpoint of adjacent fractures in accordance with a one-dimensional unsteady-flow model. A requirement for a material balance among all intersections couples the individual recharge models. FRACGEN/NFFLOW represents a significant advancement in the art of gas reservoir simulation by being the first model to readily simulate gas flow and drainage in fractured reservoirs with a discrete, irregular, and stochastic fracture network using a large number of fractures.

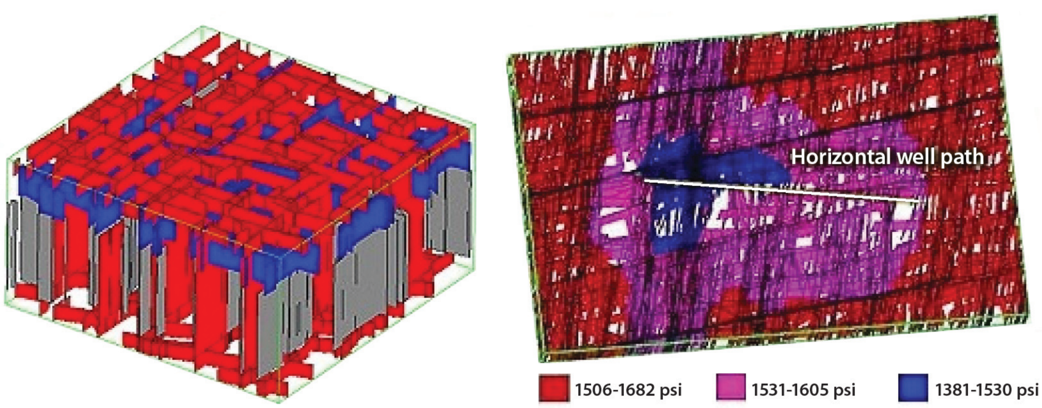

Figure A5.5. Example of Multilayer Fracture Network Using FRACGEN (left) and FRACGEN-NFLOW Output Pressure Drawdown in a Fractured Reservoir Produced by a Horizontal Well (right).

Computer simulation is an important design tool for any GS project. Its value is illustrated by the fact that virtually all petroleum reservoir development decisions consider simulation results to some degree. GS projects, regardless of size or geographic location, will require some level of modeling effort that is capable of coupling (in some degree) geophysical and geochemical processes to obtain reliable predictions of the behavior of CO_2 and other fluids and of pressure propagation. In some cases, multiple modeling codes may be needed to model different spatial scales and timeframes (LBNL, 2004).

Following the site characterization step of a GS project, working hypotheses about important mechanisms that control the behavior of injected CO_2 are developed and tested. This approach has been studied extensively over the last decade from a risk assessment perspective (Savage et al., 2004; Lewicki et al., 2006). The mechanisms that control behavior of CO_2 and its transport need to be simulated, based on an understanding of the transport and chemical processes active at the injection interval with guidance from available injection/production and monitoring data.

Simulations can be used to predict temporal and spatial migration of the injected CO_2 plume; CO_2 trapping, including structural, residual, and solubility; the effect of geochemical reactions on CO_2 trapping, long-term porosity, and permeability; confining zone and wellbore integrity; the impact of thermal/compositional gradients in the reservoir; pathways for CO_2 leakage out of the reservoir; the behavior of secondary barriers; effects of unplanned hydraulic fracturing; the extent of upward migration of CO_2 along the outside of the well casing; impacts of cement-CO_2 reactions; CO_2 movement along faults and interactions with fault gauges; and interactions that would result should CO_2 migrate outside the reservoir, including into shallow aquifers.

Numerical simulations can be used for a variety of applications, including assessing storage capacity of the reservoir, predicting plume and pressure fronts, estimating recovery volumes for EOR and ECBM applications, estimating AoR, and estimating travel times for potential leakage pathways (LBNL, 2004; Liu and Smirnov, 2007). These applications require building models representative of the candidate site using existing site-specific geophysical and geochemical data and/or data acquired during the site characterization process, supplemented by data from tools specified by the project's MVA plan. Several numerical models (simulators) are already available and being used in GS projects worldwide, with more codes being continually developed or improved. Modeling results can be used to qualify or disqualify a candidate site as suitable for GS storage.

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