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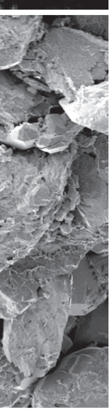
CCS GUIDELINES

Guidelines for Carbon Dioxide Capture, Transport, and Storage



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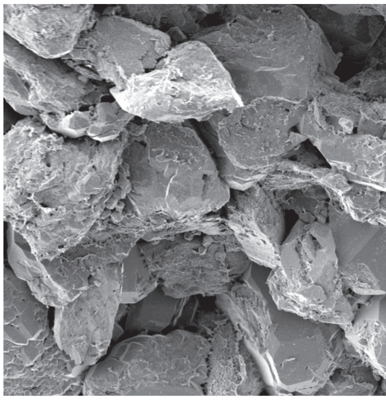

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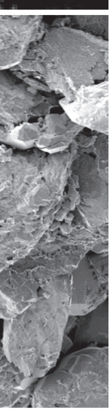

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Guidelines for Carbon Dioxide Capture, Transport, and Storage

Cite as:
World Resources Institute (WRI). CCS Guidelines:
Guidelines for Carbon Dioxide Capture, Transport, and Storage.
Washington, DC: WRI.

Published by
World Resources Institute
10 G Street, NE
Suite 800
Washington, DC 20002

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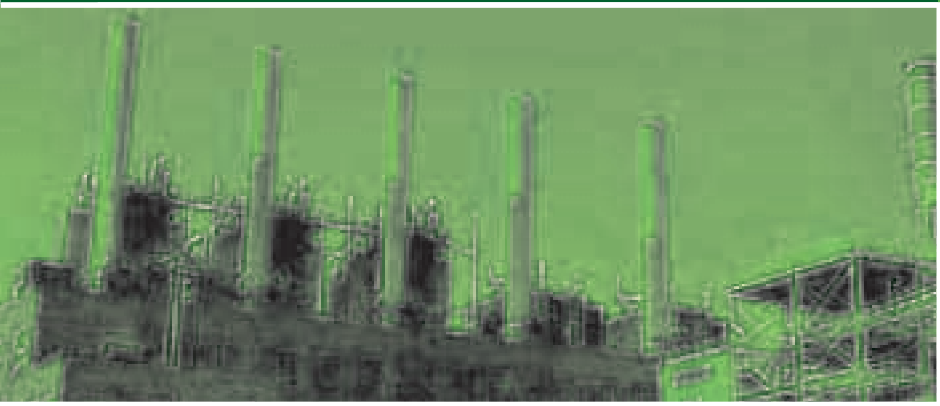
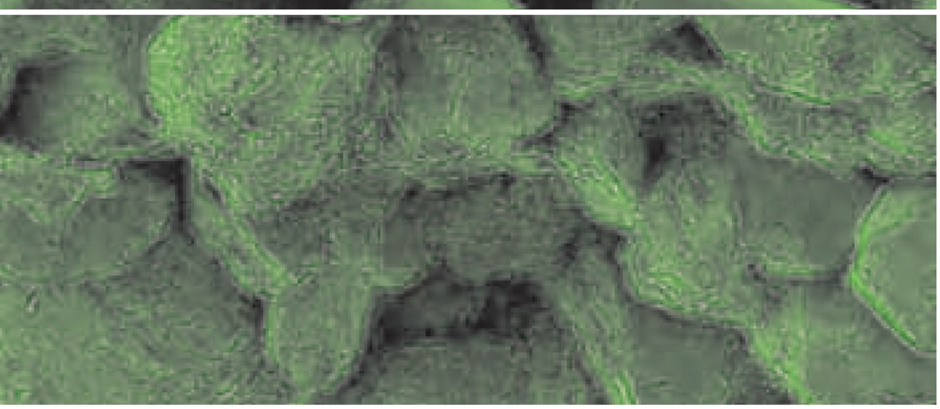
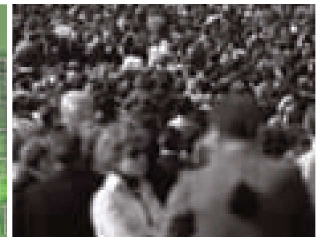
ISBN 978-1-56973-701-9





The CCS Guiding Principles



1. **Protect human health and safety.**

2. **Protect ecosystems.**

3. **Protect underground sources of drinking water and other natural resources.**

4. **Ensure market confidence in emission reductions through regulatory clarity and proper GHG accounting.**

5. **Facilitate cost-effective, timely deployment.**

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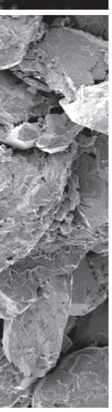

ACKNOWLEDGMENTS

This publication is the collective product of a carbon dioxide capture and storage (CCS) stakeholder process convened by the World Resources Institute (WRI) between February 2006 and September 2008. The unique perspectives and expertise that each participant brought to the process were invaluable to ensuring the development of a robust and broadly accepted set of technical guidelines for CCS. This publication would not have been produced without the leadership of WRI Climate and Energy Program Director Jonathan Pershing and the authors and editors who demonstrated outstanding commitment and diligence throughout the process. WRI would like to thank BP and the Pew Charitable Trust for their financial support, as well as all those stakeholders who generously provided in-kind contributions of their time and expertise.

We are thankful for the early leadership and management of this initiative by former WRI staff members Jeffrey Logan and John Venezia. We would also like to thank the WRI peer reviewers (Elizabeth Cook, Joseph Foti, Stephen Russell, and Neelam Singh) and the external peer reviewers (John Coequyt, Ben Hengst, Jeffrey Logan, Gregory Schnaar, and Gabriella Von Goerne) for their thoughtful review of the document prior to publication and Greg Fuhs and Seth Ort for their careful copy edit. This work and the stakeholder process also benefited substantially from the strategic insights and reviews of WRI staff members Janet Ranganathan and Debbie Boger.

DISCLAIMER

This document, designed to provide guidance to CCS project developers, regulators, and policymakers, has been developed through a diverse multi-stakeholder consultative process involving representatives from business, nongovernmental organizations, government, academia, and other backgrounds. While WRI encourages the use of the information in this document, its application and the preparation and publication of reports based on it are the full responsibility of its users. Neither WRI nor the individuals who contributed to the Guidelines assume responsibility for any consequences or damages resulting directly or indirectly from their use and application.

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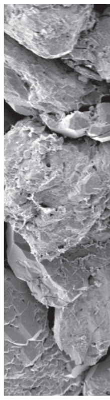
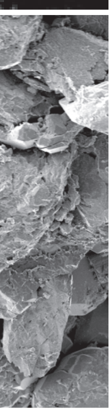
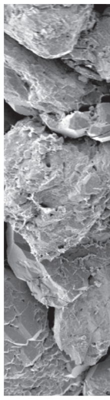










EXECUTIVE SUMMARY

The Carbon Dioxide Capture and Storage (CCS) Guidelines effort was initiated to develop a set of preliminary guidelines and recommendations for the deployment of CCS technologies in the United States, to ensure that CCS projects are conducted safely and effectively. As such, the CCS Guidelines are written for those who may be involved in decisions on a proposed project: the developers, regulators, financiers, insurers, project operators, and policymakers. These Guidelines are intended to guide full-scale demonstration of and build public confidence in CCS technologies by informing how projects should be conducted.

Worldwide increases in energy demand coupled with a continued reliance on fossil fuel resources have contributed to a significant increase in atmospheric levels of carbon dioxide (CO_2). This increase shows no signs of slowing. According to the International Energy Agency's (IEA's) *World Energy Outlook 2007*, the projected growth in energy demand will translate into a 57 percent rise in energy-related CO_2 emissions by 2030 (IEA 2007). Others argue —especially in the recent high energy price environment—that global energy demand will be much lower than the IEA forecast.

Scenarios for stabilizing climate-forcing emissions suggest atmospheric CO_2 stabilization can only be accomplished through the development and deployment of a robust portfolio of solutions, including significant increases in energy efficiency and conservation in the industrial, building, and transport sectors; increased reliance on renewable energy and potentially additional nuclear energy sources; and deployment of CCS. Slowing and stopping emissions growth from the energy sector will require transformational changes in the way the world generates and uses energy.

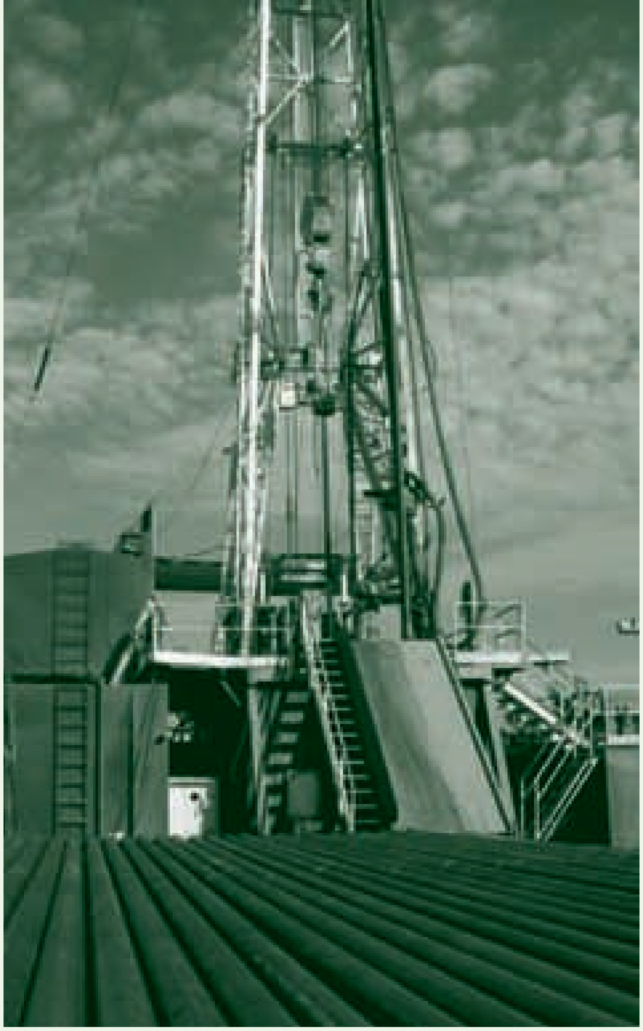
CCS is a broad term that encompasses a number of technologies that can be used to capture CO_2 from point sources, such as power plants and other industrial facilities; compress it; transport it mainly by pipeline to suitable locations; and inject it into deep subsurface geological formations for indefinite isolation from the atmosphere. CCS is a critical option in the portfolio of solutions available to combat climate change, because it allows for significant reductions in CO_2 emissions from fossil-based systems, enabling it to be used as a bridge to a sustainable energy future.

In technology development there is a period referred to as the "valley of death," where a technology has been proven in the laboratory and on a small scale, but has yet to become commercially viable. CCS technology has progressed quickly from being a concept to a key part in proposed climate change mitigation plans. This progression is partly the result of early successes in pilot capture demonstrations and field validation tests, where small volumes of CO_2 have been injected for research purposes. It is also due in large part to the experience that has been gained injecting CO_2 for enhanced oil recovery over the past three and a half decades. There are skeptics who believe that CCS remains infeasible, with continued interest driven by the lack of any other viable solution that would allow the continued use of coal. To achieve the potential benefits of CCS and prove that safe and permanent storage can be realized, it is important to continue large-scale demonstration and deployment of this technology.

Although the CCS industry is still in its formative stages, in developing the CCS Guidelines participants were able to draw from a wealth of information, analogous regulatory experience, and industrial best practices. As the knowledge and understanding of the suite of CCS technologies grow, these Guidelines will be revised to reflect emerging best practices. The potential for further development is most evident where the CCS Guidelines identify areas for additional research and, hence, suggest that extra care be taken during the early deployment phase.

This effort has progressed in the context of a swiftly changing regulatory landscape of CCS-specific regulations emerging at the U.S. federal and state levels. The CCS Guidelines complement these efforts by focusing a group of experts on specific issues in order to examine, describe, and explain best practices for the implementation of specific projects. In addition, the Guidelines introduce some larger policy issues that go beyond the regulatory frameworks proposed by federal and state governments. Appendices B, C, and D categorize the Guidelines according to the intended implementing audiences: Appendix B presents information intended for Congress, Appendix C presents information intended for regulators, and Appendix D presents information intended for operators.

A key finding of the stakeholder process is that even though additional research is needed in some areas, there is adequate technical understanding to safely conduct large-scale demonstration projects.



The Process

The purpose of the CCS Guidelines is not to make a case for or against CCS, but rather to develop practical considerations for demonstrating and deploying CCS technologies. The starting point for the CCS Guidelines stakeholder discussions was that CCS will most likely be needed to achieve the magnitude of CO_2 emissions reduction required to stabilize and reduce atmospheric concentrations of greenhouse gases (GHGs).

These Guidelines represent current understanding of how to implement CCS technologies. Discussions of the Guidelines were predicated on the following principles:

1. Protect human health and safety.
2. Protect ecosystems.
3. Protect underground sources of drinking water and other natural resources.
4. Ensure market confidence in emission reductions through regulatory clarity and proper GHG accounting.
5. Facilitate cost-effective, timely deployment.

To develop the CCS Guidelines, the World Resources Institute (WRI) convened a diverse group of over 80 stakeholders, including representatives from academia, business, government, and environmental nongovernmental organizations (NGOs). Business participants included those most likely to be involved in CCS projects: fossil energy, electric utility, insurance and service providers. These experts represent a variety of disciplines, including engineering, finance, economics, law, and social science. To have the technical discussions needed to arrive at a robust set of guidelines, all stakeholders agreed to focus the discussions and guidelines on how and not whether to implement a CCS project. These Guidelines are written in the U.S. context, since the stakeholder process involved primarily U.S. experts. WRI is in the process of conducting additional work to customize the Guidelines for other key countries, taking into account their specific local conditions and context.

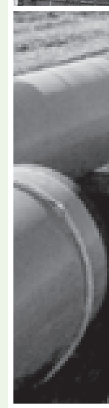
These Guidelines reflect the collective agreement of the contributing stakeholders, who offered strategic insights, provided extensive comments on multiple iterations of draft guidelines and technical guidance, and participated in workshops. The authors and editors strived to incorporate these sometimes diverse views. In so doing, they weighed conflicting comments to develop guidelines that best reflect the views of the group as a whole, and acknowledged diverging opinions among stakeholders. Although these Guidelines reflect the collective input of the contributing stakeholders, individual stakeholders were not asked to endorse them. The identification of the individual stakeholders should not be interpreted as, and does not constitute, an endorsement of these Guidelines by any of the listed stakeholders.

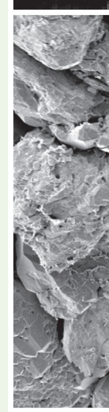
Since this project's inception, rapid expansion of and interest in CCS technologies have accelerated movement toward the development of regulations and policies to support CCS. As such, the organizational and individual composition of the contributing stakeholders has changed over time. The stakeholders listed in this document contributed by attending workshops on the draft Guidelines between December 2007 and July 2008, and/or providing written comments. Other key stakeholders contributed early on in shaping the Guidelines. A detailed description of the CCS stakeholder process is provided in Part 1 and Appendix A of these Guidelines.

Limitations of the Guidelines

These Guidelines address most of the technical issues involved in the design, implementation, and decommissioning of CCS. However, it is important to note that there are other important issues involved in successful scale-up of CCS that were beyond the scope and expertise of the WRI-convened stakeholder process. These issues include:

- Procedures for engaging local communities in the design and implementation of CCS,
- Guidelines on the compensation of property owners regarding pipeline right-of-way and pore space ownership,





- Application of public right-to-know information disclosure and third-party verification of operator-submitted information, and
- How to address any upstream impacts associated with the increased use of coal per unit of energy generated as a result of the energy penalty associated with the use of CCS.

While the Guidelines include references to resources for these issues, they are not intended to provide a comprehensive treatment of these issues. Throughout the Guidelines, areas are highlighted where more research is needed, and the Guidelines can be revised to reflect emerging best practices as at-scale experience is gained. Also, many of the policy recommendations (such as the framework for post-closure stewardship) explore the need for additional legislation, but without going into detail. Going forward, WRI will seek opportunities to address these and other issues by convening appropriate stakeholders and by drawing from experience gained through other relevant initiatives. Finally, although this first edition of the Guidelines frames the important policy issues surrounding GHG accounting, liability, financial incentives, and long-term stewardship associated with CCS projects, the stakeholders acknowledge that more discussion—and in some cases experience—is needed to propose more robust Guidelines for these important areas.

Who Should Read This Document

These Guidelines present recommendations and best practices for those involved in the development and implementation of CCS projects. The document also provides a comprehensive introductory reference for those new to CCS who seek to understand how to responsibly conduct projects. A potential operator, financier, insurer, or regulator can use these Guidelines as a benchmark in evaluating potential project plans and as a reference on the current technical understanding of best practices for CCS, and a policymaker can use them to establish regulatory and investment frameworks that enable successful and responsible CCS deployments. It is important to note that these Guidelines are not intended to replace or provide the detailed technical knowledge that would be required to select the location for or to design and operate a CCS project. In fact, one of the findings derived from this process is that each CCS project will be unique, and a team of qualified experts will be needed to design and operate each project.

Organization of the Guidelines

The Guidelines are divided into three primary parts: Capture, Transport, and Storage. Nevertheless, decisions made regarding the specific configuration of the capture system affect the project through the final phases of post-closure storage. Similarly, up-front planning regarding the capacity of the storage reservoir in comparison to the projected CO_2 emissions is essential. A CCS project requires thoughtful integration to ensure that materials are fit-for-purpose and that the comprehensive impacts of the project are evaluated both throughout the project chain and through the expected project life cycle.

These CCS Guidelines were developed by a diverse group of stakeholders, including over 80 contributers from academia, business, government, and environmental nongovernmental organizations (NGOs).

CAPTURE

While entities have commercially deployed CO_2 capture technologies on industrial processes for various purposes, including the production of streams of CO_2 for use in enhanced oil recovery (EOR) and for sale as a food-grade product, capture technologies have not been demonstrated on commercial-scale power plants. Demonstration and potential widespread deployment of capture technologies will require owners and operators of power plants to learn new processes and adopt additional safety protocols, but these methods, guidelines, and regulations are in use in other industries. The current state of CO_2 capture technologies and the potential environmental impacts of the technologies are summarized. The Guidelines also include an analysis of the existing U.S. regulatory structure for carbon capture and highlight considerations for deployment.

TRANSPORT

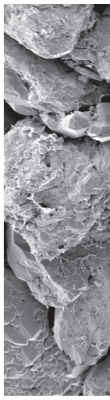
Today, there are well over 3,000 miles of CO_2 pipelines in operation in the United States. This operational experience provides a basis for the development of a CO_2 pipeline infrastructure for CCS. The Guidelines build on this experience, and are intended to inform pipeline infrastructure development for widespread deployment of CCS. The transport element of the CCS Guidelines describes existing standards for CO_2 pipeline design, operational, and regulatory practices, and identifies potential issues associated with more geographically diverse transportation of CO_2 for the purpose of geologic storage.

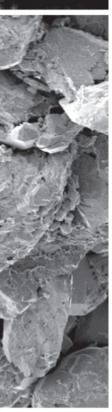
STORAGE

The storage plan for an individual site ultimately must reflect the heterogeneity in local geological conditions, be informed by knowledge gained during project operations, and be based on site-specific data. The Guidelines reflect the current understanding of operational guidelines for permanent underground storage. Proper site characterization and operation are critical to successful geologic storage efforts. Also integral to safe and effective geologic storage is developing a sound measurement, monitoring, and verification (MMV) plan, conducting a comprehensive risk analysis, and establishing a plan for the CCS project that includes considerations for long-term site stewardship.

Next Steps

As CCS technology progresses around the world, an emergent standard of conduct will evolve for both regulation of CCS as well as industrial best practices. The CCS Guidelines are intended to inform those considering CCS policies and regulations in the United States and those who manage the various aspects of CCS demonstration and full-scale projects. The Guidelines can be revised as understanding of the technology grows. Additionally, WRI will leverage this work to develop Guidelines for an international audience, including work with local stakeholders to develop Guidelines that can be implemented in other countries, such as China.





GUIDELINES

Each of the following guidelines has been excerpted from this document. Please refer to the full text of the document for an in-depth review of information pertinent to each guideline.

Capture Guidelines

Capture Guideline 1: Recommended Guidelines for CO_2 Capture (Section 2.2, page 35)

a. Demonstrations of all capture approaches (pre-combustion, post-combustion and oxy-fuel combustion) are urgently needed on commercial-scale power plants to prove the technologies.
b. There should be recognition of the potential challenges in achieving the theoretical maximum capture potential before the technologies are proven at scale. This may necessitate flexibility in establishing appropriate capture rates for early commercial-scale projects with the amount of CO_2 captured at a facility dependent on both technology performance and the specific goals of the project.
c. Standards for the levels of co-constituents have been proposed by some regulators and legislators; however, there is potential risk that this could create disincentives for reducing sources of anthropogenic CO_2 if the standard is set too stringently. Ultimately, the emphasis should be on employing materials, procedures, and processes that are fit-for-purpose and assessing the environmental impacts of any co-constituents, along with the benefits of CO_2 emissions reduction, as part of a comprehensive CCS risk assessment. Facility operators, regulators, and other stakeholders should pay particular attention to potential impacts of co-constituents in the transport and storage aspects of the project.

Capture Guideline 2: Recommended Guidelines for Ancillary Environmental Impacts from CO_2 Capture (Section 2.3, page 40)

a. When constructing a new facility or retrofitting an existing facility in the United States, operators must comply with requirements under the Clean Air Act and the Clean Water Act, as appropriate.
b. Options for minimizing local and regional environmental impacts associated with air emissions, use of water, and solid waste generation should be evaluated when considering technologies for capture.
c. Use of capture technologies could result in hazardous or industrial waste streams. Operators must follow guidelines and regulations for the handling and disposal of industrial or hazardous wastes.
d. Operators should investigate the use of combustion wastes as beneficial byproducts.
e. Currently, the U.S. Environmental Protection Agency (EPA) is considering regulation of coal combustion wastes that are sent to landfills or surface impoundments, or used as fill in surface or underground mines. Potential impacts of the volume and concentrations of hazardous materials in the waste stream from facilities with CO_2 capture should be evaluated in this context.

Transport Guidelines

Transport Guideline 1: Recommended Guidelines for Pipeline Design and Operation (Section 3.2, page 47)

a. CO_2 pipeline design specifications should be fit-for-purpose and consistent with the projected concentrations of co-constituents, particularly water, hydrogen sulfide (H_2S), oxygen, hydrocarbons, and mercury.
b. Existing industry experience and regulations for pipeline design and operation should be applied to future CCS projects.

Transport Guideline 2: Recommended Guidelines for Pipeline Safety and Integrity (Section 3.3, page 48)

a. Operators should follow the existing Occupational Safety and Health Administration (OSHA) standards for safe handling of CO_2.
b. Plants operating small in-plant pipelines should consider adopting Office of Pipeline Safety (OPS) regulations as a minimum for best practice.
c. Pipelines located in vulnerable areas (populated, ecologically sensitive, or seismically active areas) require extra due diligence by operators to ensure safe pipeline operations. Options for increasing due diligence include decreased spacing of mainline valves, greater depths of burial, and increased frequency of pipeline integrity assessments and monitoring for leaks.
d. If the pipeline is designed to handle H_2S, operators should adopt appropriate protection for handling and exposure.

Transport Guideline 3: Recommended Guidelines for Siting CO_2 Pipelines (Section 3.4, page 50)

a. Considering the extent of CO_2 pipeline needs for large-scale CCS, a more efficient means of regulating the siting of interstate CO_2 pipelines should be considered at the federal level, based on consultation with states, industry, and other stakeholders.
b. As a broader CO_2 pipeline infrastructure develops, regulators should consider allowing CO_2 pipeline developers to take advantage of current state condemnation statutes and regulations that will facilitate right-of-way acquisition negotiations.

The CCS Guidelines are intended to inform those considering CCS policies and regulations in the United States and those who manage the various aspects of full-scale CCS demonstrations.

Transport Guideline 4: Recommended Guidelines for Pipeline Access and Tariff Regulation (Section 3.5, page 52)

a. The federal government should consult with industry and states to evaluate a model for setting rates and access for interstate CO_2 pipelines. Such action would facilitate the growth of an interstate CO_2 pipeline network.

Storage Guidelines

Storage Guideline 1: Recommended Guidelines for Measurement Monitoring, and Verification (MMV) (Section 4.3.1.1, page 70)

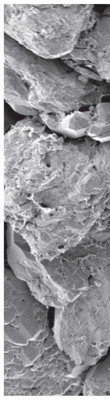
a. MMV requirements should not prescribe methods or tools; rather, they should focus on the key information an operator is required to collect for each injection well and the overall project, including injected volume; flow rate or injection pressure; composition of injectate; spatial distribution of the CO_2 plume; reservoir pressure; well integrity; determination of any measurable leakage; and appropriate data (including formation fluid chemistry) from the monitoring zone, confining zone, and underground sources of drinking water (USDWs).

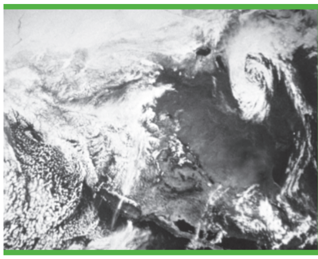
b. Operators should have the flexibility to choose the specific monitoring techniques and protocols that will be deployed at each storage site, as long as the methods selected provide data at resolutions that will meet the stated monitoring requirements.

c. MMV plans, although submitted as part of the site permitting process, should be reviewed and updated as needed throughout a project as significant new site-specific operational data become available.

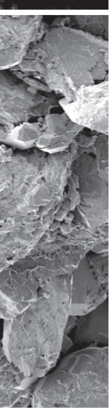
d. The monitoring area should be based initially on knowledge of the regional and site geology, overall site specific risk assessment, and subsurface flow simulations. This area should be modified as warranted, based on data obtained during operations. It should include the project footprint (the CO_2 plume and area of significantly elevated pressure, or injected and displaced fluids). Groundwater quality monitoring should be performed on a site-specific basis based on injection zone to USDW disposition.

e. MMV activities should continue after injection ceases as necessary to demonstrate non-endangerment, as described in the post-closure section (see Storage Guideline 7d).





Based on this process and the robust set of Guidelines presented herein, we believe there is sufficient evidence that CCS projects can be carried out safely and effectively to warrant quickly moving to full-scale demonstrations.



Storage Guideline 2: Recommended Guidelines for Risk Assessment (Section 4.3.1.2, page 78)

a. For all storage projects, a risk assessment should be required, along with the development and implementation of a risk management and risk communication plan. At a minimum, risk assessments should examine the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, and the fluids' potential impacts on the integrity of the confining zone and endangerment to human health and the environment.
b. Risk assessments should address the potential for leakage during operations as well as over the long term.
c. Risk assessments should help identify priority locations and approaches for enhanced MMV activities.
d. Risk assessments should provide the basis for mitigation/remediation plans for response to unexpected events; such plans should be developed and submitted to the regulator in support of the proposed MMV plan.
e. Risk assessments should inform operational decisions, including setting an appropriate injection pressure that will not compromise the integrity of the confining zone.
f. Periodic updates to the risk assessment should be conducted throughout the project life cycle based on updated MMV data and revised models and simulations, as well as knowledge gained from ongoing research and operation of other storage sites.
g. Risk assessments should encompass the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, with a focus on potential impacts to the integrity of the confining zone and endangerment to human health and the environment.
h. Risk assessments should include site-specific information, such as the terrain, potential receptors, proximity of USDWs, faults, and the potential for unidentified borehole locations within the project footprint.
i. Risk assessments should include non-spatial elements or non-geologic factors (such as population, land use, or critical habitat) that should be considered in evaluating a specific site.

Storage Guideline 3: Recommended Guidelines for Financial Responsibility (Section 4.3.1.3, page 80)

a. Based on site-specific risk assessment, project operators/owners should provide an expected value of the estimated costs of site closure (including well plugging and abandonment, MMV, and foreseeable mitigation (remediation) action) as part of their permit application. These cost estimates should be updated as needed prior to undertaking site closure.
b. Project operators/owners should demonstrate financial assurance for all of the activities required for site closure.
c. Policies should be developed for adequately funding the post-closure activities that become the responsibility of an entity assuming responsibility for long-term stewardship, as described in the Post-Closure section.
d. Because of the public good benefits of early storage projects and the potential difficulty of attracting investment, policy-makers should carefully evaluate options for the design and application of a risk management framework for such projects. This framework should appropriately balance relevant policy considerations, including the need for financial assurances, without imposing excessive barriers to the design and deployment of CCS technology.

Storage Guideline 4: Recommended Guidelines for Property Rights and Ownership (Section 4.3.1.4, page 82)

a. Potential operators should demonstrate control of legal rights to use the site surface and/or subsurface to conduct injection, storage, and monitoring over the expected lifetime of the project within the area of the CO_2 plume and (where appropriate) the entire project footprint. Regulators will also need access for inspection.
b. Continued investigation into technical, regulatory, and legal issues in determining pore space ownership for CCS is warranted at the state and federal levels. Additional legislation to provide a clear and reasonably actionable pathway for CCS demonstration and deployment may be necessary.
c. MMV activities may require land access beyond the projected CO_2 plume; therefore, land access and any other property interest for these activities should be obtained.

d. Operators should avoid potential areas of subsurface migration that might lead to claims of trespass and develop contingencies and mitigation strategies to avoid such actions.

Storage Guideline 5: Recommended Guidelines for Site Selection and Characterization (Section 4.3.2.1, page 91)

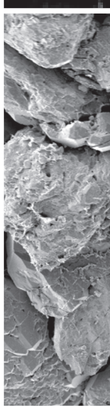
a. General Guidelines for Site Characterization and Selection
   1. Potential storage reservoirs should be ranked using a set of criteria developed to minimize leakage risks. Future work is needed to clarify such ranking criteria.
   2. Low-risk sites should be prioritized for early projects.
   3. As required by regulation, storage reservoirs should not be freshwater aquifers or potential underground sources of drinking water.
   4. Confining zones must be present that possess characteristics sufficient to prevent the injected or displaced fluids from migrating to drinking water sources or the surface.
   5. Site-specific data should be collected and used to develop a subsurface reservoir model to predict/simulate the injection over the lifetime of the storage project and the associated project footprint. These simulations should make predictions that can be verified by history-matching within a relatively short period of time after initial CO_2 injection or upon completion of the first round of wells. The reservoir model and simulations should be updated periodically as warranted and agreed with regulators.
   6. Saline formations and mature oil and gas fields should be considered for initial projects. Other formations, such as coal seams, may prove viable for subsequent activity with additional research.

b. Guidelines for Determining Functionality of Confining Zones
   1. Confining zones must be present and must prevent the injected or displaced fluids from migrating to drinking water sources as well as to economic resources (e.g., mineral resources) or the surface.
   2. Operators should identify and map the continuity of the target formation and confining zones for the project footprint, and confirm the integrity of the confining zones with appropriate tools. Natural and drilling or operationally induced fractures (or the likely occurrence thereof) should be identified.
   3. Operators should identify and map auxiliary or secondary confining zones overlying the primary and secondary target formations, where appropriate.
   4. Operators should identify and locate all wells with penetrations of the confining zone within the project footprint. A survey of these wells to assess their likely performance and integrity based on completion records and visual surveys should be conducted. These data should be made publicly available.
   5. Operators should identify and map all potentially significant transmissive faults, especially those that transect the confining zone within the project footprint.
   6. Operators should collect in-situ stress information from site wells and other sources to assess likely fault performance, including stress tensor orientation and magnitude.

c. Guidelines for Determining Injectivity
   1. If sufficient data do not already exist, operators should obtain data to estimate injectivity over the projected project footprint. This may be accomplished with a sustained test injection or production of site well(s). These wells (which could serve for injection, monitoring, or characterization) should have the spatial distribution to provide reasonable preliminary estimates over the projected project footprint.
   2. Water injection tests should be allowed in determining site injectivity.
   3. Operators should obtain and organize porosity and permeability measurements from core samples collected at the site. These data should be made publicly available.

d. Guidelines for Determining Capacity
   1. Operators should estimate or obtain estimates of the projected capacity for storing CO_2 with site-specific data (CO_2 density at projected reservoir pressure and temperature) for the project footprint. This should include all target formations of interest, including primary and secondary targets. Capacity calculations should include estimates of the net vertical volume effectively utilized or available for storage and an estimate of likely pore volume fraction to be used (utilization factor).
   2. Operators should collect and analyze target formation pore fluids to determine the projected rate and amount of

Throughout the Guidelines, areas are highlighted where more research is needed, and the Guidelines can be revised to reflect emerging best practices as at-scale experience is gained.



CO_2 stored in a dissolved phase. These data should be made publicly available as necessary for permitting and compliance purposes.

3. Operators should obtain estimates of phase-relative permeability (CO_2 and brine) and the amount of residual phase trapping. One possible approach is to use core samples with sufficient spatial density to confirm the existence of the trapping mechanisms throughout the site and to allow their simulation prior to site development. Estimates should be updated with site-specific monitoring and modeling results. These data should be made publicly available as necessary for permitting and compliance purposes.

Storage Guideline 6: Recommended Guidelines for Injection Operations (Section 4.3.2.2, page 97)

a. A field development plan should be generated early on in the permitting phase.
b. Operators should develop transparent operational plans and implementation schedules with sufficient flexibility to use operational data and new information resulting from MMV activities to adapt to unexpected subsurface environments.
c. Operational plans should be based on site characterization information and risk assessment; they should include contingency mitigation/remediation strategies.
d. Storage operators should plan for compressor and well operations contingencies with a combination of contractual agreements relating to upstream management of CO_2, backup equipment, storage space, and, if necessary, permits that allow venting under certain conditions.
e. Wells and facilities should be fit-for-purpose, complying with existing federal and state regulations for design and construction.
f. The reservoir and risk models should be recalibrated (or history-matched) periodically, based on operational data and re-run flow simulations. Immediate updates should be made if significant differences in the expected and discovered geology are found.
g. The casing cement in the well should extend from the injection zone to at least an area above the confining zone.
h. Well integrity, including cement location and performance, should be tested after construction is complete, and routinely while the well is operational, as required by regulation.
i. Water injection tests should be allowed at all prospective CCS sites.
j. Injection pressures and rates should be determined by well tests and geomechanical studies, taking into account both formation fracture pressure and formation parting pressure. Rules should not establish generally applicable quantitative limits on injection pressure and rates; rather, site-specific limitations should be established as necessary in permits.
k. Operators should adhere to established workplace CO_2 safety standards.
l. Operators should implement corrosion management approaches, such as regularly checking facilities, wells and meters for substantial corrosion. Corrosion detected should be inhibited immediately, or damaged facility components should be replaced. Dehydration of the injectate should be required to prevent corrosion, unless appropriate metallurgy is installed.
m. Operational data should be collected and analyzed throughout a project's operation and integrated into the reservoir model and simulations. The data collected should be used to history-match the project performance to the simulation predictions.

Storage Guideline 7: Recommended Guidelines for Site Closure (Section 4.3.2.3, page 103)

a. Continued monitoring during the closure period should be conducted in a portion of the wells in order to demonstrate non-endangerment, as described below.
b. For all other wells, early research and experience suggest that conventional materials and procedures for plugging and abandonment of wells may be sufficient to ensure project integrity, unless site-specific conditions warrant special materials or procedures. A final assessment should include a final cement bond log across the primary sealing interval of all operational wells within the injection footprint prior to plugging, as well as standard mechanical integrity and pressure testing.
c. Operators should assemble a comprehensive set of data describing the location, condition, plugging, and abandonment procedures and any integrity testing results for every well that will be potentially affected by the storage project.
d. Satisfactory completion of post-injection monitoring requires a demonstration with a high degree of confidence that the storage project does not endanger human health or the environment. This includes demonstrating all of the following:

One of the findings derived from this process is that each CCS project will be unique, and a team of qualified experts will be needed to design and operate a site.

1. the estimated magnitude and extent of the project footprint (CO_2 plume and the area of elevated pressure), based on measurements and modeling;
2. that CO_2 movement and pressure changes match model predictions;
3. the estimated location of the detectable CO_2 plume based on measurement and modeling (measuring magnitude of saturation within the plume or mapping the edge of it);
4. either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone;
5. that, based on the most recent geologic understanding of the site, including monitoring data and modeling, the CO_2 plume and formation water are not expected to migrate in the future in a manner that encounters a potential leakage pathway; and
6. that wells at the site are not leaking and have maintained integrity.

e. Project operators who have demonstrated non-endangerment should be released from responsibility for any additional post-closure MMV, and should plug and abandon any wells used for post-injection monitoring. At this point, the project can be certified as closed, and project operators should be released from any financial assurance instruments held for site closure. In the event that regulators or a separate entity decide to undertake post-closure monitoring that involves keeping an existing monitoring well open or drilling new monitoring wells, project operators should not be responsible for any such work or associated mitigation or remediation arising out of the conduct of post-closure MMV.

f. If one does not already exist in a jurisdiction, a publicly accessible registry should be created for well plugging and abandonment data.

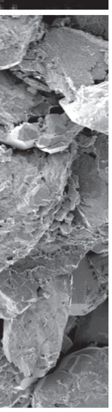
g. As a condition of completing site closure, operators should provide data on plugged and abandoned wells potentially affected by their project to the appropriate well plugging and abandonment registry. This would include the location and description of all known wells in the storage project footprint, and the drilling, completion, plugging, and integrity testing records for all operational wells.

h. The site-specific risk assessment should be updated based on operational data and observations during closure.

Storage Guideline 8: Recommended Guidelines for Post-Closure (Section 4.3.2.3, page 104)

a. Certified closed sites should be managed by an entity or entities whose tasks would include such activities as operating the registries of sites, conducting periodic MMV, and, if the need arises, conducting routine maintenance at MMV wells at closed sites over time.

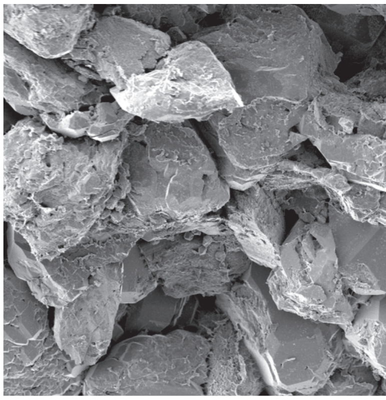
b. These entities need to be adequately funded over time to conduct those post-closure activities for which they are responsible.



A potential operator, financier, insurer, or regulator can use these Guidelines as a benchmark in evaluating potential project plans and as a reference on the current technical understanding of best practices for CCS.

INTRODUCTION

PART 1



WHAT IS CCS?

Carbon dioxide capture and storage (CCS) is the term that applies to an array of technologies through which carbon dioxide (CO_2) is captured at industrial point sources, such as fossil-fuel combustion, natural gas refining, ethanol production, and cement manufacturing plants. Once captured, the CO_2 gas is compressed into a supercritical phase and transported to a suitable location for injection into a very deep geologic formation, such as saline reservoirs, mature oil or gas fields, and potentially unminable coal seams, basalts, or other formations. Once injected, the CO_2 is isolated from the

drinking water supplies and prevented from release into the atmosphere by a primary confining zone that includes a dense layer of rock that acts as a seal and through additional trapping mechanisms. In general, it is expected that CO_2 storage projects will become more secure over time, as these additional trapping mechanisms take effect (IPCC 2005, Fig. 5.9).

Why is CCS important?

CCS is considered an essential element in a portfolio of approaches for reducing CO_2 emissions because it appears to be deployable and there is an enormous amount of potential storage capacity located around the world. To make significant reductions in greenhouse gas (GHG) emissions by mid-century, large-scale reduction opportunities, including CCS, will most likely be needed (IPCC 2005, Fig. SPM 7).

What is the status of CCS development?

The technologies involved in CCS stand at various stages of commercial readiness. Integrated projects that capture and store a large volume of CO_2 are being deployed in only a few instances, and so far, not in any baseload power plants. As reported in the 2007 Massachusetts Institute of Technology (MIT) *Future of Coal* study, additional demonstration at full scale is urgently needed to determine that the technology will work as envisioned on a large scale. This is critical to bringing the technology components to commercial readiness and to providing information needed to establish comprehensive legal and policy frameworks for widespread deployment of CCS (MIT 2007).

Today a number of small demonstration projects are underway. In the United States, the U.S. Department of Energy (DOE) sponsors a research and development program that is investing in development of the core technologies for capture, injection, and monitoring. One part of this program is the Regional Carbon Sequestration Partnerships, which is entering a third phase that will include more than 25 small-scale and up to 7 large-scale injection projects. Similar efforts are being started by governments around the world. On the regulatory and policy fronts, the U.S. Environmental Protection Agency (EPA) has released draft regulations governing the injection of CO_2 for storage. The Interstate Oil and Gas Compact Commission (IOGCC) has issued model rules and policy recommendations for CCS. And Washington State recently promulgated rules for geologic storage. These efforts are important, but they alone will not be sufficient to facilitate the broad use of CCS within a decade. Additional demonstrations and policies to provide incentives for such demonstrations are urgently needed.

Why were these Guidelines developed and through what process?

When this project was initiated in 2006, broad public awareness of CCS was low. No regulations or policies specifically targeted CCS, and there was open debate about whether and how the states and/or EPA should regulate geologic storage. This debate was fueled in part by the diverse facets of CCS. For example, although much of the technical experience for CCS is drawn from the petroleum and petrochemical industry, CO_2 sources are typically regulated under air quality rules at the state and federal levels: the U.S. Department of Transportation regulates the safety of supercritical CO_2 transport through pipeline systems and injection is typically overseen by environmental regulators when it involves waste disposal and by oil and gas regulators when it involves oil and gas operations. In addition, the natural gas industry is governed by provisions in a separate Natural Gas Storage Act.

Since this project was launched, the U.S. EPA has released for public comment draft rules governing injection of CO_2, the U.S. Congress has introduced a large number of legislative proposals to provide funding and other incentives for demonstration projects, and other governments and organizations around the world are also initiating efforts to develop and deploy CCS. In July 2008, the leaders of the Group of Eight (G8) expressed their support for CCS, saying in their official statement: "We strongly support the launching of 20 large-scale CCS demonstration projects globally by 2010, taking into account various national circumstances, with a view to beginning broad deployment of CCS by 2020" (G8 2008).

The World Resources Institute (WRI) convened a group of experts from business, government, nongovernmental organizations (NGOs), and others to develop the CCS Guidelines through an iterative process, beginning with scoping meetings in 2006. WRI commissioned the initial writing of the Guideline documents, with Thomas Curry (MJ Bradley & Associates, LLC) authoring the capture section, WRI Research Analyst Preeti Verma authoring the transport section, and Dr. S. Julio Friedmann (Lawrence Livermore National Laboratory) authoring the storage section. To ensure the development of robust and effective Guidelines, WRI predicated its process on the following principles:

1. Protect human health and safety,
2. Protect ecosystems,
3. Protect underground sources of drinking water and other natural resources,
4. Ensure market confidence in emission reductions through proper GHG accounting, and
5. Facilitate cost-effective, timely deployment.

These guiding principles were developed by the WRI CCS project team to ensure that the Guidelines reflect the objective of safe and timely deployment of CCS. The authors used these guiding principles as the basis to frame the recommendations. The original draft Guidelines were released in December 2007 at a workshop where invited experts gathered to review and discuss the draft documents. The capture and transport sections were largely agreed upon by the expert group, and were subsequently updated based on solicitations for comments and one-on-one discussions that the authors initiated with key stakeholders and experts. There was more debate about the provisions in the storage section, and it was the subject of additional expert meetings in March and June 2008. Revised versions of the storage section were released as review drafts in February and May 2008. WRI Senior Associate Sarah Forbes and Sarah Wade (AJW, Inc.) acted as supporting authors and editors for this effort following the December 2007 meeting. During the March and June 2008 expert meetings on the storage review drafts, invited stakeholders met to discuss language and key issues in depth. Notice of updated draft documents was sent to a broader stakeholder group for review, and many stakeholders provided detailed written comments.

A public workshop that focused on all three sections (capture, transport, and storage) was held in March 2008. An effort was made to include in this workshop all parties who had previously expressed interest in participating and learning more about the WRI process, as well as organizations and individuals who could provide input to further strengthen the Guidelines.

A final comprehensive review draft of the Guidelines was circulated for review in July 2008. This review draft reflected the collective input of the contributing stakeholders, listed at the front of this document, although it should be noted that individual stakeholders were not asked to endorse the Guidelines. The identification of the individual stakeholders should not be interpreted as, and does not constitute, an endorsement of these Guidelines by any of the listed stakeholders. On July 31, 2008, WRI hosted an online meeting for contributing stakeholders to kick off the peer review process. At that time, contributing stakeholders expressed interest in establishing an online forum to continue discussions. Throughout the review process, contributing stakeholders were also notified by e-mail of changes to the Guidelines.

In summary, the following workshops were specifically targeted toward the development and refinement of the Guidelines. WRI has also conducted a series of workshops to identify and explore issues related to CCS, which have informed the Guideline process and are described in Appendix A:

- February 2006—Kick-off and scoping workshop.
- December 2007—Expert meeting to discuss draft Guidelines for capture, transport, and storage.
- March 2008—All stakeholders invited to public forum to discuss February review draft Guidelines for capture, transport, and storage.
- March 2008—Storage experts' workshop to discuss February review draft Guideline text in detail.
- June 2008—Storage experts' workshop to discuss May review draft storage text.
- July 2008—Contributing stakeholders' Webinar.

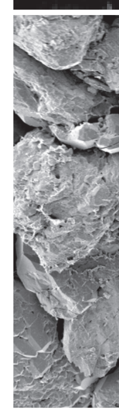
By providing background information on technical issues, the CCS Guidelines aim to facilitate the deployment of early CCS projects and to build the ideas and information for a legal and policy framework for CCS. The CCS Guidelines are meant to provide a comprehensive introductory reference for those new to CCS who need to understand how to responsibly conduct projects. A potential operator, financier, insurer, or regulator can use these Guidelines as a measure in evaluating potential project plans and as a reference on the current technical understanding of best practices for CCS. A policymaker can use them in establishing frameworks that enable successful and responsible CCS deployments. It is important to note that these Guidelines are not intended to replace or provide the detailed technical knowledge that would be required to select the location for or to design and operate a CCS project.

The other purpose of the CCS Guidelines is to clarify and present the existing knowledge on how to make the deployment of CCS safe and effective. There are some outstanding questions about how to best deploy CCS at scale, and to get to those answers there is an urgent need for conducting demonstration projects of varying sizes and configurations. In this document, we acknowledge areas where more research and demonstration are needed.

How should one approach these Guidelines?

The CCS Guidelines provide the reader with a comprehensive overview of CCS. The first section focuses on capture, the second on transport, and the third on storage. The Guidelines use a few conventions:

- First, a topic often warrants additional discussion that is not exactly germane to the narrative. We have placed such discussions in text boxes throughout the document. Some of these topics (e.g., the text box discussing "The Composition of CO_2,") are included where it first makes sense to have the discussion even though they are referred to in later sections of the Guidelines.
- Second, because a number of different industries and regulatory agencies are involved in activities that are directly related to CCS, it is no surprise that a number of different terms can apply to the same concept or item. We have attempted to define and consistently use key terms—for example, using "storage" to describe the concept of injecting CO_2 for long-term isolation or sequestration, and the term "storage project footprint" to describe the area above the plume of injected CO_2

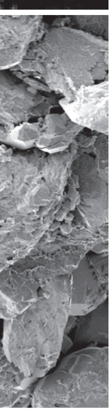


and the area of significantly elevated pressure. These terms are defined in the text when they are first used and are also defined in the Glossary at the end of the report.

- Third, there is significant overlap and iteration among and between the capture, transport, and storage phases of a project as we have defined them. We have done our best to reduce repetition and redundancy by referring the reader to various sections in the report as necessary. So, for example, in discussing the nature of what is being injected in the storage section, the reader will be referred to the discussion of captured gases in the Capture section and pipeline requirements in the Transport section.
- The Guidelines are summarized at the front of this document and are included at the end of each subsection of the text. We urge the reader to fully consider the text used to explain and provide background on the Guidelines.

Based on this process and the robust set of Guidelines presented herein, we believe there is sufficient evidence that CCS projects can be carried out safely and effectively to warrant quickly moving to full-scale demonstrations. It is important for interested parties to make the effort to understand the basic concepts involved in CCS, so that they can feel confident about the likely safety of initial projects and be informed participants in efforts to develop comprehensive policy frameworks. CCS holds promise as an important tool in addressing climate change, but that promise can only be realized if projects are effectively deployed.





Recommended Best Practices for Community Engagement in CCS Projects

The figure below provides an example of emerging best practices for meaningful community engagement. Community engagement has been recognized as an important part of industrial and municipal projects in the context of sustainable development. Integrating community engagement in future CCS projects will be an essential component. Future work to identify CCS-specific community engagement guidelines may be warranted; these Guidelines focus on the technical aspects of CCS demonstration and deployment.

What Is CO_2?

Carbon dioxide is a colorless, odorless gas made of two oxygen atoms covalently bonded to a carbon atom. It is the product of respiration and is ubiquitous in the atmosphere. However, at high concentrations it can cause asphyxiation, and because it is denser than air it can pool in low-lying areas with poor air ventilation.

Current atmospheric CO_2 concentrations are 385 parts per million, which is an increase of over 100 ppm since the beginning of the Industrial revolution. CO_2 absorbs infrared radiation in the atmosphere and consequently heats the atmosphere, contributing to global warming.

CO_2 Handling

Although CO_2 is an asphyxiant at high concentrations and can harm human health and the environment, it is benign at lower concentration and is regularly handled as part of many different industrial activities. As such, there are standards already established for CO_2 exposure and handling. Occupational hazards can be can be minimized when workers adhere to safety standards and use appropriate protective equipment. Following are some examples of already established U.S. standards:

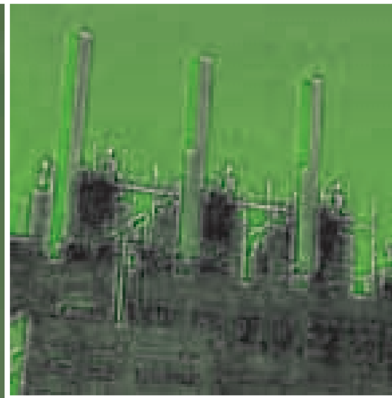
- Occupational Safety and Health Administration (OSHA) General Industry Permissible Exposure Limit (PEL): 5,000 parts per million (ppm), 9,000 milligrams per cubic meter (mg/m^3) time-weighted average (TWA).
- OSHA Construction Industry PEL: 5,000 ppm, 9,000 mg/m^3 TWA.
- American Conference of Governmental Industrial Hygienists Threshold Limit Values: 5,000 ppm, 9,000 mg/m^3 TWA; 30,000 ppm, 54,000 mg/m^3 short-term exposure limit.
- National Institute for Occupational Safety and Health Recommended Exposure Limits: 5,000 ppm TWA; 30,000 ppm short-term exposure limit.

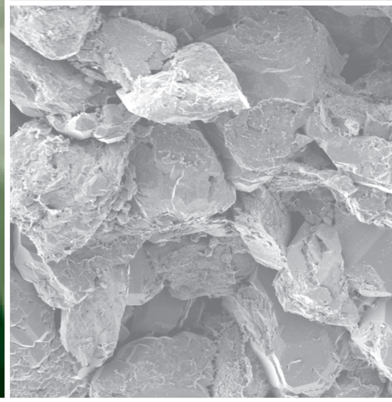
Principles for Meaningful Community Engagement	Concept	Design	Construction	Operation	Decommissioning
(1) Identify stakeholders early.	X				
(2) Define the intended outcomes of community engagement.	X				
(3) Determine whether to inform, consult, or negotiate.	X				
(4) Engage communities throughout the project cycle.	X	X	X	X	X
(5) Allow communities to raise grievances.		X	X	X	X
(6) Promote internal and external monitoring.		X	X	X	X

SOURCE: HERBERTSON 2008

CAPTURE

PART 2





2.1 INTRODUCTION

CO_2 capture refers to the separation of CO_2 from the other components in the flue gas or process stream of a power plant or an industrial facility. CO_2 capture technologies have been applied at small scales to point sources of CO_2, with the CO_2 being used for various purposes, including the production of streams of CO_2 for use to increase oil production via enhanced oil recovery (EOR) and for sale as a food-grade product for carbonating beverages. However, the technology is not deployed at the scale necessary to significantly reduce CO_2 emissions. Deployment at that scale will require research to

reduce the cost and improve the performance of capture technologies and a policy driver to reduce CO_2 emissions. The capture Guidelines are organized into two sections: the current state of CO_2 capture technologies, and the potential non-CO_2 environmental impacts of the technologies. The capture Guidelines consider the potential application of existing regulatory structures to capture facilities and suggest best practices.

Developing appropriate regulatory structures and industrial best practices for capture is important given the potential scale of deployment. According to DOE's Energy Information Administration (EIA), coal-fired power plants emitted over 1.9 billion metric tons of CO_2 in the United States in 2006 (U.S. DOE/EIA 2007). The current commercialized technology for CO_2 capture involves the use of monoethanolamine (MEA) to separate the CO_2 from the flue gas stream. Not counting the significant initial start-up quantity of MEA, coal-fired facilities would have to replace the MEA at a rate of about 1.5 kilograms per metric ton of captured CO_2 (Rao and Rubin 2006). If 90 percent of the CO_2 emitted in 2006 were captured, the entire existing U.S. coal fleet would require about 2.5 million metric tons of amines annually. In 2005, the annual worldwide demand for MEA was about 1.3 million metric tons (Dow 2007). Deploying capture technologies will not be simple, even with a commercially mature approach like MEA.

While the addition of CO_2 capture and compression processes to an existing or new power plant will require owners and operators to learn new processes and adopt additional safety protocols, these methods, guidelines, and regulations are in use in other industries. As stated by the Intergovernmental Panel on Climate Change (IPCC) in its review of CO_2 capture, "The monitoring, risk and legal aspects associated with CO_2 capture systems appear to present no new challenges, as they are all elements of long-standing health, safety and environmental control practice in industry (IPCC 2005).

2.2 TECHNOLOGY OVERVIEW

To provide a point of reference for the discussions that follow, this section offers a brief overview of the three primary approaches to CO_2 capture (pre-combustion, post-combustion, and oxy-fuel combustion) and discusses topics that could be important for technology selection.

The data in this section are estimations based on published reports about state-of-the-art technology. Improvements in existing technologies and advanced technologies for capturing CO_2 will almost certainly develop over time as more facilities are built with capture devices in place (Rubin et al. 2006). Several advanced technologies based on the use of membranes, sorbents, new solvents, and other capture mechanisms are being developed.

While there have been a limited number of demonstrations of capture on power plants (and none on a large scale), power plants represent, in aggregate, the largest potential reduction of CO_2 to which CCS can be applied. The IPCC estimated that there were almost 5,000 large power plants worldwide in 2002, with combined annual emissions of over 10 billion metric tons of CO_2. The next largest source of industrial emissions in 2002, cement production, had 1,000 sources and combined annual emissions of over 900 million metric tons of CO_2 (IPCC 2005). Given both the complexity and the potential scale of deployment for CO_2 capture from power plants, this section focuses on guidance for CO_2 capture from power plants, although the guidance can be applied across industry sectors.

Figure 1 shows the location of potential CO_2 sources in parts of North America. Electric generation (shown in blue) is the most prevalent potential source, particularly in the eastern half of the United States.

An emerging question for capture technologies is the appropriate level of capture. In the demonstration phase, there is some technical uncertainty about what level of capture can be achieved. DOE has established a goal for CO_2 capture of 90% at an increase in cost of energy services of less than 20% for post-combustion (such as MEA) and oxy-fuel combustion, and less than 10% for pre-combustion capture. The timeline for DOE's capture research is to demonstrate a series of cost-effective CO_2 capture technologies at pilot scale by 2012[1] (Figueroa et al. 2008; U.S. DOE/NETL 2007c). It is imperative that full-scale demonstration plants move forward to provide plant operators and regulators with a sense of capture performance on commercial-scale facilities. That knowledge will give operators additional confidence developing strategies to reduce CO_2 emissions. To this effect, Congress is considering some

Developing appropriate regulatory structures and industrial best practices for capture is important given the potential scale of deployment.

Figure 1: North American CO_2 Sources

SOURCE: "CARBON SEQUESTRATION ATLAS OF THE UNITED STATES AND CANADA," DOE/OFFICE OF FOSSIL ENERGY/NETL, NOVEMBER 2008

bills that would kick-start large-scale deployment of the technology, such as the Carbon Capture and Storage Early Deployment Act (U.S. Congress 2008).

Because separation and compression of CO_2 require a significant amount of additional energy, a facility with capture has to be larger than a facility without capture to achieve the same energy output. For example, capture of 90 percent of the CO_2 from a supercritical pulverized coal (SCPC) plant using current technologies would result in increased fuel consumption of 24-40 percent compared to similar plants without CO_2 capture and compression (IPCC 2005). As a result of this "energy penalty," the percentage of CO_2 that is captured is not equal to the percentage of CO_2 that is avoided through capture. Under this scenario, an SCPC plant that emitted 1 million tons of CO_2 per year prior to capture would generate 1.24–1.4 million tons of CO_2 after the addition of capture equipment in order to generate the same amount of electricity. Assuming 90 percent of the CO_2 captured, 1.12–1.26 million tons would be captured, an amount that exceeded the original amount of CO_2 emissions from the uncontrolled plant. Under this scenario 124,000–140,000 tons of CO_2 would still be emitted from the plant.

The implication of the energy penalty from an emissions accounting perspective is that the captured emissions are not equal to the avoided CO_2 emissions. Rather, the avoided emissions are equal to the emissions from a similarly sized facility without capture less the emissions to the atmosphere after capture. In the case described above, the avoided emissions would be equal to 1 million tons of original emissions minus 124,000–140,000 tons that are still emitted after capture, for a total of 860,000–876,000 tons of CO_2 avoided.

Recognizing the impact of the energy penalty on emissions, the *IPCC 2006 Guidelines for National Greenhouse Gas Inventories* include recommendations for calculating emissions from a facility with capture (Eggleston et al. 2006). It suggests using projected emissions without capture (based on fuel consumption) less the amount captured for transport (assuming the CO_2 is metered during preparation for transport).

2.2.1 Capture from Power Plants

Three main approaches are used to capture CO_2 from power plants:

- Post-combustion capture,
- Pre-combustion capture, and
- Oxy-fuel combustion.

Post-combustion capture refers to the separation of CO_2 from the flue gas of a combustion process. Fuel sources can be any hydrocarbon, such as coal, natural gas, or oil. For coal plants, post-combustion capture is typically associated with subcritical pulverized coal (PC), SCPC, ultra-supercritical pulverized coal (USCPC), and circulating fluidized bed (CFB) plants. Pre-combustion capture involves the generation of syngas (carbon monoxide plus hydrogen ($CO+H_2$)), followed by the shift reactions to convert the CO to CO_2. CO_2 is then separated from hydrogen, and the hydrogen can be burned in a turbine or used as fuel in a heater. Pre-combustion capture is often associated with integrated gasification combined cycle (IGCC) technology; however, post-combustion capture technologies can also

Table 1: Planned CO_2 Capture and Storage Projects

Project Name	Location	Feedstock	Size (MW, except as noted)	Capture Process	Start-up Date
Total Lacq	France	Oil	35	Oxy-fuel	2008
Vattenfall Oxyfuel	Germany	Coal	30/300/1000*	Oxy-fuel	2008–15
AEP Alstom Mountaineer	USA	Coal	30	Post-combustion	2008
Callide-A Oxy Fuel	Australia	Coal	30	Oxy-fuel	2009
GreenGen	China	Coal	250/800**	Pre-combustion	2009
Williston	USA	Coal	450	Post-combustion	2009–15
Kimberlina	USA	Coal	50	Oxy-fuel	2010
NZEC	China	Coal	Undecided	Undecided	2010
AEP Alstom Northeastern	USA	Coal	200	Post-combustion	2011
Sargas Husnes	Norway	Coal	400	Post-combustion	2011
Scottish & Southern Energy Ferrybridge	UK	Coal	500	Post-combustion	2011–12
Naturkraft Kårstø	Norway	Gas	420	Post-combustion	2011–12
Fort Nelson	Canada	Gas	Gas Process	Pre-combustion	2011
ZeroGen	Australia	Coal	100	Pre-combustion	2012
WA Parish	USA	Coal	125	Post-combustion	2012
UAE Project	UAE	Gas	420	Pre-combustion	2012
Appalachian Power	USA	Coal	629	Pre-combustion	2012
Wallula Energy Resource Center	USA	Coal	600–700	Pre-combustion	2013
RWE npower Tilbury	UK	Coal	1600	Post-combustion	2013
Tenaska	USA	Coal	600	Post-combustion	2014
UK CCS Project	UK	Coal	300–400	Post-combustion	2014
Statoil Mongstad	Norway	Gas	630 CHP	Post-combustion	2014
RWE Zero CO_2	Germany	Coal	450	Pre-combustion	2015
Monash Energy	Australia	Coal	60,000 bpd	Pre-combustion	2016
Powerfuel Hatfield	UK	Coal	900	Pre-combustion	Undecided
ZENG Worsham-Steed	USA	Gas	70	Oxy-fuel	Undecided
Polygen Project	Canada	Coal/ Petcoke	300	Pre-combustion	Undecided
ZENG Risavika	Norway	Gas	50–70	Oxy-fuel	Undecided
E.ON Karlshamn	Sweden	Oil	5	Post-combustion	Undecided

SOURCE: MIT 2008

* 30/300/1000 = Pilot (start time 2008)/Demo/Commercial (anticipated start time 2010–2015)

** 250/800 = Demo/Commercial

bpd = barrels per day

CHP = combined heat and power

Petcoke = petroleum coke

Advanced Pulverized Coal Combustion

The discussion of capture approaches mentions three types of pulverized coal plants: subcritical pulverized coal, supercritical pulverized coal (SCPC), and ultra-supercritical pulverized coal (USCPC). While the vast majority of existing coal-fired power plants in the United States are subcritical power plants, the current state-of-the-art technology for new U.S. pulverized coal-fired power plants is SCPC, with developers considering USCPC. Power providers in Europe, Japan, and China have constructed and are successfully operating USCPC power plants.

All three technologies employ similar processes, injecting finely ground coal through burners into a furnace for combustion, but they operate at different temperatures and pressures. As the names imply, subcritical plants operate at the lowest temperatures and pressures of the three, and USCPC units operate at the highest temperatures and pressures. USCPC units are constructed with advanced materials that are able to handle the advanced temperatures and pressures. While specific parameters vary from facility to facility, a new subcritical unit might operate at 16.5 megapascals (MPa) (~2,400 pounds per square inch (psi)) and 565°C/565°C (1,050°F/1,050°F). The current U.S. Department of Energy research and development targets for USCPC units are 34.5 MPa (~5,000 psi) and 732°C/760°C (1,350°F/1,400°F).

By designing a power plant to operate at higher temperatures and pressures, plant owners are able to increase the generating efficiency. A newly constructed pulverized coal unit without CO_2 capture may have a generating efficiency (high heating value (HHV)) of 37 percent, while new SCPC and USCPC may have HHVs of 39 percent and 43 percent, respectively. At higher efficiencies, less coal is needed to generate the same amount of electricity output, resulting in lower air emissions per unit of power output and reducing the amount of CO_2 that needs to be captured. The addition of CO_2 capture technologies to any combustion technology will result in an energy penalty that decreases the generating efficiency, as discussed elsewhere in this section.

SOURCES: MIT 2007; U.S. DOE/NETL 2007

be applied to IGCC. Most studies suggest it is more cost-effective to use pre-combustion technologies with IGCC because the CO_2 can be captured at higher pressures compared to post combustion (IPCC 2005). These are described in detail below.

Oxy-fuel combustion involves the combustion of fuel in an oxygen-rich environment to dramatically increase the CO_2 concentration of the resulting flue gases. The increased CO_2 concentration (typically >80%) of the flue gas stream facilitates CO_2 separation. Oxyfiring produces lower emissions of nitrogen oxides (NO_x) compared to air-blown combustion. After combustion, the flue gas can be captured and compressed, although some cleaning to remove contaminants may be necessary before compression.

While all of the approaches appear promising for capture from power plants, none has been demonstrated on a commercial scale (IPCC 2005). Table 1 shows some of the planned CO_2 capture projects as of July 2008 (all of the projects are expected to include a storage component).

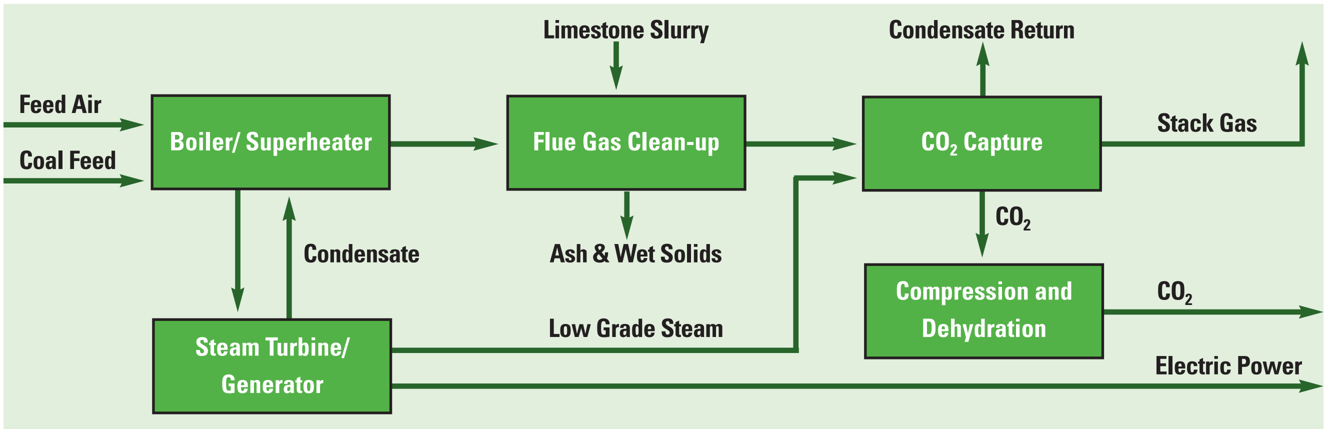
2.2.1.1 Post-Combustion Capture

Post-combustion capture requires the addition of a capture system (to separate the CO_2 from the other flue gas components and concentrate the CO_2) and a compression system (to compress the CO_2 and prepare it for transport). Leading post-combustion capture technologies also require significant cleaning of the flue gas before the capture device. In particular, sulfur levels have to be low (less than 10 parts per million (ppm) and possibly lower) to reduce corrosion and fouling of the system. Figure 2 shows a sample block diagram for post-combustion capture from a power plant.

As shown in Figure 2, after leaving the boiler, flue gas is cleaned with a scrubber that removes sulfur dioxide (SO_2) and a device that removes particulate matter (PM). The diagram shows the use of limestone slurry for this purpose, suggesting use of wet flue gas desulphurization (FGD). While wet FGD would not be a required component, it might be needed to reduce the sulfur content to the required level. Also, note that the flue gas cleanup area would include a device for PM collection. The flue gas then enters an absorption column (represented by the CO_2 capture box) that contains the amine solution. As the flue gas contacts the amine in the absorption column, the CO_2 is absorbed into the amine solution. The flue gas then exits the stack, and the amine solution is sent to a stripping column, where the CO_2 is removed from the amine solution through an increase in the solution temperature. The amine is recycled and sent to the absorption tower, while the CO_2 is cooled, dried, and compressed to a supercritical fluid (MIT 2007).

Besides the use of an amine solution (chemical absorption into solution), the options for post-combustion capture include physical adsorption with a solvent (ionic liquids) or a sorbent (metal organic frameworks), membrane separation from the gas (membrane/amine hybrids or enzymatic CO_2 processes), and cryogenic separation by distillation or freezing (U.S. DOE/NETL 2007c). Chemical absorption into a solution is currently the preferred approach for separating CO_2 from flue gases at low concentrations, such as those associated with power plants. There is considerable experience using amines, such as MEA, for the separation of CO_2 during natural gas processing and in the development of food-grade CO_2. While expensive, it is currently considered a commercial post-combustion capture process (MIT 2007).

Figure 2: Post-Combustion Capture from a Pulverized Coal-Fired Power Plant



ADAPTED FROM MIT 2007

Recently, companies have announced projects using other solvents, such as advanced amines or aqueous ammonia. Ammonia-based capture devices have received particular attention from industry as potentially more cost-effective than amine scrubbing. Pilot plant projects with both ammonia and chilled ammonia processes are scheduled for 2008. Capture technology companies have announced agreements to test the solvents on larger-scale units, if those projects are successful. Other post-combustion approaches, such as physical absorption into ionic liquids, membrane separation, enzymatic processes, and cryogenic separation, are also under development.

2.2.1.2 Pre-Combustion Capture

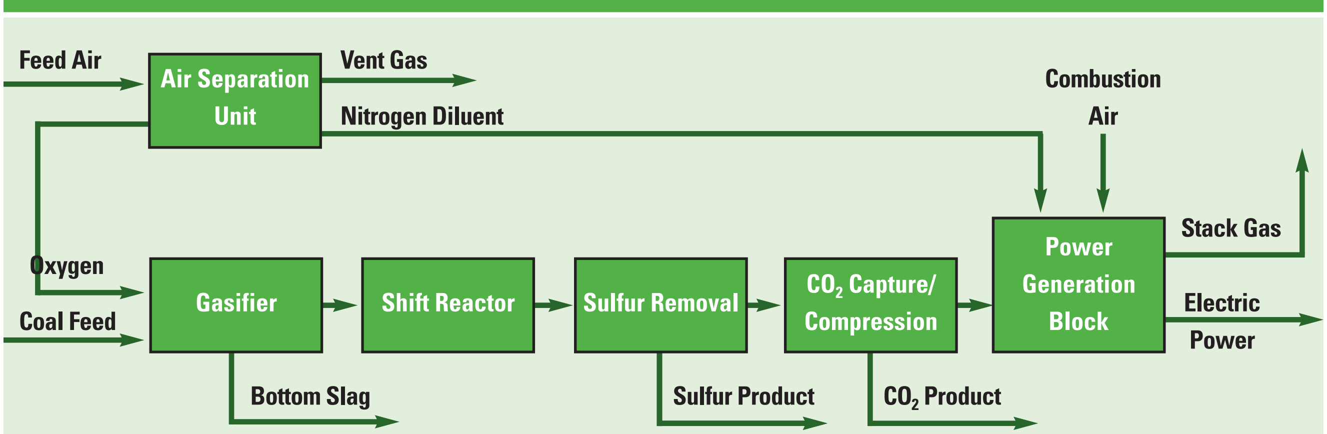
Pre-combustion capture involves the removal of CO_2 after the coal is gasified into syngas, but before combustion in an IGCC unit. As shown in Figure 3, the first step involves gasifying the coal. Then, a water-gas shift reactor is used to convert carbon monoxide in the syngas and steam to CO_2 and hydrogen. This increases the concentration of CO_2, improving CO_2 capture efficiency and increasing the amount of carbon (in the form of CO_2) that can be removed using this process. The CO_2 is removed using either a chemical or a physical solvent, such as Selexol™, and is compressed. The hydrogen is combusted in a turbine to generate electricity (MIT 2007).

While both IGCC and pre-combustion CO_2 capture technologies are considered available, only four gigawatts of IGCC power plants have been built worldwide as of the end of 2007 (IPCC 2005). None of the existing IGCC plants have the technologies needed to capture the CO_2. When CO_2 is separated from the syngas (as in pre-combustion capture), a turbine that can function in a hydrogen-rich environment is needed. Hydrogen-fired turbines are being developed for this purpose, and have been demonstrated but are not at the same state of technological readiness as syngas-fired turbines.

2.2.1.3 Oxy-Fuel Combustion

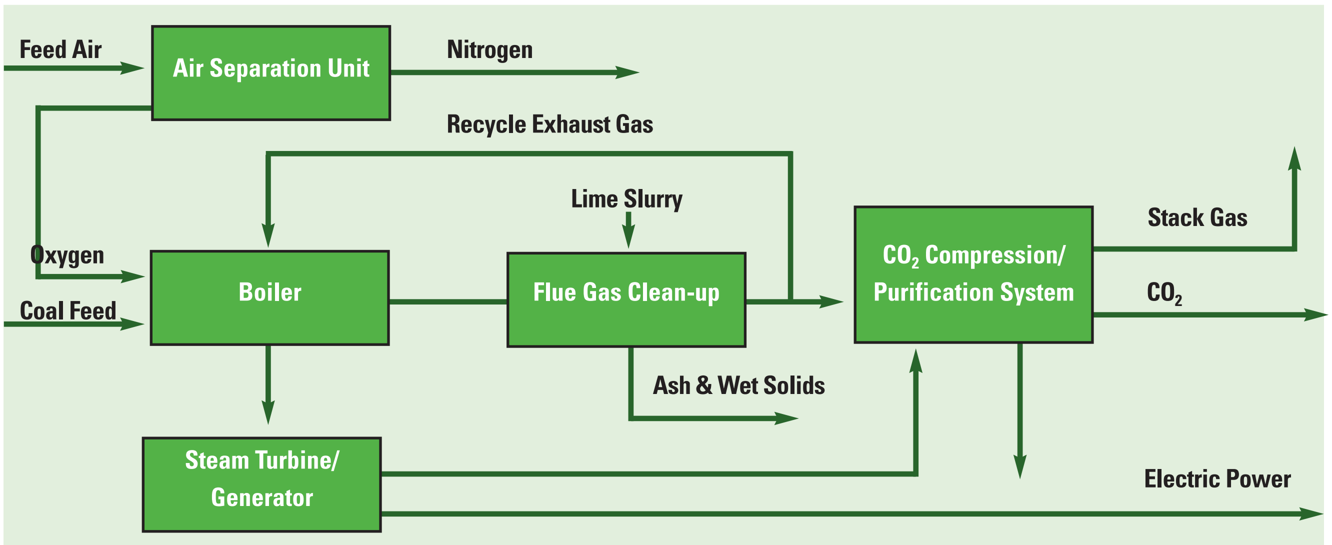
Oxy-fuel combustion involves the combustion of fossil fuels in an oxygen-rich environment (nearly pure oxygen mixed with recycled exhaust gas), instead of air. Combustion under these conditions reduces the formation of nitrogen oxides, so that the gas leaving the combustion zone is primarily CO_2 and is easier to separate and

Figure 3: Pre-Combustion Capture on an IGCC Power Plant



ADAPTED FROM MIT 2007

Figure 4: Oxy-Fuel Combustion With Capture



ADAPTED FROM MIT 2007

remove. As shown in Figure 4, an air separation unit supplies oxygen to the boiler where it mixes with the recycled exhaust gas. After combustion, the gas stream can be cleaned of PM, nitrogen oxides, and sulfur. After condensing out the water, the flue gas has a CO_2 concentration that is high enough to allow direct compression. However, the compressed flue gas may have to be further cleaned of co-constituents to reach the same purity as the compressed CO_2 resulting from post-combustion capture. As of 2008, oxy-fuel power plants are in the early stages of development with pilot-scale construction currently underway in Europe and in North America as documented in Table 1 (MIT 2007).

Figure 5 summarizes some of the critical challenges for capture identified by the DOE. The boxes under “Research Pathways” list the sorbents, solvents, membranes, and other process technologies that could be used to separate CO_2. As shown in the key, DOE considers those marked with a “C” to be commercially available, those marked with a “P” to be pilot scale, and those marked with an “L” to be laboratory scale or conceptual.

2.2.2. Capture from Industrial Sources

Although the worldwide potential for CO_2 capture from power plants is large, there may be early opportunities to demonstrate the technology in the industrial sector based on commercial experience and potential economic advantages, such as revenue from EOR. (Policies that incentivize capture from power plants could shift the economic considerations.) Capture from industrial process streams has existed for over 80 years (IPCC 2007). Most facilities currently vent the CO_2 to the atmosphere, although some compress it and sell it as food-grade or industrial CO_2.

Using CO_2 Capture Technology to Produce Food-Grade CO_2

Operators of at least three U.S. coal-fired power plants capture CO_2 from flue gas for sale as food-grade CO_2. Two of those facilities are cogeneration plants operated by AES: AES Warrior Run in Cumberland, Maryland, and AES Shady Point in Panama, Oklahoma.

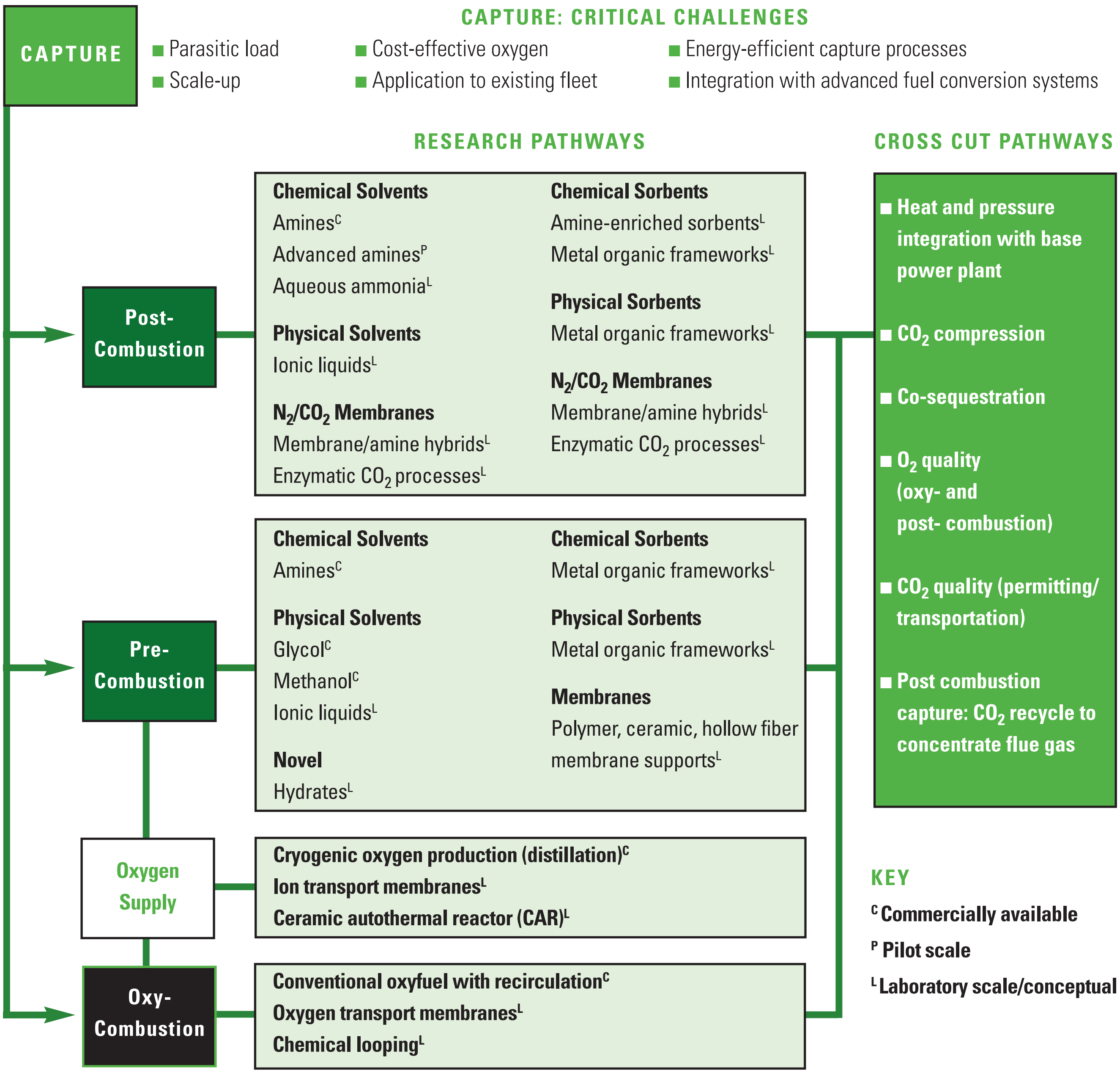
AES WARRIOR RUN (HOLT 2008)

AES Warrior Run is a 180-megawatt (MW) coal-fired facility that started commercial operation in February 2000, and AES Shady Point is a 320-MW coal-fired facility that started operation in January 1991. Both facilities use a circulating fluidized bed boiler to generate electricity and a post-combustion capture device to capture CO_2 from a slip stream of the flue gas. At AES Warrior Run, facility operators capture about 10 percent of the CO_2 generated at the facility, compared to about 5 percent at AES Shady Point. After capture, the CO_2 at both facilities is purified for sale as a food-grade product.

To capture the CO_2, operators strip CO_2 from a portion of the plant’s flue gas using an ABB Lummus scrubber system with monoethanolamine (MEA) as its solvent.

SOURCES: IEA GHG R&D 2008B; HOLT 2008; KIGER 2008

Figure 5: Critical Challenges Associated With CO_2 Capture Technologies



"CARBON SEQUESTRATION TECHNOLOGY ROADMAP AND PROGRAM PLAN 2007," DOE/OFFICE OF FOSSIL ENERGY/NETL, APRIL 2007

Existing large-scale demonstrations of CO_2 storage to date involve industrial capture of CO_2 from natural gas processing (Sleipner, In Salah, and Snohvit) or coal gasification (Weyburn).[2]

The Sleipner Project, the longest-running large-scale CCS project in the world, began capturing CO_2 from natural gas processing off the coast of Norway in 1996. During natural gas processing, CO_2 naturally present in a natural gas stream is stripped from produced natural gas in order to increase the purity for delivery into the market. In many other plants, this stripped CO_2 is vented to the atmosphere. At Sleipner, the CO_2 is captured using a conventional amine capture process, and is then stored in a saline reservoir under the North Sea.

Other industrial processes that are potential candidates for CO_2 capture are steel, cement, ammonia, and ethanol production. Capture from steel or cement production would be similar to post-combustion capture or oxy-fuel combustion with capture (IPCC 2005). Ammonia plants are a potentially attractive source because they generate a relatively pure stream of CO_2 as a byproduct. Ethanol production results in a relatively pure CO_2 stream (more than 85 percent), and it can be captured, cleaned, and stored or used for EOR

Table 2: Existing and Proposed CO_2 Storage Demonstration Projects

Project	Project Leader	Location	CO_2 Source	Size (million metric tons per year)	Start Year
Sleipner	StatoilHydro	Norway	Gas Processing	1	1996
Weyburn	Pan Canadian	Canada	Coal Gasification	1	2000
In Salah	BP	Algeria	Gas Processing	1.2	2004
K12-B	Gaz de France	Netherlands	Gas Processing	0.2	2004
Zama	Apache	Canada	Gas Processing	0.067	2006
Snohvit	StatoilHydro	Norway	Liquefied Natural Gas Processing	0.7	2008
Ketzin	CO_2Sink	Germany	Hydrogen Production	0.03	2008
Decatur	MGSC	Illinois, U.S.	Ethanol Production	0.3	2009
Gorgon	Chevron Texaco	Australia	Gas Processing	3.3	2009
Cranfield	SECARB	Mississippi, U.S.	Gas Processing	1	2008-9
Entrada	SWP	Colorado/Wyoming, U.S.	Gas Processing	1.1	2008-12
TAME	MRCSP	Ohio, U.S.	Ethanol Production	0.28	2011
Lindach	Rohoel	Austria	Industrial	0.3	TBD
Casablanca	Repsol	Spain	Refinery	0.5	TBD

SOURCE: MIT 2008

CO_2 Avoided =

CO_2 emitted without capture – CO_2 emitted with capture

(Abadi et al. 2005). Ethanol production is the source of CO_2 for a large-scale storage project announced for Illinois, which is scheduled to begin in 2009 and conclude in 2012 (ADM 2008). Capture from industrial sources can yield experience that can be directly applied to capture and storage from power plants.

2.2.3 Capture Economics

The process of removing CO_2 from flue gas or a process stream is heavily dependent on the system pressure and CO_2 concentration. At high pressures and concentrations, CO_2 is easier to remove and compress. In some cases, such as in the fermentation of ethanol, the process gas can be compressed and transported with limited need for additional treatment. In other cases, such as in pulverized coal combustion for electricity, the CO_2 has to be chemically separated from scrubbed flue gas before it can be compressed for transport.

Table 3 highlights some processes that could be targeted for CO_2 capture and provides cost estimates from a range of sources. The cost estimates are shown in dollars per metric ton of CO_2 avoided. As discussed, avoided CO_2 is calculated as the emissions from a similarly sized facility without capture less the emissions to the atmosphere after capture. The cost estimates in Table 3 include the costs of capture, compression, transport, storage, and, in most cases, monitoring. As detailed in the notes below Table 3, capture and compression dominate the cost of CCS, with estimates for transport, storage, and monitoring ranging from $5 to $10 per metric ton of CO_2. All of the estimates in Table 3 are relative to the same facility without capture.

The costs of capture from different processes often reflect the CO_2 concentrations in the flue gas or process stream. Lower cost options for CO_2 capture are often associated with processes that produce more concentrated CO_2 streams (e.g., industrial plants where operators only need to compress a process stream to prepare it for transport) (Dooley et al. 2006).

The ranges of costs in Table 3 suggest the uncertainty associated with the cost of capture. While continued research and development is expected to reduce the cost (McKinsey 2008), capture represents the largest cost associated with CCS and is a significant barrier to widespread adoption of the technology. Note that all cost estimates are highly variable based on site-specific conditions and the availability of raw materials. As described in the accompanying text box, capital costs associated with construction have increased dramatically in all industrial sectors in recent years.

2.2.4 Managing Carbon Dioxide and Co-Constituents

As discussed in more detail in the transport section, to fulfill the contractual requirements of transport and potential regulatory requirements of subsequent storage, facility operators will likely have to dry the CO_2, remove co-constituents, and compress it into a supercritical phase before it leaves the facility. Facility operators who install CO_2 capture equipment will have to follow rules and adopt practices associated with managing CO_2 on site during the capture and compression stages. Facility operators must be aware of the health, safety, and environmental risks associated with concentrated CO_2, and must be mindful of potential worker exposure to co-constituents in the CO_2 stream. Given the extensive industrial experience handling CO_2 for EOR and for sale as a food-grade product, no new regulatory structures need to be adopted. Rather, operators at facilities where CO_2 has historically not been handled will have to follow existing regulations.

When CO_2 is captured from power plants, it contains water. When combined with water, CO_2 forms carbonic acid that has the potential to corrode pipelines (it is possible, but significantly more expensive, to construct pipelines that are resistant to this corrosion). The captured CO_2 can also contain hydrogen sulfide (H_2S) (pre-combustion) and the other co-constituents shown in Table 4.

Table 3: Capture Technologies and Costs

Plant Type	Capture Process	Avoided Costs ($ per metric ton of CO_2 avoided)			
		IPCC ($2002)[a]	MIT ($2005)[c]	DOE/NETL ($2006)[d]	EPRI ($2007)[e]
Supercritical Pulverized Coal-Fired Power Plant	Post-combustion capture with amines (MEA)	$30–$71	$40.4 + $5 for transport and storage	$75	$57–$63
IGCC Power Plant	Pre-combustion capture	$14–$53	$19.3 + $5 for transport and storage	$43	$39–$56[f]
Refinery Flue Gas	Chemical absorption/ flue gas recycling	~$35[b]	NA	NA	NA
Ethanol	No capture; dehydration and compression only	~$34[b]	NA	NA	NA

SOURCES: IPCC 2005; MIT 2007; DOE/NETL 2007F; BOORAS 2007

NOTES:

a. IPCC avoided cost estimates include transport costs of $0–$5 per metric ton of CO_2 and geological storage costs of $0.6–$8.3 per metric ton of CO_2. The costs reported by the IPCC are based on a range of studies reviewed in preparation of IPCC 2005.

b. IPCC avoided cost estimates for capturing CO_2 from refinery flue gas and ethanol do not include the costs of transport and storage.

c. Researchers at MIT estimated that transportation and storage would add $5 per metric ton of CO_2 avoided. They did not include monitoring in their cost estimate. They reviewed their estimate for a supercritical pulverized coal-fired power plant with post-combustion capture in September 2008 and adjusted their estimate to $52 per metric ton of CO_2 (in 2005 dollars). They reported that they did not have enough information to revise the estimates for IGCC with pre-combustion capture. MIT's estimates assume the use of a mature technology, after the deployment of several plants with the technology.

d. Values originally reported in short tons, converted to metric tons. DOE/NETL included transportation, storage, and monitoring costs in its estimates for both captured and avoided costs. The costs were reflected in the 20-year levelized cost of electricity used to calculate the costs per metric ton. The assumptions included the cost of transporting CO_2 50 miles for storage in a geologic formation with over 30 years of monitoring. DOE/NETL estimated these costs to add about 4 mills per kilowatt-hour, representing about 10% of the total carbon capture and sequestration costs.

e. The EPRI CCS and IGCC estimates include a 10% contingency for first-of-a-kind technologies. The cost of electricity used to calculate the avoided CO_2 cost includes $10 per metric ton for transportation and storage.

f. EPRI IGCC estimate is for an average IGCC facility, and the range includes results for both Illinois #6 bituminous and Powder River Basin coal. EPRI found that the GE Total Quench technology using Illinois #6 bituminous would fall below the range shown here ($30–$34 per metric ton of CO_2 avoided).

Avoided = based on avoided CO_2 emissions, costs are relative to the same technology without capture; DOE/NETL = U.S. Department of Energy/National Energy Technology Laboratory; EPRI - Electric Power Research Institute; IGCC = integrated gasification combined cycle; IPCC = Intergovernmental Panel on Climate Change; MEA = monoethanolamine; NA = not available.

Table 4: Concentrations of Co-Constituents in Dried CO_2, Percent by Volume

	SO_2	NO	H_2S	H_2	CO	CH_4	$N_2/Ar/O_2$	Total
Coal-Fired Plants								
Post-combustion capture	<0.01	<0.01	-	-	-	-	0.01	0.01
Pre-combustion capture (IGCC)	-	-	0.01–0.6	0.8–2.0	0.03–0.4	0.01	0.03–0.6	2.1–2.7
Oxy-fuel	0.5	0.01	-	-	-	-	3.7	4.2
Gas-Fired Plants								
Post-combustion capture	<0.01	<0.01	-	-	-	-	0.01	0.01
Pre-combustion capture (IGCC)	-	-	<0.01	1.0	0.04	2.0	1.3	4.4
Oxy-fuel	<0.01	<0.01	-	-	-	-	4.1	4.1

SOURCE: IPCC 2005.

a. The SO_2 concentration for oxy-fuel and the maximum H_2S concentration for pre-combustion capture are for cases where these co-constituents are deliberately left in the CO_2, to reduce the costs of capture. The concentrations shown in the table are based on use of coal with a sulfur content of 0.86%. They would be directly proportional to the fuel sulfur content.

b. The oxy-fuel case includes cryogenic purification of the CO_2 to separate some of the N_2, Ar, O_2 and NO_x. Removal of this unit would increase impurity concentrations but reduce costs.

c. For all technologies, the impurity concentrations shown in the table could be reduced at higher capture costs.

Ar = argon; CO = carbon monoxide; H_2S = hydrogen sulfide; IGCC = integrated gasification combined cycle; N_2 = nitrogen; NO = nitric oxide; O_2 = oxygen; SO_2 = sulfur dioxide.

SOURCE: IPCC 2005

The potential for co-constituents in the CO_2 stream raises questions about downstream impacts and the necessary composition and dryness of CO_2 before it is transported and stored. As discussed in the transport section, pipeline operators transporting CO_2 for EOR contractually require facility operators to provide a CO_2 stream of a certain composition. This is done for a variety of reasons, including health and safety, corrosion prevention, and EOR operator requirements. This issue is discussed in more detail in the transport section. The potential issues or impacts associated with underground injection of co-constituents are not clearly defined due to lack of

Hydrogen Sulfide

The presence of co-constituents may create additional health and safety concerns and place additional regulatory requirements on a facility. Of particular concern is the handling of hydrogen sulfide (H_2S). Exposure to low concentrations of H_2S (<50 parts per million (ppm)) can cause eye, nose, or throat irritation. At levels above 500 ppm, H_2S can lead to a loss of consciousness or even death. The Occupational Safety and Health Administration has guidelines for handling H_2S in an industrial setting.

Escalating Costs

A number of factors have contributed to a recent escalation of costs, not just for carbon dioxide capture and storage, but for all large-scale projects in the electric sector. These factors include an increased demand for resources (raw materials, engineering expertise, and labor) as well as larger economic pressures, such as the declining value of the dollar relative to other currencies, the tightening of capital markets, and increasing oil prices.

The increased demand for resources comes from a number of areas. Foremost is economic growth in developing countries, particularly China, and the corresponding increased demand for metals, steel, and cement. Additionally, there has been a pull on resources to rebuild oil and gas platforms and refineries in the aftermath of recent hurricanes; to install air pollution control devices on power plants in response to federal air regulations; and to develop the tar sands in Canada.

As an example of the impact of these economic pressures, a number of recent projects have announced cost increases:

- Estimates of a new coal-fired power plant in Kansas proposed by Westar increased by 20–40 percent over 18 months.
- Estimates of a 1,600-megawatt (MW) coal fired power plant in Nevada proposed by LS Power Development and Dynegy more than tripled over two years.
- Estimates of an 800-MW supercritical pulverized coal power plant at Taylor Energy Center in Florida rose by $400 million (20 percent) over 17 months, resulting in the cancellation of the project.
- Estimates for a 630-MW integrated gasification combined-cycle plant in Indiana proposed by Duke Energy rose from $1.985 billion to $2.35 billion due to the increased cost of resources and demand for labor.

Two frequently cited cost indices are the IHS/Cambridge Energy Research Associates (CERA) Power Capital Costs Index (PCCI) and the IHS/CERA Downstream Construction Cost Index (DCCI). The PCCI suggests that the cost of new power plant construction in North America has increased by 130 percent since 2000, with a 69 percent increase since 2005. Focusing on coal, the PCCI suggests coal power plant capital costs increased by 2.3 percent between the third quarter of 2007 and the first quarter of 2008, and 78 percent since 2000. The DCCI recorded annual increases of 16 percent in 2006 and 14 percent in 2007. In the first quarter of 2008, the DCCI was 6 percent higher than it was in the third quarter of 2007.

SOURCES: FERNANDO ET AL. 2008; IHS/CERA 2008; MIT 2007

Retrofit of CO_2 Capture on an Existing Plant

The costs in Table 3 and the discussion of capture technologies for power plants focus on capturing CO_2 from new coal-fired power plants. Given the size of the existing coal-fired fleet and associated CO_2 emissions (1.9 billion metric tons of CO_2 in the United States in 2006 according to the Energy Information Administration), the application of capture technologies to existing coal-fired power plants is a potentially important source of CO_2 reductions. As with new pulverized coal-fired power plants, post-combustion capture technologies are the most mature (although lacking commercial-scale demonstration), while oxy-fuel technologies appear to be promising (although they are in a much earlier stage of development). Given the limited number of integrated gasification combined-cycle plants, it is unlikely that pre-combustion retrofit will be deployed on a significant scale, except in cases where proposed units are built with the intention of installing the technology in the future.

Recent analyses by the Electric Power Research Institute and the U.S. Department of Energy suggest that retrofit of capture will cost more for any of the approaches than new construction with capture. As a reference point, installing sulfur dioxide scrubbers on existing units was, on average, 1.2–1.8 times as expensive as installing them on new units. The recent analyses also suggest that the energy penalty associated with application of the approaches to existing units will be greater than it would be on a new unit.

In addition to costs, retrofitting post-combustion capture on an existing pulverized coal power plant will require operators to consider available space near a facility; a 500-MW power plant will require about six acres of space close to the plant to install post-combustion capture technologies. Upgrades to existing air quality equipment may also be required in some cases because CO_2 sorbents require significant sulfur removal from the flue gas.

Installing oxy-fuel technology on an existing coal-fired power plant will also require space considerations for the addition of an air separation unit and any additional flue gas cleaning equipment. Owners installing oxy-fuel equipment will also have to ensure that there is no leakage of air into the unit.

SOURCES: U.S. DOE/EIA 2007; DALTON 2008; CIFERNO 2007, 2008.

CAPTURE GUIDELINE 1: RECOMMENDED GUIDELINES FOR CO_2 CAPTURE

a. Demonstrations of all capture approaches (pre-combustion, post-combustion, and oxy-fuel combustion) are urgently needed on commercial-scale power plants to prove the technologies.

b. There should be recognition of the potential challenges in achieving the theoretical maximum capture potential before the technologies are proven at scale. This may necessitate flexibility in establishing appropriate capture rates for early commercial-scale projects with the amount of CO_2 captured at a facility dependent on both technology performance and the specific goals of the project.

c. Standards for the levels of co-constituents have been proposed by some regulators and legislators; however, there is potential risk that this could create disincentives for reducing sources of anthropogenic CO_2 if the standard is set too stringently. Ultimately, the emphasis should be on employing materials, procedures, and processes that are fit-for-purpose and assessing the environmental impacts of any co-constituents, along with the benefits of CO_2 emissions reduction as part of a comprehensive CCS risk assessment. Facility operators, regulators, and other stakeholders should pay particular attention to potential downstream impacts of co-constituents in the transport and storage aspects of the project.

Capture from industrial process streams has existed for over 80 years.

actual demonstration. Given the uncertainty, it is not technically or economically feasible to prescribe any standards or give guidelines for CO_2 composition.

There are potential financial advantages to leaving some co-constituents in the CO_2 stream. For example, the maximum H_2S concentration for pre-combustion capture in the coal-fired power plant case in Table 4 reflects an operator not doing any further treatment, or intentionally leaving the H_2S in the syngas. Including the H_2S with CO_2 leaving the facility could result in a cost savings because the operator would not need to install sulfur recovery equipment (Claus plant) or find an alternative method for disposing of the elemental sulfur (IPCC 2005). However, in this scenario the costs for pipeline monitoring will increase because of the presence of H_2S in the pipeline.

CO_2 composition requirements could also affect the costs associated with oxy-fuel combustion. The flue gas from oxy-fuel combustion could require significant cleaning before transport if it is expected to meet the same minimum requirements for CO_2 composition as post-combustion capture. Unlike the other capture technologies, almost 100 percent of the CO_2 in the flue gas in oxy-fuel combustion can be dehydrated and compressed (IPCC 2005). (However, CO_2 that is generated by the air-separation unit to produce the oxygen for combustion is not captured.) It is expected that the gas will be compressed and fed to a cryogenic purification process to reduce the concentration of co-constituents. Facilities could clean the gas stream to close to 100 percent CO_2 purity by including distillation in the cryogenic separation unit. This would result in a concentrated stream of co-constituents that would have to be properly handled. As an example of the co-constituents, the data in Table 4 assume that SO_2 is intentionally left in the CO_2 stream for co-storage, and that nitrogen (N_2), argon (Ar), oxygen (O_2) and oxides of nitrogen (NO_x) are partly removed using cryogenic purification. An operator could reduce costs by removing less of the co-constituents if allowed.

2.3 NON-CO_2 ENVIRONMENTAL IMPACTS

CCS technologies have the potential to play a large role in reducing CO_2 emissions. However, it is important to consider the impacts of the technologies on other parts of the environment. This section reviews the impacts on other air emissions (e.g., non-CO_2 air emissions), solid waste generation, and water use associated with current CO_2 capture technologies, and considers the existing regulatory structure for dealing with these issues. The discussion of the Clean Air Act focuses on its use to regulate non-CO_2 emissions and does not consider the potential regulation of CO_2 under the Clean Air Act.

The CO_2 capture process requires significant modifications to coal-fueled power plants, including pulverized coal (PC) combustion or IGCC processes. For PC plants, a post-combustion capture plant must be added. For IGCC, process modifications include the installation of chemical units to absorb the CO_2, shift reactors to react carbon monoxide in the syngas with steam to produce CO_2 and hydrogen, or an air separation unit to provide oxygen for combustion. Environmental impacts occur both upstream and downstream of the unit. Upstream impacts include those associated with resource extraction, while downstream impacts include changes in air emissions and water use and increased handling of solid wastes, including hazardous wastes.

Table 5: Impacts of CCS System and Energy Penalties on Plant Resource Consumption and Emission Rates (Capture Plant Rate and Change from Reference Plant Rate, kg/MWh)

Capture Plant Parameter[a]	PC-CCS[b] (kg/MWh)		IGCC-CCS[c] (kg/MWh)		NGCC-CCS[d] (kg/MWh)	
	Rate	Change from Reference	Rate	Change from Reference	Rate	Change from Reference
Resource Consumption						
Fuel	390	93	364	50	156	23
Limestone	27.5	6.8	–	–	–	–
Ammonia	0.80	0.19	–	–	–	–
CCS reagents	2.76	2.76	0.005	0.005	0.80	0.80
Atmospheric Emissions						
Carbon dioxide	107	–704	97	–720	43	–342
Sulfur oxides	0.001	–0.29	0.011	–0.13	–	–
Nitrogen oxides	0.77	0.18	0.10	0.01	0.11	0.02
Ammonia	0.23	0.22	–	–	0.002	0.002
Solid Wastes/Byproduct						
Ash/slag	28.1	6.7	34.2	4.7	–	–
FGD residues	49.6	12.2	–	–	–	–
Sulfur	NA	NA	7.7	1.2	–	–
Spent CCS sorbent	4.05	4.05	0.005	0.005	0.94	0.94

SOURCE: RUBIN ET AL. 2007, 4444–4454

[a] The net power output of all plants is approximately 500 MW. Coal plants use Pittsburgh #8 coal with 2.1% sulfur, 7.2% ash, 5.1% moisture and 303.2 MJ/kg LHV basis. Natural gas LHV = 59.9 MJ/kg. All plants capture CO_2 emissions and compress to 13.7 MPa (1,990 psi).

[b] Pulverized coal plant based on a supercritical unit with SCR, ESP and FGD systems, followed by an amine system for CO_2 capture. SCR system assumes 2 ppm ammonia slip. SO_2 removal efficiency is 98% for reference plant and 99% for capture plant. Net plant efficiency (LHV basis) is 40.9% without CCS and 31.2% with CCS.

[c] IGCC system based on Texaco quench gasifiers (2 + 1 spare), two GE 7FA gas turbines, 3-pressure reheat HRSG. Sulfur removal efficiency is 98% via hydrolyzer plus Selexol™ system; Sulfur recovery via Klaus plant and Beavon-Stretford taigas unit. Net plant efficiency (LHV basis) is 39.1% without CCS and 33.8% with CCS.

[d] NGCC plant using two GE 7FA gas turbines and 3-pressure reheat HRSG, with an amine system for CO_2 capture. Net plant efficiency (LHV basis) is 55.8% without CCS and 47.6% with CCS.

CCS = carbon dioxide capture and storage; ESP = electrostatic precipitator; FGD - flue gas desulfurization; GE = General Electric; HRSG = heat recovery steam generator; IGCC = integrated gasification combined cycle; kg = kilogram; LHV = lower heating value; MJ = megajoule; MPa = megapascals; MW = megawatt; MWh = megawatt-hour; NA = not available; NGCC = natural gas combined cycle; PC = pulverized coal; ppm = parts per million; psi = pounds per square inch; SCR = selective catalytic reduction.

The main reasons for increased environmental impacts are the significant parasitic energy loss, or energy penalty associated with the capture of the CO_2 and the subsequent regeneration of the solvent or sorbent, and the use and disposal of the solvent or sorbent. The energy penalty means that either a facility would have to be resized to combust additional fossil fuels in order to make up for lost energy output, or additional generation capacity (from a non- or low-CO_2-emitting source) would have to be constructed to make up for any lost output. The *IPCC Special Report: Carbon Dioxide Capture and Storage* estimated that capture of 90 percent of CO_2 using current technologies would result in an increased fuel consumption of 24–40 percent for new SCPC plants, 11–2 percent for natural gas combined-cycle (NGCC) plants, and 14–25 percent for IGCC systems compared to similar plants without CO_2 capture and compression (IPCC 2005).

Table 5 shows the results of an analysis conducted by researchers at Carnegie Mellon University using the Integrated Environmental Control Model. The researchers used the model to compare consumption of resources and generation of solid waste and air emissions for PC, IGCC, and NGCC plants with CO_2 capture and compression equipment to identical facilities without the CO_2 capture and compression equipment. For each technology, the first column (Rate) presents the rate in kilograms (kg) per megawatt-hour (MWh) for the factor being measured at a plant with CCS. The second column (Change from Reference) shows the incremental change of the measured factor from the reference case. All of the increases shown in Table 5 are driven by the increased need for energy, except for the CCS reagents, ammonia (NH_3), and the spent CCS sorbent, which are direct waste products from the capture process.

The data shown in Table 5 compare new facilities with capture to new facilities without capture. Retrofit of capture technologies on existing coal-fired power plants would result in greater efficiency losses and increased resource consumption. The rating of a 500-MW plant can drop by 40 percent to 294 MW with the addition of CO_2 capture devices (MIT 2007). The impact of adding capture to an IGCC or NGCC plant is also not insignificant, resulting in respective increases in fuel consumption of 50 and 23 percent.

2.3.1 Air Emissions

The second set of data in Table 5 (atmospheric emissions) shows the impact of CO_2 capture and compression equipment on air emissions. Power plants with CO_2 capture would emit a CO_2-depleted flue gas to the atmosphere. The concentrations of SO_2 in the flue gas would be lower than in the flue gas of plants without CO_2 capture, since it is removed upstream of capture to enable the CO_2 capture process to operate effectively. Other air pollutant emission rates per MWh would increase relative to reference plants without capture. NO_x emissions increase at all the facilities considered in Table 5 and ammonia emissions would increase at PC and NGCC plants as a result of ammonia slip from the selective catalytic reduction on the PC facility (as described in the footnotes to the table) and ammonia released by amine-based capture systems. These increases in NO_x and ammonia emissions could lead to increased nitrogen levels in water bodies, resulting in eutrophication and compromising water quality (Koornneef et al. 2008).

Information on emissions from oxy-fuel combustion is limited, since there are currently no commercial-scale oxy-fuel-fired power plants, and only limited pilot-scale testing has been performed. The flue gas from oxy-fuel combustion consists mainly of CO_2 and water vapor, along with excess oxygen. After removal of the water vapor, the

It is important to consider the impacts of capture technologies on other parts of the environment.

amount of CO_2 in the gas stream can vary from 80 to 98 percent, depending on the fuel used and the particular oxy-fuel combustion process. Looking back to Table 4 which included the co-constituents left in the CO_2 stream, the researchers assumed SO_2 was deliberately left in the CO_2 stream and cryogenic purification was used to separate out NO_x, N_2, Ar, and O_2. Facilities could make alternative decisions based on economic, system, transportation, or storage constraints. For example, potential corrosion of the furnace and CO_2 transportation systems due to high SO_2 concentrations in the flue gas could result in the need for desulphurization of the recycled flue gas. These decisions will affect the quantity of any air emissions, water releases, or solid wastes.

2.3.1.1 New Source Performance Standard and New Source Review

In the United States, new power plants and major modifications to existing plants are subject to New Source Performance Standards (NSPS) and New Source Review (NSR) requirements under the Clean Air Act. NSPS set air pollutant emission limitations for new and modified sources. Under Section 111 of the Act, the EPA is required to publish and periodically revise a list of industry categories and to establish standards of performance reflecting "the degree of emission reduction achievable through application of the best system of emission reduction" (Clean Air Act of 1990). The standards must take into consideration cost, non-air impacts, and energy requirements. The purpose of the NSPS program is to prevent deterioration of air quality from the construction of new and modified sources, and to reduce emission control costs by building air pollution controls into the initial design of new builds and major modifications to existing plants.

The NSR program is a preconstruction permitting program governing new sources of emissions and major modifications to existing sources. New and modified sources subject to NSR located in areas that are in "attainment" of standards for regulated air pollutants (such as SO_2, nitrogen oxides (NO_x), ozone, and PM) must install best available control technology (BACT), while new and modified sources located in "nonattainment" areas must install lowest achievable emission reduction (LAER) air pollution control technology. Case-by-case determinations of BACT and LAER emission limitations must be at least as stringent as the NSPS for any source category for which an NSPS has been set, and often are set more stringently than NSPS. This is particularly true for LAER determinations. BACT is an emission limit based on the "maximum degree of reduction of each pollutant subject to regulation … which is achievable" (CFRb), taking into account energy, environmental, and economic costs. LAER is that rate of emissions which reflects:

"(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is most stringent" (CFRa).

As a result, new U.S. power plants that are proposed with CO_2 capture systems will also have to be equipped with state-of-the-art emission controls representing NSPS and either BACT or LAER technology.

The situation with respect to retrofitting existing power plants is more complicated. Modifications of existing major sources are only subject to NSPS and NSR if (1) the modification is a non-routine physical change or change in operation, and (2) the modification will result in a new air pollutant being emitted or an increase in air pollutant(s) previously emitted.

With regard to the first criterion, the retrofit of CO_2 capture technology to an existing PC plant, whether it be post-combustion capture technology or oxy-fuel technology, would be considered a non-routine physical change under EPA's NSPS and NSR regulations. The question is whether the installation of CO_2 capture technology will result in a new air pollutant being emitted from the facility or an increase in emissions of an air pollutant previously

Table 6: Estimated Raw Water Usage With and Without CO_2 Capture

Unit Type	Without CO_2 Capture (gallons per minute)	With CO_2 Capture (gallons per minute)
Subcritical Pulverized Coal	6,212	14,098
Supercritical PC	5,441	12,159
IGCC (GEE Gasifier)	4,003	4,579
IGCC (CoP Gasifier)	3,757	4,135
IGCC (Shell Gasifier)	3,792	4,563
NGCC	2,511	4,681

SOURCE: U.S. DOE 2007A

CoP = ConocoPhillips; GEE = General Electric Energy; IGCC = integrated gasification combined cycle; NGCC = natural gas combined cycle.

emitted, thereby triggering the second criterion. Under the NSPS program, emission increases are determined by comparing maximum hourly emissions (expressed in pounds per hour (lbs/hr)) prior to the proposed change with projected maximum hourly emissions after the change. Under the current NSR regulations, emission increases are determined by comparing actual annual emissions (in tons) prior to the change with projected annual emissions (in tons) after the proposed change. If a post-combustion CO_2 capture system were added to an existing PC plant and the plant were not resized, it is likely that emissions would not increase on a per-ton basis (although emissions would increase per net MWh). However, if the plant were resized to overcome the capture plant's parasitic power load (energy penalty) and maintain a power output consistent with its original production, emissions of NO_x and mercury are likely to increase. In either case, it is also possible, that new air pollutants, such as ammonia, could be emitted from solvent-based capture processes.

Similarly, it is possible that emission increases would result if an existing PC plant were converted to an oxy-fuel-fired facility, thereby subjecting the facility to NSPS and/or NSR requirements.

2.3.2 Water Use

Power plants, with or without CO_2 capture, use large amounts of water. Table 6 lists estimates for raw water use at facilities with and without CO_2 capture on facilities with a 550-MW net output. DOE calculates the raw water usage as the difference between the total demand for water by processes and the internal recycled water available within processes (boiler feedwater blowdown, condensate, etc.). Therefore, the measurement represents the actual consumption of water. The majority of the water (71–99 percent) is consumed through the cooling process (assumed to be recirculating wet systems, described in the text box). Note that water use for PC power plants more than doubles with the addition of capture equipment.

The impacts of increased water use associated with CO_2 capture are related to the increased need for system cooling. As an alternative to wet cooling, facilities could use dry cooling technologies. There is a tradeoff between energy use and water use when dry cooling is employed. As a facility reduces water use, it increases energy use, which creates an additional energy penalty

Wet Versus Dry Cooling

Thermal power plants can be cooled by transferring the heat produced by electricity generation either to a body of water (once-through cooling) or to the atmosphere through a recirculating wet cooling system, through a dry cooling system, or through a hybrid system that incorporates elements of both recirculating wet cooling and dry cooling.

In a once-through cooling system, water is withdrawn from the environment, passed through a steam condenser and returned, slightly heated, to the source. No water is consumed or evaporated within the cooling system, but the evaporation rate from the receiving water is slightly higher.

In recirculating wet systems, smaller amounts of water (typically 2–3 percent of the amount withdrawn for once-through cooling) are taken into the plant, but the majority is evaporated in the cooling equipment (in mechanical or natural draft cooling towers), with very little water returned to the receiving water body. Water withdrawn from a local source is circulated continuously through the cooling system. The cooling system must be replenished with "make-up water" to replace that lost to evaporation and blowdown.

In dry systems, the ultimate heat rejection to the environment is achieved with air-cooled equipment that discharges heat directly to the atmosphere by heating the air. Dry systems reduce water use at a plant by eliminating the use of water for steam condensation, but increase energy consumption.

In hybrid wet-dry systems, both wet and dry components are included in the system, and they can be used separately or simultaneously for either water conservation or plume abatement purposes. Design studies have ranged from 30 to 98 percent reduction in water use compared to recirculating wet cooling.

The factors designers should consider when choosing a system include:

- Water availability, use, and consumption;
- System costs; and
- Environmental issues associated with water withdrawal and discharge.

SOURCE: MAULBETSCH 2002.

Water use for PC power plants more than doubles with the addition of capture equipment.

CAPTURE GUIDELINE 2: RECOMMENDED GUIDELINES FOR ANCILLARY ENVIRONMENTAL IMPACTS FROM CO_2 CAPTURE

a. When constructing a new facility or retrofitting an existing facility in the United States, operators must comply with requirements under the Clean Air Act and the Clean Water Act, as appropriate.

b. Options for minimizing local and regional environmental impacts associated with air emissions, use of water, and solid waste generation should be evaluated when considering technologies for capture.

c. Use of capture technologies could result in hazardous or industrial waste streams. Operators must follow guidelines and regulations for the handling and disposal of industrial or hazardous wastes.

d. Operators should investigate the use of combustion wastes as beneficial byproducts.

e. Currently, EPA is considering regulation of coal combustion wastes that are sent to landfills or surface impoundments, or used as fill in surface or underground mines. Potential impacts of the volume and concentrations of hazardous materials in the waste stream from facilities with CO_2 capture should be evaluated in this context.

(Maulbetsch 2002). The tradeoffs between dry cooling and wet cooling will be essentially the same as they are for a plant without CO_2 capture, and will be driven by local conditions and water availability. This tradeoff would most likely be balanced based on the location of the plant and its potential water demand compared to available water resources.

Water availability is becoming a concern in many U.S. regions, and it is likely that permitting any facility that uses a large amount of water will become increasingly difficult. This challenge is compounded in the climate change context, because the baseline water temperature may be higher, in addition to decreased water availability.

Retrofit of CO_2 capture equipment onto an existing plant will require amendments to a facility's Phase I National Pollutant Discharge Elimination System (NPDES) permit. The delivery, storage, and handling of combustion products and solvents or sorbents will require incorporating the processes into an existing facility's Storm Water Management and Spill Prevention Control and Countermeasures plans (U.S. DOE/NETL 2007b).

2.3.3 Solid Waste

With the increased fuel consumption, there will be a proportional increase in solid wastes, such as bottom ash, boiler slag, and fly ash, as represented by the ash/slag row in Table 5. There will also be an increase in the consumption of ammonia and limestone to reduce NO_x and SO_2 emissions, as well as wastes associated with the use of amines or other sorbents (IPCC 2005). None of the wastes generated from capture processes are expected to be unknown or substantially more hazardous than the wastes generated by conventional plants (U.S. DOE/NETL 2007b). It is expected that existing rules governing solid and hazardous wastes will cover the additional wastes associated with capture. If necessary, facilities can process chemicals from post- or pre-combustion solvents to remove metals and dispose of the spent solvents through incineration (IPCC 2005).

While the solid wastes from coal combustion contain toxics (including arsenic, mercury, chromium, lead, selenium, cadmium, and boron), the U.S. Congress categorized fossil fuel combustion wastes as "special wastes" in amendments to the Resource Conservation and Recovery Act (RCRA), and exempted them from federal hazardous waste regulations (Subtitle C of RCRA) until EPA could complete additional studies. In a series of determinations beginning in the late 1980s, EPA found that most of the exemptions should remain. However, in 2000 EPA determined that coal combustion wastes that are disposed of in landfills and surface impoundments and used as fill in surface or underground mines should be regulated as nonhazardous solid wastes under Subtitle D of RCRA (U.S. EPA 2000). It further concluded that no additional regulations are warranted for fossil fuel combustion wastes that are beneficially used (for roadways, cement and concrete products, etc.). To date, EPA has not proposed regulations under RCRA Subtitle D. However, some individual states have promulgated their own rules for handling solid wastes from coal-fired facilities.

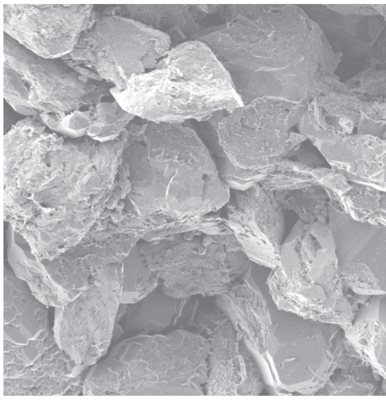
CAPTURE ENDNOTES

[1] Increase in cost includes sequestration activities

[2] coal gasification differs from IGCC in that the final product of coal gasification is a syngas that can be used in place of natural gas while an IGCC facility gasifies the coal and combusts the product to generate electricity

TRANSPORT

PART 3



3.1 INTRODUCTION

Transporting CO_2 from point-of-capture to storage sites is an important linking step in the CCS project cycle. Although CO_2 is transported via pipelines, ships, and tanker trucks for EOR and other industrial operations, pipeline transport is considered to be the most cost-effective and reliable method of transporting CO_2 for onshore CCS (Svensson 2004). The transport Guidelines are organized into four sections: design and operations, safety and integrity, siting and pipeline access, and tariff regulations.

Current pipeline operational practices are described to provide context. The Guidelines are intendedto help regulators, policy-makers, and industry prepare for the potential development of a large-scale CO_2 pipeline infrastructure.

3.1.1 Developing CO_2 Pipeline Infrastructure for CCS

Deploying CCS at a scale required to mitigate global warming will require transporting substantial quantities of CO_2 from capture to storage sites.

The nature and extent of the network of CO_2 pipelines that would be necessary to transport such amounts of CO_2 will depend on many factors, including the proximity of storage sites to the capture facilities, the costs to acquire pipeline rights of way and associated permits, the cost to construct the pipelines, and the attendant costs to operate the pipelines and comply with operations and maintenance regulations.

The CO_2 pipeline networks developed for the CCS market will evolve over time. Early projects are likely to rely on a mix of options, including use (or expansion) of the existing CO_2 pipeline infrastructure and the development of dedicated pipelines that are sized and located for individual projects to accommodate the CO_2 specifications of those projects. Under other scenarios, a fully integrated network that utilizes CO_2 from several sources may be practical. In light of the overall costs associated with CO_2 pipelines, including the uncertainty about future material costs and cost recovery, some analysts anticipate that the CO_2 network for CCS will begin with short pipelines from CO_2 sources located close to storage sites, with a larger regional network of interconnected lines developing as the number of projects grows (MIT 2007). Another study estimates that storage reservoirs may be sufficiently distributed, such that 77 percent of the total annual CO_2 emissions from the major North American sources may be stored in reservoirs directly underlying these sources, and an additional 18 percent may be stored within 100 miles of the original sources (Dahowski et al. 2006). As geologic formations are characterized in more detail and suitable repositories are identified, CO_2 sources can be mapped against storage sites with increasing certainty.

3.1.2 CO_2 Pipeline Operating Experience

In the United States, significant CO_2 pipeline operating experience exists in the EOR industry. Since the early 1970s, pipeline companies have been successfully operating a substantial CO_2 pipeline infrastructure (Figure 6), transporting an estimated 0.78 trillion cubic feet of CO_2 per year through an estimated 3,900 miles[1] of infrastructure, through pipelines of varying diameters, mainly for use in EOR.[2] The Permian Basin region of West Texas and New Mexico remains the center of CO_2-based EOR activity. The oldest long-distance CO_2 pipeline in the United States is the 140-mile Canyon Reef Carriers pipeline, which began service in 1972 for EOR in regional Texas oil fields. The longest CO_2 pipeline, the 502-mile Cortez pipeline, has been delivering about 20 million metric tons of CO_2 per year to the CO_2 hub in Denver City, Texas, since 1984.

CO_2 Composition

CO_2 used for carbon dioxide capture and storage is typically in the supercritical stage, where the density resembles a liquid but it expands to fill space like a gas. Supercritical CO_2 is purchased, as a commodity, for use in many industrial processes. In the climate change context CO_2 is most often classified as an important greenhouse gas, an emission, or—in some countries—a waste. There is concern that the classification of CO_2 under various U.S. regulatory programs (e.g., air, waste, drinking water protection) may trigger unintended requirements that impose increased cost without increasing project performance or safety.

In response to this concern, the Interstate Oil and Gas Compact Commission recommends that CO_2 not be classified as a waste and, in fact, suggests that states adopt legislation recognizing CO_2 of certain purity as a commodity. At least one state (Oklahoma) has followed this lead. International frameworks have taken varied approaches. For example, Australia regulations use "greenhouse gas substances" and the London Protocol specifies "carbon dioxide streams from carbon dioxide capture processes for sequestration." Some stakeholders have advocated for setting a CO_2 purity standard of >90 percent, but many feel that there is enough uncertainty regarding the precise composition of the CO_2 stream that it is best to simply design projects with materials and procedures that account for any co-constituents in the gas stream.

Deploying CCS at a scale required to mitigate global warming will require transporting substantial quantities of CO_2 from capture to storage sites.

3.2 PIPELINE DESIGN AND OPERATIONS

3.2.1 Pipeline CO_2 Composition

Prior to transport, captured CO_2 is conditioned to remove impurities and compressed into supercritical form. The U.S. Department of Transportation's (DOT's) Office of Pipeline Safety (OPS) defines pipeline CO_2 as a fluid consisting of more than 90 percent CO_2 molecules compressed to a supercritical state. There are currently no composition requirements (e.g., moisture or co-constituents) for the transport and geologic storage of CO_2 (MIT 2007). While there is no established standard for permitted levels of impurities in CO_2 for CCS, the pipeline-quality CO_2 compositions adhered to by the major EOR pipeline operators constitute best practice. Currently, these requirements are built into contracts between the supplier and the transporter and between the transporter and the end user.

Captured CO_2 may contain impurities like water vapor, H_2S, N_2, methane (CH_4), O_2, mercury, and hydrocarbons that may require specific handling or treatment. Before transport, the CO_2 is dehydrated to levels below 50 ppm of water. Presence of water above this level is not desirable from an operational standpoint (Aspelund and Jordal 2007). CO_2 reacts with water to form carbonic acid, which is corrosive. Additionally, under the appropriate thermodynamic conditions, hydrates (solid ice-like crystals) can form and plug the pipeline (Barrie et al. 2004). H_2S is toxic, even at low concentrations of 200 ppm. Pipelines containing H_2S will require extra due diligence, particularly near populations. However, it is important to note that it is possible to safely store H_2S with CO_2; facilities in Canada have been disposing of H_2S through injection in geologic formations since 1989 (Heinrich et al. 2004).[3] Injection of acid gas[4] currently occurs at 39 active operations in Alberta and northeastern British Columbia. Since surface desulfurization through the Claus process is generally uneconomical, and the surface storage of the produced sulfur constitutes a liability, more operators are turning to acid gas disposal by injection into deep geologic formations. Dehydration is particularly important in these cases, because H_2S reacts with water to form sulfuric acid, which is highly corrosive and may also result in pipeline cracking, increasing the potential for leaks. The presence of CH_4 affects the exhibited vapor pressure of CO_2 and complicates the accurate prediction of flow (Svensson 2004). In EOR applications, in particular where organic materials are present for bacteria, oxygen is tolerable only in minute quantities (10 ppm). Even in deep saline formations organics may be present, and significant quantities of oxygen in the gas stream could allow for formation of bacterial colonies, affecting the injection operations. Additionally and significantly, mercury is present in coal and is a natural byproduct of the combustion process; it could condense in the pipeline system and create operational issues as well as implications for storage.

While not strictly a transport issue, the impact of injection of co-constituents with CO_2 is unknown on a large scale and will most likely affect the requirements for CO_2 purity. For the sole purpose of storage, the threshold for impurities could be different; hence, the processing requirements and pipeline standards could be uniquely prescribed for a particular project (described as Type I in the textbox). On the other hand, interest in developing a network of interconnectable pipelines, for maximum utilization of geologic storage sites with or without oil recovery opportunities, may indicate the need for of a set of CO_2 specifications for pipelines similar to the ones in use today for EOR.

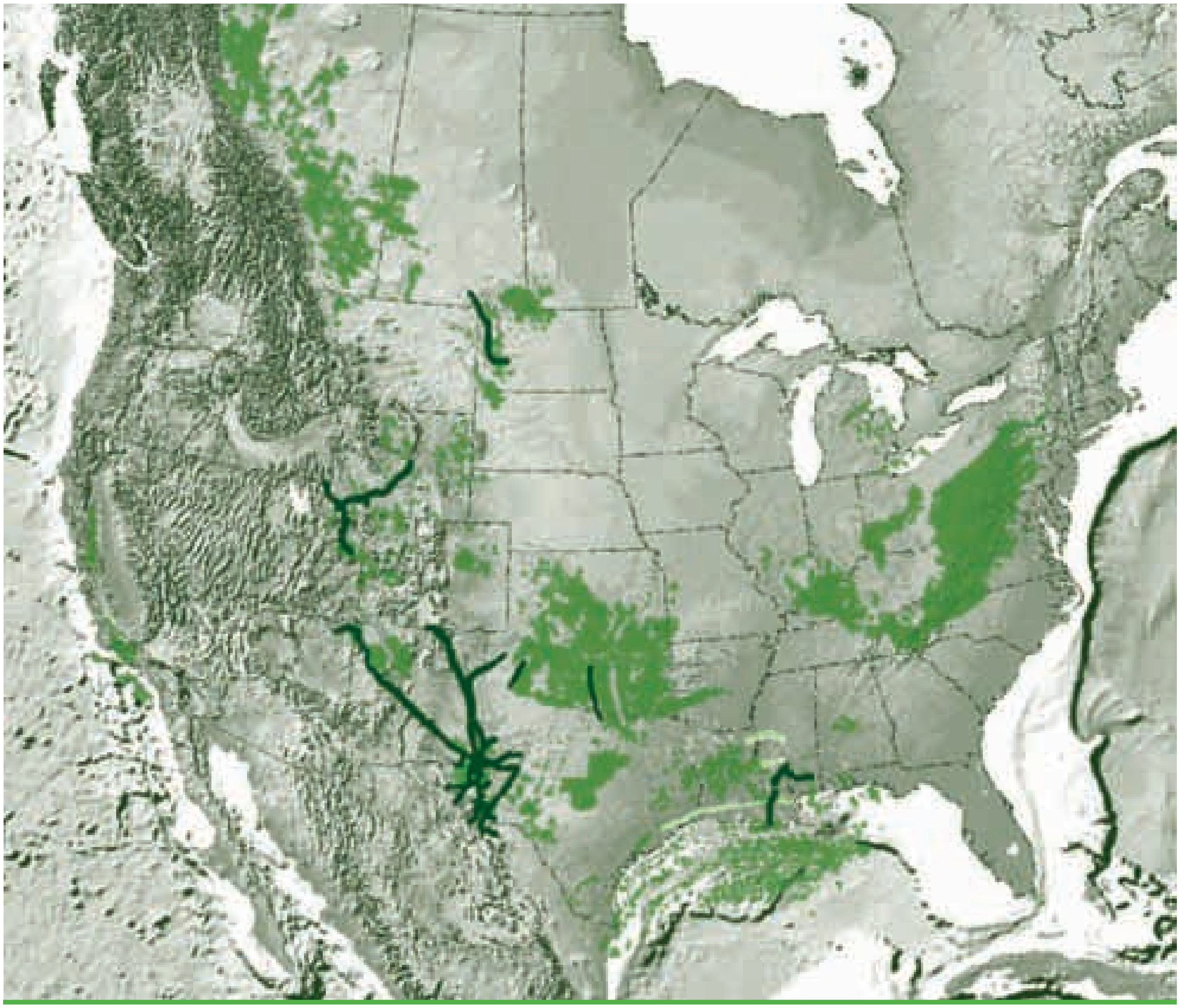
Means of Transporting CO_2

Pipelines are the dominant mode of transporting CO_2. In the United States there is an estimated 3,900 miles of CO_2 pipelines transporting CO_2 for enhanced oil recovery operations. Tanker and ship CO_2 transportation is mainly found in the food and beverage industries. About 100,000 tons of CO_2 are transported annually for these industries—far less than the amounts expected to be associated with a commercial-scale power plant, or even ethanol, cement, or natural gas refining output. The advantage of pipeline transportation of CO_2 is that it can deliver a constant and steady supply of CO_2 without the need for intermediate storage along a distribution route. Ship transportation of large quantities of CO_2 may be feasible when it needs to be transported over long distances or overseas; however, many anthropogenic CO_2 sources are located far from navigable waterways, so such a scheme will still most likely require pipeline construction between CO_2 sources and port terminals.

CO_2 Pipeline Regulations

Existing CO_2 pipelines are subject to diverse local, state, and federal regulatory oversight. The U.S. Department of Transportation's Office of Pipeline Safety (OPS) sets minimum safety standards for pipelines transporting hazardous liquids, including CO_2 (CFR 49 Part 195). OPS regulates interstate pipelines and certifies states to carry out intrastate pipeline regulation and enforcement activities. In contrast to natural gas pipelines, which are subject to siting and rate regulation under the Natural Gas Act of 1938 (as amended) by the Federal Energy Regulatory Commission, there is no federal general certification of pipeline construction or rate regulation and no federal protection from the entry of competing CO_2 pipelines. Under the Mineral Leasing Act, however, CO_2 pipelines may be subject to access and rate conditions imposed by the Bureau of Land Management when they cross federal lands, and are in any event subject to rate and some siting regulation by individual states.

Figure 6: Existing CO_2 Pipelines in the U.S.



ADAPTED FROM NATCARB DATABASE, COURTESY OF STEVE MELZER

3.2.2 Pipeline Operating Temperature and Pressure

The most efficient way to transport CO_2 is in a supercritical phase.[4] The critical point at which CO_2 exists in a supercritical phase is 1,070 psi (73 atmospheres (atm)) and 88°F (31°C) (Figure 6). CO_2 is generally transported at temperature and pressure ranges between 55°F and 110°F and 1,250 psi (85 atm) and 2,200 psi (149.6 atm), respectively (Mohitpour et al. 2007; Kinder Morgan 2006). The upper pressure limit is mostly due to economic concerns, and is set to the ASME-ANSI 900# flange rating (the maximum pressures for ANSI 900# flange is material dependent).[5] The lower pressure limit is set by the phase behavior of CO_2, and should be sufficient to maintain supercritical condition. The upper temperature limit is determined by the compressor-station discharge temperature and the temperature limits of the external pipeline coating material. The lower temperature limit is set by winter ground temperature (Farris 1983).

It is important for operators to maintain single-phase flow in CO_2 pipelines by avoiding abrupt pressure drops. In a two-phase flow, two physical phases are present in the pipeline simultaneously (e.g., liquid and gas, or supercritical fluid and gas), which creates problems for compressors and other transport equipment, increasing the chances of pipeline failure (IPCC 2005). At pressures very close to the critical point, a small change in temperature or pressure yields a very large change in the density of CO_2, which could result in a change of phase and fluid velocity, resulting in slug flow.[6] Transmission pipelines may experience changing temperatures because of both weather and pipeline conditions. Operators should include a wide margin of safety above the rated critical pressure of CO_2 to avoid complications.

EOR Industry CO_2 Purity Specifications

For enhanced oil recovery, the CO_2 concentration in the gas transportable via pipeline typically ranges from 95 to 99 percent. At pressure in a reservoir, CO_2 can combine with components in the oil to create miscibility, wherein the fluid combination moves through the reservoir with a viscosity like that of a liquid rather than a gas. For this to happen in the reservoir, the CO_2 should be quite pure. Depending on the depth of the reservoir and properties of the oil, this may be 90 percent purity or higher. Other constituents can also be important. Nitrogen and methane raise the pressure at which the dense phase is reached, as well as the minimum miscibility pressure.

A subtle feature of using highly purified CO_2 (>95%) that is not readily apparent at first glance is its ability, when compressed and cooled, to form a supercritical fluid. Should significant amounts of noncondensable gases such as oxygen, nitrogen, or methane be present in the CO_2 stream, it may not be possible to practically produce a supercritical fluid. Thus, for any proposed gas composition, the pipeline designer should conduct appropriate compositional simulations to guarantee that supercritical phase behavior can be achieved at proposed pipeline operating conditions. Additionally, oxygen may also lead to overheating at the injection point due to reaction with oil and formation of bacterial colonies.

SOURCES: ZHANG ET AL. 2004; ASPELUND AND JORDAL 2007.

3.2.3 Pipeline Design

There are existing design and safety criteria to ensure safe and reliable transport of CO_2. Pipeline designers consider the pressure, temperature, and properties of the fluid; the elevation or slope of the terrain; dynamic effects, such as earthquakes, waves, currents, live and dead loads,[7] and thermal expansion and contraction; and the relative movement of connected components. The compressibility and density of CO_2 undergo significant nonlinear variation in normal pipeline operating conditions (within normal pipeline pressure and temperature ranges). Therefore, the design of CO_2 pipelines requires point-by-point estimation of fluid properties using computational models (MRCSP 2005).

For pipeline construction, selection of pipe diameter, wall thickness, material strength, and toughness depends on the transmissible fluid's temperature, pressure, composition, and flow rate. For example, fluid flow rates are lower in larger-diameter pipes. Lower fluid flow rates result in fewer pressure drops, allowing a pipeline designer to consider reducing the pressure requirements for CO_2 entering the pipeline, or reducing the number of compressors along the pipeline. However, the installation costs of pipelines rise with increases in diameter. A designer will consider the economic tradeoff of increasing pipeline diameter with the cost of CO_2 compression.

Primary Types of CO_2 Pipelines

Existing CO_2 pipelines operate at pressures ranging from 1,250 to 2,200 pounds per square inch (psi.) Since most natural gas pipelines operate at pressures at or below 1,200 psi, CO_2 pipelines are constructed specifically for transporting CO_2 and are normally listed as either Type II or Type III pipelines. Acceptable CO_2 and co-constituent concentrations for both pipeline types are shown in the table below.

The majority of the CO_2 pipelines in North America can be listed as Type II pipelines, which serve multiple sources and user lines and have a strictly limited composition. Less common Type III pipelines have relaxed composition standards when compared to Type II pipelines. The best example of a Type III pipeline is the pipeline that connects the Dakota Gasification plant near Beulah, North Dakota with the Weyburn enhanced oil recovery (EOR) project in southern Saskatchewan. This pipeline carries a CO_2 mix that has a relatively higher hydrogen sulfide (H_2S) concentration. It should be noted that extra operational precautions are required at both the source and the sinks when there are high H_2S concentrations. As a result of the different composition standards, it will not be easy for operators to connect Type III pipelines to Type II pipelines.

Type I pipelines do not exist in today's CO_2 EOR industry, but can be developed for a specific single use (i.e., a single CCS project). These pipelines can be applied to situations wherein case-by-case specifications for CO_2 composition are appropriate based upon the capture system, but they cannot be connected with the existing CO_2 EOR pipeline network of Type II pipelines.

Parameter	Type I	Type II	Type III
CO_2—% by volume	>95%	>95%	>96%
H_2S—ppmbw	<10	<20	<10,000
Sulphur—ppmbw	<35	<30	-
Total hydrocarbons—% by volume	<5	<5	-
CH_4—% by volume	-	-	<0.7
C_2 + hydrocarbons—% by volume	-	-	<23,000
CO—% by volume	-	-	<1,000
N_2—% by volume/weight	<4	<4	<300
O_2—ppm by weight/volume	<10	<10	<50
H_2O—#/mmcf* or ppm by volume**	<25*	<30*	<20**

C_2 = carbon; CH_4 = methane; CO = carbon monoxide; CO_2 = carbon dioxide; H_2O = water; H_2S = hydrogen sulfide; mmcf = millions of cubic feet; N_2 = nitrogen; ppm = parts per million; O_2 = oxygen; ppmbw = ppm by weight

TABLE COURTESY OF STEVE MELZER.

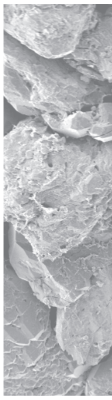
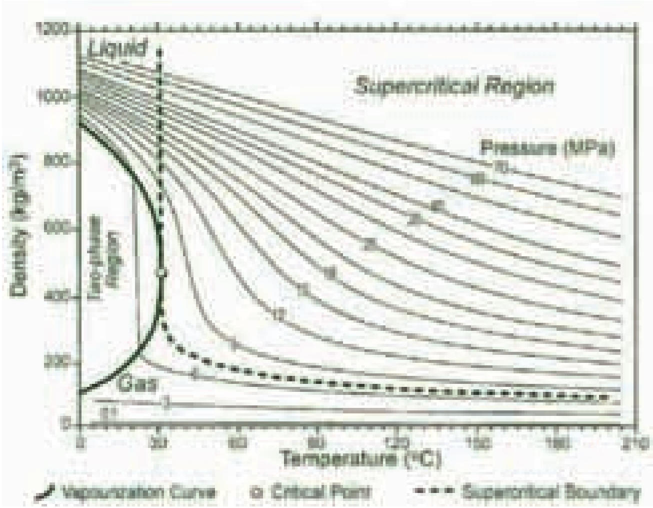


Figure 7: Variation of CO_2 Density as a Function of Temperature and Pressure



SOURCE: BACHU 2003

Compression is the largest operating cost for the transmission system. Compressors convert the transmissible gas from atmospheric pressure to supercritical state, the desired transmissible phase. Moreover, depending on the length and terrain of pipeline, recompression or decompression of CO_2 may be required to maintain supercritical phase CO_2. The CO_2 pipeline industry currently uses centrifugal, single-stage, radial-split pumps for recompression, rather than compressors (Mohitpour et al. 2007). These booster pumping stations are installed as required to maintain sufficient pressure at high elevation points, in order to ensure a single-phase CO_2 flow (Nestleroth 2007). For reference, the compression unit at the Great Plains Synfuel Plant consists of two 8-stage compressors. Feedgas is taken at 3 pound per square inch gauge (psig) and compressed to 2,700 psig, which is in the supercritical range for CO_2 (Perry and Eliasson 2004).

Avoiding initiation and propagation of longitudinal-running fractures is also essential. Fracture arresters are typically installed every 500 meters (545 yards), and lower-strength steel and thicker-wall pipe are employed (IPCC 2005; Mohitpour et al. 2007). The pipelines for CO_2 transportation are usually constructed of steel (60,000–80,000 psi yield strength), such as American Petroleum Institute (API) X60- or X80-grade material. The optimum strength and wall thickness are determined based on the aforementioned factors, as well as fabrication and handling considerations. To reduce the chances of corrosion, CO_2 pipelines typically have an external coating of fusion-bonded epoxy or polyurethane with full cathodic protection; internal pipeline coatings are also available and can be applied where appropriate (MRCSP 2005).

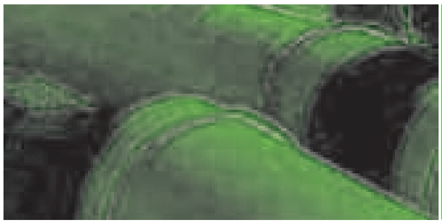
The main components of a pipeline include valves, compressors, booster pumps, pig launchers and receivers, batching stations and instrumentation, metering stations, and Supervisory Control and Data Acquisition (SCADA) systems. Valves are typically used for control functions around compressor and metering stations and at the injection sites. One important consideration in pipeline design is the distance between block valves. Block valves are used to isolate sections of pipe in the event of a leak or for maintenance. Block valves are spaced every 16–32 kilometers (10–20 miles), depending on the location of the pipe, and are installed more frequently near critical locations, such as road and river crossings and urban areas. Installing block valves more frequently increases both the cost of the pipeline and the risk of leakage from the valves themselves. The farther apart the valves are installed, the greater the volume contained between the valves, which increases the distance from the pipeline required for the gas to dissipate to a safe level in the event of a pipeline rupture (Gale and Davidson 2004). Current pipeline design safety standards already take into consideration valve spacing as a function of pipeline diameter and surrounding land use.

Instrumentation along the pipeline is typically used to measure the flow rate, pressure, and temperature of the CO_2 and provides sufficient information for the pipeline's normal operation. The instrumentation is located at compressor and metering stations and sometimes at the block valves. SCADA systems are used for remote monitoring and operation of the compressor stations and the pipeline. These systems are designed to provide operators at a central control center with sufficient data on the status of the pipeline to enable them to control the flows through the compressors and the pipeline as necessary (MRCSP 2005). Metering is used for computational pipeline monitoring (CPM) leak-detection systems for single-phase lines (without gas in the liquid). Currently CO_2 pipelines are not required to have CPM, mainly because it is technically difficult. Other leak-detection methods, such as pressure point analysis and aerial and visual surveys, may be used to ensure safe CO_2 transport.

The majority of onshore CO_2 pipelines are buried over most of their length, to a depth of 1-1.2 meters (3-4 feet), except at metering or pumping stations, and most offshore lines are also usually buried below the shallow water seabed. In deeper water, only pipelines with a diameter of less than 400 millimeters (16 inches) are trenched and sometimes buried to protect them against damage by fishing gear (IPCC 2005). The exact depth varies based on project-specific needs, and variances can be granted where appropriate.

Experience from decades of pipeline operations suggests that designing and operating CO_2 pipelines do not pose any new challenges. The optimum solution is site specific and will depend on different factors, including volumes of gas to be transmitted, gas composition, local population density, topography, and meteorological conditions.

TRANSPORT GUIDELINE 1: RECOMMENDED GUIDELINES FOR PIPELINE DESIGN AND OPERATION



a. CO_2 pipeline design specifications should be fit-for-purpose and consistent with the projected concentrations of co-constituents, particularly water, hydrogen sulfide (H_2S), oxygen, hydrocarbons, and mercury.

b. Existing industry experience and regulations for pipeline design and operation should be applied to future CCS projects.

3.3 PIPELINE SAFETY AND INTEGRITY

3.3.1 Pipeline Safety Regulations

OPS administers a national regulatory program to ensure the safety of pipelines transporting natural gas and other gases, liquefied natural gas, hazardous liquids, and CO_2.[8] CO_2 pipelines are regulated under the same rules as hazardous liquid pipelines[9] codified in 49 CFR 195 (CFRe).

While OPS is primarily responsible for developing, issuing, and enforcing pipeline safety regulations for interstate pipelines, it may authorize a state to act as its agent to inspect interstate pipelines. For hazardous liquid pipelines, currently six states maintain oversight of the interstate pipelines that cross their state (U.S. DOT 2005). Even where the oversight is delegated to a state, OPS retains responsibility for enforcement of the regulations for interstate pipelines.

Pipeline safety statutes do allow for individual states to assume the intrastate regulatory, inspection, and enforcement responsibilities under an annual certification. To qualify for certification, a state must adopt the minimum federal regulations and may adopt additional or more stringent regulations, so long as they are not incompatible. A state must also provide for injunctive and monetary sanctions that are substantially the same as those authorized by the pipeline safety statutes. Currently, 14 states are certified to regulate intrastate CO_2 pipelines.[10] A state that does not satisfy the criteria for certification may enter into an agreement to undertake certain aspects of the pipeline safety program for intrastate facilities on behalf of OPS. While the state agency under such an agreement will inspect pipeline operators to ascertain their compliance with federal safety regulations, any probable violations are reported to OPS for enforcement action. Kentucky and South Carolina operate their intrastate CO_2 pipelines under such an agreement.

For the 34 states that are not certified or that have not entered into an agreement with OPS to regulate CO_2 pipelines at the state level, the safety regulations in 49 CFR 195 apply (CFRe).

3.3.2 Comparative Safety of CO_2 Pipelines

The risks posed by increasing CO_2 pipelines should be manageable based on the extensive CO_2 pipeline operating experience of industry. The DOT data suggest that the impacts from CO_2 pipeline incidents are typically less than those from natural gas and hazardous liquid pipelines. As measured by the lack of fatalities and injuries, and significantly lower property damage, impacts from CO_2 pipeline incidents are typically less than those from natural gas and hazardous liquid pipelines.

The main cause for CO_2 pipeline incidents appears to be material failure (i.e., relief valve failure, valve/gasket/weld or packing failure), followed by corrosion and outside force (Gale and Davidson 2007; Kadnar 2007). While CO_2 is more benign than many other fluids transported through pipelines, it is important to note that the CO_2 pipeline incident statistics are also probably related to the fact that there are many fewer miles of CO_2 pipelines than pipelines transporting other fluids, and they tend to be located in less populated areas.

3.3.3 Environmental Health and Safety

Surface risks of CO_2 leakage from pipelines are covered by state environmental, health, and safety regulations, which are established by OSHA and the U.S. Department of Labor, and adopted and enforced mainly by the states (Chaudhuri 2006). The National Institute for Occupational Safety and Health (NIOSH) also carries out research and publishes its own recommendations for workplace safety. However, only those promulgated by OSHA have the force of law. The permissible exposure and air contamination limit for CO_2 as specified by OSHA is 5,000 ppm (U.S. DOL/OSHA 2007).

Siting a pipeline involves determining the route, assessing the environmental impacts at the proposed route, evaluating route alternatives, and acquiring the rights of way.

The presence of co-constituents, particularly H_2S, can also pose significant safety challenges for pipeline operations. According to NIOSH, the exposure threshold at which CO_2 is immediately dangerous to life or health is 40,000 ppm; for H_2S, it is 100 ppm. The Subcommittee on Consequence Actions and Protective Assessments (SCAPA) provides the recommendations for emergency preparedness to assist in safeguarding the health and safety of workers and the public. The SCAPA has developed Preventive Action Criteria (PAC), which provide chemical exposure limit values for well over 3,000 chemicals to support emergency response planning applications. Key components of the PACs are the Temporary Emergency Exposure Limits (TEELs). TEEL-2 refers to the maximum concentration in air below which it is believed nearly all individuals could be exposed without experiencing or developing irreversible or other serious health effects or symptoms that could impair their abilities to take protective action. For H_2S, the limit for TEEL-2 is 27 ppm. The final risk assessment report for the four candidate FutureGen sites in Illinois and Texas presents a detailed discussion on potential risks associated with CO_2 pipeline operations (U.S. DOE 2007b). Overall, the discussion found the risks to be reasonably manageable. Of the identified risks, exposure to H_2S releases was identified as one of the more prominent concerns about pipeline rupture or puncture for both workers outside of the immediate vicinity of a release and nearby populations.

OPS regulations have been very effective in ensuring the safety of CO_2 pipelines, In the 1990–2002 period there were 10 incidents, caused by relief valve failure (4), weld/gasket/valve packing failure (3), corrosion (2), and outside force (1). The incident rate was 0.00032 km^{-1} yr^{-1} (IPCC 2005). However, the administrative burden of these regulations is considered heavy, and OPS currently exempts from regulation (49 CFR 195) certain low-stress[11] pipelines, such as production, processing, gathering, and distribution pipelines; in-plant pipelines; and pipelines located in rural areas.[12] DOT has issued a Notice of Proposed Rulemaking, proposing to extend the pipeline safety regulations to the exempted pipelines (CFRe).

3.3.4 Addressing Potential Public and Environmental Concerns

To help address potential public concerns about pipelines, it is important for regulators and the industry to characterize potential risks. The potential consequences of CO_2 incidents can be modeled on a site-specific basis using several standard methods, taking into account such local conditions as topography, meteorology, and population density (IPCC 2005). For example, the EPA has a list of simulators used to model exposure hazards. These tools, which were used for the FutureGen environmental impact assessment (U.S. DOE 2007b), can help predict the potential impact of CO_2 releases from point sources, providing information to potential regulators and stakeholders regarding concerns about pipeline siting.

Other ways of addressing the potential risks are leak-detection odorants and pipeline monitoring systems (visual and aerial). Odorants are often added to natural gas distribution pipelines for leak detection because of the concerns about the toxicity and flammability of natural gas. The potential benefits as well as the costs of adding odorants to CO_2 pipelines, particularly pipelines running through heavily populated areas, should be assessed. Unlike leaks from natural gas pipelines,

TRANSPORT GUIDELINE 2: RECOMMENDED GUIDELINES FOR PIPELINE SAFETY AND INTEGRITY

a. **Operators should follow the existing Occupational Safety and Health Administration (OSHA) standards for safe handling of CO_2.**

b. **Plants operating small in-plant pipelines should consider adopting Office of Pipeline Safety (OPS) regulations as a minimum for best practice.**

c. **Pipelines located in vulnerable areas (populated or ecologically sensitive or seismically active areas) require extra due diligence by operators to ensure safe pipeline operations. Options for increasing due diligence include decreased spacing of mainline valves, greater depths of burial, and increased frequency of pipeline integrity assessments and monitoring for leaks.**

d. **If the pipeline is designed to handle H_2S, operators should adopt appropriate protection for handling and exposure.**

leaks from CO_2 pipelines are usually noticeable due to formation of visible gas, solid droplets, and temperature changes. Because CO_2 is denser than air, it has the potential to accumulate in low-lying areas under the right conditions; however, it tends to disperse very quickly, preventing accumulation. While it is highly unlikely that CO_2 could slowly leak from a pipeline and accumulate in a low-lying area (such as a basement), this remote possibility warrants a further evaluation of whether odorants should be considered in high-consequence areas. Mercaptans, naturally present in the Weyburn pipeline system, are the most effective odorants, but are not broadly suitable for this application because they are degraded by oxygen and moisture, even at very low concentrations. Disulfides, thioethers, and ring compounds containing sulfur are alternatives (IPCC 2005; Usher 1999). The challenge with odorants is that they increase the cost of using pipelines, and they are an added constituent in the injection stream.

3.4 CO_2 PIPELINE SITING REGULATION

As CO_2 pipelines are developed at the scale required for CCS, legislation imposing federal siting and economic regulation of CO_2 pipelines could be warranted. In this case, the jurisdiction of these pipelines could fall under the purview of the Federal Energy Regulatory Commission (FERC) or the Surface Transportation Board (STB). However, at the commencement of the development of interstate CO_2 pipelines during the late 1970s, both FERC and the Interstate Commerce Commission (ICC, a precursor agency to STB) determined that Congress had not extended regulatory jurisdiction over CO_2 pipelines under the existing applicable statutes (i.e., the Natural Gas Act of 1938 and the Interstate Commerce Act) (Vann, and Parfomak 2008).

3.4.1 Siting of CO_2 Pipelines

Siting a pipeline involves determining the route, assessing the environmental impacts at the proposed route, evaluating route alternatives, and acquiring the rights of way. Acquiring the rights of way usually involves gaining access to a portion of the shoulder of a road, or obtaining an easement on private property (MRCSP 2005). A rights-of-way agreement between the pipeline operator and landowner is a form of easement.[13] A new pipeline developer can either use an existing rights-of-way corridor or create a new one by negotiating with each landowner along the route.

If a landowner and the pipeline company cannot agree to a price, or if a landowner refuses to grant an easement, the pipeline company may, in some states, acquire the right to use the land through the power of eminent domain.[14] Federal and state governments have the constitutional power to grant public utilities and common carriers the power of eminent domain to acquire land for public purposes, and some states have granted this power by legislation to certain public utilities and common carriers.

A common carrier pipeline is subject to special duties under the applicable laws that generally seek to ensure fair terms of access and reasonable rates. The question whether a particular pipeline is a common carrier under the law of a particular state may depend on the particular legislative provisions of state law, the facts of the case, and judicial decisions. As put by one court, "[t]here is scarcely any field of law more ancient or more written on than that of carriers (U.S. Court of Appeals 1960)." Whether the pipeline in question is operating in interstate or intrastate commerce, however, is generally not relevant to whether it is or is not a common carrier (Gorton 1971; Speta 2002; Wyman 1904; Burdick 1911; Pitsch and Bresnahan 1996).

Unlike interstate natural gas pipelines, which are regulated by FERC[15] and whose owners may exercise eminent domain if they receive a certificate of public convenience and necessity under Section 7(c) of

Implications of CO_2 Properties on Pipeline Siting

CO_2 is colorless, odorless, tasteless, nonflammable, nonpoisonous, and soluble in water. CO_2 occurs naturally in the air we breathe and in deposits in the subsurface. A continuous exposure to CO_2 at just over a 2 percent concentration can cause depressions of the central nervous system in humans. At concentrations higher than 10 percent, it can cause severe injury or death due to asphyxiation. A property of CO_2 that needs to be considered when selecting a pipeline route is the fact that CO_2 is denser than air and can therefore accumulate to potentially dangerous concentrations in low-lying areas.

Siting Natural Gas Pipelines

Natural gas pipelines are regulated by the Federal Energy Regulatory Commission (FERC). For interstate natural gas pipelines, developers must obtain a certificate of public convenience and necessity from FERC, which establishes the terms and conditions under which the pipeline may be built and initially operated, and also confers eminent domain authority for siting pipelines. For intrastate natural gas pipelines or distribution lines, the applicable state law typically provides a mechanism under which a right of eminent domain may be acquired. The state agencies currently involved in the various processes related to siting a pipeline or distribution pipeline may include public utility commissions, natural resource commissions, oil and gas commissions, environmental protection agencies, transportation commissions, and departments of agriculture and human health.

the Natural Gas Act, no comparable federal certification is required to construct a CO_2 pipeline, nor is there any mechanism for developers of proposed CO_2 pipelines to obtain a federal right of eminent domain.[16]

The U.S. Department of the Interior's Bureau of Land Management (BLM) regulates the siting of CO_2 pipelines for EOR on BLM-managed lands. The Federal Land Policy and Management Act of 1976 (FLPMA) and the Mineral Leasing Act of 1920 as amended (MLA) contain provisions for granting rights of way for siting pipelines on federal lands managed by BLM (U.S. DOI/BLM/OS 2001; USCa). The FLPMA allows BLM to grant rights of way for pipelines transporting "liquids and gases, other than water and other than oil, natural gas, synthetic liquid or gaseous fuels, or any refined product produced therewith." Under the MLA, BLM can permit oil and natural gas pipelines. A significant difference between the MLA and the FLPMA is that the MLA imposes a common carrier requirement, while the FLPMA does not. Recent BLM practice has been to consider CO_2 as a "natural gas" (as CO_2 is mainly obtained from natural sources), and thus to grant rights of way under the MLA, which could make CO_2 pipelines eligible for the common carrier requirement.

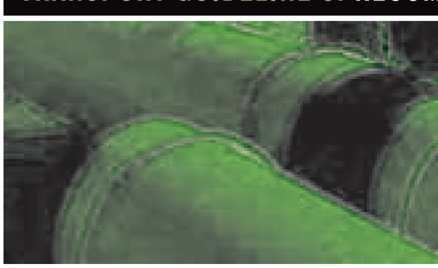
For CCS, older and well-established natural gas pipeline corridors may in some cases allow additional pipelines for CO_2 to be laid using the same right of way by negotiating an agreement with the existing right-of-way owner, which may facilitate siting of CO_2 pipelines. However, the availability of this option will depend on the particular wording of the existing right-of-way agreement or perhaps on the terms under which a particular parcel of land was originally acquired (whether through negotiation or through a condemnation proceeding). Public and private landowners may seek additional compensation for construction of an additional pipeline, and their right to do so is likely to vary, depending on the applicable law and the particular facts of the situation. Thus, the extent to which new CO_2 pipelines will be able to take advantage of current state condemnation statutes and regulations that will grant the power of eminent domain will vary state by state.

For the construction of new pipelines on a scale required for large-scale deployment of CCS, some form of federal eminent domain may be appropriate under which CO_2 pipelines might be considered a public utility or a common carrier. Obtaining a certificate of public convenience and necessity (such as the one required for interstate natural gas pipelines to obtain eminent domain from FERC) may help development of a CO_2 pipeline, as it would mean that the pipeline is being treated as a public utility, giving a pipeline developer authority to condemn a right of way.

Conversely, a common carrier requirement may complicate CO_2 pipeline development, particularly if several sources of CO_2 want to use the same pipeline to transport to a common sink. Different carriage regulations address the question of allocating available capacity or adding new capacity very differently, and it is not clear at present what type of capacity allocation and access rules may be appropriate for the CCS industry. This issue has already arisen on federal lands managed by BLM. Although the agency currently permits CO_2 pipelines for EOR under the MLA, CO_2 pipeline companies seeking to avoid common carrier requirements under CCS schemes may litigate to secure rights of way under the FLPMA (Parfomak 2008). For example, in Exxon v. Lujan, Exxon argued that its application for a CO_2 pipeline right of way should have been granted under the FLPMA rather than the MLA. The crux of the case was the reasonableness of BLM's classification of CO_2 as a natural gas under the MLA. Exxon contended that the term natural gas should be applied to the hydrocarbon fuel, while BLM maintained that natural gas under the MLA has a broader meaning, referring to all naturally occurring gases (MRCSP 2005). This may require reconsideration for CCS, as the CO_2 will be supplied from anthropogenic sources and may not fit under the definition of a natural gas.

Oversight by multiple agencies that regulate different aspects of siting CO_2 pipelines could cause delays and increase costs for pipeline developers. For interstate pipelines, developers must gain approval from numerous state agencies and individual landowners to acquire rights of way. Negotiating with multiple agencies in two or more states could be a time-consuming and expensive task for developers. But since differing rules will apply in the various states, much of this complexity will be unavoidable. One possible approach to streamline this process could be to set up a one-stop permitting process for CO_2 pipelines, where the various permitting steps required in the state can be handled by one agency in consultation with interested parties and concerned agencies. The power of

TRANSPORT GUIDELINE 3: RECOMMENDED GUIDELINES FOR SITING CO_2 PIPELINES



a. Considering the extent of CO_2 pipeline needs for large-scale CCS, a more efficient means of regulating the siting of interstate CO_2 pipelines should be considered at the federal level, based on consultation with states, industry, and other stakeholders.

b. As a broader CO_2 pipeline infrastructure develops, regulators should consider allowing CO_2 pipeline developers to take advantage of current state condemnation statutes and regulations that will facilitate rights-of-way acquisition negotiations.

eminent domain could be included in the enabling statute or regulations of such a siting agency. Thus, rather than having two separate proceedings, one for siting and one for eminent domain, a siting agency could be authorized to make both determinations at once. An entity that obtains a siting certificate would automatically have the power of eminent domain (MRCSP 2005).

Depending on terrain and length of CO_2 pipeline, pumping stations may be required and could become another siting issue. As the pumps are above ground, nearby residents could have issues with potential noise, view, safety, and security concerns. In addition, fuel (or electricity) to operate the pumps will be required to be brought to the site. With natural gas pipelines, the gas is often taken from the pipeline and used to fuel compressors.

3.5 PIPELINE ACCESS AND TARIFF REGULATION

While FERC currently regulates access to and rates for interstate (and certain intrastate) pipelines transporting natural gas (under the Natural Gas Act and subsequent statutes) and oil pipelines (under the ICA),[17] the STB[18] has regulatory oversight over the access and rates for pipelines transporting a commodity other than water, gas, or oil (including CO_2) (USCb). For the purpose of EOR, CO_2 is considered as a commodity. However, it is important to note that for the purpose of geologic storage, CO_2 may be considered a pollutant. Conflicting classification of CO_2 has important implications for CO_2 pipeline development. The IOGCC proposed that CO_2 be considered a commodity because the captured CO_2 will be sold as a valuable commodity for EOR and enhanced coalbed methane applications (Parfomak and Folger 2008).

Unlike FERC, STB does not require pipeline companies that are subject to its regulation to file tariffs and justify their rates. STB may begin a jurisdictional pipeline rate investigation only in response to a complaint filed against the pipeline operator by a third party. Thus, STB acts as a forum for resolution of disputes related to pipelines within its jurisdiction. Parties who wish to challenge a rate or another aspect of a pipeline's common carrier service may petition the STB for a hearing; there is no ongoing regulatory oversight. In contrast, natural gas pipeline operators must generally obtain approval from FERC prior to placing a new pipeline in service, and FERC is in charge of establishing just and reasonable rates in consultation with both consumers and the industry, and may review rates for natural gas pipelines on its own initiative (Parfomak and Folger 2008).

STB regulations ensure that pipelines fulfill common carrier obligations by charging reasonable rates; providing rates and services to all upon request; not unfairly discriminating among shippers; establishing reasonable classifications, rules, and practices; and interchanging traffic with other pipelines or transport modes. Under the STB's current approach (common carrier regulation), shippers may not contract for specific quantities of capacity and, therefore, do not pay related monthly demand/reservation charges. Payment is only for capacity utilization based on actual throughput volumes. The advantage for common carrier shippers is that they "pay as they go" on actual delivered volumes. The disadvantage is that the shipper may not contract for a specific level of assured capacity.

Natural gas pipelines operate on the basis of a particular form of mandatory contract carriage,[19] where shippers generally have the opportunity to contract for a reservation of available capacity in the pipeline on a nondiscriminatory basis for a specified period of time. Parties who hold firm, contracted capacity are normally not subject to proration at the behest of other shippers, thus guaranteeing that their shipments will flow. As additional capacity is needed to serve new shippers, open seasons[20] are typically held to determine the interest and economic feasibility of adding new capacity. The open seasons in natural gas pipelines are often used to ensure capacity is awarded without undue discrimination to all parties who meet the open season requirements.

Pipelines constructed for the exclusive use of a single power plant for on-site or nearby CO_2 storage could be considered an extension of the plant. Alternatively, they could be considered a non-plant asset providing a transportation service for a fee, in which case the costs could still be recovered by the utility in its rates as an operating cost. This could raise questions about cost recovery for electric utilities under state utility regulations.

Current Models for CO_2 Pipeline Ownership

Current CO_2 pipelines are primarily owned privately, and pipeline contracts/capacities are negotiated by the pipeline owner(s)/operator(s). These are both owned by one owner/operator and by a group of owners/operators (common ownership). For common ownership, every owning party has "pooled" its ownership into one entity. Tariffs are commonly calculated by dividing the annual cost of capital plus operating costs by the annual throughput volumes. All parties receive or pay a common tariff. One example of this model is the Bravo Dome pipeline, moving CO_2 from northeastern New Mexico to the Slaughter field in Hockley County, Texas.

The second type of pipeline ownership, divided ownership, is one wherein several parties own a "piece" of the pipeline but retain their interest as separate and distinct. They negotiate individual contracts independently, and separate tariffs are calculated for each individual owner. Because the existing pipelines are privately owned, there is effectively no "open access."

TRANSPORT GUIDELINE 4: RECOMMENDED GUIDELINES FOR PIPELINE ACCESS AND TARIFF REGULATION

a. The federal government should consult with industry and states to evaluate a model for setting rates and access for interstate CO_2 pipelines. Such action would facilitate the growth of an interstate CO_2 pipeline network.

TRANSPORT ENDNOTES

[1] The 3900 miles represents the regulated pipelines as per the U.S. Department of Transportation records.

[2] In contrast to CO_2 pipelines, there are more than 980,000 miles of natural gas distribution pipeline in place as per Department of Transportation 2003 statistics.

[3] In addition to providing a cost-effective alternative to sulfur recovery, the deep injection of acid gas reduces emissions of noxious substances into the atmosphere and alleviates the public concern resulting from sour gas production and flaring. Although the purpose of the acid-gas injection operations is to dispose of H2S, significant quantities of CO_2 are being injected at the same time because it is costly to separate the two gases. In the context of current efforts to reduce anthropogenic emissions of CO_2, these acid-gas injection operations represent an analogue to geological storage of CO_2.

[4] In the supercritical state, CO_2 has the characteristics of both a liquid and a gas, maintaining the compressibility of a gas and some of the properties of a liquid, such as density. Low viscosity is important for pipeline transport. In the supercritical phase, the viscosity of CO_2 is the same as in the gas phase, which is 100 times lower than in the liquid phase. Important from a cost standpoint, supercritical transport allows for substantially higher throughput through a given pipe cross-section than transport as a lower-pressure gas.

[5] ASME/ANSI (American Society of Mechanical Engineers/American National Standards Institute) pipe flanges that are made to standards called out by ASME/ANSI B16.5 or ASME/ANSI B16.47 are typically made from forged materials and have machined surfaces. They are typically in "Pressure Classes," such as 150#, 300#, 600#, and 900#, and 1500 #. These Pressure Classes have both pressure and temperature ratings for specific materials (Nayyar 2000).

[6] The two-phase flow pattern, usually called "slug flow," is encountered when gas and liquid flow simultaneously in a pipe, over certain ranges of flow rates. It is characterized by long "Taylor" bubbles, also called gas slugs, rising and nearly filling a pipe cross-section. In a slugging column, with flowing gas and liquid, the flow field is extremely complex.

[7] Live and dead loads refer to the forces exerted on the pipeline. The live loads are forces that are temporary, of short duration, or moving—for example snow, wind, earthquake, traffic movements. The dead loads are weights of material, equipment, or components that are relatively constant throughout the structure's life—for example, load due to settlement.

[8] OPS safety jurisdiction over pipelines covers more than 3,000 gathering, transmission, and distribution operators, as well as some 52,000 master meters and liquefied natural gas operators who own and/or operate approximately 1.6 million miles of gas pipelines, in addition to over 200 operators and an estimated 155,000 miles of hazardous liquid pipelines.

[9] Although CO_2 pipelines are classified as hazardous, CO_2 is not defined as a hazardous substance. It is a Class L, highly volatile, nonflammable/nontoxic material (CFRg, CFRe, Appendix B, Table 4). CO_2 pipelines are treated as hazardous and are reviewed as high-risk hazardous pipelines when they have a diameter greater than 457 mm (18 in) or when they pass through High-Consequence Areas.

[10] States certified to regulate intrastate pipelines are: Alabama, Arizona, California, Louisiana, Maryland, Minnesota, Mississippi, New York, Oklahoma, New Mexico, Texas, Virginia, Washington, and West Virginia.

[11] 49 CFR § 195.2 defines low-stress pipeline as a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum-yield strength of the pipeline (CFRf).

[12] 49 CFR § 195.2 defines rural area as an area outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area, such as a subdivision, a business or shopping center, or community development. The rural areas are considered to be the nonenvironmentally sensitive areas (CFRf).

[13] An easement is a limited perpetual interest in land that allows the pipeline owner to construct, operate, and maintain a pipeline across the land. An easement does not grant an unlimited entitlement to use the right of way. The rights of the easement owner are set out in the easement agreement.

[14] Eminent domain is the power of government to take private land for public use. Under current law there is no federal eminent domain power granted for the construction of CO_2 pipelines. A number of states, however, do allow the use of eminent domain for CO_2 pipeline construction under certain conditions.

[15] For interstate natural gas pipelines, FERC has jurisdiction over tariffs and rights of way.

[16] Although CO_2 pipelines are not explicitly excluded from FERC jurisdiction by statute, FERC ruled in 1979 that pipelines carrying CO_2 are not subject to FERC regulation (Cortez 1979).

[17] FERC is not involved in the oil pipeline siting process. However, as with natural gas, FERC does regulate transportation rates and capacity allocation for oil pipelines. It is important to note that historically oil pipelines were regulated under the Interstate Commerce Act (ICA). The ICA, as amended by the Hepburn Act of 1905, provided that the ICC was to have jurisdiction over rates and certain other activities of interstate oil pipelines, as these pipelines were considered to be common carriers. This jurisdiction was transferred to FERC in the Department of Energy Organization Act of 1977.

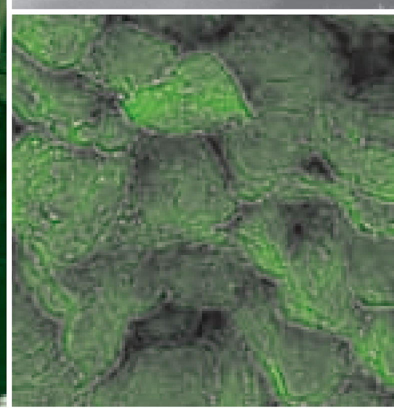
[18] STB is decisionally independent of and administratively affiliated with DOT. Pursuant to the ICA the primary mission of STB involves resolving railroad disputes. It is the successor agency to the ICC. Pipelines, like railroads, are "common carriers" used by more than one company for the transportation of goods. Therefore, the ICA also assigned the ICC (and thus the STB) oversight authority over pipelines transporting a commodity other than "water, gas or oil."

[19] Pipeline owners and financial lenders desire these long-term contracts for firm capacity to ensure repayment of the capital cost of building the pipeline. Without these commitments, gas pipeline projects, which by their nature involve a longer payout than oil projects, could not be financed. Shippers need the contract quantity commitment to ensure capacity is available to support their needs.

[20] Open seasons are commercial opportunities for potential customers to compete for and acquire capacity on a proposed or existing pipeline. Open seasons inform project sponsors of shippers' needs so they may adjust the project design accordingly.

STORAGE

PART 4



4.1 INTRODUCTION

4.1.1 Terminology

Existing injection programs provide experience for geologic storage, also known as sequestration, of CO_2. These include injection under underground injection control (UIC) well classes (Classes I, II, and V in particular) and injection for natural gas storage. In drawing on experts from these areas for help in developing the storage Guidelines, it has become clear that certain terms are used very differently within these injection programs and sometimes even between different state programs implementing

the same injection program. The Glossary at the end of the Guidelines includes terms as they are used in this document and should be consulted by the reader. In addition, a few terms that are particularly important for geologic storage are included here.

"Storage" is the primary term used to refer to geologic sequestration throughout this document. There is some debate about whether the term sequestration, storage, or disposal is the most useful in describing the injection and long-term isolation of CO_2. There are numerous considerations surrounding each term.

"Project footprint" is used as a convenient way to refer to the land surface area overlying the geologic space occupied by injected CO_2 (CO_2 plume) and the related geologic space in which there is significantly elevated pressure in the formation fluid caused by the injection of CO_2. For purposes of this document, "significantly elevated pressure" is defined as the area where the pressure differential is sufficient to cause adverse impacts to overlying receptors, such as the movement of injected or displaced fluids above the confining zone into an underground source of drinking water (USDW). The terms "CO_2 plume or injected CO_2" and "area of elevated pressure" will be used when specifically referring to the components of the project footprint.

"Closure" is used to signify the period during which injection at a project ceases, and it is demonstrated that the project does not endanger public health and the environment. Wells within a project are "plugged and abandoned" after they stop receiving CO_2 or cease to be used for monitoring (commonly referred to in other programs as closed or plugged wells). Plugging and abandoning individual wells can happen throughout a project as well, and is one part of the site closure process.

4.1.2 Organization of the Storage Guidelines

The storage Guidelines are organized in three parts. This first section is meant to give the reader an understanding of the performance expectations for appropriately sited, operated, and closed projects. It includes an overview of the key components and issues faced by storage projects, including the challenges associated with the expected variation among projects. This section provides an introduction to the array of issues that must be considered in determining what constitutes a safe and effective storage site, developing appropriate operation and closure plans, and addressing contingencies. It also serves as an introduction to the different stages of a project and those cross-cutting issues that are considered throughout the life of a project.

One finding that has emerged through the process of developing these Guidelines with stakeholders is that storage projects will unfold through a series of iterations and feedback loops: initial site characterization, well drilling and construction will be used to start a project; feedback from the initial injection and monitoring will be used to cancel, modify, or expand operations; as individual wells and injection zones reach capacity, they will be plugged and abandoned; as a project reaches capacity and the operator demonstrates non-endangerment, the site will be closed.

The second section of the storage Guidelines builds on the first section by describing these feedback loops and their integration within an individual storage project. This section also introduces the concept of regional issues that become important when several projects use the same geologic resource, underscoring the importance for coordination among storage projects in regions where multiple projects are utilizing the same reservoir(s).

The final section examines specific issues and explicitly states the recommended Guidelines for each aspect of storage. In developing this section, it was clear that certain issues, such as measurement, monitoring, and verification (MMV), cut across all phases of a storage project. Therefore, this section presents cross-cutting issues first, and then describes issues related to specific phases of a storage project. This section includes an explanation of the technical rationale supporting the Guidelines. In most cases, the recommendations are aimed at a performance-based approach, focusing on the key pieces of information needed, rather than prescribing how an operator should obtain that information. This reflects both the evolving state of knowledge and technologies for storage, and the heterogeneity in geologic resources.

4.1.3 Carbon Storage Performance Expectations

In 2005, the IPCC released the *IPCC Special Report: Carbon Dioxide Capture and Storage,* representing the current scientific consensus on the important role and efficacy of CCS as a strategy to mitigate climate change (IPCC 2005). This report put forth a set of findings that included two qualified statements about geologic storage (emphasis added):

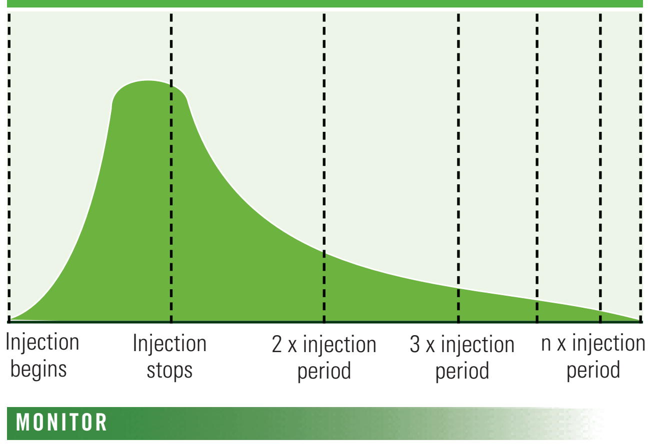
"22. With *appropriate site selection* based on available subsurface information, a monitoring programme to detect problems, a *regulatory system* and the appropriate use of *remediation methods* to stop or control CO_2 releases if they arise, the local health, safety and environmental risks of geological storage would be comparable to the risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas."

"25. Observations from engineered and natural analogues as well as models suggest that the fraction retained in *appropriately selected and managed geological reservoirs* is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1,000 years."

Based on the IPCC report and discussions among experts, these storage Guidelines assume that:

1. Scientific investigation and technical knowledge can provide the basis for safe and effective injection of CO_2 into specific geologic formations for long-term storage, keeping it isolated from drinking water supplies and preventing release to the atmosphere.
2. Existing monitoring techniques are capable of measuring the amount of CO_2 injected, and delineating the project footprint after injection. These monitoring techniques can be applied using a risk-based strategy to ensure that sensitive populations and environments are safeguarded. New monitoring techniques can improve the effectiveness and/or reduce the cost of detection and tracking.
3. Injected CO_2 is more permanently trapped in the subsurface over time, as storage mechanisms reduce CO_2 mobility and, ultimately, virtually eliminate the potential threat to drinking water supplies and the atmospheric climate. Figure 8 depicts this concept. In this conceptual example, the relative risks associated with a project are shown starting at zero before injection begins, increasing during injection operations, flattening out as injections cease, and finally declining over time as the pressure of the injection CO_2 stabilizes or reaches background levels and other trapping measures take place. This diagram will be referred to again in the Guidelines to illustrate risk concepts.
4. Contingent mitigation/remediation planning can be applied in advance of project initiation and updated throughout operations to ensure that any unexpected and undesired movement of injected CO_2 will be detected early, and if detected, addressed as needed.
5. In the United States, there is the technical potential[1] to sequester hundreds of billions of tons of CO_2 in saline formations and oil and gas fields that are located reasonably near large sources of anthropogenic CO_2. Globally, there is a conservatively estimated "technical potential of at least 2,000 $GtCO_2$ [Gigatons of carbon dioxide] of storage capacity in geological formations," including saline, oil and gas formations, coal seams (potentially), and other formations. The final volumes of "proven" storage reserves may be significantly smaller than the technical potential, but are still likely to be very large.
6. The emerging CCS industry benefits from the significant knowledge and best practices developed during over 35 years of CO_2 EOR. Because geologic storage will include new requirements, it is important to acknowledge that a significant amount of new technological learning and advancement is expected over time. With experience, the best practices for storage will evolve.

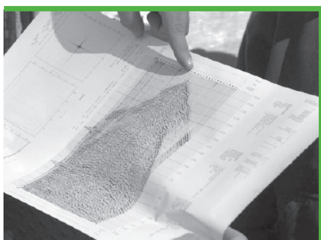
Figure 8: Conceptual Risk Profile of a Storage Project



SOURCE: BENSON 2007

4.1.4 Implications of Potential Deployment Pathways

The challenge with geologic storage, one that is captured in the IPCC statements in Section 4.1.3, is that no two sites are alike, even within the same geologic formation. As a result, there is significant need for the use of "performance standards" and flexibility, rather than rigid numeric standards and technical requirements for the siting, design, operation, and closure of storage projects. This challenge is underscored by the diversity in likely deployment pathways for storage projects. There is a strong temptation in developing these Guidelines to assume a "typical" or standard project. The reality is more likely that CCS will emerge from a number of differently sized projects that involve a combination of different CO_2 sources, compositions, infrastructure configurations, and geologic reservoir types.



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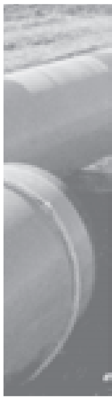



This variability underscores the need for flexibility in adapting current regulatory frameworks to the field of CCS, and iterating and updating practices as new operations and diverse projects proceed. It is expected that initial projects will evolve from the well-known subsurface conditions of oil and gas provinces, so as to minimize early project risks. As the base of experience and practice grows, regulations should evolve.

4.1.4.1 CO_2 Sources

Today there is a variable supply of CO_2 whose volume and characteristics will be heavily influenced by policy and market signals. These, in turn, will be influenced by the results of and confidence in early storage efforts. This means that the first CCS projects are likely to rely more on readily captured CO_2 (industrial sources) slip-stream capture at full-scale plants and/or pilot-scale plants with full-scale capture. As large power plants ramp up capture (90 percent of the volume of total projected emissions or better), storage projects will need to accommodate larger volumes of CO_2.

4.1.4.2 CO_2 Transport

Depending on the economics of capture and processing of the CO_2, early projects are likely to rely on a mix of transportation options, including use (or expansion) of the existing pipeline infrastructure and the development of dedicated pipelines. These individual pipelines would be sized and located for individual projects and designed to accommodate the project-specific CO_2 composition. As a result, a standard composition for CO_2 delivered for storage is unlikely. Much like CO_2 standards in EOR today, these factors will vary based on project details, and individual storage project designs will be taken into account.

4.1.4.3 Reservoir Types and Project Sizes

The largest potential capacity for CCS is in saline formations, and it is this significant capacity that drives interest in CCS as a climate change solution (IPCC 2005; Dooley et al. 2006; U.S. DOE/NETL 2007a). However, in the near term, mature oil and natural gas fields are likely to be the financially attractive sites for storage because of the comparative wealth of information regarding site-specific subsurface geology, existing infrastructure, and economic incentive in the form of recovered oil or natural gas, which will help defray the costs of capture, transportation, injection, and monitoring. With higher oil prices, increased availability of CO_2, and incentives for storage, the EOR industry could provide a mechanism for sequestering significantly more CO_2 than it does currently. Mature or abandoned natural gas fields may also provide large advantages for early storage projects. Reservoirs, such as coal seams or basalt formations, are also potential alternatives in some areas, and there will continue to be interest in conducting pilot- or larger-scale storage pilot projects in these kinds of formations. However, these formations have very different physical structures, geochemistry, trapping mechanisms, industrial bases, and regulatory frameworks compared to the other storage options. These Guidelines are geared toward near-future CCS deployment and focus on saline formations and oil and natural gas fields. They do not address other formation types, such as coal seams and basalt in detail.

Another consideration is project size and scale. In many discussions about storage, the implied deployment model seems to involve one large CO_2 source linked to one large storage project site. The reality may be quite different, as early projects will most likely vary in size for a number of reasons related to the nature of the project, the source of CO_2, cost, and other factors. Further, as new CCS projects are proposed, there may be a move toward the use of pipeline networks through which the CO_2 from several sources may be combined and then distributed to several different storage projects. Ultimately, the characteristics of any specific site need to be considered in absolute terms: Is the site suitable for storage, given the specific geology and the reservoir context?

Although there are many possible future deployment scenarios, the Guidelines focus on storage at an individual project scale with injection into single large reservoirs, noting how size/scale might affect certain assessments.

4.1.5 Identification of Storage Issues Addressed in the Guidelines

A challenge in presenting Guidelines for storage is in organizing feedback processes into the linear format of a paper. This section of the Guideline presents a brief overview of issues related to storage that need to be considered in the Guidelines. In the subsequent sections, these issues will be explored in detail.

4.1.5.1 Specific Stages of a Storage Project

SITE CHARACTERIZATION AND SELECTION

Site characterization and selection is perhaps the most important step in ensuring the safety and integrity of a storage project. During this phase, much of the site-specific data are collected and permits applications are developed. (Note: permits may be required for certain site-characterization activities, such as seismic reflection surveys.) Even though a site may be economically attractive, data collected during site characterization should be used to assess the technical feasibility of a site. The primary question is how to determine if a site is suitable for storage. The storage Guidelines describe the characteristics a target reservoir should (and in some cases should not) have, and what information is needed to prove that the project will be able to proceed effectively and economically to sequester the proposed volume of CO_2. Some of the data collected during this phase may be proprietary, or contain information controlled by a owner under copyright, patent, or trade secret laws. Where data availability is mentioned, non-proprietary data should be released.

PROJECT OPERATIONS

"Project operations" is often narrowly defined as the period of active CO_2 injection. However, in these Guidelines, site preparation and well construction are included as part of operational activities. The operational Guidelines underscore the need for integrated planning and project-specific considerations in well and facility design. An emphasis is also placed on collecting and analyzing operational data, maintaining sufficient flexibility in the operational plans to adapt as new information becomes available, and planning for contingencies.

SITE CLOSURE

Site closure occurs when injection ceases, the final wells are plugged and abandoned, and the site is certified for closure. Although individual wells may be temporarily or permanently plugged and abandoned or converted to a monitoring well during operations, Guidelines related to these activities are included under site closure. Plugging and abandonment of wells is the primary task in site closure, and storage projects will benefit from existing knowledge and standard approaches. The Guidelines specify that operators conduct a final assessment of all wells, and that data regarding each site are reported in a publicly accessible registry. During site closure, operators will undertake post-injection monitoring to demonstrate that the storage project does not endanger human health and the environment. Certification of site closure is contingent on this demonstration.

POST-CLOSURE

Post-closure is the period of time after certification of site closure. At this stage, the storage project should not endanger human health and the environment. The Guidelines propose a set of expectations for a site in the post-closure period, as well as potential mechanisms for managing post-closure MMV activities, to the extent needed.

4.1.5.2 Cross-Cutting Issues

A number of cross-cutting issues apply to all stages of a storage effort.

MMV TOOLS

MMV tools enable operators to measure aspects of site surface and subsurface conditions, and to use these measurements to analyze, simulate, and forecast CO_2 behavior. Because MMV activities represent a critical component of safe geologic storage, they should occur throughout the life cycle of a storage project. These activities allow an operator to develop a comprehensive understanding of the subsurface geology and the surface and near-surface environmental conditions at the site. By conducting a site characterization and implementing the MMV plan, an operator will be able to effectively manage risk of unexpected leakage. Further, implementation of a robust MMV plan during the early stages of a CCS project and through operations will increase the certainty around demonstration of non-endangerment, thus facilitating certification of site closure.

Estimating Storage Capacity

A number of geologic reservoirs appear to have the combined technical potential to sequester billions of tons of CO_2. The potential to store and retain captured CO_2 can be considered a type of resource. Like all geological resources (e.g., oil, gold), storage capacity can be estimated through conventional analyses and approaches that involve a number of defined assumptions.

Many estimates developed to date are regional or basin-scale resource estimates. This type of analysis applies regional estimates for porosity, formation thickness, fluid saturation, and density of stored CO_2 over large areas to develop an estimate of "potential capacity." A site geologic analysis involves the acquisition of more detailed data at a specific reservoir level and will illustrate changes within a potential reservoir across a basin. This work, though more detailed than the regional analysis, still will not replace the level of work required for specific-site characterization, or to develop an estimate of "proved reserves."

SOURCES: IPCC 2005; DOOLEY ET AL. 2006; U.S. DOE/NETL 2007A

RISK ASSESSMENT

Risk assessment is an important component of a CCS project that is conducted and updated throughout a project, rather than as a one-time action. Risk assessment should be integrated with the MMV program and should include approaches to mitigate the risk of negative impacts upon the surface, a USDW, or outside the project footprint. One key component of a risk assessment is identifying potential leakage pathways (e.g., faults, wells, fractures). This identification is then integrated with the MMV plan. Should injected CO_2 migrate toward an identified pathway, a mitigation contingency or remediation measure is implemented. A comprehensive risk assessment is needed early in the project, but risks should be continually assessed and integrated with the MMV plan. One method for ensuring this needed integration is to link the models used for risk assessment and the subsurface models that are developed and informed by MMV.

Current Regulatory Framework for Underground Injection

These Guidelines are being released in the context of an evolving regulatory framework. Several states and the U.S. Environmental Protection Agency (EPA) have initiated rulemaking for CO_2 geologic sequestration. A draft EPA rule was released in July 2008, and a final rule is planned for 2011. EPA has the authority to regulate CO_2 geologic sequestration wells under the Safe Drinking Water Act through the Underground Injection Control (UIC) Program.

The United States historically has safely injected CO_2 and other materials in the subsurface. Some of the stated storage Guidelines are covered under existing UIC rules for Class I or Class II wells. However, because long-term storage of large volumes of CO_2 presents unique issues (relative buoyancy of CO_2, corrosivity in the presence of water, mobility in the subsurface), the draft rule would create a new Class VI for CO_2 geologic storage wells and call for some significantly different provisions regarding well construction; measurement, monitoring, and verification; and closure. Several key issues may not be resolved in the state rules or the first release of the new draft UIC rule, and could significantly affect the ease of permitting storage projects.

The Guidelines include and explain important recommendations, even where there is an existing or proposed requirement under the emerging regulatory frameworks. A few important considerations include:

- Who owns the storage rights, and how they will be aggregated?
- What happens when the predicted CO_2 plume crosses state boundaries and differing regulatory jurisdictions?
- Permitting an individual well versus permitting a carbon dioxide capture and storage field or reservoir (i.e., area permit).
- Determination of the area of review requirements.
- Differences in state-level authority, legislation, or regulatory interpretation.
- Differences in publicly available data.

FINANCIAL RESPONSIBILITY

Financial responsibility must span the entire life of a project (from capture through post-closure stewardship) and must include adequate assurance that there is sufficient funding to cover the net present value of estimated closure (including well plugging and abandonment, MMV, and foreseeable mitigation) and post-closure (including foreseeable MMV and corrective action). Because of the uncertainty surrounding early storage projects and the potential difficulty of attracting investment, policymakers should carefully evaluate options for the design and application of a risk management framework for such projects. This risk management framework should appropriately balance relevant policy considerations, including the need for financial assurances, without imposing excessive barriers to the design and deployment of CCS technology. This is the least-defined cross-cutting area, and will be a topic of future discussion and analysis. It should also be noted that the Guidelines do not specify the degree or nature of financial responsibility following site closure.

PROPERTY RIGHTS

Landowners of land above or near storage projects may be directly affected by pore space ownership and property rights issues. Ensuring that the operator has obtained the right to access a private landowner's land for monitoring purposes and/or to use the subsurface pore space under that land is critical. A full-scale storage project could affect many landowners. Projects in regions where there is little experience with subsurface industry operations (e.g., oil and gas and natural gas storage) may face greater challenges in establishing agreements with landowners. Communication and clarification of property rights should be established early in the planning phases, and data on the site should be maintained in public databases through the post-closure phases. These concerns should be addressed by policymakers through legislative clarity concerning key property rights issues.

Draft Australian CCS Regulation

On May 16, 2008, the Government of Australia released draft carbon dioxide capture and storage (CCS) legislation, which was referred to the House of Representatives Standing Committee on Primary Industries and Resources for review. The Committee reported on August 15. The report provides an endorsement of the proposed regulatory framework and makes a number of recommendations for changes to the draft, which are largely aimed at refining regulatory processes. The draft legislation takes the form of a comprehensive set of amendments to the Commonwealth's *Offshore Petroleum Act 2006* and is designed to provide an enabling framework for objective-based regulation for CCS in offshore waters.

The proposed legislation accomplishes two main objectives: (1) it provides a disposition or tenure scheme for parties to acquire the right to store GHGs in the offshore; and (2) it provides a regulatory framework for reviewing and approving CCS operations on a case-by-case basis, with individual site plans and closure plans. In delivering on both of these objectives, the legislation also provides a framework for deciding upon the competing claims of petroleum operations and CCS operations. The draft legislation identifies site selection and approval and site closure as areas for regulation and proposes a framework. Finally, the legislation proposes to leave both short-term and long-term liability with the operator/licensee, largely on the basis of laws of general application.

The Disposition or Tenure Scheme

The draft legislation offers a three-tiered GHG tenure scheme modeled on the current petroleum regime: (1) a GHG assessment permit, (2) a GHG holding lease, and (3) a GHG injection license. The GHG assessment permit is a short-term exploration interest. Permits are issued based on a competitive bidding process (work-bid or cash-bid). The GHG holding lease is designed to offer some security to an explorer who has obtained a declaration of an identified GHG storage formation, but who has yet to secure a source of GHGs. The GHG injection license is the only tenure form that permits GHG injection for other than evaluative reasons. It is the functional equivalent of a production license in a petroleum disposition scheme. The three forms of tenure need not be held sequentially. In particular, an operator might proceed directly from the GHG assessment permit to the GHG injection license. The tenure scheme is underpinned by a series of prohibitions. The legislation prohibits the unauthorized exploration (s. 249AC) or injection and storage of substances (s. 249CC) in an offshore area.

Protection of Existing Petroleum Interests

The draft legislation contains a number of safeguards to protect existing petroleum interests (and, more generally, producing interests). In particular, the legislation contemplates that the Minister will not be able to approve a GHG storage operation (including an exploratory operation) if the Minister concludes that the proposed operation may cause a significant risk of significant adverse impact on those petroleum interests in the absence of an agreement between the parties.

Classification of Storage Formations

In addition to the three forms of tenure are classifications of storage formations. Each classification is associated with increased knowledge of the geological formation that is proposed for injection and storage: potential, eligible, or identified. While a tenure holder may inject GHGs into potential and eligible formations for appraisal purposes, approval for injection for permanent storage requires that there be a declaration of an identified GHG storage formation.

Regulations for Site Selection and Approval and Site Closure

The draft legislation identifies site selection and approval of storage sites and site closure as two major issues that need new regulations for CCS. Both issues are dealt with through the use of a site plan that is linked to the specific identified GHG storage formation. The approach is outcome oriented in that the overall goal is to achieve "safe and secure storage" in a formation. Site closure builds on the site plan, requiring a program (and funding) for long-term monitoring and verification by the Commonwealth.

Liability

In the Australian system, short-term liability covers the period of active exploration and injection and the period post-injection until site closure. Long-term liability refers to liability post-closure. The draft legislation proposes that in general the liabilities associated with operating and closing an injection facility should be dealt with in the same way as conventional offshore oil and gas operations. The effect of this is to apply the default tort rules of the common law and impose continuing long-term liability principally on the operator/licensee. As result the proposal will not affect an explicit transfer of liability from the operator/licensee to the government. While there may be a *de facto* transfer of liability in the event of defunct operator, such a *de facto* transfer will not impose a legal duty on government to compensate those who may be harmed.

SOURCES: AUSTRALIAN GOVERNMENT 2006; BANKS AND POSCHWATTA 2008

Note: The legislation applies to "greenhouse gas substances" (and not simply CO_2). The term is defined as: (1) CO_2, or (2) a prescribed gas, or (3) a mixture of the above plus incidental GHG-related substances and detection agents. Incidental GHG-related substances would include substances incidentally derived from the source material, capture, transportation, injection, or storage. A detection agent is a substance added to the mixture to facilitate monitoring.

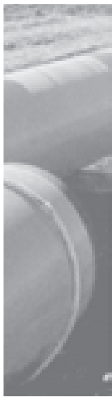
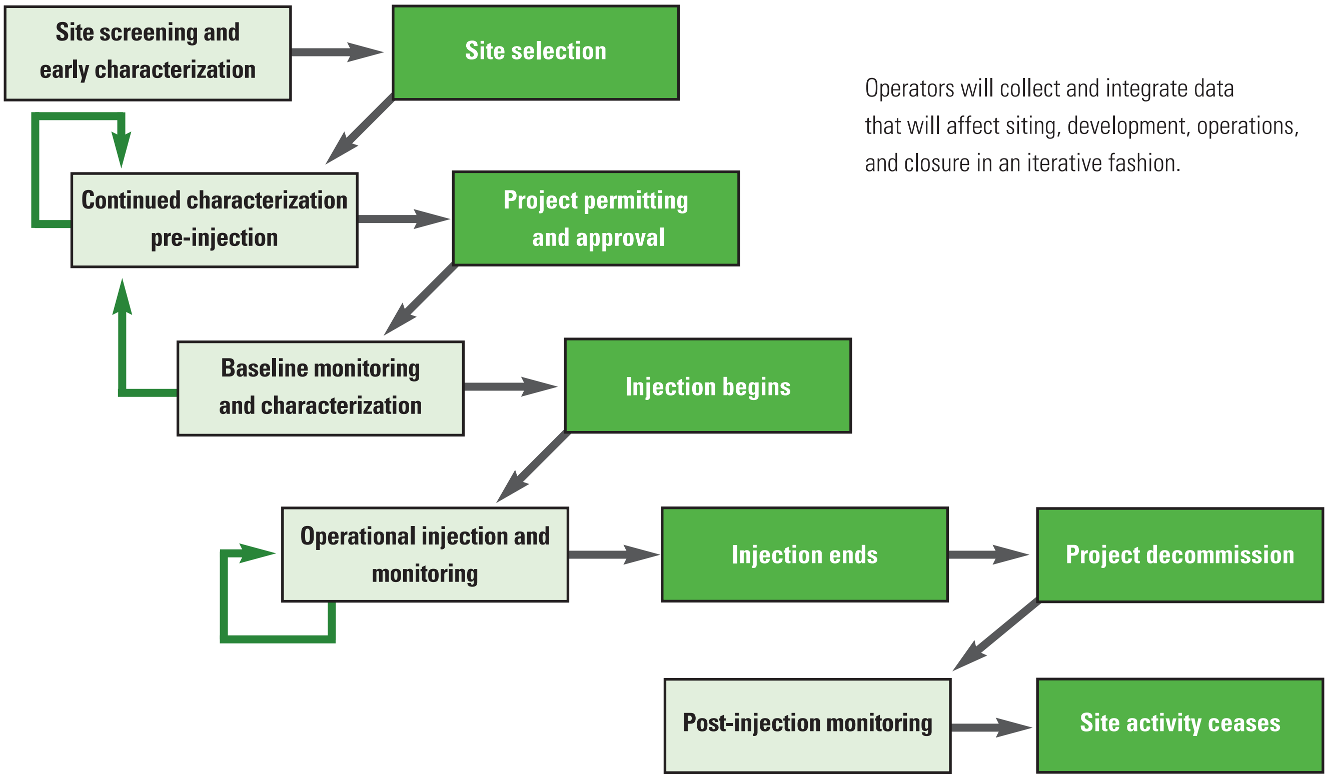




Figure 9: Integration Within a Storage Project



Operators will collect and integrate data that will affect siting, development, operations, and closure in an iterative fashion.

COURTESY OF S. J. FRIEDMANN, LLNL

4.2 INTEGRATION WITHIN AND AMONG CCS PROJECTS

Essential to the success of a storage project is integration among storage project phases (e.g., site characterization and selection, operations, site closure, and post-closure) and among various projects that use the same regional geologic formation.

4.2.1 Integration Within a CCS Project

Figure 9 illustrates important interaction in the planning and execution of each phase in the CCS project chain. It is not intended to be exhaustive and does not include public or community engagement, which should take place throughout the project. Such engagement should be prioritized, and best practices should be followed (Herbertson 2008).

Site screening and early characterization can best be defined as exploration for a potentially suitable site. A typical approach would include first developing an understanding of the regional geology and then gradually moving toward more detailed site characterization and data collection that over time result in an increasingly detailed subsurface model. At a broad level, the operator may apply screening criteria based on general site characteristics, such as population, current land use, or presence of critical habitat for threatened and endangered species. In addition, there are important geologic screening criteria, including the presence of confining zones, properties of the storage reservoir, underground storage capacity, and the extent to which factors that would reduce storage security (e.g., significant seismic activity or faults with the potential to impact protected resources or reach the near surface) are absent. At this point in the project, the geologic information will be gained from existing records of past operations or geologic studies in the region. A number of tools and approaches that can facilitate early site screening are discussed in greater detail in Section 4.3.2.1.

Once a project passes early site screening, it might be selected for more detailed characterization. The detailed site characterization effort is an exploratory process in which the operator gains site-specific geological information to better understand (with supporting data) the geologic conditions that were identified during early site screening. As a site is characterized in detail, the operator gradually begins to understand the nuances of the site-specific geology. At this point in the project, there are still questions about the subsurface that will only be answered through continued investigation and site preparation. Based on the first round of pilot projects, the best understanding of CO_2 movement will only be achieved through monitoring of CO_2 itself after initial injection (Doughty et al. 2008). That said, sufficient data will have been collected to conduct a preliminary risk analysis, design the project, and develop a preliminary model of the subsurface.

Before drilling and completing any new wells, the operator will need to obtain land and property access rights and work with the regulatory agency to obtain the needed permits. Permit applications for wells require a significant amount of information, including detailed information regarding the well specifications (depth, materials, location, etc.); the known information about the subsurface geology; data gathered during site characterization; submission of a subsurface model and monitoring plan; and detailed maps of surface and subsurface features. Permitting requirements will also include identification of any known faults and historical seismic activity and, frequently, recent seismic surveys.

If permits are received and the project scale is approved, a project will enter the site preparation and construction phase. The injection and monitoring wells will be drilled and completed according to the specifications in the permit. Throughout this phase, additional data on the subsurface will be collected and used to further characterize the site and validate the subsurface model. Baseline measurements for monitoring will also be made.

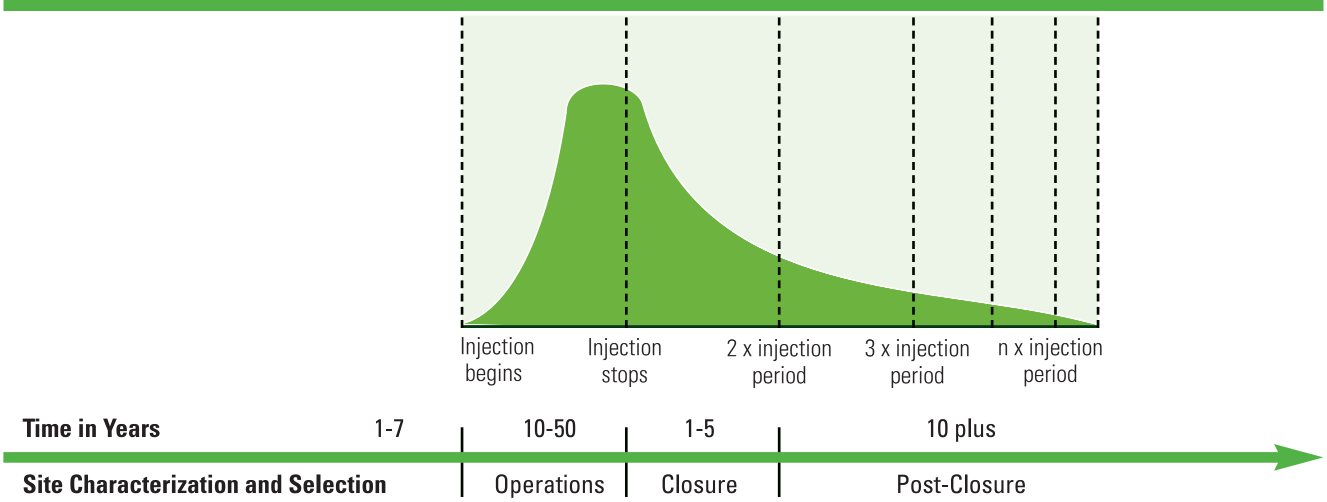
Prior to operational injection, the operator may use the newly drilled injection and monitoring wells to obtain additional information about the subsurface. Water floods and CO_2 injection tests may be conducted to provide new detail that will be incorporated into the subsurface model and further the understanding of the local geology. Throughout operations, data will be collected and used to periodically validate and, if necessary, update the model(s). Through this process, over time, the models will evolve to more closely represent subsurface conditions and predict the behavior of injected CO_2. Ongoing site characterization, monitoring, and simulation models will inform operational decisions.

Individual wells may be temporarily or permanently plugged and abandoned throughout operations, but a site will close only after injection has ceased. This phase of a project will include plugging and abandoning the majority of wells and conducting final wellbore assessments at older wells that were plugged and abandoned earlier either as part of the storage project or for use in other purposes. Following site closure, there maybe an additional period of post-closure monitoring, during which the site is assessed periodically to demonstrate that the project does not endanger human health and the environment.

4.2.1.1 Timeline for a Theoretical Project

It is difficult to establish a generic timeline for a storage project because of the vastly different starting points. In some locations, the regional geology is well understood and characterized, while others will need substantial research and characterization up front. Figure 10 maps the conceptual project risk profile (first shown in Figure 8) to a timeline for a project located in a new reservoir. Several experts have considered a conceptual approach to project responsibility or oversight (Wright 2008). An emerging view suggests a timeline in which site characterization and selection take anywhere from 1 to 7 years to complete and are fully the responsibility of the owner/operator. Injection operations last anywhere from 10 to 50 years, depending on the site, and are the responsibility of the owner/operator. Site closure overlaps with operations slightly, as some wells will be plugged and abandoned before a site is closed by an owner/operator. During site closure, injection will cease and the majority of injection wells will be plugged and abandoned, except for those used in monitoring. Monitoring will be carried out to demonstrate that the project does not endanger human health and the environment. Once a project is certified as closed, it would be managed by the government or an institution created for that purpose.

Figure 10: Projected Timeline for a CCS Project



ADAPTED FROM BENSON 2007

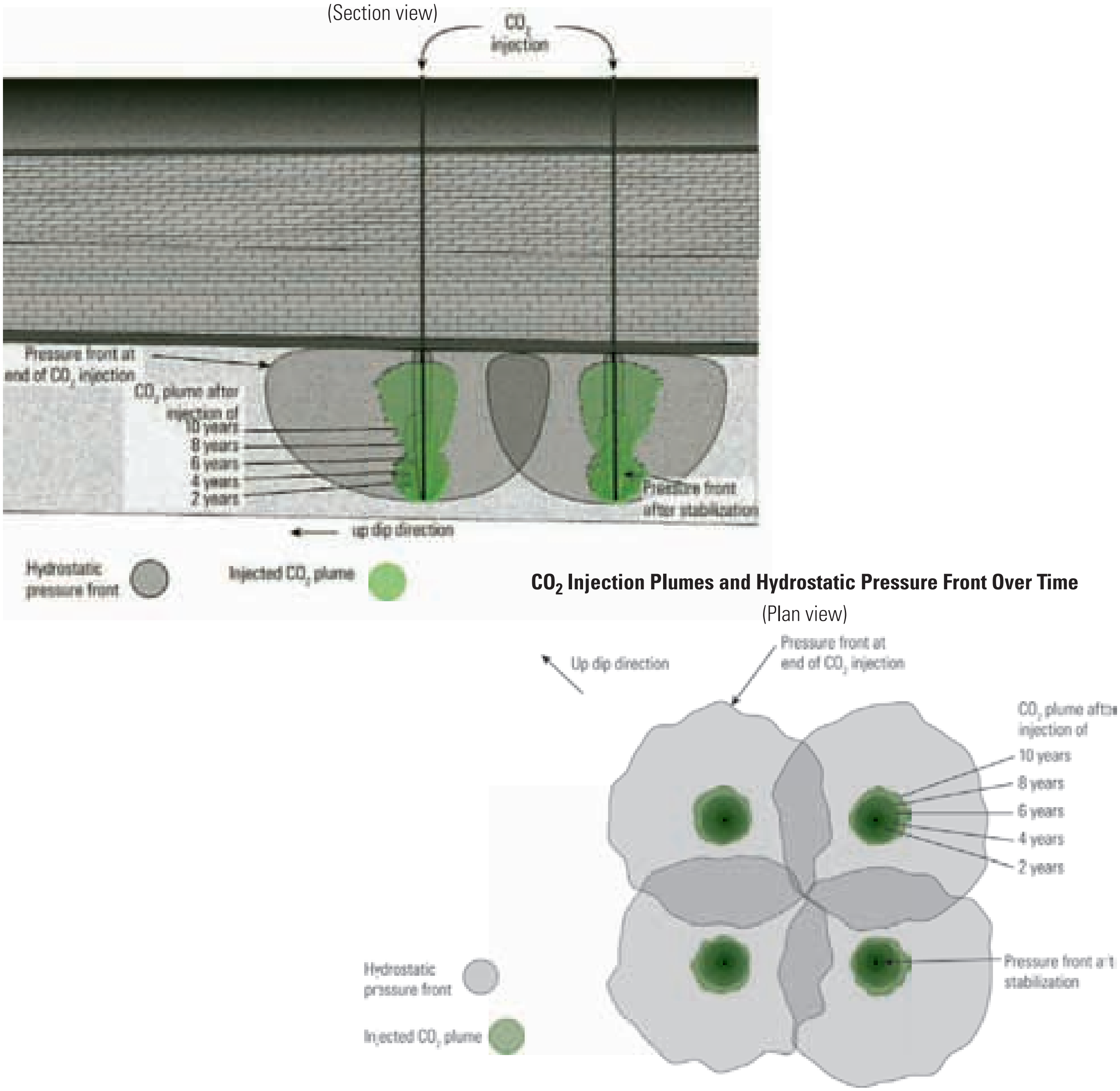
STORAGE

4.2.2 Integration Among Storage Projects: Basin Scale Management

Important integration concerns are the potential cumulative impacts of several large-scale storage projects in a single region, and the potential for one project to impact another's storage reservoir through overlapping areas of elevated pressure (such as depicted in Figure 11). These concerns are not new to injection industries. Once oil was discovered in the United States, there was a race to find, lay claim to and exploit oil fields. Six states used the constitutional right for states to "compact" or work together to address regional problems by forming the IOGCC, which comprises the oil and gas regulators from member states. "Faced with unregulated petroleum overproduction and the resulting waste, the states endorsed and Congress ratified a compact to take control of the issues (see IOGCC)." Since then, the IOGCC membership has expanded to include nearly all of the U.S. states. This model has been used by states in the mid-Atlantic/Northeast region of the country to address ground-level ozone. Similar models are found in regulatory programs that aim to protect watersheds and estuarine systems by imposing controls throughout multistate regions.

Figure 11: CO_2 Injection Plumes and Hydrostatic Pressure Viewed by Plan and Section

CO_2 Injection Plumes and Hydrostatic Pressure Front Over Time
(Section view)



COURTESY OF ILLINOIS STATE GEOLOGICAL SURVEY

In the case of storage, it is expected that the primary approach to project development in the United States will be for private industry to propose projects that make sense economically and environmentally. Given the current technical understanding of the scope of large-scale, sustained CO_2 injection projects, it is unlikely that there will be substantial negative effects associated with any single, well-chosen site in the early stages of a decentralized approach to deployment (Bradshaw et al. 2005). It is not as clear that this will remain the case as multiple well-chosen sites begin to be located near other sites. In the context of the Guidelines development stakeholders have discussed the potential effects of dozens of large projects sited within the same region, where the near- and far-field effects of single projects might begin to interfere with each other or with regional systems. Concerns include the effect of interacting areas of elevated pressure (shown in Figure 11 as the hydrostatic pressure front) and potential impacts on groundwater quality by displacement of large volumes of fluid formations, changes in regional geologic uplift or subsidence patterns, or changes in regional crustal stress orientations and magnitudes. These are issues that have been occasionally encountered in other large-scale injection or production deployments (E.J. Wilson et al; 2003; Wilson and de Figueiredo 2006), and as such, are credible concerns that can be and will most likely need to be addressed at the regional or reservoir basin level. Figure 11 illustrates the potential interference that could be experienced between sites that are located close to each other.

Basin scale management is a key area for research, and several studies are now underway, including using natural geologic system interaction as a model. Because these concerns are about deployment of multiple large injection systems, they do not present an impediment to near-term development of commercial storage projects. However, project developers should anticipate future investigations into the potential effects of multiple project deployments. The result of this research might be a recommendation for more centralized regulation of storage projects and well spacing. Regulators should consider how to most efficiently address this concern in order to reduce the chance of unintended consequences. This issue is discussed in more detail in the Site Selection and Characterization section.

Well Spacing and Unitization

The oil and gas industry often employs the practices of regulated well spacing and lease and/or tract unitization to reduce waste, conserve the resource, and optimize economic recovery, while minimizing field development costs. Regulators often get involved in well spacing decisions in order to optimize production of oil or gas. Unitization is the process of managing an oil or gas field that is owned by many parties as if it were managed by one party. These same concepts are appropriate in thinking about designing storage projects.

Image 1, below, depicts the injected CO_2 and the area of increased pressure in the groundwater. If two wells or projects are spaced close together, the project footprints can interfere with each other (Image 2). If they are placed too far apart, the space in between, which might have been suitable for storage, is wasted (Image 3). And finally, an appropriate location minimizes the amount of wasted space, and operations do not interfere with each other (Image 4). Future work needs to be done to develop an understanding of optimal spacing for CO_2, capture and storage wells.

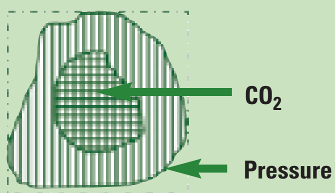


IMAGE 1

Conceptual representation of injected CO_2 and area of elevated pressure

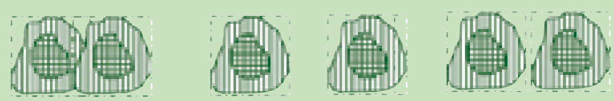


IMAGE 2 IMAGE 3 IMAGE 4

Essential to the success of a storage project is integration among storage project phases and among various projects that use the same regional geologic formation.

4.3 DETAILED DISCUSSION OF STEPS INVOLVED IN IMPLEMENTING A STORAGE PROJECT

This section includes the detailed technical Guidelines for storage practices designed to enable future storage deployments that are safe, effectively retain injected CO_2, are accepted by the public, and can be implemented cost-effectively.

4.3.1 Cross-Cutting Issues

Four issues cross-cut the single stages of a storage project: MMV, risk assessment, financial responsibility, and property rights. They are described as cross-cutting issues because they all apply to each of the single stages that follow. They are described first in an effort to avoid redundancy and repetition later in this document.

4.3.1.1 Measurement, Monitoring, and Verification

As discussed earlier, MMV is presented as a cross-cutting issue because the tools and approaches used in MMV are applied for various reasons throughout the lifetime of a storage project. Further, the results from MMV should be used in an iterative process in conjunction with modeling to inform site selection, construction, operation, closure, and long-term stewardship or mitigation of leakage should the need arise. MMV provides the interface between the project and regulators, insurers, carbon markets, and the public.

A variety of parameters can and should be measured, and numerous techniques or tools are available today. The temptation is to prescribe a standard set of tools that is deemed appropriate. However, the reality is that what may be a meaningful measurement at one site may prove virtually useless at another site (Wright 2008). Likewise, there may be a preferable substitute for a common test that is either an emerging technology or better suited for a particular site. Geologic conditions vary among potential sites, driving the need for flexibility in determining the specific MMV tools deployed at any one project.

The focus of these Guidelines is thus (1) describing the potential applications of MMV, (2) identifying the important parameters, and (3) describing existing techniques and approaches used to collect or develop MMV data. New approaches for MMV are being developed

Use of Predictive Models

Codes are the computer software (e.g., TOUGH, ECLIPSE) used to develop models, while models incorporate site-specific data into the mathematical framework of the code. Using a dynamic model, one can perform *simulations* in order to predict and understand potential changes under different scenarios or conditions. Models can be used to perform sensitivity analysis, allowing modelers to observe the relative importance of each input variable in influencing the output.

Subsurface flow simulations (also called *hydrogeologic or dynamic models*) are used to predict CO_2 plume movement and the rate and degree of CO_2 trapping mechanisms (i.e., dissolution), and to identify where to locate wells to best utilize storage capacity and avoid potential leaks. For CO_2 capture and storage (CCS), flow simulations may incorporate multiphase flow processes (e.g., immiscible displacement, capillary trapping); geochemical reactive transport (e.g., mineralization, metal mobilization); and geomechanical processes (e.g., confining zone deformation, fracturing). For CCS, the subsurface flow simulation should encompass the target reservoir and confining zone, as well as a buffer zone at the highest resolution practical. Periodic history-matching and simulation updates should be required.

The foundation of the subsurface flow simulation is a representation of the geologic structure of the system (i.e., *earth* or *static model*) that incorporates available site characterization data, such as results from well-log interpretations and seismic surveys. Typically, a three-dimensional grid is created, with up to millions of grid-blocs, or cells. Geostatistics may be used to assign reservoir properties (e.g., porosity, permeability, etc.) to each cell, interpolating where data are not available. As additional data are gathered during the site selection, characterization, and monitoring phases of the project, it is essential that the model be updated.

System-level models can use elements from subsurface flow models, as well as from models of other stages of the CCS process (e.g., pipeline transport) to support risk-based scenario evaluation. Such system models can be designed to include probabilistic data, including such factors as potential future economic conditions or uncertain regulatory requirements.

Given the current technical understanding it is unlikely that there will be substantial negative effects associated with any single, well-chosen site in the early stages of deployment.

Microseismic Monitoring

Microseismic monitoring uses a down-hole receiver array that is positioned at depth in a hole near the injection well. An image of the fracture position and orientation can be generated by mapping detected microseisms (micro-earthquakes) that may be hydraulically triggered by shear slippage along an existing or newly created fracture. Microseismic mapping can be performed in the injection well in cases where suitable offset monitoring wellbores are not available. A benefit of microseismic fracture mapping is the ability to measure very small seismic events; however, it is often difficult to detect events that are more than 800 meters away. In general, microseismic tools work best where permeability is not very high and where the rocks contain abundant natural fractures. Microseismic arrays were tested at Weyburn and are being considered at In Salah (Wright 2008).

as technology improves or new questions arise. In addition to considering the best suite of MMV tools for each project, it is also important to consider how to adopt new techniques, if warranted, as they are developed.

In general, MMV has multiple applications throughout a project life cycle:

- Measurement of rock properties (such as porosity and permeability) and subsurface characteristics are key factors in selecting suitable locations for CCS projects.
- MMV data on subsurface characteristics form the basis for a reservoir model and subsurface flow simulation that is used to predict the migration of injected CO_2. The model or simulation informs regulatory review, acquisition of property rights, and project design.
- Measurements of the flow rate, injected volume, and composition of CO_2 are used to improve the performance of a project through modifications in the operations plan and to demonstrate compliance with permit requirements.
- Monitoring wells are established to collect data, including reservoir pressure (sometimes in the porous zone immediately above the primary confining zone) and formation fluid chemistry.
- Periodic characterization of the project footprint is used to validate and update the reservoir model and flow simulation, and to ensure public and environmental safety.
- Ongoing MMV data are used to assess the subsurface flow simulations and to determine if any mitigation steps are necessary.
- Mechanical integrity tests are taken to monitor and demonstrate the integrity of the injection and monitoring well(s).

KEY MONITORING PARAMETERS

This section outlines some of the important parameters for MMV:

- Monitoring for injected or displaced fluids is used to update and validate the subsurface models.
- Reservoir pressure (injection zone) and in-situ stress monitoring aids in detection of a breach in the confining zone(s).
- Monitoring zone (immediately above the confining zone(s)) pressure and temperature allows for early detection of CO_2 movement outside the confining zone(s).
- Well integrity monitoring allows for increased confidence that fluid movement is not occurring via the wellbore outside the injection tubing.
- Monitoring CO_2 concentrations and fluxes and fluid composition enables detection of CO_2 in the groundwater or at the surface.

Table 7 summarizes the key parameters that should be monitored and indicates some of the techniques that are commonly used to assess those parameters. Note that selection of techniques will be site-specific as well as fit-for-purpose.

INJECTED AND DISPLACED FLUIDS

Monitoring the location of the CO_2 plume should begin during injection and continue after injection ceases until there is a satisfactory demonstration of non-endangerment (as discussed in section 4.3.2.3). Once injection ceases, the factors driving subsurface CO_2 displacement (buoyancy and pressure) dissipate or become stabilized (Benson 2007). In that context, the frequency of surveys may substantially decrease relative to the operational phase. During injection, plume location monitoring can be used to evaluate the validity of the subsurface flow simulation of the CO_2 plume by history-matching, or showing that the predicted behavior matches actual conditions. The goal of plume monitoring during closure is similar to that of monitoring during the operational phase. However, because there is no longer a source of active CO_2 injection, the monitoring results collected during this period will be used to validate simulations of plume movement and identify unanticipated migration toward potential leakage pathways under the new conditions. After some finite amount of time, it should be possible to understand how the reservoir heterogeneity, gravitational forces, and decline in pressure affect continued migration and validate that understanding. The duration and frequency of monitoring may increase or decrease based on site-specific information and site performance.

RESERVOIR PRESSURE AND IN-SITU STRESS MONITORING

Pressure monitoring is an important tool in managing in-situ stress, with the primary goal of ensuring that fractures that may compromise the confining unit(s) are not created, and existing sealing faults are not reopened. Experience in working with subsurface environments indicates that some fracturing of the injection reservoir itself may

Table 7: Key Geologic and Environmental Parameters to Monitor

Parameter	Techniques	Information Gathered
Project footprint at depth	■ Time-lapse seismic ■ Crosswell seismic ■ Reservoir saturation tools ■ Vertical seismic profiling ■ Electrical surveys ■ Microseismic ■ Microgravity ■ Monitoring wells ■ InSAR/tilt/GPS	CO_2 and pressure geometry and location
Reservoir pressure and temperature	■ Downhole pressure sensors ■ Bragg fiberoptic grating ■ Thermocouples	Evaluating integrity of confining unit(s) and wells
In-situ stress	■ Microseismic ■ Triaxial tensiometers ■ Other downhole stress tools	Evaluating integrity of confining unit(s) and wells
Well performance and integrity	■ Cement and casing imaging logs ■ Vertical seismic profiling ■ Well-head detection devices ■ Mechanical integrity testing	Evaluating integrity of wells, monitoring CO_2
Surface and near-surface CO_2 concentrations and fluxes	■ Groundwater sampling surveys ■ CO_2 monitors ■ Artificial and natural isotopes ■ Soil-gas surveys ■ Atmospheric eddy correlation ■ LIDAR ■ Sidescan sonar	Unanticipated leakage; early detection; mitigation planning

NOTE: the measurement, monitoring, and verification (MMV) methods discussed in this table are some of the common approaches used, but this is not intended as a prescriptive or exhaustive list of potential MMV methods that may be useful in a project. For additional information see IEA GHG R&D 2008c.

GPS = global positioning system; LIDAR = light detection and ranging

help increase storage capacity. Pressure should be monitored with care and with emphasis on not compromising the confining zone(s). Pressure measurements can be taken in existing wellbores (i.e., “down-hole”) with existing tools.

After injection stops, the geomechanical risks will decrease as reservoir pressure dissipates or stabilizes over time. The rate of dissipation is a function of reservoir heterogeneity and permeability, and the size of the pressure gradient. For many reservoirs, Darcy’s Law[2] provides a reasonable first-order characterization of how pressure will dissipate, and many simulators can provide accurate and reasonably precise predictions regarding pressure change through time. Given the anticipated pressure dissipation after closure, however, there is not a technical basis for requiring measurement of pressure for long durations after injection.

MONITORING IN THE DEEP SUBSURFACE ABOVE THE INJECTION ZONE

If CO_2 migrates from the storage formation into an overlying porous formation, it will most likely affect the overlying formation’s pore pressure, temperature, and fluid chemistry. This means that measurements for changes in pressure, temperature, and fluid chemistry in deep monitoring zones may be an effective means of early detection of leakage. Because these are direct measurements, they require wellbore access (via monitoring and/or injection wells) to at least the depth of the monitoring zone. It is possible that seismic methods may be able to detect pressure changes in the monitoring zone and may provide an alternative to direct measurements of the deep subsurface.

WELL INTEGRITY MONITORING

Maintenance of well integrity is essential, because a well failure could create a conduit for flow between all formations penetrated by the well and the surface. Wells are constructed from materials—cement (most often Portland-based) and steel—that may be degraded when exposed to carbonic acid and formation fluid (carbonic acid is formed when CO_2 comes in contact with the formation fluids in the reservoir).

Wells with casing that are fully centralized and have a competent cement job will most likely be exposed to carbonic acid under diffusion-controlled conditions, where reaction rates will be slow. Studies (Carey et al. 2006) have indicated that well cements hold their integrity, with some reaction with CO_2, over decades, but more research is needed before the implications for leakage by degradation from carbonic acid are fully understood.

The objective of well integrity monitoring is to prevent leakage and contamination of drinking water supplies (during and after operations), and to demonstrate that the risk of well leakage is sufficiently low during operation and for safe closure certification. Well integrity should be measured through the use of cement and casing mapping tools, as well as mechanical integrity tests. Integrity testing is an important requirement and common practice in existing regulations governing underground injection wells as well as oil and gas production wells.

Researchers have found that for wells that are exposed to static carbonic acid, the rate of degradation and thus the risk of leakage will diminish over time because of buffering reactions between carbonic acid and the alkaline cement. Although wells are constructed of materials that may degrade, experience is beginning to suggest that the quality of the construction may have a larger impact on the integrity of wells than the materials used in construction. This is an area where more research is needed (IEA GHG R&D 2005).

SURFACE OR NEAR-SURFACE CO_2 CONCENTRATIONS AND FLUXES

Many stakeholders view the need for surface monitoring (air and soil gas fluxes) as being a potential requirement for public acceptance; many experts believe because of the relatively low cost, it should be included in an MMV suite. However, some surface monitoring tools have been shown to give false positives (e.g., tracers, soil surveys) (T.H. Wilson et al. 2007, Ya-Mei. ang et al. 2008), and with substantial wellbore and subsurface monitoring, stakeholders expect that any CO_2 leakage should be detected long before it reaches the surface.

Although surface monitoring should not be used as a primary leak-detection measure, it may be useful in detecting very slow or diffuse seepage. CO_2 that begins migration shortly after injection may take a substantial period of time to reach the surface, especially through natural pathways, such as heterogeneous reservoirs. Thus, time to the surface will be a function of path permeability, path length, and reactivity; lower permeability, longer paths, and higher reactivity are generally likely to increase the time needed to reach the surface. Since these kinds of leaks are most likely to travel through groundwater systems to the surface, groundwater geochemical monitoring is likely to suffice as the near-surface monitoring tool for the long term. Additional surface monitoring tools, such as CO_2 sensors and soil gas flux measurements, may be useful during operational project phases or in higher-risk locations, but natural variability in CO_2 fluxes would need to be accounted for and could even undermine the effectiveness of these measurements.

Groundwater Monitoring

Changes in pH, alkalinity, and concentration of calcium or other alkaline earth metals can be measured and used to detect potential CO_2, migration. Groundwater monitoring is advised as a tool to consider throughout a CCS project. Assessment of the baseline water chemistry and mineral content is key to enabling future detection changes in groundwater quality. Much of the analysis can be completed using conventional laboratory techniques, complemented with simple one-dimensional geochemical modeling.

SOURCE: CARROLL AND AINES 2008

DEVELOPING A PROJECT-SPECIFIC MONITORING PLAN

A large number of possible tools and approaches could provide key information to operators, regulators, and other stakeholders. There is no technical agreement at present regarding a minimal or preferred set of tools for a given circumstance, nor is a uniform set of tools expected to work for all projects. However, the stakeholder group believes the current state of knowledge is sufficient for an operator to select tools and methods that can provide the most important information and services, and future regulations should be flexible to allow for the operator to choose the tools that will best facilitate effective monitoring for a given site. Over time, assuming adequate site performance and increased understanding of site geology, it is possible that the MMV needed for a site will decrease based on performance and validation. Any changes in an approved MMV plan would need to be accepted by a regulator before they could become effective.

It is important to understand the limitations of MMV techniques and, therefore, of MMV programs. For example, monitoring programs cannot quantify all aspects of CO_2 fate and transport in the subsurface. Nor should they be expected to detect all leakage in every location. All monitoring programs are limited by the complexities of the subsurface and atmosphere and by the detection limits of the tools. Currently available precision for CO_2 EOR well-head flow meter accuracy in the United States is roughly ±1% (API 1995). As such, direct metering of the injected volume should not be expected to provide precision beyond this standard.

Because of the variability in project sites, these Guidelines do not suggest requiring a specific set of monitoring tools. However, the following key techniques should be considered, if they can be used to provide useful data given the site characteristics and are reasonably cost-effective:

- Pressure, temperature, and fluid chemistry monitoring in the injection reservoir and a monitoring zone immediately above the primary confining zone,
- Vertical seismic profiling,
- Seismic and time-lapse seismic (3- and 4-D),
- Use of tiltmeters, InSAR, or other surface deformation detection tools,
- Microseismic monitoring, and
- Surface air monitoring.

There is particular sensitivity to any regulatory requirements for 3- or 4-D seismic tests because of potential limitations in some geologic formations. Although the first two commercial CCS projects (Sleipner and Weyburn) used 4-D seismic for plume location very successfully, there are some places where it will not work (Arts et al. 2002; Wilson and Monea 2004).

ELEMENTS OF A MEASUREMENT, MONITORING, AND VERIFICATION PLAN

The main elements of an MMV plan include determining the extent of the area to be monitored and establishing plans for baseline, operational, and closure monitoring.

Monitoring Area. The definition of the monitoring area will be, in part, a regulatory consideration. Because of inherent uncertainties with subsurface geologies, this area should begin with the projected CO_2 plume over the project lifetime. For example, the Washington State storage rule (WAC 173-218-115) defined the area as: "The boundaries of the geologic sequestration project which shall be calculated to include the area containing ninety-five percent of the injected CO_2 mass one hundred years after the completion of all CO_2 injection or the plume boundary at the point in time when expansion is less than one percent per year, whichever is greater. . . ." (State of Washington 2008).

In addition to the projected CO_2 plume, the monitoring area should include any area of significantly elevated pressure. Significantly elevated pressure is considered to be a level of pressure to potentially cause adverse impacts to overlying receptors. For example, any pressure that would raise a column of water to the lowermost USDW and, in most cases, outside the confining zone is significant. Combined, these two areas form the project footprint. The extent of the project footprint may change over the lifetime of the project. Monitoring should occur over the project footprint, be informed by data gathered during the site characterization, and be updated in real time with newly collected operational monitoring data used to update the model of the subsurface CO_2 plume. The key to this performance-based approach will be defining the interval between model updates by identifying what constitutes the need to re-evaluate the subsurface model. One approach that could be followed would be to review the monitoring area along with a permit renewal application, or to have a required periodic re-evaluation.

Baseline Monitoring. Effective MMV relies on establishing an initial baseline before injection, and then monitoring after injection begins to detect and characterize changes in important parameters. Thus, it is essential to establish a pre-injection baseline. Baseline surveys should be conducted for each relevant monitoring parameter. In some cases, this will require simply the deployment of tools or one round of data collection to define the initial state (e.g., 3-D seismic, microgravity). For other tools or approaches, it may require weeks, months, or even years of monitoring and characterization to understand the natural fluctuations at a site (atmospheric or soil CO_2). Potential operators should understand the nature of their site in order to predict their monitoring needs and deploy their preferred monitoring suite far enough in advance to establish a baseline with sufficient accuracy and precision for successful site management. This must take place over enough of the project footprint to fully monitor the first project stage. EOR sites may pose unique challenges for baseline monitoring and any challenges with collecting such baseline data should not preclude secure storage at an EOR site.

Operational Monitoring. Operational monitoring for a large-scale CO_2 injection facility will closely resemble the injection facilities of a CO_2 EOR flood. This has been the case at the existing commercial operations at Weyburn, In Salah, and Sleipner. In particular, standard monitoring, such as injection volume, well-head and down-hole pressure, and injection zone monitoring are expected in order to satisfy local safety requirements and the basic needs of operators to know that the CO_2 is properly handled (Melzer et al. 1996a).

Jarrell et al. (2002) write extensively on the operational monitoring needed for CO_2 EOR with conventional technology and accepted approaches. Some of these parameters (e.g., produced oil volume) will not be relevant for saline formation storage projects. However, the following are key components of operational monitoring for CCS projects:

- **Pre-injection well logging:** If operators plan to use existing wells for injection, then they will need to investigate the well history, integrity, perforation status, and injection profiles. In some cases, redesign, recompletion, and re-evaluation may be needed.
- **Injection metering:** All injection wells should have flow meters and pressure sensors to accurately measure injection into each well.
- **Injection profiles:** This temperature or tracer type logging reveals where the injectant is flowing. Such measurements are not continuous, but may be required early in the injection and on an occasional basis afterward (e.g., once a year).
- **Reservoir pressure data:** This may be accomplished either with down-hole pressure sensors or by inverting surface pressure and injection data, given knowledge of the injection profile. Down-hole sensors should be deployed (Magruder et al. 1990; Pittaway and Runyan 1990).

4-D Seismic Surveys

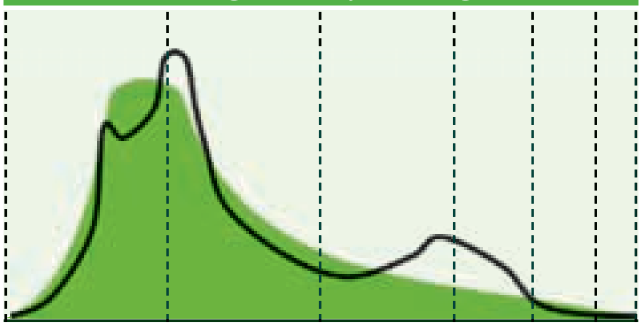
4-D seismic surveys are collected by sending sound waves into the ground from a controlled source (on land this is commonly a Vibroseis truck) and gathering them with geophones set out in a dense array. The acoustic wave signals can detect small changes in density and velocity, including those caused by variations in rock and fluid properties at depth. These signals are processed and rendered in a 3-D grid called a seismic volume. A fourth dimension is achieved when the seismic data are acquired at different times over the same area.

SOURCES: ARTS ET AL. 2002; WILSON AND MONEA 2004

- **Step-rate tests:** These tests are collected before injection to reveal the maximum allowable pressure without inducing failure or formation parting pressures (Magruder et al. 1990; Pittaway and Runyan 1990).
- **Pattern balancing:** In the case where fluid is withdrawn, this information helps to improve the advance of the flood, thereby increasing the amount of CO_2 that contacts rock and formation fluids. It derives from the other data but requires separate analysis.

Closure Monitoring. Once injection ceases, CO_2 will continue to displace water, migrate, dissolve, and mineralize. The pressure within the injection formation will decline as the pressure decreases, and more CO_2 will be permanently trapped as a residual or dissolved phase. Reactive, CO_2-rich formation fluids will be buffered through dissolution and precipitation, thereby reducing their reactivity and increasing their pH. Figure 12 shows the conceptual risk profile used at the beginning of the Guidelines. Here it has been modified to show the possibility that any single project will not have a smooth, even progression of risk, but instead may experience site-specific risks due to geochemical reactions and rock kinetics not fully described in site characterization. During the operational life of a project, MMV programs may detect these risk-exposure pathways, and adjustments in the MMV strategy can be made. There is a continuing potential to encounter previously uncharacterized risk-exposure pathways post-closure, although the likelihood of this may decrease after injection. Because the risk of leakage is expected to decline through time, the amount of monitoring after site closure should be less than that during operation. While many of the key parameters remain important (e.g., reservoir pressure), the degree of sophistication and diligence can be reduced based on site-specific performance showing that the plume is behaving as predicted in the simulation model. In the case where this performance is not achieved during the operational life of a project and/or post-closure MMV gives rise to concerns, the MMV program will most likely be extended or expanded during post-closure.

Figure 12: Conceptual Risk Profiles for a Large CCS Project Through Time

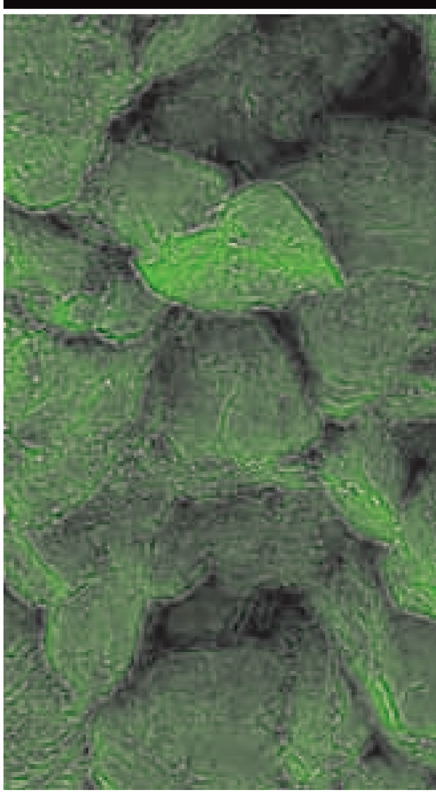


MONITOR

The green shaded curve represents a project with increasing pressure to some predetermined limit and decreasing risk subsequent to injection. The black line represents an alternate potential risk profile in which secondary increases in risk are a function of local geochemical risks of transport processes.

ADAPTED FROM BENSON 2007

STORAGE GUIDELINE 1: RECOMMENDED GUIDELINES FOR MMV



a. MMV requirements should not prescribe methods or tools; rather, they should focus on the key information an operator is required to collect for each injection well and the overall project, including injected volume, flow rate or injection pressure, composition of injectate, spatial distribution of the CO_2 plume, reservoir pressure, well integrity, determination of any measurable leakage, and appropriate data (including formation fluid chemistry) from the monitoring zone, confining zone, and underground sources of drinking water (USDWs).

b. Operators have the flexibility to choose the specific monitoring techniques and protocols that will be deployed at each storage site, as long as the methods selected provide data at resolutions that will meet the stated monitoring requirements.

c. MMV plans, although submitted as part of the site permitting process, should be updated as needed throughout a project as significant new site-specific operational data become available.

d. The monitoring area should be based initially on knowledge of the regional and site geology, overall site-specific risk assessment, and subsurface flow simulations. This area should be modified as data obtained during operations warrant. It should include the project footprint (the CO_2 plume, the extent of injected or displaced fluids, and any areas of significantly elevated pressure). Groundwater quality monitoring should be performed on a site-specific basis based on injection zone to USDW disposition.

e. MMV activities should continue after injection ceases as necessary to demonstrate non-endangerment, as described in the post-closure section (see Storage Guideline 7d).

A Conceptual Approach to Selecting Appropriate MMV Tools

British Petroleum (BP) has presented a conceptual approach for selecting appropriate measurement, monitoring, and verification (MMV) tools based on work conducted for the In Salah project. The figure below depicts a graph with axis for (1) the benefit of the information on the vertical scale and (2) the cost of obtaining the information on the horizontal scale. In both cases, these aspects should be evaluated based on the specific characteristics of the site at hand.

Based on the site-specific geology at the In Salah project site, potential MMV techniques were identified, both techniques that are thought to be key MMV tools (in dark green), as well as techniques that the project wished to test (in light green). It is important to note that the MMV techniques indicated in the figure are ones considered in the In Salah research project. This figure is not being used to suggest that all of the MMV techniques listed are appropriate for other projects, but rather to highlight the process used at In Salah to determine which MMV techniques best suited that project.

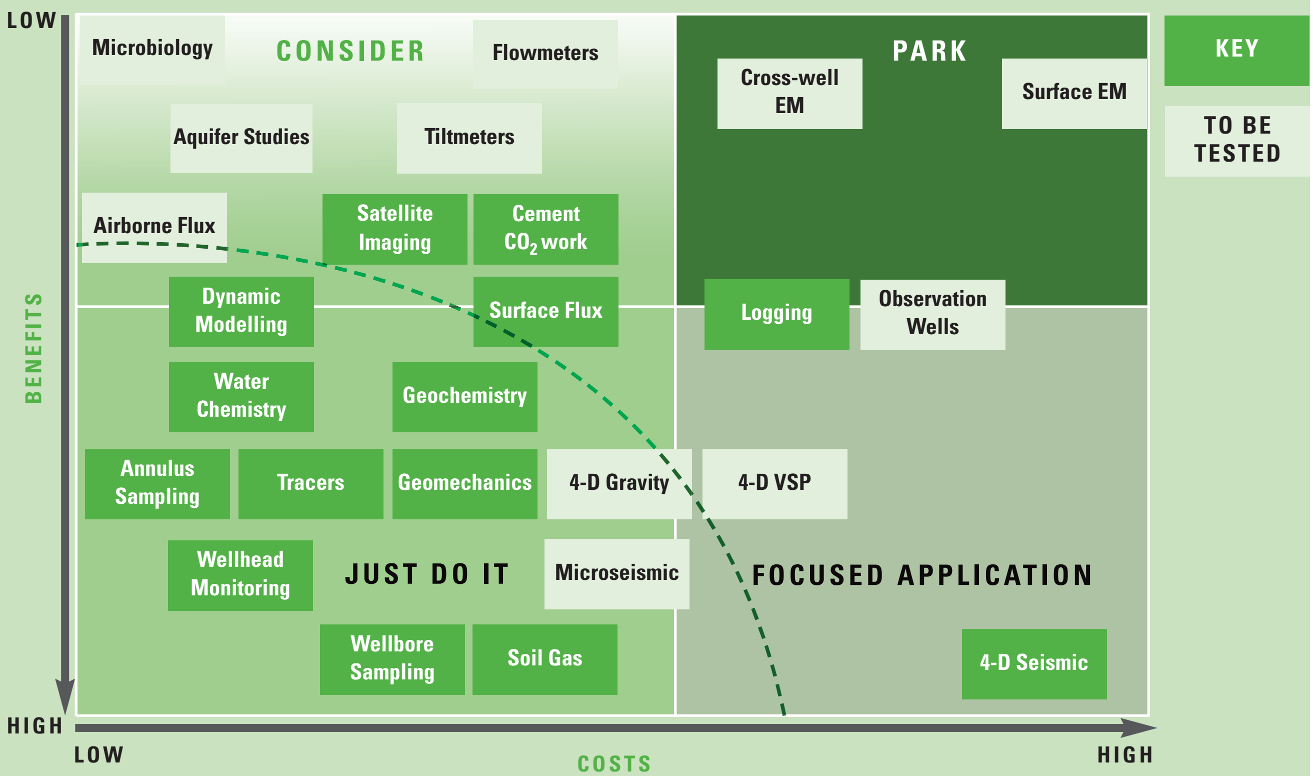
Combined, this graph creates four quadrants:

- The "Just Do It" quadrant represents techniques that have a high information value and a low cost.
- The "Consider" quadrant represents techniques that do not appear to provide significant information value, but are considered because they are low-cost techniques.
- The "Park" quadrant represents techniques that have high costs and a low information value. These techniques are not attractive.
- The "Focused Application" quadrant represents techniques that provide valuable information about the project but are high in cost. These approaches might be used judiciously. For example, careful planning might be undertaken to ensure that, if used, 4-D seismic is run in such a way as to provide maximal information.

The dotted line on the graph represents a hypothetical cost/benefit horizon for selecting MMV tools. As a preliminary assessment, those techniques located to the left of the red dotted line appear to make sense for the project and those outside of this horizon may be inappropriate.

Once a preliminary assessment pointed to a potential suite of appropriate MMV techniques, further analysis was done to determine their cost-effectiveness. A few techniques were found to be more effective than originally anticipated, while others were found to be less informational or more expensive to conduct.

This conceptual approach may be useful to developers and regulators in considering how to determine the most appropriate MMV strategy.



SOURCE FOR FIGURES: WRIGHT 2008

4.3.1.2 Risk Assessment

Risk assessment and management is included as a cross-cutting issue because it is used not only to help select project sites and design operations plans, but also, throughout the life of a CCS project, to ensure its continued safety and integrity through operations, closure, and post-closure. Risk assessment involves the identification (or qualification) and quantification of hazards, including the probability of features, events, and processes that can result in undesirable impacts on human health, the environment, and potentially other receptors. Once risks are assessed, a project developer may choose not to proceed with a project or manage those risks through decisions in the project design, operations, and MMV plans. Risk mitigation is the planning for and implementation of contingency plans, should the need arise, to remediate adverse impacts. Such planning should also include risk reduction measures, identifying potential negative impacts and taking steps to reduce their likelihood and/or severity. Since the approach to risk should be consistent during any stage of a CCS project, it is described in detail here and referred to as needed throughout the rest of the Guidelines.

Risk assessment is central to many industrial activities. A body of literature and established practices for this type of analysis already exist (U.S. EPA 2008e; Duguid and Celia 2006; Friedmann 2004; Oldenburg et al. 2002). It is assumed that project developers will utilize these approaches to evaluate and manage risks that are reasonably common to large industrial projects, such as power plants and oil production operations. This section draws from that body of knowledge to focus on the primary risk of concern in relation to CCS: the potential for CO_2 leakage resulting in adverse impacts on human health and the environment.

Any viable site for storing CO_2 will most likely include some number of identified hazards. When appropriately characterized and managed, the hazards for most sites will not present a substantial leakage risk (IPCC 2005). The risks associated with the hazards identified should also influence MMV strategies for a given site. Potential operators should undertake substantial efforts within the proposed site area to identify hazards and assess the risk of leakage through mapping, analysis, and simulation.

HAZARD IDENTIFICATION

Hazard identification should focus on the main potential pathways for CO_2 leakage: (1) insufficiency of the confining unit(s) or cap rock failure, (2) artificial penetrations (wells), (3) transmission through faults and fractures, and (4) naturally occurring or induced seismic events that may lead to new or expanded transmissive faults cross-cutting protected resources or reaching near the surface environment (Friedmann 2007).

PROTECTING THE INTEGRITY OF THE CONFINING ZONE

Later in the Guidelines, the characteristics of a good confining zone are discussed in depth, including areal extent and rock properties. In addition, priority should be placed on evaluating any potential vulnerability in the primary cap rock and the remainder of the confining unit(s). An important vulnerability stems from over-pressurization of the injection reservoir. It is standard practice to address this concern by controlling injection pressure and monitoring reservoir pressure.

From a technical perspective, there are several ways to measure the yield strength of a cap rock, including laboratory tests on core samples and conventional well tests (e.g., leak-off test, parting pressure tests, step-rate tests). These tests are used to calculate the reservoir pressure that would induce failure (known as fracture gradient or fracture pressure). Typically, the injection permit requires that injection pressures remain below levels that approach the fracture pressure or would unduly increase reservoir pressure. During risk assessment, a developer should define this threshold for the unique geology of that CCS project site and implement control measures to ensure that injection pressures do not induce failure. Most injection regulations require an operator to ensure that injection operations do not exceed some portion of the fracture pressure. While using this kind of a numeric standard may be appropriate in most cases, under certain stress, mechanical strength, and poroelastic conditions, fault valving (causing otherwise non-transmissive areas of a fault plane to intermittently transmit fluid) can happen even if injection pressures are set at levels that avoid fracturing the cap rock. Specific geologic conditions may require setting an injection pressure that is well below the fracture pressure.

ARTIFICIAL PENETRATIONS—WELLS

Deep wells pose a challenge for CCS. They are necessary for injection and monitoring, and they provide the access necessary for acquiring site characterization data to define the thickness and areal extent of potential storage reservoirs and confining units. The challenge is that while more wells that penetrate the deep subsurface provide more information about the subsurface geology, they also pose an increased risk as a potential pathway for leakage. By penetrating the confining zone (or cap rock), the same wells that provide critical data also potentially compromise the primary storage mechanisms for CO_2 storage: physical trapping. To maintain operational integrity, wells that are no longer in operational service should be cased and cemented (this occurs during construction) and, ultimately, plugged and abandoned (Jarrell et al. 2002).

Despite the long, successful history of well engineering, there are potential failure mechanisms that could allow CO_2 to escape from storage reservoirs through wellbores (Gasda et al. 2004; Scherer et al. 2005). The integrity of a wellbore is influenced by several factors, including the age of the well, type and condition of casing, quality of completion, number of re-completions, method of plugging and abandonment, and post-closure history (Ide et al. 2006).

Several approaches can be employed to understand well-related leakage potential and to mitigate potential risks. There have been several attempts to generate statistical and physical methods to quantify the risks associated with wells in a CCS project (Celia et al. 2006). Careful review of public drilling and completion records archived by state agencies can inform this type of analysis and generate regional or basin-scale screening tools. In addition, conventional geophysical tools can detect casing from old "unknown" wells, including buried, lost, and mislocated wells (Veloski and Hammack 2006). These surveys have increased in popularity due to their relatively low cost and high utility. Finally, it is possible to monitor wells directly through regular surveys to detect leakage. In the event that leaks are detected, conventional approaches (Rabia 1986) can be used to re-complete active wells or plug abandoned wells.

FAULTS

The wide variety of geologic formations around the world presents a complex, heterogeneous collection of materials. Over time, this material has undergone horizontal and vertical movement, which has flexed, folded, and fractured the strata. These features, events, and processes have created areas with oil and gas accumulations and potential CO_2 storage sites, but they also represent potential leakage pathways. In the context of CO_2 capture and geologic storage, the impact of the presence of faults is highly site specific. Some faults are conduits for rapid fluid migration, while others seal the confining zone and prevent fluid migration (More et al. 1994).

In considering the role of faults at a potential site, two important points should be emphasized:

The results from MMV should be used in an iterative process in conjunction with modeling to inform site selection, construction, operation, closure, and long-term stewardship.

(1) *The presence of seismically active faults does NOT exclude a site from either holding CO_2 or being considered for storage, although a strong demonstration must be made that there would be no risk of leakage resulting from seismic activity.* There are many places in the world where large volumes of buoyant fluids (e.g., oil, gas, and CO_2) are trapped indefinitely in the presence of seismic activity, including California, Wyoming, Alaska, Turkey, Western Australia, Papua New Guinea, Indonesia, and Iran. After the injection of almost 9,000 metric tons of CO_2 in the Nagaoka CCS demonstration, operations were disrupted by the Mid-Niigata Chuetsu 6.0-magnitude earthquake. Following careful evaluation, it was determined that the wells, the reservoir, and the facility were intact and undamaged, and injection resumed (RIITE 2008).

(2) *Many aspects of a fault affect its ability to trap CO_2 at a site.* These include the geometry of the fault, its complexity, the orientation of the fault relative to regional stresses, the amount and distribution of fault gouge, and the occurrence of either elevated or reduced pressure nearby (Yielding 1997). In some cases, it is relatively straightforward to obtain key pieces of information that can be used to understand the potential risks presented by a fault or network of faults. Recently, Chiaramonte et al. (2007) gathered information to estimate the potential for faults within one oil field to transmit CO_2. In their calculation, one fault had a very low chance of becoming transmissive, and would require injections well above reasonable operational pressures to act as a leakage conduit. In contrast, another fault network in a different part of the field would act as a conduit for CO_2 in the presence of even a small injection. If this were an operational site, the southern part of the field would be a good zone of storage, while the northern part would not because of the possibility for transmissive faults at operational pressures. This example highlights the need for careful site characterization in selection and the importance of high-quality data.

The presence of large, active faults should not necessarily preclude prospective sites from selection as storage sites. Rather, the complex nature of faults in and associated with potential injection sites must be characterized, considered, and managed as part of a risk assessment and MMV plan. Hazard identification should focus on faults that could be transmissive within the injection reservoir or confining zone and expected project footprint, as faults only represent a substantial hazard if they can transmit large volumes of CO_2.

SEISMICITY

It has been known for roughly 40 years that, under some circumstances, injection of large fluid volumes can generate seismic activity (Wesson and Craig 1987). In most cases, these effects will be quite small, but under the wrong circumstances they may be quite large. The most spectacular example comes from the Rocky Mountain Arsenal near Denver, Colorado (Evans 1966). In that case, injection of large volumes of fluid produced earthquakes as large as magnitude 5.3 (Evans 1966; Healy et al. 1968). It is important to note that at that site, the target rocks were completely impermeable, and as a result of injection of fluids, sustained very large pressure buildups in the rock's fractures. This is not likely to be true for commercial CO_2 storage sites, where injection will occur in porous rock units.

One relevant case of induced earthquakes involves the Rangely oil field in northwestern Colorado (Hefner and Barrow 1992). This site was the target of a series of experiments led by Stanford University to generate small earthquakes in the hope of preventing larger events. Between 1969 and 1972, the researchers injected very large volumes of water into a fault in order to cause earthquakes (Raleigh et al. 1976). The fault was selected because it was thought to be close to failure. After several series of injections, the team was able to generate several seismic events. However, the largest of these events was magnitude 3.1, which could barely be felt at the surface. The overwhelming majority of induced earthquakes were less than magnitude 1, too small to feel at the surface. After these experiments, the Rangely field became a site of active CO_2 injection (Klusman 2003b).

Injection of CO_2 near a fault will not automatically trigger a large earthquake. As discussed above, the case of Rangely demonstrates that large CO_2 injections are possible without inducing earthquakes. Similarly, the history of water-flooding and formation fluid injection in California oil fields also demonstrates that large volumes of fluid may be injected next to large faults without causing failure. However, careful site characterization and operation, along with a risk assessment, are critical to managing seismicity, and the uncertainties related to CO_2 injection can only be answered with large-scale injection tests.

Seismic risks related to elevated pressure during injection should be assessed during site characterization. Appropriate MMV should be designed to (1) assess the validity of the characterization and (2) to ensure that any pressure or fluid composition thresholds leading to unacceptably high risks are avoided. Microseismic monitoring is a mature technology that shows promise as a tool to achieve these goals.

EVALUATION OF RECEPTOR IMPACTS

As stated earlier, the expectation is that appropriately selected and managed sites will retain the injected CO_2 for thousands of years, and that leaks to the atmosphere are unlikely (IPCC 2005). A comprehensive risk assessment is part of that site management. For the purposes of risk assessment, a priority is to evaluate what would happen if CO_2 migrated unexpectedly through the confining unit(s), potentially resulting in undesirable impacts on a variety of potential receptors. While still in the subsurface, CO_2 could impact sources of drinking water or diminish the value of mineral rights. If leaked to the surface, CO_2 could collect and harm humans, animals, and plants; cause other property damage; and contribute to climate change.

HUMAN AND ECOSYSTEM IMPACTS

Risks to people and ecosystems arise from the potential for CO_2 to accumulate in low-lying areas or areas with poor air ventilation. If CO_2 leaks to the surface in areas with poor ventilation, such as basements or shallow dips in the ground, it can accumulate to levels that could cause stress or even asphyxiation in humans and animals. For humans, concentrations above 50,000 ppm can cause unconsciousness, with possible death at concentrations above 100,000 ppm. Plants are affected when the roots become saturated with CO_2.

CO_2 quickly dissipates into the atmosphere; however, it is heavier than air, and there are known fatalities associated with natural releases of CO_2 (Lewicki et al. 2006). An important part of risk assessment is developing an understanding of the general topography and population base of the area above a storage project. Although the EPA Program does not require it, other regulatory programs administered by EPA require modeling and analysis of calm conditions (where wind does not expedite dispersion) in evaluating airborne emission risks. Operators should consider modeling denser-than-air releases. If potential concerns are identified, then steps can be taken to prevent adverse impacts.

GROUNDWATER

Risks to groundwater quality arise from the potential for CO_2 to mobilize organic or inorganic compounds, acidification, and contamination by trace compounds in the CO_2 stream, intrusion of native saline groundwater into USDWs, and the potential for the CO_2 to displace subsurface fluids on a regional scale. The risks resulting from CO_2 migrating from the injection zone into a potable aquifer need to be better understood. Scientific studies bounding the potential harm to groundwater resources from CO_2 leakage would provide better constraints on the overall relevance of this risk. For example, if a site has high natural occurrences of toxic metals (e.g., arsenic) or high volatile organic carbon content, site assessors would need to analyze the site hydrology and geochemistry to understand potential health effects for a given CO_2 leakage rate and concentration (Friedmann et al. 2006).

ATMOSPHERIC RELEASE

The potential of a diffuse subsurface CO_2 leak to affect human health and safety is minimal in many regions, because of atmospheric mixing that prevents high atmospheric CO_2 concentrations from making contact with a potential receptor (Bogen et al. 2006; Lewicki et al. 2006). A circumstance that might produce higher rates of CO_2 release (and thus high concentrations and greater potential for receptor impacts) is uncontrolled venting from abandoned or orphaned wells, but even those cases are not expected to result in substantial receptor impacts (Bogen et al. 2006). As described above, another circumstance that could result in high concentrations of CO_2 would be if a slow leak accumulated in an unventilated area. These scenarios can be avoided with proper site selection and diligent risk analysis, MMV, and contingency mitigation plans.

A Conceptual Approach to Risk Assessment

Schlumberger Carbon Services (a service provider for carbon dioxide capture and storage; measurement, monitoring, and verification; and risk assessments) recently presented an example of a risk assessment for a planned storage project in Illinois. To develop this risk assessment, Schlumberger convened a group of experts to rank a list of more than 80 risk elements—or features, events, and processes (FEPs)—based on "likelihood" (L) and "severity" (S). These rankings were developed through a group process and independent surveys of the experts.

The rankings were assessed through two methods. First, the team developed a combined (L*S) ranking and compared group and individual ratings. Second, the team mapped FEPs on a grid, with severity on the vertical axis and likelihood on the horizontal axis. These approaches provide the project team with a good assessment of concerns that could arise at the specific site and will enable them to both incorporate those risks into the reservoir models and also to mitigate those risks through careful planning and operations. This kind of assessment will also help the team to design a monitoring plan and interact with the public and regulators. It is important to note that this kind of assessment can be repeated over time; it is not a static analysis.

SOURCE: HNOTTAVANGE-TELLEEN 2008.

Risk management plans for CCS projects should span the project life cycle and be updated periodically to evaluate risks based on any new data collected.

In considering the potential atmospheric release hazards at a site, one should consider existing cases of CO_2 well failure (Bachu 2000; Gouveia et al. 2005; Holloway et al. 2007). These can serve as the basis for scenarios to understand potential impacts of site release.

The other risk from atmospheric release is the contribution of the released CO_2 to global climate change, negating the benefits assigned to a storage project. There may be several ways of addressing this risk, including discounting the climate change benefit, using insurance or options on allowances, and other financial risk management approaches.

RISK MANAGEMENT

Once risks are understood, a project developer can take steps to avoid or manage them. These include deciding not to proceed with injection at a particular site. However, other steps can be taken to modify the design as well as the operation. MMV plans contribute by providing early detection to ensure risks are not realized. Risk management plans for CCS projects should span the project life cycle and be updated to evaluate the risks associated during capture, transportation, and injection of the CO_2, as well as risks associated with post-closure storage. As shown in Figure 10, the risk of CO_2 leakage to the atmosphere is expected to be greatest during the early operational phases of a storage project. Examples of operational leakage include compressor failures that result in the need to vent CO_2, wellbore failures, and other incidental operational emissions. Many of these risks are relatively common to large industrial projects, and there are standard practices for managing them. However, some of these risks are unique to storage.

MITIGATION OR REMEDIATION PLANNING

To mitigate the risks of unanticipated migration of the CO_2 plume and potential leakage, operators should develop a contingency mitigation plan or remediation strategies, and make efforts to reduce identified risks. The approach should reflect both the site hazard priority and the concerns of local regulators and communities regarding potential impacts to groundwater, the atmosphere, or the confining unit(s). For example, if groundwater contamination is both a particular site hazard and regulated under stringent local water quality guidelines, then a specific mitigation plan for groundwater contamination should be part of the operational management plan. Potential operators should develop minimal mitigation plan requirements. It is important that the contingency mitigation plans are neither unduly burdensome nor too lax. One method used in Chevron's Gorgon Project in Australia is a mitigation plan that includes defined actions in response to indicators (signposts) with technology descriptions (Chevron Australia).

To address the anticipated risks, several approaches could be considered based on project-specific leakage risks. Table 8 summarizes the potential risk scenarios and remediation options. It is important to note that while mitigation techniques may exist, careful consideration as to cost and effectiveness needs to be given before employing these approaches. In some cases, leakage will not result in contamination and may not require significant mitigation. In other cases, a mitigation technique may prove to be very costly or may result in other issues needing to be addressed, such as produced brines or waste materials requiring disposal. The potential environmental impacts of remediation options should be part of a comprehensive environmental impact study.

Table 8: Possible Risk Scenarios and Remediation Options for Geologic Carbon Storage Projects

Risk Scenario	Mitigation/Remediation Options
Leakage through faults, fractures and spill points	■ Shut off valves to stop injection. ■ Lower injection rates/pressure. ■ Lower reservoir pressure by removing water or other fluids from the storage reservoir. ■ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ■ Install chemical sealant barriers to block leaks (Jarrel et al. 2002). ■ Stop injection, extract CO_2 from storage reservoir, and re-inject it into a more suitable reservoir.
Leakage through active or abandoned wells	■ Repair leaking wells by replugging with cement. ■ Repair leaking injection wells with standard well recompletion techniques, such as replacing the injection tubing and packers. ■ Plug and abandon wells that cannot be repaired. ■ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ■ Install chemical sealant barriers to block leaks. ■ Stop injection.
Leakage into the vadose zone and accumulation in soil	■ Extract CO_2 from the vadose zone and soil gas by standard vapor extraction techniques. ■ Pump CO_2 away from trenches or other low-lying areas, and either vent or reinject it in the subsurface. ■ Employ passive remediation, such as diffusion and barometric pumping to slowly deplete one-time releases of CO_2 into the vadose zone. This method may not be effective for managing ongoing releases, because it is relatively slow. ■ Irrigation and drainage or alkaline supplements (such as lime) can be used to remediate soils that have acidified because of CO_2 exposure. ■ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ■ Install chemical sealant barriers to block leaks. ■ Stop injection.
Accumulation of CO_2 in groundwater	■ Drill wells that intersect the accumulations in groundwater, and use them to extract the CO_2, either in pure form or dissolved in groundwater. ■ Dissolve mineralized CO_2 in water, and extract it as a dissolved phase through a groundwater extraction well. ■ Pump CO_2-contaminated groundwater to the surface, and aerate it to remove the CO_2. For possible trace element contamination, "pump-and-treat" methods can be used. ■ Create hydraulic barriers to immobilize and contain any contaminants by appropriately placed injection and extraction wells. ■ Employ passive methods that rely on natural biogeochemical processes. ■ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ■ Install chemical sealant barriers to block leaks. ■ Stop injection.
Accumulation of CO_2 in indoor environments with chronic low level leakage	■ Manage potential slow indoor releases with basement/substructure venting or pressurization. Both would have the effect of moving soil gases away from the indoor environment. ■ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ■ Stop injection. ■ Use fans to disperse CO_2, similar to radon fans.
Accumulation in surface water	■ Shallow surface water bodies that have significant turnover (shallow lakes) or turbulence (streams) will quickly release dissolved CO_2 back into the atmosphere. ■ Do not locate projects near deep, stably stratified lakes; however, if impacted, active systems for venting gas accumulations in these lakes have been developed and applied at Lakes Nyos and Monoun in Cameroon. ■ Create a hydraulic barrier by increasing reservoir pressure upstream of the leak. ■ Install chemical sealant barriers to block leaks. ■ Stop injection.

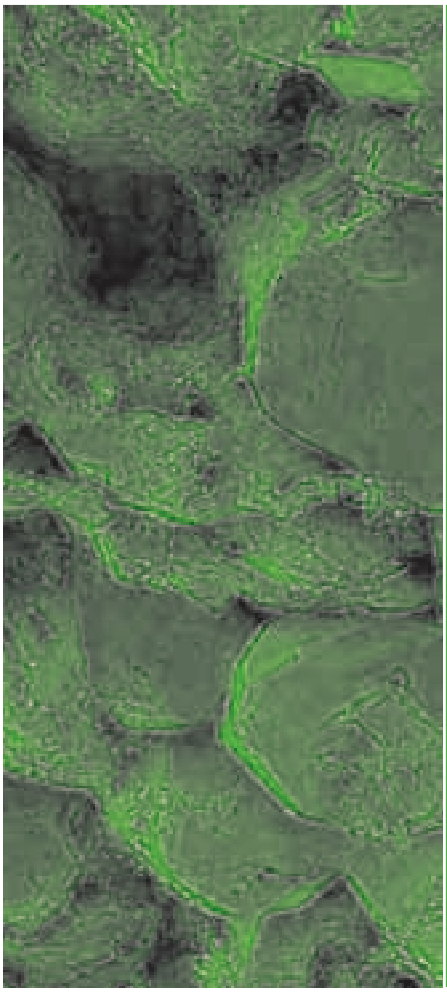
CONTINUES NEXT PAGE

Table 8: Possible Risk Scenarios and Remediation Options for Geologic Carbon Storage Projects (continued)

Risk Scenario	Mitigation/Remediation Options
Large releases of CO_2 to the atmosphere	■ Use large fans to rapidly dilute CO_2 to safe levels for releases inside a building or confined space. ■ Dilution from natural atmospheric mixing (wind) will rapidly dilute CO_2 from outdoor releases over a large area in many cases. ■ Install chemical sealant barriers to block leaks. ■ Stop injection.

SOURCES: IPCC 2005; U.S. DOE 2007B

STORAGE GUIDELINE 2: RECOMMENDED GUIDELINES FOR RISK ASSESSMENT



a. For all storage projects, a risk assessment should be required, along with the development and implementation of a risk management and risk communication plan, should be required for all storage projects. At a minimum, risk assessments should examine the potential for leakage of injected or displaced fluids via wells, faults, fractures and seismic events, and the fluids' potential impacts on the integrity of the confining zone and endangerment to human health and the environment.

b. Risk assessments should address the potential for leakage during operations, as well as over the long term.

c. Risk assessments should help identify priority locations and approaches for enhanced MMV activities.

d. Risk assessments should provide the basis for mitigation/remediation plans for response to unexpected events; such plans should be developed and submitted to the regulator in support of the proposed MMV plan.

e. Risk assessments should inform operational decisions, including setting an appropriate injection pressure that will not compromise the integrity of the confining zone.

f. Periodic updates to the risk assessment should be conducted throughout the project life cycle based on updated MMV data and revised models and simulations, as well as knowledge gained from ongoing research and operation of other storage sites.

g. Risk assessments should encompass the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, with a focus on potential impacts on the integrity of the confining zone and endangerment to human health and the environment.

h. Risk assessments should include site-specific information, such as the terrain, potential receptors, proximity of USDWs, faults, and the potential for unidentified borehole locations within the project footprint.

i. Risk assessments should include non-spatial elements or non-geologic factors (such as population, land use, or critical habitat) that should be considered in evaluating a specific site.

4.3.1.3 Financial Responsibility

In the context of geologic storage, financial responsibility is the obligation of the project operator to pay for defined activities associated with the operation of a CCS project. Specifically, financial assurance is predicated on the expected value of the estimated cost to conduct closure (including well plugging and abandonment, MMV, and foreseeable mitigation (remediation)). In certain situations, financial assurance can also be used to hedge the financial consequences of potential cost overruns associated with these activities, as well as the financial consequences of unanticipated events (e.g., compressor breaks, CO_2 migration). Typically, regulators are concerned with ensuring that adequate funds are in place to close or complete projects, and financiers or risk managers are concerned with ensuring that the costs are predictable and adequate funds are in place for the entire life of the project.

Project developers will estimate these costs during project planning and will use this information to evaluate return on investment and financial risk exposure. These will be important drivers for determining whether to proceed with a project, and serve as an essential foundation for obtaining financing. As project size and uncertainty increase, so does financial risk. Companies will strive to minimize and mitigate this risk through a variety of means. A financial responsibility framework will establish the obligations of various parties to "guarantee the construction, operation, closure, and, to the degree appropriate, safe post-closure monitoring of their facilities." Further, an effective financial assurance framework will (E.J. Wilson et al. 2007):

1. Ensure funds are adequate;
2. Ensure funds are readily accessible;
3. Establish minimum standards for financial institutions securing funds (or underwriting risk);
4. Ensure continuity of financial responsibility, if and when sites are transferred;
5. Not impose excessive barriers to projects that have public benefits.

Current regulations governing underground injection wells require project owners and/or operators to demonstrate financial assurance for the costs of plugging and abandoning wells, certification of site closure (MMV), and foreseeable mitigation (remediation). Generally, the accepted instruments for financial assurance are third-party financial mechanisms, including trust funds, surety bonds, letters of credit, insurance, or self-insurance through a financial test and/or corporate guarantees. CCS facilities will be required to demonstrate financial assurance for CCS activities as part of U. S. EPA proposed rule for Geological Sequestration. The requirement to enforce financial assurance provisions may be delegated to primacy states with primacy authority under the EPA UIC Program.

A remaining issue to be resolved with respect to financial responsibility and CCS projects is the degree to which financial assurance is necessary to cover the costs of potential long-term stewardship at sites that are certified as closed. In theory, well-sited, constructed, operated, and closed projects should not pose a threat to human health and the environment. In thinking about storage, and especially the first demonstration projects, there is a higher degree of uncertainty about when it will be possible to demonstrate non-endangerment in order to complete site-closure. This uncertainty may increase the perceived risk exposure to levels that serve as a barrier to investment.

In response, an effort has been made to break down the components of potential financial responsibility. During each stage of a project, there will be some need to conduct MMV; based on the MMV findings, unplanned changes in operations plans or implementation of mitigation measures may be required. If problems arise, there may be the need to undertake mitigation (remediation), and potentially address compensatory damages, as well as related tort liability. Stakeholders have noted that these financial consequences have the largest potential uncertainty and seem to be of the greatest concern. The challenge is in designing a financial responsibility framework that encourages a project operator/owner to minimize occurrence of these events, and therefore minimizes the attendant financial burden. Nonetheless, despite best efforts, problems may arise that are due not to negligence but instead to incomplete scientific or technical understanding.

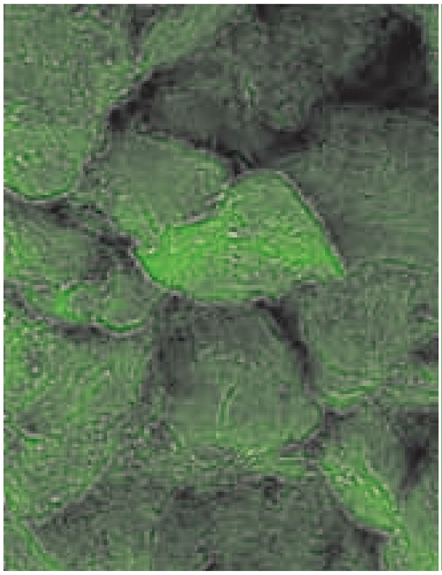
As described in the WRI Issue Brief on CCS liability:

"It is generally accepted that financial responsibility requirements serve as an inducement to firms to properly operate and maintain their facilities. In the case of CCS, the intent is to minimize the number of orphaned facilities, ensure proper long-term stewardship, and mitigate any environmental risks from site releases. At its core, financial responsibility is an issue of risk management. A well-established financial responsibility program will balance stakeholder interests and ensure the safe closure and responsible post-closure stewardship and monitoring. Specifically, an effective financial responsibility framework will ensure that developers and operators maintain adequate financial resources to fulfill their near- and long-term obligations. Additionally, it will encourage competition and foster beneficial market impacts, including (E.J. Wilson et al. 2007):

- Targeted Capital Investment, whereby firms have the incentive to design, site and operate facilities that reduce the likelihood of injury to environmental/public health and minimize litigation risk.
- Deterrence and Precaution, whereby firms will have the incentive to undertake operating decisions that consider environmental (and remediation) costs.
- Optimal Pricing and Consumption, whereby firms are stimulated to appropriately internalize costs, minimizing excessive consumption of environmentally damaging goods"

Several models have been proposed to balance the need to hold project operators/owners accountable for the performance of their projects and to ensure that in the event of costly damages, project operators/owners have some ways to mitigate their financial risk exposure. One potential approach is found in the oil and gas industry's orphan well programs. Under these programs, existing well operators pay a fee into a fund that is usually managed by a state and that can be used to pay for completion or mitigation at wells that have been orphaned (IOGCC and U.S. DOE/NETL 2008). Other proposed models rely on a combination of individual and shared risk management systems, which involve federal indemnity for a portion of the potential responsibility.

STORAGE GUIDELINE 3: RECOMMENDED GUIDELINES FOR FINANCIAL RESPONSIBILITY



a. Based on site-specific risk assessment, project operators/owners should provide an expected value of the estimated costs of site closure (including well plugging and abandonment, MMV, and foreseeable mitigation (remediation) action) as part of their permit application. These cost estimates should be updated as needed prior to undertaking site closure.

b. Project operators/owners should demonstrate financial assurance for all of the activities required for site closure.

c. Policies should be developed for adequately funding the post-closure activities that become the responsibility of an entity assuming responsibility for long-term stewardship, as described in the Post-Closure section.

d. Because of the public good benefits of early storage projects and the potential difficulty of attracting investment, policymakers should carefully evaluate options for the design and application of a risk management framework for such projects. This framework should appropriately balance relevant policy considerations, including the need for financial assurances, without imposing excessive barriers to the design and deployment of CCS technology.

Discussions are underway to determine the best approach to ensure financial responsibility for storage projects. This is a topic that warrants further discussion among the stakeholder group, as there are significantly divergent views on the scope, need for, and nature of financial responsibility mechanisms for CCS. Future stakeholder discussions and resulting recommendations will consider the usefulness and potential structure for a private/public framework to be adopted at the state or federal level. In the meantime, the above preliminary Guidelines are recommended. It should be acknowledged that these financial responsibility Guidelines may be modified as a result of future stakeholder discussions. Also, they do not specify the degree or nature of financial responsibility following site closure certification.

4.3.1.4 Property Rights and Ownership

Property rights and ownership are considered cross-cutting issues because an operator of a storage project will need to work with a number of property owners throughout the project life cycle to obtain legal access to surface and subsurface pore space. Access to the subsurface pore space containing the CO_2 plume should be procured during the early planning stages of the project, along with surface access for any monitoring that would occur on property beyond what is owned by the operator. However, continued

Storage on Federal Lands

Federal lands offer attractive social and economic advantages for private and public storage projects, including ease of gaining legal access to surface and subsurface property with clear ownership, enhancing national energy security, and providing for early deployment of critical carbon mitigation technology. In accordance with federal statutory mandates, the U.S. Department of the Interior's (DOI) Bureau of Land Management and the Minerals Management Service should take steps to create the policies and procedures in the near term that allow for the responsible deployment of storage in the long term.

DOI is currently working to develop a framework for geologic storage on public lands and will be providing a report to the Senate Energy and Natural Resources Committee and House Natural Resources Committee in December 2008, including recommendations for:

- Potential storage sites on federal lands in different formation types.
- A proposed framework for leasing public land for geologic storage.
- A procedure for public review of storage plans.
- A procedure for protecting natural and cultural resources.
- A framework for issuing rights of way for CO_2 pipelines on public lands.
- The status of federal leasehold and mineral estate liability for long-term stewardship.

Potential operators should undertake substantial efforts within the proposed site area to identify hazards and assess the risk of leakage through mapping, analysis, and simulation.

communication with neighboring affected landowners is essential throughout a storage project, especially as land use and ownership may change through the course of a project's operational life, and doing so can help ensure the success of long-term stewardship. There are many analogues to storage from a property-ownership perspective, including experience gained through the oil and gas industry. In the United States, there are important nuances in property rights that vary significantly by state. This section proposes Guidelines that will help facilitate clarity in ownership issues for storage projects.

SUBSURFACE OWNERSHIP

In the U.S. context, it is likely that surface owners also own the right to the pore space unless they have explicitly included pore space in the lease or sale of the mineral rights in the subsurface. However, there is not full clarity on this issue, and some believe that for storage in mature oil and gas fields, project developers may need to acquire both the surface and the mineral rights if those have been previously separated. It is expected that this issue will gain clarity only after a series of state legislative actions and case law are developed.

Currently, there are two theoretical models for access to the pore space for CO_2 injection and ownership for CO_2 injection into saline formations in the U.S. context (de Figueiredo 2007). Neither model was reviewed by the stakeholder group; both are provided for illustrative purposes.

- Private ownership model, where the surface owner owns the pore space rights. These can be sold or leased or condemned and can be purchased or leased accordingly, or condemned and captured by eminent domain.
- Public interest model, where much like the air space where the federal government establishes the flight patterns for public safety, there may be a rationale for government influence over the pore space in the public interest of addressing climate change.

Many states as well as the IOGCC have supported the notion that pore space ownership should follow surface ownership (Nowakowski 2008). In March 2008, Wyoming became the first state to enact a law that clarifies ownership for storage pore space. The law went into effect in July 2008 and clearly states that in Wyoming, pore space for carbon storage follows the surface owner. A New Mexico report completed in December 2007 also recommends this approach to ownership, with likely discussions expected during the 2009 session.

Once clarity about the requirements for obtaining ownership rights is established, the operator can lease or buy the storage pore space from the necessary property owners, just as mineral rights and natural gas pore space are leased or bought in many states. In cases where a lease agreement cannot be established, eminent domain could be applied. Eminent domain for natural gas storage pore space has been applied in several states, including Illinois and New York, but other states have chosen not to invoke eminent domain for this purpose. The existing variety in the application of law for property ownership of mineral resources could complicate projects where the CO_2 plume will cross state boundaries. So far, in the United States, the discussions on pore space ownership have emphasized that the operator should procure unambiguous legal access to storage pore space based on the laws in that jurisdiction/state. Some have also proposed that storage pore space be unitized in the same way that oil and gas fields are unitized, which would ease the leasing process for potential operators.

In the European Union, pore space is owned by the state, which significantly simplifies ownership (Haszeldine et al. 2007). Ultimately, it is not clear how subsurface property rights will be resolved, either nationally or internationally. In the short term, operators are served in all contexts by working with states and governments on legal clarification and to site early projects where there are small numbers of surface owners (e.g., large ranches, state land) and where the informed consent of the community can be secured.

LAND ACCESS AND GEOPHYSICAL TRESPASS

Access to the surface and subsurface for both injection and monitoring is central to storage operations. *Before injection, it is absolutely imperative to have unambiguous authority to access the pore space involved,* through subsurface leases, surface owner agreements, or grants from the state or federal government (IOGCC 2007). No operator should undertake subsurface injection without clear access from title holders to the injection zone.

It may be necessary to monitor in a region that, within reason, is larger than or different from the predicted project footprint. This may be a result of inaccurate subsurface characterization and injection simulation. However, even if all predictions and characterizations are accurate, many geophysical or hydrological monitoring methods will require an area larger than the project footprint. In the case of 3- or 4-D seismic, microseismic, or gravimetric surveys, a surface area larger than the project footprint is needed to extend geophones to gain fold and resolution. In the case of wellbore monitoring, prudence, regulation, or technical accuracy may require monitoring of wells beyond the project footprint.

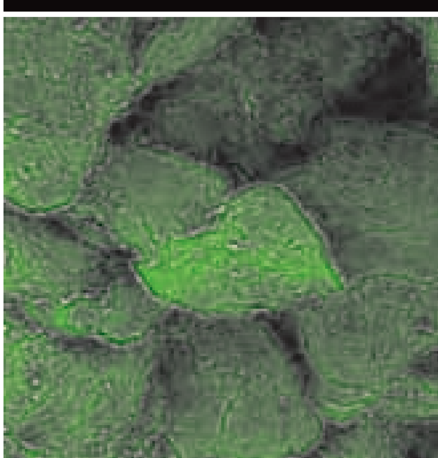
In cases where monitoring needs may extend beyond the CO_2 plume, geophysical trespass (unauthorized collection of geophysical data) may become an issue. In such cases, monitoring activities may collect information that demonstrates a lack of other mineral resources (e.g., oil and gas) at a site (Wilson and de Figueiredo 2006). Since the opportunity to survey and explore is in itself an asset, monitoring can cause damages to some parties (such as loss of property value). More likely, concern over geophysical trespass may limit monitoring opportunities in a way that does not serve operators, regulators, or public stakeholders. This issue will require further focus from potential CCS parties and legislators. It may be possible in the near term to avoid this issue by initiating projects in areas where these issues are straightforward (e.g., public lands, existing oil fields), or where extensive exploration, production, or subsurface operation has made these issues moot.

SUBSURFACE TRESPASS AND RESOURCE DEGRADATION

Subsurface trespass, the reduction in value of mineral resources due to subsurface incursions, is likely to prove a cause for legal action (IOGCC 2007, Wilson et al. 2006). In most cases, incursions are local and limited, and commonly occur near the boundary of subsurface operations. There is an established body of case law associated with water flooding, enhanced oil recovery, and natural gas storage that can be applied to actions where subsurface trespass is suspected or maintained. Similarly, there is a base of operational experience that can be used to prevent or mitigate subsurface trespass. This includes modeling and simulation to anticipate potential problems and wells to intercept fluid migration and prevent trespass. While this may present potential risk to operators, proper site characterization, planning, and monitoring should be able to avoid trespass and its associated legal troubles.

In contrast, it is possible that large injections or multiple large injections in a reservoir may result in far-field resource degradation where no attribution is possible. One hypothetical case involves shallow formation fluid intrusion caused by displacement of saline formation waters far from injected CO_2. In a region where many injections are occurring, attribution may be impossible (this situation could be made worse by transboundary issues). While there is no particular action or Guidelines for potential operators in this regard, it may be useful for state and federal regulators or legislators to begin to consider this problem to provide clarity for future cases.

STORAGE GUIDELINE 4: RECOMMENDED GUIDELINES FOR PROPERTY RIGHTS AND OWNERSHIP



a. Potential operators should demonstrate control of legal rights to use the site surface and/or subsurface to conduct injection and monitoring over the expected lifetime of the project within the area of the CO_2 plume and (where appropriate) the entire project footprint. Regulators will also need access for inspection.

b. Continued investigation into technical, regulatory, and legal issues in determining pore space ownership for CCS is warranted at the state and federal levels. Additional legislation to provide a clear and reasonably actionable pathway for CCS demonstration and deployment may be necessary.

c. MMV activities may require land access beyond the projected CO_2 plume; therefore, land access and any other property interest for these activities should be obtained.

d. Operators should avoid potential areas of subsurface migration that might lead to claims of trespass and develop contingencies and mitigation strategies to avoid such actions.

4.3.2 Project Stage Issues

This section describes the issues arising during site characterization and selection, operations, and site closure.

4.3.2.1 Site Characterization and Selection

Site characterization and selection is the most important step in ensuring the integrity of a storage project. This step provides the opportunity to evaluate a series of geologic and nongeologic factors that will influence the design, cost, and ultimate success of a potential storage project.

Suitable storage sites have both a confining zone and a storage formation, as shown in Figure13. The confining zone(s) must prevent vertical migration of CO_2. Typical confining zones, or cap rock layer, can be shales and thick deposits of evaporites (e.g., gypsum, salts). Storage formations must have sufficient porosity for storage capacity and sufficient permeability to allow injection of the captured CO_2. Typical target formations can be clastic sedimentary rocks (such as sandstones or conglomerates) or carbonates (such as limestones or dolostones). Under the right circumstances, other kinds of formations might serve as storage reservoirs, such as unminable coal seams, basalts, and evacuated salt caverns.

The conceptual approach for site characterization and selection is a selection process in which a small number of candidate sites are identified based on readily available information and preferences. Then the sites are further investigated, which includes site-specific risk assessments as described earlier, to evaluate and rank them. Finally, detailed site characterizations are conducted to finalize site selection and prepare permit applications. This approach is described in the second part of this section.

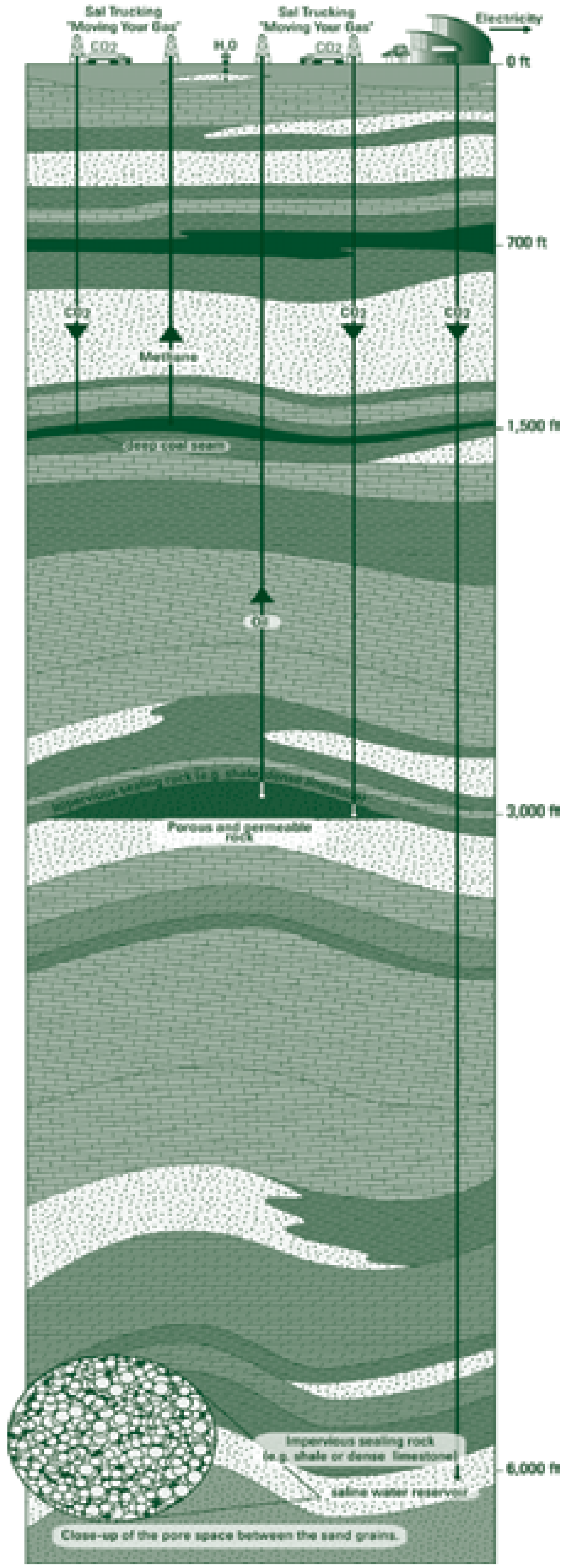
The suitability of a site for storage is a function of three primary technical factors: the effectiveness of a confining zone in preventing upward migration of CO_2; the injectivity of the storage reservoir; and the volumetric capacity of the reservoir to hold injected CO_2. These factors are discussed in the third part of this section. In areas with significant pre-existing data (e.g., mature oil and gas fields), site characterization will be easier to complete. In areas with very little pre-existing data about the subsurface, site characterization will be a more involved process that will require more time and expense to complete.

THE GOAL OF SITE CHARACTERIZATION

The purpose of a storage project is to store CO_2 underground indefinitely (IPCC 2005). The goal of site characterization is to set the stage for successful long-term storage. It is important to consider the following points in establishing Guidelines for site characterization:

- Certain basic information about the rock formations throughout the United States (and perhaps most of the world) exists in state

Figure 13: Geologic Storage Reservoir with Multiple Confining Zones



COURTESY OF ILLINOIS STATE GEOLOGICAL SURVEY

STORAGE

and other public geologic surveys. Additional information is also held by private firms. This basic information includes the location of sedimentary basins and other general characteristics; it will serve as a preliminary screening tool.

- Detailed information about a site may be extensive in areas where there has been exploration for oil or minerals and will be less extensive in areas where there has been limited exploration. With characterization and development of the storage site, the level of knowledge will grow.
- A specific regulatory framework for CO_2 storage operations is still emerging (E.J. Wilson et al. 2007). However, much of the basic framework can be drawn from related areas. For example, in July 2008 the EPA issued a proposed rule covering CO_2 injection for storage projects. If finalized, this rule would require specific site characterization and selection activities for CO_2 injection wells. Further, there are established provisions for addressing subsurface trespass in the oil and gas industry that could be used as models for storage.
- There are many viable strategies to detect leakage should it occur, and a suite of potential mitigation and remediation strategies to prevent human health, safety, and environmental impacts. The human health, safety, and environmental risks from CO_2 exposure require high concentrations (Snodgrass 1992; Rice 2004). Potential areas where CO_2 could accumulate should be identified through the risk assessment and should be a consideration in site selection.

Initial site characterization will help to make a credible case that CO_2 can be injected and stored safely and effectively at a site indefinitely. This would be similar to the characterization necessary to sustain natural gas storage, defend oil and gas exploration investments, and permit industrial waste injection—all of which carry similar uncertainties in their initial stages. As such, pre-injection site characterization should provide:

- A geologic analysis of the storage reservoir(s) and confining zone(s), as well as an analysis of the chemistry of the groundwaters in the vicinity of the proposed storage project. Both will contribute to establishing baseline information for future MMV analysis.
- A field development plan for the storage project, including well and facility designs, injection pattern, and possible evolution of the injection pattern, as well as deployment of MMV tools and risk management plans.
- A demonstration of the ability to meet financial responsibilities in the operation and closure of the storage project.

These goals may be readily met with existing tools and techniques. The ability to select and operate a site effectively will improve through time (Mignone and Socolow, in review).

A CONCEPTUAL APPROACH TO SITE CHARACTERIZATION AND SELECTION

The process of site characterization and selection has been described as an exploration for bounded pore space. It is a series of steps that is used first to identify and assess potential sites and then to confirm the selection and promotion of chosen sites.

Acquiring the information needed to assess the suitability of a reservoir for storage will usually require investments in drilling, surveying, and site-specific data collection.

To minimize cost and impact, site characterization tends to follow a "down-selection" process. As a first step, the operator develops a conceptual model of the regional geology, which serves as the basis for the computational reservoir model. This conceptual model is based on readily available data, and includes the general location and classification of rock types in a selected area, known wells, faulting, and seismic activity. Candidate locations are identified based on a series of technical and nontechnical site-specific factors. Technical factors include data from existing core samples, available seismic surveys, records and descriptions of existing or plugged and abandoned wells, and other available data (some of which may need to be purchased if held by private companies). Nontechnical factors include the location of CO_2 emission sources, property ownership, land use, and available infrastructure. Once a small number of candidate sites are prioritized, an operator may start doing some test drilling or other on-site measurements, such as seismic survey work to develop site-specific reservoir models, and make a final site selection. In an area where there is not an extensive amount of existing data from core samples and other tests, this work may need to be conducted over a large area and could involve multiple test wells.

The information gathered during site characterization is assembled into a permit application, a reservoir model, and the preliminary project design. If a permit is granted, an operator will complete the initial site characterization by completing initial injection wells, conducting injection tests as needed, and validating the reservoir model.

Implicit in this discussion is the notion that after detailed review, some candidate sites may not qualify for use. Such sites are similar to "dry holes" in the oil business. That is, although the preliminary data suggested they would be good locations for storage, actual results from drilling, and perhaps even test injection, reveal that the geology is such that they should not be used for long-term injection and storage. The site characterization process may also reveal that some sites have weaknesses that could be addressed through appropriate project design and operation.

In the context of this discussion, there are potential tradeoffs in site performance between having more or less site characterization. Each site is different, and the level of necessary site characterization will vary. This is not to suggest that one general type of site is better than another. For example, sites in well-characterized geology may be spatially limited or may have a larger number of deep boreholes, so may require a different emphasis in risk assessment and management and more wellbore characterization work. For some deep saline formations, the lack of pre-existing characterization may result in a need for more iteration in the early stages of a project. A homogeneous, deeper, and well-sealed saline reservoir may not encounter these issues. The key practice is iteration, and ability to match expectations or predictions through the course of site evaluation.

KEY FACTORS IN RESERVOIR SUITABILITY

These Guidelines focus on three main reservoir attributes: the effectiveness of the confining zone(s) that will serve as the primary mechanism for ensuring injected CO_2 does not migrate vertically; the injectivity or rate at which CO_2 can be injected into the reservoir; and the estimated capacity of the injection field. These factors (along with community support) are critical in determining the suitability of a site and in comparing potential sites. Not all of the information necessary to assess these three factors is going to be readily available without investing in drilling, surveying, and sampling activities.

CHARACTERISTICS OF EFFECTIVE CONFINING ZONE(S)

A primary geologic confining zone is essential for effectively sequestering large volumes of CO_2. Injected CO_2 will be buoyant, thus gravitational (buoyancy) forces will drive CO_2 upward from the injection point to the top of the storage formation. A confining zone (also called a cap rock, confining unit, or seal) is a geologic formation that overlies the target formation. It can impede this buoyant flow effectively because it is very fine grained and has extremely small pore throats (making it essentially impermeable to CO_2) (Watts 1987; Harrington and Horseman 1999). In many reservoirs, this will be the most important trapping mechanism of the injection target. For a confining zone to be effective, it must be laterally extensive and thick enough to counter the total buoyant forces of a CO_2 accumulation at depth over the injection area. Marine and lacustrine shales and thick deposits of evaporites (e.g., anhydrite/gypsum, salts) are common cap rocks in a confining zone. As geologic analogs have demonstrated, evaporites exhibit rheologic properties (flow), which in the presence of CO_2 contributes to healing fractures, preserving the lateral continuity of the sealing formation.

Storage Mechanisms

Several mechanisms work in combination to ensure that CO_2 remains in the storage reservoir. Supercritical CO_2 is buoyant, and will migrate upward. This migration can be prevented by a confining zone overlying the injection formation. Storage through this *physical trapping* contains very high fractions of CO_2, and acts immediately to limit vertical CO_2 migration. *Capillary trapping* can immobilize a substantial fraction of CO_2. This mechanism also acts immediately and is sustained over long time scales. CO_2 trapped this way may be considered permanently trapped. A fraction of the CO_2, will *dissolve* into other pore fluids, including hydrocarbons (oil and gas) or brines. Depending on the fluid composition and reservoir condition, this may occur rapidly (seconds to minutes) or over a period of tens to hundreds of years. Over very long time scales, much of the dissolved CO_2 may react with minerals in the rock volume to dissolve or precipitate new carbonate minerals, often called *mineral trapping*. Precipitation of carbonate minerals permanently binds CO_2 in the subsurface; dissolution of minerals generally neutralizes carbonic acid species and increases local pH, buffering the solutions and trapping CO_2 as an ionic species (usually bicarbonate) in the pore volume.

For a seal to be considered suitable for storage, it must be predictable and have:

a. Large, laterally continuous coverage over the proposed injection reservoir;
b. Low vertical permeability;
c. High capillary entry pressure;
d. Sufficient thickness to trap the expected volume of CO_2;
e. The expectation that faults and fractures, if present, will seal;
f. The ability to prevent vertical migration of injected CO_2, demonstrated through pressure differential, salinity differential, or a history of trapping oil or gas;
g. Adequate rheological (fluid flow) properties; and
h. Clear indications that any artificial penetrations of the confining zone will also properly trap CO_2.

The confining zone can be enhanced by the presence of a structural trap. A trap is a geologic formation in a structural or stratigraphic position that can receive and retain a large volume of CO_2 for a sustained period of time by constraining lateral migration of injected CO_2. Traps can be formed in naturally occurring rock folds or structures, or they may be naturally created through faulting. Oil, natural gas, and natural deposits of CO_2 are typically found in traps into which they have migrated and have been stored for millions of years. Another type of storage opportunity might exist in an area with a laterally extensive confining zone that is formed according to the regional dip (angle) of the geologic formation(s).

There are many conventional approaches to assessing the characteristics outlined above. To begin, if a rock unit already traps hydrocarbons at depth, especially natural gas, then it is highly likely that it will also trap CO_2 (Klusman 2003b). Thickness of a confining zone can be assessed with conventional well-logging tools and techniques, and stratigraphic mapping and analysis can be used to assess likely lateral continuity. In addition, capillary entry pressure measurements on core samples can quantify the amount of buoyant force a cap rock lithology can maintain before failure. Ultimately, characterizations must also rely on estimates of geomechanical, hydrodynamic, and confining zone integrity for the rock system, fault system, and well system. The more confining units present, the greater their thickness and extent, the better engineered the wells, and the higher the confidence that the reservoir will serve as a good site for storage.

Conventional data sets and analyses can and do underlie current site characterizations. Some of these include depth-structure maps, well-log correlations, well completion records, 2-D and 3-D seismic volumes, and fault maps. Many of these data sources are interpretations and contain various degrees of certainty. As such, precise quantitative estimates may be difficult or impossible to provide. Such precision, however, is not necessary to accurately characterize site effectiveness. For example, continuity and thickness of cap rock, presence and properties of multiple confining zones, and structural closure may be easily defined with limited data and analysis. Other aspects (e.g., Mohr failure criteria, capillary entry pressure) are straightforward but require basic analysis (Streit and Hillis 2004). Some aspects are fairly straightforward but require a degree of geological sophistication (e.g., fault reactivation potential, fault-seal analysis, in-situ stress tensor characterization) (Wiprut and Zoback 2002; Gibson-Poole et al. 2005; Friedmann and Nummedal 2003). Some factors are extremely difficult to define (e.g., well behavior in 50–100 years) and cannot be unambiguously circumscribed in any reasonable operational context. However, relevant data sets can provide a technical basis for assessing the likely degree of efficacy and safety, and relevant procedures (e.g., aeromagnetic surveys) can serve as a component of due diligence in relation to unexpected and difficult-to-define phenomena.

Again, relevant analogs and empirical characterization can be used to help determine the effectiveness of the confining zone(s) as appropriate, until standard measures and best practices are broadly accepted. For example, if a regionally extensive shale unit is an effective regional hydrocarbon-confining zone, that information should positively affect the determination of CO_2 storage effectiveness; if the hydrocarbon is natural gas, the likely effectiveness of the confining zone is greater (Watts 1987). In some cases, this type of data and analysis can provide the most important and most accurate information available to characterize likely site effectiveness.

INJECTIVITY

Injectivity describes the rate of injection that can take place in a given well and reservoir. As indicated in Table 9, injectivity is calculated based on a variety of data, including effective thickness over the injection interval, reservoir permeability, bulk connectivity, and reservoir pressure. The units of injectivity can vary with the data source, and include m^3/day/Pascal/m and barrels/day/psi/ft. Much of the data exist for oil and gas fields, but would be available only on a limited basis for other targets, such as saline formations. However, conventional wells, geophysical surveys, and core analysis would be able to provide reasonable estimates of injectivity for a project. Crucially, the injectivity depends on the interval of reservoir exposed to the wellbore; thus, injectivity may be increased through drilling long-reach horizontal wells or increasing well count. If there is damage to the reservoir at the wellbore that restricts injectivity, a small hydraulic fracture or acid stimulation may be applied to correct it.

The amount of data needed to properly quantify injectivity may vary by site, but it is highly unlikely that one well and a limited geological or geophysical survey could alone provide enough data to prove a reservoir has the needed injectivity. In many commercial applications, the degree of reservoir connectivity is not well understood for many years. Empirical and theoretical approaches will be important and can provide additional information and allow for consideration of multiple scenarios. In many cases, injectivity data from neighboring oil, gas, and water wells, plus information from analogous reservoirs, can provide this information.

CAPACITY

Storage capacity is measured in units of volume (standard cubic feet, barrels). Several parameters are used to generate a capacity estimate, of which pore volume is the most important. Pore volume is a bulk term based on effective formation thickness and porosity. Estimates of pore volume can be derived from data generated through core analysis, wireline logs, or geophysical surveys. In some cases, 3-D seismic surveys may be combined with well data to estimate the formation porosity (Saggaf et al. 2003; Bachrach and Dutta 2004). Often, a hydrodynamic simulation is needed to estimate overall storage capacity.

A second key parameter in capacity estimates is the *utilization factor,* or the effective pore volume. This is the fraction of the pore volume that would actually retain or store injected CO_2. Utilization factor is a function of the fluid already present in the reservoir, and reservoir heterogeneity at all scales, ranging from pore-throat diameters to kilometer-scale connectivity, unit architecture, and residual phase (or capillary) trapping (Juanes et al. 2006; Ide et al. 2007). The utilization factor is also a function of the development strategy and well planning, such that capacity can be increased by more wells or better well design. Utilization factors vary from site to site, and can range between 5 and 50 percent, although most are less than 25 percent.

An important consideration is that estimates of capacity are affected by reservoir heterogeneity, which determines the shape of the CO_2 plume. Reservoir pressure constraints also affect the ultimate capacity of a reservoir.

Inherent in any discussion regarding capacity are the assumptions about storage mechanisms. Capacity assessments for saline formations sometimes assume or calculate a dissolved fraction of CO_2 of 3–6 percent (Bachu and Adams 2003). In the case of a structural or stratigraphic closure, a substantial fraction of the pore volume might be filled with CO_2 as a pure phase. Moreover, CO_2 buoyancy may make it difficult to store CO_2 in a substantial fraction of the available pore space. Finally, it may be extremely difficult to predict the amount of residual phase trapping (capillary trapping) without extensive sampling and analysis, and this is a focus of research efforts (Holtz and Bryant 2005).

Site characterizations should be used to estimate the volume that would be stored as a dissolved phase, as a trapped residual phase, or as a trapped contiguous, buoyant phase (these proportions will also affect effectiveness or storage integrity). Statements of these assumptions would allow for easy updating of initial capacity estimates once new data become available. In practical terms, analog and empirical data sets should be considered for initial capacity estimates, but further scientific understanding regarding trapping mechanism assumptions is needed; this is an important area for additional research.

Table 9: Examples of Information and Data Sources for Characterization of Storage Sites

Attribute of Formation	Key Information	Basic Data Sources	Basic Analysis	Advanced Analysis
Proof of functional confining zone(s)	■ Presence, number, continuity, thickness, and character of confining zone ■ Fault azimuth and offset ■ Surface and formation well density ■ Well construction and plugging history	■ Cores ■ Well-logs ■ Structure maps ■ In-situ stress ■ Well location maps ■ Well drilling and plugging records ■ 3-D seismic volumes	■ Stratigraphic analysis ■ Structural analysis ■ Reservoir models ■ Simple calculation ■ Mohr-Coulomb failure calculation ■ Conventional simulation ■ Core analysis ■ Well location verification ■ Well logging-through casing (e.g., cement bonding logs)	■ Aeromagnetic surveys ■ Capillary entry pressure tests ■ Fault segmentation analysis ■ Advanced simulation
Injectivity	■ Thickness, porosity, and permeability ■ Production/flow rate ■ Delivery rate connectivity	■ Conventional core analysis ■ Well-logs ■ Production history ■ Injection or leak-off tests ■ Pressure	■ Stratigraphic analysis ■ Population of static geological models ■ Core plug analysis ■ Conventional simulation ■ Well pump tests/ injection tests	■ Detailed stratigraphic characterization ■ Hydro-fracture analysis ■ Special core analysis
Capacity	■ Accessible pore-volume ■ Lateral extent ■ Area of injection ■ Trapping mechanism	■ Conventional core analysis ■ Well-logs ■ Structure maps ■ 3-D seismic data	■ Stratigraphic analysis ■ Structural analysis ■ Static geomodels ■ Simple calculation ■ Conventional simulation ■ 3-D seismic mapping	■ Advanced simulation ■ Fill-spill analysis ■ Special core analysis

METHODS FOR ASSESSING RESERVOIR SUITABILITY

Examples of the information and potential data sources used to assess the three primary attributes of a potential storage formation (confining zone(s), injectivity, and capacity) are found in Table 9. This information is typically required by regulators as part of an injection permit application. It is important to note that some of this analysis will be conducted after receipt of the appropriate permit, while the plans for completing the injection well and plan are being completed. The selection of tools listed in Table 9 will be based on site-specific geology, as well as operational plans and needs.

APPLICATION OF OIL AND GAS INDUSTRY INSIGHTS AND METHODOLOGIES

A considerable amount of understanding of trapping systems, operating experience, and technology developed by oil and gas operations is directly applicable to storage site characterization and selection. Examples of proven natural geologic CO_2 traps offer insights useful to storage projects.

Many of the data, tools, and analytical approaches outlined in Table 9 are employed by the oil and gas industry, including the sources of key data and the tools for understanding the subsurface environment. Several steps involved in site characterization are analogous to activities used by oil and gas operators during exploration:

- Identifying regional prospective areas or "plays" based on limited geological data. This specifically involves identification of major regional formations that would serve as either good reservoirs or good confining zones.
- Identifying and selecting specific locations that have the highest chance of success. This involves finding the optimal combination of maximal storage capacity and minimal risk.
- Understanding and managing the uncertainty in the geological structures, strata, data, and conceptual models to provide firm constraints to engineers and decision makers.
- Providing enough information for development planning, including operating pressures and well design.
- Ensuring that important nontechnical issues (e.g., land access) do not prohibit or inhibit work at the site.

As discussed in the Risk Assessment section, other considerations beyond the effectiveness of the confining zone, injectivity, and estimated capacity should be used in selecting sites, including:

- Proximity to sensitive populations;
- Ecosystems (including critical habitat for threatened/endangered species);

- Current and projected land use in the nearby area;
- Property rights and the number of landowners involved;
- The ease of implementing recovery, mitigation, or remediation activities if such a need arises (these may be required for financial assessment purposes);
- Demonstration of technical and financial assurance on the part of the owner/operator or developer; and
- Proximity and vulnerability of underground resources (e.g., underground drinking water, mineral resources).

SITE CHARACTERIZATION AS AN OPERATIONAL CONCERN

Planning that occurs during the site characterization phase is critical to operational success. Site characterization is the first step in planning monitoring networks, locating potential injection projects, developing operational guidelines, seeking regulatory and public approval, and obtaining project financing (Cook 2006). It is also critical to the safe and effective long-term storage of CO_2 underground. Proper characterization and planning will reduce costs; failure to undertake appropriate steps in site characterization could create operational problems and expose an operator to liability. Finally, tremendous amounts of information about a site are gathered during the operational injection phase. Care should be taken to incorporate this information into the site understanding to both improve the performance of the site and avoid failures.

INJECTION SCALE

Successful operational experience with injecting CO_2 in the subsurface at rates of ~1 million metric tons of CO_2 per year has been demonstrated through projects like Sleipner (Statoil), Weyburn (EnCana), and In Salah (BP). The Gorgon project (Chevron) is currently the largest proposed project, and is near completion at the rate of ~3 million metric tons per year. The DOE regional partnerships have also conducted smaller-scale research injections (thousands of tons), with a validation phase planned for 2008–2010 during which 500,000–1,800,000 tons will be injected at each of several projects during a 3-year injection period.

These projects have been primarily associated with research and/or natural gas recovery operations. CCS associated with commercial power plants could be at significantly larger scales. For example, a 1,000-MW IGCC power plant with 90 percent CO_2 capture would produce over 6 million metric tons of CO_2 per year. Assuming an operational lifetime of 60 years, that translates to 320 million metric tons of CO_2. Translated to reservoir barrels, that would be 120,000–200,000 barrels per day or 2.8–4.4 billion barrels over a 60-year operation.

As referenced in the basin-scale discussion, the location of several storage projects of this scale within a single region could pose challenges as several projects compete for a finite volume of pore space. Further, not all storage projects will tie an individual source to a single injection well. A few sources may share a pipeline to a larger storage field, or the specific characteristics of the local geology may require multiple injection wells for one site. For example, three injection wells are used for the 1 million metric tons per year injected in BP's In Salah project. Although it's easiest to think in terms of one source and one injection well, this will likely not always be practical.

In the site characterization and selection phase, it is essential that subsurface reservoir models be developed that accurately model the injection at the planned scales. This model development will most likely assist in determining the number of injection and monitoring wells needed, and is a precursor to finalizing operational plans. At a regional scale, cooperation and coordination among projects that use the same basin should be required, and can be facilitated through requirements for maintaining public databases that include sufficient data regarding storage projects.

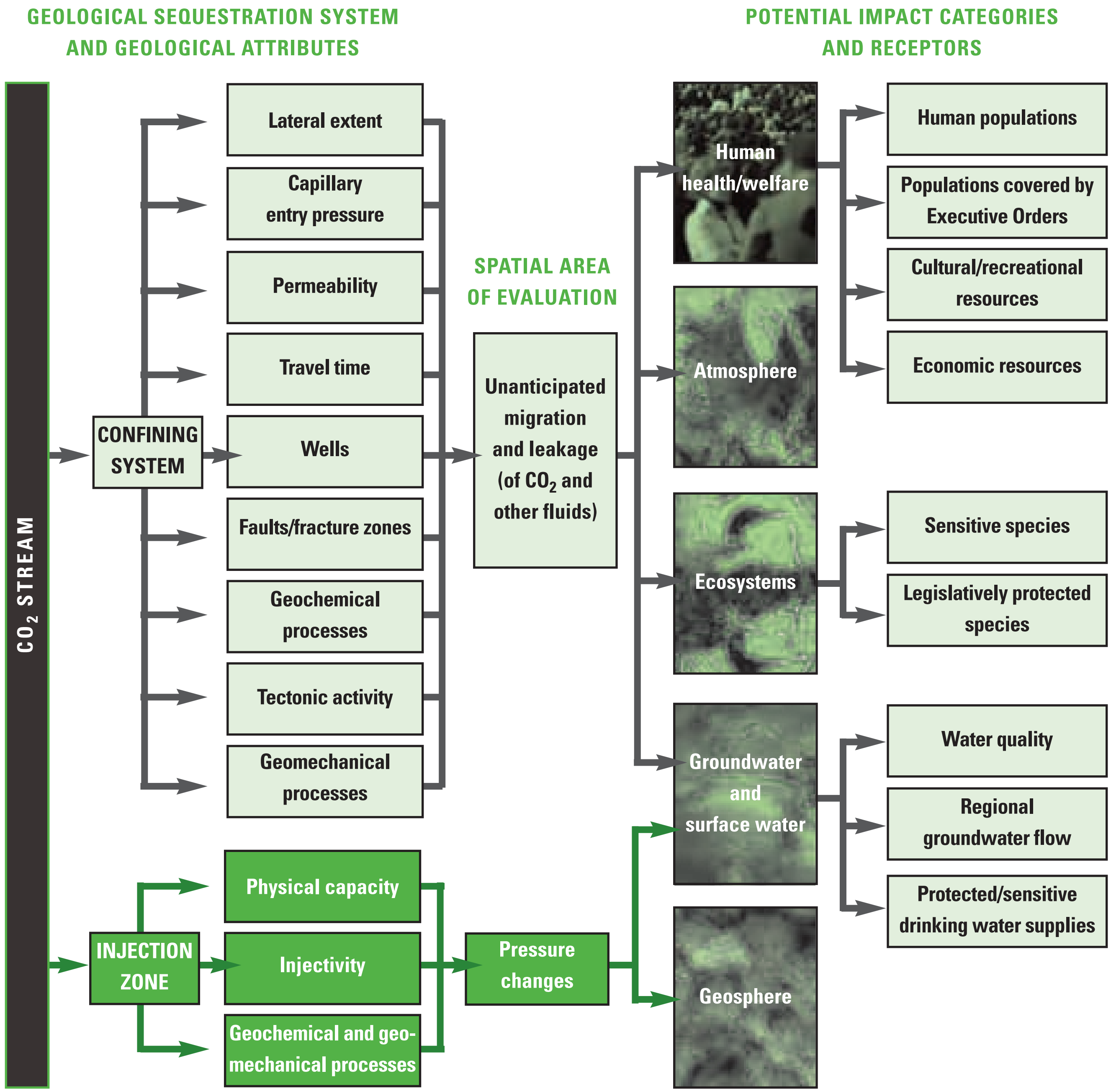
EMERGING TOOLS FOR SCREENING SITES

Several tools can help project developers evaluate potential storage sites. Typically, these are risk assessment tools that use a decision tree approach to characterize sites and the factors that may contribute to leakage or increased susceptibility to impacts from leakage. The tools assist the user with a methodic analysis of potential features, processes, events, and receptors of concern. Such an assessment can be used to determine what measures may be necessary to prevent or mitigate any identified risks, or even to make a go/no-go decision about proceeding with a site.

One of the tools to be released is expected to be a site certification framework tool developed by the CO_2 Capture Project, a research consortium of oil, gas, and electric industry representatives working in collaboration with federal governments (CCP 2007). Another tool

Site characterization and selection is the most important step in ensuring the integrity of a storage project.

Figure 14: Conceptual Figure of the EPA Vulnerability Evaluation Framework



ADAPTED FROM U.S. EPA 2008G

is a Vulnerability Evaluation Framework (VEF) developed by EPA's Office of Air and Radiation, and released as a supporting technical document to the draft UIC geologic sequestration rule (U.S. EPA 2008g). The conceptual VEF is depicted in Figure 14.

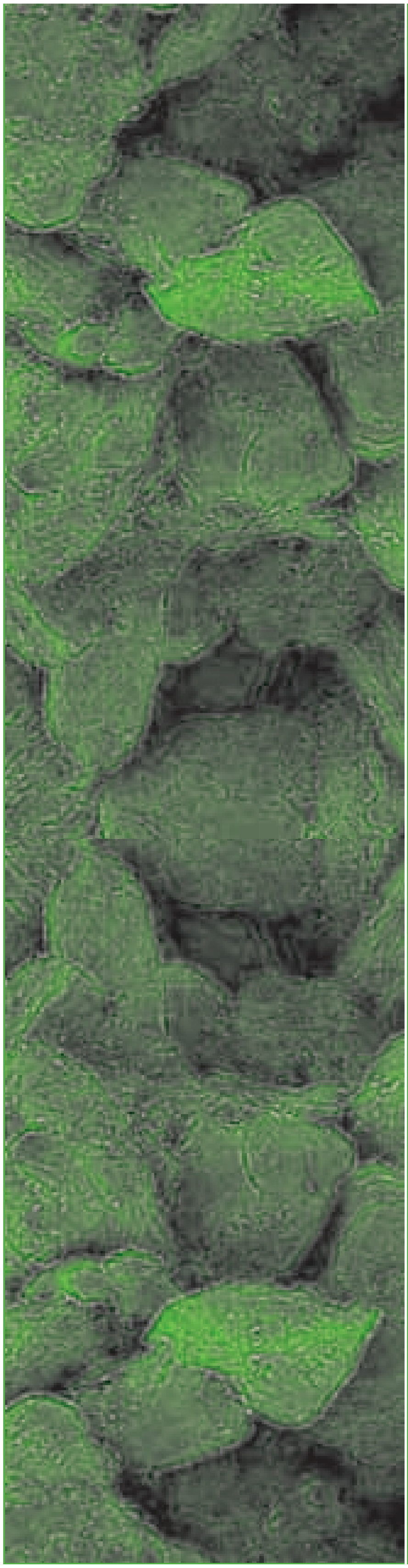
Finally, CO_2-PENS, developed by DOE's Los Alamos National Laboratory, is a system-level framework and model that can be used to screen multiple sites and determine the long-term risks associated with CO_2 storage at specific sites (Pawar et al. 2008).

SITE CHARACTERIZATION AND SELECTION—SUMMARY

In reviewing the framework for detailed site characterization, a few points stand out:

- **Site selection will often involve selection from a number of promising sites.** Prospective sites can be ranked according to key criteria that affect the effectiveness of storage. Such criteria will be based on the results of early research-oriented projects, as well as natural analogues where CO_2 and/or hydrocarbons

STORAGE GUIDELINE 5: RECOMMENDED GUIDELINES FOR SITE SELECTION AND CHARACTERIZATION



a. General Guidelines for Site Characterization and Selection

1. Potential storage reservoirs should be ranked using a set of criteria developed to minimize leakage risks. Future work is needed to clarify such ranking criteria.
2. Low-risk sites should be prioritized for early projects.
3. As required by regulation, storage reservoirs should not be freshwater aquifers or potential underground sources of drinking water.
4. Confining zone(s) should be present that possess characteristics sufficient to prevent the injected or displaced fluids from migrating to drinking water sources or the surface.
5. Site-specific data should be collected and used to develop a subsurface reservoir model to predict/simulate the injection over the lifetime of the storage project and the associated project footprint. These simulations should make predictions that can be verified by history-matching within a relatively short period of time after initial CO_2 injection or upon completion of the first round of wells. The reservoir model and simulations should be updated periodically as warranted and agreed with regulators.
6. Saline formations and mature oil and gas fields should be considered for initial projects. Other formations, such as coal seams, may prove viable for subsequent activity with additional research.

b. Guidelines for Determining Functionality of the Confining Zone(s)

1. Confining zone(s) must be present and must prevent the injected or displaced fluids from migrating to drinking water sources as well as economic resources (e.g., mineral resources) or the surface.
2. Operators should identify and map the continuity of the target formation and confining zone for the project footprint and confirm the integrity of this confining zone(s) with appropriate tools. Natural and operationally induced fractures (or the likely occurrence thereof) should be identified.
3. Operators should identify and map auxiliary or secondary confining zones overlying the primary and secondary target formations, where appropriate.
4. Operators should identify and locate all wells with penetrations of the confining zone within the project footprint. A survey of these wells should be conducted to assess their likely performance and integrity based on completion records and visual surveys. These data should be made publicly available.
5. Operators should identify and map all potentially significant transmissive faults, especially those that transect the confining zone within the project footprint.
6. Operators should collect in-situ stress information from site wells and other sources to assess likely fault performance, including stress tensor orientation and magnitude.

c. Guidelines for Determining Injectivity

1. If sufficient data do not already exist, operators should obtain data to estimate injectivity over the projected project footprint. This may be accomplished with a sustained test injection or production of site well(s). These wells (which could serve for injection, monitoring, or characterization) should have the spatial distribution to provide reasonable preliminary estimates over the projected project footprint.
2. Water injection tests should be allowed in determining site injectivity.
3. Operators should obtain and organize porosity and permeability measurements from core samples collected at the site. These data should be made publicly available.

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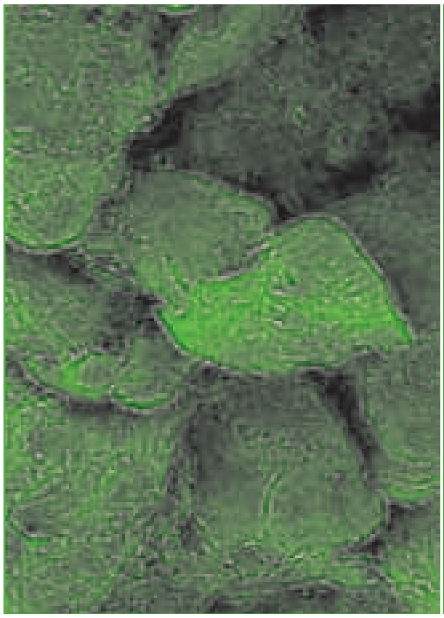
STORAGE GUIDELINE 5: CONTINUED



d. Guidelines for Determining Capacity

1. **Operators should estimate or obtain estimates of the projected capacity for storing CO_2 with site-specific data (CO_2 density at projected reservoir pressure and temperature) for the project footprint. This should include all target formations of interest, including primary and secondary targets. Capacity calculations should include estimates of the net vertical volume effectively utilized or available for storage and an estimate of likely pore volume fraction to be used (utilization factor).**
2. **Operators should collect and analyze target formation pore fluids to determine the projected rate and amount of CO_2 stored as a dissolved phase. These data should be made publicly available as necessary for permitting and compliance purposes.**
3. **Operators should obtain estimates of phase-relative permeability (CO_2 and brine) and the amount of residual phase trapping. One possible approach is to use core samples with sufficient spatial density to confirm the existence of the trapping mechanisms throughout the site and to allow their simulation prior to site development. Estimates should be updated with site-specific monitoring and modeling results. These data should be made publicly available as necessary for permitting and compliance purposes.**

have been effectively trapped. Future work will need to address the specific criteria and methodology for implementation.

- **In general, conventionally acquired data appear sufficient.** Absent a specific need, advanced tools or special measurements should not be required. Rather, well-log data, conventional core analysis, and basic geological maps serve the primary data needs. Several commercial projects nationwide and worldwide are proceeding on this basis. A regulator or financier may request to see this information.
- **There are some common work requirements.** All projects will need a reservoir model that is based on stratigraphic and structural analysis. The same is true for conventional multi-phase-flow simulation. In some cases, 3-D seismic data acquisition and mapping may provide key information (but should not be uniformly required).
- **The site selection process should strive for accuracy, rather than precision.** This point derives from the goals of initial characterization, which focus on determining whether a site appears suitable. Prospective sites may lack data sufficient to precisely estimate some parameters. However, there is often enough data to accurately assess site performance. As a development proceeds, more data will become available to provide greater precision and accuracy.
- **The amount of data needed will vary case by case.** The density of data, the depth of prior operational knowledge, the number of wells likely to intersect the plume, and the local geology will all play a role in how much new information will need to be collected. Operators, regulators, and stakeholders need to understand this variability and consider regulatory frameworks flexible enough to encompass many different geological settings and data sets. For example, before allowing injection, current regulatory frameworks for injection wells require a certain amount of information and additional data gathered during drilling.
- **Analog data are of value.** In many cases, certain kinds of data or data density may be absent. Where appropriate, existing information can serve to provide important information about a site. However, if local data are severely limited or if little is known about a particular reservoir, new information is likely to be required.

4.3.2.2 Operations

As described earlier, the operational phase of a project overlaps with activities that take place during site characterization and selection as well as closure. The primary activities of this phase include operational planning, site preparation, pre-injection drilling, well and facility construction, logging and operational data collection, and injection planning and execution. Many of the stated operational guidelines may be standard industry practices or requirements under existing regulatory regimes that should be applied through best practices and regulations for CCS projects.

OPERATIONAL PLANNING AND MANAGEMENT

Robust operational plans are needed that include integration and feedback with MMV plans, as well as contingency mitigation/remediation plans based on the risk assessment. Operational planning should include establishing the technical plan for construction and drilling, a management plan, and an implementation plan.

The suitability of a site for storage is a function of three primary technical factors: the effectiveness of a confining zone in preventing upward migration of CO_2; the injectivity of the storage reservoir; and the volumetric capacity of the reservoir to hold injected CO_2.

Information gained during site characterization, along with the engineering requirements dictated by the CO_2 source, provides a technical basis for operational planning. These data inform operational and capital decisions that must be made before injection can begin. For some CCS projects, particularly in saline reservoirs, limited information will be available to make these decisions. Operators should ensure that sufficient flexibility exists in their plans to adapt to the unexpected and maintain safe and effective project execution.

One important step prior to commencing CO_2 injection is to define the structure of its implementation through a project management plan (Melzer et al. 1996b). Defining the team, its structure of accountability, and clear expectations for each member will help to ensure that the implementation moves forward smoothly to operation. Given the anticipated long duration of storage projects, this plan should be resilient to changes in management and fluctuations in economics. As a best practice, project operators should develop a transparent operational plan and implementation schedule. It is likely such a plan will be required by regulators as part of the permit application.

The project implementation plan should include the framework for injection operations, including timing and staging of injection, well and facility design, plans for establishing the injection pressure and rate, corrosion prevention procedures, and operational data collection. Each of these topics is described in detail in subsequent sections.

TIMING AND STAGING

Operational decisions will include deciding when to commence injection, where to inject, and in how many stages or steps. Operations may be staged in two different ways: starting in one area of the proposed project and expanding laterally, or starting with one injection zone and expanding vertically into another (Masoner and Wackowski 1995; Jarrell et al. 2002). In the near term, choices about timing and staging of injection will follow new policies and regulations concerning CO_2 emissions as well as permitting and economic constraints for early projects. For example, potential operators may choose to vent a fraction of a pure CO_2 stream in the near term, with the expectation of increasing the number of compressors and injection wells as regulatory constraints on CO_2 emissions grow. Similarly, power generators may build a new plant with 20–60 percent capture, but anticipating additional capture facilities in the future.

Decisions of timing and staging are inherently different for storage in saline formations and mature oil and gas fields. For oil and gas fields, enhanced hydrocarbon recovery considerations are likely to play an enormous role in decision making (Jarrell et al. 2002). However, the economics of enhanced recovery may drive decisions that run counter to maximizing CO_2 storage. To date, there is little information and no consensus on how timing and staging of injection trade off between maximizing recovery and maximizing storage, and no relevant information as to how early choices in EOR affect the latter outcome (Kovscek and Cakici 2005).

Conventional data sets and analyses can and do underlie current site characterizations

For saline formations, the inclination may be to deploy enough wells all at once to handle large volumes of CO_2, say on the scale of a large power plant. The timing may be set by the start-up of generating plants, and the project may require a single stage. There are two strong disadvantages to such projects: the initial capital outlay will be the largest in this context, and the risk will be the highest (Jarrell et al. 2002). To minimize the financial and operational risks, potential saline formation project operators may want to look for opportunities to stage injection, possibly in as many as four stages. Such staging can reduce the financial and operational risks associated with trying to start all at once by allowing for additional characterization wells and surveys.

Operators will need to work closely with CO_2 suppliers to ensure that drilling and injection schedules meet the needs of generators and point source suppliers on a technical basis. An important parameter in proper storage project planning is the CO_2 delivery contract that will include delivery volumes at a given temperature, pressure, and purity. Potential operators may need to provide storage for a fixed volume and a fixed rate. To honor the terms of this contract, operators may require flexible storage options to handle problems at wells, troubles with injectors, or unforeseen geological limits on injectivity. They should consider having capacity to manage potential unanticipated pipeline surges if any could arise. An alternative would be to seek regulations that would allow a maximum allowance for venting in the event of equipment failure.

SITE PREPARATION AND WELL CONSTRUCTION

WELL AND FACILITY DESIGN

Wells and facilities for geological storage should be designed with the following objectives:

- To ensure operational safety and effectiveness;
- To improve operational performance;
- To optimize well spacing, thereby minimizing capital and operating costs and environmental impacts; and
- To minimize the size of the CO_2 plume (site-specific considerations).

To achieve these goals, many factors will be considered, including the presence and availability of prior wells, rock properties, injection rate per well, data gathering needs, composition of new and prior casing and tubing, well monitoring plans, and number of likely injection zones. Full-flow reservoir injection simulations will be needed to compare different drilling configurations, well counts, and perforation lengths. Injection pressures will be constrained by the formation parting or fracture pressure. Selective injection equipment may be necessary to pack (or close) off different injection zones and limit risk of wellbore failure (Franks 1991). This equipment is often required by regulators, and operators should draw on past CO_2-EOR experience in well construction design and material selection (Stone et al. 1989).

PRE-INJECTION DRILLING

Drilling will provide access to the subsurface for data collection, injection, and monitoring. In some (maybe many) wells, actual geological conditions could differ from what was predicted. These may include subtle or substantial differences in injection target thickness, porosity, permeability, or even presence of the target reservoir. Wells may also encounter small faults not found during characterization.

Differences between the expected and actual geology are most probable in saline formation injections without nearby wells or detailed geophysical surveys. Conventional wireline logs, including the so-called "quad combo" (gamma ray, resistivity, bulk density, and neutron porosity) and well-diameter caliper logs are likely to be sufficient for lithologic characterization, although some special well logs (e.g., Formation MicroImager, FMI) may be needed. If there is no formation parting pressure or stress azimuth information in areas around planned injection wells, this information should be gathered and integrated into the project management plan. Ultimately, representative conventional and sidewall cores of the cap rock and the reservoir are likely to be needed to reduce uncertainty. In the case of saline formation projects, these cores should be described and analyzed to confirm or modify hypotheses of subsurface lithology and rock property distributions.

Once this information is gathered and analyzed, potential operators must decide whether the differences between expected and discovered geology and rock properties merit revision of geological models and flow simulations. It is very important to modify these models to incorporate these new data if substantial differences are detected.

WELL CONSTRUCTION

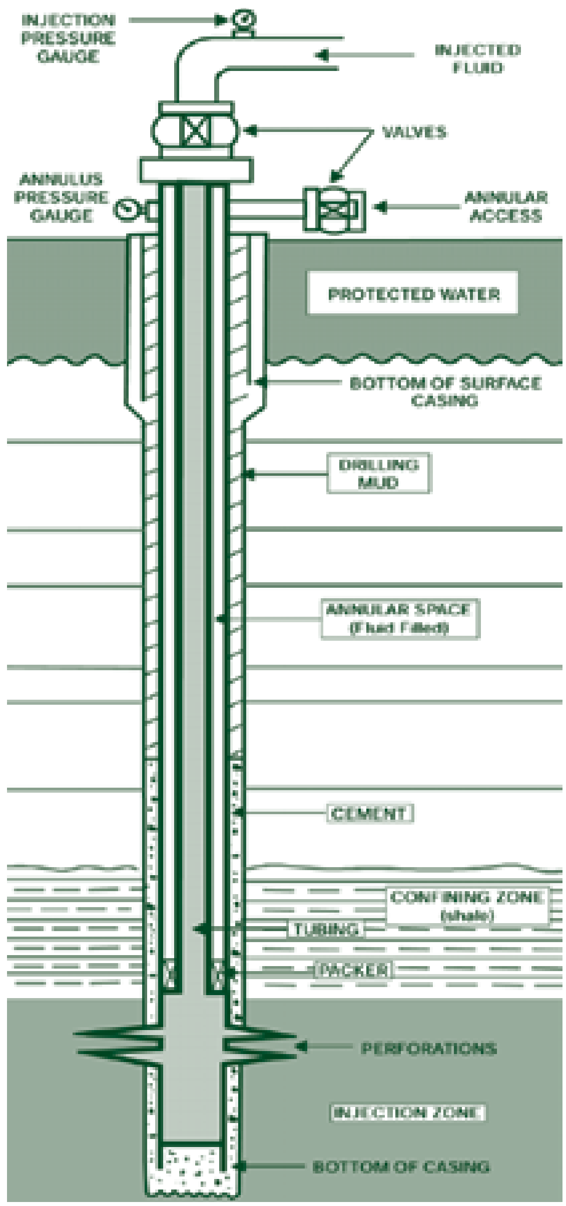
Initial experience suggests that existing tools for well construction and design are adequate, provided the materials are fit-for-purpose.

In many cases, stakeholders believe that traditional casing material (steel) and cement (Portland cement) will prove to be sufficient. Advanced corrosive-resistant cements are under development and being tested in some research projects. Additional research is being conducted on the effects of composition, curing, and fluid exposure on cements (Kutchko et al. 2007; Duguid 2008; Duguid et al. 2006; Anstice et al. 2005). These may be evaluated as the technology progresses and when the site-specific conditions suggest it may be warranted. All wells should be cased and cemented, but there is considerable discussion regarding whether the cement needs to extend to the surface. Long stands of cement require staging tools to relieve column pressures and can create pathways to the surface. Figure 15 shows the placement of cement and casing in a typical U.S. UIC Class II (EOR) injection well. In some cases, Class II wells are constructed using more rigorous standards if the site-specific conditions warrant. UIC Class I wells are constructed similarly, but face more rigorous requirements for both construction and testing than typical Class II wells.

EPA's draft UIC regulations for CO_2 injection wells (Class VI) outline performance standards for well construction, and it should be noted that some state regulations currently require all wells to be cemented to the surface. Exemptions to this requirement may be warranted in some geologic settings; however, at a minimum, the cement should extend from the injection zone to an area above the confining zone or cap rock that overlies the confining unit. This will ensure that CO_2 cannot move between formations along the well bore. If a secondary confining unit is present, the cement should extend above that as well. Exact well designs may vary among sites, depending on site-specific geologic conditions.

Well integrity, including cement location and performance, should be tested after construction is complete to ensure the compatibility of the materials with the subsurface environment. Well design, including the placement of the casing, has implications on which MMV technologies may be employed, underscoring the need for integrated planning.

Figure 15: Example of a Class II or EOR Injection Well



SOURCE: NMOCD

INJECTION GUIDELINES

Once injection is planned and permitted, storage operations must proceed in a safe and effective way. These operations will be similar to conventional CO_2-EOR operations in many ways, including the choice of equipment and established occupational safety requirements.

SETTING INJECTION PRESSURE AND RATE

The appropriate tools and experience in setting the injection pressure and rate are available from EOR experience and are not expected to differ substantially from existing UIC regulations for Class II wells. One important difference is that because the reservoir is being produced during EOR injections, the pressure dissipates. Gaseous CO_2 is compressible and changes state dramatically with small pressure and temperature changes, making setting the target injection pressures and rates for wells more complex than for water injection. For supercritical CO_2, densities more closely match typical liquid density.

Water injection step tests can be used before injection to determine the maximum allowable pressure. Sometimes the tests require some fracturing of the reservoir. However, since this information is of critical importance to successful geological storage operations, potential operators should be allowed to conduct water injection step tests at all prospective sites and permitted wells within the injection footprint.

Injecting CO_2 above formation fracture or parting pressure could be valuable to increasing injectivity or could be needed for achieving injection rates. While in the near term injecting above formation fracture or parting pressure is not recommended, a regulatory framework should not rule out this option in the future because occasionally injections exceeding these pressure levels may be needed to regain injectivity and flow of CO_2. In such cases, induced fracture geometries should be controlled so that the confining zone is never penetrated (Fry et al. 2005). Setting an injection rate is a complex process that needs to take into account site-specific characteristics and operational history.

DEHYDRATION AND CORROSION CONTROL

Corrosion control helps ensure site performance and effective storage, reduces unanticipated shutdowns that could lead to venting, and reduces operational expense. CO_2 will dissolve quickly in water to form carbonic acid, which is corrosive for most carbon steels. Although some CO_2 EOR projects have shown little corrosion (Pittaway and Rosato 1991), others have exhibited substantial degradation of tubing or casing (Holm and O'Brien 1987). Corrosion prevention does not require expensive alloys or coatings for operations, but does require operational diligence and mitigation (Jarrell et al. 2002).

Dehydration of the injectate is a critical component of corrosion management. Water present in the injectate will form carbonic acid; dehydration removes water from the injectate, reducing the presence of carbonic acid and, thus, corrosion (Ball and Harrell 1985). Commercial dehydrators are readily procured, but the equipment must be properly sized to CO_2 facilities. Even then, minor pitting is likely to occur, and regular inspection and periodic ultrasonic scanning is recommended. Continuous or periodic introduction of inhibitors has proven useful in many contexts—more so than plastic coatings, chrome-7 alloys, or batch inhibitors (Jarrell et al. 2002).

In addition to the engineering solution of dehydrating the CO_2 stream, natural factors reduce the potential for carbonic acid formation. First, the chemical reaction where CO_2 is converted to carbonic acid is limited by kinetics, such that only about 1 percent of the available CO_2 can be converted.[3] Also, when dehydrated CO_2 is continuously injected, a "bubble effect" occurs where the nearby rocks are dewatered, making formation water unavailable for in-situ carbonic acid formation.

Resolving Differences Between Predicted and Measured Performance

As discussed in the measurement, monitoring, and verification (MMV) section, one value of operational data is validating the subsurface model. What happens when the model and data disagree? The operator must analyze the information and determine whether a model update is warranted or if a contingency mitigation or remediation measure should be considered.

Following are examples of signals that may warrant an unscheduled model update or consideration of a contingency mitigation:

- Higher or lower than predicted reservoir pressure.
- Reservoir pressure that approaches the identified limits of the cap rock.
- Loss of injectivity.
- Unexplained movement of the CO_2 toward a source of drinking water or the surface.
- MMV data that indicate unexpected change relative to baseline CO_2 measurements (e.g., far-field microseismic events).
- Dramatically different plume geometry and extent of migration rate compared to predicted.

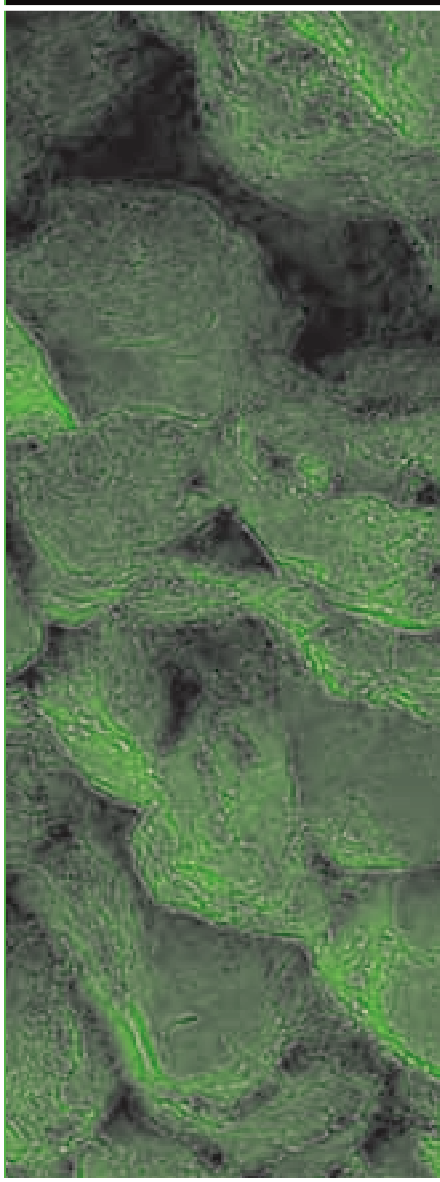
A key challenge in developing Guidelines for CO_2 capture and storage is characterizing uncertainty (or the level of confidence in predictions), identifying how to monitor for this uncertainty, and outlining the management options an operator has in addressing the unexpected. In the context of the environmental impact statement for Chevron's Gorgon project in Australia, a methodology for identifying "signposts" was developed, which merits consideration for future projects. Signposts are metrics that specify which measurements indicate when an unexpected result has occurred. For example, to address uncertainty regarding potential failure of the seal, the stated signpost is "seismic and/or borehole monitoring showing CO_2 stratigraphy above the Dupuy" (the injection reservoir). Development of such project-specific signposts can be a useful tool in communicating the potential impacts of a project and summarizing potential management options (Chevron Australia 2005).

OPERATIONAL LOGGING AND DATA COLLECTION INFORM OPERATIONS

It is expected that CO_2 injection projects will operate for at least 20 years and quite possibly for as long as 60 years. Whether this takes place in one stage or multiple stages, it is expected that some injection conditions may change dramatically over the project lifetime. Previously unidentified reservoir heterogeneities, changes in porosity and permeability due to precipitation or dissolution of minerals, or pressure interference between wells could present conditions that require alternative approaches to reservoir management. New wells may become necessary, old wells may require workovers or shut-in, and injection patterns may need rebalancing. To understand these changes, monitoring, data analysis, and reservoir modeling should occur throughout a project's operation. Many of the standard tools for operational monitoring are described in the cross-cutting MMV section, and these tools may include well-head metering of injection, well-head sensors for pressure and CO_2, injection profiling, reservoir pressure data (down-hole sensors if possible), step-rate tests, and pattern balancing.

It will be prudent for investigators to optimize operations. Operational data should be used to run new simulations and prepare new development plans that redress difficulties encountered. This creates an iterative approach to improving injection operations by increasing performance and reducing costs.

STORAGE GUIDELINE 6: RECOMMENDED GUIDELINES FOR INJECTION OPERATIONS



a. A field development plan should be generated early on in the permitting phase.

b. Operators should develop transparent operational plans and implementation schedules, with sufficient flexibility to use operational data and new information resulting from MMV activities to adapt to unexpected subsurface environments.

c. Operational plans should be based on site characterization information and risk assessment; they should include contingency mitigation/remediation strategies.

d. Storage operators should plan for compressor and well operations contingencies with a combination of contractual agreements for upstream management of CO_2, backup equipment, storage space, and, if necessary, permits that allow venting under certain conditions.

e. Wells and facilities should be fit-for-purpose, complying with existing federal and state regulations for design and construction.

f. The reservoir and risk models should be recalibrated (or history-matched) periodically, based on operational data and re-run flow simulations. Immediate updates should be made if significant differences in the expected and discovered geology are found.

g. The casing cement in the well should extend from the injection zone to at least an area above the confining zone.

h. Well integrity, including cement location and performance, should be tested after construction is complete, and routinely while the well is operational, as required by regulation.

i. Water injection tests should be allowed at all prospective CCS sites.

j. Injection pressures and rates should be determined by well tests and geomechanical studies, taking into account both formation fracture pressure and formation parting pressure. Rules should not establish generally applicable quantitative limits on injection pressure and rates; rather, site-specific limitations should be established as necessary in permits.

k. Operators should adhere to established workplace CO_2 safety standards.

l. Operators should implement corrosion management approaches, such as regularly checking facilities, wells, and meters for substantial corrosion. Corrosion detected should be inhibited immediately, or damaged facility components should be replaced. Dehydration of the injectate should be required to prevent corrosion, unless appropriate metallurgy is installed.

m. Operational data should be collected and analyzed throughout a project's operation and integrated into the reservoir model and simulations. The data collected should be used to history-match the project performance to the simulation predictions.

4.3.2.3 Managing the End of a Storage Project: Site Closure and Post-Closure

It is important to set expectations for managing the end of a storage project that are achievable and meet the likely needs of potential regulators and public stakeholders, ensuring the likely permanent storage of the CO_2. To this end, successful site closure and post-closure should entail the following:

a. Site closure encompasses both the plugging and the abandonment of each individual well within a project, as well as the closure of the overall project. The majority of site closure activities will take place once all injection has ceased.

b. Site closure does not end until post-injection monitoring and modeling demonstrate with a high degree of confidence that neither injected nor displaced fluids endanger human health and the environment, all wells have been plugged and abandoned, and records have been transferred to a public database.

c. Successful site closure should have the following qualities:
   1. There should be no migration or release of CO_2 from closed sites through geological or engineering hazards that could compromise human health or safety.
   2. CO_2 retention levels should be high enough to avoid health and safety impacts and to substantially contribute to atmospheric stabilization goals.
   3. Closure should be accomplished using reasonable, established, and cost-effective methodologies.
   4. Once a site is certified as closed, it should continue to be safe, effective, and secure.

d. Project operators who have demonstrated non-endangerment should be released from financial responsibility for further additional MMV activities. Operators should plug and abandon any wells used for post-injection monitoring. At this point, the project can be certified as closed, and project operators should be released from any financial assurance instruments held for site closure. In the event that regulators or a separate entity decide to undertake post-closure monitoring that involves keeping an existing monitoring well open or drilling new monitoring wells, project operators should not be responsible for any such work or associated mitigation or remediation arising out of the conduct of post-closure MMV.

e. Policymakers should carefully evaluate options for the design and application of a risk management framework for long-term stewardship. This will be a topic of future discussions and analysis.

SITE CLOSURE

The primary activities of site closure include plugging and abandoning individual wells, conducting a final assessment, and, as needed, reworking all of the wells potentially affected by the storage project. Regulatory programs governing the construction and operation of wells require the operator to submit records describing the wells to be kept in a publicly accessible database. This section of the Guidelines reiterates the importance of this reporting, and describes the type of data related to storage project closure that should be included to facilitate future stewardship.

WELL PLUGGING AND ABANDONMENT

The importance of well plugging and abandonment is underscored for storage because of three critical factors associated with injected CO_2: (1) CO_2 is buoyant; (2) in the presence of water, it can be both reactive and corrosive; and (3) pressure in the reservoir will increase during active injection. These factors could lead to degrading the well components, including casing, cement, and the spaces surrounding them. The proper plugging and abandonment of wells during site closure will facilitate the long-term protection of health, safety, and the environment through retention of CO_2 in the subsurface.

All oil, gas, and other UIC wells must undergo plugging and abandonment procedures as specified in existing regulations. For CO_2 injection wells or other wells in the project footprint, plugging and abandonment is the final task to ensure injected CO_2 is isolated from drinking water supplies or the atmosphere, and is central to the task of proper site closure. Many states and countries have developed regulations for this practice that govern integrity testing and placement of cement or mechanical plugs in the well (Figure 17). These regulations provide a default standard for plugging and abandonment as minimum standards. However, the unique nature of CO_2 storage places some additional concerns and considerations, as discussed below.

Materials. As described in the section on well construction, materials for storage wells should be fit-for-purpose. Portland cement is the industry standard for plugging of wells. Following the development of cement compositional standards by the American Petroleum Institute in 1953, Portland cement has proven performance under a variety of operating conditions, including acid gas disposal and CO_2-EOR.

Site closure is certified when there has been a demonstration that the CO_2 is properly contained within the confining zone and will not endanger public health and the environment.

A number of researchers have raised concerns that carbonic acid formed from CO_2 injection could lead to Portland cement corrosion, potentially compromising the long-term performance of a CO_2 storage site (Dow 2007; Gasda et al. 2004). Specifically, exposure to carbonic acid can cause degradation through the cement's loss of density and/or strength, and increased porosity (IEA GHG R&D 2005; Crow et al. 2008).

Recent laboratory experiments have confirmed that CO_2 does degrade cements, although comparisons between the laboratory responses and field data and samples suggest that any risks are likely manageable (MIT 2007; IEA GHG R&D 2006; Skinner 2003; Sweatman 2008). Potentially aiding the case for Portland cement, field studies conducted on core samples for existing well casings show that cements may become more resistant to corrosion and leakage with time. The SACROC study of well casing core samples in wells used for EOR show a mineralization within the cement that reduces porosity and leads to equilibrium in the reaction between the cement surface and CO_2 infused formation fluid. Recent work at SACROC supports this, in that there has been no leakage of CO_2 into fresh groundwater within the site (Duncan 2008).

There is also field experience in managing corrosion in tubing by coating it with cement, which has been a standard practice with CO_2-EOR injections (Schremp and Robertson 1975). There is limited literature regarding potential for corrosion of metal casing or tubing by CO_2, although operational corrosion management is well documented (Larkin 2006;. Newton and McClay 1977). It is not clear if special alloys or coatings provide any benefit in the field, and research on post-closure well material performance under realistic laboratory and/or field settings is recommended.

The efficacy of Portland cement is an area of active research and debate within the technical community, and some stakeholders support the use of newer corrosion-resistant materials. The IPCC *Special Report* also suggested that, where possible, operators should consider using cements designed to be resistant to CO_2 corrosion (IPCC 2005). However, field trials of special cements remain inconclusive, and while they do inhibit corrosion, concerns remain about the strength, bonding, and long-term performance of these novel materials (Gardner and Carpenter 2008; IEA GHG R&D 2006). On this basis, the stakeholder group generally agreed that it is premature to set Guidelines for use of novel materials in plugging wells beyond current regulatory requirements and practice. Rather, efforts should focus on plugging procedures.

Procedures. Plugging and abandonment is a well-established technology with many standard procedures for wells (Williams et al. 2000; Jarrell et al. 2002). Most states have regulations regarding the length of plug and acceptable procedures. The requirements regarding these specifications differ, depending on the nature of the well and the injectate. At present, it appears that standard approaches and methodologies are likely to prove sufficient for plugging CO_2 injection wells, provided that the materials do not degrade (see previous section on materials). However, given the central importance of plugging and abandonment, research should evaluate the need to develop technical standards for plugging CO_2 injection wells and ensuring storage integrity in the future that differ from current standard practices.

FINAL WELLBORE ASSESSMENT

Wells are the primary potential leakage pathway for closed storage projects. The final assessment is intended to ensure that injected CO_2 will not escape through closed wells. It consists of a assembling a comprehensive set of data describing the location, condition, and plugging procedures for every well that will be potentially affected by the storage project. Based on an assessment of the data, some wells may need to be further investigated and possibly reworked. In conducting a final assessment, it is important to consider the integrity of the whole well, including the annulus, casing, and wellbore. The methods for testing an engineered system (well) can be conducted in the subsurface and, to a certain extent, at the surface.

SUBSURFACE ASSESSMENTS FOR WELLBORE INTEGRITY

Cased-hole logging is used to understand wellbore environmental performance over long time periods. This approach is widely used by operators of geological storage industrial analogs, such as oil wells. Continued improvements in logging technology are being made, and at some point in the future the CCS community may select a preferred suite or set of tools. Until such a time, logging should be used in a final assessment to demonstrate:

a. a high quality of cement bond to casing and formation in the primary sealing interval, using a cement bond log with no pathways or fractures;
b. limited corrosion of the wellbore casing; and
c. continued conformance to other regulatory requirements.

Several methods, such as cement bond logging, flow-behind casing, oriented acoustic, and ultrasonic logging, can help to verify that both casing and cement maintain integrity before plugging.

In addition, several other approaches can be used in the subsurface to assess integrity. These include pressure tests, radioactive tracer tests, thermal tests, and mechanical integrity testing.

Until technically based CCS-specific standards are accepted into practice, regulators should remain flexible regarding the tools needed to conform to these goals. Regulators should also accommodate new cost-effective tools as they become available, provided they meet requirements.

SURFACE ASSESSMENT

A number of assessments can be conducted at the surface to aid in a final assessment. Magnetometers can be used to locate the steel plates and other metal components of old wells. Commonly when wells are plugged and abandoned, cement plugs are placed at strategic depths to ensure that hydrocarbons or potential contaminants do not reach the surface (Figure 16), and steel plates are welded onto the upper casing units. Most wells within the field are likely to be plugged and abandoned this way, and it may be impractical, unreasonable, or imprudent to reopen all old wells within the field for logging.

It is possible that well integrity failures at significant depth could bring carbonic acid to shallow depths within the well, ultimately risking corrosion and integrity losses at the surface. While the considerable experience with plugged wells with either CO_2 or H_2S fluid systems would indicate this is not an observed phenomenon, old wells can be reasonably assessed through surface surveys that visually inspect the closure plates and use commercial hand-held CO_2 detectors to find evidence of failure, integrity loss, or material flux. Soil gas surveys and hand-held CO_2 detectors could also be used to find evidence of failure, integrity loss, or material flux.

CERTIFICATION OF SITE CLOSURE

Site closure is certified when there has been a demonstration that the CO_2 is properly contained within the confining zone and will not endanger public health and the environment. During the closure period and depending on the specific characteristics of the storage reservoir, the pressure of the injected CO_2 stabilizes or begins to dissipate to the point at which it can be demonstrated that the injected CO_2 does not endanger human health and the environment. Certain MMV activities should be carried out during the closure period to make this demonstration. These MMV activities may indicate the need to rework some closed wells or to mitigate the migration of injected CO_2. Once the site is certified for closure by the applicable regulatory agency, project operators are relieved of the responsibility for further MMV and any associated mitigation or remediation arising out of the conduct of post-closure MMV, and any financial assurance instruments held in place for site closure are returned or voided.

DEMONSTRATION OF NON-ENDANGERMENT

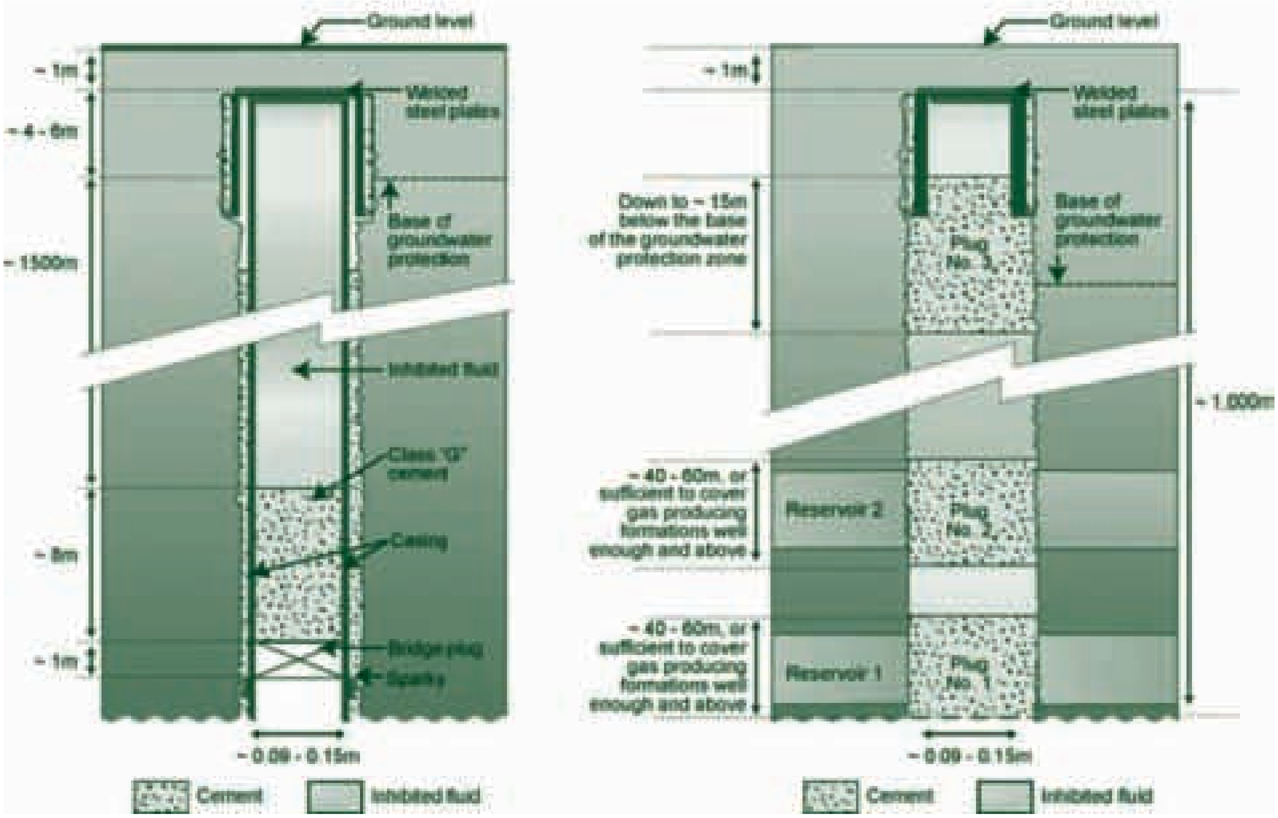
A comprehensive discussion of MMV as integral to all storage project phases is regarded as a cross-cutting topic. In the closure phase, the key MMV question is: At what point can it be demonstrated with a high degree of confidence that the injected CO_2 does not endanger human health and the environment? This is a primary concern of the public and regulators as well as operators.

A fundamental factor in making this demonstration is to show that there is a reasonably consistent history-match in the magnitudes and trends of modeled and measured behavior of the injected CO_2. Specific criteria for making this and other key determinations would include demonstrating the following:

- the estimated magnitude and extent of the project footprint (CO_2 plume and area of elevated pressure), based on measurements and modeling;
- that CO_2 movement and pressure changes match model predictions;
- the estimated location of the detectable CO_2 plume based on measurement and modeling (measuring magnitude of saturation within the plume or mapping the edge of it);
- either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone;

Figure 16: Examples of How Cased and Uncased Wells Are Abandoned

Cased Abandoned Well | **Uncased Abandoned Well**



SOURCE: IPCC 2005

- that, based on the most recent geologic understanding of the site, including monitoring data and modeling, the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway; and
- that wells at the site are not leaking and have maintained integrity.

The following parameters will be useful in most cases and should be monitored unless site-specific conditions suggests otherwise: CO_2 plume location, injection reservoir pressure, well integrity, and the geochemistry and pressure of the subsurface in a porous zone above the primary confining zone. In addition, near-surface monitoring may be useful as a safeguard in areas with sensitive populations or ecosystems. The specifications for post-injection MMV, including the duration and spatial extent, need to be driven by the characteristics of each site.

CO_2 Plume Location. Once injection ceases, the area of elevated pressure and CO_2 concentration from injection operations will stabilize or dissipate. After some finite amount of time, it should be possible to understand how the reservoir heterogeneity, gravitational forces, and decline in pressure affect continued migration of the injected CO_2. Plume location is determined through a combination of direct measurement and the use of flow simulation modeling. The validity of the flow simulation is demonstrated through history-matching of predicted and measured plume characteristics. The flow simulation for CO_2 migration is developed during the site characterization process, and is then updated, calibrated, and validated during active injection and during post-injection monitoring. The methodology for determining the plume location will vary based on the geological conditions at the site; differing combinations of direct measurement and updated simulations will prove useful based on the MMV collected throughout the project.

Reservoir Pressure. In some cases, reservoir pressure will be substantively higher at project closure than project inception. In all cases, unless pore fluids are produced, pressure will be highest at closure. After injection ceases, the geomechanical risks will decrease as reservoir pressure dissipates over time. The rate of dissipation is a function of reservoir heterogeneity, permeability, and the size of the pressure gradient. For many reservoirs, simple analytical calculations (like Darcy's Law) may provide a reasonable first-order characterization of how pressure will dissipate, and simulators can provide accurate and reasonably precise predictions regarding pressure change through time.

Operators can continue down-hole pressure monitoring with the existing tools and methods used during the operational phase. Given the anticipated pressure stabilization or dissipation after closure, however, there is no reason to measure pressure for long durations after injection. The objective of reservoir pressure monitoring is to match the predicted pressure drop to the observed pressure drop, or to demonstrate that the pressure behaves as expected and that the risk of failure has decreased enough for safe closure.

Well Integrity. Even after injection ceases and the storage project enters the closure phase, wells represent the most important hazard element and well failure represents the largest potential risk. The potential for well failure will be a function of potential flaws as well as reservoir pressure and chemistry. As discussed above, reservoir pressure will drop through time after injection ceases. In almost all cases, this will reduce the mechanical failure potential for wells. Pressure monitoring and the mechanical integrity tests conducted at site closure provide a rigorous basis to assess mechanical risks. Future research and modeling are warranted to assist with more confident determination of risk profile through time. The objective of well integrity monitoring is to prevent contamination of drinking water supplies and ensure retention of CO_2, or to demonstrate that the risk of well failure has decreased enough for safe closure.

Subsurface Monitoring of a Porous Zone Located Above the Primary Confining Zone. Monitoring the formation fluid chemistry and pressure of the deepest porous zone located above the primary confining zone during the time period where reservoir pressure is increasing (active injection) is thought to be an effective approach for early detection of leakage across the primary confining zone. When such MMV is included in a project plan, these measurements will contribute to a successful determination of non-endangerment. It is important to note that depending on local geologic and hydrologic conditions, this technique will not work in all cases in all areas.

Near-Surface Monitoring and Detection. As discussed above, the risks associated with pressure and chemistry should generally decrease with time; therefore, the need for surface monitoring arrays should decrease as well. However, CO_2 that begins migration shortly after injection may take a substantial period of time to reach the surface, especially through natural pathways such as faults and heterogeneous reservoirs. This time to the surface will be a function of path permeability, path length, and reactivity; lower permeability, longer paths, and higher reactivity are generally likely to increase the time needed to reach the surface. The flux of CO_2 along tortuous natural pathways is likely to be small, and significant human health risks are unlikely. Since these kinds of leaks are most likely to travel through groundwater systems to the surface, groundwater geochemical monitoring is likely to suffice in detecting any substantial flux.

Influence of Geologic Conditions on Duration and Spatial Extent of Post-Injection MMV. As discussed in the site characterization section, all storage reservoirs must have a primary confining zone that prevents vertical migration of injected CO_2. Many storage sites will also have a primary trap that physically constrains the lateral migration of injected CO_2. In all cases, secondary trapping will begin to take place through a series of mechanisms, including residual trapping, dissolution of CO_2 into the formation fluid, and mineralization. As these trapping mechanisms take effect, the potential for injected CO_2 to migrate will diminish over time.

Rapid or unexpected post-injection migration is a point of concern. There are two ways to evaluate its potential. The first is to take physical measurements that show that the injected CO_2 plume has stopped moving or has stabilized, and that the residual pressure throughout the reservoir is returning to levels near the original hydrostatic pressure of the reservoir. In reservoirs with lateral seals, it could take a relatively short period of time to see stabilization. In this kind of configuration, a CO_2 accumulation will remain intact, trapped in the reservoir indefinitely. Over the long term, there may be interest in monitoring the pressure of the reservoir for a finite duration to determine if leakage is occurring.

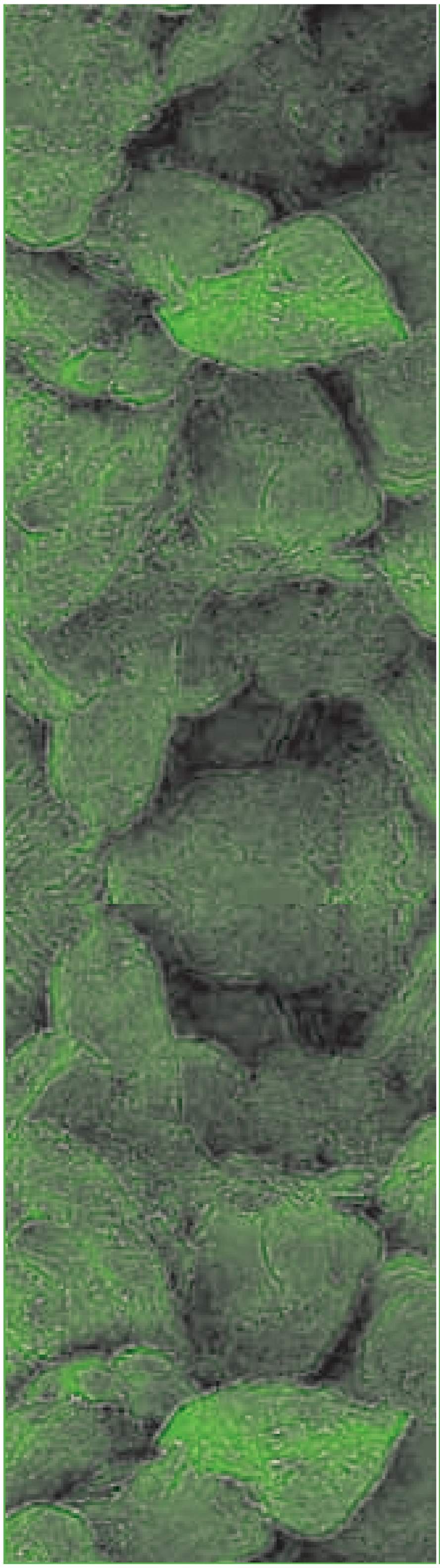
In other reservoir configurations with limited or no lateral traps, it may take longer for the plume to stabilize. In these cases, it may be acceptable to use a combination of geophysical measurements and validated model predictions to satisfactorily demonstrate that the plume will stabilize and does not endanger human health and the environment. To rely on this approach, the models would need to be vetted by experts and would need to have been updated, calibrated, and validated throughout the operational life of a project as well as during the post-injection monitoring period.

Finally, low-permeability sites may have less injectivity, but may also have much more residual phase trapping and capillary resistance to flow. This aspect may ultimately prove to be valuable in assessing storage resource. It bears repeating that CCS has yet to be deployed into an active carbon market; as such, decision makers and potential regulators should refrain from prescriptive solutions without a sound technical basis.

COMPLETION OF SITE CLOSURE

Once it has been demonstrated that the storage project does not endanger public health and the environment, the project operator should qualify for regulatory approval of certification of site closure. At this point, the project operator should be released from additional MMV requirements and any associated mitigation or remediation arising out of the conduct of post-closure MMV, and any financial assurance instruments for site closure should be released. This process should formally recognize the appropriate operation and closure of a site.

STORAGE GUIDELINE 7: RECOMMENDED GUIDELINES FOR SITE CLOSURE



a. Continued monitoring during the closure period should be conducted in a portion of the wells in order to demonstrate non-endangerment, as described below.

b. For all other wells, early research and experience suggest that conventional materials and procedures for plugging and abandonment of wells may be sufficient to ensure project integrity, unless site-specific conditions warrant special materials or procedures. A final assessment should include a final cement bond log across the primary sealing interval of all operational wells within the injection footprint prior to plugging, as well as standard mechanical integrity and pressure testing.

c. Operators should assemble a comprehensive set of data describing the location, condition, plugging, and abandonment procedures, and any integrity testing results for every well that will be potentially affected by the storage project.

d. Satisfactory completion of post-injection monitoring requires a demonstration with a high degree of confidence that the storage project does not endanger human health or the environment. This includes demonstrating all of the following:

1. the estimated magnitude and extent of the project footprint (CO_2 plume and area of elevated pressure), based on measurements and modeling;
2. that CO_2 movement and pressure changes match model predictions;
3. the estimated location of the detectable CO_2 plume based on measurement and modeling (measuring magnitude of saturation within the plume or mapping the edge of it);
4. either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone;
5. that, based on the most recent geologic understanding of the site, including monitoring data and modeling, the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway; and
6. that wells at the site are not leaking and have maintained integrity.

e. Project operators who have demonstrated non-endangerment should be released from responsibility for any additional post-closure MMV, and should plug and abandon any wells used for post-injection monitoring. At this point, the project can be certified as closed, and project operators should be released from any financial assurance instruments held for site closure. In the event that regulators or a separate entity decide to undertake post-closure monitoring that involves keeping an existing monitoring well open or drilling new monitoring wells, project operators should not be responsible for any such work or associated mitigation or remediation arising out of the conduct of post-closure MMV.

f. If one does not already exist in a jurisdiction, a publicly accessible registry should be created for well plugging and abandonment data.

g. As a condition of completing site closure, operators should provide data on plugged and abandoned wells potentially affected by their project to the appropriate well plugging and abandonment registry. This would include the location and description of all known wells in the storage project footprint, and the drilling, completion, plugging, and integrity testing records for all operational wells.

h. The site-specific risk assessment should be updated based on operational data and observations during closure.

REGISTRATION AND REPORTING

Because there are always uncertainties in the subsurface, it is possible that even properly completed, operated, and abandoned wells could fail at some future date. Wells represent a potential leakage pathway that could require some degree of mitigation. Further, as understanding of unexpected events and the performance of wells over long time periods evolves, additional, possibly CCS-specific, well plugging and abandonment measures may prove reasonable to implement at wells that were previously plugged and abandoned.

Currently, most regulations governing the construction, operation, and closure of wells include requirements for the operator to submit records for inclusion in publicly accessible databases. To simplify and expedite any conditional re-examination or re-entry of storage wells or wells potentially affected by a storage project, operators should be required to submit site closure information to the appropriate regulatory agency to complete site closure. This would include the location and description of all known wells in the project footprint, and the drilling, completion, plugging, and integrity testing records for all operational wells. In addition to location, description, and well records, the registry may also include an estimate of the plume footprint for a given period of time. This information should be included in the site closure documentation but should also have been filed with each well when it was operational.

POST-CLOSURE

Given the expected number and scale of storage sites, as well as the intended long-term duration of CO_2 retention in the subsurface, additional management of sites certified as closed is/may be warranted. Therefore, these Guidelines recommend that an entity be tasked (or created) with oversight that would include such activities as operating the registries of sites; conducting periodic MMV; and, if the need arises, conducting routine maintenance at MMV wells. This effort could be funded by a fee assessed on sequestered tons or through some other mechanism.

The subject of certification and management of the closed sites has been a matter of substantial discussion among potential operators, insurers, regulators, subject experts, and potential legislators (de Figueiredo 2007; IOGCC 2007). Several goals and concerns are worth noting, some of which are in apparent conflict:

- One objective is to create the right set of incentives for project developers to invest in and safely site, construct, operate, and close storage projects. Conversely, incentives should not make it more cost-effective for project operators to take undue risks in these activities or to be negligent. Private companies may be reluctant to engage in storage operations if required to carry a financial commitment and liability out into the indefinite future, which could impede deployment of the technology.
- Second, given the expected volume of CO_2 to be sequestered over time frames that may outlast the lifetimes of the private project owners, it is important to ensure that institutions are in place to track closed sites and to attend to concerns, if any, that arise over time. It is important to ensure that such institutions have adequate funding to carry out these activities. There is concern that provisions put in place today would need to withstand changes in government, technology, and across generations, presenting a number of legal and ethical challenges.
- Third, despite best efforts and best scientific understanding, some storage projects may fail, resulting in migration of CO_2 and related damages. Concern about this risk could discourage early projects. Given the societal benefit of learning more about storage, innovative risk management solutions may be warranted for these projects and may include public-private partnerships or other models for limited transfer of financial responsibility (e.g., Price-Anderson, the Asbestos Fund, leaking underground storage tank funds, and rate-based funds where a small surcharge is added to either production or sales to offset potential mitigation costs).

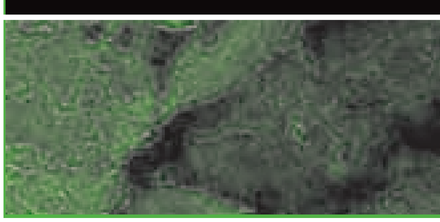
STORAGE ENDNOTES

[1] "Technical potential" as defined in the IPCC Third Assessment Report is the amount by which it is possible to reduce GHG emissions by implementing a technology or practice that already has been demonstrated (IPCC 2001)

[2] Darcy's Law is used to understand fluid flow through a geologic reservoir, where flow (units of volume over time) is calculated based on permeability, pressure, and area as well as the viscosity of the fluid.

[3] The actual fraction of CO_2 that enters the dissolved phase is a fraction of the CO_2 in contact with water and the limitations of reaction kinetics.

STORAGE GUIDELINE 8: RECOMMENDED GUIDELINES FOR POST-CLOSURE

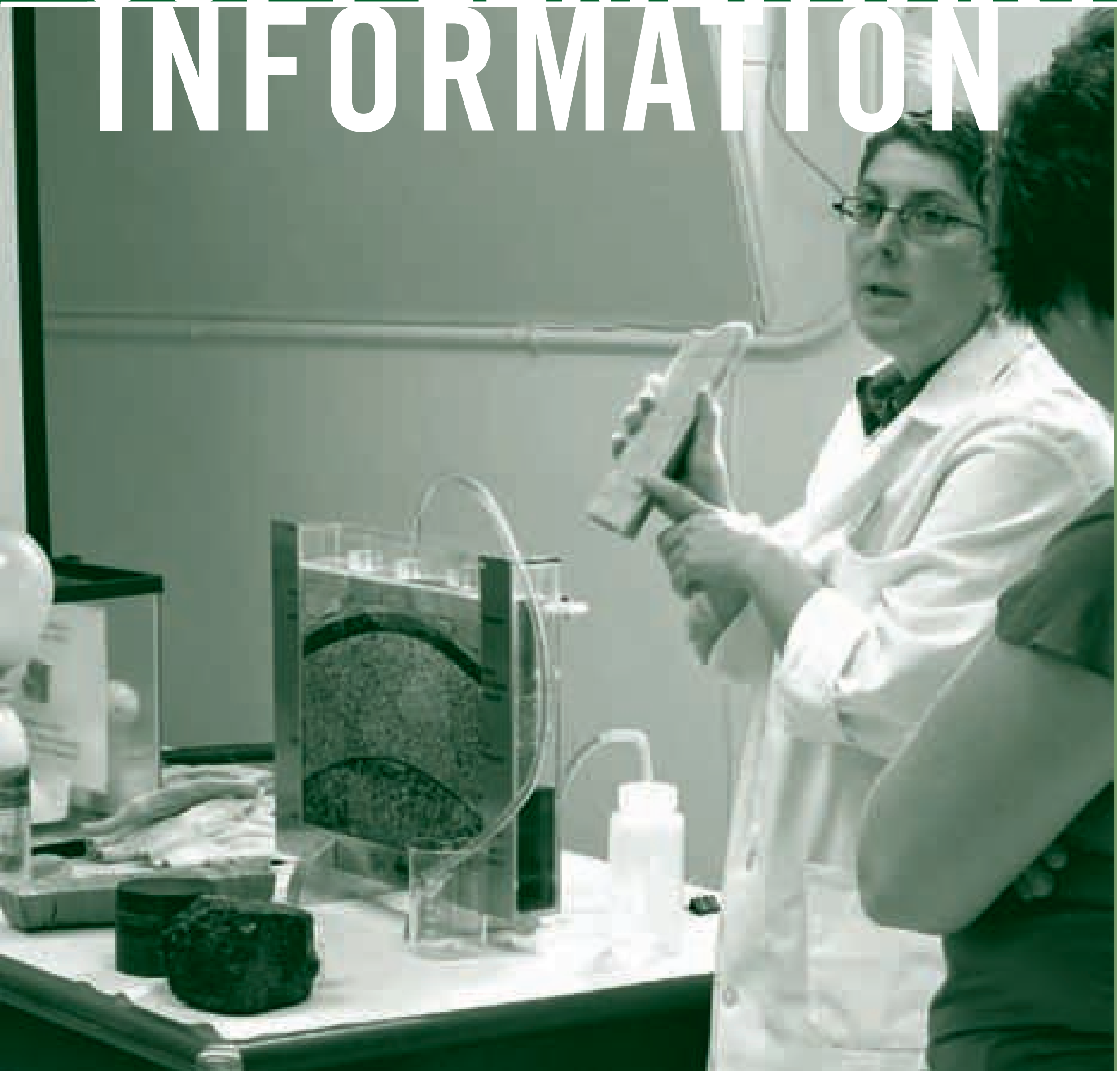


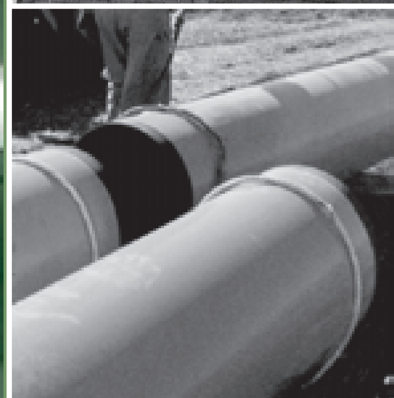
a. Certified closed sites should be managed by an entity or entities whose tasks would include such activities as operating the registries of sites; conducting periodic MMV; and, if the need arises, conducting routine maintenance at MMV wells at closed sites over time.

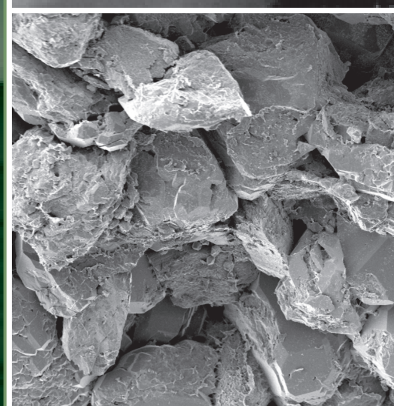
b. These entities need to be adequately funded over time to conduct those post-closure activities for which they are responsible.

SUPPLEMENTARY INFORMATION

PART 5







GLOSSARY AND ACRONYMS

Note: in drafting this glossary the authors have drawn heavily from two key resources: (1) Glossary included in EPA's draft UIC Class VI Rule http://www.epa.gov/safewater/uic/pdfs/prefr_uic_co2rule.pdf and (2) Schlumberger's online oilfield glossary http://www.glossary.oilfield.slb.com/default.cfm

2-D, 3-D, and 4-D: two-, three-, and four-dimensional

3-D seismic: Seismic energy is used to determine the composition, fluid content, extent, and geometry of rocks in the subsurface. Three-dimensional (3-D) seismic surveys include numerous vertical and horizontal sampling lines, resulting in enough spatial resolution to provide detailed information about fault distribution and subsurface structure characteristics.

4-D seismic: 3-D seismic data acquired over the same area at different times, allowing for observations in changes in fluid location and saturation, pressure, and temperature over time. It is sometimes also referred to as time-lapse seismic.

above-zone monitoring: Monitoring (pressure, temperature, fluid chemistry, etc.) in the porous zone above the confining zone.

ADM: Archer Daniels Midland Company

AEP: American Electric Power

amines: Chemicals used to separate carbon dioxide from flue gas in post-combustion capture. The current commercialized technology involves the use of monoethanolamine.

ANSI: American National Standards Institute

API: American Petroleum Institute

Ar: Argon

area of pressure elevation: A zone of elevated pressure created by the injection of carbon dioxide into the subsurface. For geologic storage, this refers to the area where there is a pressure differential sufficient to cause adverse impacts to overlying receptors, such as the movement of injected or displaced fluids above the confining zone into an underground source of drinking water.

area of review: The region surrounding the geologic storage project that may be affected by the injection activity. The area of review is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and includes the area of elevated pressure.

ASME: American Society of Mechanical Engineers

atm: Standard atmosphere. This unit of pressure is defined as being precisely equal to 101.325 kilopascals.

atmospheric eddy correlation: Measurement of the fluxes within the atmosphere over time. For carbon dioxide capture and storage, this type of measurement can be made at the surface to detect changes in carbon dioxide concentrations.

baseload power plant: A plant that produces electricity at an essentially constant rate. These plants are operated to maximize system mechanical and thermal efficiency and minimize system operating costs. A baseload plant is typically characterized by relatively high fixed costs and low unit operating costs. Traditionally, coal and nuclear plants and some high-efficiency steam electric plants have been considered baseload plants (Spectra Energy).

basin scale: Over a large area or basin that encompasses a potential storage reservoir with significant lateral extent. This area may cross state boundaries.

BACT: Best available control technology. An emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated pollutant that would be emitted from a source when considering energy, environmental, and economic impacts and other costs. The reductions must be achievable with available methods, systems, and techniques for controlling a given pollutant.

Barrel-mile: One barrel, transported one mile, equals one barrel-mile, normally measured in billion barrel-miles. There are 42 gallons in a barrel (Association of Oil Pipe Lines).

BAU: Business as usual

BLM: Bureau of Land Management. A bureau within the U.S. Department of the Interior, BLM is responsible for carrying out a variety of programs for the management and conservation of resources on 258 million surface acres, as well as 700 million acres of subsurface mineral estate. These public lands make up about 13 percent of the total land surface of the United States and more than 40 percent of all land managed by the federal government.

block valves: Valves used to isolate sections of pipe in the event of a leak or for maintenance. Block valves are typically spaced every 16–32 kilometers (10–20 miles), depending on site-specific conditions, and are often installed more frequently near critical locations, such as road and river crossings and urban areas.

BP: British Petroleum.

bpd: Barrels per day

Bragg fiber-optic grating: A short segment of optical fiber that reflects particular wavelengths. It can be used as an optical filter and is relevant to carbon dioxide capture and storage in the context of distributed temperature sensing in the well bore.

cap rock: A geologic formation stratigraphically overlying the injection zone that acts as a barrier to fluid movement (synonyms: confining zone, seal).

capacity: Estimate of the pore volume that is expected to be available to store carbon dioxide over the project lifetime. Capacity estimates should be specific to the target injection zone at the proposed project site.

capillary entry pressure: Capillary forces hold a fluid in a capillary or a pore space. Capillary entry pressure is dependent on the properties of the fluid and surface and dimensions of the space. The capillary pressure curve is important for understanding saturation distribution in the reservoir and affects fluid flow through the subsurface.

carbonate: A class of sedimentary rock whose chief mineral constituents (95 percent or more) are calcite and aragonite (both $CaCO_3$) and dolomite [$CaMg(CO_3)_2$], a mineral that can replace calcite during the process of dolomitization. Limestone, dolostone or dolomite, and chalk are carbonate rocks. Although carbonate rocks can be clastic in origin, they are more commonly formed through processes of precipitation or the activity of organisms, such as coral and algae. Carbonate rocks can serve as hydrocarbon reservoir rocks, particularly if their porosity has been enhanced through dissolution.

casing: The pipe material placed inside a drilled hole to prevent it from collapsing. The two types of casing in most injection wells are surface casing, which is the outermost casing that extends from the surface to the base of the lowermost underground source of drinking water, and long-string casing, which extends from the surface to or through the injection zone.

CCS: Carbon dioxide capture and storage. The process of capturing carbon dioxide from an emission source, converting it to a supercritical state, transporting it to an injection site, and injecting it into deep subsurface rock formations for long-term storage. CCS is sometimes referred to in the literature as carbon dioxide capture and sequestration.

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

CERA: Cambridge Energy Research Associates

certification of site closure: Formal acknowledgment by the regulatory body that an operator has completed requirements at a site. Certification of site closure takes place when there has been a demonstration that the CO_2 is properly contained within the confining zone and will not endanger public health, the environment, or natural resources.

CFB boiler: Circulating fluidized bed. CFB boilers use coal in 3/8-inch pieces (rather than pulverized) mixed with limestone and burn it at lower temperatures (1,500–1,650°F) compared to conventional boilers. Air is blown into the boiler to suspend, or fluidize, the mixture. Criteria pollutant emissions are reduced in CFB applications because the limestone is to lime in the boiler, which absorbs sulfur dioxide, and lower combustion temperatures yield less nitrous oxide emissions (Blankinship 2008).

CFR: Code of Federal Regulations. The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the U.S. federal government. The CFR is divided into 50 titles that represent broad areas subject to federal regulation. Each volume of the CFR is updated once each calendar year and is issued on a quarterly basis (GPO Access).

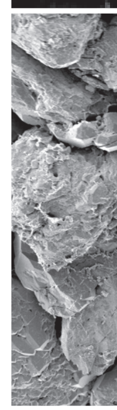
CH_4: Methane. A hydrocarbon that is a greenhouse gas with a global warming potential most recently estimated at 23 times that of carbon dioxide (based on the IPCC Third Assessment Report). It is emitted from a variety of both anthropogenic and natural sources. Anthropogenic sources of methane include fossil fuel production, animal husbandry, rice cultivation, biomass burning, and waste management. Natural sources of methane include wetlands, gas hydrates, permafrost, termites, oceans, freshwater bodies, non-wetland soils, and other sources, such as wildfires.

characterization: Collecting data and building a model that incorporates the characteristics of the reservoir that are pertinent to its ability to store carbon dioxide.

chemical absorption: A chemical process whereby molecules from the flue gas absorb to other molecules to yield pure carbon dioxide.

Class I UIC well: Permitted under the Underground Injection Control Program, Class I wells inject hazardous and nonhazardous wastes into deep, isolated rock formations that are thousands of meters below the lowermost underground source of drinking water. Class I wells are classified as hazardous, nonhazardous industrial, municipal, or radioactive, depending on the characteristics of the fluid injected. The construction, permitting, operating, and monitoring requirements are more stringent for Class I hazardous wells than for the other types of injection wells. There are approximately 550 Class I wells in the United States.

Class II UIC well: Permitted under the Underground Injection Control Program, Class II wells inject fluids associated with oil and natural gas production. Most of the injected fluid is salt water, which is brought to the surface in the process of producing oil and gas. In addition, brine and other fluids (including carbon dioxide) are



injected to enhance oil and gas production. There are approximately 144,000 Class II wells in operation in the United States, which collectively inject over 2 billion gallons of brine every day.

clastic: Sediment consisting of broken fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks, such as conglomerate, sandstone, siltstone, and shale.

Claus plant or process: A sulfur-recovering unit that uses the Claus process to remove sulfur from a gas stream. The multistep Claus process recovers sulfur from gaseous hydrogen sulfide in raw natural gas or in byproduct gases from industrial processes, such as those created refining crude oil.

CO: Carbon monoxide

CO+H_2: Carbon monoxide plus hydrogen

CO_2: carbon dioxide. A naturally occurring gas that is also a byproduct of the combustion of fossil fuels, biomass, other industrial processes, and land-use changes. CO_2 is the principal anthropogenic greenhouse gas responsible for global warming. It is the reference gas against which other greenhouse gases are measured; therefore, it has a global warming potential of 1.

CO_2 Capture Project: An international effort funded by eight of the world's leading energy companies. Working with governments, nongovernmental organizations, and other stakeholders, the project aims to reduce the cost of CO_2 capture from combustion sources and develop methods for safely storing CO_2 underground.

CO_2 enhanced oil recovery: The improved or tertiary recovery of oil by miscible displacement of oil through injection of carbon dioxide.

CO_2-PENS: Developed by the U.S. Department of Energy's Los Alamos National Laboratory, a system-level framework and model that can be used to screen multiple sites and determine the long-term risks associated with carbon dioxide storage at specific sites.

CO_2 plume: The underground extent, in three dimensions, of the injected carbon dioxide.

co-constituent: Non-carbon dioxide compounds in the emissions stack gas or process stream captured for compression and transport to a geologic storage location.

common carrier pipeline: A pipeline system used by many entities that must be accessible upon reasonable request. Common carrier status depends on whether the substance being transported via pipeline is "in or affecting interstate commerce" and/or whether the state law requires that it be a common carrier. Almost all interstate pipelines are common carriers (Shell Pipeline).

CPM: Computational pipeline monitoring. A software-based monitoring tool that allows the pipeline dispatcher to respond to a pipeline operating anomaly that may be indicative of a leak or release (U.S. EPA 1997).

condemn a right of way: Declare a property convertible to public use under the right of eminent domain.

confining zone: A geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone that acts as a barrier to fluid movement (synonyms: cap rock, seal).

contingent mitigation: A key component of the operational planning process that takes account of reasonably foreseeable events that may prevent completion of normal operations. The formal plans and procedures for any operation should include normal operating procedures, contingency plans, and emergency responses.

CoP: Conoco Phillips

core analysis: Laboratory analyses performed on the formation core samples as part of a site characterization process.

criteria pollutant: The 1970 amendments to the Clean Air Act required EPA to set National Ambient Air Quality Standards for certain pollutants known to be hazardous to human health. EPA has identified and set standards to protect human health and welfare for six pollutants: ozone, carbon monoxide, total suspended particulates, sulfur dioxide, lead, and nitrogen oxide. The term, "criteria pollutants" derives from the requirement that EPA must describe the characteristics and potential health and welfare effects of these pollutants. It is on the basis of these criteria that standards are set or revised.

crust: The thin, outermost shell of the Earth that is typically 3–46 miles (5–75 kilometers) thick. The crust overlies the more dense rock of the mantle, which consists of rocks composed of minerals like pyroxene and olivine, and the iron and nickel core of the Earth.

cryogenic separation: Cryogenic separation by distillation or freezing is a method for post-combustion carbon dioxide capture.

Cullender and Smith: A method used for calculating static bottom-hole pressure in gas wells.

demonstration: Study of the feasibility of disseminating, implementing, or applying research and development findings. In this context, a demonstration project is designed to prove the feasibility of carbon dioxide capture and storage, which is critical for the potential deployment of the technology.

deployment: Implementation of a technology to realize its economic and social benefits following its successful demonstration.

dry cooling: A method for cooling thermoelectric power plants whereby air-cooled equipment discharges heat directly to the atmosphere by heating the air. Dry systems reduce water use at a plant by eliminating the use of water for steam condensation, but increase energy consumption compared to wet cooling systems.

Easement: A legal agreement that allows the pipeline owner to construct, operate, and maintain a pipeline across the land. An easement does not grant an unlimited entitlement to use the right of way; rather, the rights of the easement owner are set out in the easement agreement.

ECBM: Enhanced coalbed methane. The process of injecting a gas (e.g., carbon dioxide) into coal, where it is adsorbed to the coal surface and methane is released. Methane can be captured and produced for economic purposes.

EHS: Environment, health, and safety

EIA: U.S. Energy Information Administration. An independent statistical agency within the U.S. Department of Energy.

EJ: Exajoule. A unit of energy. One EJ is equal to 1018 Joules.

eminent domain: Federal and state governments have the constitutional power to grant public utilities and common carrier pipelines the power of eminent domain to acquire land for public purposes.

EOR: Enhanced oil recovery. Also referred to as tertiary recovery, the third stage of oil (or other hydrocarbon) production, during which sophisticated techniques that alter the original properties of the oil are used. EOR's purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir. EOR can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. The three major types of EOR operations are chemical flooding (alkaline flooding or miscellar-polymer flooding), miscible displacement (carbon dioxide injection or hydrocarbon injection), and thermal recovery (steam-flood or in-situ combustion).

EPPA: Emissions Predictions and Policy Analysis. A global, applied, general-equilibrium model of economic growth, international trade, and greenhouse gas emissions run by the Massachusetts Institute of Technology Joint Program on the Science and Policy of Global Climate Change. The model is used to calculate paths of future greenhouse gas emissions, and to provide economic analysis of proposed control measures.

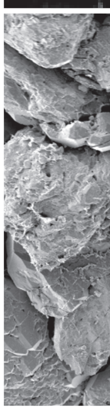
EPRI: Electric Power Research Institute

ESP: Electrostatic precipitator. A pollution control device for removing particulate matter from a waste gas stream in a power plant or industrial process.

FEP: Features events and processes

FERC: Federal Energy Regulatory Commission. An independent federal agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines, as well as licensing hydropower projects. FERC has regulatory oversight over the rates and access of interstate natural gas and oil pipelines, as well as the siting of interstate natural gas pipelines.





FGD: Flue gas desulfurization. Also known as a scrubber, an environmental control technology used for removing sulfur dioxide from the exhaust flue gas in power plants.

FHWA: Federal Highway Administration. An agency within the U.S. Department of Transportation.

fill-spill analysis: A method to identify traps or leak points in a subsurface reservoir.

fit-for-purpose: Designed to function according to specific conditions and parameters, fit-for-purpose is not a standard, but reflects the flexibility in choosing the materials and procedures, depending on the level of co-constituents in the carbon dioxide stream. Given the lack of knowledge and uncertainty regarding the effect of injecting co-constituents in the storage reservoir, this flexibility is warranted in choosing material or designing regulations.

flange: A connection profile used in pipe work and associated equipment to provide a means of assembling and disassembling components. The design and specification of a flange relate to the size and pressure capacity of the equipment to which it is fitted.

flange rating: The rating of flange reflects the design pressure a flange can withstand. There are several standards for pipeline flange rating. Pipe flanges that are made to standards called out by ASME/ANSI B16.5 or ASME/ANSI B16.47 are typically made from forged materials and have machined surfaces (the biggest difference between 16.5 and 16.47 is in the diameter). They are typically in "pressure classes" such as 150, 300, 600, 900, 1500, and 2500 pounds. These pressure classes have pressure and temperature ratings for specific material—for example, a steel 900 steel flange is rated up to 2,200 pounds at temperatures of less than 100°F.

FLPMA: Federal Land Policy and Management Act. Passed in 1976, FLPMA provided guidance for multiple-use management of public lands by the Bureau of Land Management (U.S. DOI/BLM/OS 2001).

FMI: Formation Micro Imager. Developed by Schlumberger, the FMI records high-resolution microelectrical wellbore data. Microresistivity data are mapped to produce wellbore images that document bed boundaries, stratigraphic surfaces, and fractures with resolution approaching 5 millimeters.

formation fluid: The brine originally trapped in the geologic formation.

formation fracture pressure: Pressure level above which the injectate will initiate a new fracture in intact rock.

formation parting pressure: The pressure level above which the injectate will propagate, open, or extend a pre-existing flaw in rock (a fault, fracture, bedding plane, etc.).

fracture: A crack within a rock (not related to foliation or cleavage in metamorphic rock), along which there has been no movement. Fractures can enhance the permeability of rocks by connecting pores together. For this reason, fractures are induced mechanically in some reservoirs to boost hydrocarbon flow.

fracture arresters: Used on the pipelines to control ductile fractures.

ft: Feet

FutureGen: Initiative launched by the U.S. Department of Energy (DOE) in 2003 to build a 275-megawatt integrated gasification combined-cycle (IGCC) carbon dioxide capture and storage (CCS) plant. DOE announced a restructuring of the FutureGen approach in January 2008, proposing to use federal funding to demonstrate CCS technology at multiple commercial-scale IGCC or advanced coal power plants, in lieu of a single demonstration (U.S. DOE/NETL 2007d).

G8: Group of Eight. An exclusive body of the world's leading seven industrialized nations (France, Germany, Italy, Japan, United Kingdom, United States, Canada) and Russia. The members of the G8 set out to tackle global challenges through discussion and action. Since 1975, the members of the G8 have been meeting annually to deal with the major economic and political issues facing their domestic societies and the international community as a whole (G8 2008).

GE: General Electric

GEE: General Electric Energy

geologic storage: Also called geologic sequestration, refers to the indefinite isolation of carbon dioxide in subsurface formations. Injected carbon dioxide is trapped within the pore space, dissolved in formation fluids, and (over long time periods) mineralized.

GHG: Greenhouse gas. Gases that absorb infrared radiation in the atmosphere, including (but not limited to) water vapor, carbon dioxide, methane, nitrous oxide, hydrochlorofluorocarbons, ozone, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Gorgon project: A project undertaken by the Australian subsidiaries of Chevron, ExxonMobil, and Shell to develop the greater Gorgon gas fields located in the offshore region of western Australia. The carbon dioxide produced during the natural gas processing will be injected into deep formations for geologic storage (U.S. DOE 2008).

GPS: Global positioning system. A space-based radio-navigation system that provides reliable positioning, navigation, and timing services to civilian users on a continuous worldwide basis. For anyone with a GPS receiver, the system will provide accurate location and time information in all weather, day and night, anywhere in the world.

$GtCO_2$: Billion metric tons of carbon dioxide

GW: Gigawatt. One GW is equal to one billion watts.

H_2: Hydrogen

H_2CO_3: Carbonic acid

H_2O: A molecule of water.

H_2S: Hydrogen sulfide. A colorless gas that is odorless at high concentrations, but smells like rotten eggs in low concentrations. Hydrogen sulfide is produced during the decomposition of organic matter and occurs with hydrocarbons in some areas. H_2S is toxic; its effect depends on duration, frequency, and intensity of exposure and the susceptibility of the individual.

hazard: Risk assessment terminology that identifies potential undesirable outcomes that a potential project should consider.

HHV: High heating value. The amount of heat produced by the complete combustion of a unit quantity of fuel. A high heating value is obtained when all combustion products are cooled and the water vapor formed during combustion is condensed.

high-consequence area: As per US DOT Pipeline hazard and safety regulations 49 CFR 195, § 195.450 Definitions (CFRf)—High consequence area means: (1) A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists; (2) A high population area, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile; (3) An other populated area, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; (4) An unusually sensitive area, as defined in §195.6.

history-match: Calibrate

HRSG: Heat-recovery steam generator. A generator that recovers heat from a hot gas stream and produces steam that can be used in a process or to drive a steam turbine. A common application for an HRSG is in a combined-cycle power station, where hot exhaust gas from a gas turbine is fed to an HRSG to generate steam, which in turn drives a steam turbine.

hybrid wet-dry cooling: Systems separately or simultaneously use wet and dry cooling technologies for either water conservation or temperature impact abatement purposes associated with thermoelectric power production.

ICA: Interstate Commerce Act. Passed in 1887, the ICA created the Interstate Commerce Commission. It was designed to address the issues of railroad abuse and discrimination.

ICC: Interstate Commerce Commission. Created by the Interstate Commerce Act of 1887, the ICC's objective was to make and enforce regulations concerning interstate commerce. The agency was abolished in 1995, and its remaining functions were transferred to the Surface Transportation Board within the U.S. Department of Transportation.

IEA: International Energy Agency

IECM: Integrated Environmental Control Model. Developed by Carnegie Mellon University for the National Energy Technology Laboratory, the IECM allows systematic analysis of emission control options for coal-fired power plants employing a variety of pre-combustion, combustion, and post-combustion control methods (U.S. DOE/NETL 2008).

IGCC: Integrated gasification combined cycle. Technology that produces electricity by first gasifying coal to produce syngas (a mixture of hydrogen and carbon monoxide). After cleanup, the syngas is burned in a gas turbine that drives a generator. The turbine exhaust goes to a heat recovery generator to raise steam, which drives a steam turbine.

in: Inch

In Salah project: Based in Algeria's In Salah gas development area, the In Salah project is a joint venture of British Petroleum, Sontrach, and Statoil. It involves the development of seven proven gas fields in the southern Sahara, 1,200 kilometers south of Algiers. Around 1 million metric tons of carbon dioxide is injected into the reservoir each year for geologic storage (CO_2 Capture and Storage).

Injection zone: Target geologic formation where CO_2 is injected.

Injectivity: A measure of the ability of the reservoir to store the injected CO_2; injectivity is a function of the reservoir's porosity and permeability.

IOGCC: Interstate Oil and Gas Compact Commission. A multistate government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources, while protecting health, safety, and the environment.

IPCC: Intergovernmental Panel on Climate Change. An independent scientific body tasked with assessing the scientific, technical, and socioeconomic information relevant for understanding the risk of human-induced climate change.

kg: Kilogram

km: Kilometer

lacustrine: Pertaining to an environment of deposition in lakes, or an area having lakes. Because deposition of sediment in lakes can occur slowly and in relatively calm conditions, organic-rich source rocks can form in lacustrine environments.

LAER: Lowest achievable emission reduction. The level of control required of a major source of pollution subject to New Source Review requirements for nonattainment areas. The LAER requirement applies only to the criteria pollutants for which the region is designated as not being in attainment with emission standards. LAER employs the most stringent emissions limitation contained within the implementation plan of any state for the stationary source category. Facility operators much meet the LAER, unless they can demonstrate that such emission limitations are not achievable.

leakage: Significant movement of the carbon dioxide plume outside the confining zone.

leak-off test: A test to determine the strength or fracture pressure of the injection reservoir. The results of the leak-off test dictate the maximum pressure that may be applied to the well. To maintain safe operations, the maximum operating pressure is usually slightly below the leak-off test result.

leasehold: The right to hold or use property for a fixed period of time at a given price, without transfer of ownership, on the basis of a lease contract.

LHV: Lower heating value. The amount of heat released by combusting a specified quantity of fuel, assuming that the produced water remains as a vapor and the heat of the vapor is not recovered.

LIDAR: Light detection and ranging. An optical remote-sensing system that measures the property of scattered light to collect topographic data.

lithology: The macroscopic nature of the mineral content, grain size, texture, and color of rocks.

live and dead loads: Forces exerted on a pipeline. Live loads are forces that are temporary, of short duration, or moving—for example snow, wind, earthquake, and traffic movements. Dead loads are weights of material, equipment, or components that are relatively constant throughout the structure's life—for example, load due to settlement.

LNG: Liquefied natural gas

logging: The measurement versus depth or time, or both, of one or more physical properties in or around a well. The term is derived from the word "log" used in the sense of a record or a note.

low-stress pipelines: The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration defines a low-stress pipeline as a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe (CFRf).

m: Meter

MEA: Monoethanolamine. An organic chemical compound used to separate CO_2 from flue gas in post-combustion capture.

membrane separation: The process for separating carbon dioxide from the flue gas using membrane/amine hybrids or enzymatic CO_2 processes. Permeation of CO_2 through polymeric membranes occurs where a constituent passes through the membrane by diffusion and sorption by the fluid on the other side of the membrane. The driving force is achieved either by pressure or by concentration difference across the membrane.

metal organic frameworks: Crystalline compounds comprised of metal ions coordinated to organic molecules to form one-, two-, or three-dimensional porous structures. These frameworks are used as sorbents for post-combustion carbon dioxide capture.

MGSC: Midwest Geological Sequestration Consortium

microgravity: Small changes in gravity that result from changes or movement in the subsurface.

microseismic: Microearthquakes triggered by subsurface movements.

MIT: Massachusetts Institute of Technology

MLA: Mineral Leasing Act of 1920, as amended, 30 U.S.C. § 181 et seq. Under the MLA, the Bureau of Land Management grants leases for development of deposits of coal, phosphate, potash, sodium, sulfur, and other leasable minerals on public domain lands and on lands having federal reserved minerals. The MLA establishes qualifications for mineral lessees, sets out maximum limits on the number of acres of a particular mineral that can be held by a lessee, and prohibits alien ownership of leases, except though stock ownership in a corporation (Feriancek 1999).

mitigation: The effort to reduce loss of life and property by lessening the impact of accidents or, in this case, potential damage resulting from carbon dioxide leaks.

mm: Millimeter

MMS: Minerals Management Service. A bureau within the U.S. Department of the Interior that manages the nation's natural gas, oil, and other mineral resources on the outer continental shelf. MMS also collects, accounts for, and disburses more than $8 billion per year in revenues from federal offshore mineral leases and from onshore mineral leases on federal and Native American lands (U.S. DOI/MMS).

MMV: Measurement, monitoring, and verification.

monitoring wells: Wells that collect data, including reservoir pressure, temperature, formation fluid chemistry, and other key reservoir characteristics.

MPa: Megapascal. A unit of pressure. One megapascal is equal to 106 Pascals.

MRCSP: Midwestern Regional Carbon Sequestration Partnership

MW: Megawatt. One MW is equal to 1 million watts. The watt is the International System of Units' (SI) standard unit of power (energy per unit time), the equivalent of one joule per second. Watt measures the rate of energy use or production.

MWh: Megawatt-hour

N_2: Nitrogen

N_2O: Nitrous oxide

NA: Not available

NETL: National Energy Technology Laboratory. A national laboratory owned and operated by the U.S. Department of Energy.

NG: Natural gas

NGCC: Natural gas combined cycle. Generating facilities that use natural gas as a fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the hot exhaust gas from the turbine is used to generate steam in a waste hest recovery unit. The steam is then used to produce more electricity. The output from both the gas turbine and the steam turbine electrical generators is combined to produce electricity very efficiently.

NGO: Nongovernmental organization

NH_3: Ammonia. A pungent, colorless gas formed mainly from volatilization of decomposing excreta or fertilizers. Ammonia is found in small quantities in the atmosphere, being produced from the putrefaction of nitrogenous animal and vegetable matter. Due to its many uses, ammonia is one of the most highly produced inorganic chemicals.

NIOSH: National Institute for Occupational Safety and Health. A federal agency within the U.S. Department of Health and Human Services that conducts research and makes recommendations for workplace safety. However, only regulations promulgated by the Occupational Safety and Health Administration have the force of law.

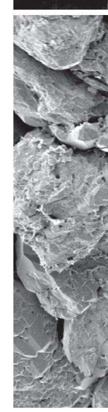
NO: Nitric oxide

NO_2: Nitrogen dioxide

NO_X: Oxides of nitrogen. The gases consisting of one molecule of nitrogen and varying numbers of oxygen molecules. Nitrogen oxides are produced in the emissions of vehicle exhaust and from power stations. In the atmosphere, nitrogen oxides can contribute to the formation of photochemical ozone (smog), impair visibility, and have health consequences; thus, they are considered pollutants.

NPDES: National Pollutant Discharge Elimination System. As authorized by the Clean Water Act, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into U.S. waters.

NSPS: New Source Performance Standards. National standards that set air pollutant emission limitations for new and modified sources. Under Section 111 of the Clean Air Act of 1990, the U.S. Environmental Protection Agency is required to publish and



periodically revise a list of industry categories and to establish standards of performance reflecting "the degree of emission reduction achievable through application of the best system of emission reduction." The purpose of the NSPS program is to prevent deterioration of air quality from the construction of new and modified sources of pollution and to reduce control costs by building air pollution controls into the initial design of new builds and major modifications to existing plants (CFRb).

NSR: New Source Review. A preconstruction permitting program, established by the U.S. Congress as part of the 1977 Clean Air Act Amendments, governing new sources and major modifications to existing sources of pollution. New and modified sources subject to NSR located in areas in attainment of standards for regulated air pollutants (such as sulfur dioxide, nitrous oxide, ozone, and particulate matter) should install best available control technology (BACT), while new and modified sources located in nonattainment areas should install lowest achievable emission reduction (LAER) control technology. Case-by-case determinations of BACT and LAER emission limitations should be at least as stringent as the New Source Performance Standard (NSPS) for any source category for which an NSPS has been set and often are set stricter than the NSPS. This is particularly true for LAER determinations (U.S. EPA 2008d).

NZEC: Near-Zero Emission Coal. The joint UK-China initiative to address the challenge of increasing energy production from coal in China and the need to tackle growing carbon dioxide emissions. Additionally, the UK-China NZEC agreement was signed at the EU-China Summit under the UK's presidency of the EU in September 2005 as part of the EU-China Partnership on Climate Change. The agreement has the objective of demonstrating advanced, near-zero emissions coal technology through carbon dioxide capture and storage in China and the European Union by 2020.

O_2: Oxygen

OPS: Office of Pipeline Safety. The federal safety authority for ensuring the safe, reliable, and environmentally sound operation of the U.S. pipeline transportation system. Acting through OPS, the U.S. Department of Transportation's (DOT's) Pipeline and Hazardous Materials Safety Administration administers the DOT's national regulatory program to ensure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to ensure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities (U.S. EPA 2008c; CFRe).

open season: Commercial opportunities for potential users to compete for and acquire capacity on a proposed or existing pipeline. Open seasons can influence the ultimate project design.

OSHA: Occupational Safety and Health Administration. An agency within the U.S. Department of Labor charged with developing and enforcing environmental, health, and safety standards for workplace safety.

oxy-fuel combustion: Involves pulverized coal, supercritical pulverized coal, ultra-supercritical pulverized coal, and circulating fluidized bed combustion in an oxygen-rich environment to dramatically increase the CO_2 concentration of the resulting gases. After combustion, the flue gas can be captured and compressed, although it will most likely be cleaned before compression.

P: Pascal. The International System of Units' (SI) standard unit for measuring pressure. The Pascal is a measure of perpendicular force per unit area.

PAC: Preventive Action Criteria. Criteria developed by the Subcommittee on Consequence Actions and Protective Assessments that provide chemical exposure limit values for well over 3,000 chemicals to support emergency response planning applications.

parasitic energy loss: Also referred to as an energy penalty, the energy used by a control device. Instead of being converted into electricity or being used to power a process, the energy is used to reduce the emissions from the facility.

PC: Pulverized coal

PEL: Permissible exposure limit. The Occupational Safety and Health Administration (OSHA) sets enforceable PELs to protect workers against the health effects of exposure to hazardous substances. PELs are regulatory limits on the concentration of a substance in the air. They may also contain a skin designation. OSHA PELs are based on an 8-hour time-weighted average exposure (U.S. DOL/OSHA 2007).

petcoke: Petroleum coke

PHMSA: Pipeline and Hazardous Materials Safety Administration. An agency within the U.S. Department of Transportation.

physical adsorption: Adsorption can be either physical or chemical in nature. Physical adsorption resembles the condensation of gases to liquids and depends on the physical, or van der Waals, force of attraction between the solid adsorbent and the adsorbate molecules.

pipeline metering: Methods and tools for measuring the volume of liquid in the pipeline necessary for accounting purposes.

plugging and abandonment: To prepare a well to be closed permanently, after injection stops and project operations are complete.

PM: Particulate matter. Very small pieces of solid or liquid matter, such as particles of soot, dust, fumes, mists, or aerosols. The physical characteristics of particles, and how they combine with other particles, are part of the feedback mechanisms of the atmosphere.

point source: The anthropogenic source of emissions that is located at an identifiable point in space. The term covers stationary sources, such as sewage treatment plants, power plants, other industrial establishments, and similar buildings and premises of small spatial extension.

pore space: A discrete void within a rock that can contain air, water, hydrocarbons, or other fluids.

portland cement: ASTM (American Society for Testing and Materials) C150 defines portland cement as "hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter ground addition" (U.S. DOT/FHWA).

post-combustion capture: The addition of a capture and compression system on the back end of the power plant to capture the carbon dioxide from the flue gas and compress it for transport.

post-closure: The period after certification is received, when the responsibility transfers from the operator to another entity.

ppm: Parts per pillion. The number of parts of a chemical found in one million parts of a particular gas, liquid, or solid.

PRB: Powder River Basin

pre-combustion capture: Associated with integrated gasification combined cycle, pre-combustion capture involves the capture of carbon dioxide after the coal is converted into syngas but before combustion of the syngas.

pressure wave: Area of elevated pressure that is associated with the injected carbon dioxide plume.

Price-Anderson Act: Passed in 1957, the Price-Anderson Act partially indemnifies the nuclear industry against liability claims arising from nuclear incidents, while still ensuring compensation coverage for the general public. The Act establishes a no-fault insurance-type system in which the first $10 billion is funded by industry, and any claims above $10 billion are covered by the federal government (U.S. DOE 2008b).

primacy under EPA UIC program: Developed by the U.S. Environmental Protection Agency (EPA), the Underground Injection Control Program requirements were designed to be adopted by states, territories, and tribes. These jurisdictions can submit an application to EPA to obtain primary enforcement responsibility, or primacy, to oversee the injection activities within their jurisdictions (CFRd).

project footprint: An area potentially impacted by the injection of carbon dioxide that includes the carbon dioxide plume as well as the area of elevated pressure.

psi: Pounds per square inch or pound-force per square inch. In the United States, psi is the primary unit of measure for pressure. Almost all pressure instruments are specified and display in psi units. A 1-pound-force applied to an area of 1 square inch, 1 psi equals 6,894.76 Pascals.

psig: Pound per square inch gauge

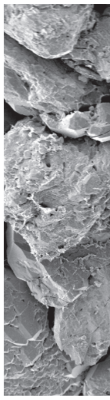
pulverized coal power plants: Power plants that generate electricity by injecting finely-ground coal through burners into a furnace for combustion. Pulverized coal (PC) power plants are differentiated by the temperatures and pressures of operation. Subcritical PC units are the least efficient, and typically operate at about 1,000°F) and 2,400 pounds per square inch (psi). Supercritical PC units are the next most efficient, and operate at around 1,050°F and 3,500 psi. Ultra-supercritical PC units are the most efficient, and operate above 1,200°F and 5,000 psi. The majority of existing PC units in the United States are subcritical. Ultra-supercritical units require advance materials and have been successfully constructed and operated in Europe and Japan.

R&D: Research and development

radioactive tracer test: Generally used in injection wells to avoid radioactive contamination at the surface. The main applications of radioactive tracers include establishing flow profiles in injection wells, detecting fluid movements behind the pipe, and locating leaking packers and fluid movement between wells.

RCRA: Resource Conservation and Recovery Act. The public law that creates the framework for the proper management of hazardous and nonhazardous solid waste.

receptor: A receptor is sensitive to the risks of potential release of carbon dioxide. For the purposes of risk assessment, a priority is to evaluate whether migration of the CO_2 from the confining unit(s)



could have undesirable impacts on a variety of potential receptors. For example, while still in the subsurface, CO_2 could affect sources of drinking water or diminish the value of mineral rights. If leaked to the surface, CO_2 could collect and harm humans, animals, and plants, cause property damage, and diminish the climate benefits of storage.

Regional Carbon Sequestration Partnerships: In 2003, DOE created a network of seven Regional Carbon Sequestration Partnerships to help develop the technology, infrastructure, and regulations to implement large-scale carbon dioxide sequestration in different regions and geologic formations within the United States. The seven partnerships are: Big Sky Regional Carbon Sequestration Partnership, Plains CO_2 Reduction Partnership, Midwest Geological Sequestration Consortium, Midwest Regional Carbon Sequestration Partnership, Southeast Regional Carbon Sequestration Partnership, Southwest Regional Partnership on Carbon Sequestration, and the West Coast Regional Carbon Sequestration Partnership (U.S. DOE 2008a).

remediation plan: A corrective action plan that outlines methods for mitigating potential hazards or undesirable outcomes. Remediation plans should be based on site-specific risk assessments.

reservoir: A discrete geologic formation, such as the injection reservoir for storing carbon dioxide.

retrofit: Addition of new technologies or features to an existing system, such as the addition of carbon dioxide capture technology to an existing power plant.

rheological properties: Rheology is the study of the deformation and flow of matter. The rheological properties of a liquid are dominant features that can be quantified to characterize its behavior, and the response of a liquid to a forced shearing flow is the basis for determining its specific rheological properties. General qualitative terms used to describe these properties are viscoelastic, Newtonian, non-Newtonian, thixotropic, and dilatant. Quantitative parameters used are viscosity, elasticity, shear rate, shear strain, and shear stress.

right of way: Usually involves gaining access to a portion of the shoulder of a road, or obtaining an easement on private property. The pipeline right of way consists of a parcel of land under which the pipeline is buried. Right of way is often about 15 meters (50 feet) wide.

risk assessment: A scientifically based process comprising four steps: hazard identification, hazard characterization, exposure assessment, and risk characterization.

RST: Reservoir Saturation Tool. A tool used for evaluating fluid saturation. The traditional methods of evaluating fluid saturation behind casing are limited to either high-salinity water or nontubing wells. The RST overcomes these limitations by combining both thermal decay time and carbon oxygen logging in a tool slim enough to log through tubing.

rural areas: The Code of Federal Regulations defines rural areas as areas outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area, such as a subdivision, a business or shopping center, or community development. Environmentally sensitive areas are classified separately (CFRf).

SACROC: Scurry Area Canyon Reef Operators Committee. A carbonate reef complex in the Permian Basin of west Texas. SACROC is the oldest carbon dioxide-enhanced oil recovery site in the United States, with CO_2 injection since 1972. For the past 38 years, more than 55 million tons of CO_2 have been injected in SACROC.

SCADA: Supervisory Control and Data Acquisition. SCADA systems utilize computer technology to continuously gather data (e.g., pressure, temperature, and delivery flow rates) from remote locations on the pipeline. SCADA systems can also provide input for real-time models of the pipeline operation (U.S. EPA 1997).

SCAPA: Subcommittee on Consequence Actions and Protective Assessments. Provides the recommendations for emergency preparedness to assist in safeguarding the health and safety of workers and the public.

SCPC: Supercritical pulverized coal

selective catalytic reduction: A control technology that injects ammonia into the exhaust across a catalyst bed, causing a reduction reaction that destroys nitrogen oxide.

SDWA: Safe Drinking Water Act. Authorizes the U.S. Environmental Protection Agency (EPA) to set national health-based standards for drinking water to protect against both naturally occurring and man-made contaminants that may be found in drinking water. EPA, states, and water systems then work together to make sure that these standards are met. The SWDA was originally passed by Congress in 1974 to protect public health by regulating the nation's public drinking water supply. Amended in 1986 and 1996, the law requires many actions to protect drinking water and its sources: rivers, lakes, reservoirs, springs, and groundwater wells. The SDWA does not regulate private wells that serve fewer than 25 individuals (U.S. EPA 2008d).

sealing fault: The term "fault seal" is used to describe the effect of fault zones on impairing across-fault fluid flow. These dynamic seals might not be capable of retaining hydrocarbons over a geological timescale, but their relatively low permeability may inhibit movement of carbon dioxide.

SECARB: Southeast Regional Carbon Sequestration Partnership.

Shale: A fine-grained, fissile, detrital sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. It is the most abundant sedimentary rock. Its typical fine grain size and lack of permeability, a consequence of the alignment of its platy or flaky grains, allow shale to form a good cap rock for hydrocarbon traps.

SI: International System of Units standard unit

side-scan sonar: A system for acoustic surveying deployed in marine environments to yield an image of the seafloor and shallow sediments. The side-scan sonar generates a pulse on the order of 30–120 kilohertz that is reflected from the seafloor.

Sleipner project: The Sleipner project has been injecting 1 million tons of carbon dioxide per year since 1996 without leakage. The CO_2 from a natural gas processing facility is injected into salt water containing a sand layer called the Utsira formation, which lies 1,000 meters (3,280 feet) below sea bottom (Statoil).

slip-stream capture: The capture of a portion of a process or exhaust stream instead of the entire stream. Slip-stream capture is particularly useful in demonstration projects where the entire process or exhaust stream would be too large for the demonstration device to control.

slug flow: A two-phase flow pattern, usually called slug flow, is encountered when gas and liquid flow simultaneously in a pipe, over certain ranges of flow rates. Slug flow is characterized by long "Taylor" bubbles, also called gas slugs, rising and nearly filling a pipe cross-section. In a slugging column, with flowing gas and liquid, the flow field is extremely complex.

SO_2: sulfur dioxide

sorbents: Absorbents and adsorbents, referred to as "sorbents," are used in environmental, industrial, agricultural, medical, and scientific applications to retain liquids and gases. Absorbents incorporate substances throughout the body of the absorbing material, while adsorbents gather substances over the surface of the material (U.S. EPA 2008b).

sour gas: A term used for gases that are acidic either alone or when associated with water. Two sour gases associated with oil and gas drilling and production are hydrogen sulfide and carbon dioxide. Sulfur oxides and nitrogen oxides, generated by oxidation of certain sulfur- or nitrogen-bearing materials, are also in this category, but are not found in the anaerobic conditions of the subsurface.

SO_X: Sulfur oxides. A general term used to describe the oxides of sulfur—pungent, colorless gases formed primarily by the combustion of fossil fuels. Sulfur oxides, which are considered major air pollutants, may damage the respiratory tract as well as vegetation.

SPE: Society of Petroleum Engineers

subsidence: Movement of land downward relative to the surface. Subsidence of a surface can be induced due to several reasons, such as dissolution of limestone, mining, faults, extraction of natural gas and oil, extraction of underground water, and seasonal effects.

supercritical fluid: Defined as a substance above its critical temperature and critical pressure. The critical point represents the highest temperature and pressure at which the substance can exist as a vapor and liquid in equilibrium. The critical point at which CO_2 exists in a supercritical phase is 1,070 pounds per square inch (73 atmospheres) and 88°F (31°C). In the supercritical state, CO_2 has the characteristics of both a liquid and a gas, maintaining the compressibility of a gas and some of the properties of a liquid, such as density.

STB: Surface Transportation Board. Created in the Interstate Commerce Commission Termination Act of 1995, STB is the successor agency to the Interstate Commerce Commission. STB is decisionally independent but is administratively affiliated with the U.S. Department of Transportation. Its primary mission is to resolve railroad disputes. Pipelines, like railroads, are common carriers used by more than one company to transport goods. Therefore, the Interstate Commerce Act also assigned the Interstate Commerce Commission (and thus the STB) authority over pipelines transporting a commodity other than "water, gas or oil" (U.S. DOT/STB).

SWP: Southwest Regional Partnership

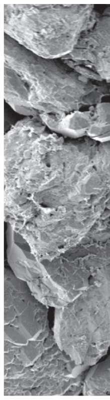
TAME: The Midwest Regional Carbon Sequestration Partnership is conducting a field test that would permanently store carbon dioxide deep below the ground underneath the recently completed The Andersons Marathon Ethanol LLC, or TAME, ethanol plant near Greenville, Ohio (MRCSP 2008).

target formation: A geologic storage formation for CO_2 injection. Suitable target formations must have sufficient porosity for storage capacity and sufficient permeability to allow injection of the captured CO_2. Typical target formations can be clastic sedimentary rocks, such as sandstones or conglomerates, or carbonates, such as limestones or dolostones. Under the right circumstances, other kinds of formations might serve as storage reservoirs, such as unminable coal seams, basalts, and evacuated salt caverns.

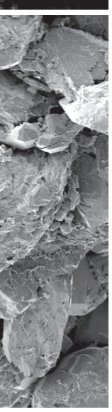
TBD: To be determined

TEEL: Temporary emergency exposure limit. The chemical exposure limit value, used for Protective Action Criteria for emergency planning of chemical release events (SCAPA 2008).

thermocouples: A thermoelectric temperature sensor consisting of two dissimilar metallic wires, coupled at the probe tip (measurement junction) and extended to the reference (known temperature)







junction. The temperature difference between the probe tip and the reference junction is detected by measuring the change in voltage (electromotive force) at the reference junction (efunda).

time-lapse seismic: Seismic data from the surface or a borehole acquired at different times over the same area to assess changes in the subsurface with time. Time-lapse seismic data can repeat 2-D, 3-D (yields 4-D seismic data), crosswell, and/or VSP data.

tort liability: A "tort" is an injury to another person or to property that is compensable under the law. Negligence, gross negligence, and intentional wrongdoing are types of tort (NC State).

tortuous: Complex, marked with bends, or not straightforward. In this context, the tortuous leaks are associated with faults with lower permeability, longer paths, and higher reactivity, which is likely to increase the time needed for carbon dioxide to reach the surface in case of leakage. The flux from tortuous leaks along natural hazards is likely to be small, and significant human health risks are unlikely. Since these kinds of leaks are most likely to travel through groundwater systems to the surface, groundwater geochemical monitoring is likely to suffice in detecting any substantial flux.

transmissive fault: A fault or fracture with sufficient permeability and vertical extent to allow rapid migration of large volumes and prompt movement of fluids between formations.

trapping mechanisms: Mechanisms by which carbon dioxide is stored in the geologic formations, including physical (pore space trapping) and chemical (dissolution) processes that take place both quickly and over long time periods (mineralization).

TWA: Time-weighted average. An average value of exposure over the course of an 8-hour work shift. The permissible exposure limit can be defined in two ways: ceiling values and 8-hour TWAs.

UIC: Underground Injection Control. Administered by the U.S. Environmental Protection Agency (EPA), the UIC Program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. EPA's regulations group injection wells into six groups or "classes," including the new Class VI geologic sequestration class (U.S. EPA 2008c).

USCPC: Ultra-supercritical pulverized coal. USCPC units are highly efficient and require advanced materials. They have been successfully constructed and operated in Europe and Japan.

U.S DOE: United States Department of Energy. A cabinet-level department of the U.S. government with an overarching mission of advancing the national, economic, and energy security of the United States; promoting scientific and technological innovation in support of that mission; and ensuring the environmental cleanup of the national nuclear weapons complex.

U.S. DOI: United States Department of the Interior. A cabinet-level department of the U.S. government and the principal conservation agency of the United States. Through its eight bureaus and agencies, DOI manages 500 million acres of surface land, or about one-fifth of the land in the United States.

U.S. DOT: United States Department of Transportation. A cabinet-level department of the U.S. government with a mission to serve the country by ensuring a fast, safe, efficient, accessible, and convenient transportation system that meets vital national interests and enhances the quality of life of U.S. citizens. DOT is comprised of 13 operating administrations and bureaus, each with its own management and organizational structure, including the Surface Transport Board and Pipeline and Hazardous Materials Safety Administration.

U.S. EPA: United States Environmental Protection Agency. A federal agency that leads the environmental science, research, education, and assessment efforts in the United States.

USDW: Underground source of drinking water. An aquifer or portion of an aquifer that supplies any public water system; or that contains a sufficient quantity of groundwater to supply a public water system, and currently supplies drinking water for human consumption; or that contains fewer than 10,000 milligrams per liter of total dissolved solids and is not an exempted aquifer.

vadose zone: The region of aeration above the water table. Water within this interval, which is moving downward under the influence of gravity, is called vadose water, or gravitational water.

VEF: Vulnerability Evaluation Tool. Developed by the U.S. Environmental Protection Agency, an analytical framework that identifies and offers approaches to evaluate the potential for a carbon dioxide capture and storage (CCS) project to experience carbon dioxide leakage and associated impacts. The VEF is focused on the three main parts of CCS systems: the injection zone, the confining system, and the CO_2 stream.

VSP: Vertical seismic profiling. A technique of seismic measurements used for correlation with surface seismic data. In VSP the energy source, the detectors, or both, are in a borehole. Hydrophones, geophones, or accelerometers inside the wellbore record reflected seismic energy originating from a seismic source at the surface near the well.

wellbore: The physical hole that makes up the well. It can be cased, open, or a combination of both.

well integrity: The application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the entire life cycle of the well and of course safety aspects (Petroleum 2004).

wet cooling: A method of cooling thermal power plants using water, either by once-through cooling systems or recirculating wet systems

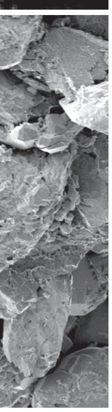
Weyburn project: Carbon dioxide injection and storage underground in depleted oil fields is occurring in the Weyburn oil field in Saskatchewan, Canada. The source of CO_2 is a gasification plant in Bulah, North Dakota (IEA GHG R&D).

wireline log: A method of continuous measurement of formation properties with electrically powered instruments. The record of measurements, typically a long strip of paper, is called a log. In wireline measurements, the logging tool is lowered into the open wellbore on a multiple-conductor, contra-helically armored wireline. Once lowered to the bottom of the interval of interest, the logging tool takes measurements on the way out of the wellbore.

WRI: World Resources Institute

ZENG: Zero Emission Norwegian Gas. A program being co-developed by Lyse Energi AS, Nebb Engineering AS, Procom Venture AS, and CO_2-Norway. The program is currently undertaking a 7.6 million NOK Concept Definition study and is working toward an investment decision for a 50–70 megawatt electric demonstration power plant at Risavika, Norway. The power generation process being developed will result in zero emission of both carbon dioxide and oxides of nitrogen. It provides an alternative to conventional gas-fired power plants with post-combustion CO_2 capture. One of the key technologies being considered in the ZENG Risavika concept is a gas generator developed by Clean Energy Systems, USA that enables combustion of natural gas and oxygen to form CO_2 and steam.





APPENDIX A:
EARLY WRI CCS STAKEHOLDER MEETINGS

WRI has conducted a series of discrete workshops to identify and explore issues related to CCS. These workshops, briefly summarized in this appendix, helped inform the Guidelines process and are documented on the WRI Web site (http://www.wri.org/). Meetings and activities that were part of the Guidelines development process, beginning in December 2007, are summarized in the Introduction to this document.

FEBRUARY 2006:
FIRST CCS MEETING

Participants were invited to this kickoff meeting because of their expertise in the CCS field. During this preliminary workshop, participants discussed the possibility of working toward Guidelines for CCS. An end result was the subsequent formation of working groups in two key areas: measurement, monitoring, and verification (MMV) and liability. A summary of that first workshop is available at http://pdf.wri.org/carboncapture_060228_workshopsummary.pdf.

FEBRUARY 2006–SEPTEMBER 2006:
LIABILITY AND MMV WORKING GROUP MEETINGS

The liability and MMV working groups met periodically by phone after the initial CCS meeting. During this phase, stakeholders made hands-on contributions. The liability working group worked to develop case studies for legal and regulatory analogs. The compilation of that work is available at http://pdf.wri.org/Full_Case_Studies_Info.pdf.

SEPTEMBER 2006:
FIRST CCS LIABILITY WORKSHOP

As a result of this workshop, WRI began work to develop a straw proposal for CCS liability policy (see http://pdf.wri.org/css_liability_summary_092906.pdf). At this time, some concern was raised about the need to include stakeholders who oppose CCS approaches. The liability working group decided that, to have the technical discussions needed to arrive at a robust set of Guidelines, the group would include only representation from stakeholders who agreed with evaluating CCS as a potential tool for reducing greenhouse gas emissions.

OCTOBER 2006:
MMV ROLE-PLAY WORKSHOP

Workshop participants simulated a public/regulatory hearing on the potential siting of a CCS project. The workshop summary and list of attendees (primarily researchers and industry representatives) are available at http://pdf.wri.org/ccs_siting_workshop_summary_110806.pdf.

JUNE 2007:
TECHNICAL AND INSURANCE EXPERTS MEETING

WRI convened a group of technical and insurance experts to explore long-term liability issues related to CCS (http://pdf.wri.org/ccs_liability_workshop_final_060507.pdf). At this time, the development of the Guidelines was identified as a separate activity that was part of a larger WRI stakeholder process.

NOVEMBER 2007:
SECOND CCS LONG-TERM LIABILITY MEETING

Participants recommended that WRI convene small working groups to follow up on key issues identified during the meeting and share results of these discussions in a liability paper, working toward integration with the Guidelines development effort. Future work will better define the Guidelines for long-term liability (http://pdf.wri.org/wri_ccs_liability_nov1_workshop.pdf).

APPENDIX B:
GUIDELINES FOR POLICYMAKERS

Capture

- Demonstrations of all capture approaches (pre-combustion, post-combustion, and oxy-fuel combustion) are urgently needed on commercial-scale power plants to prove the technologies. (Capture Guideline 1a)

- There should be recognition of the potential challenges in achieving the theoretical maximum capture potential before the technologies are proven at scale. This may necessitate flexibility in establishing appropriate capture rates for early commercial-scale projects with the amount of CO_2 captured at a facility dependent on both technology performance and the specific goals of the project. (Capture Guideline 1b)

- Standards for the levels of co-constituents have been proposed by some regulators and legislators; however, there is potential risk that this could create disincentives for reducing sources of anthropogenic CO_2 if the standard is set too stringently. Ultimately, the emphasis should be on employing materials, procedures, and processes that are fit-for-purpose and assessing the environmental impacts of any co-constituents, along with the benefits of CO_2 emissions reduction as part of a comprehensive CCS risk assessment. Facility operators, regulators, and other stakeholders should pay particular attention to potential impacts of co-constituents in the transport and storage aspects of the project. (Capture Guideline 1c)

- When constructing a new facility or retrofitting an existing facility in the United States, operators must comply with requirements under the Clean Air Act and the Clean Water Act, as appropriate. (Capture Guideline 2a)

Transport

- Considering the extent of CO_2 pipeline needs for large-scale CCS, a more efficient means of regulating the siting of interstate CO_2 pipelines should be considered at the federal level, based on consultation with states, industry, and other stakeholders. (Transport Guideline 3a)

- The federal government should consult with industry and states to evaluate a model for setting rates and access for interstate CO_2 pipelines. Such action would facilitate the growth of an interstate CO_2 pipeline network. (Transport Guideline 4a)

Storage

- Policies should be developed for adequately funding the post-closure activities that become the responsibility of an entity assuming responsibility for long-term stewardship, as described in the Post-Closure section. (Storage Guideline 3c)

- Because of the public good benefits of early storage projects and the potential difficulty of attracting investment, policymakers should carefully evaluate options for the design and application of a risk management framework for such projects. This framework should appropriately balance relevant policy considerations, including the need for financial assurances, without imposing excessive barriers to the design and deployment of CCS technology. (Storage Guideline 3d)

- Continued investigation into technical, regulatory, and legal issues in determining pore space ownership for CCS is warranted at the state and federal levels. Additional legislation to provide a clear and reasonably actionable pathway for CCS demonstration and deployment may be necessary. (Storage Guideline 4b)

- Certified closed sites should be managed by an entity or entities whose tasks would include such activities as operating the registries of sites; conducting periodic MMV; and, if the need arises, conducting routine maintenance at MMV wells at closed sites over time. (Storage Guideline 8a)

- These entities need to be adequately funded over time to conduct those post-closure activities for which they are responsible. (Storage Guideline 8b)

APPENDIX C:
GUIDELINES FOR REGULATORS

Capture

- There should be recognition of the potential challenges in achieving the theoretical maximum capture potential before the technologies are proven at scale. This may necessitate flexibility in establishing appropriate capture rates for early commercial-scale projects, with the amount of CO_2 captured at a facility dependent on both technology performance and the specific goals of the project. (Capture Guideline 1b)

- Standards for the levels of co-constituents have been proposed by some regulators and legislators; however, there is potential risk that this could create disincentives for reducing sources of anthropogenic CO_2 if the standard is set too stringently. Ultimately, the emphasis should be on employing materials, procedures, and processes that are fit-for-purpose and assessing the environmental impacts of any co-constituents, along with the benefits of CO_2 emissions reduction as part of a comprehensive CCS risk assessment. Facility operators, regulators, and other stakeholders should pay particular attention to potential impacts of co-constituents in the transport and storage aspects of the project. (Capture Guideline 1c)

- When constructing a new facility or retrofitting an existing facility in the United States, operators must comply with requirements under the Clean Air Act and the Clean Water Act, as appropriate. (Capture Guideline 2a)

- Use of capture technologies could result in hazardous or industrial waste streams. Operators must follow guidelines and regulations for the handling and disposal of industrial or hazardous wastes. (Capture Guideline 2c)

- Currently, EPA is considering regulation of coal combustion wastes that are sent to landfills or surface impoundments, or used as fill in surface or underground mines. Potential impacts of the volume and concentrations of hazardous materials in the waste stream from facilities with CO_2 capture should be evaluated in this context. (Capture Guideline 2e)

Transport

- CO_2 pipeline design specifications should be fit-for-purpose and consistent with the projected concentrations of co-constituents, particularly water, hydrogen sulfide (H_2S), oxygen, hydrocarbons, and mercury. (Transport Guideline 1a)

- Existing industry experience and regulations for pipeline design and operation should be applied to future CCS projects. (Transport Guideline 1b)

- Operators should follow the existing OSHA standards for safe handling of CO_2. (Transport Guideline 2a)

- Plants operating small in-plant pipelines should consider adopting OPS regulations as a minimum for best practice. (Transport Guideline 2b)

- Pipelines located in vulnerable areas (populated, ecologically sensitive, or seismically active areas) require extra due diligence by operators to ensure safe pipeline operations. Options for increasing due diligence include decreased spacing of mainline valves, greater depths of burial, and increased frequency of pipeline integrity assessments and monitoring for leaks. (Transport Guideline 2c)

- If the pipeline is designed to handle H_2S, operators should adopt appropriate protection for handling and exposure. (Transport Guideline 2d)

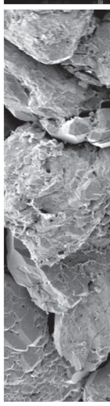
- As a broader CO_2 pipeline infrastructure develops, regulators should consider allowing CO_2 pipeline developers to take advantage of current state condemnation statutes and regulations that will facilitate right-of-way acquisition negotiations. (Transport Guideline 3b)

Storage

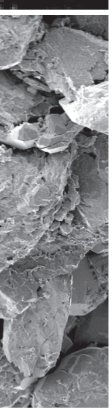
- MMV requirements should not prescribe methods or tools; rather, they should focus on the key information an operator is required to collect for each injection well and the overall project, including injected volume; flow rate or injection pressure; composition of injectate; spatial distribution of the CO_2 plume; reservoir pressure; well integrity; determination of any measurable leakage; and appropriate data (including formation fluid chemistry) from the monitoring zone, confining zone, and USDWs. (Storage Guideline 1a)

- Operators should have the flexibility to choose the specific monitoring techniques and protocols that will be deployed at each storage site, as long as the methods selected provide data at resolutions that will meet the stated monitoring requirements. (Storage Guideline 1b)
- MMV plans, although submitted as part of the site permitting process, should be updated as needed throughout a project as significant new site-specific operational data become available. (Storage Guideline 1c)
- The monitoring area should be based initially on knowledge of the regional and site geology, overall site specific risk assessment, and subsurface flow simulations. This area should be modified as warranted, based on data obtained during operations. It should include the project footprint (the CO_2 plume and area of significantly elevated pressure, or injected and displaced fluids). Groundwater quality monitoring should be performed on a site-specific basis based on injection zone to USDW disposition. (Storage Guideline 1d)
- MMV activities should continue after injection ceases as necessary to demonstrate non-endangerment, as described in the post-closure section. (Storage Guideline 1e)
- For all storage projects, a risk assessment should be required, along with the development of a risk management and risk communication plan. At a minimum, risk assessments should examine the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, and the fluids' potential impacts on the integrity of the confining zone and endangerment to human health and the environment. (Storage Guideline 2a)
- Risk assessments should address the potential for leakage during operations as well as over the long term. (Storage Guideline 2b)
- Risk assessments should help identify priority locations and approaches for enhanced MMV activities. (Storage Guideline 2c)
- Risk assessments should provide the basis for mitigation/remediation plans for response to unexpected events; such plans should be developed and submitted to the regulator in support of the proposed MMV plan. (Storage Guideline 2d)
- Risk assessments should inform operational decisions, including setting an appropriate injection pressure that will not compromise the integrity of the confining zone. (Storage Guideline 2e)
- Periodic updates to the risk assessment should be conducted throughout the project life cycle based on updated MMV data and revised models and simulations, as well as knowledge gained from ongoing research and operation of other storage sites. (Storage Guideline 2f)
- Risk assessments should encompass the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, with a focus on potential impacts to the integrity of the confining zone and endangerment to human health and the environment. (Storage Guideline 2g)
- Risk assessments should include site-specific information such as the terrain, potential receptors, proximity of USDWs, faults, and the potential for unidentified borehole locations within the project footprint. (Storage Guideline 2h)
- Risk assessments should include non-spatial elements or non-geologic factors (such as population, land use, or critical habitat) that should be considered in evaluating a specific site. (Storage Guideline 2i)
- Based on site-specific risk assessment, project operators/owners should provide an expected value of the estimated costs of site closure (including well plugging and abandonment, MMV, and foreseeable mitigation/remediation action) as part of their permit application. These cost estimates should be updated as needed prior to undertaking site closure. (Storage Guideline 3a)
- Project operators/owners should demonstrate financial assurance for all of the activities required for site closure. (Storage Guideline 3b)
- Potential operators should demonstrate control of legal rights to use the site surface and/or subsurface to conduct injection, storage, and monitoring over the expected lifetime of the project within the area of the CO_2 plume and (where appropriate) the entire project footprint. Regulators will also need access for inspection. (Storage Guideline 4a)
- Continued investigation into technical, regulatory, and legal issues in determining pore space ownership for CCS is warranted at the state and federal levels. Additional legislation to provide a clear and reasonably actionable pathway for CCS demonstration and deployment may be necessary. (Storage Guideline 4b)
- MMV activities may require land access beyond the projected CO_2 plume; therefore, land access and any other property interest for these activities should be obtained. (Storage Guideline 4c)









- Operators should avoid potential areas of subsurface migration that might lead to claims of trespass and develop contingencies and mitigation strategies to avoid such actions. (Storage Guideline 4d)
- Potential storage reservoirs should be ranked using a set of criteria developed to minimize leakage risks. Future work is needed to clarify such ranking criteria.(Storage Guideline 5a.1)
- Low-risk sites should be prioritized for early projects. (Storage Guideline 5a.2)
- As required by regulation, storage reservoirs should not be freshwater aquifers or potential underground sources of drinking water. (Storage Guideline 5a.3)
- Confining zones must be present that possess characteristics sufficient to prevent the injected or displaced fluids from migrating to drinking water sources or the surface. (Storage Guideline 5a.4)
- Site-specific data should be collected and used to develop a subsurface reservoir model to predict/simulate the injection over the lifetime of the storage project and the associated project footprint. These simulations should make predictions that can be verified by history-matching within a relatively short period of time after initial CO_2 injection or upon completion of the first round of wells. The reservoir model and simulations should be updated periodically as warranted and agreed with regulators. (Storage Guideline 5a.5)
- Confining zones must be present and must prevent the injected or displaced fluids from migrating to drinking water sources as well as economic resources (e.g., mineral resources) or the surface. (Storage Guideline 5b.1)
- Operators should identify and map the continuity of the target formation and confining zone for the project footprint, and confirm the integrity of the confining zone(s) with appropriate tools. Natural and drilling- or operationally-induced fractures (or the likely occurrence thereof) should be identified. (Storage Guideline 5b.2)
- Operators should identify and map auxiliary or secondary confining zones overlying the primary and secondary target formations, where appropriate. (Storage Guideline 5b.3)
- Operators should identify and locate all wells with penetrations of the confining zone within the project footprint. A survey of these wells should be conducted to assess their likely performance and integrity based on completion records and visual surveys. These data should be made publicly available. (Storage Guideline 5b.4)
- Operators should identify and map all potentially significant transmissive faults, especially those that transect the confining zone within the project footprint. (Storage Guideline 5b.5)
- Operators should collect in-situ stress information from site wells and other sources to assess likely fault performance, including stress tensor orientation and magnitude. (Storage Guideline 5b.6)
- If sufficient data do not already exist, operators should obtain data to estimate injectivity over the projected project footprint. This may be accomplished with a sustained test injection or production of site wells. These wells (which could serve for injection, monitoring, or characterization) should have the spatial distribution to provide reasonable preliminary estimates over the projected project footprint (Storage Guideline 5c.1)
- Water injection tests should be allowed in determining site injectivity. (Storage Guideline 5c.2)
- Operators should obtain and organize porosity and permeability measurements from core samples collected at the site. These data should be made publicly available. (Storage Guideline 5c.3)
- Operators should estimate or obtain estimates of the projected capacity for storing CO_2 with site-specific data (CO_2 density at projected reservoir pressure and temperature) for the project footprint. This should include all target formations of interest, including primary and secondary targets. Capacity calculations should include estimates of the net vertical volume effectively utilized or available for storage and an estimate of likely pore volume fraction to be used (utilization factor). (Storage Guideline 5d.1)
- Operators should collect and analyze target formation pore fluids to determine the projected rate and amount of CO_2 stored as a dissolved phase. These data should be made publicly available as necessary for permitting and compliance purposes. (Storage Guideline 5d.2)
- Operators should obtain estimates of phase-relative permeability (CO_2 and brine) and the amount of residual phase trapping. One possible approach is to use core samples with sufficient spatial density to confirm the existence of the trapping mechanisms throughout the site and to allow their simulation prior to site development. Estimates should be updated with site-specific monitoring and modeling results. These data should be made publicly available as necessary for permitting and compliance purposes. (Storage Guideline 5d.3)
- A field development plan should be generated early on in the permitting phase. (Storage Guideline 6a)

- Operators should develop transparent operational plans and implementation schedules with sufficient flexibility to use operational data and new information resulting from MMV activities to adapt to unexpected subsurface environments. (Storage Guideline 6b)
- Operational plans should be based on site characterization information and risk assessment; they should include contingency mitigation/remediation strategies. (Storage Guideline 6c)
- Storage operators should plan for compressor and well operations contingencies with a combination of contractual agreements relating to upstream management of CO_2, backup equipment, storage space, and, if necessary, permits that allow venting under certain conditions. (Storage Guideline 6d)
- Wells and facilities should be fit-for-purpose, complying with existing federal and state regulations for design and construction. (Storage Guideline 6e)
- The reservoir and risk models should be recalibrated (or history-matched) periodically, based on operational data and re-run flow simulations. Immediate updates should be made if significant differences in the expected and discovered geology are found. (Storage Guideline 6f)
- The casing cement in the well should extend from the injection zone to at least an area above the confining zone. (Storage Guideline 6g)
- Well integrity, including cement location and performance, should be tested after construction is complete, and routinely while the well is operational, as required by regulation. (Storage Guideline 6h)
- Water injection tests should be allowed at all prospective CCS sites. (Storage Guideline 6i)
- Injection pressures and rates should be determined by well tests and geomechanical studies, taking into account both formation fracture pressure and formation parting pressure. Rules should not establish generally applicable quantitative limits on injection pressure and rates; rather, site-specific limitations should be established as necessary in permits. (Storage Guideline 6j)
- Operators should adhere to established workplace CO_2 safety standards. (Storage Guideline 6k)
- Operators should implement corrosion management approaches, such as regularly checking facilities, wells and meters for substantial corrosion. Corrosion detected should be inhibited immediately, or damaged facility components should be replaced. Dehydration of the injectate should be required to prevent corrosion, unless appropriate metallurgy is installed. (Storage Guideline 6l)
- Operational data should be collected and analyzed throughout a project's operation and integrated into the reservoir model and simulations. The data collected should be used to history-match the project performance to the simulation predictions. (Storage Guideline 6m)
- Continued monitoring during the closure period should be conducted in a portion of the wells in order to demonstrate non-endangerment, as described below. (Storage Guideline 7a)
- For all other wells, early research and experience suggest that conventional materials and procedures for plugging and abandonment of wells may be sufficient to ensure project integrity, unless site-specific conditions warrant special materials or procedures. A final assessment should include a final cement bond log across the primary sealing interval of all operational wells within the injection footprint prior to plugging, as well as standard mechanical integrity and pressure testing. (Storage Guideline 7b)

- Operators should assemble a comprehensive set of data describing the location, condition, plugging, abandonment procedures, and any integrity testing results for every well that will be potentially affected by the storage project. (Storage Guideline 7c)
- Satisfactory completion of post-injection monitoring requires a demonstration with a high degree of confidence that the storage project does not endanger human health or the environment. (Storage Guideline 7d) This includes demonstrating all of the following:

  1. the estimated magnitude and extent of the project footprint (CO_2 plume and the area of elevated pressure) based on measurements and modeling;
  2. that CO_2 movement and pressure changes match model predictions;
  3. the estimated location of the detectable CO_2 plume based on measurement and modeling (measuring magnitude of saturation within the plume or mapping the edge of it);
  4. either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone;
  5. that, based on the most recent geologic understanding of the site, including monitoring data and modeling, the CO_2 plume and formation water are not expected to migrate in the future in a manner that encounters a potential leakage pathway; and
  6. that wells at the site are not leaking and have maintained integrity.

- Project operators who have demonstrated non-endangerment should be released from responsibility for any additional post-closure MMV, and should plug and abandon any wells used for post-injection monitoring. At this point, the project can be certified as closed, and project operators should be released from any financial assurance instruments held for site closure. In the event that regulators or a separate entity decide to undertake post-closure monitoring that involves keeping an existing monitoring well open or drilling new monitoring wells, project operators should not be responsible for any such work or associated mitigation or remediation arising out of the conduct of post-closure MMV. (Storage Guideline 7e)
- If one does not already exist in a jurisdiction, a publicly accessible registry should be created for well plugging and abandonment data. (Storage Guideline 7f)
- As a condition of completing site closure, operators should provide data on plugged and abandoned wells potentially affected by their project to the appropriate well plugging and abandonment registry. This would include the location and description of all known wells in the storage project footprint, and the drilling, completion, plugging, and integrity testing records for all operational wells. (Storage Guideline 7g)
- The site-specific risk assessment should be updated based on operational data and observations during closure. (Storage Guideline 7d)

APPENDIX D:
GUIDELINES FOR PROJECT DEVELOPERS AND OPERATORS

Capture

- There should be recognition of the potential challenges in achieving the theoretical maximum capture potential before the technologies are proven at scale. This may necessitate flexibility in establishing appropriate capture rates for early commercial-scale projects, with the amount of CO_2 captured at a facility dependent on both technology performance and the specific goals of the project. (Capture Guideline 1b)
- Standards for the levels of co-constituents have been proposed by some regulators and legislators; however, there is potential risk that this could create disincentives for reducing sources of anthropogenic CO_2 if the standard is set too stringently. Ultimately, the emphasis should be on employing materials, procedures, and processes that are fit-for-purpose and assessing the environmental impacts of any co-constituents, along with the benefits of CO_2 emissions reduction as part of a comprehensive CCS risk assessment. Facility operators, regulators, and other stakeholders should pay particular attention to potential impacts of co-constituents in the transport and storage aspects of the project. (Capture Guideline 1c)
- When constructing a new facility or retrofitting an existing facility in the United States, operators must comply with requirements under the Clean Air Act and the Clean Water Act, as appropriate. (Capture Guideline 2a)
- Options for minimizing local and regional environmental impacts associated with air emissions, use of water, and solid waste generation should be evaluated when considering technologies for capture. (Capture Guideline 2b)
- Use of capture technologies could result in hazardous or industrial waste streams. Operators must follow guidelines and regulations for the handling and disposal of industrial or hazardous wastes. (Capture Guideline 2c)
- Operators should investigate the use of combustion wastes as beneficial byproducts. (Capture Guideline 2d)

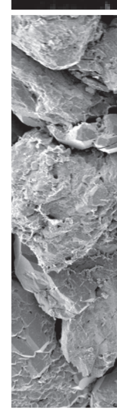
Transport

- CO_2 pipeline design specifications should be fit-for-purpose and consistent with the projected concentrations of co-constituents, particularly water, H_2S, oxygen, hydrocarbons, and mercury. (Transport Guideline 1a)
- Existing industry experience and regulations for pipeline design and operation should be applied to future CCS projects. (Transport Guideline 1b)
- Operators should follow the existing OSHA standards for safe handling of CO_2. (Transport Guideline 2a)
- Plants operating small in-plant pipelines should consider adopting OPS regulations as a minimum for best practice. (Transport Guideline 2b)
- Pipelines located in vulnerable areas (populated, ecologically sensitive, or seismically active areas) require extra due diligence by operators to ensure safe pipeline operations. Options for increasing due diligence include decreased spacing of mainline valves, greater depths of burial, and increased frequency of pipeline integrity assessments and monitoring for leaks. (Transport Guideline 2c)
- If the pipeline is designed to handle H_2S, operators should adopt appropriate protection for handling and exposure. (Transport Guideline 2d)

Storage

- MMV requirements should not prescribe methods or tools; rather, they should focus on the key information an operator is required to collect for each injection well and the overall project, including injected volume; flow rate or injection pressure; composition of injectate; spatial distribution of the CO_2 plume; reservoir pressure; well integrity; determination of any material leakage; and appropriate data (including formation fluid chemistry) from the monitoring zone, confining zone, and USDWs. (Storage Guideline 1a)
- Operators should have the flexibility to choose the specific monitoring techniques and protocols that will be deployed at each storage site, as long as the methods selected provide data at resolutions that will meet the stated monitoring requirements. (Storage Guideline 1b)

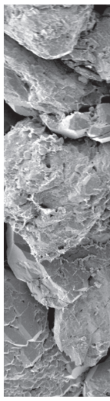




- MMV plans, although submitted as part of the site permitting process, should be updated as needed throughout a project as significant new site-specific operational data become available. (Storage Guideline 1c)
- The monitoring area should be based initially on knowledge of the regional and site geology, overall site specific risk assessment, and subsurface flow simulations. This area should be modified as warranted, based on data obtained during operations. It should include the project footprint (the CO_2 plume and area of significantly elevated pressure, or injected and displaced fluids). Groundwater quality monitoring should be performed on a site-specific basis based on injection zone to USDW disposition. (Storage Guideline 1d)
- MMV activities should continue after injection ceases as necessary to demonstrate non-endangerment, as described in the post-closure section. (Storage Guideline 1e)
- For all storage projects, a risk assessment should be required, along with the development and implementation of a risk management and risk communication plan. At a minimum, risk assessments should examine the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, and the fluids' potential impacts on the integrity of the confining zone and endangerment to human health and the environment. (Storage Guideline 2a)
- Risk assessments should address the potential for leakage during operations as well as over the long term. (Storage Guideline 2b)
- Risk assessments should help identify priority locations and approaches for enhanced MMV activities. (Storage Guideline 2c)
- Risk assessments should provide the basis for mitigation/remediation plans for response to unexpected events; such plans should be developed and submitted to the regulator in support of the proposed MMV plan. (Storage Guideline 2d)
- Risk assessments should inform operational decisions, including setting an appropriate injection pressure that will not compromise the integrity of the confining zone. (Storage Guideline 2e)
- Periodic updates to the risk assessment should be conducted throughout the project life cycle based on updated MMV data and revised models and simulations, as well as knowledge gained from ongoing research and operation of other storage sites. (Storage Guideline 2f)
- Risk assessments should encompass the potential for leakage of injected or displaced fluids via wells, faults, fractures, and seismic events, with a focus on potential impacts to the integrity of the confining zone and endangerment to human health and the environment. (Storage Guideline 2g)
- Risk assessments should include site-specific information, such as the terrain, potential receptors, proximity of USDWs, faults, and the potential for unidentified borehole locations within the project footprint. (Storage Guideline 2h)
- Risk assessments should include non-spatial elements or non-geologic factors (such as population, land use, or critical habitat) that should be considered in evaluating a specific site. (Storage Guideline 2i)
- Based on site-specific risk assessment, project operators/owners should provide an expected value of the estimated costs of site closure (including well plugging and abandonment, MMV, and foreseeable mitigation/remediation action) as part of their permit application. These cost estimates should be updated prior to undertaking site closure. (Storage Guideline 3a)
- Project operators/owners should demonstrate financial assurance for all of the activities required for site closure. (Storage Guideline 3b)
- Potential operators should demonstrate control of legal rights to use the site surface and/or subsurface to conduct injection and monitoring over the expected lifetime of the project within the area of the CO_2 plume and (where appropriate) the entire project footprint. Regulators will also need access for inspection. (Storage Guideline 4a)
- Continued investigation into technical, regulatory, and legal issues in determining pore space ownership for CCS is warranted at the state and federal levels. Additional legislation to provide a clear and reasonably actionable pathway for CCS demonstration and deployment may be necessary. (Storage Guideline 4b)
- MMV activities may require land access beyond the projected CO_2 plume; therefore, land access and any other property interest for these activities should be obtained. (Storage Guideline 4c)
- Operators should avoid potential areas of subsurface migration that might lead to claims of trespass and develop contingencies and mitigation strategies to avoid such actions. (Storage Guideline 4d)

- Potential storage reservoirs should be ranked using a set of criteria developed to minimize leakage risks. Future work is needed to clarify such ranking criteria. (Storage Guideline 5a.1)
- Low-risk sites should be prioritized for early projects. (Storage Guideline 5a.2)
- As required by regulation, storage reservoirs should not be freshwater aquifers or potential underground sources of drinking water. (Storage Guideline 5a.3)
- Confining zones must be present that possess characteristics sufficient to prevent the injected or displaced fluids from migrating to drinking water sources or the surface. (Storage Guideline 5a.4)
- Site-specific data should be collected and used to develop a subsurface reservoir model to predict/simulate the injection over the lifetime of the storage project and the associated project footprint. These simulations should make predictions that can be verified by history-matching within a relatively short period of time after initial CO_2 injection or upon completion of the first round of wells. The reservoir model and simulations should be updated periodically as warranted and agreed with regulators. (Storage Guideline 5a.5)
- Saline formations and mature oil and gas fields should be considered for initial projects. Other formations, such as coal seams, may prove viable for subsequent activity with additional research. (Storage Guideline 5a.6)
- Confining zones must be present and must prevent the injected or displaced fluids from migrating to drinking water sources as well as economic resources (e.g., mineral resources) or the surface. (Storage Guideline 5b.1)
- Operators should identify and map the continuity of the target formation confining zone for the project footprint, and confirm the integrity of the confining zone(s) with appropriate tools. Natural and drilling- or operationally-induced fractures (or the likely occurrence thereof) should be identified. (Storage Guideline 5b.2)
- Operators should identify and map auxiliary or secondary confining zones overlying the primary and secondary target formations, where appropriate. (Storage Guideline 5b.3)
- Operators should identify and locate all wells with penetrations of the confining zone within the project footprint. A survey of these wells should be conducted to assess their likely performance and integrity based on completion records and visual surveys. These data should be made publicly available. (Storage Guideline 5b.4)
- Operators should identify and map all potentially transmissive faults, especially those that transect the confining zone within the project footprint. (Storage Guideline 5b.5)
- Operators should collect in-situ stress information from site wells and other sources to assess likely fault performance, including stress tensor orientation and magnitude. (Storage Guideline 5b.6)
- If sufficient data do not already exist, operators should obtain data to estimate injectivity over the projected project footprint. This may be accomplished with a sustained test injection or production of site wells. These wells (which could serve for injection, monitoring, or characterization) should have the spatial distribution to provide reasonable preliminary estimates over the projected project footprint (Storage Guideline 5c.1)
- Water injection tests should be allowed in determining site injectivity. (Storage Guideline 5c.2)
- Operators should obtain and organize porosity and permeability measurements from core samples collected at the site. These data should be made publicly available. (Storage Guideline 5c.3)
- Operators should estimate or obtain estimates of the projected capacity for storing CO_2 with site-specific data (CO_2 density at projected reservoir pressure and temperature) for the project footprint. This should include all target formations of interest, including primary and secondary targets. Capacity calculations should include estimates of the net vertical volume effectively utilized or available for storage and an estimate of likely pore volume fraction to be used (utilization factor). (Storage Guideline 5d.1)
- Operators should collect and analyze target formation pore fluids to determine the projected rate and amount of CO_2 stored in a dissolved phase. These data should be made publicly available as necessary for permitting and compliance purposes. (Storage Guideline 5d.2)
- Operators should obtain estimates of phase-relative permeability (CO_2 and brine) and the amount of residual phase trapping. One possible approach is to use core samples with sufficient spatial density to confirm the existence of the trapping mechanisms throughout the site and to allow their simulation prior to site development. Estimates should be updated with site-specific monitoring and modeling results. These data should be made publicly available as necessary for permitting and compliance purposes. (Storage Guideline 5d.3)





- A field development plan should be generated early on in the permitting phase. (Storage Guideline 6a)
- Operators should develop transparent operational plans and implementation schedules with sufficient flexibility to use operational data and new information resulting from MMV activities to adapt to unexpected subsurface environments. (Storage Guideline 6b)
- Operational plans should be based on site characterization information and risk assessment; they should include contingency mitigation/remediation strategies. (Storage Guideline 6c)
- Storage operators should plan for compressor and well operations contingencies with a combination of contractual agreements relating to upstream management of CO_2, backup equipment, storage space, and, if necessary, permits that allow venting under certain conditions. (Storage Guideline 6d)
- Wells and facilities should be fit-for-purpose, complying with existing federal and state regulations for design and construction. (Storage Guideline 6e)
- The reservoir and risk models should be recalibrated (or history-matched) periodically, based on operational data and re-run flow simulations. Immediate updates should be made if significant differences in the expected and discovered geology are found. (Storage Guideline 6f)
- The casing cement in the well should extend from the injection zone to at least an area above the confining zone. (Storage Guideline 6g)
- Well integrity, including cement location and performance, should be tested after construction is complete, and routinely while the well is operational, as required by regulation. (Storage Guideline 6h)
- Water injection tests should be allowed at all prospective CCS sites. (Storage Guideline 6i)
- Injection pressures and rates should be determined by well tests and geomechanical studies, taking into account both formation fracture pressure and formation parting pressure. Rules should not establish generally applicable quantitative limits on injection pressure and rates; rather, site-specific limitations should be established as necessary in permits. (Storage Guideline 6j)
- Operators should adhere to established workplace CO_2 safety standards. (Storage Guideline 6k)
- Operators should implement corrosion management approaches, such as regularly checking facilities, wells and meters for substantial corrosion. Corrosion detected should be inhibited immediately, or damaged facility components should be replaced. Dehydration of the injectate should be required to prevent corrosion, unless appropriate metallurgy is installed. (Storage Guideline 6l)
- Operational data should be collected and analyzed throughout a project's operation and integrated into the reservoir model and simulations. The data collected should be used to history match the project performance to the simulation predictions. (Storage Guideline 6m)
- Continued monitoring during the closure period should be conducted in a portion of the wells in order to demonstrate non-endangerment, as described below. (Storage Guideline 7a)
- For all other wells, early research and experience suggest that conventional materials and procedures for plugging and abandonment of wells may be sufficient to ensure project integrity, unless site-specific conditions warrant special materials or procedures. A final assessment should include a final cement bond log across the primary sealing interval of all operational wells within the injection footprint prior to plugging, as well as standard mechanical integrity and pressure testing. (Storage Guideline 7b)
- Operators should assemble a comprehensive set of data describing the location, condition, plugging, abandonment procedures, and any integrity testing results for every well that will be potentially affected by the storage project. (Storage Guideline 7c)
- Satisfactory completion of post-injection monitoring requires a demonstration with a high degree of confidence that the storage project does not endanger human health or the environment. (Storage Guideline 7d) This includes demonstrating all of the following:

  1. the estimated magnitude and extent of the project footprint (CO_2 plume and the area of elevated pressure), based on measurements and modeling;
  2. that CO_2 movement and pressure changes match model predictions;
  3. the estimated location of the detectable CO_2 plume based on measurement and modeling (measuring magnitude of saturation within the plume or mapping the edge of it);

4. either (a) no evidence of significant leakage of injected or displaced fluids into formations outside the confining zone, or (b) the integrity of the confining zone;

5. that, based on the most recent geologic understanding of the site, including monitoring data and modeling, CO_2 plume and formation water are not expected to migrate in the future in a manner that encounters a potential leakage pathway; and,

6. that wells at the site are not leaking and have maintained integrity.

- Project operators who have demonstrated non-endangerment should be released from responsibility for any additional post-closure MMV, and should plug and abandon any wells used for post-injection monitoring. At this point, the project can be certified as closed and project operators should be released from any financial assurance instruments held for site closure. In the event that regulators or a separate entity decide to undertake post-closure monitoring that involves keeping an existing monitoring well open or drilling new monitoring wells, project operators should not be responsible for any such work or associated mitigation or remediation arising out of the conduct of post-closure MMV. (Storage Guideline 7e)

- As a condition of completing site closure, operators should provide data on plugged and abandoned wells potentially affected by their project to the appropriate well plugging and abandonment registry. This would include the location and description of all known wells in the storage project footprint, and the drilling, completion, plugging, and integrity testing records for all operational wells. (Storage Guideline 7g)

- The site-specific risk assessment should be updated based on operational data and observations during closure. (Storage Guideline 7h)

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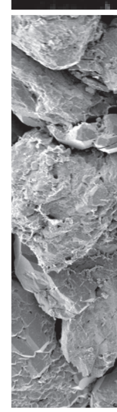

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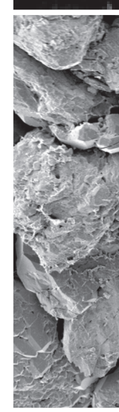

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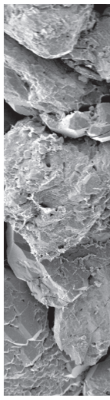

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INSIDE BACK COVER
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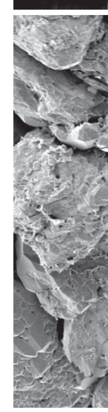

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PUBLICATIONS DIRECTOR

Hyacinth Billings, World Resources Institute

DESIGN AND LAYOUT

Alston Taggart, Studio Red

COPY EDIT

Joan O'Callaghan, Communications Collective

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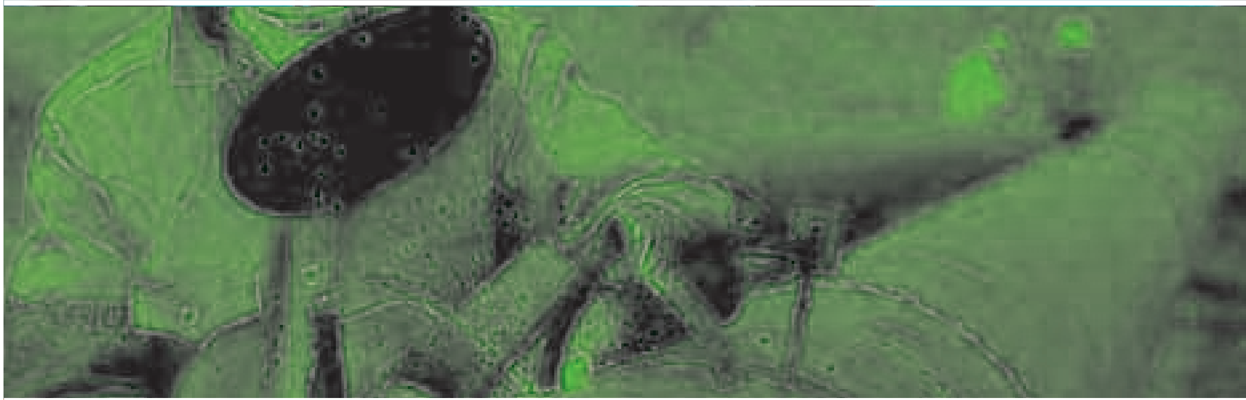

ISBN 978-1-56973-701-9