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COMMISSION

GEOLOGIC CARBON SEQUESTRATION STRATEGIES FOR CALIFORNIA

THE ASSEMBLY BILL 1925 REPORT TO THE CALIFORNIA LEGISLATURE

DRAFT STAFF REPORT

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PREFACE

This report was prepared in response to legislation passed last year, Assembly Bill 1925 (Blakeslee), Chapter 471, Statutes of 2006. The bill states,

On or before November 1, 2007, the State Energy Resources Conservation and Development Commission, in coordination with the Division of Oil, Gas, and Geothermal Resources of the Department of Conservation and the California Geological Survey, shall submit a report to the Legislature containing recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide. In formulating recommendations, the commission shall meet with representatives from industry, environmental groups, academic experts, and other government officials, with expertise in indemnification, subsurface geology, fossil fuel electric generation facilities, advanced carbon separation and transport technologies, and greenhouse gas management.

The study for the report shall be conducted using existing resources and shall include, but is not limited to, all of the following:

- *Key components of site certification protocol, including seal characterization, reservoir capacity and fluid and gas dynamics, testing standards, and monitoring strategies.*
- *Integrity and longevity standards for storage sites.*
- *Mitigation, remediation, and indemnification strategies to manage long-term risks.*

The commission shall include the report prepared pursuant to this section in its 2007 integrated energy policy report required by Section 25302 of the Public Resources Code.

The Energy Commission is currently funding studies on the feasibility of geologic carbon sequestration. This research is co-sponsored by the U.S. Department of Energy though a research program known as the WESTCARB. In addition, the Energy Commission is funding the development of improved methods to estimate greenhouse gas emissions and studying options to reduce these emissions.The WESTCARB project will provide the necessary foundational data and analysis to ensure an appropriate regulatory framework for geologic carbon sequestration, including the development of site certification protocols, integrity and longevity standards, and mitigation, remediation, and indemnification strategies. The WESTCARB project is scheduled for completion in 2010. A significant amount of data, which would be valuable for formulation of recommendations required by AB 1925, will not be available until then.

Therefore, the Energy Commission has prepared this preliminary report by the November 1, 2007 deadline required in AB 1925. This preliminary report establishes the parameters for a final report that would be due in November 2010 after the results of the WESTCARB project can be thoroughly evaluated.

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Table of Contents

List of Tables

List of Figures

List of Acronyms

AB 32	California Assembly Bill 32 (author) chapter, statute
AB 1925	California Assembly Bill 1925 (author) chapter, statute
ARB	California Air Resources Board
CCS	carbon capture and storage
CGS	California Geological Survey
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
DOGGR	Division of Oil, Gas and Geothermal Resources (California Department of Conservation)
EGR	enhanced gas recovery
EIS	environmental impact statement
EOR	enhanced oil recovery
GCS	geologic carbon sequestration
GHG	greenhouse gases
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
MIT	mechanical integrity testing
MMT	million metric tons
SB 1368	California Senate Bill 1368 (Perata) Chapter 598, Statutes of 2006
UNEP	United Nations Enviroment Programme
U.S. EPA	United States Environmental Protection Agency
WMO	World Meterological Organization

ABSTRACT

Assembly Bill 1925, passed unanimously by the California Legislature in 2006, requires the Energy Commission and the Department of Conservation to prepare a report recommending how the state could facilitate adoption of geologic carbon sequestration. This legislation is part of the state's overarching efforts to address methods for reducing greenhouse gas emissions, consistent with California's overall climate change mitigation strategies.

The relevant scientific and engineering topic areas covered by this report are: the potential to store carbon dioxide in the state's deep geologic formations, including depleted oil and gas reservoirs and saline formations, the technologies needed to capture carbon dioxide emitted from power plants and other large industrial sources in the state, and issues surrounding storage reservoir management (including site characterization, monitoring approaches, risks and their management, and remediation and mitigation measures should leakage occur). In addition, the report examines the economics of geologic carbon sequestration, and discusses issues and options for developing the necessary statutory and regulatory frameworks for carbon sequestration.

The report concludes that, while technical challenges remain, the primary barriers to progressing with initial geologic sequestration projects in the state lie within the statutory and regulatory arena. Demonstration projects and further studies are needed to advance or adapt existing knowledge and technology to geologic carbon sequestration (for example, in development of protocols for site characterization, risk assessment and monitoring), and to guide development of regulations and statutes. These efforts should provide opportunities to engage stakeholders and for public education on carbon capture and storage.

KEYWORDS

Carbon capture and sequestration, coal, climate change mitigation, electricity, carbon emissions, greenhouse gas emissions reductions, geologic sequestration, carbon dioxide

Executive Summary

Assembly Bill 1925 (Blakeslee), Chapter 471, Statutes of 2006, passed unanimously by the California Legislature, is designed to assess the present level of development of carbon capture and sequestration and its potential application for meeting California's climate change mitigation goals. This bill directs the California Energy Commission, in coordination with the Department of Conservation, to prepare a report for the Legislature that contains:

> …recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for long-term management of industrial carbon dioxide.[1]

Carbon capture and sequestration options include any process that "captures" carbon dioxide (CO_2) and stores, or sequesters, it away from the atmosphere for the purpose of mitigating climate change that is caused by atmospheric CO_2 build up. Three approaches can capture and sequester carbon: terrestrial, geologic, and oceanic. Of these, the first and second can be used in California. Terrestrial carbon sequestration involves changing the management of forests, rangelands, agricultural lands, and wetlands so that these ecosystems naturally capture and store more CO_2 and/or emit less. Geologic sequestration involves using gas separation technologies to capture CO_2 from large point sources, such as power plants, cement factories, or refineries, and inject it deep underground.

Commercial-scale application of geologic carbon sequestration, the focus of AB 1925, requires not only technological readiness, but also the construction and implementation of appropriate regulatory and statutory frameworks. Particular challenges exist for geologic sequestration because it potentially cuts across the jurisdictions of several state and federal agencies and because of its uniquely long-term nature, potentially extending to hundreds, or even thousands, of years for storage.

With respect to geologic sequestration, the relevant topics to assess the state's readiness, as called out by the AB 1925 legislation and as identified by experts on the development of carbon capture and sequestration, are:

- Potential for geologic storage in the state
- Capture technologies
- Site characterization
- Monitoring and verification
- Risks and risk management

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[1] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_1901-1950/ab_1925_bill_20060926_chaptered.pdf

- Remediation and mitigation
- Economic considerations
- Regulatory and statutory issues

Subject matter experts contributed white papers that serve as the technical foundation for this report to the Legislature, which devotes a chapter to each of these topics. The Energy Commission also is publishing the white papers as chapters in a separate document through its Public Interest Energy Research Division. Development of this report involved a process of two public workshops and presentations at technical and community meetings that engaged state agencies, other experts in various aspects of geologic sequestration, a range of stakeholders, and the public.

While technical challenges remain, the primary barriers to progress with initial geologic sequestration projects in the state lie within the statutory and regulatory arena. Demonstration projects and further technical evaluations and studies are needed, in part to guide development of regulations and statutes that are appropriate for carbon capture and sequestration. Demonstration projects, in particular, also should provide opportunities to engage stakeholders and for public education on carbon capture and storage. Many of the main areas of concern cut across topic areas and the discussion below is presented in that context. Each topic chapter of this report also includes specific suggestions not reiterated here.

Potential for Geologic Sequestration

The first step in geologic sequestration entails modifying large industrial plants, such as power plants, oil refineries, and cement plants, to separate CO_2 from process or exhaust gases. The CO_2 must then be delivered (generally via pipeline) to a storage site and injected deep underground into geologic formations that will prevent the injected CO_2 from re-entering the atmosphere for hundreds to thousands of years.

In California, suitable geologic formations include depleted or near-depleted oil and gas reservoirs and saline formations (rocks containing non-potable salty water). These targets are common in deep sedimentary basins, places where sand and mud have accumulated to great thickness over many millions of years and lithified into rock. These types of layered rocks are potentially good storage sites because they have the capacity to hold or trap large amounts of CO_2 in the pore spaces of sand layers, while overlying impermeable mud rock layers form good seals that prevent the gas from escaping upward.

Preliminary studies of the geology of the state identified a large storage resource potential, but more detailed site-specific characterization of the subsurface geology will be needed in many areas. Preliminary estimates of saline formation CO_2 storage capacity for the 10 largest sedimentary basins is between 75 and 300 metric gigatons of CO_2; for oil and gas fields, preliminary estimates are on the order of 3.5 and 1.7 metric gigatons of CO_2, respectively. There is a generally favorable correspondence within the state between locations of emission point sources and sites for geologic storage.

The existence of appropriate infrastructure and expertise, as well as economic factors, favor development of early carbon capture and sequestration projects in affiliation with CO_2-enhanced oil recovery projects in oil and gas fields. To date, the high cost of acquiring CO_2 from out-of-state sources has been a barrier to adoption of carbon dioxide-enhanced oil recovery in the state. Economic and regulatory studies need to establish the relationship between captured CO_2 cost and demand for this CO_2 for enhanced oil recovery and to evaluate the regulatory and statutory issues that would facilitate enhanced oil recovery operations that could store substantial quantities of CO_2. These projects, in turn, could provide important datasets to facilitate carbon capture and sequestration development. For example, two new power plants in California, the proposed BP-Rio Tinto-Edison Mission Energy petroleum coke gasification project in Carson (Los Angeles County) and the Clean Energy Systems oxy-combustion plant in Kimberlina (Kern County) include designs for CO_2 capture, with the prospect that the CO_2 may be sold for commercial purposes, including enhanced oil recovery. Given that economic factors favor the combination of carbon capture and sequestration with enhanced oil recovery and that many early carbon capture and sequestration projects will likely be of this type, it is important to better understand the conditions necessary to assure proper operation and oversight of these types of projects.

While early carbon capture and sequestration projects may take advantage of the opportunities for storing CO_2 in affiliation with CO_2-enhanced oil recovery projects in depleted oil and gas fields, they will not be sufficient to accommodate all of the CO_2 that must be captured from various industrial sources to enable California to meet its long-term goals for reducing greenhouse gas emissions. Commercial application of geologic sequestration in California will require use of the state's ample saline formations. Although CO_2 storage in saline formations will resemble storage in oil or gas reservoirs, the saline formations of California have not been extensively studied in the manner of oil- and gas-containing formations. These studies must be done.

Demonstration projects of CO_2 storage in saline formations at volumes and over time periods sufficient to evaluate their suitability as CO_2 storage sites also will be critical. The research and pilot projects being conducted by the WESTCARB partnership have begun the work needed to gather data and better understand saline formation storage capacity and trapping mechanisms, but more efforts are required. Data shared by operators of initial commercial projects will also improve our understanding.

The amount of CO_2 that can be sequestered annually by geologic storage is limited by the number of point sources that can be economically captured. For example, power plant emissions, based on the greenhouse gas inventory, totaling about 107 million tons of CO_2 per year, could in theory all be geologically sequestered. However, the true rate at which carbon capture and sequestration can be deployed depends on many factors, including a more detailed understanding of the storage resource and the pace of transport infrastructure development, chiefly pipeline networks.

Geologic carbon capture and sequestration can mitigate only that part of emissions associated with large single point sources, such as smoke stacks on factories or power plants. In contrast, transportation fuel emissions, California's largest sector source at about 190 million tons of CO_2 per year, consists of millions of small mobile sources, making capture impractical. However, plans for CO_2 reduction in the transportation sector include use of lower net carbon fuels, such as ethanol, which is made at fermentation-based production plants that are amenable to CO_2 capture and geologic sequestration.

Locations of the largest CO_2 point sources by type appear to match well with geologic storage sites for key areas of the state: the Los Angeles Basin, the Bakersfield area, and the San Francisco–Sacramento area. In total, some 30 industrial facilities produce over 1 million metric tons of CO_2 emissions per year. Most are natural gas-fired power plants, along with several oil refineries and cement kilns. The few coal- and petroleum coke-fired power plants in California are relatively small because they are mostly non-utility generators built as cogeneration qualified facilities.

Where large industrial sources amenable to CO_2 capture do not overlie suitable geologic CO_2 storage sites, CO_2 will have to be transported to storage sites via pipelines, trucks, trains, ships, or barges. For the large quantities of CO_2 that must be handled for sequestration, pipelines are clearly the most economic. The technical, economic, safety and permitting aspects of CO_2 pipeline transport are relatively well understood because of the many pipelines in the U.S. for the large-scale transport of CO_2 for use in enhanced oil recovery. The costs and complexity of building CO_2 pipeline infrastructure in California will depend on the proximity of CO_2 sources to preferred storage sites, available rights-of-way, the surface terrain, and current surface uses. The impacts of these factors on transport feasibility and costs must be quantified.

Based on this assessment, the report recommends the following actions:

- Improve characterization of the geologic CO_2 storage potential in the state, particularly for saline formation storage, and facilitate demonstration projects for CO_2 storage in saline formations.
- To facilitate carbon capture and sequestration infrastructure, evaluate the cost and other issues associated with pipeline development to link industrial CO_2 sources to preferred storage sites.
- Evaluate the potential in the state for use of captured CO_2 for enhanced oil recovery.

Capture Technologies and Economics

Large industrial sources of CO_2 usually do not generate emissions of high purity CO_2 at pressure. These sources include natural gas–fired power plants, cement plants, and oil refinery furnaces and boilers. Instead, the CO_2 is present in fairly dilute concentrations in their combustion exhaust or process flue gas streams. With current technologies, capture of CO_2 out of flue gas is costly. However, with respect to underground storage capacity use, energy for compression, and other costs, it would be prohibitive to inject the full flue gas stream into deep geologic formations. Therefore, CO_2 capture generally requires separation of CO_2 from other gases. Three approaches are currently available to capture CO_2 from large power plants and other industrial CO_2 sources: post-combustion, pre-combustion, and oxyfuel combustion.

Carbon capture and sequestration costs are mainly due to increased capital and internal energy needs associated with concentrating the CO_2 to a pure stream, compressing it to high pressure, and for transportation, if required. In general terms, CO_2 capture economics favor large point sources near good geologic storage sites. The economics also favors low cost fuels due to the increased energy use for CO_2 capture. CO_2 capture economics also generally favors fuels high in carbon that generate relatively higher concentrations of CO_2 in flue gas streams prior to CO_2 capture. Therefore, the costs of CO_2 capture generally are higher for natural gas-fired plants than for coal-fired plants. For either fuel type, costs per ton of CO_2 removed are higher for smaller plants than for larger plants.

Assessing the economics of carbon capture and sequestration is very challenging today, in part because no policy exists to establish a price for CO_2 in the marketplace. Additional complicating factors include the large run-up in the last several years of costs for process equipment and piping worldwide, as well as a "first-of-a-kind" premium for carbon capture and sequestration facilities. Factoring in these parameters, preliminary estimates result in CO_2 capture and compression costs on the order of $50 to $90 per metric ton of CO_2 removed, by far the largest part of the entire cost of carbon capture and sequestration.

From an economic standpoint, several "targets of opportunity" with respect to carbon capture and sequestration in California should be considered. One is the use of captured CO_2 for enhanced oil recovery, which places a value of about $20/metric ton on CO_2. The other is industrial processes with high concentrations of CO_2 in process or exhaust streams, which make these applications viable economically. Examples include fermentation processes such as those used in ethanol production, older hydrogen plants in oil refineries and chemical plants, and natural gas processing facilities. For these plants, where a high purity stream of CO_2 is produced as part of the industrial process, the capture cost will be small, and the primary expense will involve CO_2 drying and compression for injection. It is important to note that when CO_2 capture and storage is used with biomass feedstocks, there is opportunity for double reductions—in effect, "net-negative" emissions. CO_2 capture and storage from biomass is usually most effective via co-processing waste biomass whenever available at large fossil fuel facilities with CO_2 capture to achieve essential economies of scale and high annual investment utilization.

The challenge for CO_2 capture is to reduce costs and energy use relative to other CO_2 reduction options such as end-use efficiency improvement, renewables, and nuclear power. New and improved technologies being developed for CO_2 capture aim to reduce capital costs and the energy requirements for solvent regeneration. Over time, the economics of CO_2 capture are expected to improve due to technology refinements, success with novel technologies, and "learning-by-doing" to enhance capital utilization and efficiencies through commercial-scale applications.

Based on this assessment, the report recommends the following actions:

- Advance capture technologies and invest in research and development to improve the economics and efficiencies of CO_2 capture systems for major industrial sources.

Site Characterization, Monitoring and Verification, Risks, Remediation and Mitigation

From the initial design stages to post-closure, carbon capture and sequestration projects will have greater operational success and public acceptance if site characterization, monitoring and verification, risk assessment and management, and remediation and mitigation planning are integrally linked. Careful site selection and certification will form the foundation for successful long-term geologic sequestration by ensuring that CO_2 storage sites are reviewed for sufficient capacity, geologic features for secure storage, accessibility to pipelines, and other factors conducive to a technically successful project. Projects also should be designed to assure protection of the health and safety of workers, the public, and the environment which requires that the risks of the project be assessed and managed. For carbon capture and sequestration, risk derives primarily from the potential for releases of captured gases through all phases of operation, including capture, transportation, and subsurface storage. Monitoring and verification are essential to demonstrate that geologic storage is safe for the public and local communities, does not create significant adverse local environmental impacts, and is effective as a greenhouse gas control technology. Finally, remediation and mitigation procedures must be in place to cover the possibility of CO_2 leakage, out of the storage formation, during pipeline transport, or from injection activities, that could affect public health, the environment, or economic interests.

Siting of geological storage projects requires substantial subsurface characterization. However, available data and cost limit the detail, degree of quantification, and precision of characterization. The degree of site characterization should reflect the goals of the project stakeholders and be appropriate to the subsurface and surface character of the site(s) under consideration. In general, site characterization information should be sufficient to

- Identify sites with low overall risk and high chance of short- and long-term success
- Provide a technical basis for decision making for financing and insurance
- Provide data for planning, including safe and successful operations
- Design and deploy monitoring and verification tools

- Quantify and manage risk.

Existing technology and conventional data sets readily meet these goals.

Surface characterization is also an important component of site characterization. The infrastructure itself, including pipelines and monitoring equipment, has environmental and societal impacts that must be considered, including evaluation of impacts on sensitive species and other wildlife and cultural and environmental justice issues. Local land uses and structures, including pre-existing subsurface structures such as mines or basements, should be identified and their associated risks considered. Topography and prevailing meteorologic conditions must be characterized to understand the potential impact of any significant CO_2 leak.

A CO_2 storage project must be compatible with previous, current, and future uses of the site. In particular, in oil or gas producing areas, the distribution and condition of wells affect the potential for reservoir leakage. Storage projects also could influence future utilization of water and mineral resources in the area.

Proper site characterization is critical to proper risk assessment. Dividing the process of carbon capture and sequestration into above-ground and below-ground components aids in risk assessment for carbon capture and sequestration. Pre-injection risk assessment is associated with releases from surface facilities and engineered systems for separating, compressing and transporting CO_2; post-injection is focused on potential impacts of releases from wells and storage reservoirs. Predicting the future course of events at a carbon sequestration site is particularly challenging because the site must retain injected CO_2 for at least hundreds of years to be effective at mitigating greenhouse gas emissions. These timescales are short compared to geologic timescales, but very long compared to the timescales of typical risk assessments and to existing datasets for any geologic phenomena.

One of the most important purposes of monitoring and verification is to confirm that the project is performing as expected; monitoring also is needed to ensure that natural resources, such as groundwater and recoverable oil and gas, are protected and that natural ecosystems, local populations, and livestock are not exposed to unsafe concentrations. Various monitoring techniques can verify the amount of CO_2 stored, track the CO_2 plume underground, and check for potential leakage from the storage formation or to the surface. Monitoring instrumentation must be reliable, economical, and capable of detecting low-level leakage while having sufficient range to register major leaks. Currently available equipment is more than adequate to meet the needs for monitoring CO_2 injection rates, wellhead and formation pressures, and occupational safety. However, CO_2 measurement and monitoring approaches suited to the large areas and long time-scales relevant to geologic sequestration need further evaluation and refinement, perhaps best done through demonstration projects. Determining pre-injection subsurface conditions, as well as natural background levels of CO_2, is also critical to understanding project performance. Without an adequate baseline, it may not be possible to distinguish storage-related changes in the environment from natural variations. For most CO_2 storage projects, the monitoring baseline should be obtained during the pre-injection site characterization phase of the storage project.

All sites, even those with optimal features, must be assessed for potential human health and safety and environmental risks during the operational and post-operational phases of a project. Safety procedures to limit these risks and leakage response procedures will be needed. Experience with storing CO_2 in geological formations suggests that the inherent risks and potential quantities of CO_2 leakage will likely be minimal. However small the risk, CO_2 leakage can result from human error, natural hazards, or other unknown factors. Procedures are needed to cover the possibility of CO_2 migrating out of the storage formation(s) or other releases that might occur during pipeline transportation or injection activities that could affect public health, the environment, or economic interests. Analogous industries, such as natural gas storage and enhanced oil recovery, should be studied to rigorously evaluate the potential application of their remediation and mitigation procedures to geologic sequestration. However, further efforts are needed to address CO_2 monitoring, leak detection, and mitigation and remediation at greater spatial and time scales than those necessary for enhanced oil recovery operations. Priorities for continued research include procedures for identifying and addressing a failure in the reservoir seal or caprock; materials selection and construction procedures to achieve a "thousand-year well"; and the cost-effective means for securely reworking or plugging wells in a CO_2 storage environment.

From these discussions, there is a clear need to develop consistent and integrated frameworks and protocols for carbon capture and sequestration site characterization, risk assessment, monitoring and verification requirements, and mitigation and remediation planning. Currently no consensus or standard exists for these factors regarding the criteria required to adequately or even minimally address the potential concerns of operators, regulators, and other stakeholders. Considerable relevant experience is available from the oil and gas industry, natural gas storage, and underground injection of wastes. Flexibility to tailor carbon capture and sequestration frameworks to the specific geological and geographic attributes of a storage site would be beneficial. It may also be appropriate to establish a minimum set of requirements.

Based on this assessment, the report recommends the following actions:

- Develop integrated site characterization, monitoring and verification, and risk assessment protocols for CO_2 storage sites.
- Evaluate options and existing capabilities to respond to carbon capture and sequestration leakage events, including remediation and mitigation planning.

Statutory and Regulatory Issues

For carbon capture and sequestration, as for any new technology or industry, it is important that legal and regulatory standards be established to protect the public, the environment, and the state's resources and, at the same time, be designed to facilitate technical innovation and advancement. In California, as elsewhere, carbon capture and sequestration-specific regulatory and statutory frameworks do not yet exist. This report provides a review of this issue, for the purpose of assessing how current frameworks may apply to carbon capture and sequestration implementation in the state. It is not a formal legal analysis of the statutes and regulations relevant to carbon capture and sequestration. Given the complexities of the regulatory and statutory frameworks that have been identified as potentially applying to carbon capture and sequestration, a robust follow-up analysis seems warranted to establish the potential impact of including carbon capture and sequestration under existing statutes and regulations and of the effect on existing frameworks of any new carbon capture and sequestration-specific regulations and statutes.

Regulatory continuity is an important goal for the frameworks that will be established for carbon capture and sequestration. It is possible, under current regulations, for authority to become split along the lines of reservoir type and along pre-injection (surface) and post-injection (subsurface) activities. Because of the potential to affect existing industries, particularly enhanced oil recovery operations, the ramifications of different regulatory options must be studied. Ideally, a single authority should regulate the injection, storage, and monitoring of CO_2 into all potential geologic reservoirs. Another area of complexity is the interplay among ownership interests and provisions for the public good and how these diverse interests should be accommodated for the purposes of long-term geologic CO_2 storage.

A key uncertainty is the issue of liability. While the operational risks associated with transportation, injection, and storage of CO_2 have been successfully managed for many years, there is major concern with sources of liability during the post-closure phase of carbon capture and sequestration, given that no time limitations have been established, making the term in effect, unending. For industry, the concerns associated with this open-ended liability include the consequent inability to obtain insurance for the project, the potential to incur remediation costs related to CO_2 migration and/or leakage at some point in the distant future, and the disincentive that these potential costs may have on investment today in CO_2 geologic storage.

Based on this assessment, the report recommends the following action:

- Rigorously evaluate statutory and regulatory uncertainties and options for regulatory frameworks appropriate for CCS.

Education and Public Participation

Worldwide, the heightened level of activity on geologic sequestration research and applications reflects a growing consensus across a range of stakeholders for the need to incorporate carbon capture and sequestration into mitigation steps to combat climate change.

A well-trained workforce to select and certify CO_2 storage sites, install carbon capture and sequestration infrastructure, manage operations, and respond to leakage events is critical to protecting public health, safety, and the environment and to ensuring the overall success of carbon capture and sequestration projects. Regulators who oversee geologic sequestration applications may need additional training.

Public outreach activities must provide accurate information to help the public weigh the benefits and risks, as well as the safety and mitigation measures that may be taken to manage risks. Public support and participation will be a key factor in the success of early geologic sequestration projects, which should openly share information to demonstrate that long-term storage of CO_2 can be accomplished safely.

As is also true for other new technologies in the early stages of deployment, there is generally little public awareness and understanding of carbon capture and sequestration. Even though CO_2 capture and storage is a public good in contributing to global climate change mitigation, the perceptions, risks to, and benefits for the local public and communities should be acknowledged and addressed through efforts to openly share carbon capture and sequestration knowledge and pertinent project-specific information.

Based on this assessment, the report recommends the following actions:

- Facilitate training of necessary personnel.
- Encourage public participation and education.

CHAPTER 1: Role of Carbon Sequestration in Climate Change Mitigation in California

Assembly Bill 1925, AB 1925, (Blakeslee), Chapter 471, Statutes of 2006, passed unanimously by the California Legislature, aims to place an assessment of the present level of development of carbon capture and sequestration (CCS) and its potential application to meeting California's climate change mitigation goals into the hands of policymakers. This bill directs the California Energy Commission (Energy Commission), in coordination with the Department of Conservation, to prepare a report for the Legislature that contains:

> . . . recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for long-term management of industrial carbon dioxide.[2]

Governor Arnold Schwarzenegger and the California Legislature have recognized the importance of reducing carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions to safeguard the state's water supply, crops, and habitats, as well as public health. On June 1, 2005, the Governor signed Executive Order S-3-05, which established three target reduction levels for GHG emissions in California: 2000 levels by 2010; 1990 levels by 2020; and 80 percent below 1990 levels by 2050.[3]

Upon passage of AB 32, the Global Warming Solutions Act of 2006 (Nuñez), Chapter 488, Statutes of 2006, California began to identify ways to meet the second target of reducing GHG emissions to 1990 levels by 2020.[4] SB 1368 (Perata), Chapter 598, Statutes of 2006, followed, mandating that new or renewed long-term contracts to purchase electricity from baseload facilities meet the GHG emission performance standard established by the California Public Utilities Commission (CPUC) and the Energy Commission, in consultation with the Air Resources Board (ARB).[5] These initiatives, as well as AB 1925 and other recent legislation, demonstrate that California's policymakers understand that achieving the state's GHG reduction goals will require a substantial ongoing effort across multiple economic sectors and a portfolio of energy solutions, including renewables, energy efficiency, alternative transportation fuels, and application of CCS options.

CCS options include any process that "captures" carbon dioxide and stores, or sequesters, it away from the atmosphere for the purpose of mitigating climate change that is caused by

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[2] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_1901-1950/ab_1925_bill_20060926_chaptered.pdf

[3] Executive Order S-3-05 by the Governor of the State of California. June 1, 2005 (http://www.climatechange.ca.gov)

[4] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf

[5] http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1351-1400/sb_1368_bill_20060929_chaptered.pdf

atmospheric CO_2 buildup. Three approaches can capture and sequester carbon: terrestrial, geologic, and oceanic. Terrestrial carbon sequestration involves changing the management of forests, rangelands, agricultural lands, and wetlands so that these ecosystems naturally capture and store more CO_2 and/or emit less CO_2. Geologic sequestration involves using gas separation technologies to capture CO_2 from large point sources, such as power plants, cement factories, or refineries, and inject it deep underground. Oceanic storage involves injection of captured CO_2 into the deep ocean or the enhancement of natural processes for CO_2 uptake[6] by ocean waters or organisms. To be effective in curbing the rise in atmospheric CO_2 concentrations, each of these options must keep CO_2 stored for many decades or longer.

All of these approaches are applicable to CO_2 from any source. Specifically, terrestrial CCS directly mitigates CO_2 buildup in the atmosphere; geologic CCS can mitigate CO_2 from any point source of emissions that can be effectively captured and transported to a storage site; and oceanic CCS may involve capture of point source emissions or direct atmospheric removal.

As oceanic CCS involves non-sovereign deep seafloor or waters of the open ocean, it is, by nature, an international effort, and is not discussed further in this report. On the other hand, terrestrial sequestration, while not addressed by AB 1925, can be undertaken by individual landowners, states, or nations and may be an important approach for California to meet its CO_2 reduction goals, particularly its 2020 targets. Unlike geologic sequestration, terrestrial methods are not CO_2-source specific; that is, they provide reductions to the state's gross emissions and can therefore mitigate emissions from dispersed sources such as the state's largest CO_2 source, the transportation sector. The state's GHG inventory already contains an entry for terrestrial sequestration—the negative emissions provided by land use change and forestry sinks.[7]

AB 1925 focuses solely on geologic carbon sequestration and even more specifically on its commercial-scale application. Although, as discussed above, the acronym CCS can be inclusive of all three types of carbon capture and storage, for the remainder of this report, the acronym CCS will be used to refer specifically to carbon capture with geological sequestration. Commercial-scale application of geologic carbon sequestration requires not only technological readiness, but also the construction and implementation of appropriate regulatory and statutory frameworks. Particular challenges exist for geologic sequestration because it potentially cuts across the jurisdictions of several state and federal agencies and because of its uniquely long-term nature, potentially extending to hundreds, if not thousands, of years for storage.

Activities to facilitate development of CCS are increasing in scope and number worldwide. Three relatively large geological storage projects, Statoil's Sleipner Saline Aquifer CO_2 Storage

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[6] Uptake of CO_2 by the ocean waters involves the chemical and physical exchange of CO_2 from the atmosphere into the ocean. Biological uptake is done predominantly by open ocean single-celled organisms that photosynthesize or precipitate mineral shells that contain carbonate.

[7] Inventory of California Greenhouse Gas emissions and Sinks: 1990-2004 PIER Report CEC-600-2006-013-SF December 2006.

project in the North Sea off Norway;[8] the Weyburn Project in Saskatchewan, Canada;[9] and the In Salah Project in Algeria,[10] together sequester 3 to 4 million metric tons per year, which approaches the output of a typical 500-megawatt coal-fired power plant. Statoil estimates that Norwegian GHG emissions would have risen incrementally by 3 percent if the CO_2 from the Sleipner project had been vented rather than sequestered.[11]

In the United States, the Department of Energy has numerous ongoing projects to facilitate CCS science and technology development and public understanding. Among these are seven regional partnerships that include about 40 states. These partnerships are conducting small-scale terrestrial and geologic sequestration demonstrations, as well as providing assessments and databases of the distribution of large emission sources and candidate CO_2 storage sites within the United States.[12] The WESTCARB partnership, led by the Energy Commission, includes California, Nevada, Oregon, Washington, Arizona, and Alaska, as well as British Columbia. In addition, the FutureGen Project, the first project to combine coal gasification for electric power and hydrogen generation with carbon sequestration at a commercial scale, has reached the stage recently of completing the Environmental Impact Statement (EIS) and risk assessments of candidate construction sites in Illinois and Texas.[13]

In June 2007, the ARB released the final report of recommendations on the design of a cap-and-trade system to reduce greenhouse gas emissions in California. The report outlines the various opportunities and challenges of different design elements in an emissions trading program. A main purpose of the cap-and-trade program is to bring about low-cost emissions reductions within sectors covered by the program wherein a cap limits emissions and creates a market for trading emissions allowances where every ton of emissions has a price. This price provides sustained incentives for developing new technologies that can reduce GHG emissions because an entity that adopts a new technology that reduces its emissions will have to hold fewer allowances. The report outlines four different options for defining the scope of a California GHG cap-and-trade program, but does not explicitly consider CCS options. The program options differ in their coverage of CO_2 emissions from fossil fuel combustion in California, proposed points of regulation, and the infrastructure required for program administration, but all of them require a provision to address emissions associated with imported electricity. All of

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[8] http://www.statoil.com/statoilcom/SVG00990.NSF/web/sleipneren?opendocument

[9] http://www.co2captureandstorage.info/project_specific.php?project_id=70

[10] http://www.co2captureandstorage.info/project_specific.php?project_id=71

[11] http://www.statoil.com/statoilcom/SVG00990.NSF/web/sleipneren?opendocument

[12] http://drysdale.kgs.ku.edu/natcarb/eps/natcarb_alpha_content.cfm

[13] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

the programs create incentives for CCS, the strength of which would depend on the relative costs of allowances compared to costs to implement CCS.[14]

CCS also was not included in the Energy Commission's scenario analyses of California's electricity system, the purpose of which is to examine the implications of resource plans featuring very high penetrations of preferred resources (energy efficiency measures and renewable energy generation) in California and the Western Interconnection as defined by the Western Electricity Coordinating Council (WECC).[15] Among the variables the study examines is the effect of these scenarios on GHG emissions compared to a base case scenario of conventional resources.

In spite of the exclusion of CCS, the study nevertheless has some interesting implications for the future potential of CCS. For example, all scenario analyses predict that the increase in use of preferred resources results in decreases in natural gas resource use, but the overall amount of coal use in the WECC region increases in all except one case. The least-cost principles used for power plant dispatch decisions thus may not lead to the lowest carbon emissions choices without CCS. However, when CCS is employed, the cost of coal-fired power increases, and both the relative cost and the GHG emissions rankings of the scenarios may be altered significantly. There is a need for further study of how inclusion of CCS influences these potentially competing goals and how policies, such as potential loading order requirements positioning fossil-fuel power plants with CO_2 capture (resulting in CO_2 emissions well below the greenhouse gas performance standard) ahead of fossil-fuel power plants without CO_2 capture, might improve this situation. While the likely rate of deployment of geologic CCS is probably too slow for consideration of this technology in policy decisions over the short-term to 2020, over the longer term, to 2050, geologic (and terrestrial) sequestration within California and the WECC region, should be incorporated into any evaluations to understand how policy can achieve GHG goals while continuing to provide power at the lowest possible cost to Californians.

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[14] Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California: Recommendations of the Market Advisory Committee to the California Air Resources Board, 2007. http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF

[15] Jaske, M.R., 2007, Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report CEC-200-2007-010-SD

CHAPTER 2: Key Implementation Issues

The Intergovernmental Panel on Climate Change (IPCC), jointly established in 1988 by the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP), in 2005 issued a landmark report, *Special Report on Carbon Dioxide Capture and Storage*, which states:

> 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 environment risks of geological storage would be comparable to the risks of current activities such as natural gas storage, EOR[16] and deep underground disposal of acid gas.[17]

While the IPCC statement concludes that geologic sequestration could have comparable risk to operations common in the energy industry, it echoes the AB 1925 legislation in highlighting the key areas where systems or methodologies appropriate to CCS are needed to achieve comparable levels of risk and public acceptance.

With respect to geologic sequestration, the relevant topics to assess the state's readiness, as called out by the AB 1925 legislation and identified by experts on the development of CCS, are:

- Potential for geologic storage in the state
- Capture technologies
- Site characterization
- Monitoring and verification
- Risks and risk management
- Remediation and mitigation
- Economic considerations
- Regulatory and statutory issues

Subject matter experts contributed white papers that serve as the technical foundation for this report, which devotes a chapter to each of the issues. The Energy Commission also is publishing these white papers as chapters in a separate report through its Public Interest Energy Research division. Development of the report involved a process of two public workshops and presentations at technical and community meetings that engaged state agencies, other experts in various aspects of geologic sequestration, a range of stakeholders, and the public.

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[16] enhanced oil recovery

[17] Intergovernmental Panel on Climate Change, *Special Report on Carbon Dioxide Capture and Storage*, 2005. http://www.ipcc.ch

There is generally little public awareness and understanding of CCS, as is the case with other new technologies in the early stages of deployment. In particular, public skepticism remains high for many types of large industrial projects such as CCS until familiarity is established, new technologies have proved to be safe and effective, and operations have established good safety and environmental records. Many other studies of CCS have highlighted education and public outreach as critical efforts, particularly if done in conjunction with well conceived and executed demonstration projects.[18] For example, a workshop report in support of the G8 Plan of Action on Climate Change, Clean Energy and Sustainable Development, co-sponsored by the International Energy Agency (IEA) and the Carbon Sequestration Leadership Forum, notes that:

> An informed public is critical to be able to move forward with near-term CCS opportunities, particularly those who may be affected by a CCS project. Therefore, education and outreach are essential elements. To…[assure the public that a project will protect]… health, safety and the environment, these activities need to provide timely information on 1) the state of technology development, 2) explanations of the risks and benefits associated with their use and 3) information on how monitoring and verification will be employed in CCS projects. Special attention is needed to address concerns about long-term retention in geologic storage.[19]

Given that, in some cases, CCS projects may be located near large industrial facilities with a history of significant emissions, some communities in these areas may view CCS as yet another burden they are inequitably being asked to bear. Even though CO_2 capture and storage is designed to be a beneficial technology, contributing to mitigation of anthropogenic CO_2 buildup, the risk-benefit perception of the public and local communities derives from complex issues that CCS project operators should address through efforts to openly engage these groups and share pertinent information.

There is also a key technical need for workforce training for commercial CCS deployment. A shortage of professionals with relevant experience, chiefly geoscientists and engineers, can substantively impact the rate of growth of a CCS industry. These same professionals also are in demand by the conventional oil, gas, and power sectors, adding competition for key technical workers to the problem. This shortage can eventually be addressed by professional re-training and development of academic resources, but may be problematic in the short-term. While a nationwide problem, the shortage is likely to affect California sooner because of the state's already increasing demand for energy sector specialists.

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[18] For example, Massachusetts Institute of Technology, 2007, The Future of Coal, MIT Press; International Energy Agency, 2006, *Near-Term Opportunities for Carbon Dioxide Capture and Storage*.

[19] International Energy Agency, 2006, Near-Term Opportunities for Carbon Dioxide Capture and Storage.

CHAPTER 3: Potential for Capture and Geologic Sequestration

The first step in geologic sequestration entails modifying industrial plants, such as power plants, oil refineries, and cement plants, to separate CO_2 from process or exhaust gases. The CO_2 must then be delivered (generally via pipeline) to a storage site and injected deep underground into geologic formations that will prevent the injected CO_2 from re-entering the atmosphere for hundreds to thousands of years.

In California, suitable geologic formations include depleted or near-depleted oil and gas reservoirs and saline formations (rocks containing non-potable salty water). These targets are common in deep sedimentary basins, places where sand and mud have accumulated to great thickness over many millions of years and lithified into rock. These types of layered rocks are potentially good storage sites because they have the capacity to hold or trap large amounts of CO_2 in the pore spaces of sand layers, while overlying impermeable mud rock layers form good seals that prevent the gas from escaping upward. Storage takes place at depths below 800 meters (m), about 2500 feet, where ambient pressures and temperatures result in CO_2 as a liquid-like, supercritical phase. Under these conditions, the density of CO_2 will range from 50 to 80 percent of the density of water, resulting in buoyant forces that tend to drive CO_2 upward. Over time, numerous mechanisms trap the CO_2 in the reservoir, including physical (hydrodynamic and capillary trapping) and chemical (solubility and mineral trapping) processes, as shown in Figure 1.

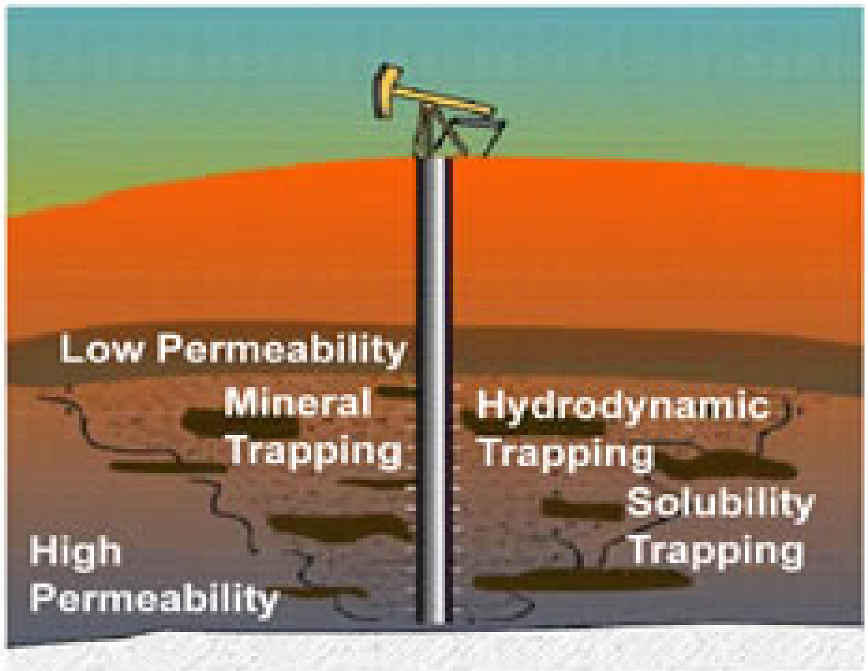
Potential for Sequestration

Although the idea of intentionally storing large quantities of CO_2 in underground rock formations for extended periods is new, natural CO_2 reservoirs have existed for many millions of years, and gas injection and storage have been successfully practiced for many decades. For more than 30 years, the oil industry has reinjected produced gas for various purposes, including reservoir pressure maintenance, avoidance of sour gas processing in locations without markets for sulfur byproducts, disposal of gas processing byproducts, and to eliminate flaring. The oil industry also commonly uses CO_2 and other gases for enhanced oil recovery (EOR), wherein injected gases mobilize residual oil and gas. While CO_2 injection to enhance methane recovery from coal beds has been field tested and studied extensively, there is also potential for enhanced gas recovery (EGR) from depleted gas reservoirs. In both EOR and EGR, the CO_2 is left behind in the reservoir at the close of operations.

The Weyburn project in Canada is an example of a CO_2-EOR project intended to conclude with storing of large quantities of CO_2. Industrial CO_2 arrives at the Weyburn Oilfield in Saskatchewan from the Dakota Gasification Company's plant in Beulah, North Dakota, via a

200-mile (325 kilometer) pipeline. Over the life of the project, an additional 130 million barrels of oil may be produced, and net CO_2 storage is estimated at 20 million metric tons MMT.[20]

Figure 1: Trapping Mechanisms in Geologic Sequestration



Source: WESTCARB http://www.westcarb.org/
Geologic sequestration relies on trapping CO_2 in high permeability strata beneath a low permeability seal. Types of trapping are shown.

California has about 25,000 injection wells for oil and gas operations that, in 2005, injected some 3 billion barrels of fluids and approximately 250 million cubic feet of gas for enhanced oil recovery and disposal of wastes from oil and gas production.[21] Many of these wells are associated with EOR projects involving use of steam injection to mobilize high viscosity oils. Studies and demonstration projects have shown that CO_2 injection also can be an effective means of enhancing recovery of these types of oils. However, without CCS, CO_2 -EOR operations are unlikely to catch on in the state given the high cost of transport of CO_2 from natural reservoir sources outside the state.

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[20] "IEA GHG Weyburn CO2 Monitoring and Storage Project," http://www.ieagreen.org.uk/glossies/weyburn.pdf

[21] http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm

As part of WESTCARB's Phase I studies, the California Geological Survey (CGS) provided a timely preliminary screening to identify those basins having the greatest geologic potential for long-term CO_2 storage.[22] Given the diversity and complexity of California's geology, a systematic effort to individually map the many potential sequestration zones or associated seals was beyond the Phase I scope. In Phase II of the WESTCARB project, and scheduled for completion in June 2008, CGS is mapping selected geologic formations in greater detail. Prior to selecting specific sites for future sequestration, more detailed site-specific characterization of the subsurface geology will be needed in many areas with sequestration potential.

CGS initially identified and cataloged 104 sedimentary basins that underlie approximately 33 percent of the area of the state. These basins include all large oil- and gas-producing basins, as well as numerous smaller basins (Figure 2). Where basins extended offshore, only the onshore portions were considered.

These basins were then screened, using available data, to make preliminary determinations of their geologic suitability for CO_2 sequestration. Screening criteria included the presence of significant porous and permeable units in which to store CO_2, thick and pervasive seals to restrict migration of CO_2, and sufficient basin depth to provide the confining pressure required to inject and store CO_2 in its high-density, low-volume supercritical phase. Accessibility was also considered, and basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs administered lands, and military installations were excluded. Most of the basins excluded for this reason are located in eastern and southeastern California. These basins were then screened, using available data, to make preliminary determinations of their geologic suitability. Potential storage sites include both oil and gas reservoirs and deep units filled with salty non-potable groundwater (saline formations).[23]

Of the 27 basins which met the screening criteria, the most promising are the larger basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda basins. Favorable attributes of these basins include (1) geographic distribution; (2) thick sedimentary fill with multiple porous and permeable zones; (3) thick, laterally persistent sealing units; (4) availability of good datasets to characterize the subsurface; and (5) numerous abandoned or mature oil and gas fields that might be reactivated for CO_2 sequestration or benefit from CO_2 enhanced oil and gas recovery operations. Preliminary estimates of saline formation CO_2 storage capacity for these 10 basins is between 75 and 300 metric gigatons tons of carbon dioxide (GT CO_2); for oil and gas fields, preliminary estimates are on the order of 3.5 and 1.7 GT CO_2, respectively (see Table 1).

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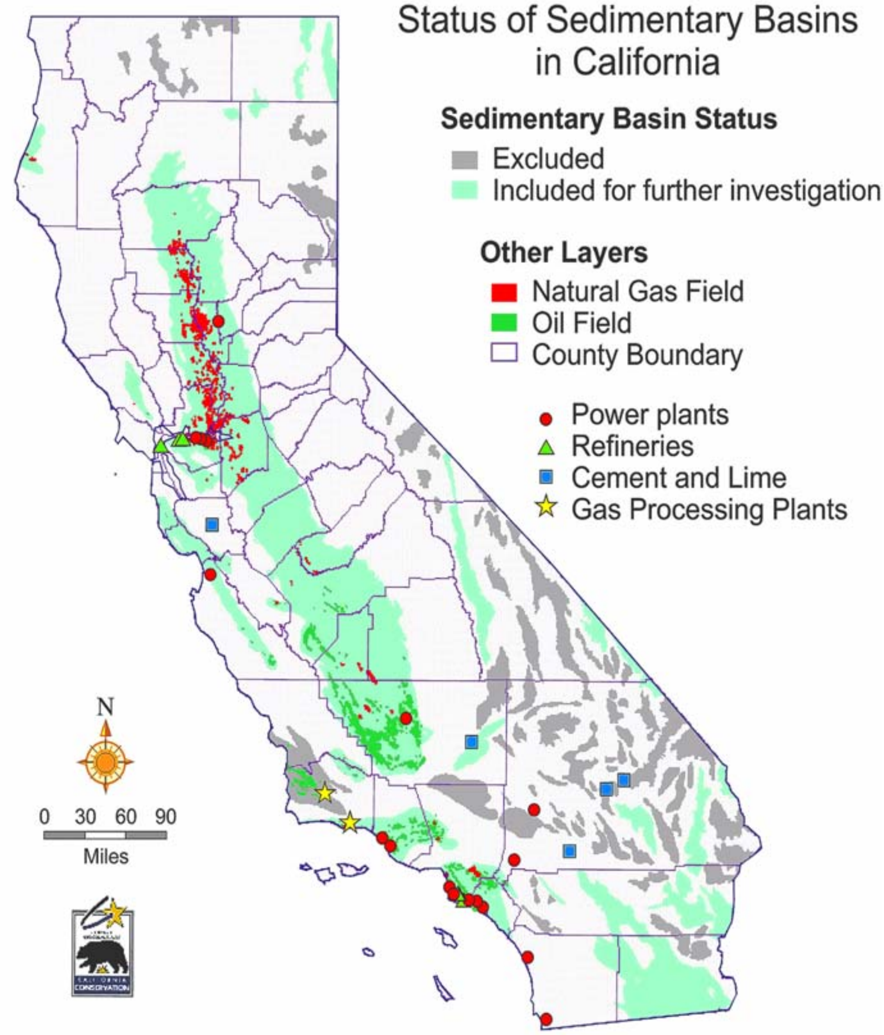
[22] Downey, C. and J. Clinkenbeard, 2005, An Overview of Geologic Carbon Sequestration Potential in California" California Geological Survey for the California Energy Commission PIER Energy-Related Environmental Research, 500-03-018.

[23] Clinkenbeard, PIER White Paper on Areas in California Potentially Suitable for Geologic Storage of CO_2.

Figure 2: Sedimentary Basins and CO_2 Point Sources



Source: West Coast Regional Carbon Sequestration Partnership CO_2 Sequestration GIS Analysis WESTCARB Report contract # DE-FC26-03NT41984, September 2005. Prepared by Howard Herzog, Massachusetts Institute of Technology; An Overview of Geologic Carbon Sequestration Potential in California" PIER Report 500-03-018, June 2005. Prepared by C. Downey and J. Clinkenbeard, California Geological Survey

Sedimentary basins in California, showing those that passed screening (green) and those that failed screening criteria (gray), with overlay of large CO_2 point sources.

Table 1: Estimates of CO_2 Storage Capacity in California

Type of Storage Reservoir	Number of Fields	Estimated Total Storage Capacity (MMT CO_2)
A: Oil Fields		
Oil fields with CO_2 storage potential	176	3,563
Oil fields with miscible CO_2-EOR potential	121	3,186
Oil fields with immiscible CO_2-EOR potential	18	178
Oil fields with CO_2 storage capacity but no EOR potential (fields lacking API data also included)	37	199
Oil fields without CO_2 storage potential	55	0
Oil fields without depth information	61	0
B: Gas Fields		
Gas fields with CO_2 storage potential	128	1666
Gas fields without CO_2 storage potential	36	0
Gas fields without enough information	33	0
C. Saline Formations	10 largest basins	75,000 -300,000

Sources: West Coast Regional Carbon Sequestration Partnership CO_2 Sequestration GIS Analysis WESTCARB Report contract # DE-FC26-03NT41984, September 2005. Prepared by Howard Herzog, Massachusetts Institute of Technology; An Overview of Geologic Carbon Sequestration Potential in California" PIER Report 500-03-018, June 2005. Prepared by C. Downey and J. Clinkenbeard, California Geological Survey.

This large range of estimates for saline formations results from differences in methods for calculating capacity[24] and from uncertainties in geologic characterization due to incomplete data coverage. More detailed mapping of these geologic units would help to constrain these estimates. Detailed, formation-specific mapping to define the thickness, extent, and continuity of potential reservoir and sealing units will be required. Additional geological characterization of these basins, including detailed, formation-specific mapping to define the thickness, extent,

[24] Carbon Sequestration Atlas of the United States and Canada. U.S. Department of Energy, National Energy Technology Laboratory, 2007.

and continuity of potential reservoir and sealing units will be required before their specific potential for CO_2 sequestration can be more accurately assessed.

Final selection of a sequestration site in any of these basins would require more detailed, site-specific data and detailed analysis of the geologic characteristics of the site and of the subsurface. Because of their large storage potential and broad distribution, most geological sequestration will likely occur in saline formations. However, initial projects generally have been proposed for depleted oil and gas fields, accompanying enhanced oil recovery, due to the high density and quality of subsurface data and the potential for economic return. Whether targets are depleted hydrocarbon reservoirs or saline formations, geologic characterization must be followed by detailed study of appropriate monitoring system designs, potential health and environmental risks, transport issues, and economics in order to assess a potential site.

From a technical standpoint, the amount of CO_2 that can be sequestered annually by geologic storage is limited by the number of point sources that can be economically captured. For example, power plant emissions, based on the GHG inventory, totaling about 107 MMT CO_2/year, could all theoretically be geologically sequestered. However, the true rate at which CCS can be deployed depends on many factors, including a more detailed understanding of the storage resource and the pace of transport infrastructure development, chiefly pipeline networks. To this end, the U.S. Congress is currently considering bills that would authorize the U.S. Geological Survey and the U.S. Department of Energy to begin a detailed national sequestration resource assessment.

Large CO_2 Sources for Capture

Because the cost and viability of CO_2 capture and storage depends partly on the locations of plants (sources) relative to sequestration sites (sinks), WESTCARB has undertaken preliminary studies of source-sink matching in the state.[25]

In California, in 2004, various types of industrial facilities and the transportation sector were the major sources generating anthropogenic CO_2. Total California CO_2 net emissions in 2004 are estimated at about 356 million metric tons per year (MMT CO_2/yr) in-state and an additional 61 MMT CO_2 generated out-of-state to make imported electricity.[26] Only that part of emissions associated with large single point sources, such as smoke stacks on factories or power plants, can be mitigated by geological CCS. For example, transportation fuel emissions, the largest

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[25] Herzog, H.J., 2005, West Coast Regional Carbon Sequestration Partnership CO2 Sequestration GIS Analysis Topical Report West Coast Regional Carbon Sequestration Partnership (WESTCARB),DOE Contract No.: DE-FC26-03NT41984

[26] *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004*. PIER report CEC-600-2006-013-SF, December 2006.

sector source at about 190 MMT CO_2/yr consists of millions of small mobile sources, making capture impractical. CO_2 reduction in the transportation sector favors improved conservation and efficiency, use of lower net carbon fuels, and terrestrial sequestration.

The map of California in Figure 2 also shows locations of the largest CO_2 point sources by type overlain on geological basins. The figure suggests a reasonable correspondence of CO_2 point sources to geologic sinks for the Los Angeles Basin, the Bakersfield area and the San Francisco – Sacramento area.

Figure 3 graphically illustrates the largest specific power plant and industrial CO_2 point sources in California by type source and annual CO_2 emissions. There are about 30 facilities emitting over 1 MMT CO_2/yr. Most are natural gas-fired power plants, along with several oil refineries and cement kilns. The few coal- and petroleum coke-fired power plants in California are relatively small as they are mostly non-utility generators built as cogeneration qualified facilities under previous regulations that limited their size to less than 80 megawatts (MWe).

However, much larger CO_2 point source coal-fired utility power plants in Arizona, Nevada, and Utah import their electricity to California. Several of these big out-of-state coal power plants supplying electricity to California are very large point sources, in the range of 4 to 10 MMT CO_2/yr.

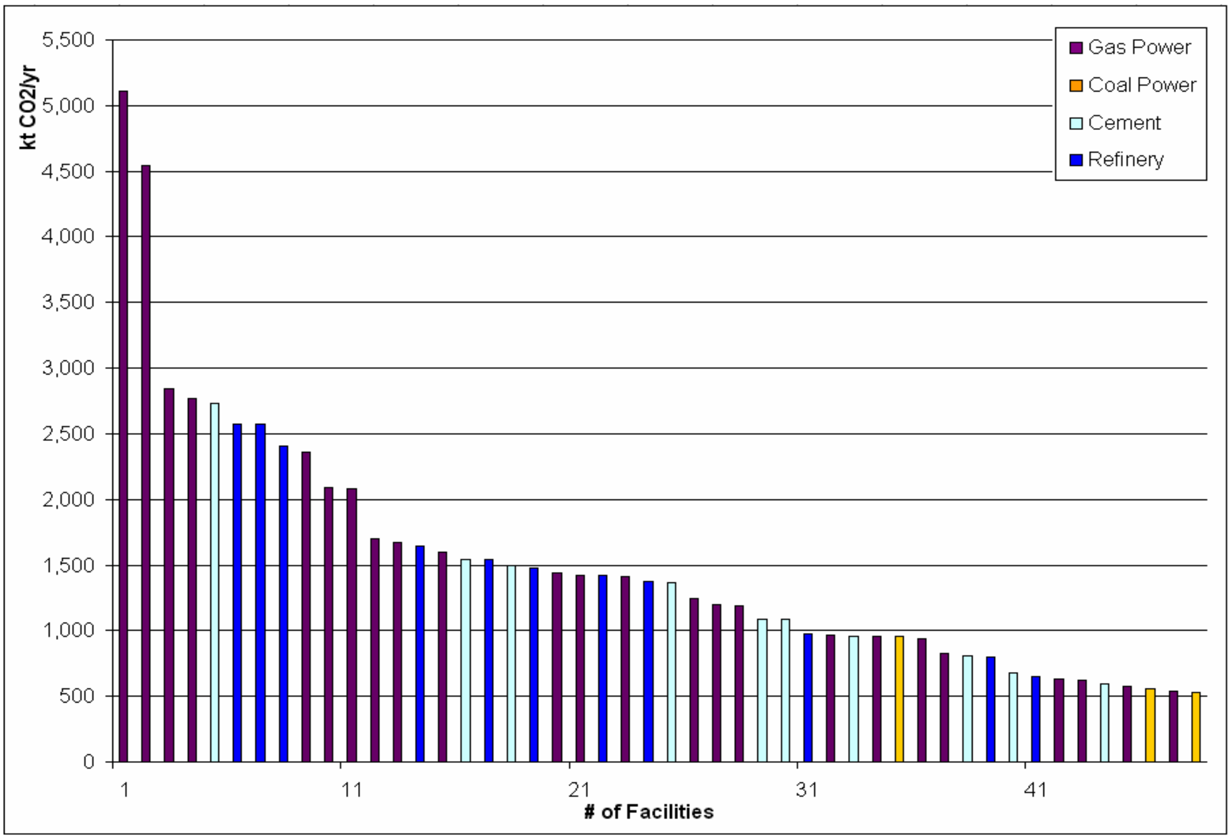
In aggregate, in 2004, according to the state's GHG inventory, fossil fuel power plants represented the largest industrial source of CO_2 within California, emitting about 47 MMT CO_2/year, mostly from natural gas combined cycle plants.[27] From the standpoint of other sectors with large point sources, refineries are important, creating about 18 MMT CO_2/yr, as are cement producers, emitting about 12 MMT CO_2 /yr.[28] The numbers for refineries and cement producers are from a WESTCARB Phase I study[29] and are difficult to compare to those in the GHG inventory for California. The state's inventory accounting methods divide point source emissions according to the origin of the CO_2 generation. For example, cement plant emissions are separated into parts due to cement production and due to fossil fuel use, whereas the WESTCARB study focused on assessment of total emissions for specific point sources. From the standpoint of facilitating CCS, developing a robust database that allows source-sink matching is needed—that is, identifying the sizes of single-point sources of emissions for capture and their relationship geographically to the sinks, the underground reservoirs into which the captured CO_2 will be injected.

Figure 3: Largest Specific California CO_2 Sources by Type and Size

[27] Ibid.

[28] Herzog, 2005, Op. cit.

[29] Herzog, 2005, Op. cit.



Source: Howard Herzog, MIT Laboratory for Energy and the Environment

In ranking point sources, in addition to location information, the concentration of CO_2 in stack emissions is important. The higher concentrations of CO_2 in the flue gases of coal-fired power plant emissions make them less expensive to capture than those of natural gas-fired plants. Refineries fall between natural gas combined cycle and coal-based plants, but generally constitute a number of separate flue gas streams. Cement plants also have very high flue gas concentrations. Ethanol plants also have a high CO_2 concentration exhaust. Given that the number of ethanol plants in the state could rise markedly depending on bio-fuels policy and investment decisions, these plants offer the potential for inclusion of CO_2 capture and storage to create "net negative" CO_2 emissions.

Table 2: Industrial and Electric Utility Point CO_2 Sources within California in 2004

Source Type	Facilities	CO_2 Emissions (MMT/yr)
NG Power Plants	221	58
Oil Power Plants	3	0
Coal Power Plants	8	3
Cement Kilns	11	12
Ethanol Plants	4	less than 1
NG Processing	31	?
Oil Refineries	15	18
Total	293	About 90

Source: Howard Herzog, MIT Laboratory for Energy and the Environment

Transport of CO_2

Where large point sources do not overlie suitable CO_2 storage sites, CO_2 may have to be transported to storage sites via pipelines or shipped on trucks, trains, ships, or barges. The technical, economic, and permitting issues of CO_2 compression and pipeline transport are well known because of the large-scale use of CO_2 for over 20 years for EOR. CO_2 is also transported via pipeline for a number of industrial uses.

In today's commercial markets, CO_2 is routinely transported in tanker trucks as liquid CO_2 at 20 bar and -20°C. However, for the large quantities of CO_2 that will have to be transported for sequestration, tanker transport is uneconomic. Pipelines are likely to be the primary mode of CO_2 transport for sequestration operations. Over 2,500 km of CO_2 pipeline exist in the U.S. today with a capacity in excess of 40 MMT CO_2/yr (see Table 3). These pipelines were developed to support EOR operations, primarily in west Texas and Wyoming.[30]

In these pipelines, CO_2 is transported as a dense, single phase at ambient temperatures and supercritical pressures. The CO_2 is typically compressed to 150 bar or more at its source. To maintain supercritical pressures, booster compressors may be needed along the length of the pipeline. However, not all pipelines require recompression. For example, the Weyburn pipeline, which transports CO_2 about 330 km from an industrial facility in North Dakota to an EOR site in

[30] Katzer, J. and Herzog, H., PIER White Paper on Economics of CO_2 Capture and Sequestration

Saskatchewan, Canada, operates without a recompression system.[31] To avoid corrosion and hydrate formation, water levels are typically kept below 50 parts per million. To assure single phase flow, non-condensable gases (nitrogen and oxygen, for example) are removed, and pressures are kept in excess of the critical pressure for CO_2 (73.9 bar).[32]

The regulatory authority in California for CO_2 pipelines is the Office of the State Fire Marshal.

Table 3: Major CO_2 Pipelines in the United States

Pipeline	Operator	Capacity (MMT CO_2/yr)	Length (km)	Year finished	Origin of CO_2
Cortez	Kinder Morgan	19.3	808	1984	McElmo Dome
Sheep Mountain	BP Amoco	9.5	660		Sheep Mountain
Bravo	BP Amoco	7.3	350	1984	Bravo Dome
Canyon Reef Carriers	Kinder Morgan	5.2	225	1972	Gasification plants
Val Verde	Petrosource	2.5	130	1998	Val Verde Gas Plants
Weyburn	North Dakota Gasification Co.	5	328	2000	Gasification Plant

Source: IPCC Special Report on Carbon Dioxide Capture and Storage, 2005, Cambridge University: Cambridge http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_Chapter4.pdf

31 IPCC Special Report on Carbon Dioxide Capture and Storage, 2005, Cambridge University: Cambridge http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_Chapter4.pdf

32 Katzer, J. and Herzog, H., Op cit.

CHAPTER 4: Capture Technologies

CO_2 capture and compression costs account for about 70 to 80 percent of the entire cost of geological CCS. These costs are mainly due to increased capital and internal energy needs associated with concentrating the CO_2 to a pure stream and compressing it to high pressure, as well as for transportation if required. The challenge for CO_2 capture is to reduce costs and energy use relative to other CO_2 reduction options such as conservation, efficiency, renewables, and nuclear power.

Although CO_2 capture is usually associated with man-made CO_2 from fossil fuels, the CO_2 can also be from utilization of any carbonaceous fuel. This is significant as CO_2 capture and storage from biomass represents double reductions. CO_2 capture and storage from biomass is usually most effective via co-processing waste biomass whenever available at large fossil fuel facilities with CO_2 capture to achieve essential economy of scale and high annual investment utilization.

Current Capture Methods

Large CO_2 sources usually do not generate emissions of pure CO_2 at pressure. The volumes, costs, and energy use would be too high to geologically inject the full flue gas stream. Therefore, CO_2 capture generally requires separation of CO_2 from other gases. Three approaches are currently available to capture CO_2 from large power plants and other industrial CO_2 sources: post-combustion, pre-combustion, and oxyfuel combustion. The descriptions of these technologies rely heavily on information provided by Simbeck.[33]

Post-combustion consists of CO_2 capture from a flue gas after conventional combustion. Essentially all traditional combustion uses air as the oxidant, and the flue gas is generated at ambient pressure. Therefore, CO_2 capture from this resulting flue gas is a relatively harder separation due to the very low pressure and the low CO_2 concentration in a mostly nitrogen (N_2) flue gas. The presence of remaining excess oxygen (O_2) in the flue gas required for complete combustion is an additional issue.[34] This CO_2 separation requires chemical solvent absorber/stripper systems, usually amine reactions, and special chemical inhibitors due to the presence of O_2. To reverse the amine reaction, the stripping reboiler steam requirements are quite high—about 1.5 tons of steam per ton of CO_2 captured. In addition, the flue gas must be low in nitrogen dioxide (NO_2) and especially sulfur dioxide (SO_2) before entering the absorber to avoid fixation reactions with the recycle amine solution. Depending on the flue gas

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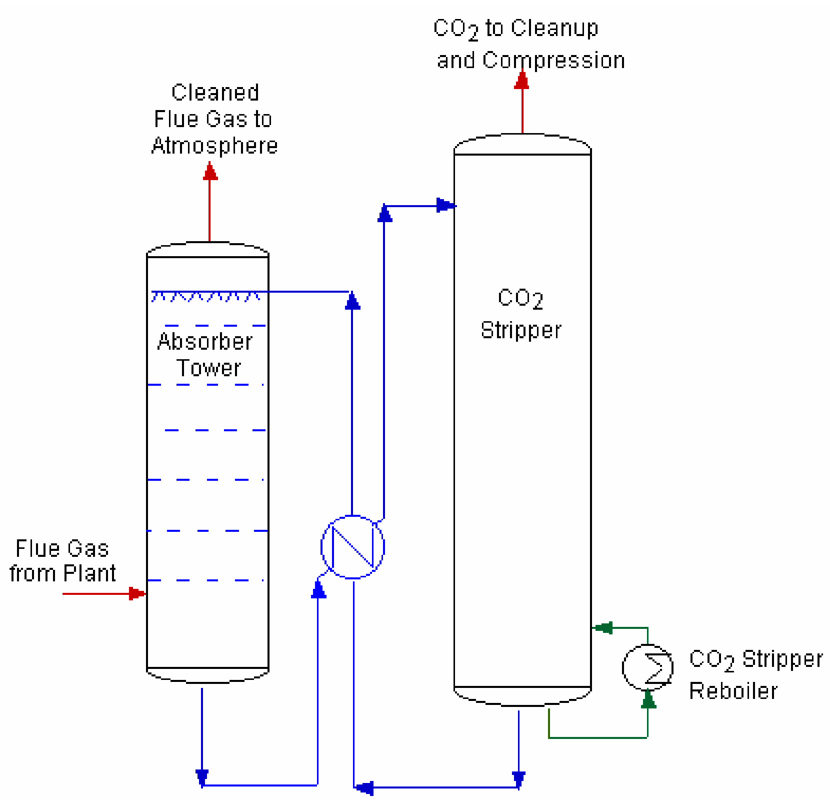
[33] Simbeck, D., PIER White Paper on Capture.

[34] Ibid.

composition following conventional emission controls, supplemental NOx[35] reduction and SO_2 removal systems may be required.[36]

Figure 4 is a simple diagram of a post-combustion CO_2 capture system. It consists of a CO_2 absorber processing the entire flue gas and then regenerating the recycled scrubbing liquid in a stripper producing the high purity CO_2 stream. The captured CO_2 leaving the stripper then requires drying and compression to very high pressure before pipeline transportation to the geologic injection location. Chemical amine solvent absorber/stripper systems are commonly used for removing CO_2 from raw natural gas at high pressure and without the presence of O_2. However, only about 10 small operating post-combustion CO_2 capture facilities exist worldwide for flue gas application. The largest operating system is only 330 tons per day CO_2 capture from the flue gas.

Figure 4: Post-Combustion CO_2 Capture Absorber and Stripper



Source: Electric Power Research Institute (EPRI)

Post combustion and oxyfuel combustion CO_2 capture technologies are less commercially developed. Post-combustion consists of CO_2 capture from a flue gas after conventional

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[35] NOx refers collectively to all gases composed of nitrogen and oxygen, that is, NO, NO_2, etc.

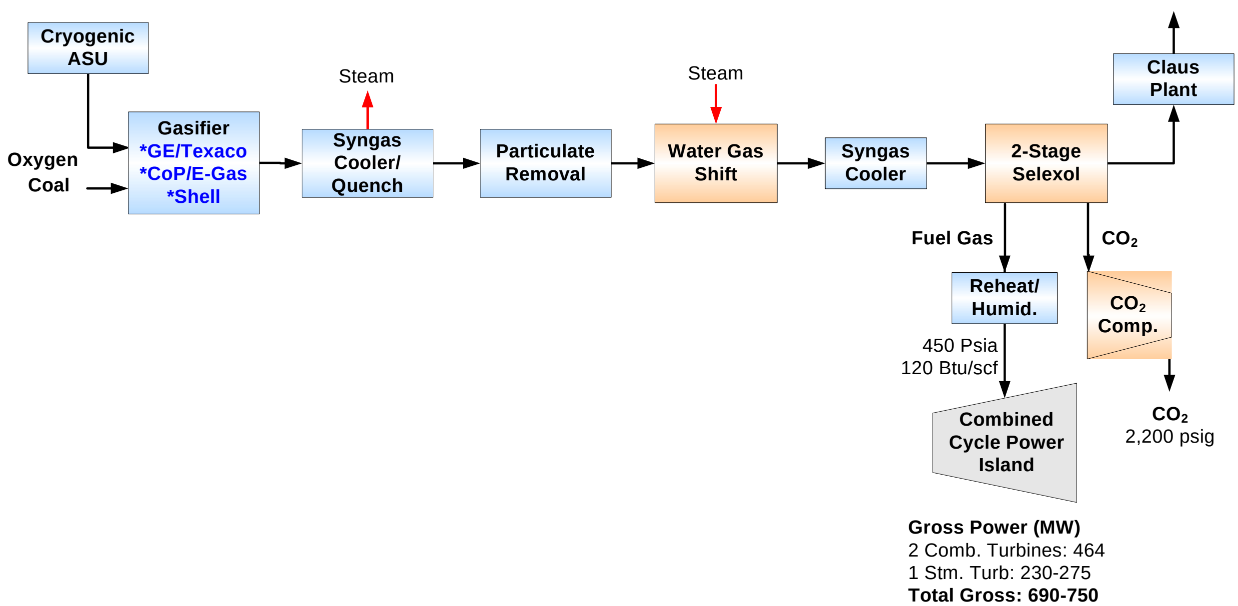
[36] Simbeck, Op. cit.

combustion. However large-scale demonstrations of both are likely to begin in just a few years. Both CO_2 capture technologies likely have advantages for retrofit of existing facilities. They also avoid the complex chemical processes of pre-combustion. Minimal integration with existing facilities may favor post combustion fuel gas CO_2 capture. Oxyfuel combustion CO_2 may have advantages for existing cement kiln retrofits. However, in both retrofit applications, the CO_2 capture costs associated with the increased heat and power use must be considered.

The key advantage of post-combustion CO_2 capture is its ability to be added onto any existing flue gas stream. This can favor its use for retrofit of existing facility flue gas without major process changes and rebuilds. In addition, the electric utility industry generally views this as similar to flue gas desulphurization systems, with which coal-fired utilities have significant experience.

The challenge of post-combustion CO_2 capture is the larger requirement for heat and power associated with the amine stripping and compression of the wet, near atmospheric pressure CO_2 leaving the stripper. This can significantly reduce the overall (net) capacity and efficiency. In addition, the CO_2 absorbers are also very large due to the low pressure and low concentration of CO_2 of the flue gas. The actual volume of gas processed in the post-combustion absorber is about 60 to 100 times larger than the actual volume of gas processed in pre-combustion absorber for the same amount of CO_2 capture.

Figure 5: Pre-Combustion CO_2 Capture in Coal-Based Power Generation



Credit: U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL)

Pre-combustion CO_2 capture, involving capture of the CO_2 before combustion, is the most complex of the three CO_2 capture options and involves three main process steps. First, the original carbonaceous fuel is converted into "syngas," which is a mixture of mostly carbon monoxide (CO) and hydrogen (H_2). This is usually done via gasification with oxygen (O_2) and some water (H_2O) at high pressure. Next, the CO in this syngas is converted with more H_2O (as steam) to mostly H_2 and CO_2. Finally, the CO_2 is separated from the H_2. Figure 5 is a simplified flow diagram illustrating the process steps in converting coal via gasification into hydrogen based electric power along with CO_2 capture before combustion.

The first conversion step is the most complex and costly; whereas, the third step is relatively easy due to the high pressure and high concentration of the CO_2 with mostly H_2. This CO_2 removal is usually done via physical solvent liquid absorber/stripper systems. The energy requirements of this stripping is quite low as much of the CO_2 flashes out of the physical solvent once the pressure is reduced for stripping. The resulting, relatively pure and dry CO_2 stream is then compressed to a high-pressure supercritical gas (liquid-like conditions) for effective transportation via pipeline to a geologic injection location for storage. The partial flashing of the CO_2 from physical solvent at moderate (3 to 6 atmospheres) pressure also reduces the CO_2 compression power requirements and costs.

Pre-combustion CO_2 capture is already used to supply about 10 MMT CO_2/yr for EOR. However, this has not yet been done in electric power applications, which are the principal large point sources of CO_2 in California and of power imported into California. The proposed pre-combustion CO_2 capture project in Carson, California, is an important demonstration of CO_2 capture in power generation. Pre-combustion also has the potential advantage of making CO_2-free hydrogen for other applications besides electric power generation, such as transportation fuels. This could be quite important in California where CO_2 emissions from transportation fuel use are over three times greater than CO_2 emissions from in-state electric power generation.

Pre-combustion is the most commercially developed of the three CO_2 capture options. There are over 30 commercial gasification facilities that manufacture pure H_2 for ammonia fertilizer from coal and oil plus over 10 oil refinery facilities manufacturing hydrogen from residue pitch or petroleum coke. There are operating units with greater than 3,500 tons per day CO_2 separation from H_2. This is more than 10 times larger than the biggest operating post-combustion CO_2 capture system.

There is already a large (2 MMT CO_2/yr) pre-combustion CO_2 capture process and a 200-mile CO_2 pipeline at the Dakota Gasification coal to synthetic natural gas plant in North Dakota. This CO_2 is effectively used and geologically stored through EOR operations near Weyburn, Saskatchewan, Canada. In fact 30 percent of the 35 MMT CO_2/yr used to produce 250,000 barrels per day of oil via EOR in North America is from pre-combustion CO_2 capture. This 10 MMT CO_2/year for EOR from man-made pre-combustion CO_2 sources include gasification, natural gas purification and ammonia plants. The other 70 percent of the CO_2 used for EOR is from lower cost natural CO_2 geologic domes.

With regard to use of H_2 in power generation, General Electric (GE) has over 450,000 hours of commercial operating experience firing H_2-rich fuel gas in its gas turbines. Most of that experience is in turbines with relatively low firing temperature for industrial cogeneration applications where high firing temperatures are not critical to efficiency. However, central power plants would require state-of-the-art high temperature gas turbines to obtain good efficiency and reasonable economics. Several commercial operations have state-of-the-art "F" class gas turbines firing as high as 44 percent by volume of hydrogen fuel gas. Nitrogen from the air separation unit (oxygen plant) is added to reduce NOx formations and increase the gas turbine capacity.

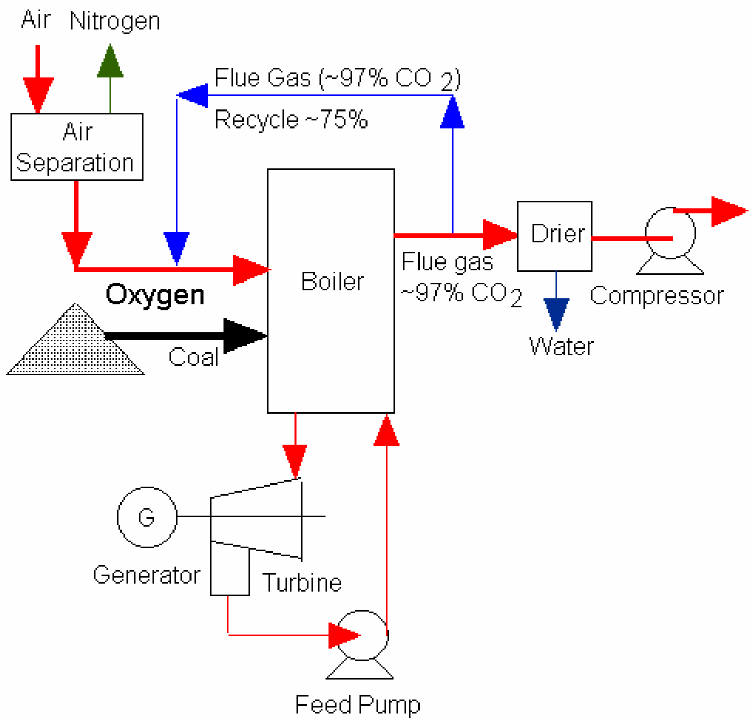
The key advantage of pre-combustion CO_2 capture is the use of H_2 as an intermediate energy carrier. H_2 has many potential strategic long-term utilization advantages over just steam or direct heat with post or oxyfuel combustion CO_2 capture. Effective uses of H_2 include high power-to-heat ratio gas turbine-based cogeneration; clean conventional transportation fuel via hydrocracking heavy oil fractions; or syngas-to-liquids (like Fischer-Tropsch) and the "hydrogen economy" for H_2-based fuel cells. This is significant in California where transportation fuel CO_2 emissions are much greater than CO_2 emissions from power plants or other industrial applications.

The challenge of pre-combustion CO_2 capture is its complex chemical processing associated with the first gasification step of converting fuels into CO and H_2 syngas at pressure. This type of expertise and experience is generally limited to the chemical and oil industries. In addition, pre-combustion CO_2 capture is usually most effective for new construction or major rebuilds of existing energy facilities.

Oxyfuel combustion involves replacing conventional air combustion with oxygen (O_2). Figure 6 is a simplified diagram of an oxygen-fired coal boiler for CO_2 capture. Combustion with oxygen in place of air results in a flue gas of mostly CO_2 along with water (H_2O), a few percent O_2 and N_2 plus trace amounts of NOx and SO_2 depending on the fuel. The ultra-high temperature and heat flux (heat release per unit of volume) of oxygen combustion requires dilution of this combustion, usually with large amounts of recycle flue gas or the addition of liquid water. The flue gas recycle dilution option has issues with water vapor and SO_2 build-ups to more than traditional levels.

Oxyfuel combustion for CO_2 capture is the least developed of the three options. It has only been tested at relatively small pilot plant scale. However, oxygen combustion has been commercially done for retrofit of an existing nickel ore kiln in Sudbury, Canada, for concentration of SO_2 for ultimate recovery via conversion to sulfuric acid (H_2SO_4). Oxygen combustion is also used for basic oxygen furnaces in steel making as well as for a few aluminum and glass melting furnaces.

Figure 6: Oxygen Combustion Coal Boiler



Source: Electric Power Research Institute (EPRI)

The key advantage of oxyfuel combustion for CO_2 capture is its potential ability to retrofit existing combusting systems. This could be especially attractive for existing combustion systems where the air-to-oxygen combustion conversion enables increased capacity. This might be the case for existing cement kilns or fluid catalytic crackers in oil refineries. Another advantage is the avoidance of complex chemical processes associated especially with pre-combustion but also with post-combustion absorber/stripper systems, thus eliminating the need for CO_2 and NOx controls. This assumes "raw" CO_2 from oxyfuel combustion can be compressed and geologically stored.

The large capital costs and power requirements of oxygen production present a challenge for oxyfuel combustion. Relative to pre-combustion, oxyfuel requires two to three times more oxygen for the same amount of CO_2 capture. The high power use of this large oxygen requirement can significantly reduce overall (net) capacity and efficiency. There are also technical and environmental issues associated with compressing and transporting raw CO_2 from oxygen combustion. This may require processing of the raw CO_2-rich flue gas into a purer CO_2 stream as in pre- and post-combustion CO_2 capture.

New Technologies under Development

A number of new and improved technologies are being developed for CO_2 capture, with the aim of reducing costs and energy use and thus improving overall economics and efficiency.

"Learning-by-doing" has been a quite successful approach to reducing NOx and SO_2 control costs in power generation. CO_2 capture costs and efficiency will likely improve with time due to larger scale operations and lessons-learned with current CO_2 capture technologies, as well as through new technologies and developments. In addition, each type of CO_2 capture has both short-term and longer-term development issues.

Post-combustion CO_2 capture has short-term needs for large scale operating experience in integrated power generation. Based on the success of learning-by-doing in power plant NOx and SO_2 controls, this should help reduce capital costs. Effective use of improved "hindered" amines and better low-level heat integration should also help reduce net energy and capacity losses. These improvements should happen in the next few years via large-scale post-combustion CO_2 capture for a natural gas combined cycle plant being proposed in Norway. This is especially important due to the high portion of total electric power generated via natural gas combined cycle in California.

One longer-term technology development that could significantly improve post-combustion CO_2 capture is the chilled ammonia process being developed by Alstom along with support by a group of power generators led by the Electric Power Research Institute (EPRI) in California. The use of chilled ammonia in place of amines as the chemical reactant in the absorber/stripper system could significantly reduce both the stripping steam as well as the CO_2 compressor power requirements. If successfully developed, it would improve pre-combustion CO_2 capture costs and efficiency associated with the CO_2 compression saving. However, post-combustion capture would derive even greater benefits.[37]

The chilled ammonia CO_2 capture process is in the early stage of development, but is projected to progress quickly if successful at each stage. SRI International in Menlo Park, California, is currently developing small bench-scale process. We Energies' Pleasant Prairie power plant near Kenosha, Wisconsin, is planning a 1.7 MWe pilot plant. If that is successful, American Electric Power (AEP) plans a large 30 MW_e pilot plant starting in 2008, followed by a 200 MW_e demonstration starting in 2011. These U.S. developments are all for coal-fired power plants. Statoil and E.ON are planning pilot and demonstration units of similar size and time frame in Europe for natural gas use.

There is commercial large-scale experience with all the process steps involved in pre-combustion CO_2 capture. However, all steps are not used in a single integrated power plant application. Thus, the short-term need for pre-combustion is to build a large power plant with integrated pre-combustion CO_2 capture and storage. This is the focus of the proposed BP-Rio Tinto-Edison Mission Energy project at Carson, California, a coke gasification project. It is also the goal of the proposed FutureGen coal gasification project. Carson is more focused on learning-by-doing; whereas, FutureGen plans to also incorporate many advanced technology developments. The proposed Carson project has the advantage of combining the strong

[37] Simbeck, Op. cit.

chemical process and essential geologic expertise of BP with the strong solids handling and processing expertise of Rio Tinto and the strong power generation expertise of Edison.

There are a number of technology developments that could improve pre-combustion costs and performance. These include current developments in advanced membranes, oxygen generation and gas turbines. However, the longer-term technology that could significantly improve pre-combustion CO_2 capture is the likely development of solid oxide fuel cells. This could avoid a number of process steps and energy losses. High-pressure solid oxide fuel cells could directly convert CO-rich syngas directly into electricity and CO_2 (at high pressure) in just one high efficiency step.

Oxyfuel combustion CO_2 capture has the short-term needs for scale up from relatively small pilot tests to larger commercial demonstrations. There are also several rather radically different developments in oxyfuel combustion processes.

The short-term focus of the traditional coal utility and coal boiler vendors is on testing larger oxyfuel coal boilers. Several groups are doing this work. The largest and fastest moving effort is in Canada by Saskatchewan (Sask) Power with Babcock & Wilcox (B&W) and Air Liquide. Others include Vattenfall in Eastern Europe and Jupiter Oxygen in the United States, which are developing much smaller scale demonstrations before moving to such large sizes.

The short-term focus by those more interested in natural gas-based power is the development of the Clean Energy Systems oxygen-fired turbine in California. This process is based on natural gas (or gasification-based CO-rich syngas) firing with oxygen plus water injection in a modified high temperature and reheat steam turbine that operates somewhat like a gas turbine. A small 5 MW_e pilot unit has been successfully tested near Bakersfield, California. Fifty MW_e demonstration units with natural gas are proposed for development in both California and Norway and could start as early as 2009.

The longer-term term technology that could significantly improve oxyfuel combustion is the development of improved oxygen production via chemical looping or ionic transport membranes. Advanced oxygen production could greatly reduce the capital costs and power requirements for the big oxygen demands of oxyfuel combustion. Successful developments could also be modified for improvements in pre-combustion, but the greater benefits would be for oxyfuel combustion.

Costs

A subsequent chapter on economics discusses costs in detail. However, a brief overview of the key cost issues specific to CO_2 capture and compression is provided here.

Capture and compression are the most expensive part of CCS, typically 70 to 80 percent of the total costs. In addition, CO_2 capture costs are about twice those of CO_2 compression. These costs are due to return on added investment, increased operating costs, and lost efficiency and/or capacity associated with added heat and power for CO_2 capture and compression.

Product cost increase (or CO_2 avoidance costs) of CO_2 capture can vary significantly due to many issues. Nevertheless, in general terms, CO_2 capture economics favors large point sources near good geologic storage sites. The economics also favors low cost fuels due to the increased energy use for CO_2 capture. CO_2 capture economics also generally favors fuels high in carbon that generate high CO_2 in gas streams prior to CO_2 capture. Therefore, the costs of CO_2 capture generally favor large CO_2 point sources with higher CO_2 concentrations in emissions and thus favor coal-based electric power generation over natural gas combined cycle.

The cost of CO_2 capture will likely increase product costs. For power generation, the power plant "gate" or wholesale electricity cost can increase by about 50 percent. On a delivered power cost basis in California, this translates to an electricity cost increase of about 20 percent for residential consumers to 30 percent for industrial consumers. CO_2 avoidance costs of CO_2 capture are more complex to estimate and can vary much more as power costs increase. This is principally due to the big impact of the fuel used (cheap high-carbon coal versus expensive low-carbon natural gas) and whether new or retrofit facilities are involved.

To date, all significant CO_2 reduction options (including CO_2 capture) include some form of CO_2 reduction mandates, CO_2 reduction incentives/subsidies or CO_2 emission taxes. For example, current wind turbine power is given a direct subsidy of $18/MWh of electricity generated. From a CO_2 perspective, when wind turbine power is generated, it avoids natural gas-based power generation at CO_2 emissions of about 0.5 ton CO_2/MWh. Therefore, the wind power "equivalent" CO_2 avoidance subsidy is $36/ton CO_2 ($18/MWh subsidy divided by 0.5 tons CO_2 avoided). Using the same approach, the CO_2 avoidance cost for CO_2 capture could be calculated by the same basic relationship of increase in power cost (if no subsidy) divided by the reduction or avoidance in CO_2 emissions by CO_2 capture.[38]

Retrofits vs. New Construction

Retrofits to capture CO_2 from existing power plants and other large CO_2 point source facilities may have benefits or penalties relative to new plant construction. The engineering and design issues associated with retrofits can be complex.

CO_2 capture retrofit can be just a simple add-on to existing equipment. However, this will generally lead to large additional energy use and perhaps large capacity reduction. Existing facilities also can be rebuilt at the same time to regain some of the efficiency and capacity loss inherent to CO_2 capture. There are also important site-specific factors such as fuel costs, physical

[38] Simbeck, Op. cit.

space limitations, and permitting issues. Fuel costs become increasingly important for natural gas due to its current energy price at three to six times that of coal or petroleum coke.

Existing power generation will generally have a higher CO_2 avoidance cost than new construction due to the baseline power costs being lower when the existing capital is already a "sunk" investment and in many cases has already been mostly paid off. Therefore, existing plants will usually require a higher CO_2 tax than a new power plant to economically justify CO_2 capture. This is especially true for paid-off coal power plants due to the much lower fuel costs relative to natural gas-based power plants.

CHAPTER 5: Site Characterization

Use of CCS to meet emissions reductions goals will require many sites suitable for long-term injection and storage of large volumes of CO_2.[39] From this standpoint, a storage site should be able to accept a large volume of CO_2 at a high rate and store it permanently and safely. Site characterization and proper site selection and certification are paramount to the success of CCS projects, both for assuring sequestration goals and for environmental and human health and safety and should play a central role in the commercialization and deployment of CCS technology.[40]

The Goals of Site Characterization

Siting of geological storage projects requires substantial geological characterization. However, the detail, degree of quantification, and precision of characterization are limited by available data and cost. Perfect rendering of the subsurface is neither possible nor desirable. The degree of site characterization should reflect the goals of the project stakeholders and be appropriate to the subsurface and surface character of the site(s) under consideration. In general, site characterization information should be sufficient to:

- Identify sites with low overall risk and high chance of short- and long-term success
- Provide a technical basis for decision making for financing and insurance
- Provide data for permitting and planning, including surface and subsurface operations
- Design and deploy monitoring and verification tools
- Quantify and manage risk.[41]

These goals may be readily met with existing technology and conventional data sets.

Surface characterization is also important. The infrastructure itself, including pipelines and monitoring equipment, has environmental and societal impacts that must be considered, including evaluation of impacts on sensitive species and other wildlife, and cultural and environmental justice issues. Local land uses and structures, including pre-existing subsurface structures such as mines or basements, should be identified and their associated risks

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[39] Massachusetts Institute of Technology, 2007, The Future of Coal, MIT Press. http://www.mit.edu/coal

[40] Friedmann, S.J., White Paper on Site Characterization for Geological Carbon Sequestration: Key Technical Issues and Potential Due-Diligence Requirements.

[41] Cook PJ, 2006, Site Characterization, Proceedings, International Symposium on Site Characterization for CO2 Geological Storage, Lawrence Berkeley National Laboratory, Berkeley, CA, 3-5

considered. Topography and prevailing meteorologic conditions must be characterized to understand the potential impact of any significant CO_2 leak.

A CO_2 storage project must be compatible with previous, current, and future uses of the site. In particular, in oil or gas producing areas, the distribution and condition of wells affect the potential for reservoir leakage. Storage projects also could affect future utilization of water and mineral resources in the area. The IPCC report defines the following criteria as necessary to prevent endangering water resources:

- A CO_2-receiving zone of sufficient depth, lateral extent, thickness, porosity, and permeability
- A trapping mechanism that is free of major non-sealing faults
- A confining system of sufficient regional thickness and competency
- A secondary containment system which could include buffer aquifers and/or thick, impermeable confining rock layers[42]

While there is presently no accepted set of practices, many conventional technologies and approaches can assess the viability of a sequestration site. The oil and gas industry has developed a wide array of techniques for subsurface characterization and gas monitoring that can be applied to site characterization. Techniques also exist to acquire the site information needed to assess potential environmental and socio-economic impacts from infrastructure, operations, and any future leakage, as is demonstrated in the recent EIS for FutureGen.[43] Important characterizing parameters include the mineral composition of the reservoir rocks and any fluids present, sequences of overlying rocks, extent and thickness of the reservoir, position of the water table, direction of water flow, presence of impermeable layers, presence of faults and fractures, in-situ stress fields, and permeability/porosity distributions.

Key Considerations

Storage Mechanisms

For saline formations and depleted oil and gas fields, expected CO_2 storage mechanisms are reasonably well defined and understood.[44] As noted previously, both physical and chemical mechanisms can trap CO_2 in the storage reservoir.

Physical barriers, or seals, to CO_2 migration out of the crust to the surface, commonly are in the form of impermeable layers (for example, shales, evaporites) overlying the sequestration target.

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[42] Intergovernmental Panel on Climate Change, Special Report on Carbon Dioxide Capture and Storage, 2005. http://www.ipcc.ch

[43] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

[44] U.S. Department of Energy, 2007, Basic Research Needs for Geosciences: Facilitating 21st Century Energy Systems, Washington, 287 p., http://www.sc.doe.gov/bes/reports/list.html

Like a lid on a jar, these barriers create a trap that keeps fluids from migrating upward. This hydrodynamic storage mechanism is similar to the processes by which hydrocarbon reservoirs form, which allow for natural gas storage and which create natural CO_2 accumulations. Storage through physical trapping allows for very high fractions of CO_2 within pore volumes (80 percent or greater), and acts quickly. Physical trapping can be compromised or minimized by either a breach of the physical barrier or by CO_2 unpredictably migrating over the long term, for long distances, past the extent of the barrier.

As CO_2 gas fills pores in the rock, capillary forces can immobilize a substantial fraction of the CO_2 bubble, commonly estimated to be between 5 and 25 percent of the CO_2-bearing pore volume. This volume of trapped CO_2 is difficult to predict, but can be measured directly. Capillary trapping acts quickly, is sustained over long time scales, and is considered a permanent trap.

Once in the rock, CO_2 also will dissolve into other pore fluids, including hydrocarbons (oil and gas) and brines. Depending on the fluid composition and reservoir conditions, this may occur rapidly (seconds to minutes) or over a period of tens to hundreds of years. The volume of CO_2 dissolved into brines commonly ranges from 1 to 4 percent of the pore volume.[45] CO_2 is appreciably more soluble in oil. Depending on the ambient water chemistry, a certain fraction of the CO_2 converts to bicarbonate, HCO_3^-, and from that state, can be formed into carbonate minerals, effectively removing the CO_2 permanently. This process tends to be very slow, and it may take hundreds to thousands of years to store appreciable CO_2 volumes.[46] Dissolved CO_2 also may react with the rock to dissolve both carbonate and silicate minerals. Mineral dissolution buffers the brine against reductions in pH that CO_2 in water might otherwise cause.

Although substantial work remains to characterize and quantify these mechanisms, the level of understanding currently is sufficient to develop estimates of the percentage of CO_2 that can be stored over some period of time. Confidence in these estimates is bolstered by studies of hydrocarbon systems, natural gas storage operations, hazardous waste injection, and CO_2-enhanced oil recovery. Finally, the range of length and time scales over which trapping mechanisms act suggests that the system becomes progressively more effective at sequestering CO_2 (see Figure 11 in Chapter 8).

Site Hazards, Geological and Engineered

The earth's crust is complex and heterogeneous. Although, as noted above, sites can be identified with the potential to store CO_2 for long periods, there are features, events, and processes that could potentially lead to unintended CO_2 release. These features, events, and

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[45] Bergman, PD, and Winter, EM, Disposal of carbon dioxide in aquifers in the US, Energy Conversion & Management, 1995, v.36, pp. 523

[46] U.S. Department of Energy, 2007, Op. cit.

processes represent hazards that could compromise site storage integrity.[47] They form two categories: geological hazards that are naturally occurring, and engineered hazards that are man-made. This section focuses on these hazards within the context of CCS operations siting.

Cap Rock Integrity

In California, almost all cap-rock candidates are relatively thick shales deposited in open marine basins.[48] For example, the Kreyenhagen shale and shales of the Temblor Formation hold large accumulations of oil and gas over the San Joaquin Basin and as such, should hold large CO_2 volumes as well. If a unit already traps hydrocarbons at depth, especially natural gas, then it is highly likely that it will also trap CO_2.[49] Breaches through this sealing unit compromise the storage integrity of the reservoir and may be engineered (for example, wells) or natural (faults and fractures).[50]

There are many conventional approaches to assess the integrity of a potential cap-rock. Thickness of a sealing unit can be assessed with conventional well-logging tools and techniques, and stratigraphic mapping and analysis can be used to assess lateral continuity. In addition, capillary pressure measurements on core samples can quantify the amount of buoyant force a cap-rock lithology can maintain before failing.[51, 52]

Some cap rocks, on the basis of their mineral composition, may be more suitable as cap rocks for CO_2 storage. Some rocks appear to react to CO_2 and swell, thereby further reducing their

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[47] Friedmann, S.J., 2007, Operational protocols for geologic carbon storage: Facility life-cycle and the new hazard characterization approach, 6th Annual NETL conference on Carbon Capture and Sequestration, Pittsburgh, PA Exchange Monitor, Oral 03

[48] Beyer LA, 1995, San Joaquin Basin, USGS 1995 National Oil And Gas Assessment, http://energy.cr.usgs.gov/oilgas/noga/1995.html Magoon LB, 1995, Sacramento Basin, USGS 1995 National Oil And Gas Assessment, http://energy.cr.usgs.gov/oilgas/noga/1995.html; Keller MA, 1995, Ventura Basin, USGS 1995 National Oil And Gas Assessment, http://energy.cr.usgs.gov/oilgas/noga/1995.html; Meyer LA, 1995, Los Angeles Basin, USGS 1995 National Oil And Gas Assessment, http://energy.cr.usgs.gov/oilgas/noga/1995.html

[49] Christopher C, and Iliffe, J, 2006, Reservoir Seals: How they work and how to choose a good one, Proceedings from the International Symposium for Site Characterization for CO2 Storage, Berkeley, CA pp 12-15

[50] Freidmann, S.J., Op. cit.

[51] Harrington, J.F., and Horseman, S.T., 1999, Gas transport properties of clays and mudrocks, in, A.C. Aplin et al (eds.), Muds and Mudstones: Physical and Fluid Flow properties, Geol. Soc. Special Publication 158, 107-124

[52] Bolas HMN, Hermanrud C, and Tiege, GMG, 2005, Seal Capacity estimation from subsurface pore pressures, Basin Research, v. 7 pp. 583-599

porosity and permeability.[53] In considering potential sites for CCS, it may be advantageous to assess the mineralogy of target cap rocks to understand their auto-sealing potential.

Faults

Frequent tectonic activity in California has produced many natural fault and fracture networks in the subsurface. Some of these systems are active and generate small and large earthquakes today. Others are inactive and in some cases have not slipped or deformed in many millions of years.

Faults may either serve as barriers or conduits to flow.[54] Under the right circumstances, faults can provide pathways for fluids and, in some circumstances, bring those fluids to the surface. This has been repeatedly seen in ancient and modern fault systems, which serve as loci for hydrocarbon seeps, hot springs, and cold springs. It is worth noting that faults only represent a substantial hazard for CCS if they can transmit large volumes of CO_2 at a high rate.

In some modern and ancient systems, CO_2 migrates, usually at low flux rates, along or very close to fault systems. These include the ancient Moab fault, the modern Crystal Geyser fault system, and natural CO_2 seeps at Latera, Italy, near Rome.[55, 56] Apart from volcanic regions, there are no documented sites of catastrophic release of gases up faults or fractures. In volcanic networks, gases such as steam and CO_2 combine with heat to rapidly expand, causing often sudden gaseous eruptions to the surface. However, sites of active volcanism or high geothermal activity will not be candidates for CO_2 sequestration.

In the context of CO_2 sequestration, the presence of faults is neither good nor bad. Some faults are conduits for rapid fluid migration; others seal and prevent fluid migration. 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 zones of either elevated or reduced pressure nearby. 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.

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[53] Watson MN, Daniel RF, Tingate PR, Gibson-Poole CM, 2005, CO2-related seal capacity enhancement in mudstones: Evidence from the Pine Lodge natural CO2 accumulation, Otway Basin, Australia, in, Wilson M, Morris T, Gale J, and Thambimuthu K (eds), Greenhouse Gas Control Technologies, Proceedings from the 7th Greenhouse Gas Control Technologies Conference, Vol. 2, Elsevier, 2313-2316.

[54] Wilkins SJ, and Naruk SJ, 2007, Quantitative analysis of slip-induced dilation with application to fault seal, AAPG Bulletin, V. 91, pp. 97-113

[55] Friedmann, Op. cit.

[56] Ibid.

Recently, a study was done in an oil field at Teapot Dome, Wyoming, to estimate the potential for faults to fail and leak CO_2.[57] In this study, one fault had a very low chance of failure and would accept injections well above reasonable operational pressures without failing. In contrast, for another fault network in a different part of the field, even a small injection pressure could potentially cause failure. Thus, one part of the field would be a good zone of storage, while another would not. This example highlights the need for careful site characterization in selection and the importance of high quality data.

Injection of CO_2 near a fault will not automatically trigger a large earthquake, as the case of Rangely, discussed below, demonstrates. Similarly, the history of waterflooding and brine injection in California oil fields also demonstrate that large volumes of fluid may be injected next to large faults without causing failure.

Wells

It is widely believed that wells represent the largest hazard to CCS. Production wells for oil, gas, or water usually are designed to bring fluids (oil, water, gas) to the surface rapidly, in effect compromising the natural storage mechanisms of the Earth's crust. In order to maintain operational integrity, these wells are cased and cemented and, when operations are completed, ultimately plugged and abandoned.[58] Despite the long, successful history of well engineering, many potential failure mechanisms could potentially allow CO_2 to escape from deep reservoirs.[59, 60] Many conditions control a well's potential for leakage, including the age and plugging mechanism, quality of completion, and post-closure history.

In the context of site characterization, there are several approaches to understand well hazards and mitigate potential risks. There have been several attempts to generate statistical and physical methods to quantify risks.[61] Such methods can be used as a crude screening tool on a

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57 Chiaramonte, L., Zoback, M., Friedmann, SJ, and Stamp, V., 2007, Seal integrity and feasibility of CO2 sequestration in the Teapot Dome EOR pilot: geomechanical site characterization, Environmental Geoscience, v.53

58 Jarrell, PM, CE Fox, MH Stein, and SL Webb, 2002, Practical Aspects of CO2 flooding. Monograph 22. Society of Petroleum Engineers, Richardson, TX, USA.

59 Gasda, S.E., Bachu, S., and Celia, M.A., 2004, The potential for CO2 leakage from storage sites in geological media: Analysis of well distribution in mature sedimentary basins. Environmental Geology 46 (6–7), 707–720.

60 Scherer, G.W., M.A. Celia, J.H. Prevost, S. Bachu, R. Bruant, A. Duguid, R. Fuller, S.E. Gasda, M. Radonjic, and W. Vichit-Vadakan, 2005, Leakage of CO2 through Abandoned Wells: Role of Corrosion of Cement", in The CO2 Capture and Storage Project (CCP), Volume II, D.C. Thomas and S.M. Benson (Eds.), 823-844,

61 Celia, M.A., Kavetski, D., Nordbotten, J.M., Bachu, S., and Gasda, S., 2006, Implications of abandoned wells for site selection. Proceedings, International Symposium on Site Characterization for CO2 Geological Storage, Lawrence Berkeley National Laboratory, Berkeley, CA, 157–159.

regional basis and can be improved through careful review of public drilling and completion records. In addition, studies show that conventional geophysical tools can, under some circumstances, detect the presence of buried, lost, and mislocated wells.[62] It is also possible to monitor wells directly through regular surveys to detect leakage. As is discussed in the chapter on remediation and mitigation, if leaks are detected, conventional approaches can be used to re-complete and plug abandoned wells.

Induced Seismicity

It has been known for roughly 40 years that, under some circumstances, injection of large fluid volumes can generate earthquakes. In most cases, these earthquakes will be quite small, but under the wrong circumstances may be quite large. The most spectacular example comes from the Rocky Mountain Arsenal. In that case, injection of large volumes of water produced earthquakes as large as magnitude 5.3.[63, 64] It is important to note that the target rocks were very impermeable and as a consequence, sustained very large pressure build ups. Given that CCS sites need good permeability, sites with similar characteristic to the Arsenal would not be selected.

One important case of induced earthquakes involves the Rangely oil field in northwestern Colorado. This site was the target of a series of experiments led by Stanford University to generate earthquakes in the hope of preventing large events. Between 1969 and 1972, the researchers injected very large volumes of water into a fault to induce seismic activity. The fault was selected because it was thought to be close to failure. After several series of injections, the team was able to generate seismic events. The largest of these events was magnitude 3.1, which could barely be felt at the surface. The overwhelming majority of the earthquakes were too small to feel at the surface.[65] After these experiments, the Rangely field became a site of active CO_2 injection. For 20 years and with nearly 50 million tons of injection, no leakage has been detected at the surface.

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[62] Veloski, G. and Hammack, R., 2006, In An Evaluation of Helicopter and Ground Methods for Locating Existing Wells, CO2SC Symposium, Berkeley, California, March 20-22, 2006, 2006; Lawrence Berkeley National Laboratory: Berkeley, California, pp 62-66

[63] Evans DM, 1966, The Denver Area Earthquakes and the Rocky Mountain Arsenal Disposal Well, 3 The Mountain Geologist 23 [Reprinted in Engineering Case Histories No. 8, 25, Geological Society of America (1970)]

[64] Healy HJ, Rubey WW, Griggs DT, and Raleigh CB, 1968, The Denver Earthquakes, 161 Science 1301.

[65] Raleigh CB, Healy JH, and Bredehoeft JD, 1976, An experiment in earthquake control at Rangely, Colorado. Science 191:1230-37

Injection Scale

Injection scale must be central to considerations of plant siting, permitting, and regulation. Most commercial projects are highly likely to inject very large volumes of CO_2 for a long time. For example, an 800-MW natural gas combined cycle power plant with an 85 percent capacity factor and 90 percent capture, would produce 2.5 MMT CO_2/year. Injecting this CO_2 for 60 years requires the following parameters for a potential storage site:

- The ability to accept injection of 3000 to 5000 metric tons CO_2/day
- The ability to accept 66 to 110 million metric tons over 60 years plant operation
- Very high chance of effective storage well beyond those 60 years

Parameters of Site Characterization

While many possible goals and terms may be pursued in site characterization, it is difficult to imagine the success of a large-scale injection project without knowledge of three parameters: injectivity, capacity, and effectiveness:

- Injectivity is the rate at which CO_2 injection may be sustained over fairly long intervals of time (months to years)
- Capacity is the total volume of potential CO_2 storage at a site or in a formation
- Effectiveness, sometimes also called containment, is the ability of the formation to store the injected CO_2 well beyond the lifetime of the project

Injectivity, the ability of the rock around the injection well to pass injected CO_2 into the reservoir, affects the rate at which CO_2 can be pumped into the reservoir, the pressure needed for injection, and the overall capacity of the reservoir over the life of the operation. Injectivity is affected by parameters such as rock type, fluid type(s) in the rock pores, drilling and completion fluids, and pressure differentials. Capacity assessment depends on successful quantitative prediction of the ability of physical and chemical processes to trap large volumes of CO_2 in the reservoir effectively (effectiveness). A seal over a CO_2 reservoir is an impermeable rock layer that must block upward migration of CO_2 from the underlying reservoir, and its integrity, depends on its composition and the engineering of wells, past and present, which intersect it. Table 4 outlines key information, data, and analyses needed to determine these parameters.

Basic Data Integration and Analysis

Regulatory frameworks should be flexible enough to encompass many different geological settings and data sets. In designing protocols for detailed site characterization, several points stand out:

- In general, conventional 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 are the primary data needs. This suggests that injectivity, capacity, and effectiveness can be defined and defended in many contexts.
- There are some common elements to any site characterization process: for all terms, a basic static geological model based on stratigraphic and structural analysis is of basic value. The same is true for conventional multi-phase flow simulation.
- The amount of data needed will vary on a case-by-case basis. The density of data, the depth of prior operational knowledge, the number of wells likely to intersect the plume, and the local geology all will determine what is needed.
- Analog data are of value. Where appropriate, analog information can serve to improve or condition injectivity, capacity, or effectiveness information. However, if local data are severely limited or if little is known about a particular site, collection of new information is likely to be required.
- Characterization should evolve as more data become available. Highly prospective sites lack data sufficient to make precise estimates of key parameters. However, there may be enough data to make preliminary assessments of site performance. As a development proceeds, more data will become available to provide improvements to the original assessment.

Table 4: Information and Data Sources for Site Characterization

Key term	Key information	Basic data sources	Basic analysis	Advanced analysis
Injectivity	Effective thickness and permeability, production/flow rate, delivery rate connectivity	Conventional core analysis, well-logs, production history, stem or leak-off tests, pressure	Stratigraphic analysis, population of static geological models, core plug analysis, conventional simulation, well pump tests/stem tests	Detailed stratigraphic characterization, hydro-fracture analysis, special core analysis
Capacity	Effective thickness, accessible pore-volume, area of injection, trapping mechanism constraint	Conventional core analysis, well-logs, reserves, structure maps, 3D seismic volumes	Stratigraphic analysis, structural analysis, static geomodels construction, simple calculation, conventional simulation, 3D seismic mapping	Advanced simulation, fill-spill analysis, special core analysis
Effectiveness	Presence, number, continuity, thickness, and character of seal; fault azimuth and offset; basic failure criteria; surface and formation well density; well completion history	Cores, well-logs, structure maps, in-situ stress, well location maps, well completion records, 3D seismic volumes	Stratigraphic analysis, structural analysis, static geomodels construction, simple calculation, Mohr-Coulomb failure calculation, conventional simulation, special core analysis, well completion history, well location verification	Aeromagnetic surveys, capillary entry pressure tests, fault segmentation analysis, advanced simulation, well logging-through casing (e.g., cement bonding logs)

Source: Friedmann, PIER White Paper

Potential Due Diligence

Ideally, project site selection and certification for injection would involve detailed characterization given the geological heterogeneity of the Earth's crust. In many cases, this will require new geological and geophysical data sets. In that context, what might constitute due diligence for developing site characterization criteria depends on whether targets are depleted oil and gas fields or saline formations.

Depleted Oil and Gas Fields

An oil or gas field has already held buoyant fluids in the crust for millions of years. In addition, extensive site information exists due to commercial hydrocarbon exploration and operation. These basic facts make it likely that a site can readily be characterized. Oil and gas fields will have an advantage regarding effectiveness in that the trap and pore volume are well delineated and basic effectiveness is readily defended. However, greater due diligence may be needed to characterize effectiveness in terms of wells, including age, completion zones, and if abandoned, plugging history. For depleted hydrocarbon fields, the key issues may involve incremental costs necessary to ensure well or field integrity; otherwise, the due diligence may be straightforward and the burden to operators relatively light.

Base Case

A depleted oil or gas field is likely to have well, core, production, and perhaps reflection seismic data that could be used in a fairly short time frame (order of months). Injectivity will be constrained by initial pressure, current pressure, and production history, and capacity by the pore volume and structural spill point, and current pressure. If such data are available, no additional data may be required. Effectiveness can be determined by the seal character and the structural configuration, and this information can be readily augmented with data regarding fault orientation and in-situ stresses. There also may be information on borehole breakouts, well failure events, subsidence, waterfloods, and well recompletions that could inform effectiveness determinations. If not, in-situ stress characterization may be advisable.

Because oil and gas fields have large numbers of well penetrations, it will be important to understand the distribution and state of wells. This may involve a well census, confirmation of well locations, aeromagnetic surveys, and/or reviews of completion records. In some cases, it may be necessary to re-enter wells and run wire-line tools to determine well conditions at depth for the intervals of interest.

Extended Case

Conceivably, additional data (for example, well-bore integrity analysis, capillary entry pressure data) may be required. If there are questions or concerns about injectivity or capacity, these may be addressed through production tests or conventional reservoir simulation. Depending on the completion and operation history of the field, it may be prudent to undertake a well re-completion program in the field to help assure effectiveness.

Saline Formations

In contrast to a depleted oil or gas field, a saline formation may have limited well data and lack core or seismic data altogether. To help constrain subsurface uncertainty, geological characterization may require new data such as exploratory wells, geophysical surveys, or regional hydrological analysis. For saline aquifers, key needs are appropriate mapping of potential permeability fast paths out of the reservoir, accurate rendering of subsurface heterogeneity and uncertainty, and appropriate geomechanical characterization. Existing technology is well suited to defining saline aquifer cases, and the burden of proof should be manageable, even in a cost-constrained environment.

Base Case

Injectivity may be readily constrained if the target formation is already receiving injected fluids. However, it is more likely that little will be known about the short or long-term injectivity, and analog data may prove important. For example, if there are nearby natural gas storage sites or oil fields in the target formation, data might available. This was the case for the FutureGen plant siting. However, the absence of reliable analog data may require injectivity tests from an exploratory well.

The key terms to define capacity as a function of pore volume might be readily calculated even in areas of poor data density. In the absence of a well defined closure, capacity estimates will derive from calculation of volumes stored by specific mechanisms. This might require special analysis and regional hydrological characterization. Effectiveness would require, at a minimum, analog data on the sealing cap rock and some effort to constrain the locations of any documented deep wells. Although circumstances may vary, it may be necessary to provide evidence of the absence of large-offset faults. Again, new data collected from at least one exploratory well, especially, in-situ pressure and stress data, would improve the local case for effective storage.

Extended Case

For cases where additional analysis is required to satisfy due diligence, injectivity characterization may require a new well and integration of appropriate analog data. Some special core analyses, such as relative permeability curves, might be acquired for this purpose. Capacity would also be readily calculated. Conventional simulations would be needed to predict plume extent. In such cases, vertically stacked reservoir targets would have a distinct advantage in that the same injection volume would have a smaller geographic extent or footprint.

Determination of effectiveness may require more substantial characterization. In addition to one high quality sealing unit, multiple seals may be advisable. In-situ stress determination and special geomechanical analyses (for example, leak-off tests, capillary entry pressure) might be required. In situations where there is little structural or geophysical information available, geophysical surveys (3D reflection seismic surveys of the central target area, for example) might be used to demonstrate the absence of potentially leaky structures. To address questions of well integrity, aeromagnetic surveys and some well re-completions might be advised. Alternatively, an initial commitment to regular and comprehensive monitoring and verification may offset concerns about initial characterization, depending on the local geology.

Monitoring in Site Characterization

There is an important connection between site monitoring, discussed in a subsequent chapter, and site characterization. In most cases, site characterization will be completed before gathering of baseline monitoring data. It is generally thought that site characterization can determine the choice of monitoring suite and tool deployment, which are often sensitive to crustal physics, chemistry, reservoir geometry, and hazard distribution. However, some monitoring approaches, particularly remote geophysical applications such as 3D reflection seismology, provide crucial information on structure and stratigraphy relevant to characterization. In some circumstances, geophysical potential field surveys (microgravity, aeromagnetic) may be used to provide information on shallow fault location or well distribution.

Monitoring can provide pre- and post-injection site comparisons. This was demonstrated at both Sleipner and Weyburn, where the monitoring programs revealed important heterogeneities of the reservoir, persistent fracture networks, crustal velocity information, and permeable fast pathways. This kind of information can serve to improve the understanding of the site substantially and could improve predictions of plume geometry and extent as well as potential failure risks.

Technical Gaps and Needs

For a given site, it is technically possible and reasonable to collect and analyze data that inform site characterization efforts and permitting. It is not yet clear, however, what minimal information is required to satisfactorily address the key concerns of potential stakeholders. As discussed above, industrial practice in analog industries (such as oil production, natural gas storage) and fundamental knowledge can be used to begin to define minimal technical constraints. A focused scientific and technical effort aimed at drafting minimum technical constraints for site characterization could provide guidance quickly and clearly. Such a program should complement existing efforts (for example, WESTCARB and more generally other efforts within the Department of Energy's Regional Partnership program) and be appropriate to California's unique geology (refer to Chapter 3.).

CHAPTER 6: Monitoring and Verification

Monitoring and verification are essential to demonstrate that the practice of geologic storage is safe, does not create significant adverse local environmental impacts and is effective as a greenhouse gas control technology. One of the most important purposes of monitoring is to confirm that the project is performing as expected; monitoring also may be needed to ensure that natural resources, such as groundwater and recoverable oil and gas, are protected and that natural ecosystems, local populations, and livestock are not exposed to unsafe concentrations.

A monitoring program should be required as part of the permitting process and be based on generally applicable guidelines as well as approaches tailored to the conditions and risks at each specific storage site. Flexibility to tailor verification monitoring to the specific geological attributes of the storage site would be beneficial: however, it may also be appropriate to establish a minimum set of monitoring and verification requirements, perhaps in conjunction with a similar effort in site characterization. Prior experience and regulations from related activities such as natural gas storage, CO_2 enhanced oil recovery, and disposal of industrial wastes in deep geologic formations may be good analogs. For verification, the most practical and cost-effective approaches would rely on a combination of measurements and model predictions to assess annual emissions from the storage reservoir.

Monitoring costs will depend on many factors, including the plume size, regulatory requirements, the length of monitoring, geologic site conditions, and the particular methods selected for application. Studies to date show that monitoring costs will likely be less than $0.50 per ton of CO_2 injected. Assignment of responsibility and cost for long-term monitoring of the site post-closure also has to be addressed.

Monitoring and verification techniques must be able to detect migration and leakage at spatial and temporal resolutions appropriate to the aims of geologic storage. Monitoring instrumentation must be capable of detecting low-level leakage, but also have sufficient range to register catastrophic leaks. The current state of the art is more than adequate to meet the needs for monitoring CO_2 injection rates, wellhead and formation pressures, and occupational safety. On the other hand, CO_2 measurement and monitoring approaches on the temporal and spatial scales relevant to geologic sequestration need further development.

Measurement technologies for monitoring geologic storage of CO_2 are available from a variety of other applications, including the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, food preservation and beverage industries, fire suppression, and ecosystem research.[66, 67] Geophysical,

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[66] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations.

hydrological, and geochemical techniques exist to monitor CO_2 or its effects in the subsurface or at the surface. Remote sensing techniques, using satellite or airborne instrumentation, also can be used to monitor large areas.

Establishing natural background levels of CO_2 is key to understanding reservoir performance. Without an adequate baseline, it may not be possible to separate storage-related changes in the environment from natural spatial and temporal variations in the monitoring parameters. If CO_2 is stored in oil or gas reservoirs, it may be important to also monitor for other constituents found in these environments that may be carried along with CO_2 in the event that leakage occurs.

Purposes of Monitoring

A monitoring program can have several purposes, namely, tracking the location of the plume of injected CO_2, ensuring that injection and abandoned wells are not leaking, and verification of the quantity of CO_2 injected underground. Figure 7 illustrates examples of requirements for a storage program and how these should guide a monitoring program. It may also be desirable to monitor other parameters to assess the performance of the storage project, or, in the event of leakage, assess the source of leakage, design a remediation scheme, and assess environmental impacts, specifically:

- Evaluate how effectively the storage volume is being used
- Provide information on the extent of solubility and mineral trapping
- Locate faults or other features that may be leaking CO_2
- Assess groundwater quality

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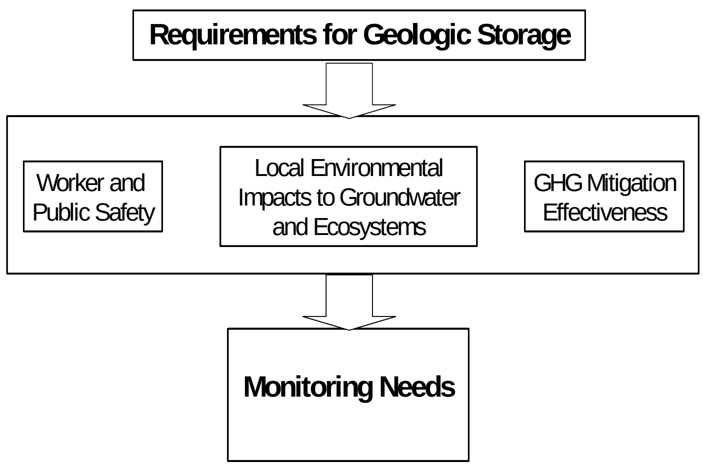
[67] Benson, S.M., J. Apps, R. Hepple, M. Lippmann, C.F. Tsang, and C. Lewis, 2002(b), Health, Safety, and Environmental Risk Assessment for Geologic Storage of Carbon Dioxide: Lessons Learned from Industrial and Natural Analogues, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

- Detect and monitor CO_2 concentrations in the vadose zone and soils
- Monitor ecosystem impacts
- Monitor micro-seismicity associated with CO_2 injection

One of the most important purposes of monitoring is to confirm that the project is performing as expected from predictive models. This is particularly valuable in the early stages of a project when the opportunity exists to alter the project or, if it is not performing adequately, to abandon the storage site altogether. Moreover, monitoring data collected early in the project are often used to refine and calibrate the predictive model, improving the basis for predicting the longer-term performance of the project. This approach was successfully applied in the Sleipner Project, where the first set of monitoring data significantly changed the conceptual model and promoted better understanding of fine-scale reservoir heterogeneity.[68]

Figure 7: Flow Chart of EH&S Requirements for CCS



Credit: Benson and Myer, white paper

Comparing model predictions with monitoring data is the key to model calibration and performance confirmation. While this is simple in principle, the linkage between the model results and monitoring data should be considered during the design stage. Issues such as which parameters should be monitored, timing of measurements, spatial scale and resolution of measurements, and location of monitoring points all needed to be considered.

From the standpoint of public acceptance, knowing that monitoring can be done to provide this information could provide greater assurance that geologic storage can be accomplished safely and effectively.

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[68] Chadwick, A., P. Zweigel, U. Gregersen, G.A. Kirby, and P.N. Johannessen, 2002, Geological Characterization of CO2 Storage Sites: Lessons from the Sleipner, Northern North Sea, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002..

Importance of a Well-Defined Baseline

It can be very challenging to detect changes in CO_2 concentrations resulting from CCS projects because of the complexity of the environment and the ubiquity of CO_2 in the environment. CO_2 is in the air, water, and soils around us and can vary on daily, seasonal, or longer time frames depending on the sources, sinks, and long-term processes affecting CO_2 concentrations. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of CO_2; instead, it is the changes in these parameters over time that can be used to detect and track migration of CO_2 and its reaction products.

For these reasons, it is important to have a well-defined baseline that includes not only the average value of these parameters, but also how they vary in space and time before the project begins. This "time-lapse" approach is the foundation for monitoring CO_2 storage projects. Otherwise, it my not be possible to separate storage-related changes in the environment from the natural spatial and temporal variations in the monitoring parameters. For most storage projects, baseline data will be obtained during the pre-injection site characterization phase of a storage project. This is particularly important for geologic storage projects in deep saline aquifers, for which there is less prior data than for depleted oil and gas fields.

Measurement Methods

Measurement technologies for monitoring geologic storage of CO_2 are available from a variety of other applications, including the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, food preservation and beverage industries, fire suppression, and ecosystem research.[69]

CO_2 Flow Rates, Injection, and Formation Pressures

Measurements of CO_2 injection rates are a common oil field practice, and instruments are available from commercial manufacturers. Typical systems use orifice meters or other differential producing devices that relate the pressure drop across the device to the flow rate.

[69] Benson et al., 2002a; 2002b, op cit.

Recent enhancements in the basic technology are now available that allow for accurate measurements and injection control, even under varying pressure and temperature conditions.[70]

Measurements of injection pressure at both the wellhead and in the formation are also routine. A wide variety of pressure sensors, including piezo-electric transducers, strain gauges, diaphragms, and capacitance gauges are available and suitable for monitoring CO_2 injection pressures. Over the past two decades, fiber optic pressure and temperatures sensors have been developed, and many manufacturers now sell these products. Fiber optic cables are lowered into the wells and connected to the sensors to provide real-time formation pressure measurements. These new systems are expected to provide even more reliable measurements and well control.[71]

The current state of the art is more than adequate to meet the needs for monitoring CO_2 injection rates and wellhead and formation pressures. These will provide quantitative measures of the amount of CO_2 injected at a storage site for inventories, reporting, and verification and as input to modeling.

Direct Measurement Methods for CO_2 Detection

Direct measurements of CO_2 in air, water, or soils may be required as part of the monitoring program. For example, CO_2 concentrations in the air near the injection wells or abandoned wells may be monitored as a precaution to ensure worker and public safety at the storage site. In addition, nearby groundwater monitoring wells may be monitored periodically to ensure that the CO_2 storage project is not harming groundwater quality. If there is an indication that CO_2 has leaked from the primary storage reservoir and migrated to the surface, vadose zone and soil gas CO_2 concentrations may be monitored.[72]

Even when the storage project poses no safety or environmental concerns, direct measurement of CO_2 concentrations and CO_2 reaction products may assist in determining the extent of solubility and mineral trapping. In addition, in some cases it may be desirable to have a method

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[70] Wright, G. and Majek, 1998, Chromatograph, RTU Monitoring of CO_2 Injection. Oil and Gas Journal, 20 July, 1998.

[71] Brown, G. A. and A. Hartog, November 2002, Optical Fiber Sensors in Upstream, Oil and Gas, Journal of Petroleum Technology.

[72] Strutt, M.H., S.E. Beaubien, J.C. Baubron, M. Brach, C. Cardellini, R. Granieri, D.G. Jones, S. Lombardi, L. Penner, F. Quattrocchi, and N. Voltattorni, 2002, Soil Gas as a Monitoring Tool of Deep Geological Sequestration of Carbon Dioxide: Preliminary Results from the Encana EOR Project in Weyburn, Saskatchewan (Canada), Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

to uniquely identify and trace the movement of injected CO_2 from one part of the storage structure to another.

CO_2 Sensors for Measurement in Air

Sensors for monitoring CO_2 continuously in air are used in a wide variety of applications, including CO_2 demand-controlled HVAC systems, greenhouses, combustion emissions measurement, and the monitoring of environments in which carbon dioxide is a significant hazard (such as breweries). Such devices, which rely on infrared detection principles, are referred to as infrared gas analyzers. Infrared gas analyzers used in occupational settings are small and portable. Most use nondispersive infrared or Fourier Transform infrared detectors. Both methods depend upon light attenuation by CO_2 at a specific wavelength, usually 4.26 μm. For extra assurance and validation of real-time monitoring data, federal regulatory agencies[73] use periodic gas sampling bags and gas chromatography for measuring CO_2 concentrations. Mass spectrometry is the most accurate method for measuring CO_2 concentration, but it is also the least portable. Electrochemical solid-state CO_2 detectors exist, but they are not cost-effective at this time.[74]

Common field applications in environmental science include the measurement of CO_2 concentrations in soil air, flux from soils, and ecosystem-scale carbon dynamics. Diffuse soil flux measurements are made using simple infrared analyzers.[75] For example, the US Geological Survey measures CO_2 fluxes on Mammoth Mountain using these types of detectors.[76] Biogeochemists study ecosystem scale carbon cycling using CO_2 detectors on towers that are 2- to 5-meters tall (eddy flux correlation measurements) in concert with wind and temperature data to reconstruct average CO_2 flux over large areas.

Remote sensing of CO_2 releases to the atmosphere is another more complicated method because of the long path length through the atmosphere over which measurements are made and

[73] For example, National Institute of Occupational Safety and Health, Occupational Safety and Health Act and the Environmental Protection Agency

[74] Tanura, S., N. Imanaka, M. Kamikawa, and G. Adachi, 2001, A CO_2 Sensor Based on a Sc^{3+} Conducting $Sc_{1/3}Zr_2(PO_4)_3$ Solid Electrolyte, *Sensors and Actuators B*, **73**, pp. 205-210.

[75] Oskarsson, N.K., Palsson, H. Olafsson, and T. Ferreira, 1999, Experimental Monitoring of Carbon Dioxide by Low Power IR-Sensors; Soil Degassing in the Furnas Volcanic Centre, Azores, *J. Volcanol. Geotherm. Res*, **92**, pp. 181-193m.

[76] LI-COR, Inc., website, home, www.licor.com/, LI-COR environmental hme page, http://env.licor.com/, information on gas analyzers, http//env.licor.com/products/gas.htm, 2001; Sorey, M.L., C.D. Farrar, W.C. Evans, D.P. Hill, R.A. Bailey, J.W. Hendley II, and P.H. Stauffer, 1996, Invisible CO_2 Gas Killing Trees at Mammoth Mountain, California, *U.S. Geological Survey Fact Sheet*, pp. 172-196, http://wrgis.wr.usgs.gov/fact-sheet/fs172-96/,http://quake.wr.usgs.gov/prepare/factsheets/CO2/; USGS, 2001(c), Long Valley Observatory home page, http://lvo.wr.usgs.gov/.

because of the inherent variability of background atmospheric CO_2. The total amount of CO_2 integrated by a satellite through the depth of the entire atmosphere is large. Infrared detectors measure average CO_2 concentration over a given path length, so a diffuse or low-level leak viewed through the atmosphere by satellite would be undetectable. In contrast, SO_2 and integrated total atmospheric CO_2 are routinely measured.[77] Geologists use airborne instrumentation called COSPEC to measure the attenuation of solar ultraviolet light relative to an internal standard. Carbon dioxide is measured either directly by a separate IR detector, or calculated from SO_2 measurements and direct ground sampling of the SO_2/CO_2 ratio for a given volcano or event.[78] Remote-sensing techniques currently under investigation for CO_2 detection are LIDAR (light detection and range-finding) which is a scanning airborne laser, and DIAL (differential absorption LIDAR) that looks at reflections from multiple lasers at different frequencies.[79]

Geochemical Methods and Tracers

Geochemical methods are useful both for directly monitoring the movement of CO_2 in the subsurface and for understanding the reactions taking place between CO_2 and the reservoir fluids and minerals.[80] Fluid samples can be collected either directly from the formation using a downhole sampler or from the wellhead if the well from which the sample is collected is pumped. Downhole samples are considerably more costly, but have the advantage that they are more representative of the formation fluids because they are not depressurized as they flow up the well. Methods for collecting downhole and wellhead fluids samples are well developed, and geochemical sampling is conducted on a routine basis.

Fluid samples can be analyzed for major ions (for example, Na, K, Ca, Mg, Mn, Cl, Si, HCO_3^- and SO_4^{2-}) pH, alkalinity, stable isotopes (such as, ^{13}C, ^{14}C, ^{18}O, ^{2}H), and gases, including

[77] Lopez-Puertas, M. and F.W. Taylor, 1989, Carbon Dioxide 4.3 Um Emission in the Earth's Atmosphere: a Comparison Between NIMBUS 7SAMS Measurements and Non-local Thermodynamic Equilibrium Radiative Transfer Calculations, *J. Geophys. Res.,* **94**(D10), pp. 13,045, 13,068.

[78] Hobbs et al. 1991, Mori and Notsu 1997, USGS 2001)

[79] Hobbs, P.V., L.F. Radke, J.H. Lyons, R.J. Ferek, and D.J. Coffman, 1991, Airborne Measurements of Particle and Gas emissions from the 1990 Volcanic Eruptions of Mount Redoubt, J. Geophys. Res., 96(D10), pp. 18,735-18,752.; Menzies, R.T., D.M. Tratt, M.P. Chiao, and C.R. Webster, 2001, Laser Absorption Spectrometer Concept for Globalscale Observations of Atmospheric Carbon Dioxide, 11th Coherent Laser Radar Conference, Malvern, United Kingdom.

[80] Gunter, W.D., R.J. Chalaturnyk, and J.D. Scott, 1998, Monitoring of Aquifer Disposal of CO2: Experience from Underground Gas Storage and Enhanced Oil Recovery, Proceedings of GHGT-4, Interlaken, Switzerland, pp. 151-156; Gunter, W.D. and E. Perkins, 2001, Geochemical Monitoring of CO2 Enhanced Oil Recovery. Proceedings of the NETL Workshop on Carbon Sequestration Science, http://www.netl.doe.gov/.

hydrocarbon gases, CO_2, and its associated isotopes.[81] Standard analytical methods are available to monitor all of these parameters, including the possibility of continuous real-time monitoring for some of the geochemical parameters.

Natural tracers (isotopes of C, O, H and noble gases associated with the injected CO_2) and introduced tracers (noble gases, SF_6, and perfluorocarbons) also may provide insight about the underground movement of CO_2 and reactions between CO_2 and the geologic formation.[82] Tracers may also provide the opportunity to uniquely identify the source of CO_2. While it is comparatively straightforward to measure the parameters listed above, interpreting these measurements to infer information about geochemical reactions is much more challenging. Only recently has a great deal of attention been paid to understanding reactions between CO_2 and deep geologic formations shortly after CO_2 is introduced into the environment.[83]

Indirect Measurement Methods for CO_2 Plume Detection

Indirect measurements for detecting CO_2 in the subsurface provide methods for tracking migration of the CO_2 plume in locations where there are no monitoring wells, or for providing higher resolution monitoring between wells or behind the cased portion of a well. Such indirect methods fall into four categories: well logs; geophysical monitoring methods such as seismic, electromagnetic, and gravity; land surface deformation using tiltmeters, plane, or satellite-based geo-spatial data; and satellite-based imaging technologies such as hyperspectral and IR imaging.

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[81] Ibid.

[82] Emberley, S., I. Hutcheon, M. Shevalier, K. Durocher, W.D. Gunter, and E.H. Perkins, 2002, Geochemical Monitoring of Fluid-Rock Interaction and CO2 Storage at the Weyburn CO2-Injection Enhance Oil Recovery Site, Saskatchewan, Canada, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002; Blencoe, J.G., D.R. Cole, J. Horita, and G. Moline, 2001, Experimental Geochemical Studies Relevant to Carbon Sequestration, Proceedings of the First National Symposium on Carbon Sequestration, U. S. National Energy Technology Laboratory, Washington DC; Kennedy, B.M. and T. Torgersen 2001, Multiple Atmospheric Noble Gas Components in Hydrocarbon Reservoirs: A Study on the Northwest Shelf, Delaware Basin, SE, New Mexico. Submitted to Geochimica Cosmochimica Acta, Also Lawrence Berkeley National Laboratory Report, LBNL-47383.

[83] Bachu, S. and W.D. Gunter, 1994, Aquifer Disposal of CO2: Hydrodynamic and Mineral Trapping, Energy Conversion and Management, 35, pp. 269-279; Johnson, J.W., J.J. Nitao, C.I. Steefel, and K.G. Knauss, 2001, Reactive Transport Modeling of Geologic Sequestration in Saline Aquifers: the Influence of Intra Aquifer Shales and the Relative Effectiveness of Structural, Solubility, and Mineral Trapping During Prograde and Retrograde Sequestration, Proceedings of the First National Symposium on Carbon Sequestration, U. S. National Energy Technology Laboratory. Washington DC.

The utility of these indirect methods is determined by (1) their threshold for detection of the presence of CO_2, (2) the extent to which the signal is uniquely related to the presence of CO_2 (for example, distinguishing between the effects of a pressure increase and the presence of CO_2), and (3) the degree of quantification that is possible (for example, the fraction of the pore volume occupied by CO_2).

To date, three-dimensional (3-D) seismic reflection surveys have been used to monitor, with excellent success, migration of the CO_2 plume injection in the Utsira Formation in Statoil's Sleipner Vest CO_2 storage project, the Frio Brine Pilots I and II, the Nagaoka project in Japan and the Weyburn Project.[84] The success of this technology bodes well for the ability of indirect methods to track plume migration in the subsurface. However, 3-D seismic reflection surveys may not always be so successful; costs for these surveys are high compared to other available monitoring methods, and in some cases, the spatial resolution or the detection threshold may not be adequate. In addition, performing traditional 2- and 3-D seismic surveys in urban settings may be difficult or impossible. Therefore, additional methods for plume detection are being evaluated, including innovate real-time seismic monitoring approaches.[85]

Well Logs

One of the most common methods for evaluating geologic formations is the use of well logs. Logs are run by lowering an instrument into the well and taking a profile of one or more physical properties along the length of the well. A wide variety of logs is available and can measure many parameters—from the condition of the well to the composition of pore fluids to the mineralogy of the formation. For geologic storage of CO_2, like for natural gas storage and disposal of industrial wastes in deep geologic formations, logs will be most useful for detecting the condition of the well and ensuring that the well itself does not provide a leakage pathway for CO_2 migration. Several logs are routinely used for this purpose, including temperature, noise, casing integrity, and radioactive tracer logs.[86] It is worth noting that the resolution of well logs may not be sufficient to detect very small rates of seepage through microcracks. The RST log, which can be used to estimate the saturation of CO_2 in the pore space, has also been used with excellent success at the Frio Brine Pilot Tests in Texas.[87]

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[84] Korbol, R., and Kaddour, A., 1995. Sleipner Vest Co2 disposal – Injection of Removed CO2 into the Utsira Formation. Energy Conversion and Management,36, 3-9, 509-512.

[85] Daley, T., R.D. Solbau , J. B. Ajo-Franklin, S. M. Benson (2007) Continuous Active-Source Seismic Monitoring of CO2 Injection in a Brine Aquifer, Geophysics, in press

[86] Benson et al., 2002a, Op. cit.

[87] Hovorka, S.D., S. M. Benson, C. Doughty, B. M. Freifeld, S. Sakurai, T. M. Daley, Y. K. Kharaka, Mark H. Holtz, R. C. Trautz, H. S. Nance, L. R. Myer and K. G. Knauss. Measuring permanence of CO2 storage in saline formations: the Frio experiment. Environmental Geosciences; June 2006; v. 13; no. 2; p. 105-121; DOI: 10.1306/eg.11210505011

Geophysical Monitoring Methods: Seismic, Electromagnetic, and Gravity

It is natural to consider geophysical techniques for monitoring CO_2 migration because of the large body of experience in their application in the petroleum industry. Among geophysical techniques, seismic methods are by far the most highly developed. The most likely mode of application will be time-lapse, in which the difference between two surveys would be used to evaluate the movement of CO_2. As mentioned above, this technique has been used very effectively for monitoring CO_2 movement in the Utsira Formation, the Frio Brine Pilot, Weyburn and Nagaoka in Japan. Though time-lapse imaging is becoming more common, it is a much less mature technology than exploration geophysics.

The applicability of geophysical techniques depends, first, on the magnitude of the change in the measured geophysical property produced by CO_2, and second, on the inherent resolution of the technique. Finally, the applicability also depends on the configuration in which the measurement is deployed.

Gravity methods sense changes in density; electrical methods primarily respond to changes in resistivity; and seismic methods depend on both density and elastic stiffness. Gravity has been used to monitor CO_2 migration in off-shore environments at the Sleipner Project and was able to detect the injected CO_2. These physical properties are known for CO_2, typical reservoir fluids, and their mixtures, and so assessments can be made of expected changes in geophysical properties.[88] CO_2 is resistive, so electrical methods are candidates for brine bearing formations. For most of the depth interval of interest for sequestration, CO_2 is less dense and more compressible than brine or oil, so gravity and seismic methods are candidate methods for brine or oil bearing formations. At shallow depths, CO_2 has gas-like properties so none of the geophysical methods are good candidates for monitoring CO_2 within a shallow dry natural gas reservoir. Even in this case, however, since brine formations are commonly found above gas reservoirs, geophysical methods would still be candidates for detection of leaks. Research continues to refine the information available on the influence of varying CO_2 saturations on seismic and electrical properties.[89]

The size of a region containing CO_2 also must be sufficient to generate an interpretable geophysical signal. A relevant concept is resolution, which, in geophysics, is defined as the ability to distinguish separate features. For seismic methods, resolution is usually discussed in the context of reflection processing and expressed in terms of the size of the feature compared to

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[88] Batzle, M. and Z. Wang, 1992, Geophysics, 57, pp. 1396-1408 Magee, J.W. and J.A. Howley, 1994, Gas Processors Association, Tulsa, OK Research Report, RR-136; National Institute of Science and Technology (NIST), 1992, NIST Database 14 Mixture Property Database, version 9.08, U.S. Department of Commerce.

[89] Myer, L.R., 2001, Laboratory Measurement of Geophysical Properties for Monitoring CO_2 Sequestration, *Proceedings, First National Symposium on Carbon Sequestration*, U. S. National Energy Technology Laboratory, Washington DC.

the seismic wavelength. Numerous researchers have studied ways to improve seismic resolution.[90] Vertical resolution relates to bed thickness and the critical resolution thickness is about 1/8 wavelength. For thinner beds, separate reflections from the top and bottom cannot be identified. Lateral resolution is related to Fresnel zone size. When the lateral dimension is less than one Fresnel zone, reflected amplitudes are a function of size, in addition to property contrasts. Myer and others[91] studied the resolution of surface seismic for detecting subsurface volumes containing CO_2 and concluded that, at depth, a plume as small as 10,000 to 20,000 tons of CO_2 may be detectable, but would be difficult to resolve.

More recent work suggests that faults and fractures can be detected by seismic methods even though their thickness is much less than 1/8 wavelength.[92] Because the porosity of fractures, or a fault, is a small percentage of the total rock volume, the detectable volume of CO_2 would be much smaller than that cited above.

Seismic methods cover several frequency ranges. Surface seismic methods produce energy from 10 Hertz Hz to about 100 Hz. Crosswell seismic methods using rotary sources produce energy in the 100 Hz to 500 Hz range and, using piezoelectric sources, in the 1 to 2 KHz range. Borehole seismic methods produce energy in the 10 KHz range. Frequency is related to wavelength through velocity, so for typical sedimentary rocks, wavelengths of surface seismic methods are in the range of about 10 to 100 meters, suggesting that CO_2 plumes as thin as 2 to 15 meters may be detected. Wavelengths of high frequency borehole-deployed methods are much shorter, implying high resolution, but scattering and intrinsic attenuation limit the distance over which an interpretable signal will travel. High frequency borehole methods can penetrate only a few meters into typical sedimentary rock.

The resolution of potential field methods (essentially all geophysical methods other than seismic) is not formally defined. It is generally recognized that the resolution of these methods is much less than that of seismic.

Finally, all of the methods described above can be deployed in a number of ways, depending on the resolution and spatial coverage needed. For example, seismic data can be obtained in two or

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[90] Widess, M., 1973, How Thin Is a Thin Bed?, *Geophysics*, **38**(6), pp. 1176-1180; Sheriff, R., 1977, Limitations on Resolution of Seismic Reflections and Geologic Detail Derivable from Them, in Seismic Stratigraphy—Applications to Hydrocarbon Exploration, Memoir 21, G. Payton editor, *American Association of Petroleum Geologists*, pp. 3-14.

[91] Myer, L.R., G.M. Hoversten, and E. Gasperikova, 2002, Sensitivity and Cost of Monitoring Geologic Sequestration Using Geophysics, presented at the Sixth International Greenhouse Gas Technologies Conference (GHGT-6), Kyoto, Japan, 1-4 October, 2002

[92] Schoenberg, M., 1980, Elastic Wave Behavior across Linear Slip Interfaces, Journal of Acoustical Society of America, 68(5), pp. 1516-1521; Pyrak-Nolte, L., L.R. Myer, N. Cook, 1990, Transmission of Seismic Waves Across Single Fractures, Journal of Geophysical Research, 95(86), pp. 8617-8638.

three dimensions where the seismic source and receiver are located at the ground surface. Alternatively, higher resolution data can be obtained from vertical seismic profiling where receivers are located along the length of a wellbore. Even higher resolution data can be obtained by locating the source and receivers in wellbores and imaging between them. Successful images of CO_2 migration during EOR have been obtained using cross-well seismic imaging. Similar configurations are applicable to electromagnetic techniques, including electromagnetic EM and electrical resistivity methods. Recent efforts are developing electrical resistance tomography, a simple approach that uses the wells themselves as electrodes, as a low-cost, low-resolution method for tracking CO_2 movement within a wellfield. A pilot test of this technology is underway at the Vacuum Field in New Mexico.[93]

One of the shortcomings of all these techniques is the difficulty in quantifying the amount of CO_2 that is present. For example, the presence of only a small amount of CO_2 creates large changes in the seismic velocity and compressibility of the rock.[94] However, as the pore space is filled with a larger fraction of CO_2, little additional change occurs. There is ongoing work to develop methods to quantify the saturation of CO_2 in the pore space by combining electrical and seismic imaging measurements.[95] While it is unlikely that monitoring the saturation of CO_2 will be needed as part of a routine monitoring program, having this capability may be useful for improving understanding of geologic CO_2 storage. Similar limitations may apply to quantifying the rate at which leakage is occurring using geophysical techniques alone.

Land-Surface Deformation, Satellite, and Airplane-Based Monitoring

Recent advances in satellite imaging provide new opportunities for using land surface deformation and spectral images to indirectly map migration of CO_2. Ground surface deformation can be measured by satellite and airborne interferometric synthetic aperture radar (InSAR) systems.[96] Tiltmeters placed on the ground surface can measure changes in tilt of a few

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[93] Newmark, R.L., A.L. Ramirez, and W.D. Daily, 2002, Monitoring Carbon Dioxide Sequestration Using Electrical Resistance Tomography (ERT): A Minimally Invasive Method, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

[94] Arts, R., O. Eiken, A. Chadwick, P. Zweigel, L. van der Meer, and B. Zinszner ,2002, Monitoring of CO2 Injected at Sleipner Using Time Lapse Seismic Data, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

[95] Hoversten, G.M., R. Gritto, T.M. Daley, E.L. Majer, and L.R. Myer, 2002, Crosswell Seismic and Electromagnetic Monitoring of CO_2 Sequestration, Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, 1-4 October, 2002.

[96] Zebker, H., 2000, Studying the Earth with Interferometric Radar, *Computing in Science and Engineering*, **2**, No. 3, pp. 52-60, May-June, 2000.

nano-radians.[97] Taken separately or together these measurements can be inverted to provide a low-resolution image of subsurface pressure changes. While these technologies are new and have not yet been applied for monitoring CO_2 storage projects, they have been used in a variety of other applications, including reservoir monitoring and groundwater investigations.[98] Satellite spectral imaging has been used to detect CO_2-induced tree kills from volcanic outgassing at Mammoth Mountain, California.[99] Maturation of these technologies may provide a useful and comparatively inexpensive method for monitoring migration of CO_2 in the subsurface and for ecosystem monitoring.

Monitoring Programs and Approaches

The information provided above demonstrates that the toolbox of monitoring methods is large and provides reasonable assurance that the location of the CO_2 plume can be tracked. The challenge for any particular project is to design a monitoring program that is effective for a particular geological setting, that provides the information needed to demonstrate safe and secure storage—and that provides early warning should anything go wrong.

Figure 8 illustrates components of the subsurface system and the opportunities they present for monitoring. For on-shore geological storage reservoirs, monitoring can take place in the storage reservoir itself or in shallow saline formations that contain secondary accumulations of CO_2, as dissolved and secondary accumulations in groundwater, CO_2 in vadose zone gas, terrestrial ecosystems and finally by monitoring direct emissions into the atmosphere. While leaking faults and fractures (indicated by sub-vertical white lines in the diagram) would also contain CO_2, detection is likely to be difficult here as a result of their comparatively small size and unfavorable geometry. For off-shore storage reservoirs, the deeper components of the system are the same as their on-shore counterparts. However, as CO_2 approaches the seabed, the physical environment, ecosystems, and monitoring approaches are quite different. Dissolution into seawater, transport with the water column, and discharge at the sea-air interface present special monitoring challenges. Table 5 summarizes the methods, benefits and drawbacks for

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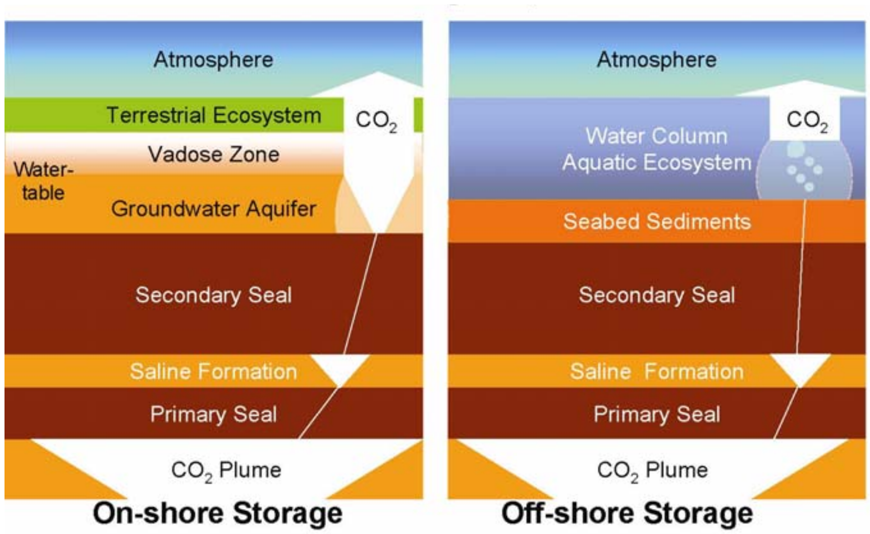
[97] Wright, C., E. Davis, W. Minner, J. Ward, L. Weijers,E. Schell, and S. Hunter, 1998, Surface Tiltmeter Fracture Mapping Reaches New Depths-10,000 Feet and Beyond?, *Society of Petroleum Engineering 39919*, April 1998.

[98] Vasco, D.W., et al., 2001, Geodetic Imaging: High Resolution Monitoring Using Satellite Interferometry, *Geophysical Journal International*, **200**, pp. 1-12; Hoffmann, J., H.A. Zebker, D.L. Galloway, and F. Amelung, June 2001, Seasonal Subsidence and Rebound in Las Vegas Valley, Nevada Observed by Synthetic Aperture Radar Interferometry, *Water Resources Research*, **37**, No. 6, p. 1551.

[99] Martini, B.A., E.A. Silver, D.C. Potts, and W.L. Pickles, 2000, Geological and Geobotanical Studies of Long Valley Caldera, CA, USA Utilizing New 5m Hyperspectral Imagery, Proceedings *of the IEEE International Geoscience and Remote Sensing Symposium*, July 2000.

monitoring each of these components of the system in the context of inventory verification and carbon credit trading.

Figure 8: Monitoring Options



Schematic showing the components of the subsurface and how they may be used for monitoring.

Credit: Benson and Myer, PIER White Paper

As indicated by the information in Table 5, there are a large number of approaches and options for monitoring emissions from geological storage reservoirs. Today, the most practical and cost-effective approach would rely on a combination of measurements and model predictions to assess annual emissions from the geological storage reservoir. Since the same combination of measurements would not be appropriate for all storage sites, flexibility to tailor the monitoring to the specific geological attributes of the storage site would be beneficial.

Table 5: Monitoring Approaches

System Component	Monitoring Methods	Benefits	Drawbacks
Storage reservoir	Seismic Gravity Well logs Fluid sampling	History match to calibrate and validate models Early warning of migration from the storage reservoir	Mass balance difficult to monitor Dissolved and mineralized CO_2 difficult to detect
Shallower saline formations below secondary seals	Seismic Pressure Gravity Well logs Fluid sampling	Good sensitivity to small secondary accumulations (~10^3 tonnes) and leakage rates Early warning of leakage	Detection difficult if secondary accumulations do not occur Dissolved and mineralized CO_2 difficult to detect

Table 6 : Onshore and Offshore Monitoring Approaches

Onshore			
System Component	Monitoring Methods	Benefits	Drawbacks
Groundwater aquifers	Seismic Pressure EM Gravity SP Well logs Fluid sampling	Sensitivity to small secondary accumulations (~10^2-10^3 tonnes) and leakage rates More monitoring methods available Detection of dissolved CO_2 less costly with shallow wells	Detection after significant migration has occurred Detection after potential groundwater impacts have occurred
Vadose zone	Soil gas and vadose zone sampling	CO_2 accumulates in vadose zone making detection easier compared to atmospheric detection Early detection in vadose zone could trigger remediation before large emissions occur	Significant effort for null result (e.g. no CO_2 from storage detected) Detection only after some emissions are imminent Does not provide quantitative information on emission rate

Table 6 con't : Onshore and Offshore Monitoring Approaches

System Component	Monitoring Methods	Benefits	Drawbacks
Terrestrial ecosystems	Vegetative stress	Vegetative stress can be readily observed using routine observation Satellite and plane-based methods available for quick reconnaissance	Detection only after emissions have occurred Vegetative stress can be caused by other factors Land use change could alter the baseline Does not provide quantitative information on emission rates May not be useful in some ecosystems (e.g. deserts)
Atmosphere	Eddy covariance Flux accumulation chamber Optical methods	Good for quantification of emissions	Distinguishing storage emissions from natural ecosystem and industrial sources necessitates comprehensive monitoring May not be best suited for detecting anomalous emissions due to relatively small footprint compared to the size of the plume Significant effort for null result

Table 6 con't : Onshore and Offshore Monitoring Approaches

Offshore			
System Component	Monitoring Methods	Benefits	Drawbacks
Water Column	Ship based fluid sampling and analysis Autonomous vehicles with CO_2, pH and carbon cycle sensors	Direct measurement of water column and fluxes (using inverse models)	Distinguishing storage related fluxes from natural variability requires comprehensive monitoring Quantifying separate phase CO_2 flux Significant effort for null result
Atmosphere	Optical methods Eddy covariance	Direct measurement of emission rate	Technology not well developed for this application Quantification of emissions may be impractical Changing emission footprint from ocean currents Likely to be costly to maintain Significant effort for null result

Source: Benson and Myer, PIER White Paper

A Tailored Approach to Monitoring

The value of taking a tailored approach to monitoring is twofold. First, the monitoring program focuses on the largest risks. Second, since monitoring may be expensive, a tailored approach will enable the most cost effective use of monitoring resources. Having said this however, it is likely that there will be a minimum set of monitoring requirements that will be based on experience and regulations from related activities such as natural gas storage, CO_2 enhanced oil recovery, and disposal of industrial wastes in deep geologic formations.

The monitoring program for CO_2 storage projects should be tailored to the specific conditions and risks at the storage site. For example, if the storage project is in a depleted oil reservoir with a well-defined cap rock and storage trap, the most likely pathway for leakage is the injection well itself or perhaps, abandoned wells from former reservoir operations.[100] In this case, the monitoring program should focus on detecting leakage from the injection well, locating any abandoned wells in the area, and ensuring they are not leaking CO_2 to the land surface or shallow aquifers. On the other hand, if a project is in a brine-filled formation where the cap rock is less well defined or lacks a local structural trap, the monitoring program should focus on tracking migration of the plume and ensuring that is does not leak through the cap rock.

Health and Safety Monitoring

If CO_2 is stored in oil or gas reservoirs, it may be important to also monitor other constituents that may be carried along with CO_2 in the event that leakage occurs. For example, if the storage reservoir contains natural gas or hydrogen sulfide, these too may leak toward the surface if a leakage path is established. Since methane is flammable and H_2S is highly toxic, these gases pose a greater risk than CO_2 and therefore, should also be monitored. Similarly, brine displaced from a hydrocarbon reservoir may contain dissolved organics and since supercritical CO_2 is an excellent solvent for oil, CO_2 may also transport hydrocarbons. Groundwater monitoring for displaced hydrocarbon may also be desired to ensure that groundwater resources are protected.

Monitoring Costs

Monitoring costs will depend on many factors, including the plume size, regulatory requirements, the length of time that monitoring is required, geologic site conditions, and the particular methods selected for application. As discussed above, many of the technologies likely to be used are already in widespread use in the oil and gas industries, and the costs for these

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[100] Benson et al., 2002a, Op. cit.

technologies are well constrained. In comparing costs of individual technologies within this group, it is seen that the cost of conducting a 3-D seismic survey is large compared to any other technology. Consideration of the need for 3-D seismic surveys thus has a significant impact on monitoring costs.

There is limited information available on costs for monitoring of sequestration projects. Benson and others estimated life-cycle monitoring costs for two scenarios: (1) storage in an oil field with EOR, and (2) storage in a saline formation.[101] The scenarios were not developed to be prescriptive of what a monitoring program should be, but are representative of plausible examples. For each scenario, cost estimates were developed for a "basic" and an "enhanced" monitoring program. The basic monitoring program included periodic 3-D seismic surveys, microseismic measurements, wellhead pressure, and injection rate monitoring. The enhanced monitoring program added periodic well logging, surface CO_2 flux monitoring, and other advanced technologies. The assumed duration of monitoring included a 30-year injection period as well as a post-injection monitoring period of 20 years for the EOR scenario and 50 years for the saline formation scenario. For the basic monitoring program the undiscounted cost for both scenarios was \$0.16 – \$0.19/ton CO_2. For the enhanced program, the undiscounted cost was \$0.27 – \$0.30/ton CO_2.

Monitoring of off-shore sequestration projects will involve many of the same techniques used in on-shore projects. However, operation in the off-shore environment will influence costs. In general, acquisition of 3-D seismic data is less expensive off-shore than on-shore, particularly for large scale surveys. Off-shore seismic surveys involve ship-towed systems while on-shore surveys involve wheeled vehicles and manual labor. Well-based measurements, however, are more expensive off-shore because of rig costs.

Case Studies and Pilot Projects

Several CO_2 storage projects are now underway or are planned for the near future where the demonstration and evaluation of monitoring technology is a major focus of the project. These projects include Sleipner, Weyburn, the Frio project in Texas, and the West Pearl EOR Project in southwestern New Mexico. In addition, several pioneering projects have demonstrated the effectiveness of monitoring technologies for tracking CO_2 migration in the reservoir. These include EOR projects at Lost Hills Oil Field in the Central Valley of California, the Vacuum Field in New Mexico, and the Rangely Field in Colorado, as well as natural analog studies in Europe, Australia, and the United States.[102] These projects have shown that many of the

[101] Benson et al., 2005, Op. cit.

[102] Benson S. and Myer L., PIER White Paper on Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide

methods described here can play a valuable role in ensuring safe and effective geologic storage of CO_2.

CHAPTER 7: Risks and Risk Management

Geologic storage projects should be designed to assure protection of the health and safety of workers, the public and the environment. Risk assessment and management for CCS focuses on potential releases of captured gases through all phases of operation, including capture, transportation, and subsurface storage. The study by Price, et al., provided the foundation for this chapter.[103]

While there is substantial relevant information available from existing analogous industries (e.g., natural gas storage, CO_2-EOR, and underground waste injection), findings from ongoing and early CCS projects will be important in guiding development of risk assessment and management practices specific to CCS. For example, the risk assessment report for the FutureGen Project provides an early example of how existing risk assessment tools can be applied to evaluate candidate sites for a CCS project.[104] Given the long-term nature of CCS projects, the time frame for risk assessments is an important consideration. The FutureGen risk assessment uses 50 years for the pre-injection period, and 5000 years for the post-injection period, also selected by the Weyburn EOR project.[105]

Risk assessment for CCS is aided by dividing the process into above-ground and below-ground components; pre-injection risk assessment is associated with releases from surface facilities and engineered systems for separating, compressing and transporting CO_2; post-injection is focused on potential impacts of releases from wells and storage reservoirs.[106]

Goals of Risk Assessment and Management

The goal of risk assessment is to quantify the likelihood of harm (or loss) and to present such analyses in a format that assists decision makers who must act to tolerate, mitigate, or eliminate the potential harm. The goal of risk management is to establish the practical significance of the assessed risks, compare the costs of reducing these risks to benefits gained, compare the risks to the societal benefits derived from incurring the risk, and to establish political and institutional processes of reducing risks.[107]

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[103] Price, P.N., McKone, T and Sohn, M.D., PIER White Paper on Carbon Sequestration Risks and Risk Management

[104] Ibid.

[105] Ibid.

[106] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

[107] Price, et al., Op. cit.

Risk Assessment

Risk assessment requires not simply an evaluation of what deleterious effects are possible, but also an assessment of the likelihood of these effects. Risk assessment should address three questions:

(1) What can go wrong?

(2) How likely is it to happen?

(3) What are the consequences?[108]

The first question is answered by a hazard assessment, defining accidents, failures, or exposure sequences beginning with their initiating event, followed by any chain of events that either mitigate or facilitate a progression toward harm. This process results in an "end state". For engineered systems, this is commonly called an accident or failure sequence. In toxicology, this is the source-to-dose-to-response sequence. The answer to the second question is the frequency or probability of that sequence occurring. The third question is addressed by the end-state, which expresses consequences in risk assessments as some number of fatalities, injuries, or diseases for human health risk, as the expected effect on species or ecosystems for ecological risk, or as dollars lost in financial risk.

The Society for Risk Analysis (SRA) has broadly defined risk as the:

"potential for realization of unwanted, adverse consequences to human life, health, property, or the environment; estimation of risk is usually based on the expected value of the conditional probability of the event occurring times the consequence of the event given that it has occurred."[109]

Risk assessment starts with hazard identification, which refers to identifying all possible hazards without focusing on the likelihood of harm or the extent of damage. After hazard identification, the next step is risk characterization. Risk characterization involves detailed assessment of each identified hazard in order to determine the risk posed by the hazard. Risk characterization includes three principal elements:

identify all of the scenarios in which the negative effects of the hazard would be realized,

quantify the negative consequences associated with each scenario, and

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[108] Kaplan, S. and B. J. Garrick, "On the Quantitative Definition of Risk," Risk Analysis, Volume 1, No. 1, pp 11-27, 1981.

[109] Society for Risk Analysis web site (2007) http://www.sra.org/resources_glossary.php

assess the magnitude and sources of uncertainty that limit the precision of the estimates in parts (1) and (2).[110]

For hazard scenario identification, a Features-Events-Processes (FEP) methodology, which systematically identifies and ranks the importance of various attributes of the site and possible events, has been developed for CCS and may provide a useful framework for evaluating candidate CCS sites in California.[111] Probabilistic approaches, such as complementary cumulative distribution functions (CCDF), which calculate reasonable expectations for ranges of parameter variability and for conceptual or scenario uncertainties, also could be used.[112]

The Dose-Response Relationship

Probably the greatest hazard associated with CCS is the potential for a leakage event to expose people, animals, or plants to harmful levels of chemicals. It is important to note that if projects are designed with the goal of near zero-emissions, other types of gases in addition to CO_2, will be captured and sequestered.[113] In addition, subsurface leakage may also result in secondary processes that generate other compounds. When chemical exposure is a risk component, risk assessment requires the inclusion of "exposure assessment," additional steps to quantify the probability that hazardous concentrations of the chemical will be realized in exposure media, such as ambient air and indoor air, and then, the potential for these concentrations to cause adverse effects on people or the environment.[114]

CO_2 occurs naturally, and all animals (including humans) have a long evolutionary history of exposure to several hundred parts per million of CO_2 in air. The current atmospheric concentration of CO_2 is about 380 parts per million. The atmospheric concentration is expected to increase over the next hundred years or more due to continued fossil fuel burning, and is predicted to exceed 600 parts per million by the end of this century.

Humans, like other animals, are tolerant of CO_2 concentrations much higher than normal without known ill effects. CO_2 concentrations above about 800 parts per million can lead to a perception of stale air, but without apparent physiological effects. Some people (such as submariners) have been exposed to 1000 parts per million (i.e., 0.1 percent) CO_2 for several weeks, again with no known effects; however, one might speculate that some subgroups, such as people with decreased lung function, might be more susceptible.

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[110] Price et al., Op. cit.

[111] http://www.quintessa.org/consultancy/index.html?co2GeoStorage.html

[112] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations, Lawrence Berkeley National Laboratory Report LBNL-51170.

[113] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

[114] Price, et al., Op. cit.

From about 1,000 to 1,500 parts per million CO_2 is a respiratory stimulant, causing an increased breathing rate, but it has no other known physiologic effects. From 1500 to 3000 parts per million, the CO_2 concentration in blood increases above normal levels, making the blood acidic (a condition called acidosis). A significant increase in respiratory rate, and some discomfort, sets in at about 30,000 parts per million (3 percent) of airborne CO_2, and above 5 percent the effects become severe and loss of consciousness can occur. Federal occupational safety and health regulations limit workplace exposure to an average of less than 5,000 parts per million (0.5 percent) for a 40-hour work-week.[115]

Ecosystem impacts from exposure to elevated concentrations of CO_2 are poorly understood. Plants in general are even more tolerant than invertebrates to elevated CO_2, and so any small-scale, short-term gas leaks would have minimal impacts. Persistent leaks, in contrast, could suppress respiration in the root zone or result in soil acidification, and catastrophic releases could certainly kill vegetation as well as animals. Most of the controlled experiments have focused on moderate increases in CO_2 concentrations expected from anthropogenic buildup of CO_2 or to test stimulation by CO_2 of plant productivity in greenhouses. These studies have shown that moderate increases in CO_2 concentrations stimulate plant growth, while decreasing the loss of water through transpiration. At the other end of the scale, tree kills associated with soil gas concentrations in the range of 20 to 30 percent CO_2 have been observed from volcanic out-gassing at Mammoth Mountain, California. Little information is available in the intermediate range of 2 to 30 percent. In addition, information on the tolerance of aquatic ecosystems to short-term, catastrophic releases was not found and may need to be researched.[116]

Risk Management

Once the risks associated with a project have been identified and quantified, a decision maker or regulator develops a basis for evaluating these risks and then, as necessary, takes action to communicate and manage the risks, including evaluating the benefits vs. costs of risk reduction, based on economic, environmental and societal criteria. There are four types of analyses used commonly in the risk management process—risk-benefit, cost-benefit, risk-risk, and cost-effectiveness. A risk-benefit analysis compares the risks added by an activity to the concurrent benefits (usually economic) provided to society. A cost-benefit analysis relates the financial cost (in dollars) of reducing risk to the benefits (in equivalent dollars or an appropriate surrogate) gained by reducing risk. A risk-risk analysis establishes the significance of an estimated risk by

[115] Ibid.

[116] Ibid.

comparing it to some other commonly accepted risk. A cost-effectiveness analysis is used to compare risk reduction options on a per unit cost basis.[117]

For CCS, a new and unfamiliar technology, the communication of its risks relative to familiar hazards, is an important aspect of risk management. In addition, CCS risks need to be place in the context of its climate change benefits, and compared to risks associated with other options for mitigating the same degree of GHG emissions.

Addressing Uncertainty

All risk assessments are conducted without complete and perfect knowledge and/or data—addressing the uncertainty arising from this problem is perhaps foremost among the recurring themes in risk assessment. In addressing uncertainty, it is important to distinguish between random variations (or variability) and chance outcomes, and lack of knowledge.[118] More research (both observational and theoretical) can reduce risk due to lack of knowledge (for example, risk due to a lack of good data for site characterization), however, uncertainty due to chance or randomness can only be better characterized, but not reduced, with more research (for example, the heterogeneity inherent in subsurface formations).

Reducing uncertainties does nothing in and of itself to reduce risks. However, identifying sources of risk and quantifying risk are very important. More site characterization information could reveal previously unknown problems, such as faults or fractures, thus increasing the estimated risk to the point that the site is unacceptable; or the new information could confirm that the site is acceptable. The risk hasn't changed, but the knowledge of the risk has changed, and this can affect decisions.

The International Program on Chemical Safety proposed four tiers for addressing uncertainty in exposure assessment ranging from the use of default assumptions to sophisticated probabilistic risk assessment. Although these tiers were developed for chemical safety, they provide a good basis for discussing uncertainties in other contexts as well, including CCS.[119]

Effective policies are possible under conditions of uncertainty, provided that the uncertainty is taken into account.[120,121] In order to make risk assessment consistent with such an approach, it

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[117] Ibid.

[118] Price, et al., Op. cit.

[119] Ibid.

[120] Berger, J.O., 1985, Statistical Decision Theory and Bayesian Analysis. Springer-Verlag, New York.

[121] Ludwig, D, Hilborn, R., and Walters, C., 1993, Uncertainty, resource exploitation, and conservation: Lessons learned from history, Science 260, 17-36, April, 1993.

should incorporate a formal quantitative treatment of uncertainties in the risk characterization step. Regulations that provide site- and project-specific flexibility, for example, could help to address uncertainty. For CCS, as is discussed above, the degree of uncertainty in site characterization can be highly variable, and it may be important to consider a variety of plausible approaches (e.g., site planning), a variety of possible scenarios (e.g., a range of realizations in storage reservoir simulations), actions that are robust to uncertainties (e.g., conservative requirements for well completions), actions that are informative to reducing uncertainty (e.g., monitoring programs), and to update site characterizations and risk assessments as new data become available. In this way, the ability to assess carbon sequestration risks will improve with time and with experience. Especially in the early years, each sequestration site is not just a place to get rid of CO_2, it is also an experiment that will provide valuable data for use in future sequestration efforts. In this context, an adaptive decision-making approach may be appropriate for development of CCS:

- Start with sites, technologies, and actions for which the risk is believed to be acceptable now, even if this is a small list. As knowledge increases, the list will grow.
- In some cases, the information that can be gained from an action, or from using a certain site, may be important to consider, in addition to the probability of success. If two sites or technologies are judged to be acceptable in terms of risk and total cost, but one would provide information that the other would not, the one that provides new information should be considered.

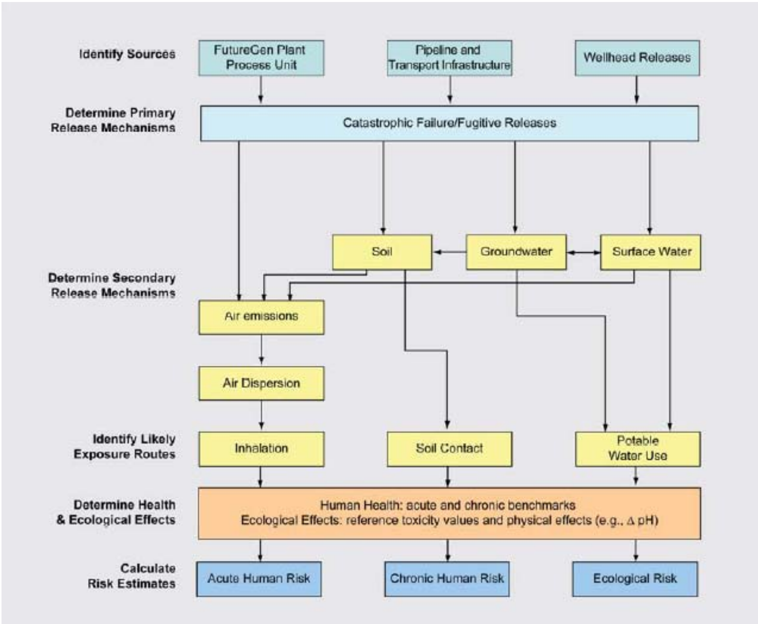
Carbon Sequestration Risk Scenarios

Figures 9 and 10 show generic scenarios for pre-injection and post-injection leakage risk assessment developed for the FutureGen project. These diagrams show the relationships among sources, primary and secondary processes that generate a gas release, exposure media or routes, and human health or ecological effects. In the pre-injection case, the engineered systems that produce and transport CO_2 can be sources of released gas, either during normal operations or when systems fail due to external disruptions. In the post-injection case, injected gas can escape through failure of the injection borehole seal, through known or previously unrecognized abandoned wells, and through fractures or faults that may transect the reservoir cap rock. The sequestered gas may also have environmental impacts even without leakage to the atmosphere, either by transport into aquatic ecosystems or underground sources of drinking water, or by enhancement of radon migration into indoor air. Receptors of concern from atmospheric emissions include workers in the plant, nearby human populations, and areas of natural resource value. Besides these groups of individuals, receptors of concern from surface leaks include aquatic ecosystems, consumers of affected drinking water supplies, and residents affected by enhanced radon intrusion into indoor air.[122]

In order to understand the risk associated with a potential CCS site, the site conditions must be evaluated in the context of the development plans for the project. Both surface characteristics, such as locations of sensitive ecosystems, surface lakes, topography, locations of population centers, and subsurface features, such as potable groundwater resources, depth to target reservoir, fault and fracture distributions, cap-rock thickness, existing well locations, and other parameters as described in the chapter on geologic site characterization, should be included. In

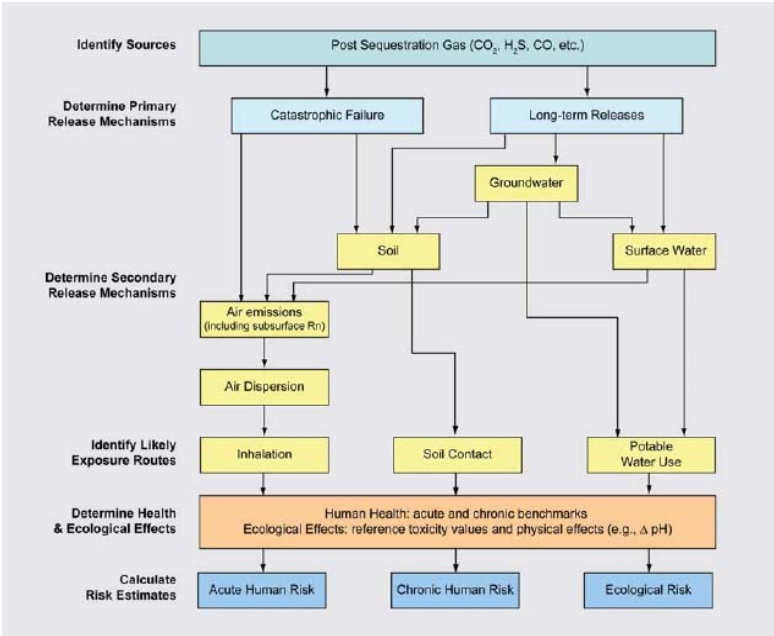
[122] http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

Figure 9: Generic Pre-Injection Risk Assessment Developed for FutureGen



Credit: Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement
http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

Figure 10: Generic Post-Injection Risk Assessment Developed for FutureGen



Credit: Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement
http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/

addition, project information, such as number of wells needed, distances and available pipeline right-of-ways between the CO_2 capture site and the storage site, should be provided.

The potential hazards associated with CCS have been studied extensively.[123,124] Those pertaining to CCS projects in California include hazards due to leakage and induced seismic activity, such as:

1. Human injury, death, or environmental damage caused by exposure to hazardous levels of CO_2 or other chemicals associated with a leakage event;
2. Property damage to mineral or groundwater resources through (a) contamination of groundwater, natural gas, or oil resources or of underground storage facilities, (b) pressure-induced migration of oil or gas that complicates extraction or renders it infeasible, or (c) precluding mining operations in adjacent areas;
3. Property damage, environmental damage or human injury from induced seismic activity due to increased fluid pressure deep underground (see section in Site Characterization chapter above);
4. Injury or death to workers through heavy-machinery accidents and other industrial accidents not covered in Item 1, above.

The risks associated with these hazards are not fixed quantities, rather they depend on the sites used for sequestration, on technologies, and on operating practices used for injection, etc. Quantitatively characterizing the risks associated with specific sequestration sites, pipeline routes, and management strategies will be important for CCS risk assessment, and can be aided by previous experience and analogs in related industries. For example, injection of CO_2 for EOR has parallels with CCS injection, CO_2 pipelines for EOR already exist, and natural gas and other types of pipelines are extensively used. Underground injection also has been used for natural gas and liquid and gaseous waste disposal. Some large-scale CCS projects already are underway and can provide useful data. In short, there is a foundation of real-world experience that can help with risk quantification for potential CCS hazards.[125]

With respect to #4 above, all industrial construction and drilling operations involve accident risks to workers, which are well understood, not unique to CCS, and addressed through Cal OSHA and industry safety practices.

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[123] Intergovernmental Panel on Climate Change, 2005, Special Report on Carbon Dioxide Capture and Storage. http://www.ipcc.ch

[124] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations, *Lawrence Berkeley National Laboratory Report LBNL-51170*.

[125] Price, et al., Op. cit.

With respect to #1-3 above, CCS researchers have identified theoretically plausible scenarios – failure mechanisms – that could lead to hazards being realized.[126] Researchers typically examine possible scenarios for CO_2 leakage, including:

- Leakage from pipelines or pumping stations to the surface or shallow subsurface;
- Leakage from geologic storage reservoirs, including pathways through wells, faults or fractures or other breaches in cap-rock integrity, to the surface or shallow subsurface;
- Leakage into groundwater;
- Leakage into natural gas or oil deposits;
- Over-pressuring from CO_2 injection that could induce fault re-activation or fracturing, thereby increasing permeability and possible leakage risks and inducing seismic activity.[127]

Scenario 1: Pipeline Leaks

Precautions are well established for existing pipelines to minimize the likelihood of a major pipeline breach. Moreover, pipeline distribution systems, including carbon dioxide pipelines, have a fairly good safety record. Long-distance carbon dioxide pipelines in the U.S. total about 2600 km and produced no injuries or fatalities over a thirteen-year period.[128] CCS would require building many more pipelines, some of which would likely pass through or near densely populated areas since they must originate at power stations.[129]

Natural gas pipelines are, of course, different from carbon dioxide pipelines in several significant ways, the most important of which is that natural gas is highly flammable. There are 295,000 miles of natural gas transmission pipelines in the U.S., and about 1.4 million miles of distribution pipelines. According to the Pipeline and Hazardous Materials Safety Administration, during the 10-year period from 1994-2003 (inclusive), 795 natural gas pipeline accidents resulted in 26 fatalities, 97 injuries, and $256 million property damage. Most of the fatalities and injuries were due to fires or explosions associated with pipeline leaks, almost a third of which are due to damage during excavation. Notably, 20 percent of these incidents were due to corrosion. Conventional pipelines for most materials use carbon-manganese steel, which is not corroded by carbon dioxide if humidity in the pipeline is low, and so it will likely

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[126] Ibid.

[127] Ibid.

[128] Gale, J. and J. Davison, 2002: Transmission of CO_2 – safety and economic considerations. Energy, Special issue dedicated to 6th International Conference on Greenhouse Gas Control Technologies, Editors, P. Freund, Y. Kaya and N. Lior, Vol 29, No. 9-10, July – August 2004, pp 1319-1328.

[129] Price, et al. Op. cit.

be economically important to dry the carbon dioxide before transport (standard practice for CO_2-EOR pipelines). Outright breakage of pipelines during earthquakes (or other land movements such as landslides) that cause large ground movements are thought to be rare. More commonly, gradual shifts in the ground may cause stresses that lead to small leaks.[130]

A small pipeline leak could cause harm if the carbon dioxide pools in a depressed area. The concentration of carbon dioxide would be determined by the competition between the rate that carbon dioxide leaks from the pipeline and enters the depression area, and the rate that carbon dioxide escapes the depressed area due to wind. If the release is very small, or if wind mixes the air in the depressed area significantly and regularly, the concentration in the area will be well below a level of concern. Risks from pooling apply to other types of dense gases in pipelines, and so analysis of this risk should include examination of existing analogous data sources.

A large pipeline leak resulting from a major rupture would release a large quantity of carbon dioxide very quickly. Such a release would be short-lived and would be rapidly detected by pipeline monitoring (and perhaps immediately apparent to people in the vicinity as well). As with the risk of a small leak, the risk of a large leak is not unique to CO_2 and experience with other types of pipelines can provide useful quantitative information on the statistical distribution of leak sizes and frequencies that can be expected.

Steps can be taken to minimize risks from carbon dioxide pipelines (as from any hazardous materials pipelines). These include:

- Site pipelines away from populous areas when possible;
- Avoid running pipelines near homes in sheltered, populated valleys where leaking carbon dioxide could accumulate to dangerous levels;
- Monitor pipelines regularly for corrosion;
- Monitor constantly for leaks;
- Install safety valves to shut off the pipeline in the event of a large leak;
- Consider adding odorant to carbon dioxide, as is done with natural gas, to allow people to easily notice small leaks.

Scenario 2: Leakage from Geological Storage to Air

Risk from Slow, Steady Discharge

Releases of CO_2 that are much too small to cause widespread death or injury can still cause acute local problems, including human fatalities. Human, animal, and plant fatalities from carbon dioxide have occurred near hot springs and fumaroles. The area around Mammoth Mountain, California provides a good illustration. Mammoth Mountain is a young volcano. In

[130] Price, et al. Op. cit.

1990, following a series of small earthquakes the previous year, CO_2 began leaking upwards along faults from a natural subterranean reservoir of CO_2. The amount of CO_2 leakage has been estimated at about 300 tons per day for the entire fault system, which covers several square miles, but the leaks are concentrated in certain areas. The high level of CO_2 in soils in some areas has killed over one hundred acres of trees, and the airborne concentrations are high enough to endanger animals or people in depressions and enclosed spaces. Three ski patrol members were killed in 2006 when they fell into a snow cave created by a fissure containing very high concentrations of CO_2. A contrasting example of CO_2 leakage to the surface is provided by the "Crystal Geyser" in Utah. Crystal Geyser is an uncompleted oil well in Utah that was abandoned around 1940 after intersecting a natural pressurized CO_2 reservoir. It erupts like a geyser and can eject up to 40 tons of carbon dioxide mixed with water during a two-hour eruption. Terrain near the geyser is fairly flat, and does not have depressions that tend to accumulate carbon dioxide. Visitors to the site during eruptions have not experienced ill effects, even when standing directly under the ten-foot-high jet of carbonated water ejected from the geyser.

Risk From Fast, Large Discharge

As noted above, volcanic terrains tend to produce natural CO_2 and other gases that can leak to the surface through the extensive open fault and fracture networks typically associated with these tectonically or seismically active areas. The Kilauea Volcano in Hawaii emits on average 4 million tons CO_2/yr. More than 438,000 tons CO_2/yr leaked in the Mammoth Mountain area, California, from 1990 to 1995. In Cameroon, Africa, very unusual geologic circumstances lead to the periodic buildup and rapid degassing of CO_2 from lakes that occupy volcanic craters, Lake Nyos and Lake Monoun. Large-scale fatalities have occurred near these lakes.

In 1987, the sudden release of over 1.2 million tons of CO_2 from Lake Nyos resulted in the deaths of over 1700 people; in 1985, a smaller release from Lake Monoun killed over 30 people.[131] For comparison, a 1000 MW coal-fired power plant emits about 30,000 tonnes of carbon dioxide per day; the Lake Nyos release represents about 40 days of emissions from a large power plant and is about the same as the amount injected annually at the world's largest sequestration projects today.

There have been attempts to compare CCS reservoir leakage risk to the risks associate with Lake Nyos.[132] However, not all natural systems are appropriate risk analogs for CO_2 sequestration.[133]

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[131] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations, Lawrence Berkeley National Laboratory Report LBNL-51170.

[132] Ibid.

[133] *A Review of Natural CO_2 Occurrences and Releases and their Relevance to CO_2 Storage*. http://www.co2storage.org/Reports/Natural%20Releases%20Report.pdf

CO_2 sequestration targets formations that lie deep in sedimentary basins within tectonically stable geologic environments which are very unlike the volcanic terrains of Lake Nyos. For CCS, plausible pathways for leakage to the surface include orphaned, plugged and abandoned or operating wells, faults and fractures, fault re-activation, and diffuse seepage through the overlying rocks and soil. None of these pathways is a likely conduit for the sudden release of quantities of gas like that which escaped from Lake Nyos.[134] CO_2 migration in fractures through hundreds of meters of rock is, in no way, comparable to the process by which a density inversion causes a lake to overturn. Even if leakage occurs from compromised wells, several mechanisms limit the rate of release, such as low rates of CO_2 transfer from reservoir to wellbore and the "Joule-Thomson effect" whereby CO_2 would freeze and solidify on its way up a well due to the sudden drop in pressure.[135]

Given the special conditions that are required for a Lake Nyos-type event, the risk of such an event from a failed CCS site is low, even if no special precautions are taken. A simple method for avoiding anything remotely similar is to avoid selecting sites underlying deep lakes—only two lakes in the U.S. are at all similar to Lake Nyos—one is Crater Lake in Oregon, the other is Lake Tahoe in California/Nevada, and neither of these areas is geologically suitable for CCS.

However, to some degree, this begs the question as to whether a Nyos-type event could happen in any surface water body overlying or adjacent to a CCS reservoir which leaked into it. One important characteristic of Lake Nyos is that it remains stratified or layered over years, allowing the CO_2 to build up in the bottom layer of the lake out of contact with the atmosphere. While lakes do stratify frequently in other places, the turnover of lake water happens frequently, often seasonally, such that any gas collecting in bottom layers is removed. While it is unreasonable to dismiss CCS based on an analogy with Lake Nyos, it may also be prudent, should deep lakes that stratify be above or adjacent to a project, to ascertain their turnover rates during the site characterization process.

Scenario 3: Leakage from Geological Storage to Groundwater

The regulations in the Underground Injection Control program were designed to protect drinking water resources. A look at the history of industrial liquid waste disposal provides a good example of how regulation can reduce risk to groundwater. Similar precautions can be applied to CCS projects, as is discussed below in the chapter on regulatory and statutory issues.

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[134] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations, Lawrence Berkeley National Laboratory Report LBNL-51170.

[135] Ibid.

Early performance of underground waste injection projects was mixed, with many examples of well failures and contamination of drinking water aquifers. Failures were attributed to (1) poor characterization of the confining units; (2) improper well completion techniques; (3) use of well construction materials that were incompatible with the waste streams and, consequently, corroded; (4) inconsistent or inadequate monitoring; and (5) leakage through abandoned wells. Because of these problems and the inconsistent approach to oversight, progressively more stringent regulations were put in place to make the practice of industrial waste disposal by liquid injection safer. By 1988, the current set of UIC regulations was put in place and since that time there have been no incidents where drinking-water contamination has been reported.[136]

However, from a risk assessment standpoint, the hazardous waste injection analog is not perfectly applicable to carbon dioxide because (1) the quantity of carbon dioxide that would be injected into sequestration sites dwarfs the amount of toxic material injected into waste storage sites; (2) carbon dioxide is buoyant, whereas most toxic material injected into waste wells is approximately neutral; and (3) carbon dioxide is far less toxic than most materials that are injected for hazardous waste disposal. The IPCC report, as cited in the chapter above on site characterization, provides a list of criteria to protect groundwater resources.

Scenario 4: Leakage from Geological Storage to Fossil Fuel Assets

If CO_2 from CCS projects migrates into fossil fuel reservoirs apart from the storage site, as is discussed below in the chapter on regulatory and statutory issues, there are issues with property damage to consider. Conversely, such leakage could very well improve oil recovery and benefit the property owners. The probability of leakage to a fossil fuel asset is likely to be similar to the probability of leakage to groundwater and can be decreased in the same way, through proper site selection.

Climate Change Risk

It is important to note that leakage of any type of captured CO_2, in addition to the hazards discussed in the previous subsections, also returns carbon into the atmosphere, creating a "climate change" risk. Both catastrophic leaks and slow leakage, particularly disperse, slow leaks that are undetectable by many monitoring technologies, can contribute to this type of risk.

Predicting the future course of events at a carbon sequestration site is particularly challenging because the site must retain injected CO_2 for at least hundreds of years to be effective at mitigating GHG emissions. These timescales are short compared to geologic timescales, but very long compared to the timescales of typical risk assessments, and to existing datasets for

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[136] Ibid.

any geologic phenomena. This issue is discussed in greater detail in the chapter on monitoring and verification.

CHAPTER 8: Remediation and Mitigation of CO_2 Leakage

Despite site selection and CO_2 injection procedures to minimize risk, prudence suggests that policies and regulations be established to mitigate and remediate any situation in which public health, economic activity, or the environment could be negatively affected by releases of CO_2. [137] The PIER white paper by Kuuskraa provided the foundation for this chapter.[138]

A series of actions are central to preventing and correcting leakage of CO_2 from geological formations, namely rigorous site selection, assured well integrity, long-term modeling of the CO_2 plume, monitoring of the injected CO_2 (including early identification of leakage), and prompt mitigation and remediation actions should any CO_2 leakage occur. Experience with storing CO_2 in geological formations at the Weyburn, In Salah, and Sleipner projects suggests that the inherent risks and potential quantities of CO_2 leakage will likely be minimal. However small the risk, CO_2 leakage can result from human error, natural hazards, or other unknown factors. Orphaned wells, compromised reservoir seals, and migration of CO_2 beyond a confining structure are potential leakage pathways.[139] If sustained CO_2 leakage were to occur to any significant degree, by any pathway, the risks of unintended consequences from a geological storage project would increase.[140]

Should a situation of unacceptable project risk arise, existing oil and gas field mitigation and remediation practices and technologies could address most of the concerns related to CO_2 injection and storage in association with EOR. Many of these practices would also be directly transferable to CCS projects without EOR, in depleted hydrocarbon reservoirs and saline formations. Nonetheless, further efforts are needed to address longer-term CO_2 storage monitoring, leak detection, and mitigation/remediation at spatial and temporal scales longer than those for EOR operations. The closest long-term analog for CO_2 storage, the natural gas storage industry, has a portfolio of safe and reliable technologies to monitor, detect, and remediate natural gas leakage, which should be applicable or adaptable to CCS. These include reservoir pressure control, shallow gas recycle, wellbore remediation, well re-plugging, and in extreme cases, reservoir abandonment and relocation.

A high priority would be development of procedures for identifying and then sealing a failure in the reservoir seal or cap rock. Equally valuable would be work on materials selection and

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[137] Kuuskraa, V., PIER White Paper on Overview of Mitigation and Remediation Options for Geological Storage CO_2

[138] Ibid.

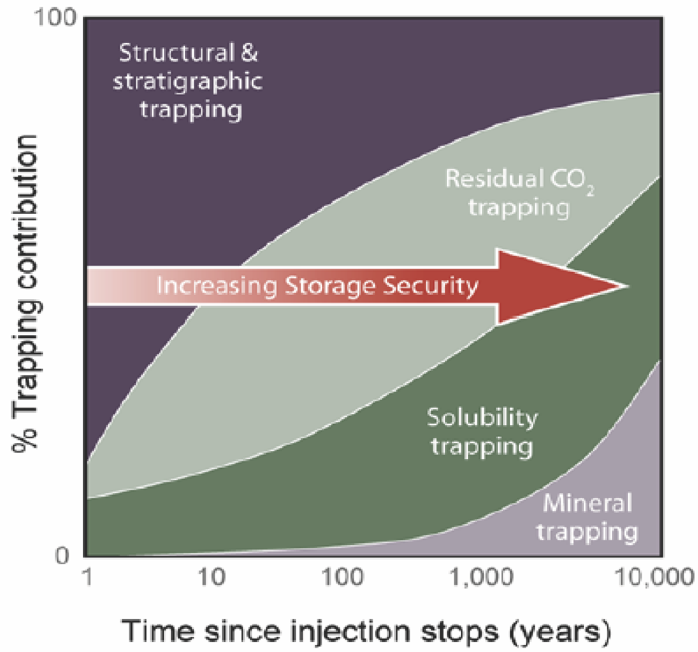
[139] Ibid.

[140] Ibid.

procedures for achieving a "thousand-year well." More also needs to be done to develop cost-effective means for reliably locating and assessing the status of orphaned or old plugged and abandoned wells and on technologies for securely reworking or plugging wells in a CO_2 storage environment.

The science and technology of remediating CO_2 leakage is still emerging. With appropriate leak prevention and mitigation strategies, it will become possible to achieve one of the challenging goals facing the storage of CO_2 in geological formations, assuring the long-term security of CO_2 storage. In this context, it is important to recall previous discussion (see chapter on site characterization) of storage mechanisms which suggests that the security of storage increases over time (Figure 11).

Figure 11: CO_2 Storage Trapping Mechanisms and Increasing Storage Security with Time



Credit: Heidug, Wolfgang, "Risk Management for CCS and CO2 Policy," presentation at the WBCSD/IETA side event, SBSTA 24, Bonn, 19 May 2006.

Background

With thorough site assessment, rigorous monitoring and a pro-active leakage prevention and remediation strategy, the use of geologic storage of CO_2 can be safe, secure and worthy of public acceptance. Of particular note is the excellent reliability and safety record of the natural gas storage industry, the closest long-term analog for CO_2 storage. Still, CO_2 leakage diagnosis and remediation, particularly remediation, has received much less attention and priority than this important topic deserves. For example:

- A search of the technical literature identifies very few technical reports or papers that concentrate on CO_2 leakage remediation. Generally, this topic, even when addressed, is given only "high level" and brief discussion in papers addressing geological storage of CO_2.
- There is only one in-depth study of remediation experiences and "lessons learned" for the most analogous activity to CO_2 storage, the natural gas storage industry. The work by Perry[141] provides original data and thorough investigation of this topic, including its relevance to CO_2 storage.

Existing Remediation and Mitigation Procedures

California has a series of statutes that govern mitigation and remediation of oil and gas leakage.[142] These existing statues could be modified to include reference to, and provisions for, CCS, or serve as a starting point for developing specific statutes for mitigation and remediation of leakage from CO_2 storage sites. Statutory provisions of relevance are contained in the following sections of the Public Resources Code:

Section 3208. Well Completion Abandonment and Reabandonment

Section 3219. Blowout Prevention and Insurance

Section 3220. Well Integrity

Section 3224. Order for Repair

Section 3240. Abandoned Wells

Section 3241. Extracting Gas from High Risk Areas

Section 3240. Hazardous Wells

Further study of the natural gas storage industry may provide relevant analogs for remediation experiences, practices, and "lessons learned." There are nine natural gas storage fields in northern and southern California, owned and operated either by PG&E or Southern California

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141 Perry, K, 2003, *Natural Gas Storage Experience and CO_2 Storage*, report prepared for the CO_2 Capture Project by the Gas Technology Institute.

142 California Laws For Conservation Of Petroleum & Gas, ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf

Gas. These storage facilities, designed to help meet seasonal gas demand and improve the efficiency of securing gas supplies, are regulated by the CPUC. They have operated safely.

Natural gas has been stored and recycled in geologic formations for nearly 100 years. Approximately 600 U.S. storage reservoirs, containing nearly 8 Tcf of natural gas (equal to about 2 billion metric tons of CO_2 storage volume), help meet peak natural gas demand during winter and provide a repository for excess natural gas production during summer. An in-depth survey of U.S. gas storage operations was conducted for the CO_2 Capture Project by K. Perry of the Gas Technology Institute (Perry, 2003). In this survey and its associated report, Perry identifies ten examples of leakage from natural gas storage facilities, mostly occurring prior to 1970 before the use of modern site appraisal and well completion practices. This survey provides valuable information on the portfolio of technologies used by the underground gas storage industry to monitor, detect and remediate natural gas leakage. The nature of these leaks and the remediation action taken are summarized in Table 8.

Mitigation and Remediating Cap Rock Leaks

Five of the gas storage leakage incidents involved leakage of natural gas through the cap rock or seal, requiring that three of the gas storage reservoirs be abandoned:

- In the late 1960’s, an overly shallow aquifer-based gas storage field was established in Northern Indiana. After leakage was detected in a number of the nearby water wells, the gas storage field was drawn down and abandoned. (Current regulations would no longer allow or certify such a shallow gas storage field.)
- In mid-1953, shortly after the Herscher-Galesville aquifer-based gas storage field in Illinois was put on operation, bubbles of gas appeared in shallow water wells in the area. Four mitigation actions were taken that have enabled this gas storage project to continue operating for 50 years, namely: (1) drilling of shallow wells to capture the leaked gas; (2) reinjection of the captured gas back into the Galesville Formation; (3) injection of water into a formation above the Galesville Formation to provide a pressure boundary; and, (4) maintaining lower pressures in the main Galesville Formation gas storage zone.

Table 7: Gas Storage Fields with Some Type of Natural Gas Leak

Field Type and Location	Type of Leak	Remediation Action Taken
1. Cap rock and Seal Problems		
Aquifer – Indiana, U.S.	Reservoir Too Shallow	Field Abandoned
Aquifer – Illinois U.S.	Cap rock Aquifer	Pressure Control
Aquifer – Midwest U.S.	Cap rock Shallow	Gas Recycle
Aquifer – Midwest U.S.	Cap rock	Field Abandoned
Aquifer – Midwest U.S.	Cap rock	Reservoir Abandoned, Deeper Zone Developed for Gas Storage
2. Wellbore and Casing Problems		
Aquifer Storage, Wyoming, U.S.	Wellbore Leak	Wellbore Remediation
Depleted Gas Field, Canada	Wellbore Leak	Wellbore Remediation
Depleted Gas Field, W. Virginia, U.S.	Casing Leak	Wellbore Remediation
Depleted Field, California, U.S.	Improperly Plugged Well	Re-Plug Old Well
Salt Cavern, Kansas, U.S.	Wellbore Leak	Wellbore Remediation

Source: Kuuskraa, PIER White Paper

- Gas leakage through the cap rock was noted in two Mt. Simon and one adjacent St. Peter Sandstone aquifer-based gas storage fields in the Midwest. In one case, shallow gas well drilling and gas recycling were implemented to remediate the problem. In the second case, the gas storage field was abandoned leaving behind a small volume of stored gas. In the third case, the shallower zone was abandoned and a deeper formation in the field was developed for gas storage.

Mitigating and Remediating Wellbore and Casing Leaks

Four of the gas storage leakage incidents involved temporary wellbore or casing leaks that were corrected with wellbore remediation and well plugging:

- In the early 1980's, the Leroy aquifer-based gas storage field in the Thaynes Formation, Uinta County, Wyoming observed gas bubbling to the surface from a wellbore leak. The problem was corrected by reducing the gas injection and operating pressures and conducting a wellbore remediation.
- Casing and wellbore leaks were detected in depleted gas formation-based gas storage fields in West Virginia and in Ontario, Canada. Repairing defective casing and reworking the wells were undertaken to remediate these problems.
- In the 1970's, the gas storage operator at Montebello, California observed that an old well, plugged before current standards were put in place, was causing gas to migrate into a shallower zone (but not to the surface). Proper plugging of this old well to today's standards remediated the problem.
- In early 2001, high pressure natural gas began escaping from a casing leak at one of the salt caverns at the Yaggy gas storage field outside of Hutchison, Kansas. The 60 million cubic feet of gas in the S-1 man-made salt cavern escaped and traveled toward Hutchinson, a town with a population of 40,000. The lateral migration pathway was a thin dolomite interval above the top of the storage cavern. The leaked gas led to a series of explosions, gas geysers and two deaths, the first-ever deaths due to operation of natural gas storage. The Yaggy gas storage field was closed for two years before further diagnostic and remediation efforts enabled this gas storage field to resume operations.

Wellbore and Other CO_2 Leakage Scenarios

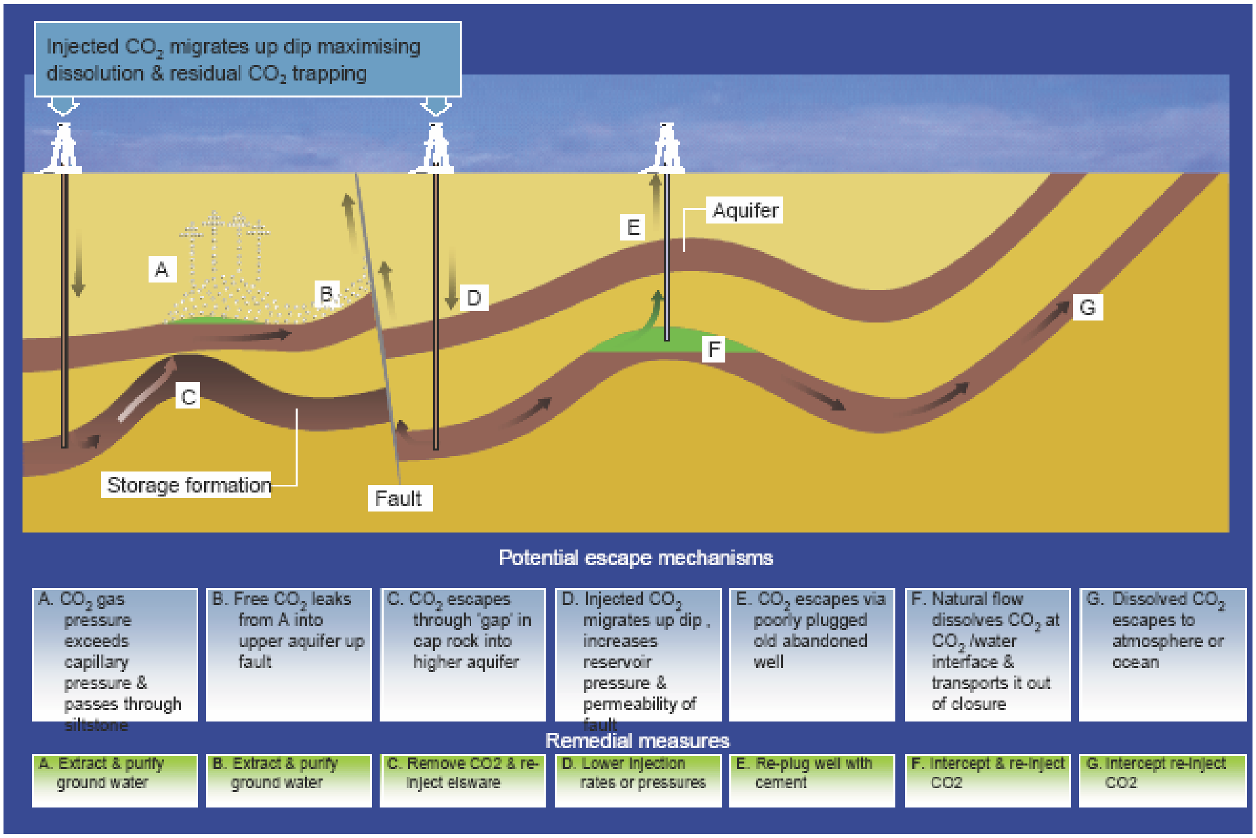
Classification of CO_2 Leakage Scenarios

Three general types of subsurface leak scenarios are possible at CO_2 storage sites, namely:

- Seal failure (capillary failure, faults and fractures)
- Bypassing of trap (spillage, aquifer migration)
- Wellbore failure.

A more detailed classification of seven potential CO_2 escape mechanisms has been set forth by the Australian CO2CRC, as displayed in Figure 12. In addition, the CO2CRC has, on a very brief form, matched each potential escape mechanism with a potential remediation measure.

Figure 12: Overview of Potential CO_2 Escape Mechanism and Associated Remediation Measures



Credit: Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC).

Reservoir Aspects of Remediation

All CO_2 storage projects will be designed and conducted with the goal and expectation that no CO_2 will leak from the containment formation. But, unexpected things can and do happen. The remediation actions, should leakage occur, will depend, to a considerable extent, on the type of reservoir in which the CO_2 is stored, as discussed below.

Depleted Oil and Gas Fields

CO_2 stored in this class of structurally confined reservoirs will most likely be the most effectively contained and easiest to monitor, offering the best chance of successful remediation. Once leakage has been detected, the first step would be to measure, as soon as possible, the extent and nature of the leakage, which will help guide the method and pace of remediation. For example, if leakage merely transports CO_2 into a securely sealed, secondary storage reservoir, remediation may not be needed. On the other hand, if the CO_2 leak is detected at the surface, prompt action will be essential. Initial steps for remediating minor leakage in wellbores may involve injecting mud, cement, or conformance-enhancing polymers to seal off the suspected leakage source. Should these steps fail or should leakage be high, a more radical approach may involve producing CO_2 back up the injection wells to the surface, then reinjecting the CO_2 into a more secure stratigraphic zone or reservoir within the field, or even transporting it to another site, preferably without venting. Contingency plans to deal with leakage will be needed for each CO_2 storage site in an oil and gas formation, so that remediation action can be taken promptly should leakage occur.

Extraction and transportation of the injected CO_2 (without ventings) can be a complicated, time-consuming and costly process. In particular, considering the very large volumes of CO_2 being stored, transporting and injecting this CO_2 at another site may take several years of operation. Numerous new CO_2 injection wells will be needed, and a CO_2 pipeline will likely be needed if the new storage area is at a different location from where the leakage is occurring. While the new storage facility is being constructed, venting may be unavoidable.

Projects Involving EOR or EGR

In certain geologically favorable settings, CO_2 may be injected for recovering more of the hydrocarbon (oil or natural gas) remaining in the reservoir. In enhanced oil (EOR) and gas recovery (EGR) applications, essentially all of the originally purchased and injected CO_2 is reinjected (after separation of the produced oil or natural gas). As such, essentially all of the originally purchased and injected CO_2 will remain stored in the reservoir after termination of enhanced oil or gas recovery.

CO_2 is a valuable commodity when used for EOR or EGR. As a result, operators take special care to avoid CO_2 leakage or loss. In most cases prior to initiating EOR and EGR, an operator will conduct a field-wide study to identify and remediate any abandoned or improperly plugged wells. In addition, the operator will use a variety of instruments and procedures to identify and correct leaks or loss of CO_2 out of the target reservoir interval. Existing oil and gas field mitigation and remediation practices and technologies appear to be adequate for addressing most of the CO_2 injection and storage issues with EOR or EGR. However, new efforts are needed to address the needs for longer term CO_2 storage monitoring, leak detection and mitigation/remediation after completion of EOR/EGR operations.

Saline Formations

CO_2 stored in saline formations, particularly those lacking structural closure, will be much more challenging to access and recover should remediation be necessary. Over time, CO_2 injected into a saline formation becomes increasingly dispersed due to regional hydrologic flow. Should a CO_2 leak occur, the first step will involve, to the extent possible, determining the location, nature, and extent of the leak. Wellbore leaks in saline aquifers can be addressed in a manner similar to that in oil or natural gas reservoirs. In cases where the leakage has been caught early and the risks posed are low, the most prudent option may be to just stop CO_2 injection in the location near the leakage and allow the reservoir to stabilize until proper remediation measures can be implemented. If the CO_2 leaked is significant, it may be necessary to produce the CO_2 from the reservoir near where the leak is occurring, and reinject the CO_2 elsewhere into a more suitable location in the saline formation or into an alternative geologic structure, as described for depleted oil and gas reservoirs above. Contingency plans to deal with leakage events, should they occur, will also need to be developed for each storage project injecting CO_2 into a saline formation.

Technologies for Mitigation and Remediation

Basic Steps for Remediating Leakage

Three conceptual steps apply, perhaps with some modification, to leakage from any type of geologic storage, including from CO_2 storage. In general, other than plugging the source of the leak (such as in a wellbore or a fracture), the following basic mechanisms can be used to mitigate or stop CO_2 leakage from a reservoir:

- Reduce the pressure in the storage reservoir from which the leak is occurring;
- Increase the pressure in the geologic interval (generally a shallower reservoir) into which the leak is occurring; and
- Intercept the CO_2 plume and extract the CO_2 from the reservoir before it leaks, and, if possible, reinject CO_2 into another formation.

Response Technologies and Actions

Nine essential CO_2 remediation and mitigation steps form the core of any strategy and response to CO_2 leakage, summarized as follows:

- Stop CO_2 Injection. Injection into the storage reservoir, at least in the vicinity of the leak, should be halted immediately.
- Notification and Survey. The geographic area of the leak should be surveyed for homes, farms, businesses, etc., that could be impacted or endangered. State and local officials should be notified as necessary and/or required.
- Identify Source of Leak. An investigation into the source of the leak should begin immediately. Other wellbores, if they exist, should be checked for anomalous pressures and well logs may be run in suspect wells.
- Wellbore Leaks. In the case of a leaking wellbore, the actions include squeeze cementing behind the well casing, taking other well remediation actions or plugging the problem well.
- Cap rock or Spill-point Leaks. In the case of a suspected cap rock or spill-point leak, the local geology should be reviewed for the most likely area of CO_2 accumulation above the storage zone. (Ideally, this characterization should have been done as part of the site selection process, and should be readily available.) These secondary CO_2 accumulation settings will generally consist of permeable, porous formation above the storage formation, with some type of impermeable cap rock overlaying it.

- Conduct Integrated Leakage and Accumulation Study. Once the shallow geology is reviewed, a study should be conducted integrating all information on hand, such as the surface location of the CO_2 leak in relation to structural high points in shallower zones. A good description of this process for geological investigation, as it applies to gas storage reservoirs, is provided by Katz and Coats.[143]
- Drill Shallow CO_2 Recovery Well. Based on this information, one or more wells may need to be drilled in shallower zones to locate and recover any CO_2 migrating to those zones. This process may need to be repeated and modified if the first wells do not locate the migrating CO_2, or if the CO_2 has migrated to multiple horizons.
- Create Pressure Boundaries. Alternatively, the leak, depending on circumstances, may also be controlled by lowering the pressure in the storage zone, or by creating a hydraulic barrier by increasing the pressure upstream from the leak
- Remediation or Reconfigure Storage Site. The final mitigation step is to either plug the leak, if located, or reconfigure that storage operation to reduce the likelihood of future leakage.

Tables 8 and 9 summarize four potential CO_2 leakage scenarios and the remediation options available to mitigate and address these problems.

[143] Katz, D.L, and K.H. Coats, Underground Storage of Fluids, Ulrich's Books, 1968.

Table 8: Remediation Options for CO_2 Leakage from Geological Storage Projects Scenario Remediation Options

Leakage	Remediation Options
1. Leakage Through Cap rock	• Lower injection pressure by injecting at a lower rate or through more wells; • Lower formation pressure by removing water or other fluids from the storage reservoir; • Intersect the leakage with extraction wells in the vicinity of the leak; • Create a hydraulic barrier by increasing pressure upstream of the leak; • Stop CO_2 injection and produce from the storage reservoir and reinject into a more suitable storage structure.
2. Leakage Out Of Confining Structure	• Stop CO_2 injection; • Begin investigation into the source of the leak immediately; check wellbores for anomalous pressures, run well logs on suspect wells; • Review local geology for the most likely areas of CO_2 accumulation above the storage zone. Integrate all information on hand, such as the surface location of leak in relation to structural high points in shallower zones; • Drill in the shallower zones to locate and recover any migrating CO_2; • Create a barrier by increasing the pressure upstream from the leak.
3. Leakage Due To Lack Of Well Integrity	• Repair previously drilled leaking wells with standard oil and gas field well recompletion techniques; • Repair leaking CO_2 injection wells by squeezing cement behind the well casing to plug leaks behind the casing; • Plug and abandon injection wells that cannot be repaired by traditional methods.
4. Leakage Due To Well Blow-out	• Remediate injection or abandoned well blow-outs with standard techniques to 'kill' a well, such as by injecting heavy mud into casing; • If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and 'kill' the well by pumping mud down the interception well.

Source: Benson, S.M. and R.P. Hepple "Detection and Options for Remediation of Leakage from Underground CO_2 Storage Projects," In E.S.Rubin, D.W.Keith and C.F.Gilboy (Eds.), Proceedings of the 7th International Conference on Greenhouse Gas Technologies, Elsevier, 2005.

Table 9: Options for Remediating the Impacts of CO_2 Leakage Projects

Remediation Needed	Remediation Options
1. Remediating Accumulation Of CO_2 In Groundwater	• Accumulations of CO_2 in groundwater can be removed by drilling wells that intersect the accumulations and extracting the CO_2; • Residual CO_2 that is trapped as an immobile gas phase can be removed by dissolving it in water and extracting it as a dissolved phase using groundwater extraction wells; • CO_2 that has dissolved in the shallow groundwater could be removed, if needed, by pumping to the surface and aerating it to remove the CO_2; • For metals or other trace contaminants mobilized by acidification of the groundwater, 'pump-and-treat' methods can remove these contaminants. Alternatively, hydraulic barriers can be created to immobilize and contain the contaminants by appropriately placed injection and extraction wells.
2. Remediating Leakage Into The Vadose Zone And CO_2 Accumulation In Soil Gas	• CO_2 can be extracted from the vadose zone and soil gas by standard vapor extraction techniques using horizontal or vertical wells; • Fluxes from the vadose zone to the ground surface can be decreased or stopped by using gas vapor barriers. Pumping of water from below the vapor barrier can be used to deplete the accumulation of CO_2 in the vadose zone; • Since CO_2 is a dense gas, it can be collected in subsurface trenches and then pumped from the trenches and released to the atmosphere or reinjected back underground; • Passive remediation techniques that rely on diffusion and 'barometric pumping' can be used to slowly deplete one-time releases of CO_2 into the vadose zone; • Acidification of the soils from contact with CO_2 can be remediated by irrigation and drainage or agricultural supplements such as lime to neutralize the soil;
3. Remediating Large Releases Of CO_2 In Near-Surface Atmosphere	• For releases inside a building or confined space, large fans can be used to rapidly dilute CO_2 to safe levels; • For CO_2 releases over a large area, dilution from natural atmospheric mixing (wind) will be the only practical method for diluting the CO_2; • For ongoing leakage in established areas, the risks of exposure to high concentrations of CO_2 can be reduced by ensuring that the rate of air circulation is high enough for adequate dilution.
4. Remediating Accumulation Of CO_2 In Indoor Environments	• Slow CO_2 releases into structures can be eliminated by using techniques that have been developed for controlling release of radon and volatile organic compounds into buildings, including, basement/substructure venting or pressurization. These actions would dilute the CO_2 before it enters the indoor environment.

Source: Modified from Benson, S.M. and R.P. Hepple "Detection and Options for Remediation of Leakage from Underground CO_2 Storage Projects," In E.S.Rubin, D.W.Keith and C.F.Gilboy (Eds.), Proceedings of the 7th International Conference on Greenhouse Gas Technologies, Elsevier, 2005.

Remediating Associated Impacts of CO_2 Leakage

Once the source of the CO_2 leak has been identified and mitigated, the next step is to examine how to remediate, when required, the associated impacts of CO_2 leakage. The text below and Table 10 shows these remediation options.

1. Remediating Accumulation of CO_2 in Groundwater. CO_2 contamination of groundwater can be remediated by the "pump and treat" method. Water is pumped to the surface and aerated to flash the CO_2. The water can then be either pumped back underground or used. CO_2 migrating to a drinking water reservoir will likely leach some amount of minerals along the way and transport them into the water. Treatment for such constituents is more involved and expensive, but could also be accomplished with the "pump and treat" approach.

2. Remediating the CO_2 Leakage into Vadose Zone. The transport and immobilization of CO_2 in the vadose zone is similar to the transport and immobilization of other common vadose zone contaminants. As such, soil vapor extraction (SVE) technology could be used for removing CO_2 from soil. Several soil remediation scenarios, examined with the TOUGH2 numerical simulator, indicated that large amounts of CO_2 could be readily removed from the vadose zone using SVE technology.[144]

3. Extracting CO_2 from Near-Surface Accumulations. Horizontal pinnate (leaf-vein pattern) drilling, which has been commercially applied to coalbed methane development, can provide a useful method for accessing CO_2 in near-surface reservoirs and accumulation zones.

4. Remediating Surface Accumulations of CO_2. If CO_2 were to migrate up through the soil and into populated areas, there is a danger of CO_2 collecting in basements and low-lying areas and creating an asphyxiation hazard. Mitigation efforts would include using dispersal equipment (such as fans) and CO_2detectors. In addition, shallow wells could be drilled to intercept and vent the migrating CO_2.

Mitigation and Remediation Costs

The CO_2 mitigation and remediation strategy needs to be integrated into the overall CO_2 storage project. The likelihood of needing remediation will be greatly reduced if a rigorous geologic and engineering analysis is performed up front as part of storage site selection and project design and a comprehensive monitoring system is installed. This is essential because if a leak occurs, the geologic and engineering cost for remediating the leak can at times be comparable to, and may exceed, the costs of the original CO_2 storage site selection, project design and

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[144] Zhang, Y, C.M. Oldernburg, and S.M. Benson, "*Vadose Zone Remediation of CO2 Leakage from Geologic Carbon Sequestration Sites*," presentation at the Third Annual Conference on Carbon Capture and Sequestration, Alexandria, Virginia, May 6, 2004.

implementation, particularly if the CO_2 storage has to be abandoned with the CO_2 transferred to an alternative site.

An additional cost of CO_2 leakage would be the loss of any CO_2 credits for storing CO_2. Even a modest CO_2 leak involving 20,000 tons of CO_2 (one day of CO_2 emissions from a large coal-fired power plant) would result in a loss of $0.5 million per day (assuming a CO_2 credit of $25 per tonne, in U.S. dollars).

The costs associated with the various activities for remediating CO_2 leaks are summarized below. The discussion of costs assume that an adequate monitoring and leak detection system has already been put into place.

Depending on the nature of the CO_2 leakage problem being addressed, the costs of leak remediation can vary widely. Set forth below are estimated costs for solving four types of problems -- locating the source(s) of the CO_2 leak, plugging old wells, remediating active CO_2 injection wells, and remediating a leak in the cap rock.

Costs for Locating Sources of CO_2 Leaks

The most likely source for CO_2 leaks will be the wells, either the older, abandoned wells or the newly drilled CO_2 injection and monitoring wells. Considerable industry expertise exists for identifying the source of CO_2 leaks in wells.

The costs for locating a single leaking abandoned well (or even a group of wells) will be modest, set at $200,000 per survey (including interpretation), with significant economies of scale in multi-well situations. (For the purpose of the illustrative example, it is assumed that five to ten such surveys would be conducted in the 50 year life of the project.)

For CO_2 injection wells, a new set of logs (such as a cement bond log) or other diagnostic tools (such as a downhole wireline video camera or a spinner survey) may need to be run to more precisely identify the exact location and cause of the leak in a new CO_2 injection well.

Assuming two diagnostic logs costing $200,000 (including rig time) plus a diagnostic and management charge of $100,000, the costs for this wellbore-based leak detection procedures would be $300,000 per well. (For the illustrative example, 10 to 20 wellbores are assumed to need logging during the 50 year life of the project.)

The process for locating geologically based CO_2 leaks in a storage formation is much more challenging. The costs will be a function of the size of the leakage area, the conditions at the surface overlying the storage formation (industrial, suburban, farmland, etc.), and, perhaps most important, the requirements imposed by regulatory authorities. Establishing the cause and source of a geologically based CO_2 leak may require investigating a large area, with emphasis on areas of potential cap rock weakness (such as faulted areas) and structural “spill-points”. As such, a new large scale seismic survey may need to be conducted over the area where surface CO_2 leakage has been detected. In addition, new leak detection wells (potentially horizontal wells) may need to be drilled and tested to more precisely locate the source for the CO_2 leak and, ultimately, capture the leaked CO_2 for reinjection. (For the illustrative example, assume there is a need for one to two such 20 square mile seismic surveys and a cost of $150,000 per square mile for 3D seismic, including processing and interpretation. Also, assume there are two to four horizontal leak detection wells costing $4 million per well, including testing and subsequent operations).

Costs for Well Plugging

Well plugging costs will depend on whether the requirement is to plug a recently abandoned well, an old, previously plugged and abandoned well, or a well that was never plugged. In addition, the costs will depend on the location of the well being plugged. For example, a well located in an easily accessible location will have much lower costs than a well in a difficult-to-access location or in a densely populated area. Nonetheless, well plugging (in a typical 7,500 foot well) could cost as little as $25,000 and as much as $200,000. On average, most well plugging operations will cost $100,000 per well, without considering the salvage value of the casing, if any. (In the illustrative example, assume there is a need to plug 10 to 20 old, abandoned wells leaking CO_2.)

Costs for Well Remediation

Remedial cementing jobs, intended to repair a simple wellbore leak in a CO_2 injection well, may cost $40,000 to $50,000, on average, but could vary considerably depending on the nature of the leak and the condition of the wellbore. A more involved remediation, required when a substantial section of the well has leaks or damage, would require placing and cementing in place a smaller diameter liner inside the well casing. The costs of this remediation step is estimated at $100,000 per well. In some cases, a leaky CO_2 injection well cannot be repaired, and must be plugged. In this case, the costs would include plugging the original leaking well and drilling a new replacement CO_2 injection well. New well costs can range from $500,000 for a shallow 3,000 foot (760 meter) well, to over $5 million for a deep 15,000 foot (4,600 meter) well. Well costs have increased considerably in the last few years and today, a medium depth, 7,500 foot CO_2 injection well will cost on the order of $3.5 million. The main cost components that have dramatically increased are rig fuel (diesel oil), tubulars (steel), and the day-rate for drilling rigs. (For the illustrative example, one significant remediation is assumed for each of the CO_2 injection wells (20 remediations) and the need to re-drill two to four new, moderate depth CO_2 injection wells.) In the case of a well blow-out, an extremely rare event in natural gas storage operations, the remediation step is to inject heavy fluids or even drill a directional well to intercept the damaged well. The costs can range from relatively moderate costs of well plugging to very high costs for drilling a costly directional well by which to access the blow-out and then converting this well (or drilling a new well) for CO_2 injection. (Because of the unique circumstances and rare occurrence of this problem, no cost estimates were made.)

Costs for Remediation of Leaks in Cap rock

The first step in mitigating a CO_2 leak in the cap rock would be to stop CO_2 injection and to inject water into a formation above the cap rock to create a positive pressure barrier, if possible. This would involve drilling and operating new water injection wells, with costs comparable to those set forth above.

Creating a positive pressure barrier for mitigating the CO_2 leak would involve drilling and completing horizontal water injection wells and installing a water source well and water injection facilities. Estimates place the cost of horizontal well at $4 million and the cost of the water source and injection facility at $2 million. (The example assumes two to four horizontal wells plus one water plant.)

There are no documented cases of fully remediating a leak in a cap rock, in either a CO_2 storage or a natural gas storage project. In general, performing such a remediation effort is speculative at best. Consequently, the costs associated with this remediation action are unknown and not estimated by this study. The development of possible approaches for remediating leaks in cap rock remains an important area for future research.

Example Storage Case

To further illustrate the costs of remediation, a sample saline formation storage site was assumed. The main assumptions are as follows:

- The storage site serves one new 1,000 MW coal-fired IGCC power plant, with 6 million metric tons of annual CO_2 emissions. The site will operate for 50 years, with 30 years for CO_2 injection and 20 years for post-closure monitoring.
- The CO_2 storage site has 20 new CO_2 injection wells, each capable of injecting 1,000 metric tons of CO_2 per day (with a 90 percent operating factor), including 2 spare CO_2 injection wells.
- The CO_2 plume extends radially and underlies an area of about 50 square miles (216 km2) at the end of 50 years.

Based on this example, the overall costs for leak prevention and leak remediation are as shown in Table 11.

The cost for a comprehensive CO_2 leak detection and remediation program is estimated to be on the order of $35 to $66 million per site, unless the problem is so severe that the original CO_2

storage site needs to be abandoned. Assuming the injection of 180 million metric tones of CO_2, the cost per ton for these efforts would be about $0.20 to $0.36 per metric ton of CO_2. However, should the CO_2 leakage problems not be able to be remediated, the costs would become large and include establishing a new storage facility and transporting some or all of the CO_2 to the new facility.

CO_2 Leakage Prevention/Remediation Strategies and Needs

A comprehensive strategy for leak prevention and remediation for CO_2 storage would contain five main elements, as further discussed below.

1. Selecting Favorable Storage Sites with Low Risks of CO_2 Leakage.

No other single aspect of a leak prevention and remediation strategy is more important than selecting a safe, secure site in the first place. All potential CO_2 leakage pathways need to be fully addressed for evaluating the favorability of a storage site using an extensive set of the tools and procedures.

2. Placing Emphasis on Well Integrity.

There are three key priorities for ensuring long-term well integrity at a CO_2 storage site.

- Identifying the older, abandoned wells in the vicinity of the proposed CO_2 storage site and replugging these wells, where necessary.
- Designing and installing the CO_2 injection wells so that they will resist loss of cement integrity and corrosion of casing from the acidic CO_2 and water mixture. Using CO_2 resistant cements provides one option for maintaining cement integrity.
- The third priority is properly closing the CO_2 storage site at the end of CO_2 injection, including plugging all CO_2 injection and observation wells to promote long-term storage integrity.

3. Installing and Maintaining a Comprehensive Monitoring System for the CO_2 Storage Site.

First and foremost, the CO_2 monitoring system will need to serve as an "early warning system" of any impending CO_2 leakage. For this, there is need for a variety of monitoring wells to provide downhole pressure and other data, for CO_2-sensitive logging tools, and for near-surface CO_2 detection wells and systems to identify any leakage through or around the reservoir seal. Figure 13 provides an illustration of the type of wells used to monitor a natural gas storage facility. In addition, a variety of pressure monitors and cement bond logs will need to be used for assuring wellbore integrity.

Table 10: Representative Costs for Leak Mitigation and Remediation

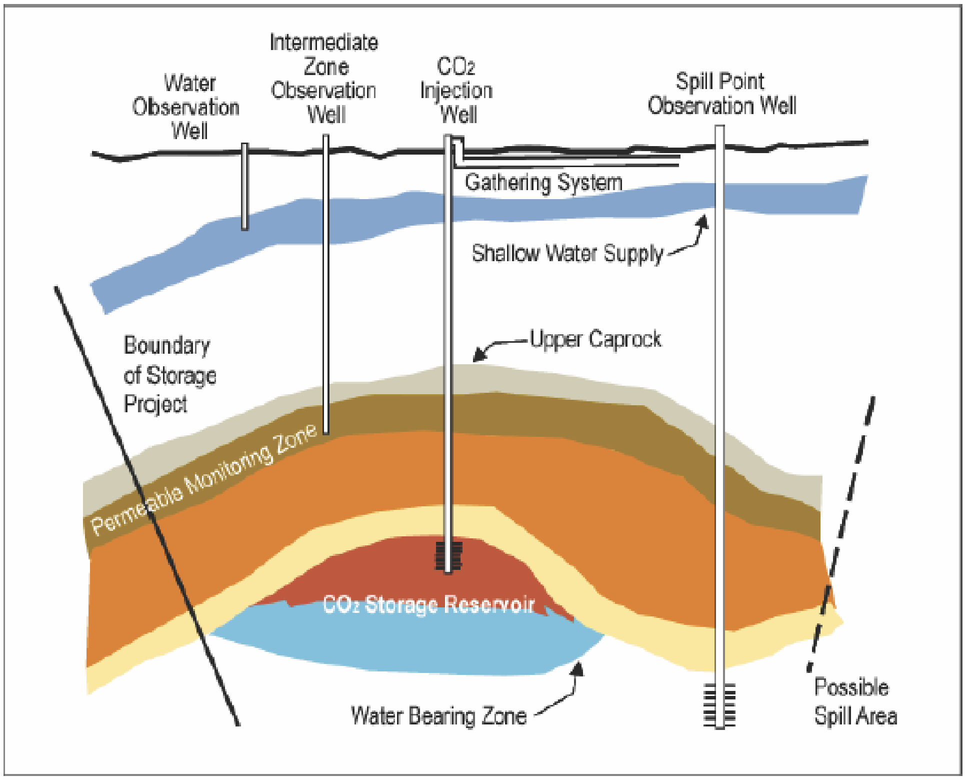
Remediation Activity	Costs ($ Million)	Assumptions
1. Locating Sources of CO_2 Leaks		
• Locating Old, Abandoned Wells	$1.0 to $2.0	Assumes 5 to 10 leak location surveys
• New CO_2 Injection Wells	$3.0 to $6.0	Assumes 10 to 20 sets of diagnostic logs
2. Well Plugging		
• Plugging Old, Abandoned Wells	$1.0 to $2.0	Includes plugging of 10 to 20 old wells
3. Well Problems		
• Remediation	$2.0	Includes remediating 20 CO2 injection wells
• New Wells	$7.0 to $14.0	Includes drilling 2 to 4 new CO2 injection wells
4. Geologic/Cap rock Leakage		
• Diagnostic Survey	$3.0 to $6.0	Includes 1 to 2 20 sq mi seismic surveys
• Horizontal Leak Detection Wells	$8.0 to $16.0	Includes 2 to 4 horizontal wells
• Pressure Boundary	$10.0 to $18.0	Includes 2 to 4 horizontal wells plus one water plant
• Other Problems	Large	May need to abandon original storage site and build a new site

Source: Kuuskraa, PIER White Paper

4. Conducting a Phased Series of Reservoir Simulation-Based Modeling to Track and Project the Location of the CO_2 Plume.

Based on experiences to date, multiple stages of reservoir simulation are recommended to support leak prevention and remediation efforts in CO_2 storage. The first stage of reservoir simulation would be undertaken during the initial site selection process to project the anticipated movement and location of the CO_2 plume. The second stage of reservoir simulation would be undertaken after the CO_2 injection and observation wells have been drilled and more site specific geological and reservoir data have been collected. The third stage of reservoir simulation would be initiated once the CO_2 monitoring systems provide new information on the flow direction and location of the CO_2 plume. This third stage of reservoir simulation, often repeated, would be used to project the long-term (1,000 year) trapping and immobilization of the CO_2 plume.

Figure 13: Monitoring in Natural Gas Storage Fields



Credit: Modified after Katz, D.L, and K.H. Coats, Underground Storage of Fluids, Ulrich's Books, 1968.

5. Establishing a "Ready-to-Use" Contingency Plan/Strategy for Remediation.

A "ready-to-use" CO_2 leakage mitigation and remediation plan needs to be in place and immediately put into operation once a leak in the CO_2 storage field has been detected.

Recommendations for Improving CO_2 Storage Remediating Technology

Clearly, this overview study and chapter on CO_2 leak prevention and remediation serves as merely a first step forward. Fruitful next steps would include the following:

- Develop a "Best Practices Remediation Manual". It would be most valuable to develop and maintain this manual to provide a comprehensive strategy and available technologies for CO_2 leak prevention and remediation. As new insights on remediation are developed, these would need to be added to this "Best Practices Manual" to keep it "evergreen";
- Study Remediation in the Natural Gas Storage Industry. Given its value as the most relevant analog to CO_2 storage, undertaking additional studies of the remediation experiences, practices and "lessons learned" of the natural gas storage industry would benefit CCS. Fruitful areas for exploration would be further detailed on leak source identification and the costs of remediation;
- Invest in Research and Technology Development in Remediation for CO_2 Storage. Of high priority would be much more intensive investigations and field trials of procedures for identifying and then sealing a failure in the cap rock. Equally valuable would be work on materials and procedures for achieving greater well integrity, leading toward a "thousand year well;"
- Develop New Procedures and Technology for Locating and Assessing the Integrity of Abandoned Wells. Valuable work on this topic has been undertaken by the U.S. DOE/NETL, but much more needs to be done to develop cost-effective means for reliably locating and assessing the status of old, abandoned wells near a CO_2 storage site. As valuable would be the development of new procedures and technologies for securely plugging old, abandoned wells;
- Launch a Series of "Best Practice", Large-Scale Field Tests of CO_2 Storage. An important emphasis in these large-scale field tests would be establishing and testing an integrated system involving CO_2 monitoring, CO_2 leak detection and remediation. A valuable side benefit would be learning, much more reliably, the actual costs of installing such an integrated system.

CHAPTER 9: Economic Considerations

Assessing the economics of CCS is very challenging today, in part because no policy exists to establish a price for CO_2 in the marketplace. The costs associated with CCS are made up of the cost of additional equipment required to capture, transport, inject and store CO_2, as well as the additional energy requirements that go along with each step. For many CO_2 sources, the capture cost is the largest component and is the best starting point for evaluating and ranking the cost of CCS projects. Capture costs scale with purity of the CO_2 and there are economies of scale associated with total source size. Additional issues relevant to the economics of CCS in California include the proximity of CO_2 sources to the storage reservoirs, and opportunities that arise from a regional (vs. state) perspective. Injection costs typically fall between those of capture and those of transport and are dependent on the specific geological characteristics of the storage site. Additional complicating factors include the large run-up in costs for process equipment and piping worldwide in the last several years, as well as a "first-of-a-kind" premium for CCS facilities.

Capital and operating costs depend on the concentration and pressure of the CO_2 in source gas streams, total source size, and transport costs. In general, because the capital and operating costs for equipment are sized to the volume of gas to be separated and are amortized across tons captured, gas stream sources with lower CO_2 concentrations have higher costs per ton of CO_2. Application to larger CO_2 sources should have a lower cost per metric ton of CO_2. Capture costs will typically be lowest for new construction; whereas costs for retrofits will be highly site dependent and significantly higher.

Pipelines are typically the best choice to transport captured CO_2, but currently no significant CO_2 pipeline infrastructure exists in the state. For most large industrial sources, the cost of building pipelines is relatively low, but other issues, such as crossing difficult terrain or densely populated areas, may make pipeline construction much more costly or even infeasible. This cost also is influenced, of course, by the distance between the location of the CO_2 source and the target CO_2 sequestration site. However, natural gas power plants and other large industrial sources in California are generally in close proximity to good candidate sequestration sites, which should help to keep transportation costs low.

Some of the best opportunities to influence California's greenhouse emissions may be through applying CCS to large coal plants serving California loads, located in Arizona, New Mexico, Utah and Nevada. These plants would be most economic from the standpoint of capture costs, and the emissions associated with electricity imported into the state as part of the state's GHG inventory.[145] Because of the relatively higher concentration of CO_2 in the flue gases, CO_2 capture

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[145] Inventory of California Greenhouse Gas emissions and Sinks: 1990-2004 PIER Report CEC-600-2006-013-SF December 2006.

for coal-fired power plants is less expensive than for gas-fired plants on the basis of per ton of CO_2 removed. Incremental costs for adding CO_2 capture and compression to new coal plants would typically be about \$60/ton CO_2 (or \$30/ton CO_2 if coupled to an EOR project). Once again, costs for retrofits would be higher.

While the component technologies for CO_2 capture and sequestration are all commercial today, they typically have not been applied to the types of sources, at the scale, or within the integrated, optimized systems needed to accomplish CCS on an ongoing basis. As such, initial CCS applications will be "first-of-a-kind" and will be more costly than the projected cost for an "N^{th} plant", after applying the lessons-learned from initial projects to the next generation. CCS is no different than other process technologies and should be subject to significant lessons-learned, cost reductions, efficiency gains, and economies of scale.

Nonetheless, from an economic standpoint, there are several "targets of opportunity" with respect to CCS in California that should be considered. One is the use of captured CO_2 for enhanced oil recovery, which places a value of about \$20/metric ton on CO_2. As noted previously, California has many producing oil reservoirs which could benefit from CO_2-based enhanced oil recovery. The second is industrial CO_2 streams that are currently emitted as essentially pure CO_2. In these cases, CO_2 capture is an integral part of the industrial process, and the capture-only cost is included in the process cost. The cost to produce supercritical CO_2 for transport is the compression and drying cost, which is typically low. Examples include natural gas processing plants which separate CO_2 from methane in produced gas, fermentation processes producing ethanol, ammonia plants, and some hydrogen production plants in or associated with refineries. Although these pure CO_2 streams represent a small fraction of California's CO_2 emissions, they are emissions targets that should have a low overall CCS cost, unless they are too small to gain economies of scale.

Select industrial plants also offer targets of opportunity for early CCS application because they are virtually economical today; for example, an industrial process that produces a high-purity CO_2 stream (e.g., hydrogen or ethanol plant) that could be coupled to an EOR project. Such applications could almost assuredly be developed in time for AB 32 compliance, but the total amount of CO_2 emissions reduction available from the number of projects that could be underway by 2020 would be relatively small. It is important to note, however, that coupling CCS with production of biofuels, such as ethanol, has the potential to generate "net-negative" emissions. For example, carbon-neutral bioethanol plants emit high CO_2 concentrations in exhaust; if this CO_2 is injected underground for storage in geologic formations, there is an overall net transfer of CO_2 out of the atmosphere and biosphere to long-term geologic storage. Depending on bio-fuels policy and investment decisions, the number of ethanol plants in the state could rise markedly. With respect to hydrogen fuels, CO_2-free hydrogen can be made through pre-combustion CO_2 capture, which involves three main process steps that convert a carbon fuel source to CO_2 and H_2, followed by CO_2 separation from the H_2. Pre-combustion CO_2 capture coupled with geologic sequestration is planned for the proposed hydrogen power project in Carson, California, but this approach applies equally to projects generating hydrogen transportation fuels.

Capture Economics

The CO_2 avoided cost typically reported in the literature is about $40 per metric ton CO_2 for supercritical pulverized coal with post-combustion capture and about $30 per metric ton of CO_2 for coal-based IGCC with pre-combustion capture. For nominal 90% removal technologies applied to baseloaded units with uncontrolled CO2 emissions of about 830 kg/MWh (1830 lb/MWh), this translates to an added production cost of $32/MWh for a PC unit and $24/MWh for an IGCC unit. These values were for the cost environment between 2000 and 2004 and are too low for 2007. Table 11 shows the CO_2 avoided costs for a new plant with capture in the U.S. Gulf Coast for the 2007 construction cost environment adjusted by a differential construction cost index for California, with a premium added for first-of-a-kind contingency requirements. Cost increases are mainly due to higher capital costs for facilities in California and are about $10 per metric ton of CO_2 avoided. Although not shown in Table 11, retrofits will typically have a higher capital cost per unit capacity and thus a higher CO_2 avoided cost. While this analysis is generally indicative of relative costs, there is need for design work specific to the western states to define the cost associated with each application. CO_2 transport and injection costs are not included in these numbers.

Table 12 summarizes the estimated avoided cost for the large stationary CO_2 sources in California. The avoided cost is specific to the scale indicated and will change with the scale of the process. The size used as a basis for the calculations in Table 12 is near the upper end of the range for California stationary CO_2 sources and thus, represents the lower range of the CO_2 avoided costs for each application. For smaller flue gas streams and smaller NGCC units (< 500 MWe) the cost of capture equipment and operation will be higher. Similarly, for smaller furnaces, boilers, heaters, the cost will be higher on the basis of per unit of thermal energy or per ton of CO_2 removed. In most cases the application will involve a retrofit on an existing process and equipment; and as noted above, this will increase the capital cost and the CO_2 avoided cost. The numbers in Table 12 are indicative of the relative cost across the set of sources in the table. It will be somewhat different for each specific case. For example, the CO_2 avoided cost for fired heaters and CO_2 capture from refineries could vary considerably depending on the specific situation and location but will probably be about as or somewhat more costly than CO_2 capture from NGCC. These numbers are for the capture and compression part only. To get a total life-cycle CCS cost, transport and injection adds on average $10 per metric ton of CO_2. If the storage site involves EOR, $20 per metric ton of CO_2 should be subtracted to get the CCS cost.

Table 11: CO_2 Avoided Cost Increases for Power Generation and Flue Gas Capture

CO_2 Source	CO_2 Avoided Cost, $ per tonne			
	PC	IGCC	NGCC	Fired Heaters
Cost Basis/Fuel	PRB subbituminous coal*	PRB subbituminous coal*	Natural Gas**	Fuel gas
U.S. Gulf Coast	46	34	65	64
California	54	42	73	72
California plus first-of-a-kind	55	47	76	74

*Reference or Basline is SCPC without capture with PRB coal

** Reference or baseline is NGCC without capture

Calculations of avoided costs with accounting for the California construction cost environment and first-of-a-kind contingencies. *Source: Katzer and Herzog, PIER White Paper*

For retrofits of existing plants or facilities, several factors significantly affect the economics of a project. These include unit size, operating efficiency, and emissions controls, as well as land availability or other space constraints at the plant site. Existing plants are frequently smaller, have lower generating efficiency, and may not have highly-efficient emissions control systems relative to new builds. The energy requirement for CO_2 capture is usually higher for retrofits because of less efficient heat integration for sorbent regeneration in an existing plant. For power generation, plant output reduction could be as high as 40 percent for retrofits versus up to 30 percent reduction for new plants.[146] Note that this also implies more water use per unit of electricity produced. Existing plants that are not equipped for adequate NOx control or with a flue gas desulfurization system for SO_2 control must be retrofitted or upgraded for high-efficiency sulfur capture as a pretreatment system for the CO_2 capture and recovery system.

Table 12: Estimated CO_2 Avoided Cost for Large Sources

[146] Bozzuto, C.R., N. Nsakala,G. N. Liljedahl, M. Palkes, J.L. Marion, D. Vogel, J. C. Gupta, M. Fugate, and M. K. Guha, Engineering Feasibility and Economics of CO2 Capture on an Existing Coal-Fired Power Plant, N. U. S Department of Energy, Editor. 2001, Alstom Power Inc.

CO2 Generating Technology	Hydrogen, ammonia production	IGCC	Supercritical PC	NGCC	Fired heaters, Furnaces & Boilers
Nature of Gas Stream	Pure CO_2 stream from process	PRB subbituminous coal	PRB subbituminous coal	Natural gas	Fuel gas or liquids; low CO_2 conc.
Process scale or CO_2 rate	1 million tonnes/yr	500 MW_e	500 MW_e	500 MW_e	1.2 million tonnes/yr
CO_2 avoided cost, $/tonne	10	47*	55*	76**	74

* Reference or baseline is SCPC without capture with PRB coal

** Reference or baseline is NGCC without capture

Calculations of avoided costs with accounting for the California construction cost environment and first-of-a-kind contingencies. *Source: Katzer and Herzog, PIER White Paper*

All these factors lead to higher overall costs for retrofits. If the original unit is fully paid off, the cost of electricity after retrofit could be slightly less to somewhat more than that for a new purpose-built pulverized coal plant with integral CO_2 capture because of the higher capital carrying charge for the new plant.[147] However, an operating plant will usually have some residual value, and the reduction in plant efficiency and output, increased on-site space requirements, and unit downtime are all complex factors not fully accounted for in this analysis. For smaller, older units, rebuilding the entire boiler and power generation sections may be the best alternative. Generally, the cost of CO_2 avoided is expected to be 30 to 40 percent higher than for a purpose-built capture plant. For example, based on an Alstom retrofit design study, an MEA retrofit of a supercritical pulverized coal would lead to a CO_2 avoided cost of about $70 per metric ton versus about $55 per metric ton for a new plant with integrated post-combustion capture. This example illustrates the relative increase in costs that can be expected for retrofits. In practice, retrofits require case-by-case detailed design-based examination.

Power Plants

There has been significant detailed engineering design work done on CO_2 capture with power generation to provide a sound basis for cost estimates. Using design work from 2000 to 2004, which was a period of unusual cost stability, as a starting point, costs for CCS in a U.S. Gulf Coast construction environment for this period were developed. Note that for less mature technologies, the costs are representative of an N^{th} plant, where N is a small number. These costs were then updated to 2007 dollars to account for recent construction cost increases,

[147] Ibid.

indexed to address the California construction cost environment, and modified to account for costs associated with first-of-a-kind plant applications.

There is a large range of variability in power plant and CCS costs. Every plant and its design parameters are unique, and projected costs reflect this in the literature as values spanning a range. For clarity, costs are given as indicative values, rather than as ranges.

Power generation and CO_2 capture costs are dependent on a large number of factors. To reduce the complexity, a consistent design and operating basis was used for each plant (e.g., 85 percent capacity factor for plants without capture and for plants with capture; and 90 percent CO_2 capture for all capture plants), focus on the primary commercial generating technologies, and use of industry-typical procedures (EPRI-recommended approach) to calculate the levelized cost of electricity (COE) and cost of CO_2 avoided. The most common power generating technologies are compared, without CO_2 capture and with CO_2 capture for new 500 MW_e plants. Two coals (Illinois # 6 and Powder River Basin) and natural gas were used as fuels. All costs are reported in 2007 dollars where the construction cost environment is similar to that on the U.S. Gulf Coast.

The results of this analysis show that the main effects are the impact of CO_2 capture on electricity cost and the climate mitigation cost, expressed as $ per metric ton of CO_2 avoided (the CO_2 avoided cost). This represents the true cost per ton of CO_2 not emitted or avoided and takes into account the loss in generating efficiency of the power plant due to the additional energy required for CO_2 capture. The avoided cost is calculated as the difference in electricity costs (in $/MWhe) between a reference plant and a CO_2 capture plant divided by the difference in CO_2 emissions (in ton CO_2/MWhe) of the same two plants.

To account for the California construction cost environment, capital costs were indexed upward by 25 percent. This still provides only an estimate of the cost for any specific project in a given location in California. Specific cases may be significantly more costly or possibly less costly because of local conditions.

High-Purity Industrial Sources

There are a range of industrial sources that produce essentially pure CO_2 as an integral part of the process, and the high-purity CO_2 is currently vented directly to the atmosphere. In these cases, the cost of the CO_2 separation is already part of the process cost. These streams are associated with some gas processing, petrochemical, and fermentation plants. In these cases, the cost of CO_2 capture is simply the cost of drying and compressing the CO_2 to a supercritical liquid. For a moderately large scale stream of 2 million metric tons per year of CO_2 and an electricity price of $0.05/kWhe, the cost is about $10 per metric ton of CO_2 avoided. Barring other issues, large high-purity CO_2 streams should be the most economic sources of CO_2 for sequestration.

Hydrogen production requires the separation of CO_2 from the desired H_2 product. Traditional hydrogen purification processes using amine-based absorption systems are capable of producing a CO_2 stream that is 99.8 volume percent CO_2. Recent designs using pressure-swing adsorption produce a CO_2 stream that is only about 50 percent CO_2.[148] Where the CO_2 stream is high purity, the incremental cost of capture is drying and compression. However, hydrogen production, typically by steam reforming of natural gas, involves high-temperature fired heaters. Thus, in addition to the high-purity CO_2 stream discussed above, hydrogen production units have substantial flue gas streams with a low CO_2 concentration, and the cost of CO_2 capture from these flue gas streams is much higher. Large amounts of hydrogen are produced in California, associated with oil refining, either in or near the existing refineries. In the future, hydrogen production for vehicle fuel may also increase.

Natural gas sweetening plants remove CO_2 in excess of about 2 percent in produced natural gas so the gas has a higher heating value and can be pipelined without inducing corrosion in the lines. These vented streams are typically high purity CO_2 and represent significant point sources of CO_2. Two plants, Sleipner in the North Sea and In Salah in Algeria are each capturing about 1 million metric tons of CO_2 per year and sequestering it in deep geologic formations. In the U.S., about 6.5 million metric tons of CO_2 per year from natural gas sweetening are being used for enhanced oil recovery.[149] California has 31 gas processing facilities that may be targets for capture and sequestration.

Ethanol production by fermentation is another process that produces a stream of pure CO_2 from the fermentors and is on the increase. This CO_2 can be captured by drying and compressing although these streams are relatively small. Fermentation CO_2 emissions are about 3480 metric tons per million gallons of ethanol. A typical plant will have a pure CO_2 emissions stream of about 0.2 million metric tons per year, which is too small to have much economy of scale. As with hydrogen production, these facilities also have flue gas streams from fired heaters and steam generators that have low CO_2 concentrations. These flue gas streams, because of the small scale of current fermentation plants, also suffer from the economics of small scale and are expected to have an avoided cost in excess of $80 per metric ton of CO_2. California has four fairly large ethanol fuel production plants, and more can be expected.

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[148] SRI-International, *Chemical Economics Handbook*, ed. S. International. Vol. Industrial Gases. 2003, Menlo Park

[149] Beecy, D.J., V. A. Kuuskraa. Basic Strategies for Linking CO2 Enhanced Oil Recovery and Storage of CO2 Emissions. in 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7). 2004. Vancouver, Canada: Elsevier.

Low-Purity Industrial Sources

There are a broad range of low-purity CO_2 sources that are large enough that the economics of CCS for them may be within reason. These are mainly flue gases from fired heaters and furnaces which have CO_2 concentrations ranging from 7 to 9 percent. The cost of capture will vary considerably for such sources depending on size, type, and location of the industrial process. In general, the costs will be lower for processes running with a high stream factor, processes that can use waste heat to regenerate the capture solution, and processes that have high CO_2 concentration in the flue gas and that have large CO_2 emissions rates. Beyond that, each case will involve retrofitting CO_2 capture, recovery and compression equipment into the flue gas stream, and detailed engineering design data will be required for quality cost numbers. Simbeck estimates the costs for recovery of CO_2 from a 48.5 million scf/h industrial flue gas stream using amine adsorption to be $72 per metric ton of CO_2 avoided.[150] Typical costs in most California are likely to exceed this. Other estimates range from $70 to $90 per metric ton of CO_2 avoided.

Oil refineries and petrochemical plants represent the second largest CO_2 source in California at about 18 million metric tons of CO_2 per year (see Table 2, previously). The primary sources are fired process heaters and steam boilers which are typically located at multiple locations around a refinery or petrochemical plant. To achieve economies of scale would require using a centralized CO_2 absorber/regenerator unit. This would require the collection of the various flue gas sources and their aggregation at a central location. The benefits gained from a centralized CO_2 capture/recovery unit would be at least partially offset by the cost of added pipes and ducts. Limited estimates suggest an avoided cost of $70 to $100 per metric ton of CO_2 avoided. Without further design studies, these numbers should be considered approximate. Considering the amount and cost of duct work required aggregating the various flue gas streams, this estimate may be low.

Cement and lime kilns are the third largest stationary CO_2 source in California at about 12 million metric tons of CO_2 per year. Cement and lime kilns have flue gas CO_2 concentration in the range of 25 to 35 percent. This higher concentration results in a reduced avoidance cost of about $55 per metric ton of CO_2 avoided.

Transport and Storage Economics

Transport costs are highly non-linear for the amount transported, with economies of scale being realized at about 10MtCO_2/yr (Figure 14). While the figure shows typical values, costs can be highly variable from project to project due to both physical (e.g., terrain pipeline must traverse)

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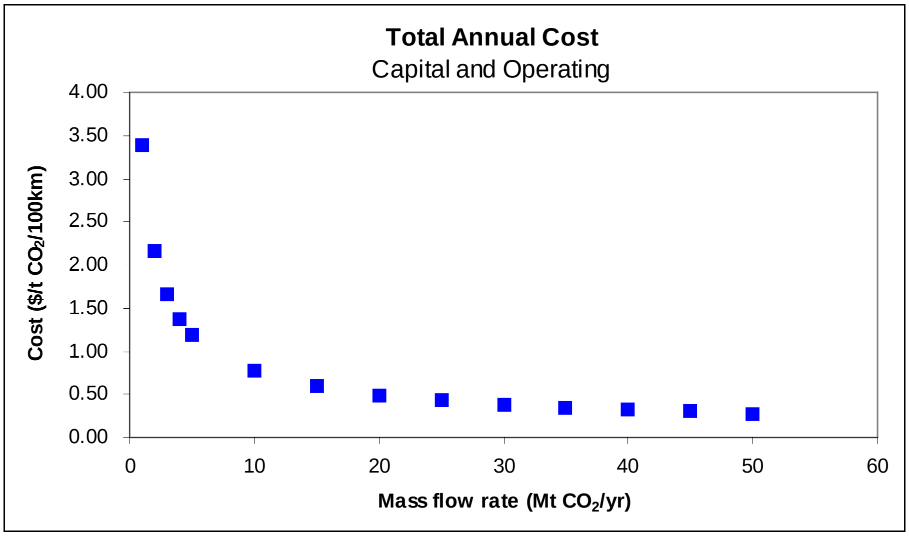
[150] Simbeck, D., Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream, J. Katzer, Editor. 2007.

and political considerations. For a 1 GW_e coal-fired power plant, a pipeline would need to carry about 6-7 Gt CO_2/yr. This would result in a pipe diameter of about 16 inches and a transport cost of about \$1/t CO_2/100 km. Transport costs can be lowered through the development of pipeline networks as opposed to dedicated pipes between a given source and sink.

Figure 14: Illustrative Costs for CO_2 Transport via Pipeline



Costs expressed as a function of CO_2 mass flow rate. ***Credit: Heddle, G., H. Herzog, and M. Klett., 2003, The Economics of CO2 Storage. MIT LFEE 2003-003. Available from: http://sequestration.mit.edu/pdf/LFEE_2003-003_RP.pdf.***

High-Purity Industrial Sources

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[151] SRI-International, Chemical Economics Handbook, ed. S. International. Vol. Industrial Gases. 2003, Menlo Park.

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Injection and Storage

The major cost for injection and storage are associated with the drilling of wells. Other significant cost items include site selection and characterization, as well as flowlines and connectors. In general, no additional pressurization of the CO_2 is required for injection because of the high pressure in the pipeline and the pressure gain due to the gravity head of the CO_2 in the wellbore. Monitoring costs have been assumed to be very small, about $0.1 to 0.3/ton CO_2.[152]

Costs for injecting the CO_2 into geologic formations will vary on the formation type and its properties. For example, costs increase as reservoir depth increases and reservoir injectivity

[152] Intergovernmental Panel on Climate Change, ed. IPCC Special Report on Carbon Dioxide Capture and Storage. ed. B.E.A. Metz. 2005, Cambridge University: Cambridge. http://www.ipcc.ch/

decreases (lower injectivity results in the drilling of more wells for a given rate of CO_2 injection). A range of typical injection costs has been reported as $0.5 to $8/ton CO_2.[153]

Combining storage with EOR can help offset some of the capture and storage costs. EOR credits of up to $20/ton$CO_2$ may be obtained.

The California Context

The issue of source-sink matching, that is, the proximity of CO_2 point sources to geologic storage sites, was discussed earlier in the chapter on California's potential for geologic storage. The proximity of sources and sinks are an important economic consideration. Based on the information summarized in that chapter, it appears that most sources are located in close proximity to potential storage sites. This is confirmed with a quantitative assessment, showing:

- About 79 percent of emissions sources are within 50 km of a potential EOR site;.
- About 92 percent are within 50 km of a non-EOR geologic formation;
- Only 9 percent are greater than 100 km from a potential EOR site;
- 100 percent are within 100 km of a non-EOR geologic formation.

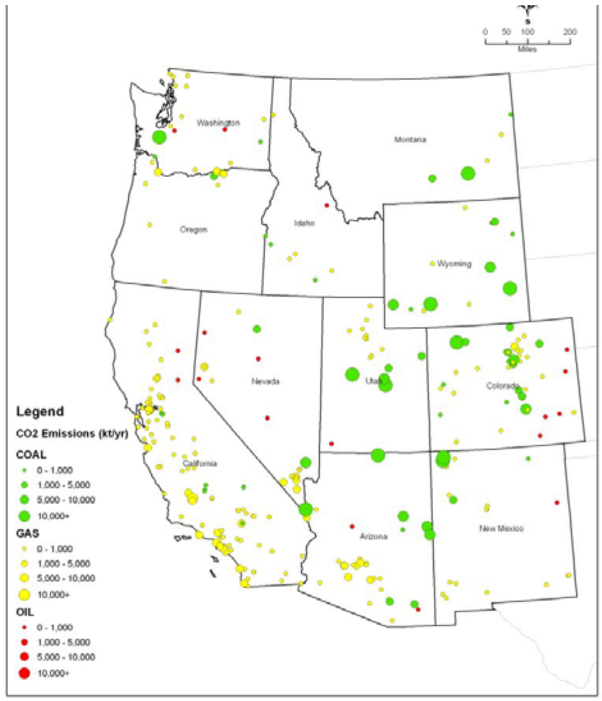
California is a big importer of electricity. While most of the in-state power plants are gas-fired, most of the imported electricity comes from coal-fired power plants. Because of the much larger emission factor for coal versus gas (0.83 tonCO_2/MW_e h vs. 0.37 ton CO_2/MW_e h, from Table 10), CO_2 emissions from imported electricity are greater than for electricity generated in-state. The numbers reported for 2004 are 61 MMT CO_2 imported vs. 47 MMT CO_2 in-state.[154]

This raises an interesting policy question regarding the implementation of CCS technology as to whether CCS programs should be implemented regionally as opposed to strictly in-state. Arguments for a regional policy include that the mitigation cost for CCS from coal-fired plants (primarily out-of-state) is significantly lower than from gas-fired plants, and from the viewpoint of the atmosphere, it is irrelevant where the CO_2 emissions are reduced. Secondly, electricity freely flows throughout the Western Electricity Interconnect.

Figure 15: Location and Size of Fossil-Based Power Plants in the Western U.S. Electricity Grid

[153] Ibid.

[154] Inventory of California Greenhouse Gas emissions and Sinks: 1990-2004 PIER Report CEC-600-2006-013-SF December 2006.



Credit: Massachusetts Institute of Technology, 2007, MIT CO2 Source Database 2007.

This question is not unique to California, but has actively been dealt with in Norway for at least the past 10 years and has been a major issue in their national elections.[155] Norway has an electricity system based primarily on hydroelectric power, but also owns large gas fields in the North Sea. In years of low rainfall, Norway imports power, primarily from coal-fired power plants in Denmark. The need for new power has prompted proposals for gas-fired power plants. On one hand, these gas plants will be less carbon-intensive than Denmark's coal plants, but on the other, these gas plants will increase Norway's CO_2 emissions. So the questions facing Norway are whether to build new domestic gas-fired power plants and if so, should they be required to capture and sequester the CO_2.

Scale Impacts

In general, the economics of CCS exhibits significant economies of scale. An example of this was shown earlier for pipeline transport (Fig. 14), which assumes the building of new pipeline. If the amount of CO_2 to be transported is about 10 MMT/yr or greater, the cost is only about \$0.5/tonCO_2/100 km. However, this cost doubles at 5 MMT/yr and is greater than \$3/tonCO_2/100 km for 1 MMT/yr.

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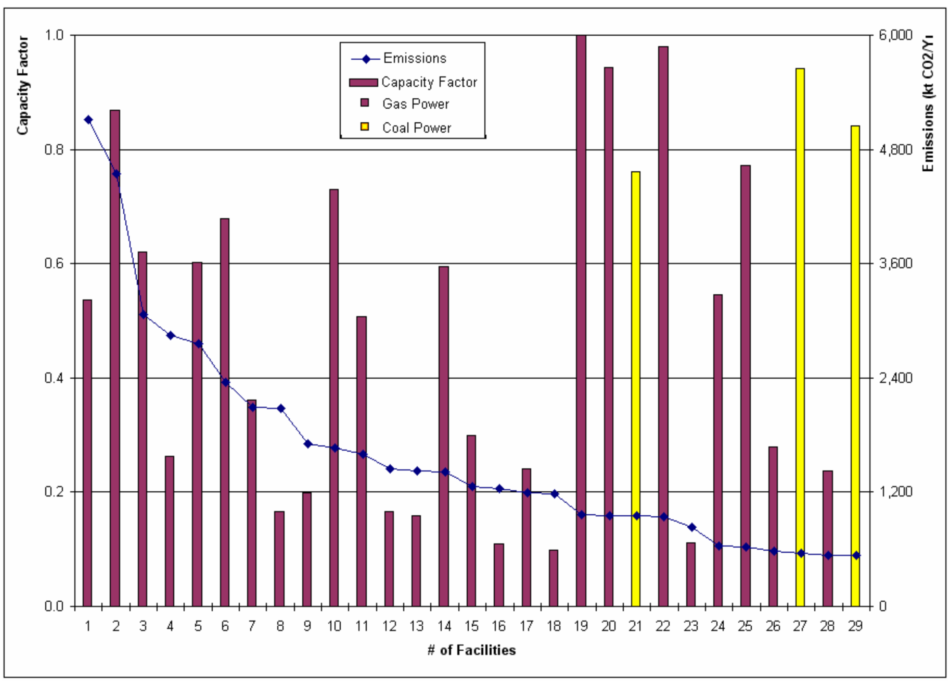
[155] Quiviger, G. Building New Power Plants in a CO2 Constrained World: A Case Study from Norway on Gas-Fired Power Plants, Carbon Sequestration, and Politics. 2001 2001 [cited Masters; Available from: http://sequestration.mit.edu/pdf/Quiviger_thesis.pdf.

Figure 15 shows the current CO_2 emissions from the largest power plants in the Western Electricity Interconnect's region. In California, 30 facilities emit more than 1 MtonCO_2/yr, but only two emit about 5 Mt CO_2/yr. The 48 facilities that have emissions greater than 0.5 MtonCO_2/yr contribute about 80 percent of the emissions. These plants would have reasonable economies of scale for capture, but not necessarily for transport, unless there is close proximity of these sources to appropriate storage sites.

For power plants, another scale issue is the capacity factor. For the economics described in section 8.2, a capacity factor of 85 percent was assumed. Operating at smaller capacity factors result in higher costs. For the 28 power plants shown in Figure 15, only 6 operated at 85 percent or greater capacity in 2004, while 14 operated at 50 percent or less (Figure 16). In general, the capacity factor is determined on a plant's dispatch order based on marginal operating cost. In absence of a carbon price, adding CCS to a power plant raises the marginal operating cost, thereby lowering the capacity factor.

Figure 16: Capacity Factor and CO_2 Emissions for Fossil Fueled Power Plants in California



Plants with CO_2 emissions greater then 500 kt/yr. *Credit: Katzer and Herzog, PIER White Paper*

Financial Issues

CCS technology is very capital intensive. Retrofitting a 1000 MW_e gas-fired power plant will require hundreds of millions of dollars in investment. Building a new 500 MW_e coal-fired power plant will require in excess of a billion dollars. Lenders and investors need to recoup this investment over a long time period (typically 15-25 years). Since CCS is driven by regulation, these investments will require some sort of long-term regulatory certainty.

Fluctuations in the price of EU allowances provide an illustrative example. Prior to April, 2006, the price was high enough to create interest in CCS projects and quite a few initiatives were announced. However, in April 2006, the allowance price fell. Prices on the future market for 2008-2012 are in the range of $20/ton CO_2, but there is no information on what the post-2012 market (post-Kyoto protocol) will look like. Therefore, the risks are much too great to encourage CCS projects based solely on EU allowances.

If encouraging CCS investment is a policy goal, then to address the financial risks, CCS should be included in considerations of options when CO_2 mitigation policies that create carbon markets or subsidies are evaluated.

Other Issues

The costs reported in the previous two sections do not assume any contingencies to cover issues that may lead to increased costs. Potential issues that can significantly increase costs include permitting requirements, monitoring costs, property rights acquisition, and liability. These issues are discussed in other chapters of the report.

CHAPTER 10: Regulatory and Statutory Issues

In California, as elsewhere, CCS-specific regulatory and statutory frameworks do not yet exist. The PIER report study by Wade provided the foundation for this chapter,[156] which is not intended as a formal legal analysis, but rather as a review by technical staff familiar with these issues for the purpose of assessing how current frameworks may apply to CCS implementation in the state. [157]

Given the complexities of the regulatory and statutory frameworks identified by this study as applicable to or analogous to CCS, a robust follow-up analysis seems warranted. This analysis should establish the potential impact of including CCS under existing statutes and regulations and, conversely, the impact of any new CCS-specific regulations and statutes on existing frameworks. Legal and regulatory standards must be established to protect the public, the environment, and the state's resources and simultaneously facilitate technical innovation and advancement.

The process of assessing and developing regulations and statutes for large-scale deployment of CCS is just beginning internationally and nationally.[158] In the United States, numerous agencies are examining these issues. For example, the U. S. Environmental Protection Agency (U.S. EPA) has examined the suitability of provisions for injection wells under its underground injection control (UIC) program. It recently decided that regulators can permit CCS projects under provisions for Class V wells, but it also has initiated a process to determine whether a new class of well is needed for CCS. The Interstate Oil and Gas Compact Commission (IOGCC) is

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[156] Wade, S.J., PIER White Paper on Legal and Regulatory Frameworks, Property Rights and Liability.

[157] This section has been prepared by the Energy Commission's technical staff in response to directives in AB 1925 (ch.471, stats. of 2006). It represents a synthesis of secondary sources and staff opinions. This section is not intended to be a legal analysis of the issues raised or identified.

[158] International Energy Agency, 2005, Legal Aspects of Storing CO_2 :http://www.iea.org/textbase/nppdf/free/2005/co2_legal.pdf; International Energy Agency, 2007, Legal Aspects of Storing CO_2 – Update and Recommendations. http://www.iea.org/Textbase/npsum/legalCO2SUM.pdf ; Robertson, K., J. Findsen, and S. Messner, 2006, *International Carbon Capture and Storage Projects Overcoming Legal Barrier.* Science Applications International Corporation DOE/NETL-2006/1236; Solomon, S., Kristiansen, B., Stangeland, A., Torp, T.A., Karstad, O., 2007, A proposal of Regulatory Framework for Carbon Dioxide Storage in Geological Formations. Prepared for International Risk Geovernance Council Workshop. Washington, D.C.

developing model rules.[159] The state of New Mexico recently released its assessment of the scope of regulatory and statutory issues related to CCS projects. [160]

Implicit in pursuit of these efforts is the premise that CCS projects can be carried out safely and in a manner that protects public health, property, the environment, and resources, including underground sources of drinking water (designated USDWs by the U.S. EPA) and hydrocarbon resources. These studies also emphasize the urgent need to encourage initial demonstration projects to guide the development of regulations.[161] For example, the U.S. EPA's Class V Guidance states:

> Permitting [pilot] projects as Class V experimental technology wells – while maintaining the UIC Program's protective safeguards of [USDWs] and public health – will assist future decision making and the development of a scientifically sound management framework for commercial-scale CO_2 injection projects, if needed, in the future.[162]

If California's goal is to facilitate large scale CCS deployment to reduce greenhouse gas emissions, the current pace of regulatory and statutory assessment and development may not be sufficient. In 2004, a review was done of the environmental regulations potentially applying to geological CCS projects in California. That study concluded that a project developer might need to acquire as many as 15 permits from federal, state, and local authorities; it stressed the need to quantitatively assess the effects of regulations on future project development.[163] Although it seems that some projects, particularly if EOR-affiliated, could be permitted under existing regulations and statutes, there is an obvious need to resolve the complexities and ambiguities that arise when current frameworks are applied to CCS.

Within a CCS project, the storage site is the element least accommodated by current regulatory and statutory frameworks. Existing regulations for industrial facilities and pipelines are applied relatively easily to CCS surface infrastructure. However, the large scale of CCS projects, including pipeline infrastructure, deployment of instrument arrays for site characterization and

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159 IOGCC Reports "Carbon Capture and Storage: A Regulatory Framework for States" and "DOE Award No. DE-FC26-03NT41994 Amendment No. A000 – Final Report" (2005) found at: http://www.iogcc.state.ok.us/PDFS/CarbonCaptureandStorageReportandSummary.pdf

160 "Carbon Dioxide Sequestration: Interim Report on Identified Statutory and Regulatory Issues," New Mexico Energy, Minerals, Natural Resources Department, Oil Conservation Division, June 27, 2007

161 e.g., International Energy Agency, 2007, Legal Aspects of Storing CO_2 – Update and Recommendations. http://www.iea.org/Textbase/npsum/legalCO2SUM.pdf

162 Dougherty, C., McLean, B., US EPA, Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects – UIC Program Guidance (UUICPG #83), March 1, 2007, page 1.

163 Vine, E., 2004: Regulatory constraints to carbon sequestration in terrestrial ecosystems and geological formations: a California perspective. Mitigation and Adaptation Strategies for Global Change, 9, 77–95.

monitoring, and the size of the subsurface reservoirs, will undoubtedly require the permitting and approval process to include multiple local entities, as well as state and, possibly, federal, including property owners and regulatory agencies. If regulatory and statutory frameworks can be designed to clarify and streamline the project approval process while still addressing the public interest and concerns of stakeholders, CCS projects would be better positioned to move forward in pace with greenhouse gas reduction policies.

This study, as well as many others,[164] identifies three main areas that require clarification and streamlining:

- Assignment of authority to regulate in a uniform manner, the injection, storage, and accounting of CO_2 into all potential geologic reservoirs, not limited to oil and gas, for purposes of long-term/permanent sequestration
- Ownership conflicts among mineral estate interests, pore space/storage owners, surface interests, and groundwater users, issues of public good, and use of eminent domain in condemnation of storage space and transportation corridors
- Long-term liability issues, including qualifications, procedures, funding mechanisms, and potential to establish a mechanism or authority to transfer liability/ownership to the state or other public entity

Regulatory Authority and Continuity

California has a long history of regulating operations that have similarities to CCS. These include oil and gas production and disposal activities, waste injection wells, and natural gas storage. The frameworks governing these analogs establish performance-based standards that should be relatively easy to apply to initial CCS projects. At the same time, these existing frameworks are not perfectly suited to CCS. It should be possible to work within existing regulatory frameworks to permit early and pilot CCS projects, but there are critical gaps which must be addressed prior to widespread commercialization.

Underground Injection Control Programs

Injection wells related to oil and gas production, including CO_2 injection wells, and waste injection wells are regulated through the U.S. EPA's underground injection control (UIC) program. As noted above, to date, U.S. EPA has issued guidance that allows small-scale pilot CO_2 injection wells to be regulated as Class V (experimental) wells during an interim period,

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[164] New Mexico Energy, Minerals, Natural Resources Department, Oil Conservation Division, 2007, Carbon Dioxide Sequestration: Interim Report on Identified Statutory and Regulatory Issues.

but anticipates making a permanent classification determination, involving an existing class or creation of a new one specifically for CO_2 storage.

All UIC wells and underground injection regulations are described in various parts of the Code of Federal Regulations, Title 40 (40 CFR).[165] These regulations set out certain minimum requirements for Class I, II, and III wells and govern the siting, corrective action, drilling, construction, mechanical integrity testing, operation, monitoring, closure, and abandonment of each class of UIC well. The requirements for Class I hazardous wells are the most rigorous, followed by Class I non-hazardous, Class II, and Class III wells.

It is possible for states to obtain primary authority (primacy) from U.S. EPA to implement the regulatory program for all well classes, all wells unrelated to oil and gas production (Classes I, III, and V), or just oil- and gas-related wells (Class II). The U.S. EPA implements the UIC program for all wells in all Native American lands and for 10 states; 34 states have primacy for all well classes; and 6 states share responsibility. U.S. EPA also has delegated primary enforcement responsibility to three territories.[166]

California currently shares primacy with U. S. EPA. The California Division of Oil, Gas, and Geothermal Resources (DOGGR) in the Department of Conservation implements Class II wells, and U.S. EPA Region 9 implements all other classes of wells. Roughly 25,000 Class II wells are currently operating in California, but only a small number (less than 20) of Class I and Class V have operated or currently operate in the state.[167]

It is important to understand the differences among the regulations for these well classes and how inclusion of CCS within a class may affect CCS and/or other operations that have potential to be considered analogous. Specifically, decisions on CO_2 injection well classification need to consider the affect of that classification on existing EOR wells. These decisions also have implications for maintaining regulatory continuity for existing Class II wells within depleted oil or gas reservoirs that operators wish to convert to CCS projects. In this way, there is a potentially strong dependence between the well classification decision and the opportunity for captured CO_2 to be utilized for EOR in the state, as well as for the utilization of depleted oil and gas reservoirs for CCS.

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165 40CFR Parts 144 and 146 for UIC; Parts 35, 124, 145, 147 and 148 also pertain to underground injection.

166 USEPA, UIC program Website, State UIC Programs, found online at: http://www.epa.gov/safewater/uic/primacy.html

167 **http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm**

Title 40 of the Federal Code of Regulations, Part 146, contains the technical criteria and standards for all wells under the UIC program and is divided into subsections pertaining to all wells or specific classes:[168]

- Part 146(A) contains general provisions applicable to all wells and addresses the area of review, corrective action (requirements to address improperly plugged and abandoned wells in the area of review), mechanical integrity testing (MIT), and plugging and abandonment of wells.
- Part 146(B) pertains to Class I non-hazardous waste wells.
- Part 146(C) pertains to Class II wells.

Both Parts 146(B) and 146(C) cover issues related to well construction, operation, monitoring, reporting, and other considerations related to permitting and approval to operate wells. Both Parts B and C allow the permit writer to require additional information or to impose more rigorous requirements as warranted by the nature of the geologic target formation and of the fluid being injected. Also, the UIC program includes a public participation process, which requires notification of draft permit issuance and an opportunity for public comment, including public hearings.[169]

The California rules governing Class II wells are found in the California Code of Regulations, Title 14, Division 2, Chapter 4.[170] These rules govern all onshore and offshore oil and gas wells, including Class II injection wells. They include provisions for well operations and spacing and general requirements for wells, including site characterization, construction requirements, blow out prevention, operation, corrective action, mechanical integrity testing, monitoring and reporting, closure and abandonment, environmental protection, and unitization. The California Class II rules also enable the permit writer to require additional information or to impose requirements as needed for a specific well.[171]

Differences among Federal Class I and II and California Regulations

The primary differences among the federal Class I and Class II and the California regulations are in the minimum standards or requirements they impose – not in the level of rigor that could

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[168] Wade, Op. cit.

[169] 40 CFR Part 124.

[170] California Laws For Conservation Of Petroleum & Gas, **ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf** ; California Code of Regulations, Title 14, Division 2, Chapter 4, Sections 1712-1981.2 **ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC04.pdf**

[171] Wade, Op. cit.

be required if deemed necessary. Some specific examples of differences relevant to using these class designations for CCS are:[172]

- Well Construction: Class I non-hazardous well regulations are more prescriptive than Class II in requirements for the tubing and packer design and are based on the corrosiveness and other physical and chemical properties of the injected fluid.
- Mechanical Integrity Testing: Regulations for Class I are more rigorous than for federal Class II. Class II well operators can use cementing records instead of temperature and/or noise logs to demonstrate that no significant fluid movement is occurring into potable aquifers through vertical channels adjacent to the injection well bore.[173] Additional testing can be required as necessary. The California rules require a two-part mechanical integrity test—the first, before injection begins; the second, shortly after—and lays out specific mechanical integrity testing schedules for water disposal, waterflood, and steamflood operations that range from yearly to every five years. U.S. EPA requires mechanical integrity tests every five years for both Class I and II wells. There is room for the permit writer to establish additional requirements for mechanical integrity testing as needed, including a mechanical integrity testing schedule.
- Operation: Class I nonhazardous rules specify a default annulus fluid and require maintenance of annulus pressure in order to monitor for potential leakage. It is not clear that the California rules explicitly consider this provision, and it is not included in the federal Class II standards. Both rules require that injection pressures not exceed the fracture gradient associated with the injection zone.
- Monitoring: Class I nonhazardous wells are required to continuously monitor injection pressure, flow rates, volume, and annulus pressure. Class II wells are required to periodically monitor this information and are required to have equipment for continuous monitoring in place.
- Ambient Monitoring: Based on a site-specific assessment, Class I nonhazardous well operators must propose an ambient monitoring plan. A plan includes identifying possible risks and receptors potentially affected by leakage and a mitigation plan (sometimes referred to as a Contingency Management Plan or CMP) to be activated before the unanticipated movement of injected fluid could cause damages. Class I nonhazardous regulations establish a procedure for developing these safeguards. Federal Class II regulations do not require ambient monitoring plans, but do provide for an option to require additional monitoring and contingency plans to address well failure. California requires a monitoring system[174] and also allows the Division of Oil

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[172] Ibid.

[173] 40 CFR Part146.8 (a) (2).

[174] Section 1724,7 (c) (3)

and Gas to require additional information, such as a safety program for "large, unusual" projects.[175]

- Reporting: Under the federal program, Class I nonhazardous well operators report on a quarterly basis, and Class II well operators report on an annual basis. California requires monthly reporting for Class II injection wells.
- Approval Process: The federal program for injection well approval is built around a multi-step process. An operator files a permit application containing the required information. Presuming the application is complete, the permit writer issues (or denies) a draft permit for public comment. After the public comment period and final review, the permit writer issues (or denies) a final permit. The applicant must then demonstrate the internal integrity of the permitted well before approval to operate is granted and injection can take place. The California rules allow for a much speedier process in which operators seek an injection project permit and, if the project is approved, they can then rapidly obtain permits for individual wells within the project.

Fit of Underground Injection Control Programs to Carbon Capture and Sequestration

Previous research also shows that neither the federal Class I or II regulations is perfectly appropriate to the needs for CCS. Table 12 shows one such assessment. The table lists major parameters related to CCS projects that should be addressed through regulation and the criteria expected to apply over the long term. It then provides an evaluation of the appropriateness of existing federal Class I and Class II rules to address these issues. One issue highlighted by the table is that federal Class I and Class II regulations are insufficient for the large volumes injected and for very long storage periods of CCS projects. As noted in previous chapters, CCS projects require understanding the reservoir and plume behavior at a large scale. The UIC program does allow for area permits, a process that could be adapted for CCS. In California, the Class II well permitting process used by the Division of Oil and Gas incorporates consideration of the project as a whole. As defined by the Division of Oil and Gas, the general procedure for a Class II well permit is as follows:

Operators of Class II injection wells must file for a permit with the Division. Before a permit is issued, the proposed injection project is studied by Division engineers and reviewed by the appropriate Regional Water Quality Control Board. Division engineers evaluate the geologic and engineering information, solicit public comments, and hold a public hearing, if necessary. Injection project permits include many conditions, such as approved injection zones, allowable injection pressures, and testing requirements.[176]

Given the importance of site characterization and monitoring for CCS, as discussed in previous chapters of this report, it may be beneficial to use options within the UIC programs for an area-,

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[175] Section 1724.7 (e).

[176] http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm

or reservoir-based, rather than a well-based, focus for regulating CCS projects. The current approach in California of approving a permit application for an oil field or project and then approving wells within that field or project may be a workable analog, especially for CCS projects in oil or gas fields where significant amounts of background geologic data are available. In saline formations, where few data have been collected historically, it may be useful to consider minimal requirements for background information on the pertinent hydrologic area or region.

One option recently proposed calls for a two-step permitting process in saline formations.[177] The first step is a general area permit for a formation or a large section of a reservoir. The second step is permitting individual wells. Factors to be considered the first step include:

- Surface distribution of characteristics and risk receptors
- Subsurface brine distribution
- Subsurface geologic conditions
- Regional variation in reservoir capacity and quality
- Regional flow characteristics
- Regional variation in quality of primary and secondary seals[178]

The requirements for individual well permitting would include more detailed technical and financial requirements. Some have raised concerns that such an approach would create permitting delays while data were collected on different reservoirs.[179] An important role of pilot and early projects will be to define the minimal data requirements necessary to permit CCS in saline formations.

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[177] Nicot, J.P., Duncan, I.J., Science-Based Permitting of Geological Sequestration Of CO2 In Brine Reservoirs In The U.S., Gulf Coast Carbon Center, Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin, Austin, TX, 78713, USA, pp. 11-12.

[178] Ibid.

[179] Wade, Op. cit.

Table 13: Considerations and Evaluation of Federal Class I and II UIC Regimes for CCS

Parameter	CCS Specific Need	Class I Non-Hazardous	Class II
Large Quantities of Injectate	Adequate review of surrounding geology, historic activity to assure sufficient confinement of injected CO_2	Not Sufficient: traditional AOR process and calculation need to be adapted to CO_2. Each well must be permitted individually	Not Sufficient: traditional area of review small and often not backed by a calculation. Significant adaptation needed for GS. Area permit possible
Containing Buoyant Fluid	Sufficient trapping mechanisms need to be present to insure that injected CO_2 will remain underground	Historical experience with fluids denser than formation water, siting requirements, no faulting complex geology, earthquakes etc. FL not successful containing buoyant fluid	CO_2 EOR experience is extensive, but no direct experience with containment of buoyant fluid, sited where oil and gas reserves are located
Time	Injected CO_2 must remain underground for hundreds to thousands of years	Not sufficient: no storage time specified for Class I N-H wells, no post-closure verification of waste storage	Not sufficient: no storage time specified, no post-closure verification of injectate storage
Surface Leakage	Few small leaks okay, but need to be monitored to ensure environment and human health (operator and exposed population) not overly harmed	Focused on water contamination: no leakage allowed, injected fluid must not migrate into USDWs or cause other formation fluids to inject into USDWs, though FL 'solution' proposes creating a special instance of a Class I well.	Focused on water contamination: no leakage allowed, injected fluid must not migrate into USDWs or cause other formation fluids to inject into USDWs. Many exempted aquifers, migration would be OK
Site Monitoring: Subsurface	Techniques to show how CO_2 is flowing through formation and not leaking to surface	Monitoring wells may be required to check for USDW contamination, rarely are, no other methods are required, surface monitoring provided by state EH&S schemes	Monitoring wells may be required to check for USDW contamination, very rarely are, no other methods are required, surface monitoring provided by state EH&S schemes

Table 13 con't: Considerations and Evaluation of Federal Class I and II UIC Regimes for CCS.

Parameter	CCS Specific Need	Class I Non-Hazardous	Class II
Site Monitoring: Injection Well	Measurements to ensure that well is sound and not providing inadvertent leakage pathway	Current reporting of injection well and mechanical integrity testing required every 5 years	Current reporting of injection well and mechanical integrity testing required every 5 years, cement test is review of past records, no physical test required, if cement degradation within the operational period is a concern, need to revisit requirements
Site Verification: Accounting, Reporting	Verification of amount of CO_2 injected important for larger accounting regime	Metering of injection and quarterly reports standard practice	Metering of injection and annual reports standard practice
Post-Injection Operation	Well abandonment and long-term monitoring, long-records archiving	Well plugging and abandonment procedure, records kept for 5 years by operator, regulatory agency records well location and plugging records.	Well plugging and abandonment procedure, records kept for 5 years by operator, regulatory agency records well location and plugging records.
Programmatic Mandate	CO_2 shall remain subsurface and not harm environment or human health	No migration into or between USDWs	No migration into or between USDWs

Source: Wilson, E.J., Managing the Risks of Geologic Carbon Sequestration: A Regulatory and Legal Analysis, Ph.D. Thesis, Department of Engineering and Public Policy, Carnegie Mellon University (October 2004), Table 5.4

Natural Gas Storage Regulatory Programs

Another possible regulatory analog is natural gas storage. The natural gas storage fields in the state are regulated by the California Public Utilities Commission (CPUC). Wells approved for natural gas storage are exempt from the UIC program. In California, such wells are reviewed under the California Environmental Quality Act (CEQA).[180] As noted above for UIC classification, the implications of adopting elements of this approach for CCS must be carefully studied in order to understand their impact on CCS and other operations.

Regulatory Continuity

One issue that previous reviews have raised is that differences in how captured CO_2 is classified—as a waste product or an industrial product—may lead to ambiguities and discontinuities in how CO_2 is regulated among reservoir types or at different points in the CCS process (from capture, through transportation, and in storage).[181] The point also has been made, however, that many compounds are industrial products that can also become wastes through improper handling or through industrial processing. Likewise, chemical compounds in wastes, through recycling, can become industrial products. Through these chains, these compounds are subject to whatever requirements for protection of the environment, health, and safety are appropriate for collection, use, or disposal.[182]

From a regulatory standpoint, there are hazardous and nonhazardous designations for waste. CO_2 is not currently classified in the U.S. or in California as hazardous waste and is not regulated under the Clean Water Act.[183] If CCS were to fall under the UIC program as discussed above, and if CCS injection wells were classified as Class I, they would fall within the nonhazardous subclass. For indoor air, the concentrations at which carbon dioxide is identified as hazardous are contained in occupational health and safety requirements (see previous chapter on risk and risk management for additional information).[184]

Industry groups engaged in EOR activities tend to advocate the classification of captured CO_2 as an industrial product.[185] Currently, if CO_2 is used for enhanced resource recovery, it is considered an industrial product because the CO_2 is used to extract oil, gas, or methane

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[180] Wade, Op. cit.

[181] New Mexico Energy, Minerals, Natural Resources Department, Oil Conservation Division, 2007, Op cit.; Robertson, K., 2006, Op cit..

[182] Wade, Op. cit.

[183] Ibid

[184] Benson, et al. 2002a, 2002b, Op. cit.

[185] Robertson et al., Op. cit.

resources.[186] If captured CO_2 used for EOR changes classification from a waste to an industrial product at some point between capture and transportation to injection and storage, there may be potential operational, economic, and regulatory implications for the feasibility of using captured CO_2 gas for EOR operations. For example, handling requirements may change, depending upon whether the CO_2 is designated for industrial use for EOR or for storage in a CCS project. Inflexible classifications could present difficulties for projects that originally were EOR operations that subsequently become CCS operations.

On the other hand, when the focus shifts to long-term health and environmental, including climatic, impacts, there is a tendency to classify captured CO_2 as a waste product.[187] This is the case particularly for CCS projects developed solely for the purpose of CO_2 storage. In particular, CCS projects in saline formations clearly do not have an industrial or resource recovery component. In any case, care should be taken to avoid adoption of an inflexible regulatory framework that results in classifying captured CO_2 differently depending on the type of storage reservoir, that is, industrial product for depleted hydrocarbon reservoirs, waste product for saline formations, or its point in the CCS process.

There may be additional ramifications resulting from adoption of a classification for CO_2 if California ever considers using storage reservoirs for CCS in formations which extend offshore, including its legality and treatment under international treaties and national coastal laws and regulations. There are currently several regional and global treaties that could apply to offshore CO_2 storage projects. Offshore projects have been allowed as industrial storage or enhanced resource recovery projects under international marine treaties[188] because the purpose of the storage has not been considered disposal, but rather a part of an industrial process. Given that these treaties were established before the emergence of CCS as a major option for reducing CO_2 emissions, the treaties originally did not address CCS, but recent amendments have been made (London Protocol, February 2007) or are being considered to explicitly allow CCS.[189]

If it is decided that CCS should be regulated within the UIC program, there also is a possibility for regulatory discontinuity. Currently, the application to CCS of the federal and California rules suggests that there would be differences in regulations and regulatory authorities for CCS projects in depleted hydrocarbon reservoirs versus those in saline formations. Given the shared

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[186] Interstate Oil and Gas Compact Commission (IOGCC), 2005, Carbon Capture and Storage: A Regulatory Framework for States, Summary of Recommendations.

[187] Robertson, et al., Op. cit.

[188] These treaties include the London Convention on the Prevention of Marine Pollution by Dumping Wastes and Other Matters (London Convention) and the Protocol to the London Convention (London Protocol), the United Nations Convention on the Law of the Sea (UNCLOS), and the Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR).

[189] http://www.ieta.org/ieta/www/pages/getfile.php?docID=1989

primacy for the UIC program in California, use of this program for CCS injections wells would divide regulation of CCS injection wells between California's Division of Oil and Gas and U.S. EPA Region 9. If CCS wells are permitted as Class II, the Division of Oil and Gas would have the authority to regulate CCS projects in depleted oil and gas reservoirs; however, U.S. EPA Region 9 would have authority for any CO_2 injection into saline formations. In the long run, if the UIC program is used, and it is determined that one regulatory agency should take the lead on all CCS projects in the state, a negotiated agreement may be an option for consolidating CCS regulatory authority. For example, the Division of Oil and Gas has authority, through a negotiated agreement with U.S. EPA, to regulate geothermal wells.[190]

Ownership Issues

The implementation of CCS creates potential for ownership conflicts among mineral estate interests; pore space/storage owners, surface interests, and groundwater users; issues of public good, and use of eminent domain in condemnation of storage space and transportation corridors. As is the case for natural gas storage projects, acquiring property rights for CCS projects rather than for secondary recovery in oil and gas fields may require a different strategy; CCS also raises different issues in saline formations than in depleted oil and gas targets.

The three main property interests relevant to CCS are surface owners (injection facilities and monitoring stations), subsurface owners (storage reservoir, pore space, mineral rights, water rights), and owners of the CO_2 itself. Because property ownership also entails liability, there are significant implications resulting from property rights determinations. It is also critical to determine if, when, and how private liability is transferred to the public sector, to establish the entity that determines to whom property rights belong, to establish public and private methods of acquiring relevant property rights, and to establish protocols to manage the title to the actual CO_2 from capture, through transportation, to injection and long-term storage.[191]

Property Ownership

In most cases, specific contracts address property rights issues at the start of the development of each project, and the contracting parties determine which laws apply and how.[192] However, property rights for CCS are still a new issue for which protocols are not yet clearly defined, making it difficult for contracting parties to make such determinations.

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190 http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm

191 Wade, Op. cit.

192 Robertson, et al., Op cit.

There are generally two schools of thought regarding property rights: the first granting rights that include ownership of the material (in this case, the CO_2), which entails greater liability on the property right holder, and the second, granting rights according to a service provided, meaning that property rights follow the steps in the disposal process. Superfund in the United States is an example of the second service-type property right in which liability is imposed on all parties responsible for the presence of a hazardous material at a facility or site. Liability is much broader and can affect a wider range of participants and for extensive periods of time.[193]

A primary question to resolve for CCS is ownership of subsurface pore space in the storage reservoir. There seems to be some ambiguity in existing statutes in the U.S., and so it is unclear, if subsurface pore space is owned by surface property owners, whether it can be transferred via easements, decoupled from the surface estate and purchased in the same way as mineral rights, or unitized to serve the public good.

The system of protecting property rights in the United States is founded on the premise that the surface owner owns the rights to the property below the surface, extending to the center of the earth, and above the surface, extending to the heavens. The Fifth Amendment to the U.S. Constitution protects the individual's property rights. This philosophy is evident in the approach to acquiring mineral rights for the production of gas, oil, coal, and other minerals, whereby it is common to separate the mineral and surface estates to allow the surface owner to sell or lease mineral rights of the property while still preserving rights to the surface estate.[194]

That said, the "center of the earth to the heavens" approach to property rights has been modified by unitization statutes to recognize the public interest in conserving oil and gas resources and to ensure that they are not wasted. Most oil and gas producing states have statutes for compulsory unitization of oil pools or fields under specific conditions. Many also govern well spacing to optimize opportunities to recover oil and gas. Common-law property rights also have been modified in recognition of the public interest as there have been changes in technology and the practical limitations on property use. For example, planes flying over an individual's property would not necessarily constitute trespass. The public trust doctrine also protects navigable waterways and tidal areas for the common use of the public. This doctrine is cited in programs that guarantee public access to shorelines, tidal zones, and navigable waterways.

In short, there is both strong legal support for maintenance of common-law property rights and precedents for limiting those rights for the public's benefit. If CCS is deployed at the scale envisioned to significantly address climate change, the size and extent of CCS projects would require the negotiation or condemnation of property rights from huge numbers of property

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[193] Ibid.

[194] Wilson, E.J., 2004, Managing the Risks of Geologic Carbon Sequestration: A Regulatory and Legal Analysis, Ph.D. Thesis. Department of Engineering and Public Policy, Carnegie Mellon University.

owners. At the same time, if CCS is deployed on such a scale, it would represent a significant public benefit as a climate change mitigation strategy. Since most CCS projects will be located in very deep formations (more than 2,600 feet), it is unlikely that surface owners that do not already have known mineral deposits at these depths will be affected. On the other hand, there are arguments for maintaining pore space as private property. As technology changes, there will be new ways to produce hydrocarbons that today might be considered uneconomic; likewise, discoveries may be made of new uses for minerals and deep geologic formations, and so property with no known mineral deposits today may become valuable in the future. For the near future, it seems likely that CCS operations will be commercial endeavors with values that depend in part on the value placed on avoided carbon emissions. Given this, CCS storage space may become a part of the value of the property in the same way that mineral resources are.

Acquisition of Rights

At the federal level and in California, applicants are not required to demonstrate that they have acquired the subsurface rights to the mineral or surface estate in order to obtain injection permits, and issuance of injection permits does not convey such property rights. Rather, operators engaged in injection are potentially liable for trespass and damages if their actions infringe on others' property rights. To avoid this potential outcome, it is common practice for well operators to assess the need to acquire subsurface rights based on the potential impact of their injection activities and to set about acquiring those rights through common market negotiation or through the exercise of eminent domain in certain cases. Property rights for the surface or mineral estate can be acquired through traditional market mechanisms such as purchase, lease, or other means of transfer, or through eminent domain or condemnation authority that forces the transfer for an amount determined to be fair market value.[195]

Given the climate change mitigation goals associated with CCS, there is clearly a "public-good" aspect to these projects. However, it is unclear whether CCS projects would fall under mechanisms currently in place by which eminent domain or condemnation is asserted. In any case, the use of these authorities is very controversial and should not be taken lightly.

There are two instances described in the California Laws for Conservation of Petroleum & Gas in which the state can override the rights of a single property owner in consideration of larger concerns of the public. In the first instance, forced unitization of an oil pool or pools is allowed as part of an approved field re-pressuring plan to arrest subsidence.[196] In the second instance, forced unitization of an oil pool, pools, or portions thereof is allowed if three-quarters of the

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[195] Wade, Op. cit.

[196] Section 3319. California Laws For Conservation Of Petroleum & Gas, ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf

working interests and three-quarters of the royalty interests agree to unitize.[197] In both cases, procedures are outlined to determine a fair market value and compensate the existing property rights owner for the use of the property rights in question. In addition, public utilities may petition the CPUC for approval to condemn property for the purpose of offering competitive services. If the CPUC agrees that such condemnation is in the public interest, the utility can go to superior court to condemn the property. The utility is required to pay the property owner fair market value for the condemned property. Finally, Article 1, Section 19 of the California State Constitution allows for use of eminent domain authority for a private or public entity to obtain property rights, given a court determination of public use and fair compensation.

CCS in Oil and Gas Fields

It seems obvious, but is worth noting that oil and gas have monetary value as commodities. People sever the surface and mineral rights of a property bearing oil or gas deposits in order to harvest the hydrocarbon while preserving the right to use the surface land. Injection for secondary recovery is a proactive means of producing oil and gas, and well operators acquire the rights to the mineral estate for this purpose. CCS projects differ from enhanced recovery projects in that their purpose is to store CO_2 indefinitely. It is unclear whether CCS operators need to acquire mineral rights if the sole purpose is CO_2 storage. It is not clear that CO_2 storage precludes the opportunity to produce oil or gas in the future. However, in a carbon constrained world with carbon markets and credits, any future oil and gas production would have to address the ramifications of co-producing sequestered CO_2.

Some similar issues arise with natural gas storage projects. These might include property access for monitoring wells; limiting exploration and injection activities by others in nearby areas; and compensation for any gas, oil, or other mineral resource in place that may no longer be producible because of the storage project. To avoid litigation, natural gas storage operators typically negotiate with both the surface owner and mineral rights owner to acquire the right to store natural gas in a property.[198]

CCS in Saline Formations

Under the UIC program, for Class I and Class V, there is no requirement to obtain the subsurface rights associated with the properties through which the injected fluid moves. However, there is a mandate to avoid interference with the production of oil and gas. There is little case law regarding determination of trespass in saline formations where there is no probability of producing oil or gas. However, there are a few cases related to natural gas storage, where the courts have ruled that, because the leasing or sale of storage space is

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[197] Section 3642. Ibid.

[198] Fish, J.R., Nelson, R., Building Your Own Underground Gas Storage Project: From Leasing To Open Season Under FERC Order No. 636, 40 Rocky Mt. Inst. 19-25 (1994).

valuable, use of pore space for natural gas storage does constitute trespass. This issue needs clarification for CCS projects.[199]

Long-Term Stewardship and Liability

Liability for geologic sequestration of CO_2 comes from three major sources: non-permanence of storage, in situ risks, and operations impacts. Non-permanence of storage relates to risk of CO_2 release back into the atmosphere, assuming CO_2 emissions will be controlled under a regulatory regime in the future and that there will be potential liability associated with leakage and its potential impact on climate change. Potential liability may arise from the following in situ risks: formation leaks to the surface, migration of CO_2 within the formation, and seismic events. These types of events may lead to liability related to local public health and/or environmental impacts. While the operational risks associated with transportation, injection, and storage of CO_2 have been successfully managed for many years, the major concern with both the second and third liability sources is during the post-closure phase, given that no time limitations have been established, making the term in effect, unending.

While the operational risks associated with transportation, injection, and storage of CO_2 have been successfully managed for many years in EOR, the long-term liability for CCS sites after closure is almost unique to CCS. Given that no time limitations have been established, liability associated with formation leaks to the surface, off-site migration of CO_2 underground, and damage to wells from seismic events, is, in effect, unending, as these events could occur at any time, far into the future. For industry, the concerns associated with this open-ended liability include the project's lack of insurability, the potential for remediation costs related to CO_2 migration and/or leakage at some point in the distant future, and the disincentive that these potential costs may have on investment today in CO_2 geologic storage.[200] Before a CCS industry develops (for example, for pioneer projects), liability may be particularly problematic. For example, Texas and Illinois, in competing for the FutureGen project, passed legislation accepting ownership and liability for this specific project's injected CO_2, with some conditions specified but without extending to any future commercial projects.[201]

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[199] Wade, Op. cit.

[200] Ibid.

[201] Illinois General Assembly: SB1704 and HB 1777 found online at (June 2007 Draft): http://www.ilga.gov/legislation/BillStatus.asp?DocNum=1704&GAID=9&DocTypeID=SB&LegId=29844&SessionID=51&GA=95; Texas Legislature: SB 1461 (http://www.capitol.state.tx.us/tlodocs/80R/billtext/pdf/SB01461F.pdf) and HB 149 (http://www.capitol.state.tx.us/tlodocs/793/billtext/pdf/HB00149F.pdf)

Long-term liability issues are viewed by industry as a major constraint that may prevent the widespread adoption of CCS in California. Because geologic CCS could be carried out as part of the state's policy to lower greenhouse gas emissions, transfer of liability to the public sector after an operator has met requirements for a given time period has been postulated as one option to remove this barrier.

The choice of regulatory frameworks also has important implications for long-term stewardship and liability. Any policy for long-term liability will have to include the following elements:

- A regulatory entity and funding to carry out monitoring, verification, and mitigation activities
- Processes and funding to mitigate or remediate any potential damages that arise
- Processes for those incurring damages to seek compensation

All of these elements will be required to demonstrate that the practice of CCS continues to be safe and effective as a greenhouse gas control technology far into the future. These elements also must assure that there is adequate funding and administrative support for post-closure monitoring and maintenance and for remediation and mitigation, if necessary.

Provisions under the Underground Injection Control Program

Rules regarding injection well closure under federal Class I and California Class II regulations are fairly similar. Both require that operators provide financial assurance for the proper closure, plugging, and abandonment of wells; contain performance standards for demonstrating proper closure and construction of the plug; and allow the permit writer to impose additional safeguards in the design of the plug if warranted. However, neither set of regulations contemplates a post-closure stewardship period.

Federal Class I rules require operators to demonstrate financial responsibility for closure through a series of mechanisms. Although there is not a large amount of experience with Class I wells, what history exists suggests that these financial assurance provisions are sufficient to induce proper closure of Class I wells.[202] Class II wells in California have a bond requirement of $50,000 per well. The bond is released when the operator properly closes, plugs, and abandons the well.[203]

Neither the Class I nonhazardous nor the Class II (federal or California versions) includes provisions regarding post-closure activities. The Class I hazardous waste rules do anticipate some post-closure activities, but they are more related to problems discovered during the

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[202] Wade, Op. cit.

[203] Section 3205.2, California Laws For Conservation Of Petroleum & Gas, ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf

operational life of a project than to long-term routine maintenance and monitoring. In the case of Class I nonhazardous and Class II wells, enforcement of remediation and mitigation actions is only triggered if a leak or other problem associated with a well is detected. However, both the Class I nonhazardous and California Class II rules can require injection well monitoring plans during operations, and these could potentially be extended to include post-closure activities. Neither of these rules clearly ends the liability of a well operator when it has been determined that a well is properly closed. If leakage or a problem associated with an injection well occurs after proper closure, the responsibility for conducting and paying for clean up is currently likely to be determined by the courts. If a responsible party can be identified and is solvent, they may be required to pay for clean up and damages. If no responsible party can be identified, clean up may fall to state or federal programs. California has several programs for dealing with problem wells and gas leakage: the Hazardous and Idle-Deserted Well Abatement Fund, the Acute Orphan Well Account, and the Methane Gas Hazards Reduction Assistance programs.[204]

FutureGen

California may want to explore options for actions similar to those taken by Texas and Illinois for the FutureGen project. In particular, this is a possible way to facilitate initial pilots or projects prior to the establishment of an industry that is sufficiently robust to create an indemnification fund.

As mentioned previously, the U.S. Department of Energy's FutureGen project, combining coal gasification for electric power and hydrogen generation with carbon sequestration at a commercial scale, has reached the stage recently of completing EIS and risk assessments of candidate construction sites in Illinois and Texas. As for other pioneer CCS projects, liability is a problematic issue for the FutureGen Alliance, the consortium of companies and government agencies, developing the project. The request for proposals for the FutureGen project required a proposer to discuss "the extent to which it can or is willing to take title to the injected CO_2 and/or indemnify or otherwise protect the FutureGen Industrial Alliance and its members from any potential liability associated with the CO_2. Offerors may discuss other alternatives…"[205]

In response, both Illinois and Texas passed legislation. Although the provisions are not finalized, both states have taken the approach that the state will take title to the injected CO_2 and through that process will assume all liability for it once it is injected. In both cases, the legislation applies only to specifically named sites that are being considered for FutureGen and does not apply if FutureGen is located at a different site. Both states are using highly qualified

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[204] California Laws For Conservation Of Petroleum & Gas, ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf

[205] http://www.netl.doe.gov/technologies/coalpower/futuregen/

field teams based in state universities or geological surveys to oversee the injection and subsequent monitoring.

However, differences also exist in each state's approach. Illinois is imposing a restriction that the injected CO_2 must remain underground.[206] The Texas legislation raises the potential of using the stored CO_2 at a later time for enhanced oil recovery or some other use.[207]

Other Programs for Long-Term Stewardship and Liability Coverage

Another option for ensuring adequate funding to cover liability and post-closure activities is to require that a per-ton fee be collected in an interest-bearing account for use in the post-closure time frame. An example is the Acute Orphan Well Account, administered by the State of California and overseen by the Conservation Committee of Oil and Gas Producers.[208] Another program, the Hazardous and Idle-Deserted Well Abatement Fund, collects annual fees on idle wells into an escrow account.[209]

Another recent suggestion is the creation of a public corporation to collect and administer a "CO_2 Storage Fund" and to assume liability for those CCS projects that satisfactorily demonstrate containment of the CO_2 plume. The purpose of the fund would be to finance monitoring, maintenance and mitigation activities; complete orphaned CCS wells; compensate for tortious liability (damages); and fund remediation. The source of funds would be a small levy charged on per-ton basis for stored CO_2, interest from the fund, and, possibly, reimbursements from operators under certain conditions. Successful projects could be handed over fully to the corporation 10 years after closure. At that time, the operator would predict future potential leakage (from modeling) and compensate the fund for that leakage. Only storage wells (not enhanced recovery wells) would be eligible, though enhanced recovery wells could convert to storage wells. Also, in order to jumpstart projects, the government could fund

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[206] Illinois General Assembly: SB1704 and HB 1777 found online at (June 2007 Draft): http://www.ilga.gov/legislation/BillStatus.asp?DocNum=1704&GAID=9&DocTypeID=SB&LegId=29844&SessionID=51&GA=95

[207] Texas Legislature: SB 1461 (http://www.capitol.state.tx.us/tlodocs/80R/billtext/pdf/SB01461F.pdf) and HB 149 (http://www.capitol.state.tx.us/tlodocs/793/billtext/pdf/HB00149F.pdf)

[208] Section 3262, California Laws For Conservation Of Petroleum & Gas, ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf

[209] Section 3206(b), California Laws For Conservation Of Petroleum & Gas, ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf

the levy for research or early projects. There are other provisions in this proposal relating to determination of damages on a no-fault basis and rules for compensation.[210]

The Interstate Oil and Gas Compact Commission is working on a model rule and although it has not been publicly presented, briefing materials suggest that the model rule will include provisions for the creation of a fund to cover the cost of long-term stewardship and some limitations on liability for projects that successfully demonstrate compliance with applicable laws.[211]

Outside the CCS and natural resources fields, there are also programs that may provide analogs for addressing long-term liability, including the Price Anderson Nuclear Industries Indemnity Act, the National Flood Insurance Program, and the National Vaccine Injury Compensation Program:

- Price Anderson Nuclear Industries Indemnity Act: This program is essentially, a risk-pooling program, with three tiers of requirements:
    - Tier 1 (individual financing) requires the individual nuclear plant to obtain primary insurance coverage up to a mandated level (as of 2005, $300 million per plant).
    - Tier 2 (collective financing) requires that each company contribute up to a statutory cap of $95.8 million in the event of a nuclear accident. As of 2006, the fund was valued at approximately $10 billion in nominal terms, if all of the nuclear reactors were required to pay their full obligation to the fund. Payments are not made into the fund unless an accidental release occurs, and actual payments made in the event of an accident are capped at about $15 million per year until claims are met or the maximum individual liability has been reached. The federal government can defer payments into the fund to defray financial distress within the industry.
    - Tier 3 (federal financing) requires the federal government to backstop the remaining balance owed to claimants through the general treasury, once the individual and collective caps are reached.[212]

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210 de Figueiredo, M.A., H.J. Herzog, P.L. Joskow, K.A. Oye, and D.M. Reiner. Regulating Carbon Dioxide Capture and Storage. April 2007 [cited; Available from: http://web.mit.edu/ceepr/www/2007-003.pdf

211 Interstate Oil and Gas Compact Commission reports "Carbon Capture and Storage: A Regulatory Framework for States" and "DOE Award No. DE-FC26-03NT41994 Amendment No. A000 – Final Report" (2005) found at:
http://www.iogcc.state.ok.us/PDFS/CarbonCaptureandStorageReportandSummary.pdf

212 Trabucchi, C., 2007, Industrial Economics, Summary of Finanacial Responsibility Frameworks for Use as Potential Models for Managing Long Term Liability Associated with CCS. Presentation at WRI Risk Workshop, June 2007.

- The National Flood Insurance Program is federally funded, guaranteeing flood insurance to homeowners located in communities that have adopted flood plain management programs in an effort to reduce future flood damage. It was designed to encourage communities to plan to avoid predictable flood damage.

CHAPTER 11: Conclusions

While technical challenges remain, the primary barriers to progressing with initial geologic sequestration projects in the state lie within the statutory and regulatory arena. However, demonstration projects and further technical evaluations and studies are needed, in part to guide development of regulations and statutes that are appropriate for CCS. Demonstration projects, in particular, also should provide opportunities to engage stakeholders and for public education on carbon capture and storage. The following information summarizes the primary conclusions and makes recommendations from this report's main topics.

Potential for Geologic Sequestration

Improve geologic characterization of the storage potential in the state, particularly for saline formation storage, and facilitate a demonstration project for CO_2 storage in a saline formation.

While preliminary studies of the geology of the state identify a large storage resource potential, more detailed site-specific characterization of the subsurface geology will be needed in many areas with sequestration potential. Preliminary estimates of saline formation CO_2 storage capacity for the 10 largest basins is between 75 and 300 metric gigatons of carbon dioxide (GT CO_2); for oil and gas fields, preliminary estimates are on the order of 3.5 and 1.7 GT CO_2, respectively. There is reasonably good agreement within the state between locations of emission point sources and sites for geologic storage.

While early projects may take advantage of the opportunities for doing CO_2 storage in affiliation with CO_2-EOR projects in depleted oil and gas fields, they will not be sufficient to accommodate all of the CO_2 that will have to be captured from various industrial sources to enable California to meet its long-term goal for reducing greenhouse gas emissions. Thus, commercial application of geologic sequestration in California will require use of the state's ample saline formations. Although CO_2 storage in saline formations will resemble storage in oil or gas reservoirs, the saline formations of California have not been extensively studied in the manner of oil- and gas-containing formations. These studies must be done.

Demonstration projects of CO_2 storage in saline formations at volumes and over time periods sufficient to evaluate their suitability as CO_2 storage sites also will be critical. The research and pilot projects being conducted by the WESTCARB partnership have begun the work needed to gather data and better understand saline formation storage capacity and trapping mechanisms, but more efforts are required.

To facilitate CCS infrastructure, evaluate the cost and other issues associated with pipeline development to link industrial CO_2 sources to preferred storage sites.

Where large industrial sources amenable to CO_2 capture do not overlie suitable geologic CO_2 storage sites, CO_2 will have to be transported to storage sites via pipelines, trucks, trains, ships, or barges. For the large quantities of CO_2 that must be handled for sequestration, pipelines are clearly the most economical mode of transport. The technical, economic, safety, and permitting aspects of CO_2 pipeline transport are relatively well understood because of the many pipelines in the U.S. for the large-scale transport of CO_2 for use in EOR. The costs and complexity of building CO_2 pipeline infrastructure in California will depend on the proximity of CO_2 sources to preferred storage sites, available rights-of-way, the surface terrain, and current surface uses, but the impacts of these factors on transport feasibility and costs must be quantified.

Evaluate the potential in the state for captured CO_2 to be used for EOR

The high cost of supplying CO_2 from out-of-state sources is a barrier to adoption of CO_2-EOR in the state. Economic and regulatory studies need to establish the relationship between captured CO_2 cost and demand for this CO_2 for EOR. They also need to evaluate the regulatory and statutory issues that would facilitate EOR operations that use and store CO_2. These projects, in turn, would provide important datasets to facilitate CCS development. Two new power plants in California, the proposed BP-Rio Tinto-Edison Mission Energy petroleum-coke gasification project in Carson (Los Angeles County) and the Clean Energy Systems plant in Kimberlina (Kern County) include designs for CO_2 capture, with the prospect that the CO_2 may be sold for commercial purposes, including EOR. Given that economic factors favor the combination of CCS with EOR and that many early CCS projects will likely be of this type, it is important to better understand the conditions necessary to facilitate these types of projects.

Capture Technologies and Economics

To advance capture technologies, invest in research and development to improve the economics and efficiencies of CO_2 capture systems for major industrial sources.

With regard to capture, current technologies result in high capture costs, given the dilute concentrations of CO_2 in the process or exhaust streams at California's largest industrial CO_2 sources. These include natural gas–fired power plants, cement plants, and oil refinery furnaces.

Estimates are on the order of \$50–\$90 per metric ton of CO_2 removed, by far the largest part of the entire cost of CCS. Costs are at the lower end for the large out-of-state coal-fired power plants serving California. New and improved technologies being developed for CO_2 capture aim to reduce capital costs and energy requirements, including those for solvent regeneration.

Over time, the economics of CO_2 capture are expected to improve due to technology refinements, success with novel technologies, and "learning-by-doing" to improve efficiencies through commercial-scale applications.

Initial commercial experience in California may come from select industrial processes with high concentrations of CO_2 in process or exhaust streams, which make these applications the most viable economically. Examples include fermentation processes such as those used in ethanol production, hydrogen plants in oil refineries and chemical plants, and natural gas processing facilities where CO_2 is co-produced with gas. For these plants, where a high purity stream of CO_2 is produced as part of the industrial process, the capture cost will be small, and the primary expense involves CO_2 drying and compression for injection. There is also the opportunity for "net-negative" carbon emissions when CCS is combined with plants that use biomass.

Site Characterization, Monitoring and Verification, Risks, Remediation and Mitigation

Develop site characterization, monitoring and verification, and risk assessment protocols for CO_2 storage sites.

Careful site selection and certification will form the foundation for successful long-term geologic sequestration by ensuring that CO_2 storage sites are reviewed for sufficient capacity, geologic features for secure storage, accessibility to pipelines, and other factors conducive to a successful project. Currently, there is no consensus or standard regarding what criteria are required to adequately or even minimally characterize a site to address the potential concerns of operators, regulators, and other stakeholders. Considerable relevant experience is available from the oil and gas industry, natural gas storage, and underground injection of wastes. Rules or guidelines for qualifying a site and regulatory overview for a site certification process will have to address stakeholder concerns. A flexible approach based on injectivity, capacity, and effectiveness parameters is an option.

Geologic CO_2 injection and storage projects will employ various monitoring techniques to verify the amount of CO_2 stored, track the CO_2 plume underground, and check for potential leakage from the storage formation(s) or at the surface. Monitoring instrumentation must be reliable, economical, and capable of detecting low-level leakage while having sufficient range to register major leaks. Currently available equipment is more than adequate to meet the needs for monitoring CO_2 injection rates, wellhead and formation pressures, and occupational safety. However, CO_2 measurement and monitoring approaches suited to the large areas and long time scales relevant to geologic sequestration need further evaluation and refinement, perhaps best done through demonstration projects.

Determining pre-injection subsurface conditions, as well as natural background levels of CO_2, is also critical to understanding project performance. Without an adequate baseline, it may not be possible to distinguish storage-related changes in the environment from natural variations. For most CO_2 storage projects, the monitoring baseline should be obtained during the pre-injection characterization phase of a storage project, and should be incorporated into protocols.

Evaluate options and existing capabilities to respond to CCS leakage events, including remediation and mitigation planning.

Even sites with optimal features for CO_2 storage will have to be assessed for potential human health and safety and environmental risks during the operational and post-operational phases of a project. Safety procedures to limit these risks and leakage response procedures will be needed. Experience with storing CO_2 in geological formations suggests that the inherent risks and potential quantities of CO_2 leakage will likely be minimal. However small the risk, CO_2 leakage can result from human error, natural hazards, or other unknown factors. Procedures are needed to cover the possibility of CO_2 migrating out of the storage formation(s) or other releases that might occur during pipeline transportation or injection activities that could affect public health, the environment, or economic interests. Analogs such as the natural gas storage industry should be studied, as well as the safety practices for EOR, to rigorously evaluate their potential application to geologic sequestration. However, further efforts are needed to address CO_2 monitoring, leak detection, and mitigation and remediation at greater spatial and time scales than those that have been needed for EOR operations. Priorities for continued research include procedures for identifying and addressing a failure in the reservoir seal or cap rock; materials selection and construction procedures to achieve a “thousand-year well”; and the cost-effective means for securely reworking or plugging wells in a CO_2 storage environment.

Statutory and Regulatory Issues

Rigorously evaluate statutory and regulatory uncertainties and options for regulatory frameworks appropriate for CCS.

Regulatory continuity is an important goal for the frameworks that will be established for CCS. It is possible, under current regulations, for authority to become split along the lines of reservoir type and along pre-injection (surface) and post-injection (subsurface) activities. Because of the potential to impact existing industries, particularly EOR operations, the ramifications of different regulatory options must be studied. Ideally, a single authority should regulate the injection, storage, and monitoring of CO_2 into all potential geologic reservoirs. Another area of complexity is the interplay among ownership interests and provisions for the public good and how these diverse interests should be accommodated for the purposes of long-term geologic CO_2 storage.

A key uncertainty is the issue of liability. While the operational risks associated with transportation, injection, and storage of CO_2 have been successfully managed for many years, there is major concern with sources of liability during the post-closure phase of CCS, given that no time limitations have been established, making the term in effect, un-ending. For industry, the concerns associated with this open-ended liability include the lack of insurability of the project, the potential to incur remediation costs related to CO_2 migration and/or leakage at some point in the distant future, and the disincentive that these potential costs may have on investment today in CO_2 geologic storage

Education and Outreach

There is an obvious role for the state's education system in facilitating training and in providing information on CCS in the context of other ongoing efforts to provide information and education on climate change.

Facilitate training of necessary personnel.

A well-trained workforce to select and certify CO_2 storage sites, install CCS infrastructure, manage operations, and respond to leakage events is critical to protect public health, safety, and the environment and to ensure the overall success of CCS projects. Additional training may be needed for regulators who oversee geologic sequestration applications.

Encourage public participation and education.

Worldwide, the heightened level of activity on geologic sequestration research and applications reflects a growing consensus across a range of stakeholders that there is a need to incorporate CCS into mitigation steps to combat climate change. Public outreach activities must provide accurate information to help the public weigh the benefits and risks, as well as the safety and mitigation measures that may be taken to manage risks. The success of early geologic sequestration projects will be a key factor in gaining public support by demonstrating that long-term storage of CO_2 can be accomplished safely.

As is also true for other new technologies in the early stages of deployment, there is generally little public awareness and understanding of CCS. Even though CO_2 capture and storage is a public good in contributing to global climate change mitigation, the perceptions, risks to and benefits for the local public and communities should be acknowledged and addressed through efforts to openly share CCS knowledge and pertinent project-specific information.