# GEOLOGIC CARBON SEQUESTRATION STRATEGIES FOR CALIFORNIA: REPORT TO THE LEGISLATURE

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# PREFACE

This report was prepared in response to legislation, Assembly Bill 1925 (Blakeslee, Chapter 471, Statutes of 2006), which 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 sequestration 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 California 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 through a research program known as 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 second phase of the WESTCARB project is scheduled for completion by 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 first of two reports in response to AB 1925. This report establishes the parameters for the second report to be submitted in November 2010 after the results of the WESTCARB project can be thoroughly evaluated.

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| | |
|---|---|
| AB 32 | California Assembly Bill 32 (Núñez) Chapter 488, Statutes of 2006 |
| AB 1925 | California Assembly Bill 1925 (Blakeslee) Chapter 471, Statutes of 2006 |
| ARB | California Air Resources Board |
| CCS | carbon capture and sequestration |
| 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 |
| EOR | enhanced oil recovery |
| GHG | greenhouse gases |
| IOGCC | Interstate Oil and Gas Compact Commission |
| IPCC | Intergovernmental Panel on Climate Change |
| MMT | million metric tons |
| SB 1368 | California Senate Bill 1368 (Perata) Chapter 598, Statutes of 2006 |
| U.S. EPA | United States Environmental Protection Agency |
| WECC | Western Electricity Coordinating Council |
| WESTCARB | West Coast Regional Carbon Sequestration Partnership |

# ABSTRACT

Assembly Bill 1925 (Blakeslee, Chapter 471, Statues of 2006), passed unanimously by the California Legislature in 2006, requires the California 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 efforts to assess methods for reducing greenhouse gas emissions within California's overall strategy to mitigate anthropogenic climate change.

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, the technologies needed to capture carbon dioxide emitted from power plants and other large industrial sources in the state, and issues surrounding sequestration 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 capture and sequestration.

The report concludes that, although technical challenges remain, the primary barriers to progressing with initial geologic sequestration projects concern economic viability and statutory and regulatory issues. The exceptions may be projects facing fewer cost barriers because they combine sequestration with enhanced hydrocarbon recovery or take advantage of industrial process with relatively pure $CO_2$ emission streams. Further studies, including demonstration projects, are needed to integrate or adapt existing knowledge and the technology of geologic carbon sequestration and to guide development of regulations and statutes. These efforts should provide public education on carbon capture and sequestration, opportunities to engage stakeholders, and better understanding of the economic factors and business case considerations that will affect commercial adoption.

# KEYWORDS

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

# Executive Summary

Assembly Bill 1925 (Blakeslee, Chapter 471, Statutes of 2006), passed unanimously by the California Legislature, directs the California Energy Commission, in coordination with the Department of Conservation, to prepare a report for the Legislature containing:

> …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 to mitigate anthropogenic climate change caused by atmospheric $CO_2$ buildup. Three major 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, the focus of AB 1925, involves using gas separation technologies to capture $CO_2$ from large point sources, such as power plants, cement factories, or refineries, then injecting it deep underground.

Achieving commercial-scale application of geologic carbon sequestration requires not only technological readiness and economic viability, but also appropriate regulatory and statutory frameworks. Geologic sequestration poses particular challenges because it potentially cuts across the jurisdictions of several state and federal agencies and sequestration of $CO_2$ should extend potentially for well over a hundred years to be effective at mitigating $CO_2$ buildup in the atmosphere.

As identified by the AB 1925 legislation and technical experts, several topics are relevant to assessing the state's readiness for commercial-scale geologic sequestration:

- Geologic potential for sequestration in the state
- Capture technologies
- Site characterization
- Monitoring and verification
- Risks and risk management
- Remediation and mitigation
- Economic considerations
- Regulatory and statutory issues

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[1] Legislative Counsel, "Assembly Bill 1925," *Official California Legislative Information*, n.d., <http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_1901-1950/ab_1925_bill_20060926_chaptered.pdf>.

To develop this report, the Energy Commission engaged subject matter experts who developed white papers that serve as a technical foundation for each chapter. The Energy Commission is publishing the white papers in a separate document through its Public Interest Energy Research Program. Other activities to gather information for this report also included holding two public workshops and attending technical and community meetings to engage other state agencies, additional experts in various aspects of geologic sequestration, a range of stakeholders, and the public.

This report is a preliminary effort to capture the issues associated with a rapidly emerging new technology. Given the pace of development of carbon capture and sequestration technology worldwide and the range of activities planned over the next three years in California, a follow-up report is planned for 2010. Specifically, the Energy Commission is funding studies on the feasibility of geologic carbon sequestration, co-sponsored by the U.S. Department of Energy though a research program known as the West Coast Regional Carbon Sequestration Partnership. In addition, the Energy Commission is funding the development of improved methods to estimate greenhouse gas emissions and studying options to reduce these emissions. These efforts are necessary to provide the foundational data and analysis to support developing an appropriate regulatory framework for geologic carbon sequestration, including site certification protocols; integrity and longevity standards; and mitigation, remediation, and indemnification strategies. Thus, a significant amount of data that will be critical to formulating the recommendations required by AB 1925 will not be available until nearly 2010.

This report focuses on identifying the parameters pertinent to adoption in California of commercial geologic sequestration that need further study or analysis of their implications for the state. The 2010 report will summarize the results of these studies and analyses and make recommendations in accordance with the legislation.

## Potential for Commercial Capture and Sequestration

Capture and geologic sequestration involve three major components: modifying large industrial plants, such as power plants, oil refineries, and cement plants, to capture $CO_2$ from process or exhaust gases; delivering the $CO_2$ to a sequestration site, generally by pipeline; and injecting the $CO_2$ deep underground into rock formations that will prevent it from re-entering the atmosphere for a hundred years or longer.

Achieving widespread adoption of commercial sequestration depends on finding a size correspondence between industrial $CO_2$ sources and the capacities of safe, accessible sequestration sites and an economic correspondence between the costs of capture and sequestration and the value placed on the $CO_2$. Source and site correspondence includes factors such as source emissions volumes relative to underground sequestration capacity and the distance between the source and the sequestration site. Costs of capture vary widely with the type and size of the emissions source. The value for $CO_2$ may be set by policy in accordance with climate change mitigation objectives or realized by sale of the captured $CO_2$ for industrial purposes, such as enhanced oil recovery.

From a theoretical standpoint, the amount of $CO_2$ emissions that can be sequestered annually by geologic sequestration is limited by the number and size of point sources that can be captured. For example, power plant emissions, based on the greenhouse gas emissions inventory, totaling about 108 million tons $CO_2$ per year (61 out-of-state and 47 in-state), could all theoretically be geologically sequestered.

In practical terms, assuming that a business case or policy develops that favors carbon capture and sequestration deployment, the rate of deployment may still be limited by insufficient understanding of the sequestration resource potential, the pace of transport and other infrastructure development, and other factors. Practicality and economics also limit carbon capture and sequestration to that part of the emissions inventory associated with large single point sources, such as smokestacks on factories or power plants. In California, about 30 facilities emit more than 1 million tons of $CO_2$ per year each. 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 non-utility generators built as cogeneration qualified facilities. The largest $CO_2$ point sources within the state's inventory of emissions are related to California's imported electricity. Several of the coal-fired power plants in Arizona, New Mexico, and Utah that supply electricity to California produce emissions in the range of 4 to 20 million tons of $CO_2$ per year.

Capture also would be impractical, for example, for transportation fuel emissions, which come from millions of small mobile sources and constitute California's largest sector source at about 190 million tons of $CO_2$ per year. Plans for $CO_2$ emissions reduction in the transportation sector typically focus on using lower net carbon fuels, such as ethanol. However, bioethanol plants have highly concentrated $CO_2$ emissions, which make them potentially good opportunities for low-cost capture. While emissions today total less than 1 million tons per year from a few ethanol plants, the number of plants in the state should rise significantly, presuming sustained favorable biofuels policies and financing. These plants offer the potential for using geologic sequestration to create "net negative" $CO_2$ emissions because biomass derived fuels are already nearly carbon neutral (see Chapter 4).[2]

California has many rock formations that potentially are suitable sites for geologic sequestration. Sequestration targets commonly are rock layers within deep sedimentary basins, places where sand and mud have accumulated to thousands of feet of thickness over many millions of years and lithified into rock. These types of layered rocks are potentially good sequestration 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 to prevent the gas from escaping upward. Preliminary estimates of $CO_2$ sequestration capacity for

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[2] "Net-negative" emissions are possible from sequestering emissions from energy derived from biomass. Because plants withdraw $CO_2$ from the atmosphere, when biomass is burned, the $CO_2$ simply returns to the atmosphere—a carbon-neutral situation. However, if the emissions from burning biomass are sequestered, a net transfer of that carbon occurs from the atmosphere to underground storage, which can be booked in the emissions inventory as a subtraction from gross emissions.

formations within the 10 largest sedimentary basins lie between 75 and 300 metric gigatons of $CO_2$. Capacity estimates are better constrained for a small, but important, subset of target formations that contain oil and natural gas. Sequestration estimates are 3.5 metric gigatons of $CO_2$ for oil and 1.7 metric gigatons for natural gas reservoirs.

Geologic sequestration in the subset of target formations that have produced oil and natural gas for long periods has several advantages. Because these formations are oil- and gas-bearing, they have demonstrated, over geologic time, their ability to retain buoyant fluids like $CO_2$. In addition, through exploration and production activities, the subsurface geology in these areas usually is very well-characterized. Oil and gas operations have the appropriate infrastructure and require expertise similar to that needed for $CO_2$ injection. Furthermore, a project may use the injected $CO_2$ to extract additional oil and gas from the formation in a process known as $CO_2$-enhanced oil recovery, thereby creating a value for the $CO_2$.

However, there are additional considerations when the target is a formation where hydrocarbons are present, including statutory issues related to protection of mineral rights and ambiguities under existing frameworks as to how the project may be regulated (see Chapter 10). Although it is not clear to what degree enhanced oil recovery using $CO_2$ might supplant existing approaches, $CO_2$ capture for sequestration creates a potentially economic supply of $CO_2$ within the state for this purpose. The high cost of acquiring $CO_2$ has been a barrier to adoption of $CO_2$-enhanced oil recovery because there are no low-cost sources of $CO_2$ in California. Economic studies should establish the relationship between cost and demand for use of captured $CO_2$ in enhanced oil recovery in the state. Existing regulatory and statutory frameworks for enhanced oil recovery must be examined carefully to see if they are appropriate and sufficient for sequestration and, conversely, if inclusion of sequestration would disrupt existing practices.

Many proposed early carbon capture and sequestration projects in California will likely include consideration of selling captured $CO_2$ for enhanced oil recovery. For example, two proposed California power plant projects, the joint Hydrogen Energy (BP-Rio Tinto) and Edison Mission Energy petroleum coke gasification project and the Clean Energy Systems oxy-combustion plant (Kern County), include carbon capture and sequestration in conjunction with $CO_2$ sales for enhanced oil recovery.

Large point sources in California generally are located favorably, within about 30 miles of suitable sites for geologic sequestration, including many oil and gas formations with enhanced hydrocarbon recovery potential. The Los Angeles Basin, the Bakersfield area, and the San Francisco–Sacramento area are key industrial areas that also have good sequestration sites. Where large industrial sources amenable to $CO_2$ capture do not overlie suitable geologic $CO_2$ sequestration sites, $CO_2$ will have to be transported, most likely via pipeline. The technical, economic, safety, and permitting aspects of $CO_2$ pipeline transport are relatively well understood because of the many pipelines in other states that transport large volumes 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 sequestration sites, available rights-of-way, the surface terrain, and current surface land uses.

## Capture Technologies and Economics

Current technologies to capture $CO_2$ out of flue gas are costly. However, the alternative of injecting the full flue gas stream into deep geologic formations would be prohibitive with respect to use of underground sequestration capacity, energy, and other costs. Three approaches are available to capture $CO_2$ from large power plants and other industrial $CO_2$ sources: post-combustion, pre-combustion, and oxy-firing combustion.

Carbon capture and sequestration costs are mainly due to the capital equipment and energy used to concentrate the $CO_2$ to a purer stream, compress it to high pressure, and transport it to a sequestration site. In general terms, the opportunities for lowest cost per ton of $CO_2$ captured will be found at large point sources located near good geologic sequestration sites and that use low-cost fuels high in carbon, which generate higher concentrations of $CO_2$ in flue gas streams. Consequently, the costs of $CO_2$ capture generally are higher per ton of $CO_2$ for smaller sources and for natural gas-fired plants relative to coal-fired plants.

Large industrial $CO_2$ sources, such as natural gas–fired power plants, cement plants, and oil refinery furnaces and boilers, do not generate emissions of high purity $CO_2$ in their combustion exhaust or process flue gas streams. Instead, the $CO_2$ is present in fairly dilute concentrations and has to be separated or captured from the main flue gas stream. In the case of power plants, coal-fired plants have higher concentrations of $CO_2$ in emissions flue gases compared to natural gas-fired plants, making them less expensive options per ton of $CO_2$ captured. 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 $CO_2$ concentrations. Fermentation processes at ethanol plants produce nearly pure $CO_2$ emissions.

Assessing the business case for carbon capture and sequestration is very challenging, in part because no policy exists presently 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 for $CO_2$ capture and compression costs, which are estimated to constitute 70 to 80 percent of a CCS project's total costs, are on the order of $50 to $100 per metric ton of $CO_2$ removed for a range of sources, from coal-fired plants at the low end, to oil refineries at the high end. The carbon price estimated to stabilize $CO_2$ concentrations at 550 parts per million by 2100, according to the Intergovernmental Panel on Climate Change, is $20 to $80 per metric ton by 2030, and $30 to $155 per ton by 2050. Technologic advances could lower these ranges by $15 per ton. The panel also estimates that a sustained or increasing real price over decades of $20 to $50 per ton would be necessary to make greenhouse gas reduction options economically attractive to the power sector by 2050. However, comparisons with the carbon capture and sequestration costs are difficult because the carbon stabilization estimates were made before the recent run up in construction and materials costs.

To be practical, carbon capture and sequestration costs also must be competitive with the costs of other $CO_2$ emissions reduction options such as end-use efficiency improvements, renewables, and nuclear power. The run up in materials and construction costs has affected both renewables and nuclear options. For example, the Department of Energy reports increases over the last five years of over 50 percent in the costs of construction for wind turbines.[3] Thus, comparisons must be done using contemporaneous estimates. In addition, in comparing alternatives for power generation, it is important to consider the capabilities of each alternative to meet baseload and peak demand.

While trading in efficient carbon markets may prove to be the most economic way for various sectors or locations to meet any mandated emissions reductions or caps, carbon capture and sequestration technology has the flexibility to achieve reductions in many locations and major economic sectors. Applying the technology to large out-of-state coal-fired power plants targets the largest point sources of carbon emissions in California's emissions inventory, which are also the lowest cost opportunities per ton of $CO_2$ captured; nevertheless, it may be necessary to establish in-state options for sequestration to attract or retain industries faced with mandated emissions reductions or caps. In-state options also may be needed in the absence of regional carbon crediting agreements among the western states. While one solution to decreasing emissions in the transportation sector relies on shifting to bio-derived fuels, geologic sequestration of ethanol plant emissions gives this sector an additional opportunity to achieve further emissions reductions.

## Geologic Sequestration Project Components

In addition to considerations of economic success, projects must be designed to assure successful technical operation and protection of the health and safety of workers, the public, and the environment. Carbon capture and sequestration projects require surface and subsurface site characterization, monitoring and verification of the stored $CO_2$; health, safety and environmental risk assessment and management; and remediation and mitigation planning.

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 sequestration. 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 meteorological conditions must be characterized to understand the potential impact of any significant $CO_2$ leak. Monitoring and verification are essential to demonstrate that geologic sequestration is safe for the public and local communities, does not create significant adverse local environmental impacts, and is effective as a greenhouse

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[3] Wiser, R. and Bolinger, M., 2007, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 200,* U.S. Department of Energy, Energy Efficiency and Renewable Energy <http://www1.eere.energy.gov/windandhydro/pdfs/41435.pdf>

gas control technology. Finally, remediation and mitigation procedures must be in place to cover the possibility of $CO_2$ leakage, whether from the sequestration formation, during pipeline transport, or from injection activities.

A $CO_2$ sequestration project also 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. Sequestration projects also could influence future use of water and mineral resources in the area.

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. Subsurface parameters of importance include the rate at which $CO_2$ can be injected into the rock formation, the capacity of the rock to store $CO_2$, and the geologic features that affect the security of sequestration. Surface parameters include the locations of the sequestration site and the emissions source, routes of necessary pipelines, and consideration of the societal and environmental effects of infrastructure and operations. While availability of data and cost of data acquisition may be limiting, 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

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 the assessment process. 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 sequestration 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 a hundred years to be effective at reducing greenhouse gas buildup in the atmosphere. These timescales are short compared to geologic timescales, but very long compared to the timescales of typical risk assessments and to existing datasets on 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 sequestration formation 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. 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 sequestration-related changes in the environment from natural variations.

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 necessary. 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 should cover the possibility of $CO_2$ migrating out of the sequestration formation(s) or other releases that might occur during pipeline transportation or injection activities that could affect worker safety, public health, the environment, or economic interests.

Existing technology and conventional data sets can readily meet the needs of carbon sequestration projects. However, $CO_2$ measurement and monitoring approaches suited to the large areas and long timescales relevant to geologic sequestration need further evaluation and refinement, perhaps best done through demonstration projects. 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 should address $CO_2$ monitoring, leak detection, and mitigation and remediation at greater spatial and time scales than those pertaining to enhanced oil recovery 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 cost-effective means for securely reworking or plugging wells in a $CO_2$ sequestration 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. Projects will be more successful operationally and gain public acceptance more readily if these components are integrally linked. Currently no consensus or standard exists to set criteria for these components that will 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 sequestration site would be beneficial. It may also be appropriate to establish a minimum set of requirements.

## 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. At the same time, standards should be designed to limit economic impacts and facilitate technical innovation and advancement. In California, carbon capture and sequestration-specific regulatory and statutory frameworks do not yet exist. There is increasing activity internationally and nationally to develop these frameworks and California can benefit from study and analysis of these efforts.

This report provides a review of this issue to assess how current frameworks may apply to carbon capture and sequestration implementation in the state; however, 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 before 2010 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. To facilitate early projects may require determining, case-by-case, the best regulatory approaches to meet emissions mitigation goals, maintain protection of the public and local environment, and at the same time, retain business incentives to undertake carbon capture and sequestration.

Regulatory continuity is an important goal for the frameworks to 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, sequestration, and monitoring of $CO_2$ into all potential geologic reservoirs. Another area of complexity is the interplay among ownership interests and the public good and how these diverse interests should be accommodated for geologic $CO_2$ sequestration.

A key uncertainty is the issue of liability. While the operational risks associated with transportation, injection, and sequestration 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 and thus 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 sequestration.

## 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 that carbon capture and sequestration should be included in strategies to mitigate anthropogenic $CO_2$ buildup in the atmosphere.

A well-trained workforce to select and certify $CO_2$ sequestration 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 siting and permitting 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 important to the success of early geologic sequestration projects, which should openly share information on all aspects of the project.

As is 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 sequestration is a public good in contributing to global anthropogenic 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.

## Recommendations

In that this is a preliminary report, which is to be followed by a more comprehensive analysis in 2010, its recommendations focus on information needed for the 2010 report, which will contain the recommendations requested by the AB 1925 legislation.

1. Over the next three years, any state planning and other analyses involving energy or greenhouse gas emissions reduction strategies, as appropriate, should include consideration of carbon capture and sequestration options. Better cost estimates should be developed, and policy makers at all levels of government should consider them an appropriate proxy for the long-term value of $CO_2$ reduction.
2. Further examination is needed of the scenarios for carbon capture and sequestration adoption identified in this report as early opportunities, based on potentially close-to-favorable business cases. These opportunities may have greater value than as niche applications and may facilitate creation of an in-state market for $CO_2$ by demonstrating enhanced oil and gas production.
3. Demonstration projects in the United States and around the world over the next three years will provide key data to set carbon capture and sequestration policy. They should be facilitated and carefully studied, and may provide early insight into public and property owner concerns about risks.
4. California's power imports encourage consideration of carbon capture and sequestration in a regional context. Coordinated investigations of carbon capture and sequestration for power plants should take place involving other states in the Western Electricity Coordinating Council region. This should be done in the

context of recognizing the connection between regional climate change and electricity generation objectives and involve consideration of how carbon responsibility should “flow” with electricity.

5. Regulatory and statutory ambiguities and barriers identified in this report must be addressed, potentially through efforts that cut across the agencies that will ultimately be involved in regulating carbon capture and sequestration, from surface facilities through injection to sequestration and verification of climate change mitigation. These efforts would include evaluating the need for protocols and, as applicable, drafting them. This would include protocols for site characterization, monitoring and verification, and contingency plans for remediating leakage.

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

Assembly Bill 1925, (Blakeslee, Chapter 471, Statutes of 2006), passed unanimously by the California Legislature, aims to provide policy makers with an assessment of the present level of development of carbon capture and sequestration (CCS) technology and its potential application to meeting California's climate change mitigation goals. 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.[4]

Governor Arnold Schwarzenegger and the California Legislature have recognized the importance of reducing carbon dioxide ($CO_2$) and other greenhouse gas (GHG) emissions to the atmosphere to combat climate change. 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.[5]

Upon passage of Assembly Bill 32, the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006), California began to identify ways to meet the second target of reducing GHG emissions to 1990 levels by 2020.[6] Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006), followed with a mandate for new or renewed long-term contracts to purchase electricity from baseload facilities to 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).[7] These initiatives, as well as AB 1925 and other recent legislation, demonstrate that California's policy makers 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.

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[4] Legislative Counsel, "Assembly Bill 1925," *Official California Legislative Information*, n.d., <http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_1901-1950/ab_1925_bill_20060926_chaptered.pdf>.

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

[6] Legislative Counsel, "Assembly Bill 32," *Official California Legislative Information*, n.d., <http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf>.

[7] Legislative Counsel, "Senate Bill 1368," *Official California Legislative Information*, n.d., <http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1351-1400/sb_1368_bill_20060929_chaptered.pdf>.

CCS options include any process that "captures" $CO_2$ and stores, or sequesters, it away from the atmosphere to mitigate climate changes associated with atmospheric $CO_2$ buildup. The Intergovernmental Panel on Climate Change (IPCC) identifies four approaches to capture and sequester carbon: terrestrial, geologic, mineral, 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, then injecting it deep underground. Mineral sequestration, which involves enhancing the reactions of metal oxide-bearing materials with $CO_2$, is a component of geologic sequestration if done underground, but also can be done at the surface in processing plants. Oceanic sequestration involves injection of captured $CO_2$ into the deep ocean or the enhancement of natural processes for $CO_2$ uptake[8] 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 at least long enough for atmospheric $CO_2$ concentrations to stabilize.

These approaches can be applied to reduce atmospheric $CO_2$ generally or to remove emissions from specific sources. Terrestrial CCS directly reduces $CO_2$ buildup in the atmosphere. Geologic CCS can be used for $CO_2$ from any point source of emissions that can be effectively captured and transported to a sequestration site. 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 must be 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 result in subtractions from the state's gross $CO_2$ emissions, thus providing a way to counter emissions from disperse or mobile sources such as those in the state's largest $CO_2$ emissions sector, transportation. The state's GHG inventory already contains an entry for terrestrial sequestration—the negative emissions provided by land use change and forestry sinks.[9]

Although, as discussed above, the acronym CCS can be inclusive of all three types of carbon capture and sequestration, for the remainder of this report, the acronym CCS will be used to refer specifically to carbon capture with geological sequestration. Generally, in discussion of CCS, the terms "storage" and "sequestration" are used interchangeably. However, the term "storage" also is used to describe cases where a substance is put away with the intent of using it

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[8] Uptake of $CO_2$ by the ocean waters is the transfer of $CO_2$ from the atmosphere into the ocean by chemical, physical, or biological processes. Biological uptake is done predominantly by open ocean single-celled organisms that photosynthesize or precipitate shells made of carbonate minerals.

[9] Bemis, Gerry, 2006, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004.* California Energy Commission, Special Projects Office, CEC-600-2006-013-SF.

at some future time, as in “natural gas storage.” The term “sequestration” does not have this ambiguity. In keeping with the terminology used in AB 1925, this report uses the term “sequestration” in preference to “storage.”

AB 1925 focuses solely on geologic carbon sequestration and even more specifically on its commercial-scale application. Commercial-scale application of CCS requires not only technological readiness, but also appropriate regulatory and statutory frameworks. Particular challenges exist for CCS because it potentially cuts across the jurisdictions of several state and federal agencies. In addition, these frameworks also must address the time scales over which CCS reservoirs must retain $CO_2$.

There are several pertinent questions for defining what time scale is necessary and achievable for sequestration:

- What time scale is needed to achieve effective mitigation of GHG buildup and of global warming?
- What time scales are achievable given the natural processes that influence the ability of a reservoir to retain $CO_2$?
- What time scales are achievable for engineered reservoir elements such as wells to retain $CO_2$?

The answers to these questions are not unequivocal. To be an effective mitigation approach for GHG buildup and global warming, CCS time scales must be long enough to result in stabilization of atmospheric $CO_2$ concentrations and global temperatures. The minimum period is controversial but appears to be at least a few hundred to a thousand years.[10] Time scales for the likely effectiveness achievable by sequestration correspond roughly to the magnitudes of the periods of natural cycling of the sequestration reservoir.[11] For example, deep ocean cycles are on the order of hundreds to a few thousand years, so the deep oceans could sequester $CO_2$ for a similar timeframe. Terrestrial sequestration is on the order of decades to a few hundred years, but may be an order of magnitude longer if significant amounts of carbon can be retained in soils. The deeply buried sedimentary rocks that serve as geologic sequestration reservoirs are subject to tectonic cycles that are on the order of many millions of years. For all practical purposes, geologic sequestration can be viewed as permanent based on natural cycles. However, catastrophic natural events, such as earthquakes for geologic sequestration reservoirs or wildfires for terrestrial reservoirs, can suddenly compromise the ability of a reservoir to retain sequestered $CO_2$. The engineered elements of a geologic sequestration site, such as wells, also may shorten the effective retention period of a sequestration reservoir.

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[10] Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

[11] Ibid.

For CCS to have merit as a climate change mitigation strategy, the time scales for $CO_2$ retention achievable by engineered elements and natural processes in the sequestration reservoir must significantly exceed the time scales necessary for effective GHG mitigation. Based on observations and analysis of current $CO_2$ sequestration sites, natural systems, engineering systems and models, the fraction retained in appropriately selected and managed geologic reservoirs is very likely to exceed 99 percent over 100 years, and is likely to exceed 99 percent over 1000 years.[12] In either case, CCS would prove to be an effective climate change mitigation option, noting that perfect retention of sequestered $CO_2$ is not required. Over such long periods, low leakage rates do not appreciably reduce the effectiveness of sequestration.

In addition to consistency with climate change goals and technically achievable constraints, time scales for CCS projects must be practical and consistent with overarching energy policy goals. Timelines set for CCS projects, for example, might depend on factors such as the maximum atmospheric concentration of $CO_2$ that is set as a policy goal and the timing of that maximum, but also on the anticipated duration of the fossil fuel era, the availability of alternative fuels, and alternative energy and climate change mitigation strategies in the event that deeper emissions cuts are necessary in the future. The practicality of CCS may depend on economic and logistical factors that constrain activities such as site monitoring and stewardship to human institutional timelines, which rarely have exceeded a few hundred years.

Activities to facilitate development of CCS are increasing in scope and number worldwide. For example, three relatively large CCS projects—Statoil's Sleipner Saline Aquifer $CO_2$ Storage project in the North Sea off Norway;[13] the Weyburn Project in Saskatchewan, Canada;[14] and the In Salah Project in Algeria[15]—are underway. Together, these sequester 3 to 4 million metric tons (MMT) per year, which approaches the output of a typical 500 megawatt (MW) coal-fired power plant. Statoil estimates that Norwegian GHG emissions would have risen incrementally by 3 percent if the $CO_2$ captured during processing of natural gas at Sleipner had been vented rather than sequestered.[16]

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 and several Canadian provinces. These partnerships are conducting small-scale terrestrial and geologic sequestration field tests, as well as providing assessments and databases of the distribution of large emission sources and candidate $CO_2$ sequestration sites within the United States.[17] The West Coast Regional Carbon

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[12] Ibid.

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

[14] <http://www.co2captureandstorage.info/project_specific.php?project_id=70>.

[15] <http://www.co2captureandstorage.info/project_specific.php?project_id=71>.

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

[17] <http://drysdale.kgs.ku.edu/natcarb/eps/natcarb_alpha_content.cfm>.

Sequestration Partnership (WESTCARB), led by the Energy Commission, includes California, Nevada, Oregon, Washington, Arizona, and Alaska, as well as British Columbia. In addition, the Department of Energy's plans in 2008 for FutureGen call for development of multiple CCS sequestration projects at near-commercial scale of about one million metric tons of $CO_2$ injected per year; FutureGen had been focused previously on development at one site selected from four candidate sites in Illinois and Texas and had completed environmental impact and risk assessments for CCS at those sites in 2007.[18]

Within California, studies of strategies for GHG reductions to meet the 2020 goals of AB 32 or the longer term goals of Executive Order S-3-05 generally have not included CCS options. Such studies include a 2007 report released by the Governor's Market Advisory Committee to the ARB. This report contains recommendations on the design of a cap-and-trade system to reduce GHG emissions in California. Another example is the Energy Commission's scenario analysis of California's electricity system. Although the rate of deployment of geologic CCS is probably too slow for consideration of this technology in policy decisions over the period to 2020, over the longer term to 2050, geologic (and terrestrial) sequestration within California and the Western Electricity Coordinating Council (WECC) region should be incorporated into any evaluations to understand how policy and technology can achieve GHG goals while continuing to provide fuels and power at the lowest possible cost to Californians.

The cap-and-trade report outlines the various opportunities and challenges of different design elements in an emissions trading program. A main purpose of a cap-and-trade program is to bring about low-cost emissions reductions within sectors covered by the program. A cap limits emissions and creates a market for trading GHG emissions allowances where every ton of emissions has a price. This price provides a signal for developing new technologies that can reduce GHG emissions. An entity that adopts a new technology to reduce 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 they all require a provision to address emissions associated with imported electricity. All of the options create price signals for CCS, the strength of which would depend on the relative costs of allowances compared to costs to implement CCS.[19]

The Energy Commission's scenario analyses of California's electricity system 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

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[18] <http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/>.

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

Interconnection as defined by the WECC.[20] 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 increased use of preferred resources results in decreased natural gas use, but the overall amount of coal use in the WECC region increases in all cases except one. The least-cost principles used for power plant dispatch decisions are unlikely to impact coal use without an explicit carbon cost adder of at least $30 per ton.[21]

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

[21] Ibid.

# CHAPTER 2: Key Implementation Issues

There is general agreement among experts that risks associated with CCS technology are at levels acceptable to society for other industrial processes. For example, the Intergovernmental Panel on Climate Change (IPCC), established jointly in 1988 by the World Meteorological Organization and the United Nations Environment Programme, issued a landmark report in 2005, *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[22] and deep underground disposal of acid gas.[23]

This statement concludes that geologic sequestration could have comparable risk to operations common in the energy industry. It also anticipates the AB 1925 legislation in identifying the key areas where systems or methodologies appropriate to CCS must achieve acceptable levels of health, safety, and environmental risk. In addition, AB 1925 recognizes that CCS deployment depends on constraining financial and legal risks. The relevant topics for CCS implementation identified by AB 1925 or by CCS experts are:

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

The Energy Commission engaged experts to develop white papers on these subjects. These papers serve as the technical foundation for this report, which devotes a chapter to each topic. The Commission also is publishing these white papers in a separate report through its Public Interest Energy Research division. Development of the AB 1925 report also included two public workshops and presentations at technical and community meetings in order to engage state agencies, other experts in various aspects of CCS, a range of stakeholders, and the public.

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[22] Enhanced oil recovery.

[23] Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

Beyond technical, regulatory, and economic issues, public perception of the technology may be a barrier to commercial deployment of CCS. There is generally little public awareness and understanding of CCS, as is usually the case with any new technology 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 proven to be safe and effective, and operations have established good safety and environmental records.

Many studies of CCS highlight education and public outreach as critical efforts, particularly if done in conjunction with well conceived and executed demonstration projects.[24] 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 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.[25]

Local versus global risk perceptions are important considerations. Even though CCS is designed to be a beneficial technology, contributing to mitigation of anthropogenic $CO_2$ buildup and reduction of global climate change risk, such advantages may not be paramount in local risk-benefit perceptions. In some cases, CCS projects may be located near large industrial facilities with a history of significant emissions. Communities near these facilities may view CCS as yet another burden they are inequitably being asked to bear. CCS project proponents must address these perceptions through efforts to openly engage the public 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 eventually can 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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[24] For example, see Massachusetts Institute of Technology, 2007, *The Future of Coal,* MIT Press and International Energy Agency, 2006, *Near-Term Opportunities for Carbon Dioxide Capture and Storage*.

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

# CHAPTER 3: Potential for Capture and Geologic Sequestration

CCS involves three major components: modifying large industrial plants, such as power plants, oil refineries, and cement plants, to capture $CO_2$ from process or exhaust gases; delivering the $CO_2$ to a sequestration site, generally by pipeline; and injecting the $CO_2$ deep underground into rock formations that will prevent it from re-entering the atmosphere for time periods sufficient to attain climate change mitigation goals (see Chapter 1).

While, from a technical standpoint, the amount of $CO_2$ that can be sequestered annually by CCS is limited by the number of point sources that can be equipped with capture technology, capture is practical and economic only for large point sources or sources with very high concentrations of $CO_2$ in process or exhaust gases. In practical terms, assuming that a business case or policy develops that favors CCS deployment, the rate of deployment also may be limited by insufficient understanding of the sequestration resource potential, the pace of transport and other infrastructure development, and other factors.

Although the idea of intentionally storing large quantities of anthropogenic $CO_2$ in underground rock formations to mitigate GHG emissions is new, natural $CO_2$ reservoirs have existed for many millions of years. The practice of gas injection for storage or other purposes also is common and has been done safely and successfully for many decades. For more than 35 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), a process where injected gases mobilize residual oil and natural gas.

## Large $CO_2$ Sources for Capture

The cost and viability of CCS depends, in part, on the locations of plants (sources) relative to sequestration sites (sinks). In 2004 to 2005, WESTCARB undertook preliminary studies of source-sink matching in California.[26] The map in Figure 1 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.

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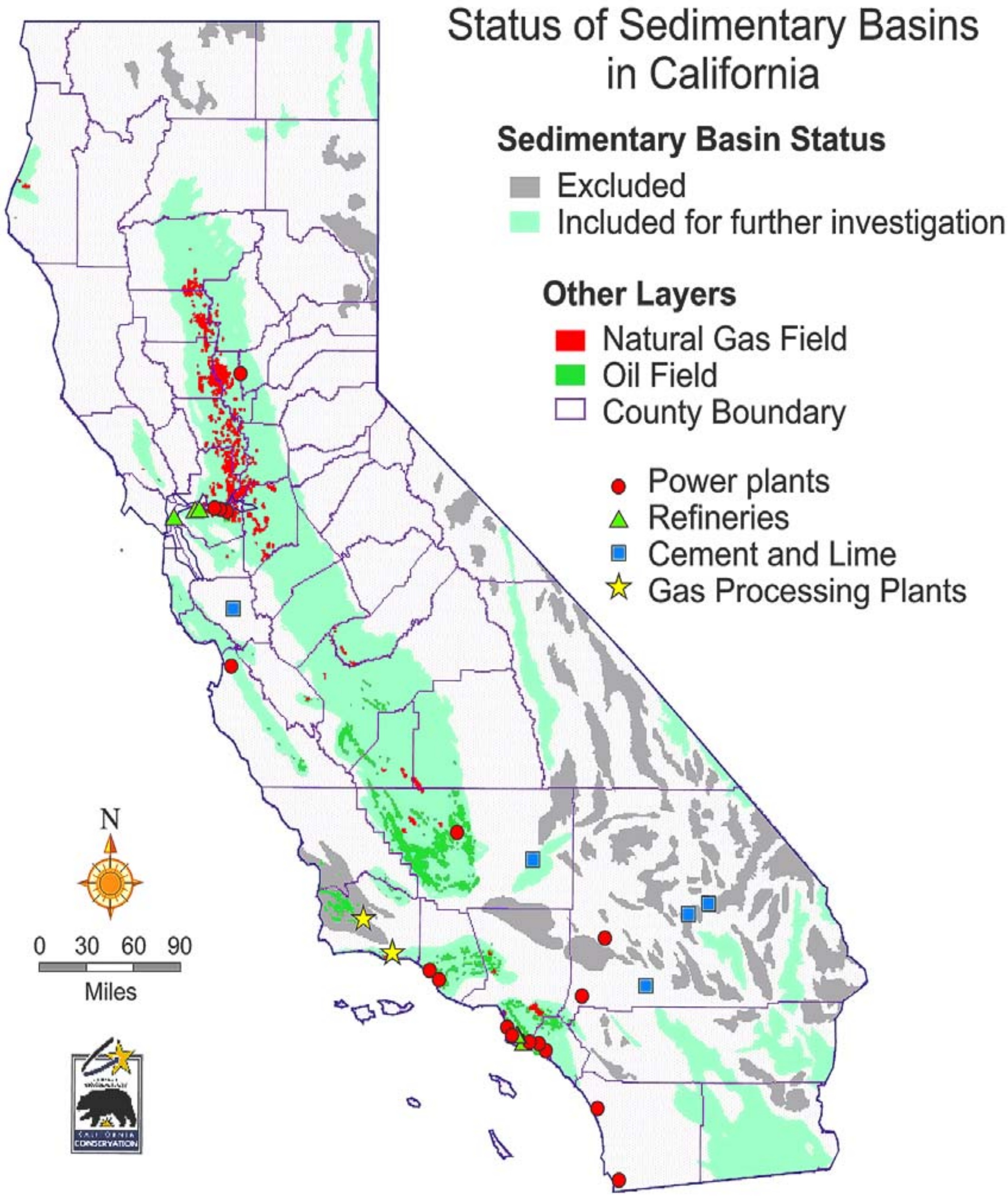
[26] Herzog, H.J., 2005, *West Coast Regional Carbon Sequestration Partnership $CO_2$ Sequestration GIS Analysis.* Topical Report West Coast Regional Carbon Sequestration Partnership (WESTCARB), DOE Contract No.: DE-FC26-03NT41984.

**Figure 1: Sedimentary Basins and $CO_2$ Point Sources**



Sources: 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; Downey, Cameron and John Clinkenbeard, 2006, *An Overview of Geologic Carbon Sequestration Potential in California*. California Energy Commission, PIER Energy-Related Environmental Research, CEC-500-2006-088.

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

In California, various types of industrial facilities and the transportation sector are the major sources generating anthropogenic $CO_2$. Total gross California $CO_2$ emissions in 2004 were estimated at about 356 MMT $CO_2$ per year in-state and an additional 61 MMT $CO_2$ generated out-of-state from electricity imports.[27] For 2004, the state's GHG inventory shows that fossil-fuel combustion for electricity generation within California emitted about 47 MMT $CO_2$/year, mostly from natural gas plants, and fossil fuel combustion in the industrial sector totaled about 67 MMT $CO_2$/year.[28] Within the industrial sector, the largest point sources are oil refining and cement production, creating about 18 MMT $CO_2$ per year, and about 12 MMT $CO_2$ per year respectively.[29] The $CO_2$ emissions estimates for refineries and cement plants are from the WESTCARB study[30] and are difficult to compare with the data in the GHG inventory for California because 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 attributable to cement production and to use of various fuels, and, for refineries, into components such as emissions from use of natural gas, distillate, or residual oil. The WESTCARB study focused on quantifying total emissions from specific plants or point sources and summed these emissions to estimate the total for a sector.

From a theoretical standpoint, the amount of $CO_2$ emissions that can be sequestered annually by CCS is limited by the number and size of point sources that can be captured. For example, power plant emissions, based on the greenhouse gas emissions inventory, totaling about 108 million metric tons $CO_2$/year (61 out-of-state, and 47 in-state), could all theoretically be geologically sequestered. In practical terms, however, and assuming that a business case or policy develops that favors CCS deployment, the rate of deployment may still be limited by factors such as insufficient understanding of the sequestration resource potential and by the pace of transport and other infrastructure development. Practicality and economics also limits CCS to that part of the emissions inventory associated with large single point sources, such as stacks on factories or power plants. Capture would be impractical, for example, for transportation fuel emissions, California's largest sector source at about 190 million metric tons of $CO_2$ per year, because the emissions come from millions of small mobile sources. Plans for $CO_2$ emissions reduction in the transportation sector typically focus on using lower net carbon fuels, such as ethanol.

Figure 2 shows annual average $CO_2$ emissions from the largest specific power plant and industrial $CO_2$ point sources in California. There are about 30 facilities each emitting more than 1 million metric tons of $CO_2$ 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

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[27] Bemis, Gerry, 2006, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004.* California Energy Commission, Special Projects Office, CEC-600-2006-013-SF.

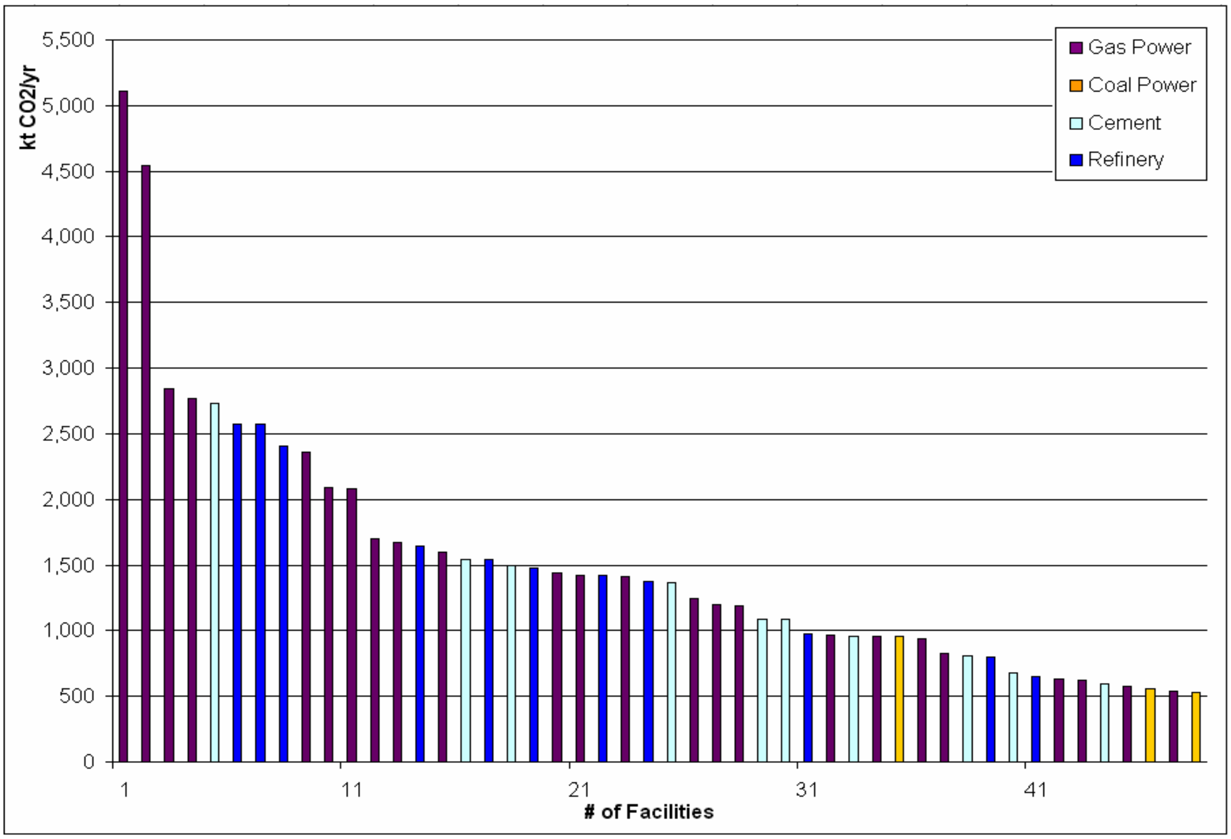
[28] Ibid.

[29] Herzog, H.J., 2005, op. cit.

[30] Herzog, H.J., 2005, op. cit.

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.

**Figure 2: Largest Specific California $CO_2$ Sources by Type and Size**



Source: Katzer, J. and Herzog, H., 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

The largest $CO_2$ point sources within the state's inventory of emissions are related to California's imported electricity. Several of the coal-fired utility power plants in Arizona, New Mexico, and Utah that supply electricity to California produce emissions in the range of 4 to 20 million metric tons of $CO_2$ per year.

In assessing industrial point sources for $CO_2$ capture, the concentration of $CO_2$ in the process or exhaust stream relative to the concentrations of other gases is important to the economics of the capture process. Usually, the stream is flue gas at atmospheric pressure. In the case of power plants, coal-fired plants have higher concentrations of $CO_2$ in emissions flue gases compared to natural gas-fired plants, making them less expensive options for capture on a basis of cost per ton of $CO_2$ avoided. Refineries fall between natural gas combined cycle and coal-based plants, but generally constitute a number of separate flue gas streams; cement plants have higher flue gas $CO_2$ concentrations. Fermentation processes at ethanol plants produce nearly pure $CO_2$ emissions. While emissions today total less than 1 million metric tons per year from a few ethanol plants, the number of plants in the state could rise significantly, presuming sustained favorable biofuels policies and financing. These plants offer the potential for using CCS to create "net negative" $CO_2$ emissions because biomass derived fuels may be already nearly carbon neutral (see Chapter 4).

## Transport of $CO_2$

Where large point sources do not overlie suitable sequestration sites, $CO_2$ may have to be transported via pipelines or on trucks, trains, ships, or barges. In today's commercial markets, $CO_2$ is routinely transported in tanker trucks as liquid $CO_2$ at 20 bars (290 pounds per square inch) and -20°C (-4°F); however, for the large quantities of $CO_2$ involved in CCS, tanker transport is impractical and uneconomic. Pipelines are the likely mode of $CO_2$ transport for sequestration operations.

The technical, economic, and permitting issues associated with $CO_2$ compression and pipeline transport are well known in the U.S. because of the large-scale use of $CO_2$ for over 20 years in EOR operations in many other states. $CO_2$ is also transported via pipeline for a number of industrial uses in California and other states. Over 1,500 miles of $CO_2$ pipelines exist in the U.S. today with a capacity in excess of 40 MMT $CO_2$ per year. Table 1 lists the pipelines developed to support EOR operations, primarily in west Texas and Wyoming.[31]

In these pipelines, $CO_2$ that is produced primarily from natural $CO_2$ reservoirs is transported as a dense, single phase at ambient temperatures and supercritical pressures. The $CO_2$ is typically compressed to 150 bar (2200 pounds per square inch) or more at its source. To maintain supercritical pressures, booster compressors may be necessary along the length of the pipeline. However, not all pipelines require recompression. For example, the Weyburn pipeline, which transports $CO_2$ about 200 miles from an industrial facility in North Dakota to an EOR site in Saskatchewan, Canada, operates without a recompression system.[32] 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 or 1070 pounds per square inch).[33]

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[31] Katzer, J. and Herzog, H., 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

[32] Metz, B.E.A., ed., 2005, op. cit.

[33] Katzer, J. and H. Herzog, op. cit.

**Table 1: Major $CO_2$ Pipelines in the United States**

| **Pipeline** | **Operator** | **Capacity (MMT $CO_2$/yr)** | **Length (miles)** | **Year finished** | **Origin of $CO_2$** |
|---|---|---|---|---|---|
| Cortez | Kinder Morgan | 19.3 | 502 | 1984 | McElmo Dome |
| Sheep Mountain | BP Amoco | 9.5 | 410 | | Sheep Mountain |
| Bravo | BP Amoco | 7.3 | 217 | 1984 | Bravo Dome |
| Canyon Reef Carriers | Kinder Morgan | 5.2 | 140 | 1972 | Gasification plants |
| Val Verde | Petrosource | 2.5 | 81 | 1998 | Val Verde Gas Plants |
| Weyburn | North Dakota Gasification Co. | 5 | 203 | 2000 | Gasification Plant |

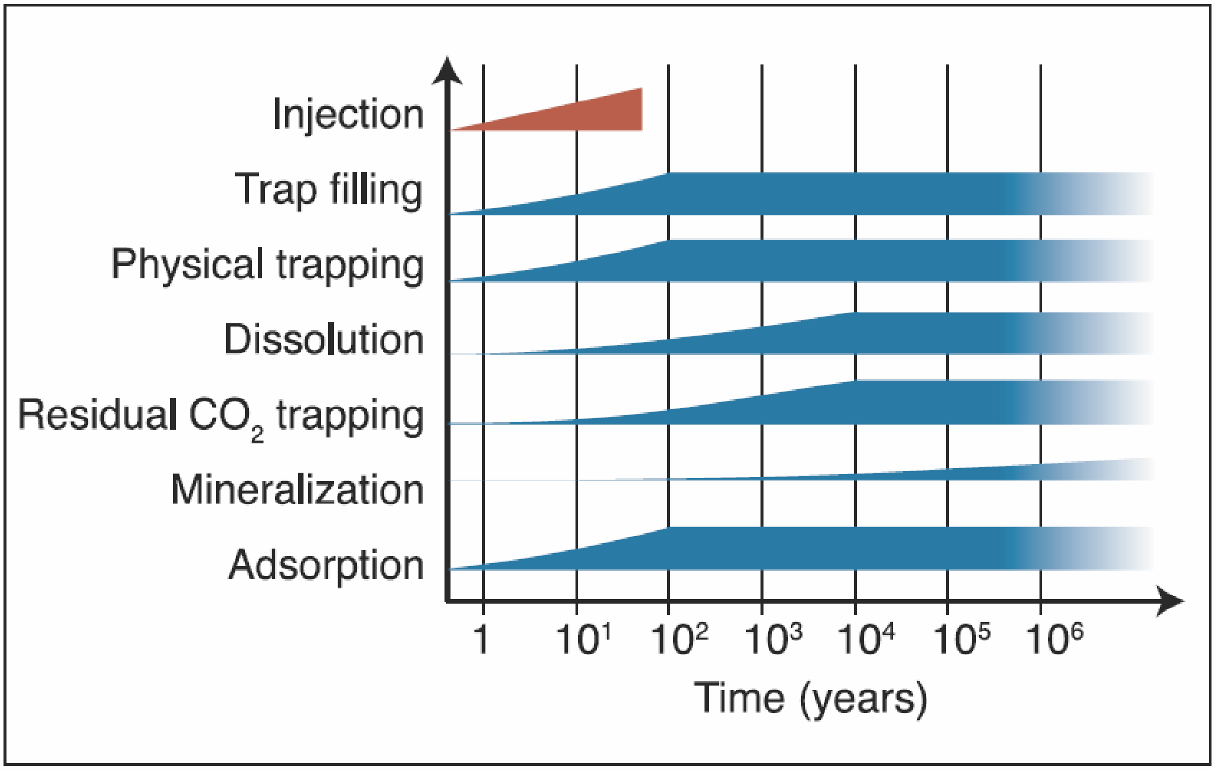
Source: Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage.* Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

## Potential for Geologic Sequestration

Suitable sequestration sites are commonly found in deep sedimentary basins, places where sand and mud have accumulated to thousands of feet in thickness over many millions of years and lithified into rock. These types of layered rocks are potentially good sequestration 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. Sequestration takes place at depths below 2,500 feet where pressures and temperatures keep $CO_2$ in a liquid-like, supercritical phase. In this phase, $CO_2$ occupies the least volume per unit mass, and its density ranges from 50 to 80 percent of the density of water.

In most sedimentary formations, the pore spaces of the rocks are occupied by highly saline waters, or brines; in some, other fluids, such as oil or natural gas, also may be present. Although supercritical $CO_2$ is much less buoyant than gaseous $CO_2$, it is still more buoyant than water, resulting in a tendency for the $CO_2$ to migrate upward. In the early stages of sequestration, the overlying seals and pore spaces of the reservoir trap the buoyant $CO_2$ physically (trap filling and physical trapping) as a separate fluid. Over time, some of the $CO_2$ also dissolves in the water and reacts chemically with the water and rock (dissolution, mineralization, adsorption), as shown in Figure 3.

## Figure 3: Types and Timescales of $CO_2$ Sequestration Mechanisms



Source: Metz, B.E.A., 2005, *Special Report on Carbon Dioxide Capture and Storage.* Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_Chapter4.pdf>.

Schematic shows the time evolution of various $CO_2$ sequestration mechanisms operating in deep formations during and after injection. Time is shown on an exponential scale were $10^1$ is 10 years, $10^2$ is 100 years, and so on.

As part of WESTCARB's Phase I studies, the California Geological Survey (CGS) developed a preliminary screening method to identify sedimentary basins with the greatest geologic potential for $CO_2$ sequestration.[34] 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 work scope. In WESTCARB Phase II, the California Geological Survey will complete mapping of selected geologic basins and formations in greater detail. Prior to selecting specific sites for sequestration projects, even more detailed site-specific characterizations of the subsurface geology will be needed.

The California Geological Survey initially identified and cataloged 104 sedimentary basins that underlie approximately 33 percent of the area of the state. These basins include oil- and gas-

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[34] Downey, Cameron and John Clinkenbeard, 2006, *An Overview of Geologic Carbon Sequestration Potential in California*. California Energy Commission, PIER Energy-Related Environmental Research, CEC-500-2006-088.

producing regions (see Figure 1). Where basins extend offshore, only the onshore portions were considered.

The basins were then screened, using available data, to make preliminary determinations of their suitability for $CO_2$ sequestration. Accessibility was a screening factor, and thus, basins were excluded that lay under national and state parks and monuments, wilderness areas, Bureau of Indian Affairs administered lands, and military installations. Most of the excluded basins are located in eastern and southeastern California where there are few large industrial sources of $CO_2$. Geologic screening criteria included the presence of significant porous and permeable units to store large amounts of $CO_2$, 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.

For basins that passed the initial screening, available data were used to make preliminary determinations of potential sequestration resource capacity. A total of 27 basins met the screening criteria. Of these, the most promising for sequestration are 10 of the largest: the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda basins. These basins include potential sequestration sites in both depleted oil and gas reservoirs and non-hydrocarbon-bearing formations.[35] Favorable attributes of these basins include:

- Good geographic distribution relative to emissions sources
- Thick sedimentary fill with multiple porous and permeable zones
- Thick, laterally persistent sealing units
- Availability of good datasets to characterize the subsurface
- 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 $CO_2$ sequestration resource capacity for these 10 basins are between 75 and 300 metric gigatons tons of $CO_2$.

The large range in sequestration resource capacity results from differences in methods for estimating capacity[36] and from uncertainties in geologic characterization due to incomplete data coverage. More precise assessment of the specific potential of these basins for $CO_2$ sequestration requires additional geological characterization, including detailed, formation-specific mapping to define the thickness, extent, and continuity of potential reservoir and sealing units.

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[35] Clinkenbeard, J., 2008, "Areas in California Potentially Suitable for Geologic Storage of $CO_2$," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009. .

[36] U.S. Department of Energy National Energy Technology Laboratory, 2007, *Carbon Sequestration Atlas of the United States and Canada.* <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/ATLAS.pdf>.

Resource capacity estimates are better constrained for the small, but important, subset of formations that contain oil and gas. Sequestration estimates are 3.5 gigatons of $CO_2$ for oil and 1.7 gigatons for natural gas reservoirs (Table 2). Many oil reservoirs in California, even those still actively operated, contain significant volumes of saline water which is co-produced with the oil. Although some CCS studies segregate potential sequestration targets into either saline formations or depleted hydrocarbon reservoirs, it is more accurate to view sequestration sites as saline formations with or without a history of hydrocarbon production. In addition, the same injection well could be used to sequester $CO_2$ in both a saline formation and a depleted hydrocarbon reservoir, given that saline waters almost always underlie hydrocarbon reservoirs.

### Table 2: Estimates of $CO_2$ Sequestration Resource Capacity in California in Oil- and Gas-Bearing Formations

| **Type of Sequestration Reservoir** | **Number of Fields** | **Estimated Total Capacity (MMT $CO_2$)** |
|---|---|---|
| A: Oil Fields | | |
| Oil fields with $CO_2$ sequestration 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 $CO_2$ sequestration capacity but no EOR potential (fields lacking American Petroleum Institute data also included) | 37 | 199 |
| Oil fields without $CO_2$ sequestration potential | 55 | 0 |
| Oil fields without depth information | 61 | 0 |
| B: Natural Gas Fields | | |
| Gas fields with $CO_2$ sequestration potential | 128 | 1666 |
| Gas fields without $CO_2$ sequestration potential | 36 | 0 |
| Gas fields without enough information | 33 | 0 |

Sources: Herzog, H.J., 2005, *West Coast Regional Carbon Sequestration Partnership $CO_2$ Sequestration GIS Analysis.* Topical Report West Coast Regional Carbon Sequestration Partnership (WESTCARB), DOE Contract No.: DE-FC26-03NT41984; Downey, Cameron and John Clinkenbeard, 2006, *An Overview of Geologic Carbon Sequestration Potential in California*. California Energy Commission, PIER Energy-Related Environmental Research, CEC-500-2006-088.

Geologic sequestration in the subset of formations that have produced oil and natural gas for long periods offers several advantages. Because these formations are oil and gas-bearing, they have demonstrated, over geologic time, their ability to retain buoyant fluids like $CO_2$. In addition, through exploration and production activities, the subsurface geology in theses areas usually is very well-characterized. Oil and gas operations have the appropriate infrastructure in place and require expertise similar to that needed for $CO_2$ injection. Furthermore, a project may use the injected $CO_2$ to extract additional oil and gas from the formation, thereby creating a value for the $CO_2$. However, there are additional considerations when the CCS target is a formation where hydrocarbons are present, including statutory issues related to protection of mineral rights and ambiguities under existing frameworks as to how the project may be regulated (see Chapter 10).

It is important to note, however, that the degree of geologic isolation of the target formation may still be very high even when no hydrocarbons are present, although the evidence is less obvious. The chemical composition of deep saline waters indicates the degree of isolation of the formation from regional hydrodynamic systems. In some cases, these waters still retain the signature of the seawater that was originally trapped in the pore spaces of the sediments before lithification and deep burial, evidence of a degree of isolation even greater than that of many hydrocarbon-bearing structures.

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.[37] Many of these wells are associated with EOR projects, but $CO_2$-EOR is extremely limited in California because the cost of transporting $CO_2$ into the state is prohibitive. Although it is not clear to what degree $CO_2$-EOR might supplant existing EOR approaches, $CO_2$ capture for sequestration creates a potentially economic supply of $CO_2$.

Although $CO_2$ injection to enhance oil recovery is a well established and proven technology, its use for enhanced natural gas recovery is relatively new. Methane recovery through $CO_2$ injection into coal beds has been field tested and studied in the laboratory with good results, suggesting there is also potential for enhanced gas recovery (EGR) from depleted gas reservoirs.

Although in both EOR and EGR, the $CO_2$ is left behind in the reservoir at the close of operations, the intention of these projects has not been to sequester $CO_2$. The Weyburn Oilfield in Saskatchewan, Canada, however, is a recent example of a $CO_2$-EOR project intended to conclude with sequestration of large quantities of industrial $CO_2$ from the Dakota Gasification Company's plant in Beulah, North Dakota. Over the life of the project, an additional 130 million barrels of oil may be produced, with net $CO_2$ sequestration estimated at 20 MMT.[38]

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[37] <http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm>.

[38] International Energy Agency, *IEA GHG Weyburn $CO_2$ Monitoring and Storage Project,* n.d. <http://www.ieagreen.org.uk/glossies/weyburn.pdf>.

# CHAPTER 4: Capture Technologies

Costs of CCS projects are mainly due to the increased capital equipment and internal energy needs associated with concentrating the $CO_2$ to a pure stream and compressing it to high pressure for transportation or injection. Typically, the costs for $CO_2$ capture and compression account for about 70 to 80 percent of the entire project cost. Thus, the challenge to making CCS economically practical relative to other $CO_2$ reduction options, such as conservation, energy efficiency, renewables, and nuclear power, is managing the costs and energy use associated with $CO_2$ capture and compression.

Although $CO_2$ capture is usually associated with man-made $CO_2$ from fossil fuel use, the $CO_2$ can also be from utilization of any carbonaceous fuel. This is significant because applying CCS to power plants or transportation fuels plants that utilize biomass allows for negative emissions–actual subtractions from the gross GHG emissions inventoried. CCS associated with biomass is potentially most economic when co-processing waste biomass at large fossil fuel facilities with $CO_2$ capture to achieve essential economies-of-scale and high annual investment utilization.

## Current Capture Methods

Industrial processes emitting large $CO_2$ volumes usually do not generate an emissions stream of high purity $CO_2$ at above-atmospheric pressure. Instead, the stream is most often boiler or furnace exhaust gas at atmospheric pressure and of which nitrogen is the most prevalent constituent. As a result, the volumes, costs, and energy use involved in injecting the full flue gas stream deep underground would be prohibitively high. 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 oxy-firing (or oxy-fuel) combustion. The descriptions of these technologies rely on information in the PIER white paper by Simbeck.[39]

### *Post-Combustion Capture*

Post-combustion capture consists of processes that separate $CO_2$ from 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 relatively capital- and energy-intensive due to the low pressure and low $CO_2$ concentration in a flue gas composed mostly of nitrogen. The presence of excess oxygen ($O_2$), required for

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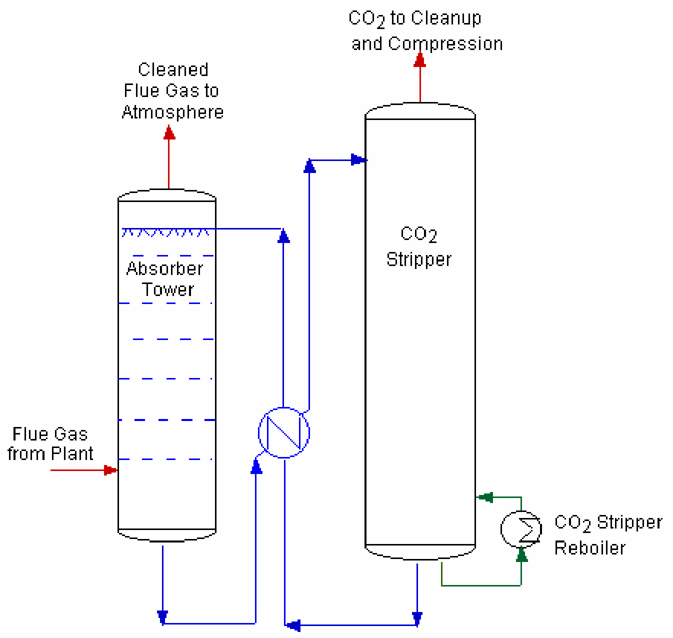
[39] Simbeck, D., 2008, "$CO_2$ Capture Processes," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER white paper on *Capture.*Energy-Related Environmental Research, CEC-500-2008-009.

complete combustion, as a residual in the flue gas poses additional challenges.[40] Post-combustion separation requires chemical solvent absorber/stripper systems, typically using amine solvents and special chemical inhibitors to curb reactions with the residual $O_2$. To regenerate the amine solvent by reversing the reaction requires heat, typically from steam, and the energy 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 $CO_2$ absorber to avoid fixation reactions with the recycled amine solution. Depending on the flue gas composition following conventional emission controls, supplemental $NO_x$[41] reduction and $SO_2$ removal systems may be required.[42]

Figure 4 depicts a simple 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 that releases the $CO_2$ as a high-purity stream. The captured $CO_2$ leaving the stripper then requires drying and compression to very high pressure before being transported via pipeline to the injection location. Chemical amine solvent absorber/stripper systems are commonly used for removing $CO_2$ from raw natural gas at high pressure without the presence of $O_2$.

**Figure 4: Post-Combustion $CO_2$ Capture Absorber and Stripper**



Source: Holt, Neville, 2005, *Advanced Coal Technologies with $CO_2$ Capture.* Electric Power Research Institute Global Climate Change Research Seminar, June 1-2, 2005 Washington D.C.

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[40] Ibid.

[41] $NO_x$ refers collectively to all gases composed of nitrogen and oxygen, that is, NO, $NO_2$, etc.

[42] Simbeck, D., op. cit.

Only about 10 small operating post-combustion $CO_2$ capture facilities exist worldwide for flue gas application. The largest operating system only captures about 330 tons of $CO_2$ per day. However, post-combustion capture is being proposed for a large Norwegian 800 MW natural gas-fired combined cycle power plant (see Chapter 9 for more information about this project).

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 retrofitting existing facilities without major process changes and rebuilds. In addition, the electric utility industry generally views this as similar to flue gas desulfurization systems, with which coal-fired utilities have significant experience.

A major challenge for post-combustion $CO_2$ capture is accommodating the large requirements for heat and power for amine stripping and for compression and drying of the wet (water-saturated) $CO_2$ that leaves the stripper. These requirements can significantly reduce the overall (net) capacity and efficiency of the plant. In addition, the $CO_2$ absorbers must be very large due to the low pressure and low concentration of $CO_2$ in 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 a pre-combustion absorber for the same amount of $CO_2$ capture.

## *Pre-Combustion Capture*

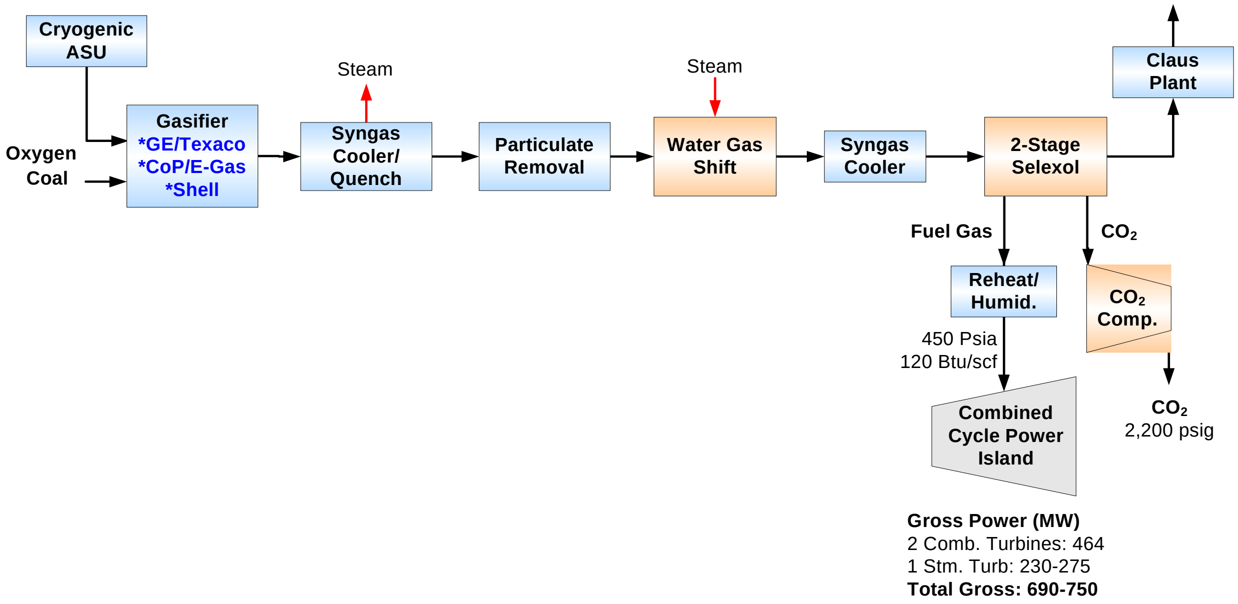
Pre-combustion $CO_2$ capture, involving capture of the $CO_2$ before combustion, is the most complex of the three $CO_2$ capture options and involves three main process steps. First, the original carbonaceous fuel is converted into "syngas," which is a mixture of mostly carbon monoxide (CO) with some hydrogen ($H_2$). For solid fuels, this conversion is usually done via gasification with oxygen ($O_2$) and some water ($H_2O$) at high pressure. It can also be done with steam methane reforming or autothermal reforming. 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 $H_2$. The simplified flow diagram in Figure 5 illustrates 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. For power generation from coal, the reliability of the gasifiers has historically been a concern and may require equipment redundancy to assure reliable power generation. The third step of $CO_2$ removal is relatively less expensive, compared to atmospheric-pressure amine systems, due to the high pressure and high concentration of the $CO_2$ and is usually done via physical solvent liquid absorber/stripper systems. Specifically, the energy requirement for stripping is about 20 percent lower than for post-combustion capture because much of the $CO_2$ flashes out of the physical solvent once the pressure is reduced for stripping. The resulting, relatively pure $CO_2$ stream is then dehydrated and compressed to a high-pressure supercritical gas (liquid-like conditions) for effective transportation via pipeline to an injection location for sequestration.

Pre-combustion is the most commercially developed of the three $CO_2$ capture options. Over 30 commercial gasification facilities manufacture pure $H_2$ for ammonia fertilizer from coal and oil. More than 10 oil refinery facilities manufacture hydrogen from residue pitch or petroleum coke.

Operating units separate more than 3,500 metric tons of $CO_2$ per day from $H_2$. This is more than 10 times the amount for the biggest operating post-combustion $CO_2$ capture systems.

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



Source: U.S. Department of Energy National Energy Technology Laboratory, 2007, Cost and Performance Baseline for Fossil Energy Plants, May 15, 2007.

Pre-combustion $CO_2$ capture is already used to supply about 10 MMT $CO_2$ per year for EOR. About 30 percent of the 35 MMT $CO_2$ per year used to produce 250,000 barrels per day of oil via EOR in North America is from pre-combustion $CO_2$ capture. This $CO_2$ comes from pre-combustion $CO_2$ sources that include gasification, natural gas purification and ammonia plants. The other 70 percent of the $CO_2$ used for EOR is from natural $CO_2$ sources. There is a large (2 MMT $CO_2$ per year) pre-combustion $CO_2$ capture operation at the Dakota Gasification coal-to-synthetic-natural-gas plant in North Dakota. A 200-mile pipeline takes the $CO_2$ for EOR use and geologic sequestration in oilfields near Weyburn, Saskatchewan, Canada.

Apart from this experience base, however, pre-combustion $CO_2$ capture has not yet been put into practice at electric power plants, which are the principal large point sources of $CO_2$ in California's GHG emissions inventory. The proposed Hydrogen Energy pre-combustion $CO_2$ capture project in California would be an important demonstration of this technology in application to power generation.

The key advantage of pre-combustion $CO_2$ capture is the use of $H_2$ as an intermediate energy carrier. $H_2$ has many potentially strategic long-term advantages over just steam or direct heat with post-combustion or oxy-firing 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 (such as Fischer-Tropsch) and the "hydrogen economy" for $H_2$-based fuel cells. These applications could be quite important in California where $CO_2$ emissions from transportation fuel use are roughly four times greater than $CO_2$ emissions from in-state electric power generation.

With regard to use of $H_2$ in power generation, General Electric 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 the fuel to reduce $NO_x$ formation and increase the gas turbine power output.

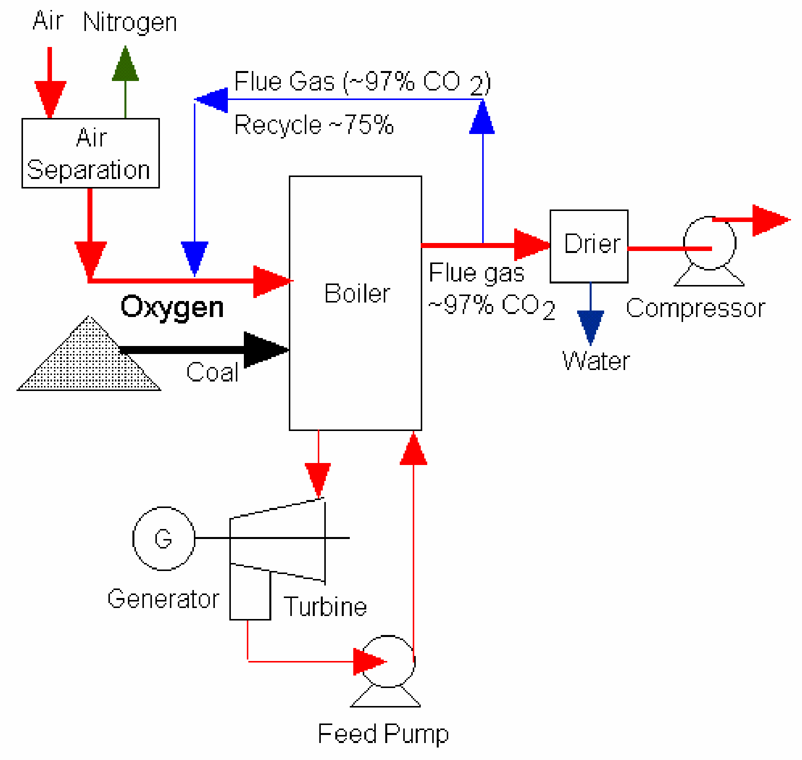
The challenge of pre-combustion $CO_2$ capture is in the complex chemical processing associated with the first gasification step of converting fuels into CO and $H_2$ syngas at pressure. The necessary expertise and experience is generally in the chemical and oil industries, not the power industry. There is also a significant capital investment required for equipment to convert feed stocks to synthesis gas. The high energy intensiveness of the syngas production step also may result in the total energy required per unit of $CO_2$ captured being greater for pre-combustion than for post-combustion capture. Pre-combustion $CO_2$ capture is usually most appropriate for new construction or major rebuilds of existing energy facilities. It is also especially practical when the $CO_2$ removal step is part of the basic process so that additional costs derive only from dehydration and compression.

### Oxy-Firing Combustion

Oxy-firing combustion involves replacing air in the combustion process with a blend of high-purity oxygen ($O_2$) and recirculated flue gas. Figure 6 shows 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 $NO_x$ and $SO_2$ depending on the fuel. The ultra-high temperature and heat flux (heat release per unit of volume) that would otherwise occur in direct combustion with pure oxygen requires dilution of the oxidant stream with large amounts of recycle flue gas. This flue gas recycle dilution poses some additional design challenges because water vapor and $SO_2$ build up to more than traditional levels.

Oxy-firing combustion for $CO_2$ capture is the least developed of the three options. It has only been tested at a 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: Oxy-Firing Combustion Coal Boiler**



Source: Holt, Neville, 2005, *Advanced Coal Technologies with $CO_2$ Capture.* Electric Power Research Institute Global Climate Change Research Seminar, June 1-2, 2005 Washington D.C.

Oxy-firing combustion has several advantages assuming that the "raw" $CO_2$ from oxy-firing combustion can be compressed and geologically stored. One advantage is that oxy-firing combustion for $CO_2$ capture is suited to retrofits of existing combustion systems. It is especially attractive for systems, such as existing cement kilns or fluid catalytic crackers in oil refineries, where the air-to-oxygen combustion conversion enables increased capacity. Another advantage is the avoidance of complex chemical processes associated with pre-combustion and with post-combustion absorber/stripper systems, which while eliminating the need for $SO_2$ and $NO_x$ controls adds a relatively expensive oxygen plant. A third advantage is that the overall energy requirements of oxy-firing are less than for post-combustion capture, a key advantage for high-cost energy environments such as California.

The large capital costs and power requirements of oxygen production present a challenge for oxy-firing combustion. Relative to pre-combustion $CO_2$ capture, oxy-firing requires two to three times more oxygen for the same amount of $CO_2$ removal. The high power requirement of this large oxygen plant can significantly reduce overall (net) capacity and efficiency of the plant. There also may be 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, involving the same approaches used for pre- or 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. For example, two joint industry projects, the $CO_2$ Capture Project and Cachet, are focusing research on improving $CO_2$ capture technologies for natural gas feeds for power production and existing large combustion sources, such as process heaters and boilers, or gas turbines.

$CO_2$ capture costs and efficiencies will likely improve with increasing scale of operations over time and from lessons learned with current $CO_2$ capture technologies. "Learning-by-doing" has been a quite successful approach for other process and environmental control technologies. For example, this approach was primarily responsible for reducing $NO_x$ and $SO_2$ control costs in coal power generation.

Post-combustion $CO_2$ capture has several short-term development needs. One is for large-scale operating experience in integrated power generation. One opportunity in the next few years is the large-scale post-combustion $CO_2$ capture planned for a natural gas combined-cycle plant being proposed in Norway (see Chapter 9). For California, following the Norwegian experience may be especially important due to the high portion of total electric power generated via natural gas in the state. Effective use of improved "hindered" amines and better low-level heat integration also should help reduce net energy and capacity losses.

One longer-term technology development that could significantly improve post-combustion $CO_2$ capture is the chilled ammonia process being developed by Alstom with support by power generators through the Electric Power Research Institute. 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. However, the cost of chilling the flue gas would be significant. If successfully developed, this technology would improve post-combustion $CO_2$ capture costs and efficiency.[43]

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 operating a small bench-scale process. We Energies' Pleasant Prairie power plant near Kenosha, Wisconsin, is planning a 1.7 MW pilot plant. If the pilot plant is successful, American Electric Power plans a large 20 MW pilot plant starting in 2008, followed by a 200 MW

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[43] Simbeck, D., op. cit.

demonstration that could start as soon as 2011 or 2012. These U.S. projects are focusing on applications 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.

The short-term development need for pre-combustion $CO_2$ capture is to build a large power plant with integrated pre-combustion CCS. There is commercial large-scale experience with all the process steps involved in pre-combustion $CO_2$ capture; however, not all steps have been used in a single integrated power plant application. This integrated process is proposed for the Hydrogen Energy (BP-Rio Tinto-Edison Mission Energy) project in California using petroleum coke gasification. It was also the goal of the originally proposed FutureGen coal gasification project and is also part of the recently conceived derivative projects. The proposed Hydrogen Energy project has the advantage of integrating expertise among its partners, combining the chemical process and geologic expertise of BP, the solids handling and processing expertise of Rio Tinto, and the power generation expertise of Edison Mission Energy.

Oxy-firing combustion $CO_2$ capture should be scaled up from relatively small pilot tests to larger commercial demonstrations. There are several rather radically different approaches evolving in oxy-firing combustion development. The near-term focus of the traditional coal boiler vendors is on testing larger oxy-firing coal boilers. Several groups are doing this work. One is in Canada by Saskatchewan's SaskPower with Babcock & Wilcox (B&W) and Air Liquide. Others include Vattenfall in Germany, involving Alstom, and Jupiter Oxygen in the United States, which are developing small-scale demonstrations. Natural gas-based power vendors are showing interest in the development of the Clean Energy Systems "rocket-engine" oxygen-fired gas generator and associated power turbine in California. Specifically, Clean Energy Systems' process is based on natural gas, heavy oil emulsion, or gasification-based CO-rich syngas firing with oxygen plus water injection in a modified high-temperature steam turbine that operates somewhat like a gas turbine. A small 5 MW pilot unit has been successfully tested near Bakersfield, California. A 49 MW demonstration unit operating initially on natural gas is proposed for Clean Energy Systems' California site for startup in 2010.

A number of technology developments could improve pre-combustion $CO_2$ capture costs and performance. These include current developments in advanced membranes, oxygen generation and gas turbines. However, solid oxide fuel cells are probably the most significant technology over the long term for improving pre-combustion $CO_2$ capture. Their use could avoid a number of process steps and energy losses. For example, high-pressure solid oxide fuel cells could convert CO-rich syngas directly into electricity and $CO_2$ (at high pressure) in just one high-efficiency step. Development of improved oxygen production via chemical looping or ionic transport membranes could significantly improve oxy-firing combustion. Advanced oxygen production could greatly reduce the capital costs and power requirements for the large oxygen demand of oxy-firing combustion. Successful developments also could be modified to improve pre-combustion $CO_2$ capture, but the greater benefits would be for oxy-firing combustion.

## Costs

Capture and compression are the most expensive part of CCS, typically 70 to 80 percent of the total costs. $CO_2$ 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. Chapter 9 discusses costs in detail.

$CO_2$ capture costs can vary significantly due to many issues. In general terms, $CO_2$ capture economics favor large point sources near good geologic sequestration sites, low-cost fuels due to the increased energy use for $CO_2$ capture, and fuels high in carbon that generate high concentrations of $CO_2$ in exhaust streams. Therefore, the costs of $CO_2$ capture generally favor coal-based electric power generation over natural gas combined cycle.

The cost of $CO_2$ capture will increase product costs. For power generation, the power plant "gate" or wholesale electricity cost may increase by about 50 percent. $CO_2$ 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 impact of the fuel used (cheap high-carbon coal versus expensive low-carbon natural gas) and whether new or retrofit facilities are involved.

## 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.

A post-combustion $CO_2$ capture retrofit can be a relatively simple, although substantial, set of equipment added to a plant near the stack. 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 that capture equipment is added to regain some of the efficiency and capacity loss inherent to the $CO_2$ capture process. There are also important site-specific factors such as fuel costs, physical 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 injection and sequestration of large volumes of $CO_2$.[44] From this standpoint, a sequestration site should be able to accept a large volume of $CO_2$ at a high rate and store it safely and effectively for long periods (see Chapter 1 for more on time scales). Site characterization and proper site selection and certification are paramount to the success of CCS projects. Characterizing and choosing appropriate sites for CCS assures that the climate change mitigation goals of sequestration are met and protects the environment and human health and safety. The PIER white paper by Friedmann provided the foundation for this chapter.[45]

## The Goals of Site Characterization

Siting of geological sequestration projects requires substantial surface and subsurface characterization. However, the degree of detail, 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 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 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[46]

Surface characterization is important, and, in practice, should not depart significantly from approaches used for siting other industrial facilities. Traditional power plant siting decisions focus on surface site characterization primarily, but the addition of CCS affects the information needed for these decisions. CCS requires additional infrastructure. In addition to the plant and capture facilities, other infrastructure, such as pipelines and reservoir monitoring equipment, has environmental and societal impacts. These impacts include potential effects on sensitive

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

[45] Friedmann, S.J., 2008, "Site Characterization for Geological Carbon Sequestration: Key Technical Issues and Potential Due-Diligence Requirements," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009

[46] Cook P.J., 2006, "Site Characterization," *Proceedings, International Symposium on Site Characterization for $CO_2$ Geological Storage,* Lawrence Berkeley National Laboratory, Berkeley, CA, pp. 3-5.

species and other wildlife, as well as 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 meteorological conditions must be characterized to understand the potential impact of any significant $CO_2$ leak. Furthermore, surface characterization must be coordinated with subsurface characterization.

A CCS 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. CCS 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[47]

For subsurface characterization of CCS sites, there is presently no accepted set of practices. For this reason, subsurface characterization issues are the main focus of this chapter. Many conventional technologies and approaches from existing industries are appropriate. In particular, the oil and gas industry has developed a wide array of techniques for subsurface characterization and gas monitoring that has application to CCS site characterization. The recent risk and environmental impact assessment for FutureGen used existing techniques.[48] 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.

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[47] Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

[48] <http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/>.

## Key Considerations

### *Sequestration Mechanisms*

Expected $CO_2$ sequestration mechanisms are reasonably well defined and understood.[49] As noted previously, both physical and chemical mechanisms can trap $CO_2$ in the sequestration reservoir. Physical barriers, or seals, that keep $CO_2$ from migrating out of the crust to the surface commonly are in the form of impermeable layers (for example, shales, evaporites) overlying the sequestration target. Like a lid on a jar, these barriers create a trap that keeps fluids from migrating upward. This hydrodynamic sequestration mechanism is similar to the processes by which hydrocarbon reservoirs form, which allow for natural gas storage and which create natural $CO_2$ accumulations. Sequestration 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 past the extent of the barrier.

As $CO_2$ gas fills pores in the rock, capillary forces can immobilize a substantial fraction of the $CO_2$, 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.[50] $CO_2$ 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.[51] 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 understand these mechanisms, enough is known to develop estimates of the percentage of $CO_2$ that can be stored over some period of time for a given site. The time scales over which trapping mechanisms act also suggests that the

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[49] U.S. Department of Energy, 2007, *Basic Research Needs for Geosciences: Facilitating 21st Century Energy Systems*, Washington, D.C., <http://www.sc.doe.gov/bes/reports/list.html>.

[50] Bergman, P.D., and E.M. Winter, 1995, "Disposal of carbon dioxide in aquifers in the U.S.", *Energy Conversion & Management*, v. 36, p. 523.

[51] U.S. Department of Energy, 2007, op. cit.

subsurface sequestration reservoir becomes progressively more effective at storing $CO_2$ over time (refer back to Figure 3).

## *Site Hazards, Geological and Engineered*

The earth's crust is complex and heterogeneous. Although, as noted above, it is possible to identify potential sites generally, more specific details are necessary for proper site assessment. Features, events, and processes can be systematically identified to define hazards that could compromise site sequestration integrity.[52] 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 originally deposited in open marine basins.[53] 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 $CO_2$.[54] Breaches through this sealing unit compromise the integrity of the reservoir and may be engineered (for example, wells) or natural (faults and fractures).[55]

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,

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[52] 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.

[53] Beyer, L.A., 1995, "San Joaquin Basin", *USGS 1995 National Oil And Gas Assessment*, <http://energy.cr.usgs.gov/oilgas/noga/1995.html>; Magoon, L.B., 1995, "Sacramento Basin", *USGS 1995 National Oil And Gas Assessment*, <http://energy.cr.usgs.gov/oilgas/noga/1995.html>; Keller, M.A., 1995, "Ventura Basin", *USGS 1995 National Oil And Gas Assessment*, <http://energy.cr.usgs.gov/oilgas/noga/1995.html>; Meyer, L.A., 1995, "Los Angeles Basin", *USGS 1995 National Oil And Gas Assessment*, <http://energy.cr.usgs.gov/oilgas/noga/1995.html>.

[54] Christopher, C., and J. Iliffe, 2006, "Reservoir Seals: How They Work and How to Choose a Good One." *Proceedings from the International Symposium for Site Characterization for $CO_2$ Storage,* Berkeley, California. pp. 12–15.

[55] Friedmann, S.J., 2008, "Site Characterization for Geological Carbon Sequestration: Key Technical Issues and Potential Due-Diligence Requirements," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

capillary pressure measurements on core samples can quantify the amount of buoyant force a cap rock lithology can maintain before failing.[56, 57]

Some cap rocks, on the basis of their mineral composition, may be more suitable for $CO_2$ sequestration. These rock types react to $CO_2$ and swell, thereby further reducing their porosity and permeability.[58] 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.[59] Under the right circumstances, faults can provide pathways for fluids and, in some circumstances, bring those fluids to the surface. This has been seen repeatedly 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, both in Utah, and natural $CO_2$ seeps at Latera, Italy, near Rome.[60, 61] 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.

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[56] Harrington, J.F., and S.T. Horseman, 1999, "Gas transport properties of clays and mudrocks." In A.C. Aplin et al. (eds.), *Muds and Mudstones: Physical and Fluid Flow Properties*, Geological Society Special Publication 158, pp. 107–124.

[57] Bolas, H.M.N., C. Hermanrud, and G.M.G. Tiege, 2005, "Seal Capacity Estimation from Subsurface Pore Pressures." *Basin Research*, v. 7 pp. 583-599.

[58] Watson, M.N., R.F. Daniel, P.R. Tingate, and C.M. Gibson-Poole, 2005, "$CO_2$-Related Seal Capacity Enhancement in Mudstones: Evidence from the Pine Lodge Natural $CO_2$ Accumulation, Otway Basin, Australia." In Wilson M., T. Morris, J. Gale, and K. Thambimuthu (eds), *Greenhouse Gas Control Technologies, Proceedings from the 7th Greenhouse Gas Control Technologies Conference*, Elsevier, v. 2, pp. 2313-2316.

[59] Wilkins, S.J., and S.J. Naruk, 2007, "Quantitative Analysis of Slip-Induced Dilation with Application to Fault Seals." *American Association of Petroleum Geologists Bulletin*, v. 91, pp. 97-113.

[60] Friedmann, S.J., op. cit.

[61] Ibid.

In the context of $CO_2$ sequestration, the presence of faults is neither good nor bad. Some faults are conduits for 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 to understand the potential risks presented by a fault or network of faults.

Recently, a study was done in an oil field at Teapot Dome, Wyoming, to estimate the potential for faults to fail and leak $CO_2$.[62] 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 for sequestration, 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. A test done at Rangely Field, Colorado, described below, demonstrates this assertion. Similarly, the history of waterflooding and brine injection in California oil fields provides evidence 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 potential hazard in 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 sequestration 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.[63] Despite the long, successful history of well engineering, there are potential failure mechanisms that could allow $CO_2$ to escape from deep reservoirs.[64, 65] Many conditions control a well's potential for leakage, including the age and plugging mechanism, quality of completion, and post-closure history.

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[62] Chiaramonte, L., M. Zoback, S.J. Friedmann, and V. Stamp, 2007, "Seal Integrity and Feasibility of $CO_2$ Sequestration in the Teapot Dome EOR Pilot: Geomechanical Site Characterization." *Environmental Geoscience*, v. 53.

[63] Jarrell, P.M., C.E. Fox, M.H. Stein, and S.L. Webb, 2002, *Practical Aspects of $CO_2$ Flooding.* Monograph 22. Society of Petroleum Engineers, Richardson, TX, USA.

[64] Gasda, S.E., S. Bachu, and M.A. Celia, 2004, "The Potential for $CO_2$ Leakage from Storage Sites in Geological Media: Analysis of Well Distribution in Mature Sedimentary Basins." *Environmental Geology* 46 (6–7), pp. 707–720.

[65] 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 $CO_2$ through Abandoned Wells: Role of Corrosion of Cement." In D.C. Thomas and S.M. Benson (Eds.), *The $CO_2$ Capture and Storage Project (CCP)*, Volume II, pp. 823–844,

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.[66] Such methods can be used as a crude screening tool on a 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.[67] It is also possible to monitor wells directly through regular surveys to detect leakage. As is discussed in Chapter 8, if leaks are detected, conventional approaches can be used to re-complete and plug these 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.[68, 69] It is important to note that the target rocks were very impermeable and as a consequence, sustained very large pressure buildups. Given that CCS sites need good permeability, sites with similar characteristics to the Arsenal would not be selected.

One important case of induced earthquakes involves Rangely 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, with magnitude 3.1, could barely be felt at the surface. Most were much smaller.[70] 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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[66] Celia, M.A., D. Kavetski, J.M. Nordbotten, S. Bachu, and S. Gasda, 2006, "Implications of Abandoned Wells for Site Selection." *Proceedings, International Symposium on Site Characterization for $CO_2$ Geological Storage*, Lawrence Berkeley National Laboratory, Berkeley, CA, pp.157–159.

[67] Veloski, G. and R. Hammack, 2006, "An Evaluation of Helicopter and Ground Methods for Locating Existing Wells." *Proceedings, International Symposium on Site Characterization for $CO_2$ Geological Storage*, Lawrence Berkeley National Laboratory, Berkeley, California, pp. 62–66.

[68] Evans, D.M., 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)].

[69] Healy, H.J., W.W. Rubey, D.T. Griggs, and C.B. Raleigh, 1968, "The Denver Earthquakes." *Science* v. 161, p. 1301.

[70] Raleigh, C.B., J.H. Healy, and J.D. Bredehoeft, 1976, "An Experiment in Earthquake Control at Rangely, Colorado." *Science* v. 191, pp. 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 sequestration site:

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

## Parameters of Site Characterization

While it is possible to pursue many approaches for site characterization, it is difficult to imagine siting a large-scale injection project without knowledge of three fundamental 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 $CO_2$ sequestration 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 reservoir seal, an impermeable cap rock layer, is a key control on trapping, blocking the upward migration of $CO_2$ from the underlying reservoir. Seal integrity depends on the cap rock composition and the engineering of wells, past and present, which intersect it. Table 3 outlines key information, data, and analyses needed to determine these parameters.

## Table 3: Information and Potential Data Sources for Site Characterization

| Key Term | Key information | Basic Data Sources | Basic Analysis from Data | 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, seismic volumes | Stratigraphic analysis, structural analysis, static geomodels construction, simple calculation, conventional simulation, 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, 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, S.J., PIER white paper on Site Characterization for Geological Carbon Sequestration: Key Technical Issues and Potential Due-Diligence Requirements.

## 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. 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 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 necessary 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 may 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 improve the original assessment.

## 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 some cases, this will require new geological and geophysical data sets, depending on data already available, local geological complexity, and potential risks. What might constitute due diligence in the context of developing site characterization criteria is site-dependent. However, there are general differences between what is needed for depleted oil and gas fields and what is needed for formations without a history of hydrocarbon production, where little to no previous data have been collected.

### *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 for abandoned wells, their 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) to construct a geologic model. Injectivity will be constrained by initial pressure, current pressure, and production history, and capacity by the pore volume, 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, and 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 targeted well re-completion program in the field to help assure effectiveness.

## *Formations without Hydrocarbon Production History*

In contrast to depleted oil or gas fields, other potential sequestration sites are likely to have limited to no pre-existing well data, core, or seismic data. To help constrain subsurface uncertainty, geological characterization may require new data from exploratory wells, geophysical surveys, or regional hydrological analysis. For these sites, 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 define these 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 some of the FutureGen plant sites. Otherwise, it may be necessary to perform 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, at least one additional seal may be advisable. In situ stress determination and special geomechanical analyses (for example, leak-off tests, and capillary entry pressure) might be required. In situations where there is little structural or geophysical information available, geophysical surveys (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 an appropriate regular monitoring and verification program 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 Chapter 6, 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 potential failure risks, which then could be used to modify operational parameters and monitoring programs.

## 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 of the subsurface can be used to begin to define minimal technical constraints. A focused scientific and technical effort aimed at drafting minimum and appropriate technical constraints for site characterization could provide regulatory guidance quickly and clearly. Such a program would complement existing efforts (for example, WESTCARB and more generally other efforts within the Department of Energy’s Regional Carbon Sequestration Partnerships 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 CCS is safe. Monitoring the sequestration site for $CO_2$ leakage shows that there are no significant adverse local environmental impacts; verification shows that the site is retaining stored $CO_2$ such that it will be an effective greenhouse gas mitigation technology for the long term.

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 $CO_2$ concentrations. The PIER white paper by Benson and Myer provided the foundation for this chapter.[71]

An appropriate 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 sequestration site. Flexibility to tailor verification monitoring to the specific geological attributes of the sequestration site would be beneficial; however, it may also be appropriate to establish a minimum set of monitoring and verification requirements that address the goals of the CCS project. This could be done 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 sequestration 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 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 sequestration. Monitoring instrumentation must be capable of detecting significant low-level leakage, but also have sufficient range to register large-scale leaks, should they occur. 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. However, $CO_2$ measurement and monitoring approaches for subsurface processes have yet to be proven at the temporal and spatial scales relevant to geologic sequestration. While the current capabilities are not an impediment to

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[71] Benson S. and L. Myer, 2008, "PIER white paper on *Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.," Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

undertaking CCS, monitoring and verification approaches will likely benefit from lessons learned through demonstration and early projects.

Measurement technologies for monitoring geologic sequestration 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.[72, 73] Geophysical, 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 may 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 sequestration-related changes in the environment from natural or other anthropogenic 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 verifying the quantity of $CO_2$ injected underground. Figure 7 illustrates examples of requirements for CCS and how these should guide a monitoring program. It may also be desirable to monitor other parameters to assess the performance of the CCS 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 sequestration 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
- Detect and monitor $CO_2$ concentrations in the vadose zone and soils
- Monitor ecosystem impacts

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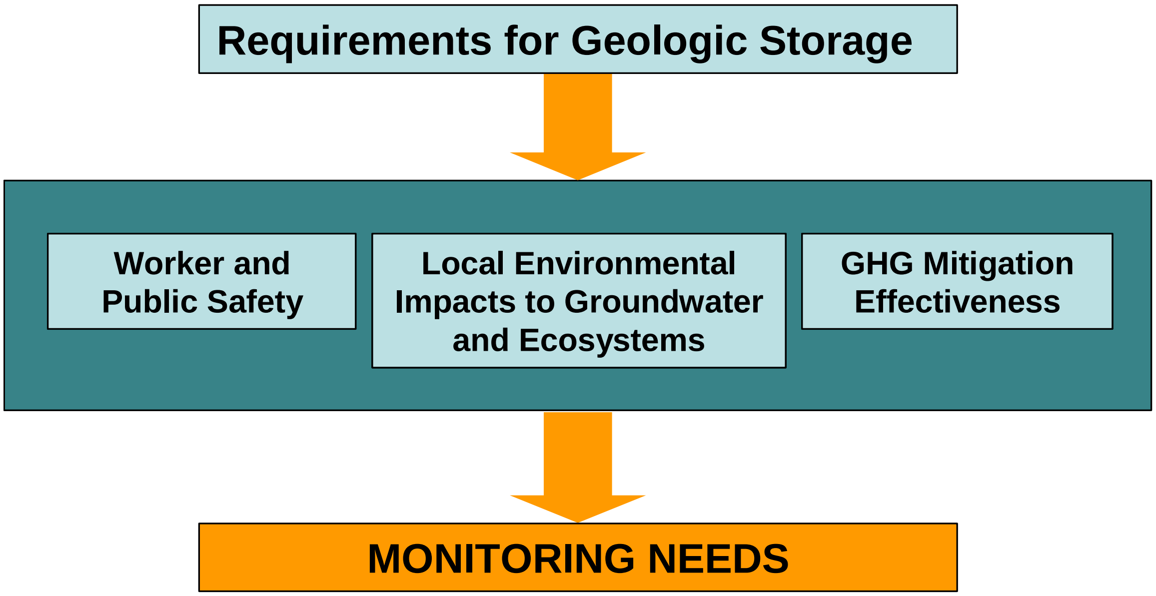
[72] Benson, S.M., R. Hepple, J. Apps, C.F. Tsang, and M. Lippmann, 2002(a), "Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geologic Formations." *Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6)*, Kyoto, Japan, 1-4 October, 2002.

[73] 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.

- 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 sequestration 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.[74]

**Figure 7: Flow Chart of Environmental, Health, and Safety Requirements for CCS**



Source: Benson S. and L. Myer, 2008, "PIER white paper on *Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.," Assessment of Geologic Carbon Sequestration in California*, E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

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

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[74] 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.

parameters should be monitored, timing of measurements, spatial scale and resolution of measurements, and location of monitoring points all must be considered.

From the standpoint of public acceptance, knowing that monitoring can be done to provide this information could provide greater assurance that CCS can be accomplished safely and effectively. Monitoring and verification data also can provide information to determine future levels of monitoring activity and whether or not site decommissioning requirements have been met.

## Importance of a Well-Defined Baseline

It can be very challenging to detect changes in $CO_2$ concentrations associated with 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 CCS 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 CCS projects. Otherwise, it may not be possible to separate sequestration-related changes in the environment from the natural or non-sequestration-related anthropogenic variations in the monitoring parameters. For most CCS projects, baseline data will be obtained during the pre-injection site characterization phase. This is particularly important for CCS projects in areas where there is little prior data.

## Measurement Methods

Measurement technologies for monitoring geologic sequestration 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, the food preservation and beverage industries, fire suppression, and ecosystem research.[75]

### *$CO_2$ 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

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[75] Benson, S., et al., 2002(a); 2002(b), op. cit.

differential producing devices that relate the pressure drop across the device to the flow rate. Recent enhancements in the basic technology are now available that allow for accurate measurements and injection control, even under varying pressure and temperature conditions.[76]

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.[77]

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 sequestration 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 sequestration site. In addition, nearby groundwater wells may be monitored periodically to ensure that the CCS project is not harming groundwater quality. If there is an indication that $CO_2$ has leaked from the primary sequestration reservoir and migrated to the surface, vadose zone and soil gas $CO_2$ concentrations may be monitored.[78]

Even when a CCS 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 to uniquely identify and trace the movement of injected $CO_2$ from one part of the sequestration structure to another.

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[76] Wright, G. and G. Majek, 1998, "Chromatograph, RTU Monitoring of $CO_2$ Injection." *Oil and Gas Journal*, v. 20.

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

[78] 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.

## $CO_2$ 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 $CO_2$ 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. For extra assurance and validation of real-time monitoring data, federal regulatory agencies[79] use gas sampling bags and gas chromatography for periodic measurements of $CO_2$ 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.[80]

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.[81] For example, the US Geological Survey measures $CO_2$ fluxes on Mammoth Mountain using these types of detectors.[82] Biogeochemists study ecosystem scale carbon cycling using $CO_2$ detectors on towers that are 6 to 16 feet tall (eddy flux correlation measurements) in concert with wind and temperature data to reconstruct average $CO_2$ fluxes 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 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, often to detect the extent of emissions

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[79] For example, National Institute of Occupational Safety and Health, Occupational Safety and Health Administration and the Environmental Protection Agency.

[80] 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.

[81] 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." *Journal of Volcanology and Geothermal Research* v. 92, pp. 181-193m.

[82] 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/>; United States Geological Survey, 2001(c), Long Valley Observatory home page, <http://lvo.wr.usgs.gov/>.

from volcanic events.[83] 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.[84] 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.[85]

### 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.[86] Fluid samples can be collected either directly from the formation using a downhole sampler or from the wellhead by pumping. 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, $^{13}C$, $^{14}C$, $^{18}O$, $^2H$), and gases, including hydrocarbon gases, $CO_2$, and its associated isotopes.[87] 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

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[83] Lopez-Puertas, M. and F.W. Taylor, 1989, “Carbon Dioxide 4.3 μm Emission in the Earth’s Atmosphere: A Comparison Between NIMBUS 7SAMS Measurements and Non-local Thermodynamic Equilibrium Radiative Transfer Calculations.” *Journal of GeophysicalResearch* v. 94(D10), pp. 13,045–13,068.

[84] 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.” *Journal of Geophysical Research* v. 96(D10), pp. 18,735–18,752.

[85] Ibid.; Menzies, R.T., D.M. Tratt, M.P. Chiao, and C.R. Webster, 2001, “Laser Absorption Spectrometer Concept for Global Scale Observations of Atmospheric Carbon Dioxide.” *11th Coherent Laser Radar Conference*, Malvern, United Kingdom.

[86] Gunter, W.D., R.J. Chalaturnyk, and J.D. Scott, 1998, “Monitoring of Aquifer Disposal of $CO_2$: 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/>.

[87] Ibid.

underground movement of $CO_2$ and reactions between $CO_2$ and the geologic formation.[88] 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.[89]

## *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.

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 $CO_2$ sequestration project, the Frio Brine Pilots I and II, the Nagaoka project in

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[88] Emberley, S., I. Hutcheon, M. Shevalier, K. Durocher, W.D. Gunter, and E.H. Perkins, 2002, "Geochemical Monitoring of Fluid-Rock Interaction and $CO_2$ Storage at the Weyburn $CO_2$-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." *Lawrence Berkeley National Laboratory Report*, LBNL-47383.

[89] Bachu, S. and W.D. Gunter, 1994, "Aquifer Disposal of $CO_2$: 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 D.C.

Japan and the Weyburn Project.[90] 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 innovative real-time seismic monitoring approaches.[91]

### 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 for measurement of many parameters—from the condition of the well to the composition of pore fluids to the mineralogy of the formation. For geologic sequestration of $CO_2$, as 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.[92] 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.[93]

### 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. The most highly developed by far are seismic methods. 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.

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[90] Korbol, R., and A. Kaddour, A., 1995, "Sleipner Vest $CO_2$ Disposal – Injection of Removed $CO_2$ into the Utsira Formation." *Energy Conversion and Management,* v. 36, 3-9, pp. 509-512.

[91] Daley, T., R.D. Solbau , J. B. Ajo-Franklin, S. M. Benson, 2007, "Continuous Active-Source Seismic Monitoring of $CO_2$ Injection in a Brine Aquifer." *Geophysics,* in press.

[92] Benson, S., et al., 2002a, op. cit.

[93] 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, 2006, Measuring Permanence of $CO_2$ Storage in Saline Formations: The Frio Experiment." *Environmental Geosciences,* June 2006; v. 13; no. 2; pp. 105–121; DOI: 10.1306/eg.11210505011.

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 of the technique also depends on the configuration in which the measurement is made. For example, 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 methods used to monitor $CO_2$ migration in off-shore environments at the Sleipner Project were able to detect the injected $CO_2$.

Because the physical properties are well known for $CO_2$, typical reservoir fluids, and their mixtures, assessments can be made of expected changes due to $CO_2$ migration and whether they would be detectable by various geophysical methods.[94] For example, supercritical $CO_2$ is resistive whereas saline water is conductive; therefore, electrical methods are candidate monitoring techniques. At most sequestration depths, $CO_2$ is less dense and more compressible than brine or oil, so gravity and seismic methods are appropriate. At shallow depths, $CO_2$ has gas-like properties, so none of the geophysical methods is a good candidate for monitoring $CO_2$ within a shallow dry natural gas reservoir. Even in this case, because brine formations are commonly found above gas reservoirs, geophysical methods may 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.[95]

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 the seismic wavelength. Numerous researchers have studied ways to improve seismic resolution.[96] 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

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[94] Magee, J.W. and J.A. Howley, 1994, *Research Report, RR-136,* Gas Processors Association, Tulsa, OK; National Institute of Science and Technology (NIST), 1992, *NIST Database 14 Mixture Property Database*, version 9.08, U.S. Department of Commerce.

[95] 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 D.C.

[96] 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 G. Payton (ed), *Seismic Stratigraphy—Applications to Hydrocarbon Exploration,* Memoir 21, American Association of Petroleum Geologists, pp. 3–14.

contrasts. Myer and others[97] 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.[98] This suggests that methods might be developed to locate potential leak paths using seismic methods.

Seismic methods cover several frequency ranges. Surface seismic methods produce energy from 10 to 100 Hertz (Hz). Crosswell seismic methods using rotary sources produce energy in the 100 to 500 Hz range and, using piezoelectric sources, in the 1 to 2 KiloHertz (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 30 to 300 feet, suggesting that $CO_2$ plumes as thin as 6 to 50 feet may be detectable. 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 feet into typical sedimentary rocks.

The resolutions of geophysical methods other than seismic mostly are 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 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 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 well field. A pilot test of this technology has been done at the Vacuum Field in New Mexico.[99]

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

[98] 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, and N. Cook, 1990, "Transmission of Seismic Waves Across Single Fractures." *Journal of Geophysical Research*, v. 95(86), pp. 8617–8638.

[99] 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.

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.[100] 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.[101] While it is unlikely that monitoring the saturation of $CO_2$ will be needed as part of a routine monitoring program, this capability may be useful for improving general understanding of geologic $CO_2$ sequestration. 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.[102] Tiltmeters placed on the ground surface can measure changes in tilt of a few nano-radians.[103] 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 $CO_2$ sequestration projects, they have been used in a variety of other applications, including oil and gas reservoir monitoring and groundwater investigations.[104] Satellite spectral imaging has been used to detect $CO_2$-induced tree kills from volcanic outgassing at Mammoth Mountain, California.[105] 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 although they may rely on detecting effects that are

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[100] Arts, R., O. Eiken, A. Chadwick, P. Zweigel, L. van der Meer, and B. Zinszner, 2002, "Monitoring of $CO_2$ Injected at Sleipner Using Time Lapse Seismic Data." *Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6)*, Kyoto, Japan, 1-4 October, 2002.

[101] 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.

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

[103] 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.

[104] Vasco, D.W., et al., 2001, "Geodetic Imaging: High Resolution Monitoring Using Satellite Interferometry." *Geophysical Journal International*, v. 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*, v. 37, No. 6, p. 1551.

[105] 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.

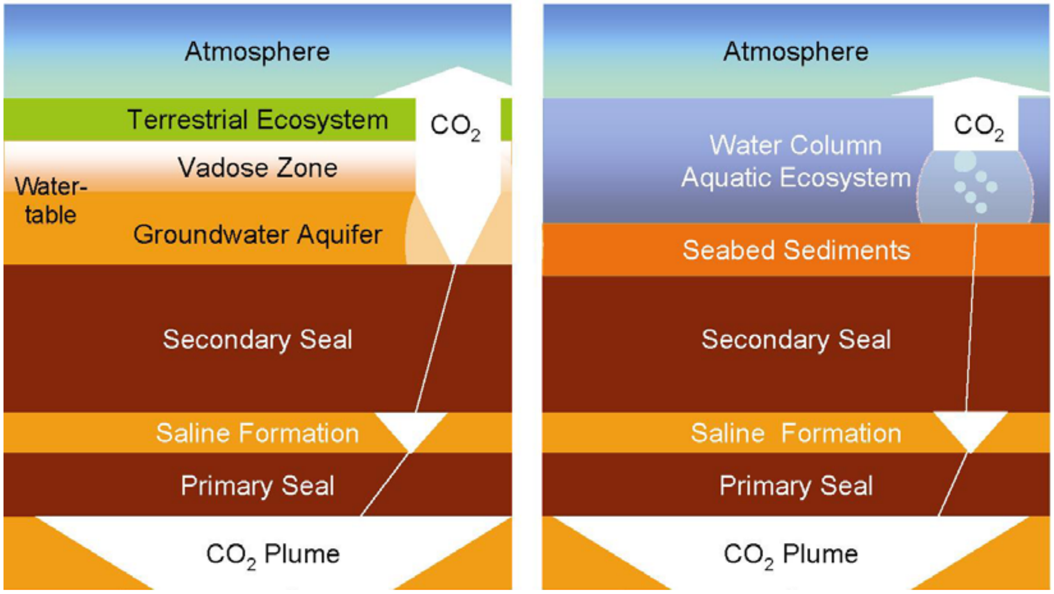
gradual cumulative ecosystem responses and that may preclude timely mitigation and remediation of leakage events.

## Monitoring Programs and Approaches

The information provided above demonstrates that the toolbox of available monitoring methods is diverse and applicable from multiple vantage points and scales. Available methods also provide 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 that demonstrates 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 sequestration reservoirs, monitoring can take place in the reservoir itself or in shallow formations that contain secondary accumulations of $CO_2$. These secondary accumulations may be as dissolved and separate phases in groundwater or as vadose zone gas.

**Figure 8: Monitoring Options**



Source: Benson S. and Myer L., PIER white Paper on Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.

Schematic showing the components of the subsurface and how they may be used for monitoring at on-shore (left) and off-shore (right) sequestration sites.

Monitoring can also take place within terrestrial ecosystems or by measuring emissions into the atmosphere. While for any leak, the mass of $CO_2$ rising to the surface would decrease as some is left behind along the migration path, the volume of the $CO_2$ expands as it becomes a gas as pressure declines, hence, the increase in the width of the $CO_2$ vector in the diagram. While leaking faults and fractures (indicated by sub-vertical white lines in the diagram) would also contain $CO_2$, detection there is likely to be difficult as a result of their comparatively small size and unfavorable geometry.

For off-shore sequestration or any formation lying beneath a deep water body, the deeper components of the system are the same as their on-shore counterparts. However, as $CO_2$ approaches the interface between sediments and water, 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.

Tables 4, 5, and 6 summarize the methods, benefits, and drawbacks for monitoring each of the components of a sequestration system in the context of inventory verification and carbon credit trading. As indicated by the information in the tables, a large number of approaches and options are available for monitoring emissions. 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 sequestration reservoir. Since the same combination of measurements would not be appropriate for all CCS sites, flexibility to tailor the monitoring to the specific geological attributes of the sequestration site would be beneficial.

**Table 4: General Monitoring Approaches**

| System Component | Monitoring Methods | Strengths | Weaknesses |
|---|---|---|---|
| Sequestration reservoir | Seismic<br>Gravity<br>Well logs<br>Fluid sampling | History match to calibrate and validate models<br>Early warning of migration from the sequestration reservoir | Mass balance difficult to monitor<br>Dissolved and mineralized $CO_2$ difficult to detect |
| Shallower saline formations below secondary seals | Seismic<br>Pressure<br>Gravity<br>Well logs<br>Fluid sampling | Good sensitivity to small secondary accumulations (~1000 metric tons) and leakage rates<br>Early warning of leakage | Detection difficult if secondary accumulations do not occur<br>Dissolved and mineralized $CO_2$ difficult to detect |

Source: Benson S. and L. Myer, 2008, “PIER white paper on *Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.,” Assessment of Geologic Carbon Sequestration in California*, E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

## Table 5 : Onshore Monitoring Approaches

| System | Methods | Strengths | Weaknesses |
|---|---|---|---|
| Groundwater aquifers | Seismic<br>Pressure<br>EM<br>Gravity<br>SP<br>Well logs<br>Fluid sampling | Sensitivity to small secondary accumulations (~100-1000 metric tons) or leakage rates<br>More monitoring methods available<br>Detection of dissolved $CO_2$ less costly with shallow wells | Detection after significant migration has occurred<br>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<br>Early detection in vadose zone could trigger remediation before large emissions occur | Significant effort for null result (e.g. no $CO_2$ from sequestration detected)<br>Detection only after some emissions are imminent<br>Does not provide quantitative information on emission rate |
| Terrestrial ecosystems | Vegetative stress | Vegetative stress can be readily observed using routine observation<br>Satellite and plane-based methods available for quick reconnaissance | Detection only after emissions have occurred<br>Vegetative stress can be caused by other factors<br>Land use change could alter the baseline<br>Does not provide quantitative information on emission rates<br>May not be useful in some ecosystems (e.g. deserts) |
| Atmosphere | Eddy covariance<br>Flux accumulation chamber<br>Optical methods | Good for quantification of emissions | Distinguishing sequestration emissions from natural ecosystem and industrial sources necessitates comprehensive monitoring<br>May not be best suited for detecting anomalous emissions due to relatively small footprint compared to the size of the plume<br>Significant effort for null result |

Source: Benson S. and L. Myer, 2008, "PIER white paper on *Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.," Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

### *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. 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, or disposal of industrial wastes in deep geologic formations. This is appropriate if these minimum standards are well-founded and general enough to be universally applicable to CCS projects.

**Table 6: Offshore Monitoring Approaches**

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

Source: Benson S. and L. Myer, 2008, “PIER white paper on *Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.,” Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

The monitoring program for CCS projects should be tailored to the specific conditions and risks at the sequestration site. For example, if the project is in a depleted oil reservoir with a well-defined cap rock and sequestration trap, the most likely pathway for leakage is the injection well itself or perhaps orphaned or abandoned wells from former reservoir operations.[106] 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 sequestration reservoir contains natural gas or hydrogen sulfide ($H_2S$), these too may leak toward the surface if a leakage path is established. Since natural gas is flammable and $H_2S$ is highly toxic, these gases pose a much 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 hydrocarbons may 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 widespread in the oil and gas industries, and the costs for these technologies are well constrained. In comparing costs of individual technologies within this group, 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 CCS projects. Benson and others estimated life-cycle monitoring costs for two scenarios: (1) sequestration in an oil field with EOR, and (2) sequestration in a saline formation.[107] 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

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[106] Benson, S., et al., 2002a, op. cit.

[107] Benson, S., et al., 2005, op. cit.

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 per ton $CO_2$. For the enhanced program, the undiscounted cost was \$0.27 – \$0.30 per ton $CO_2$.

Monitoring of off-shore sequestration projects will involve many of the same techniques used in on-shore projects. However, differences in operations in an 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. The cost effectiveness of various options for seabed monitoring has not been determined.

## Case Studies and Pilot Projects

Several CCS 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.[108] These projects have shown that many of the methods described here can play a valuable role in ensuring safe and effective geologic sequestration of $CO_2$.

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[108] Benson S. and L. Myer, 2008, "PIER white paper on *Monitoring to Ensure Safe and Effective Geologic Storage of Carbon Dioxide.," Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

# CHAPTER 7: Risks and Risk Management

Geologic sequestration 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 sequestration. The PIER white paper by Price, et al., provided the foundation for this chapter.[109]

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.[110] Given the long time scales 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, intervals also selected by the Weyburn EOR project.[111]

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 sequestration reservoirs.[112]

## 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.[113]

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[109] Price, P.N., T. McKone, and M.D. Sohn, 2008, "PIER white paper on Carbon Sequestration Risks and Risk Management,". *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

[110] Ibid.

[111] Ibid.

[112] <http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/>.

[113] Price, P.N., 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:

- What can go wrong?
- How likely is it to happen?
- What are the consequences?[114]

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 mitigates or facilitates 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 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."[115]

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:

1. Identify all of the scenarios in which the negative effects of the hazard would be realized
2. Quantify the negative consequences associated with each scenario
3. Assess the magnitude and sources of uncertainty that limit the precision of the estimates in parts (1) and (2)[116]

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[114] Kaplan, S. and B. J. Garrick, 1981, "On the Quantitative Definition of Risk," *Risk Analysis*, v. 1, No. 1, pp. 11–27.

[115] Society for Risk Analysis web site, 2007, <http://www.sra.org/resources_glossary.php>.

[116] Price, P.N., et al., op. cit.

For hazard scenario identification, a Features-Events-Processes, or 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.[117] Probabilistic approaches, such as complementary cumulative distribution functions, which calculate reasonable expectations for ranges of parameter variability and for conceptual or scenario uncertainties, also could be used.[118]

## 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.[119] 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.[120]

$CO_2$ 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 1,000 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.

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 1,500 to 3,000 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 $CO_2$. Above 5 percent, the effects

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[117] <http://www.quintessa.org/consultancy/index.html?co2GeoStorage.html>.

[118] 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.

[119] <http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/>.

[120] Price, P.N., et al., op. cit.

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.[121]

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 places like 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 exists and merits additional research.[122]

## 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 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.[123]

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

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[121] Ibid.

[122] Ibid.

[123] Ibid.

## 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.[124] 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.[125]

Effective policies are possible under conditions of uncertainty, provided that the uncertainty is taken into account.[126, 127] In order to make risk assessment consistent with such an approach, it 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 (for example, site planning), a variety of possible scenarios (for example, a range of realizations in sequestration reservoir simulations), actions that are robust to uncertainties (for example, conservative requirements for well completions), actions that are informative to reducing uncertainty (for example, 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:

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[124] Ibid.

[125] Ibid.

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

[127] Ludwig, D., R. Hilborn, and C. Walters, 1993, Uncertainty, Resource Exploitation, and Conservation: Lessons Learned From History." *Science* 260, pp. 17-36, April, 1993.

- 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.[128]

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 and subsurface features should be included. Surface characteristics include: locations of sensitive ecosystems; surface lakes; topography; and locations of population centers. Subsurface characteristics include: potable groundwater resources; depth to the target reservoir; fault and fracture distributions; cap rock thickness; existing well locations; and other parameters as described in Chapter 5. In addition, project information, such as number of wells needed, distances and available pipeline right-of-ways between the $CO_2$ capture site and the sequestration site, should be provided.

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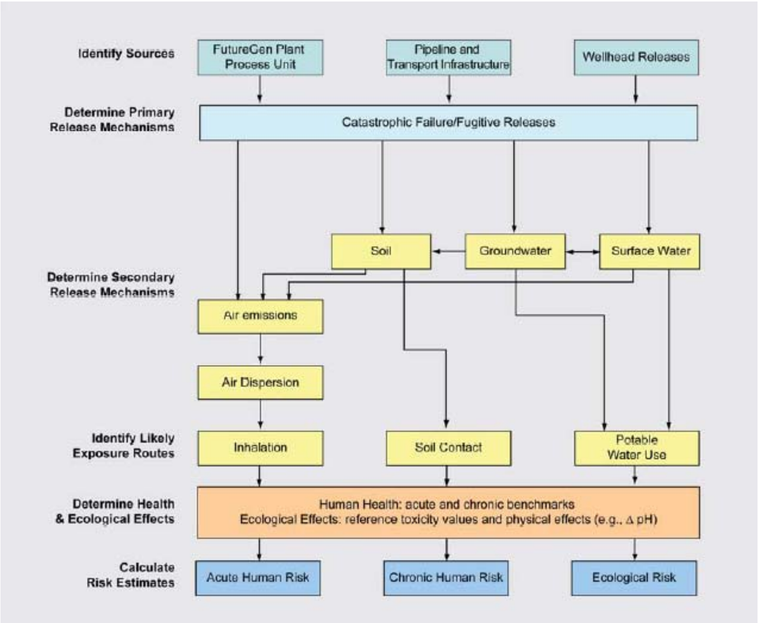
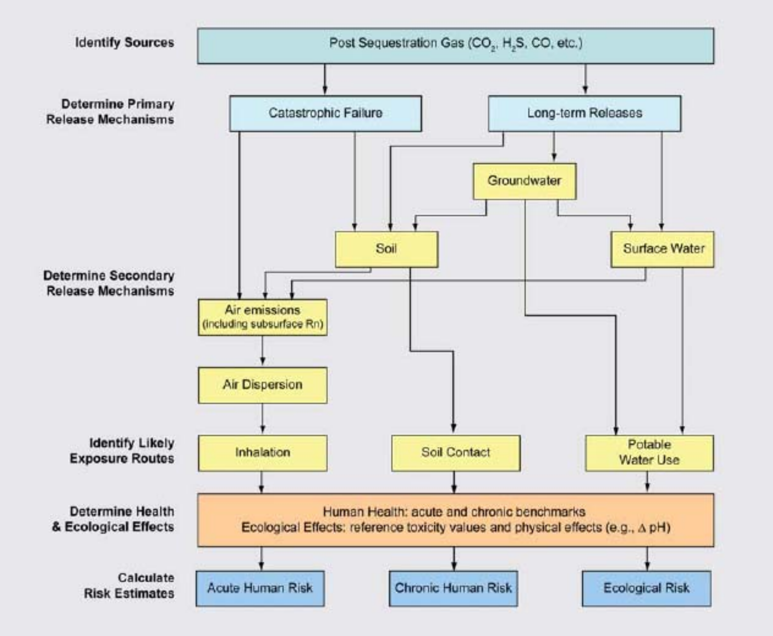
[128] <http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/>.

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



Source: 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**



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

The potential hazards associated with CCS have been studied extensively.[129, 130] 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 Chapter 5)
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 factors such as the sites used for sequestration, on technologies, and on operating practices used for injection. 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.[131]

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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[129] Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

[130] 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*.

[131] Price, P.N., 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.[132] 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 sequestration 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 [133]

## *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 $CO_2$ pipelines, have a fairly good safety record. Long-distance $CO_2$ pipelines in the U.S. total about 1,560 miles and produced no injuries or fatalities over a thirteen-year period.[134] 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 or other industrial point sources.[135]

Natural gas pipelines are, of course, different from $CO_2$ 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 $CO_2$ if humidity in the pipeline is low, and so it will likely be economically important to dry the $CO_2$ before transport (standard practice for $CO_2$-EOR pipelines). Outright breakage of

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[132] Ibid.

[133] Ibid.

[134] 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,* v. 29, No. 9-10, July – August 2004, pp. 1319-1328.

[135] Price, P.N., et al., op. cit.

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.[136]

A small pipeline leak could cause harm if the $CO_2$ pools in a depressed area. The concentration of $CO_2$ would be determined by the competition between the rate that $CO_2$ leaks from the pipeline and enters the depression area and the rate that $CO_2$ 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 $CO_2$ 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 $CO_2$ 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 $CO_2$ 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 $CO_2$, as is done with natural gas, to allow people to easily notice small leaks

## *Scenario 2: Leakage from Geological Sequestration 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 under unusual conditions. However, in general, slow discharges are not likely to cause death or property damage.

Human, animal, and plant fatalities from $CO_2$ have occurred near hot springs and fumaroles. The area around Mammoth Mountain, California, provides a good illustration. Mammoth Mountain is a young volcano. In 1990, following a series of small earthquakes the previous year,

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[136] Ibid.

$CO_2$ 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 $CO_2$.

Contrasting examples are found in the types of settings that are more appropriate to CCS. Over the long history of $CO_2$-EOR operations in the U.S., there are no documented examples of slow leaks that caused human fatalities. Another well-studied example of $CO_2$ leaks to the surface is "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 $CO_2$ mixed with water during a two-hour eruption. Terrain near the geyser is fairly flat, and does not have depressions that tend to accumulate $CO_2$. 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.[137]

## 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 of $CO_2$ per year. More than 438,000 tons of $CO_2$ per year 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 numbers of 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 1,700 people; in 1985, a smaller release from Lake Monoun killed over 30 people.[138] For comparison, a 1,000 MW coal-fired power plant emits about 30,000 metric tons of $CO_2$ 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 CCS projects today.

There have been attempts to compare CCS reservoir leakage risk to the risks associate with Lake Nyos.[139] However, not all natural systems are appropriate risk analogs for $CO_2$ sequestration.[140]

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[137] Bogen, K., E.A. Burton, S. J. Friedmann, and F. Gouveia, 2006, "Source Terms for $CO_2$ Risk Modeling and GIS/Simulation Based Tools for Risk Characterization." *Proceedings of the 8th International Meeting on Greenhouse Gas Technology (GHGT-8)* Tronheim, Norway.

[138] Benson, S.M., 2002a, op. cit.

[139] Ibid.

Geologic sequestration targets formations that lie deep in sedimentary basins within tectonically stable geologic environments that 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.[141] $CO_2$ migration in fractures through hundreds of feet 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.[142]

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 Sequestration 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.

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

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[140] *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>.

[141] Benson, S.M., 2002a, op. cit.

[142] Ibid.

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 Underground Injection Control program regulations was put in place and, since that time, no incidents of drinking-water contamination have been reported for wells regulated by the program.[143]

However, from a risk assessment standpoint, the hazardous waste injection analog is not applicable to $CO_2$ because (1) the quantity of $CO_2$ that would be injected into sequestration sites dwarfs the amount of toxic material injected into waste storage sites; (2) $CO_2$ is buoyant, whereas most toxic material injected into waste wells is approximately neutral; and (3) $CO_2$ is far less toxic than most materials that are injected for hazardous waste disposal. The IPCC report, as cited in Chapter 5, provides a list of criteria to protect groundwater resources.

### *Scenario 4: Leakage from Geological Sequestration to Fossil Fuel Assets*

If $CO_2$ from CCS projects migrates into fossil fuel reservoirs apart from the sequestration 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 a hundred years or more 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 any geologic phenomena. This issue is discussed in greater detail in Chapter 8.

In discussing climate change risk, however, the relative climate risk from CCS leakage has to be compared to risks associated with other GHG mitigating technologies, and to the risks

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[143] Ibid.

associated with not sequestering $CO_2$ at all. While evaluation of such risks has been the subject of much debate, there is little data available yet to allow quantitative comparisons.

# 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 for CCS establish contingency plans to mitigate and remediate any situation in which public health, economic activity, or the environment could be negatively affected by releases of $CO_2$. [144] The PIER white paper by Kuuskraa provided the foundation for this chapter.[145]

Actions central to preventing and correcting leakage of $CO_2$ from geological formations include a rigorous site selection process, assuring well integrity, 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.[146] If sustained $CO_2$ leakage were to occur to any significant degree by any pathway, the risks of unintended consequences from a CCS project would increase.[147]

Should unacceptable project risk arise, existing oil and gas field mitigation and remediation practices and technologies are sufficient to address most of the concerns related to $CO_2$ injection and sequestration in association with EOR. Many of these practices would also be directly transferable to CCS projects without EOR. Nonetheless, further studies should address longer-term $CO_2$ sequestration monitoring, leak detection, and mitigation/remediation at spatial and temporal scales longer than those for EOR operations. Another close analog for $CO_2$ sequestration, 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 recycling, wellbore remediation, well re-plugging, and in extreme cases, reservoir abandonment and relocation.

A high priority for future work would be development of procedures for identifying and then sealing or avoiding an imminent failure in the reservoir seal or cap rock. Equally valuable would be work on materials selection and well procedures. More also should be done to

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[144] Kuuskraa, V., 2008, “PIER white paper on Overview of Mitigation and Remediation Options for Geological Storage $CO_2$.,” *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

[145] Ibid.

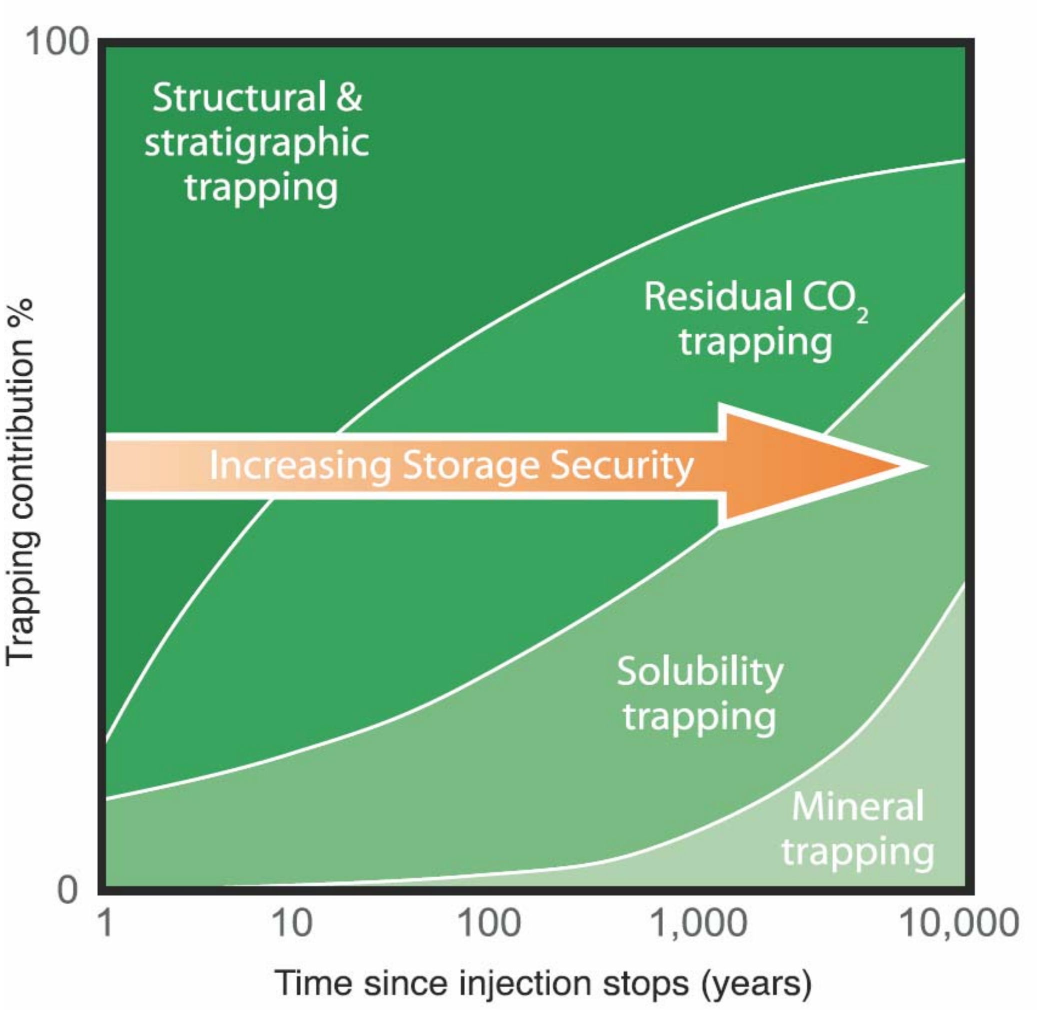
[146] Ibid.

[147] Ibid.

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 $CO_2$ sequestration 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 CCS, assuring that $CO_2$ remains effectively sequestered. In this context, it is important to recall previous discussions (see Chapter 5) of sequestration mechanisms which suggest that the security of sequestration increases over time (Figure 11).

**Figure 11: $CO_2$ Sequestration Trapping Mechanisms and Increasing Sequestration Security with Time**



Source: Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

## Background

With thorough site assessment, rigorous monitoring, and a proactive leakage prevention and remediation strategy, large-scale and widespread use of geologic sequestration 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, perhaps a close analog for $CO_2$ sequestration. 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 sequestration of $CO_2$.
- There is only one in-depth study of remediation experiences and "lessons learned" for the analogous activity in the natural gas storage industry. The work by Perry[148] provides original data and thorough investigation of this topic, including its relevance to $CO_2$ sequestration.

Further study of the natural gas storage industry may provide relevant analogs for remediation experiences, practices, and "lessons learned." Natural gas storage facilities may be owned and operated by public utilities or privately held. These storage facilities, designed to help meet seasonal gas demand and improve the efficiency of securing gas supplies, are regulated by the CPUC. Injection wells for natural gas storage fall under the U.S. EPA Underground Injection Control program.

Natural gas has been stored and recycled in geologic formations for nearly 100 years. Approximately 600 U.S. storage reservoirs, containing nearly 8 trillion cubic feet of natural gas (equal to about 2 billion metric tons of $CO_2$ storage volume), help meet peak natural gas demand during the winter and provide a repository for excess natural gas production during the summer. The in-depth survey of U.S. gas storage operations by Perry identifies 10 examples of leakage from natural gas storage facilities, mostly occurring prior to 1970 before the use of modern site appraisal and well completion practices.[149] 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 7.

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[148] Perry, K., 2003, *Natural Gas Storage Experience and $CO_2$ Storage*, report prepared for the $CO_2$ Capture Project by the Gas Technology Institute, July 2003.

[149] Ibid.

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

| **Field Type and Location** | **Type of Leak** | **Remediation Action Taken** |
|---|---|---|
| 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 |
| 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, V., PIER white paper on *Overview of Mitigation and Remediation Options for Geological Storage $CO_2$.*

### *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 1960s, 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 without further incidents 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.

- 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 1980s, 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 1970s, 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. About 60 million cubic feet of gas in the man-made salt cavern escaped and traveled toward Hutchinson, a nearby 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 $CO_2$ sequestration sites, namely:

- Seal failure (capillary failure, faults and fractures)
- Bypassing of the 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 (Figure 12). In addition, the CO2CRC has matched each potential escape mechanism with a potential remediation measure.

### *Reservoir Aspects of Remediation*

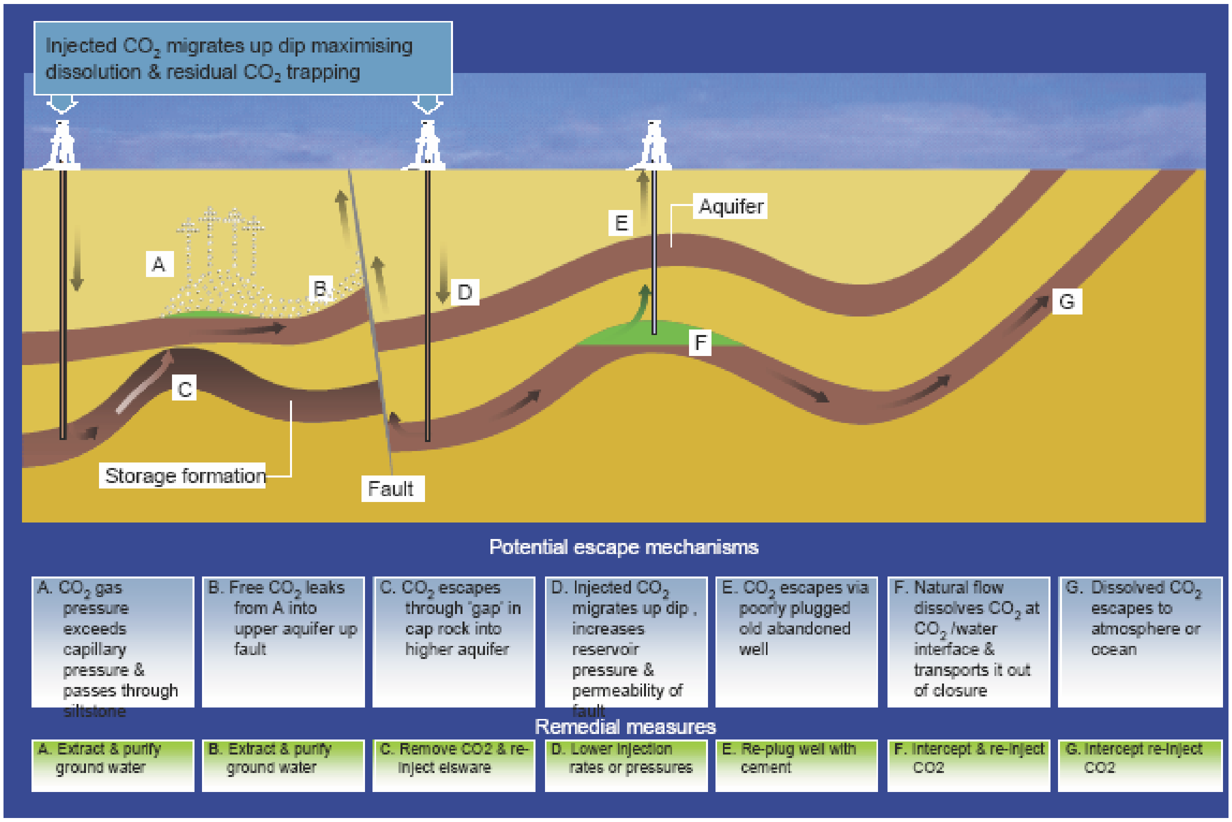
All CCS projects will be designed and conducted with the goal and expectation that no significant leakage of $CO_2$ will occur. As noted in Chapter 5, proper site characterization is the first defense against unforeseen leakage. But, unexpected things can and do happen. The remediation actions, should 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 likely be effectively contained, easy to monitor, and offer good chances for successful remediation of leakage should it occur. 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 sequestration reservoir, remediation may not be necessary. 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 rates 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 loss through venting. Contingency plans to deal with leakage will be necessary for each $CO_2$ sequestration site in oil and gas formations, so that remediation action can be taken promptly should leakage occur.

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

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



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

## 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 may be necessary to establish practices for post-closure $CO_2$ monitoring, leak detection and mitigation/remediation after EOR/EGR operations.

#### Formations without Structural Closure

$CO_2$ stored in formations that lack structural closure will be much more challenging to access and recover should remediation be necessary. Over time, $CO_2$ injected into a formation may become 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 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 $CO_2$ leak 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. Contingency plans to deal with hazards resulting from leakage events, should they occur, also should be developed.

## 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 $CO_2$ sequestration. 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 in the area where the leak is occurring
- Increase the pressure in the geologic interval (generally a shallower reservoir) into which the leak is occurring
- Intercept the $CO_2$ plume and extract the $CO_2$ from the reservoir before it leaks, and, if possible, reinject the $CO_2$ 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:

- 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 sequestration zone. (Ideally, this characterization should have been done as part of the site selection process, and should be readily available.) The secondary $CO_2$ accumulation settings will generally consist of permeable, porous formations above the sequestration formation, with some type of impermeable cap rock overlying them.
- Conduct Integrated Leakage and Accumulation Studies. 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.[150]
- Drill Shallow $CO_2$ Recovery Wells. Based on this information, one or more wells may be drilled in shallower zones to locate and recover any $CO_2$ migrating to those zones. This process may 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 may also be controlled by lowering the pressure in the sequestration zone, or by creating a hydraulic barrier by increasing the pressure up-gradient from the leak.
- Remediate or Reconfigure Sequestration Site. The final mitigation step is to plug the leak if it can be located or to reconfigure the sequestration 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.

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

## Table 8: Remediation Options for $CO_2$ Leakage from Geological Sequestration Projects

| **Leakage** | **Remediation Options** |
|---|---|
| Leakage Through Cap Rock | Lower injection pressure by injecting at a lower rate or through more wells;<br>Lower formation pressure by removing water or other fluids from the sequestration reservoir;<br>Intersect the leakage with extraction wells in the vicinity of the leak;<br>Create a hydraulic barrier by increasing pressure upstream of the leak;<br>Stop $CO_2$ injection and produce from the sequestration reservoir and reinject into a more suitable sequestration structure. |
| Leakage Out of Confining Structure | Stop $CO_2$ injection;<br>Begin investigation into the source of the leak immediately; check wellbores for anomalous pressures, run well logs on suspect wells;<br>Review local geology for the most likely areas of $CO_2$ accumulation above the sequestration zone. Integrate all information on hand, such as the surface location of leak in relation to structural high points in shallower zones;<br>Drill in the shallower zones to locate and recover any migrating $CO_2$;<br>Create a barrier by increasing the pressure upstream from the leak. |
| Leakage Due to Lack of Well Integrity | Repair previously drilled leaking wells with standard oil and gas field well recompletion techniques;<br>Repair leaking $CO_2$ injection wells by squeezing cement behind the well casing to plug leaks behind the casing;<br>Plug and abandon injection wells that cannot be repaired by traditional methods. |
| 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;<br>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, 2005, "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.

### Remediating Associated Impacts of $CO_2$ Leakage

Once the source of a $CO_2$ leak has been identified and mitigated, the next step is to examine how to remediate, when required, the associated effects of $CO_2$ leakage. Options include:

1. Remediating Accumulation of $CO_2$ in Groundwater. $CO_2$ contamination of groundwater can be remediated by the "pump-and-treat" method in which water is pumped to the surface and aerated to remove the $CO_2$. The water can then either be pumped back underground or used for other purposes. $CO_2$ migrating into a drinking water reservoir may leach minerals along the way, adding salts and other chemicals to the water. Treatment to remove such constituents is more involved and expensive, but could also be accomplished with the "pump-and-treat" approach.
2. Remediating $CO_2$ Leakage into the Vadose Zone. Vadose zones include rock and soil above the water table. Soil vapor extraction technology may be useful for removing $CO_2$ from this zone. Reactive transport simulation of several soil remediation scenarios show that large amounts of $CO_2$ would be readily removed from the vadose zone using this technology.[151]
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. Efforts may include using dispersal equipment such as fans and $CO_2$ detectors. In addition, shallow wells may be drilled to intercept and vent the migrating $CO_2$.

## Mitigation and Remediation Costs

A $CO_2$ mitigation and remediation strategy must be integrated into the overall CCS project plan. The potential need for remediation will be lessened if a rigorous geologic and engineering analysis is performed up front as part of sequestration 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 $CO_2$ sequestration site selection, project design, and implementation, particularly if the site has to be abandoned and the $CO_2$ transferred to an alternative site.

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[151] Zhang, Y, C.M. Oldenburg, and S.M. Benson, 2004, "Vadose Zone Remediation of $CO_2$ Leakage from Geologic Carbon Sequestration Sites." *Third Annual Conference on Carbon Capture and Sequestration.* Alexandria, Virginia, May 6, 2004.

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

| Issue | Options |
|---|---|
| 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 $CO_2$;<br>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;<br>$CO_2$ that has dissolved in the shallow groundwater could be removed, if needed, by pumping to surface and aerating to remove $CO_2$;<br>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. |
| Remediating Leakage into the Vadose Zone and 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;<br>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;<br>Since $CO_2$ is a dense gas, it can be collected in subsurface trenches and pumped, then released to the atmosphere or reinjected<br>Passive remediation techniques that rely on diffusion and 'barometric pumping' can be used to deplete one-time releases<br>Acidification of soils from $CO_2$ can be remediated by irrigation, drainage or agricultural supplements such as lime to neutralize the soil; |
| Remediating Large Releases 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;<br>For $CO_2$ releases over a large area, dilution from natural atmospheric mixing (wind) will be the only practical method for diluting $CO_2$;<br>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. |
| Remediating Accumulations Indoors | 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, 2005, "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.

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 metric ton).

The costs associated with the various activities for remediating $CO_2$ leaks are summarized below. The discussion of costs assumes that an adequate monitoring and leak detection system has already been put into place. It estimates costs for possible approaches and does not intend to propose any specific protocols for detection and remediation.

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 sources for $CO_2$ leaks will be either orphaned or abandoned wells or 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 leakage from a single orphaned or abandoned well (or even a group of wells) will be modest, about $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) could 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 a wellbore-based leak detection procedure would be $300,000 per well. (For the illustrative example, 10 to 20 wellbores are assumed to be logged during the 50-year life of the project, assuming leakage is detected.)

The process for locating geologically based leaks of $CO_2$ from the sequestration reservoir is much more challenging. The costs will be a function of the size of the leakage area, the conditions at the surface overlying the formation (industrial, suburban, farmland, sensitive ecosystems, etc.), and, perhaps most important, the requirements imposed by regulatory authorities upon evidence of leakage. 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 be conducted over the area where surface $CO_2$ leakage has been detected. In addition, new leak detection wells (potentially horizontal wells) may be drilled and tested to more precisely locate the source for the $CO_2$ leak and, ultimately, capture the leaked $CO_2$ for reinjection. (The illustrative example assumed a need for one to two 20-square mile seismic surveys and a cost of \$150,000 per square mile for 3-D seismic, including processing and interpretation. It also assumed 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 orphaned 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 average \$40,000 to \$50,000, 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 may require placing and cementing a smaller diameter liner inside the well casing. The cost 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 injection well. New well costs can range from \$500,000 for a shallow 3,000-foot well, to over \$5 million for a deep 15,000-foot 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 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 and oil and gas 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 for well plugging to very high costs for drilling a directional well 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, if necessary, to inject water into a formation above the cap rock to attempt 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 a 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 CCS 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 Sequestration Case*

To further illustrate the costs of remediation, a sample sequestration site scenario was created. The main assumptions are as follows:

- The site serves one new 1,000 MW coal-fired power plant, with 6 MMT 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 site has 20 new $CO_2$ injection wells, each capable of injecting 1,000 metric tons of $CO_2$/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 at the end of 50 years.

Based on this example, the overall costs for leak prevention and leak remediation are shown in Table 10.

The estimated costs for a comprehensive $CO_2$ leak detection and remediation program are on the order of $35 million to $66 million per site, unless the problem is so severe that the original $CO_2$ sequestration site needs to be abandoned. Assuming the injection of 180 million metric tons 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 remediable, the costs would become large and include establishing a new sequestration facility and transporting some or all of the $CO_2$ to the new facility.

### Table 10: Representative Costs for Leak Mitigation and Remediation

| **Remediation Activity** | **Costs ($ Million)** | **Assumptions** |
|---|---|---|
| 1. Locating Sources of $CO_2$ Leaks | | |
| Locating orphaned wells | $1.0 to $2.0 | 5 to 10 leak location surveys |
| New $CO_2$ injection wells | $3.0 to $6.0 | 10 to 20 sets of diagnostic logs |
| 2. Well Plugging | | |
| Plugging abandoned or orphaned wells | $1.0 to $2.0 | Includes plugging of 10 to 20 wells |
| 3. Well Problems | | |
| Remediation | $2.0 | Includes remediating 20 $CO_2$ injection wells |
| New wells | $7.0 to $14.0 | Includes drilling 2 to 4 new $CO_2$ injection wells |
| 4. Geologic/Cap Rock Leakage | | |
| Diagnostic survey | $3.0 to $6.0 | Includes 1 to 2 20-square mile 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 sequestration site and build a new site |

Source: Kuuskraa, V., 2008, "PIER white paper on Overview of Mitigation and Remediation Options for Geological Storage $CO_2$.," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

## $CO_2$ Leakage Prevention/Remediation Strategies and Needs

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

### *1. Selecting Favorable Sequestration 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 must be fully addressed for evaluating the favorability of a sequestration site using an extensive set of the tools and procedures.

## 2. Placing Emphasis on Well Integrity

There are three key priorities for ensuring well integrity at a $CO_2$ sequestration site.

- Identifying the older, abandoned wells in the vicinity of the proposed 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.
- Properly closing the site at the end of $CO_2$ injection, including plugging all $CO_2$ injection and observation wells to promote sequestration integrity.

## 3. Installing and Maintaining a Site-Appropriate Monitoring System for a $CO_2$ Sequestration Site

First and foremost, the $CO_2$ monitoring system should serve as an "early warning system" of any impending $CO_2$ leakage. For this, there is need for a risk-based number 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 should be used for assuring wellbore integrity.

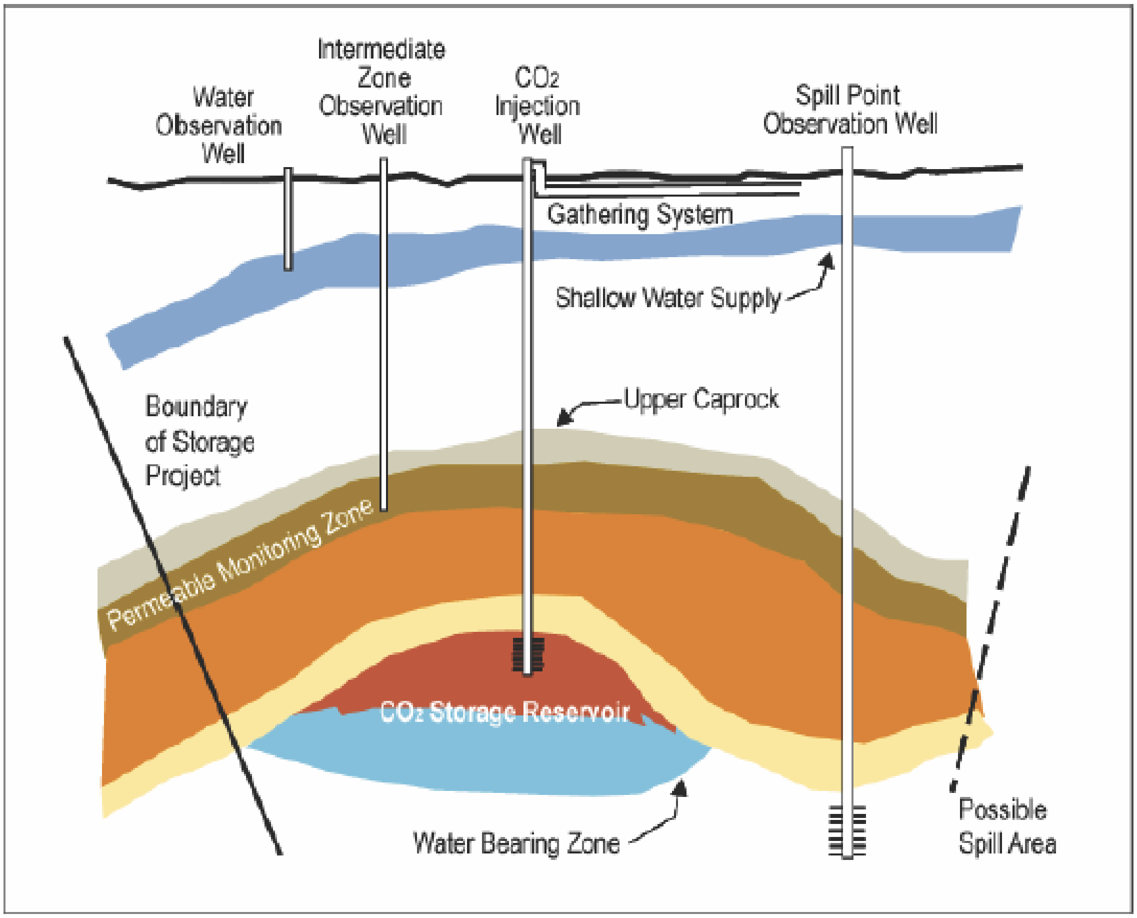
## 4. Conducting a Phased Series of Reservoir Simulation-Based Modeling to Track and Project the Location of the $CO_2$ Plume

Based on experiences to date, multiple stages of reservoir simulation are recommended to support leak prevention and remediation efforts in $CO_2$ sequestration. The first stage of reservoir simulation would be undertaken during the initial site selection process to predict the anticipated movement and location of the $CO_2$ plume. The second stage 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 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 would be iterative and used to predict trapping and immobilization of the $CO_2$ plume. These simulations could be used to determine whether site decommissioning criteria are met and to design future monitoring programs.

## 5. Establishing a Contingency Plan/Strategy for Remediation

A $CO_2$ leakage mitigation and remediation plan must be in place and immediately put into operation once a leak in the $CO_2$ sequestration field has been detected.

**Figure 13: Monitoring in Natural Gas Storage Fields**



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

## Recommendations for Improving $CO_2$ Leakage Remediation Technology

Clearly, this overview 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, they should be added to the manual to keep it current.
- Study remediation in analog industries. Given their value as relevant analogs to $CO_2$ sequestration, undertaking additional studies of the remediation experiences, practices, and lessons learned in the natural gas storage industry and EOR industry

would benefit CCS. Fruitful areas for exploration would be further detailed work on leak source identification and the costs of remediation.

- Invest in research and technology development in remediation for $CO_2$ leakage. Of high priority would be much more intensive investigations and field trials for identifying leakage from a failure in the cap rock and procedures for sealing it. Equally valuable would be work on materials and procedures for achieving greater well integrity.
- 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 must be done to develop cost-effective means for reliably locating and assessing the status of old, abandoned wells near a $CO_2$ sequestration site. An equally valuable approach 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 $CO_2$ sequestration. An important emphasis in these large-scale field tests would be establishing and testing an integrated system for $CO_2$ monitoring, $CO_2$ leak detection, and leakage 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 challenging, in part because no policy yet exists to establish a price for $CO_2$ in the marketplace. The costs of CCS include those associated with the additional equipment required to capture, transport, inject, and store $CO_2$, as well as the additional energy requirements that go along with each step. Additional issues that affect the economics of CCS include the proximity of $CO_2$ sources to suitable sequestration reservoirs, and whether emissions mitigation opportunities are viewed from a regional or in-state perspective. For new power plants, there may be a trade-off between locating power plants close to sequestration sites or close to the electric load.[152] Injection costs depend on the specific geological characteristics of the sequestration site.

The $CO_2$ price estimated to stabilize atmospheric concentrations at 550 parts per million by 2100, according to the IPCC, is $20 to $80 per metric ton of $CO_2$ by 2030, and $30 to $155 per metric ton of $CO_2$ by 2050.[153] Technologic advances could lower these price ranges by $15 per metric ton. The IPCC also estimates that a sustained or increasing real price over a period of decades of $20 to $50 per metric ton would be necessary to make greenhouse gas mitigation options economically attractive to the power sector by 2050. However, comparisons with current estimates of CCS costs are difficult because the IPCC's carbon stabilization estimates were made prior to the recent run up in construction and materials costs.

To be practical, CCS costs also must be competitive with the costs of other $CO_2$ emissions reduction options such as end-use efficiency improvement, renewables, and nuclear power. The run up in materials and construction costs has affected renewables and nuclear options as well as advanced coal power systems with CCS. For example, the Department of Energy reports an increase in the costs of construction for wind turbines over the last five years of over 50 percent.[154] Comparisons must be made using contemporaneous estimates. In addition, in comparing alternatives for power generation, it is important to consider the capabilities of each

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[152] Newcomer, A., and J. Apt, 2007, *Implications of generator siting for $CO_2$ pipeline infrastructure.* Carnegie Mellon Electricity Industry Center Working Paper CEIC-07-11 <www.http://wpweb2.tepper.cmu.edu/ceic/PDFS/CEIC_07_11_mos.pdf>.

[153] Solomon, S., D., Qin, M. Manning, R.B. Alley, T. Berntsen, N.L. Bindoff, Z. Chen, A. Chidthaisong, J.M. Gregory, G.C. Hegerl, M. Heimann, B. Hewitson, B.J. Hoskins, F. Joos, J. Jouzel, V. Kattsov, U. Lohmann, T. Matsuno, M. Molina, N. Nicholls, J. Overpeck, G. Raga, V. Ramaswamy, J. Ren, M. Rusticucci, R. Somerville, T.F. Stocker, P. Whetton, R.A. Wood and D. Wratt, 2007, "Technical Summary." In: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom, and New York, N.Y, USA.

[154] Wiser, R. and Bolinger, M., 2007, *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006,* U.S. Department of Energy, Energy Efficiency and Renewable Energy <http://www1.eere.energy.gov/windandhydro/pdfs/41435.pdf>

alternative to meet baseload and peak demand. Making these comparisons is beyond the scope of this preliminary report.

Unlike some alternatives for mitigation, CCS technology has the flexibility to achieve reductions in many locations and major economic sectors. CCS, like any other new process technology, also should experience a decline in costs as lessons learned, efficiency gains, technology improvements, and economies of scale from early projects are applied. Although the component technologies for CCS are commercial today, they typically have not been applied to the most economically suitable types of industrial sources, at the necessary scale, or in the integrated manner needed to optimize the technology in terms of cost and performance.

## Capture Economics

For many $CO_2$ sources, the capture cost is the largest cost element and the best starting point for evaluating and ranking the cost of CCS projects. In general, because the capital and operating costs for equipment depend on the volume of gas to be separated, and, in conventional methods for reporting, the costs are amortized across the amount of $CO_2$ captured, sources with lower $CO_2$ concentrations in their exhaust gases have higher costs per unit of $CO_2$ removed. Because economies of scale apply, larger $CO_2$ sources should have lower costs per unit of $CO_2$ removed. Capture costs per unit of $CO_2$ removed will typically be lowest for new construction; whereas the comparable costs for retrofits will be significantly higher. Costs—especially for retrofits—are also highly site-dependent.

### *Power Plants*

Detailed engineering design studies have been conducted for coal combustion- and gasification-based power plants with $CO_2$ capture. Although these studies provide a sound basis for cost estimates in terms of dollars per metric ton of $CO_2$ avoided, there may still be a large degree of uncertainty in cost estimates due to a number of factors. Every plant and its design parameters are unique, and projected costs found in the literature reflect this as values spanning a range. For simplicity, costs given below are indicative values rather than as ranges, but in all cases there is some uncertainty surrounding the estimates.

Given that this is a preliminary study, certain assumptions were made to simplify the approach for estimating $CO_2$ capture costs. As a starting point, costs for CCS in a U.S. Gulf Coast construction environment were developed using design studies from 2000 to 2004, a period of unusual cost stability. Costs were updated to 2007 dollars, adjusted to account for recent construction cost increases nationally, indexed to reflect the California construction cost environment, and modified further to account for costs associated with first-of-a-kind plant applications. For example, to account for the California construction cost environment, capital costs were indexed upward by 25 percent relative to the Gulf Coast construction environment. The resulting adjusted values still provide 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.

For each plant, a consistent set of design and operating parameters also was assumed:

- An 85 percent capacity factor (baseload duty) for all plants, with and without $CO_2$ capture
- $CO_2$ capture at 90 percent for all capture plants
- Primary commercial generating technologies and use of industry-typical procedures (as recommended by the Electric Power Research Institute) to calculate the levelized cost of electricity and cost of $CO_2$ avoided per MW
- New 500 MW plants
- Two coals (Illinois # 6 and Powder River Basin) and natural gas as fuels

For less mature technologies, the costs should be representative of an Nth plant, with N equal to a small number, on the order of 5 to 7. Because CCS is in its very early stages of application, particularly in power generation, most operations will essentially be first-of-a-kind. In this case, the capital costs are expected to be somewhat higher than those for the Nth plant. To account for some of the uncertainties associated with this situation, those technologies that would be first-of-a-kind applications were given a 10 percent additional contingency. Consequently, cost projections for an initial or first-of-a-kind plant are higher than for an “Nth plant,” as the next generation of CCS systems would apply lessons learned from initial projects to reduce costs.

The $CO_2$ avoided cost 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 $ per MWh) between a reference plant without $CO_2$ capture and a $CO_2$ capture–equipped plant divided by the difference in $CO_2$ emissions (in tons of $CO_2$ per MWh) of the same two plants. Results of these calculations for three types of power plants, with two different fuel sources for the coal plants, are shown in Table 11.

Table 12 summarizes the influence of the different factors discussed above on the costs of $CO_2$ avoided for the three types of power plants in Table 11 and also for fired heaters at other industrial plants. For example, for Powder River Basin coal with integrated gasification combined cycle, the $CO_2$ avoided cost increases from about $34 to $47 per metric ton when California construction cost environment and first-of-a-kind factors are considered. 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. It should be noted that $CO_2$ transport and injection costs are not included in these numbers.

## Table 11: Coal- and Natural Gas-Based Power Generation Performance with and without $CO_2$ Capture in the California Construction Cost Environment and Accounting for First-of-a-Kind Technology Applications

| FEED | Bituminous Coal, Illinois # 6 | | | | Subbituminous Coal, Powder River Basin | | | | Natural Gas | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Technology** | **Supercritical PC** | | **IGCC** | | **Supercritical PC** | | **IGCC** | | **NGCC** | |
| | **w/o capture** | **w/ capture** | **w/o capture** | **w/capture** | **w/o capture** | **w/ capture** | **w/o capture** | **w/capture** | **w/o capture** | **w/capture** |
| **PERFORMANCE** | | | | | | | | | | |
| Heat rate (1), Btu/kWh | 8,868 | 11,652 | 8,891 | 10,942 | 9,177 | 12,149 | 9,510 | 11,692 | 6,808 | 7,977 |
| Generating efficiency (HHV) | 38.5% | 29.3% | 38.4% | 31.2% | 37.2% | 28.1% | 35.9% | 29.2% | 50.2% | 42.8% |
| Feed, kg/h | 184,894 | 242,950 | 185,376 | 228,155 | 237,057 | 313,826 | 245,641 | 302,004 | 66,810 | 78,197 |
| $CO_2$ emitted, kg/h | 414,903 | 54,518 | 411,824 | 50,686 | 418,958 | 55,464 | 429,788 | 52,840 | 184,062 | 21,565 |
| $CO_2$ captured at 90%, kg/h (2) | 0 | 490,662 | 0 | 456,174 | 0 | 499,172 | 0 | 475,564 | 0 | 194,088 |
| $CO_2$ emitted, g/kWh | 830 | 109 | 824 | 101 | 838 | 111 | 860 | 106 | 368 | 43 |
| | | | | | | | | | | |
| **COSTS*** | | | | | | | | | | |
| Total Plant Cost, $/kWe | $2,050 | $3,360 | $2,430 | $3,170 | $2,230 | $3,640 | $2,740 | $3,640 | $755 | $1,490 |
| Total Capital Required, $/kWe | $2,380 | $3,890 | $2,900 | $3,770 | $2,590 | $4,210 | $3,260 | $4,330 | $845 | $1,670 |
| | | | | | | | | | | |
| Inv. Charge, ¢/kW-h @ 15.1% (3) | 4.16 | 6.81 | 4.93 | 6.43 | 4.52 | 7.38 | 5.56 | 7.38 | 1.53 | 3.02 |
| Fuel, ¢/kWh | 1.33 | 1.75 | 1.33 | 1.64 | 0.92 | 1.21 | 0.95 | 1.17 | 4.08 | 4.79 |
| O&M, ¢/kWh | 0.75 | 1.60 | 0.90 | 1.05 | 0.75 | 1.60 | 0.90 | 1.05 | 0.39 | 0.68 |
| **COE, ¢/kWh** | **6.24** | **10.16** | **7.16** | **9.12** | **6.19** | **10.20** | **7.41** | **9.60** | **6.01** | **8.49** |
| | | | | | | | | | | |
| **Cost of $CO_2$ avoided[4] vs. supercritical PC for same coal w/o capture (ref case), $/tonne** | | **54.4** | | **39.6** | | **55.1** | | **46.6** | | **76.4** |
| **Reference Case** | | **Ill. #6, SCPC w/o capture** | | **Ill. #6, SCPC w/o capture** | | **PRB, SCPC w/o capture** | | **PRB, SCPC w/o capture** | | **NGCC w/o capture** |
| | | | | | | | | | | |
| **Basis**: 500 MWe plant net output, 85% capacity factor: Illinois # 6 coal (61.2% wt C, 10,900 Btu/lb HHV, $1.50/mm Btu), PRB coal (48.2% C, 8340 Btu/lb HHV, $1.00/mm Btu); NG @ $6.00/mm Btu | | | | | | | | | | |
| (1) efficiency = 3414 Btu/kWe-h/(Heat rate) | | | | | | | | | | |
| (2) 90% removal used for all capture cases, consistent with EPRI | | | | | | | | | | |
| (3) Annual carrying charge of 15.1% from EPRI-TAG methodology, based on 55% debt @ 6.5%, 45% equity @ 11.5%, 38% tax rate, 2% inflation rate, 3 year construction period, 20 year book life, applied to total plant cost to calculate investment charge | | | | | | | | | | |
| (4) Does not include costs associated with transportation and injection/storage which are on average $8.00/tonne CO2. NGCC is W vs. WO capture. | | | | | | | | | | |
| * Capital Numbers updated to 2007 with CE Plant Cost Index; increased to California Cost Environment using an additional factor of 1.25, and added expected FOAK Costs | | | | | | | | | | |

Source: Katzer, J. and H. Herzog, 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

Costs analyses were performed for three types of power plants (PC—pulverized coal; IGCC—integrated gasification combined cycle; and NGCC—natural gas combined cycle) and with two different fuel sources for the coal plants (a subbituminous Powder River Basin coal and a bituminous Illinois #6 coal). Metric tons are denoted as "tonne."

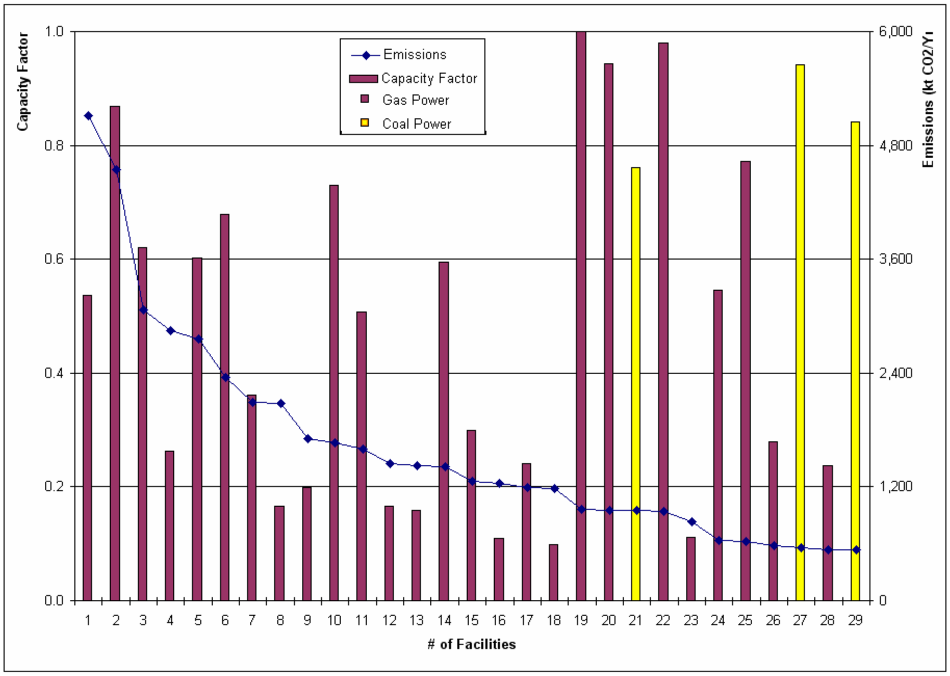
## Table 12: Estimated $CO_2$ Avoided Costs for New Facilities

| | $CO_2$ Avoided Cost, $ per tonne | | | |
|---|---|---|---|---|
| **$CO_2$ Source** | **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** | | | | |
| | | | | |

Source: Katzer, J. and H. Herzog, 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

Calculations of avoided costs with accounting for the California construction cost environment and first-of-a-kind contingencies. Metric tons are denoted as "tonne."

## Figure 14: Capacity Factor and $CO_2$ Emissions for Fossil Fueled Power Plants in California



Source: Katzer, J. and H. Herzog, 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

Power plants in California with $CO_2$ emissions greater than 500,000 tons per year.

Figure 2, in Chapter 3, shows the current $CO_2$ emissions from the largest facilities in California: 30 facilities emit more than 1 MMT $CO_2$ per year each; only two of these emit about 5 MMT $CO_2$ per year. The 48 facilities that each have emissions greater than 0.5 MMT $CO_2$ per year contribute about 80 percent of the in-state large industrial facility 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 sequestration sites.

For power plants, another important cost factor is the capacity factor. As described above, this study used a capacity factor of 85 percent. Operation at lower capacity factors results in higher costs on a per ton of $CO_2$ avoided basis. For the 28 power plants shown in Figure 2, only six operated at 85 percent or greater capacity in 2004, whereas 14 operated at 50 percent or less (Figure 14). [Note: Coal-fired power plants in neighboring states serving California loads tend to operate at high capacity factors.] In general, the capacity factor is determined on a plant's dispatch order based on marginal operating cost. In the absence of a carbon price, adding CCS to a power plant raises the marginal operating cost, thereby lowering the capacity factor.

For retrofits of existing plants or facilities, several factors strongly affect the economics of a project. These include unit size, operating efficiency, and emissions controls, as well as land availability and the degree of space constraints at the plant site. Existing plants are frequently smaller, have lower generating efficiency, and may have less efficient emissions control systems relative to new plants. The energy requirement for $CO_2$ capture is usually higher for retrofits because there are fewer opportunities in an existing plant for efficient heat integration with sorbent regeneration equipment. For power generation, plant output reduction could be as high as 40 percent for retrofits versus up to 30 percent reduction for new plants.[155] Note that this also implies more water use per unit of electricity produced. Existing plants that are not equipped for adequate $NO_X$ control or with a flue gas desulfurization system for $SO_2$ control must be retrofitted or upgraded for high-efficiency removal of these pollutants as a pretreatment system for the $CO_2$ capture and recovery system.

All these factors lead to higher overall costs for retrofits. If the original generating unit is fully paid off, the cost of electricity after retrofitting could range from slightly less than to somewhat more than that for a new, purpose-built, pulverized coal plant with integral $CO_2$ capture, depending on the capital carrying charge for the new plant.[156] However, an operating plant will usually have some residual value, and the reduction in plant efficiency and output, increase in footprint, 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 would be about 30 to 40 percent higher for retrofits than for purpose-built pulverized coal plants with $CO_2$ capture. For example, based on

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[155] Bozzuto, C.R., N. Nsakala, G.N. Liljedahl, M. Palkes, J.L. Marion, D. Vogel, J.C. Gupta, M. Fugate, and M.K. Guha, 2001, *Engineering Feasibility and Economics of $CO_2$ Capture on an Existing Coal-Fired Power Plant.* U.S. Department of Energy.

[156] Ibid.

an Alstom retrofit design study, an amine scrubber retrofit of a supercritical pulverized coal plant 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. In practice, retrofits require case-by-case detailed design-based examination.

### *Industrial Sources*

Table 13 compares the power plant costs of $CO_2$ avoided with the estimated avoided cost per metric ton of $CO_2$ for other large stationary industrial $CO_2$ sources in California, also accounting for the California construction environment and first-of-a-kind contingencies. The avoided cost is specific to the size indicated and will change with the scale of the industrial process unit. The calculations in Table 13 use a value near the upper end of the size range of California stationary $CO_2$ sources (see Chapter 3) and thus represent the low end of the range of potential costs per metric ton of $CO_2$ avoided for each application; for smaller flue gas streams and smaller natural gas combined cycle plants (<500 MW), the costs would be higher. Similarly, for smaller furnaces, boilers, and heaters, costs would be higher per unit of thermal energy or per ton of $CO_2$ removed. In most cases, the application will involve a retrofit of an existing process or equipment and, as noted above, this will increase the capital cost per unit of process output and the $CO_2$ avoided cost.

**Table 13: Estimated $CO_2$ Avoided Cost for Large Sources**

| 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**

Source: Katzer, J. and H. Herzog, 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

Cost analyses for integrated gasification combined cycle (IGCC) and supercritical pulverized coal (SCPC or PC) power plants using Powder River Basin (PRB) coal, natural gas combined cycle (NGCC) power plants, and other industrial sources. Calculations of avoided costs include accounting for the California construction cost environment and first-of-a-kind contingencies. Metric tons are denoted as "tonnes."

The numbers in Table 13 can be used to compare the relative costs for the set of source types in the table. For example, the $CO_2$ avoided cost estimated for fired heaters with $CO_2$ capture at refineries is about the same as for natural gas combined cycle power plants. The cost advantages of having a high-purity $CO_2$ process stream are clear, where $CO_2$ avoided costs drop to $10 per metric ton, one-fifth to one-seventh of the costs associated with other source types. However, costs will differ with each specific case, varying considerably depending on the size, location, and other parameters.

The numbers tabulated above are for the capture and compression costs only. To get a total life-cycle CCS cost, transport and injection adds, on average, $10 per metric ton of $CO_2$. If the sequestration site involves EOR, up to $20 per metric ton of $CO_2$ (the average rate paid in 2007 in the United States for $CO_2$ for EOR) could be subtracted to get the CCS cost.

## High-Purity Sources

As noted previously, there are a range of industrial sources that produce essentially pure $CO_2$ as an integral part of the process, and this 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 natural 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 state (for cost-effective transportation and volumetrically efficient storage). For a moderately large-scale stream of 1 MMT per year of $CO_2$ and an electricity price of $0.05/kWh, 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 CCS.

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 percent $CO_2$ by volume. Recent designs using pressure-swing absorption produce a $CO_2$ stream that is only about 50 percent $CO_2$ by volume.[157] Where the $CO_2$ stream is high purity, the incremental cost of capture is essentially the cost of 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 in association with oil refining, either in or near existing refineries. In the future, hydrogen production for vehicle fuel may also increase.

Natural gas processing 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

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

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 MMT of $CO_2$ per year and sequestering it in deep geologic formations. In the United States, about 6.5 MMT of $CO_2$ per year from natural gas processing are being used for enhanced oil recovery.[158] California has 31 gas processing facilities that may be candidates for CCS.

Ethanol production by fermentation is another process that produces a stream of pure $CO_2$ from the fermentors; installed capacity is on the increase. The $CO_2$ from such units can be captured simply by drying and compressing, although stream volumes are relatively small. Fermentation-related $CO_2$ emissions are about 3,480 metric tons per million gallons of ethanol. A typical plant will have a pure $CO_2$ emissions stream of about 0.2 MMT 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 with relatively low $CO_2$ concentrations. These flue gas streams, because of the small scale of current fermentation plants, also suffer from the higher costs associated with smaller units, and are expected to have an avoided $CO_2$ cost in excess of $80 per metric ton. California has four fairly large ethanol fuel production plants, and more are expected.

### Low-Purity 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 typically 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 that can use waste heat to regenerate the capture solution, with high $CO_2$ concentrations in the flue gas, or 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. Detailed engineering design data will be required to produce high-quality cost estimates. Simbeck, for example, estimates the costs for recovery of $CO_2$ from a 48.5 million standard cubic feet per hour industrial flue gas stream using amine scrubbing to be $72 per metric ton of $CO_2$ avoided.[159] Other estimates range from $70 to $90 per metric ton of $CO_2$ avoided.

Oil refineries and petrochemical plants represent the second largest type of $CO_2$ point source in California at about 18 MMT of $CO_2$ per year. The primary sources within a refinery are fired process heaters and steam boilers, which are typically found at multiple locations within the plant. To achieve economies of scale would require collecting the various flue gas sources at one location with a centralized $CO_2$ absorber/regenerator unit. The benefits gained from a

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[158] Beecy, D.J., and V.A. Kuuskraa, 2004, "Basic Strategies for Linking $CO_2$ Enhanced Oil Recovery and Storage of $CO_2$ Emissions." *7th International Conference on Greenhouse Gas Control Technologies (GHGT-7).* 2004. Vancouver, Canada: Elsevier.

[159] Simbeck, D., 2007, *Generic Industrial $CO_2$ Capture for Any Large $CO_2$ Flue Gas Stream*, J. Katzer, Editor.

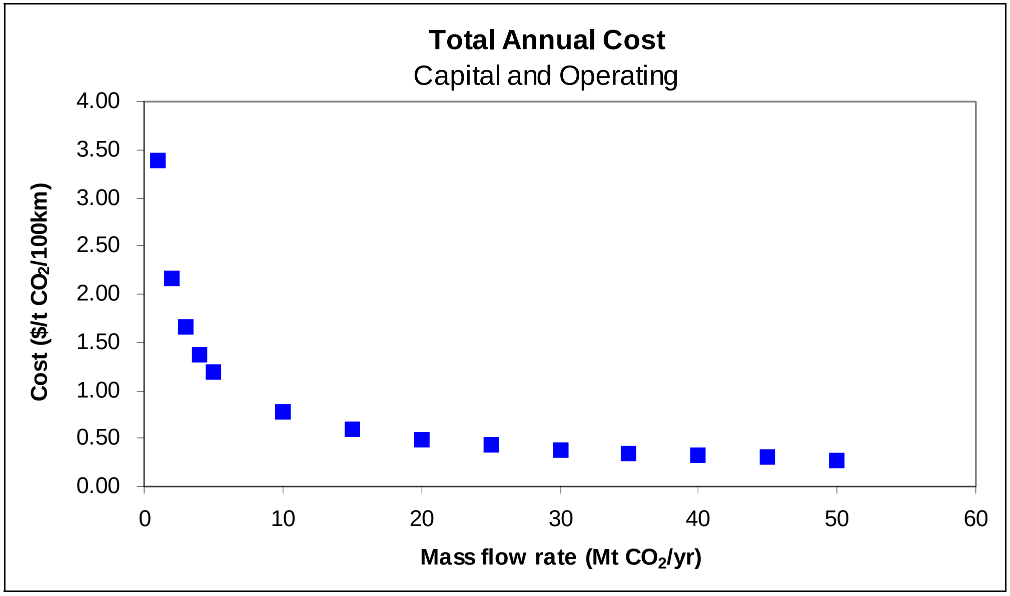
centralized $CO_2$ capture/recovery unit would be at least partially offset by the cost of adding pipes and ducts. Preliminary estimates suggest costs of $70 to $100 per metric ton of $CO_2$ avoided. Considering the amount and cost of duct work required to aggregate the various flue gas streams, this estimate may be low.

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

## Transport, Injection, and Sequestration Economics

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 is also influenced, of course, by the distance between the location of the $CO_2$ source and the target $CO_2$ sequestration site. Fortunately, 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.

**Figure 15: Illustrative Costs for $CO_2$ Transport via Pipeline**



Source: Heddle, G., H. Herzog, and M. Klett, 2003, *The Economics of $CO_2$ Storage.* MIT LFEE 2003-003. Available from: <http://sequestration.mit.edu/pdf/LFEE_2003-003_RP.pdf>.

Pipeline transport costs expressed as a function of $CO_2$ mass flow rate. A distance of 100 km is equivalent to 62 miles. Miles are used in the discussion in the text.

Transport costs are highly non-linear for the amount transported, with economies of scale being realized at about 10 MMT $CO_2$ per year (Figure 15). If the amount of $CO_2$ to be transported is about 10 MMT per year or greater, the cost is only about $0.8 per metric ton of $CO_2$ per 100 miles. However, this cost doubles at 5 MMT per year and is greater than $4.8 per metric ton of $CO_2$ per 100 miles for 1 MMT per year. While the figure shows typical values, costs can be highly variable from project to project due to both physical (for example, the terrain the pipeline must traverse) and socio-political considerations. For a 1,000 MW coal-fired power plant, a pipeline would need to carry about 6 to 7 MMT $CO_2$ per year. This would result in a pipe diameter of about 16 inches and a transport cost of about $1.6 per metric ton $CO_2$ per 100 miles. Developing pipeline networks, as opposed to building dedicated pipes between a given source and sink, reduces aggregate transport costs.

The major costs for injection and sequestration are associated with the drilling of wells. Other cost items include site selection and characterization, as well as flow lines 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 per metric ton $CO_2$.[160] Costs for injecting the $CO_2$ into geologic formations will vary with the formation type and its properties. For example, costs increase as reservoir depth increases and reservoir injectivity 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 per metric ton $CO_2$.[161]

## Financial and Other Issues

CCS technology is very capital intensive. For example, retrofitting a 1,000 MW gas-fired power plant would require hundreds of millions of dollars in investment. Building a new 500 MW coal-fired power plant will require in excess of a billion dollars. Lenders and investors expect to recoup this investment steadily over a long time period, typically 15 to 25 years, and will require some sort of long-term regulatory certainty and stability in carbon markets.

The effect on interest in CCS investment attributed to fluctuations in the price of European Union allowances provides an example of the influence of carbon markets. Prior to April 2006, the European Union 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 to 2012 are in the range of $20 per ton $CO_2$, but there is no information on what the post-2012 market (post-Kyoto protocol) will look like. Consequently, the financial

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[160] Metz, B.E.A., ed., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final.pdf>.

[161] Ibid.

uncertainty is much too great to support interest in CCS projects based solely on carbon allowance pricing.

Finding value for $CO_2$ apart from carbon credit markets also reduces financial risk. For example, combining sequestration with EOR can help offset some of the capture and sequestration costs. Recent prices as of 2007 for $CO_2$ used for EOR are around $20 per metric ton, but fluctuate with the price of oil.

The costs reported within this chapter do not include contingencies to cover issues that may lead to increased costs. These include permitting requirements, monitoring costs, property rights acquisition, and liability. Of these, long-term liability seems to be of greatest concern. These issues are discussed in other chapters of the report.

## The California Context

Applying CCS technology to large out-of-state coal-fired power plants addresses the biggest point sources of $CO_2$ emissions in California's emissions inventory; nevertheless, pursuing in-state opportunities for sequestration may be necessary to attract or retain industries faced with mandated $CO_2$ emissions reductions or caps. In-state options may also be needed in the absence of regional carbon crediting agreements among the western states. Decreasing emissions in the transportation sector relies on shifting to bio-derived fuels, but CCS of ethanol plant emissions gives this sector an additional opportunity to achieve further $CO_2$ emissions reductions.

The issue of source-sink matching—that is, the proximity of $CO_2$ point sources to geologic sequestration sites—was discussed in Chapter 3. The proximity of sources and sinks is an important economic consideration, and most sources in California are located close to potential sequestration sites. This is confirmed with a quantitative assessment showing:

- About 79 percent of emissions sources are within 30 miles of a potential EOR site
- About 92 percent are within 30 miles of a non-EOR geologic formation
- Only 9 percent are greater than 60 miles from a potential EOR site
- All sources are within 60 miles of a non-EOR geologic formation

### *Regional Opportunities*

California, as a big importer of electricity, has significant out-of-state opportunities to reduce $CO_2$ emissions (Figure 16). Given the difference in the typical avoided cost of $CO_2$ for coal and natural gas power plants, the best economic opportunities to reduce California's total $CO_2$ emissions, as measured when including emissions from electricity imports, may be to apply CCS to the large, out-of-state coal plants serving California loads.[162] Most of the in-state power

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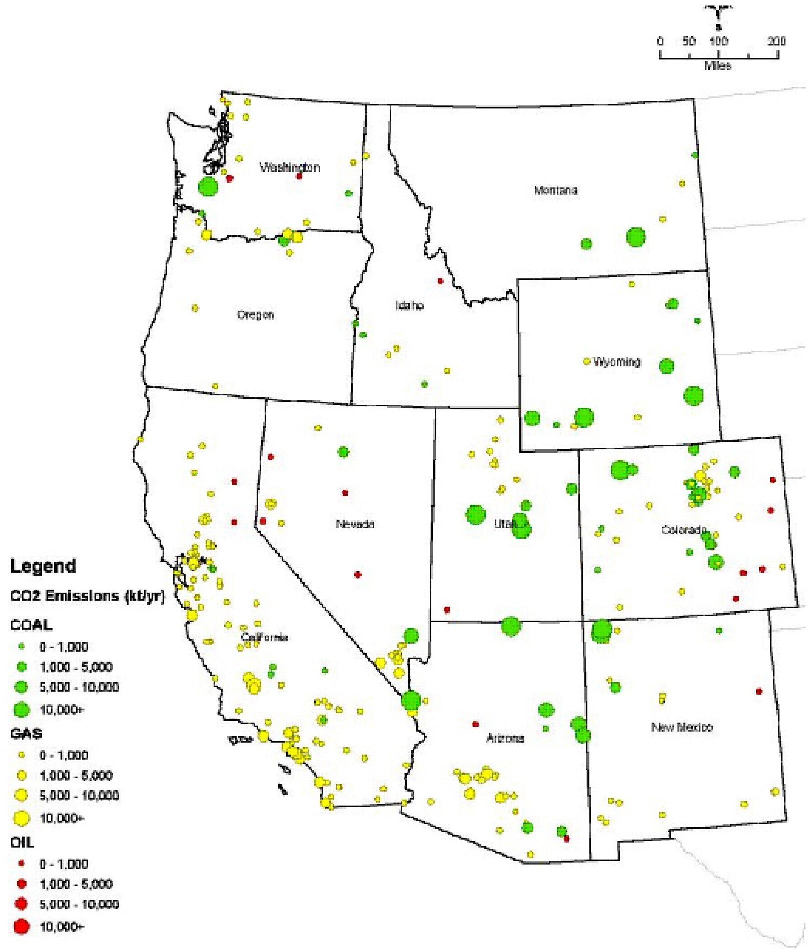
[162] Bemis, Gerry, 2006, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004.* California Energy Commission, Special Projects Office, CEC-600-2006-013-SF.

plants are gas-fired, whereas much of the imported electricity comes from coal-fired power plants. Emissions totals reported for 2004 are 61 MMT $CO_2$ for electricity imports versus 47 MMT $CO_2$ for in-state generating units.[163] There is also a large difference in $CO_2$ emissions per unit of electricity generated between coal and gas plants: 0.83 ton $CO_2$ per MWh for a new coal plant, versus 0.37 ton $CO_2$ per MWh for a new natural gas combined cycle plant.

## Figure 16: Location and Size of Fossil-Based Power Plants in the Western U.S. Electricity Grid



Source: Katzer, J. and H. Herzog, 2008 "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

Comparison of relative sizes and types of emissions sources demonstrates that the most economic sources for CCS, large coal-fired power plants, lie outside of California.

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[163] Ibid.

The banking of emissions reductions for imported electricity raises an interesting policy question regarding the implementation of CCS technology: should CCS programs be implemented regionally? Arguments for a regional policy include economic optimization given that the mitigation costs for CCS from coal-fired plants (primarily out-of-state) are significantly lower than from gas-fired plants in California. Further, from the viewpoint of meeting atmospheric stabilization targets, it is irrelevant where the $CO_2$ emissions are reduced. Thirdly, electricity freely flows throughout the Western Electricity Interconnect, suggesting the carbon credits could do so as well.

The question of optimizing CCS opportunities in a regional context is not unique to California. For example, Norway has been actively dealing with this issue for over 10 years.[164] Norway has an electricity system based primarily on hydroelectric power, but it 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 natural gas power plants to be built in Norway. On one hand, these gas plants will be less carbon-intensive than Denmark's coal plants; on the other hand, these gas plants will increase Norway's $CO_2$ emissions. If Norway decides to build new domestic gas-fired power plants, it must also decide whether to require those plants to capture and sequester their $CO_2$ emissions.

Recently, Norway decided to build a 420 MW gas-fired power plant at Kårstø. Although the plant is being built without CCS, plans are to add CCS with operation commencing in 2011 to 2012.[165] At present, the cost to add CCS to this plant is estimated to be 700 Norwegian krone per ton of $CO_2$ (about U.S. $120 to $130 per metric ton of $CO_2$ in 2007). This is an extremely high mitigation cost, given the European Union futures market in the timeframe from 2008 to 2012 for carbon allowances prices $CO_2$ at only about U.S. $20 per metric ton.

In addition to the Kårstø plant, two other projects are being considered. There is interest, for start-up in 2010, in using CCS with gas turbines at the Statoil refinery at Mongstad, a cogeneration facility that will provide 280 MW of electricity and 350 MW of heat.[166] The current plan calls for an initial $CO_2$ capture pilot plant rated at 100,000 metric tons per year, with full-scale $CO_2$ capture by 2014. Another proposed venture is to introduce gas turbines at the Statoil complex in Tjeldbergodden, with the captured $CO_2$ to be used for EOR in Shell's Draugen field. However, the CCS aspect of this project was rejected in June 2007 as being too expensive.

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[164] Quiviger, G., 2001, *Building New Power Plants in a $CO_2$ Constrained World: A Case Study from Norway on Gas-Fired Power Plants, Carbon Sequestration, and Politics.* Massachusetts Institute of Technology, M.S. Thesis. Available from: <http://sequestration.mit.edu/pdf/Quiviger_thesis.pdf>.

[165] Power-Technology.com, *Kårstø 420 MW Gas-Fired Power Plant, Norway*, <http://www.power-technology.com/projects/karsto/#adEnd> (November 21, 2007).

[166] The Royal Norwegian Ministry of Petroleum and Energy, *The Mongstad Plant and Agreement Between the State and Statoil About $CO_2$ Handling*, <http://www.regjeringen.no/en/dep/oed/Subject/Carbon-capture-and-storage/The-Mongstad-plant-and-agreement-between.html?id=439428> (November 21, 2007).

### *In-State Opportunities*

Several "targets of opportunity" within California also should be considered. One is the use of captured $CO_2$ for enhanced oil recovery. While prices fluctuate with the price of oil, in recent years, EOR operations in other states have valued $CO_2$ at around $20 per metric ton. As noted previously, California has many producing oil reservoirs that could benefit from $CO_2$-based enhanced oil recovery. The second opportunity is application to industrial $CO_2$ streams that are essentially pure $CO_2$. Examples include natural gas processing plants that separate $CO_2$ from methane in produced gas, fermentation processes producing ethanol, ammonia plants, and some hydrogen production plants in or associated with oil refineries. Although these pure $CO_2$ streams presently represent a small fraction of California's $CO_2$ emissions, as early CCS projects they would likely have relatively low overall costs, assuming they are located reasonably close to suitable sequestration sites and can realize some economies of scale.

Although CCS for some of these industrial processes could be economic today, particularly if coupled to an EOR project, these applications are not likely to make a significant contribution to overall $CO_2$ emissions reductions. Such applications could almost assuredly be developed in time for AB 32 compliance, but the total reduction of $CO_2$ emissions would be relatively small given the number and size of these sources and likely number of projects that could be underway by 2020.

It is important to note, however, that coupling CCS with production of alternative fuels could result in significant reductions to California's greenhouse gas emissions inventory in the future. Biofuels, such as ethanol, have the potential to generate "net-negative" emissions.[167] When the near-carbon-neutral emissions from bioethanol plant exhaust are injected for underground sequestration, there is an overall net transfer of $CO_2$ out of the atmosphere and biosphere to geologic storage. Depending on biofuels policy and investment decisions, the number of ethanol plants in the state could rise markedly by 2050. With respect to hydrogen fuels, $CO_2$-free hydrogen and a high-purity $CO_2$ exhaust stream 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 $H_2$ (see Chapter 4). Pre-combustion $CO_2$ capture coupled with geologic sequestration is planned for Hydrogen Energy's proposed IGCC power project in California. Projects generating hydrogen for transportation fuel using this process also are potentially good candidates from an economic standpoint for CCS.

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[167] See footnote #2 for an explanation of "net-negative" emissions.

# CHAPTER 10: Regulatory and Statutory Issues

In California, as elsewhere, CCS-specific regulatory and statutory frameworks do not yet exist. However, extensive regulatory frameworks do exist to govern activities directly analogous to CCS, including the injection of fluids for oil and gas production, liquid waste disposal and natural gas storage. Use of these as regulatory analogs should apply the caveat, however, that business model differences between these types of operations and CCS may affect their applicability. Notably, CCS projects are likely to lack an economically motivated private sector decision maker for much of the lengthy storage cycle.

This chapter, based on the PIER study by Wade,[168] is a technical review to assess how current regulatory frameworks may apply to permitting of CCS demonstration projects in the state and what modifications may be necessary to support commercial-scale CCS deployment. It is not a formal legal analysis of the statutes and regulations relevant to CCS.[169]

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 and stressed the need to quantitatively assess the effects of regulations on future project development.[170] Even though 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 sequestration site is the element least accommodated by current regulatory and statutory frameworks. Existing regulations for industrial facilities and pipelines may be applied to CCS surface infrastructure in a relatively straightforward manner. However, the large scale of CCS projects, including pipeline infrastructure, deployment of instrument arrays for site characterization and monitoring, and the size of the subsurface reservoirs, will undoubtedly require a permitting and approval process that includes property owners, multiple local entities, as well as state and/or federal 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

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[168] Wade, S.M., PIER white paper on2008, "Legal and Regulatory Frameworks, Property Rights and Liability," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

[169] This section has been prepared by the California Energy Commission's technical staff in response to directives in AB 1925 (Blakeslee, Chapter 471, Statutes 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.

[170] Vine, E., 2004, "Regulatory Constraints to Carbon Sequestration in Terrestrial Ecosystems and Geological Formations: A California Perspective." *Mitigation and Adaptation Strategies for Global Change*, v. 9, pp. 77–95.

projects would be better positioned to move forward in pace with the demands of GHG reduction policies. A robust follow-up analysis is warranted to determine the best approach for developing CCS-specific regulations and statutes to govern commercial-scale CCS deployment. Such an analysis should establish the potential effects of including CCS under existing statutes and regulations and, conversely, the impact of any new CCS-specific regulations and statutes on existing frameworks.

Numerous efforts underway around the world may help to inform future efforts in California. The International Energy Agency, for example, has assessed the legal aspects of large-scale deployment of CCS.[171] In the United States, agencies at the federal, regional and state levels also are examining these issues. The U. S. Environmental Protection Agency (U.S. EPA) has examined the suitability of provisions for injection wells under its Underground Injection Control program. It recently decided that regulators can permit pilot CCS projects under provisions for Class V wells, and it has announced its intent to release a draft $CO_2$ injection rule by mid-2008.[172] In September of 2007, the Interstate Oil and Gas Compact Commission (IOGCC) published a legal and regulatory guide for U.S. states and Canadian provinces.[173] The state of New Mexico recently issued its assessment of the scope of regulatory and statutory issues related to CCS projects.[174] Other states, including Indiana, Kansas, Kentucky, North Dakota, Ohio, and Washington, are in the process of developing statutes, regulations or other policies supporting CCS.[175]

Implicit in 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 and other underground resources such as

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[171] 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 a Regulatory Framework for Carbon Dioxide Storage in Geological Formations.* Prepared for International Risk Governance Council Workshop. Washington D.C.

[172] See the EPA Underground Injection Control website for the most recent status of this effort: <http://www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment>.

[173] Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Capture and Geological Storage, 2007, *Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces*, September 25, 2007, <http://www.iogcc.state.ok.us/docs/MeetingDocs/Master-Document-September-252007-FINAL(2).pdf>.

[174] New Mexico Energy, Minerals, Natural Resources Department, Oil Conservation Division, 2007, *Carbon Dioxide Sequestration: Interim Report on Identified Statutory and Regulatory Issues* New Mexico Energy, Minerals, Natural Resources Department, Oil Conservation Division, June 27, 2007.

[175] Wade, S., op. cit.

hydrocarbons or minerals. These studies also emphasize the urgent need to encourage initial demonstration projects to guide the development of regulations.[176] For example, the U.S. EPA's Class V Guidance states:

> Permitting [pilot] projects as Class V experimental technology wells—while maintaining the Underground Injection Control program's protective safeguards of underground sources of drinking water 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.[177]

Three main areas require clarification and streamlining:

- Assignment of authority(ies) to regulate in a uniform manner the siting, transport, injection, sequestration, and accounting of $CO_2$ for all potential types of sources and sequestration sites and for purposes of $CO_2$ 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

### *Power Plant Siting*

Under CEQA and the Warren-Alquist Act, the Energy Commission has the authority to investigate and license new or existing power plants. Adding CCS to new plants or by retrofitting existing plants would require the Energy Commission to consider the ramifications of these additions on energy facility siting decisions. For example, site assessments would have to consider proximity to suitable sequestration sites or $CO_2$ pipeline corridors when identifying new power plant locations. The addition of CCS also changes the potential effects of power plants on water use, air quality, and other health, safety, and environmental risks. All of these influences would have to be incorporated into site assessments.

As exemplified in FutureGen's risk assessments and environmental impact statements, while CCS operations are naturally divisible into surface (pre-injection) and subsurface (post-injection) components, these assessments also must be integrated. Current regulatory

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[176] International Energy Agency, 2007, op. cit.

[177] Dougherty, C. and B. McLean, 2007, *Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects – UIC Program Guidance (UUICPG #83),* March 1, 2007, U.S. Environmental Protection Agency <http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonseuestration_final-03-07.pdf>.

frameworks in California would appear to divide CCS projects along similar lines: CEQA and Warren-Alquist would apply to surface components of a CCS project; the Underground Injection Control program would apply to subsurface components. While the explicit jurisdictions with respect to CCS of these frameworks should be investigated more thoroughly in a follow-up analysis, it appears that achieving an integrated site assessment will require coordination among the relevant agencies.

### *Transport*

The regulatory authority in California for $CO_2$ pipelines is the Office of the State Fire Marshal. As noted in Chapter 3, the technical, economic, and permitting issues relevant to $CO_2$ compression and pipeline transport are well known in the United States. Relatively large-scale pipelines for $CO_2$ have existed for over 20 years for EOR operations in many other states, but $CO_2$ transport via pipeline in California is limited to relatively small volumes for industrial use. Thus, while the regulations for $CO_2$ pipelines are well established, the large size of $CO_2$ pipelines for CCS may result in additional considerations for siting decisions and requirements for safe operation. The potential differences between regulating pipelines from the standpoint of permitting, health and safety, and climate-mitigation compliance also should be considered.

Pipeline transport issues may be an area for further analysis prior to issue of the 2010 report, but should be focused on examining the role of pipeline infrastructure to facilitate potential early opportunities for CCS in the state, such as use of captured $CO_2$ for EOR, $CO_2$ capture from high-purity streams at existing industrial sources, or proposed power and biofuels projects incorporating CCS.

### *Injection Wells*

California has a long history of regulating operations similar to geologic sequestration. These include oil and gas production and disposal activities, waste injection wells, and natural gas storage. All of these analogs fall within the U.S. EPA's Underground Injection Control program, which sets out certain minimum requirements according to a classification system for wells.

Various parts of the Code of Federal Regulations, Title 40 (40 CFR) describe all Underground Injection Control wells and regulations.[178] These regulations set out certain minimum requirements for Class I, II, and III wells that govern the siting, corrective action, drilling, construction, mechanical integrity testing, operation, monitoring, closure, and abandonment of each class of Underground Injection Control well. The requirements for Class I hazardous wells are the most rigorous, followed by Class I non-hazardous, Class II, and Class III wells.

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[178] 40 CFR Parts 144 and 146 for Underground Injection Control; Parts 35, 124, 145, 147 and 148 also pertain to underground injection.

It is possible for states to obtain primary authority (primacy) from the U.S. EPA to implement the regulatory program for all or a portion of the well classes. California currently shares primacy with the U.S. EPA. The California Division of Oil, Gas, and Geothermal Resources (DOGGR) in the Department of Conservation implements Class II wells and has limited authority to permit geothermal wells, while U.S. EPA Region 9 implements all other classes of wells. Roughly 25,000 Class II wells currently operate in California, but only a small number (less than 20) of Class I and Class V have operated or currently operate in the state.[179]

These frameworks establish performance-based standards that should be relatively easy to apply to initial CCS projects, but at the same time, they are not perfectly suited to CCS. Although it should be possible to work within existing regulatory frameworks to permit early and pilot CCS projects, there are critical gaps that must be addressed prior to widespread commercialization. As noted previously, to date, the U.S. EPA has issued guidance that allows $CO_2$ injection wells to be regulated as Class V (experimental) wells, and it anticipates making a permanent classification for $CO_2$ injection within an existing class or by creating a new class specifically for CCS.

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 should consider the effect 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 may 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.

The technical criteria and standards for wells under the Underground Injection Control program apply to all wells or to specific classes:[180]

- 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, 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, 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 the fluid being injected. Also, the Underground

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[179] <http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm>.

[180] 40CFR Part 146.

Injection Control program includes a public participation process, which requires notification of draft permit issuance and an opportunity for public comment, including public hearings.[181]

The California rules governing Class II wells are found in the California Code of Regulations, Title 14, Division 2, Chapter 4.[182] These rules govern all onshore and offshore oil and gas wells, including Class II injection wells in oil and gas fields and at natural gas storage sites. Like the federal Underground Injection Control rules, the California rules 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.[183]

### Differences among Federal Class I and II and California Well 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 be required. Some specific examples of differences relevant to using these class designations for CCS are:[184]

- Well Construction: Federal 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: Federal regulations for Class I are more rigorous than for 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.[185] 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 lay out specific mechanical integrity testing schedules for water disposal, waterflood, and steamflood operations that range from yearly to every five years. The U.S. EPA requires mechanical integrity tests every five years for both Class I and II wells. There is an option for the permit writer to establish additional requirements

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[181] 40 CFR Part 124.

[182] 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>.

[183] Wade, S., op. cit.

[184] Ibid.

[185] 40 CFR Part 146.8 (a) (2).

for mechanical integrity testing as needed, including a mechanical integrity testing schedule.

- Operation: Federal Class I non-hazardous 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 require continuous monitoring of injection pressure, flow rates, volume, and annulus pressure. Class II wells require periodic monitoring of this information and must have equipment for continuous monitoring in place.
- Ambient Monitoring: Based on a site-specific assessment, Class I operators must propose an ambient monitoring plan. This plan must identify possible risks and receptors potentially affected by leakage and include a mitigation plan (sometimes referred to as a Contingency Management Plan) to be activated before the unanticipated movement of injected fluid could cause damages. Class I regulations establish a procedure for developing these safeguards. Federal Class II regulations do not require ambient monitoring plans, but they do provide an option for requiring additional monitoring and contingency plans to address well failure. California requires a monitoring system[186] and also allows the regulator to require additional information, such as a safety program for "large, unusual" projects.[187]
- Reporting: Under the federal program, Class I 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 involves 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 decides whether to issue 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.

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[186] Section 1724.7 (c) (3).

[187] Section 1724.7 (e).

## Table 14: Considerations and Evaluation of Federal Class I and II Well Regulations 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 should 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 should 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[188] | Not sufficient: no storage time specified for Class I non-hazardous 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 should 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 |

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[188] See discussion of time scales for sequestration in Chapter 1.

## Table 14 cont'd: Considerations and Evaluation of Federal Class I and II Well Regulations 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 monitoring, 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.

### Fit of the Underground Injection Control Program to Carbon Capture and Sequestration

Previous research shows that neither the federal Class I nor Class II regulations are perfectly appropriate to the needs for CCS. Table 14 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 of $CO_2$ injected and for the very long time scales of CCS projects. As noted in previous chapters, CCS projects require understanding the reservoir and plume behavior at a large scale. The Underground Injection Control 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.[189]

Given the importance of site characterization and monitoring for CCS, as discussed in previous chapters, it may be beneficial to use options within the Underground Injection Control program to establish a process for permitting both an area or reservoir and the subsequent wells associated with the project. 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 areas 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.[190] The first step entails securing a general area permit for a formation or a large section of a reservoir. The second step involves permitting individual wells. Factors to be considered in the first step include:

- Surface distribution of characteristics and risk receptors
- Subsurface brine distribution
- Subsurface geologic conditions

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[189] <http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm>.

[190] Nicot, J.P. and I.J. Duncan, *Science-Based Permitting of Geological Sequestration Of $CO_2$ 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.

- Regional variation in reservoir capacity and quality
- Regional flow characteristics

Regional variation in quality of primary and secondary seals[191]The requirements for individual well permitting would include more detailed technical and financial requirements. Some stakeholders have raised concerns that such an approach would create permitting delays while data were collected on different reservoirs.[192] An important role of demonstration projects should be to define the minimal data requirements necessary to permit CCS.

## *Carbon Accounting and Climate Mitigation*

As part of California's climate change mitigation goals, $CO_2$ emissions are currently controlled under AB 32. CCS projects may be subject to regulation by the agency(ies) tasked with assuring climate change mitigation goals are met and/or with GHG emissions accounting. As climate regulations are rapidly evolving in the state, this issue will be addressed in more detail in the follow-up 2010 report.

## *Regulatory Continuity*

Coordination among the agencies responsible for emissions mitigation, injection, transport, and power plants will be necessary to effectively meet the goals of implementing CCS. There is high potential for ambiguities and discontinuities in how $CO_2$ injection may be regulated among reservoir types (with or without hydrocarbons present) or at different points in the CCS process (from capture, through transportation, and underground).[193]

One example is related to EOR. Currently, if $CO_2$ is used for enhanced hydrocarbon recovery, it is an industrial product because the $CO_2$ is used to extract oil, gas, or methane resources.[194] If operations that capture $CO_2$ for sequestration are classified differently, there potentially may be 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 sequestration in a CCS project. This also could present difficulties for projects that originally were EOR operations that subsequently become CCS operations.

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[191] Ibid.

[192] Wade, S., op. cit.

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

[194] Interstate Oil and Gas Compact Commission (IOGCC) Task Force on Carbon Capture and Geological Storage, 2007, *Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces*, September 25, 2007, <http://www.iogcc.state.ok.us/docs/MeetingDocs/Master-Document-September-252007-FINAL(2).pdf>.

There may be additional ramifications resulting from adoption of a classification for $CO_2$ injection if California ever considers using sequestration 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 geologic sequestration projects. Offshore projects have been allowed as industrial storage or enhanced hydrocarbon recovery projects under international marine treaties[195] because the purpose of the storage has not been considered disposal, but rather as 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.[196]

Within the Underground Injection Control program, there also is a possibility for regulatory discontinuity. Given the shared primacy for the Underground Injection Control program in California, use of this program for CCS injections wells could 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, under the Class I program, U.S. EPA Region 9 would have authority for any $CO_2$ injection into formations without hydrocarbons. In the long run, if 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.[197]

## 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 may require a different strategy than that used for secondary recovery in oil and gas fields; CCS also raises different issues in nonhydrocarbon-bearing targets than in oil and gas targets.

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[195] 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).

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

[197] <http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm>.

The three main property interests relevant to CCS are surface owners (injection facilities and monitoring stations), subsurface owners (sequestration reservoir, pore space, mineral rights, water rights), and owners of the $CO_2$ itself. Because property ownership potentially 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 sequestration.[198]

## *Property Rights*

There are generally two schools of thought regarding property rights: the first grants rights that include ownership of the material (in this case, the $CO_2$), which entails greater liability on the property rights holder, and the second grants 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 of 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.[199]

A primary question to resolve for CCS is ownership of subsurface pore space in the sequestration reservoir. There seems to be some ambiguity in existing statutes in the United States, 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.[200]

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

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[198] Wade, S., op. cit.

[199] Ibid.

[200] 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.

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, airplanes flying over an individual's property at a safe altitude would not normally 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 are 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 a scale necessary to significantly address climate change, the size and extent of CCS projects would require the negotiation or condemnation of property rights from large numbers of property 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. Because most CCS projects will be located in very deep formations (more than 2,600 feet), it is arguable whether 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 in deep geologic formations, and so property with no known mineral deposits today may become valuable in the future. For the near future, however, it seems likely that CCS operations will be commercial endeavors with values that depend significantly on the value placed on avoided $CO_2$ emissions. Given this situation, CCS storage space, similar to mineral resources, may become a part of the value of the property.

## 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.[201]

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

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[201] Wade, S., op. cit.

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.[202] In the second instance, forced unitization of an oil pool, pools, or portions thereof is allowed if three-quarters of the working interests and three-quarters of the royalty interests agree to unitize.[203] 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.

Under the Underground Injection Control program, for Class I and Class V wells, 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 formations where there is little to 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 valuable, use of pore space for natural gas storage does indeed constitute trespass. This issue needs clarification for CCS projects.[204]

### 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 $CO_2$ sequestration. It is not clear that $CO_2$ sequestration 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 $CO_2$.

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[202] Section 3319. California Laws for Conservation of Petroleum & Gas, <ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf>.

[203] Section 3642. Ibid.

[204] Wade, S., op. cit.

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 beneath a property.[205]

## Long-Term Stewardship and Liability

Liability for geologic sequestration of $CO_2$ comes from three major sources: non-permanence of sequestration, in situ risks, and operational impacts. Non-permanence of sequestration 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 the climate. 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. Although the operational risks associated with transportation, injection, and sequestration 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.

While the operational risks associated with transportation, injection, and sequestration 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 any point in the distant future, and the disincentive that these potential costs may have on investment today in CCS.[206] Before a CCS industry develops, liability concerns may be particularly problematic for early or demonstration projects. For example, Texas and Illinois, in competing for the FutureGen project, passed legislation accepting ownership and liability for that specific project's injected $CO_2$, albeit some conditions specified but without extending such provisions to any future commercial project.[207]

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[205] Fish, J.R. and R. Nelson, 1994, "Building Your Own Underground Gas Storage Project: from Leasing to Open Season Under FERC Order No. 636." 40 *Rocky Mt. Inst.* pp. 19-25.

[206] Ibid.

[207] Illinois General Assembly: SB1704 and HB 1777 found online at <http://www.ilga.gov/legislation/BillStatus.asp?DocNum=1704&GAID=9&DocTypeID=SB&LegId=29844&SessionID=51&GA=95>; Texas Legislature: SB 1461 found online at

Long-term liability issues are viewed by industry as a major constraint that may prevent the widespread application of CCS in California and elsewhere. Because geologic CCS could be carried out as part of the state's policy to lower GHG emissions, transfer of liability to the public sector after an operator has met a given set of 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 should 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 GHG 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 extensive experience with Class I wells, the existing history suggests that the financial assurance provisions are sufficient to induce proper closure of Class I wells.[208] 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.[209]

Neither the Class I nonhazardous nor the Class II (federal or California versions) includes provisions regarding post-closure activities. Conversely, the Class I hazardous waste rules do anticipate some post-closure activities, but the rules focus on problems discovered during the

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<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] Wade, S., op. cit.

[209] 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 rather than on 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. None 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 approved 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, that party 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 addressing 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.[210]

## *FutureGen*

As a means of encouraging early projects, California may want to explore options similar to the actions taken by Texas and Illinois in competing for the original FutureGen project. In particular, this is a possible way to facilitate initial demonstrations or research-oriented projects prior to the establishment of an industry that is sufficiently robust to create an indemnification fund.

The U.S. Department of Energy's FutureGen project, both in its original and revised concepts, combines coal gasification for electric power with pre-combustion $CO_2$ capture and sequestration at a commercial scale. As with other pioneer CCS projects, liability was a problematic issue for the FutureGen Industrial Alliance, the consortium of companies and government agencies that developed the initial concept 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…."[211]

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

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[210] California Laws for Conservation of Petroleum & Gas, <ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf>.

[211] <http://www.netl.doe.gov/technologies/coalpower/futuregen/>.

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

Each state's approach also differed in some respects. Illinois imposed a restriction that the injected $CO_2$ must remain underground.[212] The Texas legislation allowed for the possibility that the stored $CO_2$ might be used at a later time for enhanced oil recovery or other purpose.[213]

## *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 operators pay a fee based on the amount of $CO_2$ injected that would be deposited 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.[214] Another California program, the Hazardous and Idle-Deserted Well Abatement Fund, collects annual fees on idle wells into an escrow account.[215]

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 injected $CO_2$ 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 pay for remediation. The source of funds would be a small levy charged on the basis of the amount of $CO_2$ injected, accrued interest on fund assets, and, possibly, reimbursements from operators under certain conditions. Successful projects could be handed over fully to such a public corporation after a specified time period, for example, 10 years after closure. At that time, the operator would predict future potential leakage (from modeling) and compensate the fund for that possible future leakage. Only sequestration wells (not enhanced oil or gas recovery wells) would be eligible, though enhanced hydrocarbon recovery wells could convert to sequestration wells. Also, in order to jumpstart projects, the government could fund the levy for research-oriented or a certain number of early

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

[213] 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>.

[214] Section 3262, California Laws for Conservation of Petroleum & Gas, <ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf>.

[215] Section 3206(b), California Laws for Conservation of Petroleum & Gas, <ftp://ftp.consrv.ca.gov/pub/oil/laws/PRC01.pdf>.

commercial projects. There are other provisions in this proposal relating to determination of damages on a no-fault basis and to rules for compensation.[216]

The IOGCC suggests provisions for the creation of a state trust fund to cover the cost of long-term stewardship as well as some limitations on liability for projects that successfully demonstrate compliance with applicable laws.[217]

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 individual nuclear plant operators 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.[218]
- 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.

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[216] de Figueiredo, M.A., H.J. Herzog, P.L. Joskow, K.A. Oye, and D.M. Reiner, 2007, *Regulating Carbon Dioxide Capture and Storage.* Massachusetts Institute of Technology, April 2007. <http://web.mit.edu/ceepr/www/2007-003.pdf>.

[217] Interstate Oil and Gas Compact Commission Task Force on Carbon Capture and Geological Storage, 2007, op. cit.

[218] Trabucchi, C., 2007, "Industrial Economics, Summary of Financial Responsibility Frameworks for Use as Potential Models for Managing Long Term Liability Associated with CCS." Presentation at *World Resources International Risk Workshop,* June 2007.

# CHAPTER 11: Conclusions and Recommendations

Commercial-scale CCS is likely to be applied widely in the state only when a business case can be made for applying the technology. This business case depends mainly on the costs associated with the technology, including costs for regulatory compliance, the value of $CO_2$ set by policy or market systems, and sufficient stability and certainty in these parameters to support long-term investment. Based on the analyses of technology costs, as described in Chapter 9, and in the absence of a relatively high, sustained value for $CO_2$, CCS does not presently appear to be an economic approach for achieving emissions reduction in the near-term in California, except perhaps in cases where a high-purity $CO_2$ stream is already being produced during routine industrial operations. Although the current economics may suggest an approach of deferring consideration or deployment of CCS to a future timeframe, from the standpoint of meeting its GHG emissions reduction goals, there are a number of reasons to ensure that the state will be able to take timely advantage of CCS as a GHG emissions reduction strategy should it become necessary.

First, from a global perspective, once any GHG emissions mitigation technologies are selected, they should be brought on line as rapidly as possible. Achieving stabilization of atmospheric $CO_2$ at the levels suggested by the IPCC, for example, requires implementing GHG emissions reduction strategies sooner rather than later. Delaying emissions reductions significantly decreases the likelihood of reaching these stabilization goals. Thus, it is important to identify and remove barriers to adopting viable mitigation technologies as soon as possible to assure the technologies can be brought on line when they are considered necessary and economic. For capital intensive technologies like CCS, long ramp-up times often precede widespread use due to regulatory and financial uncertainties and to the time needed to complete a sufficient number of build-and-test cycles during the proof-of-concept and demonstration phases that precede commercialization.

Second, from a national or regional perspective, as noted earlier, CCS is moving forward and will influence the energy and GHG emissions inventory for California whether or not CCS projects are actually done in the state. Given that one-sixth of California’s annual emissions are associated with imported electricity (61 of 356 tons of gross $CO_2$ emissions in 2004), it is imperative to include the influence of CCS adoption in other states in California’s planning analyses. For example, in electricity scenarios, adding CCS to out-of-state plants that provide electricity to California affects electricity production costs and, potentially, dispatch preferences. The cost and carbon rankings of CCS-equipped power plants burning fossil fuels also change significantly relative to the state’s preferred energy resources. Furthermore, from the standpoint of reducing California’s GHG emissions inventory, it is more economic to apply CCS to out-of-state coal plants than to in-state natural gas plants.

Third, California’s policy makers should be able to compare and evaluate all technically viable GHG reduction options, including CCS, to meet the state’s emissions reductions goals in the near and far terms. Within the state, many agencies are now actively engaged in assessing which technologies will be needed and to what degree they should be deployed to meet the

GHG emissions goals for 2020 as laid out in AB 32. The potential effects of adopting various options on the state's economy are also the subject of extensive study. Assuming the state moves forward with the next phase of Executive Order S-3-05, even greater efforts will be needed to identify the options for and economic consequences of achieving the deep cuts in GHG emissions required by the 2050 goals. These goals will be much more challenging to meet as the system will already have taken advantage of readily available and lower-cost measures. These efforts must identify those mitigation technologies that can have the greatest long-term impact for the least public cost and create the least damage to economic health. It may become important that CCS can operate within the fossil fuel dependent infrastructure of California's current economy to provide nearly carbon-free electricity.

In that this is a preliminary report, which is to be followed by a more comprehensive analysis in 2010, its recommendations focus on information needed for the 2010 report, which will contain the full set of recommendations requested by the AB 1925 legislation.

1. Over the next three years, any state planning and other analyses involving energy or GHG emissions reduction strategies, as appropriate, should include consideration of CCS options. Better CCS cost estimates should be developed, and policy makers at all levels of government should consider them an appropriate proxy for the long-term value of $CO_2$ reduction.
2. Further examination is needed of the scenarios for CCS adoption identified in this report as early opportunities, based on potentially close-to-favorable business cases. These opportunities may have greater value than as niche applications and may facilitate creation of an in-state market for $CO_2$ by demonstrating enhanced oil and gas production.
3. Demonstration projects in the United States and around the world over the next three years will provide key data to set CCS policy. They should be facilitated and carefully studied, and may provide early insight into public and property owner concerns about risks.
4. California's power imports encourage consideration of CCS in a regional context. Coordinated investigations of CCS for power plants should take place involving other states in the WECC region. This should be done in the context of recognizing the connection between regional climate change and electricity generation objectives and in consideration of how carbon responsibility should "flow" with electricity.
5. Regulatory and statutory ambiguities and barriers identified in this report must be addressed, potentially through efforts that cut across the agencies that will ultimately be involved in regulating CCS, from surface facilities through injection to underground sequestration and verification of climate change mitigation. These efforts would include evaluating the need for CCS protocols and, as applicable, drafting them. This would include protocols for site characterization, monitoring and verification, and contingency plans for remediating leakage.