BACKGROUND REPORTS FOR THE CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Prepared by the Technical Advisory Team
in support of
The California Carbon Capture and Storage Review Panel

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Contents

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Abbreviations and Acronyms

ARB – California Air Resources Board
ARRA – American Recovery and Reinvestment Act of 2009
CAA – Clean Air Act
CEC – California Energy Commission (also Energy Commission)
CEQA – California Environmental Quality Act
CERCLA – Comprehensive Environmental Response, Compensation, and Liability Act
CPUC – California Public Utilities Commission
DOE – U.S. Department of Energy
DOGGR – Division of Oil, Gas and Geothermal Resources
DOT – Department of Transportation
EJ – Environmental Justice
Energy Commission – California Energy Commission
EOR – enhanced oil recovery
EPS – Emissions Performance Standard
FERC – Federal Energy Regulatory Commission
GHG – greenhouse gas
GS – geologic storage
LCFS – low carbon fuel standard
LGP – loan guarantee program
MOU – Memorandum of Understanding
MRR – mandatory reporting regulation (ARB) or rule (U.S. EPA)
MRV – monitoring, reporting, and verification
$MTCO_2e$ – metric ton of CO^2 equivalent
NETL – The National Energy Technology Laboratory
NGA – Natural Gas Act
NSR – New Source Review
PHMSA – Pipeline and Hazardous Materials Safety Administration
PIER – Public Interest Energy Research
PSD – Prevention of Significant Deterioration [program]
SIP – State Implementation Plan
SDWA – Safe Water Drinking Act
UIC – underground injection control
USDW – underground sources of drinking water
EPA – U.S. Environmental Protection Agency
WCI – Western Climate Initiative
WESTCARB – The West Coast Regional Carbon Sequestration Partnership

1. Overview of the Carbon Capture and Storage Panel Review Process

1.1. Introduction

California policy commits the State to reducing greenhouse gas (GHG) emissions. To meet this commitment, considerable efforts are focused on improving end-use energy efficiency and increasing the amount of electricity produced from renewable energy resources. These measures are expected to suffice to meet the 2020 goal of reducing the state's GHG emissions to 1990 levels. However, to meet the more stringent 2050 goal of 80 percent below 1990 levels, it will be necessary for the State to deploy additional technologies. Among these is carbon capture and storage (CCS), which may need to be deployed on a significant scale to curb CO_2 emissions from power plants and industrial sources.

CCS refers to climate change mitigation technologies that capture carbon dioxide (CO_2) and store it long-term to reduce the accumulation of CO_2 in the atmosphere. Geologic CCS captures CO_2 from power plants and industrial sources and sequesters the gas in deep-lying subsurface geologic formations. Terrestrial CCS refers to methods that enhance the naturally occurring storage of carbon in ecosystems such as forests, rangelands, agricultural lands, and wetlands.

The largest contributors to California's GHG emissions inventory, after transportation, are large industrial and electric power generating facilities. California's electricity sector is primarily supplied by in-state natural gas combined cycle plants, while out-of-state coal-fired plants account for 20 percent of electrical supply. Other large California point sources include cement plants and oil refineries. The application of CCS to new and existing facilities, both in- and out-of-state, could significantly lower their CO_2 emissions contributions to California's GHG inventory.

To justify capital investments in CCS technology, industry needs to know with certainty how CCS will be regulated, how carbon will be valued as a commodity, and how the emissions reductions from geologic storage will be treated under a state-administered cap-and-trade program. Although recent actions at the federal level have clarified significant regulatory issues for geologic storage of CO_2, gaps remain in California law and/or regulation, which necessitate the State taking its own steps to develop appropriate regulations—and, if necessary, new laws—to regulate CCS.

CCS is recognized by state, national, and international policymakers as necessary for meeting long-term energy and climate change mitigation goals. Because California is a leader in addressing GHG emissions, it is imperative for the State to demonstrate additional initiative in supporting a range of technologies that cover all major types of emissions sources. Integrating CCS into the state's policy mechanisms will facilitate commercial adoption of this critical technology by the industrial and electricity sectors and better position the State to meet its target GHG reduction levels.

1.2. The Carbon Capture and Storage Review Panel

Recognizing the importance of CCS for California's industrial and electricity sectors, the California Public Utilities Commission (CPUC), California Energy Commission (Energy Commission), and the Air Resources Board (ARB) created a CCS Review Panel in February 2010. The Panel, composed of experts from industry, trade groups, academia, and environmental organizations, was asked to:

1. Identify, discuss, and frame specific policies addressing the role of CCS technology in meeting the State's energy needs and greenhouse gas emissions reduction strategies for 2020 and 2050;
2. Support development of a legal/regulatory framework for permitting proposed CCS projects consistent with the State's energy and environmental policy objectives.

The Panel held five public meetings on April 22, June 2, August 18, October 21, and December 15, 2010, to arrive at its recommendations. These meetings were designed to solicit input from technical experts and key stakeholders and to allow Panel members to deliberate among themselves in an open, public setting. The Panel was asked to submit its written recommendations to the three principal agencies by the end of 2010.

Appendix A contains the Charter for the Panel. Appendix B contains a list of the Panel members and their qualifications. Appendix C contains a list of presenters and links to public testimony, presentation materials, and written comments. A Technical Advisory Team (TAT)[1] of state agency representatives and expert consultants was also formed to assist the Panel in its deliberations. A listing of TAT members is in Appendix D. White papers produced by TAT members, as well as other relevant materials, are included in subsequent Appendices.

1.3. Need for a Clear State Policy and Regulatory Framework

For CCS technologies to become part of California's climate change mitigation effort, a clear, transparent, flexible, and adaptable statutory or regulatory framework is needed. There are, at present, no commercial-scale CCS projects in California. For projects in the planning stages, unresolved economic, regulatory, and statutory issues present significant impediments to developers. Some issues, such as injection well classification and emissions accounting, are being addressed by the U.S. Environmental Protection Agency (EPA) at the federal level.[2] However, other critical gaps or areas of ambiguity remain, including long-term liability for stored CO_2 and pore-space ownership. The latter is generally conceded to fall under the purview of the states, which have historically adjudicated property rights.

The charter of the CCS Review Panel was developed to determine ways to address some of the most significant regulatory, institutional, and policy challenges facing CCS technology adoption in California. The Panel's recommendations are designed to (1) support consideration of new state legislation that addresses statutory gaps, (2) identify state policy instruments or incentives to facilitate CCS adoption, and (3) assist in establishing regulatory authority, including delineating the roles and responsibilities of key state permitting agencies.

During the time that the Panel was meeting and deliberating, other significant events occurred on the international, federal, and state levels. The meeting in Cancun of the Conference of Parties to the U.N. Framework Convention on Climate Change in late November/early December 2010 recognized that CCS "is a relevant technology for the attainment of the ultimate goal of the Convention and may be part of a range of potential options for mitigating greenhouse gas emissions" and prescribed specific conditions

[1] Also referred to as the Technical Advisory Committee.
[2] http://www.epa.gov/climatechange/emissions/

and modalities for its eligibility under the Clean Development Mechanism.[3] In August 2010, the federal government completed a multi-agency task force study that emphasized the importance of CCS for reducing GHG emissions and identified measures to help facilitate its use.[4] In November 2010, EPA issued new regulations under the Underground Injection Control (UIC) Program for the injection of CO_2 into subsurface formations[5] for the purpose of sequestration, as well as a subpart to the Greenhouse Gas Reporting Rule[6] for annual reporting of emissions from geologic sequestration projects. These EPA regulations are designed to safeguard underground sources of drinking water and to monitor, verify, and report the injected CO_2. Lastly, in California, on December 16, 2010, the Air Resources Board approved cap-and-trade rules that plan to incorporate CCS as a technology that can be utilized to meet GHG emissions reductions.

[3] http://unfccc.int/files/meetings/cop_16/application/pdf/cop16_cmp_ccs.pdf
[4] http://fossil.energy.gov/programs/sequestration/ccs_task_force.html
[5] http://water.epa.gov/type/groundwater/uic/class6/gsclass6wells.cfm
[6] http://www.epa.gov/climatechange/emissions/subpart/rr.html

2. California Policy Context for CCS

2.1. Current State Policy

On June 1, 2005, Governor Schwarzenegger signed Executive Order S-3-05, which established target reduction levels for GHG emissions in California: 2000 levels by 2010; 1990 levels by 2020; and 80 percent below 1990 levels by 2050. With the passage of Assembly Bill 32, the Global Warming Solutions Act of 2006, (Núñez, Chapter 488, Statutes of 2006), California adopted the second target of reducing GHG emissions to 1990 levels by 2020. AB 32 directed ARB to begin developing discrete early actions to reduce greenhouse gases while preparing a scoping plan to identify how best to reach the 2020 limit.

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 (EPS) of 1100 lbs CO_2/MWh established by CPUC and the Energy Commission, in consultation with ARB.

Assembly Bill 1925, (Blakeslee, Chapter 471, Statutes of 2006), passed unanimously by the California Legislature, aimed to provide policymakers with an assessment of the present level of development of geologic CCS and its potential application to meeting California's emission reduction goals. The bill directed the Energy Commission, in coordination with the Department of Conservation, to prepare a report for the Legislature. Published in 2008, the "AB 1925 report"[7] elucidated the potential for CCS technologies to contribute significantly to the state's GHG emissions reductions. What remains unclear is how CCS, whether by geologic, terrestrial, or beneficial use applications, fits into California's overall strategy or policies to reduce its GHG emissions. Studies of strategies to meet either the 2020 goals of AB 32 or the longer-term 2050 goals of Executive Order S-3-05 have generally not included CCS options.

Emissions Performance Standards

The current regulations implementing SB 1368 allow for the use of CCS to meet the EPS, but the mechanisms for determining compliance are unclear. The Energy Commission regulation states that for covered procurements that employ geologic CO_2 storage, the successfully sequestered CO_2 emissions shall not be included in the annual average CO_2 emissions. The EPS for such power plants shall be determined based on projections of net emissions over the life of the power plant. CO_2 emissions shall be considered successfully sequestered if the sequestration project meets the following requirements:

- Includes the capture, transportation, and geologic formation injection of CO_2 emissions
- Complies with all applicable laws and regulations
- Has an economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the sequestration project is operational

[7] Burton, Elizabeth A., Richard Myhre, Larry Myer, and Kelly Birkinshaw, *Geologic Carbon Sequestration Strategies for California, Report to the Legislature*. California Energy Commission, Systems Office. CEC-500-2007-100-CMF.

These requirements differ from AB 32 requirements in a few key ways.[8] First, the EPS is based on emissions over the lifetime of the plant whereas AB 32 is based on annual emissions, and the low carbon fuel standard (LCFS) considers life-cycle emissions (including indirect emissions). Second, the EPS requires an economically and technically feasible plan for permanent storage, while AB 32 accounting would need a quantification methodology for any emissions and verification of permanent storage. The definition of permanent storage is not included and may have different criteria than those under the AB 32 regulations (which have yet to be defined).

Low Carbon Fuel Standard

Executive Order S-01-07 directed ARB to create a LCFS to help meet the 2020 goal outlined in AB 32. The order calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. The LCFS is separate from the mandatory reporting regulation and the cap-and-trade program and has its own reporting tools and credit-trading requirements. The LCFS framework is based on the premise that each fuel has a "life-cycle" GHG emission value that is then compared to a standard. The life-cycle analysis includes the direct emissions associated with producing, transporting, and using the fuels in motor vehicles, as well as additional emissions, direct and indirect, derived from effects of using that fuel—for example, emissions that result from changes in land use for crop-based fuels.

The standards are expressed as the carbon intensity of gasoline and diesel fuel and their alternatives in terms of grams of CO_2 equivalent per megajoule (gCO_2E/MJ). Providers of transportation fuels must demonstrate that the mix of fuels they supply meet the LCFS intensity standards for each annual compliance period by reporting all fuels and tracking the fuels' carbon intensity through a system of credits and deficits. Credits are generated from fuels with lower carbon intensity than the standard. Deficits result from the use of fuels with higher carbon intensity than the standard. A regulated party meets its compliance obligation by ensuring that the amount of credits it earns (or acquires) is equal to or greater than the deficits it has incurred. Credits may be banked and traded within the LCFS market to meet obligations.

CCS is specified as an option for producers of high carbon intensity crude oil to reduce emissions for production and transport of crude oil to less than 15 gCO_2e/MJ. CCS could also be considered when used for the production of alternative transportation fuels such as hydrogen, compressed natural gas, and electricity. For CCS to be incorporated into the LCFS, a quantification methodology would be necessary.

The Cap-and-Trade Program and the Mandatory Reporting Regulation

A 2007 report released by the Governor's Market Advisory Committee to the ARB contains the first published recommendations on the design of a cap-and-trade system to reduce GHG emissions in California.[9] ARB, in its Climate Change Scoping Plan,[10] proposed to implement such a program, which would place an overall limit on GHG emissions from most of California's economy. Within capped sectors, some emissions reductions will be attained through direct regulations (e.g., LCFS, vehicle

[8] See AB 32 Regulations and CCS in Appendix M.
[9] Market Advisory Committee, 2007, Recommendations for Designing a Greenhouse Gas Cap-and-Trade Program for California: http://www.energy.ca.gov/2007publications/ARB-1000-2007-007/ARB-1000-2007-007.PDF
[10] http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm

efficiency measures, and renewable portfolio and electricity standards), while additional reductions will be incentivized by the price placed on GHG emissions through the imposition of a cap. Together, direct regulations and price incentives will ensure that emissions are reduced cost-effectively to the level of the overall cap.

In October 2010, ARB released draft regulations for a California cap-and-trade program. The program relies on standardized methods established by the Mandatory Reporting Regulation (MRR) of 2007 (effective January 2009) to provide source emissions data. ARB approved the cap-and-trade regulation and revisions to the MRR to support the cap-and-trade program at its December 16, 2010, Board meeting, including the following directive that pertained to CCS:

"BE IT FURTHER RESOLVED that the Board directs the Executive Officer to initiate a public process to establish a protocol for accounting for sequestration of CO_2 through geologic means and recommendations for how such sequestration should be addressed in the cap and trade program, including separate requirements for carbon capture and geologic sequestration performed with CO_2-enhanced oil recovery; carbon injected underground for the purposes of enhanced oil recovery will not be considered to be an emissions reduction without meeting ARB's monitoring, reporting, verification, and permanence requirements."[11]

The cap-and-trade regulation[12] sets a statewide cap on GHG emissions from covered entities. Each covered entity will be required to submit to ARB one allowance for each metric ton of CO_2 equivalent ($MTCO_2e$) emissions. The total number of allowances created will be equal to the cap set for cumulative emissions from all covered sectors for that year. ARB will distribute allowances to capped entities, either through direct allocation or through auction. In addition to allowances, a limited amount of emission reductions (offsets) from sources that are outside the cap will be authorized. Both allowances and offsets can be traded among entities. Economic analysis estimates an allowance price of around $21 in 2020.[13]

Starting in 2012, the cap-and-trade program will cover industrial sources emitting more than 25,000 $MTCO_2e$/year and electricity generation, including imports. In 2015, the program will expand to include transportation fuels, industrial combustion at facilities emitting less than 25,000 $MTCO_2e$ per year, and all commercial and residential fuel combustion of natural gas and propane. Sources will be required to surrender compliance instruments equal to their annual emissions at the end of each compliance period, each of which is proposed to be three years in length (2012–2014, 2015–2017, and 2018–2020). ARB will use MRR data to determine which entities have a compliance obligation and how many compliance instruments each entity must surrender. An entity will have to offer allowances or offset credits for each metric ton of CO_2e it reports emitting.

[11] California Air Resources Board, December 16, 2010, California Cap-and-Trade Program Proposed Resolution with 15-Day Modifications, Resolution 10-42: http://www.arb.ca.gov/cc/capandtrade/capandtrade/draft%20resolution.pdf.

[12] California Air Resources Board, October 28, 2010, Proposed Regulation to Implement the California Cap-and-Trade Program: http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm

[13] California Air Resources Board, 2010, Updated Economic Analysis of California's AB 32 Climate Change Scoping Plan: http://www.arb.ca.gov/cc/scopingplan/economics-sp/economics-sp.htm

GHG Accounting for CCS Under Other Regimes

U.S. EPA, the European Union, the Intergovernmental Panel on Climate Change, non-profits, and industry organizations are developing or have developed national and international accounting guidelines or systems for CCS to ensure that CO_2 can be quantified and verified as permanently stored. Any of these systems could be adapted to comply with ARB's programs, which also require an accurate accounting of the CO_2 during capture, transport, and storage. It should be noted, however, that monitoring requirements for emissions accounting purposes may differ from those for protecting human health and safety, drinking water, or other resources.

2.2. Perspectives on the Role of CCS in California

Oil and Gas Industry

Enhanced oil recovery (EOR) using CO_2 is commonly practiced in Texas and New Mexico but not in California, due to a lack of local, large-volume CO_2 supplies. The potential for commercial-scale anthropogenic supplies of CO_2 from capture processes applied to in-state facilities is creating increased interest in CO_2-EOR by California oil and gas producers.

The oil and gas industry has nearly 40 years of experience transporting and injecting CO_2 for EOR. In the United States alone, the industry operates more than 13,000 CO_2-EOR wells, over 3,500 miles of high pressure CO_2 pipelines, and has injected approximately 600 million tons of CO_2 for EOR, all while maintaining an excellent health, environment, and safety record.[14] Currently, over 2 billion cubic feet of CO_2 is injected underground each day in EOR operations in West Texas, producing an additional ~250,000 barrels of oil a day.[15]

When CO_2 is used during EOR, sequestration occurs as part of the process. For this reason, public policy that encourages the use of anthropogenic CO_2 for EOR will also be supporting GHG emissions reductions, along with increased domestic energy production.

The technology, operating procedures, and regulatory requirements that have been developed for CO_2-EOR are extensive, mature, and generally appropriate for CCS. The underground injection of CO_2 for enhanced recovery of hydrocarbons is fully and adequately regulated by U.S. EPA under the Clean Water Act's UIC Program[16] and other environmental regulatory programs (i.e., air, water, and solid waste programs).

Given the established nature, safety record, and economic value of CO_2-EOR operations, an approach that encourages CO_2-EOR for GHG emissions reductions will want to allow such projects to function as much as possible within the existing regulatory framework for EOR operations, while still ensuring that the monitoring, verification, reporting, and closure standards of applicable federal or state GHG emissions programs are met.

Further discussion of CO_2-EOR is found in Appendix O.

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[14] Parker, M., J. Meyer, and S. Meadows, *Carbon Dioxide Enhanced Oil Recovery Injection Operations Technologies* (Poster Presentation), 9th International Conference on Greenhouse Gas Control Technologies, 16–20 November 2008, Washington D.C.

[15] Ibid.

[16] http://water.epa.gov/type/groundwater/uic/index.cfm

Electric Power Generation

In order for the State to achieve its aggressive GHG reduction goals, the electricity sector needs to build low-carbon generation. There are three possible approaches to decarbonizing the electricity sector, which can be used in combination:

- Renewable energy
  - Renewable energy development is required under California's Renewable Portfolio Standard, and will likely play an expanding role in the state's energy portfolio. However, permitting for new sites and transmission lines is meeting opposition in some instances, and the intermittent output profile of wind and solar, without significant investments in energy storage, raises questions of grid reliability.
- Nuclear energy
  - New nuclear power is banned in California until there is a permanent federally managed repository for nuclear waste or reprocessing of spent nuclear fuel has been demonstrated and approved in the United States. Finding safe and socially acceptable ways to deal with nuclear waste remains a challenge for nuclear power.
- CCS
  - A Low Carbon Portfolio Standard is needed to reward utilities for purchasing electricity with CCS.

At this point, it is extremely difficult to accurately determine the costs of CCS to the electric utilities and their ratepayers. However, early adopters' financial numbers show that the addition of CCS adds considerable expense to the operation of those facilities. For the utilities, the costs of CCS will be passed on to ratepayers through Power Purchase Agreements. This issue will need to be addressed by the state government and the CPUC, working with consumer advocates and the utility sector.

In recognition of the advantages to the State that come from being in a leadership position in deploying CCS technologies and of the public-interest benefits of early mover projects, which will be shared by all Californians, the costs could also be spread to all Californians. For the electric sector, this would ease concerns that CCS could pose undue financial burdens to any single utility and its ratepayers.

Other Industries

To date, technologies making use of CO_2, including EOR, have had a negligible impact on overall anthropogenic CO_2 emissions.[17,18] Eventually, new technologies that facilitate the use of CO_2 may increase the market demand for CO_2 captured from power plant and industrial sources, thus improving the economic viability of CO_2 capture, while reducing GHG emissions and providing useful products to the public.

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[17] IPCC, 2005: *IPCC Special Report on Carbon Dioxide Capture and Storage.* Chapter 7 Mineral carbonation and industrial uses of CO_2. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[18] Koljonen, Tiina, Hanne Siikavirta, Ron Zevenhoven, *CO_2 Capture, Storage and Utilization in Finland, Project Report, VTT Processes, Systems and Models*, Aug. 29, 2002, www.vtt.fi/inf/julkaisut/muut/2002/co2capt.pdf

Possible CO_2 use technologies include those that combine geological storage of CO_2 and energy production, in a manner somewhat analogous to EOR, such as enhanced gas recovery or enhanced geothermal systems, where CO_2 replaces water as a heat exchange fluid. In this general category of CO_2-use technology, CCS is joined to the enhanced recovery of a geological resource, such as oil, natural gas, geothermal heat, minerals, or water.

There are other types of CO_2-use technologies, where the CO_2 is either stored non-geologically, or is used in such a way as to reduce net GHG emissions. The former include the synthesis from a CO_2 feedstock of solid materials such as plastics, or carbonates that can be used in cement or construction materials, which result in the carbon being trapped within the solid material.

A more detailed discussion of the uses of CO_2 is provided in Appendix E.

2.3. Deployment Considerations for Geologic CCS in California

Widespread deployment of geologic CCS in the State will require integrated assessments that include engineering analysis of sources, analysis of pipeline, rail, or other transportation alternatives, and geologic characterization of the subsurface at sequestration sites. One such preliminary assessment, currently being undertaken by the West Coast Regional Carbon Sequestration Partnership (WESTCARB), focuses on existing and newly permitted natural gas combined cycle power plants, which predominate in California's electricity generation mix. Any future energy infrastructure planning or assessments done by the State that include fossil fuel sources could also include provision for such integrated CCS assessments.

Sources

For 2008, the state's GHG reporting data[19]show that the largest in-state emissions come from refineries, natural gas electricity production, and cement plants. For the electric power sector, it is important to note that emissions counted in the state's inventory include in-state and out-of-state GHG emissions. Plans for CO_2 emissions reduction in the transportation sector typically focus on using lower net carbon fuels, such as electric-powered vehicles, which would shift emissions from the transport to the power sector.

Effective initial deployment of CCS to achieve the greatest impact on the state's GHG emissions might best be focused on the largest in-state point sources, and also on out-of-state sources in the context of regional climate change initiatives and in consideration of the western regional energy infrastructure. By 2050, assuming moderate economic growth, achieving the 2050 target level of about 90 MMT/year would require reducing emissions by 10 MMT/year each year starting in 2010, or 14 MMT/year starting in 2015.[20] While it seems evident that CCS technology must play an important role in achieving these reductions, deployment may not be rapid enough (even with policies that enable an economically favorable case for CCS adoption) if it is not accompanied by sufficient understanding of the sequestration resource potential or transport and other infrastructure development.

[19] California Air Resources Board, Mandatory GHG Reporting Data, Emissions Reported for Calendar Year 2008 http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm

[20] Schiller, S. "Implications of Defining and Achieving California's 80% Greenhouse Gas Reduction Goal," California Institute for Energy and Environment. Fourth Annual California Climate Change Conference. Sacramento, CA 9-13-2007.

Transport of CO_2[21]

Where large point sources do not overlie suitable sequestration sites, CO_2 will 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; however, for the large quantities of CO_2 involved in CCS, tanker transport is impractical and uneconomic. Rail has been considered viable in some cases, but pipelines are the most likely mode of CO_2 transport for commercial-scale sequestration operations.

The technical, economic, and permitting issues associated with CO_2 compression and pipeline transport are well understood because of the large-scale use of CO_2 for over 20 years in EOR operations in many other states. To assure single phase flow and optimize volumetric flow, the CO_2 is typically compressed at the source to a supercritical state—150 bar (2200 pounds per square inch) or more, and non-condensable gases (nitrogen and oxygen, for example) are removed. Booster compressors may be necessary along lengthy pipelines. To avoid corrosion and hydrate formation, water levels are typically kept below 50 parts per million.

More information on CO_2 pipelines can be found in Appendix I.

Geologic Suitability

In California, suitable geologic formations for CO_2 storage include depleted or near-depleted oil and gas reservoirs, as well as saline formations (rocks containing non-potable salty water). These targets are common in deep sedimentary basins, where sand and mud have accumulated to great thickness over many millions of years and lithified (compacted under pressure into rock). These types of layered rocks are potentially good storage sites because they have the capacity to hold (trap) large amounts of CO_2 in the pore spaces of permeable layers such as sandstone, while overlying impermeable mud-rock layers form good seals that prevent the gas from escaping upward. Optimal sequestration takes place at depths below 2,500 feet (800 meters) where pressures and temperatures keep CO_2 in a liquid-like, supercritical phase, which makes it less buoyant.

As part of the WESTCARB project, the California Geological Survey (CGS) developed a preliminary screening method to identify sedimentary basins in California with the greatest geologic potential for CO_2 sequestration.[22] The CGS initially identified and cataloged 104 sedimentary basins that underlie approximately 33 percent of the area of the state. For basins that passed the initial screening, available data were used to make preliminary determinations of potential storage resource capacity. A total of 27 basins met the screening criteria. Using the methodology developed to support National Energy Technology Laboratory's *Carbon Sequestration Atlas of the United States and Canada*,[23] the CO_2 storage "resource" for the 10 onshore basins was calculated to be between 75 and 300 gigatonnes of carbon dioxide (GT CO_2). For oilfields, preliminary estimates are on the order of 1.3 to 3.4 GT CO_2, and for natural gas fields, from 3.0 to 5.2 GT CO_2. The preliminary estimates indicate that the resource for geologic storage of CO_2 is ample. For comparison, the CO_2 emissions from power and industrial sources

[21] Adapted from Burton et al., op. cit.
[22] 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.
[23] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html

in California are currently about 0.08 GT per year. Final selection of any sequestration site in California will require detailed site-specific data and detailed analysis of the subsurface.

Appendix F contains more information on geologic storage potential in California.

2.4. Health and Safety Issues and Related History

The risks to human health and the environment associated with CO_2 capture, transport, and geologic storage need to be taken into consideration in the development of CCS policy for California. The possible adverse effects from a concentrated CO_2 leak from a storage site, a pipeline or other form of transport, or from the chemicals used during capture at industrial facilities must be guarded against by enacting policies to ensure proper site selection and characterization, monitoring and safety measures, and mitigation planning.

Although the idea of intentionally storing large quantities of CO_2 in underground geologic formations for extended periods is relatively new, established industrial operations—including petroleum exploration and production, EOR using CO_2, underground natural gas storage, and disposal of acid gas and hazardous wastes—provide many decades of relevant knowledge and experience for determining the risks of geologic storage. This experience base also provides the methods, tools, and approaches to manage these risks through careful site selection, characterization, injection, and monitoring.

CO_2 is non-toxic and nonflammable. Humans exhale CO_2 and plants uptake CO_2 for photosynthesis. However, there are rare examples of naturally occurring CO_2 in volcanic regions posing risks of asphyxiation in humans and animals. High concentrations in the soil will also stress vegetation and can eventually kill it. Careful consideration must therefore be given to the selection of pipeline routing, storage sites, development of operational procedures to guard against leakage, and monitoring procedures to check for leaks during operation and after injection stops.

An abrupt failure of a pipeline could lead to a high velocity release of CO_2, although it will not explode because CO_2 is nonflammable. The possibility of such an event needs to be taken into consideration in the design, construction, operating, and monitoring procedures for CO_2 pipelines. Loss of control of wells could also lead to high velocity releases of CO_2 (well blowouts). Such a release would not produce a fire or a toxic spill, but the risks of well blowouts must still be taken into consideration in the design, construction, and operation of CO_2 wells.

Induced seismicity is another risk consideration during CO_2 injection operations. It is well recognized that injecting fluids into the subsurface can result in seismic events, although the vast majority of these are not recognized as earthquakes because they do not release enough energy to be felt at the surface. In fact, there is an entire technology associated with the use of these small events, called microseismic events, as a tool for monitoring the movement of fluids in the subsurface. Although rare, there have been instances in which non-CCS injection operations—including some engineered geothermal operations—have resulted in ground motion that was felt by near-by communities. Seismic risks therefore need to be taken into consideration during site selection and in the design, operation, and monitoring of CO_2 storage projects. The identification and proximity of active faults will need to be considered during site selection, and specialized seismic monitoring may be warranted as part of the overall monitoring, verification, and reporting (MRV) plan.

Appendix R contains more information on the risks of geologic CO_2 storage.

2.5. California CCS Policy in Context with Federal Developments

There has been considerable activity on the federal level that impacts CCS from a regulatory and institutional perspective. In addition to the section below, additional information on federal activities can be found in Appendix G.

Source Emissions

Stationary source emissions of GHGs are now subject to regulation under the federal Clean Air Act (CAA),[24] pursuant to the decision of the United States Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497 (2007), which held that GHGs met the CAA's definition of "air pollutant." Pursuant to the *Massachusetts v. EPA* decision, the EPA issued its so-called "Endangerment Finding" on December 15, 2009.[25] In the Endangerment Finding, EPA concluded that six GHGs—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—may reasonably be anticipated to endanger public health and welfare. On the same day, EPA issued what is known as its "Cause or Contribute Finding," in which it defined the applicant "air pollutant" as the same six GHGs, in aggregate, and found that this new "air pollutant," when emitted from new motor vehicles and new motor vehicle engines, contribute to GHG air pollution that endangers public health and welfare.

On April 2, 2010, EPA published a notice that is known as the "Johnson Memo Reconsideration."[26] In that notice, EPA interpreted the CAA term "subject to regulation," which is one of the regulatory triggers for permitting under the CAA's Prevention of Significant Deterioration (PSD) program. The Johnson Memo Reconsideration concluded that EPA's imposition of GHG tailpipe emission standards for certain mobile sources (which were subsequently published on May 7, 2010),[27] would trigger PSD applicability for GHG-emitting stationary sources on or after January 2, 2011, which is the date when the GHG tailpipe emissions standards took effect. On June 3, 2010, EPA published what is commonly referred to as the "Tailoring Rule,"[28] which limits the applicability of PSD permitting for GHGs to only the highest-emitting GHG sources; in the absence of the Tailoring Rule, the PSD program's existing 100/250 ton-per-year thresholds would have applied.[29]

As required by the CAA, all states, including California, are currently modifying their applicable air regulations and CAA State Implementation Plans (SIPs) to satisfy these new federal requirements. On September 2, 2010, EPA proposed a "SIP Call" that provisionally found that the applicable SIPs for thirteen states, including California (Sacramento Metropolitan AQMD), lacked adequate provisions to apply PSD requirements to GHG-emitting sources.

[24] 42 U.S.C. § 7401 et seq.
[25] 74 Fed. Reg. 66496 (Dec. 15, 2009).
[26] 75 Fed. Reg. 17004 (April 2, 2010).
[27] 75 Fed. Reg. 25324 (May 7, 2010).
[28] 75 Fed. Reg. 31514 (June 3, 2010).
[29] Under the Clean Air Act, sources that have the potential to emit 250 tons per year or more of pollutants subject to regulation (or 100 tons per year or more if a source belongs to a list of 28 specified source categories) are major sources for purposes of the federal PSD program.

One issue being addressed by EPA is whether CCS is deemed a best available control technology (BACT) in the future. In November 2010, EPA issued non-binding BACT guidance for stationary sources of GHG emissions that trigger PSD effective January 2, 2011. This document and accompanying White Papers covering various industrial source categories summarize information on control techniques and measures to reduce GHG emissions from specific industrial sectors. While the guidance points out that CCS is a promising technology in the early stage of demonstration and commercialization, the guidance identifies the process as an expensive technology and unlikely to be selected as BACT in most cases.

From the source perspective, EPA has taken the following additional actions with respect to CCS. On October 30, 2009, EPA published its final rule requiring the mandatory reporting of GHGs (MRR).[30] The MRR applies to "Suppliers of Carbon Dioxide," which includes, in part: (i) facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground; and (ii) facilities with CO_2 production wells that extract a CO_2 stream for the purpose of supplying CO_2 for commercial applications.

On December 1, 2010, EPA finalized a rule that included CCS in the mandatory reporting of emissions under the GHG Reporting Program.[31]A key feature of the rule is the use of monitoring, reporting, and verification plans covering CO_2 injection operations and geologic storage sites for emissions accounting purposes. Lastly, by the end of 2010, EPA may propose a regulation that would clarify how the Resource Conservation and Recovery Act (RCRA) could apply to "CO_2 streams" in the CCS context.

Pipelines

There is no federal regulatory framework for siting CO_2 pipelines on private land, however, CO_2 pipelines can be sited on federal land under both the Federal Land Policy and Management Act and the Mineral Leasing Act. With respect to safety regulation, the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has primary authority to regulate interstate CO_2 pipelines under the Hazardous Liquid Pipeline Act of 1979. CO_2 pipelines used to distribute CO_2 within an oil field for EOR are excluded from DOT's regulation.

California does not have a statute specifically addressing the siting of CO_2 pipelines on state or private land, although it is possible they could fall under Pub. Util. Code §227 and §228, which address "pipeline corporations." The CEC certificates thermal generation facilities, which may include CO2 mitigation measures. Additional processes at the CPUC (and possibly the CEC) might enable the use of eminent domain for operators of CO2 pipelines. Such processes might include a determination that a particular pipeline is a "public utility," with a determination that the project is in the public interest and necessity. With respect to safety regulation in California, the State Fire Marshal has "exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines" under the Elder California Pipeline Safety Act of 1981 and has adopted PHMSA's safety regulations for this purpose. Lastly, it should be noted that literally thousands of miles of carbon dioxide pipelines are currently providing the gas for EOR operations in the Permian Basin in West Texas.

[30] 74 Fed. Reg. 56260 (Oct. 30, 2009).
[31] 75 Fed. Reg. 75060 (December 01, 2010).

Geologic Injection and Storage

Hazard Classification of CO_2 Injectate Under Federal Law

Perhaps of greatest relevance for geologic sequestration and for purposes of the pending Safe Drinking Water Act (SDWA) (42 U.S.C. §§ 300f to 300j-26) sequestration regulations (discussed separately below), EPA has referenced the CO_2 injectate with respect to the term "carbon dioxide stream," which means: "carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from source materials and the capture process, and any substances added to the stream to enable or improve the injection process."[32] According to EPA, carbon dioxide is not a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund) (42 U.S.C. §§ 9601 to 9675).[33] Thus, geologic sequestration of CO_2, in and of itself, should not give rise to CERCLA liability. Sequestration of CO_2 could give rise to CERCLA liability, however, if the CO_2 stream contained constituents that are CERCLA hazardous substances from the source materials or the capture process or if the CO_2 stream reacted with groundwater to produce a CERCLA hazardous substance.

Injection Well Regulation

In November 2010, EPA announced federal requirements under the Underground Injection Control (UIC) program, as authorized by the Safe Drinking Water Act.[34] The final rule establishes new federal requirements for the underground injection of CO_2 for the purpose of long-term storage. A new well class—Class VI—has been listed to ensure the protection of underground sources of drinking water (USDW) from injection related activities.

The elements of the final rule include, but are not limited to:

- Geologic site characterization to ensure the wells are properly sited
- Requirements for the construction and operation of the wells that include construction with injectate-compatible materials and automatic shutoff systems
- Periodic re-evaluation of the area around the injection well to incorporate monitoring and operational data and verify the movement of carbon dioxide according to prediction
- Rigorous testing and monitoring of each project that includes testing of mechanical integrity of the well, groundwater monitoring, and tracking of the location of the injected carbon dioxide
- Extended post-injection monitoring and site care to track the location of the injected carbon dioxide until it is demonstrated that USDW are no longer endangered
- Clarified and expanded financial responsibility requirements to ensure that funds will be available for corrective actions, if necessary
- Considerations for permitting wells that are transitioning from Class II (EOR) to Class VI that clarifies the primary purpose of the well.

[32] 73 Fed. Reg. 43492, 43535 (July 25, 2008).
[33] 73 Fed. Reg. 43,492, 43,504 (July 25, 2008).
[34] http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm

These new requirements are designed to promote transparency and national consistency in permitting CCS activities while maintaining flexibility, as appropriate. It is unclear if the final regulations will allow states such as California to have primacy enforcement authority over the new Class VI wells. Section 1422 of the SDWA provides that the states may apply to EPA for primary enforcement responsibility to administer the UIC program; governments receiving such authority are referred to as "primacy states."

Long Term Stewardship

Although there have been bills introduced on this subject in Congress, there is no federal program for the long-term stewardship of geologic storage sites during the site's "post-closure phase,"[35] which is also sometimes referred to as the "stewardship period."

Financial Support

The federal government has signaled its support of CCS technology development through a variety of funding assistance programs for qualifying CCS projects. A summary of these programs can be found in Appendix G.

White House Task Force Report

On August 12, 2010, the White House's Interagency Task Force on CCS (Task Force) delivered its report to the President of the United States.[36] Co-chaired by EPA and DOE, the Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years, with a goal of bringing five to ten commercial demonstration plants online by 2016. The report reflects input from fourteen federal agencies and departments, as well as hundreds of stakeholders and CCS experts. [37]

2.6. Policy Developments in Other States

Twenty states have enacted policies related to CCS. Policies in ten of those states are limited to studies and incentives, while the other ten states have addressed at least one of the major regulatory issues for CCS such as property rights, permitting rules, or long-term stewardship. Notably, none of the states with robust CCS policies have enacted state-level policies that limit GHG emissions like California.

A listing of CCS policies in other states is included in Appendix H.

[35] The U.S. Department of Energy, consistent with the laws of several states, considers the "post-closure phase" to mean the period after the site has been closed and "during which ongoing monitoring is used to demonstrate that the storage project is performing as expected until it is safe to discontinue further monitoring." http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html.

[36] http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

[37] http://fossil.energy.gov/programs/sequestration/ccs_task_force.html

3. Issues Requiring Attention and Resolution to Enable Safe and Effective CCS Demonstrations and Commercial Deployment in California

3.1. The Regulatory Framework for CCS Projects

What Constitutes a Project?

CCS projects will assume different configurations, however, there are several common elements between potential projects. Conceptually, CCS projects can be divided into CO_2 capture, transport, and storage components. The capture side, which includes the source of the CO_2 and the process whereby the CO_2 is separated and compressed, is likely to exhibit the greatest variety among projects. For example, the source facility may be a power plant, refinery, cement plant, or ethanol plant, and the capture process may be accomplished with chemical or physical separation technologies.

The transport component of commercial-scale projects is unlikely to vary significantly among different projects, and will consist of dedicated networks of CO_2 pipelines. The sequestration aspect will likely exhibit some variability depending whether the storage formation is a depleted or actively producing hydrocarbon reservoir or a saline formation. However, in all cases, the storage infrastructure will consist of monitoring and injection wells, surface and subsurface monitoring equipment, and surface infrastructure related to the wells, monitoring, or management of CO_2 prior to injection and of any produced formation fluids. If CO_2 reuse technologies are involved in a project, facilities for manufacturing, for hydrocarbon separation, treatment, and transport, or for other types of processing may be co-located at or near the CO_2 source or pipeline.

Treatment of "Capture" Under Current California Law

The permitting process for industrial development projects, such as CO_2 capture projects, in California involves a multitude of federal, state, regional, and local agencies, each with its unique authorities and regulatory requirements. Often, the agencies act independently of one another, and have permitting timeframes that are not closely coordinated. Typically, the first state agency to act on a permit application by a developer becomes the lead agency for the environmental document required under the California Environmental Quality Act (CEQA). The lead agency under CEQA coordinates its review of an Environmental Impact Report or Negative Declaration with the other responsible permitting agencies.

The current regulatory framework allows a project developer to approach different agencies at different times to initiate permit applications and to begin to address the environmental documentation requirements of CEQA. The timing of a permit application filing is the responsibility of the project developer.

One-Stop Permitting for Power Plants in California

For the permitting of power plants, the Energy Commission serves as the lead permitting agency and also as the lead agency under CEQA. The Energy Commission's 12-month, one-stop state permitting process

is a certified regulatory program under CEQA.[38] The Energy Commission's license and certification process subsumes the requirements of state, local, or regional agencies otherwise required before a new plant is constructed, while federal permits are issued within the timeframe of the Energy Commission's licensing process. However, there have been cases where federal and state permitting timelines have not been closely matched. The Energy Commission coordinates its review of the facility with other permitting agencies to ensure consistency between their requirements and its own conditions of certification.[39]

To date, CCS has not been a significant factor in the Energy Commission's siting process. In the case of a power plant project that involves carbon capture, the Energy Commission considers the environmental impacts of the entire facility and incorporates permit conditions to ensure that the CO_2 injection process is conducted in an environmentally safe manner. Under current law and regulations, these conditions of certification incorporate the regulatory requirements of other federal, state, regional, and local agencies into a single permitting process.[40] In most cases, applicable federal permits for activities associated with the power plants would still need to be obtained, since federal authority can pre-empt state authority.

Appendix N contains more information on permitting CCS projects in California.

GHG Issues Pertaining to the Regulation of CO_2 Capture

Aside from the siting procedures described above, a set of climate related issues applies to the permitting of the CO_2 capture plants as well. These pertain to how California regulates GHG emissions in general, and CO_2 in particular. Specifically, the CPUC[41] (in the case of investor-owned utilities) and the Energy Commission[42] (in the case of public power) implement the Emissions Performance Standard (EPS), which was instituted under Senate Bill 1368.[43] The Energy Commission, counties, and other "lead agencies" consider whether CO_2 emissions constitute a significant impact and prescribe mitigation (CEQA or equivalent). ARB implements AB 32 by a cap-and-trade program and MRR, but California's Air Districts can apply their own GHG standards to emission sources. For CCS projects the missing element is a protocol that recognizes CCS as a compliance mechanism under AB 32, and a methodology for quantifying the emission reductions.

CCS is already recognized as a compliance mechanism by the Energy Commission under the SB 1368 rules. In addition, CPUC modified its rules implementing the EPS in July 2009, to further clarify the

[38] Authority for power plant licensing by the Energy Commission is found in Public Resources Code Section 25000 et seq.

[39] PRC Section 25500 specifically provides:"In accordance with the provisions of this division, the Commission shall have the exclusive power to certify all sites and related facilities in the state, whether a new site and related facility or a change or addition to an existing facility. The issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local, or regional agency, or federal agency to the extent permitted by federal law, for such use of the site and related facilities, and shall supersede any applicable statute, ordinance, or regulation of any state, local, or regional agency, or federal agency to the extent permitted by federal law."

[40] http://www.energy.ca.gov/public_adviser/power_plant_siting_faq.html

[41] http://www.cpuc.ca.gov/PUC/energy/Climate+Change/070411_ghgeph.htm

[42] http://www.energy.ca.gov/emission_standards/index.html

[43] Perata, Chapter 598, Statutes of 2006. The law ensures that long-term investments in baseload generation by the state's utilities meet an emissions performance standard, set at 1,100lb CO_2/MWh generated.

content of the plan a load-serving entity must file as part of an application for a Commission finding that a power plant with CCS complies with the EPS.[44]

3.2. Regulation and Permitting of CO_2 Pipelines

In many instances, CO_2 capture and CO_2 storage will not occur at the same site. Pipelines will be needed to transport captured CO_2 from the capture site to the injection site. This section briefly describes the current regulation of CO_2 pipelines in terms of both safety and siting authority. It also discusses tools to acquire or use rights-of-way for CO_2 pipeline.

Developing a transportation infrastructure to accommodate future CCS projects may encounter challenges regarding technology, cost, regulation, policy, rights-of-way, and public acceptance. However, given that CO_2 pipelines exist today and the similarity of this infrastructure to others that have been developed, such as natural gas pipelines, none of these challenges is expected to be a major barrier to deployment.

The need for CO_2 pipelines may not be limited to geologic storage projects, as pipelines would likely be needed to transport large quantities of CO_2 for any other process that may be developed for beneficially reusing, or otherwise handling CO_2 at commercial scales.

Safety

CO_2 pipelines have been operating in the United States for almost 40 years, and there are approximately 3,600 miles of CO_2 pipelines in operation today. The Pipeline and Hazardous Materials Safety Administration (PHMSA), which is part of the Department of Transportation, regulates the safety of interstate CO_2 pipelines. Although CO_2 is not considered a hazardous liquid under PHMSA's regulations, it is effectively treated as if it were a hazardous liquid (i.e., subject to the same regulatory framework). These regulations address design, construction, operation and maintenance, corrosion control, and reporting requirements.

The CO_2 pipeline safety record, with respect to both the frequency and consequence of failure, is comparable to traditional gas transmission and hazardous liquids pipelines. There is very minimal risk associated with operating CO_2 pipelines. CO_2 is not flammable and the risk profile for CO_2 pipelines is somewhat different than for traditional gas transmission and hazardous liquids pipelines. However, special care must be given to a variety of design, operational, and human safety considerations in order to better compensate for CO_2 system-specific issues.

The State Fire Marshal has the "exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines" within California. The State Fire Marshal has adopted PHMSA's safety regulations. While there is some ambiguity (because carbon dioxide is not a hazardous liquid), it does appear that the State Fire Marshal could have the authority to implement these requirements and regulate the safety of any intrastate CO_2 pipelines in California.

[44] Decision 10-07-046 of July 29, 2010 modified the existing rules (set forth in Decision 07-01-039) to clarify that the plan must comply with federal and/or state monitoring, verification and reporting requirements applicable to projects designed to permanently sequester carbon dioxide and prevent its release from the subsurface, and (2) to further specify how a plan may meet monitoring, verification and reporting requirements if federal and/or state requirements do not exist or have not been finalized. See: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/121474.htm

Siting

Because pipelines can cover large distances, siting pipelines can be extraordinarily complex. Construction in populated or environmentally sensitive areas poses significant challenges. It may be difficult for project sponsors to obtain rights-of-way, and the lack of eminent domain rights can necessitate the costly rerouting of pipelines, potentially leading to the cancellation of a project for economic reasons. Another natural consequence of lacking state condemnation authority is that rights-of-way may tend to target federal and state lands for crossing. The ability to get a land use agreement across government lands, both federal and state, will be a significant incentive and may result in less desirable locations being sought. Long CO_2 pipelines may prove to be impractical, if not impossible, to site without the power of eminent domain.

California does not have a statute specifically authorizing the use of eminent domain for CO_2 pipelines. In addition there is no federal authority for siting CO_2 pipelines on private land. Although public utilities in California can exercise the power of eminent domain in certain circumstances, other entities that could sequester CO_2 lack that ability, which could hinder the broader implementation of carbon sequestration. For that reason, legislation authorizing the use of eminent domain for CO_2 pipelines would likely further the implementation of carbon sequestration.

Rate regulation

There is a particular need for flexibility in any law providing for the rate regulation for services provided by CO_2 pipelines, because of the current uncertainty as to who will own and operate such facilities, and what business model the providers of these services will use. The need for regulatory flexibility should be balanced with a need to provide potential industry participants with some degree of certainty concerning the applicable regulatory regime.

The approaches presented below illustrate the range of possible ways to regulate the rates, terms, and conditions of service of CO_2 pipelines and storage facilities.

- Approach 1 – CO_2 pipelines' rates and services would be left to commercial contracts.
- Approach 2 – An "open access/transparency" model of regulation would require CO_2 pipelines to provide open and non-discriminatory access both to owners of the facilities and to non-owners. This model would also emphasize public disclosure of commercial transactions and terms and conditions of service, but leave the negotiation of the specific rates, terms, and conditions of service to the mutual agreement of the commercial parties.
- Approach 3 – A traditional utility model of regulation would establish more detailed regulatory oversight of rates and terms and conditions of service along the lines of traditional public utility regulation. This approach would give a regulator the maximum amount of control over the rates, terms, and conditions of service.

3.3. Regulation of CO_2 Injection Under Current California Law

CO_2 injection is governed under the Underground Injection Control (UIC) Program.[45]As described in a previous section, EPA has just issued regulations for a new class of wells for CCS (Class VI).[46] Class II governs CO_2 injection for the purposes of EOR. In California, EPA administers all well classes except Class II. The Division of Oil, Gas and Geothermal Resources (DOGGR) shares primacy with EPA for Class II wells. It is uncertain whether California will seek primacy for the Class VI well category, which governs CO_2 injection for storage.

3.4. Ownership of Pore Space for CO_2 Storage

Geologic CCS projects are contingent upon the project operators obtaining the right to inject and store CO_2 within subsurface pore space. California courts have not addressed the issue of whether pore space is part of the surface or mineral estate, however, common law from other states indicates that pore space typically belongs to the surface owner.[47]

Under this scenario, implementation of a carbon storage project that underlies the properties of multiple owners could be stopped by a single owner's refusal to participate. This issue creates potential barriers for CCS projects in California. To better enable deployment of CCS, the State should consider addressing two issues related to pore space rights: 1) clarification of pore space ownership and 2) creation of mechanisms to acquire pore space rights.

The first issue—clarification of pore space ownership—could be addressed with a legislative declaration that pore space belongs to surface owners (at least by default). This would be consistent with legislation in other states (Montana, North Dakota, and Wyoming), and existing treatment of pore space in the context of oil and gas production and natural gas storage. Alternatively, the legislature could declare pore space to be a public resource or choose to recognize private interests in pore space only when the property owner has a reasonable and foreseeable use of it.

The second issue—mechanisms to acquire pore space rights—could be addressed by establishing authority for CCS projects to obtain these rights either by eminent domain or by unitization.[48] Eminent domain is commonly used to acquire property rights for projects that have a public purpose. Unitization is a long-established mechanism used in the context of oil and gas production, whereby hold-out property owners share in the revenues from production but cannot stop production from occurring. Louisiana has established a process by which to use eminent domain for carbon sequestration, and Montana, North Dakota, and Wyoming have authorized the use of unitization.

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[45] http://water.epa.gov/type/groundwater/uic/index.cfm
[46] Ibid.
[47] Even though pore space in California is most likely part of the surface estate, the mineral estate has a dominant right to use the pore space in the production of valuable minerals. For this reason, oil and gas lessees typically have the right to inject and store CO_2 in pore space but only for so long as oil and gas production is occurring and only to the extent necessary for oil and gas production.
[48] California could also consider how sequestration projects can obtain the right to use state-owned pore space.

3.5. Requirements for Monitoring, Reporting, and Verification

Monitoring, reporting, and verification (MRV)[49] can be undertaken for different reasons, including ensuring groundwater protection, quantifying and verifying GHG emission reductions, or validating model predictions. Thus MRV requirements can be quite varied depending on the purpose and any applicable statute requirements.

Current State Laws or Regulations

Numerous state regulations from ARB, the Energy Commission, CPUC, and DOGGR could incorporate MRV requirements. Statute requirements are discussed in Section II. None of the current regulations specify MRV requirements for CCS projects, although DOGGR does have requirements for MRV as it relates to protecting underground sources of drinking water during enhanced oil recovery operations. Since the current requirements only measure volumes and not specific content, these requirements would need to be revised for a CCS project in order to track how much CO_2 remains in the pore space. MRV requirements could be coordinated between the agencies with differences as necessary to meet statutory mandates.

Relevant MRV Models

MRV methodologies have been developed by different organizations for different purposes. U.S. EPA, the European Union, the Intergovernmental Panel on Climate Change, non-profits, industry organizations, and others are developing or have developed MRV plans for GHG accounting programs, injection safety programs, or for other purposes.

For example, under the Clean Air Act, EPA has expanded the MMR to include facilities that inject and store CO_2 for the purposes of geologic sequestration[50] or enhanced oil and gas recovery.[51] A key feature of this proposal is the use of "monitoring, reporting and verification" plans for geologic storage sites. In addition to MRV for GHG accounting purposes, EPA, under the Safe Drinking Water Act, issued a final rule for wells that inject CO_2 for sequestration.[52] This regulation has MRV requirements for the purpose of protecting underground sources of drinking water.

California could use these models as a starting point for its own regulatory efforts. Revisions may be necessary to ensure the MRV requirements are in line with California regulations, policy, and geologic conditions. Any revisions would likely need to include a public review process. In the case of MRV in accounting methodologies, ARB has harmonized its MRR with EPA reporting methodologies and incorporated third-party offset protocols after a public review and revision process. For MRV for CO_2 injection, the state agency applying for primacy over Class VI wells (assuming California seeks primacy) must have authority as stringent as the EPA regulations. The MRV requirements of the different state

[49] Other similar terms are frequently used including MVA for monitoring, verification, and accounting, and MMV for monitoring, measurement, and verification.
[50] 75 Fed. Reg 75060 (12/01/2010), see: http://www.epa.gov/climatechange/emissions/subpart/rr.html
[51] 75 Fed. Reg 75060 (12/01/2010), see: http://www.epa.gov/climatechange/emissions/subpart/uu.html
[52] http://water.epa.gov/type/groundwater/uic/upload/GS-fact-sheet-111210.pdf

agencies could be coordinated to ensure consistency and reduce administrative burden, as long as all the program goals and requirements are met.

3.6. Long-Term Stewardship and Liability of Storage Sites

For CCS to be effective, the CO_2 must remain underground for a long period—hundreds or thousands of years. This requires institutional, administrative, and regulatory approaches for long-term stewardship to protect the public and to properly assess the efficacy of storage sites.

Although operational risks associated with the transport and injection of CO_2 in the subsurface during EOR operations have been successfully managed for many years, the long-term (post-closure) liability for CCS raises new issues. It is important to note that the entity accepting the liability will likely (without the development of institutional initiatives) be responsible for the cost of continuing MRV activities, any mitigation or remediation required, and compensation for any damages if leakage occurs.

After CO_2 injection ceases and well closure has been successfully completed, there is an extended period during which the behavior of the CO_2 in the subsurface will need to be monitored to track the size and location of the CO_2 plume, its movement, and ultimate stabilization. Such longer-term monitoring can provide a basis for determining whether the CO_2 remains contained and environmental credits may be claimed. The frequency of monitoring and whether it should be conducted by a public agency or a private entity is an additional factor to be resolved. There is no widespread consensus on how long the post-closure MRV phase should last, with opinions ranging from 10 to 50 years. The variation in these suggested timeframes arises from the fact that CCS technology is still new and there have not been enough large-scale demonstration projects to conclusively answer the question in all circumstances due to variables in location and the types of geologic storage formations involved.

Some confusion results from the observation that the terms “long-term liability” and “long-term stewardship” are often used interchangeably. However, these terms denote distinct concepts that should be kept separate. The term “stewardship” means primary responsibility for the ongoing operation, safety, and maintenance of the project, and especially the monitoring of CO_2 behavior in the reservoir. While this may appear to be less a legal than an operational issue, the determination of operational “ownership” will certainly carry a degree of liability. Long-term stewardship requires funding for administrative and operational oversight of post-closure MRV.

“Liability” is taken to denote financial responsibility for a CCS project, either in its individual phases or as a whole. This includes financial responsibility for what can be considered as normal industrial operations of a project, as well as financial responsibility arising out of an event or events that impact the health, safety, and/or well-being of people, including but not limited to impacts to the environment, drinking water, agricultural resources, and/or wildlife. Liability also includes financial exposure under a regulatory regime if CCS credits are used to meet carbon reduction goals and standards and the sequestration fails through leakage. Long-term liability, however, does not have a defined cost, but instead a risk factor that balances likelihood of an event against the monetary consequences of that event. This latter cost is currently rather difficult to establish for insuring long-term post-closure operations.

The issues raised by long-term liability are not amenable to one-size-fits-all resolution. In the absence of an affirmative government (federal, state, or local) policy decision to take on liability that it otherwise

would not, liability issues are typically resolved either by resort to normal common law principles already in place or in special cases by negotiation on a case-by-case basis for particular contracts. In other words, it would be incumbent upon the operator to justify the need for public indemnity in a specific project. It may be ill-advised to invoke blanket public indemnity where, in individual cases, such may not be required. Much discussion of liability has been in the context of limiting a company's exposure to long-term liability in order to promote the development of this technology in the "public interest."[53] However, creating innovative risk techniques, such as insurance, bonding, or pooled federal funding might encourage CCS development but also preserve federal and state liability frameworks to promote safe practices.

One option is for government agencies to take on the long-term responsibilty for CCS sites after a certain number of years following the post-closure phase, by which time, the plume is largely or fully stabalized. The rationale for a government role in indemnifying long-term liability is due to the belief that CCS is in the public interest and that long-term liability issues should not, at this early stage in the development of the industry, be a barrier to further development. Some states have adopted legislation to accept varying limited liability. In some cases, the risk and performance of the CCS site is linked to liability transfer.

Another option is to create a carbon storage stewardship trust fund financed by fees from operators to ensure compensation for potential damages. Most of these programs respond retroactively, whereas CCS seeks a proactive framework. Where there is evidence of willful neglect of regulations or purposely providing misleading information, liability should be sought from the operator or descendents by the post-closure administrator. However, this is potentially difficult to determine, hence the desirability of a trust fund of some type.

Further discussion of long-term stewardship and liability of CCS sites is found in Appendix P.

3.7. Commercial Considerations/Incentives/Policy Drivers

CCS offers the promise of large GHG emissions reductions via a relatively small number of projects at the state's largest industrial facilities, but it is a capital- and energy-intensive technology with long development leadtimes.

Although CCS involves component technologies that have been used commercially in various industries, CCS is not practiced in an integrated, commercial manner today at the scale necessary to make meaningful reductions in man-made GHG emissions. Yet, many GHG stabilization studies forecast CCS to be a major contributor to GHG emissions reduction, especially in the period after 2020. Thus, the focus of public and private sector researchers, technology providers, industries slated for GHG emissions regulation, and financiers/investors is to accelerate CCS commercial readiness and market introduction.

[53] California has limited liability in various other situations when it is in the public interest. *See, e.g.*, CAL. CIV. CODE § 1714.5(b) (limiting liability for disaster service workers). However, courts have sometimes adopted "remedial innovations" when confronted with situations in which a serious loss occurred but no compensation was available. *In re Paris Air Crash*, 622 F.2d 1315, 1320 (9th Cir. 1980) (citing, among others, *Brown v. Merlo*, 8 Cal. 3d 855 (1973), in which the California Supreme Court held that a statute precluding automobile "guests" from suing the driver for negligence violated the equal protection clause).

Governments and regulatory bodies are encouraging technology development, demonstration, and early deployment through public policies and incentives.

Financial incentives to encourage investment in CCS demonstrations and early commercial projects tend to address one of three cost centers: capital cost, financing cost, and operating cost. Examples of federal incentives that reduce the capital cost of CCS projects are investment tax credits and U.S. Department of Energy cost share grants. An example of an incentive that reduces the cost of financing (and increases the likelihood of financial closure) is the U.S. Department of Energy loan guarantee program. Examples of incentives that reduce net operating costs are federal carbon sequestration tax credits (i.e., the Section 45Q credits in the Energy Improvement and Extension Act of 2008) and accelerated equipment depreciation schedules.

State government incentives can also address these cost centers through programs similar to those offered by the federal government, such as investment tax credits and accelerated depreciation, and through credits or exemptions to taxes uniquely imposed at the state/county level, such as property taxes. California currently offers, for example, a property tax exemption for certain investments in renewable energy technologies.

Utility rate regulation is another area where states traditionally have jurisdiction. In many states, Public Utilities/Service Commissions have authority over cost recovery for power plants built or owned by investor-owned utilities, and for long-term power purchase contracts by investor-owned utilities from plants developed and operated by independent generators. PUCs can approve “above market” costs for power from generation sources deemed to be in the public interest, although such above-market costs may adversely affect regulated utilities’ competitiveness in the retail electric market. In states where customers have access to energy service providers other than a local investor-owned utility, such as California, cost allocation mechanisms may be needed to socialize the above-market costs to all customers so that investor-owned utility customers alone do not bear the cost for the public-interest benefit. Because the CPUC has jurisdiction over only a portion of the California’s electricity service providers, the Legislature would need to establish such cost allocation mechanisms for power plant CCS applications.

The CPUC has authorized rate recovery for feasibility studies of integrated gasification combined cycle plants with CCS in exchange for public release of study results. Other states have a mixed record of support for such study costs, with some regulatory commissions approving, and some denying, rate recovery requests.

Where CO_2 emissions are regulated, annual allowances for emissions have been distributed to affected sources on the basis of historic emissions or benchmark values or via auction, or some combination thereof. In cases where allowances are auctioned, various proposals have been made to direct the resulting revenue to new technology demonstrations. For example, revenue from the New Entrants Reserve in the European Trading Scheme will be directed toward renewables and CCS demonstrations. Elsewhere, energy bill assistance for low-income households has been proposed. Bonus allowances for early CCS adopters have also been proposed as a means to offset competitive challenges in the years immediately following application (e.g., proposed Waxman-Markey federal legislation in 2008). The Air Resources Board could design the California cap-and-trade program such that allowance value is used to encourage

early applications of CCS through allowance allocation schemes or through the designation of CCS as a GHG-reducting technology allowed to receive electrical distribution utility auction proceeds, or the State Legislature could appropriate allowance auction proceeds to CCS.

One rationale for California "topping off" federal CCS incentives is the recognition that costs for land, labor, materials, and utilities tend to be higher in California than the national average (by perhaps on the order of 20% on a blended average basis), and thus a higher total value of incentive may be needed here to engender the desired degree of market response. Given current budget challenges and the myriad approaches available for incentives, California should evaluate its options to encourage early CCS projects in California and consider implementing those expected to be the most effective.

Because CCS changes the production cost profile of power plants or other industrial manufacturing operations, they may be temporarily uncompetitive relative to plants without CCS, particularly in the era immediately after regulations take effect, when allowance price caps and other measures limit the price of CO_2 emission allowances. For power plants with CCS, for example, high dispatch rates are essential to minimizing levelized cost impacts on a per-kWh basis. The California Independent System Operator (dispatch center) has mechanisms to prevent dispatch curtailment for fossil power plants with CCS, typically designation as "must run" units.

3.8. Role of Public Outreach, Education, and Acceptance

Despite growing awareness of CCS in the energy, agriculture/forestry, environmental science, and policy communities, the general public remains largely uninformed about CCS technology and its potential role in mitigating adverse climate change. Given the magnitude of the challenge posed by global climate change, it is in California's interest to have a knowledgeable populace prepared to engage in setting and implementing the state's climate and energy policies. The first step to meaningful public engagement on CCS is public understanding. It is natural for people unfamiliar with a technology to approach it with skepticism and concern, and it is the obligation of CCS policy and project stakeholders to invest in public outreach and education.

For policy-oriented agencies, CCS outreach will benefit by being positioned within the context of other major policy initiatives, principally energy supply and demand and the state's plan to reduce greenhouse gases to mitigate climate change. When CCS is presented in this manner, the public can better weigh its potential to contribute to the state's goal of fostering economic growth and opportunity while protecting human health and the environment.

It is often important to begin discussions of CCS by reminding people that $CO_2$is a non-toxic, non-flammable, natural constituent of the atmosphere that plays an essential role in plant photosynthesis. However, this information needs to be presented along with some discussion of the increasing CO_2 concentrations in the atmosphere, which are leading to climate change. Although the risks associated with CCS projects are real and need to be addressed and explained, public perception of the risks is frequently based on unfamiliarity with subsurface storage mechanisms. Learning that storage takes place at depths more than half a mile deep and storage formations are overlain by sealing formations that prevent CO_2 from migrating upward can allay concerns about sudden catastrophic releases and water contamination.

Further discussion of public outreach by California agencies is found in Appendix K.

3.9. Environmental Justice

The Environmental Justice (EJ) movement addresses the statistical reality that people who inhabit the most polluted environments are commonly people of color and the poor. Poorer communities, which often co-exist in proximity to facilities that have historically had negative environmental impacts, can be in line to host more of these types of facilities. Studies of these communities have shown that they exhibit higher levels of illness, disease, and premature deaths than do other areas.

Concerns of EJ communities often pertain to large industrial facilities such as power plants, refineries, cement plants, chemical plants, as well as truck and ship traffic, and issues associated with dumping and incineration sites. Fossil fuels figure significantly in EJ concerns because of impacts to air, land, and water associated with their extraction or production, the emissions from their refining and combustion, and their waste byproducts (e.g., coal ash and petroleum coke). EJ activists advocate moving away from the extraction and use of fossil fuels, and transitioning to sustainable alternatives.

EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies."

According to a presentation given before the Panel,[54] EJ advocates would expand EPA's definition to include "the avoidance of disproportionate environmental impacts on communities of low income residents and people of color, including:

- Cumulative health impacts on a region or community
- Fair and equitable use of government spending
- Health considerations sharing equal consideration with economic interests
- Long-term sustainability issues
- Fixing the health problems of dirty air and finding co-benefits of reductions in GHG emissions

In relation to CCS, a number of factors could lead to EJ concerns, depending on the location of a project. This is largely due to the fact that such projects will typically involve an industrial facility, although concerns over CO_2 pipelines and storage operations could also arise.

Materials on environmental justice are contained in Appendix L.

[54] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/presentations/CCS_vs_Environmental_Justice_Document.pdf

4. Appendix A: Charter of the California Carbon Capture and Storage Review Panel

Purpose of the Panel

The official title of the panel is "the California Carbon Capture and Storage Review Panel." It has been created to advise the California Energy Commission, the California Public Utilities Commission, the Air Resources Board, the Dept of Conservation and other state agencies on CCS policy.

Panel members were chosen because of their strong interest and record of accomplishment in developing energy and environmental public policy. The goals of the Panel and its supporting advisory team will be to:

- Identify, discuss, and frame specific policies addressing the role of CCS technology in meeting the State's energy needs and greenhouse gas emissions reduction strategies for 2020 and 2050; and

- Support development of a legal/regulatory framework for permitting proposed CCS projects consistent with the State's energy and environmental policy objectives.

Tasks

The Panelists will need to seek input from stakeholders and have the ability to direct and review informational material provided by a technical advisory team. The proposed meetings and subsequent deliberations will focus on:

1. Identifying and evaluating legal and regulatory barriers to deploying CCS

2. Consideration of CCS policy frameworks used elsewhere, gaps, alternatives, and their applicability in California

3. Developing specific committee recommendations

The product of this effort will be a final report from the Panel that discusses the major barriers identified, specific recommendations for resolving the regulatory and legal barriers, and the policy rational for the recommendations.

Technical Advisory Team

The Panel will be assisted by a technical advisory team. This team will include consultants and State of California agency staff. Depending on the needs of the panel, the technical support team will be available to organize the meetings, collect information, conduct analyses, attend and write summaries of the panel meetings, and interact with California agency staff to develop briefing materials for panel members and assist in drafting the final report.

Time Commitment

Panel Members: Up to four meetings, travel to Sacramento for meetings, and approximately 2 days of prep time.

5. Appendix B: Members of the California Carbon Capture and Storage Review Panel

(Read panelist biographies at www.climatechange.ca.gov/carbon_capture_review_panel/documents/CCS_Panel_Members.pdf)

Carl Bauer
Chairman CCS Review Panel
Retired Director National Energy Technology Laboratory

Sally Benson
Director of Global Climate & Energy Program (GCEP)
Stanford University

Kipp Coddington
Partner, Mowrey Meezan Coddington Cloud LLP

John Fielder
President, Southern California Edison

John King
Chairman, North American Carbon Capture & Storage Association

Kevin Murray
Managing Partner, The Murray Group

George Peridas
Climate Center Scientist
Natural Resources Defense Council

Catherine Reheis-Boyd,
President, Western States Petroleum Association

Edward Rubin
Professor of Engineering & Public Policy
Carnegie Mellon University

Dan Skopec
Chair, California CCS Coalition

6. Appendix C: California Carbon Capture and Storage Review Panel Meeting List of Presenters

First Panel Meeting - April 22, 2010

PDF files of the presentations given at the April 22 meeting may be viewed online at www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-04-22/presentations

Topic	Presenter
Welcome, Introductions, and Opening Remarks	**Mary Nichols** **Chairman** **California Air Resources Board** **Carl Bauer** **Chairman CA CCS Review Panel** **Director (Ret.) National Energy Technology Lab** **Karen Douglas** **Chairman** **California Energy Commission**
Technology Overview and Status • **Subsurface** (Subsurface_Technology_Overview.pdf) • **CO_2 Capture** (CO2 Capture-Technology Overview.pdf)	**Larry Myer** **WESTCARB Technical Director (Ret.)** **Lawrence Berkeley National Laboratory** **George Offen** **Senior Technical Executive** **Electric Power Research Institute**
Permitting- Existing Regulatory Authority and Jurisdiction in California (Permitting-Existing Regulatory Authority and Jurisdiction in California.pdf)	**Elizabeth Burton** **Carbon Management Program Project Leader** **Lawrence Livermore National Laboratory**
Regulatory Activities in Other States (State Legislative and Regulatory Actions.pdf)	**Sean McCoy** **Project Manager, CCS Regulatory Project** **Carnegie Mellon University**
Greenhouse Gas Accounting for Carbon Capture and Sequestration (Greenhouse Gas Accounting for Carbon Capture and Sequestration.pdf)	**Elizabeth Scheehle** **Carbon Capture and Sequestration Staff Lead** **California Air Resources Board**
CCS: Property Law and Liability Issues (CCS-Property Law and Liability Issues.pdf)	**Jerry Fish** **Partner at Stoel Rives LLP**

Presentation topics in **bold**; online PDF file names in parentheses ( )

Second Panel Meeting - June 2, 2010

PDF files of the presentations given at the June 2 meeting can be viewed at www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/presentations

Topic	Presenter
Welcome, Introductions, and Opening Remarks	**Carl Bauer** **Chairman CA CCS Review Panel** **Director (Ret.) National Energy Technology Lab**
CCS: California Permit Process and Identification of Gaps (Permitting-Existing Regulatory Authority and Jurisdiction in California.pdf)	**Jerry Fish** **Partner at Stoel Rives LLP**
Hydrogen Energy California Project: Update and Regulatory Experience (HECA Project-Update and Regulatory Experience.pdf)	**Maha Mahasenan** **Hydrogen Energy California (HECA)**
Environmental Perspectives of Geologic CCS (Environmental Perspectives of Geologic CCS.pdf)	**Tim O'Connor** **Environmental Defense Fund**
CO_2 Enhanced Oil Recovery, Surveillance During CO_2-EOR (Surveillance During CO_2-EOR.pdf)	**Steve Melzer** **Melzer Consulting, Inc.**
Utility Perspectives on CCS (Utility Perspectives on Carbon Capture and Storage.pdf)	**Mark Nelson** **Southern California Edison**
Carbon Capture and Storage Versus Environmental Justice (CCS vs. Environmental Justice Document.pdf)	**Tom Frantz** **Association of Irritated Residents (AIR)**

Third Panel Meeting - August 18, 2010

PDF files of the presentations given at the August 18 meeting can be viewed at www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-08-18/presentations

Topic	Presenter
Welcome, Introductions, and Opening Remarks	**Carl Bauer** **Chairman CA CCS Review Panel** **Director (Ret.) National Energy Technology Lab**
Water and Carbon Capture and Storage (01 Bourcier Cal CCS-Panel.pdf)	**Bill Bourcier** **Lawrence Livermore National Laboratory**
CCS in California: The Ratepayer Perspective (02 Ashuckian CCS Presentation.pdf)	**David Ashuckian** **Deputy Dir., Division of Ratepayer Advocates** **California Public Utilities Commission**
Environmental Justice Issues and CCS (03 Williams Environmental Justice Issues and Carbon Sequestration.pdf)	**Jane Williams** **Executive Director** **California Communities Against Toxics**
Carbon Dioxide Injection and Storage in Saline Aquifers (04 Bruno Climate Change Panel Presentation.pdf)	**Michael Bruno** **President** **Terralog Technologies**

Fourth Panel Meeting - October 21, 2010

PDF files of the presentations given at the October 21 meeting can be viewed at www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-10-21/presentations

Topic	Presenter
Welcome, Introductions, and Opening Remarks	**Carl Bauer** **Chairman CA CCS Review Panel** **Director (Ret.) National Energy Technology Lab**
California's Role in CCS Deployment (audio on WebEx Recording)	**David Hawkins** **Director of Climate Programs** **Natural Resources Defense Council**
Federal Interagency Task Force on CCS (Federal Interagency Report on CCS.pdf)	**Darian Ghorbi** **Planning and Environmental Analysis** **Department of Energy**

Final Panel Meeting - December 15, 2010

The final meeting consisted of deliberations between the Panel members. No presentations were given.

7. Appendix D: Carbon Capture and Storage Technical Advisory Team

TECHNICAL ADVISORY TEAM MEMBERS

Lisa Babcock – State Water Resources Control Board's Groundwater Protection Section

Susan Brown – California Energy Commission

Elizabeth Burton – WESTCARB, Lawrence Berkeley National Laboratory

John Clinkenbeard – California Geological Survey

Mary Jane Coombs – California Air Resources Board

Jerry Fish – Stoel Rives LLP

Rob Habel – Division of Oil, Gas, and Geothermal Resources

Judith Iklé – California Public Utilities Commission

Steve Melzer – Melzer Exploration

Larry Myer – Lawrence Berkeley National Laboratory

Richard Myhre – Bevilacqua-Knight, Inc.

George Robin – U.S .Environmental Protection Agency Region IX

Elizabeth Scheehle – California Air Resources Board

Terry Surles, Team Lead – Desert Research Institute

ENERGY COMMISSION SUPPORT STAFF

Mike Gravely
Elizabeth Keller
Martha Krebs
Bryan Lee
Sarah Michael
John Reed
Connie Sichon
Linda Spiegel

CALIFORNIA PUBLIC UTILITIES COMMISSION SUPPORT STAFF

Carol Brown

8. Appendix E: Uses of Carbon Dioxide

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Uses of Carbon Dioxide

OCTOBER 4, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

John Reed
Primary Author

Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

Options for Permitting Carbon Capture and Sequestration Projects in California

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

AB 32 Regulations and CCS

Public Outreach Considerations for CCS in California

Review of Saline Formation Storage Potential in California

1. Introduction

In addition to using CO_2 for enhanced oil recovery (EOR), there are many other possibly beneficial and revenue-generating uses for captured CO2 in various stages of development. Technologies using CO_2 might advance greenhouse gas (GHG) reduction goals by either preventing the captured CO_2 from entering the atmosphere, or by using the CO_2, or a chemical product produced from CO_2, in a way that displaces the emission of other GHGs.

2. Background

To date, technologies making beneficial use of CO_2, such as EOR, have had a negligible impact on overall anthropogenic CO_2 emissions. The volumes of the current merchant and captive CO_2 markets combined amount only to about 1% of global anthropogenic CO_2 emissions.[55,56] Furthermore the current market demand for CO_2 is mostly addressed by geological sources of CO_2 (including essentially all of the CO_2 used in EOR),[57] the use of which provides no reduction in GHG emissions to the atmosphere. The majority of CO_2 in the merchant market[58] is used for EOR (~70-80%),[59] along with a significant portion used in the food processing industry. CO_2 in captive chemical processes[60] is most commonly used in the production of urea ($(NH_2)_2CO$) for fertilizer.[61] CO_2 currently being utilized that has been separated from flue gas or chemical process streams is generally either captured from relatively pure flue gas streams (e.g., ethanol distilleries) or from process streams where CO_2 capture and separation is necessitated by a need for product purity (e.g., natural gas pipelines or ammonia production). Only about 2% of the demand for CO_2 is currently met through capturing CO_2 from power plant or industrial flue gas streams, which have relatively dilute CO_2 content and no current requirement for CO_2 capture and separation.

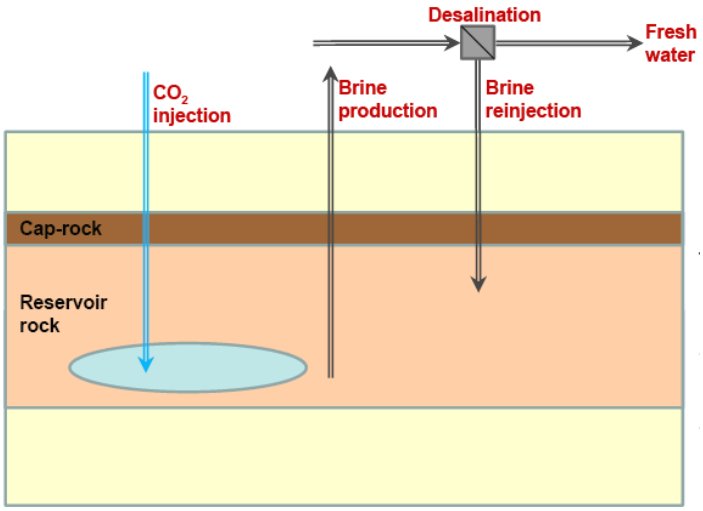

Figure 1. Desalination of aquifer brines displaced by CCS to create fresh water. Source William Bourcier, LLNL.

[55] IPCC, 2005: *IPCC Special Report on Carbon Dioxide Capture and Storage*. Chapter 7 Mineral carbonation and industrial uses of CO_2. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
[56] Koljonen, Tiina, Hanne Siikavirta, and Ron Zevenhoven, CO_2 Capture, Storage and Utilization in Finland, Project Report, VTT Processes, Systems and Models, Aug. 29, 2002, www.vtt.fi/inf/julkaisut/muut/2002/co2capt.pdf
[57] H. Audus, H. Oonk, 1997, An assessment procedure for chemical utilization schemes intended to reduce CO_2 emission to atmosphere, Energy Conversion and Management, 38 (suppl, Proceedings of the Third International Conference on Carbon Dioxide Removal, 1996), S 409- S 414.
[58] Market in which CO_2 is bought and sold competitively by multiple market participants
[59] Koljonen et al., 2002, op. cit.
[60] CO_2 produced onsite by the user of the CO_2 and not sold to outside customers.
[61] IPCC, 2005, loc. cit.

New technologies that facilitate the use of CO_2 could increase the demand for CO_2 captured from power plant and industrial sources, improving the economic viability of CO_2 capture, and reduce GHG emissions, while providing useful products to the public. Technologies making use of CO_2 could possibly provide other positive environmental and economic benefits as well, including reduced water consumption, replacement of toxic chemicals, and displacement of imported fuels, chemicals. or minerals. Some of the technological possibilities for CO_2 use will be discussed in Section 3.

The importance of finding value for CO_2 independent of any proposed regulation, carbon credit markets, or carbon taxes has been stressed in previous studies including the AB 1925 report to the California legislature "Geologic Carbon Sequestration Strategies For California: Report To The Legislature"[62] and the 2009 Integrated Energy Policy Report published by the California Energy Commission.[63] The example of Hydrogen Energy California (HECA) illustrates how a commercial-scale carbon capture project at a fossil-fired power plant can move forward in California under the current regulatory environment, without the existence of carbon credits or carbon taxes, if it is linked to a promising and potentially economical use for the captured CO_2; although it should be noted that HECA, like many new alternative energy projects, has received government support including $308 million from the Department of Energy (DOE) through the American Recovery and Reinvestment Act of 2009 (ARRA). In the case of HECA, the captured CO_2 will be delivered by pipeline to Occidental Petroleum's Elk Hills oilfield for EOR, which is a relatively well established and understood use of CO_2. However, there is a need for new, alternative uses of captured CO_2 since EOR will not be appropriate for all carbon capture operations and locations, nor will EOR be able to absorb all of the CO_2 that could potentially be captured from industrial point sources.

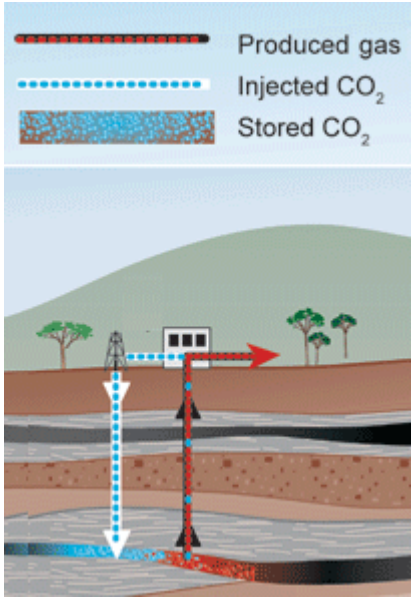

Figure 2. Enhanced coal bed methane recovery. Source CO2CRC; IPCC, 2005.

3. Technology Overview

3.1. CO_2 Use With Geological Storage

At the August 18th Carbon Capture and Storage (CCS) Review Panel Meeting, Dr. William Bourcier from Lawrence Livermore National Laboratory discussed coupling geological storage (GS) of CO_2 to the production of brine under high pressure, which may allow relatively inexpensive production of fresh water from brine through reverse osmosis.[64] This is an example of a possible use of CO_2 (Figure 1). In addition to fresh water, it is possible that valuable minerals such as lithium, used in rechargeable batteries, can be economically recovered from some brines.

[62] http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-CMF.PDF
[63] http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF
[64] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-08-18/presentations/01_Bourcier_Cal_CCS-Panel.pdf

Other technologies joining GS to some useful product that are being researched include enhanced gas recovery (EGR) with GS (Figure 2), and enhanced geothermal systems using CO_2 (EGS-CO_2), instead of water, as a heat exchange fluid (Figure 3).[65] Both of these technologies resemble EOR in that they provide a dual benefit of additional energy generation combined with GS. However, instead of being joined to the recovery of oil, GS is joined to the enhanced recovery of natural gas or geothermal heat for EGR and EGS-CO_2 respectively. The company GreenFire Energy, a member of the West Coast Regional Carbon Sequestration Partnership (WESTCARB),[66] is attempting to commercialize EGS-CO_2 technology with a demonstration plant planned near St. Johns Dome in New Mexico and Arizona. Other companies involved in this EGS-CO_2 project include Alta Rock Energy headquartered in Sausalito California.

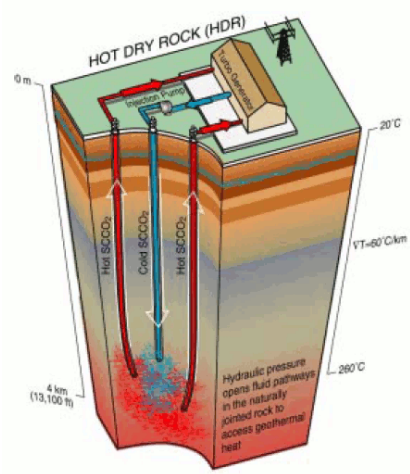

Figure 3. Enhanced geothermal system using supercritical CO_2. Source Donald Brown, LANL.

3.2.CO$_2$ Use With Non-Geological Storage

As mentioned in the AB 32 Scoping Plan published by the California Air Resources Board, there are other strategies for preventing the release of CO_2 into the atmosphere in addition to GS, such as the industrial fixation of CO_2 into inorganic carbonates.[67] Technologies are being developed today that synthesize solid materials such as plastics, or carbonates that can be used in cement or construction materials, from a CO_2 feedstock. A number of companies are trying to commercialize technologies for converting CO_2 into carbonates including WESTCARB member Calera Corporation, based in Los Gatos.

All of the examples given in Section 3.1 and 3.2 represent technologies that may someday help advance GHG reduction goals by storing CO_2 long-term, while providing additional benefits and useful products to the public.

3.3.CO$_2$ Use Without Long-Term Storage

There are other technologies under development that do not provide long-term storage of CO_2, but which still could reduce overall GHG emissions by either 1) using CO_2 in a way that displaces the emission of other GHGs, or 2) converting CO_2 into a chemical that can in turn displace the emission of other GHGs. An example of the former is using CO_2 as a refrigerant that substitutes for chemicals currently used in refrigeration that are far more potent greenhouse gases than CO_2, such as hydrofluorocarbons (over 1000X stronger greenhouse effect per unit volume than CO_2). An example of the latter is the wide array of "CO_2-to-fuel" technologies being researched with the goal of producing liquid fuels ranging from methanol or ethanol to gasoline or diesel out of CO_2 and water, along with an energy input (preferably from a CO_2-free source such as solar or wind). Fuels produced from waste CO_2 might displace the use of

[65] Donald Brown, "*A Hot Dry Rock Geothermal Energy Concept Utilizing Supercritical CO_2 Instead Of Water*," Proceedings, Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, Jan 24-26, 2000.

[66] The California Energy Commission organized and leads the WESTCARB partnership, and, along with DOE, is a principal funder of its work. www.westcarb.org

[67] http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

petroleum-derived fuels, which could result in reduced net GHG emissions, as well as address security issues related to importing oil.

Some of the better-known types of CO_2-to-fuel technologies are biologically based and use algae and other photosynthetic microorganisms in the conversion of CO_2, water, and sunlight into liquid fuel. The California Energy Commission through the Public Interest Energy Research (PIER) Program is funding R&D in this area such as the Algae OMEGA project at NASA Ames.[68] The federal government is also investing a substantial amount in this area including recent funding for the Consortium for Algal Biofuels Commercialization based in San Diego. Perhaps less well known are the efforts to chemically convert CO_2 into liquid fuels, but research is also being conducting in this area at a number of places including the newly founded DOE Joint Center for Artificial Photosynthesis headed by the California Institute of Technology.

Some uses of CO_2 that are being researched do not clearly reduce GHG emissions directly or indirectly, but still provide some other public benefit such as displacing the use of the toxic chemicals or saving water. Examples include using CO_2 as a solvent in place of perchlorethylene for dry cleaning, or using CO_2 as a non-toxic grain silo fumigant. CO2Nexus out of Hermosa Beach California is receiving PIER funding to demonstrate a Supercritical Carbon Dioxide-based Laundry System that avoids the use of toxic chemicals and saves water.

3.4.Summary Of Technologies

These examples give just a few of the possible uses for CO_2. It is evident that the possible uses of CO_2 vary greatly and cover a wide range of fields and applications. However, they can generally be placed in the following categories:

- Carbon capture and geological sequestration joined to the enhanced recovery of any geological resource, including oil, natural gas, geothermal heat, minerals, or water
- Biological conversions of CO_2 to fuel or other useful chemicals
- Chemical conversions of CO_2 to fuel or other useful chemicals
- Use of CO_2 as a heat exchange fluid or working fluid
- Use of CO_2 as a cushion (or base) gas (e.g., for natural gas storage or Compressed Air Energy Storage (CAES))
- Use of CO_2 as a solvent
- Use of CO_2 as a fumigant, propellant, or inert gas
- Use of CO_2 in the dry ice state

The many different technologies being investigated for the beneficial use of CO_2 vary widely in their stages of development, from those being tested at the bench-scale to technologies that are close to commercialization. They also vary widely in their potential to impact overall GHG emissions.

[68] http://www.energy.ca.gov/2010publications/CEC-500-2010-FS/CEC-500-2010-FS-001.PDF

The question of how much technologies that put CO_2 to useful purpose will be able to reduce net GHG emissions is an area of debate and uncertainty as illustrated by this quote taken from the 2005 Intergovernmental Panel On Climate Change Report Technical Summary:

"Another important question is whether industrial uses of CO_2 can result in an overall net reduction of CO_2 emissions by substitution for other industrial processes or products. This can be evaluated correctly only by considering proper system boundaries for the energy and material balances of the CO_2 utilization processes, and by carrying out a detailed life cycle analysis of the proposed use of CO_2. The literature in this area is limited but it shows that precise figures are difficult to estimate and that in many cases industrial uses could lead to an increase in overall emissions rather than a net reduction."[69]

There is a need to better understand the viability of the various technological options for CO_2 use and their potential to incentivize industrial carbon capture and provide substantive GHG emissions reductions. Where research funding can be most effectively invested in this area to advance GHG reduction goals, given the many diverse types and stages of beneficial CO_2 use technologies, is an important question that the Energy Commission is preparing a research roadmap to address.

4. Policy Options On CO_2 Use

Given the many existing and potential uses of CO_2, one option to consider would be for California to declare that CO_2 is a commodity as other states have done, including Louisiana (HB 661 2009).[70] This would follow the recommendation of the "Storage of Carbon Dioxide in Geologic Structures - Legal and Regulatory Guide for States and Provinces,"[71] published by the Interstate Oil and Gas Compact Commission (IOGCC), of which California is a member. However, declaring CO_2 to be a commodity could have implications on how, and by which agencies, CO_2 capture and use is regulated, which need to be analyzed in detail.

In public comments received by the California CCS Review Panel, there has been an expressed desire that non-geological sequestration strategies, such as the conversion of CO_2 to carbonates, be formally recognized as a viable sequestration option, and that there be a more explicit recognition that CCS is broader than simply gas separation and geologic storage.[72] These comments also highlight how concerns involved with non-geological types of sequestration and CO_2 use will likely have different policy interests and priorities than ones involved with GS.

For uses of CO_2 that involve GS such as the enhanced recovery of natural gas, geothermal heat, minerals, or water, it would appear possible that such technologies could be treated under a similar policy framework as EOR joined to CCS (CCS/EOR). However, it has been found that there may be significant differences between CCS/EOR and CCS in saline formations e.g., differences in monitoring, measurement, and verification (MMV), possible differences in UIC well classification, as well as possible

[69] IPCC, 2005, Technical Summary.
[70] http://www.legis.state.la.us/billdata/streamdocument.asp?did=668800
[71] http://groundwork.iogcc.org/sites/default/files/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf
[72] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/comments/Calera_Comments.pdf

differences in state permitting agencies. One can reasonably foresee that each type of enhanced recovery of a geological resource joined to GS would likely have its own set of unique requirements as well.

The differences between CO_2 use technologies that generally involve GS (e.g., Section 3.1), and those that do not (e.g., Sections 3.2 and 3.3), are even more significant, and one would expect that to be reflected in the policy priorities associated with each respective technology type. For example, in the case of carbonate materials made using CO_2, many of the significant issues that confront GS such as long-term stewardship, liability, and risks associated with storage are far less of a worry.[73] This is due to carbonates generally being solid, highly thermodynamically stable compounds. However, carbonates could still have their own unique accounting issues since carbonates can react over time releasing CO_2 under certain conditions (e.g., acidic environments), so sequestration over the long term could be less than the CO_2 initially captured.

There are policy issues confronting the non-GS strategies that could be addressed to help them advance. For example, it has been proposed that the state could help create a market that establishes value for CO_2 mitigation through a policy framework that resembles what has been implemented for renewable power with the Renewable Portfolio Standard (RPS).[74] It has also been suggested that sources creating CO_2 neutral or negative products should get reduction or offset credits not only for the emissions prevented at their facilities, but also for those that would have resulted in the use of carbon intensive conventional materials.[75] For example, if a power plant captures a ton of CO_2 and converts it to two tons of a cement product, the source could get credit for both the initial emissions captured, and for the emissions that would have resulted from the production of conventional cement. Since Portland (i.e., conventional) cement manufacturing emits roughly one ton of CO_2 for each ton of cement,[76] under such a system credit would be given for three tons of CO_2 emissions avoided per ton of CO_2 captured and converted to cement product.[77]

The idea of getting credit for emissions avoided that would have resulted from the production of conventional products is very relevant to all of the CO_2 use technologies that do not sequester CO_2, such as CO_2-to-fuel technologies. The claimed GHG reduction for these technologies generally rests on a comparison to a "business as usual case" e.g., a car burning diesel made from CO_2 captured from flue gas versus one burning diesel made from petroleum. In both cases, CO_2 is emitted from the tail pipe but the former case could result in less net CO_2 emissions than the latter business-as-usual case when accounting for both flue gas and tailpipe emissions combined. Further complicating matters is the importance of the

[73] IPCC, 2005. Chapter 7 Mineral carbonation and industrial uses of CO_2.
[74] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/comments/Calera_Comments.pdf
[75] Ibid.
[76] CO_2 emissions in conventional cement manufacturing result from heating limestone ($CaCO_3$) in a process known as calcination, which releases CO_2 to give quicklime (CaO), as well as from the fossil fuel consumed in generating the heat needed for calcination, along with energy needed for the rest of the manufacturing process.
[77] A number of complicating factors can be envisioned under such a system including the possible application of CCS at conventional cement factories to capture CO_2 emitted from calcination and/or fossil fuel combustion, as well as the energy source used in the CO_2-to-carbonate process – whether it's fossil-fuel or renewable. Since both the company manufacturing CO_2 negative cement, and the source of CO_2 used in the cement e.g., a power plant, should not both receive credit for carbon captured, the regulatory regime would need to be structured so that double counting of CO_2 reductions does not occur.

source of the CO_2 in this accounting. For example, CO_2 captured from a fermentation process at an ethanol refinery is made from carbon absorbed from the air through photosynthesis, while the carbon from CO_2 captured at a coal plant is from underground. The California Low Carbon Fuel Standard provides a model for addressing these kinds of life-cycle carbon intensity questions in a way that could be applied to emerging CO_2-to-fuel technologies,[78,79] as well as in a more general sense to other CO_2 use technologies that displace the emissions of other GHG rather than sequester CO_2.

5. Summary

There are many different opportunities for CO_2 use that could serve the dual purpose of reducing GHG emissions and providing some additional public benefit including, but not limited to, useful new or improved products, new jobs and industries, increased energy independence and security, reduced water consumption, replacement of toxic chemicals, or displacement of imported fuels, chemicals, or minerals by locally abundant CO_2 feedstock or chemical products or fuels derived from CO_2.

Some types of CO_2 use such as the enhanced recovery of natural gas, geothermal heat, minerals, or underground water involve the geological sequestration of CO_2, and hence might be able to be treated with similar policies as CCS/EOR, although each type of technology would likely have its own unique set of requirements.

Other uses of CO_2 do not involve geological sequestration, and the policy priorities connected to these technologies will likely differ significantly from those associated geological sequestration. Addressing their unique policy priorities may help some of these other promising technologies advance towards commercialization, and help California meet its greenhouse gas reduction goals.

[78] http://www.arb.ca.gov/fuels/lcfs/lcfs.htm
[79] http://www.energy.ca.gov/low_carbon_fuel_standard/

9. Appendix F: Review of Saline Formation Storage Potential in California

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Review of Saline Formation Storage Potential in California

AUGUST 4, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Larry Myer
Primary Author

Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

Options for Permitting Carbon Capture and Sequestration Projects in California

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

AB 32 Regulations and CCS

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Introduction

One of the prerequisite conditions for consideration of CCS as a method for reducing CO_2 emissions is that there be appropriate geologic conditions and sufficient capacity for storage of the CO_2 in the deep subsurface. This paper presents a brief review of the geologic attributes which make a site suitable for storage, a summary of the locations in California suitable for storage, and indications of the ample resource available for storage.

Background and Storage Basics

Although the idea of intentionally storing large quantities of CO_2 in underground geologic formations for extended periods is relatively new, natural CO_2 reservoirs, as well as oil and gas reservoirs—many containing large percentages of CO_2—have existed for millions of years. Relevant industrial experience includes natural gas injection and storage, which has been successfully practiced for many decades. For more than 30 years, the oil industry has re-injected produced gas for various purposes, including reservoir pressure maintenance, avoidance of sour gas processing in locations without markets for sulfur by-products, disposal of gas processing by-products, and to eliminate flaring. Salty water co-produced with oil has been similarly re-injected. The oil industry also commonly uses CO_2, water/steam, and nitrogen for enhanced oil recovery (EOR), wherein injected fluids mobilize residual oil to producing wells.

In California, suitable geologic formations for CO_2 storage include depleted or near-depleted oil and gas reservoirs and saline formations (rocks containing non-potable salty water). These targets are common in deep sedimentary basins, places where sand and mud have accumulated to great thickness over many millions of years and lithified (compacted under pressure into rock). These types of layered rocks are potentially good storage sites because they have the capacity to hold or trap large amounts of CO_2 in the pore spaces of permeable layers such as sandstone, while overlying impermeable mud-rock layers form good seals that prevent the gas from escaping upward. Both oil and gas reservoirs and saline formations derive from the same lithified sand and mud in a sedimentary basin, so the physical properties of the rocks of relevance to CO_2 storage, such as the porosity and permeability of the sandstones, and impermeability of the mud-rock seals, are the same in both cases. Oil and gas reservoirs can be thought of as local regions within saline formations where hydrocarbons fill most of the pore space between the sand grains.

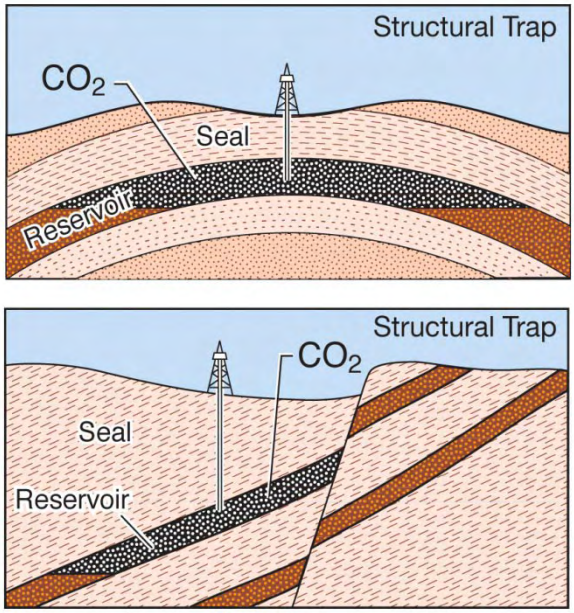

Figure 4: Illustration of sealing mechanisms created by formation deformation (top) and by faulting (bottom).

In order to make the most efficient use of underground pore space, and to maximize the vertical separation between storage formations and potable water, CO_2 storage takes place at depths below 800 meters, about 2500 feet, where ambient pressures and temperatures result in CO_2 as a liquid-like, supercritical phase, which occupies much less volume than gaseous phase CO_2 captured at industrial facilities. Under

supercritical conditions, the density of CO_2 will range from 50 to 80 percent of the density of water. Because it's still lighter than the native formation water, a buoyant force will tend to lift the CO_2 upward, (hence, the need for impermeable overlying seals as discussed earlier). Over time, several additional trapping mechanisms work to immobilize the CO_2 in the reservoir, including physical (capillary trapping) and chemical (solubility and mineral trapping) processes. Collectively, these are referred to as "secondary" trapping mechanisms.

One geologic attribute that is necessary for the existence of oil and gas reservoirs, but not necessarily required for CO_2 storage because of secondary trapping, is structural closure, wherein geologic layers have been deformed or altered in a way that prevents lateral and upward movement of the hydrocarbons. The "classic" hydrocarbon reservoir is exemplified by seal rocks deformed into the shape of a dome, or inverted bowl (see Figure 4), under which the hydrocarbons have collected. In California, stratigraphic traps where the reservoir rock pinches out or terminates laterally in an impermeable rock "sandwich" are common. Another very common structural closure mechanism in California is faulting. As rocks on one side of a steeply dipping fault are moved relative to those on the other side, reservoir rocks are brought into contact with impermeable rocks, preventing lateral movement of fluids. In some instances, however, faults can act as leakage paths. If faults are present, a necessary part of site characterization is to assess if they are seals or not.

The California CO_2 Storage Resource

As part of the WESTCARB project, the California Geological Survey (CGS) conducted screening studies to identify California sedimentary basins having the greatest potential for long-term geologic CO_2 storage. CGS initially identified and cataloged 104 onshore sedimentary basins that collectively underlie approximately 33 percent of the area of the state. These basins include all large oil- and gas-producing basins, as well as numerous smaller basins. These basins were then screened, using available data, to make preliminary determinations of their geologic suitability for CO_2 sequestration. Screening criteria included the presence of significant porous and permeable units in which to store CO_2, thick and pervasive seals to restrict migration of CO_2, and sufficient basin depth to provide the confining pressure required to keep injected CO_2 in its high-density (low-volume) supercritical phase. Accessibility was also considered, and basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs administered lands, and military installations were excluded. Most of the basins excluded for these reasons are located in eastern and southeastern California.

Of the 27 onshore basins that met the screening criteria, the most promising are the larger basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda basins. Favorable attributes of these basins include (1) geographic distribution; (2) thick sedimentary fill with multiple porous and permeable zones; (3) thick, laterally persistent sealing units; (4) availability of good datasets to characterize the subsurface; and (5) numerous abandoned or mature oil and gas fields that might be reactivated for CO_2 sequestration or benefit from CO_2 enhanced oil and gas recovery operations.

Using the methodology developed to support NETL's Carbon Sequestration Atlas of the United States

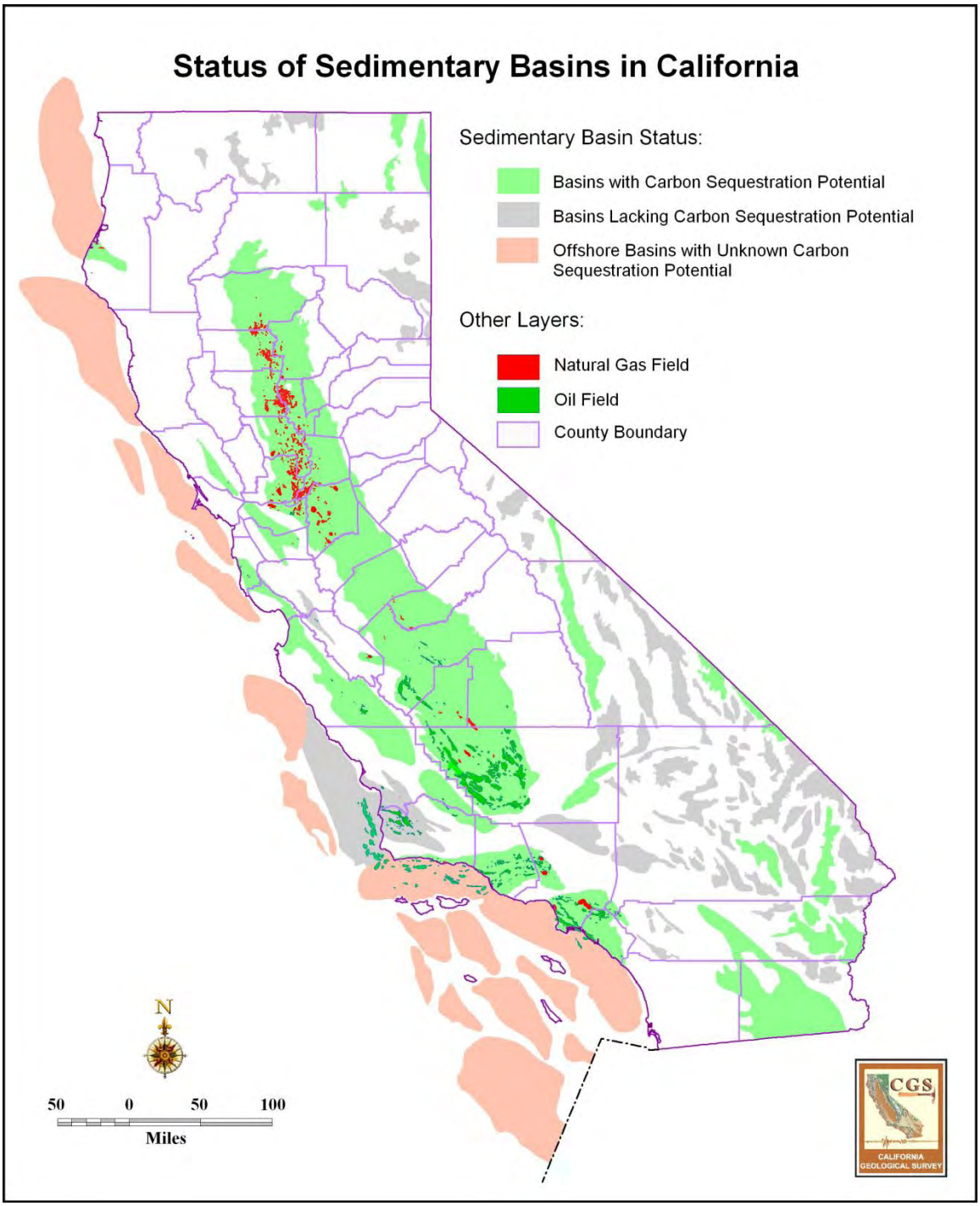

Figure 5. Map of sedimentary basins in California showing those currently identified as having CO_2 storage potential. Oil and gas fields are co-located is several basins with high storage potential, suggesting opportunities for CO_2-enhanced recovery.

and Canada, the CO_2 storage "resource" for the 10 onshore basins was calculated to be between 75 and 300 gigatonnes of carbon dioxide (GT CO_2). For oilfields, preliminary estimates are on the order of 0.3 to 1.3 GT CO_2, and for natural gas fields, from 3.0 to 5.2 GT CO_2. The preliminary estimates indicate that the resource for geologic storage of CO_2 is ample. For comparison, the CO_2 emissions from power and industrial sources in California are currently about 0.08GT per year.

Californians may also find candidates for CO_2 storage in nearly all of the 20 offshore basins identified by CGS, however, a lack of available data has limited the quantification of their CO_2 sequestration potential to areas where oil and gas exploration has occurred. A CGS study of the oil and gas fields of the Los Angeles and Ventura offshore basins estimated 0.24 GT of capacity in depleted hydrocarbon reservoirs.

Figure 5 shows all the sedimentary basins in California, along with those currently identified as having CO_2 storage potential.

Although early carbon capture and sequestration projects may take advantage of the opportunities for storing CO_2 in conjunction with CO_2-enhanced hydrocarbon recovery projects in depleting oil and gas fields, such applications will not be sufficient to accommodate all of the CO_2 that must ultimately be captured from California industrial sources. Commercial application of geologic sequestration in California will require use of the state's saline formations.

The saline formation storage resource numbers quoted above arise from estimates made with limited geologic data, and without any constraints due to technology, cost, or regulations. As both geologic and non-geologic constraints are added, storage resource values, while still quite large, will be decreased. This can be seen in the continued work by the California Geological Survey to better define the state's CO_2 storage resource.

CGS has completed a more detailed, formation-specific mapping of the southern portion of the Sacramento Basin, representing a little more than 22% of the area of the Central Valley. CGS used information from about 6,200 wells to better define the thickness, extent, and continuity of potential reservoir sands and seals in the Mokelumne River, Starkey, and Winters formations. Using the NETL methodology for calculation of CO_2 storage resource yielded a total of 3.5–14.1 GT for the mapped formations. On a percentage area basis, this represents about a factor of 3 decrease in the preliminary storage resource quoted above, though still very large relative to current California emissions.

Final selection of a sequestration site in any of the California basins will require more detailed, site-specific data and detailed analysis of the subsurface. Thorough knowledge of the geologic structure and properties is key to minimizing the risk of leakage. From this perspective, storage locations in saline formations that are located vertically between, or laterally adjacent to, existing oil/gas reservoirs have an advantage over other locations because of the large body of pre-existing subsurface knowledge gained from the oil/gas exploration and production activities. A disadvantage of existing oil/gas reservoirs is that the existence of old wells, potentially not constructed or closed to modern standards, increases the risk of leakage. Generally, this risk increases with the age of the wells. Therefore, identification and assessment of existing deep wells at or near a proposed CO_2 storage project will need to be an element of site characterization. Whether targets are depleted hydrocarbon reservoirs or saline formations, site

characterization must be followed by detailed study of appropriate monitoring systems, potential health and environmental risks, transport issues, and economics in order to assess a potential site.

Connecting Sources to Storage Sites

Locations of many of the largest CO_2 point sources appear to match well with geologic storage sites in saline formations for key areas of the state: the Los Angeles Basin, the southern San Joaquin Valley, and the Sacramento-San Joaquin river delta. Co-location of major CO_2-producing sources with suitable sinks is not a given, however, so the lack of a CO_2 pipeline infrastructure in California could present a barrier to early commercialization in some instances. In total, some 30 California industrial facilities each produce over 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 California are relatively small because they were mostly non-utility generators built as cogeneration qualified facilities.

Summary

In summary, work to date has shown that the CO_2 storage resource in California is ample and well matched with major industrial point sources. Saline formations represent the largest CO_2 storage resource, by far. Depleted oil and gas reservoirs represent a smaller fraction of the total storage resource, but are attractive for early projects because of the greater availability of data for site characterization and the prospect of offsetting revenue from hydrocarbon sales. Though existing geologic data is generally more limited than for existing oil and gas reservoirs, saline formation storage is attractive because these formations are more broadly distributed relative to sources, and the risks of leakage due to leakage from existing wells is less. Ultimately, saline formation storage will be necessary to accommodate all of the CO_2 that must be captured from industrial point sources to enable California to meet its long-term goals for reducing greenhouse gas emissions. Because California's saline formations have not been extensively studied, further work is needed to better define the best storage sites within areas defined as storage resources. Selection of any specific storage site will require site-specific data acquisition, geologic modeling and analysis of potential health and environmental risks, monitoring system design, and analysis of transport issues and economics.

10. Appendix G: Federal Overview

Source Emissions

Stationary source emissions of greenhouse gases (GHG) are now subject to regulation under the federal Clean Air Act (CAA) (42 U.S.C. § 7401 et seq.) pursuant to the decision of the United States Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497 (2007) which held that GHGs met the CAA's definition of "air pollutant." Pursuant to the *Massachusetts v. EPA* decision, the U.S. Environmental Protection Agency (EPA) issued its so-called "Endangerment Finding" on December 15, 2009. 74 Fed. Reg. 66496 (Dec. 15, 2009). In the Endangerment Finding, EPA concluded that six GHGs—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—may reasonably be anticipated to endanger public health and welfare. On the same day, EPA issued what is known as its "Cause or Contribute Finding"; in that finding, EPA defined the applicant "air pollutant" as the same six GHGs, in aggregate, and found that this new "air pollutant," when emitted from new motor vehicles and new motor vehicle engines, contribute to GHG air pollution that endangers public health and welfare. Id.

On April 2, 2010, EPA published a notice that is known as the "Johnson Memo Reconsideration," 75 Fed. Reg. 17004 (April 2, 2010). In that notice, EPA interpreted the CAA term "subject to regulation," which is one of the regulatory triggers for permitting under the CAA's Prevention of Significant Deterioration (PSD) program. The Johnson Memo Reconsideration concluded that EPA's imposition of GHG tailpipe emission standards for certain mobile sources (which were subsequently published on May 7, 2010; 75 Fed. Reg. 25324 (May 7, 2010)) would trigger PSD applicability for GHG-emitting stationary sources on or after January 2, 2011, which is the date when the GHG tailpipe emissions standards took effect. On June 3, 2010, EPA published what is commonly referred to as the "Tailoring Rule." 75 Fed. Reg. 31514 (June 3, 2010). The Tailoring Rule limits the applicability of PSD permitting for GHGs to only the highest-emitting GHG sources; in the absence of the Tailoring Rule, the PSD program's existing 100/250 ton-per-year (tpy) thresholds would have applied.[80]

As required by the CAA, all states, including California, are currently taking steps to modify their applicable air regulations and CAA State Implementation Plans (SIP) to satisfy these new federal requirements. On September 2, 2010, EPA proposed a "SIP Call" that provisionally found that the applicable SIPs for thirteen states, including California (Sacramento Metropolitan AQMD), lacked adequate provisions to apply PSD requirements to GHG-emitting sources.

One issue to be addressed by EPA going forward is whether CCS is deemed BACT in the future. BACT is applied on a case-by-case; takes into account energy, environmental, and economic impacts and other costs; and must be "achievable" for the facility. 42 U.S.C. § 7479(3). EPA's 1990 Draft NSR Workshop Manual, which despite its draft status represents longstanding EPA policy and is used in BACT determinations to this day, states that "if the technology has been installed and operated successfully on

[80] Under the Clean Air Act, sources that have the potential to emit 250 tons per year or more of pollutants subject to regulation (or 100 tons per year or more if a source belongs to a list of 28 specified source categories) are major sources for purposes of the federal PSD program.

the type of source under review, then it is demonstrated, and it is technically feasible." Draft NSR Workshop Manual, p. B.17 (EPA 1990).

From the source perspective, EPA has taken the following additional actions with respect to CCS. On October 30, 2009, EPA published its final rule requiring the mandatory reporting of GHGs (MRR). 74 Fed. Reg. 56260 (Oct. 30, 2009). The MRR applies to "Suppliers of Carbon Dioxide," which includes, in part: (i) facilities with production process units that capture and supply CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground; and (ii) facilities with CO_2 production wells that extract a CO_2 stream for the purpose of supplying CO_2 for commercial applications.

On April 12, 2010, EPA proposed an expansion of the MRR to include facilities that inject and store CO_2 for the purposes of geologic sequestration or enhanced oil and gas recovery. 75 Fed. Reg. 18576 (April 12, 2010). A key feature of this proposal is the use of "monitoring, reporting and verification" plans for geologic storage sites. EPA transmitted the final version of this rule to OIRA on August 6, 2010, which means that its publication should be imminent.[81]

Pipelines[82]

There is no current federal regulatory scheme for siting CO_2 pipelines on private land, but CO_2 pipelines can be sited on federal land under both the Federal Land Policy and Management Act and the Mineral Leasing Act. With respect to safety regulation, the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has primary authority to regulate interstate CO_2 pipelines under the Hazardous Liquid Pipeline Act of 1979. CO_2 pipelines that are used to distribute CO_2 within an oil field for purposes of enhanced oil recovery (EOR) are excluded from DOT's regulation. California does not have a statute specifically addressing the siting of CO_2 pipelines on state or private land. However, the California Public Utilities Commission (CPUC) could authorize the use of eminent domain by public utilities to site CO_2 pipelines in conjunction with power generating facilities. With respect to safety regulation in California, the State Fire Marshal has "exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines" under the Elder California Pipeline Safety Act of 1981 and has adopted PHMSA's safety regulations for this purpose.

[81] Similarly, and although not a federal requirement or program per se, the Pew Center on Global Climate Change (Pew) announced on September 30, 2010 that it was developing a framework to quantify GHG reductions from CCS. In its announcement, Pew stated that the "framework will have broad applicability and could support federal and state policy makers in developing meaningful plans to cut GHG emissions over time." http://www.pewclimate.org/press-center/press-releases/pew-center-global-climate-change-developing-framework-quantify-ghg-reduc.

[82] For more background and analysis of pipeline regulation, see *Carbon Dioxide Pipelines*, White Paper, presented at August 18, 2010 California Carbon Capture and Storage Review Panel meeting.

Geologic Injection and Storage

Hazard Classification of CO_2 Injectate Under Federal Law

Perhaps of greatest relevance for geologic sequestration and for purposes of the pending Safe Drinking Water Act (SDWA) (42 U.S.C. §§ 300f to 300j-26) sequestration regulations (discussed separately below), EPA has referenced the CO_2 injectate with respect to the term "carbon dioxide stream," which means: "carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from source materials and the capture process, and any substances added to the stream to enable or improve the injection process." 73 Fed. Reg. 43492, 43535 (July 25, 2008). According to EPA, carbon dioxide is not a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund) (42 U.S.C. §§ 9601 to 9675).[83] Thus, geologic sequestration of CO_2, in and of itself, should not give rise to CERCLA liability. Sequestration of CO_2 could give rise to CERCLA liability, however, if the CO_2 stream contained constituents that are CERCLA hazardous substances from the source materials or the capture process or if the CO_2 stream reacted with groundwater to produce a CERCLA hazardous substance.

Injection Well Regulation

In November 2010, EPA published Federal Requirements Under the Underground Injection Control (UIC) for Carbon Dioxide Geologic Sequestration Wells, Final Rule as authorized by the Safe Drinking Water Act. The final rule establishes new federal requirements for the underground injection of carbon dioxide for the purpose of long-term storage. A new well class—Class VI has been listed to ensure the protection of underground sources of drinking water (USDW) from injection related activities.

The elements of the final rule include, but are not limited to:

1. Geologic site characterization to ensure the wells are properly sited
2. Requirements for the construction and operation of the wells that include construction with injectate-compatible materials and automatic shutoff systems
3. Periodic re-evaluation of the area around the injection well to incorporate monitoring and operational data and verify the movement of carbon dioxide according to prediction
4. Rigorous testing and monitoring of each project that includes testing of mechanical integrity of the well, groundwater monitoring, and tracking of the location of the injected carbon dioxide
5. Extended post-injection monitoring and site care to track the location of the injected carbon dioxide until it is demonstrated that USDW are no longer endangered
6. Clarified and expanded financial responsibility requirements to ensure that funds will be available for corrective actions, if necessary
7. Considerations for permitting wells that are transitioning from Class II (EOR) to Class VI that clarifies the primary purpose of the well.

These new requirements are designed to promote transparency and national consistency in permitting CCS activities while maintaining flexibility, as appropriate. It is unclear if the final regulations will allow states such as California to have primacy enforcement authority over the new Class VI wells. Section

[83] 73 Fed. Reg. 43,492, 43,504 (July 25, 2008).

1422 of the SDWA provides that the states may apply to EPA for primary enforcement responsibility to administer the UIC program; governments receiving such authority are referred to as "primacy states."

Long Term Stewardship

Although there have been bill introduced on this subject in Congress, there is no federal program for the long-term stewardship of geologic storage sites during the site's "post-closure phase,"[84] which is also sometimes referred to as the "stewardship period."

Financial Support

The federal government provides a variety of funding assistance to qualifying CCS projects.

Tax-Related Incentives

Section 45Q Sequestration Credit

The Energy Improvement and Extension Act of 2008 ("EIEA")—enacted last fall as part of the Emergency Economic Stabilization Act of 2008—added a new section 45Q sequestration tax credit. Section 45Q has two parts. The first part is a credit of $20 per metric ton for "qualified carbon dioxide" captured by a taxpayer at a qualified facility and disposed of by such taxpayer in secure geological storage (including storage at deep saline formations and unminable coal seams under such conditions as the Secretary of the Treasury may determine).

The second part allows a credit of $10 per metric ton of qualified carbon dioxide that is captured by the taxpayer at a qualified facility and used by such taxpayer as a tertiary injectant (including carbon dioxide augmented waterflooding and immiscible carbon dioxide displacement) in a qualified enhanced oil or natural gas recovery project. In early 2009, as part of the American Recovery and Reinvestment Act (ARRA), this provision was amended to require that the qualified carbon dioxide end up in "secure geological storage."

"Qualified carbon dioxide" is defined as carbon dioxide captured from an industrial source that (1) would otherwise be released into the atmosphere as an industrial emission of greenhouse gas, and (2) is measured at the source of capture and verified at the point or points of injection. Qualified carbon dioxide includes the initial deposit of captured carbon dioxide used as a tertiary injectant but does not include carbon dioxide that is recaptured, recycled, and re-injected as part of an enhanced oil or natural gas recovery project process.

Federal legislation recently has been recently to amend the section 45Q credit. S. 3935, the "Advanced Energy Tax Incentives Act of 2010," would provide the following changes to section 45Q: (i) increase the 75 million metric ton cap to 100 million metric tons; (ii) please a 10 million metric ton credit cap on any one project; (iii) increase the $20 ton credit amount to $35; (iv) toughen the definition of "qualified facility" to include a requirement that the taxpayer show "contractual intent to inject and permanently sequester the full amount of captured carbon dioxide"; and (v) add new provisions to allow credit

[84] The U.S. Department of Energy, consistent with the laws of several States, considers the "post-closure phase" to mean the period after the site has been closed and "during which ongoing monitoring is used to demonstrate that the storage project is performing as expected until it is safe to discontinue further monitoring." http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html.

certification in advance, with a look-forward period of 10 years, measured from the date when the taxpayer has received its permits under the CAA. S. 3935 remains pending the Senate.

Funding/Stimulus Programs

ARRA allocated $3.4 billion to DOE for CCS-related grants and related expenditures, including: (i) Clean Coal Power Initiative Round III[85]; (ii) industrial CCS; (iii) site characterization activities in geologic formations; (iv) geologic sequestration training and research; and (v) direct program funding.

Federal Loan Guarantees

DOE's Loan Guarantee Program (LGP) was established under EPAct and was designed to support eligible projects that avoid, reduce or sequester air pollutants, including anthropogenic emissions of GHGs using new and innovative technology. DOE issued a final rule governing the LGP on October 23, 2007; under that rule: (i) applicants must pay administrative costs and the credit subsidy cost of their proposed project; (ii) the loan guarantee must not cover more than 80% of the total project cost; (iii) the loan guarantee must not finance tax-exempt debt obligations; (iv) project sponsors must make a significant equity contribution to the project; and (v) DOE must hold the first lien on all project assets pledged as collateral for the loan.

White House Task Force Report

On August 12, 2010, the White House's Interagency Task Force on CCS (Task Force) delivered its report to the President of the United States. Co-chaired by EPA and DOE, the Task Force was tasked with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing 5 to 10 commercial demonstration plants online by 2016. The report reflects input from 14 federal agencies and departments as well as hundreds of stakeholders and CCS experts. A presentation by a DOE representative was made on this subject at the October 21, 2010 Panel meeting.[86]

[85] DOE's goals in Round 3 are to cost share to demonstrate at commercial scale in a commercial setting technologies that: (1) operate at 90% carbon dioxide capture efficiency; (2) make progress toward capture and sequestration at less than 10% increase in the cost of electricity for gasification systems and less than 35% for combustion and oxy combustion systems; and (3) make progress toward capture and sequestration of 50% of plant CO_2 output at a scale sufficient to evaluate impact of the carbon capture technology on plant operations, economics, and performance. At least 300,000 tons per year of carbon dioxide emissions from the demonstration plant must be captured and sequestered or put to beneficial reuse. The carbon capture process must operate at a capture efficiency of at least 90%.

[86] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-10-21/presentations/Federal_Interagency_Report_on_CCS.pdf

11. Appendix H: State-based Overview

Twenty states have enacted policies related to CCS. Policies in ten of those states are limited to studies and incentives, while the other ten zdtates have addressed one of the major regulatory issues for CCS such as property rights, permitting rules, and long-term stewardship. The following table provides a summary of major aspects of CCS legislation in these ten states. Notably, none of the states with robust CCS policies in place have state-level policies limited emissions of greenhouse gases like California.

Summary of state geologic storage policies as of May 1, 2010 (Source: Pollak, et al. 2010)

State	Property Rights, incl. Access to Pore Space	Permitting Rules	Long-term Stewardship
Kansas 2009: KAR 82-3-1100-1120 2007: HB 2719	N/A	Agency: KS Corporation Commission. Rules adopted Feb. 2010	State will assume long-term site management, but limited liability. Fund established for long-term monitoring and remediation.
Louisiana 2009: HB 661 2008: HB 1220, 1117	Addresses CO_2 ownership, liability during operations, and eminent domain. Does not address pore space ownership.	Agency: Office of Conservation, Dept. of Nat. Resources. Rules not yet proposed.	State will assume long-term ownership but limited liability. Fund established for long-term monitoring and limited remediation.
Montana 2009: SB 498	Addresses pore space ownership, liability during operations, mineral rights primacy, CO_2 ownership, and provides for unitization.	Agency: MT Board of Oil and Gas Conservation, with comments from MT Board of Env. Review. Rules not yet proposed.	State will assume long-term ownership and liability. Fund established for all long-term liabilities.
North Dakota 2009: SB 2095, SB 2139	Addresses pore space ownership, CO_2 ownership, liability during operations, mineral rights primacy, and provides for unitization.	Agency: ND Industrial Commission. Rules adopted November 2009	State will assume long-term ownership and liability. Fund established for all long-term liabilities.
Oklahoma 2009: SB 610 2008: SB 1765	Addresses CO_2 status and ownership and mineral rights primacy. Inventory accounting rules adopted. Does not adress pore space ownership and liability during operations.	Agency: Corporation Commission for fossil fuel-bearing formations; Dept. of Env. Qual. for all others. Rules not yet proposed.	N/A
Texas 2009: HB 1387, HB1796	Addresses CO_2 ownership, liability during operations. Does not address pore space ownership.	Agency: Railroad Commission, Texas Commission on Env. Quality. Draft rules issued March 26, 2010	State will assume limited long-term site management but not all liabilities. Fund established for long-term monitoring and limited remediation.
Utah 2008: SB 202	N/A	Agency: Dept. Of Env. Quality. Rules not yet proposed.	N/A

State	Property Rights, incl. Access to Pore Space	Permitting Rules	Long-term Stewardship
Washington 2008: WAC 173-407-110 2007: ESSB 6001	N/A	Agency: Department of Ecology Rules adopted in 2008.	N/A
West Virginia 2009: HB 2860, W.V. Code, Chap. 22, Art. 11A	Addresses mineral rights primacy. Assigns study group to make recommendations on other issues such as pore space ownership by 2011.	Agency: Dept. of Env. Protection Rules not yet proposed.	N/A
Wyoming 2010: HB 17 2009: HB 57, 58, 80, Water Qual. Rules & Regs. Chap. 24** 2008: HB 89, 90	Addresses pore space ownership, CO_2 ownership, liability during operations, mineral rights primacy, and provides for unitization.	Agency: Dept. of Env. Quality. Draft rules published 3/13/09, rev. 9/25/09	State will assume limited long-term site management but not all liabilities. Fund established for long-term monitoring.

N/A – Not Addressed **Proposed Rules

References

McCoy, S.T., M. Pollak and R.L. Gresham, "State Legislative and Regulatory Actions: Review, Motivation, and Effects on Geologic Sequestration of Carbon Dioxide," Presentation to the California Carbon Capture and Storage Review Panel Meeting, Sacramento, CA, April 22, 2010.

Pollak, M., R.L. Gresham, S.T. McCoy and S.J. Phillips, "State Regulation of Geologic Sequestration: 2010 Update," Proceedings of Ninth Annual Conference on Carbon Capture & Sequestration, Pittsburgh, PA, May 10 -13, 2010.

12. Appendix I: Carbon Dioxide Pipelines

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Carbon Dioxide Pipelines

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

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Review of Saline Formation Storage Potential in California

Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

AB 32 Regulations and CCS

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Carbon capture and sequestration are unlikely to occur on the same site. Pipelines will be needed to transport captured carbon dioxide (CO_2) from the capture site to the injection site. This issue paper briefly describes the current regulation of CO_2 pipelines in terms of both safety and siting authority. It also discusses tools to acquire or use rights-of-way for CO_2 pipeline.

Pipeline Safety

CO_2 pipelines have been operating in the United States for almost 40 years, and there are approximately 3,600 miles of CO_2 pipelines in operation today.[87] The Pipeline and Hazardous Materials Safety Administration ("PHMSA"), which is part of the Department of Transportation, regulates the safety of interstate CO_2 pipelines under the Hazardous Liquid Pipeline Safety Act of 1979.[88] CO_2 is defined under PHMSA's regulations as "a fluid consisting of more than 90 percent CO_2 molecules compressed to a supercritical state."[89]Although CO_2 is not considered a hazardous liquid under PHMSA's regulations, it is effectively treated as if it were a hazardous liquid (*i.e.*, subject to the same regulatory framework).[90] These regulations address design, construction, operation and maintenance, corrosion control, and reporting requirements.[91]

The State Fire Marshal has the "exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines" in California under the Elder California Pipeline Safety Act of 1981.[92] The State Fire Marshal has adopted PHMSA's safety regulations.[93] However, it is not clear whether the State Fire Marshal has authority to regulate the safety of intrastate CO_2 pipelines, because supercritical CO_2 has not be defined as a hazardous liquid.[94] The California Public Utilities Commission does apply PHMSA's

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[87] Adam Vann & Paul W. Parfomak, *Regulation of Carbon Dioxide (CO_2) Sequestration Pipelines: Jurisdictional Issues* (April 15, 2008).
[88] *See* 49 U.S.C. §§ 60102(i).
[89] 49 C.F.R. § 195.2.
[90] *See* Philip M. Marston & Patricia A. Moore, *From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage*, 29 ENERGY L. J., 421, 450 (2008).
[91] *See* 49 C.F.R. Pt. 195.
[92] CAL. GOV'T CODE §§ 51010 *et seq.*
[93] *See* 19 CAL. CODE REG. § 2000.
[94] In 1988 Congress amended the Hazardous Liquid Pipeline Safety Act to require that the Secretary of Transportation regulate CO_2 pipeline facilities. *See* 54 Fed. Reg. 41912, 41913 (Oct. 12, 1989). Although the Elder California Pipeline Safety Act has been amended since 1988, its scope does not appear to have been similarly broadened to include CO_2 pipelines. Because PHMSA's regulations do not define CO_2 as a hazardous liquid, the State Fire Marshal may not have authority under the Elder California Pipeline Safety Act to regulate the safety of intrastate CO_2 pipelines in California. Legislative action may be needed to address this situation.
California's Division of Oil, Gas & Geothermal Resources ("DOGGR"), which is part of the Department of Conservation, regulates "facilities attendant to oil and gas production, including pipelines not subject to regulation" under the Elder California Pipeline Safety Act. CAL. PUB. RES. CODE § 3106(a). *See also* CAL. PUB. RES. CODE § 3010 (defining production facility as "any equipment attendant to oil and gas production or injection operations including, but not limited to, * * * pipelines that are not under the jurisdiction of the State Fire Marshal" under the Elder California Pipeline Safety Act). Assuming intrastate CO_2 pipelines are not subject to regulation under the Elder California Pipeline Safety Act, DOGGR could assert jurisdiction over intrastate CO_2 pipelines to the extent they are used for enhanced oil recovery. However, the better interpretation of this statutory provision is that DOGGR has authority over CO_2 pipelines that are part of oil production facilities. *See* 56 Fed. Reg. at 26923 (describing how PHMSA's predecessor exempted CO_2 distribution facilities "downstream of where carbon dioxide is delivered to a production facility in the vicinity of a well site" from regulation under its Hazardous Liquid

safety regulations to pipelines operated by public utilities, such the federal safety regulations may apply to an intrastate CO_2 pipeline operated by a public utility in California.[95] At this time there are no CO_2 pipelines in California.

Pipeline Siting

a) Cortez Pipeline Case Study

Because pipelines can cover large distances, siting pipelines can be extraordinarily complex. Built by Shell in the early 1980s, the Cortez Pipeline extends over 500 miles from Colorado, through New Mexico, and into Texas, and is used to transport CO_2 produced from geologic reservoirs for use in enhanced oil recovery. Almost 130 miles of the route cross federal land, for which BLM issued an easement after extensive environmental review.[96] Shell obtained easements from the Bureau of Indian Affairs to cross eighteen miles of "allotment lands" held in trust for individual Navajos by the federal government. Another 30 miles traversed Native American reservations, and Shell negotiated easements with the respective tribes, but was prepared to utilize a longer, alternative route around the reservations if negotiations were unsuccessful, because it could not condemn a route through the reservations. The pipeline also crossed roughly 70 miles of state land. Finally, property rights had to be obtained from over 700 different landowners for nearly 300 miles of private land. Most of the crossing rights for this private land were obtained through negotiated agreements, which were undoubtedly influenced by the Shell's ability to condemn the easements if negotiation was unsuccessful.[97] In the end, twelve condemnation suits had to be filed. Simply put, long CO_2 pipelines are impractical, if not impossible, to site without the power of eminent domain.

b) No Federal Siting Authority for Non-Federal Land

No federal agency exercises authority over the siting of interstate CO_2 pipelines on non-federal land.[98] In 1979 the Federal Energy Regulatory Commission ("FERC") ruled that the Natural Gas Act ("NGA") did not give it jurisdiction over a proposed interstate pipeline that would transport 98% pure CO_2.[99] In the last

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Pipeline Safety Act's regulations). In any event, DOGGR does not yet have authority over CO_2 pipelines used for pure carbon sequestration (*e.g.*, in saline formations).

[95] *See* CPUC General Order No. 112-E, Subpart C.

[96] Roger G. Ryman, *Cultural, Technical and Environmental Hurdles Overcome: The Story of the Cortez Pipeline Before Construction*, RIGHT OF WAY (June 1982). Shell also had to obtain permits to cross nearly 40 federal and state highways, and franchises from each of the 14 counties along the route were required to cross county roads.

[97] N.M. STAT. ANN. § 70-3-5.A. *See also* 1983-1986 Op. Att'y Gen. N.M. 146 (Jan. 19, 1984) (opining that even though New Mexico case law required that condemnation result in "public use" rather than "public benefit," a court would give great deference to the legislatures determination that a CO_2 pipeline was a "public use" even though the public would not be entitled to use the pipeline).

[98] *See generally* Marston, footnote 90 *supra* at 452-54.

[99] *Cortez Pipeline Co.*, 7 FERC 61024 (1979) (concluding that "no goal or purpose of the NGA [would be advanced] by assuming jurisdiction over the [proposed CO_2 pipeline] project. This result is reached by considering the source of the production, the use of the production, and the actual chemical composition of the production involved, in light of the goals of the NGA").

five years, FERC has reaffirmed that it does not have jurisdiction over CO_2 pipelines.[100] Consequently, unless the federal government amends the NGA to cover CO_2 pipelines, the federal power of eminent domain is not available for interstate CO_2 pipelines.[101]

c) The Bureau of Land Management ("BLM") Can Authorize the Crossing of Federal Land

BLM has authority under two statutory schemes to permit the siting of CO_2 pipelines on federal land. Pursuant to Title V of the Federal Land Policy and Management Act ("FLPMA"), BLM can issue rights-of-way over and under federal land for a variety of systems including the following: (1) systems for the transportation and storage of liquids and gasses (other than natural gas or synthetic gaseous fuels), which would include anthropogenic CO_2 produced at biofuels plants, coal gasification plants, or captured from stacks of coal or gas fired power plants; (2) systems for the generation of electric energy, which might include sequestration facilities required for electric power plants; and (3) any other systems or facilities that are in the public interest and require rights-of-way.[102] In addition, BLM can authorize pipelines for the transportation of "naturally-occurring carbon dioxide" under Section 28 of the Mineral Leasing Act.[103] Pipelines authorized under the Mineral Leasing Act become "common carriers" that must "accept, convey, transport, or purchase without discrimination all * * * gas delivered to the pipeline."[104]

d) Siting Under State Law

A handful of states have enacted statutes specifically authorizing the use of eminent domain for CO_2 pipelines.[105] These statutes tend to fall into one of two categories.[106] In one category are eminent domain statutes that are closely related to enhanced oil recovery.[107] Pipelines used for carbon sequestration outside of enhanced oil recovery would not be able to utilize the eminent domain authority granted in this category of statutes. In the other category are eminent domain statutes that require the CO_2 pipeline become a common carrier.[108] For example, Texas only authorizes the use of eminent domain for CO_2

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[100] *Southern Natural Gas Co.*, 115 FERC 62266 (2006) (The pipeline "following abandonment by sale will be either non-jurisdictional intrastate [natural gas] or CO 2 facilities, and therefore, the facilities will be exempt from jurisdiction under" the NGA.).

[101] *See* 15 U.S.C. § 717f(h) (authorizing holder of FERC-issued certificate of public convenience and necessity to condemn easements for interstate natural gas pipelines).

[102] 43 U.S.C. § 1761(a). Section 302(b) of FLPMA, which authorizes BLM to issue easements, permits, and leases for industrial and commercial uses that cannot be authorized under other laws, could be another source of siting authority. *See* Department of the Interior, Report to Congress: Framework for Geological Carbon Sequestration on Public Land (2009)

[103] *See Exxon Corporation v. Lujan*, 970 F.2d 757 (10th Cir. 1992) (interpreting 30 U.S.C. § 185(a)).

[104] 30 U.S.C. § 185(r)(2)(A).

[105] *See, e.g.*, LA. REV. STAT. ANN. § 19:2(10); MISS. CODE ANN. § 11-27-47; N.M. STAT. ANN. § 70-3-5.A; N.D. CENT. CODE §§ 49-19-01(1), 49-19-12; TEX. NAT. RES. CODE §§ 111.002(6), 111.019(a).

[106] *See* Joel Mack & Buck Endemann, *Making Carbon Sequestration Feasible: Toward Federal Regulation of CO_2 Sequestration Pipelines*, 38 ENERGY POLICY 735, 737 (2010).

[107] LA. REV. STAT. ANN. § 19:2(10) (authorizing use of eminent domain for CO_2 pipelines to be used in enhanced oil recovery operations in Louisiana or in other states); MISS. CODE ANN. § 11-27-47 (authorizing use of eminent domain for CO_2 pipelines to be used in enhanced oil recovery operations in Mississippi). Although New Mexico's statute is not expressly tied to enhanced oil recovery, it is part of New Mexico's chapter of laws concerning oil and gas.

[108] N.D. CENT. CODE §§ 49-19-01(1), 49-19-12; TEX. NAT. RES. CODE §§ 111.002(6), 111.019(a).

pipelines if the pipeline company agrees in writing that it is "a common carrier subject to the duties and obligations conferred or imposed by this chapter."[109] The obligations that accompany designation as a common carrier could be problematic for CO_2 pipelines,[110] which may well be built with just enough capacity and be contractually obligated to transport all the CO_2 generated from a particular emitter.

There are two general constitutional restraints on the exercise of eminent domain: the taking must be for a "public use" and "just compensation" must be paid.[111] Of these two restraints, the "public use" limitation is the more visible concern when the condemned land will be "used" by a private entity. However, "public use" has been defined broadly by California courts as "a use which concerns the whole community or promotes the general interest in its relation to any legitimate object of government."[112] Further, the California legislature has provided that any use for which statutes allow eminent domain to be exercised constitutes a legislative declaration that such use is a public use.[113]

California does not have a statute specifically authorizing the use of eminent domain for CO_2 pipelines. However, public utilities in California can use the power of eminent domain when needed for their facilities.[114] For example, a "pipeline corporation may condemn any property necessary for the construction and maintenance of its pipeline."[115] Pipeline corporations could include entities that own or operate pipelines used to transmit CO_2 in a supercritical state.[116] Utilizing this authority, however, would require that the operator of a carbon sequestration pipeline be a public utility,[117] which could in turn limit the sphere of emitters that might be able to implement carbon sequestration.

One alternative to condemning easements across private land is to utilize existing public easements, such as roads. In *Bello v. ABA Energy Corp.* the California Court of Appeals upheld a privately-owned natural

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[109] TEX. NAT. RES. CODE §§ 111.002(6). *See also* N.D. CENT. CODE § 49-19-11 (requiring that the pipeline must "agree expressly that it, without discrimination, will accept, carry, or purchase, the * * * carbon dioxide of the state or of any person not the owner of any pipeline, operating a lease or purchasing * * * carbon dioxide at prices and under regulations to be prescribed by the" Public Service Commission).

[110] *See, e.g., Tex. Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas LLC*, 296 S.W.3d 877 (Tex. Ct. App. 2009) (involving contention that CO_2 pipeline for enhanced oil recovery cannot be a common carrier). This case is now pending before the Texas Supreme Court.

[111] *City of Oakland v. Oakland Raiders*, 32 Cal. 3d 60, 64 (1982). *Cf. Murphy v. Burch*, 46 Cal. 4th 157, 170 (2009) (noting that valid public use does not exist when the condemnation would "benefit only a private company or individual").

[112] *City of Oakland*, 32 Ca. 3d at 69.

[113] CAL. CODE CIV. PRO. § 1240.010.

[114] CAL. PUB. UTIL. CODE §§ 610 *et seq.*

[115] CAL. PUB. UTIL. CODE § 615.

[116] CAL. PUB. UTIL. CODE § 227 (defining pipeline as a facility use to transmit "crude oil and other fluid substances except water through pipe lines"). *See also* CAL. PUB. UTIL. CODE §§ 217, 218, 612 (authorizing electric corporations to utilize the power of eminent domain for electric facilities, which could conceivably include pipelines to dispose of CO_2). Common carriers, *i.e.*, entities providing transportation for the public, also have the power to condemn property that is necessary for its facilities. CAL. PUB. UTIL. CODE §§ 211, 620. *But see Tex. Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas LLC*, 296 S.W.3d 877 (Tex. Ct. App. 2009) (involving contention that CO_2 pipeline for enhanced oil recovery cannot be a common carrier because it does not offer service to the public).

[117] *See* CAL. PUB. UTIL. CODE § 216(a) (requiring that public utilities perform a service for, or delivery a commodity to, the public). *See also* CAL. PUB. UTIL. CODE § 625 (requiring that the Public Utilities Commission must find that condemnations by public utilities for the purpose of offering competitive services would serve the public interest).

gas exploration and production company's installation of pipelines within public rights-of-way.[118] To do so, a proposed use should:

> "(1) serve as a means, or be incident to a means, for the transport or transmission of people, commodities, waste products or information, or serve public safety; (2) serve either the public interest or a private interest of the underlying landowner that does not interfere with the public's use rights; and (3) not unduly endanger or interfere with use of the abutting property."[119]

Of course, permission is needed from the public entity with jurisdiction over the right-of-way.

Summary

There may be a gap in the California's regulation of the safety of intrastate CO_2 pipelines. Although the California Public Utilities Commission applies federal pipeline safety standards to pipelines owned by public utilities, the State Fire Marshal's legal authority under the Elder California Pipeline Safety Act of 1981 may not extend to CO_2 pipelines and legislation may be required to address this issue.

The development of CO_2 pipelines for enhanced oil recovery illustrates that long CO_2 pipelines are impractical, if not impossible, to site without the power of eminent domain. There is no federal authority for siting CO_2 pipelines on private land. Although public utilities in California can exercise the power of eminent domain in certain circumstances, other entities that could sequester CO_2, such as oil refineries, lack that ability, which could hinder the broader implementation of carbon sequestration. For that reason, legislation authorizing the use of eminent domain for CO_2 pipelines that are not owned and operated by public utilities would likely further the implementation of carbon sequestration.

[118] 16 Cal. Rptr. 3d 818 (Cal. Ct. App. 2004).
[119] *Id.* at 829-20 (internal citations omitted).

13. Appendix J: Approaches to Pore Space Rights

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Approaches to Pore Space Rights

AUGUST 10, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

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Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Carbon sequestration cannot occur absent the right to inject and store carbon dioxide (CO_2) in subsurface pore spaces.[120] Three general approaches for addressing this issue have evolved over the past few years. This issue paper briefly describes these approaches and identifies positives and negatives of each. These positives and negatives are not listed in any particular order.

Complete Private Property Approach

This approach recognizes that the right to use the pore space for the injection and sequestration of CO_2 is a property right that must be obtained.[121] If there is a single property owner, that owner owns the right to use the subsurface pore space, but if the mineral rights have been severed, then the owner of the mineral estate has the dominant right to use pore space as necessary to produce valuable minerals.[122] Consequently, the surface estate owner's use of pore space cannot interfere with the mineral estate, and injecting gases into unacquired pore space could constitute a trespass against both the surface and the mineral estate.[123]

Because it can be difficult to establish that a mineral estate has been exhausted (*i.e.*, there are no more minerals that can be produced), under this approach a carbon sequestration project may need to obtain rights to use the pore space from the owners of both the surface estate and the mineral estate. This could be accomplished in a few different ways. First, a carbon sequestration project could obtain the necessary rights by means of negotiated agreements with the property owners, including any lessees of the mineral estate and any royalty owners. Second, if it had the power of eminent domain, a carbon sequestration project could condemn the rights. Third, if the requisite statutory authority existed, the state could unitize the rights within the targeted geologic structure.

a) Positives:

i) Consistent with public perception of property rights. The principle that ownership of property includes the right to control the use of that property is a fundamental concept in this country. Because this approach builds off this fundamental concept by requiring that the right to inject and sequester CO_2 underground be obtained from property owners, this approach does not require charting a new path for property rights. This makes acceptance and implementation less controversial.

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[120] *See generally* Jerry R. Fish and Thomas R. Wood, *Geologic Carbon Sequestration: Property Rights and Regulation*, 54 ROCKY MT. MIN. L. INST. 3-1 (2008).

[121] *See* CAL. CIV. CODE § 829 ("The owner of land in fee has the right to the surface and to everything permanently situated beneath or above it.").

[122] The terms "surface estate" and "mineral estate" are commonly used in the context of severed property rights. However, these terms are misnomers, because the owner of the "surface estate" owns everything, including rights to use the subsurface, except for and subservient to the right to produce valuable minerals. In addition, the owner of the "mineral estate" has certain rights to use the surface in connection with the production of valuable minerals.

[123] *See Cassinos v. Union Oil Co.*, 18 Cal. Rptr. 2d 574 (Cal. App. 1993). Trespass could also result if injected gas causes brine to migrate into the pore space of another property that did not previously contain brine. For example, if displaced brine interfered with oil or gas production or fresh water aquifers, a cause of action for trespass could exist under *Cassinos*. *See also* footnote 125 below and accompanying text.

ii) **Payment to property owners may lessen opposition to carbon sequestration and may help encourage development.** Development of the subsurface has economic benefits, such as revenues from produced oil or rent from stored natural gas. Property owners understand and expect that they will be compensated when someone else wants to use their land. This has been common practice throughout California's history (*e.g.*, from the mid-nineteenth century gold rush and the early twentieth century oil and gas boom to today's oil and gas production, natural gas storage, and wind farms). Because obtaining the requisite property rights—whether that be through negotiated agreements, unitization, or condemnation—will result in dollars in property owners' pockets, property owners may be more inclined to support this approach to carbon sequestration. Further, to the extent that such compensation is tied to actual sequestration (*e.g.*, an amount per ton of injected CO_2) rather than a one-time lump sum, a constituency of property owners will form that will want to see carbon sequestration happen.

iii) **IOGCC Model Statute.** Oil and gas regulators from across the country have recommended that carbon sequestration by treated like natural gas storage, and several states, such as Wyoming, Montana, and North Dakota, have enacted legislation following this recommendation. The legislatures in such states have directed that pore space belongs to the surface estate and provided mechanisms to unitize pore space within geologic structures. Consequently, property owners will be compensated for carbon sequestration that may occur beneath their property. In light of this, California property owners would likely be hostile to an alternative approach under which they may not receive any compensation.

iv) **Consistent with developing market for sequestration property rights.** Money is already being expended to acquire the right to inject and sequester CO_2 in pore space in other states, just as has been done for natural gas storage in California. This developing market relies on the traditional conception of property rights (*i.e.*, that property cannot be used without acquiring the right to do so from the property owner). Changing the law mid-stream would frustrate these earlier investments in carbon sequestration rights and delay the implementation of actual carbon sequestration projects by these early movers.

v) **Ability to deal with holdouts through unitization.** The risk of holdouts is present whenever large parcels of land with fragmented ownership must be assembled for a development project. For public projects, this problem is often addressed by the government's power of eminent domain. Secondary recovery, which typically involves injecting water to produce otherwise unrecoverable oil and gas, implicates this same risk of holdouts, because it almost always requires coordinating activities across properties owned by different parties. Many states

have addressed this problem by creating a statutory process through which multiple properties can be brought together and operated as a single unit.[124] Through such statutory unitization processes, a state agency allocates production to the various property owners within the unit on an equitable basis. If property owners elect not to participate, they cannot claim that the subsurface waterflooding constitutes a trespass.[125]

Wyoming, Montana, and North Dakota have addressed the risk of holdouts by applying the unitization concept to carbon sequestration. For example, under SB 498 in Montana, once a carbon sequestration project controls subsurface storage rights to 60% of the storage capacity in a proposed storage area, it can apply to unitize the storage area.

Unitization also has advantages over condemnation. The fair market value of condemned property is determined by what is taken rather than what is created.[126] Thus, property owners do not share in the upside of the project. In contrast, holders of unitized oil and gas leases continue to share in the upside. Similarly, carbon sequestration proceeds could be allocated to the owners of the storage rights within a unitized storage area, such that they have a stake in the financial upside of the project but are not liable for damages. This could make them more amenable to such a process, especially in light of the fact that their individual subsurface storage rights may be worth little in a condemnation proceeding.

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[124] Statutory or compulsory unitization is distinct from contractual or voluntary unitization, which relies upon unitization clauses that are often found within oil and gas leases. California's limited compulsory unitization statute is found at CAL. PUB. RES. CODE §§ 3630 *et seq.* Contractual unitization requires that the various leases contain compatible unitization clauses. Furthermore, contractual unitization only works if all of the lessees are willing to unitize; if not, contractual unitization is ineffective.

[125] *See, e.g.*, *Baumgartner v. Gulf Oil Corp.*, 168 N.W.2d 510, 516 (Neb 1969) (holding that "where a secondary recovery project has been authorized by the [Nebraska Oil and Gas Conservation Commission] the operator is not liable for willful trespass to owners who refused to join the project when the injected recovery substance moves across lease lines," because public policy seeks to avoid the waste of natural resources that would occur absent secondary recovery). As such, unitization could be useful for addressing issues related to brine displacement in saline formations as well. *See* footnote 123 above. *See also Alameda County Water District v. Niles Sand & Gravel Co.*, 112 Cal. Rptr. 846 (Cal. Ct. App. 1974) (holding that interference with gravel mining caused by migration of fresh water injected underground through a state-authorized aquifer storage and recovery project was not compensable).

[126] *See Pacific Gas & Elec. Co. v. Zuckerman*, 234 Cal. Rptr. 630, 637 (Cal. Ct. App. 1987).

b) Negatives:

i) **Transaction costs.** Obtaining property rights from private property owners, whether it be through negotiated agreements, unitization, or condemnation, will undoubtedly result in transaction costs, especially for commercial scale sequestration projects, which may require 100 to 200 square miles of pore space rights.[127] To the extent that geologic structures suitable for carbon sequestration are owned by multiple parties, which is almost certainly the case given the large size of these structures, transaction costs will increase. This inefficiency that could impede the implementation of carbon sequestration, especially in situations where ownership is highly fragmented, if unitization is not an option. However, because developers are currently acquiring sequestration rights in some states, notwithstanding fragmented ownership, the inefficiencies may not be significant.

ii) **Potential for holdouts.** Building upon the transaction costs associated with negotiated agreements, unless there is a way to address the risk of holdouts, the actual development of carbon sequestration project could be delayed or be more capital intensive. Unitization and eminent domain could both serve as mechanisms to deal with this risk, but both create additional problems. For example, the time saved by not having to buy out holdouts through a negotiated agreement could be consumed by litigation related to the unitization or condemnation. Further, unless these mechanisms allow carbon sequestration projects to use pore space pending an allocation/compensation decision (*e.g.*, a quick take provision), the timeline for actual implementation could still be quite long.[128]

iii) **Increased operating costs.** The need to compensate property owners for the use of pore space will increase the operational cost structure for carbon sequestration projects. This could mean that some percentage of potential carbon sequestration projects will not be economically viable. But the same could be said of wind or solar projects (*i.e.*, if access to land were free more projected would be viable).

iv) **Continued uncertainty regarding ownership of pore space.** Ownership of pore space is not typically set out in the deeds that split property into surface and mineral estates. Consequently, there is often uncertainty as to who has the right to use the pore spaces absent the presence of oil or gas. Those states that have addressed the pore space property right issue have created interpretive

[127] An optimal site for carbon sequestration would have a geologic structure that limits lateral expansion of the CO_2 plume and has multiple injection zones, which would decrease the size of the area for which pore space property rights are needed.

[128] Under CAL. CODE CIV. PRO. § 1255.410, a "quick take" in California requires at least 60 days, and if opposed the condemnor must demonstrate that "there is an overriding need" to possess the property now, "a substantial hardship" will occur if the quick take is denied, and that substantial hardship outweighs any hardship on the condemnee.

presumptions prior conveyances of property. For example, there is a rebuttable presumption under Wyoming's HB 89 that pore space is owned by the surface owner. This presumption, however, is not conclusive, which means that courts may still need to determine who owns the pore space for a particular property. Obtaining such determinations could delay the implementation of carbon sequestration projects.

c) **Legislation Needed:** This approach would require legislation that allocates ownership of pore space, defines ownership of injected CO_2, and allows for unitization and/or eminent domain to acquire pore space, including pore space owned by state and local governments.

Limited Private Property Approach

This approach tweaks the traditional concept of underground property rights from the oil and gas context. Instead of an absolute right to pore space, this approach is based on the idea that subsurface property rights are "contingent upon interference with reasonable and foreseeable use" of the property.[129] Consequently, so long as the sequestration of CO_2 would not interfere with such uses, a carbon sequestration project would not need to obtain the right to use pore space from property owners.

This approach is most prominently reflected in the CCS Reg Project's recently published model legislation. Under this model legislation, a carbon sequestration project could apply for a "pore space permit," which would convey the exclusive privilege to access and use identified pore space for carbon sequestration. Prior to issuing a pore space permit, the state environmental protection agency would conduct a proceeding in which holders of a "non-speculative economic interest" (*i.e.*, the ability to economically recover actual mineral resources or engage in other current or imminent subsurface activities that have substantial economic value) could participate. Anyone that did not participate in this proceeding would waive any and all subsurface property rights that might be affected by the proposed carbon sequestration project. If the injection and sequestration of CO_2 would cause actual and substantial damages to such an interest, then either (i) the project would be modified to avoid the damages, (ii) the carbon sequestration project would have to negotiate an agreement with the holder of the interest, or (iii) the state environmental protection agency could authorize condemnation of the interest.

In summary, under this approach, unless a landowner could show current or imminent mineral or other subsurface activities with substantial economic value, the landowner would have no subsurface property rights and a carbon sequestration project could proceed simply by obtaining a pore space permit.[130] If such subsurface property rights were demonstrated to exist, then the carbon sequestration project would address these rights through means similar to those described under the Complete Private Property Approach (*e.g.*, negotiated agreements or condemnation).

[129] *Chance v. BP Chemicals, Inc.*, 670 N.E.2d 985, 993 (Ohio 1996) (holding that migrating hazardous waste did not constitute a trespass).

[130] The Kentucky legislature considered a bill with a similar approach this year. HB 491 would have declared geologic strata beneath 5,500 feet that does not contain either "recoverable or marketable" minerals or water that can be used for a beneficial purpose to be property of the state.

a) Positives:

i) **Pore space permit not required.** Under the CCS Reg Project's model legislation, there is no requirement that a pore space permit be obtained. Consequently, developers who have already acquired carbon sequestration property rights would not be required to utilize this process.

ii) **Property rights adjudicated once and for all in a unified process.** By addressing property rights in an adjudicative proceeding prior to injection, carbon sequestration projects would have greater certainty regarding risk of legal liability. Further, by utilizing a unified process, carbon sequestration projects would avoid piecemeal litigation.

iii) **Application to saline formations.** Most property owners probably would not have current or imminent subsurface activities of substantial economic value in geological structures containing only saline formations. Because this approach eliminates private pore space property rights for this category of property owners, this approach could be advantageous for encouraging carbon sequestration in saline formations.

b) Negatives:

i) **Inconsistent with public perception of property rights.** Because this approach would be perceived as taking the pore space rights of many property owners (*e.g.*, those without current or imminent subsurface activities that have substantial economic value), enacting this approach may encounter strong public opposition. This inconsistency with the public perception of property rights may also prompt litigation that could delay implementation of projects utilizing this process.

ii) **Perceived lack of fairness.** One of the sticks in property owners' bundle of rights is the right to explore for valuable minerals. However, under this approach, owners whose property had not been explored, and thus did not have a non-speculative economic interest, would "waive" their pore space rights. This could readily be perceived as unfair, especially (1) as landowners often have neither the financial wherewithal nor the technical expertise themselves to explore for valuable minerals, (2) if other properties had been explored and valuable minerals had been found, and (3) in light of technological advances that make previously unrecoverable minerals recoverable (*e.g.*, horizontal drilling and fracturing now allow recovery from gas shales). Such property owners may view this as a process to avoid paying for their property rights and oppose its implementation.

iii) **Inconsistent with developing market for sequestration property rights.** It is unclear whether already obtained carbon sequestration property rights would be considered a non-speculative economic interest in the adjudicatory process. If not, existing sequestration easements and leases obtained by early movers could be worthless, which could delay actual implementation of sequestration projects and anger those property owners that thought they would be receiving remuneration for granting carbon sequestration rights.

iv) **Expertise of adjudicatory entity.** Subsurface property rights can be very complex. The adjudicatory entity would require not only the expertise to resolve these issues, but also the reputational wherewithal to support the legitimacy of its decisions in the public's eye. It may well be difficult for a state environmental protection agency, as under the CCS Reg's model legislation, to build such expertise for subsurface property right adjudications.

v) **Application to mineral rights.** Although surface owners may very well have no realistic expectation to use geological structures suitable for carbon sequestration, mineral estate owners undeniably have an expectation that they may explore the subsurface. The Limited Private Property Approach, however, only recognizes that right if there is the ability to economically recover actual mineral resources in the very near future. This creates a number of problems. First, the scope of what economically recoverable mineral resources changes with the price of the resource. More oil is economically recoverable when the price is at $80/barrel than at $40/barrel. Consequently, mineral rights would morph into a property right, the existence of which depends upon market conditions at a particular point in time. Second, knowledge regarding the existence of mineral resources is limited. A mineral estate owner may know that valuable minerals exist beneath a property but does not yet know whether they are economically recoverable. Similarly, an area's geology may suggest that valuable minerals exist underneath the surface, but until the subsurface is explored, no one knows whether that is really true. Third, as described above, what is recoverable can change in the future due to technological advances. Consequently, mineral owners' rights may be eliminated under this approach because the property has not yet been explored or the minerals are not economically recoverable under current market conditions or with current technology.[131] Mineral owners would almost certainly oppose this approach for these reasons.

In addition, this approach does not apply neatly to carbon sequestration that might occur in depleted oil and gas reservoirs. The mineral estate owners in that

[131] It is also unclear what would happen if valuable minerals were discovered in the course of the sequestration project. Would these be the property of the state? The carbon sequestration project? The prior mineral estate owner?

situation may still have non-speculative economic interests (*e.g.*, secondary recovery could be used to produce additional oil). Consequently, the carbon sequestration project would have to utilize the same Complete Private Property Approach's tools (*e.g.*, negotiated agreements and condemnation). This approach then may not do anything to substantially advance implementation of projects in these reservoirs, which may be the low-hanging fruit for carbon sequestration.

c) **Legislation Needed:** This approach would require legislation that establishes the process by which property rights are adjudicated, defines a "fair" threshold at which a property right to pore space is recognized (*e.g.*, "non-speculative economic interest" in the CCS Reg's model legislation), and allows for eminent domain of recognized pore space rights, including pore space containing minerals and pore space owned by state and local governments.

Public Resource Approach

Case law suggests that aquifer storage and recovery ("ASR") law could serve as a third approach at least for carbon sequestration in saline formations. In *Alameda County Water District v. Niles Sand & Gravel Co.* a gravel operator alleged that the flooding of his gravel pits that resulted from an ASR program constituted a taking because it interfered with subsurface rights and the business operations.[132] Recognizing that the regulation of the state's water resources was a constitutional exercise of the state's police power, the California Court of Appeals held that the water district's activities were a legitimate exercise of the police power and that the adverse effect on the gravel operator's use of its property was not compensable.[133] This line of reasoning is somewhat analogous to the rationale of preventing the waste of natural resources that underlies trespass cases involving secondary recovery in oil and gas fields.[134] To the extent that California under its police power can use saline formations and the geologic structures in which they occur for public purposes, legislation potentially could be enacted that authorizes the use of saline formations for carbon sequestration without infringing upon private subsurface property rights.

a) **Positives:**

i) **Does not require acquisition of pore space rights.** Acquiring pore space rights, whether it be under the Complete Private Property Approach or the Limited Private Property Approach will take both time and money. In contrast, the Public Resource Approach eliminates the need to spend time and money acquiring pore space rights.

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[132] 112 Cal. Rptr. 846 (Cal. Ct. App. 1974).

[133] *Id.* at 855. *See also Board of County Commissioners v. Park County Sportsmen's Ranch, LLP*, 45 P.3d 693, 707 (Colo. 2002) ("[B]y reason of Colorado's constitution, statutes, and case precedent, neither surface water, nor ground water, nor the use rights thereto, *nor the water-bearing capacity of natural formations belong to a landowner* as a stick in the property rights bundle.") (emphasis added)).

[134] *See, e.g., Railroad Com. of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962) (holding that migrating water from secondary recovery operations authorized by Railroad Commission order in non-unitized field did not constitute a trespass on adjacent mineral estate because this would discourage secondary recovery). *See also* footnote 125 above.

b) Negatives:

i) Uncertainty regarding utilizing police power to effect carbon sequestration in saline formations. Western states, including California, have long recognized the value of fresh water and the need to protect it. This recognition underlies ASR jurisprudence. Similarly, there is plenty of legal support for statutory unitization and governmental authorization of secondary recovery operations in order to prevent the waste of oil and gas. In contrast, carbon sequestration is a new concept. Consequently, regardless of how laudable promoting carbon sequestration may be from a public policy perspective, there would be unavoidable legal uncertainty regarding the state's use of saline formations for carbon sequestration. The courts would have to resolve this issue, which could delay implementation of carbon sequestration projects.

ii) Application limited to saline formations. Although saline formations may have the largest carbon sequestration capacity, some see depleted oil and gas reservoirs as the low-hanging fruit. However, this approach is not applicable to such reservoirs, because injecting CO_2 would allow for the recovery of previously unrecoverable minerals. By being limited to saline formation, this approach may not help spur early carbon sequestration projects.

iii) Could require creation of public sequestration entity. Reliance on the state's police power may necessitate that a public entity do the sequestration, just as a water district was conducting the ASR operation in *Alameda County Water District*.[135] One must consider how quickly a public entity could actually implement a carbon sequestration project in an era of uncertain public finances. Further, the potential for liability will accompany any public entity that is actually conducting injection and sequestration operations.

iv) Eliminates private sequestration rights in saline formations. This approach, like the Limited Private Property Approach, could be perceived as taking the pore space rights of many property owners and could encounter public opposition for this reason. Further, this approach could wipe out investments that private parties may have made in obtaining sequestration rights in saline formations, which could delay implementation of carbon sequestration projects.

c) **Legislation Needed:** This approach would require legislation that recognizes saline formations as public resources and authorizes a public agency to either conduct sequestration operations or permit private entities to conduct sequestration operations on the public's behalf.

[135] However, courts have upheld private entities' use of unappropriated pore space in the oil and gas context when that use is authorized by a public entity. *See, e.g., Railroad Com. of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962).

14. Appendix K: Public Outreach Considerations for CCS in California

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Public Outreach Considerations for CCS in California

AUGUST 11, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

Options for Permitting Carbon Capture and Sequestration Projects in California

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Carbon Dioxide Pipelines

Review of Saline Formation Storage Potential in California

Overview of the Risks of Geologic CO2 Storage

AB 32 Regulations and CCS

Approaches to Pore Space Rights

Uses of Carbon Dioxide

Introduction

Undertaking carbon capture and sequestration (CCS) in California will require significant public outreach and education to explain the technology and its role in the state's climate and energy policies, and to assure informed public participation. This paper briefly describes CCS outreach activities by three agencies with a major role in CCS policymaking: (1) the California Energy Commission, (2) the California Air Resources Board, and (3) the California Public Utilities Commission. General recommendations for undertaking public outreach for CCS in California are included at the paper's end.

Public Outreach by the California Energy Commission

Through its Public Interest Energy Research (PIER) program, the California Energy Commission operates a comprehensive set of global climate change research projects spanning regional impacts assessments, mitigation, and adaptation. Supporting public outreach activities include the California Climate Change web portal and an annual climate change research conference attended by more than 400 people.

In the area of CCS specifically, the PIER program's research and outreach efforts are chiefly conducted through the West Coast Regional Carbon Sequestration Partnership (WESTCARB), which is funded by the U.S. Department of Energy (DOE) and managed by the California Energy Commission (which also cofunds the partnership). Since 2003, WESTCARB has conducted an active program of public education and outreach in seven western states (AK, AZ, CA, HI, NV, OR, and WA) and one Canadian province (BC). The California Energy Commission also independently funded researchers at the University of California–Berkeley to examine the factors contributing to public perceptions toward CCS.

WESTCARB Public Outreach Activities

Using a variety of media, WESTCARB outreach activities have targeted multiple stakeholder groups including the research community, policymakers, regulators, industrial partners, educators, the inquisitive public, and communities near proposed field projects. WESTCARB's outreach program to date—coordinated by the California Energy Commission's Media Office—has included the following activities:

Website

WESTCARB's website (http://www.westcarb.org) conveys current information on CCS technology, project activities, and links to news stories, climate change reports, presentations, and study results.

Fact sheets and primers

Single-sheet summaries are available on WESTCARB goals and activities and on the fundamentals of carbon sequestration, including CO_2 capture from industrial point sources, pipeline transportation, geologic storage, and terrestrial sequestration. WESTCARB also provides facts sheet for briefing policymakers and for each field project, which are updated annually for the duration of the project and are posted on the WESTCARB website.

Annual business meetings (open to the public)

WESTCARB's annual business meetings cover the full scope of WESTCARB's activities, as well as regional and national CCS-related topics. Presentations from each annual meeting are posted on WESTCARB's website (http://www.westcarb.org/technicalpresentations.html).

The meetings are held in different locations to encourage participation by the organizations and policymakers of the member states. Past meetings have been held in Portland, Oregon; Berkeley, California; Phoenix and Scottsdale, Arizona; Seattle, Washington; and Anchorage, Alaska. The 2010 meeting is scheduled for October 19–20 in Sacramento, California, to dovetail with the final meeting of the California Carbon Capture and Storage Review Panel on October 21, 2010.

Public educational workshops

In conjunction with some of its earlier business meetings, WESTCARB conducted public workshops with expert speakers covering climate change and CCS fundamentals. Program content and pre-meeting mailings were tailored to stakeholder issues of regional significance (e.g., forest management in the Pacific Northwest). More recently, WESTCARB has teamed with universities and environmental organizations that have organized informational workshops on CCS activities and issues in California. These workshops have been well attended, typically drawing 100–200 participants.

Public meetings for communities near project sites

With support from field project partners, WESCARB has held community meetings on geologic CO_2 storage assessments in Holbrook and Kykotsmovi, Arizona; and Thornton, Stockton, and Rio Vista, California. WESTCARB has held community meetings for forestry-based terrestrial sequestration projects in Lakeport, Oregon, and Anderson, California.

Participation in major CCS conferences and forums

WESTCARB-sponsored research is disseminated at CCS conferences and forums including DOE's Annual Conference on Carbon Capture and Sequestration, IEA's International Conference on Greenhouse Gas Control Technologies, and the Groundwater Protection Council's Annual Forum. WESTCARB researchers have worked with the California Climate Action Registry to develop and test protocols for terrestrial carbon sequestration projects.

Media interviews

Requests by reporters for information or interviews have resulted in numerous articles featuring WESTCARB's work and have helped spread awareness of CCS. In 2008, for example, WESTCARB's Technical Director was interviewed for "The Morning Report" on KQED radio. Earlier, he had appeared on "TechTV." In 2009, several WESTCARB researchers wrote articles for *Southwest Hydrology* magazine, which devoted an issue to CCS and featured an article on WESTCARB's Arizona geologic characterization well. WESTCARB's terrestrial sequestration researchers and project site landowners in Shasta County, California, were featured in an award-winning public television documentary, now available on DVD.

News releases for major announcements pertaining to WESTCARB have been issued by DOE, Governor Schwarzenegger's Office, the California Energy Commission, and Lawrence Berkeley National Laboratory. WESTCARB also supports its project partners in drafting news releases related to CCS pilots, as needed.

Middle and high school teacher trainings

WESTCARB has spoken at two teacher training workshops in California in conjunction with the Keystone Center's "CSI: Climate Status Investigations." The trainings, which present CCS within the

context of energy use and climate change, provide teachers with exercises and curricula to use in the classroom.

Participation in DOE Regional Carbon Sequestration Partnerships' Outreach Working Group

Outreach coordinators for DOE's seven Regional Carbon Sequestration Partnerships regularly hold conference calls or meet face-to-face to share experiences and ideas and to undertake joint projects. Most notable was the DOE *Best Practices Manual for Public Outreach and Education for Carbon Storage Projects*, published in December 2009.

CCS workshops for the California Integrated Energy Policy Report

WESTCARB personnel organized California Energy Commission public workshops on CCS in conjunction with the biennial Integrated Energy Policy Report (IEPR) in 2005, 2007, and 2009. As part of the 2007 IEPR cycle, WESTCARB staff led workshops, commissioned topical white papers by CCS subject matter experts, and wrote the synthesis report, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature*, fulfilling a requirement of Assembly Bill 1925, which was passed unanimously by the Legislature in 2006 (the same session that produced Assembly Bill 32, the Global Warming Solutions Act of 2006).

Carbon Sequestration Atlas of the United States and Canada

WESTCARB contributes to each edition of DOE's "Carbon Atlas" by providing maps, photos, text, and data tables that reflect the Partnership's findings. The award-winning Carbon Atlas[136] is widely distributed on Capitol Hill.

Public Outreach by the California Air Resources Board

The California Environmental Protection Agency's Air Resources Board (ARB) holds the primary responsibility for monitoring and regulating sources of greenhouse gases in order to reduce emissions.

ARB has long history of conducting education and outreach campaigns in an effort to support an understanding of, and compliance with, California's various air quality regulations. This experience base includes Department of Motor Vehicles inserts and smog station placards, fact sheets, webcasts and workshops, FAQs, news releases and an RSS news feed, and an e-mail service where subscribers can select from multiple topics pertaining to air quality.

In preparing the AB 32 Climate Change Scoping Plan, ARB undertook a broad and extensive public outreach and engagement effort involving dozens of workshops, meetings, and webcasts throughout the state. Hundreds of Californians attended these events and provided suggestions for improving the Plan. Additionally, ARB received thousands of letters, postcards, e-mails, and other comments. All told, more than 42,000 people voiced an opinion on the Plan.

Public outreach remains an important element in the implementation of AB 32, which calls for a steering committee of state agencies, the state's air districts, and public and private entities to "develop a coordinated array of messages and draw upon a wide range of messengers to deliver them." A further directive notes, "these will include regional and local governments whose individual outreach campaigns

[136] http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/index.html

can reinforce the broader state outreach themes while also delivering more targeted messages directly tied to specific local and regional programs."

Inclusiveness and outreach were also embodied in the AB 32 legislation, with the call for formation of an Environmental Justice Advisory Committee chartered to advise ARB on the Climate Change Scoping Plan and on other pertinent matters in the implementation of AB 32.

Although CCS is not viewed as a centerpiece of ARB's compliance strategy for AB 32 (it is in the "Research" section of the Scoping Plan), sustainable forest management practices (for terrestrial sequestration) have been included among the "Recommended Actions." ARB has sought to increase CCS knowledge internally and publicly through presentations in the "Chair's Seminar Series" (webcast talks) and through other venues. As the role of CCS grows in the future as California reduces its GHG emissions cap, ARB will step up its public processes for CCS education and outreach.

Public Outreach by the California Public Utilities Commission

The California Public Utilities Commission (CPUC) may address CCS education and outreach in conjunction with its activities regulating investor-owned electric and natural gas utilities operating in California. Support for CCS research and development is noted in the RD&D section of the Energy Action Plan, which CPUC developed jointly with the California Energy Commission.

CPUC has a deep experience base in consumer education and outreach, including a Public Advisor's Office and a separate Business and Community Outreach program to assist California communities, local governments, and businesses. The Public Advisor's Office regularly resolves complaints and administers public participation hearings on controversial open proceedings before the CPUC. The Business and Community Outreach program sponsors five Outreach Officers to represent the agency throughout California and to assist communities in understanding CPUC programs and policies. These outreach officers schedule workshops and presentations in communities to explain current policy efforts, actively solicit consumers feedback, and resolve issues before complaints escalate.

On January 21, 2010, as part of its ongoing "21st Century Thought Leaders" series of public forums, CPUC held a panel discussion on "Carbon Capture and Storage and the Role It Plays in Climate Change Mitigation." The panel discussion was aimed at providing broader public understanding of CCS strategies. This event is now available for viewing in the video webcast archive of the series.[137]

Recommendations for CCS Public Outreach in California

Agency and Developer Roles:

In California, where multiple agencies and non-governmental organizations will be involved in CCS-related public communications, the scope and focus of their efforts will be reflective of the primary role(s) they fulfill.

For policy-oriented agencies, CCS outreach will benefit by being positioned within the context of other major policy initiatives, principally energy supply and demand and the state's plan to reduce greenhouse

[137] See http://www.cpuc.ca.gov/PUC/hottopics/7other/081027_thoughtseries.htm.

gases to mitigate climate change. When CCS is presented in this manner, the public can better weigh its potential to contribute to the state's goal of fostering economic growth and opportunity while protecting human health and the environment.

In developing policies for CCS, California's agencies will want to use transparent processes and provide multiple opportunities for public input. Companion efforts to further public awareness and education on CCS will engender meaningful public engagement.

Permitting agencies will undoubtedly focus on providing a clear delineation of the permitting process—what steps are followed to obtain a permit, what areas the permit covers, and how the permit is administered—so that the public can understand the agency's response to the proposer's application. Such agencies can further public understanding by furnishing materials explaining the fundamentals for CCS and by allowing for extra time at public meetings for basic educational purposes.

For California's educators, CCS represents an opportunity to develop or expand curricula to provide students with the education and training to find gainful employment in this newly emerging field. A broad range of professionals work on CCS, including geologists, hydrologists, engineers, drill rig crews, and chemists. A robust CCS industry will create new well-paying jobs, and teachers and professors may need to receive additional training to be able to teach and mentor their students. Already, many California schools and universities partner with industry practitioners to conduct field research. The involvement of teachers and students, particularly in early CCS projects, should be encouraged.

In addition to serving students with professional pursuits, California educators can help create a populace well informed on CCS fundamentals (as well as other climate change mitigation measures), contributing toward sound energy and climate policymaking.

CCS project developers will interact with stakeholders on many levels, however, outreach to communities surrounding proposed project sites will be particularly important and should be as inclusive as possible. Good community relations is an essential element to sustainable business success, and although each community is unique, major groups to consider in outreach planning include elected and safety officials; neighboring landowners and tenants; business, civic, environmental, and religious groups; neighborhood associations; schoolteachers; and local media. Contacts within such groups or organizations can assist with public notice of local meetings.

Process Recommendations:

- ***Allocate sufficient time and resources to support an inclusive outreach effort***
- ***Engage and provide a public forum for knowledgeable independent experts on CCS subjects***
- ***Communicate the scope, methods, and findings of risk assessments in an honest and open manner***
- ***Communicate in the language and through the channels most familiar to target audiences***
- ***Provide ample and non-intimidating vehicles for public comment***
- ***Keep outreach materials up-to-date and aligned with policy and project developments***
- ***Look for opportunities to share and coordinate outreach materials among organizations***

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15. Appendix L: Environmental Justice

The Environmental Justice (EJ) movement was born to addresses the statistical fact that people who live, work and play in America's most polluted environments are commonly people of color and the poor. Communities of color, which are often poor themselves, are routinely targeted to host facilities that have negative environmental impacts, or have historically co-habited the same areas as those facilities. The EJ movement has been championed primarily by African-Americans, Latinos, Asians, Pacific Islanders, and Native Americans. The pollution can take the form of air, water, or land pollution, but the domination of resources such as land or water by those facilities is also at issue with environmental justice, as is economic welfare and a community's sense of justice itself. The health effects resulting from exposure to pollution are widely recognized, while specific studies at EJ communities have shown how these communities exhibit higher levels of illness, disease, and premature deaths than in other areas.

The EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies."[138] The Agency explains that "'fair treatment' means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies."[139] Further, EPA explains that "'meaningful involvement' means that people have an opportunity to participate in decisions about activities that may affect their environment and/or health; the public's contribution can influence the regulatory agency's decision; their concerns will be considered in the decision making process; and the decision makers seek out and facilitate the involvement of those potentially affected."

California state law defines environmental justice to mean "fair treatment of people of all races, cultures, and incomes with respect to the development of environmental laws, regulations, and policies." EJ advocates, according to a presentation to this Panel,[140] would be more expansive and define environmental justice as everything in the EPA definition plus the avoidance of disproportionate environmental impacts on communities of low income residents and people of color, including:

- Cumulative health impacts on a region or community
- Fair and equitable use of government spending
- Health considerations sharing equal consideration with economic interests
- Long-term sustainability issues
- Fixing the health problems of dirty air and finding co-benefits of reductions in GHG emissions

[138] See: http://www.epa.gov/compliance/ej/
[139] See: http://www.epa.gov/compliance/ej/basics/index.html
[140] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/presentations/CCS_vs_Environmental_Justice_Presentation.pdf
See also: http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/presentations/CCS_vs_Environmental_Justice_Document.pdf

Typical concerns of EJ communities revolve around large industrial facilities such as power plants, refineries, cement plants, chemical plants, as well as truck and ship traffic and issues associated with dumping and incineration sites. Fossil fuels are often at the center of EJ concerns for a number of reasons that include the air, land, and water impacts associated with their extraction or production (e.g., coal mining or oil/gas wells), the emissions from their refining and combustion, and their waste byproducts (e.g., coal ash and petroleum coke). EJ activists commonly advocate a move away from the extraction and use of fossil fuels, and their replacement with clean, sustainable alternatives.[141]

In relation to CCS, a number of factors could lead to EJ concerns, depending on the location of a project. This is largely due to the fact that such projects will typically be complex set-ups that feature an industrial facility where the CO_2 is captured, a pipeline to transport it, and a sequestration site.

The capture plant is likely to be of most concern to EJ communities, due to its size and complexity. Such a plant may, or may not, present additional issues over and above a similar plant without CO_2 capture. In the case of a power plant, for example, it is possible that CO_2 capture may involve the use of some additional chemicals which are not commonly used in power plants, but which are used in industrial facilities elsewhere. It is also possible that the land footprint of a plant with capture will be larger, although this is likely to be an incremental difference rather than one of orders of magnitude.

Pipelines transporting CO_2 do not differ in any significant respect to pipelines transporting other substances. In some cases, CO_2 is a more benign substance that poses lower risks than, for example, flammable natural gas. The siting of these pipelines, therefore, is not expected to pose any EJ issues over and above typical pipeline proposals.

The sequestration of CO_2 will require some infrastructure to be built. Typically, this will comprise injection and monitoring wells, and some minimal access to land for geophysical monitoring. The number of wells for a new facility injecting into a saline formation will range from approximately 2–20, with the most likely number being in the middle-to-low end of the range, depending on the site's geologic characteristics. For an operational EOR site, existing wells could be used entirely, or some new wells added, along with CO_2 separation facilities.

It is therefore evident that the siting of CCS projects does have EJ dimensions, as would be expected for large industrial facilities. The siting of a new plant capture plant is likely to be of most concern, and will essentially carry same considerations for air, land, and water as a plant without capture. In addition, some particular aspects of a CCS plant, such as the use of specific chemicals, greater truck traffic, or a slightly larger surface footprint might raise some additional incremental issues that go beyond the base plant without CCS. The pipeline transportation and sequestration of CO_2 should present a smaller challenge as far as EJ is concerned, because the surface footprint is smaller, the infrastructure of a far smaller scale, and the emissions sources far fewer compared to the capture plant. This does not eliminate concerns however, as previous siting of oil and gas wells in highly populated and EJ areas is a reality and problematic from both an environmental and equity standpoint. It is possible that even a handful of CO_2

[141] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-08-18/presentations/03_Williams_Environmental_Justice_Issues_and_Carbon_Sequestration.pdf

injection and monitoring wells could be the straw that breaks the camel's back if the location is poorly chosen.

More generally, previous experience with industrial activities and facilities is likely to color EJ communities' reaction to CCS proposals as well as their perception of the risks of CCS itself. As a result, despite the scientific consensus that the risks related to the sequestration side of a well-sited and operated project are similar to commonly performed activities such as natural gas storage and enhanced oil recovery,[142] it is expected that some segments of the population in EJ communities will regard the injection of CO_2 itself as a dangerous, dumping activity, akin to the dumping of waste, and treat it as an EJ issue per se. Others might take a different view of the risks involved.

Based on the above, we do not see CCS as a technology that poses additional EJ concerns over and above what current industrial activities pose, but we recognize that these concerns are numerous. California should be mindful of EJ concerns and issues when it comes to siting CCS projects, and ensure that their impacts are mitigated and that they do not unfairly affect disproportionately burdened communities. At the same time, the state should seek to meet its energy needs through clean and sustainable means to the extent possible.[143]

[142] IPCC, 2005: *IPCC Special Report on Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

[143] A WebEx recording of the August 18, 2010, meeting including Jane Williams' presentation is available at: http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/index.html

16. Appendix M: AB 32 Regulations and CCS

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

AB 32 Regulations and CCS

DECEMBER 27, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

Options for Permitting Carbon Capture and Sequestration Projects in California

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

Review of Saline Formation Storage Potential in California

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Overview

This paper examines key AB 32 regulations where CCS might play a role. It summarizes the requirements of the regulations, their current status, and regulatory needs and timeframes. Additionally, the paper describes the importance of proper greenhouse gas accounting that is necessary for several AB 32 regulations. Finally, the paper mentions the similarities and differences between AB 32 and other regulations in terms of monitoring and accounting.

The Air Resources Board (ARB) recognizes that carbon capture and sequestration (CCS) might be a technology to help reach our long-term greenhouse gas (GHG) reduction goal of an 80% reduction from 1990 GHG emission levels by 2050.[144] In the near term, the Global Warming Solutions Act of 2006 (AB 32) requires ARB to reduce GHG emissions to 1990 levels by 2020. ARB will use a variety of programs including the Low Carbon Fuel Standard (LCFS)[145] and a cap-and-trade program[146] to reach the target. The Board has indicated that CCS may play a role in those regulations.

ARB's AB 32 Regulations Relevant to CCS

As mentioned above, ARB must develop programs and regulations to reduce California's emissions to 1990 levels by 2020, a reduction of approximately 30%, based on 2008 estimates. This will be done with a mixture of a cap-and-trade program and other regulations. The next sections will discuss the three most relevant regulations: the Mandatory Reporting Regulation (MRR), the cap-and-trade program, and the Low Carbon Fuel Standard (LCFS).

Before delving into the regulatory details, it is important to understand how CCS may play a role in the California cap-and-trade program. One way is that capture could occur at a capped source and be reported via the MRR, but there is no methodology for reporting this reduction. Secondly, CCS could occur at a non-capped source and be eligible to produce an offset credit that could be obtained by a capped entity but, again, there is no methodology or protocol through which CCS could receive credit. The next two sections will go into detail on the MRR and cap-and-trade Regulation, their requirements, and how CCS could be incorporated into them. The paper will then look at the LCFS.

Mandatory Reporting Regulation

AB 32 requires major sources to report on their emissions of greenhouse gases. The Air Resources Board approved the Mandatory Reporting Regulation in December 2007, which became effective January 2009. Revisions to the regulation to support the cap-and-trade program and to harmonize with the U.S. EPA greenhouse gas reporting requirements were approved by the Board on December 16, 2010. The regulation will result in a reporting and verification program that ensures accurate,[147] permanent,[148] and verifiable[149] reporting.

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[144] Executive Order S-3-05, http://gov.ca.gov/index.php?/print-version/executive-order/1861/
[145] http://www.arb.ca.gov/fuels/lcfs/lcfs.htm
http://www.arb.ca.gov/regact/2009/lcfs09/lcfscombofinal.pdf
[146] http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm
[147] "Accurate" means that the result of the measurement or calculation is close to the true value of the particular quantity, taking into account both random and systematic errors.

The MRR provides standardized methods for entities to measure, monitor, report, and verify emissions. Standardization allows for ARB to determine the validity and accuracy of the reported emissions and provides consistency across reporting entities, and is key to having a robust reduction program to verify progress towards reduction goals. The reporting requirements must have rigor and consistency to support a trading program.

California's largest industrial GHG emitters reported their emissions, and electricity retail providers and marketers reported electricity transaction information, for the first time in 2009. The 2008 GHG emissions reports include data from the following industrial sectors: cement plants, oil refineries, hydrogen plants, electricity generating facilities, cogeneration facilities, other large stationary combustion sources, and electricity retail providers and marketers. Only sources that meet certain size thresholds are subject to reporting. Through the 2010 reporting year, the threshold for oil refineries, hydrogen plants, and large stationary combustion facilities is ≥25,000 metric tons (MT) of CO_2 per year, and ≥1 megawatt generating capacity and ≥2,500 $MTCO_2$/yr for electricity generating and cogeneration facilities. Mandatory Reporting Regulation revisions approved in December 2010 require new reporting by fuel suppliers (suppliers of transportation fuels, suppliers of natural gas, natural gas liquids, and liquefied petroleum gas), suppliers of carbon dioxide, and oil and gas exploration and production facilities. Furthermore, facilities and suppliers with emissions between 10,000 and 25,000 $MTCO_2e$/yr will have abbreviated reporting requirements, and power plants and cogeneration facilities emitting between 2,500 and 10,000 $MTCO_2e$/yr will no longer be subject to reporting requirements. Reporting under these MRR revisions will first take place in 2012 for reporting of 2011 emissions.

Facilities subject to mandatory reporting are required to have their greenhouse gas emissions verified by a third-party ARB accredited verification body beginning in 2010 for their 2009 reported emissions. Facilities will be subject to annual verification under the proposed cap-and-trade program. Only ARB-accredited verification bodies[150] and verifiers may provide verification services for the purposes of mandatory greenhouse gas emissions reporting.

While provisions for reporting of CCS are not currently included in the MRR, they would be included in future MRR revisions when a CCS protocol is finalized under the cap-and-trade regulation. Since CCS cuts across numerous sectors and potentially entities (e.g., electricity provider, pipeline operator, and sequestration site operator), determining reporting rules is key. It could be treated as three separate

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[148] "Permanent" means either that GHG reductions or removal enhancements are not reversible, or when GHG reductions or removal enhancements may be reversible, mechanisms are in place to replace any reversed GHG emission reductions or removal enhancements to ensure that all credited reductions endure for a period that is comparable to the median atmospheric lifetime of an anthropogenic CO_2 emission. The duration for this period is based upon the best available science, and may be periodically reviewed and revised.

[149] "Verifiable" means that a GHG data report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body. "Verification" is the independent audit of the emissions data report relative to a standard (regulatory requirement – MRR in this case)

[150] Frequently asked questions about verification: http://www.arb.ca.gov/cc/reporting/ghg-ver/faq.pdf
List of ARB accredited verification bodies: http://www.arb.ca.gov/cc/reporting/ghg-ver/arb_vb.htm
List of ARB accredited verifiers: http://www.arb.ca.gov/cc/reporting/ghg-ver/verifiers_web.xls
Verification Fact Sheet: http://www.arb.ca.gov/cc/reporting/ghg-ver/verification.pdf
Verification Overview Presentation: http://www.arb.ca.gov/cc/reporting/ghg-ver/verification_webinar_1-27-10.pdf

reporting sectors or as one CCS sector. Until this detail is determined, many issues will be unresolved. For example, what entity reports emissions and reductions and is responsible for leaks? Determining which is best for ensuring full reporting and compliance with emission obligations as well as avoiding double counting would be a necessary step.

Summary and Key Points of MRR:

- Basis for cap-and-trade program compliance
- MRR includes out-of-state electricity provided to California
- ARB is responsible for a reporting and verification program that ensures accurate, permanent, and verifiable reporting.
- There is currently no mechanism for CCS to be reported under the MRR.
- Any future inclusion of CCS would be at least a year-long process.
- A robust CCS reporting quantification methodology is necessary first and it must meet the criteria listed in the third bullet.
- Many details (e.g., who reports, what are the monitoring requirements) for CCS to be included in the MRR are unclear at this point.

Cap-and-Trade Regulation

The cap-and-trade regulation,[151] approved by the Air Resources Board on December 16, 2010, imposes a statewide cap on greenhouse gas emissions from included entities. One metric ton of carbon dioxide equivalent emissions equals one allowance. The total number of allowances created is equal to the cap set for cumulative emissions from all covered sectors for that year or group of years. ARB will distribute allowances, or emissions permits, to capped entities. In addition to allowances, a limited amount of emission reductions from sources that are outside the cap coverage could be authorized; these reductions are called offsets. Both allowances and offsets, which are both types of compliance instruments, can be traded among entities. The most recent economic analysis estimates an allowance price around $21 per allowance in 2020.[152]

Entities will be required to surrender compliance instruments equal to their annual emissions at the end of each compliance period, each of which will be three years in length (e.g., 2012–2014, 2015–2017, and 2018–2020). The program will cover large industrial sources ($\geq$25,000 $MTCO_2e$/year) and electricity generation starting in the first compliance period. Transportation fuels, industrial combustion at facilities emitting less than 25,000 $MTCO_2e$ per year, and all commercial and residential fuel combustion of natural gas and propane will be included in the program starting in the second compliance period.

The Air Resources Board will use Mandatory Reporting Regulation data to determine which entities have a compliance obligation and how many compliance instruments each entity must surrender.

[151] http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm, http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm

[152] ARB's Updated Economic Analysis of California's Climate Change Scoping Plan.

Though no mechanism currently exists for CCS to be reported under the MRR or to count as an emissions reduction under the cap-and-trade regulation, the resolution[153] adopting the cap-and-trade program directed ARB's Executive Officer to

"initiate a public process to establish a protocol for accounting for sequestration of CO_2 through geologic means and recommendations for how such sequestration should be addressed in the cap-and-trade program, including separate requirements for carbon capture and geologic sequestration performed with CO_2-enhanced oil recovery; carbon dioxide injected underground for the purposes of enhanced oil recovery will not be considered to be an emissions reduction without meeting ARB's monitoring, reporting, verification, and permanence requirements."

ARB will pursue an open process, including public workshops and comment periods, in establishing a carbon capture and geologic sequestration protocol. This may include adapting a rigorous methodology developed by another entity. Any methodology developed outside of the AB 32 program must be revised to make it compliance grade for AB 32 and consistent with ARB regulations

Offsets

Carbon capture and geologic sequestration could only produce compliance-grade offsets under the California cap-and-trade program if performed at non-capped facilities and if the Board approved a CCS offset project protocol. This section will talk about criteria that an offset project protocol would need to meet to be accepted under the cap-and-trade program.

AB 32 requires offsets to meet rigorous criteria that demonstrate that the emission reductions are real, permanent, verifiable, enforceable, and quantifiable. [154] Further, the action or project must also be additional to what is required by law or regulation or would otherwise have occurred. Additionality is

[153] California Air Resources Board, December 16, 2010, California Cap-and-Trade Program Proposed Resolution with 15-Day Modifications, Resolution 10-42: http://www.arb.ca.gov/cc/capandtrade/capandtrade/draft%20resolution.pdf.

[154] Definitions:

"Real" means, in the context of offset projects, that GHG reductions or removal enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate and conservative methodologies that account for all GHG sources, sinks and reservoirs within the offset project boundary and account for offset uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

"Permanent" means, in the context of offset protocols, either that GHG reductions or removal enhancements are not reversible, or when GHG reductions or removal enhancements may be reversible, mechanisms are in place to replace any reversed GHG emission reductions or removal enhancements to ensure that all credited reductions endure for a period that is comparable to the median atmospheric lifetime of an anthropogenic CO_2 emission. The duration for this period is based upon the best available science, and may be periodically reviewed and revised.

"Verifiable" means that a GHG offset project data report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

"Verification" is the independent audit of the emissions data report relative to a standard (regulatory requirement – MRR in this case)

"Enforceable" means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

"Quantifiable" means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or removals relative to an activity baseline in a reliable and replicable manner for all GHG emission sources, sinks or reservoirs within the offset project boundary, while accounting for offset uncertainty and activity-shifting leakage and market-shifting leakage.

proposed to be determined via a performance standard and not a strict financial additionality criterion. Offsets are currently only allowed from ARB-approved protocols, but ARB may link with other cap-and-trade programs in the future, thereby indirectly accepting other programs' offset protocols. Offset protocols must be approved by the Board after an environmental impact assessment is conducted in compliance with the California Environmental Quality Act (CEQA).

The cap-and-trade program allows each capped facility to submit offsets to cover up to 8 percent of its compliance obligation.

Summary and Key Points of Cap-and-Trade Regulation:

- CCS could be counted under the cap-and-trade program either through a direct emissions reduction at a capped source or as an offset for CCS occurring at a non-capped source.
- ARB plans to establish a protocol to account for sequestration of CO_2 through geologic means.
- CCS could only be an offset at a non-capped source.
- AB 32 requires ARB to monitor compliance with and enforce any regulation adopted under the Act.

Low Carbon Fuel Standard

The Low Carbon Fuel Standard (LCFS) is one part of ARB's goal to meet the 2020 goals outlined in AB 32. Executive Order S-1-07[155] requested that ARB create an LCFS. The order calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. The LCFS is separate from Mandatory Reporting and the cap-and-trade program; it has its own reporting tools and credit-trading requirements.

The LCFS framework is based on the premise that each fuel has a "life-cycle" GHG emission value that is then compared to a standard.[156] This life-cycle analysis represents the GHG emissions associated with the production, transportation, and use of low carbon fuels in motor vehicles. The life-cycle analysis includes the direct emissions associated with producing, transporting, and using the fuels. In addition, the life-cycle analysis considers other effects, both direct and indirect, that are caused by the change in land use or other effects. For some crop-based biofuels, the LCFS has identified land use changes as a significant source of additional GHG emissions.

The standards are expressed as the carbon intensity of gasoline and diesel fuel and their alternatives in terms of grams of carbon dioxide equivalent per megajoule (gCO_2E/MJ). Providers of transportation fuels must demonstrate that the mix of fuels they supply meet the LCFS intensity standards for each annual compliance period. They must report all fuels and track the fuels' carbon intensity through a system of credits and deficits. Credits are generated from fuels with lower carbon intensity than the standard. Deficits result from the use of fuels with higher carbon intensity than the standard. A regulated party meets its compliance obligation by ensuring that the amount of credits it earns (or acquires) is equal to, or

[155] http://gov.ca.gov/executive-order/5172/

[156] For petroleum-based fuels, the life-cycle analysis is also referred to as "well-to-wheels"; for fuels produced from crops, the life-cycle analysis is sometimes referred to as "seed-to-wheels."

greater than, the deficits it has incurred. Credits may be banked and traded within the LCFS market to meet obligations.

ARB is developing a secure on-line LCFS Reporting Tool (LRT) to support the reporting requirements of fuels and other data to the state. ARB will review the reports for completeness and accuracy, evaluate the data to determine compliance, and conduct field investigations and audits to verify and validate the information.

CCS is specified as an option for producers of High Carbon Intensity Crude Oil (HCICO) to reduce emissions for production and transport of crude oil to less than 15 gCO_2e/MJ and thereby no longer be considered HCICO. CCS could be considered when used for the production of alternative fuels such as hydrogen, compressed natural gas (CNG), or electricity. For CCS to be incorporated into the LCFS, a quantification methodology would be necessary.

Summary and Key Points of LCFS:

- CCS is specified as an option to lower the carbon intensity of high carbon intensity crude oil to the California default.
- CCS could be considered when used for the production of alternative fuels such as biofuels, hydrogen, CNG, or electricity.
- There is no CCS project protocol in place. Any protocol developed may be different from the protocol established for the MRR and cap-and-trade program.

Accounting and AB 32 Regulations

Accurately accounting for carbon dioxide captured, transported, and sequestered is necessary for ARB to ensure that the sequestered CO_2 can be quantified and verified as permanent. Both the reductions and emissions from the mitigation technology would need to be considered. Reporting and offset methodologies must be consistent and rigorous enough to support a trading system.

Unlike the Division of Oil, Gas, and Geothermal Resources' (DOGGR) monitoring requirements, ARB's accounting methodologies must be able to accurately quantify emissions and reductions. Any accounting scheme must identify and quantify leakage to the atmosphere. A monitoring program designed purely for health and safety or to protect drinking water would not be sufficient for quantification purposes, where every ton of CO_2 leaked to the surface or lost as fugitives at a compressor or wellhead has to be quantified.

Measurement, monitoring, verification, and reporting must occur through ARB's system in order to ensure consistent application and compliance with overall AB 32 programs. AB 32 requires ARB to monitor, verify, and enforce the greenhouse gas Mandatory Reporting Regulation as well as ensure that any greenhouse gas reductions are accurate, permanent, and verifiable. ARB's approach has been to develop sector-based rather than project-based accounting requirements.

Carbon capture and sequestration brings unique considerations to GHG accounting as it includes reductions and emissions that cross sectoral boundaries. Reductions occur at an industrial facility but emissions occur both at the facility during capture and elsewhere as the carbon dioxide is transported, compressed, and injected into the subsurface. Additionally, the sequestration site would need to be able to

verify that the reductions are permanent. Enhanced oil recovery with sequestration would present more considerations because emissions can occur in the production, recycling, and reinjection phase. The subsurface could also need to be monitored for migration to other producing sites or abandoned wells.

The U.S. Environmental Protection Agency, European Union, Intergovernmental Panel on Climate Change, non-profits, industry organizations, and others are developing or have developed national and international accounting guidelines or systems for CCS; however, any and all of them would need to be revised to be compliance-grade for ARB's programs. The revisions process would be public and include technical and policy changes to ensure that the quantification methodology is appropriate for California conditions including consistency with the MRR and cap-and-trade regulation as well as considering any changes necessary to account for different risks due to California geology and seismicity concerns.

Some fundamental questions arise when considering how CCS might be accounted for under AB 32 regulations:

- What level of measurement/monitoring certainty would be enough?
    - Currently the Mandatory Reporting Regulation has established a +/- five percent standard for the measurements that generate fuels emissions estimates.
    - Would a monitoring plan need to be able to detect a leak of x amount with x likelihood? (e.g., if a leak were detected, would it need to be quantified within +/- five percent?)
    - Can current monitoring techniques quantify leaks with enough accuracy and precision?
    - If measurement accuracy and precision is not high enough, would it be sufficient to incorporate the uncertainty into the emissions and reductions accounting?
- How would permanence be addressed?
    - Cap-and-trade program current thinking:
        - If reductions or removals may be reversible (e.g., there could be an emissions leak):
            - Mechanisms must be in place to replace any reversed carbon.
            - The operator must ensure that credited reductions endure for a period comparable to the atmospheric lifetime of anthropogenic CO_2 emissions.
    - Permanence is addressed in the four offset protocols adopted by the Board.
- Who verifies the emissions and reductions?
    - Under the cap-and-trade program, ARB requires verification statements from third-party verifiers for both reporting and offsets.
    - LCFS: ARB
- Who would be responsible if there is a reversal (e.g., if there is a leak to the atmosphere)?

- ARB is considering how to address this issue under the cap-and-trade program.
- Under LCFS, this issue remains to be addressed.
- Reversal discussions must consider all sectors covered by AB 32 and would not be limited to CCS.

ARB Regulatory Process and Timelines

ARB engages in an extensive public process with any regulation or regulatory change. A full regulatory development process can take years, whereas a revision to a regulation may not take as long. After an extensive public participation process of generally 6 months or longer, staff submits an initial statement of reasons detailing the rationale for a regulation and recommends a regulation or regulatory change. The documents are made public through a 45-day notice for comment. Staff then presents the information to the Board, which determines its approval or denial. If the regulation is approved, staff provides the proposed final regulation to the state's Office of Administrative Law (OAL), along with a final statement of reasons incorporating responses to comments. OAL has a year after the initiation of the 45-day comment period to act on the regulation.

Consistency with Other Agencies

In addition to AB 32 programs, other agencies have a role in regulating and monitoring CCS either through greenhouse gas or underground injection related regulations. Two important programs to consider are the Emission Performance Standard (EPS) under SB 1368 and the Underground Injection Control program.

The EPS establishes a standard for CO_2 emissions at baseload plants and includes a provision to allow CCS to be used to meet that standard. The CO_2 emission performance standard (EPS) for baseload generation owned by, or under long-term contract to, the state's utilities is 1,100 lbs CO_2/MWh. The California Energy Commission and the California Public Utilities Commissions implement this standard and it is a separate process from the AB 32 regulations. The current regulations implementing SB 1368 at CEC and the CPUC allow for the use of CCS to meet the EPS but the details for determining compliance are unclear. The CEC regulation states that for covered procurements that employ geologic CO_2 sequestration, the successfully sequestered carbon dioxide emissions shall not be included in the annual average CO_2 emissions. The EPS for such power plants shall be determined based on projections of net emissions over the life of the power plant. Carbon dioxide emissions shall be considered successfully sequestered if the sequestration project meets the following requirements:

1) Includes the capture, transportation, and geologic formation injection of CO_2 emissions;
2) Complies with all applicable laws and regulations; and
3) Has an economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the sequestration project is operational

These requirements differ from AB 32 requirements in a few key ways: 1) The EPS is based on emissions over the lifetime of the plant, whereas the MRR considers annual emissions and the LCFS considers life-cycle emissions (including indirect emissions); 2) the EPS requires an economically and technically

feasible plan for permanent sequestration and the MRR and cap-and-trade program require a quantification methodology that can quantify any emissions and verify permanent sequestration. The definition of permanent sequestration is not included and may have different criteria than those defined under the AB 32 regulations. For these reasons, AB 32 regulations will have different requirements for compliance than SB 1368.

The following table details the different requirements of the various agencies' regulations:

Regulation	Agency	Permanence	Monitoring Goal or Requirement	Metric for Estimating GHG Emissions to Atmosphere
Emission Performance Standard	CEC and CPUC	Included but not defined	Unclear	Lifetime annual average GHG emissions
Mandatory GHG Reporting Regulation and Cap-and-Trade Regulation	ARB	All credited reductions endure for a period that is comparable to the median atmospheric lifetime of an anthropogenic CO_2 emission	Detect and quantify emissions (if any) and verify permanence	Annual Emissions
Underground Injection Control Program	DOGGR or U.S. EPA	Not necessary as long as underground sources of drinking water are protected	Protect underground sources of drinking water	None
Low Carbon Fuel Standard	ARB	Not addressed for CCS at this time	Verify carbon intensity of fuel	Life-cycle carbon intensity of fuel

CCS projects would get a permit from the Underground Injection Control (UIC) Program, which requires monitoring similar but not identical to ARB needs. The UIC program is under the federal Safe Drinking Water Act and its mandate is to protect underground sources of drinking water (USDW). Although the permits require monitoring to ensure USDW protection, the monitoring is not designed to quantify emissions or ensure permanence, which are key components of AB 32 related monitoring needs.

Although ARB cannot use other agencies' requirements directly, ARB realizes the utility of remaining consistent across agencies and streamlining the process as much as possible. However, since the needs for the EPS and the UIC programs are significantly different from the need for quantification for a carbon trading scheme, monitoring and other requirements would be inherently different.

Summary and Key Points

The following is a summary of key points related to AB 32 regulations and the potential inclusion of CCS:

- AB 32 requires ARB to implement a GHG reporting program and the agency is accountable for ensuring the reductions are real, permanent, quantifiable, verifiable, and enforceable.
    - ARB must implement the monitoring and verification processes
    - Uses third-party verification

- A cap-and-trade program and the LCFS are just two tools to meet the 2020 emissions goal.
- A robust protocol and quantification methodology are required for CCS projects to play a role in AB 32 regulations.
    - The timeline could be several years to develop and finalize a protocol and quantification methodology and incorporate it into regulations
- There are differences among ARB regulations and between ARB regulations and those of other agencies. Consistency in methods such as monitoring plans or quantification methodologies is ideal but there are different needs necessary to meet the different statutory authority and program goals. For example, each regulation has a different compliance time-frame and/or mechanism for quantifying greenhouse gas emissions:
    - ARB: Reporting through the current Mandatory Reporting Regulation and compliance with the cap-and-trade regulation requires rigorous quantification of annual emission estimates on a facility level.
    - CEC/CPUC: The Emission Performance Standard requires compliance with a lifetime annual average carbon dioxide emission level.
    - DOGGR: The Underground Injection Control Program does not consider quantification but ensures protection of underground sources of drinking water with no quantification of greenhouse gas emissions.

The regulatory and statutory differences mean that AB 32 regulations would have different monitoring, quantification, reporting, and verification needs and requirements for compliance from each other and other agency's regulations.

17. Appendix N: Options for Permitting Carbon Capture and Sequestration Projects in California

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Options for Permitting Carbon Capture and Sequestration Projects in California

AUGUST 17, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Susan Brown
Primary Author

Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

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Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

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Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

Review of Saline Formation Storage Potential in California

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Overview

This paper summarizes and evaluates options for establishing a regulatory framework for geologic carbon capture and storage (CCS) projects in California. It examines existing regulatory models, including one-stop or single-agency versus multiple-agency permitting and the use of Memoranda of Understanding, and briefly discusses the pros and cons of each of these approaches. Discussion of long-term stewardship, legal liability, property ownership, public outreach and the treatment of CCS under state climate change legislation (Assembly Bill 32) or under a state or federal cap-and-trade will be discussed in other white papers.

Current Permitting Process in California

The permitting process for industrial development projects in California involves a multitude of federal, state, regional and local agencies, each with its unique authorities and regulatory requirements. Often, the agencies act independent of one another, and permitting timeframes are not closely coordinated. Typically, the first state agency to act on a permit application by a developer becomes the lead agency for the environmental document required under the California Environmental Quality Act (CEQA). The lead agency under CEQA coordinates its review of an Environmental Impact Report or Negative Declaration with the other responsible permitting agencies.

The current regulatory framework allows a project developer to approach different agencies at different times to initiate permit applications and to begin to address the environmental documentation requirements of CEQA. The timing of when a permit application is filed, and which permitting agency is the first to act on a permit, is the responsibility of the project developer. See Table 1 of this paper which summarizes the roles and responsibilities of California's permitting agencies.

Regulatory Gaps

Gaps currently exist in how California regulations will apply to geologic CCS projects, and especially CCS project that do not involve Enhanced Oil Recovery (EOR). These gaps will either be addressed by the U.S. EPA in its proposed rulemaking on CCS, by the establishment of Memorandum of Understanding among agencies, or by an application from a designated state regulatory agency to obtain "primacy" over CCS injection wells. Also, no state agency has the explicit authority to regulate CO2 pipelines, and Monitoring, Measurement and Verification (MMV) requirements for geologic carbon sequestration have yet to be established. These last two topics are being addressed in separate white papers.

One-Stop Permitting for Power Plants with CCS

The California Energy Commission serves as the lead agency for the permitting of power plants which are retrofitted with CCS technology and also serves as the lead agency under the California Environmental Quality Act (CEQA). The Energy Commission's 12-month, one-stop state permitting process is a certified regulatory program under the California Environmental Quality Act (CEQA).[157]

[157] Authority for power plant licensing by the Energy Commission is found in Public Resources Code Section 25000 et seq.

The Energy Commission's license and certification process subsumes the requirements of state, local, or regional agencies otherwise required before a new plant is constructed, while federal permits are issued within the timeframe of the Energy Commission's licensing process. However, there have been cases where federal and state permitting timelines have not been closely matched. The Energy Commission coordinates its review of the facility with other permitting agencies to ensure consistency between their requirements and its own conditions of certification. [158]

Prior to 1975, utilities were required to go through a multi-agency process to obtain permits from numerous federal, state, and local agencies before constructing new power plants. The Legislature established the California Energy Commission in 1975 and mandated a comprehensive, single-agency state permitting process for new power plants. The Legislature gave the Energy Commission the statutory authority to license thermal power plants of 50 megawatts or greater along with the transmission lines, fuel supply lines, and related facilities to serve them.

Until very recently, CCS was not a significant factor in the Energy Commission's siting process. In the case of a power plant project that involves carbon capture, the Energy Commission considers the environmental impacts of the entire facility and incorporates permit conditions to ensure that the CO_2 injection process is conducted in an environmentally safe manner. Under current law and regulations, these conditions of certification incorporate the regulatory requirements of other federal, state, regional and local agencies into a single permitting process.[159] In most cases, applicable federal permits for activities associated with the power plants would still need to be obtained, since federal authority can pre-empt state authority.

At this point in the regulatory process, DOGGR has said that it does not have the authority to regulate permanent carbon sequestration even if it's tied to oil and gas operations, such as Enhanced Oil Recovery (EOR). In a March 1, 2010, letter from Bridgett Luther, the Director of the Department of Conservation, to Dan Pellisier, Deputy Cabinet Secretary for Resources in the California Governor's Office, the department which oversees DOGGR, concluded: "…DOGGR currently has neither the statutory authority nor the technical staff on hand to regulate pure CCS projects…"

For CCS projects not associated with thermal power plants, the Division of Oil, Gas and Geothermal Resources does not have the authority to regulate non-EOR CCS projects, and does not have the staff resources necessary to assume the role of permitting such projects. For example, CCS projects involving saline formations are not currently within the purview of DOGGR, unless they are associated with oil, gas or geothermal operations.

[158] PRC Section 25500 specifically provides: "In accordance with the provisions of this division, the Commission shall have the exclusive power to certify all sites and related facilities in the state, whether a new site and related facility or a change or addition to an existing facility. The issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency, or federal agency to the extent permitted by federal law, for such use of the site and related facilities, and shall supersede any applicable statute, ordinance, or regulation of any state, local, or regional agency, or federal agency to the extent permitted by federal law."

[159] For further information, see http://www.energy.ca.gov/public_adviser/power_plant_siting_faq.html

Under current law and regulation, DOGGR regulates the drilling and operation of wells that are classified as Class II wells under authority delegated from the U. S. Environmental Protection Agency (EPA). In this capacity, it sets requirements for any subsurface injection of fluids for enhanced recovery of oil or natural gas, or for fluids which are brought to the surface in connection with conventional oil or natural gas production. [160]

Primacy for Permitting Pure CCS Projects

The U.S. EPA is the lead agency for the Underground Injection Control (UIC) program and the lead agency for environmental documentation required under the National Environmental Policy Act (NEPA). DOGGR has the authority delegated by EPA for Class II EOR projects, while U.S. EPA issues permits for Class V wells (CO_2 injection). Through its proposed rulemaking, the U.S. EPA is currently in the process of determining who will ultimately be the lead agency for permitting pure CCS projects. The U.S. EPA is establishing regulations for CCS projects, under its existing authority for the UIC Program, including a new, proposed class of injection wells, Class VI, for geologic sequestration projects.[161]

One option is for a California agency to submit a request that the U.S. EPA grant "primacy" to a designated state regulatory agency for the permitting of Class VI wells, in addition to Class II wells. Under current authority, DOGGR has primacy for regulating only Class II wells (oil and gas) which was granted under the Safe Water Drinking Act. Whether or not DOGGR is eligible to apply for "primacy" for Class VI wells will depend on the terms and requirements of the EPA rulemaking. Much attention is being focused on how the EPA will decide to treat CCS joined to EOR. [162] Will it be covered by the existing Class II well permit? Or will it be covered by the new proposed Class VI permit?

To request primacy for Class VI wells (CCS) would require the EPA to determine under what authorities (e.g., Clean Air Act, Clean Water Act, or federal energy or climate change legislation) such primacy would be granted. For these reasons, this option will, therefore, require further examination by the California CCS Review Panel.

DOGGR, because of its long-standing involvement in regulating oil and gas resources, may be in the best position to regulate the injection of carbon dioxide into subsurface resources through a process intended to stimulate additional oil production. However, DOGGR will likely need additional statutory authority, federal delegation of "primacy" for regulating Class VI wells, and additional staff resources to perform this function.

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[160] See Section 40: Code of Federal Regulations 144.6.

[161] See 40 CFR, Parts 144 and 146: Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Proposed Rule.

[162] From 40 CFR, Parts 144 and 146: Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Proposed Rule:
"The requirements in today's proposal, if finalized, would not specifically apply to Class II injection wells or Class V experimental technology wells. Class VI requirements would only apply to injection wells specifically permitted for the purpose of GS. Injection of CO_2 for the purposes of enhanced oil and gas recovery (EOR/EGR), as long as any production is occurring, will continue to be permitted under the Class II Program. EPA seeks comment on the merits of this approach since owners or operators of some Class II EOR/EGR wells may wish to use wells for the purposes of production and GS prior to the field being completed depleted."

Other states, such as the State of Montana, have independently enacted laws that govern how carbon sequestration will be regulated and that could serve as a model for a California regulatory program. For example, Senate Bill 498 (Chapter 474, Statutes of 2009) authorizes the state oil and gas regulation to issue permits for the injection of carbon dioxide and assesses fees for administering a carbon sequestration program. As part of its program, the Board of Oil and Gas Conservation solicits comments from the Department of Environmental Quality prior to issuing an injection permit. It also contains certain provisions that allow the transfer of liability for post-injection sequestration to the State of Montana.

Current attempts to develop state-based legislation in California, such as Assembly Bill 705, as proposed on April 17, 2007, have not been successful.[163]

Case Study #1: Hydrogen Energy California

The Hydrogen Energy California (HECA) project is the first proposed power plant project using carbon capture and storage (CCS) technology to be submitted for Energy Commission for licensing. HECA will use CCS on a power plant fueled by petroleum coke, a waste product of oil refining, to produce a lower-carbon emission source of electricity. The process to be used at HECA converts petroleum coke, along with locally delivered coal and coal imported from out of state, into hydrogen, a clean-burning gas, and CO_2. CO_2 from the facility will be transported via pipeline to the Elk Hills oil field, where it will be injected into the oil reservoir and used to stimulate EOR.

As part of the Energy Commission licensing proceeding, DOGRR is regulating the EOR aspects of the proposed project, while the Energy Commission plans to fold into its license, any requirements that DOGGR would normally attach to a permit for oil and gas wells. The issue of where DOGGR's permitting authority for EOR-related CCS projects starts and ends will likely be addressed in the Energy Commission's final decision on the proposed project.[164]

Case Study #2: C6 Pilot Project in Solano County

C6 Resources, LLC was awarded a grant from the U. S. Department of Energy under the American Recovery and Reinvestment Act to examine the potential of commercial CCS for an industrial source of CO2 in the Montezuma Hills of Solano County. The setting is a rural area where surrounding lands are used for agriculture, grazing, open space and wind energy production.

A geologic CO_2 storage pilot is planned, with sequestration into deep sandstone formations containing saline formation fluids. The pilot test involves drilling injection and monitoring wells 10,000-12,000 feet deep and injecting up to 6,000 metric tons of CO_2 into the saline formation. CO_2 will be purchased from a local supplier and trucked to the pilot test site.

Permitting the project initially involves obtaining an experimental UIC permit from U.S. EPA, Region 9, and a conditional land use permit from Solano County. Experimental UIC permits for injection wells falls

[163] AB 705 would have required DOGGR to adopt standards and regulations for geologic carbon sequestration projects. The bill further proposed to require DOGGR to enter into a Memorandum of Understanding with the U. S. Environmental Protection Agency (US EPA) to develop standards and clarify the respective authorities of DOGGR and US EPA under the Underground Injection Control (UIC) Program.

[164] March 25, 2010: California Energy Commission; Energy Staff's Issues Statement; Docket No. 08-AFC-8.

under a subset of Class V wells. Within the permitting requirements, EPA relies on DOGGR standards for drilling procedures.

The U.S. EPA first needed to make a determination regarding the need for an Environmental Impact Statement under NEPA, while Solano County, the local lead agency, needed to make the determination on whether an Environmental Impact Report (EIR) is needed to satisfy CEQA.

Multi-Agency Permitting

The permitting process for industrial development projects in California involves a multitude of federal, state, regional and local agencies, each with its unique authorities and regulatory requirements. The current regulatory framework allows a project developer to approach different agencies at different times to initiate permit applications and to begin to address the requirements of CEQA. The timing of when a permit application is filed, and which permitting agency is the first to act on a permit, is the responsibility of the project developer.

The California Permit Streamlining Act of 1977 was enacted as a way of addressing a complicated and often uncoordinated permit process. This Act added a series of timelines and deadlines to expedite government permitting of industrial development projects. In other words, it enacted a calendar of events by which a permit applicant could expect prompt review of a development project.

Under the Act, if a public agency does not approve or deny a project within the statutory time limit, the project is deemed approved. The Act establishes that the lead agency must approve or deny a project within 6 months of certifying an Environmental Impact Report (EIR), or within 3 months of adopting a Negative Declaration. Other agencies, who are not the lead agency, must the act within 6 months from the time a permit application is filed.

In California, the permitting process is coordinated with the environmental review process required by CEQA. A lead state agency, typically the first agency to act on a given project, determines whether a project is exempt from CEQA or whether it must require a negative declaration, mitigated negative declaration, or an EIR. It is the responsibility of the lead agency to involve other permitting agencies so that a coordinated environmental review results.[165]

However, multi-agency permitting, if it is not conducted on parallel timeframes or closely coordinated by the lead agency, can be time-consuming and costly for developers, including CCS project developers. If public opposition to a given project surfaces during the permit or environmental review process, the project can be further delayed. Furthermore, court challenges of a permit decision made by a permitting agency can add considerable time to the development process. Lastly, permitting agencies can reject applications from developers as incomplete, which increases the time frame for completing the process, or they can deny a permitting application within the required timeframes.

As a result, the permitting timeframes established in the 1977 Permitting Act are not always strictly adhered by permitting agencies, and are difficult to enforce.

[165] See www.ceres.ca.gov/ceqa/guidelines/intro.html

Use of Memoranda of Understanding

Coordination among regulatory agencies can be further improved through Memoranda of Understanding, especially where there is overlap or the potential for duplication of regulatory requirements. In California, MOUs have been established for the permitting of geothermal energy projects on federal lands, the joint review of Solar Thermal Power Plants, and the review of wave energy projects by the Federal Energy Regulatory Commission and California agencies. Similar MOUs for the permitting of CCS projects in California would be helpful in clarifying regulatory jurisdiction and in improving interagency coordination.[166] An MOU can also serve to designate the lead agency. However, the use of an MOU cannot cure inherent statutory conflicts in existing laws and regulations, and would need to be evaluated further on a case-by-case basis.

Case Study #3: MOU between DOGGR and the State Water Board

In California, the Division of Oil and Gas and Geothermal Resources regulates the drilling and operation of wells associated with oil and gas production and geothermal resources. As part of its responsibilities for the permitting of oil, natural gas and geothermal drilling, DOGGR approves any subsurface injection or disposal of waste fluids in connection with oil or natural gas production, including Class II wells, under its delegated authority from the U. S. Environmental Protection Agency. See California Code of Regulations, Title 14, Division 2; Chapter 4.

There are currently no specific requirements for CO_2 injection, which is not like cyclic steam or gas storage. Please note that gas storage is only for natural gas. Section 3007 of the Public Resources Code defines gas as: "Gas" means any natural hydrocarbon gas coming from the earth." This section would likely exclude the storage of any anthropogenic CO_2 under DOGGR laws and regulations.[167]

The State Water Board is responsible for regulating any discharge that may affect surface and groundwater in California. The Board is also responsible for water rights and establishes state requirements on water quality control. Nine semi-autonomous regional water boards are responsible for the day-to-day implementation of the Porter-Cologne Act and the Clean Water Act in California. In the case of CCS projects, the Regional Boards would be involved in the permitting of carbon dioxide injection projects affecting surface or groundwater and would propose appropriate mitigation measures.[168]

The DOGGR and the State Water Board entered into an MOU for permitting Class II wells for EOR in 1991. DOGGR has the lead role in regulating Class II injection wells for EOR, since the agency requested and was given "primacy" by the U.S. EPA under the federal UIC program. To avoid duplication of effort and increase coordination, the Regional Water Control Boards consult with DOGGR and regulate surface discharges, but do not issue a permit for Class II injection wells for EOR projects.

[166] June 2, 2010: Presentation by Jerry R. Fish, Stoel Rivers, LLP, before the CCS Review Panel.
[167] E-mail communication between Susan J. Brown, Senior Policy Analyst, California Energy Commission, and Rob Habel, Chief Deputy, Division of Oil and Gas and Geothermal Resources; April 29, 2010 .
[168] E-mail communication between Susan J. Brown and Lisa Babcock, Senior Engineer, State Water Resources Control Board on May 10, 2010.

Similar MOUs relating to the permitting of non-EOR CCS projects may be helpful and could involve the Energy Commission, CPUC, DOGGR, Water Boards, Air Quality Management Districts, and local agencies, such as cities and counties.[169] This approach needs to be further explored.

Challenges and Recommendations in Defining a Regulatory Framework for Geologic CCS Projects

Any legal or regulatory framework that is established for permitting CCS projects should be clear and transparent, providing needed guidance to project developers on specific regulatory requirements. In addition, such a framework should balance the need for regulatory certainty with the need to protect public health and safety and the environment. Such a framework should aim to:

- Maintain consistency in state permitting requirements for all types of geologic CCS projects
- Clarify the respective roles and boundaries of each of the agencies while reducing regulatory uncertainty
- Define and prescribe specific Measurement, Monitoring and Verification (MMV) requirements that are appropriate, clear, and effective and that govern the long-term performance of the reservoir
- Define specific regulatory requirements that provide guidance for early, first-of-its kind geologic CCS projects, until a permanent statutory or regulatory framework is established.
- Quantify and verify the greenhouse gas (GHG) reductions possible through permanent storage of CO_2 using advanced and emerging CCS technologies.[170]
- Address facility decommissioning issues in the permitting and regulatory process.

A September 2007 Report by the Interstate Oil and Gas Compact Commission (IOGCC) made a series of specific recommendations for establishing Model General Rules and Regulations which provide a useful starting point for new California laws or regulations. More specifically, the IOGCC recommended rules which:

- Define carbon dioxide as "anthropogenically sourced CO_2 which is produced as a byproduct of combustion in the industrial process" and not geologically occurring CO_2.
- Recommend that a single state regulatory agency be identified with full authority to regulate CCS projects, which involve oil and gas development and deep saline formations, and issue a permit to operate a CO_2 storage facility.
- Recognize that the designated state regulatory agency have the authority to require an operator to submit any data necessary to evaluate a proposed CO_2 storage project.
- Specify model procedures and standards for permitting and operating CCS projects.
- Identify as an issue what happens when an oil and gas EOR project operating under oil and gas leases converts to a CO_2 storage project for purposes of regulation.
- Identify the need for a comprehensive monitoring and verification process for the sub-surface reservoir operation that provides for early detection of any leakage or any releases of CO_2, and

[169] Presentation by Jerry R. Fish of Stoel Rivers, LLP to the California Carbon Capture and Sequestration Review Panel on June 2, 2010,

[170] Presentation by Elizabeth Burton, Lawrence Livermore National Laboratory, before the CCS Review Panel on April 22, 2010.

prescribes mitigation measures to protect public health and safety.[171]

In addition, guidance on how to establish a model permitting process for CCS projects can be found in proposed California state legislation, Assembly Bill 705, as proposed in 2007, which was discussed above.

Pros and Cons of Option #1: Single Agency Permitting

Pros:

- Consolidates the project review, with the potential for time and cost savings for project developers
- Clarifies the lead permitting agency, eliminating the current regulatory uncertainty faced by first-of-its kind CCS technology projects.
- Possible without changes in law or regulation for geologic CCS projects associated with Enhanced Oil Recovery (EOR).
- Would allow state regulation of CCS development under authority delegated by U.S. EPA.
- Such delegation would allow states to craft more streamlined permitting processes and to require stricter environmental requirements than federal requirements.
- Having a single agency would also simply reimbursement of fees associated with permitting CCS projects.

Cons:

- Identifying a single agency, such as DOGGR, as the lead agency for <u>all</u> CCS development projects will require new legislation and additional staff resources.
- Vesting additional regulatory responsibility with the DOGGR will involve new regulations, which could take up to 2 years to enact.
- Obtaining "primacy" beyond Class II wells to Class VI wells under delegated authority from U.S. EPA may initially be time-consuming.

Pros and Cons of Option #2: Multiple Agency Permitting

Pros:

- Does not require statutory or regulatory changes to maintain the current permitting process within existing regulatory authorities.
- Could allow parallel, complimentary permitting by a multitude of federal, state, regional and local agencies, if permitting time frames are closely aligned and coordinated.
- Could allow agencies to coordination the preparation of joint environmental documents.

Cons:

- Fails to provide regulatory certainty for early, first-of-its kind CCS development projects.
- Duplicative permitting may be cumbersome and could be confusing for project developers.

[171] A Report by the Interstate Oil and Gas Compact Commission Task Force entitled "Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces," dated September 25, 2007.

Pros and Cons of Option #3: Use of Memoranda of Understanding

Pros:

- Improves coordination among multiple agencies, without the need for new legislation or regulations
- Clarifies the respective roles of each of the agencies while reducing regulatory uncertainty
- Maintains current permitting processes under existing regulatory authorities.

Cons:

- May not be binding, if involved agencies lack the needed statutory authority to permit all forms of CCS development projects.

Table 1
Summary of California Permitting Agencies and Authorities
Carbon Capture and Storage Projects

Agency	Permit Required	Regulatory Authority
County or City	Conditional Use Permit Building Permits Usually lead agency for CEQA for power plants under 50 MW if built by a regulated utility .	Various Local Ordinances affecting land use
Regional Water Control Boards	Waste Discharge Requirements (in compliance with water quality control plans) NPDES Permits	California State Constitution, Article X, Chapter 2. California Water Code, Sections 13263 and 13260 CA Code of Regulations, Title 23, Division 3, and Title 27 (Solid Waste) Federal Water Pollution Control Act 33 U.S.C. sections 1342 and 1370. Section 1342(b)(1)(D) specifically authorizes states with NPDES authority "to issue permits which . . . control the disposal of pollutants into wells." **Note, however, that the definition of "pollutant" in section 1362(6) excludes "water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil or

		gas production and disposed of in a well," *so long as* the "state determines that such injection or disposal will not result in the degradation of ground or surface water resources." Code of Federal Regulations, Title 40, sections 122.21, 122.28, 123.25, 123.28 California Water Code, Sections 13377 and 13376
California Energy Commission	License for thermal power plants sized at 50 megawatts or greater Compliance with greenhouse gas emission performance standards for base load power plant purchase contracts (municipal utilities only). Current EPS is 1,100 pounds of CO2 per megawatt-hour.	Public Resources Code section 25519 and section 21000 et seq. Senate Bill 1368 (Chapter 598, Statutes of 2006) Section 2904 of Chapter 11, GHG Performance Standard, Article 1, sets annual average CO2 emissions standard.
California Public Utilities Commission	Approval of utility rate recovery for investor-owned utility projects; approves or denies ratepayer funding for CCS activities by utilities. Certificate of Public Convenience and Necessity authorizes a utility to spend ratepayer funds. Compliance with greenhouse gas emission performance standards for base load power plant purchase contracts (investor-owned utilities). Approval of pipelines that offer "transportation services" to the public and qualify as "common carrier utility." Sets safety requirements for certain intrastate natural gas pipelines.	Public Utilities Code Sections 1001-1005 Section 2904 of Chapter 11, GHG Performance Standard, Article 1, sets annual average CO2 emissions standard. Public Utilities Code Sections 211, 212, 216, 227 and 228. CPUC General Order 112-E adopts Federal standards from 49 CFR Sections 191, 192 and 199, including reporting requirements.
California Air Resources Board	Approve plans to reduce greenhouse gas (GHG) emissions by large industrial sources, such as power plants,	Assembly Bill 32, the Global Warming Solutions Act of 2006 (Nunez, Statutes of 2006) sets an economy wide cap on California

	refineries, and cement plants. Lead regulatory agency for enforcing compliance with California's GHG reduction goals.	GHG emissions at 1990 levels by 2020. Governor's Executive Orders establishing long-term greenhouse gas reduction goals and the Low Carbon Fuel Standard (LCFS) Various regulations that govern the Low Carbon Fuel Standard, mandatory reporting requirements, and a California Cap and Trade program
Local air districts	Authority to Construct and Permit to Operate	Various regulations adopted by the district governing boards
State Water Resources Control Board	Approval of water rights	Division 7 of the California Water Code (Section 13000 et sequitur)
Division of Oil, Gas and Geothermal Resources	Permits for the drilling and operation of wells associated with oil and gas production and geothermal drilling. Permits for Enhanced Oil Recovery Delegated authority from U.S. EPA for Class II wells within the Underground Injection Control (UIC) program.	California Code of Regulations, Title 14, Division 2, Chapter 4. Public Resources Code Section 3106 CA Code of Regulations 1724.6 through 1724.10 No specific requirements for CO2 injection. Only for natural gas storage. Federal Safe Drinking Water Act. Section 40: Code of Federal Regulations 144.6
State Fire Marshal	Regulates intrastate hazardous liquid pipelines, and establishes reporting requirements. No specific authority for regulating the safety of CO2 pipelines.	Elder California Pipeline Safety Act of 1981; California Government Code Section 51010 et sequitur.

18. Appendix O: Enhanced Oil Recovery as Carbon Dioxide Sequestration

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Enhanced Oil Recovery as Carbon Dioxide Sequestration

AUGUST 10, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

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Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

AB 32 Regulations and CCS

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Options for Permitting Carbon Capture and Sequestration Projects in California

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

Review of Saline Formation Storage Potential in California

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

1. Crediting and Regulating Sequestration at CO_2-EOR Sites.

To achieve California's aggressive greenhouse gas (GHG) emissions reductions goals, deployment of carbon capture and sequestration (CCS) technology may be necessary. CCS involves injecting carbon dioxide (CO_2) underground for the purpose of permanent geologic sequestration in saline formations or oil and gas reservoirs. CCS regulations must ensure both the safety of CCS operations and the permanence of sequestration.

Although CCS is an emerging technology for climate protection, the fossil fuel industry has been injecting CO_2 underground for enhanced oil recovery (CO_2-EOR) for decades. In principle, CO_2-EOR using anthropogenic CO_2 could achieve sequestration even though current practices do not usually account for it. CO_2 is not used in EOR operations in California today, but the state's climate policies are driving interest in doing so. For that reason, policies encouraging and regulating CCS must address how to treat EOR and its existing industry, infrastructure, and regulations. In particular, policymakers must determine whether and how CO_2-EOR sites should be credited with sequestration.

There are many ways that California could address this question that can be placed in two main categories. The first possible approach would be to require CO_2-EOR to meet all of the same regulatory standards as sequestration in saline formations, including site permit requirements, human health and safety protections, and monitoring, verification, and reporting plans. The second possible approach would be to customize these kinds of standards in a way that would allow CO_2-EOR to receive sequestration credit while remaining within the regulatory framework already established for EOR operations.

The long-term success of CCS as a climate protection strategy depends on limiting sequestration credit to situations where there is assurance that injected CO_2 will be permanently contained. In the nearer-term, however, the success of CCS also depends on establishing the viability of the technology and deploying in time to help meet California's greenhouse gas (GHG) emissions reductions goals. Therefore the question of how to treat EOR under CCS regulations requires balancing the need to engage and utilize the existing infrastructure of EOR without compromising the integrity of GHG emissions targets.

In addition to the broad question of how to treat CO_2-EOR in the context of CCS, this paper considers specific programs in California in which this question might arise:

- the cap-and-trade program emerging from GHG emissions reduction targets from Assembly Bill 32;
- the GHG Emissions Performance Standards for long-term power purchases established by Senate Bill 1368;
- the Low Carbon Fuel Standard established by Executive Order S-01-07; and
- permitting authority over CO_2 injection wells and the role such permits play in sequestration credit for compliance with any of the above programs.

This paper summarizes the regulatory landscape for geologic sequestration of carbon dioxide, identifies possible regulatory approaches to CO_2-EOR as sequestration, and describes the major advantages and disadvantages to these approaches. The key questions to consider are:

- **What kind of permitting requirements should there be for CO_2-EOR facilities that seek credit for CO_2 sequestration?** Should permitting requirements for CO_2-EOR facilities seeking sequestration credit be the same as other EOR facilities, the same as sequestration in saline formations, or something in between?
- **What kind of monitoring, verification, and reporting (MVR) requirements should there be for CO_2-EOR facilities that seek credit for CO_2 sequestration?** Should MVR requirements for CO_2-EOR facilities seeking sequestration credit be the same as other EOR facilities, the same as sequestration projects in saline formations, or something in between?
- **What type of credit should be considered in California?** If CO_2-EOR facilities get credit for sequestration in California, what kind of credit would they get? Would injected CO_2 count as avoided emissions or emissions offsets under a cap-and-trade program? Would sequestration credits from CO_2-EOR be sufficient to allow a power plant to pass the GHG-intensity screen imposed by SB 1368? Can CO_2-EOR assist with compliance with the Low Carbon Fuel Standard?

2. The Current Regulatory Landscape for Geologic Sequestration and CO_2-EOR.

a. **Federal.** At the federal level, CCS and CO_2-EOR are affected by efforts to establish regulations for wells used for geologic sequestration of CO_2 under the long-established Underground Injection Control program under the Safe Drinking Water Act and emerging regulations designed to control GHG emissions under the Clean Air Act.

i. **Safe Drinking Water Act,[172] Underground Injection Control (UIC) Program.** Currently, wells used for EOR are classified as Class II.[173] The U.S. Environmental Protection Agency (EPA) has proposed a new Class VI category for wells used for the geologic sequestration of CO_2. Under the proposed rules, Class VI would not apply to CO_2-EOR sites. Instead they would remain Class II wells.[174] Since the UIC program is authorized by the Safe Drinking Water Act, the rules are limited to managing health and safety issues related to drinking water. For that reason, EPA has limited authority to address risks associated with CO_2 leaking to the atmosphere in the UIC rules.

As currently proposed, EPA would treat CO_2 injection wells used for EOR completely separately from CO_2 injection wells used for geologic sequestration. Class II rules would continue to regulate and permit injection of CO_2 for EOR purposes as long as any fossil fuel production is occurring. The proposed Class VI rules would apply to any well in which CO_2 is injected for geologic sequestration and no oil or gas production is occurring.[175] However, EPA asked

[172] Safe Drinking Water Act of 1974, 42 U.S.C §§ 300f - 300j-26, 300h(b)(2)(2006).
[173] 40 C.F.R. Pt. 146, Subpart C (§§ 146.21 to 146.26).
[174] "Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells", 73 Fed. Reg. 43491-541 (July 25, 2008).
[175] 73 Fed. Reg. at 43502.

for comment on the merits of this approach "since owners or operators of some Class II [EOR] wells may wish to use wells for the purposes of production and [geologic sequestration] prior to the field being completely depleted."

ii. **Comparison of UIC Class II and Class VI requirements.** Both Class II and the proposed Class VI rules derive their authority from the Safe Drinking Water Act, and therefore focus on protecting underground sources of drinking water and not prevention protection against leakage of CO_2 to the atmosphere. In general, however, the Class VI rules would impose more stringent standards than the Class II rules, including requiring more extensive monitoring plans and more robust well construction requirements. In addition, the Class VI rules are conceived with sequestration in mind, while the Class II rules are designed for oil and gas production.

iii. **Multi-Stakeholder Discussion Recommendations.** The Class VI proposal may be modified when EPA issues its final rules. For example, the Carbon Sequestration Council's Multi-Stakeholder Discussion group (MSD) recommends that EPA clarify UIC rules to allow for a site where active oil or gas production is occurring at the same time as CO_2 sequestration under Class II permits.

Unlike EPA's proposed rules, MSD's recommendation contemplates simultaneous sequestration and oil production. Under MSD's proposal, Class II would include wells used for EOR in which sequestration is occurring during or in connection with EOR, provided that "(i) there is a reasonable expectation of more than insignificant future production volumes [of oil or gas] or rates as result of carbon dioxide injection and (ii) operating pressures are no higher than reasonably necessary to produce such volumes and rates."[176] The MSD stakeholders agreed that wells not meeting these requirements should be subject to additional requirements. Other wells used for geologic sequestration of CO_2 would be Class VI (unless they were considered "experimental" and subject to Class V rules). This proposal is meant to achieve:

- Clarity for early movers planning projects in oil and gas reservoirs.
- Assurance of acceptable regulatory requirements for sequestration in oil and gas reservoirs (Class II regulations are a known quantity).
- A clear distinction between Class II and Class VI wells based on the type of reservoir (oil and gas versus saline formation).

[176] This "bright line" rule was proposed in Carbon Sequestration Council's December 23, 2008 letter to EPA making recommendations for the proposed Class VI regulations (p. 1-2), available at http://www.carbonsequestrationcouncil.org. It should also be noted that this same "bright line" has implications for property rights at EOR sites. Most oil and gas leases automatically terminate when production ceases in paying qualities (meaning operating costs exceed revenue from production).

Stakeholders involved in developing the MSD's proposal could not agree on what MVR should be required of Class II wells to demonstrate permanent sequestration of injected CO_2.

iv. **Mandatory Greenhouse Gas Reporting Rule – Proposed Subpart RR.**[177] EPA has proposed rules for reporting GHG emissions that would require all facilities that inject CO_2 underground to report basic information. These requirements include:

(1) All CO_2 injection facilities would be required to report: the amount of CO_2 received onsite from offsite sources, the amount of CO_2 injected into the subsurface, and the source of the CO_2 (if known).

(2) Facilities injecting CO_2 for the purpose of long-term sequestration would have enhanced reporting requirements, including 1) reporting the amount of CO_2 geologically sequestered using a mass balance approach, and 2) developing and implementing an EPA approved site-specific MVR plan.

(3) EOR facilities would have the option to adopt the enhanced reporting and MVR plan requirements.

v. **Clean Air Act GHG Regulations.**[178] Unless Congress adopts a national cap-and-trade program or similar legislation, the only federal authority to regulate GHG emissions comes from the Clean Air Act. The Clean Air Act directly regulates emissions sources and does not authorize emissions credit trading for GHGs. For that reason, the idea of sequestration credit is most meaningful in states, like California, that have enacted legislation limiting GHG emissions.[179]

But Clean Air Act regulations could be important for facilities injecting CO_2 for purposes of either EOR or geologic sequestration (or both) if such facilities were to become regulated as emissions sources. Even a well-chosen and operated site may leak a small percentage of CO_2 into the atmosphere.

(1) EPA recently released its final "tailoring rule" establishing initial thresholds for requiring New Source Review Prevention of Significant Deterioration (PSD) Permits and Title V Operating Permits for new and existing industrial facilities.

(2) Very large GHG emissions sources will begin needing GHG emission permits in 2010. Sources emitting 50,000 tons per year or less will not require permits until at least 2016.

[177] Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide; Proposed Rule, 75 Fed. Reg. 18576 (April 12, 2010). Authority for this rule derives from the Consolidated Appropriations Act of 2008 (Public Law 110-161).

[178] "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," Final Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[179] Energy and climate legislation passed by the U.S. House of Representatives in 2009 (H.R. 2454, a.k.a Waxman-Markey) would establish a national economy-wide GHG cap-and-trade program. However, recent reports suggest no similar legislation will pass in the Senate this year.

(3) Even a very modest leakage rate at an EOR or geologic sequestration site could eventually trigger Clean Air Act regulations. For example, an annual leakage rate of 0.1% per year at a site injecting 10 million tons of CO_2 per year would have 10,000 tons per year of CO_2 emissions.

b. **California.**[180]

i. **Permitting CCS Projects in California.** U.S. EPA Region 9 has authority to regulate all underground injection wells in California, except those categorized as Class II. The California Division of Oil, Gas, and Geothermal Resources (DOGGR) has primacy for Class II wells, which include CO_2-EOR injection wells.[181] DOGGR could seek primacy for Class VI wells when EPA's Class VI regulations are finalized. In a March 1, 2010 letter from Bridgett Luther, the Director of the Department of Conservation, to Dan Pellisier, Deputy Cabinet Secretary for Resources in the California Governor's Office, the department which oversees DOGGR, concluded that it had sufficient authority to regulate CO_2-EOR projects, but not CCS projects without EOR.

Even though DOGGR has authority to permit a CO_2-EOR project, it does not have any specific authority related to sequestration or assuring permanence of sequestration. That means it is unclear what role a DOGGR Class II permit will play in helping a CO_2-EOR project get sequestration credit under any of California's GHG emissions reductions programs (described in more detail below).

Because sequestration naturally occurs as part of the EOR process, a Class II permit issued by DOGGR for a CO_2-EOR project might be able to include monitoring requirements that would aid in demonstrating sequestration. Under the California Environmental Quality Act (CEQA), DOGGR can impose such additional mitigation measures to assure safe operation.[182] Further, permitting CO_2 injection for EOR and sequestration is arguably consistent with DOGGR's dual mandate to increase the recovery of oil and gas resources within the state and protect the environment.[183] California permitting agencies are developing this approach for the proposed Occidental of Elk Hills, Inc. (Oxy) CO_2-EOR project associated with the proposed Hydrogen Energy California (HECA) project.[184]

It is possible then, for example, that a DOGGR Class II permit could include sufficient monitoring requirements to demonstrate permanent sequestration for purposes of the SB 1368 Emissions Performance Standard. But the Air Resources

[180] For an overview of California's existing regulatory structure for CCS, see Elizabeth Burton, "Permitting – Existing Regulatory Authority and Jurisdiction in California," presented at the California Carbon Capture and Storage Review Panel Meeting, April 22, 2010.
[181] Cal. Code Reg. Tit. 14, Div 2, Chap. 4.
[182] *See* Cal. Pub. Res. Code § 21000 et seq.
[183] *See* Cal. Pub. Res. Code §3106(a) & (b).
[184] *See* Hydrogen Energy Power Plant Licensing Case, California Energy Commission Docket Number 08-AFC-08. *See also*, Hydrogen Energy California LLC Submissions to California CCS Review Panel, July 29, 2010.

Board could have different requirements for crediting under AB 32 cap-and-trade program.

ii. **California Climate Policy and Sequestration Credit.** California climate policy is more extensive and aggressive than federal policy. There are several state level programs in which credit for geologic sequestration of CO_2 potentially could have value.

First, efforts are underway to establish a broad-based GHG cap-and-trade program in order to meet the GHG emissions targets set by AB 32. CCS has been identified as a way to avoid GHG emissions to comply with the California cap-and-trade program. Second, SB 1368 established a GHG emissions performance standard (EPS) for long-term electricity contracts to serve California consumers. The EPS allows for CCS to be used as a way to reduce the GHG intensity of electricity. Lastly, Executive Order S-01-07 established a Low Carbon Fuel Standard (LCFS) as a mechanism for the transportation sector to meet AB 32's GHG emission reduction targets. The LCFS establishes a goal of reducing the carbon intensity of California transportation fuels by at least 10 percent by 2020 to be achieved through market-based mechanisms like credit trading. CO_2-EOR could potentially provide a mechanism for reducing the carbon intensity of fuels or generating compliance credits (though it is not now among the established options).

Multiple California regulatory agencies potentially could be involved in determining standards for giving sequestration credit (or not) to CO_2-EOR sites for purposes of compliance with any or all these programs.

(1) **GHG Emissions Reduction (AB 32).** California has ambitious GHG emissions reductions targets, with short term targets set in Assembly Bill 32 in 2006 and long term goals outlined by executive order in 2005: 1990 levels by 2020; and 80 percent below 1990 levels by 2050. [185]

AB 32 directed the Air Resources Board (ARB) to prepare a scoping plan to identify the best ways to reach the 2020 target, including a cap-and-trade program. The Climate Change Scoping Plan[186] "expresses support for near-term advancement of [CCS] technology and monitoring of its development." Further, the plan states that "California should both support near-term advancement of the technology and ensure that an adequate framework is in place to provide credit for CCS projects when appropriate."

The Climate Change Scoping Plan proposes that a California Cap-and-Trade Program would regulate all electricity generation, including

[185] Assembly Bill 32, the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006):
[186] California Air Resources Board, December 2008, Climate Change Scoping Plan: A Framework for Change, http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

imports, as well as industrial sources and processes that emit 25,000 metric tons of CO_2 equivalent ($MTCO_2e$) per year or more in the first compliance period (2012–2014). Starting in the second compliance period (2015–2017) transportation fuels, all commercial and residential fuel combustion of natural gas and propane, and industrial fuel combustion at facilities with emissions below 25,000 $MTCO_2e$ would be included. The Board, in adopting the cap-and-trade regulation, directed ARB to establish a CCS protocol, which would necessarily include a quantification methodology for the emissions reductions associated with CCS. The CCS protocol will include separate provisions for sequestration with and without CO2-EOR.

In addition to the Scoping Plan, ARB developed a mandatory GHG reporting inventory, which appears at sections 95100-95133 of title 17 of CA Code. Sites where CO_2 is injected, whether for EOR or for sequestration, do not appear to be covered by the reporting rule. Revisions to the cap-and-trade program that will occur upon completion of a CCS protocol will be accompanied by complementary revisions to the Mandatory Reporting Regulation.

(2) **GHG Emissions Performance Standard (SB 1368).**[187] Senate Bill 1368 established a GHG Emissions Performance Standard (EPS) for electricity of 1,100 lbs CO_2 per megawatt-hour (MWh) of electricity delivered. (This is equivalent to the emissions from a combined-cycle natural gas power plant). The mandate applies to long-term financial commitments (more than 5 years) to purchase electricity from baseload facilities to serve California consumers. Under SB 1368, geologically sequestered CO_2 does not count as an emission from a power plant for purposes of determining EPS compliance. Sequestration is considered successful if**:**

(a) It includes capture, transportation, and injection of CO_2 emissions;

(b) Complies with applicable laws and regulations; and

(c) Has an economically and technically feasible plan that will result in permanent sequestration.[188]

The California Energy Commission (CEC) has authority to enforce the EPS for municipal utilities and has established regulations for screening long-term facilities for compliance with the EPS.[189] The regulations do not define permanence for sequestration nor do they address whether

[187] Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006)
[188] Cal. Code Regs., Chap. 11, Art. 1, § 2904(c)
[189] Cal. Code Regs., Chap. 11. Greenhouse Gases Emission Performance Standard, Article 1, § 2900 et. seq.

CO_2 derived from a power plant and sequestered at an EOR site would meet the criteria for successful sequestration. The California Public Utilities Commission (CPUC) has jurisdiction under SB 1368 to enforce the EPS on investor-owned utilities.

As discussed above, a DOGGR permit for a CO_2-EOR project related to a power plant subject to the EPS might be able to include sufficient standards to meet the CEC or CPUC's screen for determining compliance.

(3) **Low Carbon Fuel Standard (Executive Order S-01-07)**. Executive Order S-01-07 established California's Low Carbon Fuel Standard (LCFS), which sets an initial goal of reducing the carbon intensity of the state's passenger vehicle fuels by at least 10 percent by 2020.

Fuel providers are required to ensure that the mix of fuel they sell in California, on average, meets the standard on a lifecycle basis. That means the LCFS covers not only tailpipe emissions, but also emissions associated with production and distribution of transportation fuels. CCS potentially could be used to help fuel providers comply with the standard either as a method to directly to reduce the carbon intensity of certain fuels or generate tradable compliance credits.

ARB's LCFS regulations only directly address CCS in a limited way. They allow for consideration of use of CCS technology in determining the carbon intensity value of crude oil and the associated compliance obligations of the fuel provider.[190]

3. Approaches to Regulating CO_2-EOR with Sequestration.

In order for CO_2-EOR to receive credit for sequestration for any of the above-described programs, appropriate standards must be developed that will measure the quantity of CO_2 sequestered and demonstrate that sequestration is permanent. The analysis presented here focuses on regulatory frameworks for crediting CO_2-EOR with sequestration. Please see the Technical Advisory Committees other papers on permitting and MVR for a fuller discussion of the range of issues that must be considered within these regulatory frameworks.

The advantages and disadvantages of two potential regulatory frameworks are discussed below. The first approach would only credit CO_2-EOR with sequestration only when it meets the same standards as sequestration projects in saline formations. The second approach would establish customized standards for CO_2-EOR that would better accommodate on-going oil production, but still provide sufficient verification of sequestration.

We do not consider two more extreme approaches – 1) where CO_2-EOR would receive sequestration credit without providing any verification beyond the business-as-usual requirements for EOR, or 2) where CO_2-EOR would never be eligible for sequestration credit. The first would arguably undermine

[190] Cal. Code Reg. Tit. 17, § 95486 (b)(2)(A) (Determination of Carbon Intensity Values).

California's climate policies by allowing sequestration credit without verification. The latter would arbitrarily exclude a potentially important CCS technology.

a. **Credit CO_2-EOR with sequestration only if it meets the same permitting and MVR requirements as sequestration in saline formations (such as, e.g., Class VI standards).** One possible regulatory approach would be to require a CO_2-EOR site seeking credit for sequestration to meet all the regulatory requirements of saline formation sequestration. A CO_2-EOR site would only be able to receive sequestration credit by meeting all permitting, human health, environmental safety protection, and MVR requirements applicable to saline formation sequestration sites (such as Class VI permitting requirements). A CO_2-EOR site not seeking sequestration credit would be exempt from regulations aimed at geologic sequestration.

In California, this approach could translate to requiring any CO_2-EOR project seeking sequestration credit (e.g., under AB 32, SB 1368, or the LCFS) to obtain a Class VI permit and meet any additional state-imposed requirements for saline formation sequestration site.

i. **Examples.** In order to protect business as usual for the EOR industry, many CCS policies (and model policies) categorically exempt all EOR operations from new CCS regulations. Such exemptions could be interpreted to mean that a CO_2-EOR site would need to meet all standards imposed on saline formation sequestration sites in order to receive sequestration credit. For example:

(1) **Model Legislation Proposals.** The Interstate Oil and Gas Compact Commission (IOGCC) published model state legislation for regulating geologic sequestration of CO_2 that has been followed closely by several states. Under IOGCC's proposal, CO_2-EOR projects would be exempt from the regulations for saline formations unless the site operator wanted to engage in production and sequestration simultaneously, in which case the saline formation sequestration regulations would apply.[191]

The CCSReg project developed model federal legislation in 2010 that would require an EOR facility to meet all the permit requirements required of any other geologic sequestration facility in order to be credited under any federal GHG emissions reduction program.[192]

(2) **States.** Some early moving states followed the IOGCC model legislation approach. For example, Montana and Wyoming[193] categorically exempt EOR sites from most aspects of their new policies governing geologic

[191] IOGCC Task Force on Carbon Capture and Geologic Storage, "Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces, September 25, 2007.
[192] CCSReg Project, "Model Legislation: The Carbon Capture and Sequestration Regulatory Act of 2010," May 19, 2010, available at http://www.ccsreg.org/pdf/CCS_Draft_Leg_05192010.pdf.
[193] *See* Montana SB 498 (2009) and Wyoming HB 90 (2009).

sequestration, but provide guidance on how an EOR site could be converted to a geologic sequestration site.[194]

(3) **EPA Class VI Proposal**. Under its current proposal, EPA would regulate injection wells in oil and gas reservoirs under Class II rules so long as any oil and gas production is occurring. The implication is that no sequestration would be recognized until oil and gas production ceases and the Class II well could qualify as Class VI.[195]

ii. **Advantages.**

(1) **Environmental integrity.** Requiring CO_2-EOR compliance with the same permitting and MVR requirements as saline formation sequestration would ensure that sequestration credits have equivalent environmental value. The climate change mitigation purpose of geologic sequestration in a saline formation is the same as it would be in an oil reservoir. Different MVR standards are difficult to justify unless there is assurance that the standards are can be equally effective.

(2) **Clarity of regulatory purpose.** CCS and EOR have fundamentally different purposes (climate protection versus oil production). Regulations attempting to serve both purposes might shortchange one or the other.

(3) **Protection of EOR industry.** EOR business-as-usual is most securely protected by a blanket exemption for EOR from sequestration regulations.[196] Under this approach, no additional regulatory requirements would be imposed on CO_2-EOR sites unless they make a choice to become sequestration sites and follow those rules.

iii. **Disadvantages.**

(1) **Poorly fitting standards**. The extensive knowledge and characterization of oil reservoirs from years of production might justify different kinds of site characterization and MVR requirements for sequestration in oil and gas reservoirs compared to lesser known saline formations. Different requirements for CO_2-EOR do not have to be lesser requirements.

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[194] Although most states have exempted EOR from their new geologic sequestration policies, some states lay the groundwork for EOR sites to receive sequestration credit. In ND, the Industrial Commission may adopt procedures and criteria to determine the amount of injected CO_2 stored in an EOR project, to facilitate carbon credits or allowances for EOR projects. §38-22-33. West Virginia's CCS legislation clarifies that CO_2 injected for EOR is not subject to provisions of the bill and that the new law does not impede or impair EOR operations, including the right to sell emission reduction credits associated with EOR. §22-11A-8.

[195] *See* A. Scott Anderson, Environmental Defense Fund, Carbon Sequestration in Oil and Gas Fields (in Conjunction with EOR and Otherwise), at 2, White Paper for MIT EOR and Carbon Sequestration Symposium, July 23, 2010.

[196] *See* IOGCC Task Force on Carbon Capture and Geologic Storage, "Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces, September 25, 2007.

(2) **Delay in deployment of CCS.** CO_2-EOR sites are attractive for early projects because of greater availability of site characterization information and the opportunity to offset costs with oil production and sales. Regulations that are not well-designed to accommodate ongoing oil production might be a disincentive for these early projects.

(3) **Unrecognized sequestration.** If CO_2-EOR sites become regulated as emissions sources (e.g., under the Clean Air Act), fairness would suggest that their sequestration achievements should be acknowledged without requiring the site to meet otherwise inapplicable CCS permit requirements. Otherwise, CO_2-EOR might become uneconomic.

b. Customize MVR and permitting standards for CO_2-EOR that accommodate oil production, but provide sufficient verification to justify sequestration credit. An alternative regulatory approach is to assume that EOR and sequestration can and should occur simultaneously at the same site. This approach would require developing regulations that would accommodate active oil production while providing for sufficient MVR and other permitting standards to justify sequestration credits. This type of approach would allow CO_2-EOR to receive credit for CO_2 sequestration while remaining within the EOR regulatory framework (i.e., remaining a Class II injection well). However, for sequestration credit to be given, sufficient MVR and permitting standards will be required, even if they are different than those imposed on saline formation sequestration sites.

In California, this approach might take the form of DOGGR permitting CO_2-EOR injection wells under its Class II authority. Then any CO_2-EOR site wishing to receive sequestration credit would have to opt into additional MVR and other standards that satisfy other regulatory agencies charged with giving sequestration credit for purposes of AB 32, the SB 1368 EPS, of the LCFS. These other agencies might coordinate with DOGGR to have these enhanced standards be included in the Class II permit.

i. **Examples.** As discussed above, most early CCS policy and policy proposals do not create a method for crediting CO_2-EOR sites with sequestration unless they follow rules established for saline formation sequestration. But there are some examples of policies and proposals that take this approach of customizing regulations for CO_2-EOR:

(1) **Mandatory Greenhouse Gas Reporting Rule, Proposed Subpart RR**. As described above, EPA's proposed GHG reporting rule for CO_2 injection would have CO_2-EOR sites opt into the enhanced requirements for saline formation sites if they wish to receive credit for sequestration. Choosing to comply with the enhanced MVR requirements would not require changing the sites regulatory status under the UIC (i.e., changing from regulation under Class II to Class VI).

(2) **MSD Recommendation**. As described above, the Carbon Sequestration Council's MSD group's widely regarded recommendations would alter EPA's proposed geologic sequestration rules to accommodate simultaneous oil production and sequestration under Class II permits.

(3) **Texas.** In Texas, policy governing geologic sequestration of CO_2 is evolving to encourage pairing with EOR. For example, Texas HB 469 (2009) provides various tax incentives designed to encourage use of anthropogenic CO_2 for EOR. The incentives are available to CO_2-EOR that conduct monitoring and verification to reasonably demonstrate that 99% of the injected CO_2 will be sequestered for 1,000 years.

In addition to incentives, Texas is developing regulations that will accommodate simultaneous sequestration and oil production.[197] In SB 1387 (2009), the Texas legislature directed the Railroad Commission to develop rules governing geologic sequestration of CO_2. The legislation directs that UIC Class II wells are to be exempt from these rules. Further, converting a well from EOR use to geologic sequestration is not to be considered a change in the purpose of the well.

But the rules proposed by the Railroad Commission are designed similarly to the Carbon Sequestration Council's MSD recommendation. The new regulations would not apply to a Class II CO_2 injection well permitted "for the primary purpose of enhanced recovery operations from which there is a reasonable expectation of more than insignificant future production volumes of oil, gas, or geothermal energy and operating pressures no higher than reasonably necessary to produce such volumes or rates." The proposed rules would, however, allow an operator to propose to permit a project as an EOR project and a geologic storage facility simultaneously.[198] That means EOR projects that also apply for geologic storage permit would be subject some additional siting and MVR requirements to which other Class II wells would not otherwise be subject.

ii. **Advantages**

(1) **Deploying CCS sooner**. Rules designed to accommodate oil production are probably the best way to harness the infrastructure and know-how of the established industry EOR industry. Encouraging CO_2-EOR as sequestration with customized rules might be the best way to begin using CCS soon enough to put California on a path to achieving its 2050 GHG emissions reductions goals.

[197] See Texas Carbon Capture & Storage Association materials, e.g., Darrick Eugene, "The Texas Edge: SB 1387 – Framework for Geologic Storage," presented to the UT Law, Carbon, and Climate Change Conference, February 18, 2010.

[198] Texas Railroad Commission, proposed new Chapter 5, *§5.201. Applicability and Compliance.*

(2) **Recognizing the EOR knowledge base.** EOR site operators have extensive knowledge about their reservoirs, which means customized MVR requirements could be effective without being lesser than standards for saline formation sites.

(3) **Ensuring economic viability of EOR under GHG caps**. If EOR sites become regulated as GHG emissions sources under the Clean Air Act, then a method for crediting them with CO_2 they successfully sequester will be critical for the on-going economic viability of CO_2-EOR.

(4) **Encouraging CO_2-EOR in California**. There is no anthropogenic CO_2 being used for EOR in California today. Sequestration credits might be a necessary incentive to encourage CO_2-EOR sites in the state, which make good candidates for early CCS projects. The viability of CCS is important in the near-term for new power plants required to meet the SB 1368 EPS.

iii. **Disadvantages**

(1) **Complexity and uncertainty in GHG accounting.** GHG accounting is more challenging if sequestration credit is given to an operation that produces fossil fuel. Policy choices must be made about how to allocate sequestration credit among different parties and regulatory programs. For example, it could be double-counting to apply sequestration credit from CO_2-EOR to a fuel provider's LCFS obligation and to a power plant to meet its SB 1368 obligations.

(2) **Regulatory inconsistency.** Customizing regulations for sequestration at CO_2-EOR sites could mean establishing requirements that are different than requirements for sequestration in saline formations. Different standards could be equally effective if designed well, but there is a risk that one set of requirements would turn out to be less stringent than the other. California's climate programs will be less effective if sequestration credits have inconsistent environmental value.

(3) **Stakeholder discord.** Even if stakeholders agree that there should be a way for CO_2-EOR to receive sequestration credit while remaining within the EOR regulatory framework (i.e., Class II), there is no consensus on what MVR or other standards would be appropriate for verification

19. Appendix P: Long-Term Stewardship and Long-Term Liability in the Sequestration of CO_2

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

AUGUST 11, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Monitoring, Verification, and Reporting Overview

Options for Permitting Carbon Capture and Sequestration Projects in California

Approaches to Pore Space Rights

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Carbon Dioxide Pipelines

Review of Saline Formation Storage Potential in California

Overview of the Risks of Geologic CO2 Storage

AB 32 Regulations and CCS

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Purpose

This paper[199] addresses some of the issues relating to long-term stewardship and liability that are sometimes viewed as barriers to timely Carbon Capture and Storage (CCS) development projects. The paper examines various approaches for addressing liability over the long-term post-closure phase. This phase is currently of an undetermined duration (i.e., after CO_2 injection wells are capped and permanently closed). Long-term liability is a complex subject that will almost certainly involve new and potentially intractable legal issues that require case-by-case resolution which are beyond the scope of this paper. The issues related to monitoring, verification and reporting (MVR) during the post-closure phase are covered in companion white papers for the California Carbon Capture and Storage Review Panel.

Some confusion results from the observation that the terms "long-term liability" and "long-term stewardship" are often used interchangeably. However, these terms in fact denote distinct concepts that should be kept separate. "Long-term stewardship" is by whom and by what means the actual post-closure operations of a CCS project will be undertaken in the long-term. "Long-term liability", however, is a legal concept involving the issue of who is or will be financially responsible for a project and for any damages attributed to that project following closure.

Responsible and effective CO_2 sequestration requires essentially permanent emplacement of CO_2 underground with no intention of retrieving the carbon or CO_2 thus stored. This paper does not address CO_2 injection for Enhanced Oil Recovery activities. Nor does it address the issue of CO_2 ownership, pipeline transport ownership and CCS injection operator, all of which may or may not be the same entity. For the purpose of this paper, the term "stewardship" means primary responsibility for the ongoing operation, safety and maintenance of the project, and especially the monitoring of CO_2 behavior in the reservoir into which the CO_2 has been injected. "Liability" is taken to denote financial responsibility for a CCS project, either in its individual phases or as a whole. This includes financial responsibility for what can be considered as normal industrial operations of a project, as well as financial responsibility arising out of an event or events that impact the health, safety, and/or well-being of people, including but not limited to impacts to the environment, the quality of drinking water, agricultural resources, and/or wildlife. Liability also includes financial exposure under a regulatory regime if CCS credits are used to meet carbon reduction goals and standards and the sequestration fails through leakage. It should be pointed out that there are a number of industrial analogues that can be compared to all aspects of a CCS project for both liability and stewardship. However, few, if any, appropriate analogues exist for long-term post closure activities and attendant responsibilities. This paper summarizes four key issues:

- Appropriate timeframe(s) for monitoring CO_2 releases during the post-closure phase.

[199] This report necessarily discusses issues that are largely or essentially legal topics, and long-term liability in particular is primarily a legal topic. However, this report should not be considered legal advice, but rather a summary of the available public information concerning these topics. Some of these issues are complex and will take time to resolve. It is therefore beyond the scope of this report to provide definitive "answers" to these issues; instead, the intent of this report is to identify issues and options so to encourage robust discussion of, and further research into, these issues.

- Options for allocating responsibility for long-term stewardship among the participants in a CCS project, including the well/reservoir operator, the property owner, and the state and/or federal government.
- Options for allocating the legal risk among the participants in a CCS project.
- Identifying models and approaches that require further research and examination.

Policy Context

CCS is a technology which allows carbon dioxide to be separated from process and exhaust gases at large industrial facilities, such as power plants, cement plants, and oil refineries, and stored in underground geologic formations. CCS is recognized as one of the technology "tools," along with end-use energy efficiency and renewable energy technologies, for meeting California's long-term greenhouse gas (GHG) reduction goals.

For the demonstration CCS projects, it is important to clarify who is responsible for insuring against the risk of CO_2 leakage or releases into the groundwater or atmosphere. This is especially critical since current commercial insurance companies do not yet cover such occurrences. In addition, because the capture and sequestration of CO_2 involves lasting and permanent storage in underground reservoirs, it is uncertain how long the responsibility for post-closure liability must last to insure against possible leakage.

The current overriding federal legislation that controls the injection of CO_2 is Part C of the Safe Drinking Water Act, which is regulated by the U.S. EPA's Underground Injection Control policies and regulations that ensure that injection activities do not contaminate underground sources of drinking water. There are currently five Underground Injection Control (UIC) classes and a sixth is in the process of being proposed that is specifically targeted at injection for CO_2 sequestration. As part of the sixth class, the U.S. Environmental Protection Agency (U.S. EPA) lays out general requirements for financial responsibility that may "…include provisions requiring owners and operators demonstrate and maintain financial responsibility during operation, closure and the post-injection site care period."

Background

In the atmosphere, where it is normally present in low concentrations, CO_2 is harmless. CO_2 is non-flammable and inert. In that CO_2 is 1.5 times denser than air, there is tendency under stagnant conditions for any CO_2 leaking to collect in hollows or other low-lying confined spaces, which may create a hazardous situation due to CO_2 being odorless, colorless, and tasteless. The full impact of CO_2 on groundwater (where it increases the acidity) requires more research to better constrain the risk profile. It is a benign gas when compared with other gases historically stored in underground formations, such as natural gas, which is flammable and potentially explosive. As with all compounds, if it accumulates at high enough concentrations it will become a risk to animal life, but reaching such concentrations is exceedingly rare. Where they have naturally occurred is in gas emissions from volcanic provinces.

The process of injecting liquid CO_2 under pressure into the ground involves risks normally associated with analogous types of industrial and oil field activities. These risks are both well understood and insurable. The ability to quantify these known risks is due to the ability to utilize statistics from these similar activities (which would also include natural gas storage or recovery of naturally occurring carbon

dioxide resources) as analogues for carbon dioxide injection and storage in sub-surface formations. Additionally, due to the interest in CCS, since 1995 a significant amount of research, modeling, and testing has been done to document the behavior of CO_2 in various subsurface environments. Despite the generally high level of scientific comfort with this technology, it is difficult to assign a quantitative risk profile to the long-term behavior of CO_2.

Potential operators for a CCS project seek to define risk for their insurers during site preparation, injection operations, and post-closure monitoring. Responsible oversight and liability for payment are considered and agreed upon in advance, during the planning phase. But the time period commencing with post-closure monitoring into an undefined future is an institutional, financial, and regulatory challenge to CCS operations. There is a distinction between initial small-scale CCS pilot projects that might be considered exploratory and mature larger-scale commercial CCS operations for which the liability and stewardship issues may be treated differently, at least initially.

Determination of Appropriate Timeframes for MMV

After the multi-year injection activities for CO_2 and the well closure process have been successfully completed, there is an extended period during which the behavior of the CO_2 in the subsurface should continue to be monitored in order to track the size and location of the CO_2 plume, its movement, and ultimate stabilization (see Figure 6). It is the intention that this will demonstrate that CCS is effective and, thus, provides a basis for determining whether any environmental credits may be claimed. Without accurate and reliable long-term monitoring, verification, and remediation (MVR), CCS may not be successful.

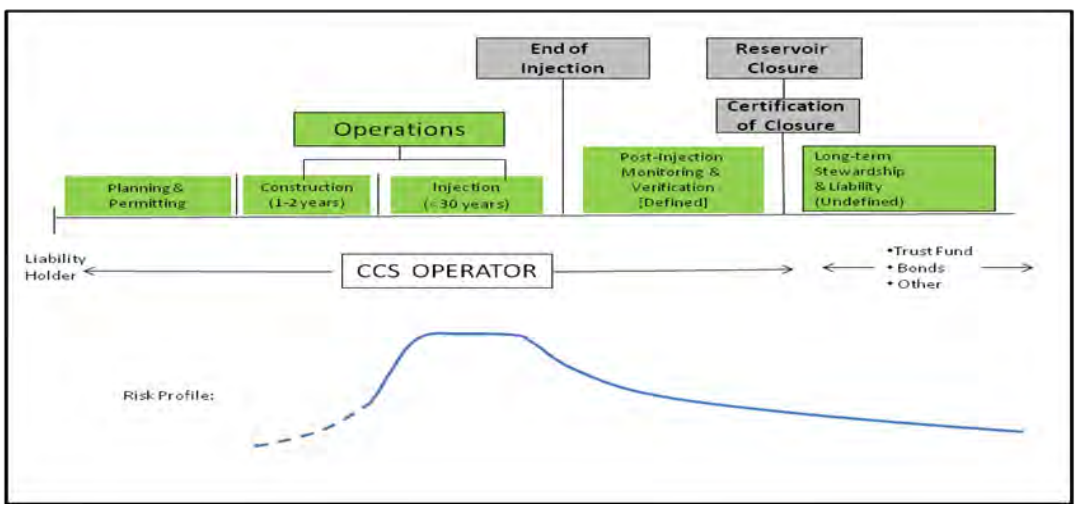

Figure 6. A schematic diagram that attempts to characterize the phases in a CCS project. This paper addresses the final (far right) phase. (After Benson & Cook, 2005).

There is not yet a widespread consensus on how long the post-closure MVR phase should be, with opinions ranging from 10 to 50 years. The variation in the suggested monitoring time frames arises from the fact that CCS technology is still relatively new and there have not been enough large-scale

demonstration projects to conclusively answer the question in all circumstances due to variables in the particular location and types of geologic storage formations involved. The appropriate length of time for long-term MVR would be based on scientific verification of plume stabilization. Once it has been reliably established that the plume has stabilized and no further plume migration will occur, MVR may be reduced or eliminated. However, premature cessation of MVR could render CCS potentially pointless and unreliable, even counterproductive to GHG reduction efforts since the expense will have been incurred, but the result not guaranteed.

The frequency of monitoring and whether it should be conducted by a public agency or a private entity is an additional factor to be resolved. A number of states have become more proactive in developing regulations that address this issue without waiting for federal guidance or regulation. For example, Montana has established in state law that the period be 15 years (Montana SB498, 2008). Long-term oversight during the post-closure phase might exceed the corporate lifespan of a commercial CCS operator, perhaps invoking another entity, private or public, to undertake this post-closure activity. The requirements associated with long-term monitoring are important as issues of financial responsibility and liability associated with continued ownership may affect how projects are to be financed and what organizations are willing to take on project risk.

Distinction Between Liability and Stewardship

The terms “long-term liability” and “long-term stewardship” are often used interchangeably. From a legal and practical standpoint, the concepts are separate, but related, and should be considered as separate. In the wider context of contracting, financing, banking, and law, these concepts are distinct, particularly as CCS moves from research and small-scale demonstration phases to large-scale implementation. Conflating the two issues may lead to confusion.

“Long-term stewardship” defines what entity will carry out the post-closure operations of a CCS project. While this may appear to be less a legal issue than an operational issue, the determination of operational “ownership” will certainly carry a degree of liability. However, there may be numerous different parties that share or assume stewardship responsibilities over the duration of the project based on future developments in institutional and governmental requirements and regulations. Conversely, “long-term liability” should be regarded as a specific legal issue that concerns which institutional entity will be legally and financially responsible if something goes wrong.

Long-term stewardship requires funding for administrative oversight of post-closure MMV, an amount for which a general budget may reasonably be established. Long-term liability, however, does not have a defined cost, but instead a risk factor that balances likelihood of an event against the monetary consequences of that event. This latter cost is currently rather difficult to establish, which is the reason that no insurance company to date has promoted plans for insuring long-term post-closure operations.

To exemplify this distinction, one might invoke the current situation of the Gulf of Mexico oil spill (not strictly analogous, but exemplary). Several entities, including at least three major private companies and the federal government, shared operational stewardship of that project. The government had a role in regulating it. The three main companies had primary responsibility for day-to-day operations and, presumably, for having risk management plans and procedures to prevent and/or stop a blow out. Now

that a spill has occurred, the question is who will be financially responsible for the damages caused by the spill and for the cost of the clean up. The ultimate decision of liability will very likely be a legal determination by a court of law or by legal settlement.

The determination of who was responsible for the day-to-day operations (stewardship) of the project is an important factor in deciding who will pay for the cleanup. But it is not the only factor, possibly not even the determinative factor. As a simple but illustrative example, if Company A is ultimately found to have had primary stewardship responsibility for the part of the project that went wrong, it may be Company A's insurance company, not Company A, that will be legally liable for the costs.

Long-Term Stewardship

Institutional and regulatory changes will be required to define the parameters associated with long-term stewardship. Long-term stewardship should be part of the initial planning and permitting activity, but it comes into effect when a sequestration project has been completed, has been monitored over the regulatory-approved time period by the operator, and has been certified as safe by a public agency. Subsequent monitoring and possible remediation, if required, would be transferred to another entity for execution and oversight. The design of the certification for closure would have basic federal requirements, but a designated state agency may impose further requirements based on special state environmental regulations and on the particular characteristics of a geological formation and other variables. Any compensation claims may be set according to local conditions and might not be appropriate to be set at a uniform federal level.

Legal issues invoked during CCS operational and immediate post-injection activities would in all likelihood be similar to those that arise in similar industrial operational analogues. These issues may include the risk of CO_2 trespassing under other owners' properties, thus, the "physical damage or actual interference with the reasonable and foreseeable use of the properties," "nuisance," and "stigma" issues, and the potential for groundwater contamination. Although current regulations being utilized for CCS are based on water quality parameters, the standards for carbon dioxide in groundwater are unclear. For a risk-based approach to be effective, a "trigger level" of CO_2 in groundwater may be considered, but the human health factor would generally be the trigger for litigation and regulatory reaction. If human health is not protected, tort liability may be invoked in addition to regulatory penalties. The migration of groundwater across ownership boundaries is an issue that will require careful monitoring and for which a resolution framework might be considered useful. The issues related to this point, particularly pore space ownership and relevant regulations are covered in a separate white paper.

A recommendation identifying responsibility for long-term MVR for any post-closure operation would be a useful outcome for this effort. Policymakers will need to provide technically grounded guidance on acceptable levels of CO_2 leakage from storage and on definitions of leakage. One proposal is that a federal agency would have oversight, both operational and policy management, for all geological sequestration undertakings. A different option is for a federal agency to have only policy oversight, but that the administration should be at the state level by a state agency or possibly a private company under contract by a state agency. The federal role in the operational aspects of long-term sequestration, such as monitoring and claims, has yet to be determined.

One model for funding long-term stewardship activities is the creation of a trust fund administered by the host state, one that is provisioned by fees from the CCS operator during the injection phase and from permits. Creating a trust fund for long-term monitoring, mitigation, and remediation would be tied to site-specific criteria, with the fee assessed and the fund size in proportion to the projected and potential needs. If fees are set too high and the trust fund becomes too large for the perceived need, a financial disincentive is created. This could be ameliorated by a capped fee structure. The fund itself should be subject to strong oversight, including periodic valuation of funds collected relative to the risk profile of pooled sites for geological sequestration. In this prevailing economic climate, isolation of such a fund from attempts to repair state deficits would be desirable, and would need to be specified in state legislation.

Long-Term Liability

This is a complex legal topic that is not amenable to one-size-fits-all resolution. In the absence of an affirmative government (any government on a federal, state, or local level) policy decision to take on liability that it otherwise would not have, liability issues are typically resolved either by resort to normal common law principles already in place or in special cases by negotiation on a case-by-case basis for particular contracts. In other words it would be incumbent upon the operator to justify the need for public indemnity in a specific project. It may be ill-advised to invoke blanket public indemnity where, in individual cases, such may not be required. Much discussion of liability has been in the context of limiting a company's exposure to long-term liability in order to promote the development of this technology in the "public interest."[200] However, an alternate goal of creative risk techniques, such as insurance, bonding, and pooled federal funding might encourage CCS development but also preserve federal and state liability frameworks to promote safe practices. Rigorous site selection, assiduous project management, and a well developed and executed MVR plan would influence the risk profile of a CCS project during its entire lifespan, which are currently often part of permitting documentation. A regulatory and legal balance that protects the development of this industry, yet also protects the public and environment from potential dangers, must be recognized.

Since there are analogous, insurable industrial activities for most of the CCS processes, only the long-term liability is considered here. Prior to the start of any project, the project developer accepts liability associated with all operations, as well as post-injection monitoring, using financial mechanisms such as insurance. If public indemnity is, at the planning stage, assumed, caution may be required to guard against a reduced incentive to ensure post-closure responsibility. There are no obvious existing activities for long-term storage with which to draw comparisons. From siting to post-injection monitoring is the length of time for which the private market can be expected to operate and, under proper regulatory oversight, be responsible for the sequestration of CO_2. There is no mature private market that will accept longer-term liabilities where risk uncertainty is essentially unknowable and for which a risk profile has not been

[200] California has limited liability in various other situations when it is in the public interest. *See, e.g.*, CAL. CIV. CODE § 1714.5(b) (limiting liability for disaster service workers). However, courts have sometimes adopted "remedial innovations" when confronted with situations in which a serious loss occurred but no compensation available. *In re Paris Air Crash*, 622 F.2d 1315, 1320 (9th Cir. 1980) (citing, among others, *Brown v. Merlo*, 8 Cal. 3d 855 (1973), in which the California Supreme Court held that a statute precluding automobile "guests" from suing the driver for negligence violated the equal protection clause).

established. It is for this reason that discussion of the topic has veered to some type of state or federal acceptance of liability once the injection process has been completed and has been certified as safe.

There is general agreement in the scientific community that the risk of CO_2 migration decreases with time as a result of geochemical and geophysical mechanisms (beyond the scope of this paper) that occur to supercritical CO_2 under pressure at the geologic depths appropriate for CCS. If the CO_2 plume becomes stable after 30-100 years (and probably within five-ten years according to modeling experiments), that is a time frame that the legal, lending, and insurance systems may address.

There are some roughly analogous precedents from which to draw, such as the Price-Anderson Act (which enabled the nuclear power industry) and the national flood insurance program. The scenario that would be likely to succeed would probably be a multi-faceted approach that would include the following attributes:

- Redundant project engineering
- A highly reliable monitoring process during the injection phase that identifies and quantifies all leaks and plume migration;
- Clearly-defined comprehensive milestones for CCS contractors to meet;
- All milestones strictly-enforced and completion verified by (state) inspectors;
- A lengthy (decades) monitoring period after well closure;
- A suite of risk-mitigation instruments for private contractors such as insurance and bonds to cover the initial post-injection MVR phase;
- Establishment of a common risk-mitigation pool fund to address leakage and well failures in CCS projects;
- Federal or state assumption of liability only after successful completion and verification of all above factors, and only if either (1) specifically negotiated or (2) as part of a formally-adopted comprehensive federal or state policy to encourage and support wide-spread implementation of CCS during its early development period until the potential risks and liabilities of CCS are more fully understood.

Various combinations of the above factors may be appropriate for different projects, depending on the specific risk profile of each project. Some of the above factors may be inappropriate in other instances. In the absence of overriding state or federal legislation, such issues will need to be addressed on a case-by-case basis.

Interest has been shown in current federal programs that concern the regulation and cleanup of “hazardous materials” under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) known as the Superfund law for remediation of hazardous waste sites. CERCLA is a complex program that could form the basis of specialized legal analysis that could provide a useful framework for CCS liability management. The way the Superfund liability is traced is quite different than in some other programs. The current hazardous waste site operator often has not born the liability. Instead, EPA has gone after the original owners of the waste regardless of who has had custody since then. If used for CCS, this would make the CO_2 generators retain the liability instead of the sequestration site operators. The role and definition of CO_2 either as a waste or a useful commodity may impact the

relevance of CCS in the Resource Conservation and Recovery Act, which is the regulation designed to control the current disposal of hazardous materials.

State common law seeks redress against claims of trespass, nuisance, strict liability, and potential for damages may be independent of federal statutes that broadly address long-term liability. Thus, certification[201] could be issued by U.S. EPA or a state. Precedent has been set by state legislation in Montana, Kansas, Louisiana, North Dakota, Wyoming, and, to a lesser extent, Texas. A special situation arose when the states of Illinois and Texas accepted long-term liability in their competitive proposals specifically for and limited to the FutureGen project. The Casey-Enzi (S.1503) and the Bingaman (S.1462) bills both contain language for federal government acceptance of long-term liability for geological sequestration projects. S.1503 offers full indemnity for all appropriate projects, while S.1462 offers this for up to ten DOE-funded demonstration projects. The Bingaman bill, which is part of the American Clean Energy Leadership Act, requires a per-ton sequestration fee to be accrued by the Treasury in a DOE-administered trust fund to compensate any future claims. Precedent has been set by the Norwegian and Australian governments for commercial geological sequestration projects (Sleipner and Gorgon, respectively).

The rationale for a government role in indemnifying long-term liability is due to the belief that CCS is in the public interest and that long-term liability issues should not, at this early stage in the development of the industry, be a barrier to further development. In the case of FutureGen, the acceptance of long-term liability became a one-time competitive tool for the states in question and was deemed beneficial to the competing states. This was a specific case and extrapolating this into general policy should be viewed with caution.

A case could be made for arguing that federally administered trust funds dispersing damage claims is not an efficient model, exemplified by Hurricane Katrina. One possible organizational approach is for joint administration of a trust fund, overseen by a federal agency that may exert emergency authority as the need arises. While no trust fund is evident, this is part of the Federal Emergency Management Agency (now part of Department of Homeland Security) activity in areas such as flood insurance and in monitoring emergency response activities as part of either natural (such as hurricanes and earthquakes) or man-made (such as oil spills and radiological releases) disasters. These programs respond retroactively, whereas CCS seeks a proactive framework, such as a process associated with the Nuclear Waste Fund. This fund provided for some of the construction costs for Yucca Mountain and operated by collecting a small millage from nuclear-generated electricity. Similarly, a small millage was also employed for decommissioning and decontamination procedures associated with the dismantling of nuclear power plants after their useful life – an activity that has been employed in at least one instance to date.

There are California examples, such as the Laws for Conservation of Petroleum & Gas Section 3205.5, which has a bond requirement for each well. The bond is released when the operator properly closes, plugs, and abandons the well. California Laws for Conservation of Petroleum & Gas Section 3206 (b) -

[201] Certification of a CCS project requires that after a defined period, CO2 has been shown to have stabilized and behaved as predicted according to rigorous monitoring and verification, and that any required surface and subsurface remediation has been completed. It is therefore reasonably predicted that the mechanical integrity of the reservoir and the CO2 will remain in place. Certification may be awarded by a designated state agency or by EPA.

Hazardous & Idle-Deserted Well Abatement Fund allows for the collection of annual fees on idle wells into an escrow account. California Laws for Conservation of Petroleum & Gas Section 3262 - Acute Orphan Well Account provides for the administration of orphan wells by California and is overseen by Conservation Committee of Oil and Gas Producers. Operators pay a fee (based on the amount injected) that is deposited in interest-bearing account for use during the post-closure period. There are provisions for the state accepting indemnity in special cases subject to review by the State Department of General Services, Office of Risk and Insurance Management.

Where there is evidence of willful neglect of regulations or purposely providing misleading information, liability should be sought from the operator or descendents by the post-closure administrator. However, this is potentially difficult to determine (as exemplified by some of the CERCLA projects), hence the desirability of a trust fund of some type.

Summary

For CCS to be effective, CO_2 must remain underground for a long period - hundreds to thousands of years. This is well beyond the historic life-span of companies and most governments. This requires institutional, administrative, and regulatory approaches for long term stewardship of these sites to protect the public and to properly assess the efficacy of the removal of carbon dioxide from the atmosphere. Another major barrier (perhaps *the* major barrier) for industry to undertake CCS projects is the undefined and open-ended liability for the site.

Although operational risks associated with the transport and injection of CO_2 in the subsurface during EOR operations have been successfully managed for many years, the long-term liability for CCS sites – post-closure – may be unique to CCS. It is important to note that the entity accepting the liability will likely (without the development of institutional initiatives) be responsible for expenses of continuing MVR activities, any mitigation or remediation required, and compensation for any damages if leakage occurs.

One option is for government agencies to take on the long-term responsibilty for CCS sites. Some states have adopted legislation to accept limited liability, but there has been little consistency in the time frames or agreement as to where the liability should ultimately reside. In some cases the risk and performance of the CCS site is linked to liability transfer.

Another option is to create an industry fund. At the federal level, bills have been introduced that would establish a carbon storage stewardship trust fund financed by fees from operators to ensure compensation for potential damages. At least one private insurer is making short term insurance policies available. Long-term liability schemes have been adopted for other industries, including bond provisions by the UIC program, trust accounts funded through fees to operators that are administered by state or industry organizations such as the Acute Orphan Well Account, the Price-Anderson indemnity program that pools risk for the nuclear industry, or the National Flood Insurance Program that is federally funded.

Examples from other states

Many states, including oil-producing states like Texas and Louisiana and coal-producing states like Wyoming and Montana, have enacted laws relating to CCS development. Based on a review of these statutes, there are some common elements:

- State policy declaration that CO_2 is a valuable commodity and that CO_2 storage provides a public benefit by reducing GHG emissions and reducing reliance on higher carbon fuels, like natural gas and coal.
- A fee-based structure to cover the state's responsibility for administering long-term monitoring and oversight of CO_2 injection and storage.
- Post-closure monitoring by the drilling or reservoir operator for a period of 10 years or longer.
- A certificate of completion to be issued by a designated state or federal agency, following permanent closure.
- In some cases, a transfer of the state's responsibility for long-term (post-closure) MVR to the federal government after a designated period of years (e.g., 10 years or longer).

A more complete listing of these selected state laws are provided in the **Examples from Other States** Section.

Federal statutes have also been proposed that provide a regulatory framework for addressing long-term liability, many of which have not yet been enacted, but are being debated in the U. S. Congress as part of national energy or climate change legislation.

The section Examples of **federal statutes, Congressional initiatives, and international activities that could relate to CCS** lists some of these activities as well as established laws.

Options

Long-term liability and long-term stewardship involve a degree of technical knowledge and experience, but they primarily require legal and financial expertise to research the issues further. The references in section **Further Reading** go into more depth in these areas. There are several existing approaches for addressing long-term liability that have been used by the federal government to reduce the financial risk of development projects. In addition, other states have enacted legislation affecting CCS development which may be examined further. At present, there is no one-size-fits-all approach or solution that can be recommended, since in the absence of special legislation, liability protection is evaluated and negotiated on a project-by-project basis. **Again, the focus of these options is on long-term liability which commences after injection and after post-injection MVR**. Some of the options include:

Liability:

- Private and self insurance to guard against the financial risk of an accident or release, to be paid by the project developers. Self-insurance is standard in the oil and gas industry and its terms are well understood.
- A federal insurance program, such as the Price Anderson Act indemnity program for nuclear power plants or the National Flood Insurance Program, which are financed by taxpayers.
- A state administered insurance program, which assesses fees on well operators or developers, similar to the well cleanup or abandonment fund for California's orphan wells.
- Other bonding or insurance mechanisms funded by industry.
- Assumption of all liability by the state (or federal government).

Stewardship:

- Identify a lead state agency charged to administer and oversee long-term MVR and to certify post-injection site closure.
- The lead state agency for administering long-term MVR and for certifying well closure would also be responsible for initial permitting of the CCS project.
- Create a fee-based geological sequestration Trust Fund administered by the state (or contractor thereof), the provisions for which would be solely for long-term MVR – and remediation if necessary. An independent, scientific framework for designing and conducting post-closure MVR would need to be established.

Examples from other states

The following are examples of current legislation in selected other states. The situation in these states may differ in numerous ways from those in California, and the information below is provided to assist in the assessment of California's direction on CCS strategies.

Illinois	Illinois House Bill 3854 creates the Carbon Capture and Sequestration Legislation Commission that will consist of 11 members (membership defined) to report by 31 December 2010. The report will address ownership of CO_2, liability for release of CO_2, acquisition and ownership of pore space, procedures and safeguards for the transportation and sequestration of CO_2, methodology to establish any necessary fees, cost or offsets, potential use of CO_2, construction of pipelines, and coordination with federal law and regulatory commissions. During the competition for Illinois to host the FutureGen Clean Coal project, the state offered to accept all title, rights, and liabilities associated with the sequestered gas, including any current or future benefits, and that the State of Illinois would indemnify the operator from all public liability action except where willful misconduct is demonstrated.
Kansas	Kansas's statutes establish a CO_2 Injection Well and Underground Storage Fund with funds from permit fees. This Fund will cover oversight of the operational phase, including mitigation of adverse environmental impacts, emergency or long-term remedial activities, and administrative costs. This state emphasizes operations concerns and to a far lesser degree the longer term issues. But it has offered assumption of long-term ownership and liability.
Louisiana	Louisiana has declared (HB661 2009) that CO_2 storage will benefit the state and that CO_2 is a valuable commodity to its citizens. It identifies its responsibility for assuring compliance with the federal Safe Drinking Water Act. This Bill lays out in more detail than other states the long-term issues for CCS, notably that (1) there is liability transfer from the operator to the state after ten years since injection cessation upon certification, (2) the liability release will only be permitted if the Trust Fund has sufficient resources and the operator has not intentionally mis-represented relevant information, (3) liability by the state is not automatic upon issuing a certification of completion, (4) liability caps for various noneconomic loss situations are described, (5) a CO_2 Geologic Storage Trust Fund is established with a formula defining the fee structure, with a fee cap, and instructions for activities for which the Fund can be used. It further allows for site-specific funds to be established. The Fund provides for long-term monitoring and remediation.
Montana	Montana enacted legislation (SB 498) with regard to Carbon Capture and Sequestration (CCS) that includes provisions for long-term stewardship and long-term liability for which the Montana Board of Oil and Gas Conservation is the

	regulating agency. A fee would need to be created to cover the state's responsibility for administering the long-term oversight of the wells. Post-closure, the operator will be responsible for monitoring and maintaining the CO_2 sequestration site to ensure that there is no risk. For Montana, the time line for corporate responsibility is 15 years, after which the operator can transfer the liability and title to the state.
New York	This state is proposing, among other items, that post-closure liability shall be transferred to the state after demonstrating no migration following a ten-year monitoring period.
North Dakota	SB2095 (2009) creates an (1) CO_2 administrative fund to pay for regulating storage sites during their construction, operations and preclosure phases, (2) a CO_2 Trust Fund to defray expenses incurred in long-term monitoring and management of the closed facility. This Bill also finds that title to the CO_2 injected into and stored in a storage reservoir remains with the operator until a certificate of completion has been issued, when the title transfers to the state. The monitoring and managing of the storage facility is the state's responsibility "…until such time as the federal government assumes responsibility for the long-term monitoring and management of the storage facilities."
Texas	Liability has been established for the operational phase only for which a fund has been established from permitting fees for injection long-term monitoring, repairs, and enforcement. The Texas Railroad Commission regulates CO_2 storage in oil and gas field and saline formations directly above and below oil and gas field. The state assumes liability for offshore sequestration.
Washington	Owner will be liable in perpetuity.
Wyoming	The 2010 session of the Wyoming legislature (HB0017) establishes a Wyoming Geologic Sequestration Special Revenue Account "…to measure, monitor and verify Wyoming geologic sequestration sites following site closure certification, release of all financial assurance instruments and termination of the permit". However, this Fund does "…not constitute a waiver by the state…of its immunity from suit, nor does it constitute an assumption of any liability by the state for…sites or the CO_2 and associated constituents injected into those sites."

Examples of federal statutes, Congressional initiatives, and international activities that could relate to CCS

- CERCLA - Role of the Comprehensive Environmental Response Compensation and Liability Act provides the regulatory framework for long-term liability.
- Price-Anderson Act, 1957 – This Act was intended to encourage the development of the nuclear industry by partially indemnifying the nuclear industry. It requires that the nuclear industry maintain certain levels of insurance and contribute to a trust fund in case of a nuclear accident. With spent nuclear fuel deposition still unresolved, the comprehensive outcome of this Act may benefit from close analysis.
- DOE CCS Roadmap 2007: This provides proposed guidance for DOE-funded demonstration projects.
- Casey-Enzi Bill (S.1502) offers full indemnity to all projects after closure. This Bill authorizes a sequestration fee to collect into a DOE-administered fund to cover long-term stewardship liabilities.
- Congress recognizes indispensability of policies that promote CCS to support continued coal use for its energy provision (50%).
- National Flood Insurance, Terrorism Risk Insurance not particularly useful models for CCS. The inherent weakness of this analogue, as manifest mainly by the imbalance between losses paid and premiums collected, is that there is no control over the risk creator. Natural hazards may often be mitigated (e.g., building levees), but this is not analogous to careful site selection and monitored CO_2 injection.
- A reasonable model is the Oil Production Act of 1990 that establishes a national Oil Spill Liability Trust Fund (in 1986) managed by the National Pollution Funds Center, an independent unit reporting directly to the Coast Guard Chief of Staff. The balance of this fund is mandated to be between $2.5B-$2.7B (notable in light of the approximate $20B oil spill in the current Gulf of Mexico spill).
- Examples from overseas include Norway's government acceptance of long-term liability from Statoil for the West Sleipner project. Australian federal and state governments jointly accepted long-term liability for the Gorgon facility.
- The European Parliament issued in 2009 Directive 2009/31/EC on the geological storage of carbon dioxide. The provisions in this Directive are similar to those outlined in this paper: in particular financial security must be established for the operations and an anticipated post-injection phase of a minimum of 30 years. Liability may be transferred to a "competent authority" after a minimum of 20 years. "Competent authority" is not defined.

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20. Appendix Q: Monitoring, Verification, and Reporting Overview

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Monitoring, Verification, and Reporting Overview

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Larry Myer
Primary Author

Other white papers for the panel will include

Enhanced Oil Recovery as Carbon Dioxide Sequestration

AB 32 Regulations and CCS

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Options for Permitting Carbon Capture and Sequestration Projects in California

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Overview of the Risks of Geologic CO2 Storage

Review of Saline Formation Storage Potential in California

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Introduction

In the context of geologic CO_2 storage (GCS), Monitoring, Verification, and Reporting (MVR)[202] refers to activities for collecting and reporting data about the characteristics and performance of GCS projects. For setting state regulatory policy, the primary purposes of MRV will be to verify that projects perform as expected—that ecosystems, local populations, livestock, and natural resources such as groundwater and recoverable oil and gas are protected, that damages from seismicity do not result from injecting CO_2, and that the proposed reduction in CO_2 emissions is achieved. This paper focuses on monitoring for leakage from the subsurface as paramount to protecting people, resources, and the environment, as well as for assuring emissions reductions. Even though monitoring of surface facilities is important, focus is on the subsurface where the technical issues are less well defined. The paper summarizes available measurement techniques for detection of leakage and the overarching approaches for combining these techniques into a monitoring program. Because of public sensitivity to earthquakes in California, a separate section is provided to discuss induced seismicity monitoring.

Overview

The major components to be addressed by monitoring in GCS projects include: (1) injection rates and pressure, (2) injection well integrity, (3) subsurface distribution of the CO_2, and (4) the local environment.[203] For on-shore geological storage reservoirs, monitoring can take place in the storage reservoir itself or in shallower formations, in the vadose zone, in terrestrial ecosystems, and in the atmosphere. Offshore monitoring of storage projects will address the same components for the subsurface, but will need to take into account potential dissolution into seawater, transport with the water column, and sea-air interface.

Many of the measurement technologies for monitoring GCS are drawn from other applications such as the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, safety procedures for industries handling CO_2, and ecosystem research.[204,205] These established practices provide numerous measurement approaches and options—a monitoring toolbox—which enables development of tailored, flexible monitoring programs for GCS. (A summary of specific measurement technologies is found in section **Monitoring Measurement Methods**.)

The value of a tailored approach to monitoring is threefold: first, optimum performance of many techniques depends on site-specific geologic attributes; second, the risks that need to be monitored will vary from site to site; and third, a tailored approach will enable the most cost-effective use of monitoring resources. From a regulatory perspective, a tailored approach will lead to regulations that are largely

[202] The term monitoring, verification, and accounting (MVA) is also commonly used.
[203] IPCC, 2005: *IPCC Special Report on Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
[204] 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.
[205] 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.

performance-based and non-prescriptive with regard to measurement methods. The downside of a tailored approach is that it will add considerable time and uncertainty (from the perspective of a project developer) to the regulatory process. The time required for an agency to review a tailored plan, and potentially coordinate reviews amongst several agencies, is much more than would be required for a prescriptive approach. In addition, regulatory staff will have to have a higher level of knowledge and expertise in the scientific underpinnings of a broad range of monitoring methods, as well as potential risks, in order to evaluate the efficacy of tailored approaches.

At a conceptual level, a tailored approach implies no distinction between saline formation MVR and MVR for enhanced oil recovery (EOR) combined with storage— in each case the program is developed according to the site-specific circumstances. Practically, there are important differences between EOR with storage and saline formation storage. Saline formation storage involves only injection of CO_2 while EOR involves production of CO_2 along with oil and other fluids, and separation and re-injection of CO_2. So, there are additional measurements and accounting steps associated with surface handling of CO_2 for EOR. Regarding the subsurface, the leakage risks for saline formation storage and EOR with storage will likely be different, leading to a different monitoring program. The risk of leakage arising from uncertainties in the geology of the site will be much less for an EOR project because of the knowledge about the subsurface obtained during development of the field for oil production. On the other hand, the risk of leakage from pre-existing wells will be higher for the EOR project.

Even if a tailored approach is followed, there are a minimum set of measurements associated with the injection well and injection operations, that would be appropriate. These include CO_2 detection sensors on the surface at the wellsite, pressure, temperature, and volume flow rate at the wellhead, downhole pressure and temperature at the injection interval, and mechanical integrity pressure testing of the casing and subsequent monitoring of annulus pressures. A performance-based approach that allows for a tailored measurement program with a minimum set of required measurements has been followed in developing the proposed EPA UIC Class VI regulations and the EPA proposed rule for mandatory reporting of greenhouse gases for injection and geologic storage. (A summary of these rules is found in section **Summary of U.S. EPA Proposed Monitoring Rules**.)

Baseline Data Collection and Subsurface Modeling

Establishing a baseline is an essential early step for successful monitoring of GCS. CO_2 is ubiquitous in the environment, both at the surface and in the subsurface, so it is important to establish initial levels before injection operations begin. Moreover, many of the parameters that can be used to monitor a storage project are not uniquely and directly indicative of the presence of CO_2; instead, it is the changes in these parameters over time that can be used to detect and track migration of CO_2 and its reaction products. For this reason, a well-defined baseline includes not only the average value of these parameters, but accounts for how they vary in space and over time before the project begins. Referred to as “time-lapse,” this approach is the foundation for monitoring CO_2 storage projects. Without time-lapse measurements, it may not be possible to separate storage-related changes in the environment from the naturally occurring spatial and temporal variations as seen in the monitoring parameters. For most GCS projects, baseline data will be obtained during the pre-injection phase of the project. This is particularly important for storage projects in deep saline aquifers, for which there is less prior data than for depleted oil and gas fields.

Collection and analysis of monitoring data continues throughout the injection phase and into the post-injection and site closure phases. It is a dynamic and iterative process in which model predictions play a critical role. One of the key outputs of site characterization is a subsurface model. Comparisons of monitoring measurements with model predictions are made repeatedly to determine if the project is performing as expected, and what adjustments can be taken if it is not. Monitoring data is used to improve the initial subsurface model, which leads to increased confidence in subsequent model predictions. As knowledge and confidence in the performance of a project increase, monitoring may be scaled back, and the spatial and temporal frequency of monitoring measurements and types of measurement may be changed to reflect this increased understanding.

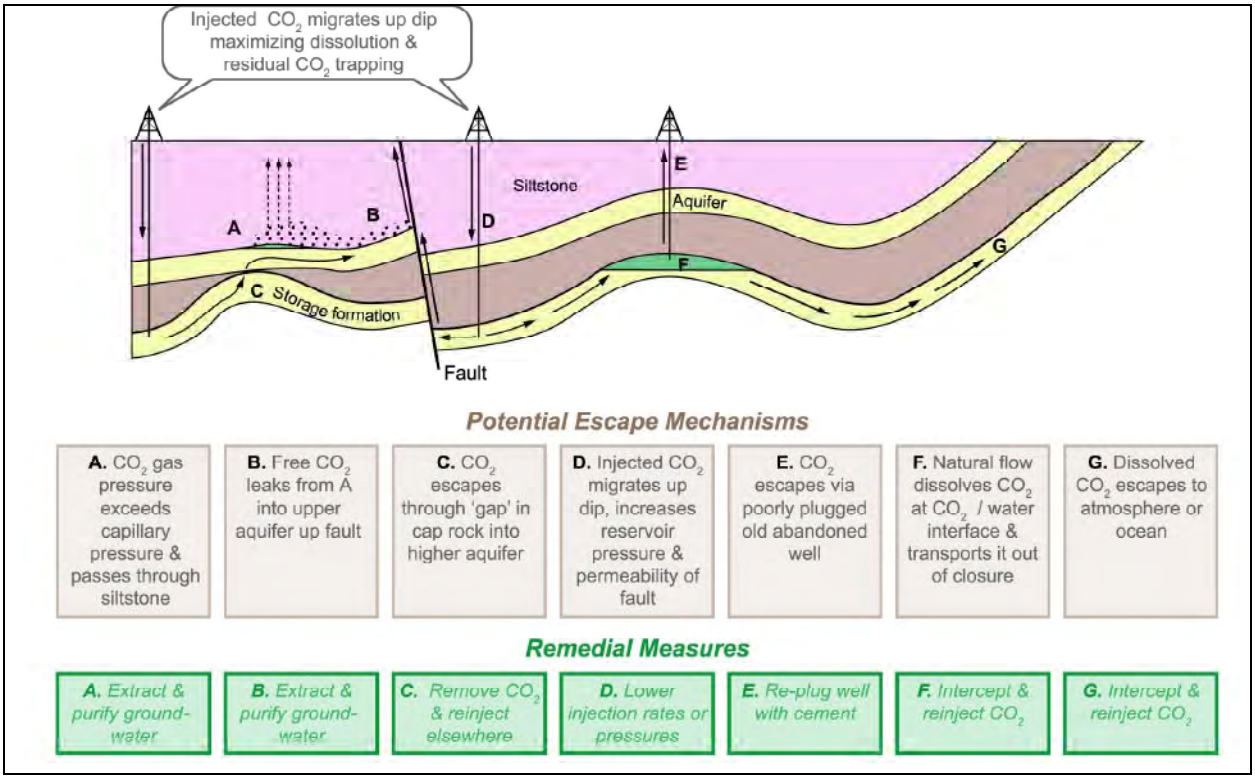

Figure 7. Potential leakage routes and remediation techniques for CO_2 injected into saline formations.[206]

Monitoring for leakage

Verification that a storage site does not leak is paramount to protecting people, resources, and the environment, as well as for assuring emissions reductions. Identification and assessment of potential leakage pathways during site characterization serves as a basis for developing appropriate operational standards, as well as monitoring and verification requirements that

address site-specific conditions. The biggest risks of leakage for GCS overall arise primarily from existing and new wellbores and fractures and faults. Other possible pathways have also been identified, along with remedial actions, as illustrated in Figure 7.

[206] IPCC, 2005.

Monitoring for wellbore leakage

Wellbores that intersect the storage formation could provide pathways for CO_2 migration. Petroleum industry experience suggests that leakage from the injection well itself is one of the most significant risks for injection projects.[207] Pre-existing wellbores are considered to present a higher risk for leakage than new wellbores because of uncertainty about their condition. Locating nearby wellbores and assessing their leakage potential will be part of site characterization for many GCS projects.

Approaches for monitoring for wellbore leakage include:

- Pressure monitoring
  - In a closed well to establish that the casing is not leaking.
  - In overlying formations, where leakage of CO_2 will result in an increase in pressure in the water in the rock.
- Careful monitoring of temperature profiles along the well to identify temperature anomalies that indicate leakage.
- Geophysical wireline logs, used routinely in the petroleum industry, provide data on the integrity of the cement filling the space between the well casing and the rock. If CO_2 were to leak through the cement between the casing and the rock, it could enter rock formations above the injection interval. Geophysical wireline logs and can detect the presence of CO_2 in the rock within about a meter of the wellbore.
- Tracers can be injected behind the casing and their movement monitored to indicate the presence of leak paths at the casing-cement-rock interface.
- Water samples
  - Extracted from formations and analyzed for CO_2, or for tracers, if any have been injected with the CO_2.
  - Shallow groundwater samples obtained from existing water wells, or for-purpose drilled wells, and analyzed for CO_2 and or CO_2-water-rock reaction products.
- Sensors placed at ground surface in the vicinity of the well to measure CO_2 concentrations in the air.

Monitoring for leakage from fractures and faults

The second major category of potential leak paths is subsurface geologic structural features, of which fractures and faults are considered to represent the greatest risks. Fractures are essentially cracks in the rock, which could provide leak paths if they are present in the seals overlying the reservoir intervals. Faults are cracks where the two surfaces forming the crack have experienced relative movement, or slip. Faults can exist at any scale, and can therefore provide potential leak paths that extend from the storage reservoir to the surface. However, it should be noted that faults can also act as effective seals and traps for CO_2 storage.

[207] Benson et al. 2002.

Approaches to mapping the movement of CO_2 in the subsurface, which can also detect leakage out of the storage reservoir from fractures and faults, include:

- Geophysical monitoring methods: seismic, electromagnetic, and gravity
  - Seismic surveys produce images of subsurface properties by generating and recording induced sound waves as they travel through the earth. Although the size of a leak that can be detected using seismic surveys depends on many site-specific parameters, field experiments such as the Frio Brine Pilot tests in Texas and the Weyburn project in Canada suggest that seismic methods can detect leaks on the order of a couple thousand metric tons, a volume which is roughly equivalent to the size of a municipal swimming pool.
  - Gravity and electrical methods create lower-resolution images of the subsurface, and are less widely tested for CO_2 applications, but should provide additional information on movement of the CO_2 plume. Gravity methods use the difference in density between CO_2 and water as a means of detection, whereas electrical methods use the difference in electrical conductivity between CO_2 and water, which is generally assumed to be saline for the purposes of CO_2 storage.
- Land-surface deformation, satellite, and airplane-based monitoring: injection of CO_2 into the reservoir causes increases in the pressure of the water in the rock, which extend far beyond the extent of the CO_2 plume. Recent work at the In Salah project in Algeria has demonstrated that small ground surface displacements, measurable from satellite-based systems, can be translated into images that show the migration of the CO_2, and would be able to show leakage via fractures and faults.
- Other approaches to monitoring for leakage due to fractures and faults require access to formations overlying the reservoir via wells. As discussed above, water samples, temperature and pressure measurement and geophysical wireline logs can be employed in such wells.

Quantification of Leakage Measurements

Consideration of potential reporting requirements needed to obtain credits for subsurface storage of CO_2 logically raises the issue of quantification of leakage. Many, if not most, of the measurement techniques discussed above for detection of a subsurface leak, also provide information which can be further analyzed to quantify the leak, though additional assumptions and data from other measurements may be needed. Site specific conditions, once again, will heavily influence the sensitivity and uncertainty in results. A handful of studies have been carried out to look at the sensitivity of pressure measurements and seismic measurements to the volume of a leak, and, as noted above, field studies to date suggest that under some circumstances, seismic methods can detect leaks of a few thousand tons of CO_2. In general, however, quantification of leakage is more challenging than leak detection and, and more experience and study is needed before definitive statements can be made about minimum detectable volumes.

Monitoring Seismicity

Public awareness of, and sensitivity to, earthquakes, will likely result in special attention being paid to the part of the monitoring program focused on detecting any seismicity that might occur at a CCS site. The major concern is that CO_2 injection will cause earthquakes, where use of the term "earthquake" for most people outside of the scientific community, infers ground motion that people can feel and likely causes some harm. In fact, the number of natural seismic events that are not felt by the public far exceeds the number which are felt, and the same can be said for seismicity induced by subsurface operations. Nonetheless, there are a number of well documented cases to show that subsurface pressure increases, either from direct injection of fluids in the subsurface for waste disposal and geothermal energy development, or impoundment of large volumes of water at the surface in reservoirs, have caused seismicity that people can feel, and in some rare instances, caused harm. Even though, to date, there are no documented instances in which CO_2 injection has induced seismicity which has caused harm, appropriate design, operational and monitoring steps need to be taken to mitigate the possibility of any such events.

Monitoring for induced seismicity begins with establishing a record of the natural background seismicity in the region encompassing the project. This record is fairly good in many parts of California because an earthquake monitoring network is already in place. This network consists of seismometers located on the ground throughout the state and connected by satellite to a data collection facility. In most instances the existing network would need to be augmented by a local network designed specifically for the site, and consisting of seismometers located on the ground surface or in shallow boreholes. The local network would enable more accurate location of events and detection of smaller events than the regional network. The record of the natural background seismicity is important since it gives a baseline to determine if an event, which occurs after injection starts, is due to injection or natural tectonic processes.

After injection begins, it is important to analyze both the time history and the magnitude of any events that occur. Instrumentation for "real time" measurement and analysis, which is available, should be employed in order to facilitate immediate response to significant events. Definition of what constitutes a "significant" event, as well as actions which need to be taken in response to the event, should be part of the seismicity monitoring plan. Many factors affect the definition of a significant event. Geologic factors affect the magnitude of shaking and the potential for damage of structures, but sensitivity of the public to any seismicity that can be felt could also be a major factor. Induced seismicity is directly related to fluid pressure in the subsurface, so reduction of fluid pressures reduces seismicity. The potential for induced seismicity will decrease during the post-injection closure phase of a storage project due to the natural reduction of fluid pressures and it can be controlled during the operational phase by control of injection rates.

Since there is a cause and effect relationship between fluid pressures and seismicity, direct monitoring of subsurface fluid pressures should also be part of the induced seismicity monitoring program.

Monitoring Costs

Monitoring costs will depend on many factors including plume size, regulatory requirements, duration of monitoring, geologic site conditions, and the particular methods selected for application. Because many of

the technologies likely to be used are already in widespread use in the oil and gas industries, and the costs for these technologies are well constrained.

Despite this knowledge, there is limited real-world information available on costs for monitoring GCS projects. Benson and others estimated life-cycle monitoring costs for two scenarios: (1) storage in an oil field with EOR, and (2) storage in a saline formation.[208] The scenarios were not developed to be prescriptive of what a monitoring program should be, but are representative of plausible examples. For each scenario, cost estimates were developed for a "basic" and an "enhanced" monitoring program. The basic monitoring program included periodic 3-D seismic surveys, microseismic measurements, wellhead pressure, and injection rate monitoring. The enhanced monitoring program added periodic well logging, surface CO_2 flux monitoring, and other advanced technologies. The assumed duration of monitoring included a 30-year injection period, as well as a post-injection monitoring period of 20 years for the EOR scenario and 50 years for the saline formation scenario. For the basic monitoring program, the undiscounted cost for both scenarios was \$0.16 – \$0.19/ton CO_2. For the enhanced program, the undiscounted cost was \$0.27 – \$0.30/ton CO_2.

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

Conclusion

Practical and cost-effective approaches to MVR will rely on a combination of measurements and model predictions, tailored to the geological attributes and risks of specific storage sites. Many current GCS projects involve research elements to further develop or adapt existing measurement tools to the characteristics of CO_2 storage or to test new techniques. This research aims to enhance our understanding of GCS, lower costs, gain lessons learned from field testing, and expand the options of an already robust monitoring toolbox.

The inherent variability in geologic environments call for flexibility in the MVR methods employed, the types and numbers of parameters measured, and the temporal and spatial frequency of their measurement. A consistent monitoring policy amongst regulatory entities will be essential to enable project developers to build unified, tailored monitoring programs that will allow GCS projects to move forward in a cost- and time-effective manner, while ensuring protection of the public, the environment, and natural resources.

[208] Benson, S.M., M. Hoversten, E. Gasperikova, and M. Haines (2005), Monitoring Protocols and Life-Cycle Costs for Geologic Storage of Carbon Dioxide, In, E.S. Rubin, D.W. Keith and C.F. Gilboy (Eds.), Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, IEA Greenhouse Gas Programme, Vancouver, BC, Volume II, p. 1259-1265.

Monitoring Measurement Methods

CO_2 Flow Rates, Injection, and Formation Pressures

Measurements of CO_2 injection rates are a common oil field practice, and instruments are available from commercial manufacturers. Typical systems use orifice meters or other differential producing devices that relate the pressure drop across the device to the flow rate. Recent enhancements in the basic technology are now available that allow for accurate measurements and injection control, even under varying pressure and temperature conditions.[209]

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.[210]

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

Direct Measurement Methods for CO_2 Detection

Direct measurements of CO_2 in air, water, or soils may be required as part of the monitoring program. For example, CO_2 concentrations in the air near the injection wells or abandoned wells may be monitored as a precaution to ensure worker and public safety at the storage site. In addition, nearby groundwater monitoring wells may be monitored periodically to ensure that the CO_2 storage project is not harming groundwater quality. If there is an indication that CO_2 has leaked from the primary storage reservoir and migrated to the surface, vadose zone and soil gas CO_2 concentrations may be monitored.[211]

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

CO_2 Sensors for Measurement in Air

Sensors for monitoring CO_2 continuously in air are used in a wide variety of applications, including CO_2 demand-controlled HVAC systems, greenhouses, combustion emissions measurement, and the monitoring of environments in which CO_2 is a significant hazard (such as breweries). Such devices,

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

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

[211] 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.

which rely on infrared detection principles, are referred to as infrared gas analyzers. Infrared gas analyzers used in occupational settings are small and portable. Most use nondispersive infrared or Fourier Transform infrared detectors. Both methods depend upon light attenuation by CO_2 at a specific wavelength, usually 4.26 μm. For extra assurance and validation of real-time monitoring data, federal regulatory agencies[212] use periodic gas sampling bags and gas chromatography for measuring CO_2 concentrations. Mass spectrometry is the most accurate method for measuring CO_2 concentration, but it is also the least portable. Electrochemical solid-state CO_2 detectors exist, but they are not cost-effective at this time.[213]

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.[214] For example, the U.S. Geological Survey measures CO_2 fluxes on Mammoth Mountain using these types of detectors,[215] and they have also been deployed at a carbon sequestration pilot study in Alabama.[216] Biogeochemists study ecosystem-scale carbon cycling using CO_2 detectors on towers that are 2- to 5-meters tall (eddy flux correlation measurements) in concert with wind and temperature data to reconstruct average CO_2 flux over large areas.

Remote sensing of CO_2 releases to the atmosphere is a 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.[217] Geologists use airborne instrumentation called COSPEC to measure the attenuation of solar ultraviolet light relative to an internal standard. CO_2 is measured either directly by a separate infrared detector, or calculated from SO_2 measurements and direct ground sampling of the SO_2/CO_2 ratio for a given volcano or event.[218] 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.[219]

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

[213] Tanura, S., N. Imanaka, M. Kamikawa, and G. Adachi, 2001, A CO_2 Sensor Based on a Sc3+ Conducting Sc1/3Zr2(PO4)3 Solid Electrolyte, Sensors and Actuators B, 73, pp. 205-210.

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

[215] 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 at http://pubs.usgs.gov/fs/fs172-96/. See also: http://volcanoes.usgs.gov/lvo/activity/monitoring/co2.php.

[216] http://www.licor.com/env/2010/pdf/soil_flux/secarb.pdf.

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

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

[219] Hobbs, P.V., L.F. Radke, J.H. Lyons, R.J. Ferek, and D.J. Coffman, 1991, Airborne Measurements of Particle and Gas emissions from the 1990 Volcanic Eruptions of Mount Redoubt, J. Geophys. Res., 96(D10), pp. 18,735-

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.[220] Fluid samples can be collected either directly from the formation using a downhole sampler or from the wellhead, if the well from which the sample is collected is pumped. Downhole samples are considerably more costly, but have the advantage that they are more representative of the formation fluids because they are not depressurized as they flow up the well. Methods for collecting downhole and wellhead fluids samples are well developed, and geochemical sampling is conducted on a routine basis.

Fluid samples can be analyzed for major ions (for example, Na, K, Ca, Mg, Mn, Cl, Si, HCO_3- and SO_4^2-) pH, alkalinity, stable isotopes (such as, ^{13}C, ^{14}C, ^{18}O, ^{2}H), and gases, including hydrocarbon gases, CO_2, and its associated isotopes.[221] 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 into the underground movement of CO_2 and reactions between CO_2 and the geologic formation.[222] 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 more challenging. Only recently has significant attention been paid to understanding reactions between CO_2 and deep geologic formations shortly after CO_2 is introduced into the environment.[223]

18,752.; Menzies, R.T., D.M. Tratt, M.P. Chiao, and C.R. Webster, 2001, Laser Absorption Spectrometer Concept for Globalscale Observations of Atmospheric Carbon Dioxide, 11th Coherent Laser Radar Conference, Malvern, United Kingdom.

[220] 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 CO_2 Enhanced Oil Recovery. Proceedings of the NETL Workshop on Carbon Sequestration Science, http://www.netl.doe.gov/.

[221] Ibid.

[222] 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. Submitted to Geochimica Cosmochimica Acta, Also Lawrence Berkeley National Laboratory Report, LBNL-47383.

[223] 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 DC.

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 infrared 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 at the Sleipner project in Norway, the Frio Brine pilots in Texas, the Nagaoka project in Japan, and the Weyburn project in Canada.[224] 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 some settings may not always be feasible because of limitations on land access or use. Therefore, additional methods for plume detection are being evaluated, including innovate real-time seismic monitoring approaches.[225]

Well Logs

One of the most common methods for evaluating geologic formations is the use of well logs. Logs are run by lowering an instrument into the well and taking a profile of one or more physical properties along the length of the well. A wide variety of logs is available and can measure many parameters—from the condition of the well to the composition of pore fluids to the mineralogy of the formation. For geologic storage of CO_2, as is true 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.[226] It is worth noting that the resolution of well logs may not be sufficient to detect very small rates of seepage through microcracks. The Resistivity (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 pilots in Texas.[227]

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[224] Korbol, R., and Kaddour, A., 1995. Sleipner Vest CO_2 disposal – Injection of Removed CO_2 into the Utsira Formation. Energy Conversion and Management,36, 3-9, 509-512.

[225] 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.

[226] Benson et al., 2002a, op. cit.

[227] Hovorka, S.D., S. M. Benson, C. Doughty, B. M. Freifeld, S. Sakurai, T. M. Daley, Y. K. Kharaka, Mark H. Holtz, R. C. Trautz, H. S. Nance, L. R. Myer and K. G. Knauss. Measuring permanence of CO_2 storage in saline

Geophysical Monitoring Methods: Seismic, Electromagnetic, and Gravity

It is natural to consider geophysical techniques for monitoring CO_2 migration because of the large body of experience in their application in the petroleum industry. Among geophysical techniques, seismic methods are by far the most highly developed. The most likely mode of application will be time-lapse, in which two surveys taken at different times 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 at the Sleipner project, the Frio Brine pilots, the Weyburn project, and the Nagaoka project. Though time-lapse imaging is becoming more common, it is a much less mature technology than exploration geophysics.

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

Gravity methods sense changes in density; electrical methods primarily respond to changes in resistivity; and seismic methods depend on both density and elastic stiffness. Gravity has been used to monitor CO_2 migration in off-shore environments at the Sleipner Project and was able to detect the injected CO_2. These physical properties are known for CO_2, typical reservoir fluids, and their mixtures, and so assessments can be made of expected changes in geophysical properties.[228] CO_2 is resistive, so electrical methods are candidates for brine bearing formations. For most of the depth interval of interest for sequestration, CO_2 is less dense and more compressible than brine or oil, so gravity and seismic methods are candidate methods for brine or oil bearing formations. At shallow depths, CO_2 has gas-like properties, so none of the geophysical methods are good candidates for monitoring CO_2 within a shallow, dry natural gas reservoir. Even in this case, however, since brine formations are commonly found above gas reservoirs, geophysical methods would still be candidates for detection of leaks. Research continues to refine the information available on the influence of varying CO_2 saturations on seismic and electrical properties.[229]

The area containing the CO_2 also must be of sufficient size 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.[230] 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

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formations: the Frio experiment. Environmental Geosciences; June 2006; v. 13; no. 2; p. 105-121; DOI: 10.1306/eg.11210505011.

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

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

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

addition to property contrasts. Myer and others[231] 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.[232] Because the porosity of fractures, or a fault, is a small percentage of the total rock volume, the detectable volume of CO_2 would be much smaller than that cited above.

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

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

Finally, all of the methods described above can be deployed in a number of ways, depending on the resolution and spatial coverage needed. For example, seismic data can be obtained in two or 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 wellfield. A pilot test of this technology is underway at the Vacuum Field in New Mexico.[233]

One limitation 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

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

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

[233] 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.

and compressibility of the rock.[234] 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.[235] While it is unlikely that monitoring the saturation of CO_2 will be needed as part of a routine monitoring program, having this capability may be useful for improving understanding of geologic CO_2 storage. Similar limitations may apply to quantifying the rate at which leakage is occurring using geophysical techniques alone.

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

Recent advances in satellite imaging provide new opportunities for using land surface deformation and spectral images to indirectly map migration of CO_2. Ground surface deformation can be measured by satellite and airborne interferometric synthetic aperture radar (InSAR) systems.[236] Tiltmeters placed on the ground surface can measure changes in tilt of a few nano-radians.[237] Taken separately or together, these measurements can be inverted to provide a low-resolution image of subsurface pressure changes. While these technologies are new for monitoring CO_2 storage projects, they have been used in a variety of other applications, including reservoir monitoring and groundwater investigations.[238] Satellite spectral imaging has been used to detect CO_2-induced tree kills from volcanic outgassing at Mammoth Mountain, California.[239] 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.

As indicated by the information in Table 1, there are a number of approaches and options for monitoring emissions from geological storage reservoirs. Today, the most practical and cost-effective approach would rely on a combination of measurements and model predictions to assess annual emissions from the geological storage reservoir. Since the same combination of measurements would not be appropriate for all storage sites, flexibility to tailor the monitoring to the specific geological attributes of the storage site would be beneficial.

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[234] 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.

[235] 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.

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

[237] 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.

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

[239] 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.

Table 1 – Monitoring Approaches

System Component	Monitoring Methods	Benefits	Drawbacks
Storage reservoir	Seismic Gravity Well logs Fluid sampling	History match to calibrate and validate models Early warning of migration from the storage reservoir	Mass balance difficult to monitor Dissolved and mineralized CO_2 difficult to detect
Shallower saline formations below secondary seals	Seismic Pressure Gravity Well logs Fluid sampling	Good sensitivity to small secondary accumulations (~10^3 tonnes) and leakage rates Early warning of leakage	Detection difficult if secondary accumulations do not occur Dissolved and mineralized CO_2 difficult to detect
Onshore			
Groundwater aquifers	Seismic Pressure EM Gravity SP Well logs Fluid sampling	Sensitivity to small secondary accumulations (~10^2-10^3 tonnes) and leakage rates More monitoring methods available Detection of dissolved CO_2 less costly with shallow wells	Detection after significant migration has occurred Detection after potential groundwater impacts have occurred
Vadose zone	Soil gas and vadose zone sampling	CO_2 accumulates in vadose zone making detection easier compared to atmospheric detection Early detection in vadose zone could trigger remediation before large emissions occur	Significant effort for null result (e.g., no CO_2 from storage detected) Detection only after some emissions are imminent Does not provide quantitative information on emission rate
Terrestrial ecosystems	Vegetative stress	Vegetative stress can be readily observed using routine observation Satellite and plane-based methods available for quick reconnaissance	Detection only after emissions have occurred Vegetative stress can be caused by other factors Land use change could alter the baseline Does not provide quantitative information on emission rates May not be useful in some ecosystems (e.g., deserts)

System Component	Monitoring Methods	Benefits	Drawbacks
Atmosphere	Eddy covariance Flux accumulation chamber Optical methods	Good for quantification of emissions	Distinguishing storage emissions from natural ecosystem and industrial sources necessitates comprehensive monitoring May not be best suited for detecting anomalous emissions due to relatively small footprint compared to the size of the plume Significant effort for null result
Offshore			
Water Column	Ship based fluid sampling and analysis Autonomous vehicles with CO_2, pH and carbon cycle sensors	Direct measurement of water column and fluxes (using inverse models)	Distinguishing storage related fluxes from natural variability requires comprehensive monitoring Quantifying separate phase CO_2 flux Significant effort for null result
Atmosphere	Optical methods Eddy covariance	Direct measurement of emission rate	Technology not well developed for this application Quantification of emissions may be impractical Changing emission footprint from ocean currents Likely to be costly to maintain Significant effort for null result

Summary of U.S. EPA Proposed Monitoring Rules

The U.S. EPA (EPA) has two separate but coordinated efforts related to monitoring of carbon capture and sequestration and enhanced oil recovery sites. The Office of Air and Radiation has issued proposed rules for reporting for carbon dioxide injection and geologic sequestration. The Office of Water has a proposed for a new class of wells (Class VI) for permitting injection of carbon dioxide under the Underground Injection Control (UIC) Program of the Safe Drinking Water Act. These two proposed rules serve different purposes. The monitoring plan under the reporting rule must be able to detect and quantify CO_2 any leakage from the subsurface to the surface. The monitoring plan for the UIC program Class VI wells must demonstrate protection of underground sources of drinking water. Other health and safety impacts are not directly addressed under either rule.

Proposed rule for mandatory reporting of greenhouse gases for injection and geologic sequestration of carbon dioxide

Subpart RR of the proposed mandatory reporting of greenhouse gases rule requires facilities that inject CO_2 for the purpose of geologic sequestration or enhanced oil recovery (EOR) to report basic information such as the quantity of CO_2 injected. Facilities that are claiming geologic sequestration will be subject to additional reporting and monitoring requirements including a mass balance estimation of CO_2 sequestered and an EPA approved monitoring, reporting, and verification (MRV) plan.[240] EOR facilities may opt into the more rigorous reporting requirements.

The proposed EPA-approved MRV plan is performance based, reflecting the commonly held belief that the most appropriate monitoring techniques should be selected based on site-specific geology and conditions. The EPA-approved MRV plan would include the following:

1. An assessment of risk of CO_2 leakage to the surface
2. A strategy for detecting and quantifying any CO_2 leakage to the surface
3. A strategy for establishing pre-injection environmental baselines
4. A summary of how the facility will calculate site-specific variables for the mass balance equation, calculating the amount of CO_2 sequestered

The monitoring plan must be found to be able to detect and quantify CO_2 leakage from the subsurface to the surface. The plan will need to prove that the chosen monitoring techniques are suitable for the type of leakage pathways and risks for each pathway.

The proposed regulation is for data collection and monitoring only and does not address impacts from leakage. The first point, assessment of risk, can be satisfied through a UIC Class VI permit, provided it includes surface monitoring and related environmental baseline components.

The overall performance standard for the monitoring plan is to detect and quantify CO_2 leakage from the subsurface to the surface. Each part listed above helps achieve the overall standard. The risk of leakage assessment must include “a combination of site characterization and realistic models that predict the movement of CO_2 over time and locations where emissions might occur.” It must account for the

[240] U.S. EPA’s usage is monitoring, reporting, and verification.

appropriate spatial area, all potential leakage pathways, and include active and abandoned wells. A model overview including sensitivity and uncertainty analysis must be provided. The second part, a strategy for detecting and quantifying CO_2 leakage to the surface must include the methodology, rationale, and frequency of monitoring. Incorporation of unexpected leakage pathways, detection limits, monitoring locations, spatial array, and frequency of monitoring are all components. The plan must outline what measurements will occur if a leak is detected and should be conservative. For example, the facility must assume the duration of the leak to be equal to the time since the last monitoring event. The first part should serve as the basis for the strategy. The third part will set a baseline that will enable the detection and quantification of leakage. The final part will ensure that all above-ground emissions are not counted as stored. Overall, these four requirements ensure that all emissions will be detected and quantified.

Some monitoring is prescribed for both EOR and geologic sequestration sites. All CO_2 injection sites would be required to use flow meters to measure the volume of CO_2 during injection. These meters can be the same as those required under the UIC program.

Proposed Rule Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells

The proposed UIC Rule for CO_2 GS Wells (Class VI) includes a combination of prescriptive and performance-based standards for monitoring. For example, the owner or operator must demonstrate internal and external mechanical integrity of the well. The internal integrity tests require use of continuous "monitoring of injection pressure, flow rate, and injected volumes as well as the annular pressure and fluid volume." The external mechanical integrity test can be done in a variety of ways, but must be one of the mentioned tests, or approved in the permitting process. However, plume and pressure front monitoring requirements are performance based with the operator required to show a monitoring plan to ensure that the injectate is safely confined in the intended subsurface geologic formations and underground sources of drinking water are not endangered. In addition, there are some requirements that pertain to all wells and some that are site-specific.

The monitoring plan "should be designed to detect changes in ground water quality and track the extent of the CO_2 plume and area of elevated pressure." The plan must also show that the site is "operating as intended and is not endangering USDWs."[241] The monitoring requirements cover the types of analysis that must be included (i.e., groundwater quality and geochemical changes above the confining zone), but do not specify the exact testing or location of monitoring. These should be "based on the identification and assessment of potential CO_2 leakage routes complemented by computational modeling of the site."

Overall, the approach combines prescriptive standards with a performance-based standard that the monitoring plan must be able to demonstrate the ability to detect changes in groundwater quality and track the CO_2 plume and pressure front.

[241] Underground sources of drinking water.

21. Appendix R: Overview of the Risks of Geologic CO_2 Storage

California Carbon Capture and Storage Review Panel

TECHNICAL ADVISORY COMMITTEE REPORT

Overview of the Risks of Geologic CO2 Storage

SEPTEMBER 3, 2010

CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL

Other white papers for the panel will include

Monitoring, Verification, and Reporting Overview

AB 32 Regulations and CCS

Long-Term Stewardship and Long-Term Liability in the Sequestration of CO2

Options for Permitting Carbon Capture and Sequestration Projects in California

Carbon Dioxide Pipelines

Approaches to Pore Space Rights

Enhanced Oil Recovery as Carbon Dioxide Sequestration

Review of Saline Formation Storage Potential in California

Public Outreach Considerations for CCS in California

Uses of Carbon Dioxide

Introduction

An understanding of the risks associated with geologic CO_2 storage is fundamental to the development of regulations that ensure protection of workers, the general population, the environment, and natural resources. Although the idea of intentionally storing large quantities of CO_2 in underground geologic formations for extended periods is relatively new, industrial operations, including petroleum exploration and production, enhanced oil recovery using CO_2, underground gas storage, and disposal of acid gas and hazardous wastes, provide many decades of relevant knowledge and experience for determining the risks of geologic storage, as well as the methods and technology to mitigate those risks. Using this knowledge as a basis, many studies have been undertaken over the last decade to determine the specific risks associated with geologic storage. There is a general consensus among the technical community, as evidenced by the *IPCC Special Report Carbon Dioxide Capture and Storage*[242] and many other papers, that through proper site selection, characterization, operation, and closure, geologic storage of CO_2 can be carried out without adverse environmental, health or safety impacts. The relatively small number of projects that have been undertaken to date specifically for purposes of CO_2 storage have thus far confirmed this conclusion.

Storage Project Risks

Geologic storage projects entail the usual risks associated with the construction and operation of large industrial projects. Storage projects will involve laying pipelines and drilling deep wells. Employees and contractors will be working outside in remote locations with large, heavy, equipment. The process of digging trenches for pipelines entails worker safety risks as well as risks to the environment. Similarly, well drilling entails risks to workers from conditions encountered in the subsurface as well as to the environment, due to construction of the drill site. These risks need to be assessed, managed, and mitigated, but will not be discussed further under the assumption that they are well understood in the context of common industrial operations.

For the remainder of the paper, discussion will focus on the risks of storage which derive particularly from the properties of CO_2 and its effect on the environment when injected. CO_2 is non-toxic and nonflammable; we exhale CO_2 when we breathe, and plants uptake CO_2 for photosynthesis. Though high concentrations of CO_2 in the atmosphere are easily dispersed by air currents, if a high concentration is allowed to persist, it can displace breathable air, posing a risk of asphyxiation in humans and animals. High concentrations in the soil will cause stress and can eventually kill vegetation. CO_2 is somewhat soluble in water, which produces the “fizz” in beer, soft drinks, and mineral water. The mild acid formed from this dissolution, however, can corrode steel and dissolve cement and rock. In the subsurface, reactions between the CO_2 in the pore water and the surrounding rock can result in the release of organic and inorganic compounds into the water. Since CO_2 will be transported and injected under elevated pressure, risks accompanying compressed gas transport and injection must be considered.

[242] IPCC, 2005: *IPCC Special Report on Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Many of the risks of geologic storage are associated with the potential for leakage, during pipeline transport or during deep subsurface storage. In order for CO_2 stored in the deep subsurface to have an adverse impact on humans, animals, vegetation, groundwater or other resources, it must reach these locations via a pathway. The primary paths for leakage from a deep reservoir would be improperly installed and/or abandoned wells, and undiscovered geologic discontinuities such as faults. There are two primary driving forces to move CO_2 upward along leak paths. The first is pressure – CO_2 must be injected at a pressure greater than the pressure in the fluids already present in the rock. The second is buoyancy – in most cases CO_2 will be less dense than the fluids already present in the rock, and will therefore try to rise upward. It should be noted that these driving forces do not remain constant over the life cycle of a storage project. After injection stops, fluid pressures in the reservoir will begin to decrease, approaching pre-injection levels. The amount of pressure recovery depends on many factors, including the size of the reservoir, and the hydrologic conditions at the boundaries of the reservoir. Buoyancy forces do not decrease, but the amount of CO_2 subject to buoyancy will decrease, both during the injection phase of a storage project and after injection stops. Over time, several processes, referred to as secondary trapping mechanisms, work to immobilize the CO_2 in the reservoir, including physical (capillary trapping) and chemical (solubility and mineral trapping) processes. After the CO_2 is immobilized, buoyancy forces are no longer a factor.

Wellbores that intersect the storage formation potentially provide a direct, short-circuit leakage pathway between the reservoir, groundwater, any other resources that might be above the reservoir, and the surface. Pre-existing wellbores are considered to present a higher risk for leakage than new wellbores because of uncertainty about their condition. The most vulnerable part of a well with regard to leakage is the annular space outside of the casing. After a well is drilled, a steel tube – the casing – is inserted in the hole and cement is pumped into the annular space between the casing and the rock. If the space is not filled completely, CO_2 could migrate upward, potentially all the way to the surface, but more likely into the well through joints in the casing.

The second major category of potential leak paths is subsurface geologic structural features, of which fractures and faults are considered to represent the greatest risks, although there are other subsurface structural features which can create a pathway for leakage (see Figure 8). Fractures, which are essentially cracks in the rock, could provide leak paths if they are present in the sealing formations overlying the reservoirs intervals where CO_2 is stored. Fractures form as a result of natural tectonic processes, but they can be induced if injection pressures are too high. It is unlikely that a single fracture would extend all the way from the reservoir to the surface, so a leakage pathway involving fractures would likely consist of a network of fractures or fractures in conjunction with some other pathway.

Faults are cracks where the two surfaces forming the crack have experienced relative movement, or slip. Faults can exist at all scales, and can therefore provide potential leak paths that extend from the reservoir to the surface. It is noted, however, that faults can also be effective seals and traps for CO_2 storage.

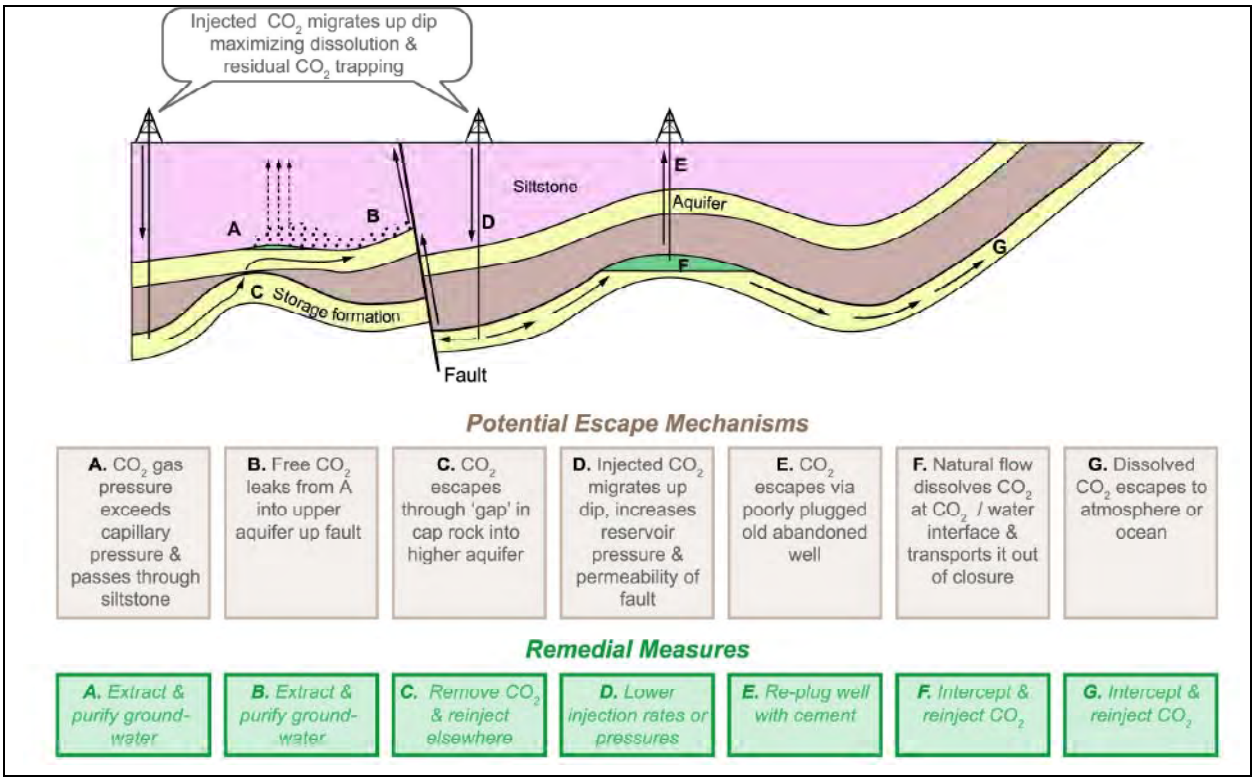

Figure 8. Potential leakage routes and remediation techniques for CO_2 injected into saline formations[243]

Because the CO_2 in pipelines, surface injection facilities, and injection wells will be at high pressure, the risks associated with industrial compressed gas operations must be considered. CO_2 is not flammable, so fire in the event of a sudden release is not a risk; however, a high-velocity (explosive) release of CO_2 could cause damage, injury, or death.

Seismicity induced by injection results from increases in the pressure in the water in the rock, which if high enough, can cause the rock to fracture or cause slip on pre-existing faults and fractures. If the area of slip is large enough, damage from shaking at the surface can result. Public awareness and sensitivity to earthquakes will likely result in special attention being paid to the risks of induced seismicity. The major concern is that CO_2 injection will cause earthquakes that people can feel and that cause some harm. In fact, the number of natural seismic events that are not felt by the public far exceeds the number which are felt, and the same can be said for seismicity induced by subsurface operations. To date, there are no documented instances in which CO_2 injection has induced seismicity that caused harm. Nonetheless, there are a number of well- documented cases to show that subsurface pressure increases, either from direct injection of fluids in the subsurface for waste disposal and geothermal energy development or from impoundment of large volumes of water at the surface in reservoirs, have caused seismicity that people felt, and in some rare instances, caused harm.

[243] Ibid.

When CO_2 is injected, some of it dissolves in the water that is in the rock, however, the injection also causes the pre-existing fluids to become compressed and displaced in order to make room for the CO_2. In saline formation storage, the movement of the displaced saline water can pose a contamination risk to groundwater and other resources, if a pathway connecting the resource to the saline water exists.

Mitigation of Storage Risks

All the risks of geologic storage can be mitigated by careful site selection and characterization, proper injection practices, and careful monitoring during injection operations and after injections stops. Confidence in the ability to mitigate storage risks, and the methods, tools, and approaches derives from many decades of experience in analogous industrial operations, including petroleum exploration and production, enhanced oil recovery using CO_2, underground gas storage, and disposal of acid gas and hazardous wastes. Convincing the public that a sufficient level of risk mitigation can be achieved remains a challenge.

Site Selection and Characterization

Not all locations in the subsurface are good for storage, so careful site selection and characterization of the subsurface geology are key to mitigation of risks. Knowledge of how hydrocarbons have accumulated and remained trapped for millions of years provides a basis for defining the geologic attributes of storage sites that will prevent leakage. The goal of site selection and characterization is to find sites with those same attributes. Geologic attributes mitigating the risk of leakage include the presence of a thick, unfractured, low-permeability seal. The presence of structural closure, required for hydrocarbon accumulation, is not essential for CO_2 storage because of the action of secondary trapping mechanisms. Faults can be good if they form barriers to leakage, bad if they can conduct CO_2 *and* provide a potential pathway out of the storage reservoir.

Available technologies that can provide the information needed for site selection and characterization include geologic mapping, seismic surveying supported by other geophysical technologies, and wells, both historical and drilled for purpose. It is impossible, however, to interrogate the subsurface at a sufficient level of detail to remove absolutely all uncertainty about properties and structure—hence the need for monitoring.

A part of site selection and characterization in California should be to establish the natural seismicity in the area of a potential site and to assess the change, if any, in seismicity due to the project. This involves both identifying existing faults and evaluating the potential for damaging shaking that might result from an earthquake. Probabilistic seismic hazard analysis (PSHA), the methodology most commonly employed in California to do this, forms the framework for an approach to evaluate the change in seismic hazard, if any, due to a CO_2 storage project.

Construction and Operating Practices

Proper construction of transport and injection facilities will mitigate many geologic storage risks. For pipeline transport, the development of pipeline complex to deliver CO_2 to the Permian Basin, Texas, CO_2-EOR operations in the 1970s motivated the promulgation of best practices and regulations. The most significant risk associated with pipeline transport is leakage, and a variety of methods are in place to

mitigate this risk. The recently completed Dakota Gasification Company pipeline has a capacity of 5 million tons a year and carries CO_2 that also contains 0.8%–2% H_2S. Any pressure drop resulting from a significant leak activates block valves, which are situated along the length of the pipeline and therefore limit the volume of the leak. The entire pipeline and compression operations are monitored by telemetry.[244] The pipeline has also been designed for internal inspection by devices to detect corrosion or other defects.

Proper well construction will be essential in mitigating leaks. Decades of experience in commercial CO_2-EOR operations provide a substantial knowledge base of construction methods and technologies, though questions remain about the need for more conservative approaches, as proposed in the EPA Class VI rules, for storage wells. Some key technical issues are associated with the specifications for the casing and the cement used to fill the annular space behind the casing. Discussions continue about whether to use corrosion resistant steels and cement and to fill the annular space from top of the well to the bottom.

Monitoring

Some uncertainty about subsurface conditions and properties will always remain at the end of the characterization phase. Likely sources of uncertainty relevant to storage risks are the potential presence of fractures in the seal, hydrologic properties of faults, in-situ stress state, and hydrologic boundary conditions. There will also be uncertainty in predictions of the area occupied by the CO_2 and the pressure increases caused by injection. A monitoring program provides two types of data that are important to risk mitigation. First, measurements provide direct evidence when something goes wrong—a leak, for example. Since leaks to the surface due to faults or fractures or other geologic pathways are not expected to happen suddenly, early detection also mitigates the risk of serious impacts. The second use of monitoring data is to reduce uncertainty in the geologic model, and increase confidence in predictions of pressures and CO_2 movement, both of which reduce risks.

Many of the measurement technologies for monitoring geologic storage are drawn from other applications such as the oil and gas industry, natural gas storage, disposal of liquid and hazardous waste in deep geologic formations, groundwater monitoring, safety procedures for industries handling CO_2, and ecosystem research. These established practices provide numerous measurement approaches and options—a monitoring toolbox—which enables development of tailored, flexible monitoring programs for geologic storage. The reader is referred to another paper prepared for the California Carbon Capture and Storage Review Panel on measurement, verification, and reporting, for further discussion of monitoring methods and techniques.

Role of Risk Assessment and Risk Management

Risk assessment and risk management are two key elements of risk mitigation and should be part of all projects. Fundamental to risk assessment is a process that identifies risks and rates each risk on the likelihood that an event will happen and the severity of that event should it occur. Each risk is then scored based on the two ratings. The outcome of the assessment is an overall ranking of the risks. In the process

[244] Duncan, I. J., Nicot, J.-P., and Choi, J.-W., 2009, *Risk Assessment for future CO_2 Sequestration Projects Based CO_2 Enhanced Oil Recovery* in the U.S., Proceedings of the 9th Greenhouse Gas Technology Conference, ScienceDirect, Elsevier Ltd., Energy Procedia, pp. 2037–2042.

of risk management, specific project-related actions are identified to mitigate the risks. The process is not static, but evolves over time as new information and confidence is gained about the subsurface.

The need for risk assessment and management is not unique to geologic storage. Over the past ten years, considerable effort has been devoted to tailoring and adapting risk assessment approaches to geologic storage. As a result, there are now commercially available "packages" specifically for geologic storage, although development of risk assessment tools remains an active area of research.

Industrial- and CCS-Specific Experience

What is defined as a significant risk involves an assessment of both the likelihood and severity of an event, however these parameters are difficult to define from a strictly theoretical basis. Case history experience and data is extremely valuable in helping to identify the types of events that are most likely to occur, as well as the impacts of those events. Case history data provide a basis for developing mitigation approaches and technologies to further reduce risks in the future.

Natural gas storage reservoirs are, in many ways, analogous to CO_2 storage projects. A 2005 study[245] found that of the approximately 600 natural gas storage projects operated in the United States, Canada, and Europe, only nine were identified as having experienced leakage: three from caprock issues, five from well bore integrity issues, and one from poor site selection (too shallow). Well integrity issues accounted for most leakage incidents with poor cement jobs, corrosion, and improperly plugged old wells as specific causes.

Recent studies of oil and gas field experience also point to well integrity issues as primary causes for leakage. A study of oil and gas wells in Alberta, Canada,[246] found an overall leakage occurrence rate of about 4.5%, where leakage flow had been identified as from either the formation through the cement behind casing into the well, or from flow outside the casing to surface. A study of CO_2-EOR experience in the Permian Basin, Texas,[247] found that a major cause of wellbore leakage was failure of mechanical components in the injection equipment and loss of control during "work-over", or well maintenance operations.

To date, there have been a relatively small number of projects worldwide dedicated to demonstration of CO_2 storage. All of these projects, however, have been subject to the same risks identified in the beginning of this paper, and none have experienced any adverse impacts. These projects provide several lessons learned relevant to risk mitigation.

Statoil's Sleipner project is the world's first commercial CO_2 storage project. Located offshore in the North Sea, it has been injecting about a million tons of CO_2 per year since 1999. The CO_2 is produced along with natural gas from a deep reservoir. It is removed from the natural gas in offshore facilities and re-injected in a saline formation located about 3000 ft beneath the seafloor. The project is notable because

[245] Perry, K., 2005, "Natural gas storage industry experience and technology: potential application to CO_2 geological storage," Chapter 9 in: *Carbon dioxide capture for storage in deep geologic formations: results from the CO_2 capture project*, Volume II, S. Benson and D. Thomas, eds, Elsevier Science, London.
[246] Watson, T., and S. Bachu, 2009, "Evaluation of the potential for gas and CO_2 leakage along wellbores," SPE 106817, presented at the E&P Environmental and Safety Conference, Galveston, TX.
[247] Duncan, I.J., op. cit.

of the successful application of 3D time-lapse seismic surveying as a monitoring tool. The seismic measurements, repeated about every 2 years, have shown the vertical and lateral spread of the CO_2 and have confirmed that the reservoir is not leaking.

The In Salah project, onshore in Algeria, is another commercial storage project in which CO_2 is produced along with natural gas, removed, and re-injected into a saline formation. About 800,000 to 1 million tons per year are injected. This project has an interesting case history because a small amount of leakage occurred from a suspended (not used) appraisal (exploration) well with the designation of KB5. The small amount of leakage was not measured, but was estimated by the operators to be less than 1 metric ton. Due to the extremely remote desert location, there is no vegetation, residents, or wildlife to be adversely impacted by a leak of any size in the vicinity of the well.

KB5 was drilled by Total in 1980. When Total relinquished their hydrocarbon lease, ownership of the well reverted to the state. When the In Salah Gas Joint Venture (BP, Sonatrach, Statoil), referred to as the In Salah JV, was formed, ownership of KB5 (and other legacy wells) remained with the state. Under Algerian hydrocarbon regulations, suspended wells should be decommissioned within two years.

The KB5 well intersected the Carboniferous formation, which was the same formation into which CO_2 would be injected. It was not plugged with cement in the Carboniferous, because, at the time it was drilled, it was a hydrocarbon exploration well, and cementing was not required if hydrocarbons were not found.

Using available data, during the design phase of the JV project in 2001, reservoir simulations indicated that CO_2 would not migrate very far in the direction of KB5. After injection started and monitoring data became available, additional simulations, coupled with satellite observations of surface deformation in 2006 and 2007 suggested that CO_2 was migrating quickly in the direction of KB5. Based on this information, a close inspection of the well was carried out during a routine surveillance visit. (The well is located in an insecure area and military escort is required for site visits.) The presence of CO_2 was detected by a leak through a missing flange. Ideally, presence of CO_2 in the well would have been detected by pressure on a gauge without any leak, but both the flange and the gauge had been stolen.

Though it is unfortunate that a leak occurred at all, this case history illustrates the value and use of surveillance and monitoring data to mitigate risk.

Induced seismicity was introduced as a risk in the initial section of this paper. Monitoring for seismicity has taken place at the Weyburn project in Canada and the Otway project in Australia. The intent of collecting the data on seismicity was to help monitor the movement of the CO_2 in the reservoir. No seismicity of sufficient amplitude to be felt at the surface was expected and none was observed.

Summary

CO_2 storage projects entail the usual risks associated with the construction and operation of an industrial project. The primary concern regarding storage is leakage, which could result in groundwater contamination, localized damage in the soil layer, significant release to the atmosphere, or health hazards. The pathways for leakage potentially include the handling of CO_2 en route to the injection site, issues with well integrity, and migration through faults or fracturing of the seal. An additional concern is

induced seismicity. All the risks of geologic storage can be mitigated by careful site selection and characterization, proper injection practices, and monitoring during injection operations and after injections stops. Confidence in the ability to mitigate storage risks and in the methods, tools, and approaches for doing so derive from many decades of experience in analogous industrial operations. The relatively few projects that have been undertaken to date specifically for purposes of CO_2 storage have been carried out without adverse impacts.

22. Appendix S: Establishing Eminent Domain Authority for Carbon Storage in California

TO: JOHN KING
CC: CALIFORNIA CARBON CAPTURE AND STORAGE REVIEW PANEL
FROM: JERRY FISH AND SARAH JOHNSON PHILLIPS

RE: Establishing Eminent Domain Authority for Carbon Storage in California

The following memorandum briefly describes I) how California grants condemnation authority to independent gas storage facility operators, II) considerations for adapting the gas storage model for carbon storage associated with carbon capture and sequestration ("CCS"), and III) sample amendments that would extend condemnation authority to carbon sequestration facility operators following the natural gas storage model.

I) The Natural Gas Storage Model:

In the early 1990s, the California Public Utilities Commission (the "CPUC" or the "Commission") adopted a "let the market decide" policy for construction or expansion of natural gas storage facilities.[248] The proceeding was prompted by the passage of AB 2744, in which the legislature urged the Commission to unbundle utility storage service, encourage development of independent storage facilities, and adopt market-based storage rates.[249] As part of the gas storage policy, the CPUC can certify independent gas storage developers as public utilities and grant them the eminent domain authority that accompanies that status. However, as providers of a "competitive service," independent gas storage developers must obtain additional approval from the Commission each time they seek to condemn property.[250]

California law grants eminent domain authority to public utilities.[251] The term "public utility" includes every common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer corporation, and heat

[248] In the Matter Of The Application of SOUTHERN CALIFORNIA GAS Company (U 904 G) For Authority To Revise Its Rates And Recover Costs For Implementation Of Its Customer Storage Program, Decision No. 93-02-013, 1993 Cal. PUC LEXIS 66, California Public Utilities Commission, February 3, 1993 (the "Storage Decision").
[249] Assembly Bill (AB) 2744, Chapter 1337 of the California Statutes of 1992
[250] The additional procedures of Pub. Util. Code §625 are required for condemnation of property necessary for providing "competitive" services and not for condemnation of property sole necessary for providing traditional utility services (i.e., "commission-ordered obligations"). Pub. Util. Code §625(a)(1)(B).
[251] There are two general constitutional restraints on the exercise of eminent domain: the taking must be for a "public use" and "just compensation" must be paid. "Public use" has been defined broadly by California courts as "a use which concerns the whole community or promotes the general interest in its relation to any legitimate object of government." See City of Oakland v. Oakland Raiders, 32 Cal. 3d 60, 64 (1982). Further, the California legislature has provided that any use for which statutes allow eminent domain to be exercised constitutes a legislative declaration that such use is a public use. CAL. CODE CIV. PRO. § 1240.010.

corporation, where the service is performed for, or the commodity is delivered to, the public or any portion thereof. Pub. Util. Code § 216(a).

Eminent domain authority for natural gas storage comes from Pub. Util. Code § 613, which gives gas corporations authority to "condemn any property necessary for the construction or maintenance of its gas plant." A "gas plant" includes "all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas, natural or manufactured, except propane, for light, heat, or power." Pub. Util. Code § 221 (emphasis added).[252]

The Commissions has issued Certificates of Public Convenience and Necessity ("CPCNs") for the construction and expansions of three independent gas storage facilities in California:

- Wild Goose Storage, Inc. ("Wild Goose") in 1997 and 2002.
- Lodi Gas Storage, L.L.C. ("LGS") in 2000, 2006, and 2008.
- Gill Ranch Storage Project ("Gill Ranch") in 2009.

As a result of approving the CPCNs for these projects, the CPUC also certified each of these entities as a public utility with respect to its gas storage project. As public utilities, they have eminent domain authority pursuant to Pub. Util. Code § 613. But, because they offer competitive services they must comply with Pub. Util. Code § 625 before exercising their eminent domain authority, which provides:

> a public utility that offers competitive services may not condemn any property for the purpose of competing with another entity in the offering of those competitive services, unless the commission finds that such an action would serve the public interest, pursuant to a petition or complaint filed by the public utility, personal notice of which has been served on the owners of the property to be condemned, and an adjudication hearing … including an opportunity for the public to participate.

Pub. Util. Code §625 (a)(1)(A). That means each time an independent gas storage project developer wishes to condemn property for its project, it must file a petition or compliant and the CPUC must determine that the request is in the public interest after a public hearing. Before making such a finding, the CPUC must conduct a hearing in the local jurisdiction that would be affected by the proposed condemnation. Pub. Util. Code § 625(a)(2)(A).

In order to find that the proposed condemnation is in the public interest, Pub. Util. Code § 625(b)(2) requires the independent gas storage project to show the following:

- The public interest and necessity require the proposed project;
- The property to be condemned is necessary for the proposed project;
- The public benefit of acquiring the property by eminent domain outweighs the hardship to the owners of the property; and

[252] In addition to the requirements set for the in the Public Utilities Code, a public utility exercising its condemnation authority must comply with the requirements of Title 7 of Part 3 of Code of Civil Procedure.

- The proposed project is located in a manner most compatible with the greatest public good and least private injury.

II) Considerations for Adapting the Gas Storage for Carbon Storage

- **New Legislation Required:** New legislation would be required to establish condemnation authority for independent CCS developers. Adapting the gas storage model for this purpose would involve the following:

    - **Public Utility Status and Regulatory Process.** Following the gas model, the CCS project operator would have to be certified as a public utility with respect to the carbon storage project. For independent natural gas operators, this occurs with approval of a CPCN. New legislation would have to contemplate the broader regulatory structure for CCS projects and determine the appropriate point in the regulatory process to confer condemnation authority and the appropriate entity on which to confer the authority.

    - **Definitions.** Types of entities that have condemnation authority as public utilities are specifically defined in the Public Utilities Code and their condemnation authority is limited to certain facilities. For example, a "gas corporation" can condemn property necessary for construction and maintenance of its "gas plant" and an "electrical corporation" may condemn any property necessary for the construction and maintenance of its "electric plant." Adapting this model for CCS would require new categories and definitions for CCS entities and CCS facilities.

    - **Extra proceedings for "competitive services."** As described above, independent natural gas storage operators are not given condemnation authority outright. As providers of a "competitive service," they must seek CPUC approval each time they wish to condemn property. A CCS project developer would very likely also be considered a provider of a competitive service and thus be subject to the same limitations.

- **Which Agency?** As with other aspects of CCS, one of the more complicated issues in establishing condemnation authority is determining which California regulatory agency should take the lead. Under current law, the CPUC has power to grant condemnation authority for gas storage and other energy and utility-related projects. However, the California Carbon Capture and Storage Review Panel is considering recommending that the California Energy Commission (the "CEC") be the lead agency for CCS permitting and regulation. But unlike the CPUC, the CEC does not have the power to grant condemnation authority under current law. Establishing parallel power in the CEC for carbon storage would require additional statutory language compared to expanding the CPUC's existing power to confer condemnation authority.

III) Example Language for New Legislation

The legislative language suggested below includes most of what would be necessary to amend the Public Utilities Code to provide independent carbon sequestration project operators with condemnation authority similar to that now held by independent natural gas storage operators.[253]

- Amend the definition of "public utility" as follows:

  Pub Util. Code § 216:

  (a) "Public utility" includes every common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, and carbon sequestration corporation, where the service is performed for, or the commodity is delivered to, the public or any portion thereof.

  (b) Whenever any common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, or heat corporation, or carbon sequestration corporation performs a service for, or delivers a commodity to, the public or any portion thereof for which any compensation or payment whatsoever is received, that common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, or heat corporation, is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part.

- Insert new definitions into Pub. Util. Code Chapter 1, General Provisions and Definitions, such as

  "Carbon sequestration corporation" includes every corporation or person owning, controlling, operating, or managing any carbon sequestration facility for compensation within this state."

  "Carbon sequestration facility" means a facility that receives and permanently stores or sequesters carbon dioxide in a geologic formation, including all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the transmission, delivery, or underground storage carbon dioxide for the purpose of geologic sequestration. A carbon sequestration facility includes any pipelines necessary for transmission and delivery of carbon dioxide. A carbon sequestration facility also includes an

[253] Note that the relatively simple amendments suggested here would expand the CPUC's existing authority. Establishing authority for the California Energy Commission would require a more comprehensive effort to amend the Public Resources Code, such as a new chapter for regulation of carbon sequestration in Division 15, Energy Conservation and Development (which governs the California Energy Commission).

enhanced hydrocarbon recovery operation if [it meets certain regulatory requirements to be determined…]"[254]

- Add additional grant of eminent domain authority under the Public Utilities Act, Chapter 3, Article 7, Eminent Domain:

  "A carbon sequestration corporation may condemn any property necessary for construction and maintain of a carbon sequestration facility."

[254] Note this definition should be made compatible with the terminology and structure of other regulatory programs established for carbon sequestration in California.