WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP
westcarb.org

Regional Technology Implementation Plan: Carbon Capture, Utilization, and Storage in the WESTCARB Region

STATUS ASSESSMENT – TOPICAL REPORT

October 2005 – May 2011

Marian Stone, Richard Myhre, and Elizabeth A. Burton

December 2012
DOE Contract No.: DE-FC26-05NT42593

California Energy Commission
1516 Ninth Street, Sacramento, CA 95814

Acknowledgments

The authors wish to thank the 2010 WESTCARB Annual Business Meeting workshop participants for their input.

Reviewers

Katie Goslee,
Carbon Specialist, Ecosystem Services
Winrock International

Dr. Niall Mateer
WESTCARB Operations Director
California Institute for Energy and Environment
University of California

Dr. Sarah Pittiglio
Energy Commission Specialist II
California Energy Commission

Please cite this work as follows:

Stone, Marian, Richard Myhre, and Elizabeth A. Burton, *Regional Technology Implementation Plan: Carbon Capture, Utilization, and Storage in the WESTCARB Region – Status Assessment*, December 2012.

ABSTRACT

Established in 2003, WESTCARB is one of seven research partnerships co-funded by the U.S. Department of Energy to characterize regional opportunities for carbon capture, utilization, and storage and to conduct technology validation projects. Led by the California Energy Commission, WESTCARB has grown to over 90 public agencies, private companies, and noprofits. The Parntership comprises Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington, and the province of British Columbia.

This report represents the 2012 view of a Regional Technology Implementation Plan (RTIP) for carbon capture and storage (CCS) technologies in the WESTCARB region. It assesses the region's opportunities for geologic and terrestrial carbon storage and examines the requisite factors for successful deployment.

Most of the WESTCARB region has substantial geologic storage potential, and studies indicate generally favorable distances between large stationary CO_2 sources and geologic sinks. Critical factors to enabling deployment lie in the policy, economic, and social realms. Three significant challenges are noted: (1) lack of climate change legislation to serve as a driver, or lack of a clear pathway for CCS where climate change legislation exists, (2) the current high cost of deployment, and (3) lack of public understanding or acceptance, which can negatively affect project siting.

The increased emphasis on using CO_2 for enhanced oil recovery represents a practical strategy for advancing CO_2 geologic storage in conjunction with a well-established industry practice that provides economic benefits. The development of other beneficial use technologies to achieve CO_2 storage (or reduced emissions) and saleable products represents similar opportunities. Nonetheless, multiple analyses of greenhouse gas mitigation pathways emphasize that geologic storage to accommodate larger volumes of CO_2 will be needed to meet the emissions reductions envisioned for the post-2020 timeframe.

Opportunities for terrestrial carbon storage can be found in large areas of the WESTCARB region and may contribute to improved resource management and habitat health, as well as providing economic and recreational benefits. The RTIP discusses four challenges to widespread terrestrial storage project development: (1) limitations on support due to lack of climate change legislation or structure of policy instruments, (2) the need for rigorous yet flexible standards to ensure the quality of carbon offsets, (3) limits on application due to competition from other land uses, and (4) the need to incorporate climate change adaptation into project planning.

The inclusion of forestry offsets in California's AB 32 cap-and-trade program represents a source of funding for terrestrial carbon storage projects and may prove beneficial to supporting broader deployment within the state, as well as in jurisidictions that become linked for trading.

ACRONYMS AND ABBREVIATIONS

ACR – American Carbon Registry

AEP – American Electric Power

ALWR – advanced light water reactors

AZGS – Arizona Geological Survey

BLM – Bureau of Land Management

CAA – Clean Air Act

CAR – Climate Action Reserve

CARB – California Air Resources Board

CEQA – California Environmental Quality Act

CCS – carbon capture and storage

CCX – Chicago Climate Exchange

CDM – Clean Development Mechanism

CPUC – California Public Utilities Commission

CT – conservation tillage

DOE – U.S. Department of Energy

ECBM – enhanced coal bed methane recovery

EOR – enhanced oil recovery

EPA – U.S. Environmental Protection Agency

EPRI – The Electric Power Research Institute

EPS – emissions performance standard

EU-ETS – European Union Emissions Trading Scheme

FERC – Federal Energy Regulatory Commission

GAO – Government Accounting Office

GHG – greenhouse gas

HECA – Hydrogen Energy California

IGCC – integrated gasification combined cycle

LCFS – low carbon fuel standard

LCOE – leveleized cost of electricity

MBF – thousand board feet

MRV – monitoring, reporting, and verification

MTR – Membrane Technology and Research, Inc.

MW – megawatt

MWh – megawatt hour

NEORI – The National Enhanced Oil Recovery Initiative

NGCC – natural gas combined cycle

NGO – non-governmental organization

NPDES – National Pollution Discharge Elimination System

PC – pulverized coal

PCOR – Plains CO_2 Reduction Partnership

RCSPs – Regional Carbon Sequestration Partnerships

REDD – Reducing Emissions from Deforestation and Forest Degradation

RGGI – Regional Greenhouse Gas Initiative

USDW – underground source of drinking water

VCS – Verified Carbon Standard

WCI – Western Climate Initiative

WESTCARB – West Coast Regional Carbon Sequestration Partnership

CONTENTS

Executive Summary 1
Carbon Capture and Geologic Storage 2
Carbon Utilization 3
Terrestrial Carbon Storage 4
Deploying Carbon Capture, Utilization, and Geologic Storage in the WESTCARB Region 7
Geologic Carbon Storage Resource Is Substantial 7
Saline Formations – The Region's Largest Storage Resource 8
Opportunities in Oil and Natural Gas Fields in Alaska and California 16
Coal Bed Storage and Methane Recovery Possible in the Pacific Northwest and Alaska 19
Researching Basalt Storage in Washington and Hawaii 20
Assessing Industrial Sources of CO_2 Emissions 21
Major Industrial CO_2 Sources Are Generally Well Matched To Sinks 22
Changes in Source Composition and Location in the Coming Years 25
Elements for Successful Commercial Deployment of CCS 26
Policy Drivers and Regulatory Development 26
U.S. Federal Climate Change Drivers 26
Canada's New Emissions Performance Standard 27
CCS State/Provincial Drivers 28
Carbon Market Evolution and Coordination 34
Technology Infrastructure 35
Capturing CO_2 35
CO_2 Pipeline Transport, Safety, and Siting 43
CO_2 Injection 45
Economics 52
Timeframes for Technology Development to Reduce Costs 53
Current and Anticipated Costs of CCS Projects 54
The Importance of Developing Multiple Technologies 55
High-Purity Sources Offer Lower-Cost Opportunities for CCS 56
Offsetting CCS Costs 57
Project Finance 60
Project Insurance Coverage 60
Models for Long-Term Liability Coverage 61
Legal Considerations for CCS Projects 62
Pore Space Ownership and Mechanisms for Acquiring Pore Space Rights 62

Pipeline Rights-of-Way Acquisition Authority 63
Public Understanding and Acceptance 64
Deploying Terrestrial Carbon Storage in the WESTCARB Region 66
Estimating Terrestrial Carbon Storage Potential 67
Afforestation/Reforestation 69
Statewide Capacity Estimates 69
Shasta County Reforestation Pilot Tests 70
Hybrid Poplars 72
Forest Conservation Management 73
Statewide Capacity Estimates for Lengthening Timber Harvest and Widening Riparian Buffers 73
Testing Forest Conservation Management in California 75
Forest Fuels Reduction 77
Avoided Forestland Conversion 79
Forests in Climate Change Policy Development 80
Reducing GHG Emissions in the Agricultural Sector 82
Wetlands as Carbon Sinks 84
Biochar 85
Project Financing and Support Mechanisms 85
Reducing Project Costs Through Aggregation 86
Funding Terrestrial Carbon Storage Through Allowance Auctions 87
The Climate Trust Funding Model 87
Terrestrial Carbon Storage Projects in Carbon Markets 88
Criteria for Qualifying Offsets 88
Additionality 89
Permanence – Guarding Against Reversals 90
Leakage 91
Enforceability 91
Voluntary Carbon Markets 92
Terrestrial Carbon Sequestration Under the California Cap-and-Trade Program 92
Expanding the Role of Terrestrial Storage Projects 94
Balancing Terrestrial Carbon Storage with Other Land Uses and Values 94
Adapting Terrestrial Carbon Storage During Climate Change 95
Knowledge and Infrastructure Needs 96

FIGURES

Figure 1. Locations of saline formations for Alaska, Arizona, California, Oregon, Nevada, and Washington 9

Figure 2. Estimated CO_2 storage resource for the largest onshore basins in Oregon (left) and Washington (right) 10

Figure 3. Geologic cross-section from Colorado River, through Black Mesa to Canyon de Chelly 11

Figure 4. Arizona's Cenozoic basins for which volume calculations have been completed 12

Figure 5. Estimated CO_2 storage resource for California's ten largest onshore basins 13

Figure 6. Geologic cross-section of the southern Sacramento Basin showing sandstones (yellow) and shales (purple) 14

Figure 7. Stratigraphic column of the Citizen Green well in the Sacramento Basin, California 15

Figure 8. Locations of major oil and gas fields in Alaska and California 18

Figure 9. Coal basins in the WESTCARB region 20

Figure 10. Emissions from large point sources in the WESTCARB region by state/province and type, as of 2012 21

Figure 11. Locations of major stationary CO_2 sources in relation to saline formations 22

Figure 12. Location of operational and planned NGCC plants in California in relation to potential CO_2 storage sinks 24

Figure 13. Schematic of oxy-combustion process for pulverized coal 39

Figure 14. Map showing location of major CO_2 pipelines for EOR in the United States 44

Figure 15. Static geomodel for the formations underlying the Kimberlina Power Plant in the San Joaquin Valley, California 48

Figure 16. Aerial view of a WESTCARB study site in northern California 51

Figure 17. EPRI analyses showing CO_2 reductions for U.S. electric sector with a full and limited portfolio of technologies 53

Figure 18. A 2010 meeting on CCS in California hosted by WESTCARB and partners 65

Figure 19. Total estimated storage (metric tons carbon, tC) through afforestation after 40 years 69

Figure 20. Carbon storage potential with hybrid poplars in Oregon and Washington without irrigation... 73

Figure 21. Baseline and project activity carbon stocks, both with and without wood products pool stocks, over the 100-year project lifetime on a per acre basis 76

TABLES

Table 1. Comparison of point source CO_2 emissions with total storage resource 23

Table 2. Status of GHG emissions reduction legislation in the WESTCARB region 28

Table 3. IGCC projects with CO_2 capture in the United States 41

Table 4. Representative cost and performance of fossil-fuel generation technologies for 2015 without CCS, and for 2025 with CCS 55

Table 5. Terrestrial carbon storage capacity estimates for rangelands and croplands in Oregon and Washington 70

Table 6. Potential for carbon accumulation in Arizona's prime riparian areas 74

EXECUTIVE SUMMARY

Studies of greenhouse gas (GHG) mitigation have identified carbon capture and storage (CCS) as critical to meeting emissions reductions in the United States and internationally. For timeframes from 2030 to 2050, deployment of CCS technologies is expected to be one of the largest contributors to CO_2 emissions reductions.[1,2]

This report represents the status assessment phase in developing a Regional Technology Implementation Plan (RTIP) for CCS in the WESTCARB region, nominally seven U.S. states (Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington) and the Canadian province of British Columbia.

The report examines factors for successful CCS deployment, as well as issues that could limit or delay application of CCS technologies and solutions for overcoming these issues. It aims to inform discussions among parties concerned with lowering the region's GHG emissions—state and provincial policymakers, public interest nonprofits, regulated industries, and project developers—who recognize the need to include CCS among the solutions that will enable the region to meet climate change mitigation goals. The report provides a framework for subsequent RTIP development for the WESTCARB region.

The RTIP covers three types of CCS:

- Carbon capture and geologic storage:
  CO_2 from stationary industrial sources such as power plants, oil refineries, cement plants, and ethanol/biofuels plants is separated from fuel or exhaust gases and transported to a storage site for injection into deep underground rock formations.

- Carbon utilization/beneficial use:
  Revenue-generating uses for captured CO_2 that either store the CO_2 (e.g., enhanced oil or natural gas recovery, enhanced geothermal energy systems, biochar) or use CO_2 to displace more potent greenhouse gases (e.g., chemical production, biofuels, fuels from biochar production).

- Terrestrial carbon storage:
  Optimizing the long-term incorporation of CO_2 into biomass, including the earth's natural absorption of CO_2, and retention of carbon in biomass and soil to increase the amount of carbon stored (e.g., tree planting and changes in forest management) or to preserve previously stored carbon (e.g., forest conservation).

Terrestrial carbon storage, carbon capture and geologic storage, and carbon utilization have the potential to significantly reduce GHG emissions in the WESTCARB region. The degree to which these climate change mitigation practices will contribute to a low-carbon future depends largely on the successful

[1] *Advanced Coal Power Systems with CO_2 Capture: EPRI's CoalFleet for Tomorrow Vision—2011 Update: A Summary of Technology Status and Research, Development and Demonstrations.* EPRI, Palo Alto, CA: 2011 1023468.
[2] "Executive Summary,"*Energy Technology Perspectives 2012: Pathways to a Clean Energy System*, International Energy Agency, 2012. (http://www.iea.org/Textbase/npsum/ETP2012SUM.pdf)

resolution of multiple technical challenges, the development of enabling policy mechanisms and economic drivers, and public acceptance.

Carbon Capture and Geologic Storage

The RTIP examines issues for carbon capture and geologic storage in six areas: policy and regulatory development, technology infrastructure, economics, project finance, legal considerations, and public understanding and acceptance. The report concludes that geologic storage does not face significant barriers in the western region in terms of overall available storage space or the technical feasibility of injecting and monitoring CO_2 in the subsurface.

Estimated storage potential in the region's broadly distributed sedimentary basins is enough to hold hundreds of years of CO_2 emissions from industrial sources. Opportunities for long-term CO_2 storage combined with enhanced oil recovery have been identified in southern California and Alaska. CO_2 storage in coal seams, along with enhanced coal bed methane production, may prove beneficial in Alaska, Oregon, and Washington. Studies matching industrial CO_2 sources to potential storage locations indicate generally moderate distances for pipeline transport between the two.

The technical aspects of injecting and monitoring CO_2 are unlikely to present a regional barrier. Both nationally and internationally, experience in oil and natural gas production and storage, the use CO_2 for enhanced oil recovery, and the success of early CO_2 storage projects lend confidence that CO_2 can be safely injected and monitored for long-term storage security.

Carbon capture and geologic storage faces three significant challenges, which are not unique to the western region.

1. **Lack of climate change legislation to serve as a driver, or lack of clear pathways for CCS where climate change legislation exists**

In the United States, anticipation of national climate change legislation has served as a driver for developing CCS technologies. In the continuing absence of such legislation, the impetus for lowering GHG emissions is coming from rulemaking by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act and from legislation enacted by some states. Similarly, Canada has had limited federal legislation and varying provincial initiatives. This approach generally fails to provide the comprehensive legislative/regulatory certainty desired by affected industries when undertaking long-term planning and financial investments.

In the WESTCARB region, British Columbia, California, Hawaii, Oregon, and Washington have enacted legislation setting GHG reduction targets. Alaska, Arizona, and Nevada have not done so. British Columbia, Arizona, California, Oregon, and Washington are participants in the Western Climate Initiative, which is seeking to design a regional GHG cap-and-trade program. Thus far, only California (along with Quebec) has developed cap-and-trade regulations, with implementation to start in 2013.

However, CCS has yet to be effectively integrated into the California's GHG compliance framework. This is due, in part, to a shorter-term focus on the state's 2020 goal of reducing emissions to 1990 levels, for which CCS technologies are not viewed as critical. If adoption of the 2050 GHG emissions reduction goal of 80% below 1990 levels is enacted, achieving this second target without substantial deployment of CCS is unlikely.[3] But the impetus for undertaking a long-term CCS project with high capital investment is largely missing until the 2050 target is codified into law.

2. Costs

The current costs of CO_2 capture and compression are relatively high, and the costs for CO_2 transportation and geologic storage are highly site-specific. It is anticipated that costs will decrease as CCS technologies—particularly for CO_2 capture and compression—evolve to realize decreased parasitic energy losses. Ideally, CCS technologies will reach this stage of maturity before regulations compel widespread deployment. Under this scenario, the economic impact of achieving GHG emissions reductions would be significantly less.

3. Public awareness and understanding

Geologic CO_2 storage can be misunderstood in public discourse. CO_2 is sometimes mistaken for a toxic or explosive substance, and the risk profile for CO_2 storage can be confused with pressurized pipelines at the surface or natural CO_2 releases associated with volcanic activity. Although outreach and education can correct misperceptions, this takes time and resources, and depends upon the willingness of audiences to participate in the process.

CCS projects tend to be better understood in communities where oil and gas production or natural gas storage are common or where local educational institutions contribute to an understanding of subsurface operations. Public acceptance is generally greater where project developers have an established community presence and are trusted, or where benefits such as jobs creation or retention are aligned with community interests. Nonetheless, good geology for CO_2 storage will not always exist under or near communities interested in hosting CCS projects, and this could affect siting.

Carbon Utilization

There are compelling economic benefits to be gained from coupling CO_2 injection for enhanced oil recovery (EOR) with long-term CO_2 storage. In the WESTCARB region, deployment of geologic storage as part of CO_2-EOR is possible in the oil producing regions of California and Alaska. In California, sufficient volumes of affordable CO_2 relative to the price of oil are not available locally, and CO_2 pipeline transport from outside the state has not been economic. Thus, CO_2-EOR awaits the development of local CO_2 supplies via capture at industrial facilities and power plants and development of an in-state pipeline infrastructure. In Alaska, there are potential opportunities for CO_2-EOR on the North Slope if natural gas fields containing CO_2 are developed (at large scale, this would require construction of a proposed natural gas delivery pipeline). In oil fields near Anchorage, CO_2 supplies may come from anthropogenic sources.

[3] *California's Energy Future – The View to 2050: Summary Report,* California Council on Science and Technology, May 2011.

In order to quantify and credit emissions reductions for CO_2-EOR projects, monitoring, reporting, and verification methods will need to be established and incorporated into state regulations in coordination with federal regulations.

Other uses for CO_2 with inherent long-term storage such as enhanced natural gas recovery (EGR), enhanced coal bed methane (ECBM) production, enhanced geothermal energy production, incorporation into building materials, and use in fuel and chemical production are not yet proven at commercial scale. Increased emphasis on developing these beneficial use technologies by U.S. Department of Energy (DOE) and others[4] is indicative of the need to couple a co-benefit revenue stream with CO_2 storage in the absence of a national policy that sets a price on GHG emissions.

Terrestrial Carbon Storage

Terrestrial carbon storage projects have been a staple of voluntary carbon markets since their inception. Public perception of terrestrial carbon storage is generally positive when it accords with land-use practices such as conservation and restoration. Many landowners are motivated to undertake projects both as a means of generating income and to improve their lands. Development and evolution of protocols/methodologies by independent carbon registries enable more project types to enter the voluntary carbon market and provide a basis for the development of offset protocols for compliance markets.

Terrestrial carbon storage faces four primary challenges, which are not unique to the western region:

1. **Limitations on support due to lack of climate change legislation or structuring of policy instruments**

Widespread deployment of terrestrial carbon sequestration becomes possible under climate change legislation and policy provisions that allow terrestrial carbon storage as a compliance option under a cap-and-trade program or by offering other financing/incentive mechanisms. Although some states in the WESTCARB region have passed climate change legislation and are moving forward with GHG reduction programs, others await federal legislation, which does not appear imminent. This limits the compliance-driven demand for terrestrial carbon storage, as well as other types of offset projects.

Policy mechanisms to date include terrestrial carbon storage to varying degrees. California’s cap-and-trade program allows regulated businesses to meet up to 8% of their compliance obligation with offsets. Given the projected size of the California carbon market and the assumption that regulated entities will utilize offsets to the fullest extent possible, this 8% is not expected to pose a barrier to offset projects during the early years of the program.

In the case of Oregon’s Climate Trust, the price of an offset is determined by the state’s Energy Facility Siting Council and was about $1.40 per metric ton of CO_2 in 2011. By law, this can be raised every other year by 50%. These parameters constrain the cost of GHG compliance to facilities and customers but limit the level of funding the Climate Trust has available for offset projects. Thus, project developers would be expected to seek funding from multiple sources.

[4] http://www.netl.doe.gov/technologies/carbon_seq/corerd/co2utilization.html

Within a carbon market, terrestrial carbon storage competes with other types of offset projects. Internationally, forestry projects under the Clean Development Mechanism have been placed at a disadvantage because the risk of reversals has been handled by issuing credits that have to be replaced upon expiration by the buyer, and therefore command lower prices than credits from other offset activities. The European Union Emissions Trading Scheme (EU-ETS), the world's largest carbon market, does not accept these temporary credits, which has limited funding for forest projects.

As the above examples illustrate, terrestrial carbon storage receives varying degrees of support under carbon regimes, which balance multiple objectives including cost containment, achievement of GHG reductions across multiple sectors, and assurance of offset quality and permanence.

2. Establishing standards to ensure the quality of offsets

The integrity of a carbon regime requires that GHG reductions be real. Offsets must be additional, verifiable, enforceable, and permanent. Thus far, there is little experience in the United States with GHG offsets in a compliance market.[5] For the voluntary market, a 2008 report by the Government Accounting Office (GAO) found that "participants in the offset market face challenges ensuring the credibility of offsets, including problems determining additionality, and the existence of many quality assurance mechanisms. GAO, through its purchase of offsets, found that the information provided to consumers by retailers offered limited assurance of credibility."[6] These same issues need to be addresssed in compliance markets.

Factors that help assure the quality of offsets include transparent, publically accessible project documentation, tracking, and accounting systems; third-party verification by qualified reviewers; and regular review and adjustment of offset program requirements to allow the program to respond to changes in science, technology, regulations, market conditions, or other relevant factors.[7]

Regional cap-and-trade programs in the United States and Canada are pursuing a standardized approach to qualifying offset projects, which establishes program requirements up-front, instead of evaluating projects on an individual basis, as has been the case for Clean Development Mechanism projects. A standardized system minimizes the potential for subjective evaluation in determining project eligibility. Projects are limited to certain categories for which sufficient market data are available and for which robust quantification, monitoring, and verification protocols already exist or can be readily developed.[8]

3. Competition from other land uses

Many lands in the western region that are favorable to terrestrial carbon storage can command high values from uses such as forest products, viticulture or other high-value crops, or conversion to development. In

[5] The Regional Greenhouse Gas Initiative accepts five types of offsets including CO_2 sequestration from afforestation.
[6] *Carbon Offsets: The U.S. Voluntary Market Is Growing, but Quality Assurance Poses Challenges for Market Participants*, GAO-08-1048, August 2008.
[7] *Ensuring Offset Quality: Design and Implementation Criteria for a High-Quality Offset Program*, developed by the Three-Regions Offsets Working Group, May 2010.
[8] Ibid.

most instances, income from carbon storage alone will not provide sufficient incentive for landowners to undertake projects. Increased carbon storage can often be accomplished in conjunction with other land uses or, in the case of development, CO_2 emissions can be kept to lower levels. Nonetheless, competition from other lands uses will undoubtedly limit the application of terrestrial carbon storage projects in some instances.

4. Climate change impacts to habitats

There is a recognized need to incorporate adaptation planning into long-term terrestrial carbon storage project planning. Successful adaptation will depend upon landowners and managers having timely access to information on anticipated changes in local conditions (e.g., soil moisture) and response options (e.g., which species can thrive in lower moisture/warmer temperature regimes and resist threats such as pest infestations). Climate change will become an increasingly relevant factor in land-use decisions where the timing of costs and returns is spread over decades.

Strategies for adapting to changing climate conditions will come from many sources. Analysts call for improved coordination among federal, state, and local agencies in conducting research and addressing situations where jurisdictions overlap.

DEPLOYING CARBON CAPTURE, UTILIZATION, AND GEOLOGIC STORAGE IN THE WESTCARB REGION

Geologic Carbon Storage Resource Is Substantial

Opportunities for geologic CO_2 storage in the WESTCARB region can be found in saline formations, unmineable coal seams, and oil and natural gas fields. Basaltic rock formations in Hawaii and eastern Oregon and Washington may also prove to be suitable for CO_2 storage, although the viability of this option has yet to be demonstrated. The region's overall geologic storage resource[9] does not present a barrier to widespread CCS deployment, with possible exceptions of Hawaii and Nevada; however, the suitability of any particular site will depend on multiple factors including proximity to CO_2 sources and reservoir-specific qualities such as porosity and permeability and integrity of sealing formations.

Saline Formations – The Region's Largest Storage Resource

Many areas of the WESTCARB region contain deep sedimentary basins with saline formations that could be used for CO_2 storage. Saline formations are sedimentary rocks saturated with brines—water that is too salty for agriculture or human consumption (EPA defines formations waters containing greater than 10,000 parts per million total dissolved solids as unsuitable for drinking water).

Sites with saline formations suitable for CO_2 storage contain laterally extensive, thick layers of high-porosity, high-permeability rock (such as sandstone) located at depths of a half mile or more. Project developers look for a saline storage formation overlain by a thick, pervasive layer of low-permeability cap rock (such as shale or mudstone). When CO_2 is injected into the saline formation, it spreads through the pore spaces of the rock. The cap rock overhead acts as a seal to prevent the CO_2 from migrating above the saline storage formation.

Within geologic formations, three major mechanisms work to trap the CO_2 in the pore spaces and increase storage security:

- Residual – CO_2 is immobilized in the pore spaces of the rock by the capillary pressure of the formation waters
- Dissolution – the CO_2 dissolves in the brine, forming a denser fluid with a tendency to sink
- Mineralization – over long periods of time, the CO_2-saturated brine reacts with minerals in the surrounding rock to form new minerals within the pore spaces

Saline formation storage estimates for the deep sedimentary basins of the WESTCARB region (Figure 1) range from 82 to 1,124 billion metric tons. Even at the low end value, this is sufficient to store hundreds of years' worth of the region's CO_2 emissions from large stationary sources.

[9] "The volume of porous and permeable sedimentary rocks available for CO_2 storage and accessible to injected CO_2 via drilled and completed wellbores. Carbon dioxide resource assessments do not include economic or regulatory constraints; only physical constraints to define the accessible part of the subsurface are applied." From: *The United States 2012 Carbon Utilization and Storage Atlas,* Fourth Edition (DOE/NETL). For the full CO_2 storage resource estimate methodology visit: http://www.netl.doe.gov/technologies/carbon_seq/natcarb/geologic-storage-estimates-for-carbon-dioxide-sept2010.pdf

In Oregon and Washington, the total CO_2 storage resource of 10 western coastal sedimentary basins is in the range of 40 billion to 590 billion metric tons. The largest is Washington's Puget Trough (Figure 2).

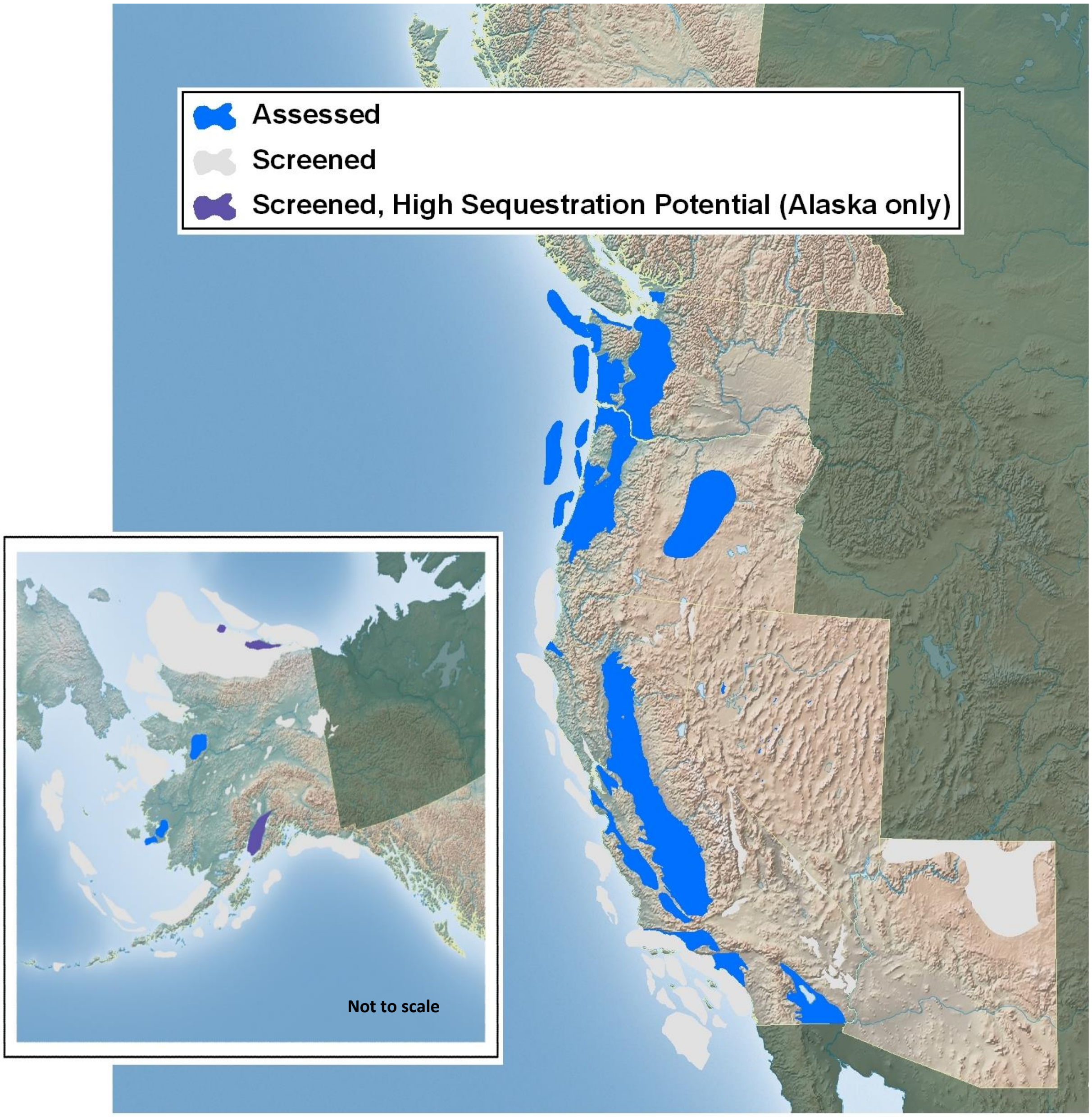

Figure 1. Locations of saline formations for Alaska, Arizona, California, Oregon, Nevada, and Washington

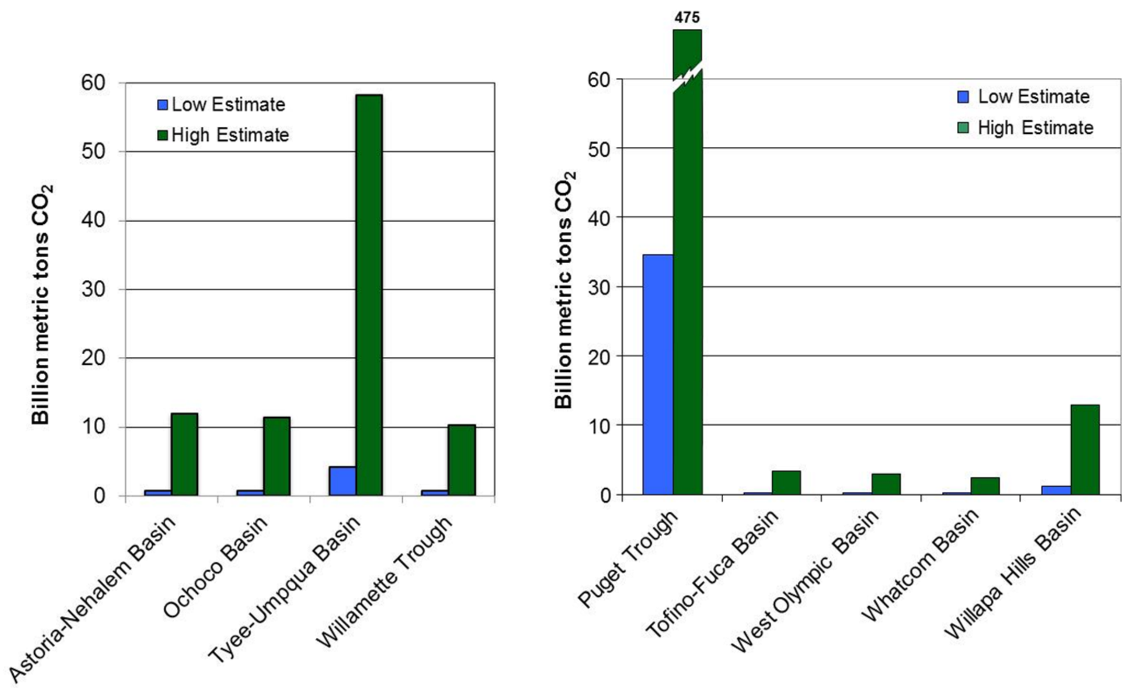

Figure 2. Estimated CO_2 storage resource for the largest onshore basins in Oregon (left) and Washington (right)

In Arizona, the Colorado Plateau (Four Corners area), where most the state's large coal-fired power plants are located, offers potential CO_2 storage strata with sealing cap rocks that are laterally extensive and up to hundreds of feet thick (Figure 3). However, geologic data needed for CO_2 storage site are generally lacking because there are few deep wells in this area. A characterization well drilled in 2009 by WESTCARB and utility industry partners near Arizona Public Service Company's Cholla Power Plant on the southern edge of the Plateau found insufficient permeability in target carbonate strata to warrant CO_2 injection at commercial scale.[10] More characterization of potential storage formations of the Colorado Plateau is needed.

[10] http://www.westcarb.org/AZ_pilot_cholla.html

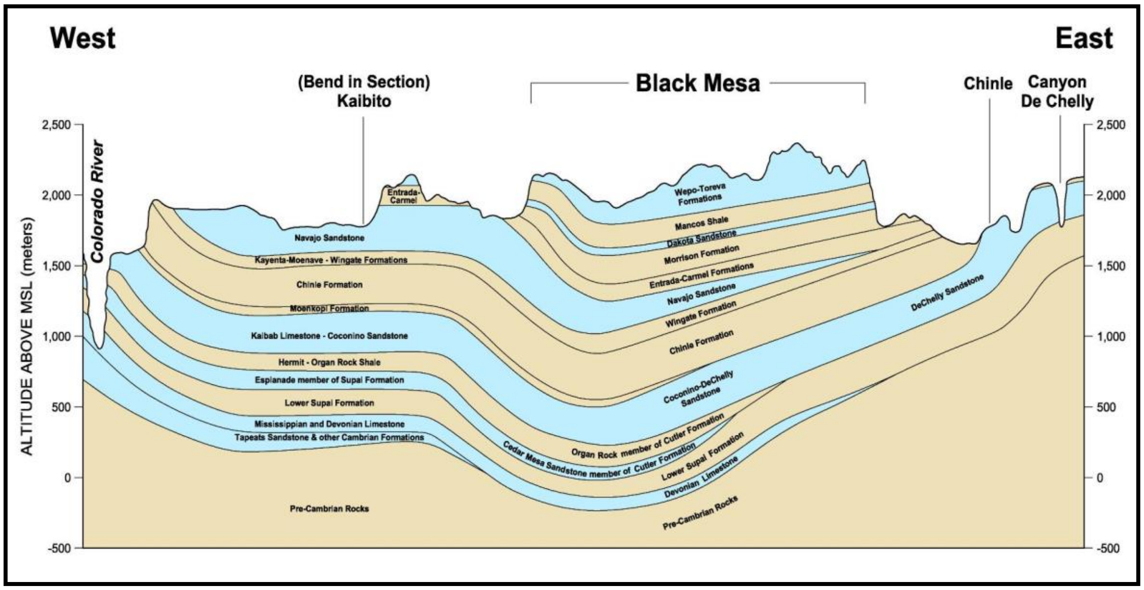

Figure 3. Geologic cross-section from Colorado River, through Black Mesa to Canyon de Chelly[11]

Cenozoic basins located near populations centers in the Basin and Range geologic province of Arizona could prove suitable for storing CO_2 from stationary sources in that area. To screen for CO_2 storage potential, the Arizona Geological Survey (AZGS) is assembling data for 88 Cenozoic sedimentary basins in the province, focusing on formation water salinities and formation volumes below 2,600 feet (790 meters) deep. Initial findings indicate that 10 relatively large basins (Figure 4) represent about 70% of the deep-basin volume in the Basin and Range province. Ongoing work by AZGS is focused on collecting and assessing more detailed data for the largest basins.

[11] Shirley, Dennis. “Arizona Utilities Saline Formation CO_2 Storage Project: Site Selection,” presentation at WESTCARB’s Annual Business Meeting, Seattle, WA, November 27, 2007.

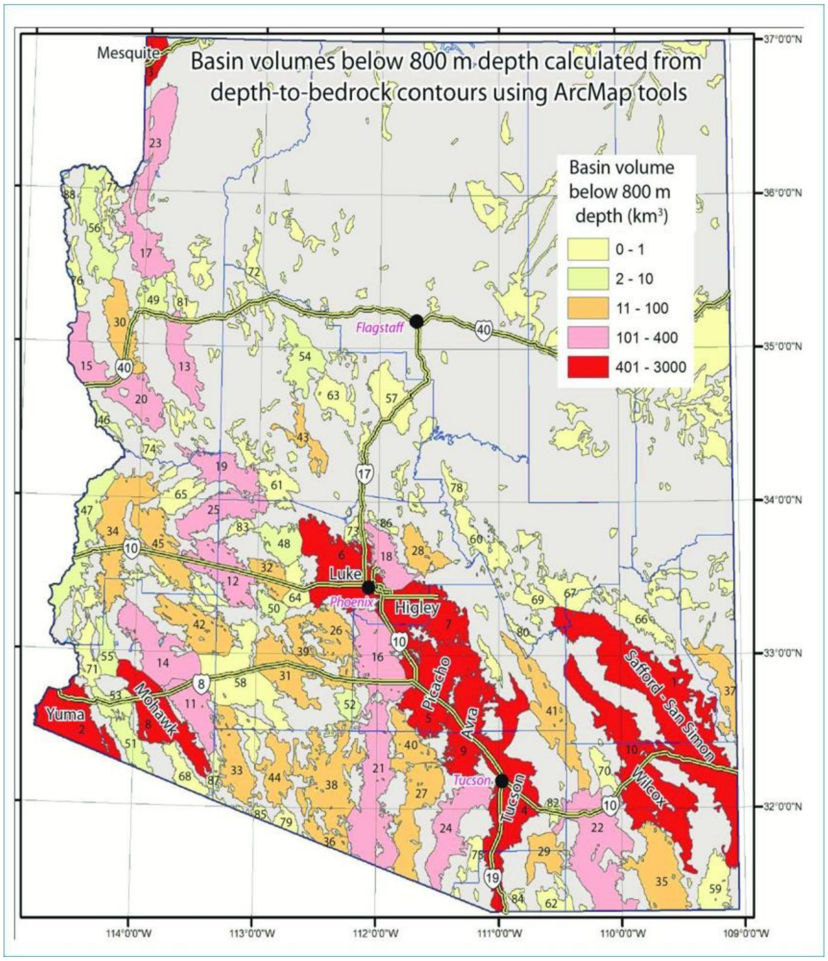

Figure 4. Arizona's Cenozoic basins for which volume calculations have been completed[12]

Areas with potential for CO_2 sequestration in Nevada are Granite Springs Valley in Pershing County, Antelope and Reese River Valleys in Lander County, and Ione Valley in Nye County. Each is larger than 12 square miles (30 square kilometers) and filled with sediments and volcanic rocks more than 3,300 feet (1,000 meters) thick. Site characterization studies are needed to determine if other geologic properties of these valleys are conducive to CO_2 storage.

In California, the California Geological Survey created an inventory of 104 basins,[13] outlines of which were digitized to produce a California sedimentary basin GIS layer. This layer was combined with a California oil and gas field layer. The basins were then screened to determine preliminary suitability for

---

[12] Spencer, Jon E., *Preliminary Evaluation of Cenozoic Basins in Arizona for CO_2 Sequestration Potential*, Arizona Geological Survey, OFR-11-05 v1.1, May 2011.

[13] 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.

CO_2 storage. Screening involved literature searches and analysis of available well logs. Criteria included the presence of significant porous and permeable strata, thick and pervasive cap rocks, and sufficient sediment thickness to provide critical state pressures for CO_2 injection (>2,625 feet/800 meters). Accessibility was also considered. Basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs-administered lands, and military installations were excluded. Structural closure or stratigraphic trapping was not considered a prerequisite for saline formations at the screening level.

Of the 27 basins that met the screening criteria, favorable attributes include: (1) geographic diversity; (2) thick sedimentary fill with multiple porous and permeable formations and hydrocarbon reservoirs; (3) thick, laterally persistent marine shale seals; (4) locally abundant geological, petrophysical, and fluid data from oil and gas exploration and production; and (5) numerous abandoned or mature oil and gas fields that might be reactivated for CO_2 storage or benefit from CO_2-enhanced recovery operations.

The aggregate CO_2 storage resource of California's ten largest onshore sedimentary basins is estimated in the range of 30 billion to 420 billion metric tons of CO_2[14] (Figure 5). The largest of these basins is the Central Valley, consisting of the Sacramento Basin (Figure 6) to the north and the San Joaquin Basin to the south.

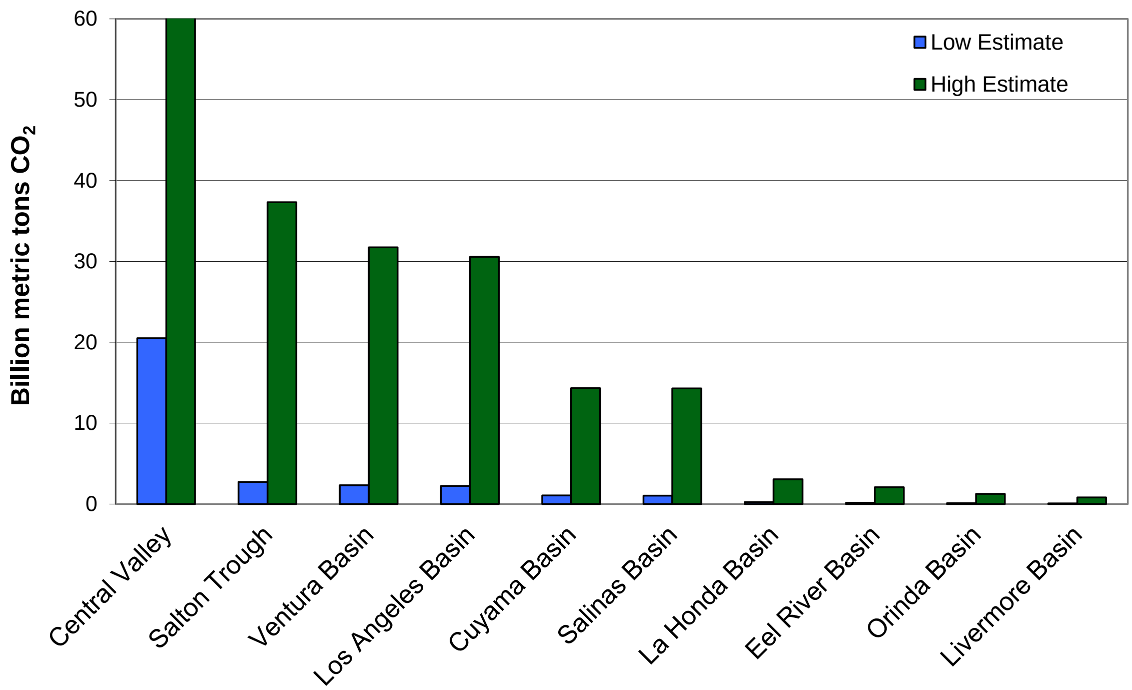

Figure 5. Estimated CO_2 storage resource for California's ten largest onshore basins

[14] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL).

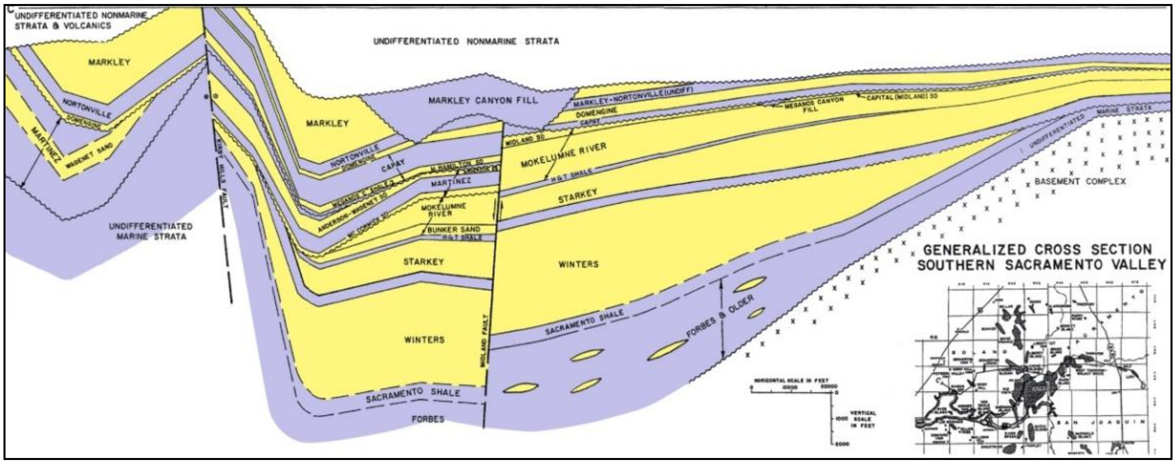

Figure 6. Geologic cross-section of the southern Sacramento Basin showing sandstones (yellow) and shales (purple)[15]

To better characterize the CO_2 storage potential of regionally extensive geologic formations in the southwestern part of the Sacramento Basin, WESTCARB drilled a stratigraphic well in the King Island gas field in December 2011. The site lies within northern California's natural gas producing region and is in proximity to major industrial and power plant CO_2 sources.

The Citizen Green well at King Island, which reused the pad and surface casing of an existing depleted natural gas well, was drilled directionally to a vertical depth of 6,900 feet (2,100 meters). Whole core recovered during drilling included 19 feet (5.5 meters) of the transition between the Nortonville Shale and Domengine Sandstone (Figure 7) and 58 feet (17.5 meters) of the upper Mokelumne River Sandstone. In addition, 43 sidewall cores were recovered from the Domengine, Mokelumne, and upper Starkey (or lower H&T) sandstones, and the Nortonville, Capay, and H&T shales. A suite of wireline logs was run over a vertical depth range of 3,250 to 6,880 feet (990 to 2,095 meters) to provide data on the porosity, permeability, mineralogy, and geomechanical properties of the formations and formation fluids. Analyses indicate high permeabilities in the Mokelumne River and Domengine Sandstones, although inadequate seals above the Domengine may exclude it as a CO_2 storage option at the King Island location.[16]

[15] Clinkenbeard, John. "California Geologic CO_2 Storage Characterization," presentation at WESTCARB's Annual Business Meeting, Seattle, WA, November 27, 2007.
[16] Beyer, John et al. "Geologic Characterization Update for California's Southwestern Sacramento Basin." Poster presentation at DOE/NETL's Carbon Storage R&D Project Review Meeting, August 21-23, 2012, Pittsburgh, PA.

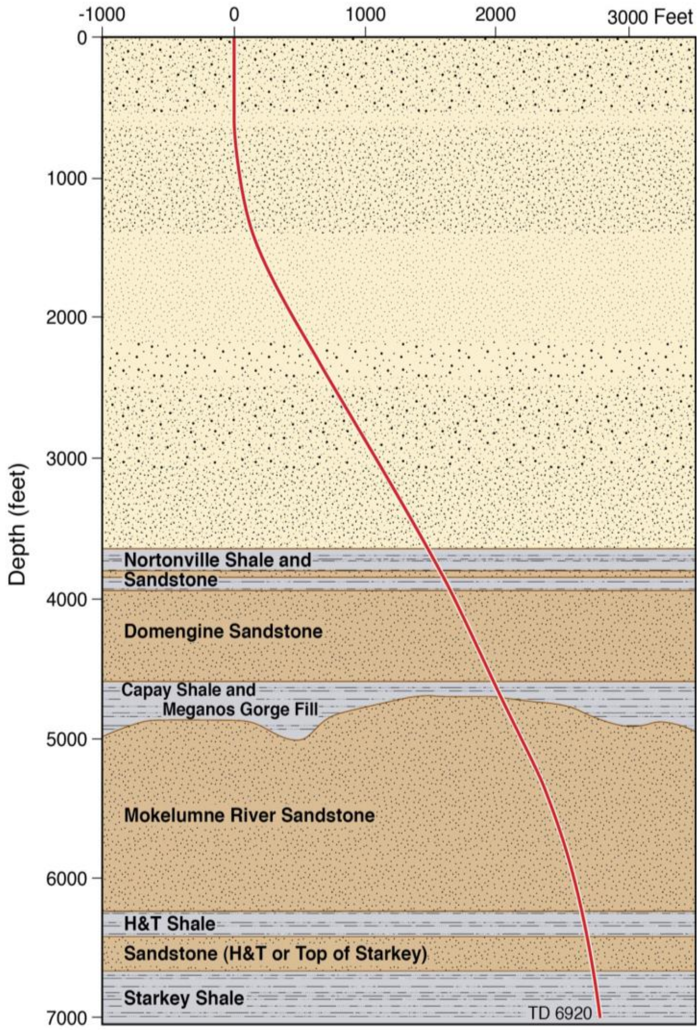

Figure 7. Stratigraphic column of the Citizen Green well in the Sacramento Basin, California

(Topography at top of Mokelumne River Sandstone based on 3D seismic interpretation by T. Fassio.)

California has numerous offshore sedimentary basins, however, a lack of available data has thus far limited the assessment of their CO_2 storage potential to areas where oil and gas exploration has occurred. A WESTCARB study identified a total of 30 offshore oil and gas fields with conventional sandstone reservoirs within the Ventura and Los Angeles basins. Of these, 24 fields are producing or have been depleted, and are likely the most promising options for offshore sub-seabed CO_2 storage based on existing production figures and reserve estimates. These fields have a cumulative estimated CO_2 storage capacity of over 236 million metric tons (MMT).[17]

[17] Downey, Cameron, John Clinkenbeard. (California Geological Survey) 2011. *Studies Impacting Geologic Carbon Sequestration Potential In Californi*, California Energy Commission. CEC-500-2011-044.

The Southern California Carbon Sequestration Research Consortium (SoCalCarb) is characterizing Pliocene and Miocene sediments for CO_2 storage in the offshore Wilmington Graben of the Los Angeles Basin.[18] These formations (more than 3,000 feet [915 meters] of interbedded sand and shale sequences at depths of 3,000–7,000 feet [915–2,135 meters]) are known to provide excellent traps for oil and gas, and have been used for large-scale underground storage of natural gas at a half dozen locations.

In Alaska, data needed to make reasonable estimates for CO_2 storage capacity are sparse or lacking for many of the vast sedimentary basins, both onshore and offshore. Research is focused on the Cook Inlet Basin and the North Slope, where proximity to industrial CO_2 sources, extensive infrastructure, and characterization data from oil and gas exploration make CO_2 storage more feasible. These two areas of high potential are likely to provide more than enough storage space for all of the CO_2 available for capture in Alaska at current and projected emission volumes.[19]

British Columbia has large sedimentary basins offshore and in the center of the province, which have yet to be fully assessed for CO_2 storage. Better understood is the Western Canada Sedimentary Basin in the northeast, where natural gas and oil production and acid gas disposal are practiced commercially.[20] A saline formation storage demonstration in this area is planned by Spectra Energy and DOE's Plains CO_2 Reduction Partnership (PCOR) using an 85% CO_2/15% H_2S gas stream from the Fort Nelson natural gas processing plant.[21]

Opportunities in Oil and Natural Gas Fields in Alaska and California

Depleted oil and natural gas reservoirs are generally excellent candidates for CO_2 storage because buoyant hydrocarbons were held in these reservoirs for millions of years, thus demonstrating their suitability for long-term CO_2 storage. Moreover, the geology of oil and gas reservoirs is well known, and existing well field infrastructure may be adapted for CO_2 injection. To assure against possible CO_2 migration through old well bores, use of depleted oil or gas reservoirs for CO_2 storage will require an assessment of closed wells to confirm their mechanical integrity. Older wells may require replugging to eliminate a possible escape path for the CO_2.

Mature oil and gas fields that are still producing may prove suitable for both CO_2 storage and increased hydrocarbon production. CO_2-EOR is one of a series of engineering strategies designed to increase the rate and ultimate amount of oil produced. For lighter oils, as reservoir energy and mobility of oil decrease, operators can increase production by injecting CO_2, which dissolves into the oil, causing it to swell and become less viscous. Where suitable, this approach can be used to extend the economic and productive life of the field, while providing long-term storage for CO_2 left behind in the formation.

[18] http://socalcarb.org/wilmington.html
[19] Shellenbaum, D.P., and Clough, J.G. 2010. *Alaska Geologic Carbon Sequestration Potential Estimate: Screening Saline Basins and Refining Coal Estimates.* Prepared for California Energy Commission, Public Interest Energy Research Program. (http://uc-ciee.org/downloads/Alaska_DNAR.pdf)
[20] Bachu, Stefan. *British Columbia's Potential for Geological Sequestration of CO_2 and Acid Gas towards Reducing Atmospheric CO_2 Emissions,* Submitted to: Resource Development & Geoscience Branch, Oil & Gas Division, B.C. Ministry of Energy and Mines, March 2005.
[21] http://www.netl.doe.gov/publications/proceedings/08/rcsp/factsheets/19-PCOR_Fort%20Nelson%20Demonstration_PhIII.pdf

During CO_2-EOR operations, CO_2 that is returned to the surface with oil via production wells is separated and re-injected. However, a significant quantity of CO_2, estimated to be one third to one half of the injected volume, becomes trapped and cannot be extracted.[22] The U.S. Department of Energy (DOE) has identified "next generation" CO_2-EOR technology options that could increase the performance of CO_2-EOR and the volume of CO_2 that could be stored compared to current practices.[23]

Oil fields with the potential for CO_2 storage or CO_2-EOR in the WESTCARB are found predominantly in Alaska and California (Figure 8). In Alaska, research is focused on two areas: (1) the Cook Inlet Basin, where proximity to industrial CO_2 sources and extensive infrastructure, as well as characterization data from oil and gas exploration and production, make CO_2 storage and EOR more feasible; and (2) the North Slope, where natural gas reserves could provide a CO_2 source to extend the productive life of the area's oil fields. (Natural gas from the North Slope typically contains about 10% CO_2, which would need to be separated before pipeline transport. However, production of large volumes of natural gas awaits development of a pipeline to bring supplies to market.)

In California, most onshore oil reservoirs are located in the southern San Joaquin Basin, Los Angeles Basin, and Ventura Basin, where WESTCARB investigators have identified approximately 0.3–1.3 billion metric tons of CO_2 storage resource potential.[24]

A DOE study of CO_2-EOR in California estimated the incremental economically recoverable oil reserves at 5.4 to 8.1 billion barrels.[25] Currently, sufficient volumes of CO_2 are not available locally, and CO_2 pipeline transport into California is considered uneconomic relative to the historical ranges of oil prices. An initial project, Hydrogen Energy California, has filed permit applications to build an IGCC plant with CO_2 capture near Bakersfield in Kern County, with plans to sell the CO_2 for EOR in the nearby Elk Hills oil fields.[26]

Storing additional CO_2 in depleted oil fields after enhanced recovery operations cease is considered an option for achieving further GHG reductions while taking advantage of well-characterized geology with proven storage security, as well as utilizing existing infrastructure such as wells, pipelines, and roads. One possible barrier to this practice is the requirement to re-permit wells used for CO_2-EOR to comply with Class VI well standards for CO_2 geologic storage, which were developed by U.S. EPA in 2010 to protect underground sources of drinking water (USDWs).

[22] Hovorka, S. and Tinker, S.W. "EOR as sequestration: Geoscience perspective," presented at the Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage, Cambridge, MA, July 23, 2010. GCCC Digital Publication Series #10-12.
[23] *Storing CO_2 with Next Generation CO_2-EOR Technology*, DOE/NETL-2009/1350, January 9, 2009.
[24] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL).
[25] DOE/NETL. *Storing CO_2 with Next Generation CO_2-EOR Technology.*
[26] http://hydrogenenergycalifornia.com/

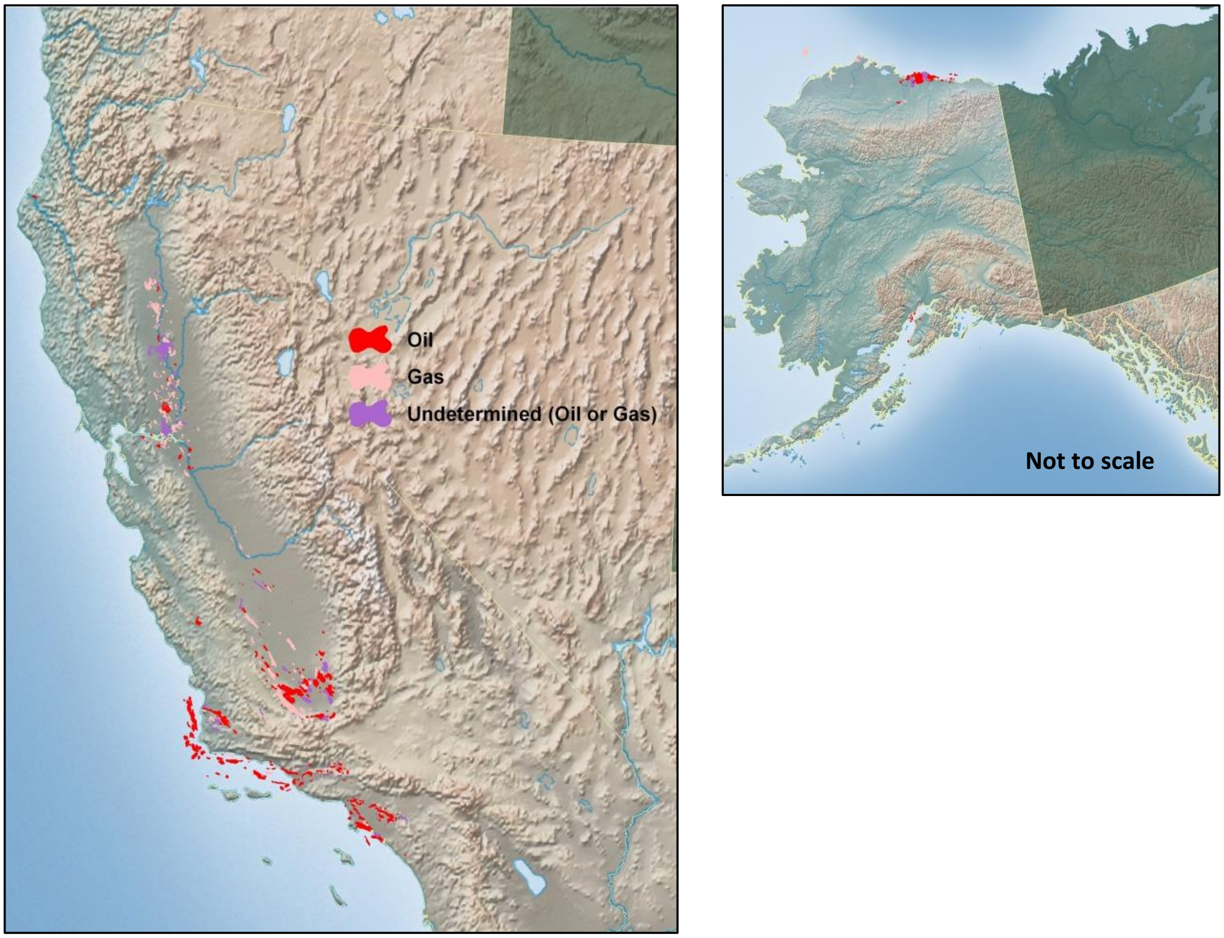

Figure 8. Locations of major oil and gas fields in Alaska and California

WESTCARB estimates the CO_2 storage potential in California's depleted natural gas reservoirs at 3.0 billion to 5.2 billion metric tons.[27] Regionally, the Sacramento Basin has the largest CO_2 storage potential, in the range of 2.0 billion to 4.1 billion metric tons. The southern portion of the basin is home to some of California's largest natural gas fields. Now largely depleted, these fields may represent opportunities for CO_2 storage following cessation of commercial natural gas production. There may also be opportunities for using CO_2 for enhanced natural gas recovery (EGR) in these fields, or as a cushion gas at natural gas storage sites; however, use of CO_2 for enhancing natural gas recovery has yet to be proven at commercial scale.

Offshore California, oil and gas accumulations have been found in the Santa Maria, Ventura, and Los Angeles basins. Most known reservoirs in the Santa Maria Basin, as well as numerous reservoirs in the Ventura Basin, occur within highly fractured shales, which are not good candidates for CO_2 storage.

[27] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL).

Estimated CO_2 storage capacity for the known developed and undeveloped offshore oil and gas fields within conventional sandstone reservoirs of the Los Angeles and Ventura Basins is 240 MMT.[28]

Coal Bed Storage and Methane Recovery Possible in the Pacific Northwest and Alaska

Coal beds that are too deep and/or thin to be mined economically may prove suitable for CO_2 storage because CO_2 readily adsorbs to coal. In some cases, CO_2 injection can be used to displace methane for enhanced coal bed methane (ECBM) recovery. Although ECBM has been successfully demonstrated in several locations at pilot scale, including in the San Juan Basin of northwestern New Mexico,[29] no commercial-sized projects have been undertaken.

In the Pacific Northwest, three deep coal bed deposits offer promise: the Bellingham Basin in northwestern Washington; the coals of the upper Puget Sound Region, south and east of the Seattle-Tacoma metropolitan area; and small, deep coal deposits in southwestern Oregon. Coal seams in the Puget Sound Region have been tested for CBM production. Initial studies show that the subsurface extent of the coal basins represents an area greater than 950 square miles (2,500 square kilometers). The estimated CO_2 storage potential in this area is 1.3 billion metric tons, and the estimated recoverable CBM is 2 to 20 trillion cubic feet (57 billion to 570 billion cubic meters).[30] In the Centralia-Chehalis Basin, a WESTCARB study estimated up to 345 MMT of storage capacity.[31]

Alaska contains major coal deposits, and CBM resources are estimated to be approximately 780 trillion cubic feet (22 trillion cubic meters), which is comparable to the CBM resources in all of the lower 48 states. However, only a portion of this resource is considered favorable for CO_2 storage due to coal quality, permeability, seam geometry, surface access, faulting, permafrost, and other site-specific conditions. The highest potential lies in the North Slope and Cook Inlet Regions, which are accessible and have coals of suitable thickness, depth, and permeability. Preliminary estimates of the geologic CO_2 storage resource in Alaska identify about 26 billion metric tons of storage in these deep coal seams.[32]

The CO_2 storage resource in coals seams in northeastern British Columbia, estimated at 170 MMT, is dwarfed by the CO_2 storage resource in oil and gas reservoirs in the area.[33]

---

[28] Ibid.
[29] http://www.netl.doe.gov/events/09conferences/rcsp/pdfs/SWP%20San%20Juan%20Basin.pdf
[30] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL).
[31] Stevens, Scott. *Centralia (Washington State) Geologic Formation CO_2 Storage Assessment*, Advanced Resources International, Inc., DOE Contract No.: DE-FC26-05NT42593, January 20, 2009. (http://uc-ciee.org/downloads/Centralia_Text.pdf)
[32] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL).
[33] *The North American Carbon Storage Atlas*, 2012, First Edition. (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf)

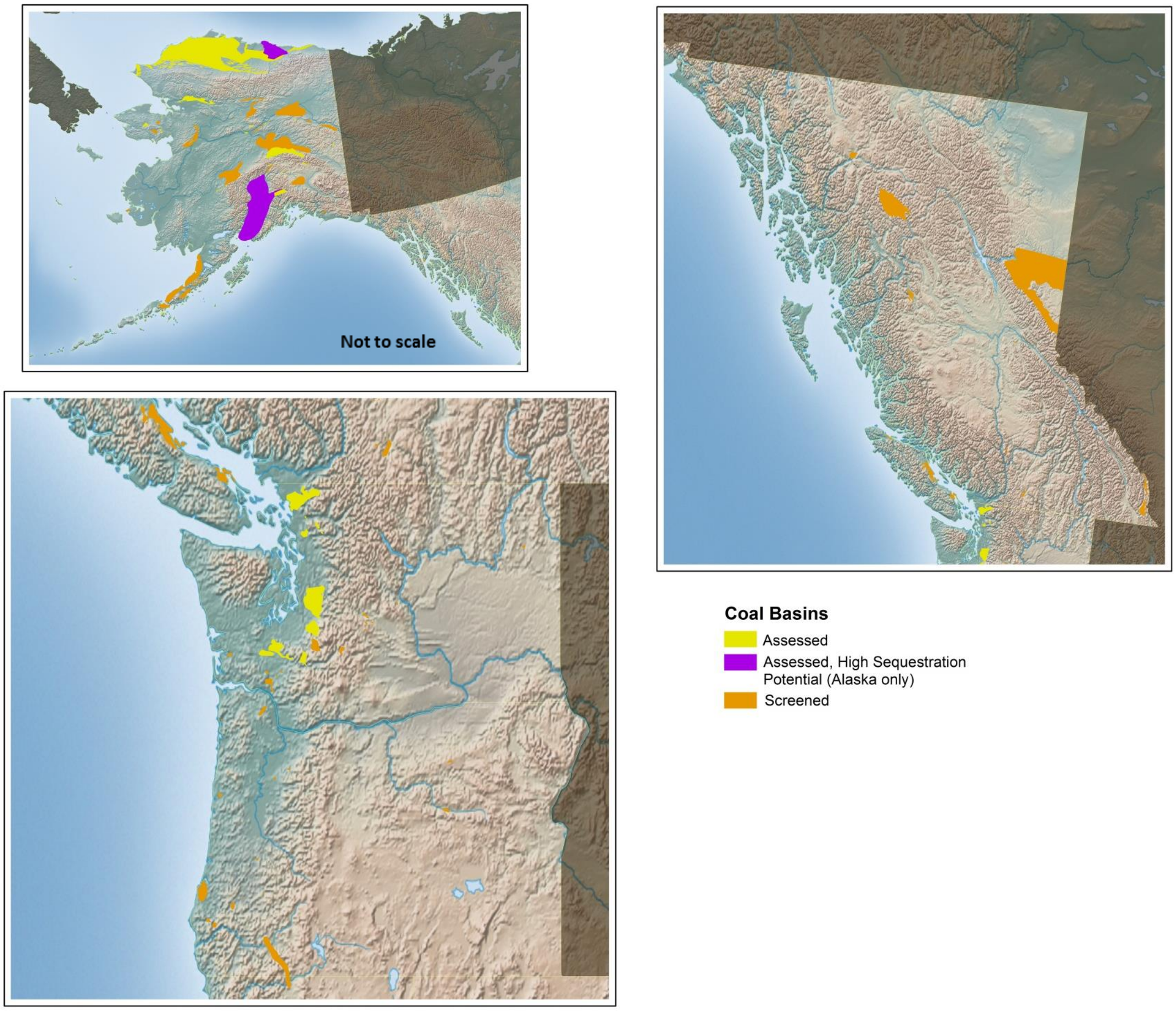

Figure 9. Coal basins in the WESTCARB region

Researching Basalt Storage in Washington and Hawaii

The Big Sky Carbon Sequestration Partnership plans to inject 1,000 tons of supercritical CO_2 into a deep basalt formation near Wallula, Washington, to assess the mineralogical, geochemical, and hydrologic impact of CO_2 in basalts.[34] Because basalts contain minerals that are very reactive with CO_2, they could potentially convert injected CO_2 into a solid form much faster than other rock types, thus providing excellent storage security. Research is focused on enhancing and utilizing the mineralization reactions and increasing CO_2 flow and distribution within a basalt formation. Basalts may also be an opportunity for CO_2 storage in Hawaii.

[34] http://www.bigskyco2.org/research/geologic/basaltproject

Assessing Industrial Sources of CO_2 Emissions

A survey of the WESTCARB region's large industrial sources or "point sources" that could reduce GHG emissions though carbon capture and geologic storage shows that electric power plants predominate, although the fuel mix used for power generation varies considerably. Arizona has the region's largest coal-fired plants. Natural gas combined cycle (NGCC) plants are significant in California and other WESTCARB states, except for Hawaii, which relies chiefly on oil-fired generation. Oil and natural gas processing dominate CO_2 emissions in Alaska, and oil refining is also a major emissions source in California. Other significant industrial CO_2 sources throughout the region include cement and lime plants, aluminum smelters, steel mills, and pulp and paper mills. The region has relatively low CO_2 emissions from agricultural processing plants, located mainly in California, and ethanol fermenters in Arizona, California, and Oregon.

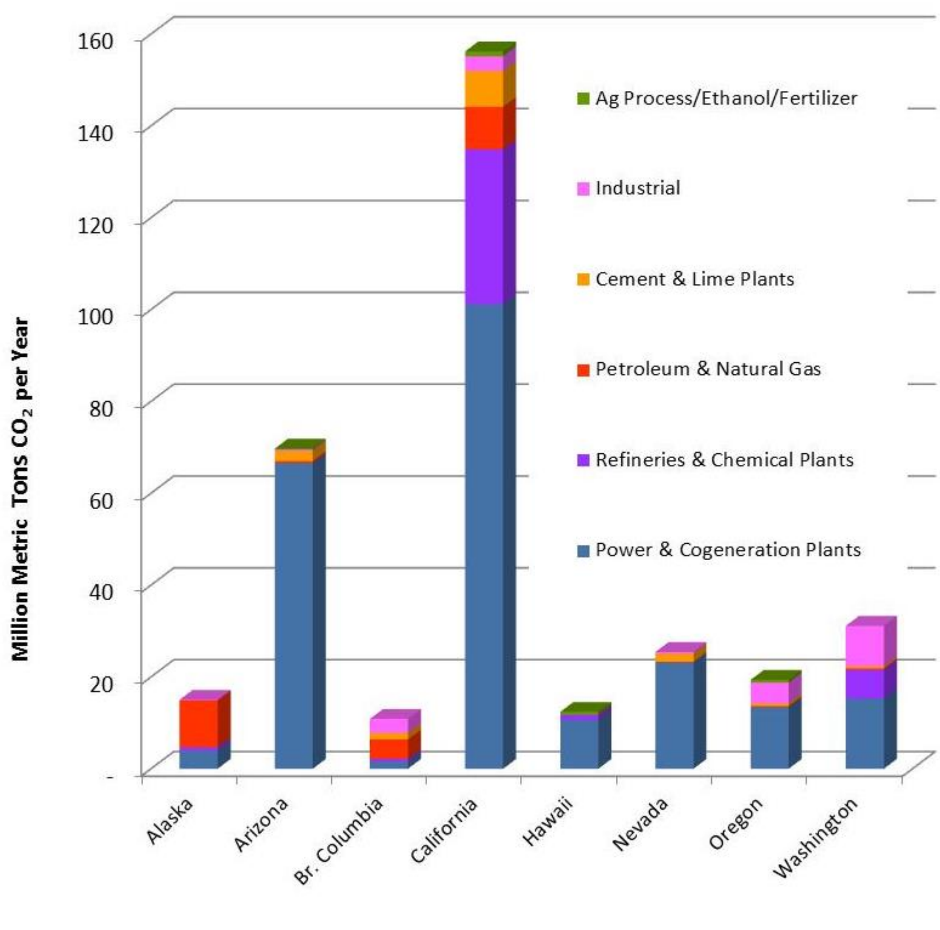

Figure 10. Emissions from large point sources in the WESTCARB region by state/province and type, as of 2012[35]

[35] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL).

Major Industrial CO_2 Sources Are Generally Well Matched To Sinks

An important consideration in planning for regional CCS deployment is source-sink matching, which maps the location and CO_2 emission volumes of stationary sources within a certain area to the locations and capacities of potential geologic storage sites (sinks).

Figure 11 shows the locations of major CO_2 sources in relation to sedimentary basins, while Table 1 contains a comparison of estimated storage capacities to large point source emissions volumes for each WESTCARB state/province.

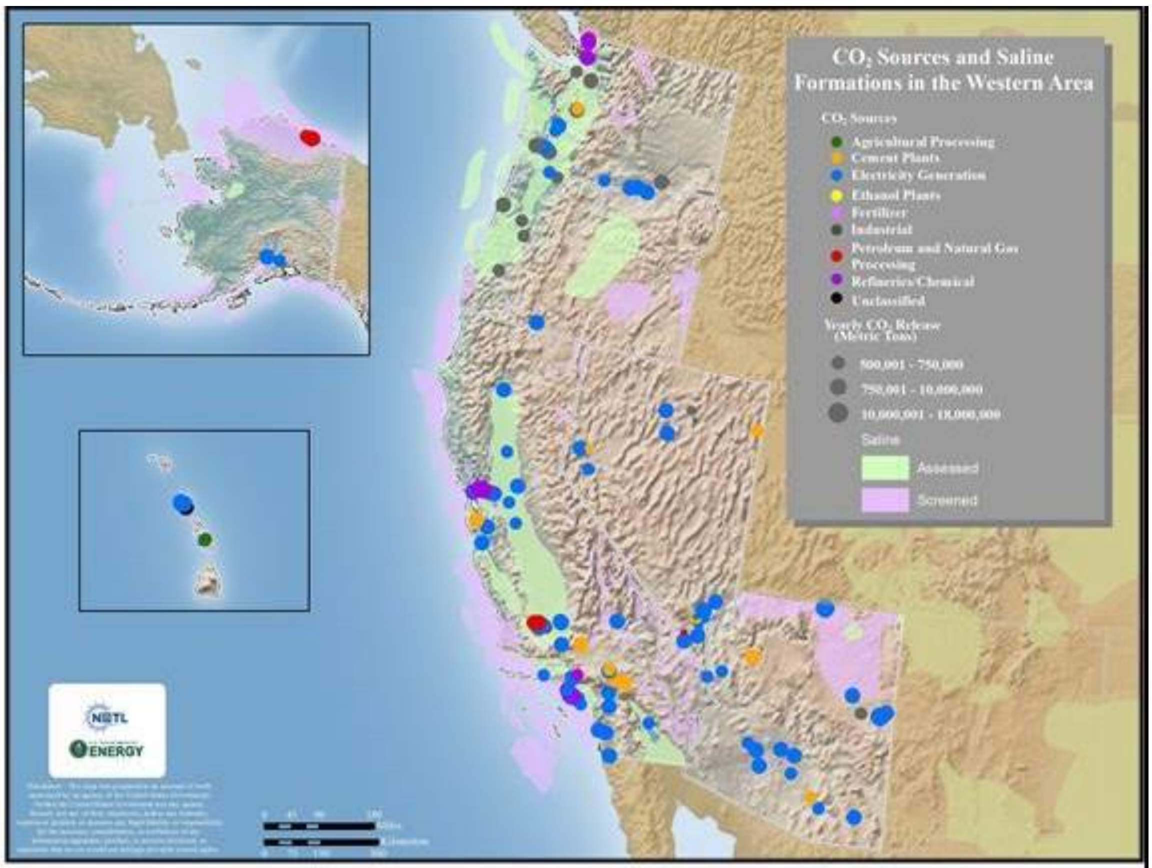

Figure 11. Locations of major stationary CO_2 sources in relation to saline formations[36]

[36] NATCARB custom map service, August 2012.

Table 1. Comparison of point source CO_2 emissions with total storage resource[37]

	# of facilities emitting more than 500,000 $MMTCO_2$ per year ($MMTCO_2$/yr)	Aggregate CO_2 emissions from facilities with greater than 500,000 $MMTCO_2$/yr	Total* Estimated Geologic Storage Resource ($MMTCO_2$)
Alaska	8	8.1	8,600–20,000**
Arizona	18	56.3	—
British Columbia	7	5.1	910–3,900
Hawaii	9	7.5	—
California	68	88.3	34,000–421,000
Nevada	12	17.1	—
Oregon	11	12.8	6,800–94,000
Washington	17	25.9	37,000–497,000

*Saline formations, unmineable coal seams, and oil and gas reservoirs.
**Saline formations not included.

A 2007 WESTCARB study[38] identified the major regional CO_2 industrial sources with emissions data and analyzed their proximity to geologic sinks using straight-line distance-based matching. A total of 58 CO_2 sources were studied, which include 10 coal-fired power plants, 27 natural gas-fired power plants, 11 cement plants, and 10 oil refineries, with combined annual emissions of 184 $MMTCO_2$ to be sequestered.[39]

If EOR sites were the only sinks used for sequestration, about one-third of the CO_2 sources (by volume) could be matched with a sink that is less than 30 miles (50 kilometers) away,[40] while about one-half of the sources could be matched with a sink that is less than 155 miles (250 kilometers) away. If all sink types are considered (i.e., unmineable coal, oil, natural gas, and saline), more than four-fifths of CO_2 sources could be matched with appropriate sinks within 30 miles.[41]

In 2010, WESTCARB began a study to assess the suitability of California's NGCC power plants for CCS retrofit, including their proximity to potential storage or CO_2-EOR sites. As part of this study, researchers at the Lawrence Livermore National Laboratory reviewed the geology at existing and planned NGCC sites (Figure 12) considering distance to nearest potential CO_2 sink, proximity to oil or gas fields,

---

[37] *The United States 2012 Carbon Utilization and Storage Atlas*, Fourth Edition (DOE/NETL). Storage resource estimates for Arizona, Hawaii, and Nevada have not yet been completed.
[38] Herzog, Howard, et al. 2007. *West Coast Regional Carbon Sequestration Partnership: Source-Sink Characterization and Geographic Information System-Based Matching.* California Energy Commission, PIER Energy- Related Environmental Research Program. CEC-500-2007-053.
[39] Based on 80% operation capacity for power plants, full production capacity for non-power stationary CO_2 sources, and a capture efficiency of 90% for all sources.
[40] Distance selected to reflect a "reasonable" distance on which to base pipeline economic assessments.
[41] Herzog. *West Coast Regional Carbon Sequestration Partnership: Source-Sink Characterization and Geographic Information System-Based Matching.*

subsurface geology, surface expression of nearby faults, and groundwater—depth to base of freshwater aquifer and depth to saline aquifer. The study concluded that, based on geologic features, CO_2 storage is likely practicable for many California NGCC plants.[42]

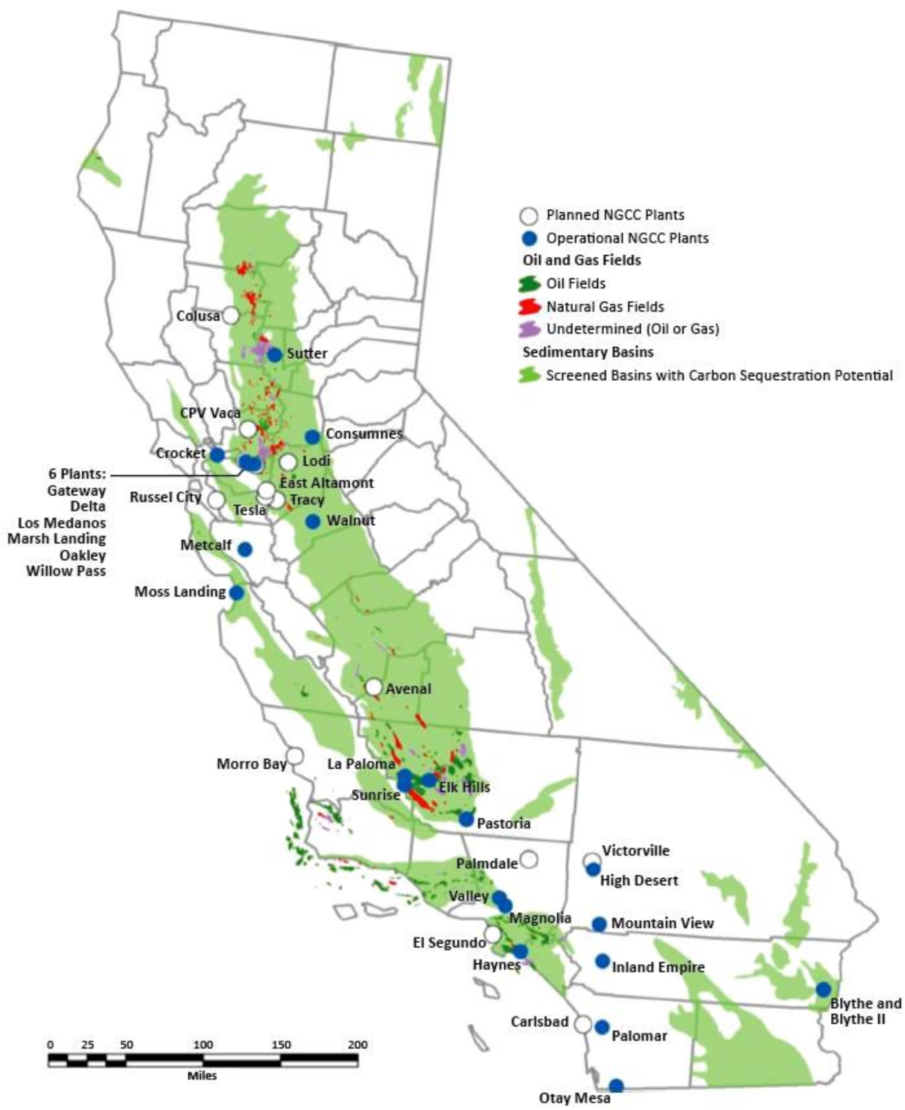

Figure 12. Location of operational and planned NGCC plants in California in relation to potential CO_2 storage sinks[43]

[42] Myers, Katie and Jeff Wagoner. "Geologic CO_2 Sequestration Potential of 42 California Power Plant Sites," presentation at WESTCARB's Annual Business Meeting, October 25, 2011, Lodi, California.
[43] Ibid.

Changes in Source Composition and Location in the Coming Years

As the region initiates policies to lower GHG emissions, changes in the overall makeup and location of stationary sources are anticipated. The region is seeing an increasing rate of coal plant retirements or conversions. Portland General Electric has agreed to shut down its coal plant in Boardman, Oregon, by 2020.[44] TransAlta expects to shut down the first of two coal-fired units at its Centralia, Washington, plant in 2020, with the second to follow in 2025.[45] The company plans to convert the site to an NGCC plant. In addition to fuel switching from coal to natural gas, biomass and petroleum coke could become more commonly used for electricity generation. For new power plants and industrial facilities, access to geologic CO_2 storage sites could become an additional requirement for siting.

Bioethanol plants have inherently high CO_2 concentrations in fermenter discharge streams, which make them good candidates for low-cost capture, provided they are large enough to realize economies of scale. Because biomass-derived fuels are already considered carbon neutral, these plants offer the potential for "net negative" CO_2 emissions if they are combined with geologic CO_2 storage. Opportunities for CO_2 capture from bioethanol production in the WESTCARB region are currently limited because there are only a few plants, all with emissions below 500,000 metric tons CO_2/yr. However, emissions from this source type have the potential to grow as the industry expands in response to renewable or low-carbon fuel standards.

A demonstration of CCS on an ethanol plant began operation in November 2011 in Decatur, Illinois. The project, which is sponsored by DOE/NETL and managed by the Midwest Geological Sequestration Consortium, is designed to sequester ~2,500 metric tons CO_2 per day in the saline Mount Simon Sandstone formation at a depth of approximately 7,000 feet (2,130 meters).[46]

[44] http://www.oregonlive.com/business/index.ssf/2010/04/pge_files_to_close_boardman_co.html
[45] http://seattletimes.nwsource.com/html/localnews/2014412221_coalplant06m.html?syndication=rss
[46] http://www.netl.doe.gov/publications/press/2011/111121_co2_injection.html

ELEMENTS FOR SUCCESSFUL COMMERCIAL DEPLOYMENT OF CCS

Although the overall outlook for CCS in the WESTCARB region on the basis of potential storage volume and source-sink matching does not appear constrained, widespread deployment of CCS technologies will also depend upon the resolution of issues pertaining to policy, technology infrastructure, economics, finance, law, and public acceptance.

Policy Drivers and Regulatory Development

GHG policy and regulatory programs that drive the development of CCS can take a number of approaches including cap-and-trade programs, carbon taxes, sector-specific performance standards, conventional command-and-control regulations, or a combination of these measures. Under any program, CCS must be recognized as a compliance option to become commercially viable. Regulators must have assurances that CO_2 injected to create an emission reduction remains sequestered, and policymakers need to decide what financial incentives are necessary to encourage demonstration and deployment of CCS.[47]

U.S. Federal Climate Change Drivers

Within the United States, federal climate change proposals have served as a signal to diverse economic sectors to prepare for regulation of GHG emissions. However, none of the proposed climate change bills has been passed into law. This presents a significant dilemma for industry planners, who prefer a clear pathway on which to base investment decisions.

Federal actions affecting CCS have emanated from U.S. EPA, which has implemented GHG reporting requirements and taken steps to begin regulating GHG emissions from the nation's largest stationary sources. EPA has also developed permitting guidelines for underground injection and storage of CO_2.

U.S. EPA Rulemaking for GHG Emissions Sources

After the U.S. Supreme Court ruled in 2007 that GHGs could be regulated under the Clean Air Act, EPA determined that CO_2 and five other heat-trapping gases were pollutants that endanger public health and welfare. A proposed rule followed to begin regulating emissions from industrial facilities emitting 27,500 tons (25,000 tonnes) of CO_2 or more per year in March 2010, with reporting required by such facilities.[48]

In May 2010, EPA issued a Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, limiting coverage of GHG permitting guidelines to the largest stationary sources of GHGs. The Rule specified that as of July 2011, Clean Air Act permitting requirements would cover all new facilities with GHG emissions of at least 100,000 tons per year (tpy) and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[49]

EPA proposed New Source Performance Standards for GHGs in March 2012, with the timetable for issuing final regulations under negotiation. The proposed standard specifies a maximum 30-year average

[47] *Carbon Capture and Sequestration: Framing the Issues for Regulation*, An Interim Report from the CCSReg Project, January 2009. (http://www.ccsreg.org/pdf/CCSReg_3_9.pdf)
[48] 74 Fed. Reg. 56373-56519 (October 30, 2009).
[49] 75 Fed. Reg. 31514 (June 3, 2010).

emission rate of 1000 lb-CO_2 per MWh (gross) for all new fossil fuel units greater than 25 MW. Permitted units that begin construction by April 12, 2013, are exempted.[50]

The proposed rule features an "alternative compliance option," which would allow coal- and petcoke-fired plants to operate up to 10 years before adding CO_2 capture, provided that their emissions rate for the first 10 years was less than 1800 lb-CO_2/MWh (gross) (817 kg-CO_2/MWh [gross]) and the rate for the subsequent 20 years was less than 600 lb-CO_2/MWh (gross) (272 kg-CO_2/MWh [gross]).[51]

U.S. EPA Rulemaking for Underground CO_2 Storage

In November 2010, EPA amended the Greenhouse Gas Reporting Program to cover monitoring and reporting requirements for facilities injecting CO_2 underground either for long-term storage (subpart RR) or for enhanced oil and gas recovery or any other purpose (subpart UU).[52] Simultaneously, acting under the authority of the Safe Water Drinking Act, EPA issued a final rule establishing a new well classification (Class VI) under the Underground Injection Control (UIC) Program for CO_2 injection for geologic storage.[53] States are allowed to seek primacy for Class VI well regulation, independent of other well classes, and several states, including North Dakota and Wyoming, began the process in 2011.

A ruling is expected in early 2013 on whether to conditionally exclude supercritical CO_2 streams injected into Class VI UIC wells for geologic sequestration from EPA's definition of hazardous waste under the Resource Conservation and Recovery Act.[54] CO_2 injected in Class II wells for the purpose of enhanced oil recovery will not be affected by this ruling.

In developing the Class VI Rule, EPA specified that Class II wells (which are used for oil and gas production and CO_2-EOR) can to be re-permited as Class VI wells, provided safeguards for protecting USDWs are observed. EPA has developed specific, risk-based factors[55] to be considered by the Director in making the determination to apply Class VI requirements to transitioning wells. A significant consideration for Class VI wells is the post-injection monitoring period, which is specified as "at least 50 years or for the duration of the alternative timeframe approved by the Director."[56]

Canada's New Emissions Performance Standard

Canada is targeting GHG reductions of 17% below 2005 levels by 2020. Coal-fired power plants produce ~15% of the nation's electricity and are responsible for 11% of its GHG emissions.[57] In September 2012, the government passed a new emissions performance standard (EPS) of 462 tons CO_2/GWh (420 tonnes CO_2/GWh) to be applied to new and old coal-fired electric generating units. New units are defined as starting electricity production commercially on or after July 1, 2015. Old units are generally defined as having reached 50 years since starting to produce electricity commercially.

---

[50] http://epa.gov/carbonpollutionstandard/pdfs/20120327proposal.pdf
[51] Ibid.
[52] 75 Fed. Reg. 75060 (December 1, 2010).
[53] 75 Fed. Reg. 77230 (December 10, 2010).
[54] http://ghgnews.com/index.cfm/epa-plans-to-finalize-co2-exemption-under-rcra-early-next-year/
[55] 75 Fed. Reg. 77245 and 77291 (December 10, 2010).
[56] 75 Fed. Reg. 77300 (December 10, 2010).
[57] http://www.ec.gc.ca/cc/default.asp?lang=En%20&n=E907D4D5-1

Temporary exemption from the new EPS may be requested by including a CCS system in the permit application either for a new-build plant or a retrofit. The exemption remains in effect until year-end 2024, subject to interim requirements that include a front end engineering design study, purchase of major equipment, and permitting and compliance with the legal regimes of the capture and storage site.

CCS State/Provincial Drivers

Several states in the WESTCARB region, as well as the province of British Columbia, have passed climate change legislation committing to a range of GHG reduction targets (Table 2). It is instructive to look more closely at the contrasting developments in Washington, British Columbia, and California.

Table 2. Status of GHG emissions reduction legislation in the WESTCARB region

Alaska	No legislation enacted to date.
Arizona	No legislation enacted to date.
British Columbia	2007: Greenhouse Gas Reductions Target Act • Reduce GHG emissions by at least 33% below the 2007 level by 2020 • Reduce GHG emission to at least 80% below the 2007 level by 2050 2008: Greenhouse Gas Reduction (Cap and Trade) Act
California	2006: Global Warming Solutions Act (AB 32) – reduce statewide GHG emissions to below 1990 levels by 2020 (Executive Order S-3-05 set a further target of 80% below 1990 levels by 2050)
Hawaii	2007: Hawaii’s Global Warming Solutions Act (Act 234) requires Hawaii to reduce its statewide GHG emissions to 1990 levels by January 1, 2020. The State Department of Health has issued proposed rules on mandatory reductions for large emitters with a target adoption timeframe of late 2012/early 2013[58]
Nevada	No legislation enacted to date.
Oregon	1997: Oregon’s CO_2 Emission Standard (1997) • In 2007, Oregon passed House Bill 3543 which mandates a reduction in Oregon’s greenhouse gas emissions to 10% below 1990 levels by 2020 and to 75% below 1990 levels by 2050. HB 3543 also created the Oregon Global Warming Commission.
Washington	2007: ESSB 6001 – established three GHG emissions reduction targets: • By 2020, reduce state climate-pollution emissions to 1990 levels • By 2035, reduce emissions to 25% below 1990 levels • By 2050, reduce emissions to 50% of 1990 levels or 70% below the state’s expected emissions that year

Washington State’s Experience in Permitting Geologic Carbon Storage Projects

Total GHG emissions in Washington for 2008 were 101.1 $MMTCO_2e$ (CO_2 equivalent), ~9% above 1990 emissions.[59] Nearly half the state’s GHG emissions are attributable to transportation, however, some 17 large stationary sources, which could be candidates for CCS, contribute roughly 26 $MMTCO_2$/yr.[60]

[58] http://hawaii.gov/health/about/proposed/cab/proposed_PDF/Public-Hearing-Final.pdf
[59] Washington Department of Ecology News Release - February 7, 2011, 11-040. (http://www.ecy.wa.gov/news/2011/040.html)

In May 2007, Washington passed ESSB 6001, which established an EPS requiring all new baseload power generation, whether in-state or imported, to have emissions equal to or less than those associated with gas-fired generation (i.e., ~1,100 pounds of CO_2 per MWh).[61]

The law specified that CO_2 injected permanently into geological formations is not counted when determining compliance with the EPS. Washington has primacy for administering its UIC wells, and in 2008, the Department of Ecology adapted the state's UIC rules to allow Class V wells to serve for CO_2 injection and storage.[62] The rules (since superseded by EPA's Class VI rulemaking) required that operators obtain a state waste discharge permit and specify additional requirements including financial assurance mechanisms to cover remediation and well closure costs should the operator not "perform as required in accordance with the permit or cease to exist."

The rules defined a post-closure period that would continue until "the department determines that modeling and monitoring demonstrate that conditions in the geologic containment system indicate that there is little or no risk of future environmental impacts and there is high confidence in the effectiveness of the containment system and related trapping mechanisms."[63] Two issues left undetermined were long-term liability for the stored CO_2 and clarification of pore space ownership, which would need to be settled under existing law.[64]

For pending power plant projects, ESSB 6001 required a detailed GHG reduction plan (GGRP) demonstrating how the project would meet the EPS. Energy Northwest filed a GGRP in July 2007 for the Pacific Mountain Energy Center, a 793 MW IGCC plant, proposed for Kalama, Washington. The state ruled that the GGRP was inadequate, describing it as "a plan to make a plan," and further proceedings on the project were stayed. The company is instead proceeding with plans for an 346 MW NGCC plant, known as the Kalama Energy Center.

The second proposed IGCC plant, the Wallula Energy Resource Center, withdrew its site-study request in March 2008 and was subsequently cancelled.

Recent geologic CO_2 storage R&D in Washington focuses on a pilot-scale project involving Battelle and the Big Sky Carbon Sequestration Partnership near Wallula. [65] In early 2009, a borehole permitted as a Class V experimental well was drilled 4,110 feet (1,250 meters) into the Columbia River basalt. A small-scale CO_2 injection is planned.

---

[60] Seventeen facilities with over 0.5 $MMTCO_2$/yr. Based on EPA 2010 GHG inventory and supplemental EGRID 2007 data.
[61] Wash. Rev. Code. § 80.80.040(1).
[62] http://apps.leg.wa.gov/wac/default.aspx?cite=173-218-115
[63] Ibid.
[64] Pollak, Melisa F. and Elizabeth J. Wilson. "Regulating Geologic Sequestration in the United States: Early Rules Take Divergent Approaches," *Environmental Science & Technology*, 2009, 43 (9), pp 3035–3041, DOI: 10.1021/es803094f.
[65] http://www.bigskyco2.org/research/geologic/basaltproject

British Columbia's Carbon Tax

British Columbia set a goal of reducing GHG emissions to 33% below 2007 levels by 2020, and to at least 80% below 2007 levels by 2050. Electricity generation accounts for just 2% of total provincial GHG emissions; fossil fuel production accounts for 21%.[66] NATCARB estimates 15 $MMTCO_2$/yr from 53 stationary sources. The province has no coal-fired power plants but produces 23 to 27 MMT of coal annually, primarily for export. In 2008, 59% of British Columbia's coal exports were destined for steel production in Asia.[67]

British Columbia enacted a carbon tax in July 2008 for purchasers and users of fossil fuels. The tax is currently set at C$25 per metric ton CO_2e, rising to C$30 per metric ton CO_2e in July 2012, with no further increases planned as yet. In order to make the tax revenue-neutral for the government and to cushion the impact to the overall economy, the revenue from the carbon tax is returned to corporations and residents via tax credits and incentives.

The overall impact on electricity users is minimized because ~85% of the province's generation comes from hydropower. The province's cement industry, however, seems to be negatively affected. According to the Cement Association of Canada, cement imports from Asia rose from 5% in 2008 to 20% in 2011.[68]

The Greenhouse Gas Reduction (Cap and Trade) Act of 2008[69] provides a statutory basis for British Columbia to develop a GHG cap-and-trade system, and the province is in the process of developing a proposed Emissions Trading Regulation and a proposed Offsets Regulation.

Accommodating CCS Under California's GHG Emissions Policies

California's statewide GHG emissions were at 456.8 $MMTCO_2e$ in 2009, a slight decrease from 2000 emissions levels, due to the economic recession and higher fuel prices.[70] Emissions from transportation were at 160 $MMTCO_2e$.[71] Some 88 $MMTCO_2$/yr can be attributed to 68 large point sources, primarily power and cogeneration plants, oil refineries, and petroleum and natural gas production.[72] Several legislative and policy drivers for reducing CO_2 emissions are relevant to the deployment of CCS in California.

The Global Warming Solutions Act of 2006 – AB 32

Executive Order S-3-05 established three GHG reduction target for the state: 2000 levels by 2010; 1990 levels by 2020; and 80% below 1990 levels by 2050. In 2006, Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006 – AB 32) committed the state to follow a number of methods to achieve the second goal.

---

[66] British Columbia Climate Action Plan. (http://www.gov.bc.ca/premier/attachments/climate_action_plan.pdf).
[67] *Coal Resources in British Columbia: Opportunities, Logistics and Infrastructure*, British Columbia Ministry of Energy, Mines and Petroleum Resources.
(http://www.em.gov.bc.ca/Mining/investors/Documents/Coal15Feb2010web.pdf)
[68] Marshall, Christa. "British Columbia Survives 3 Years and $848 Million Worth of Carbon Taxes," *The New York Times*, March 22, 2011.
[69] http://www.env.gov.bc.ca/cas/mitigation/ggrcta/emissions-trading-regulation/#summary
[70] http://www.arb.ca.gov/cc/inventory/pubs/reports/ghg_inventory_00-09_trends.pdf
[71] Ibid.
[72] Facilities with over 500,000 $MMTCO_2$/yr. Based on EPA 2010 GHG inventory data.

In December 2007, the California Air Resources Board (CARB) approved a 2020 emission limit of 427 $MMTCO_2e$. Other provisions of the bill directed CARB to adopt a Mandatory Reporting Regulation requiring the largest industrial sources to report and verify their GHG emissions, prepare a scoping plan, identify and adopt regulations for discrete early actions, and adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit GHG emissions.[73]

In its Climate Change Scoping Plan,[74] CARB proposed to implement a program that would place an overall limit or cap on GHG emissions from sources in most of California's economic sectors. Within capped sectors, some emissions reductions will be attained through direct regulations (e.g., low carbon fuel standard [LCFS], vehicle 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.

CARB approved a statewide cap-and-trade regulation in 2011.[75] As part of the resolution, CARB directed its 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 CARB's monitoring, reporting, verification, and permanence requirements."[76]

Under the cap-and-trade system, 90% of the allowance credits are assigned for free during the first two years. Additional allowances may be purchased at auction, or emitters may elect to fulfill up to 8% of their compliance obligation with CARB-approved offsets. CARB held the first allowance auction on November 14, 2012. The auction produced a settlement price of $10.09, nine cents above the floor price, with all 23.1 million available 2013 allowances sold, as well as 14% of the 40 million credits for 2015.[77] A note of uncertainty was introduced when the California Chamber of Commerce filed a lawsuit on the eve of the auction asserting that CARB had exceeded its authority by establishing an auction and equating the aution to "an unconstitutional tax."[78] CARB's proposed use of offsets has also been challenged in a separate lawsuit by two public interest groups.[79]

Low Carbon Fuel Standard

Executive Order S-1-07 directed CARB to create a LCFS to help meet the 2020 goal outlined in AB 32. The order calls for a reduction of at least 10% 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

[73] http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf
[74] *Climate Change Scoping Plan – A Famework for Change,* California Air Resources Board, December 2008.
[75] http://www.arb.ca.gov/newsrel/newsrelease.php?id=245
[76] State of California, Air Resources Board, California Cap-and-Trade Program, Resolution 10-42, December 16, 2010, Agenda Item No.: 10-11-1. (http://www.arb.ca.gov/regact/2010/capandtrade10/res1042.pdf)
[77] http://www.arb.ca.gov/cc/capandtrade/auction/november_2012/auction1_results_2012q4nov.pdf
[78] http://www.lexology.com/library/detail.aspx?g=bdd186b0-5c42-4a64-9145-815148db48bb
[79] http://www.martenlaw.com/newsletter/20120416-calif-cap-and-trade-rules-challenge

and has its own reporting tools and credit-trading requirements. CCS is specified as an option for producers of high carbon intensity crude oil to reduce emissions for production and transport of crude oil. 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.

An assessment by the California Council on Science and Technology of strategies for achieving the 2050 goal of reducing GHG emissions to 80% below 1990 levels stated that "for California, the utility of CCS in achieving a low carbon fuel portfolio could be as important as the utility of CCS for electricity production per se."[80]

The LCFS has met with legal challenges, which could influence the scope and timing of regulations. In December 2011, the U.S. District Court, Eastern District of California, ruled that the LCFS violated the commerce clause of the U.S. Constitution by interfering with and discriminating against interstate commerce, and issued an injunction prohibiting its enforcement. In April 2012, a panel of the U.S. 9th Circuit Court of Appeals removed the lower court's injunction, thus allowing ARB to move forward with the program, pending a final decision.[81]

Emissions Performance Standards

The California Public Utilities Commission (CPUC),[82] in the case of investor-owned utilities, and the Energy Commission,[83] in the case of public power, implement California's EPS for power plants, which was instituted under Senate Bill 1368.[84]

The current regulations allow for the use of CCS to meet California's EPS, but the mechanisms for determining compliance are unclear. The Energy Commission regulation states that for covered procurements that employ geologic CO_2 storage, 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:

- 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

These requirements differ from AB 32 requirements in a few key ways.[85] First, the EPS is based on emissions over the lifetime of the plant whereas AB 32 is based on annual emissions, and the LCFS

[80] *California's Energy Future – The View to 2050: Summary Report,* California Council on Science and Technology, May 2011.
[81] http://www.arb.ca.gov/fuels/lcfs/LCFS_Stay_Granted.pdf
[82] http://www.cpuc.ca.gov/PUC/energy/Climate+Change/070411_ghgeph.htm
[83] http://www.energy.ca.gov/emission_standards/index.html
[84] Perata, Chapter 598, Statutes of 2006.

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).

CPUC modified its rules implementing the EPS in July 2009, to further clarify the 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.[86]

In 2008, the Energy Commission and the Department of Conservation issued a joint report to the Legislature in compliance with AB 1925, which required that these agencies produce a report making recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for long-term management of industrial CO_2.[87] In 2010, as a follow-on to the report, in recognition of the need for a coordinated approach to developing CCS regulations, the CPUC, Energy Commission, and CARB convened a Carbon Capture and Storage Review Panel of experts drawn from industry, trade groups, academia, and environmental organizations. The Panel was instructed 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.[88]

The Panel held five public meetings in 2010 featuring testimony from technical experts and key stakeholders, and deliberations among the panelists. At the end of the year, the Panel issued twelve recommendations[89] addressing key permitting, legal, and socio-economic issues for CCS in California.

The panel recommended that California evaluate current EPA regulations and determine which, if any, state agency should seek "primacy" for permitting Class VI wells under the UIC program. California

[85] "AB 32 Regulations and CCS," Appendix M, *Background Reports for the California Carbon Capture and Storage Review Panel*, California Institute for Energy and Environment (CIEE), Berkeley, California, December 2010.
[86] 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.
(http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/121474.htm)
[87] Burton, Elizabeth A., Richard Myhre, Larry Myer, and Kelly Birkinshaw, 2008. *Geologic Carbon Sequestration Strategies for California: The Assembly Bill 1925 Report to the California Legislature.* California Energy Commission Systems Office, CEC-500-2007-100-SF.
[88] *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.
[89] http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2011-01-14_CSS_Panel_Recommendations.pdf

currently has primacy for UIC Class II wells, which are administered by the Division of Oil, Gas and Geothermal Resources. It would take enabling legislation for the state to assume primacy for Class VI wells, along with a successful application to U.S. EPA.

Other significant panel recommendations include:

- The state legislature should declare that the surface owner is the owner of the subsurface “pore space” needed to store CO_2. The legislature should further establish procedures for aggregating and adjudicating the use of, and compensation for, pore space for CCS projects.

- The state should consider legislation establishing an industry-funded trust to manage and be responsible for geologic site operations in the post-closure stewardship phase. In addition, California should proactively participate in federal legislative efforts to enact similar post-closure stewardship programs under federal law.

- The state legislature should establish that any cost allocation mechanisms for CCS project should be spread as broadly as possible across all Californians.

CCS legislation has been introduced several times seeking to establish regulatory clarity and address the statutory issues raised by the California CCS Review Panel. To date, none of these bills has passed into law.

Looking Beyond 2020 for California

Research and scenario modeling demonstrate that CCS will be critical to meeting California’s 2050 reduction goal of 80% below 1990 GHG levels,[90] as set forth in Executive Order S-3-05. However, because this target has not yet been codified into law and no provisions for attaining that goal have been mandated by the California legislature, the justification for making the large, long-term capital investments required to develop CCS is missing. Providing legislative certainty for the state’s commitment to the 2050 goal would lend confidence to developers and financiers to undertake CCS projects, which would help ensure that the technology reaches commercial readiness in time to contribute significantly to post-2020 GHG emissions reductions.

Carbon Market Evolution and Coordination

The Western Climate Initiative[91] (WCI) began in 2007 when the governors of Arizona, California, New Mexico, Oregon, and Washington signed an agreement directing their respective states to develop a regional target for reducing GHG emissions, participate in a multi-state registry to track and manage GHG emissions in the region, and develop a market-based program to reach the target. The WCI has grown to include the states of Montana and Utah and the provinces of British Columbia, Manitoba, Ontario, and Quebec.

[90] *California’s Energy Future – The View to 2050*.
[91] http://www.westernclimateinitiative.org/

The main component of the WCI strategy is a regional GHG cap-and-trade program.[92] Inherent in this joint effort is the understanding that a carbon market covering a diverse set of emission sources and a broad geographic area provides a wider range of reduction opportunities, reduces overall compliance costs, and can help minimize leakage. The roadmap for a broad-based carbon market would start with state/province-based markets merging into a regional market, followed by linking of regional markets, followed by a federally inclusive market, and ultimately the emergence of a market covering all of North America.

This is the vision behind the North America 2050 Partnership,[93] which involves state and provincial representatives from WCI, the Regional Greenhouse Gas Initiative (RGGI), and the Midwestern Greenhouse Gas Reduction Accord (Midwest Accord), who share information, engage federal agencies on policy matters, and support progress on energy and climate topics at the state and provincial level.

Among WCI participants, British Columbia, Ontario, and Quebec are still developing cap-and-trade programs. Of the WCI states, only California has enacted cap-and-trade. The program is set to launch in January 2013. Quebec’s program is on roughly the same schedule.

Technology Infrastructure

A commercial-scale CCS infrastructure will involve three major components:

- Modification of multiple large point sources (power plants, oil refineries, cement plants, etc.) to separate (capture) CO_2 from combustion exhaust gases, or in some cases from fuel gases before combustion
- A pipeline or other transportation network that delivers CO_2 to geologic storage sites (including sites for EOR or other subsurface utilization technologies)
- Infrastructure to inject CO_2 into deep porous rock formations, along with monitoring, reporting, and verification (MRV[94]) activities to account for the volume of CO_2 injected and the efficacy of the storage sites

Because of the international scope of many equipment suppliers and service providers involved in CCS technology development, and because of the public/private collaborative nature of many CCS projects and research programs, the WESTCARB region stands to benefit from and contribute to research and demonstration projects globally, which provide technology transfer and lessons learned.

Capturing CO_2

Three approaches to CO_2 capture—post-combustion, oxy-combustion, and pre-combustion—are currently the focus of extensive research, development, and demonstration (RD&D).[95,96] Coal-fueled power plants

[92] *Design for the WCI Regional Program*. (http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design)
[93] http://na2050.org/north-american-partnership-launched/
[94] Other similar terms are frequently used including MVA for monitoring, verification, and accounting, and MMV for monitoring, measurement, and verification.

are often selected for research by technology developers because of their high emissions; however, many of the processes being developed are also applicable to other power plants such as NGCC, or to other industrial facility types.

Post-Combustion CO_2 Capture

Post-combustion CO_2 capture technologies are applied after fuel combustion by separating CO_2 from the flue gas at process pressure (typically atmospheric) before the flue gas is exhausted from the plant. Post-combustion capture can be used on pulverized coal power plants, biomass power plants, NGCC plants, cement plants, and fired-furnaces or industrial boilers if large enough to be economical. Most of these technologies pass the flue gas through an absorber (scrubber), where a liquid solvent (usually an amine or ammonia compound) or a solid sorbent selectively absorbs the CO_2. The CO_2-rich solvent passes to a regenerating column (stripper), where it is heated to release a nearly pure CO_2 stream. The solvent is recycled back to the absorber to capture more CO_2. The separated CO_2 is dewatered and sometimes passed through a further stage of clean-up before compression for sale or storage.

Technologies for amine scrubbing of acid gases have been used for over 60 years in the natural gas processing, oil refining, and chemical industries, however, only a few smaller facilities use amines to capture CO_2 from oxidized gases, such as flue gas.[97] Thus, existing post-combustion capture technologies need to be scaled up to handle the higher emission volumes from power plants and other large industrial facilities. This requires larger absorption and stripping equipment and associated pumps and heat exchangers. A second challenge is posed by the energy needed to regenerate the solvent and compress the CO_2, which adds considerably to costs.

In the United States and internationally, an extensive RD&D effort is focused on improving the performance and lowering the cost of post-combustion CO_2 capture processes. Many candidate solvent formulations have been developed and tested, with the goal of achieving greater absorption capacity, faster reaction rates, less energy demand for regeneration, greater ability to accommodate flue gas contaminants, and reduced corrosivity to allow use of less expensive materials.

Two larger demonstrations at coal-fired power plants in the United States are at the American Electric Power (AEP) Mountaineer Plant in West Virginia using Alstom's Chilled Ammonia process and at Southern Company's Plant Barry in Alabama using Mitsubishi Heavy Industries' KM-CDR process and KS-1 amine solvent. At Mountaineer, the chilled ammonia pilot drew flue gas from a 20 MW equivalent slipstream for more than 6,500 hours between October 2009 and May 2011, and captured more than 50,000 metric tons of CO_2, of which some 37,000 metric tons were injected for geologic storage in two saline formations. A major scale-up of this technology at the Mountaineer Plant was placed on hold in

---

[95] *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap,* December 2010. (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf)
[96] *Advanced Coal Power Systems with CO_2 Capture,* EPRI, 1023468.
[97] *2010 Carbon Sequestration Leadership Forum Technology Roadmap: A Global Response to the Challenge of Climate Change*, November 2010.

July 2011. AEP cited the "current uncertain status of U.S. climate policy" as one of the reasons for its decision.[98]

CO_2 capture at Plant Barry started in June 2011, from a 25 MW flue gas slipstream (500 metric tons of CO_2 per day) at 90% removal efficiency. The captured CO_2 is supplied to the Southeast Regional Carbon Sequestration Partnership (SECARB) for transport via a 12-mile pipeline and injection into the Paluxy Formation (saline) within the Citronelle Dome. Injection operations started in August 2012. The project plans to store at least 200,000 metric tons of CO_2 over a two-year period, followed by three years of post-injection monitoring.[99]

Three projects in North America focused on gaining larger-scale post-combustion CO_2 capture operating experience in integrated power generation are:

- W.A. Parish Generating Station in Texas, NRG Energy, using Fluor Econamine FG Plus (amine) technology on a 240 MW subbituminous coal-burning unit to capture 1.4 $MMTCO_2$/yr. The original 60 MW equivalent project was scaled up to allow for CO_2 sales for EOR operations in the West Ranch Oil Field in Texas; CO_2 will be transported via an 80-mile pipeline.[100]

- Trailblazer Energy Center in Sweetwater, Texas, Tenaska Energy, a 600 MW unit with 85–90% capture using Fluor Econamine FG Plus, The project plans to sell the CO_2 for EOR in the Permian Basin.

- Boundary Dam Integrated Carbon Capture and Storage Demonstration Project, SaskPower, Canada, using Cansolv (amine) technology on a ~100 MW lignite-burning unit to capture 1 $MMTCO_2$/yr. Plans include selling the CO_2 for EOR in the Weyburn and Midale oil fields and providing CO_2 to the Petroleum Technology Research Centre's Aquistore research project for storage in a saline formation.

While the current generation of post-combustion technologies undergo scale up and integration into real-world power plants, research into a second generation of post-combustion technologies is advancing through lab- and small-scale testing. Alternative second-generation technologies include:

- Molecular sieves and solution-diffusion membranes

- Cryogenic separation processes that freezes out the CO_2

- Biological and mineral fixation processes

- Chemical looping

[98] Wells, Ken and Benjamin Elgin. "Carbon Capture Hopes Dim as EPA Says it Got Burned at Coal Plant," *Bloomberg,* July 20, 2011.
[99] http://www.fossil.energy.gov/news/techlines/2012/12037-CO2_Injection_Begins_in_Alabama.html
[100] http://www.netl.doe.gov/publications/factsheets/project/FE0003311.pdf

In the WESTCARB region, DOE provided funding to Membrane Technology and Research, Inc. (MTR) of Menlo Park, California, to construct a membrane skid for CO_2 capture from a slipstream of coal-fired flue gas. MTR's Polaris membrane system was tested at Arizona Public Service's Cholla Power Plant for six months in 2012 using at 0.050 kW scale. With further funding from DOE, the technology will be scaled up to a 1 MW slipstream at DOE's National Carbon Capture Center in Wilsonville, Alabama (where initial sub-MW scale testing has also taken place). Delivery of the system is expected in mid-2013. MTR estimates that when commercial the Polaris technology can will be able to capture 90% of a coal-fired power plant's CO_2 emissions with an energy penalty of 20–25% at a cost of $30 per metric of CO_2 captured.

Other technologies undergoing testing at Arizona Public Service's the Cholla Power Plant are hydrogasification (conversion of coal to synthetic natural gas using hydrogen instead of air or oxygen) and CO_2 emissions capture using algae, which can be processed into liquid transportation fuels.

Oxy-Combustion

The process of burning fuel in high-purity oxygen instead of air (which is roughly 79% nitrogen, 21% oxygen) is called oxy-combustion (Figure 13). This approach, which requires an oxygen production plant (typically an air separation unit) integrates CO_2 capture into the combustion process because precluding nitrogen results in a flue gas consisting primarily of CO_2 and water at significantly reduced volume. After dewatering and purification to remove trace gases and non-condensibles, CO_2 can be compressed for sale or storage.

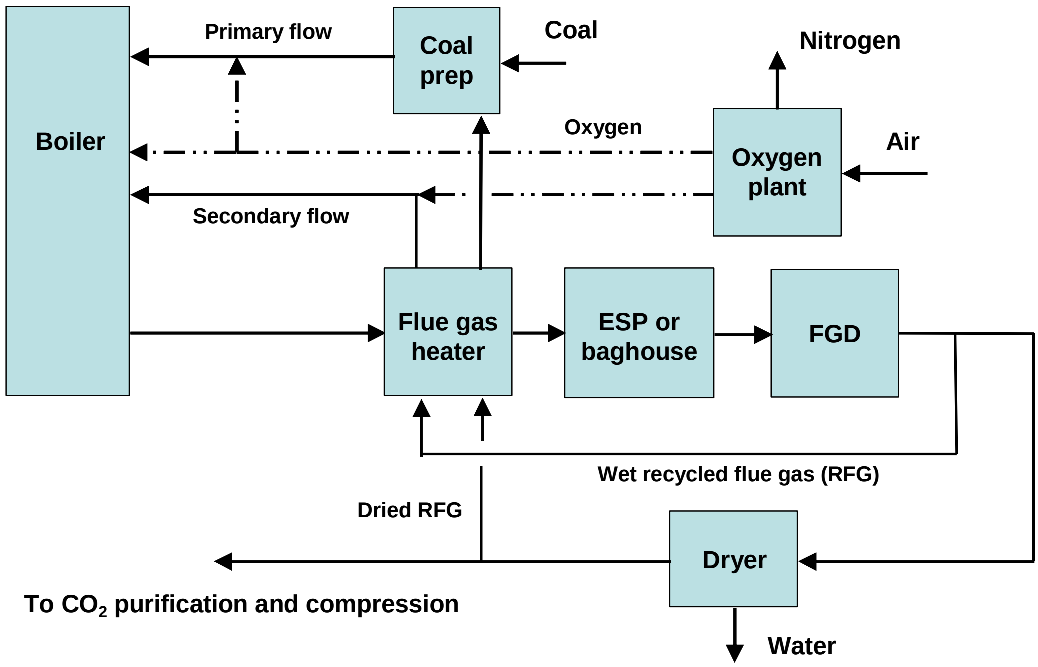

Figure 13. Schematic of oxy-combustion process for pulverized coal[101]

A key to deploying oxy-combustion economically will be the development of less energy-intensive technologies for oxygen production and CO_2 purification. Demonstrations of oxy-combustion for power generation in the 5–10 MW range have been successfully conducted in the United States. The FutureGen 2.0 project in Meredosia, Illinois, plans a 170 MW oxy-combustion unit with 90% CO_2 capture and saline formation storage.[102] The Callide Oxyfuel Project[103] in Queensland, Australia, a two-year demonstration of oxy-combustion technology retrofitted on a 30 MW coal-fired unit, includes plans to capture and store about 60,000 metric tons of CO_2 in a saline aquifer or depleted natural gas field. The Compostilla Project[104] in Spain, a 300 MW oxy-combustion project with saline formation storage, is targeted for startup in 2015–2016.

Pressurized oxy-combustion processes are also under development. An example within the WESTCARB region is Clean Energy Systems' (CES) of Rancho Cordova, California, which employs a rocket-engine-derived gas generator to create a working fluid (for turbo-expansion) of 10–20% CO_2 and 80–90% steam.[105] The CES combustor is capable of firing natural gas, CO-rich synthesis gas, or carbonaceous

[101] Wheeldon, John and Des Dillon. "Oxy-Combustion of Coal," presentation at EPRI CoalFleet Meeting, Greenville, South Carolina: July 26, 2007.
[102] http://www.futuregenalliance.org/futuregen-2-0-project/
[103] http://www.callideoxyfuel.com/What/CallideOxyfuelProject.aspx
[104] http://compostillaproject.eu/en/project
[105] http://www.cleanenergysystems.com/overview/ces_technology.html

liquids such as oil emulsions with oxygen at very high temperature; water injection for cooling immediately downstream of the combustor provides the steam comprising the majority of the working fluid, which is expanded through a high-temperature steam turbine, a modified gas turbine with reheat that serves as an intermediate-pressure turbine, and a low-pressure steam turbine. A 5 MW pilot unit was successfully tested at the Kimberlina Power Plant near Bakersfield, California, in the mid-2000s. In 2012, CES installed a 200 MW scale intermediate-pressure turbine test unit (modified from a gas turbine with Siemens) for testing in early 2013. CES is pursuing additional scale-up demonstrations and commercial projects in the United States, Europe, and the Middle East.

Pre-combustion CO_2 Capture

Pre-combustion capture technologies separate CO_2 from chemically processed gaseous fuels prior to combustion. Development efforts are focused on integrated gasification combined cycle (IGCC) power plants, which process low-cost and/or difficult to burn fuels such as coal, petroleum coke, or biomass. Gasification reactions at high temperature and moderate to high pressure partially oxidize carbon-rich fuels to produce a synthesis gas (syngas) consisting chiefly of carbon monoxide (CO) with some hydrogen and methane. CO_2 capture occurs downstream of the gasifier at moderate temperatures where steam is injected into the syngas and passed over a catalyst (known as water-gas shift reactor), which converts CO into CO_2 while producing additional hydrogen. A commercial acid gas removal process is then used to separate the CO_2 from the hydrogen and methane (all while still under pressure), which is combusted in a gas turbine to generate electricity. With the addition of CO_2 capture, turbine modifications may be required to allow the firing of hydrogen-rich syngas.

Technologies for pre-combustion CO_2 capture have extensive commercial history for removal of hydrogen sulfide (H_2S) and CO_2 from syngas produced in the petrochemical industry. Chemical (amine) and physical solvents have been used for many years at a scale approaching that needed for IGCC units, as have the water-gas shift processes that convert CO to CO_2 while producing a high-hydrogen fuel.

Much of the resurgent interest in IGCC power plants is motivated by the potential to capture CO_2 at a lower incremental cost relative to CO_2 capture for supercritical pulverized coal units, due to the inherent advantage of higher CO_2 partial pressure at the point of capture. Major IGCC projects with CO_2 capture are listed in Table 3.

Table 3. IGCC projects with CO_2 capture in the United States

Project	Net MW, Fuel	Gasifier/Acid Gas Recovery Technology	Storage, (Projected Startup Date)
Summit Texas Clean Energy Project (TCEP)	200 MW, subbituminous coal	Siemens/Selexol	2.7 MMT/yr for EOR with Urea Co-Production (2014)
Southern Company (Kemper County)—Mississippi	524 MW, lignite	TRIG/Selexol	2 MMT/yr for EOR (2014)
Hydrogen Energy California (HECA)	288 MW, coal/petroleum coke	MHI/Rectisol	2 MMT/yr for EOR with Urea Co-Production (2017)

CO_2 Purification and Compression

Water is normally removed in conjunction with CO_2 compression. Other impurities (oxygen, argon, nitrogen) typically require added purification step. The combination of sulfur species and moisture/oxygen can rapidly corrode pipeline, injection well, and possibly compressor component materials. In general, the purity requirements of the receiving pipeline or geologic formation will determine which contaminants must be removed. A capture technology that maximizes the pressure and purity of the CO_2 product will generally reduce the costs of downstream purification and compression equipment. Overall costs become relatively higher when a purer CO_2 product is required.

CO_2 is commonly compressed to about 2000 psi (a pressure at which it is a supercritical fluid) to make transportation and subsurface injection and storage more efficient. With current technology, compression of the CO_2 produced at a pulverized coal power plant may require as much as 8% of the plant's net power output.

Reduced Emissions Through Power Plant Efficiency Improvements

Improving the thermodynamic efficiency of power plants is a sound CO_2 emissions reduction strategy, which reduces all other emissions, as well. Increased thermodynamic efficiency lowers fuel consumption and reduces the amount of CO_2 generated per unit of plant output. A six percentage-point gain in plant efficiency, for example, provides a reduction in fuel consumption of roughly 20% and can provide similar reductions in CO_2 emissions.[106]

A more efficient power plant can also use a smaller, less-expensive CO_2 capture system. DOE's Advanced Materials Research Program is focused on developing high-temperature, corrosion-resistant alloys and coatings that will enable power plants to operate at higher temperatures and pressures with fewer emissions and reduced CO_2 capture costs. Other efficiency gains, with corresponding reduced

[106] *Advanced Coal Power Systems with CO_2 Capture*, EPRI, 1023468.

emissions, are expected through innovations or improvements across a range of existing power plant processes, as their costs and benefits relative to CO_2 capture are better understood.

Retrofits

It is expected that CO_2 capture and compression equipment will be installed on existing generating units as well as new units. If CO_2 capture is retrofit to existing plants as an element of an overall repowering project, some of the efficiency and capacity loss inherent to the CO_2 capture process could be offset by other improvements.

Coal-fired power plant economics suggest retrofits are most likely for large plants with high capacity factors and long remaining lives. Additional considerations include:

- Sufficient space for new CO_2 capture system and compression equipment (typically about 6 acres for a 500 MW unit)
- Adequate water supply (to accommodate increased cooling demand)
- High-performance NO_2 and SO_2 controls to reduce concentrations in the flue gas entering the CO_2 absorber to about 10 ppm or less (the exact requirement varies by solvent)
- Access to a geologic storage or opportunities to sell captured CO_2

Similarly, applying CO_2 to NGCC plants will be most economical on plants with high capacity factors and long remaining lives. The required plot space and water requirements are roughly comparable to coal plants per MW of capacity.

Water Use

The need for additional water for CO_2 capture and compression processes may pose a challenge in arid areas of the WESTCARB region or wherever water supplies are restricted.

A variety of cooling system tradeoffs should be considered when adding or retrofitting CCS, such as increased heat integration between the power plant, capture, and/or compression processes.

Many power plants also now use “zero liquid discharge” (ZLD) wastewater treatment systems to upgrade and reuse power plant wastewater. ZLD systems use evaporative or reverse osmosis processes to concentrate the impurities in the wastewater while also producing a water stream for reuse. A further evaporative process may then be used to recover most of the remaining water, leaving the impurities as solid salt cake. CO_2 capture and compression waste heat may be able to be used in the water treatment process. [107]

Alternative water sources include treated municipal wastewater, degraded surface waters such as agricultural runoff, water extracted for mitigation of groundwater contaminants, and produced water from

[107] Ibid.

oil and gas production. Additional treatment will often be required before these waters can be used in power plant or CO_2 capture and compression cooling systems.

With geologic CO_2 storage, it may be possible to supplement power plant water supply with saline formation water extracted to reduce pressure buildup from CO_2 injection. Initial calculations show that the displaced water could meet up to a third of the power plant's raw water requirements depending on the cost of reducing salinity to suitable levels.[108]

CO_2 Pipeline Transport, Safety, and Siting

Because geologic formations capable of storing CO_2 do not always underlie the facilities where CO_2 will be captured, pipelines will be needed to move compressed CO_2 from the industrial source facility to the injection site where long-term storage can take place.

Although there are no large-capacity CO_2 pipelines in the WESTCARB region at present, future development can draw on an experience base that spans almost 40 years and 3,600 miles (5800) km of CO_2 pipelines used in CO_2-EOR operations in Texas, New Mexico, Wyoming, and Mississippi, as well as a 200-mile pipeline that transports CO_2 from the Dakota Gasification Company's Great Plains synfuels plant in North Dakota to the Weyburn-Midale EOR operation in Saskatchewan, Canada.

[108] Ibid.

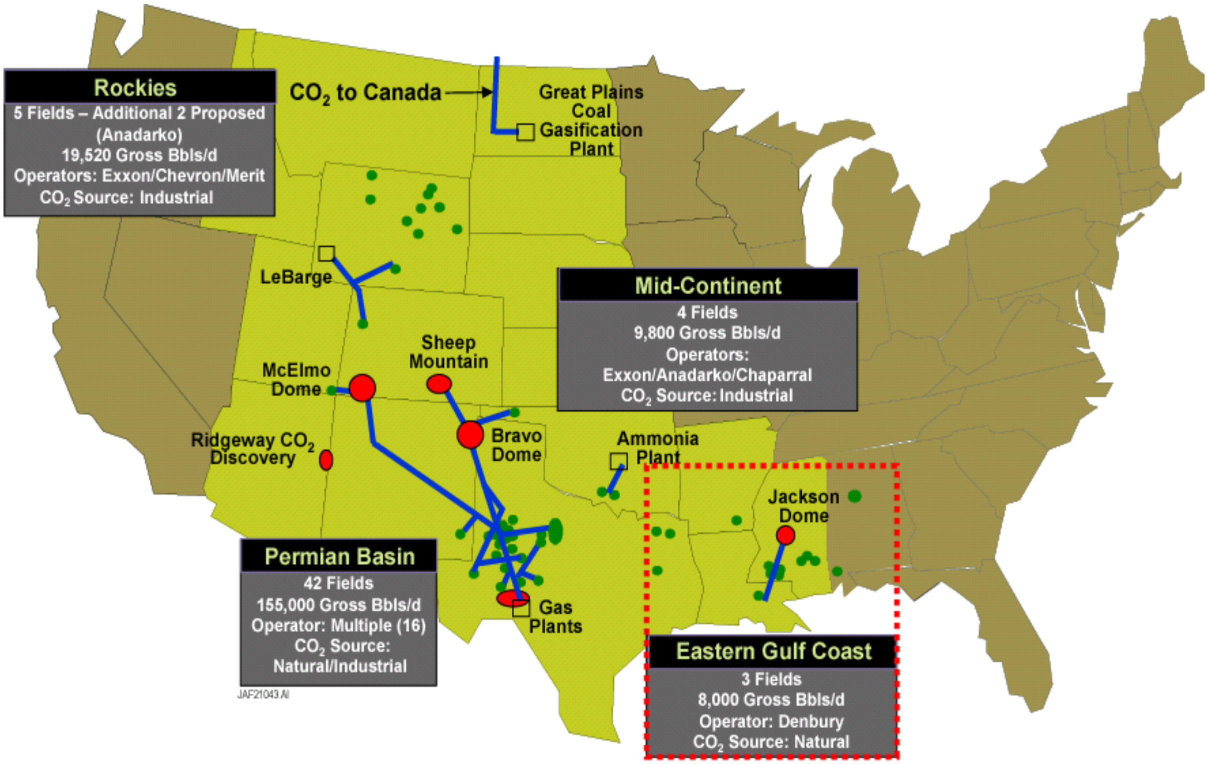

Figure 14. Map showing location of major CO_2 pipelines for EOR in the United States[109]

CO_2 does not manifest hazardous properties (i.e., toxicity, reactivity, flammability, or explosivity) that would result in regulatory classification as a hazardous material. However, current U.S. Department of Transportation requirements for pipelines transporting CO_2[110] direct the operator to perform a risk assessment. Considerations that inform pipeline design include leak detection, potential hazards (river erosion, seismic activity, etc.), environmental requirements, materials selection based on CO_2 specifications, access to valve sites, and operations and maintenance requirements.[111] Regular safety inspections and monitoring, which are established procedures in the pipeline industry, are necessary during operation, as well as keeping mitigation plans up-to-date in case of an equipment failure or leak.

CO_2 pipelines are designed and built to last for the commercial life of a project. Owners of CO_2 pipelines acting as common carriers have set specifications that limit some impurities to very low concentrations,

[109] Simbeck, Dale. "CO_2 Capture Technologies." Working Group Meeting on AB-1925 Report to the California Legislature on Accelerating Geologic Carbon Sequestration Strategies, Sacramento, CA, June 28, 2007.
[110] 49 Code of Federal Regulations [CFR] 195.
[111] Barrie, J., et al. *Carbon Dioxide Pipelines: A Preliminary Review of Design and Risks.* (http://uregina.ca/ghgt7/PDF/papers/peer/126.pdf)

generally for corrosion prevention.[112] For example, Kinder Morgan mandates oxygen concentration of less than 10 ppm, but can accommodate CO_2 containing nitrogen, argon, carbon monoxide, and light hydrocarbons at concentrations up to a total of 9%.[113] For acid gases (mostly sulfurous compounds), there does not appear to be an industry consensus. In some cases, the allowable concentration of sulfur dioxide is as low as 5 ppm. For a contract pipeline, the specifications will be up to the CO_2 supplier and user; for example, the Weyburn-Midale EOR operation allows oxygen up to 50 ppm and H_2S up to 20,000 ppm[114] because the gas is extremely dry.

Pipeline Networks Assessment in California

A preliminary analysis by the Clinton Foundation[115] identified three areas in California that could serve as hubs for CO_2 pipeline network development, based on the economic aggregation of CO_2 emissions from industrial sources and relatively short distance to sinks. In the San Francisco East Bay, 11 facilities within about a 20 mile (30 km) radius account for 14 $MMTCO_2$/yr and lie within relative proximity to the Sacramento Basin. In the Bakersfield area, 10 facilities within a 40 mile (60 km) radius account for 12.5 $MMTCO_2$/yr, with potential CO_2 storage sites and EOR opportunities found in relative proximity within the southern San Joaquin Basin. In the Los Angeles basin, 11 facilities account for 15.3 $MMTCO_2$/yr, for which storage in offshore basins could be an option.

CO_2 Injection

The injection techniques for geologic CO_2 storage are in commercial use today. The oil and gas industry in the United States has been injecting and monitoring CO_2 in the deep subsurface for the purposes of enhancing oil production for 40 years. This experience provides a robust foundation for the injection and monitoring technologies that will be needed for commercial-scale CCS.

An experience base is also developing for injection of CO_2 into saline formations, which are much more prevalent than depleted hydrocarbon reservoirs or producing oil fields suitable for CO_2-EOR. Operations in Norway[116] and Algeria[117] are each injecting over 1 $MMTCO_2$/yr. In the United States, the first injection into a saline formation of CO_2 from coal-derived flue gas was performed in October 2009 at the Alstom chilled ammonia capture pilot at AEP's Mountaineer plant. A larger injection of CO_2 from a coal plant (Southern Company's Plant Barry) is now under way in at Citronelle Dome in Alabama.[118] Multiple small-scale CO_2 injections into saline formations were successfully conducted as part of DOE's Regional

[112] *Carbon Dioxide Compression and Transportation: Issues and Research & Development Plans.* EPRI, Palo Alto, CA: 2008. 1016794.
[113] *Advanced Coal Power Systems with CO_2 Capture,* EPRI, 1023468.
[114] Ibid.
[115] Springer, Daniel and Dorota Keverian. "California Carbon Capture and Storage," presentation at WESTCARB's Annual Business Meeting, October 26, 2011, Lodi, California.
[116] http://www.statoil.com/en/TechnologyInnovation/ProtectingTheEnvironment/CarboncaptureAndStorage/Pages/CarbonDioxideInjectionSleipnerVest.aspx
[117] http://www.insalahco2.com/
[118] http://www.secarbon.org/files/anthropogenic-test.pdf

Carbon Sequestration Partnerships program,[119] adding to confidence that many saline formations can effectively store CO_2.

An important distinction between CO_2 injection for storage and CO_2 injection for EOR has to do with managing subsurface flow rates and pressure. Both practices increase reservoir pressure, however, a storage-only project may contend with greater overall pressure increases because there is no concurrent production of hydrocarbons. This issue is highly site specific, depending on the size of the reservoir, the type of closure, and the extent of geological heterogeneities. More experience with industrial-scale CO_2 storage projects is needed to refine formation pressure management options and understand associated costs.

Monitoring, Reporting, and Verification[120]

Monitoring, reporting, and verification (MRV)[121] refers to activities for collecting and reporting data about the characteristics and performance of the injection and storage of CO_2. These activities span the duration of CO_2 storage projects, starting with site characterization and continuing through injection operations, site closure, and post-closure phases.

Most current monitoring and measuring technologies for CO_2 storage are used directly or adapted from applications in oil and gas production, natural gas storage, wastewater injection, and groundwater monitoring. These established practices provide numerous measurement techniques and options—a monitoring toolbox—which enables development of tailored, flexible monitoring programs for CO_2 injection and storage.

The value of a tailored approach is threefold: first, optimum performance of many techniques depends on site-specific geologic attributes; second, the parameters 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. A tailored approach is compatible with regulations that are largely performance-based and non-prescriptive with regard to measurement methods. The downside of a tailored approach (from the perspective of a project developer) lies with the timeframe required for a permitting/compliance agency to review a tailored plan, and potentially coordinate reviews among several agencies, which will take longer than what would be required for a prescriptive approach.

EPA, in developing rules for CO_2 injection under the UIC program, generally adopted a tailored or performance-based approach to monitoring whereby project-specific testing and monitoring plans must receive approval from the UIC Director. States seeking primacy for Class VI wells will need to develop monitoring requirements that are consistent with EPA guidance, although states may choose to be more stringent. One noteable requirement of the Class VI regulation is a default 50-year post-injection site care period, entailing periodic monitoring of the site and tracking of the CO_2 plume to ensure USDWs are not

[119] http://www.fe.doe.gov/programs/sequestration/partnerships/
[120] Myer, Larry. "Monitoring, Verification, and Reporting Overview," Appendix Q, *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.
[121] The term monitoring, verification, and accounting (MVA) is also commonly used.

endangered. This timeframe can be shortened or lengthened at the discretion of the UIC Director based on site-specific data.[122]

DOE is actively pursuing research, including field testing, of monitoring techniques and practices for CCS with a goal of achieving a level of accountability such that greater than 99% of injected CO_2 can be credited and contribute to the economic viability of a storage project.[123] DOE has also published a first edition best practices guide to MRV,[124] and plans to publish an updated edition by 2016.

Additional challenges to establishing viable MRV methods arise when CO_2 is utilized for enhanced hydrocarbon recovery or other subsurface applications. In addition to meeting regulations addressing safety of people and natural resources, such as the Class VI regulations, monitoring will have to be sufficient to provide defensible data for accounting protocols to be developed for emission allowance cap-and-trade or other air regulation certification. For example, in EOR operations, CO_2 returning to the surface with produced oil is separated and reinjected numerous times in a manner akin to a closed system.

The Importance of Baselines and Subsurface Modeling

Establishing a baseline for existing site conditions is an essential early step for successful monitoring of CO_2 storage projects. 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. A well-defined baseline includes not only the average value of the parameters measured, but accounts for how they vary over time (e.g., annual cycle for soil CO_2 concentrations) 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 CO_2 storage projects, baseline data will be obtained during the pre-injection phase of the project.

A key output of site characterization is the subsurface geomodel (Figure 15), which is used to predict the position and relative saturation of CO_2. As the collection and analysis of monitoring data continues throughout the project, comparisons of actual measurements with model predictions are made repeatedly to determine if the project is performing as expected, and to adjust the initial subsurface model, which leads to increased confidence in subsequent model predictions.

[122] 75 Fed. Reg. 77267 (Decemer 10, 2010).
[123] *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, December 2010.
[124] *Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations*, DOE/NETL-311/081508 National Energy Technology Laboratory, January 2009.

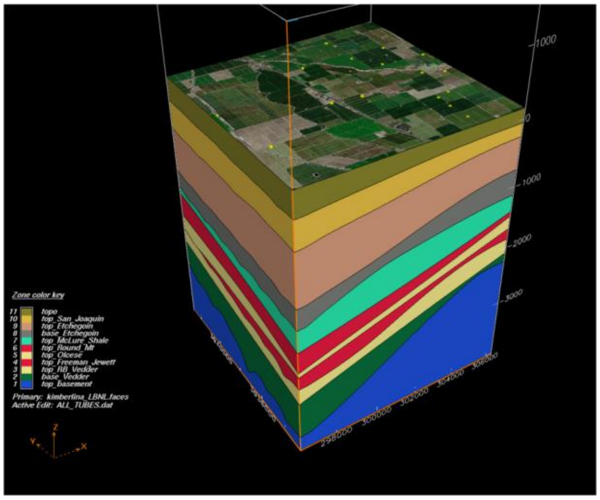

Figure 15. Static geomodel for the formations underlying the Kimberlina Power Plant in the San Joaquin Valley, California[125]

Monitoring CO_2 Distribution in the Subsurface

CO_2 storage projects typically use two types of monitoring wells: shallow groundwater monitoring wells to assure regulators that CO_2 has not encroached upon USDWs overlyng the target storage formation(s) and full-depth monitoring wells to take measurements such as cross-well seismic imaging and fluid samples at a known distance from the injection well(s). In addition, indirect methods of monitoring make it possible to track the CO_2 distribution over broad areas. 3-D seismic reflection surveys provide images of the subsurface that have been used successfully to track the migration of the CO_2 at several project sites including the Frio Brine Pilots in Texas, the Sleipner project in the North Sea, the Nagaoka project in Japan, and the Weyburn-Midale project in Saskatchewan. Satellite monitoring that detects minute vertical surface movements, which reflect shifts in the CO_2 in the subsurface over time, has been used at the In Salah project in Algeria.

Managing Leakage Risks

Experience with storing CO_2, as well as experience gained from CO_2-EOR, shows that the risks and potential quantities of CO_2 leakage will normally be minimal. However, measures must be taken to assure this is the case, and guard against human error, natural hazards, and other risk factors.

Actions central to preventing and correcting leakage of CO_2 from geological formations include a rigorous site selection process to make sure geological seals are present, assuring well integrity (e.g., cement bond between steel casing and penetrated formations), modeling of subsurface CO_2, monitoring of storage formations above the injected CO_2 (including early identification of leakage), and prompt mitigation and remediation actions should any leakage occur.

[125] Developed by Lawrence Livermore National Laboratory.

During site characterization, identification and risk assessment of potential leakage pathways, such as existing wells and fractures and faults, and identification of specific potential consequences (e.g., brine contamination of UDSWs, CO_2 infringement on mineral rights, or CO_2 escape into the atmosphere) serves as a basis for developing site-specific operational standards, as well as monitoring and verification requirements, and mitigation plans.

Improperly sealed wellbores that intersect the storage formation could provide pathways for CO_2 migration. Locating nearby wellbores and assessing their leakage potential will be part of site characterization for many CCS projects. Ongoing monitoring of any wellbores considered to pose a risk will need to be included in the monitoring program, and repairs to some wellbores may be required to ensure their integrity.

Subsurface geologic features such as fractures and faults also need to be identified and assessed during site characterization. Fractures are essentially cracks in the rock, which could provide leak paths if they are present in the seals overlying the storage formation. Faults are cracks where the two surfaces forming the crack have experienced relative movement, or slip. It should be noted that faults are not inherently problematic. Some faults create effective seals and traps for CO_2 storage, whereas others may provide potential leakage paths to shallower zones or the surface.

Several of the approaches used to map the position of CO_2 in the subsurface can also be used to detect leakage out of the storage reservoir from fractures and faults. These can be incorporated into the monitoring plan, as needed, depending on the risk assessment.

Remediation and Mitigation

Despite careful site characterization to rule out inappropriate sites and other procedures to minimize risk, CO_2 storage projects will need to establish contingency plans to mitigate and remediate any situation in which public health, economic activity, or the environment could be negatively affected by releases of CO_2.

Should an unacceptable project risk arise, existing mitigation and remediation practices and technologies from the oil and gas industry should be sufficient to address the situation. These include reservoir pressure control, shallow gas recycling, wellbore remediation, well re-plugging, and in extreme cases, project termination and site closure. Nonetheless, further studies that address CO_2 storage monitoring over longer timeframes and at greater spatial scales are needed to fully adapt these practices to CCS.

Monitoring Seismicity

In the WESTCARB region where several states are tectonically active, careful seismic profiling will factor in site selection for CO_2 storage projects. Public sensitivity to earthquakes will likely focus special attention on regulatory requirements to assure that projects do not increase seismic hazard risk or that natural seismic events do not increase project leakage risk.

Many small unfelt earthquakes are characteristic of injection activities; such micro-seismicity can in fact help to image subsurface fluid movement. Data are limited for CO_2 injection, with only low levels of induced seismicity and no large events. In other industries, subsurface pressure increases—from direct injection of fluids for waste disposal and geothermal energy development—have caused seismicity that people have felt, and in a few instances, have caused harm.[126]

Monitoring for induced seismicity begins with establishing a record of the natural background seismicity in the region encompassing the project. The record of the natural background seismicity is important because it gives a baseline to help determine if an event, which occurs after CO_2 injection starts, may be due to the injection or to natural tectonic processes. In most instances, an existing monitoring network (e.g., USGS) would need to be augmented by a local network designed 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.

Induced seismicity is related to a change in fluid pressure in the subsurface (an increase or decrease), so dissipating fluid pressure build-up from CO_2 injection operations reduces potential for seismicity. The potential for induced seismicity will decrease during the post-injection phase of a storage project due to the natural dissipation of fluid pressures and it can be controlled during the operational phase by adjusting the rate of injection and/or through fluid extraction. Because there is a cause-and-effect relationship between fluid pressures and micro-seismicity, monitoring of subsurface fluid pressures should be part of the induced seismicity monitoring program.

In 2010, WESTCARB scientists analyzed the potential for induced seismicity from a proposed small-scale (6000 metric tons) CO_2 injection project in Northern California (Figure 16).[127] The study, undertaken in response to requests by the local planning board, assessed pre-existing faults, natural seismic activity, and the underground stress state in the vicinity of the proposed injection well, with consideration given to potential risks posed by a larger-scale injection. Although the project did not proceed for business reasons, the study provided an early example of how to address seismic hazard concerns for CO_2 injection projects.

[126] http://www.livescience.com/9777-earthquake-concerns-shake-geothermal-energy-projects.html
[127] Myer, Larry et al. 2010. *Potential for Induced Seismicity Related to the Northern California CO_2 Reduction Project Pilot Test, Solano County, California*, LBNL-3720E/LLNL-TR-435831.

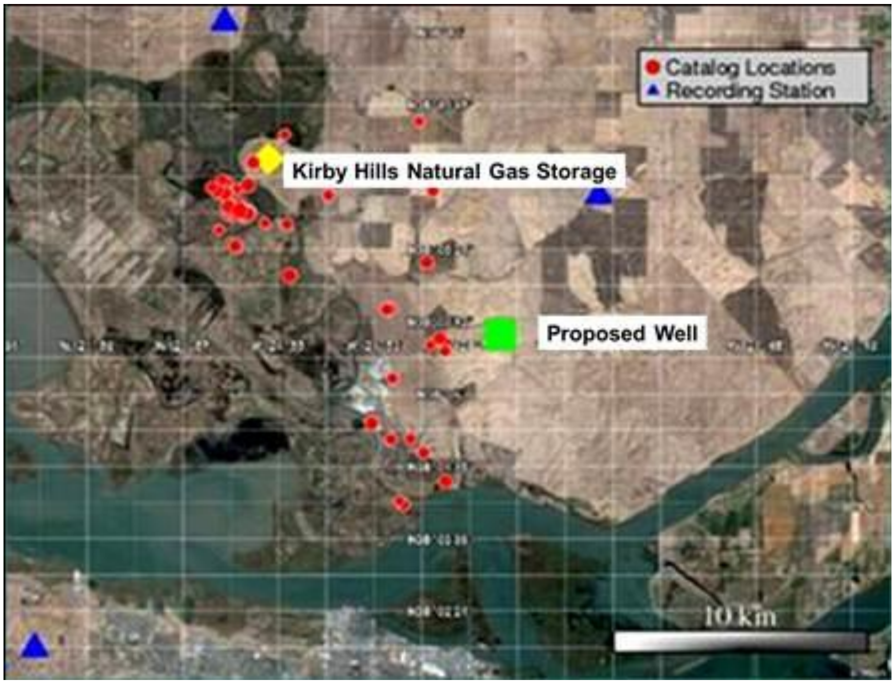

Figure 16. Aerial view of a WESTCARB study site in northern California

[Blue triangles are seismic recording stations. Red dots indicate seismic events of 2.5 magnitude or greater for 1978–2010 near a proposed injection well. The largest event had a magnitude of 3.7.]

A 2012 report by the National Academy of Sciences[128] (NAS) called for continued research into the potential for induced seismicity in large-scale geologic carbon storage projects, as well as collaboration with international CCS project operators on this subject, and the development of best practice protocols.

The NAS made the following recommendations for steps to be taken:

1. Use some of the many active fields where CO_2 flooding for EOR is conducted to understand more about the apparent lack of felt induced seismic events in these fields; because CO_2 is compressible in the gaseous phase are other factors beyond pore pressure important to understand in terms of CO_2 sequestration?

2. Develop models to estimate the potential earthquake magnitude that could be induced by large-scale CCS.

3. Develop detailed physicochemical and fluid mechanical models for injection of supercritical CO_2 into potential storage aquifers.

[128] *Induced Seismicity Potential in Energy Technologies*, prepublication, National Academy of Sciences. (http://www.nap.edu/catalog.php?record_id=13355)

Economics

The cost of CCS technologies is generally recognized as a challenge to widespread deployment. A comprehensive view encompasses the multiple factors affecting both the cost of CCS and its competing low-carbon alternatives over time, taking into account economic drivers and policy decisions on how and when progressively steep GHG emissions reductions can be achieved. Such a multi-faceted analysis suggests that CCS must transition from initial to broad application in the 2020 to 2050 timeframe, assuming that current projections of the need for (and commitment to) deep GHG emissions reductions hold and that emissions trading markets evolve in relative stability.

The IPCC Special Report on Carbon Dioxide Capture and Storage cites several studies that conclude that widespread deployment of CCS technologies would achieve GHG emission reductions at significant savings compared to scenarios without CCS (e.g., trillions of dollars for stabilization of GHGs at a concentration of 450 ppm).[129]

The Electric Power Research Institute (EPRI) examined the technical feasibility of achieving large-scale CO_2 emissions reductions for the U.S. electricity sector using a full portfolio of low-carbon technologies (energy efficiency, renewables, electric transportation, nuclear with advanced light water reactors [ALWR], and fossil power plants, both NGCC and high-efficiency coal plants—with CCS). Economic modeling showed that without advanced coal technologies and CCS (and without any expansion of nuclear power), wholesale electricity prices in 2050 could be nearly double what they would be otherwise (Figure 17). EPRI's analysis underscores the economic value of deploying multiple low-carbon technologies and the cost increases that would follow if any technology is precluded by policy or insufficient RD&D investment, thereby forcing emission reductions to be achieved using a more limited set of options.

[129] 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.

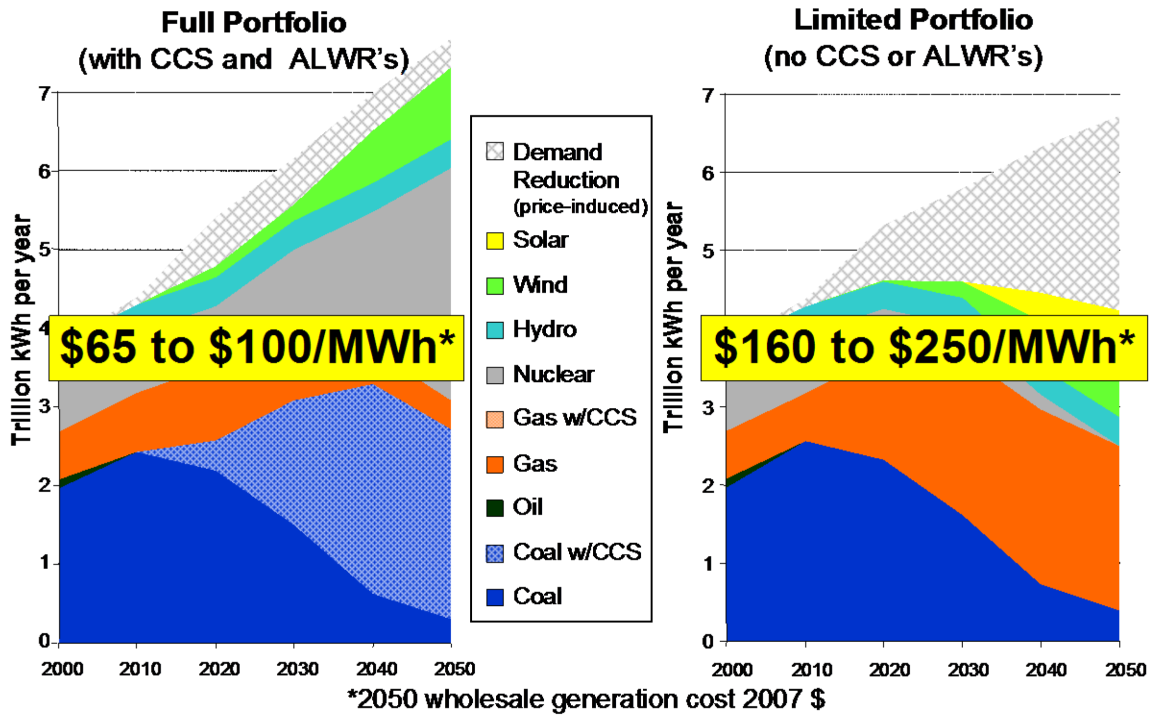

Figure 17. EPRI analyses showing CO_2 reductions for U.S. electric sector with a full and limited portfolio of technologies[130]

Timeframes for Technology Development to Reduce Costs

Ideally, CCS technologies will reach the stage of maturity where experience from early projects can be incorporated into the design process—thereby improving performance and reducing costs—before regulations compel widespread deployment. Under this scenario, the economic impact of achieving GHG emissions reductions would be significantly less.

The typical path for commercializing a technology runs from the conceptual modeling to laboratory testing, then to pilot-scale tests, larger-scale tests, full-scale demonstration, and finally to deployment of multiple systems in commercial operation. For capital-intensive technologies such as advanced power plants with CCS, each stage can take several years to complete and entails increasing levels of investment.

The historical record of technology development shows that costs, which are highest at the start of the demonstration phase, tend to fall subsequently due to:

- Experience gained from "learning by doing"
- Increasing economies of scale in design and production as order volumes rise
- Removal of contingencies covering uncertainties and first-of-a-kind costs
- Competition from second- and third-to-market suppliers

[130] *Advanced Coal Power Systems with CO_2 Capture: EPRI's CoalFleet for Tomorrow Vision,* EPRI, Palo Alto, CA: 2008. 1016877.

An International Energy Agency study conducted by Carnegie Mellon University and others predicted a similar reduction in the cost of CO_2 capture technologies as their cumulative installed capacity and experience base grows.[131] Understanding of this cost-reduction pathway is reflected in the accelerated efforts on the part of DOE and technology researchers and developers worldwide to scale up and integrate CO_2 capture and capture-related technologies.

Current and Anticipated Costs of CCS Projects

The costs of CCS comprise the additional equipment required to capture, compress, transport, inject, and monitor CO_2, as well as the additional energy requirements for these processes.

Pipeline transport costs are highly non-linear for the amount of CO_2 transported, with economies of scale being realized at about 10 $MMTCO_2$/yr. For this volume or greater, the levelized cost is about $0.80 per metric ton of CO_2 per 100 miles for flat rural terrain. However, this cost doubles for the smaller volume of 5 MMT/yr, and is greater than $4.80 per metric ton of CO_2 per 100 miles for a volume of 1 MMT per year. Pipeline costs will also vary by project, based on the distance between the CO_2 source and the storage site, as well as the terrain covered, with pipelines through congested areas or across difficult terrain costing considerably more.[132]

For a 1,000 MW coal-fired power plant with CCS, a dedicated pipeline would need to carry about 6 to 7 $MMTCO_2$/yr. This would result in a pipe diameter of about 16 inches and a transport cost of about $1.60 per metric ton of CO_2 per 100 miles for flat rural terrain. At a certain regional market size, developing pipeline networks (trunk lines), as opposed to building dedicated pipelines between each major source and sink, reduces aggregate transport costs.[133]

Costs for well drilling and CO_2 injection are dependent on the geological characteristics of the storage site. For example, costs increase as reservoir depth increases or as reservoir injectivity decreases (lower injectivity results in the need to install more injection wells for a given rate of CO_2 injection). A range of injection costs has been reported as $0.50–8.00 per metric ton CO_2. Monitoring costs have been assumed to be about $0.10–0.30 per metric ton CO_2 on a levelized basis.[134]

Roughly 70–80% of the total cost of CCS, using the current suite of technologies, can be attributed to CO_2 capture and compression. Because capturing large volumes of CO_2 from process or exhaust gases at industrial facilities is a relatively new climate change mitigation strategy, the technologies for undertaking this endeavor are in varying stages of commercial readiness. Initial applications will encounter a cost premium for first-of-a-kind issues.

DOE estimates that today's most-developed CCS technologies would add about 80% to the levelized cost of electricity (COE) for a new pulverized coal (PC) plant, and about 35% to the levelized COE for a new

---

[131] *Estimating Future Trends in the Cost of CO_2 Capture Technologies*. IEA Greenhouse Gas R&D Programme (IEA GHG): February 2006. Report 2006/6.
[132] Burton, Elizabeth. *Geologic Carbon Sequestration Strategies for California, Report to the Legislature.*
[133] Ibid.
[134] *IPCC Special Report on Carbon Dioxide Capture and Storage.*

IGCC plant.[135] DOE's RD&D effort is pursuing developments to reduce these costs (90% capture basis) to a less-than-30% increase in COE for PC power plants and a less-than-10% increase in COE for new gasification-based power plants.

Cost estimates for power plants with CO_2 capture span a range (Table 4), and project developers are advised to begin technology selection through a broad option screening process.

Table 4. Representative cost and performance of fossil-fuel generation technologies for 2015 without CCS, and for 2025 with CCS[136]

	Nominal Plant Capacity, MW	Operating Life, years	Heat Rate (Btu/kWh)	CO_2 Emissions, Metric Tons/MWh	Fuel Price, $/MMBtu	LCOE, $/MWh*
Pulverized Coal	750	40	8,750	0.84	1.8-2.0	54-60
Pulverized Coal w/CCS	600	40	9,840-11,800	0.09-0.11	1.8-2.0	87-105
IGCC	600	40	8,940	0.86	1.8-2.0	68-73
IGCC w/CCS	500	40	9,100-11,000	0.09-0.15	1.8-2.0	85-101
NGCC	550	30	6,900	0.37	4.0-8.0	49-79
NGCC w/CCS	450	30	7,140-8,000	.04	4.0-8.0	68-109

**LCOE includes transportation and storage cost of $10/metric ton CO_2, which on a per MWh basis, adds $3, $6, and $7 to NGCC, IGCC, and pulverized coal, respectively.*

The Importance of Developing Multiple Technologies

Power industry experience shows that no single generation technology holds clear-cut advantages in all regions and across the diversity of market structures. Thus, for CCS, support for comprehensive pre-commercial RD&D and market-entry demonstrations covering multiple technologies (pre-combustion, post-combustion, oxy-combustion, and novel processes) is a recommended approach. To address environmental concerns with minimal economic impact, the best strategy lies in developing a portfolio of

[135] *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap*, December 2010.
[136] *Electric Power Research Institute, Program on Technology Innovation: Integrated Generation Technology Options*, 1022782, Technical Update, June 2011.

technologies from which power producers (and regulators) can select the options most suited to preferred fuel types, local conditions, and compliance needs.[137]

High-Purity Sources Offer Lower-Cost Opportunities for CCS

The physics of CO_2 capture favor sources that produce gas streams with higher concentrations of CO_2 and at high pressure. As a result, the cost of CO_2 capture is usually lower for higher-purity CO_2 sources. Conversely, sources with low CO_2 concentrations in atmospheric pressure combustion exhaust gases have higher costs per unit of CO_2 removed.[138]

Relatively large industrial sources that produce high-purity CO_2 streams as an integral part of their processes include natural gas plants separating CO_2 from produced gas, ethanol fermentation processes, ammonia plants, and some types of hydrogen production, such as those used in oil refineries. In these cases, any cost for CO_2 separation is already part of the process cost. The remaining costs to produce supercritical CO_2 for transport are for compression and drying. For a moderate-scale stream of 2 $MMTCO_2$/yr and an electricity price of 0.05¢/kWh, the cost of compression and drying is about $10 per metric ton of CO_2 avoided.[139] Barring other issues, large high-purity CO_2 streams should be the most economic sources of CO_2 capture.

Natural gas processing plants remove CO_2 in excess of about 2% in produced natural gas to meet commercial specifications for natural gas heating value and to avoid pipeline corrosion. The processing plant vents streams that are typically high-purity CO_2 and can represent significant point sources of CO_2. Worldwide, three major CCS projects, Sleipner and Snohvit in Norway and In Salah in Algeria, are each capturing about 1 $MMTCO_2$/yr from natural gas processing facilities for storage in deep geologic formations. In the WESTCARB region, natural gas processing plants are found primarily in British Columbia , Alaska, and California.

For hydrogen production, which entails separating CO_2 from the desired H_2 product, the method of production influences the purity of CO_2 stream and the costs of capture or separation. Some traditional hydrogen plants produce a nearly pure CO_2 stream. Newer hydrogen plants tend to use pressure swing adsorption, which produces a CO_2 stream that is about 50% CO_2 by volume.[140] Further, hydrogen production by steam reforming of natural gas involves high-temperature fired heaters, which entail additional flue gas streams with a low CO_2 concentration. In the WESTCARB region, large amounts of hydrogen are used in oil refining, particularly in California, but also in Washington and British Columbia. In the future, hydrogen production for vehicle fuel may become more common, increasing corresponding CO_2 stream volumes.

Ethanol production by fermentation produces a stream of nearly pure CO_2. Fermentation-related CO_2 emissions are about 3,480 metric tons per million gallons of ethanol produced, and a typical plant will

---

[137] *Advanced Coal Power Systems with CO_2 Capture: EPRI's CoalFleet for Tomorrow Vision,* EPRI, Palo Alto, CA: 2008. 1016877.
[138] Burton, Elizabeth. *Geologic Carbon Sequestration Strategies for California, Report to the Legislature.*
[139] Ibid.
[140] Ibid.

have CO_2 emissions of about 0.2 MMT per year, which is too small to have much economy of scale.[141] Currently, ethanol production in the WESTCARB region is limited to a few smaller plants. However, this souce type has the potential to grow and could become a cost-effective source of CO_2 under favorable circumstances.

Offsetting CCS Costs

Sale of CO_2 as a Commodity

Finding value for CO_2 independent of any carbon credit markets can improve the economics of CO_2 capture. Such incremental revenue may be especially important in the near term when CCS project developers face first-of-a-kind costs and other cost premiums. To date, technologies making beneficial use of CO_2 have had a negligible impact on overall anthropogenic CO_2 emissions. The bulk of CO_2 in the merchant market[142] is used for EOR—a demand that has been met primarily by supplies from natural sources—along with a significant portion used in the food and beverage industry. CO_2 in captive chemical processes[143] is most commonly used for the production of urea fertilizer.[144]

CO_2 for EOR

The U.S. DOE has been emphasizing the economic co-benefit of using captured CO_2 to enhance hydrocarbon production. A white paper by Advanced Resources International states that "revenues from CO_2 sales to the oil industry can offset some of the costs of CO_2 capture from both natural gas-fired and coal-fired power plants, as well as other industrial facilities producing large volumes of CO_2. The support provided by CO_2-EOR for early implementation of CCS will help drive down the costs of capture, the largest cost hurdle for CCS, through 'learning by doing.'"[145]

The WESTCARB region has oil fields in Alaska and California that could benefit from CO_2-EOR to increase oil production if affordable, reliable supplies of CO_2 were available locally. For the proposed Hydrogen Energy California (HECA) IGCC power plant in Kern County, California, sale of captured CO_2 for EOR is one of four revenue streams, the others being sales of electricity, urea, and hydrogen. The CO_2 captured at the HECA power plant will be delivered via pipeline to the Elk Hills oilfield, approximately five miles away.

Longer-Term Opportunities for Generating Revenue From CO_2

In addition to CO_2-EOR, there are other possible beneficial and revenue-generating uses for captured CO_2, many of which are in relatively early stages of development. In some cases, ultimate potential use volumes are limited, but economic niches will be important in early CCS market development. Technologies using CO_2 could contribute to GHG reduction goals by either preventing 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 other GHG emissions to achieve net reductions. An example of the latter would be using CO_2 as

[141] Ibid.
[142] Market in which CO_2 is bought and sold competitively by multiple market participants.
[143] CO_2 produced onsite by the user of the CO_2 and not sold to outside customers.
[144] *IPCC Special Report on Carbon Dioxide Capture and Storage*.
[145] *U.S. Oil Production Potential From Accelerated Deployment of Carbon Capture and Storage,* Advanced Resources, International, Inc., Arlington, VA, March 10, 2010.

a refrigerant instead of hydrofluorocarbons, which have a stronger GHG effect per unit volume than CO_2.[146]

Revenue and CO_2 storage may be realized from enhanced coal bed methane production, enhanced natural gas recovery, and enhanced geothermal energy systems, however, these technologies are limited geographically and/or not sufficiently developed to provide much financial help to the first CCS projects. In particular, the use of CO_2 as a working fluid in geothermal systems, which has the advantage of both sequestering CO_2 and creating renewable power, is at an early stage of development but could prove applicable in areas of significant geothermal potential in the western United States and Canada.[147]

DOE has provided funding for a project led by GreenFire Energy in Arizona to investigate the potential for low-temperature CO_2-based geothermal power production technologies. The project plans to test several energy recovery techniques in existing shallow wells and the performance of CO_2 as a working fluid.[148] GreenFire is also investigating using geothermal heat to pressurize CO_2 for pipeline transport, thus replacing conventional technology that utilizes compressors and electricity.

Other longer-term prospects for benefical uses for CO_2 include mineralization to carbonates directly through conversion of CO_2 in flue gas, the use of CO_2 from power plants or industrial applications to grow algae/biomass for fuels production, and conversion of CO_2 to plastics or other chemicals.

Within the WESTCARB region, Calera Corporation has been developing a process that uses brines such as seawater to mineralize CO_2 from flue gas to make carbonates for use in cement and other construction materials. The company, which operates a small-scale facility in Moss Landing, California, has received funding from DOE and the Australian government to demonstrate its process at larger scale.

An evaluation of beneficial use technologies noted the lack of a systematic methodology for comparing the various technologies and called for the use of life-cycle analyses to assess the relative merits of each beneficial technology in a quantified way. The study noted that although such analyses may be particularly complex for some technologies, they would be useful for clarifying the GHG-reduction benefits from technology development.[149]

Government Incentives

Cost barriers faced by CCS developers and early users can pose a funding gap that stifles technology investment that is deemed to be in the public interest (e.g., development of cleaner, more efficient ways of producing electricity).

---

[146] Reed, John. “Uses of Carbon Dioxide,” Appendix E, *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.
[147] Burton, Elizabeth, Kevin O’Brien, William Bourcier, and Niall Mateer. 2011. *Research Roadmap of Technologies for Carbon Sequestration Alternatives.* Prepared for the California Energy Commission, Public Interest Energy Research Program. (http://uc-ciee.org/downloads/Roadmapfinal_CIEE.pdf)
[148] http://apps1.eere.energy.gov/news/progress_alerts.cfm/pa_id=401
[149] Burton, Elizabeth. *Research Roadmap of Technologies for Carbon Sequestration Alternatives.*

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. [150] Much of the research for CCS, as well as demonstration projects in the WESTCARB region and nationally, is proceeding with assistance from U.S. government federal funding.

Federal tax credits for geologic CO_2 storage became available under the Energy Improvement and Extension Act of 2008. The Act established Internal Revenue Code Section 45Q, which provides a tax credit of $20 per metric ton of CO_2 captured at a qualified facility and stored (i.e., saline formation), or $10 per metric ton of CO_2 captured at a qualified facility and used or EOR or EGR. A qualified facility is one that captures at least 500,000 metric tons of CO_2 annually. The credit is available for the first 75 MMT of CO_2 that the EPA certifies as stored in a given calendar year.

The National Enhanced Oil Recovery Initiative (NEORI) seeks to amend Section 45Q to:

- Designate the owner of the CO_2 capture facility as the primary taxpayer
- Establish a registration, credit allocation, and certification process
- Change the recapture provision to ensure that any regulations issued after the disposal or use of CO_2 shall not enable the federal government to recapture credits that were awarded according to regulations that existed at that time
- Authorize limited transferability of the credit within the CO_2 chain of custody, from the primary taxpayer to the entity responsible for disposing of the CO_2[151]

State government incentives can also address first-of-a-kind CCS costs 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.

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 substantially above-market costs may adversely affect overall economic competitiveness in the service territory. In states where customers have access to energy service providers other than a local investor-owned utility, cost allocation mechanisms may be needed to “socialize” the above-market costs to all customers so no single utility’s customers bear the cost for the public-interest benefit.

In 2011, failure to obtain PUC approval for cost recovery, in conjunction with a lack of federal regulation, led American Electric Power to terminate its agreement with DOE to develop a commercial-scale

[150] *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.
[151] http://www.neori.org/NEORI_45Q.pdf

demonstration of CCS technology at its Mountaineer Plant in West Virginia, following a successful pilot-scale project.[152]

The Division of Ratepayer Advocates, an independent division within the California PUC, has put forth the suggestion that CCS research and development could be supported by funding from all (statewide) electric utility ratepayers equally.[153] Similarly, the California Carbon Capture and Storage Review Panel recommended that "it should be state policy that the burdens and benefits of CCS be shared equally among all Californians."[154]

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 (although the first funding tranche will go exclusively to renewables). At the U.S. federal level, bonus allowances for early CCS adopters have been proposed as a means to offset early mover challenges (e.g., proposed Waxman-Markey climiate legislation in 2008).

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 before or 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. In California, the Independent System Operator (state grid dispatch center) has mechanisms to prevent dispatch curtailment for fossil power plants with CCS, typically designation as "must run" units.

Project Finance

Project Insurance Coverage

CCS projects are frequently conceived of as occurring in three phases: operations (injection), post-injection or closure, and post-closure. The risks during the operational and closure periods of CCS projects are similar to current industrial activities that are underwritten in the financial and insurance sectors and are generally not considered a significant barrier to CCS deployment. At least one major insurer now offers liability insurance during the operational life of a storage facility, as well as a separate financial assurance policy for the post-closure phase.[155]

---

[152] http://insurancenewsnet.com/article.aspx?id=268856&type=newswires
[153] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-08-18/comments/Division_Ratepayers_Advocates_Comments.pdf
[154] *Findings and Recommendations by the California Carbon Capture and Storage Review Panel*, (http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2011-01-14_CSS_Panel_Recommendations.pdf).
[155] http://www.carboncapturejournal.com/displaynews.php?NewsID=325

Models for Long-Term Liability Coverage

Geologic CO_2 storage projects include a period of post-injection monitoring, which is intended to verify that the CO_2 is stable and will not migrate. No consensus has been reached on the duration of the post-injection monitoring phase, however, timeframes of 10 to 50 years have been proposed. Under EPA's UIC Class VI rule, the well owner or operator must continue to conduct monitoring as specified in the UIC Director-approved post-injection site care and site closure plan for a nominal period of 50 years following the cessation of injection, or until (either more or less than 50 years) the owner or operator can demonstrate to the Director that the project no longer poses an endangerment to USDWs.

Long-term liability for CCS refers to the legal responsibility for any damages attributed to a project in the post-closure phase. Some CCS stakeholders consider this to be a barrier to the commercialization of CCS, primarily because businesses are not comfortable assuming risks of unknown magnitude over prolonged timeframes. In addition to potential claims for damage to other subsurface resources (e.g., natural gas or fresh water) or for damage and remediation related to CO_2 migration and/or leakage to the surface, there is also potential for financial exposure under GHG regulatory regimes if leakage results in escaped emissions that need to be accounted for through the surrender of allowances or other compliance instruments.[156]

In the United States, there is currently no comprehensive, integrated federal framework defining or allocating long-term liability for stored CO_2, however, there are several long-term liability models for CCS projects under consideration, some of which are being enacted at the state level.

Government assumption of liability – The rationale for a government role in indemnifying long-term liability is based on the belief that CCS is in the public interest and that long-term liability issues should not, particularly at this early stage, be a barrier to further development. A "certificate of completion" model has been adopted by Louisiana, Montana, North Dakota, and Wyoming,[157] whereby the operator of a geologic storage site can transfer title and liability for the stored CO_2 to the state after demonstrating to the relevant state agency that the site has been stable for a certain period of time after the last CO_2 injection period, and that the site has been properly closed. Until the time of transfer, the operator remains liable for any damages related to CO_2 migration or leaks.

Industry-funded trust fund – An example of this approach was contained in the Bingaman bill, which was part of the American Clean Energy Leadership Act of 2009, and proposed a per-ton sequestration fee to be accrued by the U.S. Department of Treasury in a DOE-administered trust fund.[158] Such a fund could also be administered by private or public corporation with a specific charter for overseeing the fund.

Private insurance – This approach could mirror the insurance requirement of the Price-Anderson Act, which mandates that the owners/operators of nuclear reactors obtain private insurance at prescribed levels, thereby creating a pool of insured entities and a stream of premiums that may in turn allow

[156] "Long-Term Stewardship and Liability of Storage Sites," Appendix P, *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.
[157] Ibid.
[158] Ibid.

insurers to provide coverage.[159] However, at present, insurers seem reluctant to issue policies for long-term post-closure operations of CCS project because of the difficulty in assessing risks. Possible workarounds include requiring insurance only for a defined level of exposure and/or allowing shorter-term policies and the periodic re-rating of insurance company risks.[160]

It is worth noting that the Price-Anderson Act provides two additional tiers of coverage beyond private insurance: a collective financing mechanism requiring that each company in the pool contribute up to a statutory cap of $95.8 million in the event of a nuclear accident, and a federal financing mechanism that requires the federal government to "backstop" the remaining balance owed to claimants through the general treasury once the individual and collective caps are reached. A similar multi-tiered design for CCS long-term liability is also a possibility.

Legal Considerations for CCS Projects

Pore Space Ownership and Mechanisms for Acquiring Pore Space Rights

Geologic CCS projects are contingent upon the project operators obtaining the right to inject and store CO_2 within subsurface pore space. Common law from some states provides that pore space belongs to the surface owner. Where subsurface minerals exist, surface owners may server ownership of the subsurface mineral rights and convey them to third parties. In these arrangements, the mineral rights owner generally has the legal right to reasonable use of the surface estate (with just compensation) for production of the minerals. CO_2 storage requires similar rights to use and access the subsurface, but it does not entail mineral production.

Clarification of pore space ownership may be addressed by legislative declaration that pore space belongs to surface owners (at least by default). This approach has been followed by Montana, North Dakota, and Wyoming. Wyoming led the way by vesting ownership of subsurface pore space to the surface owner, but allowing severance of pore space from the surface interest. North Dakota similarly vests subsurface pore space with the surface owner but expressly forbids severance of the pore space from the surface estate. Montana neither allows nor forbids it. All three states maintain the dominance of the mineral estate over both surface and subsurface.[161]

Alternatively, a 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.

Mechanisms to acquire rights to multiple adjoining subsurface estates can be addressed by establishing authority for CCS projects to obtain these rights either by eminent domain or by unitization. Eminent domain is commonly used to acquire easements for projects that have a public purpose. Unitization is a long-established mechanism used in the context of oil and natural gas production, whereby hold-out

[159] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010. (http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf).
[160] Ibid.
[161] Reed, John. "Uses of Carbon Dioxide," Appendix E, *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010. (http://www.climatechange.ca.gov/carbon_capture_review_panel/documents/2010-04-01_Other_States.pdf)

property owners share in the revenues from production but cannot stop production from occurring. Louisiana has established a process for using eminent domain for carbon sequestration, and Montana, North Dakota, and Wyoming have authorized the use of unitization.[162]

Issues pertaining to pore space rights and access can hamper CCS deployment in areas where no clear guidance is provided by adding schedule time and costs for project developers. Another limiting factor could arise from the complexity and expense of acquiring multiple property rights given the large areas CO_2 storage projects will cover. Additionally, because of the novelty of CO_2 storage as a GHG mitigation measure, there is a potential for test-case lawsuits.

For British Columbia, as for all of Canada, the crown owns the pore space and has the right to lease it to third parties for storage purposes.[163] State legislatures in the WESTCARB region have not yet clarified pore space ownership, although proposed legislation in California explicity assigns pore space to the surface estate.[164]

Pipeline Rights-of-Way Acquisition Authority[165]

Siting long CO_2 pipelines can be complex and costly, especially in populated or environmentally sensitive areas. It may be difficult for project sponsors to obtain rights-of-way, and the lack of eminent domain authority can necessitate the costly rerouting of pipelines.

No federal agency exercises authority over the siting of interstate CO_2 pipelines on non-federal land. 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. In the last five years, FERC has reaffirmed that it does not have jurisdiction over CO_2 pipelines. Consequently, unless the federal government amends NGA to cover CO_2 pipelines, the federal power of eminent domain is not available for interstate CO_2 pipelines.

The Bureau of Land Management (BLM) has authority under the Federal Land Policy and Management Act to issue rights-of-way on and beneath federal land for pipelines carrying anthropogenic CO_2. BLM also currently authorizes pipelines for the transportation of naturally occurring CO_2 under the Mineral Leasing Act. Pipelines authorized under the Mineral Leasing Act become "common carriers" that must accept and transport all gas delivered to the pipeline.

A handful of states outside of the WESTCARB region have enacted statutes allowing the use of eminent domain for CO_2 pipeline rights-of-way acquisition. In some cases, these eminent domain statutes may be restricted to CO_2 use for enhanced oil recovery. Pipelines used for CO_2 storage outside of enhanced oil recovery would not be able to utilize the eminent domain authority granted by these statutes. Other eminent domain statutes require the CO_2 pipeline (for any purpose) to function as a common carrier. For

---

[162] Fish, Jerry R. and Eric L. Martin, "Approaches to Pore Space Rights," Appendix J, *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.
[163] http://www-naweb.iaea.org/napc/ih/documents/other/INV005%20GUNTER%20(Presentation).pdf
[164] http://leginfo.ca.gov/pub/13-14/bill/sen/sb_0001-0050/sb_34_bill_20121203_introduced.html
[165] Fish, Jerry R. and Eric L. Martin, "Carbon Dioxide Pipelines," Appendix I, *Background Reports for the California Carbon Capture and Storage Review Panel*, CIEE, December 2010.

example, Texas only authorizes the use of eminent domain for CO_2 pipelines if the pipeline company agrees to serve as a common carrier. This obligation could pose a problem if a particular CO_2 pipeline is built with just enough capacity to transport CO_2 generated from a particular source.

Public Understanding and Acceptance

For CCS to be successfully deployed at scale, it will be critical to have some degree of public acceptance or tacit consent. Although there is a growing awareness among state and regional policymakers that meeting GHG emission reduction targets without CCS is unfeasible given societies' current and projected use of fossil fuels, broad public recognition of the capability and role of CCS in climate change mitigation falls short of this understanding.

Even among people who believe that manmade GHG emissions need to be curbed, CCS can be viewed as prolonging reliance on coal, or as too expensive relative to other options (i.e., the money would be better spent on energy efficiency or renewables). There is little recognition that emission reductions will be needed from other types of facilities such as oil refineries and cement plants, and even from natural-gas-fired power plants in the longer term.

Thus, discussion of CCS often needs to be framed within the context of what is realistically achievable over the next century as societies seek to balance energy demand fulfillment with lowering GHG emissions, while minimizing economic impacts.

At a community level, CCS projects sometimes find favor in areas where people are knowledgeable about production or storage of hydrocarbons. Other communities have ties to fossil-fueled power generation or other industries that are likely candidates for CCS, and foresee the benefits in having these businesses remain viable. Job creation or retention can figure prominently in local and regional planning, and CCS projects that are linked to EOR or represent new opportunities in the emerging low-carbon economy may be welcomed. Concern for the environment and a desire to help reduce GHG emissions can also motivate community members to support CCS projects.

Some communities have opposed CCS projects because of perceived risks. People are naturally wary of new technologies or technologies with which they are unfamiliar. CCS is sometimes compared to nuclear waste storage, and the risk profile of CO_2 has been confused with substances that are explosive or with highly toxic pollutants. People are often unaware that the earth stores CO_2 naturally or that EOR operators are safely injecting millions of tons of CO_2 each year. With education, communities generally become more favorably disposed toward CCS technology.

Nonetheless, the benefits and risks of CCS projects, as well as the safety and mitigation measures that may be taken to manage risks, need to be acceptable to project host communities. It is possible that public concern about the risks of CCS will decline after early projects demonstrate that storage can be conducted without significant incidents and the volume of CO_2 injected remains safely stored.

To further public education on CCS, WESTCARB has teamed with universities and environmental organizations to hold informational meetings and has participated in teachers' training for middle and high school teachers. Community meetings in Arizona and California have allowed for a two-way exchange of information between community members and WESTCARB researchers. These experiences illustrate the diversity of values and concerns that go into shaping people's responses to CCS, underscoring the importance of allowing sufficient time for outreach and engagement efforts that encompass multiple stakeholder groups.

Figure 18. A 2010 meeting on CCS in California hosted by WESTCARB and partners

As CCS becomes better established in the WESTCARB region, the development of CCS curricula and training programs and inclusion of CCS in science programs will be needed to support the creation of a qualified workforce. In 2009, using ARRA funding, DOE/NETL launched seven Regional Carbon Sequestration Training Centers to offer courses on applied engineering and science of CCS for site developers, geologists, engineers, and technicians, and to provide a technology transfer platform for CO_2 storage. As part of this program, the Carbon Tech Alliance,[166] a partnership of EOS Alliance, the Pacific Northwest National Laboratory, and the Washington Society of Professional Engineers, offers training courses and lectures on multiple CCS topics.

[166] http://www.carbontechalliance.org/

DEPLOYING TERRESTRIAL CARBON STORAGE IN THE WESTCARB REGION

Terrestrial carbon storage is the process through which CO_2 from the atmosphere is absorbed by vegetation through photosynthesis and stored as carbon compounds in soils and biomass (e.g., tree trunks, branches, foliage, and roots). Projects for terrestrial carbon storage involve changing land management practices to (1) remove more CO_2 from the air for long-term storage as carbon in biomass and soil, and/or (2) reduce carbon losses from ecosystems.

The potential for increased terrestrial carbon storage depends largely upon land use, types of vegetation or cover, and precipitation. Opportunities in the vast forests of the Pacific coast states can take the form of tree planting (afforestation or reforestation[167]), changes in forest management such as lengthening the time between timber harvests, and changes in land development practices to protect forest tracts. Removing forest fuels to reduce the severity of wildfires and the use of removed fuels in biomass energy facilities, where practical, may also be a successful strategy in addition to offering benefits beyond carbon storage.

Other biomes where increased carbon storage or reduction in GHG emissions may be realized include rangelands, where WESTCARB researchers estimate the highest regional afforestation potential lies; croplands, where changes in management, as well as crops for biomass fuels and energy are among the practices being pursued; increased biomass in wetlands, which could also contribute to preservation and/or restoration of shorelines and levees; and afforestation of riparian areas.

WESTCARB focused its terrestrial studies on the states of Arizona, California, Oregon, and Washington. Follow-on funding for terrestrial work in other areas of WESTCARB has not been forthcoming.

Estimating Terrestrial Carbon Storage Potential

Assessing the potential for increased terrestrial carbon storage starts with baseline surveys to establish carbon stocks—how much carbon is typically stored for a given area and land type—and by projecting and quantifying carbon storage and emissions from a business-as-usual approach (i.e., carbon stocks and flows that would occur if current management practices were to continue into the future).[168]

Baselines provide a reference against which to measure changes in levels of carbon stocks that occur over time, including those that would result from altering land management practices or uses. Establishing baselines is a critical early step in determining where the best opportunities for increased carbon storage lie. Baselines are also used on a project basis to provide a measurement of carbon stocks before any project activities are undertaken.

WESTCARB's early baseline studies highlight the impact of land use changes on carbon stocks. In Oregon, for example, an estimated net increase in forest area of 2.1 million acres (850,000 hectares) between 1987 and 2003 translated into an estimated gross sequestration of 23 $MMTCO_2e$/yr between

[167] Under DOE's revised 1605(b) guidelines for greenhouse gas reporting, "afforestation" is the establishment of new forests on lands that have not been forested for some considerable length of time, and is in essence a land-use change; "reforestation" is the re-establishment of forest cover, naturally or artificially, on lands that have recently been harvested or otherwise cleared of trees.
[168] *Best Practices for Terrestrial Sequestration of Carbon Dioxide,* National Energy Technology Laboratory, November 2010. (http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_Terrestrial.pdf)

1987 and 1997, and 34.4 $MMTCO_2e$/yr between 1997 and 2003. GHG emissions for Oregon (excluding forests) for 2000 were estimated at 67.7 $MMTCO_2e$.[169]

Over the same timeframe, net forested area in Washington decreased by 0.9 million acres (364,000 hectares). Emissions from this development average out to ~7 $MMTCO_2e$/yr and represent about 55% of the total gross emissions from the forest sector. Compared with total GHG emissions for the state as a whole, emissions from deforestation on non-federal land represented more than 5% of the state's total.[170]

A California study found little impact to forests from development; however, between 1987 and 1997, 573,000 acres of agricultural land were converted to non-agricultural uses. Eighty-eight percent of this change was in non-woody crops. The change in area was estimated to equal a net loss of 3.5 $MMTCO_2e$ over the 10-year period, of which 63% was due to the decrease in non-woody croplands.[171]

WESTCARB researchers evaluated changes that could lead to significant increases in carbon stocks for forests, rangelands, and crop lands in California, Oregon, and Washington. These analyses are depicted by maps and by carbon "supply curves," which illustrate how much additional carbon could be stored as the value of carbon increases and more terrestrial storage projects become economically viable.

For rangelands and croplands (lands growing wheat and hay), the potential for carbon sequestration was estimated for afforestation using native species. Historical evidence suggests that large tracts of forest once stood in many areas of these three states that currently support grazing and agriculture.

The study (1) identified existing rangelands and croplands where biophysical conditions are suitable for forests, (2) estimated carbon accumulation rates for the forest types projected to grow, and (3) assigned values to each contributing cost factor (opportunity, conversion, maintenance, measurement, and monitoring). The carbon supply was estimated for three durations of forest growth—20, 40, and 80 years—to provide an assessment for the near-term and longer-term planning horizons.

[169] Pearson, Timothy et al. (Winrock International). 2007. *Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in Oregon.* California Energy Commission, PIER Energy-Related Environmental Research Program. CEC-500-2007-025.
[170] Pearson, Timothy et al. (Winrock International). 2007. *Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in Washington State.* California Energy Commission, PIER Energy-Related Environmental Research Program. CEC-500-2007-026.
[171] Brown, S. et al. (Winrock International). 2004. *Baseline Greenhouse Gas Emissions and Removals for Forest, Range, and Agricultural Lands in California*. California Energy Commission, PIER Energy-Related Environmental Research. 500-04-069F.

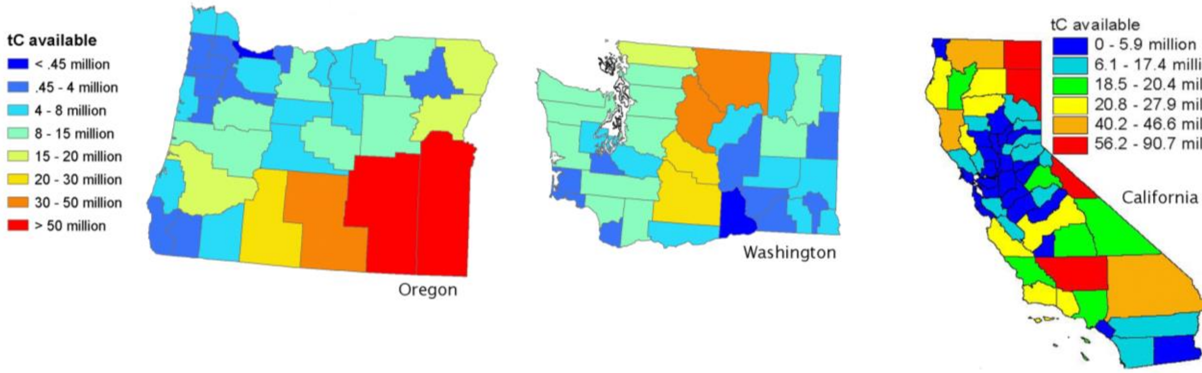

Figure 19. Total estimated storage (metric tons carbon, tC) through afforestation after 40 years

Afforestation/Reforestation

The baseline and cost-curve analyses described above led to the conclusion that the biggest potential for increased terrestrial carbon storage in the WESTCARB region is through afforestation of rangelands. In contrast, the potential for afforestation of agricultural lands is smaller because the generally high productivity and land values associated with agriculture make the opportunity costs of displacing agricultural production with carbon forestry projects unfavorable.

Afforestation can have substantial environmental and economic co-benefits in creating a healthier forest with mixed species and wildlife habitat diversity, providing timber and biomass fuel values, and reducing fire risk by interrupting the “brush-and-burn” cycle. In some cases, projects on rangelands could be carried out concurrently with the grazing of livestock, provided seedlings are protected. On a dollar per ton of CO_2-equivalent basis, costs are lowest for the longer project timespans because the trees have more time in their prime growing years, and the initial costs of land preparation, planting, and weed control are amortized over a larger quantity of sequestered carbon. This can be seen in the statewide capacity estimates discussed in next section.

Statewide Capacity Estimates

In Washington, at a levelized cost of $20 or less per metric ton of CO_2 and a project life of 20 years, almost 289 $MMTCO_2$ could be sequestered on 4.3 million acres of rangelands and croplands. At a project life of 40 years, the aggregate of projects meeting the economic criterion of $20 per metric ton rises to more than 1,233 $MMTCO_2$ on 10 million acres. Finally, at project life of 80 years, approximately 3,176 $MMTCO_2$ could be stored on 14 million acres (Table 5). Converting this total amount at 40 years to an approximate annual rate results in about 31 $MMTCO_2$/yr.[172]

In Oregon, at a levelized price of $20 or less per metric ton of CO_2 and a project life of 20 years, almost 280 $MMTCO_2$ could be sequestered on 3.3 million acres. At a project life of 40 years, the aggregate of

[172] Dushku, A. et al. (Winrock International). 2007. *Carbon Sequestration Through Changes in Land Use in Washington: Costs and Opportunities.* California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2007-075.

projects meeting the economic criterion of \$20/metric ton rises to more than 1,813 $MMTCO_2$ on 18 million acres. Finally, at project life of 80 years, approximately 4,203 $MMTCO_2$ could be stored on 24 million acres (Table 7). Converting this total amount at 40 years to an approximate annual rate results in about 45 $MMTCO_2$/yr.[173]

Table 5. Terrestrial carbon storage capacity estimates for rangelands and croplands in Oregon and Washington

	Quantity of Carbon ($MMTCO_2$) @ ≤\$20.00 per metric ton			Area Available (million acres)		
	20 years	40 years	80 years	20 years	40 years	80 years
Rangelands WA	279.4	1,178	2,450	4.2	8.8	8.9
Croplands WA	9.8	54.9	725.9	0.1	1.4	5.5
Rangelands OR	117.7	1,336	2,827	1.4	15.6	19.1
Croplands OR	162.0	477.2	1,376	1.91	2.15	5.0

An earlier study for California used different cost thresholds for analysis. For a price of <\$5.50 per metric ton and a project lifespan of 20 years, 345 $MMTCO_2$ could be sequestered on 2.7 million acres of rangeland, 3 billion metric tons CO_2 on 14.8 million acres after 40 years, and 5.5 billion metric tons on 19 million acres after 80 years.[174]

Afforestation project developers are already participating in carbon markets, including the voluntary carbon market. In the United States, the major carbon registries have protocols for conducting afforestation projects, and they are an allowable offset option under California's AB 32 cap-and-trade program, which commences in 2013.[175] Afforestation/reforestation projects are part of the Clean Development Mechanism (CDM) offset program under the Kyoto Protocol.

Shasta County Reforestation Pilot Tests

WESTCARB conducted reforestation projects in Shasta County, California, in 2007–2010. Criteria for selection required that projects be eligible for carbon registries—should landowners choose to register—

[173] Dushku, A. et al. (Winrock International) 2007. *Carbon Sequestration Through Changes in Land Use in Oregon: Costs and Opportunities.* California Energy Commission, PIER Energy-Related Environmental Research Program. CEC-500-2007-074.
[174] Brown, S. et al. (Winrock International) 2004. *Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California.* California Energy Commission, PIER Energy-Related Environmental Research. 500-04-068F.
[175] California Environmental Protection Agency, Air Resources Board, *Proposed Regulation to Implement the California Cap-and-Trade Program, Part V, Staff Report and Compliance Offset Protocol, U.S. Forest Projects*, October 28, 2010.

and that sites have less than 10% tree canopy cover for at least ten years at the start of the project in order to comply with the Climate Action Reserve's definition of reforestation.

Twelve sites were selected to include a diversity of land and project types, and reflect a broad geographic distribution across Shasta County, including lands at low, medium, and high elevations; lands suitable for oak, conifer, and oak/conifer; and diverse conditions created by the elevation, slope, climate, and vegetation. Site selection also considered the potential for replication in other areas in the WESTCARB region.

Project size ranged from 7 to 98 acres, with an average of 40 acres. Existing vegetation consisted of a variety of brush species, mostly in dense stands. Baseline carbon stocks ranged from zero for a project that had recently burned in a wildfire to 34 metric tons of carbon per acre on a site with dense old-growth manzanita. Projects were planted with ponderosa pine, mixed conifer stands, or native oaks.

Landowner interest in developing multiple revenue streams, contributing to climate change mitigation, and improving forest health or reducing fire risk led to high interest in the pilot projects and a willingness to share costs.

Projections of net carbon stocks on conifer plantings over 100 years ranged from 53 to 111 metric tons carbon/acre. The native oak planting had projected net carbon stocks of 24 metric tons carbon/acre after 100 years. Survival of planted conifer seedlings was high, despite limited rainfall in the year of planting. Project costs ranged from $354 to $1,880 per acre. Sites with high baseline carbon stocks generally do not yield a net carbon benefit until 30 to 40 years after project implementation.

The variation in costs is based largely on the amount of site preparation needed before seedlings can be planted. Clearing brush, for example, can be costly, whereas sites planted soon after a wildfire can have much lower costs if the fire has destroyed existing vegetation. A second cost consideration is the amount of vegetation control needed after planting to decrease competition from species that would overtake the seedlings during the early years of establishment.

Other considerations such as soil and precipitation, species planted, number of trees per acre planted, and seedling survival have an impact on forest growth rates and carbon stocks. For instance, Douglas fir sequesters more carbon than ponderosa pine, but tends to have a lower survival rate. Oaks grow slowly but are better suited for certain soil types (e.g., gravelly sandy loam), and have traditionally grown on rangelands where dairy farming or cattle ranching provides a primary revenue stream. When seedlings are planted on grazing lands, they require protection for several years from livestock (treeshelters can be used), which adds to project costs.

Two different approaches to disposal of brush were investigated in the Shasta County pilots.

1. Piling and burning. This is the conventional and often the only feasible approach for brush disposal in "brush-conversion" afforestation projects. This approach essentially results in the immediate emission to the atmosphere of all baseline vegetation carbon stocks.

2. Grinding and removal to a biomass energy facility. This alternative still emits as CO_2 the carbon contained in the brush, but offers a better overall GHG balance. Efficient and complete combustion at a biomass plant (where available) would likely release less non-CO_2 GHGs than pile-burning, in addition to which power plants have emissions controls. Further, electricity generated from biomass power plants may offset generation of electricity using fossil fuels, thus reducing the net emission.

Hybrid Poplars

Hybrid poplar, a short rotation woody crop, is of interest in the west coast states of California, Oregon, and Washington because of its potential as a bioenergy crop or wood products crop in combination with the potential revenue from carbon credits.

A WESTCARB study of hybrid poplars[176] found that most of the land suitable for growing this species (based on soil composition, land slope, and climate) is located on the western side of the Cascade Range in Oregon and Washington. The estimated area where hybrid poplars could be grown without irrigation in these two states totals about 2.5 million acres. Suitable land in California not requiring irrigation totals around 300,000 acres and is located primarily on the north coast.

Of these potential lands, the most suitable could produce an average of 3–4 tons carbon/acre per year. Revenue from a dedicated bioenergy plantation on a 6-year rotation is estimated to be $737–$976/acre, of which $86–$325/acre is earned from carbon credits. Revenue from a wood products plantation on a 20-year rotation is estimated to be $9,396–$10,989/acre, of which $425–$1,592/acre is earned from carbon credits.

Although the overall potential for carbon credits from hybrid poplar crops grown for wood products is expected to be less than for bioenergy crops, any hybrid poplar project would need to be assessed on a site-specific basis, and financial feasibility will vary considerably depending on local markets, the price of goods, and the price of carbon credits.

Hybrid poplar plantations are unlikely to compete successfully against the economic benefits of current crops, and may be precluded from native grasslands to avoid biodiversity losses. The best opportunities may well be found on marginal agricultural lands, degraded areas, or areas where riparian buffers can offer both economic and ecological benefits.

[176] Netzer, M., Goslee, K., Pearson, T.R.H., and Brown, S. (Winrock International). 2010 draft report. *Opportunity Assessment for Establishing Hybrid Poplars in California, Oregon, and Washington*. Prepared for the California Energy Commission, Public Interest Energy Research Program. (http://uc-ciee.org/downloads/Poplars_CA_OR_WA.pdf)

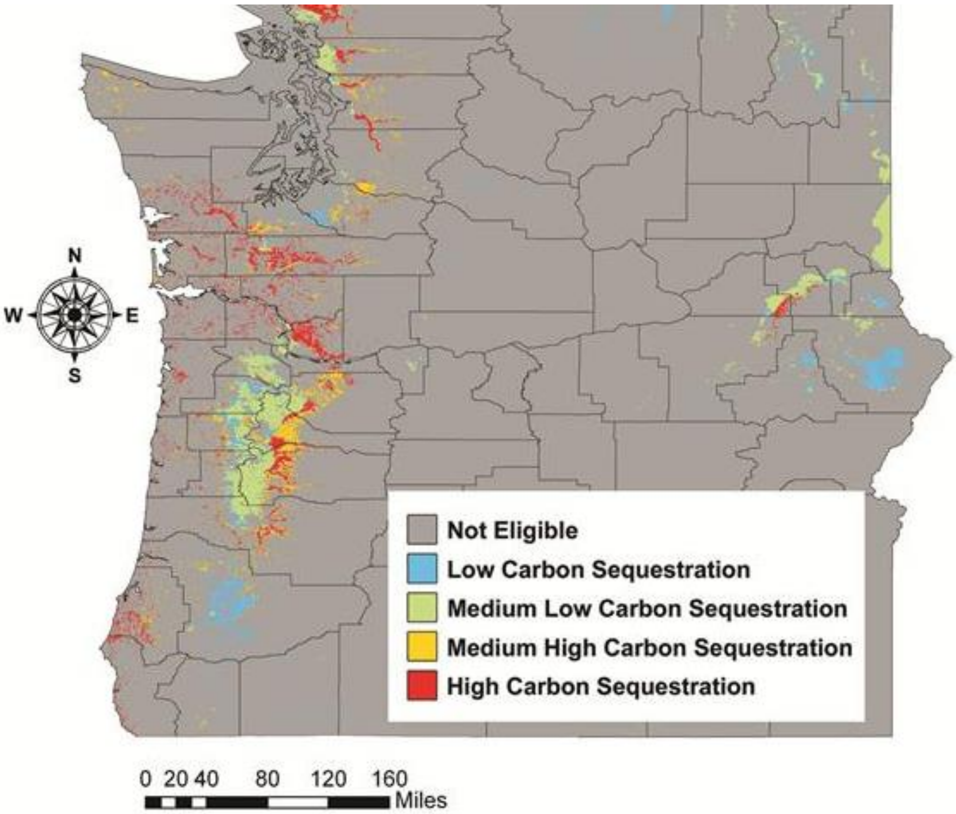

Figure 20. Carbon storage potential with hybrid poplars in Oregon and Washington without irrigation[177]

Forest Conservation Management

Forests in active harvest rotations can be managed to increase overall carbon stocks. WESTCARB researchers examined three approaches: (1) lengthening timber harvest rotations beyond the economic maturity when harvesting would normally occur, (2) widening riparian buffer zones where trees are not harvested by an additional 200 feet (61 meters); and (3) reducing hazardous fuel in forests to reduce catastrophic fires, and subsequently using fuels in biomass power plants.

Statewide Capacity Estimates for Lengthening Timber Harvest and Widening Riparian Buffers

Although Oregon and Washington have substantial forest area, the cost of carbon sequestration from changing forest management practices is relatively high and the quantity of carbon that could be sequestered is relatively small. In Oregon, if all forests on private and nonfederal public land nearing the economically optimal rotation period (790,000 acres) were to adopt management plans to increase rotation ages by up to 15 years, 35.6 $MMTCO_2$ could be sequestered for an average cost of $37 per metric

[177] *2010 Carbon Sequestration Atlas of the United States and Canada.* Third Edition (DOE/NETL).

ton. In Washington under the same scenario, acreage would be about 1.5 million acres, and 61.6 $MMTCO_2$ could be sequestered at an average cost of $37 per metric ton.

By widening the riparian buffer by an additional 200 feet, the area of mature forests in Oregon could potentially be increased by an estimated 20,700 acres. The additional carbon that could be stored on these lands if the forests were conserved is 1.25 $MMTCO_2$ at an average cost of $40 per metric ton.

In Washington, the potential area of mature forests where the riparian buffer zone could be widened by an additional 200 feet was estimated at 34,900 acres. The additional carbon that could be stored on these lands if the forests were conserved is 2.2 $MMTCO_2$ at an average cost of $33.30 per metric ton.

In California, the potential for additional carbon storage from lengthening timber harvest rotations by five years on about 300,000 acres could be 2.0 to 3.5 $MMTCO_2$ over a 20-year span, at a cost of less than $13.60 per metric ton. Widening the riparian buffer zone by 200 feet could sequester 3.91 $MMTCO_2$ at a cost between $2.70 and $13.60 per metric ton. This could occur on about 43,730 acres of forestland.[178]

In Arizona, where an arid environment and population growth make conservation of water resources especially important, WESTCARB studied the potential for afforestation of riparian areas with native species. Total acreage of these ecosystems is limited to about 4% of the state. The study cautioned that actual site selection for riparian afforestation would need to take into account all riparian functions such as preserving water quality, maintaining stream integrity, providing wildlife habitat, and controlling flood and storm water runoff.

Table 8 shows estimated carbon storage from afforestation of areas with high to very high potential. The study cautioned that actual site selection for riparian afforestation would need to take into account all riparian area functions such as preserving water quality, maintaining stream integrity, providing wildlife habitat, and controlling flood and storm water runoff.

Table 6. Potential for carbon accumulation in Arizona's prime riparian areas[179]

Native woody riparian vegetation	Acres with high to very high sequestration potential	Total carbon sequestration ($MMTCO_2e$)		
		20 years	40 years	80 years
Conifer/oak	63 thousand	3	4	4
Cottonwood/ Willow	1.6 million	75	93	97
Mesquite	1.6 million	76	94	98
Mixed broadleaf	1.5 million	69	85	90

[178] Brown, S. *Carbon Supply from Changes in Management of Forest.*
[179] Petrova, S. et al. (Winrock International) 2009 draft report. *Regional Characterization for the State of Arizona: Potential of Riparian Areas for Carbon Sequestration.* Prepared for the California Energy Commission, Public Interest Energy Research Program. (http://uc-ciee.org/downloads/AZ_riparian.pdf)

Testing Forest Conservation Management in California

WESTCARB's Bascom Pacific Conservation Forestry Project tested project conservation-based management in a commercially productive forestland in northern California in accordance with Version 2.1 of the Forest Project Protocol of the California Climate Action Registry (now the Climate Action Reserve).

Over the life of the project, 448,000 thousand board feet (MBF) of timber are harvested under the baseline activity scenario, whereas 418,000 MBF are harvested under the project activity scenario. Although the baseline scenario exhibits an average harvest rate of about 4,475 MBF per year, as much as 7,413 MBF per year are harvested per year during the initial clearcut phase and up to 14,820 MBF per year in the second clearcut phase, but only between about 1,000 and 3,000 MBF per year during intermediate thinnings, and no harvest during fallow years.

The wood products carbon pool reflects these changes by accumulating rapidly during clearcutting phases, and more slowly during intermediate thinning phases. In periods with no harvesting, decay of existing wood products leads to a slight decrease in the overall stocks in the pool.

Combining the wood products pool with the standing live tree, standing dead tree, and lying dead wood pools increases the amount of carbon stored under both the baseline activity and project activity scenarios (Figure 21). When the baseline values are averaged over the project lifetime, inclusion of wood products increases the baseline average by 179,000 tons of CO_2. Incorporating wood products also increases the cumulative emissions reductions at the end of the project lifetime by 132,000 tons of CO_2. However, cumulative emissions reductions, including wood products, remains lower than emissions reductions without wood products until 2066, at which point emissions reductions including wood products is greater through the remainder of the project lifetime.

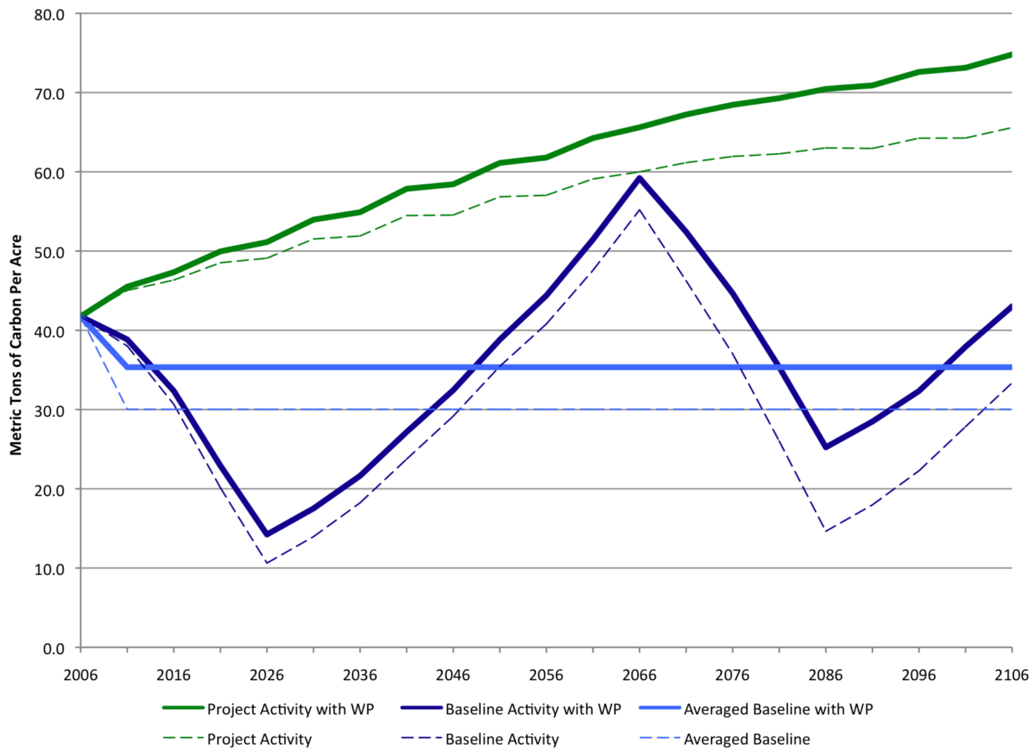

Figure 21. Baseline and project activity carbon stocks, both with and without wood products pool stocks, over the 100-year project lifetime on a per acre basis[180]

[The averaged baseline activity value is also shown. All scenarios have the same initial carbon stocks at the project start date in 2006. The averaged baseline curve begins at this same starting value, but achieves the average value by the end of the first 5-year reporting period by being reduced annually in equal increments.]

After conducting a pro forma analysis for a Bascom Pacific type project, researchers concluded that the potential financial returns from a forest conservation management project provide an incentive for landowner participation, while fostering long-term forest conservation and net gains from long-term reduction of CO_2 emissions.

The baseline inventory, when properly specified, can be cost-effectively undertaken concurrent with a conventional timber inventory, but does add expense, due to the generally higher statistical confidence required in sampling, and the inclusion of additional inventory elements such as dead biomass. Inventory costs vary with the size and heterogeneity of the property, not unlike timber inventories. Larger more

[180] Remucal, Jonathan et al. 2010 draft report. *Demonstration of Conservation-Based Forest Management to Sequester Carbon on the Bascom Pacific Forest.* Prepared for the California Energy Commission, PIER Energy-Related Environmental Research. (http://uc-ciee.org/downloads/BascomPacific.pdf)

homogenous properties will cost less to inventory than the mid-size, relatively diverse Bascom Pacific property.

Forest Fuels Reduction

Wildfire regimes differ by region and ecosystem due to differences in weather, topography, vegetation type and stand characteristics, which affect the timing, frequency, and behavior of fires. Plant communities may be well adapted to some fire regimes, but not to others. For example, species such as lodgepole, Coulter, knobcone, and Bishop pines have cones that release seed in response to heat and fires; thus the forest is adapted to moderate to high severity fires, even though fire kills individual trees. Ponderosa pine forests and oak woodlands, on the other hand, evolved with, and benefit from, frequent but relatively low intensity understory fires that remove competing vegetation without damaging trees. Seed dispersal is not dependent on fire, so high severity fires can result in extensive tree mortality.[181]

Most of the WESTCARB region experiences large wildfires. In Alaska alone, more acreage burns on average than in all of the other U.S. states combined. Although the amount of CO_2 emitted from wildfires in the United States is estimated to be equivalent to ~5% of anthropogenic emissions, a severe fire season can have a more significant impact on a state's GHG emissions, releasing as much CO_2 as the annual emissions from the entire transportation or energy sector.[182] Some researchers have suggested that wildfires may become more frequent with climate change, and that there is a significant potential for additional net release of carbon from the forests of North America in the coming decades.

A Washington study found that most ecosystems in the Pacific Northwest will likely experience an increase in area burned by the 2040s. In the U.S. Columbia Basin, average burn areas are projected to increase from about 425,000 acres annually (1916–2006) to 0.8 million acres in the 2020s, 1.0 million acres in the 2040s, and 2.0 million acres in the 2080s.[183]

In many western forests, the threat of wildfire has been exacerbated by fire suppression activities over the last 100 years. Whereas a fire return interval of every 15 to 20 years would result in low-intensity surface fires that curtail the accumulation of forest fuels, disruption of this fire pattern through suppression has resulted in the build-up of "ladder fuels" at intermediate heights, which can carry surface fires into the crowns of trees and lead to large, catastrophic fires. Such fires generally result in more tree deaths, followed in some cases by arrested succession, whereby a dominant understory species such as Manzanita prevents post-fire tree re-establishment.[184]

Evidence suggests that forest fuel treatments that thin crowded understory vegetation and remove dead biomass appear to have reduced the intensity, spread, or emissions from fires and/or slowed a fire's

[181] *2009 California Climate Adaptation Strategy,* California Natural Resources Agency. (http://resources.ca.gov/climate_adaptation/docs/Statewide_Adaptation_Strategy.pdf)
[182] Wiedinmyer, Christine and Jason C. Neff. "Estimates of CO_2 from fires in the United States: implications for carbon management," *Carbon Balance and Management,* 2007, vol. 2-10.
[183] Littell, J.S., M. McGuire Elsner, L.C. Whitely Binder, and A.K. Snover (eds). *The Washington Climate Change Impacts Assessment: Evaluating Washington's Future in a Changing Climate,* Executive Summary, Climate Impacts Group, University of Washington, Seattle, Washington, 2009.
[184] *Best Practices for Terrestrial Sequestration of Carbon Dioxide,* November 2010, DOE/NETL.

progress. To study the potential for forest fuels reduction treatments as a terrestrial carbon storage activity, WESTCARB conducted pilot projects in forests in Shasta County, California, and Lake County, Oregon.

Net impact calculations for the projects were based on field measurements of carbon stocks before and after fuel treatments, fire modeling, fire risk assessment, growth modeling, and biomass and timber accounting. The study concluded that:

- Fuel treatments resulted in increased net carbon emissions for all projects
- Fuel treatments are unsuitable for generating GHG offsets on a project by project basis
- Biomass-generated electricity from removed forest fuels, which avoids carbon emissions from fossil fuels, did not compensate for the loss of carbon stored as standing timber[185,186]

Although the results of the WESTCARB fuels reduction pilots indicate that such projects are unlikely to function as a carbon offset category, the benefits of managing forest fuels go beyond emissions considerations. In many instances, removing forest fuels can decrease the severity and size of forest fires, and reduced fire severity in one area can lower damages and emissions in surrounding untreated areas. Fuel treatments can lead to increased timber production and reduced firefighting costs, and safeguard nearby communities from life and property loss.

Currently, CO_2 emissions from biomass from forest fuels reduction activities are considered neutral under some GHG emissions regimes, including California's cap-and-trade program, which specifies that there is no compliance obligation for emissions from wood and wood waste harvested for the purpose of forest fire fuel reduction or forest stand improvement.[187]

EPA, after initially including biomass plants under its December 2010 ruling to regulate GHG emissions from industrial facilities, announced on July 1, 2011, that it will defer permitting requirements for CO_2 from the biomass-fired and other biogenic sources plants for three years, pending further scientific research.[188] EPA's decision is being challenged in court by environmental groups that contend biomass energy could reduce carbon sinks by incentivizing deforestation and other harmful practices as forest are "mined' for energy. Some environmental groups also have concerns that the carbon footprint from biomass plants is not well established.

In Lake County, Oregon, forest fuels management has been incorporated into an overall strategy that combines restoration of the region's forests with new opportunities for rural economic development.

[185] During Shasta County pilots, a significant portion of the removed fuels were hauled to a local biomass-fired power plant. The emissions from the combustion of these fuels were included in the fuel treatment emissions based on the assumption that the biomass was displacing natural gas, but with higher CO_2 emissions than natural gas.
[186] http://www.nature.com/nclimate/journal/v1/n8/full/nclimate1264.html
[187] Final Regulation Order, California Code of Regulations, Subchapter 10 Climate Change, Article 5, §95852.2. Emissions without a Compliance Obligation.
[188] "EPA to Defer GHG Permitting Requirements for Industries that Use Biomass," U.S. EPA News Release, January 12, 2011.

Multiple public and private parties[189] developed a 20-year Interagency Biomass Supply Memorandum of Understanding, signed in November 2007, which established a framework for planning and implementing forest and rangeland restoration and fuels reduction projects. A contract with the U.S Forest Service Pacific Northwest Region provides for a supply of material to support the Collins Companies' new small diameter sawmill (to better handle the smaller timber from restoration projects). A second project, Iberdrola Renewables' 26.8 MW Lakeview biomass cogeneration plant, halted construction in October 2011, for lack of a long-term power purchase agreement.[190]

In California, a lawsuit by the Center for Biologic Diversity against the planned 18.5 MW Buena Vista Biomass Power Plant in Calaveras County was settled through mediation when the plant agreed to greater transparency in harvesting by providing feedstock information to an advisory committee, which will ensure the material is renewable and harvested from sustainably managed forest lands.[191]

The projects in Oregon and California suggest that the successful deployment of new biomass power plants in the western region can effectively be undertaken in conjunction with practices for sustainable forest management, including management of forest fuels, and that such projects will benefit from gaining buy-in from a wide range of stakeholders, including environmental and community groups.

Avoided Forestland Conversion

Conversion of agricultural lands, rangelands, forest lands, and wetlands (primarily to accommodate new housing and commercial growth) is a source of GHG emissions in many states, although these are not necessarily counted in GHG inventories. California, for example, saw a population increase of nearly 48% between 1984 and 2008, according to estimates by the state's Department of Finance. In the same timeframe, farm and grazing land decreased by more than 1.3 million acres, or about one square mile per day. Urbanization accounted for the vast majority of this loss, more than 1.04 million acres.[192] California's population is still increasing, albeit more slowly since the recession of 2008, with the continuing need for additional infrastructure. Avoided conversion could become an important strategy for retaining carbon stocks to help achieve the state's GHG emissions reduction goals.[193]

For Washington, urban growth near Seattle has been a source of GHG emissions and a matter of concern to the state legislature and Washington Department of Natural Resources. The risk of conversion is especially high in Puget Sound's watersheds. From 1987–1997, an estimated 246,000 acres were deforested for urban development across the state. Forty-two percent of this area was in in three counties near Seattle, an area that represents just 8% of the state. Estimated net emissions across the three counties were over 6 $MMTCO_2e$/yr, or 45% of the total from development across the whole state.

[189] Lake County Resources Initiative, Lake County, Town of Lakeview, City of Paisley, DG Energy LLC, DG Investors LLC, The Collins Companies, Oregon Department of Forestry, USDA Forest Service Fremont-Winema National Forest, and Bureau of Land Management, Lakeview District.
[190] Williams, Christina. "Construction Halted on Lakeview Biomass Plant," Sustainable Business Oregon, October 13, 2011. (http://www.sustainablebusinessoregon.com/articles/2011/10/construction-halted-on-lakeview.html)
[191] Gibson, Lisa. "Buena Vista Biomass Power project proceeds," *Biomass Power & Thermal Magazine*, June 13, 2011.
[192] http://www.conservation.ca.gov/dlrp/fmmp/trends/Pages/FastFacts.aspx
[193] Avoided conversion projects for forests are a compliance offset option under California's cap-and-trade program.

WESTCARB researchers conducted a study of the residential development being implemented in the Puget Sound region to estimate the emissions associated with conversion of forested lands. Full accounting of emissions from development must include both the emissions from clearing the forest and the sequestration that occurs after development from carbon stock recovery.

The study found a range of net emissions from 65 to 1,285 metric tons CO_2e per development. However, a few subdivisions showed net sequestration, ranging from 7 to 305 metric tons CO_2e. Net sequestration can result when the emissions from forest clearance are low due either to low initial forest cover or to high forest cover retention.

Forest cover cleared during development varied from 57–100% in areas of less than 16 acres, but averaged just 35% for development areas that exceeded 16 acres. This relationship could form the basis of a future performance standard for development projects such that if a developer exceeded the defined area of forest retained by 10% or more, the carbon stocks of the retained forest would be creditable.

An offset project that merely halts development in a forested area would be subject to leakage risk. It is possible that as many or more emissions would result at the alternative site or sites to which the development was displaced. Instead, net emission reductions can result where development is altered without changing the number or category of developed properties. Ultimately the area of forest retained within the full boundary of the development must be increased relative to the proportion that would remain under business-as-usual.

The study observed that it could be possible to mitigate emissions from forest conversion while avoiding leakage through “cluster development,” which allows for the preservation of open space while continuing to provide the same number of lots for residential development. This can be accomplished through density incentives that are applied to reduce the minimum allowable lot size. For example, developers could receive incentives for maintaining a minimum proportion of a development site in open space. County governments could also mitigate emissions from development by directing development away from lands with forest cover to lands with less vegetation. For avoided conversion projects qualifying for offsets under the Climate Action Reserves’ Forest Protocol or California’s cap-and-trade program, preservation of forest land is achieved through a conservation easement or transfer to public ownership.

Forests in Climate Change Policy Development

Widespread deployment of terrestrial carbon sequestration depends upon climate change legislation and policy provisions allowing terrestrial carbon storage as a compliance option under a cap-and-trade program or offering other financing/incentive mechanisms.

Although some states in the WESTCARB region have passed climate change legislation and are moving forward with GHG reduction programs, others await federal legislation, which is not an eminent prospect. This limits the compliance-driven demand for terrestrial carbon storage, as well as other types of offset projects.

As of June 2012, the WESTCARB region had 31 terrestrial carbon projects (improved forest management, conservation-based forest management, and reforestation) listed with the Climate Action Reserve, of which 27 were located in California, two in Oregon, one in Hawaii, and one in Washington.[194]

Policy mechanisms include terrestrial carbon storage to varying degrees. In the case of Oregon's Climate Trust, the price of an offset is determined by the state's Energy Facility Siting Council and was about $1.40 per metric ton of CO_2 in 2011. By law, this can be raised every other year by 50%. These parameters constrain the cost of GHG compliance to facilities and customers but limit the level of funding the Trust has available for offset projects. Thus, project developers would be expected to seek funding from multiple sources.

California's cap-and-trade program allows regulated businesses to meet up to 8% of their compliance obligation with offsets. Given the projected size of the California carbon market and the assumption that regulated entities will utilize offsets to the fullest extent possible, this 8% is not expected to pose a barrier to offset projects during the early years of the program. In fact, some parties have suggested that offsets could account for 85% of GHG emissions reductions under the cap-and-trade program provided enough offsets are available under CARB's approved set of protocols. CARB's economic analyses indicate offsets could account for up to 49% of required reductions.[195]

CARB's 2020 Scoping Plan for the Global Solutions Act of 2006 (AB32) calls for maintenance of the current level of 5 $MMTCO_2e$[196] of sequestration in the state's forests through sustainable management practices, potentially including reducing the risk of catastrophic wildfire and the avoidance or mitigation of land-use changes that reduce carbon storage. The scoping plan notes that California's forests are expected to play an even greater role in achieving the 2050 GHG emissions reduction targets because trees planted in the near-term will generally maximize their sequestration capacity in 20 to 50 years.[197]

California's Natural Resources Agency amended the California Environmental Quality Act (CEQA) guidelines, effective March 2010, to include analysis of GHG emissions. A new item in the sample environmental checklist of suggested CEQA thresholds is the assessment of loss of forest land or conversion of forest land to non-forest use.[198] This new requirement has triggered the purchase of carbon offsets by some developers, as well as by industrial facility operators with expansion plans.[199]

British Columbia passed the Zero Net Deforestation (ZND) Act on May 6, 2010, setting forth the goal of achieving ZND by 2015 on all lands in the province including First Nations, federal, and private lands.

[194] Climate Action Reserve project database, June 2012.
[195] Mulkern, Anne C. "Offsets Could Make Up 85% of Calif.'s Cap-And-Trade Program," *The New York Times*, August 8, 2011.
[196] The 5 $MMTCO_2e$ emission reduction target is equal to the magnitude of the current estimate of net emissions from California's forest sector. The target can be recalibrated to reflect new information.
[197] *Climate Change Scoping Plan: A Framework for Change,* California State Air Resources Board, December 2008.
[198] 2011 CEQA Statutes and Guidelines: http://www.ceres.ca.gov/ceqa/
[199] Per Josh Margolis of $CantorCO_2e$ at the California Offsets Workshop, San Francisco, CA, August 8, 2011.

A draft Proposed Implementation Plan was issued in December 2010. In 2007, approximately 6,200 hectares were deforested in BC while 2,000 hectares were afforested. Net GHG emissions attributable to this forest loss accounted for 4.6% of the Province's emissions, about 3.1 $MMTCO_2e$.[200]

British Columbia has also developed protocols to guide the design, development, quantification, and verification of B.C forest carbon offsets from a broad range of forest activities on private and public land within the Province.[201]

Reducing GHG Emissions in the Agricultural Sector

Significant opportunities for decreasing the GHG emissions associated with agricultural activities are found with non-CO_2 greenhouse gases. Methane (CH_4) emissions, which have approximately 21 times the global warming potential of CO_2, come primarily from the enteric fermentation of livestock and from manure. Protocols to capture and destroy methane gas from manure treatment and/or storage facilities on livestock operations are available under several GHG emissions registries and are included as an offset option under California's cap-and-trade program. In California, methane emissions from manure management were 6.0 $MMTCO_2e$ in 2004.[202]

A much smaller methane source in the WESTCARB region is emissions from flooded rice fields. The flooding results in anaerobic conditions in soils, triggering decomposition of organic matter by methanogens, a class of soil bacteria that produce methane during microbial decomposition. In California, methane emissions from flooded rice fields were 0.6 $MMTCO_2e$ in 2004.[203] Recently adopted protocols or methodologies for GHG emissions reductions from rice cultivation are available at the Climate Action Reserve[204] and the American Carbon Registry.[205] Methods include reducing the duration and frequency of winter flooding, removal of rice straw from the field after harvest and before winter flooding, and replacing water seeding with dry seeding. As with many land/water use practices, other factors beyond GHG impacts warrant consideration. In the case of rice field management, bird habitat and water quality are also important issues.

Nitrous oxide (N_2O) emissions, which have approximately 300 times the global warming potential of CO_2, represent a substantial source of GHG emissions from agricultural production, primarily due to fertilizer application. The California Energy Commission reported N_2O emissions from the state's soil management to be about 19 $MMTCO_2e$ in 2004.[206] In November 2010, the American Carbon Registry issued a GHG offset methodology to quantify agriculture sector emissions reductions through changes in fertilizer management. The methodology allows for quantification of direct N_2O emissions as well as

---

[200] *British Columbia Greenhouse Gas Inventory Report 2008,* Ministry of Environment, Victoria, B.C., September 2010.
[201] *Protocol for the Creation of Forest Carbon Offsets in British Columbia, Version 1.0:* (http://www.env.gov.bc.ca/cas/mitigation/pdfs/Forest_Carbon_Offset_Protocol_v1_0_Web.pdf)
[202] *Inventory of California Greenhouse Gas Emissions and Sink: 1990 to 2004,* Staff Final Report, California Energy Commission, December 2006, CEC-600-2006-013-SF.
[203] Ibid.
[204] http://www.climateactionreserve.org/how/protocols/agriculture/rice-cultivation/
[205] http://www.americancarbonregistry.org/carbon-accounting/emission-reductions-in-rice-management-systems
[206] *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004.* CEC-600-2006-013-SF.

indirect emissions from leaching and ammonia volatilization. The approach is applicable not only to changes in fertilizer quantity (rate), but also fertilizer type, placement, timing, use of timed-release fertilizers, use of nitrification inhibitors and other practice changes. Aggregation is permitted, enabling farmers to participate in groupings of multiple farms, which lowers transactions costs, improves modeling results, and diversifies risk.[207]

Another source of agricultural CO_2 emissions is from land clearing, draining, sod breaking, cultivating, and over-fertilization, all of which have served to reduce the store of carbon in soils. Through improved or alternative management practices, many agricultural lands have the potential to become a significant carbon sinks relative to current levels. Among the practices that can improve the carbon balance in soils is conservation tillage (CT), a term that represents reduced-tillage field practices for crop production that are designed to minimize soil erosion and enhance soil tilth. As opposed to conventional tillage, which buries and mixes crop residue into the soil to prepare a seedbed for crop planting, CT systems plant directly into crop residues (no-till, or direct seeding) or only till part of the soil area (strip-till).

In California, based on carbon sequestration rates of 0.35–0.61 metric ton per hectare per year, it is estimated that agricultural land could store up to 3.9 $MMTCO_2$ /year through CT. The cost to sequester this amount of carbon in California has not been calculated, however, data from other regions of the United States suggest costs will be relatively low. The most likely crops for which CT will be adopted are tomatoes, cotton, beans, and corn, which represent a large area of California agricultural land.[208]

A study of Yolo County, California,[209] found that by adopting CT practices at carbon payments of $3 to $8 per ton per year, Yolo County could sequester as much as 33,000 to 39,000 tons of carbon, approximately 3% of the county's total carbon release. The study noted that relatively low carbon payments would likely induce the adoption of sequestering technologies by farmers. It further noted that while the carbon reduction from this single sequestration practice is relatively small, other ecosystem benefits such as reduced water runoff and dust (with associated pollution) could also be realized.

For some Yolo County's crops, however, tillage reduction presents production constraints, such as seed establishment or efficient movement of irrigation water. Also, alternative tillage practices can increase nitrous oxide emissions due to higher moisture content and increased activity of anaerobic microorganisms.[210]

One challenge faced in CT is weed control, which is frequently cited as a reason for failure of CT systems and also for limited adoption by organic growers, who rely on conventional tillage to eradicate weeds and incorporate cover crops and compost. However, CT and organic farming need not be mutually exclusive, and the use of cover crops, mulching, and other techniques for non-chemical weed control is gaining

[207] American Carbon Registry (2010), *American Carbon Registry Methodology for N_2O Emission Reductions through Changes in Fertilizer Management.* Winrock International, Little Rock, Arkansas.
[208] Brown, S. *Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California.*
[209] Howitt, R.E. et al. 2009. "Realistic payments could encourage farmers to adopt practices that sequester carbon," *California Agriculture:* Vol. 63: No. 2, Page 91.
[210] Jackson, L.E. 2009. *Potential for Adaptation to Climate Change in an Agricultural Landscape in the Central Valley of California*, California Climate Change Center, CEC-500-2009-044-F.

recognition. Alternatively, a concern has been expressed that soil carbon storage projects using conservation tillage could be conducted with genetically modified crops grown in conjunction with chemical eradication of weeds.

Conservation tillage has been most widely adopted for agronomic crop production. The overall potential for carbon storage through CT in the WESTCARB states may be curtailed by crop types, which are more heavily weighted toward higher value vegetable and specialty crops. Most vegetable growers continue to use intensive tillage for seedbed preparation.

A major consideration with systems to increase soil carbon is the need to maintain crop yields. A study that tested the transition to CT practices for cotton and tomato crops in the San Joaquin Valley of California[211] found that tomato harvest yields were increased by CT, while cotton harvest yields were decreased. During the four years of the study, tractor trips across the fields were reduced by about 50% for tomatoes and 40% for cotton in the CT systems relative to standard tillage, and dust was also reduced.

Wetlands as Carbon Sinks

The loss of coastal wetlands and marine ecosystems such as peat lands, forested tidal wetlands, tidal freshwater wetlands, and salt marshes leads to decreased carbon storage and can contribute to CO_2 emissions. In contrast to terrestrial forests, wetlands store most of the carbon below ground in an organic soil layer, which can run several feet deep.

Although some researchers contend that wetlands are more efficient than forests at carbon storage on a per acre basis, an overall accounting of GHGs needs to factor in methane and N_2O emissions from these ecosystems. In breaking down plant matter, microbes in wetlands release methane, which partly counteracts the positive climatic effects of CO_2 storage. The extent to which this happens varies from site to site, but is found to be more significant in freshwater wetlands. Methane release in tidal salt marshes is deemed negligible.

At a 14-acre pilot project on Twitchell Island in the western Sacramento-San Joaquin River Delta of California served to test “carbon farming” in conjunction with reducing land subsidence and protecting levees. Twitchell Island is about 15 feet below sea level. Researchers flooded the land shallowly and planted clumps of tules and cattails. As the plants matured, researchers raised the water level. After ten years, this experiment built two feet of peat soils, an accrual of 10 metric tons of carbon per hectare per year.[212]

This type of project could significantly reduce the risk of levee failure and the cost of levee maintenance, while providing greater security to water supplies. However, the potential for such projects to furnish carbon offsets has yet to be determined. Preliminary measurements of methane during the Twitchell project varied widely, and N_2O was not measured. Further research is needed to establish the overall GHG balance in wetlands restoration projects.

[211] Mitchell, Jeffrey P. et al. 2008. “Transition to conservation tillage evaluated in San Joaquin Valley cotton and tomato rotations,” *California Agriculture,* Vol. 62: No. 2, Page 74.
[212] http://soilcarboncoalition.org/twitchell

Co-benefits from sustainable management of coastal wetlands and marine ecosystems can include shoreline protection, water quality maintenance, flood control, habitat for birds and other wildlife, harvestable resources such as fish, as well as opportunities for recreation. Maintenance and restoration of coastal wetlands could factor in mitigating the impact of sea level rise. Coastal wetlands can attenuate wave energy and provide enhanced protection against increasingly frequent storm surge and rising sea levels, which will likely become an issue for Alaska, British Columbia, California, Hawaii, Oregon, and Washington. A few coastal communities in Alaska are already relocating further inland.[213]

Biochar

Pyrolysis, a thermochemical process where biomass is heated in the absence of oxygen or partially combusted in the presence of a limited oxygen supply, results in biochar, a concentrated carbon skeleton of the original biomass that can hold onto its carbon for hundreds, even thousands of years. Biochar can be added to soils to increase their ability to retain water and nutrients, and therefore enhance productivity. Bichar production can also serve to divert wastes such as rice residues or manure from the decomposition process that generates methane emissions. Additionally, the gases and oils that are released during pyrolysis can be combusted to create energy. Feedstock, temperature, and time of exposure to pyrolysis determine the proportions of gas, oil, and char produced and the characteristics of these outputs.[214]

Although there is significant global interest in biochar, protocols to enable biochar projects in carbon markets are generally lacking, and more study is needed to better understand the implications of adding biochar to soils, given varying pH levels and variabilities in biochar composition.[215] A WESTCARB study proposed carbon market investment criteria for biochar projects and used these to evaluate a pilot-scale project at a log yard in Philomath, Oregon.[216] The study estimated that biochar offset projects will need to produce at least 25,000 metric tons of biochar over a ten-year span to be economically feasible. The study further identified the difficulty of accounting for biochar in soils if the biochar is sold to many entities.

Project Financing and Support Mechanisms

Although terrestrial carbon storage projects can provide a relatively inexpensive way of reducing atmospheric CO_2, they can also entail high transaction costs that reduce their competitive advantage. Costs can be expected to accrue most heavily during the early phases, which can entail feasibility studies, insurance, baseline assessments, project registration, and implementation of land change practices (i.e., thinning, planting, weed control). Analyses of transaction costs found a range between $0.50–$4.50 metric ton/carbon for forestry projects sequestering between 10,000,000 and 10,000 metric tons of

[213] http://epa.gov/climatechange/impacts-adaptation/alaska.html#adapt
[214] Weisberg, Peter, Matt Delany, and Janet Hawkes, The Climate Trust, *Carbon Markets Investment Criteria for Biochar Project,* September 2010. (http://peterweisberg.files.wordpress.com/2012/08/westcarb-biochar-report-final.pdf)
[215] http://www.biochar-international.org/biochar/faqs#q7
[216] Wiesberg, P. op. cit.

carbon, respectively. Economies of scale play a large role in transaction costs, which rise steeply for projects storing less than 100,000 metric tons of carbon.[217]

Transaction costs and methodological requirements vary according to the standards used. In some instances, a small project may be able to recover transaction costs under standards that are less stringent; however, the market of potential buyers and funders will most likely shrink significantly.[218]

Funding for terrestrial carbon storage projects can come from a variety of sources including publicly traded funds, conservation non-profits, foundations, private equity, commercial banks, governments, companies, and development finance institutions. Since the advent of carbon markets, funds specifically targeted at investments in offset credits have been formed. Project developers and offset retailers will typically fund a carbon offset project and forward sell the promised credits. This mechanism generates funds to start new offset projects, although future offsets are generally worth less than existing offsets because of the risk of non-delivery. Most project developers/funders seek to place their investments in larger projects where economies of scale can improve the rate of return.

Reducing Project Costs Through Aggregation

Aggregation can facilitate participation in carbon markets for small landowners. By pooling credits from multiple projects, an aggregator is able to offer blocks of credits in a carbon market. This reduces transaction and monitoring and verification costs for project owners through economies of scale, as well as reducing transactions costs for purchasers, who can buy more credits through fewer transactions. Aggregators can also play a role in developing carbon markets by providing information to landowners on how they can participate in a carbon market.

The now-closed Chicago Climate Exchange (CCX) required landowners to work through an aggregator if their project sequestered less than 12,500 metric tons of carbon per year. The National Farmers Union defined its role as an aggregator to include:

- Arrange for third-party verification
- Register individual acreages into blocks
- Maintain a database of credits
- Send annual certifications to CCX and provide other data as needed
- Manage sales of blocks of credits
- Distribute sale proceeds to participants

The Farmers Union collected a 10% service fee from annual sale proceeds to cover administrative expenses associated with these activities.

[217] Miller, Cheryl and Dean Current. *Terrestrial Carbon Sequestration: A Survey of Policies and Programs* University of Minnesota, 2006.
[218] Olander, Jacob and Johannes Ebeling. "Building Forest Carbon Projects: Step-by-Step Overview and Guide," *Building Forest Carbon Projects*, Johannes Ebeling and Jacob Olander (eds.). Washington, D.C.: Forest Trends, 2011.

The Climate Action Reserve's approach to aggregation in Version 3.2 of the Forest Project Protocol stipulates that only projects of less than 5,000 acres may enroll in an aggregate.[219] The Reserve's policy allows for fewer sample plots per project to generate a forest carbon inventory on the grounds that greater statistical uncertainty per individual project will be compensated through aggregation with other projects. Each project in an aggregate also requires less frequent verification than is required for standalone projects. Forest owners still register individually with the Reserve and maintain a separate account, and liability for reversals lies with each individual owner. The Reserve requires that aggregators be responsible for selecting a verifier, coordinating verification schedules, and maintaining a Reserve account to receive credits transferred from the accounts of participating forest owners and from which credits must be transacted. Other services that may be provided by an aggregator, such as project development, are subject to negotiation between forest owners and the aggregator.

Under California's cap-and-trade program, CARB did not include project aggregation in the Offset Protocol for U.S. Forest Projects, reasoning that the aggregation rules were a recent addition to CAR's protocol on which the California protocol is based, and that further work is needed to ensure compatibility within the compliance offset program.[220]

Funding Terrestrial Carbon Storage Through Allowance Auctions

Auctioning of GHG allowances creates revenues that can be expected to grow under programs that scale back the number of free allowances in later years, provided the price of carbon is not undermined. Most climate change regimes allocate a portion of their allowance revenues to financing technologies and programs to reduce GHG emissions. This mechanism could be used to fund terrestrial carbon storage, and may be especially suited for projects on public lands.

The Climate Trust Funding Model

In 1997 with the passage of HB 3283, the Oregon legislature created the Oregon Carbon Standard for baseload gas power plants, non-baseload power plants, and non-generating energy facilities that emit CO_2. These entities must reduce their net CO_2 emissions 17% below the most efficient baseload gas plant in the United States. Excess CO_2 emissions beyond what can be reduced through power plant design or cogeneration may be addressed through offsets. Facilities may implement CO_2 offset projects either directly or through a third party, subject to approval by the state's Energy Facility Siting Council (EFSC). Alternatively, they may provide funds (corresponding to their CO_2 emissions at a rate determined by the EFSC) to The Climate Trust, a non-profit organization established to implement projects that reduce or sequester CO_2 emissions.

Over the history of the Oregon Standard, the overwhelming majority of facilities have chosen to offset their emissions via The Climate Trust. Every two years, EFSC may adjust the offset rate by 50%. The last rate change was in May 2007, when EFSC enacted a full 50% increase, which resulted in an offset price of $1.27 per short ton (about $1.40 per metric ton).

[219] *Guidelines for Aggregating Forest Projects,* Climate Action Reserve, Version 1.0, August 31, 2010.
[220] *Proposed Regulation to Implement the California Cap-and-Trade Program, Part V, Staff Report and Compliance Offset Protocol for U.S. Forest Projects,* California Environmental Protection Agency Air Resources Board, October 28, 2010.

In 2011, The Climate Trust had credits under contract equal to 3,006,463 metric tons CO_2e, [221] of which three forestry projects—one in Oregon, one in Washington, and one in Ecuador—accounted for over 0.5 $MMTCO_2$. Total credits delivered or retired equaled 987,756 metric tons CO_2e. In June 2011, with the passage of HB 3538, Oregon expanded the scope of offsets to allow projects for non-CO_2 GHGs to be included in compliance options.

Terrestrial Carbon Storage Projects in Carbon Markets

The shaping of terrestrial carbon storage as a GHG mitigation strategy is predominantly determined by the policies that define participation in carbon markets. For example, the inclusion of Reducing Emissions from Deforestation and Forest Degradation (REDD and REDD+) in the post-2012 United Nations Framework Convention on Climate Change process is expected to provide an incentive for undertaking forest carbon storage projects, provided the a post-2012 agreement is reached. California's inclusion of an offset protocol for U.S. Forests under the state's cap-and-trade program is also expected to act as a driver for forest carbon projects.

Thus far, participation in the primary CDM market by forestry projects appears to have been hampered by the risk management mechanism of issuing credits that have to be replaced upon expiration, and which therefore command lower prices than credits from other offset activities. The EU-ETS, the world's biggest carbon market, does not accept these temporary credits, which presents a further barrier. Other limiting factors under CDM are the lengthy process of obtaining project approval, due primarily to the use of non-standardized protocols that require a more extensive project review, and the restriction of reforestation projects to lands that were not forested on December 31, 1989.

Criteria for Qualifying Offsets

The quality of offsets—the degree to which they represent GHG emissions reductions or avoidances that are real, additional, quantifiable, permanent, verifiable, and enforceable—is based on the stringency of the protocols or standards under which they enter the market. Offsets that are verified under more exacting standards can command higher prices because buyers have faith in their value. "Higher-priced standards (>$8/tCO2e) are primarily focused on pure voluntary buyers, especially those who pay premiums for the co-benefits associated with the Gold Standard and SOCIALCARBON certification."[222] However, the requirements for meeting higher standards can be prohibitive for smaller projects.

Designing offset standards requires balancing different policy goals. If standards are too strict or narrow, good offset projects can be excluded and overall compliance costs can increase. However, if standards are too lenient, they are less likely to result in real GHG reductions and can undermine the integrity of a carbon regime.

Many standards are still evolving through a process of stakeholder input, testing, and refinement, and new protocols for different types of projects are being developed. In 2010, the Verified Carbon Standard[223]

[221] http://climatetrust.org/documents/AnnualReport2011_000.pdf
[222] Peters-Stanley, M. et al. *Back to the Future: State of the Voluntary Carbon Markets 2011,* Ecosystem Marketplace and Bloomberg New Energy Finance, June 2, 2011.
[223] Formerly the Voluntary Carbon Standard.

(VCS) accounted for over half the transactions for forest carbon in the voluntary market and was the dominant standard for projects in developing countries.[224] Ninety-five percent of the VCS transactions were also certified under the Climate, Community & Biodiversity Alliance (CCBA) Standards, one of the most prominent standards for ensuring social and biodiversity co-benefits. The widespread use of CCBA certification suggests that this standard offers a market access premium (if not a price premium as well), particularly for projects also seeking VCS certification.[225]

Additionality

A project must result in GHG emission reductions that are above and beyond what would occur under a "business as usual" scenario, including any GHG reductions or removals that would occur through compliance with laws or regulations or that would occur because the activity is economically viable without income earned from offsets credits.

Concerns have been raised about the difficulty in determining additionality, and critics charge that some offset projects would have been undertaken on the basis of their own merits without the existence of a carbon market. According to one organization with experience monitoring the development of the Kyoto Protocol's CDM offset program, "project developers have strong incentives to make claims on additionality and baselines that are skewed in their own favor. Meanwhile regulators and third-party certifiers have strong incentives to give developers' claims the benefit of the doubt for a number of reasons, including that they are under financial and/or political pressure for the system to 'work' and therefore generate large amounts of offsets."[226]

Within existing carbon offset programs, there are two basic approaches to determining additionality: project-specific and standardized.[227]

1. *Project-specific* approaches seek to assess whether a project differs from a hypothetical baseline scenario in which there is no carbon offset market. Generally, a project and its possible alternatives are subjected to a comparative analysis of their implementation barriers and/or expected benefits (e.g., financial returns). If an option other than the project itself is identified as the most likely alternative for the business as usual (or baseline) scenario, the project is considered additional. A project-specific approach has the capability to allow unique projects to qualify for carbon credits, however, the time needed to evaluate and register each project can be substantial.

2. *Standardized* approaches evaluate projects against a consistent set of criteria on a sector-wide basis. Standardized tests can involve determinations that a project:

    - Is not mandated by law

[224] Olander, Jacbob. "Building Forest Carbon Projects: Step-by-Step Overview and Guide."
[225] Ibid.
[226] "Quality Criteria for Offsets Under AB32: Comments by International Rivers," 21 May 2009, to the California Air Resources Board. (http://www.arb.ca.gov/cc/capandtrade/meetings/042809am/apr281pcintlriver.pdf)
[227] Broekhoff, D. and K. Zyla. "Outside the Cap: Opportunities and Limitations of Greenhouse Gas Offsets," *Climate and Energy Policy Series*, World Resources Institute, December 2008.

- Exceeds common practice
- Is not a least-cost option (as defined by regulators)
- Involves a particular type of high-performing technology
- Has an emission rate lower than most others in its class (e.g., relative to a performance standard)

From a regulatory perspective, standardized methodologies are advantageous because they avoid subjective evaluations at the project level and are easier to administer than project-specific standards. Additionally, they can reduce transaction costs and shorten registration periods for project developers, alleviate uncertainties for investors, and increase the transparency and consistency of regulatory decisions.

According to CAR, developing standardized methods requires significant research and analysis to establish credible benchmarks and emission factors that can be applied to similar projects throughout an entire industry or sector. Furthermore, because business-as-usual activities can vary significantly across different geographic areas, standardized benchmarks and factors for one region will not necessarily be appropriate for other regions. CAR's standardized protocols generally apply to a limited geographic area.

Permanence – Guarding Against Reversals

Permanence is an issue for terrestrial storage projects because their effects can be reversed over time. A reversal occurs when the stored carbon associated with a project is released to the atmosphere. A distinction is made between reversals that result from human activities and are considered avoidable—such as land conversion, over-harvesting, or harm due to negligence—and unavoidable reversals such as those caused by fire, pest infestation, or disease.

Buffer pools of credits from projects are a common mechanism for insuring against unavoidable reversals. A risk analysis and rating is used to determine the number of credits each project is required to contribute to the buffer pool account, which then covers all at-risk projects in the registry or program. In the event of an unavoidable reversal, credits from the buffer pool must be retired in the amount equal to the carbon that was lost. Projects are terminated when a reversal reduces carbon stocks below baseline levels. Contributions to the buffer pool are adjusted over time to reflect updated risk ratings, which are conducted as part of project verification.

In the event of an avoidable reversal, project owners must surrender offsets or compliance instruments out of their own accounts to cover the amount of the reversal. CAR's protocol stipulates that forest credits must be replaced with other forest offset credits to recognize the co-benefits of forest projects and the preferences of offset buyers in the voluntary market to ensure their investments remain in forest projects.

Under the California cap-and-trade program, intentional reversals can be compensated for with any CARB-issued or approved allowances or offset credits. This allows for fungibility across all compliance instruments in the program, and guards against a potential shortfall in forest offset credits in the case of a large intentional reversal. Unintentional reversals are insured against by contributing a percentage of CARB-issued offset credits to a forest buffer account.

Another approach to guarding against impermanence is to issue temporary or expiring credits. Credits for reversible reductions can be made to expire at a predefined date, or canceled if verification indicates that a reversal has occurred. In both cases, the holder of the credits (rather than the project developer) must procure replacement credits or allowances in order to remain in compliance with the cap-and-trade system. This approach has been adopted by the CDM for afforestation/reforestation (A/R) projects,[228] and has resulted in a lower credit price for forest carbon than for other CDM sectors, placing A/R projects at a disadvantage.[229]

Impermanence could also be addressed by issuing credits on a "discounted" basis. With this approach, less than a full credit is awarded for each ton of GHG reduction. The amount of the discount would be based on a risk assessment of expected future losses of sequestered carbon over a certain time period. Discounting has been proposed as a means of managing other risks and uncertainties pertaining to offset credit issuance, such as additionality. Currently, some CDM and CAR protocols use discounting to account for uncertainty in measurement methods.[230]

Widespread use of discounting could have adverse effects on the efficiency and integrity of carbon markets by reducing the emissions-equivalent value of offsets and the revenue flowing to offset projects. In turn, this could lead to a decrease in the supply of offsets.[231]

Leakage

Leakage is an increase in GHG emissions or decrease in sequestration outside the project boundaries that occurs as a result of project activities. Leakage can lessen or nullify gains from an offset project, as when a forest conservation project shifts logging activities to other forest land. Under some protocols/standards, project developers are required to assess and mitigate certain types of leakage and even deduct leakage that "significantly reduces the GHG emissions reduction and/or removal benefit of a project."[232]

Enforceability

Carbon offsets should be backed by regulations and tracking systems that define their creation and ownership and provide for transparency. Clear definitions of ownership are essential for enforceability and to avoid double counting. For example, a forest owner and a mill owner might both want to claim the emissions sequestered in forest products—as might the owners of the products themselves. Regulatory rules must establish who may claim the emission reductions, who is ultimately responsible for ensuring project performance, who is responsible for project verification, and who is liable in the case of reversals.[233]

---

[228] Ibid.
[229] *BioCarbon Fund Experience: Insights from Afforestation and Reforestation Clean Development Mechanisms Projects – Summary,* World Bank Carbon Finance Unit, Washington, D.C., 2011.
[230] Kollmuss, Anja, Michael Lazarus, and Gordon Smith. *Discounting Offsets: Issues and Options,* Stockholm Environment Institute Working Paper WP-US-1005, July 2010.
[231] Ibid.
[232] *The American Carbon Registry Standard, Version 2.1,* October 2010. (http://www.americancarbonregistry.org/carbon-accounting/ACR%20Standard%20v2.1%20Oct%202010.pdf)
[233] Broekhoff, D. "Outside the Cap: Opportunities and Limitations of Greenhouse Gas Offsets."

Voluntary Carbon Markets

The voluntary market is not part of any compliance or regulatory system, and almost all the carbon credits offered in this market originate from project-based transactions. Historically, 73% of forestry offsets transactions have occurred in the voluntary carbon market.[234] Buyer motivations include the desire to offset their GHG emissions, an interest in innovative philanthropy, public relations benefits, anticipation of GHG regulation, and plans to re-sell credits for a profit.

In 2010, suppliers reported a total volume of 131 $MMTCO_2e$ transacted in the global voluntary carbon markets, as compared to the 98 $MMTCO_2e$ transacted in 2009, a growth of 34%. The volume of carbon credits transacted voluntarily in 2010 represents less than a 0.1% share of the global carbon markets.[235]

This relatively small volume is nonetheless of critical importance because the voluntary market has served as an incubator of innovative protocols, registries, alliances, and project types, which inform the development of regulatory carbon markets.[236]

Terrestrial Carbon Sequestration Under the California Cap-and-Trade Program

California's cap-and-trade program requires reductions of approximately 273 $MMTCO_2e$ through 2020 as compared to business as usual, representing a reduction in emissions to 15% below 2012 levels. The program, which allows regulated businesses to meet up to 8% of their compliance obligation with offsets, stands to become a significant driver for forest carbon storage in the WESTCARB region and elsewhere. According to one analysis, regulated businesses are expected to make full use of offsets as one of the least-cost emissions reduction opportunities available. Estimates of offset demand range from approximately 214–232 $MMTCO_2e$ through 2020. As of December 2010, current offset supply eligible for use in the California market is approximately 8.3 $MMTCO_2e$.[237]

The size of the California offset market after 2020 will depend on the rate of emissions reductions required en route to the state's 2050 goal, the allowance percentage of offsets as a compliance measure, and the marginal cost of forestry-based terrestrial storage projects, as demand grows.

At present, there are four offset project types that are eligible in the California market: domestic forestry, urban forestry, livestock (manure/methane) management, and the destruction of ozone depleting substances. It is expected that the market will likely rely extensively on forest carbon offset supply.

California's offset protocols were adapted from CAR protocols. CARB staff modified the protocols to include a crediting period of 25 years for forest projects, without any explicit limitation on the number of potential renewals. Monitoring, verification, and replacement of all carbon lost through reversals is

[234] Hamilton, K. et al. *State of the Forest Carbon Markets 2009: Taking Root and Branching Out,* Ecosystem Marketplace, January 14, 2010.
[235] Peters-Stanley, M. *Back to the Future*.
[236] Hamilton, K. et al. *Building Bridges: State of the Voluntary Carbon Markets 2010,* Ecosystem Marketplace and Bloomberg New Energy Finance, June 14, 2010.
[237] Shillinglaw, Brian, MaryKate Hanlon, and Marisa Meizlish. "The California Carbon Market: Implications for Forest Carbon Offset Investment," *NewForests Market Outlook*, December 2010.

required for 100 years following the last issuance of any offset credits, consistent with the CAR's current protocol.

Projects are required to move to the latest version of CARB's protocol at the end of the crediting period as a condition of renewal. This ensures that all projects use the latest factors, and reduces the number of versions of the protocol that could potentially be in use after a period of time to assist with project verification. For example, Forest Buffer Account contribution factors, and emissions leakage factors will likely be updated in the future as better information becomes available. Transitioning projects to the most recent approved protocol will help ensure that offset credits in CARB's program are quantified using the best available science, and reduce the administrative burden of having projects operating under many different versions of the Forest Offset Protocol as it is updated over the years.

California will "grandfather" 2005-2014 vintage offsets issued under the voluntary CAR protocols for projects registered with CAR before January 1, 2012. After that date, all offset projects must be developed according to protocols adopted by CARB. California is also developing a pathway for the admission of offset credits from sector-wide emissions reductions in developing countries, beginning with Reduced Emissions from Deforestation and Degradation (REDD). California entered into a memorandum of understanding with the states of Acre, Brazil, and Chiapas, Mexico, to establish subnational REDD programs to supply credits to the California cap-and-trade market. CARB envisions a fully developed REDD market in operation by 2015 that will include activities both at the project and state level, involving government-led and private sector investment.[238] Final rules for REDD interface have yet to be worked out, however it is anticipated that within the 8% limit on offsets, REDD credits will be restricted to 25%/50%/50% for 1st/2nd/3rd compliance periods, respectively, which would translate in to a maximum of 105 $MMTCO_2$ from 2012 to 2020.[239]

The use of offsets in California's cap-and-trade program has met with a legal challenge. On March 27, 2012, two groups—Citizens Climate Lobby and Our Children's Earth Foundation—filed a petition in San Francisco Superior Court alleging that CARB's proposed use of carbon offset credits does not adhere to the requirements for GHG emissions reductions as set forth in AB 32.[240]

The lawsuit further contends that the offset protocols do not adequately assure that the GHG reductions achieved are truly additional, as required by AB 32.[241] The lawsuit seeks a repeal of the four offset protocols (domestic forestry, urban forestry, livestock [manure/methane] management, and the destruction of ozone depleting substances) and a prohibition on using offsets instead of limiting emissions to GHG allowances.

---

[238] Ibid.
[239] Ibid.
[240] http://www.martenlaw.com/newsletter/20120416-calif-cap-and-trade-rules-challenge
[241] Poloncarz, Kevin and Michael S. Balster, "Developments in California Cap-and-Trade Regulation," *Stay Current, A Client Alert from Paul Hastings*, April 2012.

Expanding the Role of Terrestrial Storage Projects

Opportunities for terrestrial carbon storage increase as carbon markets develop and link and as protocols for more types of projects are developed and adopted. The scope of terrestrial carbon storage under the California cap-and-trade could be increased beyond current parameters by extending the program to cover additional project types (CARB intends to evaluate more protocols in the future). Allowing aggregation could prove beneficial in encouraging participation by smaller landowners. A further inclusion, which could be forthcoming after further review by CARB, would be to allow for projects on federal lands.

Increasing the limit on offsets that may be purchased by regulated sources would increase the demand for offsets and lead to more terrestrial carbon storage projects, as well as other offset-generating activities, but would disincentivize emissions cuts from the regulated sector.

Balancing Terrestrial Carbon Storage with Other Land Uses and Values

Terrestrial carbon storage can add a further interest to an already complex patchwork of land uses and cultural values. Under favorable circumstances, projects have the potential to complement a range of existing activities. Examples include:

- Preserving greenbelts in housing and commercial developments
- Providing an additional revenue stream for farmers, ranchers, and forest owners
- Improving wildlife habitat and recreational activities
- Creating jobs in biomass energy and sustainable forestry and wood products

However, measures are needed to ensure that carbon storage is not pursued to the detriment of the environment or local communities. This has been a matter of particular concern for projects in developing countries. Although some environmental NGOs are involved in international forest carbon projects, others have pointed out the risks of conducting projects in situations where tenure and property rights are weak or uncertain and the national governance and policy framework is unsupportive.[242] Under such circumstances, standards for additionality and permanence are less likely to be observed, and leakage can result when local communities are impacted negatively, marginalized, or even excluded from project opportunities.[243]

The memorandum of understanding between California and Chiapas, Mexico, to allow REDD offset credits into the California cap-and-trade market has raised concerns that REDD projects could negatively impact the wellbeing of some of the indigenous communities in the jungles of Chiapas. The Climate Action Reserve, which is developing protocols for forest carbon projects in Mexico, is planning to incorporate environmental and social safeguards into the requirements for these projects.

---

[242] Blomley, Tom and Michael Richards. "Community Engagement Guidance: Good Practice for Forest Carbon Projects," *Building Forest Carbon Projects,* Johannes Ebeling and Jacob Olander (eds.). Washington, D.C.: Forest Trends, 2011.
[243] Ibid.

Within the WESTCARB region, local community interests will likely factor in the development of some projects and can help ensure that the terrestrial carbon storage does not occur at the expense of other beneficial or traditional land uses.

Adapting Terrestrial Carbon Storage During Climate Change

Climate change impacts in the WESTCARB region will benefit some species of plants over others and will vary depending on locale. Flexibility will be needed to ensure that terrestrial carbon storage projects can continue to mitigate climate change by withstanding impacts triggered by increased concentrations of CO_2, temperature change, water availability, and shifts in insect habitats and disease patterns. Land management practices, including species substitution and crop switching, will likely evolve to maintain economic viability for a range of land uses. In natural habits, using native species for conservation and restoration may need to be carefully assessed to ascertain if those species can remain viable as conditions change.

A study of agriculture in California's Central Valley concluded that climate change will lead to a northern migration of weeds, and that disease and pest pressure will increase with earlier spring arrival and warmer winters, allowing greater proliferation and survival of pathogens and parasites. Higher temperatures during the summer season will likely reduce rangeland livestock production and the supply of irrigated forage crops. The study noted that significant crop switching can be anticipated but that investments in technology, plant breeding, and cropping system research will result in less yield loss, higher yield reliability, and greater agricultural sustainability.[244]

According to the Intergovernmental Panel on Climate Change, the effects of climate change on forests can be found in decreased growth of white spruce on dry south-facing slopes in Alaska, which has declined over the last 90 years due to increased drought stress, and in semi-arid forests of the southwestern United States, where growth rates have decreased since 1895, again correlated with drought linked to warming temperatures. A combination of warmer temperatures and insect infestations has resulted in economically significant losses of the forest resource base to spruce bark beetle in both Alaska and the Yukon.[245]

However, warmer temperatures are expected to lead to increased growth rates for some forested areas. A study of the economic valuation of private timberland in California (9.2 million acres) indicated that if warming trends increase productivity in high latitude timberlands, increases in global timber prices would be curtailed based on supply. This relative decline in value for California' timber could predispose the state's timberlands to conversion to higher value uses, further exacerbating a trend that has already resulted in the loss of timberlands to residential development and vineyards.[246]

---

[244] Jackson, L.E. 2009. *Potential for Adaptation to Climate Change in an Agricultural Landscape in the Central Valley*, CEC-500-2009-044-F.
[245] Chapter 14.2.4, *Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007,* M.L. Parry, O.F. Canziani, J.P. Palutikof, P.J. van der Linden and C.E. Hanson (eds), Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
[246] Hannah, L. et al. 2009. *The Impact of Climate Change on California Timberlands,* California Energy Commission, CEC-500-2009-045-F.

The study found that adaptation programs such as altering species composition can help reduce the impact of climate change on timber values, and that participation in carbon markets can generate income in areas experiencing the greatest timber value declines, thereby providing an incentive to keep lands in forest.

Adaptation strategies for managing water resources will be critical in areas where changes in the timing and amount of water available for human use and natural habitats will lead to increased competition.[247] Approaches to sustaining water conditions in forests include managing tree densities and the use of artificial or live vegetation snow-fences to increase snowpack retention and infiltration. Watershed management approaches to improve hydrologic conditions within headwater and riparian areas include seasonal return of water to the environment from reservoirs and agriculture, and construction of wetland complexes to help maintain base flows, groundwater recharge, and timing of peak flows in headwater areas. Riparian management techniques such as reducing grazing along riparian areas and using beavers to improve stream management could help sustain flows and moderate the effects of warming air and stream temperatures.[248]

Adaptive approaches to forest regeneration can increase resilience in the short and long-term by adjusting silvicultural practices to establish forests that are more tolerant of future climate conditions. This includes planting genetically appropriate species that will be better adapted to changed climate conditions than the genotypes currently on site.

Some western state climate adaptation assessments have recognized the potential for urban forestry to mitigate local effects of rising temperature and precipitation runoff events. A 10% increase in vegetation cover can reduce ambient temperatures by 1–2°F.[249] Increased street tree cover provides shade relief, absorbs pollutants including ozone and CO_2, which may increase with climate change, and reduces stormwater pollution and flooding.

Knowledge and Infrastructure Needs

Maintaining the viability of terrestrial carbon storage projects during climate change will require new tools and techniques by which landowners, ranchers, farmers, and other land management decision-makers can access and analyze information to determine the best course of action to take in response to altering conditions.

Climate adaptation plans in several western states have called for an improved scientific knowledge base through additional research. As one plan observed, “much more needs to be known about how to downscale regional climate to local conditions and whether such downscaling will decrease the

[247] Robles, M.D. and C. Enquist. *Managing Changing Landscapes in the Southwestern United States.* The Nature Conservancy. Tucson, Arizona, 2010.
[248] Ibid.
[249] *2009 California Climate Adaptation Strategy: A Report to the Governor of the State of California in Response to Executive Order S-13-2008.* California Natural Resources Agency.

uncertainty forest managers face. Current data resources and future scenarios are generally inadequate to assess impacts at scales useful for managers."[250]

Terrestrial carbon storage will also benefit from increased coordination and collaboration between agencies at all levels, private and public land managers, conservation organizations, tribes, and other stakeholders. Such partnerships can prevent the duplication of effort in areas such as climate modeling, response modeling, or gathering and analyzing data, as well as facilitating the development and assimilation of effective adaptation approaches.[251]

Planning should include short- and long-term strategies, monitoring for unanticipated climate effects and for effectiveness of adaptation strategies, and flexibility to manage adaptively and make adjustments.

[250] "Interim Recommendations from Topic Advisory Group 3, Species, Habitats and Ecosystems," *Washington State Integrated Climate Change Response Strategy,* February 2011.
[251] Ibid.