Sequestration Options for the West Coast States

Final Report

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(WESTCARB)
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Abstract

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven partnerships that have been established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of the country. The West Coast Region comprises Arizona, California, Nevada, Oregon, Washington, Alaska, and British Columbia. Led by the California Energy Commission, WESTCARB is a consortium of about 70 organizations, including state natural resource and environmental protection agencies; national laboratories and universities; private companies working on carbon dioxide (CO_2) capture, transportation, and storage technologies; utilities; oil and gas companies; nonprofit organizations; and policy/governance coordinating organizations. Both terrestrial and geologic sequestration options were evaluated in the Region during the 18-month Phase I project. A centralized Geographic Information System (GIS) database of stationary source, geologic and terrestrial sink data was developed. The GIS layer of source locations was attributed with CO_2 emissions and other data and a spreadsheet was developed to estimate capture costs for the sources in the region. Phase I characterization of regional geological sinks shows that geologic storage opportunities exist in the WESTCARB region in each of the major technology areas: saline formations, oil and gas reservoirs, and coal beds. California offers outstanding sequestration opportunities because of its large capacity and the potential of value-added benefits from enhanced oil recovery (EOR) and enhanced gas recovery. The estimate for storage capacity of saline formations in the ten largest basins in California ranges from about 150 to about 500 Gt of CO_2, the potential CO_2-EOR storage was estimated to be 3.4 Gt, and the cumulative production from gas reservoirs suggests a CO_2 storage capacity of 1.7 Gt. A GIS-based method for source-sink matching was implemented and preliminary marginal cost curves developed, which showed that 20, 40, or 80 Mega tonnes (Mt) of CO_2 per year could be sequestered in California at a cost of $31/tonne (t), $35/t, or $50/t, respectively. Phase I also addressed key issues affecting deployment of CCS technologies, including storage-site monitoring, injection regulations, and health and environmental risks. A framework for screening and ranking candidate sites for geologic CO_2 storage on the basis of HSE risk was developed. A web-based, state-by-state compilation of current regulations for injection wells, and permits/contracts for land use changes, was developed, and modeling studies were carried out to assess the application of a number of different geophysical techniques for monitoring geologic sequestration. Public outreach activities resulted in heightened awareness of sequestration among state, community and industry leaders in the Region. Assessment of the changes in carbon stocks in agricultural lands showed that Washington, Oregon and Arizona were CO_2 sources for the period from 1987 to 1997. Over the same period, forest carbon stocks decreased in Washington, but increased in Oregon and Arizona. Results of the terrestrial supply curve analyses showed that afforestation of rangelands and crop lands offer major sequestration opportunities; at a price of $20 per t CO_2, more than 1,233 MMT could be sequestered over 40-years in Washington and more than 1,813 MMT could be sequestered in Oregon.

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1 Executive Summary

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven partnerships that have been established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of the country. The West Coast Region comprises Arizona, California, Nevada, Oregon, Washington, Alaska, and British Columbia. Led by the California Energy Commission, WESTCARB is a consortium of about 70 organizations, including state natural resource and environmental protection agencies; national laboratories and universities; private companies working on carbon dioxide (CO_2) capture, transportation, and storage technologies; utilities; oil and gas companies; nonprofit organizations; and policy/governance coordinating organizations. This report presents results of the 18-month Phase I project, in which both terrestrial and geologic sequestration options were evaluated in the Region.

The 77 major stationary CO_2 sources in the WESTCARB database have a total annual CO_2 emission of 159 Mt. A Geographic Information System (GIS) layer of source locations was developed and attributed with CO_2 emissions and other data, such as ownership, capacity, type of unit, fuels, equipment age, and operating status. A spreadsheet was developed to estimate capture costs based on three key input variables: (1) the flue gas flow rate (in tonnes per hour), (2) the flue gas composition (volume share or weight share of CO_2 in flue gas), and (3) the annual load factor.

Phase I characterization of regional geological sinks shows that geologic storage opportunities exist in the WESTCARB region in each of the major technology areas: saline formations, oil and gas reservoirs, and coal beds. This characterization work focused on sedimentary basins as the initial most-promising targets for geologic sequestration. GIS layers showing sedimentary basins, and oil, gas, and coal fields in those basins, were developed. The GIS layers were attributed with information on the subsurface, including sediment thickness, presence and depth of porous and permeable sandstones, and, where available, reservoir properties.

California offers outstanding sequestration opportunities because of large capacity and the potential for value-added benefits from enhanced oil recovery (EOR) and enhanced gas recovery (EGR). The estimate of the storage capacity of saline formations in the ten largest basins in California ranges from about 150 to about 500 Gt of CO_2, depending on assumptions about the fraction of the formations used and the fraction of the pore volume filled with separate-phase CO_2. Potential CO_2-EOR storage was estimated to be 3.4 Gt, based on a screening of reservoirs using depth, an API gravity cutoff, and cumulative oil produced. The cumulative production from gas reservoirs (screened by depth) suggests a CO_2 storage capacity of 1.7 Gt. In Oregon and Washington, sedimentary basins along the coast offer sequestration opportunities. Of particular interest is the Puget Trough Basin, which contains up to 1,130 m (3,700 ft) of unconsolidated sediments overlying up to 3,050 m (10,000 ft) of Tertiary sedimentary rocks. The Puget Trough Basin also contains deep coal formations, which are sequestration targets and may have potential for ECBM. The amount of unmineable coal in the Puget Sound basin was estimated to be over 70 billion tons, with a CO_2 storage potential of 2.8 Gt.

Using source and sink characterization data as input preliminary source-sink matching was carried out to assess regional geologic sequestration opportunities. The straight-line distance based source-sink matching results showed that if all sinks, including Nevada sinks, were considered for sequestration, more than four-fifths of CO_2 sources could be matched with appropriate sinks within 50 km. A more advanced GIS-based least-cost source-sink matching method was applied to analyze sources and sinks in California, which also takes into account the CO_2 storage capacity constraint of the sinks. For most CO_2 sources in California, the transportation costs to the corresponding EOR site are below \$10/t CO_2, less than the assumed \$16/t CO_2 credit for EOR injection. A full sequestration costing analysis, which includes capture cost, transportation cost, and injection cost (or net of EOR credit if matched to an EOR site), was also conducted for CO_2 storage in California. The results of this preliminary full sequestration cost analysis indicates that 20, 40, or 80 Mega tonnes (Mt) of CO_2 per year could be sequestered in California at a cost of \$31/tonne (t), \$35/t, or \$50/t, respectively.

Phase I work addressed key issues affecting deployment of CCS technologies, including storage-site permitting and monitoring, injection regulations, and health and environmental risks.

A framework for screening and ranking candidate sites for geologic CO_2 storage on the basis of health, safety, and environmental (HSE) risk was developed based on three fundamental characteristics of a CO_2 sequestration site. Example applications of the framework show that comparative evaluations of prospective sites with limited characterization data can be accomplished based on potential for CO_2 leakage and seepage and related HSE risk.

A web-based, state-by-state compilation of current regulations for injection wells—relevant to geologic sequestration—and required permits/contracts for land use changes—relevant to terrestrial sequestration—was developed. Links to the specific, relevant statutes are provided. An assessment of the current status of regulations showed that the regulatory framework for CO_2 injection in conjunction with EOR is well established, but the framework for injection into saline formations is poorly defined.

As a basis for development of monitoring protocols, modeling studies were carried out to assess the application of a number of different geophysical techniques for monitoring geologic sequestration of CO_2. Time-lapse performance of seismic, gravity, and electromagnetic techniques were considered for a proposed CO_2 sequestration project in the Schrader Bluff field on the North Slope of Alaska. Model results show that both seismic amplitude and seismic amplitude variation with offset could be used to make quantitative estimates of saturation changes, subject to modeling assumptions. Borehole gravity measurements just above the reservoir produced measurable change in the vertical component of gravity that could be used to map lateral distributions of injected CO_2. A preliminary model study for the Rio Vista gas field in California showed that neither gravity nor seismic methods would provide information necessary for monitoring of CO_2 movement because of small changes in reservoir properties.

A spreadsheet for carrying out life cycle assessments for power generation including capture was developed. Major point-source pollutants, in addition to CO_2, were addressed. Results of one example analysis, in which all plants in the Region are retrofit with CO_2 control, and replacement power is split 50/50 between gas turbine combined cycle and coal, the CO_2 and SO_2 emissions are reduced but the NOx and mercury are increased.

In Phase I, the focus of the terrestrial sequestration studies was the development of carbon baselines and supply curves.

In Washington, the baseline studies showed that total carbon stocks in all agricultural land amount to about 6.2 million tons. In CO_2 equivalent terms, total agricultural carbon stocks in 1997 were 22.9 $MMTCO_2eq$, and the net loss 1987–1997, disregarding non-CO_2 greenhouse gas emissions, was 0.5 $MMTCO_2eq$. Total forest carbon stocks also diminished, with the rate of loss between 1987–1997 being 62,000 ac per year, equivalent to a gross emission of 187 $MMTCO_2e$ or 12.5 $MMTCO_2e/yr$ between 1987–1997.

Total carbon stocks in all agricultural land in Oregon were estimated at 3.2 million tons. In CO_2 equivalent terms, the net loss for 1987–1997, disregarding non-CO_2 greenhouse gas emissions, was 0.6 $MMTCO_2eq$, equivalent to an annual source of 0.06 $MMTCO_2eq$. Forest carbon stocks increased over the same period, resulting in an estimated increase of 23.0 $MMTCO_2e/yr$. Forest sinks, therefore, potentially can offset as much as 50% of the state's emissions.

Total carbon stocks in all agricultural land types in Arizona were estimated at 1 million tons. In CO_2 equivalent terms, total agricultural carbon stocks in Arizona in 1997 were 3.5 million metric tons CO_2 equivalent ($MMTCO_2eq$), and the net loss for 1987–1997, disregarding non-CO_2 greenhouse gas emissions, was 0.4 $MMTCO_2eq$. Forest carbon stocks increased over the period, equivalent to an increase of 9 $MMTCO_2e$ or 0.92 $MMTCO_2e/yr$ between 1987 and 1997.

In all three states, non-CO_2 greenhouse gas emissions from nitrous oxide (N_2O; emitted from agricultural soils after fertilizer application) and methane (CH_4, from livestock and manure management) dwarf the annual CO_2 source from agricultural land conversion.

Results of the terrestrial supply curve analyses showed that afforestation of rangelands and crop lands offer major sequestration opportunities. In Washington, at a price of $20 per t CO_2, almost 289 MMT CO_2 could be sequestered over 20-years. The total amount rises sharply to more than 1,233 MMT CO_2 at 40 years and approximately 3,176 MMT CO_2 at 80 years. In Oregon, at a price of $20, almost 280 MMT CO_2 could be sequestered over 20-years. The total amount rises to more than 1,813 MMT CO_2 at 40 years and approximately 4,203 MMT CO_2 at 80 years.

2 Experimental

2.1 Geologic Source-Sink Characterization: Methodology

2.1.1 Stationary Source Characterization

Working with the Electric Power Research Institute, Nexant assembled data for power plants and major industrial sources. A Geographic Information System (GIS) layer of source locations was developed and attributed with carbon dioxide (CO_2) emissions and other data. The primary sources of information for power generating plants were the Energy Information Agency (EIA) and the U.S. Environmental Protection Agency (EPA). The EIA database contains relevant material about plants and units (*e.g.,* boiler, combustion turbine) Data important to the regional sequestration work includes ownership and location, capacity, type of unit, fuels, equipment age, and operating status. The EIA database has a significant amount of other data, including emission control equipment, which will be examined later to augment the plant and company contacts for our region. The EPA Clean Air Markets organization has a database with emissions, including CO_2. The data is for the plant and lists SO_2 and NO_X as well as CO_2. The plant heat input is also provided. California has a unique database maintained by the California Air Resources Board (CARB). The database contains valuable plant information that will facilitate contacts, and lists pollutant emissions for organics, CO, NO_X, SO_X, and particulates (PM, PM10, and PM2.5). CO_2 is not part of the CARB data.

The sample below, Figure 1, shows the type of data collected for power generation. EPA emission data is colored light blue, and the other plant and unit information is from the EIA database. Additional information is found in Appendix I.

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Arizona Electric Pwr Coop		**559.1**	**515**	**515**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Apache Station	160	2002	5,167.0	3,068,830.5	6,528.4	31,278,625			
Apache Station (Cochise)	GT1	10	10	10	CT	NG	1965	OP	
	GT2	19.8	20	20	GT	DFO	1972	OP	
	GT3	64.9	63	63	GT	DFO	1974	OP	
	ST1	75	72	72	CA	RFO	1965	OP	
	ST2	194.7	175	175	ST	SUB	1979	OP	
	ST3	194.7	175	175	ST	SUB	1979	OP	

Figure 1. Arizona fossil power generation

Only minimal data about emissions at cement and lime facilities was found. Two useful sources of data were the U.S. Geological Survey and the Portland Cement Association, which both list plants and information on location and ownership. CARB has information for the state on plant locations and criteria pollutants similar to the power plant data. The Oregon Department of Environmental Quality (DEQ) has a database for plants via their permitting process. In addition to ownership and plant contact information the DEQ data includes location by latitude and longitude. Estimates of CO_2 emissions from cement and lime plants were made using methods developed by the EPA and EIA, based on cement and lime plant capacity values. The results were sent to the Cement Industry Environmental Consortium for comment. Additional information in found in Appendix I.

Prior to introduction into a pipeline, produced natural gas is typically treated to remove moisture, organic compounds, CO_2, sulfur compounds and other contaminants. While many of the natural gas containments become byproducts and are sold, the reject gas streams may include release of the CO_2 to the atmosphere. Information about natural gas processing was obtained from the Natural Gas Supply Association's Internet site, and the EIA Natural Gas Navigator Internet site. CO_2 emissions data, however, was not available.

Data about refinery operations was obtained from the EPA, EIA, CARB and Oregon DEQ records. The main data elements relevant to the regional sequestration work are the plant capacities and plant location and contact information. Estimates of CO_2 emissions were calculated from information provided by refineries in Canada (Nyboer and Murphy, 2004). In this Canadian study, it was possible to derive a factor for CO_2 emissions based on the plant production capacity of barrels per day. Additional information is found in Appendix I.

2.1.2 Geologic Sink Characterization

WESTCARB has focused on sedimentary basins as the initial most-promising targets for geologic sequestration. Our approach for various states has followed similar steps: first, the extent (area) of the basins is determined and entered into a GIS layer. Second, baseline data are collected and preliminary screening is conducted using such criteria as the presence of porous sediments, depth, and restricted access, resulting in a list of basins for which more detailed data on geologic properties are to be obtained. Priority is given to basins in which there are potential value-added benefits from enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coal bed methane recovery (ECBM). Data from reservoirs in these basins form the bulk of the characterization data. The third step entails evaluating CO_2 storage capacity. The final step integrates the characterization data with source and transportation data to evaluate economics and develop supply curves for regional source/sink options.

In California, the California Geologic Survey identified and catalogued sedimentary basins within California's 11 geomorphic provinces. Selected basins included all large or hydrocarbon-producing basins, as well as numerous smaller basins identified from the 1:750,000 scale geologic map of California (Jennings *et al.*, 1977). Where basins extended offshore, only the onshore portions were considered. This resulted in an inventory of 104 basins, 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 to illustrate the distribution of known oil and gas fields. Basins were screened to determine preliminary suitability for potential CO_2 sequestration, with those basins not meeting the screening criteria excluded from further consideration. Screening involved literature searches and analysis of available well logs. Criteria included the presence of significant porous and permeable strata, thick and pervasive seals, and sufficient sediment thickness to provide critical state pressures for CO_2 injection (>800 m—2,625 ft). Accessibility was also considered, with basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs-administered lands, and military installations being excluded. Most of the basins excluded for this reason are located in the arid desert valleys of the Basin and Range and Mojave Desert geomorphic provinces. Structural closure or stratigraphic trapping was not considered a prerequisite for saline aquifers at the screening level.

To identify areas of adequate sedimentary fill, depth-to-basement contour maps were prepared for those basins containing sufficient basement penetrations. This included the Sacramento, San Joaquin, and Salinas basins. In some producing basins, where basement well control is limited or absent, basement contour maps were extrapolated from

shallower structure maps (Eel River Basin), or published geophysical depth-to-basement maps were used (Los Angeles, Ventura Basins).

To characterize potential saline aquifers and hydrocarbon reservoirs, oil and gas field and reservoir data were assembled for depleted and producing fields. Data was compiled in field level and reservoir-level databases and attributed to the California oil and gas field GIS layer for manipulation and spatial analysis by other WESTCARB participants. Field-level data included information such as location, depth, field area, cumulative production, and depth-to-base of fresh water. Field-level database parameters are shown in Table 1.

Table 1. Sample content of a Field Table database record

Field Code:	**VE024**
Field:	Honor Rancho Oil
Discovery Well Operator:	The Texas Co.
Discovery Well:	Honor Rancho A -1
Section:	6
Township:	4N
Range:	16W
Meridian:	SB
Discovery Date:	8/1/1950
Deepest Well Operator:	So. California Gas Co.
Deepest Well:	Wayside Unit 28
Section:	7
Township:	4N
Range:	16W
Meridian:	SB
Depth (ft.)	11,747
Field Area (ac.)	450
Cum. Oil Prod. (MBO)	31,098
Cum. Gas Prod. (MMCF)	52,992
Base Fresh Water:	1,150

Reservoir-specific parameters for producing, abandoned, or shut-in reservoirs in each field were compiled in the reservoir-level database. These data included reservoir fluid (oil, gas, water), zone status (producing, abandoned, shut-in), average depth, average thickness, producing area, porosity, permeability, initial pressure and temperature,

formation water salinity, seal thickness, trap type (structural or stratigraphic), and history of secondary and tertiary recovery efforts. A measure of "fracture intensity" was assigned for most reservoirs to instill a general sense of fracturing and/or faulting. This subjective measure was assigned a value of low, medium, or high, based solely on the number of mapped faults illustrated in published California Department of Conservation, Division of Oil, Gas, and Geothermal Reservoirs (DOGGR) field maps (L = 0–1 fault; M = 2–3 faults; H = 4+ faults). An example of reservoir database parameters is shown in Table 2.

Table 2. Sample content of a Zone Table database record

Field Code:	VE024	Perm. (md):	20
Zone:	Modelo Fm.	Perm. Range Min. (md):	179
Age:	U. Miocene	Perm. Range Max. (md):	
Oil or Gas:	O	Pressure (lb/ft.):	2,962
Date of Discovery:	12/1/1950	Press. Range Min. (lb/ft.):	4,500
Zone Status (P/A/SI):	P	Press. Range Min. (lb/ft.):	190
API Gravity:		Temperature (ºF):	
API Range Min.:	35	Temp. Range Min. (ºF):	
API Range Max.:	39	Temp. Range Max. (ºF):	
GOR:		Salinity (ppm NaCl):	
GOR Range Min.:	220	Sal. Range Min. (ppm NaCl):	11,200
GOR Range Max.:	1,250	Sal. Range Max. (ppm NaCl):	24,800
Sp. Gravity:		TDS (ppm):	20,200
Sp. Gravity Min.:	0.470	TDS Range Min. (ppm):	
Sp. Gravity Max.:	0.765	TDS Range Max. (ppm):	
BTU:	1,066	Seal:	Modelo Fm.
BTU Range Min.:		Seal Thickness (ft.):	
BTU Range Max.:		Seal Thickness Min. (ft.):	5
Cum. Oil (MBO):	29,094	Seal Thickness Max. (ft.):	50
Cum. Gas (MMCF):	47,601	Trap Type:	Stratigraphic
No Pool Breakdown:		Fault Intensity:	L
Depth (ft.):		ERP 1:	Gas Injection
Depth Range Min.:	6,481	ERP 1 Start:	1954
Depth Range Max.:	10,000	ERP 1 Stop:	1956
Thickness (ft.):		ERP 2:	Waterflood
Thickness Range Min. (ft.):	94	ERP 2 Start:	1959
Thickness Range Max. (ft.):	310	ERP 2 Stop:	1966
Producing Area (ac.):	400	ERP 3:	Waterflood
Porosity (%):		ERP 3 Start:	1972
Porosity Range Min. (%):	7	ERP 3 Stop:	1975
Porosity Range Max. (%):	26		

In Nevada, the minimum-basin-depth criterion was taken as 1,000 m (3,300 ft), owing to a generally higher geothermal gradient in the Basin and Range province. The Nevada

Bureau of Mines and Geology (NBMG) developed a GIS-based screening methodology that takes into account the proximity of potential geologic sinks to faults, mineral and geothermal resources, populated areas, other restricted lands, and water resources (Price *et al*., 2005). The NBMG also developed a method, illustrated in Table 3, to interrogate well records for information relevant to geologic sequestration.

Table 3. Information recorded from records of deep wells drilled in Nevada (Hess, 2004)

DEFINITIONS

CO_2 reservoir rock ≡ sandstone, conglomerate, sand, or gravel

Seal rock ≡ shale, mudstone, claystone, mud, clay, halite, gypsum, salt, or nonwelded (possibly clay- or zeolite-altered) ash-flow tuff

NEITHER A CO_2 RESERVOIR ROCK NOR SEAL ≡ limestone, dolomite, fractured volcanic rock, fractured sandstone, quartzite, metamorphic rocks, or granite or other igneous rocks

Data collected from well records, if available, in wells within areas not otherwise excluded for consideration of CO_2

1. Total depth of well.
2. Are there potential CO_2 reservoir rocks in the well below 1 km (3,281 ft) depth? If no, go to next well.
3. Is there a potential seal below 1 km and above that reservoir rock? If no, go to next well.
4. Depth to base of Cenozoic/Tertiary volcanic rocks and alluvium.
5. Depth to base of deepest reservoir rock in pre-Tertiary sedimentary package.
6. How fresh is the water in this deepest reservoir rock? (Total dissolved solids – TDS?)
7. How porous is this deepest reservoir rock?% of porosity?
8. How permeable is this deepest reservoir rock? K in millidarcy?
9. Thickness of the thickest single pre-Tertiary reservoir rock.
10. How fresh is the water in this thickest pre-Tertiary reservoir rock?
11. How porous is this thickest pre-Tertiary reservoir rock?
12. How permeable is this thickest pre-Tertiary reservoir rock?
13. Total thickness of all pre-Tertiary reservoir rocks.
14. Thickness of the thickest single pre-Tertiary seal rock above the deepest reservoir rocks.
15. Total thickness of all pre-Tertiary seal rocks above the deepest reservoir rocks.
16. Depth to base of deepest reservoir rock in Tertiary sedimentary package below 1 km.
17. How fresh is the water in this deepest reservoir rock in Tertiary package?
18. How porous is this deepest reservoir rock in Tertiary package?
19. How permeable is this deepest reservoir rock in Tertiary package?
20. Thickness of the thickest single Tertiary reservoir rock below 1 km.
21. How fresh is the water in this thickest single Tertiary reservoir?
22. How porous is this thickest single Tertiary reservoir?
23. How permeable is this thickest single Tertiary reservoir?
24. Total thickness of all Tertiary reservoir rocks below 1 km.
25. Thickness of thickest single Tertiary seal rock below 1 km.
26. Total thickness of all Tertiary seal rocks below 1 km.
27. Total thickness of all Tertiary seal rocks below 1 km and above shallowest reservoir rock.
28. Thickness of halite beds below 1 km.

FACTORS THAT CAN NOW BE DERIVED FROM THESE NUMBERS

A. Total thickness of potential reservoir rocks = #13 + #24
B. Total thickness of potential seal rocks above the deepest reservoir rock and below 1 km = #15 + #26
C. Reservoir rock to seal rock ratio = #A/#B, ~ sand/shale ratio

In Oregon and Washington, GIS layers were developed that give the location of sedimentary basins. Data on the overall geology of sedimentary basins and the available reservoir properties were assembled. Data from the few available deep wells penetrating the basalt layers in the eastern portions of the states were reviewed to establish the presence of sediments at depths 300 m (1,000 ft) to over 2,700 m (9,000 ft). Information on coal formations as potential sinks was also compiled, including available data on coal rank, percent methane saturation, and sorbtive capacity.

2.2 GIS Database Description

The GIS database for WESTCARB is housed in an Enterprise Geodatabase format using ArcSDE (Spatial Database Engine) from Environmental Systems Research Institute, Inc. (ESRI). This database can be connected directly to any ESRI ArcMap client version 9.0 or greater. The data layers can also be requested from the Utah Automated Geographic Reference Center (AGRC) in a format that can be used in any common GIS software. A complete list of available layers is given in Appendix II. The layers are organized into the main categories of "sedimentary basins," "sources," and "base layers." The sedimentary basin category contains sub-categories of "geologic features" and "supporting data".

An interactive web map has been created to provide access to the data layers via the internet. This interactive map can be viewed at http://atlas.utah.gov/co2wc. In addition to providing a means by which the GIS data layers can be viewed and queried, this interactive map includes tools that let the user perform some basic analysis operations, such as buffering and linear distance measurement.

In addition to the compilation of the partnership database, WESTCARB and AGRC have cooperated with, and will continue to cooperate with, the NATCARB (national carbon) database in the modeling and serving of the nationwide distributed carbon atlas. The data layers are served via ESRI's ArcIMS map services, which are harvested by the NATCARB interactive map portal. Additional information on the structure of the WESTCARB digital database is found in Appendix III.

2.3 Geologic Sequestration Options: Methodology

EPRI led the effort to define cost-effective, environmentally acceptable geologic source-sink options for the region. The Massachusetts Institute of Technology (MIT) performed GIS-based analyses to match sources with sinks in the region, and in California, made an assessment of the potential for sequestration combined with enhanced oil and gas recovery. These analyses used, as input, the data developed in the source-sink characterization work. Sfa Pacific developed a spreadsheet tool for estimating CO_2 capture costs, which were needed in the analyses. MIT also developed computer algorithms (Appendix XIX) needed for least-cost matching of sources and sinks.

Capture cost estimates made using the "*Generic* CO_2 *Capture Retrofit*" spreadsheet prepared by Sfa Pacific were based on three key input variables: (1) the flue gas flow rate (in tonnes per hour), (2) the flue gas composition (volume share or weight share of CO_2 in flue gas), and (3) the annual load factor. The spreadsheet provided estimates of capture

cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere—assumed to be 90% of the CO_2 in the flue gas. However, since the CO_2 capture process requires energy for purification and compression, the "CO_2 avoided" term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The "CO_2 captured" term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs, while the "CO_2 avoided" term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits. In order to use the Sfa Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made that power plants would operate at 80% of their designed capacity once the capture facility has been installed. Additional information is found in Appendix XX.

The transportation cost model takes the source-sink matching as *a priori* and estimates the CO_2 pipeline transportation cost at three levels: (1) one source to one sink; (2) many sources to one sink without route-sharing; and (3) many sources to one sink with route-sharing. For the simplest case of one-source-to-one-sink connection, the estimation consists of three steps. First, the pipeline diameter is calculated from the CO_2 flow rate. Second, the least-cost route is selected based on the relative cost factors assigned to various transportation obstacles for both economic and environmental concerns. The identified transportation obstacles include populated places, wetlands, national and state parks, waterways, railroads, and highways. Finally, the base-case pipeline construction cost, additional obstacle-crossing cost, and O&M cost are assigned to estimate the levelized CO_2 transportation cost. The procedures followed in each of these steps are described in Appendix XX.

2.3 Technology Deployment Issues: Methodology

Phase I work addressed key issues affecting deployment of CCS technologies, including storage-site permitting and monitoring, injection regulations, and health and environmental risks. The Action Plan for addressing these key issues in Phase II of the WESTCARB project is found in Appendix XV.

2.3.1 Regulatory Framework

Terralog Technologies worked with state agencies and EPA to compile current regulations for injection wells in the states in the WESTCARB region (see Appendix XIII). Bevilacqua-Knight, Inc., worked with Terralog to develop a web-based, state-by-state compilation, with links to the specific, relevant, statutes. Terralog also worked with various state agencies to compile regulations covering land use changes, which would be relevant to terrestrial forest sequestration activities. More information on the web-based compilation is found in Appendix X.

2.3.2 Health and Environmental Risks

In order to reduce the possibility that geologic CO_2 storage projects will result in health, safety, and environmental (HSE) impacts due to CO_2 leakage and seepage, it is essential that sites be chosen to minimize HSE risk. Lawrence Berkeley National Laboratory (LBNL) developed a spreadsheet-based Screening and Ranking Framework (SRF) for evaluating multiple sites on the basis of their potential for HSE risk due to CO_2 leakage and seepage. The SRF was formulated to evaluate three fundamental characteristics of a geologic CO_2 storage site:

1. Potential for long-term primary containment by the target formation,

2. Potential for secondary containment should the primary formation leak, and

3. Potential of the site to attenuate and/or disperse leaking CO_2 should the primary formation leak and secondary containment fail.

The SRF spreadsheet is designed to provide an independent assessment of each of these three characteristics through an evaluation of the properties of various attributes of the three characteristics. The input required by the SRF is quite general and may rely primarily on expert opinion depending on the degree of characterization and/or published information available for the sites. The assessment made in the framework is based on four classes of information: (1) site characteristics, which are defined by (2) attributes, which are defined by (3) properties, which are defined by (4) values input by the user. Further information on the framework methodology is found in Appendix IX and Appendix XII.

2.3.3 Monitoring and Verification

As a basis for development of monitoring protocols, LBNL studied the application of a number of different geophysical techniques for monitoring geologic sequestration of CO_2. The relative merits of seismic, gravity, and electromagnetic (EM) geophysical techniques were considered. The approach was to carry out numerical simulations of the response of the geophysical methods using site-specific data. Time-lapse performance of seismic, gravity, and EM techniques were considered for a proposed CO_2 sequestration project in the Schrader Bluff field on the North Slope of Alaska. Seismic and gravity responses were simulated for a simplified flow simulation model of the Rio Vista gas field in Sacramento Basin, California. In both cases, rock physics models were used to convert the output of flow simulations to changes in geophysical properties. Thus, for seismic methods, changes in saturation and fluid pressure in the reservoir, brought about by injection of CO_2 , were converted to changes in seismic velocity via the rock physics model. Numerical simulation was then used again to calculate the response of the candidate geophysical method. For example, for seismic methods, numerical simulation was used to calculate the changes in the seismic wavefield. This numerical data was then processed using the same techniques applied to seismic data acquired during geophysical field surveys. Additional information on the numerical modeling methods used in this study can be found in Appendix XIV.

2.3.4 Life Cycle Analysis

Working with EPRI, Nexant prepared a life cycle assessments (LCA) for power generation including capture. Major point-source pollutants, in addition to CO_2, were addressed. The spreadsheet (Appendix VIII) allows the user to select and specify the value of several variables to see how emission estimates are changed. The spreadsheet consists of four parts: Existing Data; Retrofit Estimates; Replacement of Lost Generation Capacity; and Estimates of LCA Emissions Caused by Retrofit Actions.

2.4 Terrestrial Sequestration Baselines and Supply Curves: Methodology

Winrock International worked with the Oregon Department of Forestry, the California Department of Forestry and Fire Protection, the Washington State Department of Natural Resources, and other state and agencies to characterize the terrestrial carbon baseline in the region, and to develop supply curves. The Oregon Department of Forestry was the lead coordinating agency for the work.

2.4.1 Baselines

The objective of the work on carbon baselines was to establish the baseline carbon stocks and changes in stocks for the forest and agricultural sectors during the most recent 10-year period for which data are available (generally the decade of the 1990s). Such baselines can assist in identifying opportunities where carbon removals (sequestration) in each sector might be increased, or carbon emissions decreased, through changes in land use and management.

The same general methodology for determining the agricultural baseline was followed in each state. As with other terrestrial carbon baselines, the areas (hectares) of different land uses and changes in land use are combined with carbon densities (tons of carbon per hectare) of each land use, to yield an estimate of the total emissions and removals of carbon associated with land management and/or conversion of lands over a given time period. Estimates of area and changes in area of agricultural and nonagricultural land use types were derived from the National Resource Inventory (NRI) database. Because of data availability, the period chosen to establish a baseline of changes in land use was 1987 to 1997. The detail of the NRI database made it possible to examine conversion of agricultural lands to other land uses, both at the state and county level of analysis, and for both perennial woody crops (fruit and nut orchards, vineyards, berry crops, etc.) and annual non-woody crops. Carbon densities in each crop type were derived from consultation with local universities and extension agents, crop biomass statistics from the U.S. Department of Agriculture–National Agriculture Statistics Service, consulting the literature, and applying standard methods for biomass carbon estimation.

The baseline for forests is separated into three components. A general forests baseline is presented at the state level for all forestlands, based on U.S. Department of Agriculture (USDA) Forest Service data, detailing change in forest area and change in carbon stocks, but with no attribution to the causes for the change. Using additional data bases, the specific cases of emissions associated with development and with fire are further examined. These components form part of the total detailed in the general forest baseline section and should not be considered separately. Additional information is found in Appendix IV.

2.4.2 Supply Curves

Methodologies developed by Winrock International in its work with Electric Power Research Institute and the California Energy Commission were applied to develop carbon supply curves for the major classes of potential land-use and forest-based activities. The approach involved two steps:

(1) Using standard data from available data sources and available methodologies, estimate the amount of carbon that will be sequestered by a particular change in land use or management practice.
(2) Prepare carbon supply curves for different classes of potential terrestrial projects, including afforestation of cropland, afforestation of rangeland, and changes in management of forestland.

The carbon supply associated with a potential change in land use was estimated through the following steps:

(1) Identify the classes of land uses and the associated changes in management that could lead to significant increase in carbon stocks.
(2) Estimate the area for each potential change in land use.
(3) Estimate the quantities of carbon per unit area that could be sequestered for the change in land use over a given time period.
(4) Estimate the total costs (opportunity, conversion, maintenance, and measuring and monitoring).

(5) Combine the estimated quantities of carbon per unit area with the corresponding area and cost to produce estimates of the total quantity of carbon that can be sequestered for a given range of costs, in $/metric ton C or $/metric ton CO_2.

For rangelands and croplands (lands growing wheat and hay), the potential carbon sequestration was estimated for afforestation using native species. Historical evidence suggests that in many areas, large tracts of forest once stood where grazing and agricultural lands do now. The general approach was to identify and locate existing rangelands and croplands where biophysical conditions could favor forests, estimate carbon accumulation rates for the forest types projected to grow, and assign values to each contributing cost factor. The carbon supply is estimated for three durations—20 years, 40 years, and 80 years of forest growth—to reflect the impact of activity duration on the likely supply and provide an assessment for the near-term and longer-term planning horizons.

For forestlands, potential carbon supply was estimated for three alternatives for 20-year and/or permanent contract periods: (1) allowing timber to age past economic maturity (lengthening rotation time); (2) increasing the riparian buffer zone by an additional 200 ft; and (3) reducing hazardous fuel in forests to reduce catastrophic fires, and subsequently using fuels in biomass power plants. For estimating the costs of allowing timber to age and the costs of enhanced riparian zone management, estimates are based on specific counties for public and private landowners, and then extrapolated to all counties throughout the state. For the fuel reduction alternative, the analysis used a "Suitability for Potential Fuel Reduction" (SPFR) score on forest landscapes where potential exists for significant carbon loss from moderate-to-high-intensity wildland fires. The SPFR scores were created in a GIS using slope, distance to biomass plants, and distance from roads as equal weighted factors in the decision-making process. Suitability scores for potential fuel reduction with highest suitability were assigned to areas with gentle grades of slope close to roads and biomass power plants. Additional information is found in Appendix XXI.

2 Results and Discussion

3.1 Geologic Source-Sink Characterization

3.1.1 WESTCARB CO_2 Emissions

The CO_2 emissions profile for the states in the WESTCARB region (Figure 2) shows that the region accounts for about 11% of the U. S. emissions, based on the 1999 EPA emission inventories from fuel combustion. Within the region, transportation accounts for 53%, utilities 13%, and industry 23%, of the emissions. Emissions from the transportation sector are somewhat higher than the national average while those of the utility sector are lower. California ranks second among all states in CO_2 emissions, with the transportation sector providing around 58% of the total. The large percentage of

emissions from mobile sources is one justification for evaluating terrestrial sequestration options. The significant percentage from industrial sources motivates analysis of industrial point sources along with power plants in assessing geologic sequestration options. The largest stationary sources in the region are power plants, oil refineries, and cement plants.

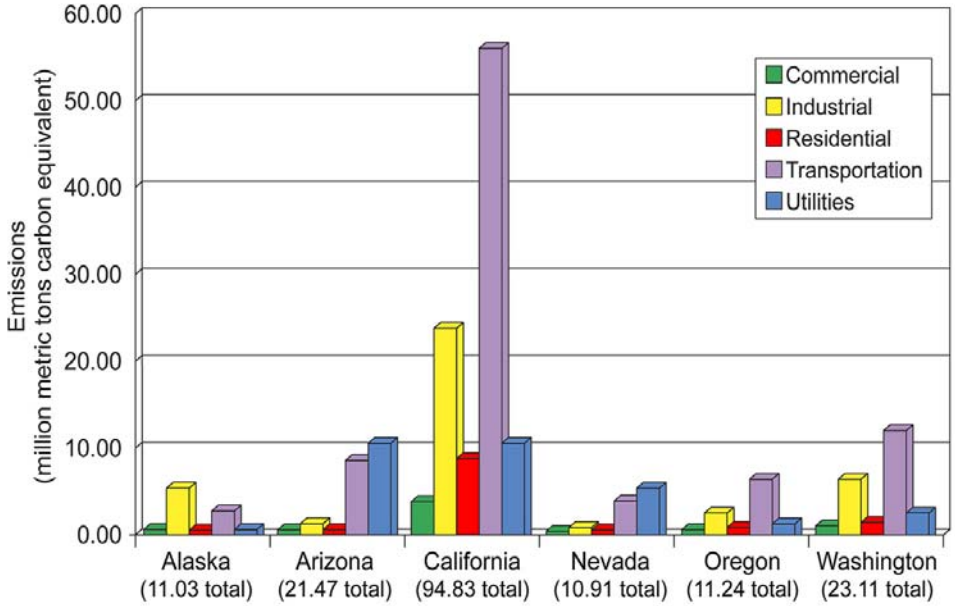


Figure 2. WESTCARB CO_2 emissions profile

The WESTCARB GIS database includes information for 77 facilities from four categories with total annual CO_2 emissions of 159 Mt. Table 4 summarizes the CO_2 emissions from major stationary sources in the WESTCARB region by facility type and by state, respectively. The CO_2 emissions from power plants are actual 2000 CO_2 emissions from eGRID database. As discussed previously, annual CO_2 emissions from cement plants and refineries are estimates based on production capacities. CO_2 emissions for gas processing plants were missing, and so were entered as zero in Table 4. Though not zero, CO_2 emissions from gas processing in WESTCARB is not significant. Power plants are the single largest source of CO_2 emissions, accounting for more than 80 percent of the emissions from the stationary sources in the database. California has the highest annual CO_2 emissions in the region, representing over one-third of the regional total emissions, followed closely by Arizona.

Table 4. CO_2 emissions from stationary sources by facility type and state

State	Power Plants		Cement		Gas Processing[d]		Refineries		Total	
	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)
AK	6	2.3	0	0.0	3	0	3	2.6	12	4.9
AZ	7	48.3	2	1.4	0	0	0	0.0	9	49.7
CA	18	36.5	6	6.0	2	0	7	11.3	33	53.8
NV	6	24.8	3[a]	0.0	0	0	0	0.0	9	24.8
OR	3	7.4	2[b]	0.6	0	0	0	0.0	5	8.0
WA	3	12.1	3[c]	0.8	0	0	3	4.4	9	17.3
Total	**29**	**131.3**	**16**	**8.8**	**5**	**0**	**13**	**18.4**	**77**	**158.5**

[a]The WESTCARB database contains no production capacity data for cement in Nevada.

[b]Only one cenment plant in Oregon has production data.

[c]Only two cement plants in Washington have production data.

[d]No production capacity data or CO_2 emission data is avaiable for gas processing facilites.

Locations of the large stationary sources in the WESTCARB states are shown in Figures 3 and 4. Additional information is found in Appendix XX.

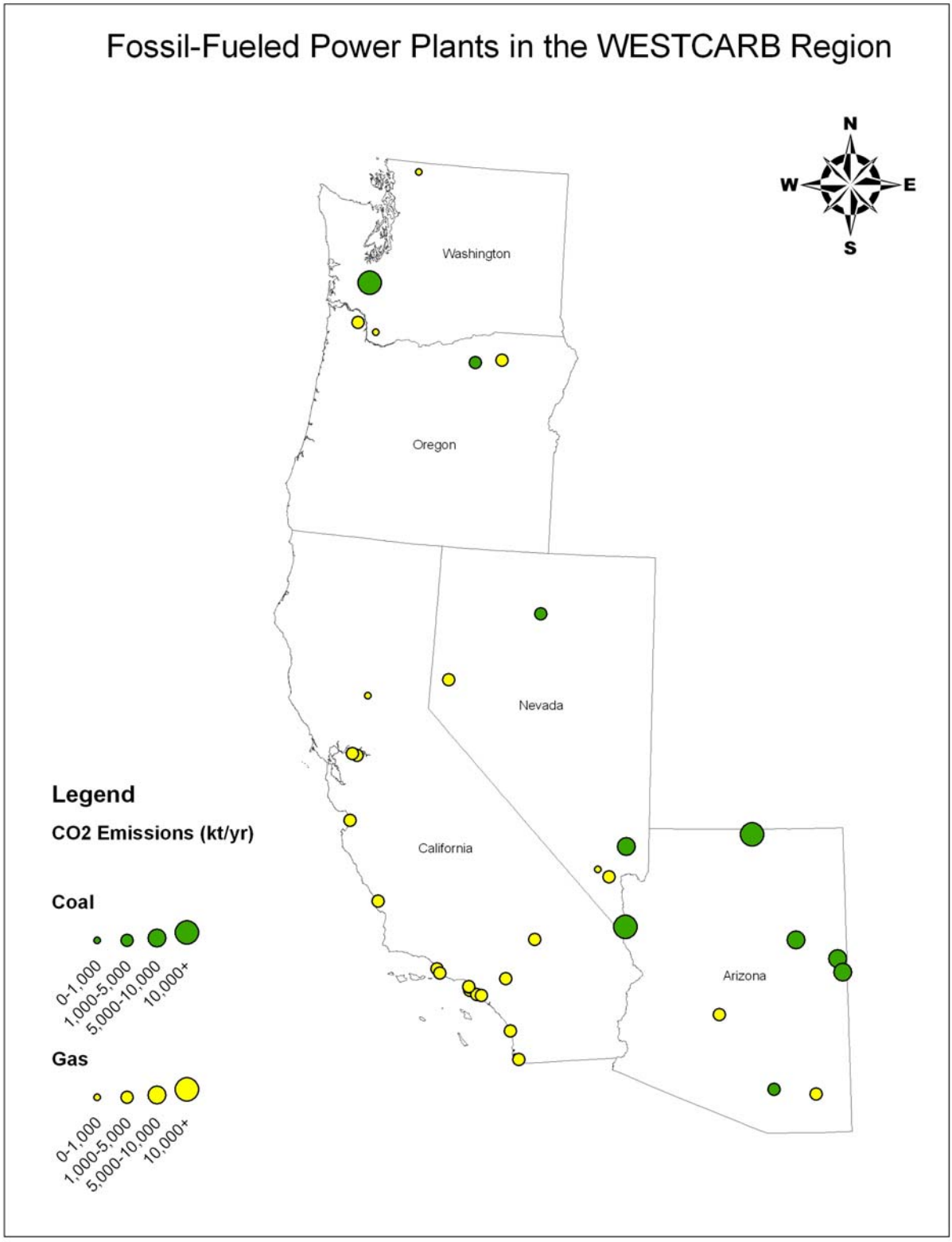


Figure 3. Fossil-fueled power plants in the WESTCARB region

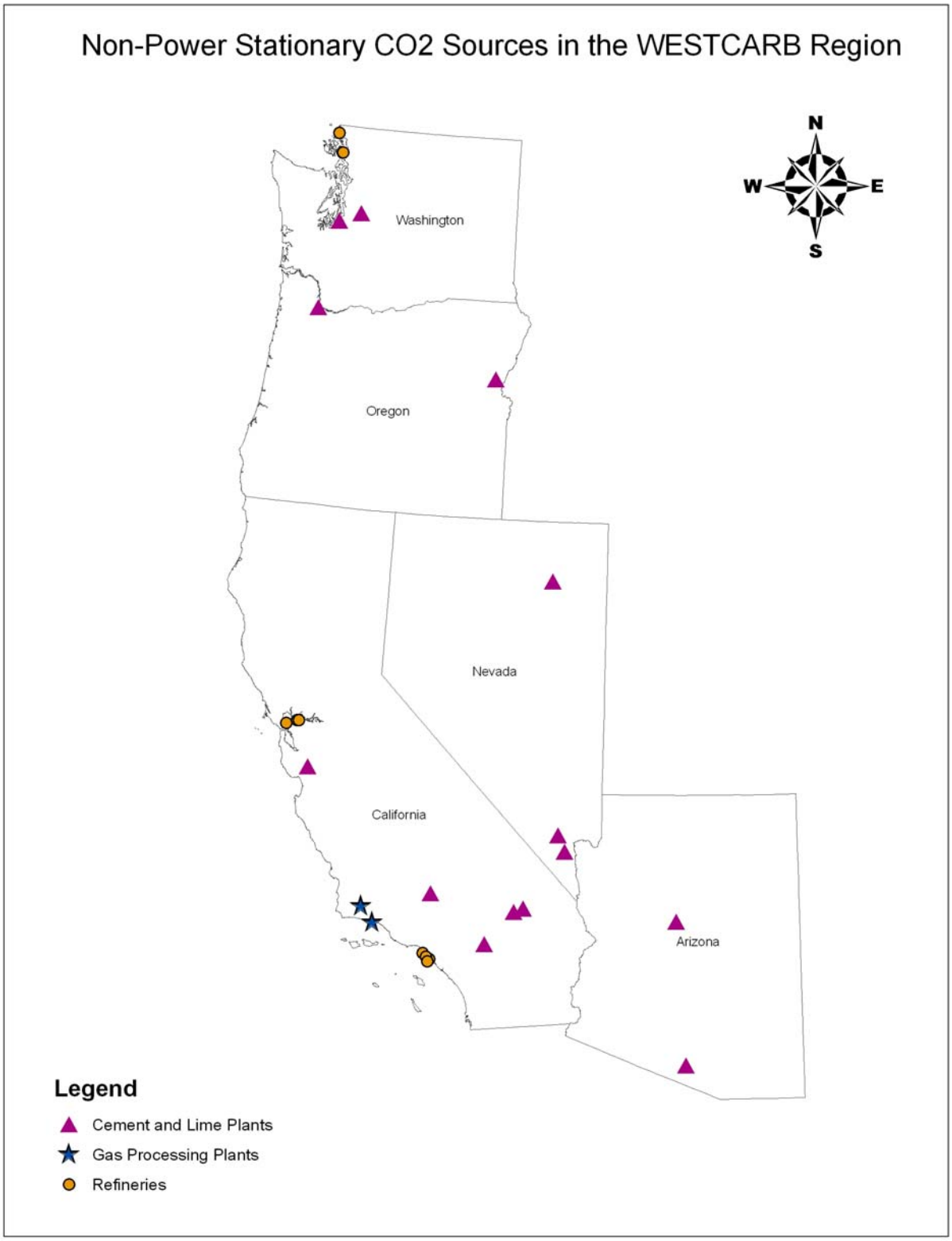


Figure 4. Non-power CO_2 sources in the WESTCARB region

3.1.2 Geologic Sinks

3.1.2.1 California

Sedimentary Basins

Of the 27 basins which met the screening criteria, the most promising are the larger Cenozoic marine basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda marine basins. Favorable attributes of these basins include (1) geographic diversity; (2) thick sedimentary fill with multiple porous and permeable aquifers and hydrocarbon reservoirs; (3) thick, laterally persistent marine shale seals; (4) locally abundant geological, petrophysical, and fluid data from oil and gas operations; and (5) numerous abandoned or mature oil and gas fields that might be reactivated for CO_2 sequestration or benefit from CO_2 enhanced recovery operations. Results for the above basins are summarized in the following pages. More detailed discussion of these, as well as other California sedimentary basins, is found in Appendix V.

The Great Valley province is an elongated topographic valley approximately 725 km (450 miles) long lying between the Sierra Nevada and the Coast Ranges, and extending from the Klamath Mountains in the north to the Transverse Ranges in the south. The Great Valley consists of a large depositional basin that has received sediments almost continuously since the late Jurassic and contains, by some estimates, as much as 12,200 m (40,000 ft) of mostly marine, sedimentary rocks (Magoon and Valin, 1995). In the subsurface, the Great Valley is divided into the Sacramento Basin in the north and the San Joaquin Basin to the south, the point of division being the buried Stockton Arch south of the City of Stockton.

The Sacramento Basin is approximately 390 km (240 miles) long and averages about 80 km (50 miles) wide. In its current form, the basin comprises an asymmetric trough with a westerly dipping basement surface ranging from surface exposures in the Sierra foothills to depths estimated to be greater than 6,700 m (22,000 ft). In contrast to the oil-prone San Joaquin Basin, the Sacramento Basin is a natural gas-producing basin. Figure 5 is a generalized cross section from the southern portion of the basin, showing major sandstone units that constitute sequestration targets and shale units that represent regional seals. Formations containing important gas reservoirs include the Winters, Starkey, Mokelumne River, and Domengine. Porosities range from 15 to 35%, and permeabilities range from 10 to 1,700 md (DOG, 1983).

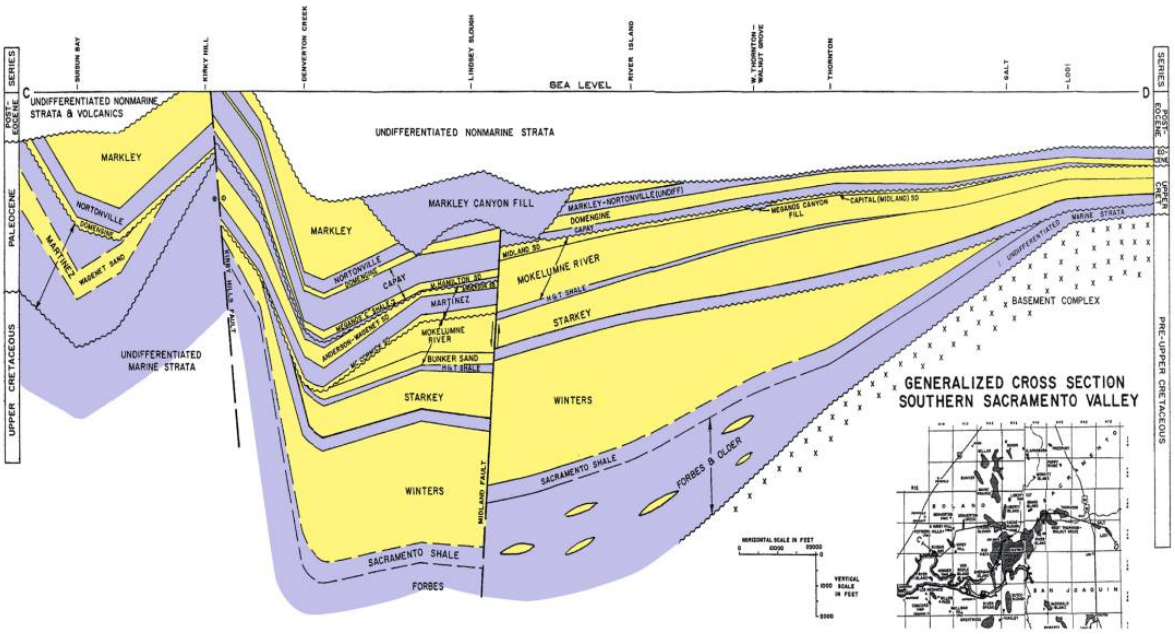


Figure 5. Generalized cross section through the southern Sacramento Valley (adapted from DOG, 1983)

A generalized sandstone isopach map of the Sacramento Basin (Figure 6) reveals good sandstone development paralleling the strike of the basin and ranging from over 300 m (1,000 ft) in Tehama County to nearly 1,220 m (4,000 ft) in Stanislaus County. The southward thickening is largely the result of the post-Cretaceous regional unconformity, which progressively truncates the sand-rich Great Valley Sequence formations to the north, leaving only Forbes and Kione formation sandstones remaining in the northernmost counties.

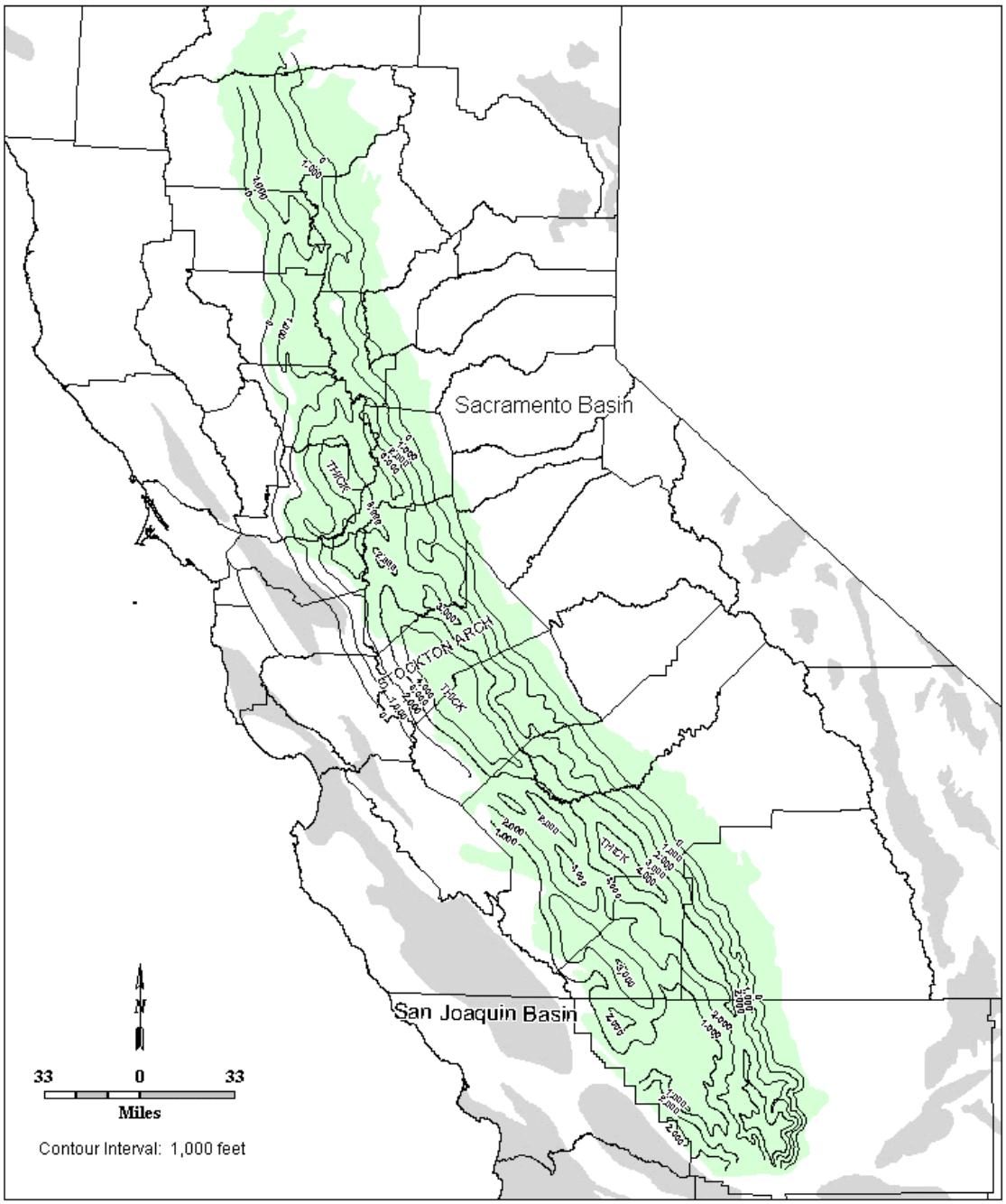


Figure 6. Generalized sandstone isopach map of the Sacramento Basin

The San Joaquin Basin comprises the southern half of the Great Valley province. It extends about 350 km (220 miles) from the Stockton Arch to its southern terminus at the northern Transverse Ranges and averages 80–115 m (50–70 miles) wide. It is bounded on the east by the Sierra Nevada and on the west by the Central Coast Ranges and the San Andreas Fault.

The basin is filled with predominantly marine Cretaceous and Cenozoic clastic sedimentary rocks that attain an aggregate thickness of over 9,150 m (30,000 ft). A generalized cross section in Figure 7 shows sandstone formations that are sequestration targets, and regional shale seals. Important oil producing formations include the Gatchell, Vedder, Jewett, and Pyramid Hill, Temblor, Stevens, Chanac and Santa Margarita, and Etchegoin. Porosities range from 10–40% and permeabilities from 0.2 md to 10,000 md. Porosity and permeability decrease with depth (DOGGR, 1998).

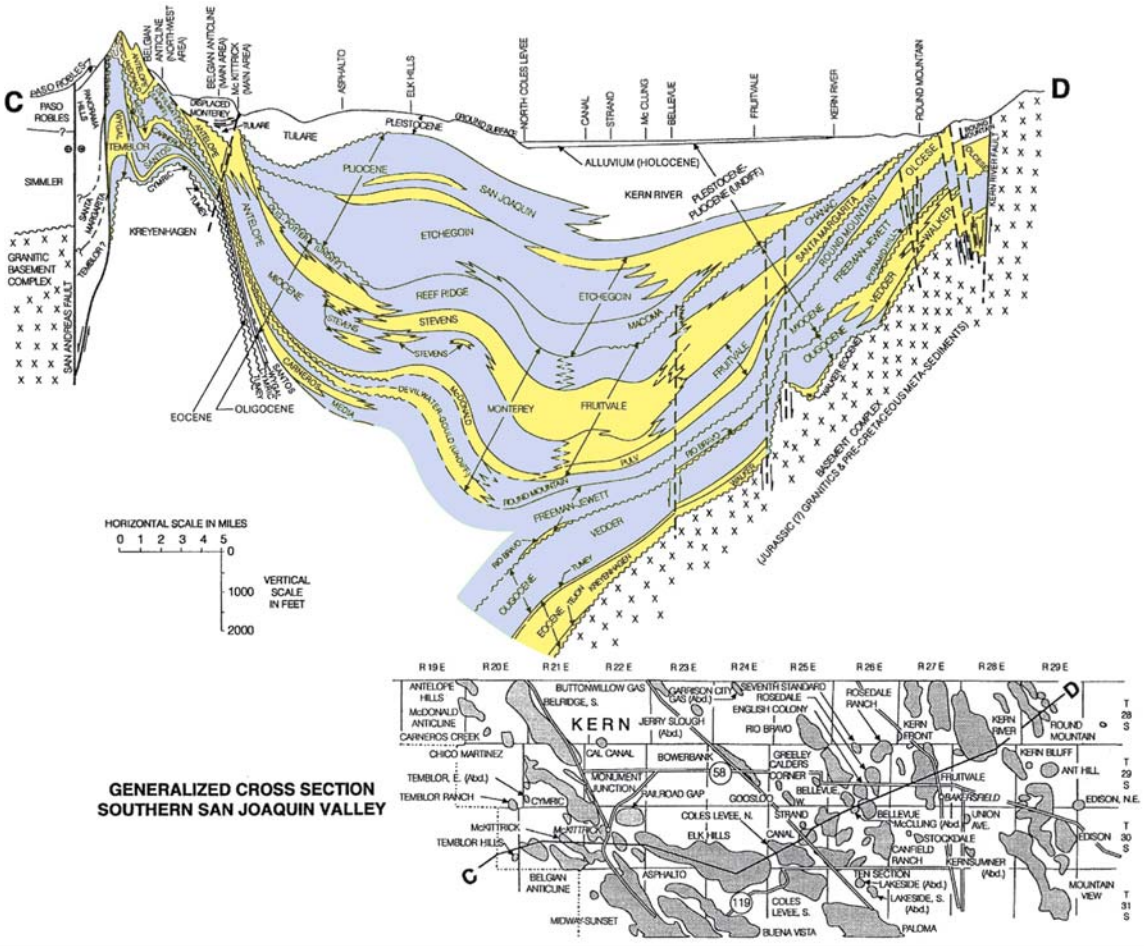


Figure 7. Generalized cross section through southern San Joaquin Valley (adapted from DOGGR, 1998)

A gross sandstone isopach map (Figure 6) shows that sandstone occurs in a trend thickening to over 1,220 m (4,000 ft) parallel to the basin axis. Unlike the Sacramento Basin, the isopach interval includes largely Eocene Gatchell Formation through Pliocene San Joaquin Formation sandstones deposited above the post-Cretaceous unconformity. However, some upper Cretaceous Great Valley Sequence sandstones contribute to the isopach in the northern basin, while lower beds of the Kern River and Tulare formations

are included in deeper portion of the southern basin.

The Transverse Ranges are an east-west trending series of mountain ranges and valleys extending about 515 km (320 miles) from Point Arguello eastward to the Mojave Desert. The largest and most important sedimentary basin within these ranges is the Ventura Basin, a complexly folded and faulted Cenozoic marine sedimentary basin. The western two thirds of the basin extends offshore to include the Santa Barbara Channel between the Channel Islands and Santa Ynez Mountains. The onshore portion comprises about 4,079 km^2 (1,575 square miles), including the Santa Clara Valley and Oxnard Plain. The onshore basin is bounded by the Santa Ynez and Santa Monica mountains to the north and south, respectively, and the San Gabriel Fault to the east. The Ventura Basin is the deepest of California's Cenozoic basins, containing more than 17,700 m (58,000 ft) of largely marine sediments. Consequently, the basin includes numerous upper Cretaceous through Pleistocene-age sandstones with sequestration potential, and possibly EOR opportunities. Figure 8 is a generalized cross section of Ventura Basin, which is characterized by major east-west trending thrust faults and tightly folded anticlinal trends that contain the majority of the basin's oil reserves. The Modelo and Pico sandstones are major oil-producing formations with porosities varying from 15 to 35% and permeabilities ranging from 8 md to 6,000 md (DOGGR, 1991). Porosity and permeability decreases with depth.

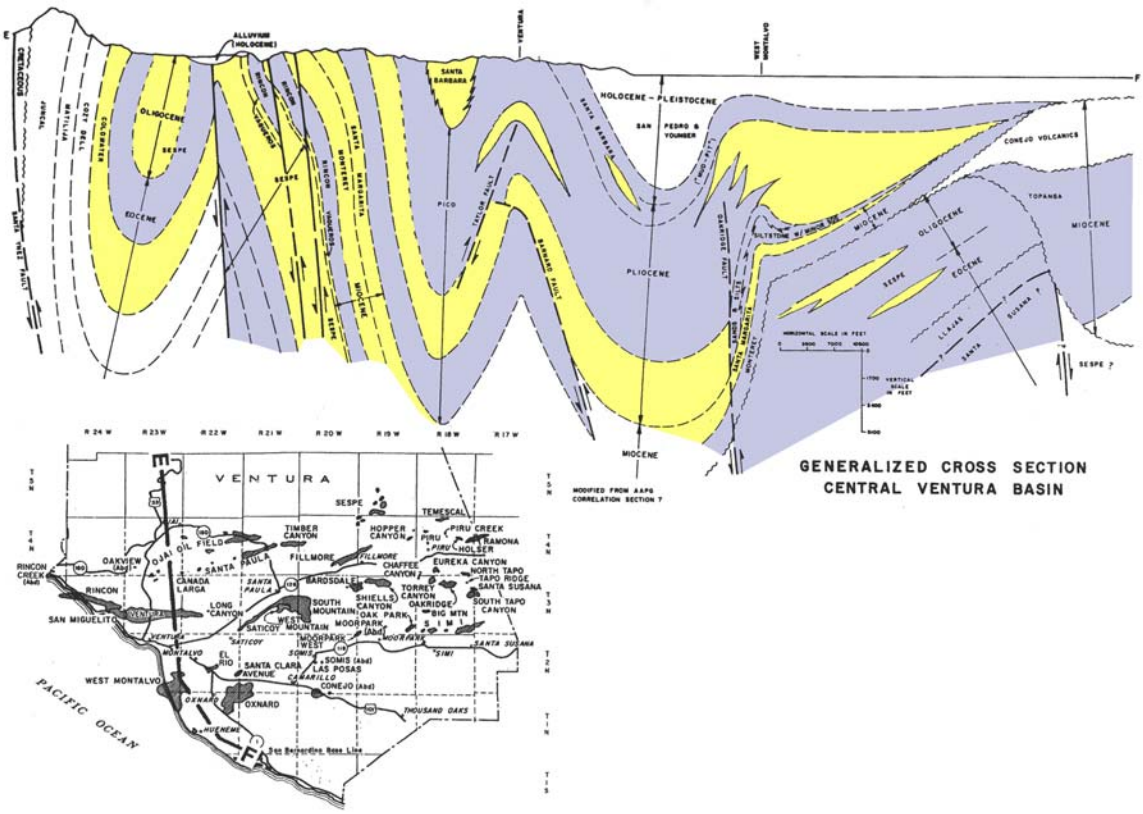


Figure 8. Generalized cross section through the Ventura Basin (adapted from DOGGR, 1991)

A sandstone isopach map for the Ventura Basin reveals three thick east-west trending sandstone zones, each exceeding 1,220 m (4,000 ft) thick, as well as significant sandstone development exceeding 300 m (1,000 ft) throughout most of the basin (Figure 9). In the deeper parts of the basin, sandstones within the isopach interval include primarily Sespe through Pico formation sandstones. Increasing contributions of Cretaceous strata, at the expense of these Eocene through Pliocene deposits, occupy the isopach interval in the shallower basin margins.

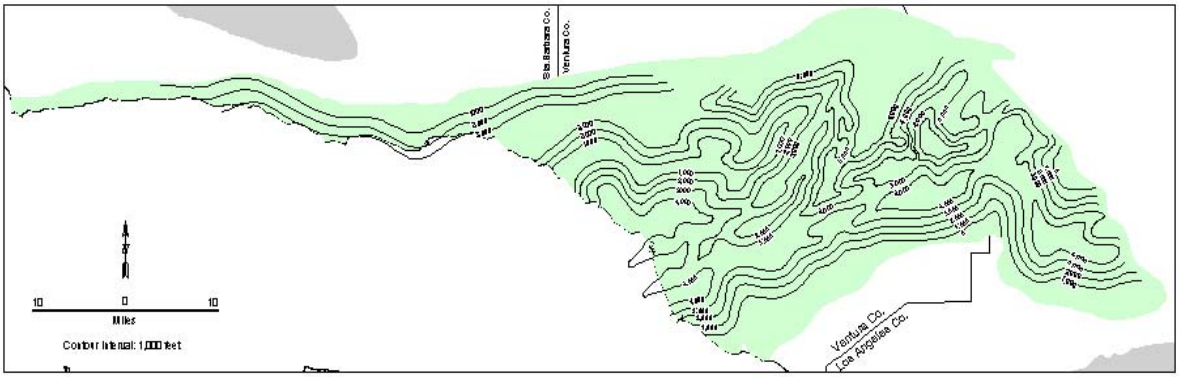


Figure 9. Generalized sandstone isopach map for the Ventura Basin

The Peninsular Ranges are a series of mountain ranges in southwest coastal California characterized by intervening northwest-trending valleys subparallel to faults branching from the San Andreas Fault zone. The Peninsular Ranges are bordered on the north by the Transverse Ranges, on the west by the Channel Islands, and on the east by the Colorado Desert province. The Los Angeles Basin is the largest of the Peninsular Range basins. It is a structurally complex basin located within the San Andreas Transform system at the intersection of the Peninsular Ranges and Transverse Ranges. It covers about 3,890 km^2 (1,500 square miles) and is bordered on the north by the Santa Monica-Hollywood-Raymond Hill Fault Zone and the Santa Monica Mountains; on the northeast by the Sierra Madre Fault and the San Gabriel Mountains; on the east and southeast by the Chino Fault, Santa Ana Mountains, and the San Joaquin Hills; and on the west and southwest by the Palo Verdes Fault. The basin contains a thick section of primarily Miocene and Pliocene sedimentary rocks estimated to be over 8,200 m (27,000 ft) thick. A generalized cross section is shown in Figure 10. The basin is considered the world's richest in terms of hydrocarbons per unit volume of sedimentary fill and contains three supergiant fields—the Wilmington, Huntington Beach, and Long Beach fields. Major oil-producing formations include the Puente and Repetto sandstones, with porosities ranging from 15 to 35% and permeabilities ranging from 10 to 3,200 md (DOGGR, 1991). Porosity and permeability decrease with depth.

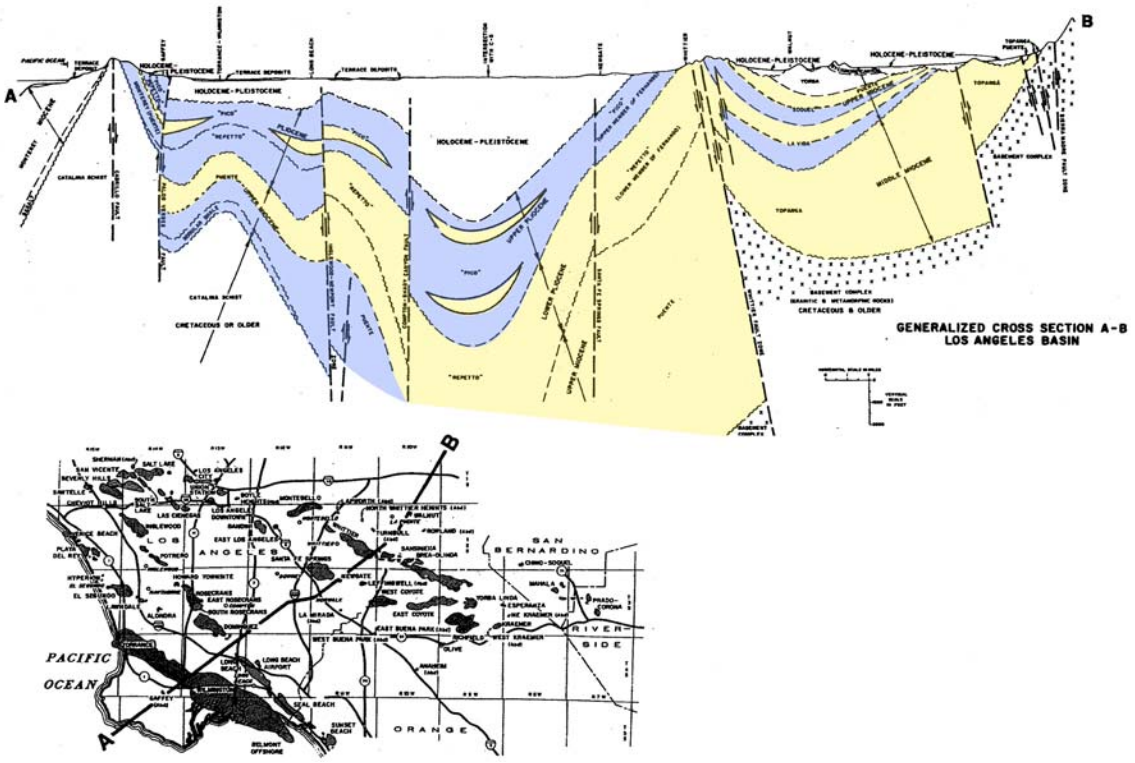


Figure 10. Generalized cross section through the Los Angeles Basin (adapted from DOGGR, 1991)

A sandstone isopach map for the Los Angeles Basin indicates that more than 1,520 m (5,000 ft) of sandstone is present within the isopach interval in the central basin, and that sandstone thickness generally correlates with relative basement depth (Figure 11). The thicker sandstone reflected in the basin center is dominated by Puente, Repetto, and Pico formation sandstones but, in the shallower basin margins, Topanga Formation and older units become locally important in the mapped interval.

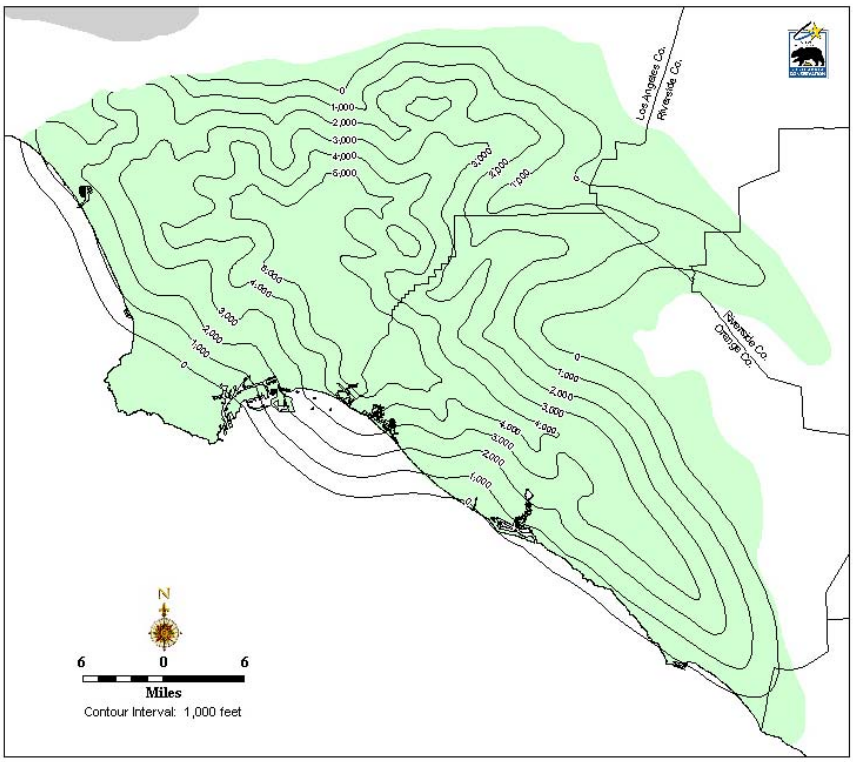


Figure 11. Generalized sandstone isopach map for the Los Angeles Basin

The Eel River, Livermore, Orinda, La Honda, Salinas, and Cuyama marine basins are all found in the Coast Ranges. California's Coast Ranges are composed of a series of northwesterly trending coastal mountain ranges and valleys extending southward from the Oregon state line to the Transverse Ranges in Santa Barbara and Ventura counties. To the east, they are bounded by the Coast Range Thrust, along which older Mesozoic rocks are thrust over Cretaceous rocks of the Great Valley Sequence in the Sacramento and San Joaquin basins.

The Eel River Basin, located in Humboldt County, is the onshore expression of a much larger offshore Cenozoic forearc basin. The onshore portion is expressed as a westerly plunging syncline. While the Freshwater Fault technically bounds the basin on the northeast, its northeast margin is more practically defined by the northeasterly dipping Little Salmon Thrust Fault. To the south, the basin is bounded by the Russ Fault, north of which the upturned beds of the Yager Formation and lower Wildcat Group are exposed. The basin contains more than 3,800 m (12,500 ft) of sedimentary fill, including over 3,350 m (11,000 ft) of dominantly Neogene marine, sandstone, siltstone, and shale resting on sandstones, conglomerates, and shales of the Cretaceous Yager Formation. Sandstones in the Bear River Beds through Rio Dell Formation may provide carbon sequestration opportunities in the deeper parts of the basin, on anticlinal closures and flanking stratigraphic pinch-outs. While individual sandstones are generally thin, a sandstone isopach map reveals a northwesterly trending zone of sandstone in excess of 760 m (2,500 ft) thick paralleling the north flank of the basin (Figure 12). Enclosing

siliceous mudstones and shales should provide seals. Porosities of the sandstones range from 12 to 30% and permeabilities range from 1 md to over 300 md (Stanley, 1995b; DOG, 1983).

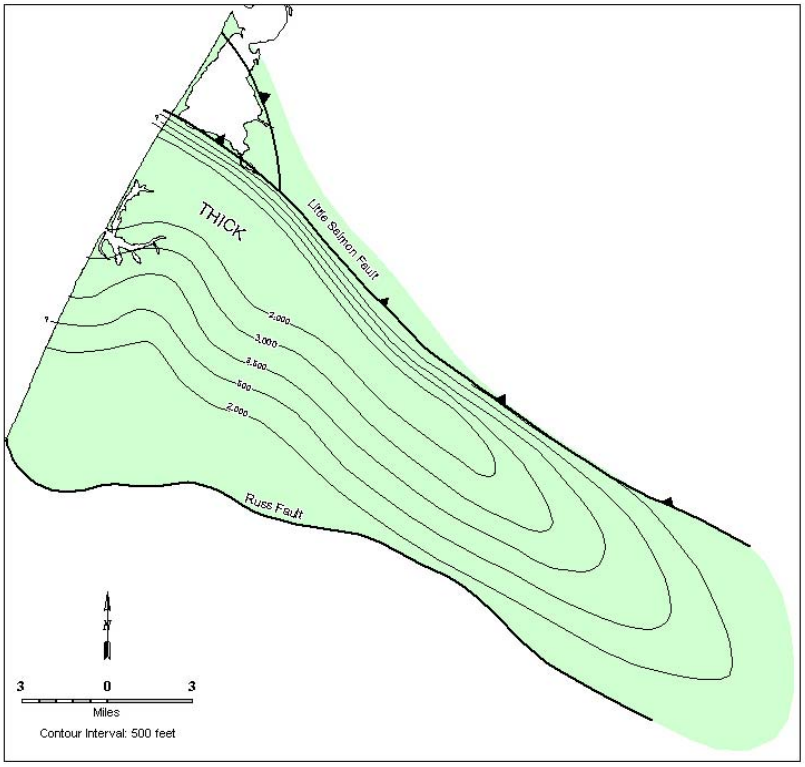


Figure 12. Generalized sandstone isopach map for the Eel River Basin

The Salinas Basin is one of several hydrocarbon-producing Cenozoic marine sedimentary basins west of the San Andreas Fault, including the La Honda Basin to the northwest and the Cuyama basin to the southeast. The basin is a narrow, northwest-trending feature extending almost 225 km (140 miles) from Monterey County southeastward into San Luis Obispo County, and varying in width from less than 16 to 48 km (10 to 30 miles). It is bordered on the east by the San Andreas Fault. To the northeast, the basin narrows where Salinian granitic basement rocks are uplifted and exposed in the Gabilan Range. The western basin margin is defined by the Jolan-Rinconda Fault Zone and uplifted granitic and metasedimentary rocks of the Santa Lucia Range. The structural and lithologic framework of the Salinas Basin consists of a series of tectonic basement blocks assembled during a complex history of subduction and transform motion along plate boundaries.

The Monterey formation sandstones are hydrocarbon producers and are potential sequestration targets in the Salinas Basin. Porosities in the shallow sands range from 15 to 39% with permeabilities of 500 to 8,000 md (DOGGR, 1991). While the Monterey sands in the known oil fields are too shallow for potential sequestration purposes, deeper

Monterey sandstones exist farther west in the deeper basin. A gross sandstone isopach map (Figure 13) shows sandstone developments thickening to over 760 m (2,500 ft) to the southwest towards the basin axis. Underlying poorly known lower-middle Miocene and Cretaceous sandstones may also be present at depth.

The La Honda Basin is located north of the Salinas Basin in Santa Clara and Santa Cruz counties between San Francisco and Monterey Bay. The basin is bounded on the northeast by the San Andreas Fault, on the northwest by granitic rocks of Montara Mountain, on the southwest by the Zayante-Vergeles Fault, and on the west by the San Gregorgio–Hosgri Fault (Stanley, 1995a). The relatively small basin comprises about 930 km^2 (360 mi^2) and represents a small sliver of the larger San Joaquin Basin, which was displaced approximately 298 km (185 miles) by right lateral slip along the San Andreas Fault. It is estimated that as many as 14,600 m (48,000 ft) of Tertiary sedimentary and volcanic strata fill the basin.

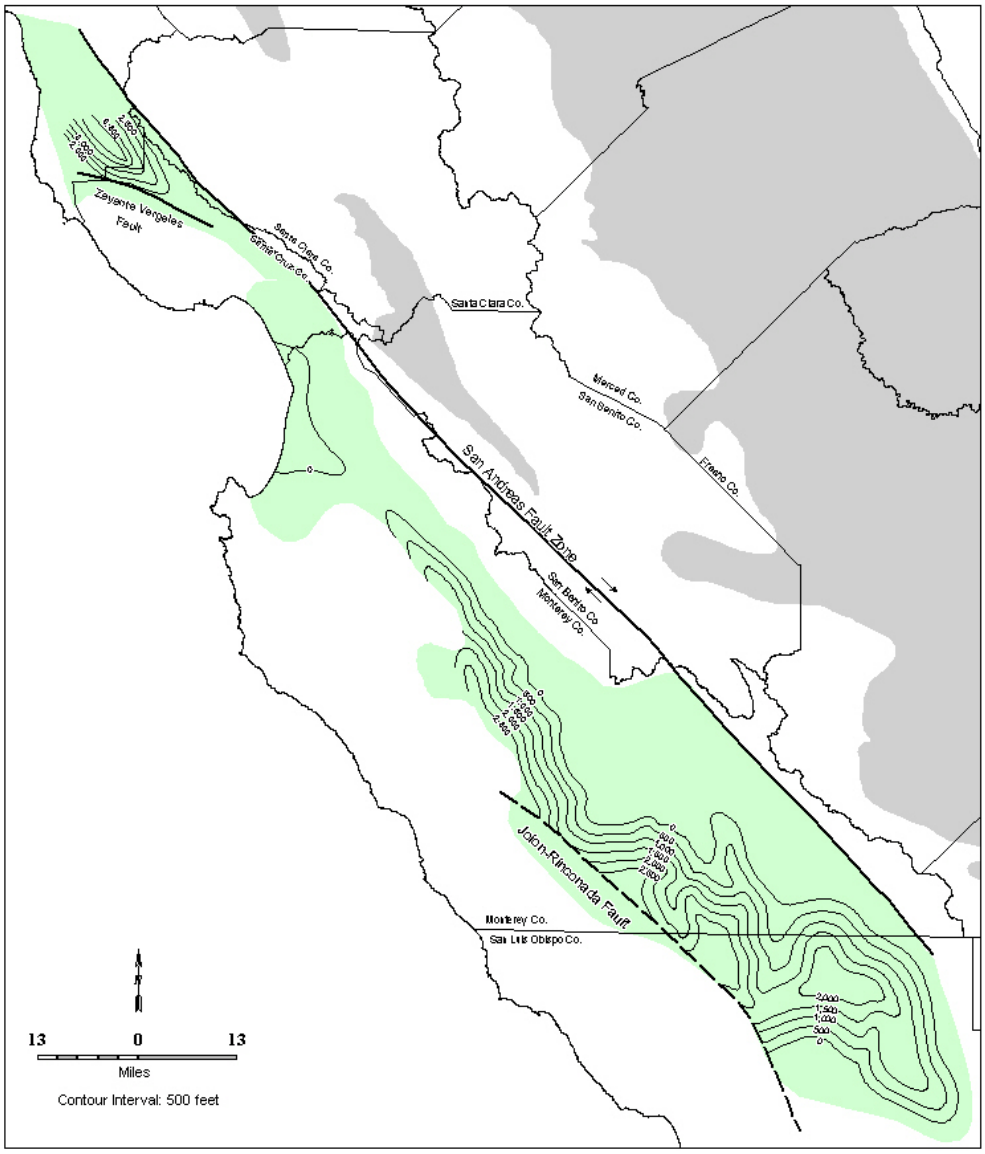


Figure 13. Generalized sandstone isopach map for the Salinas and La Honda Basins

In the eastern basin, the Butano and Locatelli formations are too shallow to be considered for CO_2 sequestration. Westward, towards the basin center, however, sandstone in the Butano and younger formations thickens markedly (Figure 13). The deepest well in the basin, drilled on the Butano Anticline, bottomed in the Butano Formation at 3,370 m (11,053 ft) and encountered more than 1,220 m (4,000 ft) of Butano sandstone within the isopach interval. The Vaqueros through Santa Margarita formations are blanketed by the Santa Cruz Mudstone and Purisima Formation, which can attain thicknesses of 2,700 m (8,900 ft) and 2,400 m (7,900 ft), respectively. Shallow producing sands in the Butano between 550 and 760 m (1,800 and 2,500 ft) deep exhibit porosities between 15 and 35% with permeabilities of 30 to 40 md, but at depth these are expected to be considerably

reduced. Shallow Purisima sandstones between 240 and 820 m (800 and 2,700 ft) deep exhibit porosities of 22 to 34% and permeabilities of 1 to 40 md (DOGGR, 1991).

The Cuyama Basin is a relatively small Cenozoic marine basin near the southern end of the Coast Ranges. It extends approximately 105 to 121 km (65 to 75 miles) in a northwest-southeast direction and varies from 13 to 29 km (8 to 18 miles) wide. It is bounded on the northeast by the San Andreas Fault zone and the Temblor Range, which separate it from the San Joaquin Basin. Its southwest margin is structurally complex and consists of at least two early Miocene wrench faults (Russell and La Panza Faults), which separate the basin from the Sierra Madre Range. The northwest end of the basin is indeterminate, but approaches the southeast end of the Salinas Basin. Its southeastern end is defined by a buried normal fault subparallel to the younger Big Pine Fault (Tennyson, 1995). The basin is structurally complex, with extensive normal faulting of the pre-Pliocene section followed by later thrust faulting of the basement through the Pliocene section, burying much of the sedimentary section below complex thrust sheets.

In the north-central portion of the basin, where deep well control exists, a sandstone isopach map (Figure 14) indicates an area of thick sandstone exceeding 1,220 m (4,000 ft) and aligned in a northwest-southeast orientation roughly paralleling the basin axis. Sandstones within the isopach interval include Branch Canyon and Painted Rock sandstones and overlying Santa Margarita sandstones. Porosities of the sandstones range from 19 to 40%, and permeabilities range from 177 to 1,300 md (DOGGR, 1991).

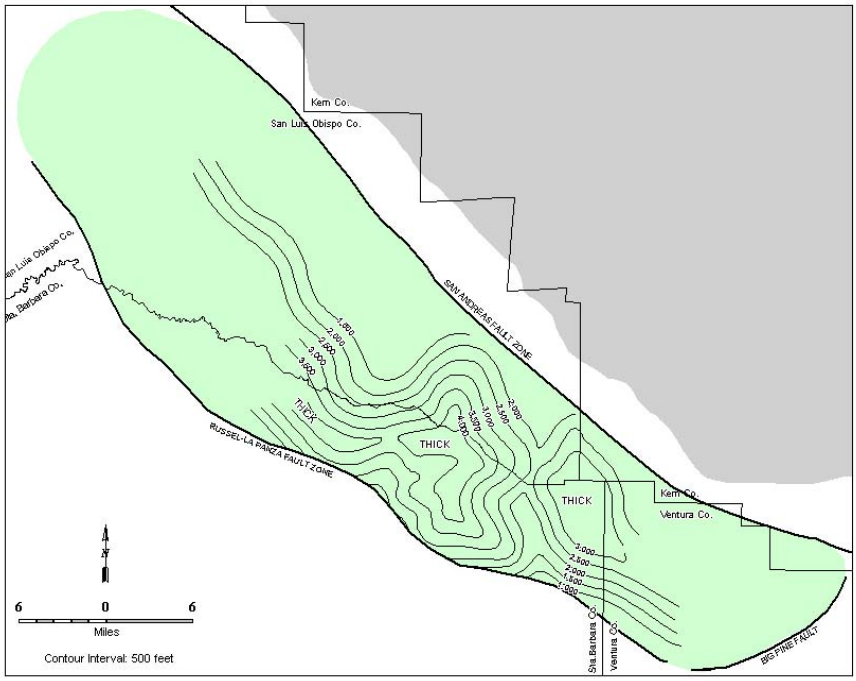


Figure 14. Generalized sandstone isopach map for Cuyama Basin

The Livermore and Orinda basins are part of a related series of deep, linear, Neogene pull-apart basins within the Coast Ranges between San Francisco Bay and the Sacramento Basin. Both basins formed under the influence of extensional stresses after the onset of strike-slip motion along the San Andreas and associated Calaveras and Hayward fault systems during the middle Miocene. The Livermore Basin is approximately 48 km (30 miles) long by 19 km (12 miles) wide. It is bounded on the north and east by Mount Diablo and the Diablo Range, and on the west and southwest by the Calaveras Fault, which separates it from the Orinda Basin. Uplifted Franciscan Complex rocks form its southern end. While the deepest well drilled bottomed at 5,306 m (17,404 ft) in Miocene sediments (Darrow, 1979), outcrop and unpublished geophysical data suggest that the Livermore Basin may be filled with as much as 6,700 m (22,000 ft) of Eocene, Miocene, and Pliocene sediments that have been extensively folded and faulted by later compressional forces caused by motion on the marginal faults.

A gross sandstone isopach map for the basin depicts an area of thicker sand development exceeding 490 m (1,600 ft) in the south central portion of the basin (Figure 15). Given the complex structural configuration of the basin, steep dips, and fault displacements along the basin margins, the isopach interval includes sandstones of the Cretaceous Panoche through Pliocene Orinda formations. Limited data on porosity and permeability yield values of about 25% and 250 md, respectively (DOG, 1983).

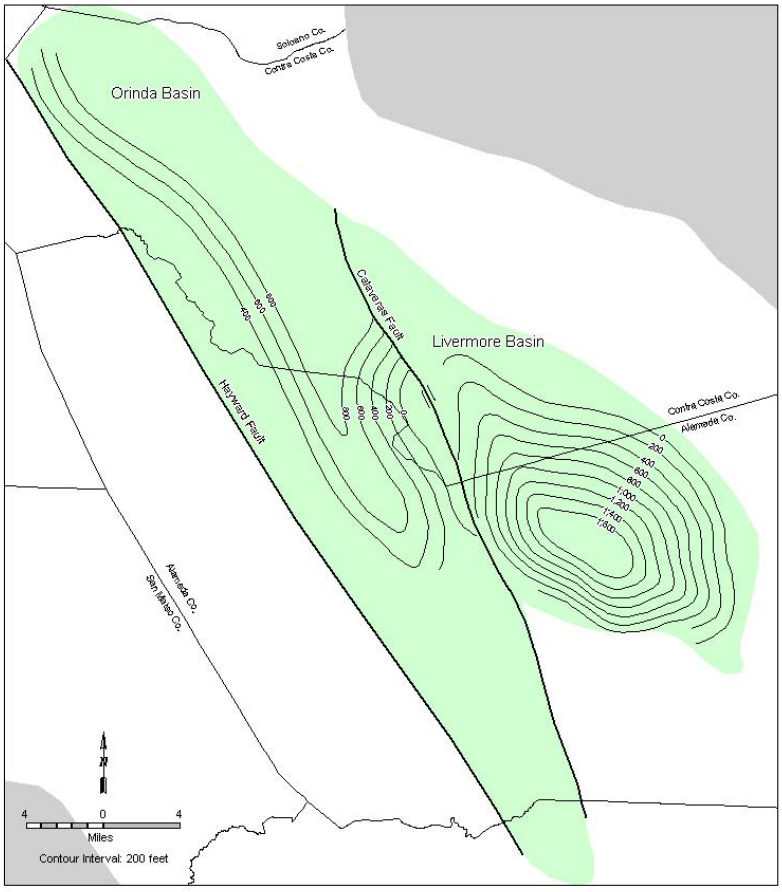


Figure 15. Generalized sandstone isopach map for Livermore and Orinda Basins

The Orinda Basin is a narrow linear basin measuring about 81 km (50 miles) by 11 km (7 miles), bounded on the west by the Hayward Fault and on the east by the Calaveras Fault. Its southern limit is the convergence of the two faults in northern Santa Clara County. Its northern end is taken to San Pablo Bay, past which the Sonoma Basin begins. Limited well control and outcrop data indicates the Orinda Basin contains a sedimentary section very similar to that of the neighboring Livermore Basin. The deepest well bottomed at 3,048 m (9,997 ft) in the abandoned one-well Pinole Point Field near the north end of the basin. Only two other wells exceeded 2,700 m (9,000 ft) with a handful going to 1,500–2,100 m (5,000–7,000 ft). The available well logs were used to construct a sandstone isopach map of logged section, which suggests a longitudinal thickness of at least 240 m (800 ft) extending from near the basin center to San Pablo Bay (Figure 15).

Capacity Assessment

Isopach and depth-to-basement maps were used to estimate the total storage capacity within saline formations in the ten largest sedimentary basins. Table 5 provides the data used to calculate the total available pore volume in the basins. Only a portion of the total pore volume is available for storage. The storage capacity is determined from the mass of CO_2 trapped in the pore space either as a separate phase or dissolved in the pore water.

Table 5. Data used for calculation of pore volume of California basins

Volumetric Data for California Basins			
	Area (sq. miles)+	**Estimated Average Thickness in m (ft)***	**Estimated Average Porosity****
Sacramento-San Joaquin basins	18,550	610 (2,000)	0.25
Los Angeles Basin	1,341	920 (3,000)	0.25
Ventura Basin	1,450	920 (3,000)	0.24
Salton Trough	2,559	610 (2,000)	0.24
Eel River Basin	175	460 (1,500)	0.26
Salinas Basin	1,343	460 (1,250)	0.28
La Honda Basin	268	460 (1,500)	0.25
Livermore Basin	144	240 (800)	0.23
Orinda Basin	296	180 (600)	0.23
Cuyama Basin	582	920 (3,000)	0.27
+Area of basin at depths greater than 800 m (2,625 ft)			
*Average sands (isopachs) thickness for depth window 800–3,050 m (2,625–10,000 ft)			
**Approx. average porosity for all zones in isopachs window			

Many factors affect the percentage of the pore space that could be occupied, including formation heterogeneity, buoyant flow, hydrologic boundary conditions, residual saturation, and other two-phase flow properties. Reservoir modeling studies also suggest that, because of two-phase conditions and diffusion, the pore volume containing dissolved CO_2 will be greater than the pore volume of separate-phase CO_2. Two other factors affecting storage capacity are the density of the in-place CO_2 and the salinity of the pore water. Formation temperature and allowable injection pressures will, in large part, determine the CO_2 density. Salinity of the pore waters is important because CO_2 solubility decreases with increasing salinity.

Figure 16 shows the results of capacity calculations for a range of pore-volume values containing separate-phase and dissolved CO_2. The calculations assumed a single density value of 600 kg/m^3 and a CO_2 dissolved mass fraction of 2.5%. Results show total storage capacity for the 10 basins ranging from about 150 Gt to about 500 Gt. The low end of this range would provide sufficient capacity for storing over 1,000 years of utility and industrial sector emissions at the current emission rates. Table 5 shows that more than half of this capacity is contained in the Sacramento-San Joaquin basins.

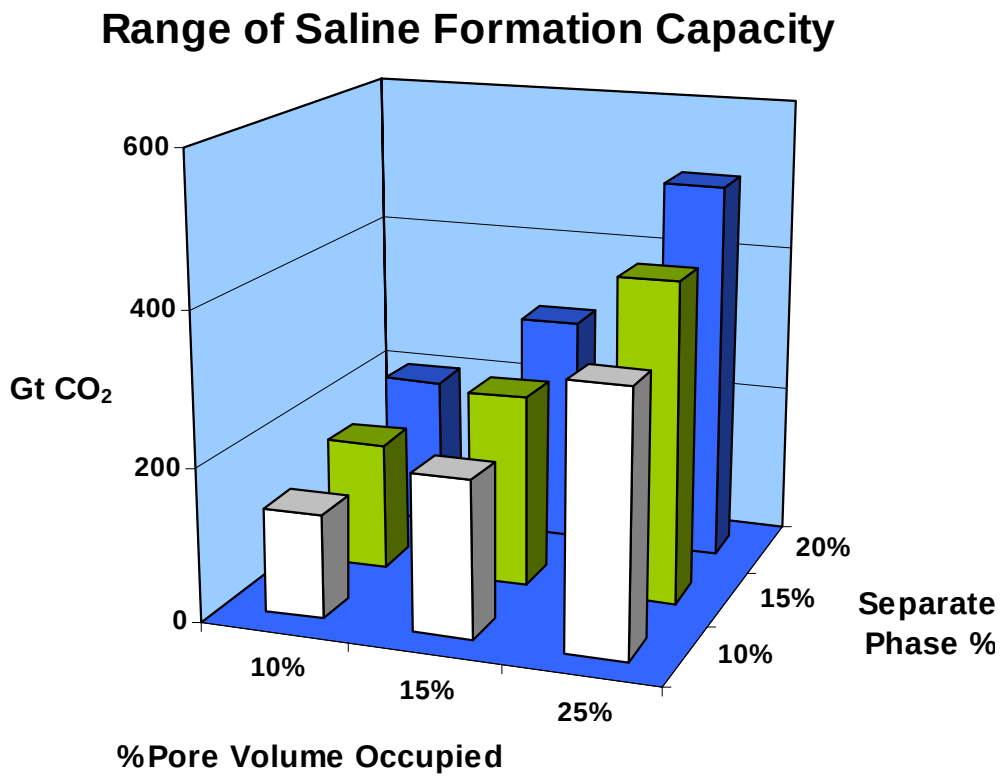


Figure 16. Total sequestration capacity of saline formations in ten largest basins in California

Several of the sedimentary basins, notably the Sacramento, San Joaquin, Los Angeles, and Ventura basins, also contain major oil and gas fields, which will likely be the first targets for geologic sequestration. Estimates for the CO_2 storage capacity of California oil and gas fields were based upon production data using Elewaut *et al*., 1996:

$$Q_{CO2} = (V_{Uoil} + V_{Ugas}) * \rho_{CO_2} / 1{,}000 \quad (1)$$

where Q_{CO2} = CO_2 storage capacity ($MtCO_2$)

V_{Uoil} = underground volume of oil produced (M m^3)

V_{Ugas} = underground volume of gas produced (M m^3), and

ρ_{CO_2} = CO_2 density at the reservoir pressure.

The underground volume of oil and gas was estimated from:

$$V_{Uoil} = V_{oil(st)} * B_o \quad (2)$$

$$V_{Ugas} = V_{gas(st)} * B_g \quad (3)$$

where $V_{oil(st)}$ = Volume of oil at standard conditions (M m^3)

$V_{gas(st)}$ = Volume of gas at standard conditions (M m^3)

B_o = Oil formation volume factor (FVF), and

B_g = Gas formation volume factor (E^{-1}).

A default FVF of 1.2 was applied for oil. The gas expansion factor E was calculated with linear relation: E = 4.8P+93.1, where P is the reservoir pressure in MPa. If the original reservoir pressure value were missing, it was calculated from the average depth of the field, assuming a gradient of 10.5 MPa/km.

An estimate of the CO_2 EOR potential for oil fields was made based on API gravity data and depth. Oil fields at depths greater than 915 m (3,000 ft) and with API gravity more than 25° were classified as fields with miscible CO_2-EOR potential. Fields at depths greater than 915 m (3,000 ft) and with API gravity between 17.5° and 25° were classified as fields with immiscible CO_2-EOR potential. Fields at depths greater than 915 m (3,000 ft) and API gravity less than 17.5° were classified as fields with storage potential but no EOR potential. The attributed GIS database was interrogated using these criteria, yielding 121 fields in California with miscible CO_2 EOR potential and a CO_2 storage capacity of 3.4 Gt. The storage capacity was increased to 3.8 Gt by including the fields in the remaining two categories. Though tiny compared to the total saline formation capacity, the storage capacity associated with potential CO_2 EOR is still equal to over 27 years of current utility and industrial sector emissions.

The capacity of California gas fields, screened by depth, was also estimated using the expression in Equation 1. The result yielded 128 gas fields with a combined storage capacity of 1.8 Gt. Oldenburg *et al*. (2001) have shown that CO_2 can be used to enhance production from depleting gas fields (EGR), though an estimate of the CO_2 EGR potential for California has yet to be done.

3.1.2.2 Oregon and Washington

Sedimentary Basins

In Oregon and Washington, the most promising near-term sedimentary basin targets are found in the Coastal Ranges and Puget-Willamette Lowlands geomorphic provinces, though several interior basins may also be important because of the location of large emission sources (Figure 17). The Coastal Ranges and Puget-Willamette Lowlands provinces are the home of a major Tertiary sedimentary belt of basins that formed in a regional fore-arc environment as the Juan de Fuca plate subducted beneath the North American Plate. These basins, the boundaries of which are uncertain at this time, are characterized by up to 6,100 m (20,000 ft) of Tertiary sedimentary rocks deposited in embayments and shallow seas. Results for these basins are summarized in the following

pages. More detailed information on these as well as other basins in Oregon and Washington is found in Appendix VI.

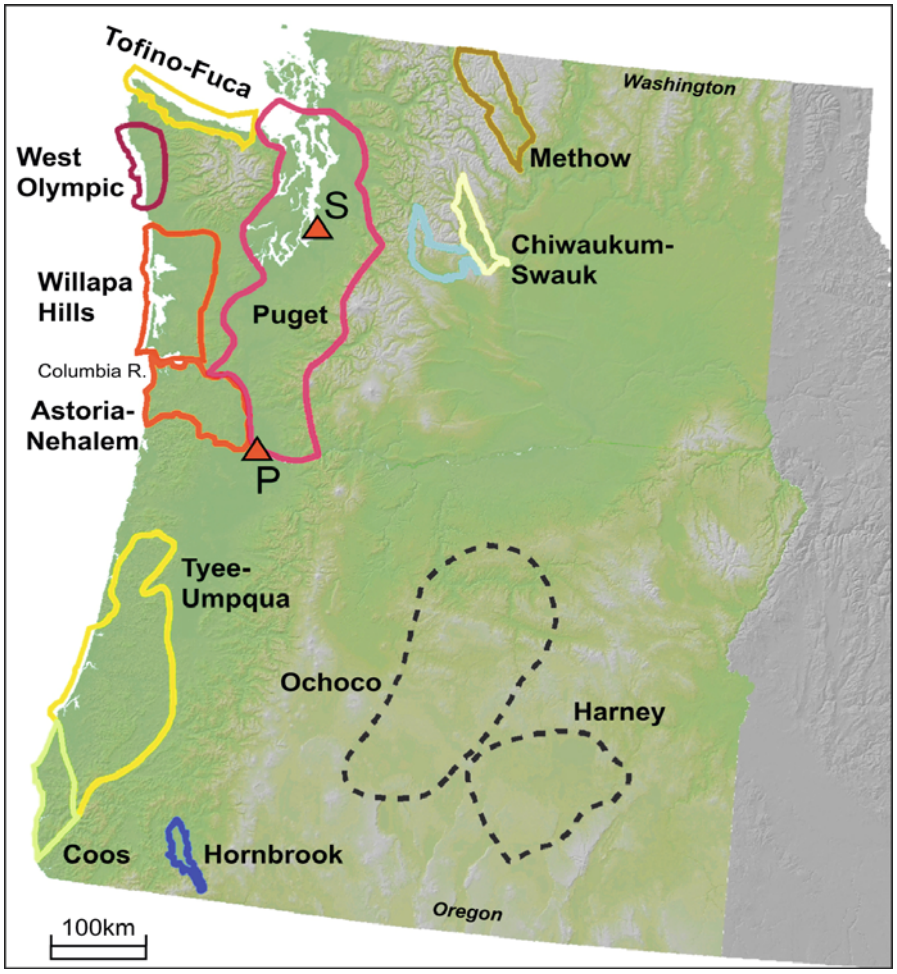


Figure 17. Sedimentary basins in Oregon and Washington. S = Seattle, Wash. P = Portland, Ore.

Three basins are found in the Coastal Ranges of Washington: Tofino-Fuca Basin, Western Olympic Basin, and Willapa Hills Basin. Of these, the Western Olympic and Willapa Hills Basins are the most promising. The Western Olympic Basin is located directly west of the Olympic Mountains in Clallam and northern Jefferson Counties, and extends westwards offshore for at least 40 miles (Wagner and Batatian, 1985). The sedimentary strata have an estimated total thickness of at least 2,700 m (9,000 ft; Figure 18), and the recognized formations are:

- Quinault Formation—Pliocene-Miocene (PLMn), up to 1,500 m (5,000 ft) of nearshore sedimentary rocks (siltstone, sandstone and conglomerate); and

- Hoh Assemblage—lower-mid Eocene, a sequence of marine rocks accreted to the continental margin:
    - Lincoln Creek Formation—Oligocene-Eocene; up to 2,700 m (9,000 ft) of massive sandstones and tuffaceous siltstones;
    - Skookumchuck Formation—mid-upper Eocene, up to 1,100 m (3,500 ft) of interbedded shallow marine and continental facies (arkosic sandstones and siltstone), and coal in upper and lower member; and
    - McIntosh Formation—mid-upper Eocene, up to 1,500 m (5,000 ft) of tuffaceous sedimentary rocks.

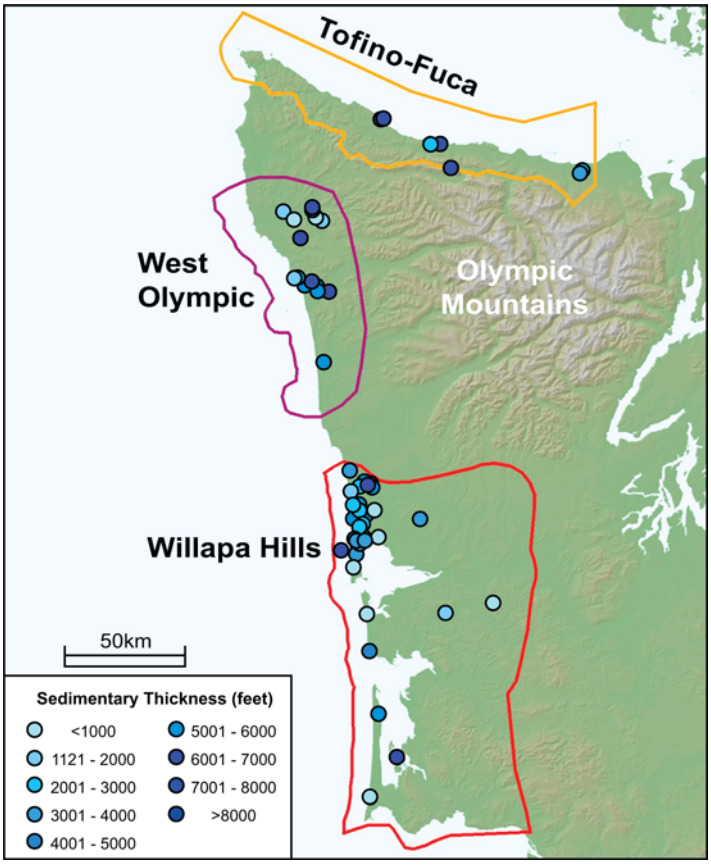


Figure 18. Sediment thickness in basins of Coastal Ranges of Washington

The basin is tectonically active and the sediments are highly deformed; some structural traps are present. The sandstones have porosities of 36–46% and permeabilities of 102 to 917 md.

The Willapa Hills (Grays Harbor) are topographic hills that rise to about 950 m (3,100 ft) above sea level and are situated between the Olympic Mountains to the north and the

Columbia River to the south. The Willapa Hills Basin contains up to 4,600 m (15,000 ft; Figure 18) of late Oligocene to Quaternary strata overlying basement/broken mélange of mid-Miocene to early Oligocene age. Eocene and Oligocene sediments consist predominantly of deep-water siliciclastics, and arkosic sandstones; interbedded volcaniclastic sandstones are contained within thick marine shale sequences.

The recognized geologic formations in the basin above the Crescent Formation are:

- Quinault Formation—Pliocene-Miocene (PLMn), nearshore sedimentary rocks (siltstone, sandstone, and conglomerate);
- Montesano Formation—mid-upper Miocene (Mm(2m)), up to 920 m (3,000 ft) of fluvial, lacustrine, brackish water, and shallow marine sediments;
- Astoria Formation—lower-mid Miocene, Mm(1a), up to 1,100 m (3,500 ft) of marine sedimentary rocks (carbonaceous, fine-grained sandstone);
- Hoh Assemblage—similar sequence to that in the Western Olympic Basin;
- Cowlitz Formation—Eocene (En(c) or Tco), unconformably overlies the Crescent Formation and contains marine/nonmarine siltstone and sandstone; and
- Northcraft Formation—Eocene (Evc(n)), up to 460 m (1,500 ft) of volcaniclastic deposits and lavas.

The Willapa Hills basin is the most promising Coastal Range Basin for hydrocarbon development, and therefore CO_2 storage, because of the deep-water sandstones, thick shales and claystones, and anticlinal traps. Sandstones of the Montesano Formation have porosities of 6.4–32.7% and permeabilities up to 522 md.

The Puget Trough Basin is located in northwestern Washington, and occupies the generally low-lying region east of the Olympic Mountains and west of the Cascade Mountains. The southern extent of the basin is defined by the mergence of the Cascade Range and Coastal Range in Lewis and Cowlitz counties. The basin consists of up to 1,100 m (3,700 ft) of unconsolidated sediments of Pleistocene age overlying up to 3,050 m (10,000 ft) of Tertiary sedimentary rocks. The geology of the Puget Trough is complex, and interpretation is made difficult by the large volume of mostly glacially derived, unconsolidated sediments. Faulting and folding is abundant, and many active faults are recognized. The faulting has resulted in the formation of several major sub-basins (Figure 19):

- Everett Sub-basin—bounded to the north and south by the North and South Whidbey Island Fault Zones, respectively, and attains a maximum thickness of between 3,050 and 4,300 m (10,000 and 14,000 ft), of which as much as 1,100 m (3,600 ft) is considered to be unconsolidated sediments (Jones, 1999);
- Seattle Sub-basin—located south of the South Whidbey Island fault, is bounded to the south by the Seattle fault and uplift, and contains up to 4,600 m (15,000 ft) of sedimentary material, of which up to 1,100 m (3,700 ft) is unconsolidated;

- Tacoma Sub-basin—located south of the Narrows Structure, up to 1,800 m (6,000 ft) thick (610 m, or 2,000 ft, of unconsolidated sediments); and
- Chehalis Sub-basin—occupies the southern portion of the Trough, south of the Olympic Gravity Anomaly; the unconsolidated sediment thickness is less than 120 m (400 ft) here.

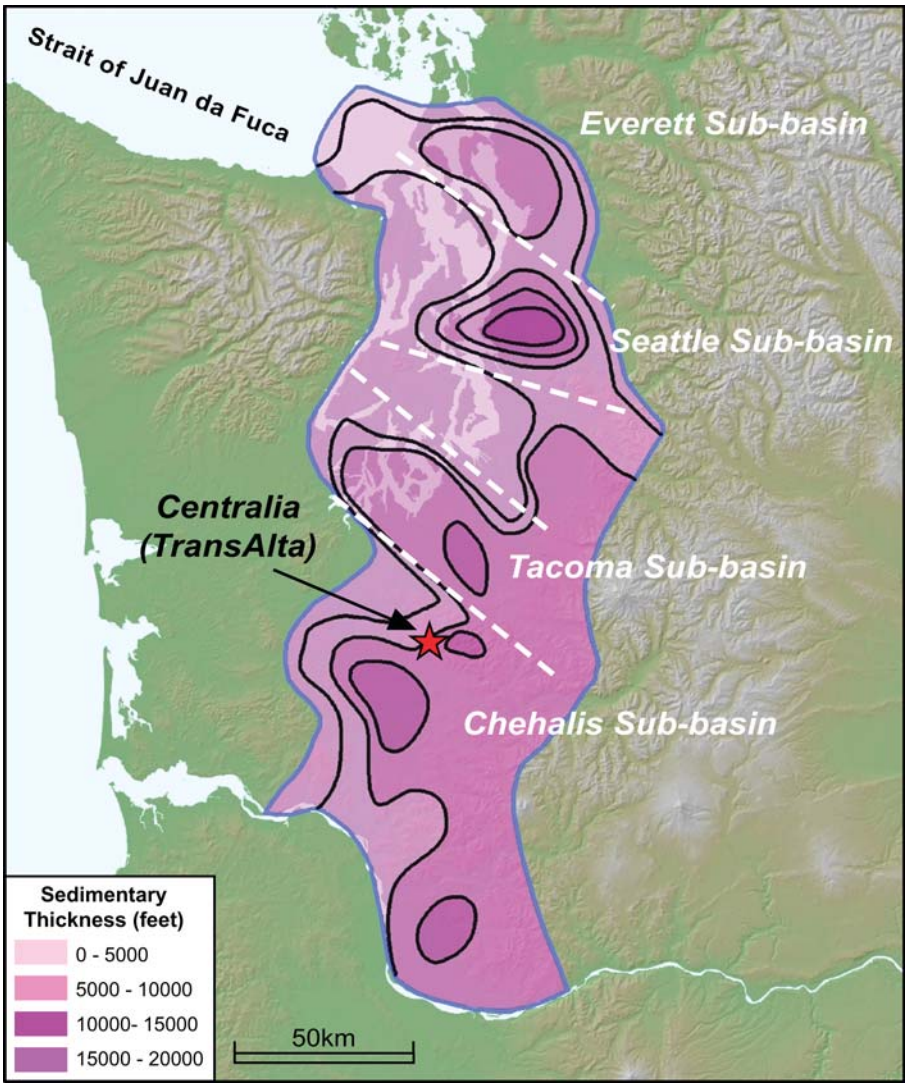


Figure 19. Sedimentary sub-basins in the Puget Trough of Washington. The location of the TransAlta power plant in Centralia, Wash., is noted.

The key sedimentary formations in the Everett-Seattle-Tacoma sub-basins are:

- Blakeley and Blakeley Harbor Formations—Oligocene-Eocene (OEm(b)), marine sedimentary rocks in the northern Puget Sound area of interbedded volcaniclastic sandstone, siltstone, shale, and conglomerate;
- Puget Group—Eocene (Ec(2pg)), continental sedimentary rocks/deposits;
- Renton Formation (Ec(2r))—continental sedimentary rocks/deposits (fine- to medium-grained, massive to cross-bedded arkosic sandstone);
- Tiger Mountain Formation (Ec(2t))—continental sedimentary rocks/deposits; and
- Tukmila Formation (Evc(t)) – volcaniclastic rocks/deposits (sandstone, siltstone, and conglomerate).

The Chehalis Sub-basin occupies the lowland area between the southern extent of Puget Sound in Thurston County, extending into Lewis County and northernmost Cowlitz County. The basin contains up to 4,600 m (15,000 ft) of sedimentary sequence. The key sedimentary formations are:

- Wilkes Formation—Miocene (Mc(w)), continental sedimentary rocks; and
- Hoh Assemblage—lower-mid Eocene, a sequence of marine rocks accreted to the continental margin; includes the Lincoln Creek, Skookumchuck, and McIntosh Formation. Both basal Lincoln Creek Sandstone and Skookumchuck sandstones serve as reservoirs in the Jackson Prairie Gas Storage Field.

Sandstones of the Skookumchuck have porosities of 30–38% and permeabilities of 135 to 3,000 md.

The Puget Trough Basin also contains deep coal formations, which are sequestration targets and may have potential for ECBM. Coals in this region occur within the Puget Group. Figure 20 provides an initial assessment of the subsurface extent of the coal basins, showing deep coals to be present over an area of approximately 2,500 km^2. Coal rank (thermal maturity) is an important factor to consider when assessing coal seams for coalbed methane and for sequestration potential. In general, coal rank increases from northwest to southeast in the Puget region, reflecting greater tectonic deformation and heat associated with Cascade Range uplift. Initial analysis indicates excellent coal seam reservoir properties: 30 m (100 ft) coal thickness (in the Skookumchuck formation), 20-24 G(m^3)/ton (700–850 ft^3/ton) CO_2 sorption capacity, and 5 md permeability. The amount of unmineable coal in the Puget Sound basin was estimated to be over 70 billion tons, with a CO_2 storage potential of 2.8 Gt.

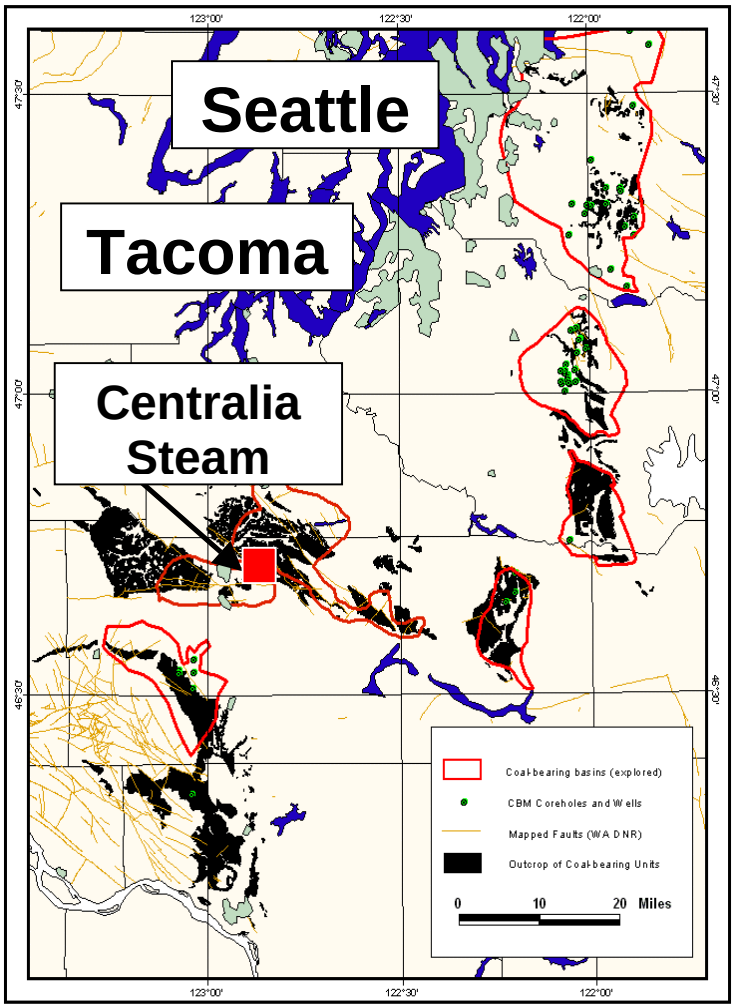


Figure 20. Estimate of extent of coal basins in Puget Trough

In Oregon, there are three main sedimentary basins in the Coastal Ranges province: Astoria-Nehalem, Tyee-Umpqua, and Coos Basins (Figure 21). They extend beneath the Willamette Lowlands, which separate the Coastal Range and the Cascade Mountains. Definition of the exact extent of each of these basins is problematic because of volcanic and sedimentary cover and tectonic deformation.

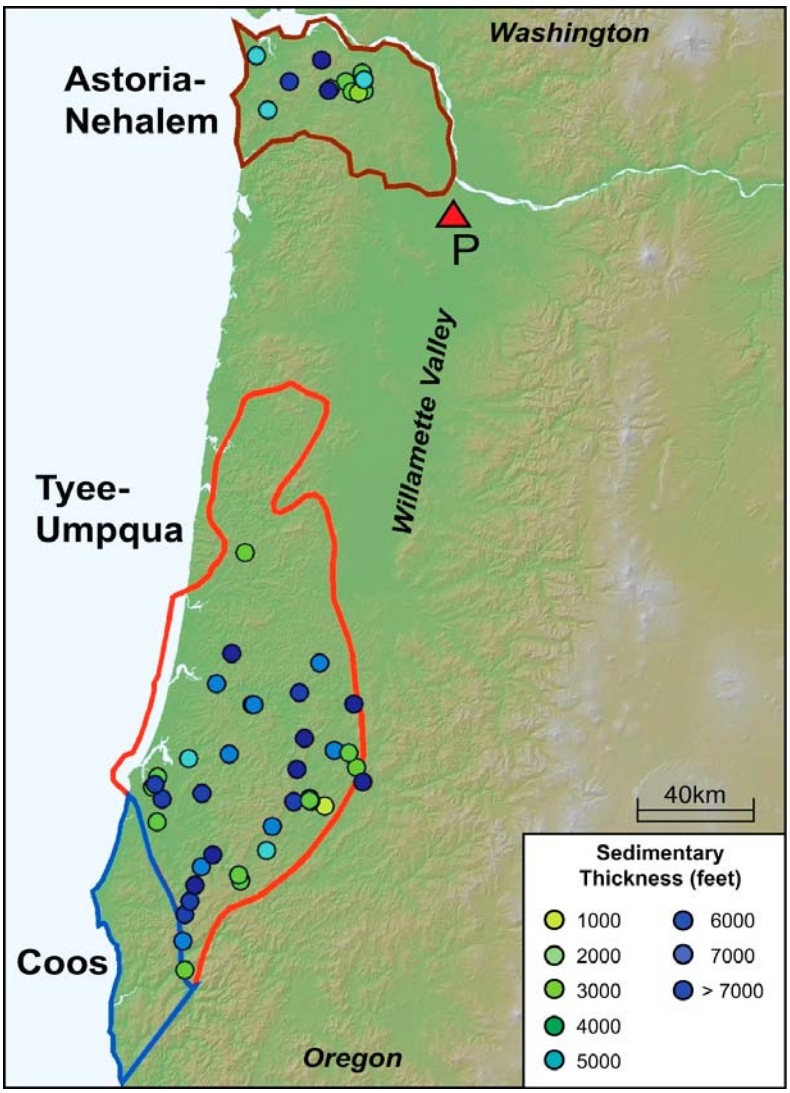


Figure 21. Sedimentary basins and sediment thickness in the Oregon Coastal Ranges. P = Portland, Ore.

The Tyee-Umpqua Basin occupies the southern half of the Coastal Range, extending from a latitude near Salem, beyond Roseburg, to the junction of the Coastal Range with the Klamath Mountains. To the west are the younger basinal sediments of the Coos Basin. The basin consists of more than 6,100 m (20,000 ft) of lower-middle Eocene sedimentary strata preserved in the Coastal Range hills. In fact, the basin contains two superimposed basins with different geologic trends and tectonic histories: the northeast-southwest trending early Eocene Umpqua Basin and the north-south trending Tyee Basin.

The main geologic units identified in the basin are as follows:

- Spencer Formations—lower-mid Eocene, up to 150 m (500 ft) of arkosic sandstone (fluvio-deltaic).

- Bateman Formation—mid-upper Eocene, up to 760 m (2,500 ft) of arkosic sandstone (deltaic) and mudstone.
- Elkton Formation—mid-Eocene, up to 920 m (3,000 ft) of mostly mudstone and minor sandstone.
- Tyee Formation—mid-Eocene, mostly 1,830 m (6,000 ft) of sandstone, deposited in a shallow marine to non-marine deltaic environment (south) to slope and deep marine basinal margin (north). The eastern margin is truncated by younger rocks or covered by younger volcanic rocks; the western margin is a passive sill or a seamount terrane of oceanic crust. Contains several recognized members.
- Umpqua Group—upper Paleocene to lower Eocene, up to 3,050 m (10,000 ft) of mudstone, sandstone, and conglomerate (nonmarine to deep marine origin). Prominent formations recognized in reports include the Camas Valley White Tail Ridge, Tenmile, and Bushnell Rock Formations.

For the massive Tyee sandstones, porosity and permeabilities average 2.76 md, respectively (Ryu and Niem, 1999).

The Coos Basin is located in coastal southwestern Oregon in the Coastal Range Province. The basin extends from the western edge of the Tyee Basin and the Klamath Mountains, and continues offshore. The geology of the basin consists of up to 3,050 m (10,000 ft) of marine sedimentary rocks. The key units are as follows:

- Bastendorff Formation—upper Eocene to lower Oligocene, up to 880 m (2,900 ft) of thinly laminated siltstone and mudstone;
- Coaledo Formation—upper Eocene, up to 1,800 m (6,000 ft) of deltaic sandstones, and prominent coal seams;
- Bateman Formation—mid-Eocene, 300 m (1,000 ft) of sandstone (near-shore, deltaic);
- Tyee Formation—similar strata to those in the Tyee Basin, up to 1,500 m (5,000 ft) thick in the Coos Basin;
- Fluornoy Formation—mid-Eocene, between 300 and 1,500 m (1,000 and 5,000 ft) of sandstone and siltstone sequence;
- Looking Glass Formation—lower Eocene, basal conglomerate and overlying fine-grained sandstone and siltstone sequence (up to 2,100 m—7,000 ft—thick); and
- Roseburg Formation—lower Eocene-upper Paleocene, between 3,050 and 3,700 m (10,000 and 12,000 ft) of rhythmites and submarine basalts.

Sandstones of the Coalcedo and Fluornoy formations have porosities of 18–43% and permeabilities of 4.5 to 1,800 md.

The Astoria-Nehalem Basin is located in northwestern Oregon, in western Columbia and eastern Clatsop counties, about 45 miles northwest of Portland. The basin contains the only economically productive gas field (known as the Mist Gas Field) in Oregon. This field occupies an area of about 13 km^2 (5 mi^2) and was first produced from in 1979. The basin geology is complex because of extensive folding and faulting. Normal and strike-slip faulting is common, with the predominant fault trend being northwest; some significant east-west and northeast-southwest faulting also exists. Faulted anticlines are reportedly the most common trap in the Mist Field. The earliest sedimentary unit is the mid-Eocene Yamhill Formation (siltstones and shales). Although the sedimentary units interfinger with the volcanics, the Yamhill does contain a prominent sandstone member. The Cowlitz Formation overlies the Yamhill Formation, and consists of micaceous, arkosic-basaltic marine sandstone, siltstone, and mudstone. Of key importance is the gas-producing Clark & Wilson (C&W) sandstone, which is overlain by a thick shale unit. The C&W sandstones have porosities up to 39% and permeabilities from 1 to 1,400 md. A sequence of marine sedimentary units overlies the Cowlitz Formation and consists of thickly to thinly bedded tuffaceous mudstone, siltstone, and sandstone. Key units include the Spencer, Keasey, Pittsburg Bluff, and Astoria Formations (all mid-upper Eocene).

There are several interior basins in Washington and Oregon that contain sedimentary deposits. Very little is known about the geology and properties of the rocks in these basins, but they could be potentially important for sequestration because of the proximity to power plants. These basins include the Methow, Chiwaukum, Ochoco, and Hornbrook. The Methow Basin contains approximately 4,000 m (13,000 ft) of sedimentary rocks, including several massive sandstones in the Winthrop Formation. The Chiwaukum Basin contains about 5,800 m (19,000 ft) of continental sedimentary sequences. The Ochoco Basin contains more than 1,500 m (5,000 ft) of fluvio-deltaic sandstones and conglomerates, and the Hornbrook Basin contains about 1,200 m (4,000 ft) of sediments. Hornbrook Formation sandstones have porosities of 6.3–18.6% and permeabilities up to 1.2 md.

3.1.2.3 Nevada

In Nevada, ongoing crustal extension is responsible for the current basin-and-range topography. Essentially every mountain range is bounded on one or both sides by a fault that has been active in Quaternary time. Sediments that have filled the basins between the mountains could provide sequestration targets, but there is generally a paucity of information on the structure and properties of these basin-filling sediments. Figure 22 shows the basins in which fill is greater than 1 km (0.6 mi), based on interpretation of gravity data, with no distinction based on rock type or structure. If all potential screening criteria are applied, the basins with the largest areas of potential for CO_2 sequestration by injection into saline aquifers are Granite Springs Valley in Pershing County, Antelope and Reese River Valleys in Lander County, and Ione Valley in Nye County. Each contains 30 km^2 (12 mi^2) or more area. The Nevada Bureau of Mines and Geology (NBMG) has no records of deep (>1,000 m, or >3,300 ft) wells in any of these areas.

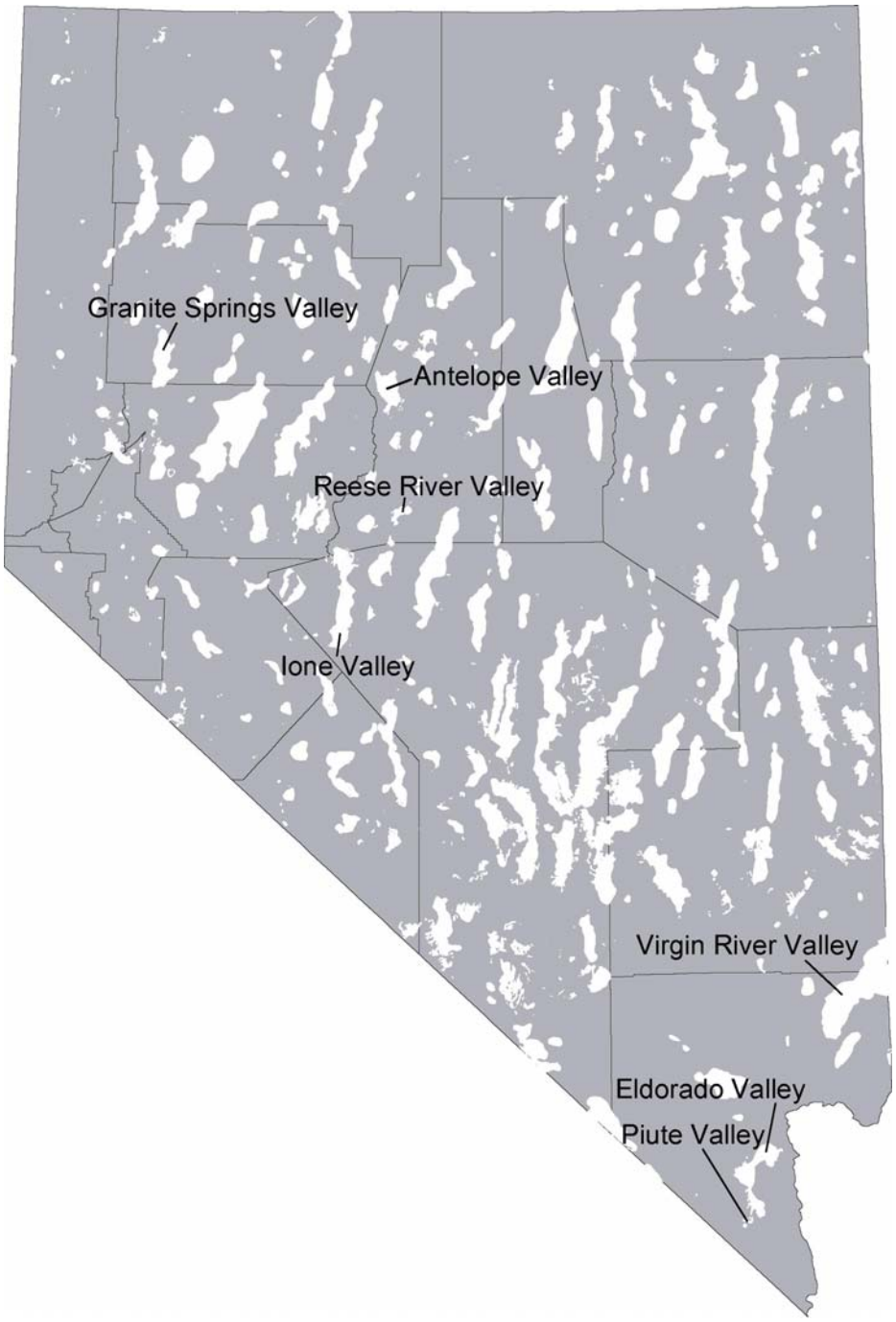


Figure 22. Nevada basins with fill thickness greater than 1 km

The NBMG constructed a conceptual model of oil and potential CO_2 reservoirs and seals in Nevada (Figure 23). NBMG states that oil occurs in two broad types of reservoirs in Nevada: fractured and permeable Paleozoic sedimentary rocks (mostly limestones but locally also sandstones), and fractured Tertiary ash-flow tuffs. They conclude that permeable, unfractured sandstones may occur in the Paleozoic section and in the Tertiary

valley-fill sequences in the basins. Seals for the oil reservoirs and, hence, potential CO_2 sequestration sites include Paleozoic marine shales, Tertiary lacustrine shales, and the nonwelded clay- or zeolite-altered upper zones of ash-flow tuffs. NBMG concludes that the best seals appear to be above the Paleozoic-Tertiary unconformity.

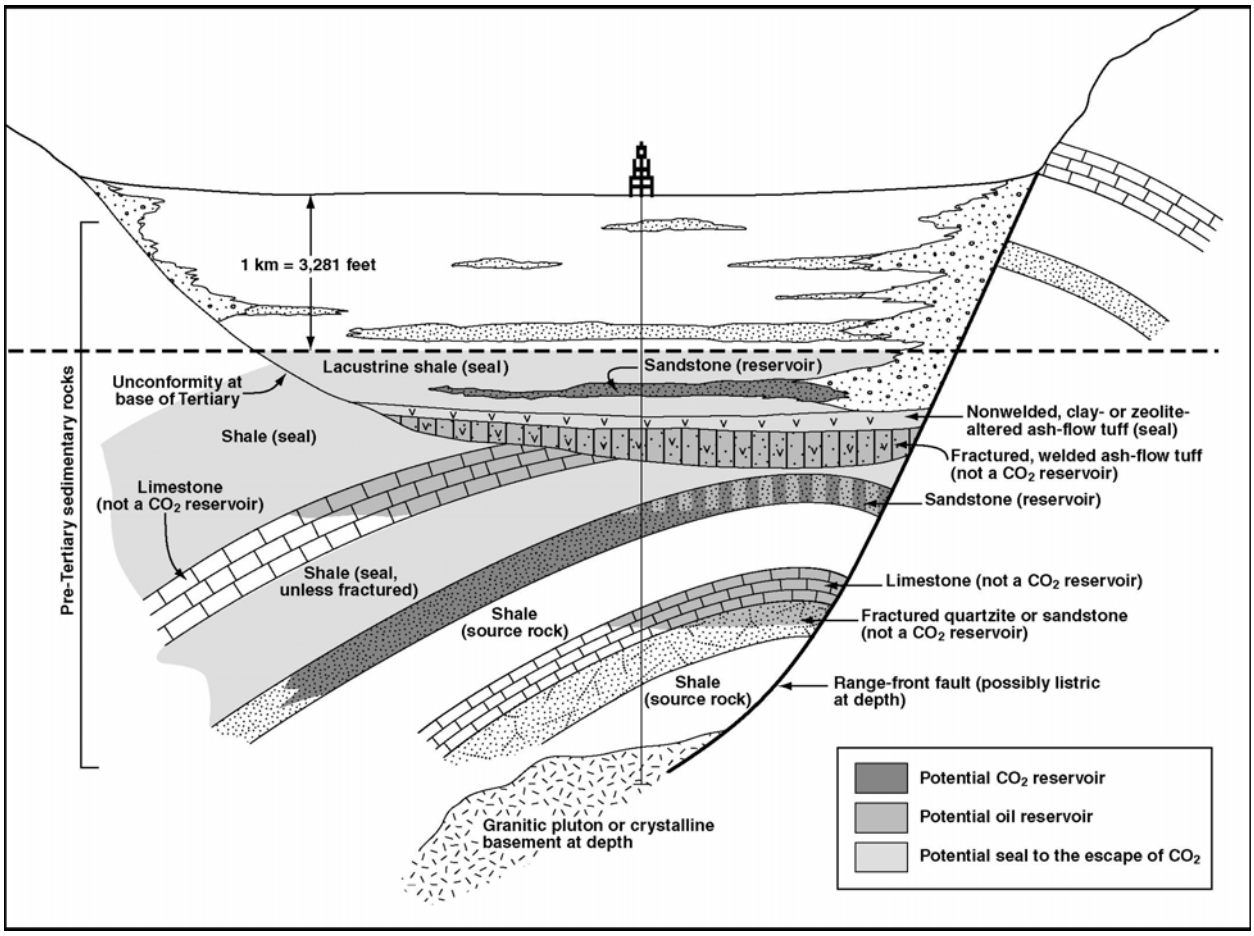


Figure 23. Conceptual model of oil reservoirs and saline formations in Nevada

Additional information on the NBMG assessment of Nevada is found in Appendix VII.

3.2 Geologic Sequestration Options

After identifying the CO_2 sources and candidate sinks, the study then evaluated the CO_2 sequestration potential in the WESTCARB region by analyzing the matching between sources and sinks. Figure 24 shows the distribution of CO_2 sources and sinks that were considered in the source-sink matching analysis. After limiting to CO_2 sources in the contiguous-U.S. part of the WESTCARB region and excluding sources without CO_2 emission data, a total of 58 CO_2 sources were studied in the source-sink matching analysis. These 58 CO_2 sources include 10 coal-fired power plants, 27 gas-fired power

plants, 11 cement plants and 10 refineries, with an annual amount of 184 Mt CO_2 to be sequestrated[1].

As a preliminary analysis, the study performed a straight-line distance based matching for the entire contiguous-U.S. part of the WESTCARB region, connecting each source to its closest sink in terms of straight-line distance. In this preliminary exercise, neither the optimal pipeline path nor the sink's storage capacity constraints were considered. The straight-line distance matching analysis was performed for each of the three different groups of eligible sinks and a combination of them altogether (see Tables 6 and 7). Given that the WESTCARB server lacked sufficient data to evaluate the CO_2 sequestration potential for Nevada, the matching exercises were performed under two scenarios: with and without Nevada saline aquifers. Tables 6 and 7 summarize the matching results under the two scenarios in terms of annual CO_2 storage capacity by marginal straight-line distance. 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 50 km (30 mi) away while about one half of the sources could be matched with a sink that is less than 250 km (155 mi) away. If all sink types, including Nevada sinks, were considered for sequestration, however, more than four-fifths of CO_2 sources could be matched with appropriate sinks within 50 km (30 mi). However, there are still some sources that cannot be matched to any sinks that is within 250 km (155 mi) from the sources.

[1] The annual amount of CO_2 to be sequestrated differs to the 159 Mt annual emissions reported previously. The 184 Mt $CO_2$was estimated under the following three assumptions: (1) an 80% operation capacity for power plants, (2) full production capacity for non-power stationary CO_2 sources, and (3) a capture efficiency of 90% for all sources.

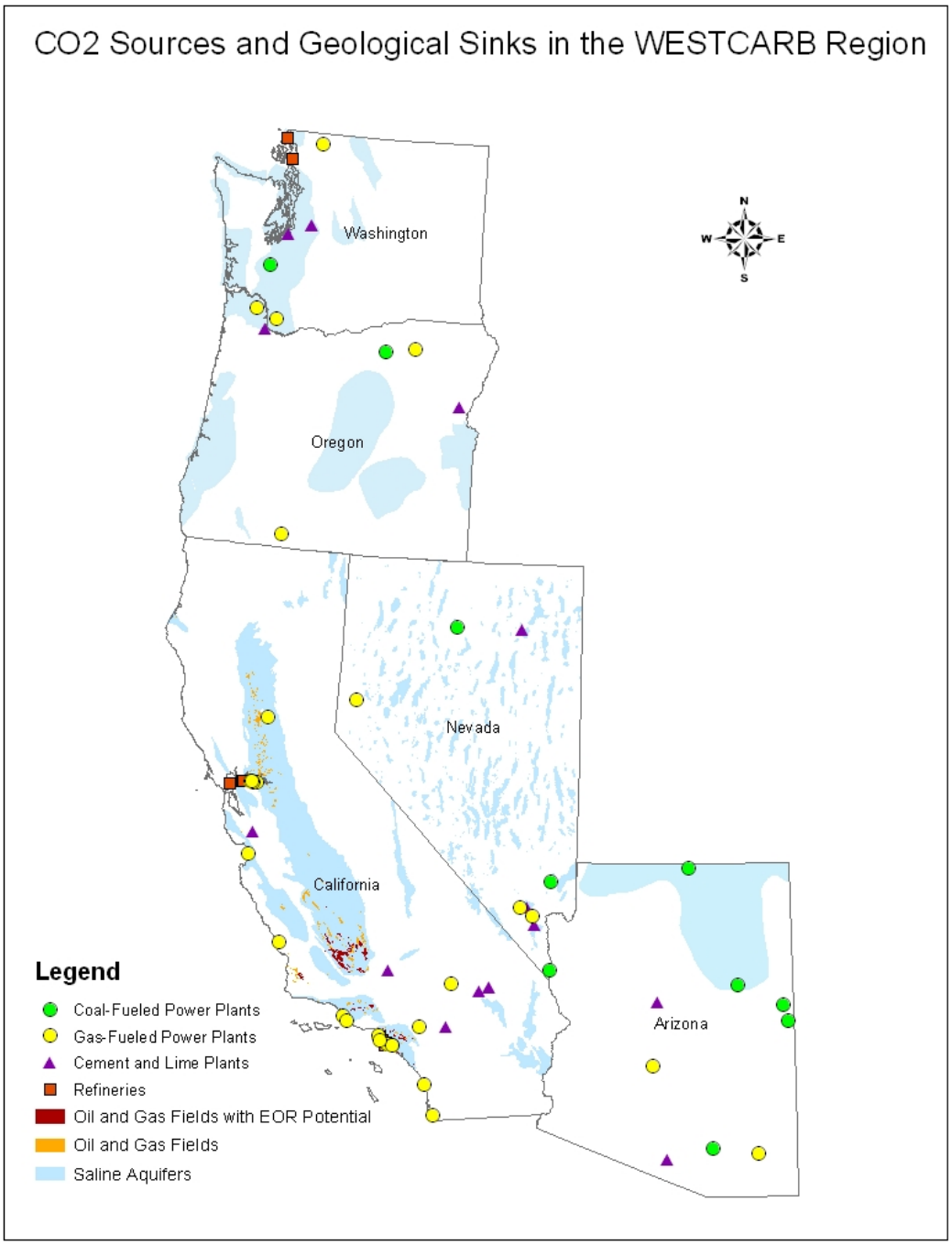


Figure 24. CO_2 sources and sinks in the WESTCARB region

Table 6. CO_2 storage capacity (Mt/yr) by marginal straight-line distance to nearest sink (Nevada aquifers included)

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in WC Region	154	174	176
All Sinks	154	174	176

Note:

The annual CO_2 storage rate was 184 Mt.

Table 7. CO_2 storage rate (Mt/yr) by marginal straight-line distance to nearest sinks (Nevada aquifers excluded)

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in WC Region Excluding Navada	139	168	176
All Sinks	139	168	176

Note:

The annual CO_2 storage rate was 184 Mt.

This study further presented a GIS-based method of matching sources and sinks considering the optimal pipeline route selection and sink's capacity constraint. The pipeline construction costs vary considerably according to local terrains, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks. In order to account for such obstacles, the locations and characteristics of these obstacles were loaded into the spatial database and were used to construct a single aggregate transportation obstacle layer. In contrast to the distance-based matching analysis, this least-cost matching analysis links each CO_2 source to a least-cost geological sink based on the sum of the transportation costs associated with the least-cost path and the injection cost subject to the sink's capacity constraint. An iterative algorithm was used to approximate an optimal system solution. Due to the limited availability of detailed sink data for the WESTCARB region, this least-cost matching analysis was only performed for California where the sink data set is relatively rich.

The least-cost source-sink matching analysis for California was conducted in two stages. In the first stage, only 35 EOR sites with storage capacity over 20 Mt[2] were included as candidate sinks, which results in an overall storage capacity of 3.2 Gt. The amount of

[2] Most of the CO_2 sources will emit more than 20 Mt CO_2 over the 25-year project lifetime.

CO_2 that needs to be sequestrated from the 31 CO_2 sources in California over 25 years was estimated to be 2.1 Gt. The cost calculation assumed a credit of $16/t CO_2 for EOR injection and omitted the injection cost. With the assumption of a constant CO_2 credit, the optimization algorithm only considers minimizing the overall transportation of the network system. Figure 25 shows the marginal per-tonne CO_2 transportation cost by annual CO_2 storage rate in oil fields with EOR potential. As the CO_2 storage capacity in the EOR sinks was larger than the 25-year CO_2 flow, all the sources were connected to their corresponding least-cost EOR sinks. The transportation costs for most of the sources are below $10/t CO_2 except for a few outliers.

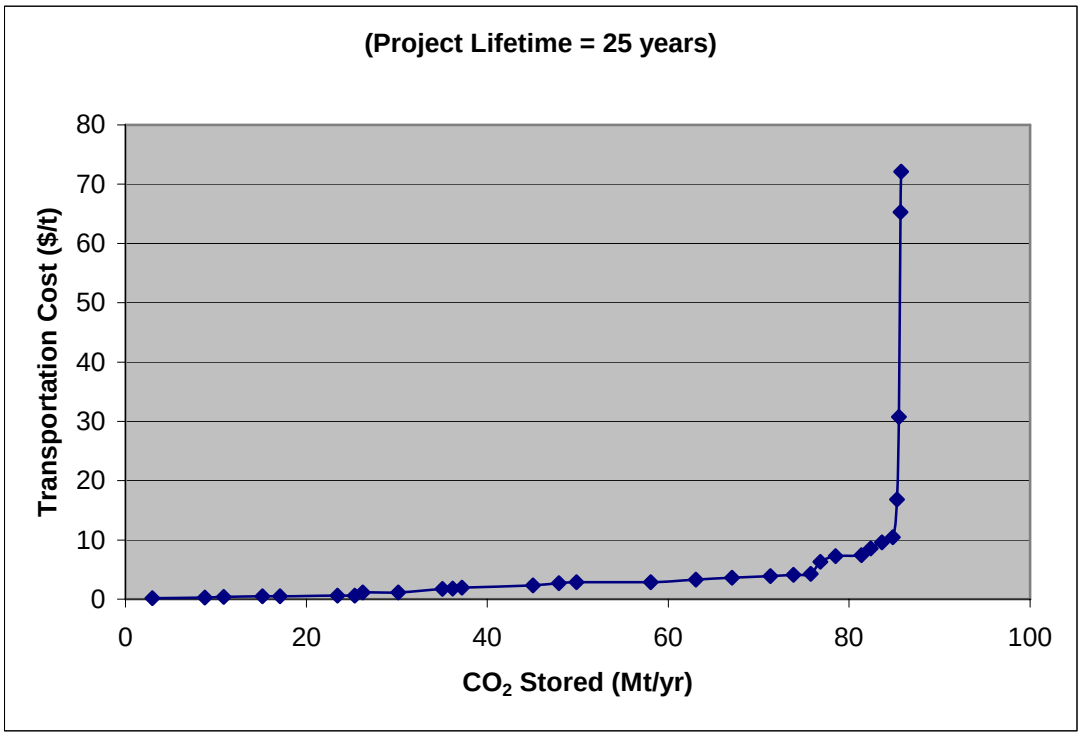


Figure 25. Marginal transportation cost by annual CO_2 storage rate in oil fields with EOR potential, California

Only four sources had transportation costs to the closest EOR site greater than the credit value of $16/t CO_2. For the second stage of least-cost source-sink matching analysis for California, a new round of source-sink matching was applied to these four sources with the same algorithm as before, but using the oil and gas fields without EOR potential and saline aquifers suitable for CO_2 storage in California as the sink layer instead. A final check was run to conduct a full-cost comparison to decide whether they should be matched to EOR or non-EOR sinks. Except for the source with transportation to EOR site of $16.8/t CO_2 that remained to be connected to its EOR destination, the other three sources were reassigned to saline aquifers instead because of the lower full costs.

Figure 26 shows the marginal full sequestration cost by annual CO_2 storage rate. For sources matched with EOR sites, the full cost estimate included costs for capture and transportation, net of an EOR credit. For sources matched with non-EOR hydrocarbon fields or aquifers, the full cost estimate included costs for capture, transportation, and injection. The results of the full cost sequestration analysis in California indicate that 20, 40, or 80 Mt of CO_2 per year could be sequestered in California at a cost of $31/t, $35/t, or $50/t, respectively.

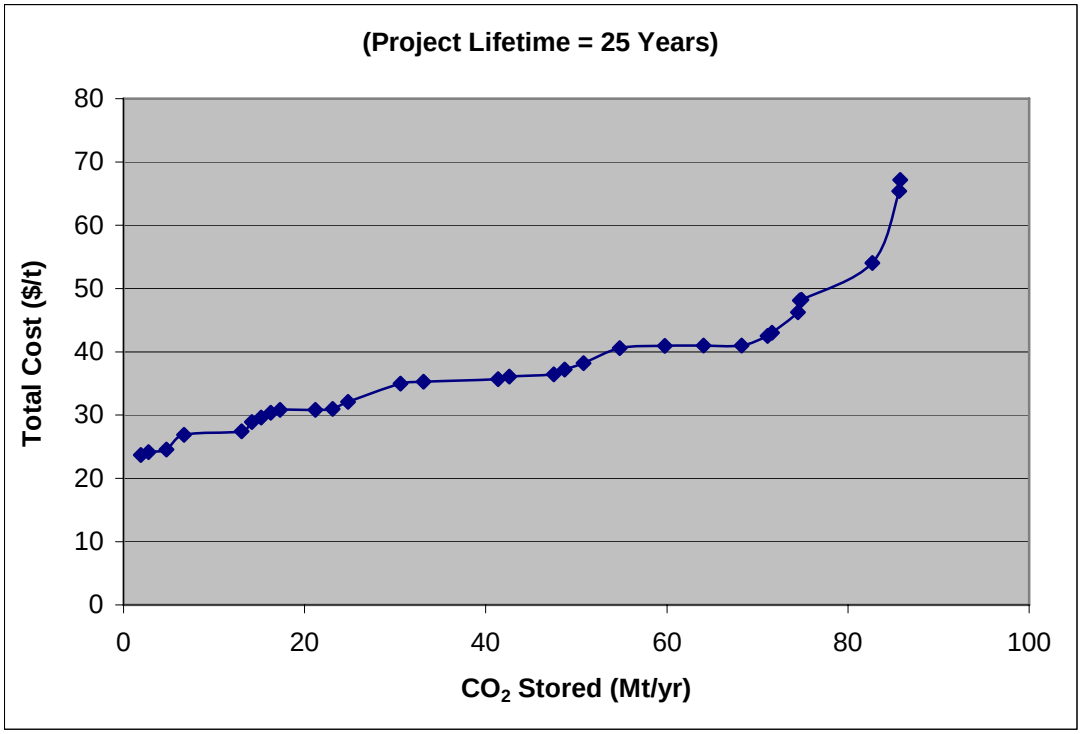


Figure 26. Marginal total cost by annual CO_2 storage rate, California

3.3 Selection of Phase II Pilots

3.3.1 Three-Step Decision Support Method

WESTCARB developed a consensus-based, three-step decision support method for evaluating potential geologic sequestration projects. A WESTCARB committee applied the method to rank the finalists for geologic pilots to be conducted during the WESTCARB Phase II project. The method involved a three step process:

Step 1: Establishing Evaluation Criteria and Scoring Guidelines

The method's first step produced consensus among evaluators on the major categories or criteria and the specific attributes or subcriteria by which candidate projects would be assessed. Scoring guidelines were then developed for each subcriterion.

Step 2: Assigning Weighting Factors to Criteria and Subcriteria

The second step produced consensus among evaluators on the relative importance of criteria and subcriteria. A commercial decision support software package (ExpertChoice) was used to develop the mathematical weighting factors based on a series of pair-wise comparisons among criteria and among subcriteria for each criterion.

Step 3: Scoring Candidate Pilot Projects

The third step produced consensus among evaluators on the score assigned to each candidate project for each subcriterion. The ExpertChoice software multiplied the criterion scores by the weighting factors to calculate composite scores for each project. The projects were then ranked by order of their score.

3.3.2 Application for Phase II Pilot Project Selection

In the case of our Phase II pilot evaluations, consensus on the major criteria, subcriteria, and scoring guidelines was achieved by circulating a "strawman" list and sharing comments and suggestions via e-mail until a mutually agreed upon set was established. The strawman list drew from basic geologic requirements for successful sequestration, pilot project experience (both generally and sequestration-specific, including Frio), and initial reservoir-scale decision analysis criteria developed by several WESTCARB partners. Some subcriteria were derived from cost-share and related requirements in DOE's Phase II Request For Proposals. Table 8 shows the resulting scoring guidelines, organized by major criteria and subcriteria.

Evaluators then met in-person to conduct the joint exercise in assigning weighting factors for the 5 criteria and 22 total subcriteria and scoring of the 5 finalist projects. The group of 6 evaluators found it could readily discuss and agree upon the relative importance of weighting factors and the project scores (as opposed to strong differences of opinion requiring individual voting). The evaluators were satisfied with the decision support method, finding it workable and objective. They also found the ExpertChoice software to be a handy tool for tabulating and graphically displaying results. The two projects with the highest scores—a combined enhanced gas recovery and saline formation injection project and a saline formation injection project near a major coal-fired power plant—were selected for inclusion in the WESTCARB Phase II proposal. The Action Plan for implementing these pilots during the Phase II WESTCARB project is found in Appendix XXII.

Table 8. WESTCARB Phase II geologic pilot scoring guidelines

MAJOR CRITERIA	Subcriteria	Scoring Guidelines
Partner Commitment	Amount of cost share	No cost share (0.0)
		Less than 10% cost share (0.2)
		10-20% cost share (0.5)
		20% cost share (0.8)
		Greater than 20% cost share (1.0)
	Site selected	No location selected (0.0)
		Suitable location selected but no specific site selected (0.25)
		Location and site(s) selected (0.5)
		Site(s) characterized (0.75)
		Injection well(s) selected (1.0)
	Level of executive interest	No or unknown executive interest (0.0)
		Letter of support under development (0.25)
		Letter of support from senior management (0.5)
		Extensive interest and letter of support from senior manager (with no specific cost share commitment) (0.75)
		Extensive interest and letter of support from management specifying cost share commitment (1.0)
	Commitment of internal staff resources	No or unknown commitment of internal staff resources (0.0)
		Low commitment of internal staff resources (0.25)
		Moderate commitment of internal staff resources (0.5)
		High commitment of internal staff resources (0.8)
		Committed and named internal resources (1.0)
	Degree of interest and awareness of climate change issues	No interest/awareness (0.0)
		Low degree of interest/awareness (0.33)
		Moderate degree of interest/awareness (0.66)
		High degree of interest/awareness (1.0)
	Unique technology (relative to other pilots)	Other sequestration pilots in same field/application or formation (0.0)
		“Typical” EOR or injection to saline formation, but first in reservoir (0.5)
		First-of-a-kind demo of new technology (1.0)
Geological	Extent of pre-existing site	No characterization (0.0)

MAJOR CRITERIA	Subcriteria	Scoring Guidelines
Characteristics	characterization	Partially characterized (0.4)
		Partially characterized with continued characterization under way (0.6)
		Fully characterized (0.8)
		Fully characterized with available well log data (1.0)
	Suitability of storage formation (confidence in permeability, no abandoned wells, etc.)	Unsuitable (0.0)
		Unknown but plausible suitability (0.25)
		High confidence in reasonable suitability, or limited information suggesting good suitability (0.5)
		Expectation of excellent suitability (0.75)
		High confidence in excellent suitability (1.0)
	Presence of adequate caprock (confidence in permanence)	No caprock (0.0)
		Unknown caprock (0.2)
		Fractured caprock (0.5)
		Adequate caprock (1.0)
	Depth between 1000 and 1500 m (deep enough for supercritical storage, but not too deep so that drilling costs are excessive)	No (0.0)
		Deeper than 1500 m (0.5)
		Yes (1.0)
	Potentially representative of large sink	Relatively unrepresentative or unknown (0.2)
		Very representative of a modest sink; near, but not beneath, major point sources (0.4)
		Moderately representative of one of the region's major sinks or very representative of a modest sink; underlying or near major point sources (0.6)
		Very representative of one of the region's major sinks; near, but not beneath, major point sources (0.8)
		Very representative of one of the region's major sinks; underlying major point sources (1.0)
Regulatory Climate	Clear regulatory authority	No (0.0)
		Partially (0.5)
		Yes (1.0)
	Regulators' experience with deep underground injection in relevant formations	No experience (0.0)
		Minimal or unknown level of experience (0.33)
		Moderate level of experience (0.66)
		Extensive experience (1.0)
	Regulators' experience with Class V or Class I permits	No experience (0.0)
		Minimal or unknown level of experience (0.33)

MAJOR CRITERIA	Subcriteria	Scoring Guidelines
		Moderate level of experience (0.66)
		Extensive experience (1.0)
	Regulators' interest in project	No interest (0)
		Low or unknown interest (0.33)
		Moderate interest (0.66)
		High interest (1.0)
Community Involvement and Concern	Size of local population	Urban (0.0)
		Suburban/vacation area (0.33)
		Rural towns and ranches/timber (0.66)
		Remote (1.0)
	Pre-existing favorable opinion about (or proximity to) injection operations	Strongly negative (0.0)
		Moderately negative (0.25)
		No opinion/neutral (0.5)
		Moderately favorable (0.75)
		Strongly favorable (1.0)
	Extent of active "NIMBY-type" community based organizations	Very well organized, very active organizations (0.0)
		Very active organizations (0.2)
		Moderately active organizations (0.4)
		No organizations (1.0)
	Presence of local educational institutions (respected community members who might corroborate sequestration value)	Elementary or K-12 only (0)
		Community college (0.5)
		One or more universities (0.8)
		Major research university (1.0)
Future Benefits	Prospect for economic opportunity (*e.g.*, EOR or EGR)	Low (0.0)
		Medium (0.5)
		High (1.0)
	Likelihood of using site for future integrated pilot and/or large-scale storage project	Unlikely (0.0)
		Moderately likely (0.5)
		Very likely (0.75)
		Very likely; underlying major point source (1.0)
	Local interest in sequestration associated job growth	No interest (0)
		Low interest (0.33)
		Moderate interest (0.66)
		High interest (1.0)

3.4 Technology Deployment Issues

3.4.1 Regulatory Framework

3.4.1.1 Geologic Sequestration

Injection of CO_2 into geologic formations requires an Underground Injection Control (UIC) permit from EPA. The UIC Program was established under the provisions of the Safe Drinking Water Act of 1974 to protect underground sources of useable water. Under this program, five classifications of wells were established:

- Class I – wells used to inject liquid hazardous wastes, industrial non-hazardous liquid, and municipal wastewater beneath the lowermost drinking-water reservoir;
- Class II – wells used to dispose of fluids associated with the production of oil and natural gas, enhanced oil recovery, and storage of liquid hydrocarbon;
- Class III – wells used to inject fluids for the extraction of minerals;
- Class IV – wells used to dispose of hazardous or radioactive wastes into or above drinking water. EPA has banned the use of these Class IV wells; and
- Class V – wells not included in the other classes used to generally inject non-hazardous fluid into or above drinking water.

EPA has delegated primary regulatory authority to state agencies that have demonstrated an ability to implement UIC programs that meet EPA requirements. These states are referred to as "primacy states". In states that have not received primacy status, the responsible permitting agency is EPA.

The regulations on CO_2 injection wells are currently in flux. Regulations are best defined for injection into oil reservoirs where the CO_2 will be used for EOR. In this case, injection wells would be classified as Class II by all 6 western states in WESTCARB. The agencies responsible for permitting such wells, and the specific relevant regulations, are summarized in Table 9.

Table 9. Federal and state EOR permit requirements. (See the Appendix of Appendix XIII for an explanation of acronyms.)

STATE	REGULATING AGENCY	WELL/PERMIT TYPE	REGULATIONS CITED
Alaska	EPA OGCC share primacy w/EPA	Class IIR	40CFR144-148 20AAC25; 31 AK O&G Consvr. Act Ch31.05
Arizona	EPA no primacy w/state OGCC	Class II 2nd jurisdiction	40CFR144-148 12AAC7; ARS 27-516

	DEQ	Aquifer Protection Permit	ARS 49-241; 18AAC,Ch9
California	EPA DOGGR share primacy w/EPA	Class II	40CFR144-148 14CCR Div2, Ch2, 4; Public Resources Code 30262
Nevada	DEP DOM BLM	Class II (Interagency Cooperation between 3 agencies)	NAC445A.810 to 445A.925 NAC Ch522; NRS 445A.470 43CFR Ch2 Part3160
Oregon	DEQ DOGAMI	Class II Interagency cooperation	40CFR144-148; 44OAR340-044-0005 and Appendix A OAR Ch.632 Div. 10; ORS 520
Washington	Dept. of Ecology DNR	Class II (joint control)	40CFR144-148; WAC173-218 78.52 RCW

Currently, the regulatory framework for saline formation CO_2 injection wells is not well defined (see Appendix XIII for further discussion).

Regulations for CO_2 injection into coal beds for enhanced coal-bed methane (ECBM) recovery vary among the three WESTCARB states (Alaska, Arizona, and Washington) that have sizable deposits. Washington (primacy status) has permitted one Class II injection well for ECBM. Since ECBM deals with hydrocarbon recovery, it appears that CO_2 injection for ECBM would lead to a Class II classification. Storage of CO_2 in ECBM produces a significant amount of water during the initial injection phase, and the disposal of the water produced may require a National Pollutant Discharge and Elimination System permit (Veil, 2002). Additional information is found in Appendix XIII.

3.4.1.2 Terrestrial Sequestration

Both Federal and State agencies will require permits for any land-use changes or disturbances associated with forest terrestrial sequestration activities. The regulating agency and applicable statutes varies depending on land ownership. Table 10 provides a summary for Arizona; data for other WESTCARB states is found in Appendix XIII.

Table 10. Potential Arizona permits/contracts for land-use changes or disturbances. (See the Appendix of Appendix XIII for an explanation of acronyms.)

TYPE OF LAND		REGULATING AGENCY	REGULATIONS CITED
State land		State Land Dept. Dept. of Fish & Wildlife DEQ (Water Quality) U.S. Fish and Game	ARS Title 37-102 and 37-622 ARS Title 17 Ch3 AAC Title 18 Ch9 50CFR17
Federal land	USDA	USDA Dept. of Fish and Game U.S. Fish and Game	36CFR Ch1 part 1 ARS Title 17 Ch3 50CFR17
	USDI – National Parks	Not allowed	
	USDI – BLM	BLM Dept. of Fish and Game U.S. Fish and Game	43CFR part 5000-5510 ARS Title 17 Ch3 50CFR17
	USDI – Tribal land	USDI BLM Local tribunal	25CFR part1 and 163 All BLM regulations HR3826 (Tribal Forest Protection Act); local tribunal laws
Private land	Forest land	Same as State land	State land regulations
	Ranch land	County/city planning DEQ (Water Quality) Dept. of Fish and Game U.S. Fish and Game	Various county/city zoning codes AAC Title 18 Ch9 ARS Title 17 Ch3 50CFR17

3.4.2 Health and Environmental Risks

A demonstration of the SRF approach described in section 2.3.2 is provided by comparison of two potential CO_2 storage sites in California: the Rio Vista Gas Field and the Ventura Oil Field.

The Rio Vista Gas Field is located in the delta region of the Sacramento-San Joaquin Rivers in the Sacramento Basin of California, approximately 75 km (47 mi) northeast of San Francisco. Published materials and expert's knowledge of the geology of the area was used to fill in values in the SRF spreadsheet and arrive at overall attribute assessments and certainties for the Rio Vista Gas Field. As shown in the Summary worksheet in Figure 27, the high attribute score displayed by the SRF spreadsheet reflects the very effective primary containment expected at Rio Vista. Secondary containment is not expected, as sealing formations above the Nortonville shale are largely absent; however, the attenuation potential is excellent at Rio Vista due largely to steady winds

and flat topography. As shown in the figure, confidence in the attribute assessments is quite high for subsurface and surface characteristics at Rio Vista because of the long history of gas production at the site. The high score and certainty at this site suggest that Rio Vista Gas Field is a good candidate for geologic CO_2 storage.

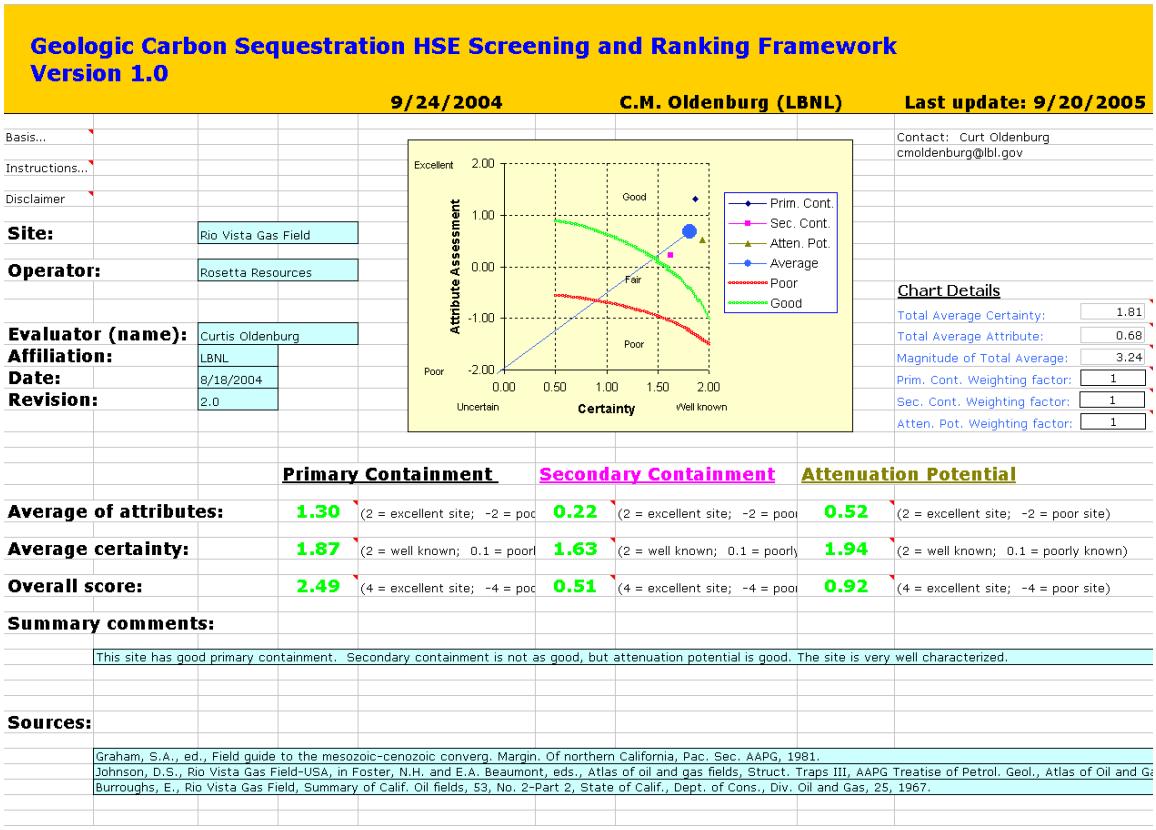


Figure 27. Summary graphic showing the attribute assessment (*y*-axis) and uncertainty (*x*-axis) of the three fundamental characteristics along with qualitative regions of poor, fair, and good HSE risk for the Rio Vista Gas Field

The Ventura Oil Field taps reservoirs in young folds and fault traps of marine sediments in the tectonically active coastal area northwest of Ventura, California. As shown in Figure 28, the Ventura Oil Field comes out worse on average than the Rio Vista Gas Field (Figure 27). The very significant oil accumulations at Ventura indicate that good traps exist, but the evidence of widespread oil and tar seepage along with the lack of significant natural gas accumulation suggest that pathways to the surface also exist. As for secondary containment, some of the oil reservoirs in the area are quite shallow, suggesting that secondary containment may occur but there is a high degree of uncertainty, especially in light of the abundant seepage. As for attenuation potential, the Ventura area is highly dissected with steep canyons that do not promote dispersion of seeping CO_2. There is also considerable population and agriculture to the southeast,

which could be exposed to seeping CO_2. Therefore, attenuation potential is also judged worse at Ventura than at Rio Vista.

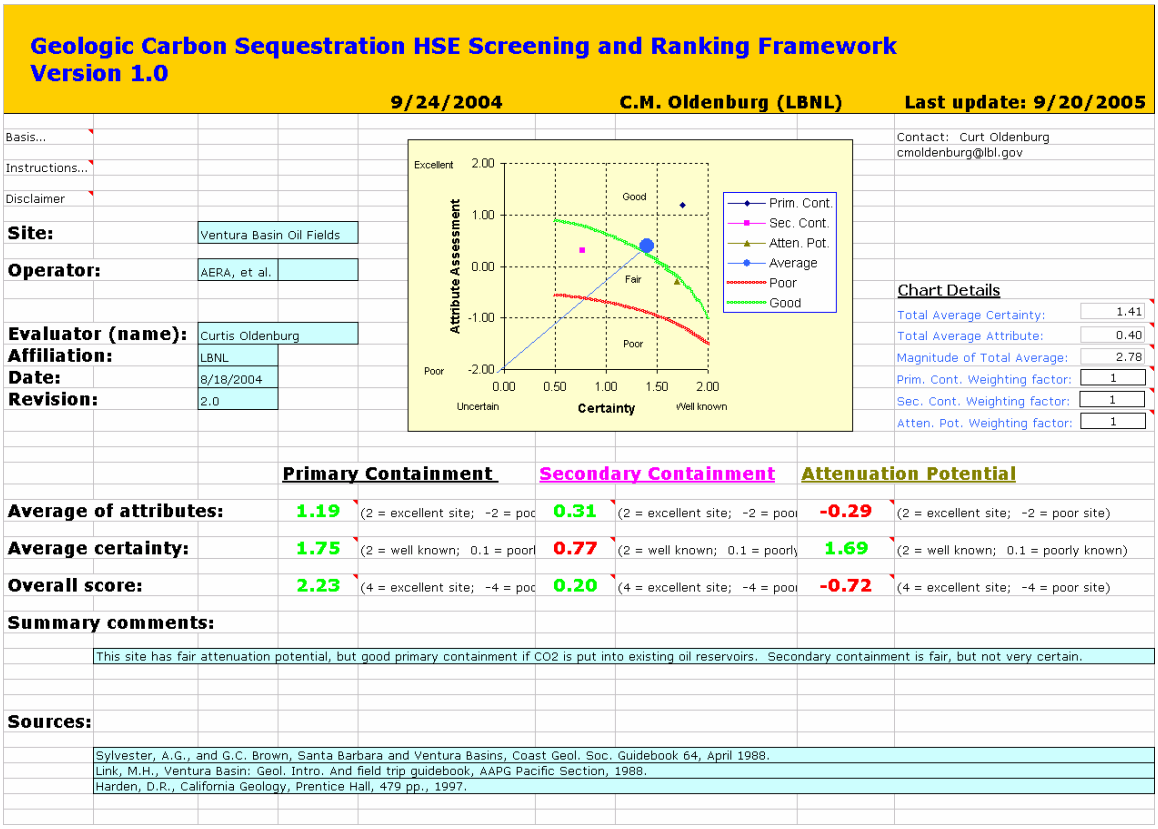


Figure 28. Summary worksheet showing the attribute assessment (*y*-axis) and uncertainty (*x*-axis) of the three fundamental characteristics for the Ventura Oil Field

Additional results and further discussion of the SRF approach are found in Appendix XII.

3.4.3 Monitoring and Verification

The time-lapse performance of seismic, gravity, and EM techniques were considered for the Schrader Bluff, Alaska, model. This model represented the most difficult end member of a complex spectrum of possible sequestration scenarios because of thin injection intervals with multiple fluid components (oil, hydrocarbon gas, brine, and CO_2). The spatial variations in the changes in the vertical component of gravity as well as the vertical gradient of the vertical component of gravity directly correlate with the spatial variations in the net density changes within the reservoir. Although the magnitude of the signals measured on the surface is in the noise level of the field survey, borehole measurements just above the reservoir do produce measurable change in the vertical component of gravity that could be used to map lateral distributions of injected CO_2. The

difference in both the borehole gravity response and the vertical gravity gradient measured in vertical profiles within boreholes clearly identifies the position of the reservoir. As shown in Figure 29, there is a clear change in seismic amplitude associated with the reservoir caused by the changes in water and CO_2 saturation (S_w and S_{CO2}, respectively). To produce the figure, the pressure response was sorted to common-depth-point (CDP) gathers, normal move-out corrected, and stacked to produce the sections for model years 2005 and 2020. The red line is a constant time horizon within the reservoir for reference. The 30 m (98 ft) reservoir interval is not uniform and is comprised of 5 m (16 ft) thick substrata, each of which has reflection coefficients at their top and base that vary with S_{CO2}. These sub-strata are all below the seismic tuning thickness, which produces a seismic response without a clear top and base reflector. There is a significant increase in S_{CO2} to the right of CDP 8412.5, producing the large change in the stacked sections shown in figure.

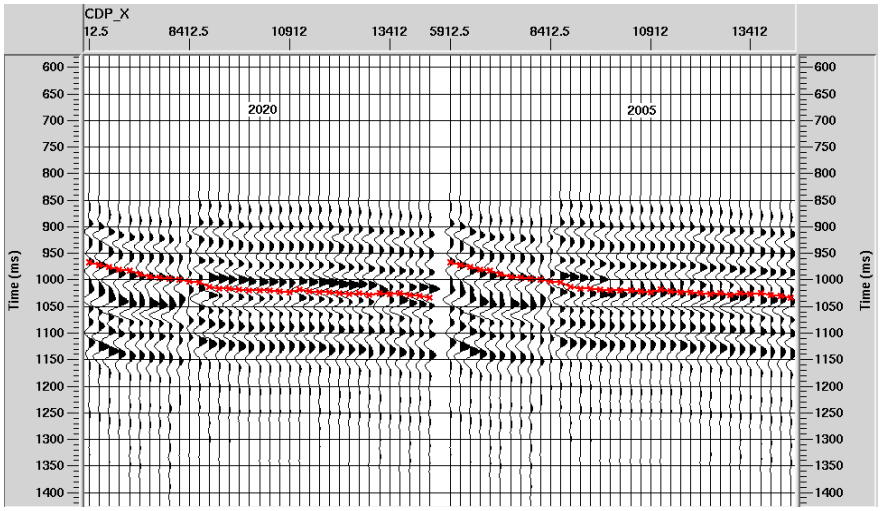


Figure 29. Stacked section for model years 2005 and 2020

In addition, modeling results show that there is a change in the seismic amplitude variation with offset (AVO). Both seismic amplitude and AVO can be exploited to make quantitative estimates of saturation changes. There is a direct one-to-one correspondence with the change in S_w and the change in the electric field amplitude. While this signal level is low, it can be measured given the signal-to-noise ratio of the data. While this represents a potential low-cost monitoring technique, it is best suited for CO_2-brine systems where there is a one-to-one correlation between the change in water saturation and the change in CO_2 saturation (since $S_w + S_{CO2} = 1$). In petroleum reservoirs such as Schrader Bluff, the presence of hydrocarbons as additional fluids eliminates the one-to-one correlation between changes in S_w and changes in S_{CO2}.

The seismic and gravity responses were simulated for a simplified flow simulation model of the Rio Vista gas field in the Sacramento Basin of California. Models were used to calculate anticipated contrasts in seismic velocity, density, and impedance in gas-

saturated rock when CO_2 is introduced. Numerical simulations were performed to evaluate whether a CO_2-CH_4 front can be monitored using seismic and/or gravity. For the model parameters used in this study, the changes in reservoir properties are very small and neither gravity nor seismic methods would provide information necessary for monitoring of CO_2 movement.

Additional information on both the Schrader Bluff and Rio Vista monitoring studies is found in Appendix XIV.

3.4.4 Life Cycle Analyses

Spreadsheets described in Section 2.3.4 were used to assess the impact on emissions of retrofitting current power generating plants in WESTCARB. Results are shown in Tables 11 and 12. Table 11 shows the existing, retrofit, and change in emissions for WESTCARB states, and for the Region. Table 12 presents the same type of comparison for fuel types. The results reflect key assumptions made on the proportion of gas and coal used for replacement power. It is interesting to note that, for the Regional case where all plants are retrofit with CO_2 control, and replacement power is split 50/50 between gas turbine combined cycle (GTCC) and coal, the CO_2 and SO_2 emissions are reduced but the NOx and mercury are increased. This is due to the criteria set for the retrofits, which are thought to be reasonable, but certainly have a range of alternative conditions.

Table 11. Report example for the states and the region

		Alaska			Arizona		
		Existing	Retrofit	Delta Emissions1	Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		905	726		7,977	6,166	
GROSS GENERATION CAPACITY, MWe		933	798		8,406	6,932	
PLANT CAPACITY FACTOR		0.42	0.42		0.63	0.63	
ANNUAL GENERATION MWh		3,353,621	2,687,518		44,187,217	37,607,268	
PLANT HEAT RATE, Btu/kWh		10,671	13,315		11,327	13,309	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		77.41%	77.41%	
NOx CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		89.34%	89.34%	
PRIMARY FUEL		Portions Below	Portions Below		Portions Below	Portions Below	
COAL		0.06	0.06		0.92	0.92	
OIL		0.10	0.10		0.00	0.00	
NATURAL GAS		0.84	0.84		0.08	0.08	
SO2 EMISSION	Tons Per Year	2,712	1,117	(1,600)	71,316	3,605	(65,530)
NOX EMISSION	Tons Per Year	7,477	7,477	90	93,877	93,877	4,460
MERCURY	Lb Per Year	13	13	-	1,432	1,432	113
CO2 EMISSION	Tons Per Year	2,288,594	228,859	(1,667,000)	49,146,500	4,914,650	(38,603,800)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

1. Assumes all replacement power is supplied by GTCC units.
2. Assumes 50% of replacement power is supplied by GTCC units and 50% by coal units.

		California			Nevada		
		Existing	Retrofit	Delta Emissions1	Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		18,713	15,035		4,604	3,592	
GROSS GENERATION CAPACITY, MWe		19,274	16,522		4,825	4,016	
PLANT CAPACITY FACTOR		0.38	0.38		0.66	0.66	
ANNUAL GENERATION MWh		62,564,201	50,267,597		26,607,155	20,644,562	
PLANT HEAT RATE, Btu/kWh		10,456	13,014		10,253	13,214	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		19.08%	19.08%	
NOx CONTROL, % OF GEN. CAPACITY		100.00%	100.00%		45.22%	45.22%	
PRIMARY FUEL		Portions Below	Portions Below		Portions Below	Portions Below	
COAL		-	-		0.71	0.71	
OIL		0.00	0.00		0.00	0.00	
NATURAL GAS		1.00	1.00		0.29	0.29	
SO2 EMISSION	Tons Per Year	312	156	(160)	53,100	2,715	(48,400)
NOX EMISSION	Tons Per Year	19,891	19,891	1,720	46,883	46,883	4,050
MERCURY	Lb Per Year	-	-	-	366	366	103
CO2 EMISSION	Tons Per Year	38,598,164	3,859,816	(27,488,200)	24,766,010	2,476,601	(17,174,900)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

		Oregon			Washington		
		Existing	Retrofit	Delta Emissions1	Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		1,768	1,399		1,954	1,513	
GROSS GENERATION CAPACITY, MWe		1,838	1,551		2,056	1,699	
PLANT CAPACITY FACTOR		0.70	0.70		0.73	0.73	
ANNUAL GENERATION MWh		10,844,263	8,566,558		12,422,893	9,618,277	
PLANT HEAT RATE, Btu/kWh		8,908	11,276		10,493	13,553	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		0.00%	0.00%	
NOx CONTROL, % OF GEN. CAPACITY		100.00%	100.00%		25.27%	25.27%	
PRIMARY FUEL		Portions Below	Portions Below		Portions Below	Portions Below	
COAL		0.35	0.35		0.83	0.83	
OIL		0.00	0.00		0.01	0.01	
NATURAL GAS		0.65	0.65		0.16	0.16	
SO2 EMISSION	Tons Per Year	14,461	762	(13,700)	83,777	4,269	(78,580)
NOX EMISSION	Tons Per Year	13,298	13,298	320	20,638	20,638	1,890
MERCURY	Lb Per Year	165	165	-	578	578	48
CO2 EMISSION	Tons Per Year	7,398,759	739,876	(5,315,900)	12,102,561	1,210,256	(8,502,100)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

		WESTCARB		
		Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		35,921	28,432	
GROSS GENERATION CAPACITY, MWe		37,332	31,519	
PLANT CAPACITY FACTOR		0.51	0.51	
ANNUAL GENERATION MWh		159,979,349	129,391,779	
PLANT HEAT RATE, Btu/kWh		10,565	13,063	
INSTALLED CONTROL EQUIPMENT				
SO2 CONTROL, % OF GEN. CAPACITY		19.64%	19.64%	
NOx CONTROL, % OF GEN. CAPACITY		84.03%	84.03%	
PRIMARY FUEL		Portions Below	Portions Below	
COAL		0.46	0.46	
OIL		0.00	0.00	
NATURAL GAS		0.54	0.54	
SO2 EMISSION	Tons Per Year	225,678	12,623	(202,950)
NOX EMISSION	Tons Per Year	202,063	202,063	20,640
MERCURY	Lb Per Year	2,554	2,554	525
CO2 EMISSION	Tons Per Year	134,300,588	13,430,059	(94,779,500)
SOLID WASTE	Tons Per Year	na	na	na

Table 12. Report example for types of fuel

		Coal			Natural Gas		
		Existing	Retrofit	Delta Emissions3	Existing	Retrofit	Delta Emissions4
NET GENERATION CAPACITY MWe		11,709	8,956		24,606	19,770	
GROSS GENERATION CAPACITY, MWe		12,412	10,132		25,345	21,726	
PLANT CAPACITY FACTOR		0.73	0.73		0.39	0.39	
ANNUAL GENERATION MWh		74,539,530	57,014,080		84,014,545	72,105,348	
PLANT HEAT RATE, Btu/kWh		11,136	14,559		10,340	12,235	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		56.04%	56.04%		0.00%	0.00%	
NOx CONTROL, % OF GEN. CAPACITY		66.54%	66.54%		93.05%	93.05%	
PRIMARY FUEL		Coal	Coal		Natural Gas	Natural Gas	
COAL		Not Applicable	Not Applicable		Not Applicable	Not Applicable	
OIL		Not Applicable	Not Applicable		Not Applicable	Not Applicable	
NATURAL GAS		Not Applicable	Not Applicable		Not Applicable	Not Applicable	
SO2 EMISSION	Tons Per Year	222,709	11,135	(200,010)	847	423	(420)
NOX EMISSION	Tons Per Year	155,693	155,693	21,180	44,783	44,783	1,660
MERCURY	Lb Per Year	2,554	2,554	601	-	-	-
CO2 EMISSION	Tons Per Year	83,351,430	8,335,143	(55,477,300)	52,171,849	5,217,185	(39,932,900)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

3. Assumes all replacement power is supplied by coal units.
4. Assumes all replacement power is supplied by GTCC units.

		Oil		
		Existing	Retrofit	Delta Emissions4
NET GENERATION CAPACITY MWe		193	155	
GROSS GENERATION CAPACITY, MWe		199	170	
PLANT CAPACITY FACTOR		0.20	0.20	
ANNUAL GENERATION MWh		339,034	272,351	
PLANT HEAT RATE, Btu/kWh		12,644	15,740	
INSTALLED CONTROL EQUIPMENT				
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%	
NOx CONTROL, % OF GEN. CAPACITY		0.00%	0.00%	
PRIMARY FUEL		Oil	Oil	
COAL		Not Applicable	Not Applicable	
OIL		Not Applicable	Not Applicable	
NATURAL GAS		Not Applicable	Not Applicable	
SO2 EMISSION	Tons Per Year	2,130	1,065	(1,060)
NOX EMISSION	Tons Per Year	1,726	1,726	10
MERCURY	Lb Per Year	-	-	-
CO2 EMISSION	Tons Per Year	342,195	34,219	(268,700)
SOLID WASTE	Tons Per Year	na	na	na

The above is one example of a possible application of the spreadsheet model; many others are possible by varying the input parameters. Additional information on the LCA analyses is found in Appendix XI.

3.5 Public Outreach

One of the WESTCARB's six primary goals is to promote public participation and education. The objective of Phase I Task 3, Implement Public Outreach, is to engage stakeholders and the public in an open dialogue on carbon sequestration technologies through multi-stakeholder public meetings, presentations at technical and policy-oriented conferences, and web and print media.

Three Phase I deliverable are associated with Task 3, Implement Public Outreach, and are summarized below: (1) education materials, (2) a summary of the multi-stakeholder public meeting, and (3) a Phase II action plan.

3.5.1 Public Outreach Education Materials

During Phase I, WESTCARB established a partnership website, http://www.westcarb.org, and produced numerous communications materials, including a fact sheet and meeting flyer, technical reports and papers, posters, news releases, and various PowerPoint presentations. WESTCARB also established web access to some of its GIS-based maps of CO_2 emission sources, geologic formations suitable for CO_2 storage, and terrestrial carbon storage baselines and supply curves for various timeframes.

All of these communication materials contribute to overall education on climate change issues, the potential role of carbon sequestration technology in mitigating adverse impacts, and WESTCARB's role in advancing our understanding of carbon sequestration opportunities. Within this body of materials, however, were several documents and web pages specifically developed as tutorials on these topics intended for general audiences. Appendix XVI contains a selection of those WESTCARB-produced tutorials.

3.5.2 Public Meeting Summary

WESTCARB held a "public forum" in Portland, Oregon, on October 27, 2004, targeted to public and private sector professionals, researchers, community leaders, and conservation/environmental groups. The half-day forum featured presentations in two panel sessions interspersed with Q&A time. The first panel addressed climate change science, its regional implications, technology/policy response options, and emerging initiatives in Oregon and Washington. This outstanding panel was composed of internationally known scientists and economists, senior representatives in state government, and a power company program manager. Their talks provided context for the second panel, comprised of WESTCARB members, who offered an overview of geologic and terrestrial sequestration and the DOE and WESTCARB programs.

About 55 people attended the forum, exceeding our expectations and nearly filling the room to capacity. About half were from WESTCARB member organizations, and half from our non-member target audience. Audience questions ranged from clarifying queries on basic climatic understanding to knowledgeable comments on current research. No contentious debate took place.

Preparations for the meeting involved audience segmentation, communication channel analysis, and crafting of direct mail and media outreach activities to reach target audiences (see Appendix XVII). Pre-meeting publicity included mailing a professional-looking flyer to more than 1000 people matching our target audience profile, and preparing news releases for local media, all of which are also included in Appendix XVII.

3.5.3 Public Outreach Strategy (Action Plan) for Phase II

WESTCARB plans to continue its successful Phase I public outreach activities (*i.e.*, web communications, handouts and mailing materials, presentations at key conferences and annual Partnership meetings, news releases to media) in Phase II, and to expand their scope to accommodate new information from the geologic and terrestrial sequestration pilot projects as well as continued characterization of the region. Planned activities are summarized in Appendix XVIII.

WESTCARB will hold general public meetings on an approximately annual basis (modeled after our successful 2004 public forum in Portland, Oregon) and pilot-project-specific public meetings on an as-needed basis. Meeting locations, even for the former, could coincide with pilot locations, or they may be held in major metropolitan areas or capital cities of the various WESTCARB states (to broaden exposure and facilitate education of the public and affiliated professionals). WESTCARB's annual business meetings will almost certainly be held in major metropolitan areas to reduce travel time and expense.

For each pilot project, and in conjunction with planning for environmental review and permitting, members of WESTCARB's Public Outreach Committee will meet with technical and public affairs representatives from the pilot host organization(s) to develop public outreach objectives, strategies, roles and responsibilities, activities, and points of contact for the project. Such plans will seek to gain stakeholder "buy in" for the project, and knowledge of local communities and any relevant histories or sensitivities will be key to successful outreach planning.

Communication activities are expected to include development of straightforward summaries of each pilot project's goals/rationale, activities, timetable, possible impacts, associated safety precautions, and benefits (in both broad terms and to the local community). These materials will be disseminated to residents, elected and safety officials, clergy, chambers of commerce, union stewards, civic group leaders, publishers of local media, employees of the pilot host, landowners, educators, and other stakeholders and concerned parties. We also expect that speaking engagements and exhibition opportunities at local venues will figure prominently in the outreach plans.

Opinion leaders will be identified and engaged in dialogue early in the process—through face-to-face meetings wherever possible. Such sessions will be designed not just to inform, but also to find areas of mutual interest (*e.g.*, expansion of local job opportunities), and to assure that community concerns are clearly understood by pilot project planners. Where advisable, WESTCARB and the pilot host organizations may engage locally trusted "key stakeholder communication facilitators" to assure effective dialogue with community leaders and/or participate in negotiations regarding permit terms and conditions.

Our planned terrestrial pilot projects involve an added challenge: they are "decentralized," and involve a suite of voluntary activities on multiple lands owned by multiple types of entities with varying objectives. Accordingly, WESTCARB plans to engage industry associations to help prepare and disseminate project materials to the forest products industry and private commercial forest owners.

WESTCARB will aggregate and report pilot project activities to the California Climate Action Registry (CCAR) and The Climate Trust in Oregon. CCAR will use the pilot projects to "road test" the forest protocols it has developed for afforestation and conservation and may use the fuel treatment pilot activities to facilitate development of new protocols for fire management. Although the ultimate aim of the pilot projects is to register certified marketable emission reductions with CCAR and The Climate Trust, WESTCARB is generally seeking to demonstrate that the applicable forest protocols are practical and functionally effective. Validation by CCAR and The Climate Trust provides public visibility for project activities and responds to the concerns and interests of a broad range of stakeholders.

To obtain an objective assessment of its public outreach activities (and to guide their refinement), WESTCARB will support independent university researchers conducting interviews and surveys to measure public perception of carbon sequestration in communities near Rio Vista, CA (*i.e.*, with a local geologic pilot) vs. similar "control" communities without pilot projects, and the effectiveness of outreach materials (or endorsements by others) in educating the public, addressing their concerns, and influencing their opinion.

Finally, WESTCARB will continue to coordinate its outreach activities with other Regional Partnerships through the Outreach Working Group and select joint activities.

3.6 Terrestrial Sequestration

3.6.1 Baselines

3.6.1.1 Washington

General Forestlands Baseline

Forest area and carbon stocks were derived from U.S. Forest Service (USFS) published data for the period 1987 to 1997. An extrapolation was made for the period 1997 to 2003

using recently completed USFS inventory data. Between 1987 and 2003 forest area in Washington decreased by 0.9 million acres. Rates of loss between 1987–1997 were 62,000 ac per year, and slowed to 49,000 ac/yr between 1997 and 2003 (Table 13). This is equivalent to a gross emission of 187 $MMTCO_2e$ or 12.5 $MMTCO_2e$/yr between 1987–1997, and 10.1 $MMTCO_2e$/yr between 1997 and 2003.

Table 13. Gross change in forest* area and forest carbon stocks in Washington

	1987	1997	2003	Annual Change 1987–1997	Annual Change 1997–2003
Area (million ac)	22.5	21.9	21.6	-0.062	-0.049
Carbon stock ($MMTCO_2e$)	3,091	2,965	2,904	-12.6	-10.1

*Includes all forests, federal and non-federal

The values presented here are gross emissions and will be reduced when consideration of the storage in dead wood and wood products pools are included. However, the emissions from forests are undoubtedly a significant proportion of the total emissions for the State of Washington, estimated to be 101 $MMTCO_2e$ in the year 1995.

Baseline for Development on Forest Lands

The baseline for emissions from development was created using land use data from the National Resources Inventory of the USDA and carbon data derived from the USFS Forest Inventory and Analysis Database (FIA). Due to data availability, the period chosen was 1987 to 1997. Due to data limitations the analysis is limited to non-federal forests and to the gross CO_2 emissions from aboveground live tree biomass on conversion of non-federal forestland to developed land uses. As the focus is on non-federal lands the analyses should only be used to explore decisions on private lands.
Between 1987 and 1997, 246,000 acres of non-federal forest were converted to development. Large losses were concentrated in the coastal regions.

For gross carbon emissions, two scenarios were considered. Under Scenario 1, all tree biomass in the converted area was immediately emitted as CO_2. Under Scenario 2 for developed areas of less than 10 acres, it was assumed that 50% of the carbon was retained in the form of residual trees. Under Scenario 1, an estimated 70.3 $MMTCO_2e$ were emitted for the 10-year period due to development. Under Scenario 2, 65.4 $MMTCO_2e$ were emitted. Development was concentrated in the Puget Sound region where the major city of Seattle is located (Table 14). In this region 60% of the emissions under scenario 1, or 56% of the emissions under scenario 2 occurred, despite the fact that the region represents only 16% of the area of the state.

Table 14. Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development on non-federal forests. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development.

	Area lost (ac)	Carbon emissions ($MMTCO_2e$) Scenario 1	Scenario 2
Puget Sound	138,500	42.3	39.4
Olympic	53,800	16.4	15.3
southwest	30,000	8.2	7.5
central	20,100	2.9	2.7
Inland Empire	3,300	0.6	0.6
TOTAL	245,700	70.3	65.4

The emissions from development on non-federal lands of 6.5–7.3 $MMTCO_2e$/yr represent between 52 and 55% of the total gross emissions from the forest sector (12.6 $MMTCO_2e$/yr between 1987 and 1997). Compared to total emissions for the state as a whole, 101 $MMTCO_2e$/yr for the year 1995 (Kerstetter, 1999), emissions from deforestation on non-federal land represent more than 5% of the total in the state.

Baseline Effect of Fire on Forest Lands

Emissions from fire were examined through overlaying the wildfire database for Washington (point data and an estimate of aerial extent) on Advanced Very High Resolution Radiometer (AVHRR) satellite imagery showing change in NDVI (normalized differential vegetation index). (NDVI measures 'greenness' of landscapes, greenness decreases immediately after fire.) This process determined the location, size and estimated intensity (based on degree of change in the NDVI) of fires between 1990 and 1996[3]. Carbon values were applied to these areas burned using data from the USDA FIA and proportional emissions from the detailed baseline fire analysis for California.

The analysis considered all forests and rangelands in Arizona, federal and non-federal. Across the six years analyzed, a total area of 70,800 hectares (0.175 million acres) of fire was recorded. This is equivalent to an average 11,800 hectares per year (29,200 ac/yr) for the period studied. Emissions totaling 1.07 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. On an averaged annual basis this is equal to 0.18 $MMTCO_2e$/yr.

Thirty-three percent of the burned area and 87% of the emissions were in forest rather than rangeland. No one year dominated fire incidence. Fifty-five percent of area burned and 44% of the emissions were from private land. Fires covered a greater extent and

[3] 1994 was excluded due to poor image quality.

caused more emissions in the north and northeast of the state. Incidence was low in the southeast and northwest.

Compared to total emissions for the state as a whole, 101 $MMTCO_2e$/yr for the year 1995, the average annual emissions from fire of 0.18 MMTCO2e represented more than 0.2% of the total in the state. However, data limitations led to the exclusion of fires from 1994. Unfortunately 1994 was a year with a total area burned that was five times greater than the average annual burn between 1970 and 2003. The inclusion of 1994 would have significantly raised the average annual emissions due to fire.

Baseline for Agricultural Lands

Agricultural land in Washington amounts to almost 15% of the total land area. The state lost agricultural land area from 1987–1997 through conversion to other land uses, in particular to urban development/transportation and the retiring of agricultural land from cultivation. In some counties, the area of woody cropland increased, but these increases were more than offset by decreases in non-woody cropland. Accompanying these losses in area were losses in standing carbon stocks on agricultural land, so that conversion of agricultural land to other uses was responsible for a net annual emission of CO_2 to the atmosphere of 0.05 $MMTCO_2eq$/yr (Table 15).

Table 15. Summary of agricultural land area and changes in area, carbon stocks and changes in stocks for Washington 1987–1997

Parameter	Units	Results
Proportion of agricultural land to total land	%	14.6
Change in agricultural land area, 1987–1997	Hectares (%)	-234,486 (8%)
Change in woody cropland area		+43,828 (37%)
Change in non-woody cropland area		-278,314 (9.9%)
Total carbon stocks in agricultural land, 1997	$MMTCO_2e$	22.9
Change in carbon stocks in agricultural land,	$MMTCO_2e$	-0.5
Estimated net annual source (emissions) from agricultural lands, disregarding non-CO_2 greenhouse gas emissions	$MMTCO_2e$	-0.05
From woody cropland		+0.1
From non-woody cropland		-0.15
Estimated net annual source from non-CO_2 greenhouse gas emissions, 1995	$MMTCO_2e$	-3.54

Emissions of CO_2 from agricultural land conversion, while the primary focus of this report due to data availability, represent only a portion of the total greenhouse gas emissions attributable to the agricultural sector. The primary non-CO_2 greenhouse gas associated with agricultural activities, emitted from agricultural soils especially after fertilizer application, is nitrous oxide (N_2O), with approximately 296 times the global warming potential of CO_2. Examination of data from Washington indicated that greenhouse gas emissions from N_2O in the agricultural sector dwarf the annual CO_2 source from agricultural land conversion: CO_2 emissions from land conversion represented about 1.4% of the total CO_2 and non-CO_2 greenhouse gas emissions attributable to the agricultural sector.

Additional information is found in Appendix IV.

3.6.1.2 Oregon

General Forest Baselines

Forest area and carbon stocks were derived from USFS published data for the period 1987–1997. An extrapolation was made from 1997 to 2003 using recently completed USFS inventory data. Between 1987 and 2003, there was an estimated increase in forest area in Oregon of 2.1 million acres or 94,000 acres per year between 1987 and 1997 and 175,000 ac/yr between 1997 and 2003 (Table 16). This is equivalent to an estimated increase of 431 $MMTCO_2e$ between 1987 and 2003 or 23.0 $MMTCO_2e$/yr between 1987 and 1997, and 34.4 $MMTCO_2e$/yr between 1997 and 2003.

Table 16. Gross change in forest* area and forest carbon stocks in Oregon

	1987	1997	2003	Annual Change 1987–1997	Annual Change 1997–2003
Area (million ac)	28.7	29.7	30.8	0.094	0.175
Carbon stock ($MMTCO_2e$)	3,327	3,557	3,763	23.0	34.4

*Includes all forests, federal and non-federal

The total emissions for Oregon (excluding forests) for the year 2000 were estimated as 67.7 $MMTCO_2e$ (from Governor's Advisory Group on Global Warming). Forest sinks, therefore, potentially can offset as much as 50% of the state's emissions.

Baseline Effect of Development on Forest Lands

The baseline for emissions from development on non-federal lands was estimated using land use data from the National Resources Inventory of the USDA and carbon data derived from the USFS FIA for the period 1987 to 1997. Due to data limitations the

analysis is limited non-federal lands and to the gross CO_2 emissions from aboveground live tree biomass on conversion of non-federal forestland to developed land uses. As the focus is on non-federal lands the analyses should only be used to explore decisions on private lands. Between 1987 and 1997, 69,000 acres of non-federal forest were converted to development. This is equal to 6,900 acres per year. Large losses were concentrated in the coastal regions.

For gross carbon emissions, two scenarios were considered. Under Scenario 1, all tree biomass in the converted area was immediately emitted as CO_2. Under Scenario 2 for developed areas of less than 10 acres, it was assumed that 50% of the carbon was retained in the form of residual trees. Under Scenario 1, an estimated 15.4 $MMTCO_2e$ were emitted due to development or 1.54 $MMTCO_2e$/yr. Under Scenario 2, 13.9 $MMTCO_2e$ were emitted or 1.39 $MMTCO_2e$/yr. Development was concentrated in the northwest region of the state where the major city of Portland is located (Table 17). In this region 56% of the emissions under scenario 1, or 58% of the emissions under scenario 2 occurred, despite the fact that the region represents only 9% of the area of the state.

Table 17. Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development on non-federal forests. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development.

Region	Area lost (ac)	Carbon emissions ($MMTCO_2e$) Scenario 1	Scenario 2
northwest	35,000	8.6	8.1
west central	14,200	3.2	2.6
southwest	15,400	3.1	2.8
central	4,100	0.51	0.46
Blue Mtns.	200	0.02	0.02
TOTAL	68,900	15.4	13.9

The emissions from development on non-federal lands of 1.39–1.54 $MMTCO_2e$/yr represent about 2.3% of the total gross emissions for the state of 63 $MMTCO_2e$/yr in 1995 (from Governor's Advisory Group on Global Warming). Oregon's forests have a net sequestration of 22 $MMTCO_2e$/yr between 1987 and 1997 (see Table 16), after accounting for the emissions from development of about 1.4 $MMTCO_2e$/yr.

Baseline Effect of Fire on Forest Lands

The emissions from fire were examined through overlaying the wildfire database for Oregon on AVHRR satellite imagery showing change in NDVI. This process determined the location, size and intensity of fires between 1990 and 1996[4]. Carbon values were

[4] 1994 was excluded due to poor image quality.

applied to these fires using data from the USFS FIA and proportional emissions from the detailed baseline fire analysis for northern California.

The analysis considered all forests and rangelands in Arizona, federal and non-federal. Across the six years analyzed, fires with a total area of 328,000 hectares (0.81 million acres) were recorded. This is equivalent to an average 54,700 hectares per year (135,100 ac/yr) for the period studied. Emissions totaling 25.0 $MMTCO_2e$ were estimated to have occurred from fire during the 6-year period. On an average annual basis this is equal to 1.03 $MMTCO_2e/yr$.

Forty-eight percent of the burned area and 83% of the emissions were in forest rather than rangeland. Fire incidence varied by year with high emissions in 1996 and low impact in 1993 and 1995. Seventy-nine percent of area burned and 83% of the emissions were from Federally owned land, 18% of the area burned and 13% of the emissions were from private land. Emissions from fire occurred throughout the state but were markedly lower in the northwest.

The emissions from fire of 1.03 $MMTCO_2e/yr$ during the 6-year period represented about 1.6% of the total gross emissions for the state of 63 $MMTCO_2e/yr$ in 1995 (from Governor's Advisory Group on Global Warming).

Baseline for Agricultural lands

Agricultural land area in Oregon amounts to about 6% of the total land area. The state lost agricultural land area from 1987–1997 through conversion to other land uses, in particular to urban development/transportation and the retiring of agricultural land from cultivation. In some counties, the area of woody cropland actually increased, but these increases were more than offset by decreases in non-woody cropland. Accompanying these losses in area were losses in standing carbon stocks on agricultural land, so that conversion of agricultural land to other uses was responsible for a net annual source (emission) of CO_2 to the atmosphere. Losses of agricultural carbon stocks over the period 1987–1997 period estimated at 160,000 tons. The estimated net annual source from Oregon agricultural lands was 0.06 $MMTCO_2eq$ (Table 18).

Table 18. Summary of agricultural land area and changes in area, carbon stocks and changes in stocks for Oregon 1987–1997

Parameter	Units	Oregon
Proportion of agricultural land of total land	%	5.9
Change in agricultural land area, 1987–1997	Hectares (%)	-75,833 (4.8%)
Change in woody cropland area		-2301 (4.1%)
Change in non-woody cropland area		-73,532 (4.8%)
Total carbon stocks in agricultural land, 1997	$MMTCO_2e$	11.6
Change in carbon stocks in agricultural land,	$MMTCO_2e$	-0.6
Estimated net annual source (emissions) from agricultural lands, disregarding non-CO_2 greenhouse gas emissions	$MMTCO_2e$	-0.06
From woody cropland		-0.02
From non-woody cropland		-0.04
Estimated net annual source from non-CO_2 greenhouse gas emissions, 1995	$MMTCO_2e$	-3.8

Examination of data from Oregon indicated that greenhouse gas emissions from N_2O and CH_4 in the agricultural sector dwarf the annual CO_2 source from agricultural land conversion: CO_2 emissions from land conversion represented about 1% of the total CO_2 and non-CO_2 greenhouse gas emissions attributable to the agricultural sector.

Additional information is found in Appendix IV.

3.6.1.3 Arizona

General Forestlands Baseline

Between 1987 and 1997 there is an estimated increase in forest area in Arizona of 0.5 million acres or a mean of 54,000 ac per year (Table 19). This is equivalent to an increase of 9 $MMTCO_2e$ or 0.92 $MMTCO_2e$/yr between 1987 and 1997.

Table 19. Gross change in forest* area and forest carbon stocks in Arizona

	1987	1997	Annual Change 1987–1997
Area (million ac)	19.4	19.9	0.054
Carbon stock ($MMTCO_2e$)	1,229	1,238	0.92

*Includes all forests, federal and non-federal

This sequestration compares with the estimated sequestration in soil and forests reported by the Arizona Climate Change Advisory Group of 6.7 $MMTCO_2e$ in the year 2000. The estimate here is clearly substantially lower. However, some of this divergence can be accounted for by the inclusion of soil carbon sequestration in the Climate Change Advisory Group analysis. In addition, there is some uncertainty on whether the carbon is artificially inflated due to a USFS change in forest definition from 10% cover to 5% cover in the study period.

The Advisory Group further estimated the gross emissions for Arizona (excluding sinks) for the year 2000 as 99 $MMTCO_2e$. Sinks, therefore, potentially can offset as much as 7% of the state's emissions.

Baseline Effect of Development on Forest Lands

The baseline for emissions from development was created using land use data from the National Resources Inventory of the USDA and carbon data derived from the USFS FIA for the period 1987 to 1997. Due to data limitations the analysis is limited non-federal lands and to the gross CO_2 emissions from aboveground live tree biomass on conversion of non-federal forestland to developed land uses. As the focus is on non-federal lands the analyses should only be used to explore decisions on private lands.

Between 1987 and 1997 3,499 acres of non-federal forest were converted to development. All of this area was located in the north of the state. This is equal to just 350 ac per year. For gross carbon emissions two scenarios were considered. Under Scenario 1, all tree biomass in the converted area was immediately emitted as $_{CO2}$. Under Scenario 2 for developed areas of less than 10 acres, it was assumed that 50% of the carbon was retained in the form of residual trees. Under Scenario 1, an estimated 152,000 t CO_2e were emitted due to development or 15,200 t CO_2e/yr. Under Scenario 2, 145,000 t CO_2e were emitted or 14,500 t CO_2e/yr (Table 20).

Table 20. Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development on non-federal forests. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development.

	Area lost (ac)	Carbon emissions ($MMTCO_2e$)	
		Scenario 1	Scenario 2
southern	0	0	0
northern	3,500	0.152	0.145

These emissions compare with the estimated gross sequestration from non-federal forests in Arizona of 0.92 $MMTCO_2e$/yr between 1987 and 1997 (see Table 19) and gross emissions for the state of 99 $MMTCO_2e$/yr (from Arizona Climate Change Advisory Group). Emissions from deforestation therefore represent a fraction of a percent of the total emissions in the state.

Baseline Effect of Fire on Forest Lands

The emissions from fire were examined through overlaying the wildfire database for Arizona on AVHRR satellite imagery showing change in NDVI. This process determined the location, size and intensity of fires between 1990 and 1996. Carbon values were applied to these fires using data from the FIA and proportional emissions from the detailed baseline fire analysis for California. The analysis considered all forests and rangelands in Arizona, federal and non-federal.

Across the seven years analyzed fires with a total area of 437,700 hectares (1.08 million acres) were recorded. This is equivalent to 62,500 ha/yr or 154,000 acres/yr. Emissions totaling 904,000 tons of carbon or 3.3 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. This is equivalent to an emission of 0.47 $MMTCO_2e$/yr.

Eighty-five percent of the burned area was on rangelands but 42% of the emissions were from the 15% of burned area that was forest. Fire incidence varied by year with high emissions in 1993 to 1996 (> 168,000 t C) and low emissions between 1991 and 1992 (< 23,000 t C). Fires occurred throughout Arizona during the study period and there was no apparent geographical relationship between either area burned or carbon emissions from fire and geographic location.

These emissions compare with the estimated gross sequestration from forests in Arizona of 0.92 $MMTCO_2e$/yr between 1987 and 1997 (see above) and gross emissions for the state of 99 $MMTCO_2e$/yr (from Arizona Climate Change Advisory Group). During the analysis period, emissions from fire therefore represented almost 0.5% of the total emissions in the state.

Baseline for Agricultural Lands

Agricultural land area in Arizona amounts to about 1.5% of the total land area. The state lost agricultural land area during 1987–1997 through conversion to other land uses, in particular to urban development/transportation and the retiring of agricultural land from cultivation. In some counties, the area of woody cropland actually increased, but these increases were more than offset by decreases in non-woody cropland. Accompanying these losses in area were losses in standing carbon stocks on agricultural land, so that conversion of agricultural land to other uses was responsible for a net annual source (emission) of CO_2 to the atmosphere. Losses of agricultural carbon stocks over the 1987–1997 analysis period were estimated at 99,000 tons. The estimated net annual source from Arizona agricultural lands was 0.04 $MMTCO_2eq$ (Table 21).

Table 21. Summary of agricultural land area and changes in area, carbon stocks and changes in stocks for Arizona 1987–1997

Parameter	Units	Arizona
Proportion of agricultural land of total land	%	1.5
Change in agricultural land area, 1987–1997	Hectares (%)	-30,759 (6.6%)
Change in woody cropland area		+687 (2.3%)
Change in non-woody cropland area		-31,446 (7.2%)
Total carbon stocks in agricultural land, 1997	$MMTCO_2e$	3.5
Change in carbon stocks in agricultural land,	$MMTCO_2e$	-0.4
Estimated net annual source (emissions) from agricultural lands, disregarding non-CO_2 greenhouse gas emissions	$MMTCO_2e$	-0.04
From woody cropland		-0.02
From non-woody cropland		-0.02
Estimated net annual source from non-CO_2 greenhouse gas emissions, 2000	$MMTCO_2e$	4.2

Examination of data from Arizona indicated that greenhouse gas emissions from N_2O and CH_4 in the agricultural sector dwarf the annual CO_2 source from agricultural land conversion: CO_2 emissions from land conversion represented less than 1% of the total CO_2 and non-CO_2 greenhouse gas emissions attributable to the agricultural sector.

3.6.2 Supply Curves

3.6.2.1 Washington

The state of Washington's lands are classified into three main groups for the analyses: forests, rangelands, and agricultural lands. Forests (about 20.2 million acres) include conifers, hardwoods, and mixed classes; rangelands (about 11.7 million acres) include a variety of non-woody and woody ecosystems; and agricultural lands (about 9.6 million acres) include a wide range of non-woody crops such as wheat and hay and woody crops such as vineyards and orchards.

For rangelands and croplands (lands growing wheat and hay), the potential carbon sequestration was estimated for afforestation using native species. Historical evidence suggests that in many areas, large tracts of forest may have once stood where grazing and agricultural lands now do. The general approach was to identify and locate existing rangelands and croplands where biophysical conditions could favor forests, estimate rates of carbon accumulation for the forest types projected to grow, and assign values to each contributing cost factor. The carbon supply is estimated for three time durations: 20 years, 40 years and 80 years of forest growth, to reflect the impact of activity duration on the likely supply and to provide an assessment for the near-term and longer-term planning horizons.

For forestlands, potential carbon supply was estimated for three alternatives for 20-year and/or permanent contract periods: (1) allowing timber to age past economic maturity (lengthening rotation time); (2) increasing the riparian buffer zone by an additional 200 feet; and (3) hazardous fuel reduction in forests to reduce catastrophic fires, and subsequent use of fuels in biomass power plants. For estimating the costs of allowing timber to age and the costs of enhanced riparian zone management, estimates are based on specific counties for public and private landowners, and then extrapolated to all counties throughout the state. For the fuel reduction alternative, the analysis used a "Suitability for Potential Fuel Reduction" (SPFR) score on forest landscapes where potential exists for significant carbon loss from moderate to high intensity wildland fires. The SPFR scores were created in a GIS using slope, distance to biomass plants, and distance from roads as equal weighted factors in the decision-making process.

Table 22 summarizes the amount of carbon and the area available for afforestation of range and crop lands at three commonly used price points: ≤ \$2.40/t CO_2 (\$8.81/t C), ≤ \$10.00/t CO_2 (\$36.67/t C), and ≤\$20.00/t CO_2 (\$73.33/t C). At a price of \$2.40/t CO_2, no carbon could be sequestered by afforesting rangelands and croplands at 20 and 40 years but the amount reaches about 1,399 MMT CO_2 at 80 years (Table 22). If prices per t CO_2 rose to \$20 it is possible to convert more productive range and crop lands with higher opportunity costs and sequestering almost 289 MMT CO_2 carbon even with a 20-year time duration, and the total amount rises sharply to more than 1,233 MMT CO_2 at 40 years and approximately 3,176 MMT CO_2 at 80 years (Table 22). Converting this total amount at 40 years to an approximate annual rate results in about 31 MMT CO_2/yr.

Although Washington has substantial areas of forests, 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. All of the carbon available at prices of less that \$10/t CO_2 for extending rotations by 5 years is located on non-federal public lands; only when prices reach between \$10-20/t CO_2 do private lands generate potential carbon credits. If all of the private and non-federal public land nearing the economically optimal rotation period (1.46 million acres) were contracted to increase rotation ages by up to 15 years, 61.6 MMT CO_2 could be sequestered for average costs of \$37/t CO_2.

The potential area of mature forests where the riparian buffer zone could be increased by an additional 200 feet was estimated at 34,9000 acres. The additional carbon that could be stored on these lands if the forests were conserved is 2.2 MMT CO_2 at an average cost of \$33.3/t CO_2.

Table 22. Summary of the quantity of carbon (million metric tons CO_2 [MMT CO_2]) and area (million acres) available at selected price points (\$/t CO_2) for afforestation of existing rangelands and croplands over 20-year, 40-year, and 80-year durations.

	Quantity of C—MMT CO_2			Area available—million acres		
Activity	**20 years**	**40 years**	**80 years**	**20 years**	**40 years**	**80 years**
Rangelands-Afforestation						
≤\$2.40	0.0	0.0	1,399	0.0	0.0	3.1
≤\$10.00	0.0	877.9	2,153	0.0	4.3	6.2
≤\$20.00	279.4	1,178	2,450	4.2	8.8	8.9
Croplands-Afforestation						
≤\$2.40	0.0	0.0	14.4	0.0	0.0	0.0
≤\$10.00	0.0	0.0	140.5	0.0	0.3	0.3
≤\$20.00	9.8	54.9	725.9	0.1	1.4	5.5

From the forest hazardous fuel reduction analysis, the area of Washington forests with historically low-severity and mixed-severity (HLS-HMS) fire regimes is estimated to be 3.3 million acres. A commonly used potential hazardous fuels treatment is "Cut-Skid-Chip-Haul" (CSCH), a treatment in which hazardous fuel is harvested in the woods, bunched and skidded to a landing, chipped into a chip van, and hauled to a biomass energy facility for electricity and/or heat generation. The area of forestlands with HLS-HMS fire regimes in the state to which this treatment could be applied is approximately 1.2 million acres. Two removal scenarios were analyzed: hazardous fuel reduction (HFR) removal of 4 bone dry tons (BDT)/acre on these lands would yield 5 million BDT biomass fuel for use in energy facilities, while removal of 8 BDT/acre would yield 10 million BDT. Total estimated costs and potential revenue from these removals was

analyzed. During moderate to intense fires, 10-70% of the biomass stock burns and is emitted as CO_2. A preliminary analysis suggested that considering the differences in CO_2 emissions between high-, medium- and low-intensity fires, HFR treatments that reduced fire intensity would avoid sufficient emissions to be able to cover, at commonly used prices for carbon of \$2.40/t CO_2 and \$10/t CO_2, the subsidies needed to pay for CSCH, adding support to the argument for qualifying fuel reduction activities as carbon offset projects.

Additional information is found in Appendix XXI.

3.5.2.2 Oregon

The state of Oregon‘s lands are classified into three main groups: forests, rangelands, and agricultural lands. Forests (about 26.1 million acres) include conifers, hardwoods, and mixed classes; rangelands (about 27 million acres) include a variety of non-woody and woody ecosystems; and agricultural lands (about 6.4 million acres) include a wide range of non-woody crops such as wheat and hay and woody crops such as vineyards and orchards.

For rangelands and croplands (lands growing wheat and hay), the potential carbon sequestration was estimated for afforestation using native species with no subsequent harvesting (*i.e.,* for restoration). Historical evidence suggests that in many areas, large tracts of forest may have once stood where grazing and agricultural lands now do. The general approach was to identify and locate existing rangelands and croplands where biophysical conditions could favor forests, estimate rates of carbon accumulation for the forest types projected to grow, and assign values to each contributing cost factor. The carbon supply is estimated for three time durations: 20 years, 40 years and 80 years of forest growth, to reflect the impact of activity duration on the likely supply and to provide an assessment for the near–term and longer-term planning horizons.

For forestlands, potential carbon supply was estimated for three alternatives: (1) allowing timber to age past economic maturity (lengthening rotation time); (2) increasing the riparian buffer zone by an additional 200 feet; and (3) hazardous fuel reduction in forests to reduce catastrophic fires, and subsequent use of fuels in biomass power plants. For estimating the costs of allowing timber to age and the costs of enhanced riparian zone management, estimates are based on specific counties for public and private landowners, and then extrapolated to all counties throughout the state. For the fuel reduction alternative, the analysis used an SPFR score on forest landscapes where potential exists for significant carbon loss from wildfires. Suitability scores for potential fuel reduction with highest suitability were assigned to areas with gentle grades of slope that are close to roads and biomass power plants.

Table 23 summarizes the amount of carbon and the area available for afforestation of rangelands and croplands at three price points: ≤ \$2.40/t CO_2 (\$8.81/t C), ≤ \$10.00/t CO_2 (\$36.67/t C), and ≤\$20.00/t CO_2 (\$73.33/t C). At a price of ≤ \$2.40/t CO_2, the no carbon can be sequestered after 20 years by afforesting rangelands and croplands, but after 80 years about 732 MMT CO_2 could be sequestered on rangelands (Table 23). If prices per t

CO_2 rose to $20 it is possible to convert more productive range and crop lands with higher opportunity costs and sequestering almost 280 MMT CO_2 carbon even with a 20-year time duration, and the total amount rises sharply to more than 1,813 MMT CO_2 at 40 years and approximately 4,203 MMT CO_2 at 80 years (Table 23). Converting this total amount at 40 years to an approximate annual rate results in about 45 MMT CO_2/yr.

Although Oregon has substantial areas of forests, 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. If all of the private and non-federal public land nearing the economically optimal rotation period (790 thousand acres) were contracted to increase rotation ages up to 15 years, 35.6 MMT CO_2 could be sequestered for average costs of $37/t CO_2.

The potential area of mature forests where the riparian buffer zone could be increased by an additional 200 feet was estimated at 20,700 acres. The additional carbon that could be stored on these lands if the forests were conserved is 1.25 MMT CO_2 at an average cost of $40/t CO_2.

Table 23. Summary of the quantity of carbon (million metric tons CO_2 [MMT CO_2]) and area (million acres) available at selected price points for afforestation on existing rangelands and croplands of Oregon over 20-year, 40-year, and 80-year durations.

	Quantity of C—MMT CO_2			Area available—million acres		
Activity	**20 years**	**40 years**	**80 years**	**20 years**	**40 years**	**80 years**
Rangelands-Afforestation						
≤$2.40	0.0	0.489	732.2	0.0	0.001	1.4
≤$10.00	0.195	337.3	2,156	0.001	1.42	12.3
≤$20.00	117.7	1,336	2,827	1.40	15.6	19.1
Croplands-Afforestation						
≤$2.40	0.0	0.0	0.0	0.0	0.0	0.0
≤$10.00	0.279	457.2	997.9	0.002	1.91	1.93
≤$20.00	162.0	477.2	1,376	1.91	2.15	5.06

From the forest hazardous fuel reduction analysis, the area of Oregon forests with historically low and mixed severity fire regimes, yet mapped today as containing high quantities of hazardous fuel, is estimated to be 10.3million acres. The area of forestlands with historically low and mixed severity fire regimes in the state to which CSCH could be applied is approximately 2.9 million acres. Two removal scenarios were analyzed: HFR removal of 4 BDT/acre on these lands would yield 12 million BDT biomass fuel for use in energy facilities, while removal of 8 BDT/acre would yield 23 million BDT. Total

estimated costs and potential revenue from these removals was analyzed. During moderate to intense fires, 10-70% of the biomass stock burns and is emitted as CO_2. A preliminary analysis suggested that considering the differences in CO_2 emissions between high-, medium- and low-intensity fires, HFR treatments that reduced fire intensity would avoid sufficient emissions to be able to cover, at commonly used prices for carbon of \$2.40/t CO_2 and \$10/t CO_2, the subsidies needed to pay for CSCH, adding support to the argument for qualifying fuel reduction activities as carbon offset projects.

Additional information is found in Appendix XXI.

4 Conclusions

Both terrestrial and geologic sequestration options were evaluated in the WESTCARB Region during the 18-month Phase I project. A centralized GIS database of stationary source, geologic and terrestrial sink data was developed. The GIS layer of source locations was attributed with CO_2 emissions and other data and a spreadsheet was developed to estimate capture costs for the sources in the region. Phase I characterization of regional geological sinks shows that geologic storage opportunities exist in the WESTCARB region in each of the major technology areas: saline formations, oil and gas reservoirs, and coal beds. California offers outstanding sequestration opportunities because of its large capacity and the potential of value-added benefits from enhanced oil recovery (EOR) and enhanced gas recovery (EGR). The estimate for storage capacity of saline formations in the ten largest basins in California ranges from about 150 to about 500 Gt of CO_2, the potential CO_2-EOR storage was estimated to be 3.4 Gt, and the cumulative production from gas reservoirs suggests a CO_2 storage capacity of 1.7 Gt. . More detailed characterization and further refinement of capacity estimates will be carried out in Phase II. A GIS-based method for source-sink matching was implemented and preliminary marginal cost curves developed, which showed that 20, 40, 80 Mt of CO_2 per year could be sequestered in California at a cost of $31/t, $35/t, or $50t, respectively. Additional work on marginal costs for geologic sequestration in WESTCARB will be carried out in Phase II. Phase I also addressed key issues affecting deployment of CCS technologies, including storage-site monitoring, injection regulations, and health and environmental risks. A framework for screening and ranking candidate sites for geologic CO_2 storage on the basis of HSE risk was developed. A web-based, state-by-state compilation of current regulations for injection wells, and permits/contracts for land use changes, was developed, and modeling studies were carried out to assess the application of a number of different geophysical techniques for monitoring geologic sequestration. Public outreach activities resulted in heightened awareness of sequestration among state, community and industry leaders in the Region. Assessment of the changes in carbon stocks in agricultural lands showed that Washington, Oregon and Arizona were CO_2 sources for the period from 1987 to 1997. Over the same period, forest carbon stocks decreased in Washington, but increased in Oregon and Arizona. Results of the terrestrial supply curve analyses showed that afforestation of rangelands and crop lands offer major sequestration opportunities; at a price of $20 per t CO_2, more than 1,233 MMT could be sequestered over 40-years in Washington and more than 1,813 MMT could be sequestered in Oregon.

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Appendixes

The following appendixes are the paper (*i.e.*, not digital) deliverables for DOE contract number DE-FC26-03NT41984, "West Coast Regional Carbon Sequestration Partnership Phase I". Digital copies of most deliverables are included on a CD-ROM packaged with this report.

Information on each appendix is outlined in Table 24. Because each appendix is an individual deliverable, the page numbering for each appendix begins anew for each document.

Table 24. WESTCARB Final Report appendixes and associated deliverable task numbers & items, titles, file names, and types

Appendix no.	Task Item no.	Deliverable Description	Title	File Name	Type
Task 1.0: Characterize the region					
I	1	A database framework	A Database Framework for the Characterization of the WESTCARB Region	41984_Task1-Item1.pdf	paper
II	2	GIS-formatted data	GIS data layers representing point sources, geologic and terrestrial sinks, and base layers	41984_Task1Item2-readme.doc, among others	GIS-formatted data
III	3	digital data dissemination framework	The WESTCARB Interactive Map / Data Sharing with NATCARB	41984_Task1-Item3.pdf	PDF of PPT
IV	4	a paper on the terrestrial baseline for the partnership states	Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in Arizona, Oregon, and Washington	41984_Task1-Item4.pdf	paper
V	5	a paper on capture and storage database	An Overview of Geologic Carbon Sequestration Potential in California--CGS Special Report 183	41984R-CGS-TR.pdf	topical report
VI			Sedimentary Basin Database for Washington and Oregon States for the Geologic Carbon Dioxide Assessment	41984R-GolderTR.pdf	topical report
VII			Preliminary Assessment of the Potential for Carbon Dioxide Sequestration in Geological Settings in Nevada	41984R-NBMG-TR.pdf	topical report
Task 2.0: Identify and Address Technology Deployment Issues					
VIII	1	"other emissions" analysis	"Other Emissions" Analysis Spreadsheet	41984_Task2-Item1.xls, 41984_Task2-Item1.pdf	Excel spreadsheet
IX	2	a risk assessment framework (and related FEPs) for the region	Health, Safety, and Environmental Screening and Ranking Framework Spreadsheet	41984_HSE-SRF-RioVista.xls, 41984_HSE-SRF-Ventura.xls, 41984_Task2-Item2.pdf	Excel spreadsheet
X	3	a Web-based compilation of regulations and permits	Permitting and Regulatory Issues Compilation	41984_Task2-Item3.pdf	PDF of PowerPoint presentation
XI	4	papers on the "other emissions" analysis	Life Cycle Assessment of Power Generation Emissions When CO_2 Removal Is Applied	40984_Task2-Item4.pdf	paper
XII		paper on the risk framework and results of related analyses	Health, Safety, and Environmental Screening and Ranking Framework for Geologic CO_2 Storage Site Selection	41984ROldenTR.pdf	topical report
XIII		paper on the the regulatory assessment	Regulatory and Permitting Issues	41984RTerralogTR.pdf	topical report
XIV		paper on the monitoring and verification protocols	Geophysical Techniques for Monitoring CO_2 Movement During Sequestration	41984R-LBNL-TR.pdf	topical report
XV	5	an action plan	Action Plan for Addressing Phase II Technology Deployment Issues	41984_Task2-Item5.pdf	action plan
Task 3.0: Implement Public Outreach					
XVI	1	education materials	Public Outreach Education Materials	41984_Task3-Item1.pdf	collection of materials
XVII	2	a summary of the stakeholder meeting	Stakeholder Public Meeting Summary	41984_Task3-Item2.pdf	summary
XVIII	3	an action plan	Action Plan for Phase II Public Outreach	41984_Task3-Item3.pdf	action plan
Task 4.0: Identify Options and Opportunities					
XIX	1	computer algorithms for data analysis	Computer Algorithms for Data Analysis	41984_Task4-Item1-readme.doc, among others	Computer codes, spreadsheet, and documentation
XX	2	methodology and results of capture/geologic storage ranking	West Coast Regional Carbon Sequestration Partnership CO_2 Sequestration GIS Analysis	41984RHerzogTR.pdf	topical report
XXI	3	a paper on terrestrial supply curves	Carbon Sequestration through Changes in Land Use in Oregon and Washington: Costs and Opportunities	41984_Task4-Item3.pdf	paper
XXII	4	an action plan for implementing Phase II pilot projects	Action Plan for Phase II Pilot Projects	41984_Task4-Item4.pdf	action plan

Appendix I, Final Report

A Database Framework for the Characterization of the WESTCARB Region

Deliverable associated with Task 1.0, Item 1

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

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August 3, 2006

DOE award no. DE-FC26-03NT41984

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1 Introduction

This paper describes the types of data collected to describe CO_2 sources and geologic sinks within the West Coast Regional Carbon Sequestration Partnership states of Alaska, Arizona, California, Nevada, Oregon and Washington. CO_2 source data includes information on large power generation facilities, petroleum refineries, steel manufacturing plants, cement and lime plants, and natural gas processing facilities. Geologic sink data includes information on on-shore sedimentary basins and oil and gas fields. These data are available via the web-based WESTCARB interactive map: http://atlas.utah.gov/co2wc.

2 CO_2 Source Data

Nexant, Inc., compiled data for power generation facilities, petroleum refineries, steel manufacturing plants, cement and lime plants, and natural gas processing facilities within the WESTCARB region. The information is categorized by states within the Partnership: Alaska, Arizona, California, Nevada, Oregon and Washington. Recommendations are included for facilities to be further examined.

2.1 Power Generation

The following set of tables present the data collected for power generation plants in the Western Partnership region's states. For most of the states, data is available from the Energy Information Agency (EIA) and from the U.S. Environmental Protection Agency's (EPA) Clean Air Markets Division. California also has a database created by the California Air Resources Board (CARB).

The original databases contain information on all type of power generation facilities. Only the fossil-fueled plants are shown here, and the very small units – mostly internal combustion machines have been screened out of the lists. Some data appears to be missing, or differently named across the databases and attempts to reconcile, or at least complete, the lists has been made for this summary. The EPA database also contains further information on unit, such as their emission control equipment and types of boilers. For each of the states, recommendations are made for plants that should be investigated further.

2.1.1 Data

2.1.1.1 Alaska

Table 1 shows the data for Alaska. The EIA database was the sole source of information for Alaska. Thus, there are no EPA emissions data such as will be presented later for other states.

Table 1. ALASKA fossil power generation[1]

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Primary Energy Source1	Year of Commercial Operation	Unit Status1	Further Data Collection
Alaska Electric G & T Coop Inc		**163.9**	**163.9**	**168**					
Soldotna (Kenai Peninsula)	**GT1	37.9	37.9	42	GT	DFO	1986	OS	NO
Alaska Electric Light&Power Co		**184.4**	**184.4**	**182**					
Auke Bay (Juneau)	14	23	23	23	GT	DFO	1994	OP	NO
Lemon Creek (Juneau)	5	17.5	17.5	17.5	GT	DFO	1980	OP	NO
	6	17.5	17.5	17.5	GT	DFO	1983	OP	NO
Chugach Electric Assn Inc		**576.3**	**471.1**	**543.4**					
Beluga (Kenai Peninsula)	1	18.8	18.9	19.6	GT	NG	1968	OP	NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Primary Energy Source1	Year of Commercial Operation	Unit Status1	Further Data Collection
	2	18.8	18.9	19.6	GT	NG	1968	OP	NO
	3	65.7	58	71.4	GT	NG	1972	OP	NO
	5	75.9	61.4	75	GT	NG	1975	OP	NO
	6	85	74.6	82.5	CT	NG	1976	OP	NO
	7	85	63	80	CT	NG	1978	OP	NO
	8	68.9	51.2	53	CA	WH	1982	OP	NO
Bernice Lake (Kenai Peninsula)	2	23	17	19.6	GT	NG	1971	OP	NO
	3	32	22.9	29.2	GT	NG	1978	OP	NO
	4	32	22.5	22.5	GT	NG	1981	OP	NO
International (Anchorage)	1	17.6	12.6	15.6	GT	NG	1964	OP	NO
	2	17.6	12.6	15.1	GT	NG	1965	OP	NO
	3	19.2	16.7	19.5	GT	NG	1969	OP	NO
Golden Valley Elec Assn Inc		**220.4**	**194.1**	**228**					
Chena (Fairbanks North Star)	6	23.1	23.1	29.3	GT	DFO	1976	OP	YES
Fairbanks (Fairbanks North Star)	GT1	17.6	16	18	GT	DFO	1971	OP	YES

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Primary Energy Source1	Year of Commercial Operation	Unit Status1	Further Data Collection
	GT2	17.6	16.3	18	GT	DFO	1972	OP	YES
Healy	1	25	25	25	ST	SUB	1967	OP	YES
North Pole (Fairbanks North Star)	1	64.7	53	65	GT	DFO	1976	OP	YES
	2	64.7	53	65	GT	DFO	1977	OP	YES
Municipality of Anchorage		**381.3**	**343.7**	**375.2**					
Anchorage 1 (Anchorage)	1	12.5	14	16.2	GT	NG	1962	OP	NO
	2	12.5	14	16.2	GT	NG	1962	OP	NO
	3	16.3	17.7	19.4	GT	NG	1968	OP	NO
	4	27	31.1	33.2	GT	NG	1972	OP	NO
George M Sullivan (Anchorage)	5	38.1	33.8	37.4	CT	NG	1975	OP	NO
	7	102.6	74.4	81.8	CT	NG	1979	OP	NO
	GT8	92.6	77.7	86.5	GT	NG	1984	OP	NO

[1] The selection of plants for further data collection is limited to the North Slope area. Other plants, regardless of other characteristics, have been screened out of future studies.

2.1.1.2 Arizona

Table 2 presents data for Arizona. The EPA emission data is shown with the light blue fill, and so marked in the left column. The other data is from the EIA database. There is EPA data for many, but not every one of the units shown by EIA. Also, as shown in Table 3, there appears to be EPA emission data for facilities not listed in the EIA data. It was outside of the Phase I scope to try and reconcile all the differences.

Table 2. ARIZONA fossil power generation

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Arizona Electric Pwr Coop Inc		**559.1**	**515**	**515**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Apache Station	160	2002	5,167.0	3,068,830.5	6,528.4	31,278,625			
Apache Station (Cochise)	GT1	10	10	10	CT	NG	1965	OP	
	GT2	19.8	20	20	GT	DFO	1972	OP	
	GT3	64.9	63	63	GT	DFO	1974	OP	
	ST1	75	72	72	CA	RFO	1965	OP	
	ST2	194.7	175	175	ST	SUB	1979	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
	ST3	194.7	175	175	ST	SUB	1979	OP	
Arizona Public Service Co		**6,934.20**	**6,040.50**	**6,244.50**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Cholla	113	2002	20,770.2	8,350,688.7	12,880.9	81,439,136			
Cholla (Navajo)	1	113.6	110	110	ST	SUB	1962	OP	
	2	288.9	245	245	ST	SUB	1978	OP	
	3	288.9	260	260	ST	SUB	1980	OP	
	**4	414	380	380	ST	SUB	1981	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Ocotillo Power Plant	116	2002	0.9	188,160.8	162.3	3,166,066			
Ocotillo (Maricopa)	1	113.6	111	113	ST	NG	1960	OP	
	2	113.6	111	113	ST	NG	1960	OP	
	GT1	53.1	54	67	GT	NG	1972	OP	
	GT2	53.1	49	67	GT	NG	1973	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
APS Saguaro Power Plant	118	2002	0.7	155,240.5	164.8	2,612,182			
Saguaro (Pinal)	1	125	110	110	ST	NG	1954	OP	
	2	125	99	99	ST	NG	1955	OP	
	GT1	53.1	47	64	GT	NG	1972	OP	
	GT2	53.1	47	64	GT	NG	1973	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
West Phoenix Power Plant	117	2002	1.1	226,570.1	58.8	3,812,454			
West Phoenix (Maricopa)	1B	132	80	97	CS	NG	1976	OP	
	2B	132	80	97	CS	NG	1976	OP	
	3B	132	80	97	CS	NG	1976	OP	
	4	34.5	33.3	33.3	ST	NG	1948	OS	
	5	16	12	12	ST	NG	1949	OS	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
	6	69	63	63	ST	NG	1950	OS	
	GT1	53.1	50	67	GT	NG	1972	OP	
	GT2	53.1	50	67	GT	NG	1973	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Yuma Axis	120	2002	1.5	204,546.0	194.4	3,441,417			
Yucca (Yuma)	GT1	23.6	18	22	GT	NG	1971	OP	
	GT2	23.6	18	22	GT	NG	1971	OP	
	GT3	72.4	52	62	GT	NG	1973	OP	
	GT4	72.4	51	61	GT	DFO	1974	OP	
	**ST1	86.7	75	75	ST	NG	1959	OP	
Salt River Proj Ag I & P Dist		**4,808.90**	**4,524.60**	**4,623.60**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Agua Fria Generating Station	141	2002	9.2	422,793.8	848.6	7,122,769			
Agua Fria (Maricopa)	AF1	113.6	113	114	ST	NG	1958	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
	AF2	113.6	113	114	ST	NG	1957	OP	
	AF3	163.2	181	184	ST	NG	1961	OP	
	AF4	80.6	73	87	GT	NG	1975	OP	
	AF5	71.2	73	82	GT	NG	1974	OP	
	AF6	71.2	73	82	GT	NG	1974	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Coronado Generating Station	6177	2002	17,727.2	5,704,592.8	11,932.7	55,600,345			
Coronado (Apache)	CO1	410.9	395	395	ST	SUB	1979	OP	
	CO2	410.9	390	390	ST	SUB	1980	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Kyrene Generating Station	147	2002	3.7	349,883.7	290.2	5,889,446			
Kyrene (Maricopa)	KY1	34.5	34	34	ST	NG	1952	OP	
	KY2	73.5	72	72	ST	NG	1954	OP	
	KY4	53.1	59	63	GT	NG	1971	OP	
	KY5	60.3	53	62	GT	NG	1973	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
	KY6	60.3	53	62	GT	NG	1973	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Navajo Generating Station	4941	2002	4,007.0	20,458,264.9	35,568.8	199,398,686			
Navajo (Coconino)	**NAV1	803.2	750	750	ST	SUB	1974	OP	
	**NAV2	803.2	750	750	ST	SUB	1975	OP	
	**NAV3	803.2	750	750	ST	SUB	1976	OP	
Santan (Maricopa)	ST1	103.5	81	91	CS	NG	1974	OP	NO
	ST2	103.5	81	91	CS	NG	1974	OP	NO
	ST3	103.5	81	91	CS	NG	1974	OP	NO
	ST4	103.5	81	91	CS	NG	1975	OP	NO
Tucson Electric Power Co		**1,489.10**	**1,345.00**	**1,345.00**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Irvington Generating Station	126	2002	3,118.6	1,227,077.9	2,540.0	14,987,367			
Irvington (Pima)	4	173.3	156	156	ST	SUB	1967	OP	NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
	GT1	27	24	24	GT	NG	1972	OP	NO
	GT2	27	25	25	GT	NG	1972	OP	NO
	ST1	108.8	81	81	ST	NG	1958	OP	NO
	ST2	108.8	81	81	ST	NG	1960	OP	NO
	ST3	113.6	105	105	ST	NG	1962	OP	NO
North Loop (Pima)	1	27	25	25	GT	NG	1972	OP	NO
	2	27	25	25	GT	NG	1972	OP	NO
	3	27	23	23	GT	NG	1972	OP	NO
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Springerville Generating Station	8223	2002	19,862.3	6,451,073.4	12,571.5	62,875,991			
Springerville (Apache)	1	424.8	400	400	ST	SUB	1985	OP	
	2	424.8	400	400	ST	SUB	1990	OP	

Table 3 shows those facilities in the EPA data that could not be matched with facilities in the EIA data.

Table 3. ARIZONA additional EPA clean air markets data (not listed in EIA data)

Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
De Moss Petrie Generating Station	124	2002	0.2	45,910.1	8.7	772,532	NO
Duke Energy Arlington Valley	55282	2002	1.5	304,663.5	33.1	5,126,560	NO
Griffith Energy LLC	55124	2002	3.4	695,712.9	109.3	11,706,616	NO
PPL Sundance Energy, LLC	55522	2002	0.0	17,519.4	6.4	294,806	NO
Redhawk Generating Facility	55455	2002	4.2	821,532.1	72.6	13,847,820	NO
Reliant Energy Desert Basin	55129	2002	7.9	1,564,885.3	139.2	26,332,245	YES
South Point Energy Center, LLC	55177	2002	6.3	1,231,999.8	96.6	20,730,793	NO

2.1.1.3 Nevada

Tables 4 and 5 present the combined EIA and EPA data, and the EPA data where matches were not found in the EIA database.

Table 4. NEVADA fossil power generation

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Nevada Power Co		**1,647.00**	**1,516.00**	**1,570.00**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Harry Allen	7082	2002	0.2	55,809.5	54.1	941,179			
Allen (Clark)	GT1	78	78	78	GT	NG	1995	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Clark	2322	2002	2.5	504,559.1	1,147.5	8,490,197			

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Clark (Clark)	1	50	42	42	ST	NG	1955	OP	
	10	90	90	90	CA	WH	1994	OP	
	2	65	66	69	ST	NG	1957	OP	
	3	75	67	70	ST	NG	1961	OP	
	9	90	89	89	CA	WH	1993	OP	
	GT4	72.4	50	59	GT	NG	1973	OP	
	GT5	86.9	70	78	CT	NG	1979	OP	
	GT6	86.9	70	78	CT	NG	1979	OP	
	GT7	86.9	70	78	CT	NG	1980	OP	
	GT8	86.9	70	78	CT	NG	1982	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Reid Gardner	2324	2002	1,977.4	5,351,897.3	10,735.0	52,290,147			
Reid Gardner	1	114	110	110	ST	BIT	1965	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
(Clark)									
	2	114	110	110	ST	BIT	1968	OP	
	3	114	110	110	ST	BIT	1976	OP	
	**4	270	275	275	ST	BIT	1983	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Sunrise	2326	2002	1.1	206,665.2	850.5	3,477,583			
Sunrise (Clark)	1	82	80	80	ST	NG	1964	OP	
	2	85	69	76	GT	NG	1974	OP	
Sierra Pacific Power Co		**1,311.00**	**1,298.70**	**1,347.80**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Fort Churchill	2330	2002	8.5	660,995.5	2,211.0	10,851,604			
Fort Churchill (Lyon)	1	105.2	113	113	ST	NG	1968	OP	
	2	105.2	113	113	ST	NG	1971	OP	
Pinon Pine (Storey)	1	113.2	89	99.8	CC	BIT	1996	OP	NO
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
Tracy	2336	2002	22.5	864,454.9	1,592.5	14,691,219			
Tracy (Storey)	3	109.6	108	108	ST	NG	1974	OP	
	4	72.5	69	84	GT	NG	1994	OP	
	GT1	12.5	10	11	GT	DFO	1961	OP	
	GT2	12.5	10	11	GT	DFO	1962	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
	GT3	72.5	69	84	GT	NG	1994	OP	
	ST1	53	53	53	ST	NG	1963	OP	
	ST2	80	83	83	ST	NG	1965	OP	
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
North Valmy	8224	2002	6,873.8	4,508,896.1	7,870.8	43,946,407			
Valmy (Humboldt)	**1	254.3	258	258	ST	SUB	1981	OP	
	**2	267	274	274	ST	SUB	1985	OP	
Southern California Edison Co		**1,636.20**	**1,580.00**	**1,580.00**					
Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
Mohave	2341	2002	40,347.0	10,153,106.2	20,266.7	99,030,892			

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary		Year of Commercial Operation	Unit Status1	Further Data Collection
Mohave (Clark)	**1	818.1	790	790	ST	BIT	NG	1971	OP	
	**2	818.1	790	790	ST	BIT	NG	1971	OP	

Table 5 presents the EPA data for Nevada that is in addition to the data shown in Table 4.

Table 5. NEVADA additional EPA clean air markets data (not listed in EIA data)

Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
El Dorado Energy	55077	2002	7.3	1,441,143.2	132.2	24,249,979	YES
Tri-Center Naniwa Energy	55494	2002	0.0	36,080.2	11.0	607,098	NO

2.1.1.4 Oregon

Tables 6 and 7 present data for the State of Oregon. Table 6 shows the EIA and EPA matching data.

Table 6. OREGON fossil power generation

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary	Year of Commercial Operation	Unit Status1	Further Data Collection
Portland General Electric Co		**1,987.00**	**1,911.50**	**1,985.50**					
Beaver (Columbia)	1	68.3	58.7	66.7	CT	NG	1974	OP	YES
	2	68.3	58.7	66.7	CT	NG	1974	OP	YES
	3	68.3	58.7	66.7	CT	NG	1974	OP	YES
	4	68.3	58.7	66.7	CT	NG	1974	OP	YES
	5	68.3	58.7	66.7	CT	NG	1974	OP	YES
	6	68.3	58.7	66.7	CT	NG	1974	OP	YES
	7	176.4	141	134	CA	WH	1977	OP	YES

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA	YES
OR	Boardman	6106	2002	12,262.4	4,126,996.4	8,400.7	40,224,136		

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary		Year of Commercial Operation	Unit Status1	Further Data Collection
Boardman (Morrow)	**1	560.5	556.7	556.7	ST	BIT		1980	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
OR	Coyote Springs	7350	2002	2.8	562,120.6	72.5	9,458,777			
Coyote Springs (Morrow)	1	185.8	143	166	CT	NG		1995	OP	
	2	80.6	70	80	CA	WH		1995	OP	

Table 7 presents EPA data.

Table 7. OREGON additional EPA clean air markets data (not listed in EIA data)

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
OR	Hermiston	54761	2002	6.2	1,260,041.0	142.6	21,202,559	YES
OR	Hermiston Power Plant	55328	2002	3.3	655,808.3	92.9	11,035,174	NO
OR	Klamath Cogeneration Project	55103	2002	5.0	999,154.7	127.8	16,812,098	YES
OR	Klamath Energy LLC	55544	2002	0.0	3,435.9	3.3	57,821	NO

2.1.1.5 Washington

Tables 8 and 9 present data for the State of Washington.

Table 8. WASHINGTON fossil power generation

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary		Year of Commercial Operation	Unit Status1	Further Data Collection
PUD No 1 of Clark County		**248**	**205**	**248**						
River Road Gen Plant (Clark)	1	248	205	248	CS	NG		1997	OP	YES
Puget Sound Energy Inc		**1,063.10**	**1,009.20**	**1,076.00**						
Encogen (Whatcom)	CTG1	39.4	40	40	CT	NG		1993	OP	NO
	CTG2	39.4	40	40	CT	NG		1993	OP	NO
	CTG3	39.4	40	40	CT	NG		1993	OP	NO
	STG	51.9	40	40	CA	WH		1993	OP	NO
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 Primary		Year of Commercial Operation	Unit Status1	Further Data Collection
WA	Frederickson Power LP	55818	2002	0.6	102,121.8	11.4	1,718,402			
Frederickson (Pierce)	1	84.6	79	89	GT	NG		1981	OP	
	2	84.6	79	89	GT	NG		1981	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
WA	Fredonia Plant	607	2002	0.8	29,166.0	4.1	473,816			
Fredonia (Skagit)	1	123.6	108	123.6	GT	NG		1984	OP	
	2	123.6	108	123.6	GT	NG		1984	OP	
Whitehorn (Whatcom)	2	88.9	79	89	GT	NG		1981	OP	NO
	3	88.9	79	89	GT	NG		1981	OP	NO

Table 9 presents EPA data.

Table 9. WASHINGTON additional EPA clean air markets data (not listed in EIA data)

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
WA	Centralia	3845	2002	19,032.2	10,484,140.6	15,469.7	102,703,316	YES
WA	Finley Combustion Turbine	7945	2002	0.1	10,076.4	0.9	123,855	NO
WA	River Road	7605	2002	3.1	621,442.4	66.3	10,456,923	YES
WA	Shuffleton	3858	2002	0.0	0.0	0.0	0	NO

2.1.1.6 California

The data from the EIA and EPA for California is presented in Tables 10 and 11.

Table 10. CALIFORNIA fossil power generation

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
Anaheim, City of		**49.3**	**44.5**	**46.5**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Anaheim Combustion Turbine	7693	2002	0.4	72,351.1	9.5	1,217,488			
Anaheim GT (Orange)	1	49.3	44.5	46.5	GT	NG		1991	OP	
Burbank City of		**259.7**	**234.2**	**234.2**						

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Magnolia	375	2002	0.0	9.1	0.0	153			
Magnolia (Los Angeles)	M2	10	10	10	CA	WH\		1984	SB	
	M3	20	20	20	ST	NG		1949	SB	
	M4	34.5	30	30	ST	NG		1953	SB	
	M5	23.1	21.7	21.7	GT	NG		1969	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Olive	6013	2002	0.3	49,040.2	34.2	825,135			
Olive (Los Angeles)	O1	50	42	42	ST	NG		1959	OP	
	O2	59.8	55	55	ST	NG		1964	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
	O3	24.4	23.5	23.5	GT	NG		1972	OP	
	O4	37.8	32	32	GT	NG		1978	OP	
Glendale City of		**291**	**263**	**282**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Grayson	377	2002	1.1	156,278.0	18.0	1,815,753			
Grayson (Los Angeles)	1	20	20	20	CA	WH		1977	OP	
	2	20	20	20	CA	WH		1977	OP	
	3	20	20	21	ST	NG		1953	OP	
	4	44	44	45	ST	NG		1959	OP	
	5	44	44	45	ST	NG		1964	OP	
	6	22	15	18	GT	NG		1972	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**	Year of Commercial Operation	Unit Status1	Further Data Collection
	7	31	20	23	GT	NG	1974	OP	
	8A	30	26	30	CT	NG	1977	OP	
	8BC	60	54	60	CT	NG	1977	OP	
Imperial Irrigation District		**507.1**	**421.7**	**449.2**					
Brawley (Imperial)	GT1	11.5	9	11	GT	DFO	1962	OP	NO
	GT2	11.5	9	11	GT	DFO	1962	OP	NO
Coachella (Riverside)	1	23.2	20	20	GT	NG	1973	OP	NO
	2	23.2	20	20	GT	NG	1973	OP	NO
	3	23.2	20	20	GT	NG	1974	OP	NO
	4	23.2	20	20	GT	NG	1976	OP	NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	El Centro	389	2002	1.5	281,422.2	304.9	4,735,485			
El Centro (Imperial)	2	34.5	30.7	30.7	CA	WH		1952	OP	
	2A	89.9	84.5	88	CT	NG		1993	OP	
	3	50	43.6	48	ST	NG		1957	OP	
	4	81.6	73.9	80	ST	NG		1968	OP	
Rockwood (Imperial)	1	25	21	25	GT	NG		1979	OP	NO
	2	25	21	25	GT	DFO		1980	OP	NO
Los Angeles City of		**4,857.30**	**4,938.10**	**4,938.10**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
CA	Harbor Generating Station	399	2002	2.2	414,555.1	76.9	6,976,052			
Harbor (Los Angeles)	10A	80	80	80	CT	NG		1994	OP	
	10B	80	80	80	CT	NG		1994	OP	
	5	86.3	86	86	CA	WH		1949	OP	
	GT6	23.6	19	19	GT	NG		1972	OP	
	GT7	23.6	19	19	GT	NG		1972	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
CA	Haynes Gen Station	400	2002	7.4	1,467,089.1	220.9	24,686,567			
Haynes (Los Angeles)	1	230	222	222	ST	NG		1962	OP	
	2	230	222	222	ST	NG		1963	OP	
	3	230	222	222	ST	NG		1964	OP	
	4	230	222	222	ST	NG		1965	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
	5	343	341	341	ST	NG		1966	OP	
	6	343	341	341	ST	NG		1967	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
CA	Scattergood Generating Station	404	2002	10.9	777,998.7	33.3	12,310,354			
Scattergood (Los Angeles)	1	163.2	179	179	ST	NG		1958	OP	
	2	163.2	179	179	ST	NG		1959	OP	
	3	496.8	445	445	ST	NG		1974	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Valley Gen Station	408	2002	0.2	48,181.6	26.0	810,264			
Valley (Los Angeles)	1	100	95	95	ST	NG		1954	SB	
	2	100	99	99	ST	NG		1954	SB	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
	3	172.8	163	163	ST	NG		1955	OP	
	4	172.8	160	160	ST	NG		1956	OP	
Modesto Irrigation District		**199**	**160.2**	**172.2**						
McClure (Stanislaus)	1	71.2	56	61	GT	DFO		1980	OP	NO
	2	71.2	56	61	GT	DFO		1981	OP	NO
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Woodland Generation Station	7266	2002	0.4	79,043.1	9.1	1,329,954			
Woodland (Stanislaus)	NA1	56	48	50	GT	NG		1993	OP	
Northern California Power Agny		**645.3**	**664.5**	**673.3**						
Alameda (Alameda)	1	25.2	24.7	26.2	GT	NG		1986	OP	NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
	2	25.2	25.4	27	GT	NG		1986	OP	NO
Lodi CC (San Joaquin)	NA1	50	50	50	GT	NG		1996	OP	NO
Lodi (San Joaquin)	1	25.2	25.9	27	GT	NG		1986	OP	NO
Roseville (Placer)	1	25.2	26	28.3	GT	NG		1986	OP	NO
	2	25.2	25.5	27.7	GT	NG		1986	OP	NO
Pacific Gas & Electric Co		**6,578.20**	**6,635.60**	**6,633.60**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Humboldt Bay	246	2002	3.9	292,734.5	870.9	4,923,881			
Humboldt Bay (Humboldt)	ST1	51.2	52	52	ST	NG		1956	OP	
	ST2	51.2	53	53	ST	NG		1958	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
CA	Hunters Point	247	2002	1.6	316,176.8	99.5	5,319,799			
Hunters Point (San Francisco)	2	107.6	107	107	ST	NG		1948	OP	
	3	107.6	107	107	ST	NG		1949	OP	
	4	156.3	163	163	ST	NG		1958	OP	
	GT1	56.3	52	52	GT	DFO		1976	OP	
Mobile GT (Mendocino)	1	13.3	15	15	GT	DFO		1975	OP	NO
	2	13.3	15	15	GT	DFO		1975	OP	NO
	3	13.3	15	15	GT	DFO		1976	OP	NO
Pasadena City of		**227.8**	**223.7**	**225.7**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Broadway	420	2002	0.3	77,417.4	30.0	1,302,664			

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
Broadway (Los Angeles)	B1	46	45	45	ST	NG		1955	OP	
	B2	46	45	45	ST	NG		1957	OS	
	B3	75	71	73	ST	NG		1965	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Glenarm	422	2002	0.0	0.0	0.0	0			
Glenarm (Los Angeles)	GT1	28.9	30.4	30.4	GT	NG		1976	OP	
	GT2	28.9	30.4	30.4	GT	NG		1976	OP	
Redding City of		**98.9**	**94.5**	**102.3**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Redding Power Plant	7307	2002	0.2	50,140.0	1.4	843,752			
Redding Power (Shasta)	1	30	28	28	ST	NG		1994	OP	

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
	2	24	24	27.6	GT	NG		1996	OP	
	3	24	24	27.6	GT	NG		1996	OP	
	4	17.6	17.6	17.6	GT	NG		1996	OP	
Sacramento Municipal Util Dist		**1,247.30**	**1,138.60**	**1,138.60**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Carson Cogeneration	7527	2002	1.6	263,969.5	28.3	4,080,615			
Carson Ice CG (Sacramento)	**1	54	41.3	41.3	CT	NG		1995	OP	
	**2	17.5	16.6	16.6	CA	WH		1995	OP	
	CCCT	54	43.3	43.3	GT	NG		1995	OP	
McClellan (Sacramento)	1	74.2	49	49	GT	NG		1986	OP	NO
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
CA	SCA Cogen II	7551	2002	2.4	445,005.1	59.6	7,492,775			
SCA (Sacramento)	**CCST	49.9	37.6	37.6	CA	WH		1997	OP	
	**CT1A	49.9	39.7	39.7	CT	NG		1997	OP	
	**CT1B	49.9	39.7	39.7	CT	NG		1997	OP	
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		YES
CA	Sacramento Power Authority Cogen	7552	2002	3.1	588,780.2	48.0	9,899,448			
SPA (Sacramento)	**CCCT	118.8	111	111	CT	NG		1997	OP	
	**CCST	55.3	53	53	CA	WH		1997	OP	
San Diego Gas & Electric Co		**247**	**230**	**230**						
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
CA	Silver Gate	309	2002	0.0	0.0	0.0	0			
Silver Gate (San Diego)	1	40	40	40	ST	DFO		1943	OS	
	2	69	62	62	ST	DFO		1948	OS	
	3	69	64	64	ST	DFO		1950	SB	
	4	69	64	64	ST	DFO		1952	OS	
Santa Clara City of		**106.1**	**95**	**105.9**						
Gianera (Santa Clara)	1	32.3	26	32	GT	NG		1987	OP	NO
	2	32.3	26	32	GT	NG		1986	OP	NO
Santa Clara Cogen (Santa Clara)	1	3.9	3.9	3.9	GT	NG		1982	OP	NO
	2	3.9	3.9	3.9	GT	NG		1982	OP	NO
Turlock Irrigation District		**283.7**	**314.1**	**313.2**						

State Company Plant (County)	Unit ID	Generator Nameplate Capacity (megawatts)	Net Summer Capacity (megawatts)	Net Winter Capacity (megawatts)	Unit Type1	Energy Source1 **Primary**		Year of Commercial Operation	Unit Status1	Further Data Collection
State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	EPA CLEAN AIR MARKETS DATA		NO
CA	Almond Power Plant	7315	2002	0.3	73,104.3	8.6	1,230,193			
Almond Power Plant (Stanislaus)	1	49.5	49.5	49.5	GT	NG		1996	OP	
Walnut (Stanislaus)	1	25	23.5	25	GT	NG		1986	OP	NO
	2	25	23.5	25	GT	NG		1986	OP	NO

Table 11. CALIFORNIA additional EPA clean air markets data (not listed in EIA data)

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
CA	AES Alamitos	315	2002	13.4	2,629,082.2	317.7	44,248,607	YES
CA	AES Huntington Beach	335	2002	4.8	928,951.2	102.1	15,633,343	YES
CA	AES Redondo Beach	356	2002	6.2	1,270,235.7	165.6	21,376,189	YES
CA	Avon	216	2002	0.0	0.0	0.0	0	NO
CA	Cabrillo Power I (Encina)	302	2002	38.3	1,599,749.3	274.6	26,841,095	YES
CA	Cal Peak Power - Border LLC	55510	2002	0.0	19,927.5	2.0	335,306	NO
CA	Cal Peak Power - El Cajon LLC	55512	2002	0.0	9,406.6	0.9	158,324	NO
CA	Cal Peak Power - Enterprise LLC	55513	2002	0.1	20,482.5	1.3	344,681	NO
CA	Cal Peak Power - Panoche LLC	55508	2002	0.0	14,519.0	1.5	244,317	NO

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
CA	Cal Peak Power - Vaca Dixon LLC	55499	2002	0.0	7,339.1	0.5	123,485	NO
CA	Calpine Sutter Energy Center	55112	2002	7.7	1,511,376.9	105.8	25,431,807	YES
CA	Chula Vista Power Plant	55540	2002	0.0	3,714.2	0.6	62,490	NO
CA	Contra Costa Power Plant	228	2002	6.0	1,180,634.4	249.6	19,866,355	YES
CA	Coolwater Generating Station	329	2002	5.0	1,019,577.8	949.6	17,156,347	YES
CA	Delta Energy Center, LLC	54001	2002	7.5	1,482,003.6	114.7	24,937,930	YES
CA	Duke Energy South Bay	310	2002	21.1	798,198.9	98.4	13,391,640	YES
CA	El Segundo	330	2002	3.3	1,465,274.6	112.9	24,656,059	YES
CA	Escondido Power Plant	55538	2002	0.0	3,639.6	0.8	61,232	NO
CA	Etiwanda Generating Station	331	2002	3.1	622,731.7	124.6	10,478,602	YES
CA	Gilroy Energy Center, LLC	55810	2002	0.0	35,341.7	42.7	594,686	NO
CA	Hanford Energy Park Peaker	55698	2002	0.0	34,171.7	385.2	574,384	NO

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
CA	Henrietta Peaker Plant	55807	2002	0.0	21,402.4	204.3	359,809	NO
CA	Indigo Energy Facility	55541	2002	0.0	55,380.9	12.9	931,886	NO
CA	Kern	251	2002	0.0	0.0	0.0	0	NO
CA	King City Energy Center	10294	2002	0.0	8,754.5	9.5	147,332	NO
CA	La Paloma Generating Plant	55151	2002	1.0	189,571.5	13.2	3,189,936	NO
CA	Lake	7987	2002	0.0	8,670.5	1.4	145,921	NO
CA	Larkspur Energy Faciity	55542	2002	0.1	30,430.3	5.6	512,000	NO
CA	Los Medanos Energy Center, LLC	55217	2002	7.7	1,515,131.3	3,586.4	25,494,977	YES
CA	Mandalay Generating Station	345	2002	2.9	585,663.9	27.2	9,854,961	YES
CA	Martinez	256	2002	0.0	0.0	0.0	0	NO
CA	Morro Bay Power Plant, LLC	259	2002	4.7	922,205.9	283.7	15,517,887	YES
CA	Moss Landing	260	2002	16.6	3,332,966.4	593.5	56,083,644	YES

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
CA	Mountainview Power Company, LLC	358	2002	0.0	0.0	0.0	0	NO
CA	NCPA Combustion Turbine Project #chr(35)#2	7449	2002	0.0	22,361.9	3.0	376,293	NO
CA	Oleum	263	2002	0.0	0.0	0.0	0	NO
CA	Ormond Beach Generating Station	350	2002	7.2	1,431,520.2	93.7	24,088,097	YES
CA	Pittsburg Power Plant (CA)	271	2002	12.8	2,509,397.6	764.5	42,225,433	YES
CA	Potrero Power Plant	273	2002	1.8	352,250.4	162.9	5,927,228	NO
CA	Riverside Canal Power Company	334	2002	0.0	0.0	0.0	0	NO
CA	Sunrise Power Company	55182	2002	1.1	205,403.3	47.6	3,456,274	NO
CA	Wellhead Power Gates, LLC	55875	2002	0.0	4,757.0	16.0	80,081	NO

State	Facility Name	Facility ID (ORISPL)	Year	SO_2 Tons	CO_2 Tons	NO_x Tons	Heat Input (mmBtu)	Further Data Collection
CA	Yuba City Energy Center	10349	2002	0.0	6,433.9	0.8	108,260	NO

California Air Resources Board Database

In addition to the EPA and EIA data noted above, California also maintains a separate database. The California data has significant overlaps with the other data, but also has some site-specific elements that the others do not contain. Table 12 shows a partial list of plants from the CARB data. Tables 13 and 14 show additional site and emission data.

Table 12. California Air Resources Board data

Your Search Criteria:
Database year is 2002. Facility SIC Code is 4911.
Sorted by District Name (A to Z).
218 records returned.

Download this data as a Comma Separated Value text file.

	Fac ID	District	Facility Name	City
1	3	Amador	Jackson Valley Energy P	Ione
2	20	Amador	Wheelabrator Martell In	Martell
3	1606	Bay Area	City Of Fairfield	Fairfield
4	14248	Bay Area	Central Pump Station	Fairfield
5	14415	Bay Area	Gilroy Energy Center Ll	Suisun City
6	13563	Bay Area	Kqed Inc	San Francisc
7	12596	Bay Area	National Park Service	San Francisc
8	11671	Bay Area	Gas Recovery Systems, I	Napa
9	3011	Bay Area	Ipt Sri Cogeneration In	Menlo Park
10	1771	Bay Area	City Of Santa Clara	Santa Clara
11	11180	Bay Area	Gilroy Energy Center, L	Gilroy
12	3243	Bay Area	Gwf Power Systems,lp (s	Pittsburg
13	14354	Bay Area	Shorenstein Company Llc	Oakland
14	1500	Bay Area	Northern Calif Power Ag	Alameda
15	13759	Bay Area	Micrel Semiconductor	San Jose

16	13594	Bay Area	Santa Clara Valley Wate	Los Gatos
17	13119	Bay Area	City Of Palo Alto Utili	Palo Alto
18	11669	Bay Area	Gas Recovery Systems, I	San Jose
19	9794	Bay Area	Wpi Packaging & Mainten	Palo Alto
20	11668	Bay Area	Gas Recovery Systems, I	Menlo Park
21	13410	Bay Area	Pacific Bell Corporatio	Walnut Creek

22	11928	Bay Area	Calpine Pittsburg Llc	Pittsburg
23	11866	Bay Area	Los Medanos Energy Cent	Pittsburg
24	10437	Bay Area	Byron Power Company,c/o	Byron
25	8664	Bay Area	Crockett Cogeneration,	Crockett

Table 13. CARB site data

Facility Information				
Facility Name :	Gilroy Energy Center, Llc		Facility ID :	11180
Street :	1400 Pacheco Pass Hwy		SIC Code :	4911
City :	Gilroy		Zip :	95020
Phone :	(408) 847-5328			
County :	Santa Clara			
Air Basin :	San Francisco Bay Area			
District :	Bay Area Aqmd			

Table 14. CARB emissions data

	Pollutant	Emissions	Unit
Data from 2002	TOG	16	Tons/Yr
	ROG	1.6	Tons/Yr
Download	CO	25	Tons/Yr
CSV file	NOX	261.1	Tons/Yr
	SOX	2	Tons/Yr
	PM	13	Tons/Yr
	PM10	12.8	Tons/Yr
	PM2.5	12.7	Tons/Yr

The Internet link highlighted in blue leads to the CARB site for more data and explanation of the terms. The CARB has also provided a spreadsheet for power plants that is specific to CO_2 emissions, and lists the locations by latitude and longitude. That data is presented here as Table 15. The data was formatted to read more easily as a table, and the facilities are sorted by the quantity of CO_2 shown. There are several blank items where the facility name is missing. An attempt was made to find the name that matched the facility code but only the one highlighted in red seemed to match. Also, three plants that may be subjected to further data collection could be new plants – too new for the EPA, EIA or CARB published data: KERN RIVER COGEN, WATSON COGEN, and SYCAMORE COGEN.

Table 15. CARB power plant and CO_2 data

Power Plant/Facility Code	CO_2 Emissions	Cartography Power Plant Database Name	Lat	Long	Primary Fuel Type
260	4,452,297	MOSS LANDING	36.81002626	-121.7735256	NG
271	4,288,462	PITTSBURG	38.04183969	-121.8940867	NG
315	3,957,192	ALAMITOS GENERATING STATION	33.77187484	-118.1017627	NG
259	3,101,024	Morro Bay Power Plant, LLC	35.37358428	-120.8571632	NG
350	2,445,546	ORMOND BEACH	34.13464809	-119.1654039	NG
400	2,238,622	HAYNES	33.76469361	-118.0958854	GAS
302	2,165,749	ENCINA	33.13790957	-117.3362904	NG
356	1,983,637	REDONDO BEACH GENERATING STAT	33.85239423	-118.3956194	NG
331	1,696,714	ETIWANDA	34.08220681	-117.5066143	NG
10496	1,688,449	KERN RIVER COGEN	35.42653591	-119.0199383	NG
228	1,664,108	CONTRA COSTA	38.02082529	-121.7611855	NG
329	1,652,392	COOLWATER	34.86753301	-116.8550332	NG
345	1,486,659	MANDALAY	34.20904491	-119.2507882	NG
330	1,447,083	EL SEGUNDO	33.91189725	-118.4247218	NG
310	1,413,186	SOUTH BAY	32.616965	-117.0971994	NG
50216	1,284,839	WATSON COGEN	33.82344406	-118.2477909	NG
50134	1,074,662	SYCAMORE COGEN	35.42653591	-119.0199383	NG
404	1,053,156	SCATTERGOOD	33.91964043	-118.4272374	GAS
399	1,024,155	HARBOR	33.78384257	-118.2195202	GAS
10002	895,505	ACE COGENERATION	35.76842447	-117.3851919	BIT

335	839,734	HUNTINGTON BEACH	33.64361334	-117.9759236	NG
52169	805,210	MIDWAY-SUNSET COGEN	35.22623281	-119.627677	NG
55084	636,410	CROCKETT COGEN	38.05296592	-122.2174783	NG
273	617,773	Not Found	37.7566141	-122.3852549	NG
7552	564,696	Not Found	38.51345841	-121.4669912	GAS
247	476,635	Not Found	37.74018394	-122.3771806	GAS
54626	472,707	MT. POSO COGENERATION	35.63075081	-118.9687743	BIT
10640	465,307	STOCKTON COGEN CO.	37.91103926	-121.2619094	BIT
54912	437,239	MARTINEZ REFINING CO.	38.01054141	-122.1132972	NG
10294	428,748	CALPINE KING CITY COGEN	36.29959628	-121.1368394	NG
10034	427,164	CALPINE GILROY I UNIT 1,2 & 3	37.0007571	-121.5365028	NG
246	426,765	Not Found	40.74296095	-124.2103062	GAS
389	425,101	EL CENTRO	32.81565696	-115.5405346	GAS
54238	409,932	Not Found	37.94466466	-121.3222531	BIT
52109	394,799	RICHMOND COGEN	37.94368149	-122.3741661	NG
10769	355,899	RIO BRAVO POSO	35.51539655	-119.0671285	BIT
10342	353,490	MARTINEZ REFINING CO.	38.01054141	-122.1132972	NG
10768	351,539	RIO BRAVO JASMIN	35.51867985	-119.0783973	PC
10213	348,024	EL SEGUNDO	33.91189725	-118.4247218	NG
341	337,466	LONG BEACH	33.7653669	-118.2251573	NG
7551	327,910	Not Found	38.52512936	-121.4059922	GAS
10684	317,112	ARGUS COGEN PLANT	35.76018446	-117.3892538	BIT
7527	298,276	CARSON COGEN	38.44657227	-121.4580439	GAS
10601	272,635	ARCO WILMINGTON CALCINER	33.793459	-118.2285183	PC

50170	226,505	BERRY COGEN - MIDWAY SUNSET	35.09949228	-119.403842	NG
50464	222,251	OXNARD II	34.21017843	-119.1410295	NG
50864	221,284	SARGENT CANYON COGEN	36.05410562	-120.8825366	NG
50865	217,213	SALINAS RIVER COGEN	36.07111715	-120.9120651	NG
50530	211,545	TEXACO LOS ANGELES REFINERY			OG
10886	208,780	GAYLORD CONTAINER	38.01403765	-121.7741722	NG
10373	206,045	Not Found	36.26854112	-119.6490639	PC
10370	204,491	WILBUR EAST POWER PLANT	38.00400842	-121.76071	PC
54001	202,072	CALPINE PITTSBURG	38.01864134	-121.8612474	NG
52096	199,645	PLACERITA UNIT I	34.37938306	-118.5013603	NG
10368	197,688	LOVERIDGE ROAD POWER PLANT	38.00737502	-121.8689077	PC
10367	195,184	EAST THIRD STREET POWER PLANT	38.02891269	-121.8537905	
10811	191,675	NAVAL STATION / NAVAL TRAINING CENTER	32.76486514	-117.1137484	NG
420	186,273	BROADWAY	34.12732216	-118.1290553	GAS
50612	183,545	MCKITTRICK COGEN	35.3224949	-119.6780733	NG
50493	181,660	DOUBLE "C" LTD.	35.50316082	-119.0351303	NG
50495	181,122	HIGH SIERRA LTD.	35.50612483	-119.0345213	NG
54768	181,103	LIVE OAK COGEN	35.61000279	-118.9123103	NG
10677	180,364	AES PLACERITA	34.37631723	-118.5085788	NG
10369	180,192	WILBUR WEST POWER PLANT	38.00391621	-121.7876322	PC
50119	179,248	FOSTER-WHEELER MARTINEZ COGEN L.P.	38.02356093	-122.0765382	PC
10371	178,157	NICHOLS ROAD POWER PLANT	38.02179124	-121.8784327	PC
10649	177,688	BEAR MOUNTAIN LTD.	35.42305482	-118.9367203	NG
10349	177,484	GREENLEAF UNIT TWO	39.13015881	-121.6412459	NG

50752	174,608	SOUTH BELRIDGE COGEN	35.44365351	-119.7376909	NG
10850	171,976	MOHAVE GENERATING STATION	35.11722222	-118.5332294	NG
50494	171,679	KERN FRONT LTD.	35.45345919	-119.0300528	NG
10169	171,269	CARSON COGEN CO.	33.87809288	-118.2498901	NG
10650	167,149	BADGER CREEK LTD.	35.60895981	-118.9449433	NG
50299	165,119	RIPON MILL	37.73338654	-121.1189194	NG
50003	161,856	CHALK CLIFF COGEN	35.09258094	-119.4067183	NG
50270	160,994	SANTA YNEZ	34.46408446	-120.0403139	NG
50270	160,994	Not Found			NG
6013	160,250	OLIVE	34.18099157	-118.3152187	GAS
10350	159,900	GREENLEAF UNIT ONE	39.04946335	-121.6882042	NG
10168	159,456	CARDINAL COGEN	37.43178417	-122.1812918	NG
10635	158,613	CORONA COGEN	33.8947384	-117.5779602	NG
52107	158,319	CHEVRON - KERN RIVER EASTRIDGE	35.44639464	-119.0139332	NG
54451	157,568	LOS ANGELES REFINERY	33.78433281	-118.2908472	OG
50388	153,221	Not Found	38.01634682	-122.2647894	NG
54749	152,923	GOAL LINE	33.12258489	-117.1002021	NG
7266	152,519	WOODLAND	37.65299886	-121.0191883	GAS
7307	150,714	REDDING POWER	40.49444917	-122.4930861	GAS

2.2 Petroleum Refining and Steel Manufacturing

Data sources for information on petroleum refineries and steel manufacturing plants include published data from EPA, EIA, and CARB. The Oregon Department of Environmental Quality (DEQ) Internet site was also useful. The DEQ Facility Profiler site provides names, addresses and latitude and longitude for permitted facilities, and is found at: http://deq12.deq.state.or.us/fp20/StartPage.aspx.

2.2.1 Petroleum Refinery Data

2.2.1.1 Alaska

Table 16 lists the refineries found in the EPA data for Alaska. They are sorted by size – barrels per day (BPD) of production. The EPA site does not provide CO_2 or other air emission data (other than total emissions), but other information is provided at the links in Table 16. Each facility level statistics link has another link to more detail that does include the latitude and longitude for the plant.

The "Further Data Inquiry" column reflects Nexant's recommendation for further study.

Table 16. EPA refinery data and links

Facility Information	Data Links	BPD	Further Data Inquiry
WILLIAMS ALASKA PETRO INC.1100 H & H LANE NORTH POLE, AK NO DATA PET.AK0003	Facility-level Statistics	197,000	Yes
TESORO ALASKA PETROLEUM CO KENAI SPUR ROAD KENAI, AK NO DATA PET.AK0001	Facility-level Statistics	72,000	Yes
PETRO STAR INC.NO DATA VALDEZ, AK NO DATA PET.AK0006	Facility-level Statistics	46,000	Yes
PETRO STAR INC.1200 H&H LANE NORTH POLE, AK NO DATA PET.AK0004	Facility-level Statistics	15,000	No
PHILLIPS ALASKA, INC.NORTH SLOPE KUPARUK, AK NO DATA PET.AK0002	Facility-level Statistics	14,000	No
BP EXPLORATION ALASKA NO DATA PRUDHOE BAY, AK NO DATA PET.AK0005	Facility-level Statistics	14,000	No

Table 17 presents data from the EIA that shows a breakdown of production at the refineries. This data was used as a basis for calculation of CO_2 emissions.

Table 17. EIA refinery data

(Barrels Per Stream Day)

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Total Alaska	0	2,800	5,000	0	4,000	0	0	13	20
Tesoro Petroleum Corp.									
Kenai	0	0	2,000	0	4,000	0	0	13	20
Williams Alaska Petro Inc.									
North Pole	0	2,800	3,000	0	0	0	0	0	0

2.2.1.2 Arizona

No petroleum refineries were found in the data for Arizona.

2.2.1.3 California

Table 18 presents the EPA Internet data for California. The first 6 and largest facilities are suggested for future work.

Table 18. EPA refinery data and links

Facility Information	Data Links	BPD	Further Data Inquiry
CHEVRON USA INC324 W EL SEGUNDO EL SEGUNDO, CA NO DATA PET.CA0021	Facility-level Statistics	260,000	Yes
BP WEST COAST PRODUCTS LLC NO DATA LOS ANGELES, CA NO DATA PET.CA0024	Facility-level Statistics	260,000	Yes

Facility Information	Data Links	BPD	Further Data Inquiry
CHEVRON USA INC NO DATA RICHMOND, CA NO DATA PET.CA0030	Facility-level Statistics	225,000	Yes
TESORO REFINING & MARKETING CO. AVON REFINERY MARTINEZ, CA NO DATA PET.CA0026	Facility-level Statistics	166,000	Yes
EQUILON ENTERPRISES LLC3485 PACHECO BLVD MARTINEZ, CA NO DATA PET.CA0025	Facility-level Statistics	160,000	Yes
EXXON MOBIL OIL CORP.3700 WEST 190TH ST TORRANCE, CA NO DATA PET.CA0034	Facility-level Statistics	149,000	Yes
TOSCO REFINING CO.1660 W. ANAHEIM ST WILMINGTON, CA 90744 PET.CA0038	Facility-level Statistics	131,000	No
VALERO REFINING CO. NO DATA BENICIA, CA NO DATA PET.CA0019	Facility-level Statistics	130,000	No
EQUILON ENTERPRISES LLC2101 E PACIFIC COAST WILMINGTON, CA NO DATA PET.CA0036	Facility-level Statistics	98,000	No
ULTRAMAR INC NO DATA WILMINGTON, CA NO DATA PET.CA0037	Facility-level Statistics	79,000	No
TOSCO REFINING CO. NO DATA RODEO, CA NO DATA PET.CA0031	Facility-level Statistics	73,000	No
EQUILON ENTERPRISES LLC NO DATA BAKERSFIELD, CA NO DATA PET.CA0018	Facility-level Statistics	66,000	No
PARAMOUNT PETROLEUM CORP 14708 DOWNEY AVE PARAMOUNT, CA NO DATAPET.CA0029	Facility-level Statistics	47,000	No
TOSCO REFINING CO. 2555 WILLOW ROAD ARROYO GRANDE, CA NO DATAPET.CA0014	Facility-level Statistics	42,000	No
PETROLEUM FUEL & TERMINAL (TEXACO) 2050 EDISON WAY LONG BEACH, CA NO DATAPET.CA0023	Facility-level Statistics	26,000	No
KERN OIL & REFINING CO. NO DATA BAKERSFIELD, CA NO DATAPET.CA0015	Facility-level Statistics	25,000	No

Facility Information	Data Links	BPD	Further Data Inquiry
SAN JOAQUIN REFINING CO INC NO DATA BAKERSFIELD, CA NO DATAPET.CA0016	Facility-level Statistics	24,000	No
HUNTWAY REFINING CO. NO DATA BENICIA, CA NO DATAPET.CA0020	Facility-level Statistics	13,000	No
CONOCO PHILLIPS 1660 SINTON RD. SANTA MARIA, CA 93454PET.CA0201	Facility-level Statistics	9,500	No
LUNDAY THAGARD CO. 9301 S GARFIELD SOUTH GATE, CA NO DATAPET.CA0033	Facility-level Statistics	8,500	No
HUNTWAY REFINING CO. 1651 ALAMEDA ST WILMINGTON, CA NO DATAPET.CA0035	Facility-level Statistics	5,500	No
TENBY INC. NO DATA OXNARD, CA NO DATAPET.CA0028	Facility-level Statistics	4,000	No
TRICOR REFINING LLC NO DATA OILDALE, CA NO DATA PET.CA0027	Facility-level Statistics	NIL	No

The EIA data for California is shown in Table 19. Additional contact information and latitude and longitude are shown for the first plant; similar information has been collected for other plants.

Table 19. EIA refinery data

(Barrels Per Stream Day)

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Total California	161,700	1,500	74,183	28,300	70,200	26,400	125,410	1,138	4,196
BP West Coast Products LLC									
Bp Carson Refinery External Affairs Group 1801 E. Sepulveda Blvd. Carson, CA 90749 (310) 816-8100 Email: info@bpcarson.com Latitude: 33.91633 Longitude: -118.39614	15,000	0	0	0	0	0	12,900	105	350

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Chevron U.S.A. Inc.									
Chevron USA, Inc. 324	24,500	0	0	4,000	20,000	0	18400	147	600
Chevron Richmond Refinery	21,000	0	0	6,000	28,000	18,500	0	185	448
Edgington Oil Co.									
EDGINGTON OIL CO.	0	0	10,750	0	0	0	0	0	0
ExxonMobil Refg & Supply Co.									
EXXONMOBIL OIL CORP. TORRANCE REFY.	24,000	0	0	0	0	0	17,725	138	440
Greka Energy									
SANTA MARIA REFINING COMPANY	0	0	6,000	0	0	0	0	0	0
Kern Oil & Refining Co.									
Bakersfield	0	0	0	0	0	0	0	0	5
Lunday Thagard									
South Gate	0	0	5,833	0	0	0	0	0	0
Paramount Petroleum Corp.									
Paramount	0	0	16,500	0	0	0	0	0	0
Phillips 66 Co.									
Arroyo Grande	0	0	0	0	0	0	5,500	0	110
Rodeo	0	0	0	0	9,400	0	5,200	84	310
Wilmington	9,900	0	0	3,100	12,800	0	16,800	105	370
San Joaquin Refining Co Inc.									
Bakersfield	0	1,500	6,500	0	0	4,000	0	4	3
Shell Oil Products US									
(Formerly Equilon Enterprises LLC)									
Bakersfield	0	0	0	700	0	0	6,000	25	105
Martinez	11,000	0	15,000	0	0	3,900	8,385	107	437
Wilmington	12,500	0	0	7,500	0	0	10,000	15	285

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Tenby Inc.									
Oxnard	0	0	1,600	0	0	0	0	0	0
Tesoro Refg & Mktg Co									
(Formerly Ultramar Inc.)									
Martinez	14,000	0	0	0	0	0	8,600	82	200
Ultramar Inc.									
Wilmington	14,000	0	0	7,000	0	0	9,500	0	230
Valero Refining Co. California									
Benicia	15,800	0	9,000	0	0	0	6,400	141	303
Wilmington	0	0	3,000	0	0	0	0	0	0

In addition to the National databases by EPA and EIA, the State of California also has significant sources of energy data in the offices of the California Energy Commission (CEC), and CARB. The CARB Internet site at http://www.arb.ca.gov/app/emsinv/facinfo/facinfo.php?dd= has a listing of the refineries in California, and for each has emission data for criteria pollutants, but not CO_2.

Table 20. CARB list of refineries

#	Fac ID	District	Facility Name	City	#	Fac ID	District	Facility Name	City
1	12626	Bay Area	Valero Refining Company	Benicia	26	22194	S. Coast AQMD	Arco	Long Beach
2	10	Bay Area	Chevron Products Compan	Richmond	27	24364	S. Coast AQMD	Industrial Process & Ch	Long Beach
3	16	Bay Area	Conocophillips - San Fr	Rodeo	28	28188	S. Coast AQMD	Union Oil Co Of Cal	Los Angeles
4	12870	Bay Area	Shell Chemical Lp	Martinez	29	37369	S. Coast AQMD	Paramount Petr Corp	Long Beach
5	11	Bay Area	Shell Martinez Refinery	Martinez	30	56056	S. Coast AQMD	Texaco Refining & Marke	Los Angeles
6	14628	Bay Area	Tesoro Refining And Mar	Martinez	31	87942	S. Coast AQMD	San Luis Tank Piping Co	00

#	Fac ID	District	Facility Name	City	#	Fac ID	District	Facility Name	City
7	14630	Bay Area	Tesoro Refining And Mar	Pittsburg	32	800012	S. Coast AQMD	Arco Products Co	Carson
8	14629	Bay Area	Tesoro Refining And Mar	Martinez	33	800026	S. Coast AQMD	Ultramar Inc (nsr Use O	Wilmington
9	845	San Joaq. Valley	Tesoro Refining Marketi	Stockton	34	800030	S. Coast AQMD	Chevron U.s.a. Inc.	El Segundo
10	50297	San Joaq. Valley	Mt Poso Tank Farm	Oildale	35	800089	S. Coast AQMD	Mobil Oil Corp	Torrance
11	207	San Joaq. Valley	World Oil Corp.	Bakersfield	36	800103	S. Coast AQMD	Powerine Oil Co (eis Us	Santa Fe Spr
12	46	San Joaq. Valley	Tricor Refining, Llc	Oildale	37	800116	S. Coast AQMD	Shell Oil Co (eis Use O	Wilmington
13	44	San Joaq. Valley	Tricor Refining, Llc	Oildale	38	800119	S. Coast AQMD	Shell Oil Co (eis Use)	Van Nuys
14	38	San Joaq. Valley	Kern Oil & Refining Com		39	800164	S. Coast AQMD	Powerine Oil Company	Long Beach
15	37	San Joaq. Valley	Kern Oil & Refining Com	Bakersfield	40	800183	S. Coast AQMD	Paramount Petr Corp	Paramount
16	34	San Joaq. Valley	Equilon Enterprises Llc	Bakersfield	41	800184	S. Coast AQMD	Golden West Ref Co	Santa Fe Spr
17	35	San Joaq. Valley	Las Palmas Oil & Dehydr	Bakersfield	42	800264	S. Coast AQMD	Edgington Oil Company	Long Beach
18	33	San Joaq. Valley	Equilon Enterprises Llc	Bakersfield	43	800275	S. Coast AQMD	Chemoil Refining Corp.	Signal Hill
19	36	San Joaq. Valley	San Joaquin Refining Co	Bakersfield	44	800362	S. Coast AQMD	Tosco Refining Company	Carson
20	13	San Luis Obispo	Tosco Santa Maria Refin	Arroyo Grand	45	800363	S. Coast AQMD	Tosco Refining Company	Wilmington
21	4640	Santa Barbara	Smrc/union Sugar	Santa Maria	46	800370	S. Coast AQMD	Equilon Enterprises, Ll	Wilmington
22	64174	S. Coast AQMD	Texaco Refining And Mar	Anaheim	47	800372	S. Coast AQMD	Equilon Enterprises, Ll	Carson
23	11056	S. Coast AQMD	Chevron U.s.a. Inc	San Gabriel	48	800393	S. Coast AQMD	Valero Wilmington Aspha	Wilmington
24	12395	S. Coast AQMD	Union Oil Of Cal, Oil &	Saugus					
25	16213	S. Coast AQMD	Mobil Oil Corp, West Co	Torrance					

Table 21 shows one example of the emission data on the links to all the facilities. The abbreviations for the pollutants are provided as links on the CARB site. The links have been removed from the table for simplicity.

Table 21. CARB emissions data

	Pollutant	Emissions	Unit
Data from 2002	TOG	2084.6	Tons/Yr
	ROG	1461.7	Tons/Yr
Download	CO	739.8	Tons/Yr
CSV file	NOX	2898.3	Tons/Yr
	SOX	1465.8	Tons/Yr
	PM	404.5	Tons/Yr
	PM10	357	Tons/Yr
	PM2.5	346.1	Tons/Yr

2.2.1.4 Nevada

EPA and EIA data for Nevada are presented in Tables 22 and 23. There is only the one small plant, and further data collection is not suggested because the plant is not a large source of CO_2. The difference in the databases for production (5,000 BPD versus 2,000 BPD) is noted.

Table 22. EPA refinery data and links

Facility Information	Data Links	BPD	Further Data Inquiry
EAGLE SPRINGS REFINING NO DATA EAGLE SPRINGS, NV NO DATA PET.NV0105	Facility-level Statistics	5,000	No

Table 23. EIA refinery data

(Barrels Per Stream Day)

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Total Nevada	0	0	2,000	0	0	0	0	0	0
Foreland Refining Corp.									

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Eagle Springs	0	0	2,000	0	0	0	0	0	0

2.2.1.5 Oregon

Tables 24 and 25 show the single refinery (asphalt producer) in Oregon.

Table 24. EPA facilities and links

Facility Information	Data Links	BPD	Further Data Inquiry
CHEVRON U.S.A. INC. 5501 NW FRONT AVE PORTLAND (WILBRIDGE), OR NO DATA PET.OR0117	Facility-level Statistics	8,500 ASPHALT PLANT	No

Table 25. EIA refinery data

(Barrels Per Stream Day)

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Total Oregon	0	0	8,400	0	0	0	0	0	0
Chevron U.S.A. Inc.									
Portland (Willbridge)	0	0	8,400	0	0	0	0	0	0

2.2.1.6 Washington

Several significant refinery operations exist in Washington, as shown in Tables 26 and 27. Three are recommended for further investigation.

Table 26. EPA refinery data and links

Facility Information	Data Links	BPD	Further Data Inquiry
ATLANTIC RICHFIELD COMPANY NO DATA BLAINE, WA 98231 PET.WA0169	Facility-level Statistics	223,000	Yes
PUGET SOUND REFINING CO. NO DATA ANACORTES, WA NO DATA PET.WA0168	Facility-level Statistics	145,000	Yes
TESORO NORTH WESTWEST MARCH POINT ROAD ANACORTES, WA 98221 PET.WA0167	Facility-level Statistics	110,000	Yes
TOSCO REFINING CO., FERNDALE REFINERY NO DATA FERNDALE, WA NO DATA PET.WA0170	Facility-level Statistics	89,000	No
U S OIL & REFINING CO3001 MARSHALL AVE TACOMA, WA NO DATA PET.WA0173	Facility-level Statistics	42,000	No

Table 27. EIA refinery data

(Barrels Per Stream Day)

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Total Washington	28,300	0	13,500	12,300	2,700	0	16,000	128	453
BP West Coast Products LLC									
Ferndale (Cherry Point)	0	0	0	6,000	0	0	7,600	128	242
Phillips 66 Co.									
Ferndale	5,500	0	0	2,700	0	0	0	0	46
Shell Oil Products US									
(Formerly Equilon Enterprises LLC)									
Anacortes	10,400	0	0	0	0	0	8,400	0	155
Tesoro West Coast									
Anacortes	12,400	0	5,500	3,600	0	0	0	0	0
U.S. Oil & Refining Co.									

State/Refiner/Location	Alkylates	Aromatics	Asphalt and Road Oil	Isobutane	Isopentane and Isohexane	Lubricants	Marketable Petroleum Coke	Hydrogen MMcfd	Sulfur (short tpd)
Tacoma	0	0	8,000	0	2,700	0	0	0	10

2.2.2 Steel Manufacturing Data

There are several mini-mill steel production facilities (Table 28) in the West Coast Region. These were not found to be significant stationary CO_2 sources for WESTCARB.

Table 28. EPA steel manufacturing data and links

Facility Information	Data Links	Production tons/year	Further Data Inquiry
ARIZONA			
NORTH STAR STEEL CO. 3000 HIGHWAY 66 SOUTH KINGMAN, AZ 86401STL.AZ0034	Facility-level Statistics	500,000	Yes
CALIFORNIA			
TAMCO 12459 ARROW HIGHWAY RANCHO CUCAMONGA, CA 91739STL.CA0035	Facility-level Statistics	700,000	Yes
OREGON			
CASCADE STEEL ROLLING MILLS 3200 NORTH HIGHWAY 99W MCMINNVILLE, OR 97128STL.OR0080	Facility-level Statistics	700,000	Yes
OREGON STEEL MILLS, INC.14400 N. RIVERGATE BLVD.PORTLAND, OR 97203STL.OR0081	Facility-level Statistics	1,000,000	Yes
WASHINGTON			
BIRMINGHAM STEEL CORP. 2424 S.W. ANDOVER SEATTLE, WA 98106STL.WA0115	Facility-level Statistics	840,000	Yes

Table 29 shows generic CO_2 emissions for steel manufacturing.

Table 29. Steel manufacturing CO_2 emissions

CO_2 emissions per metric ton of liquid steel	
Process	**Kg/ton**
Ore/pellet/coke/blast furnace/BOF	2,010
Ore/pellet/Midrex plant/EAF	1,874
Ore/pellet/Corex plant/BOF	3,089
50-percent ore/rotary hearth and scrap/EAF	1,872
40-percent ore/iron carbide and scrap/EAF	982
Ore/iron carbide/carbide-to-steel process	1,089
Scrap/EAF	641
Note: Assumes coal-generated electricity used for oxygen generation and all other electricity.	
Source: Gordon Geiger	

BOF: Basic Oxygen Furnace
EAF: Electric Arc Furnace

2.3 Cement Plants, Lime Plants, and Natural Gas Processing

2.3.1 Cement and Lime Plant Data

The following tables list cement and lime plants for the West Coast Regional Partnership. No cement plants were found for Alaska, so it is believed that cement is imported to Alaska from other West Coast plants.

2.3.1.1 Arizona, Nevada, and Washington

All the plants for Arizona, Nevada and Washington were designated for further investigation. Lacking plant-specific CO_2 data, a methodology proposed by the EPA was used for estimating CO_2. The plant information (Table 30) is from the U.S. Geological Survey 2002 Directory of Lime Plants (http://minerals.usgs.gov/minerals/pubs/commodity/lime/limedir02.pdf); the Portland Cement Association (PCA) list of members on the Internet at: http://www.cement.org/pca/pca_directory.asp .

Table 30. Cement and lime plants (AZ, NV, WA)

ARIZONA	NEVADA (LIME PLANTS)	WASHINGTON
Arizona Portland Cement Company 2400 N. Central Ave., Ste. 308 Phoenix, AZ 85004-1396 Phone: 602-271-0069 Fax: 602-254-9027	**Chemical Lime Co.** Apex Plant, Henderson Plant Old Salt Lake Highway N. Las Vegas, NV 89124	**Ash Grove Cement Co.** Seattle, WA Plant Henrik Voldbaek-Plant Manager 3801 E. Marginal Way, S. Seattle, WA 98134-1147 Phone: (206) 623-5596 FAX: (206) 623-5355
Rillito Cement Plant 11115 Casa Grande Hwy P.O. Box 338 Rillito, Arizona 85654 520/682-2221	**Graymont Western US Inc.** Pilot Peak Elko Plant 3950 South 700 East Suite 301 Salt Lake City, UT 84107	**Ash Grove Cement Co.** 11811 NE 1st St., Ste. A310 Bellevue, WA 98005 **Phone:** 425-688-0110 **Fax:** 425-688-0122
Phoenix Cement 8800 E. Chaparral Rd, Ste. 155 Scottsdale, AZ 85250-2618 Phone: 480-850-5757 Fax: 480-850-5758		**Lafarge North America Inc.** N 209 Havana St. Spokane, WA 99202 Phone: 509-535-0181 Fax: 509-535-0184
Clarkdale Plant: Phoenix Cement Company 3000 W. Cement Plant Road P.O. Box 428 Clarkdale, AZ 86324 Phone: (928) 634-2261 Fax: (928) 634-3543		**Seattle Cement Plant** SEATTLE, WASHINGTON US 98106-1517 Tel: +1 206-937-8025 Fax: +1 206-932-3803
		Graymont Western US Inc. Tacoma Plant Tacoma Lime Division (C&S) 3950 South 700 East Suite 301 Salt Lake City, UT 84107

2.3.1.2 California

Table 31 lists the California plants taken from the CARB Internet site. These plants have been screened by the amounts of emissions shown by the CARB data.

Table 31. California cement and lime plants

Cement Plants

	FAC ID	DISTRICT	FACILITY NAME	CITY	Further Data Inquiry
1	11800001	Mojave Desert	Mitsubishi Cement 2000	Lucerne Vall	Yes
2	1200003	Mojave Desert	Txi Riverside Cement Co	Oro Grande	Yes
3	800182	S. Coast AQMD	Riverside Cement Co (ei	Riverside	No
4	800181	S. Coast AQMD	California Portland Cem	Colton	Yes
5	100006	Mojave Desert	Cemex - River Plant	Victorville	No
6	100005	Mojave Desert	Cemex - Black Mountain	Apple Valley	Yes
7	1551	Bay Area	Rmc Pacific Materials I	Fairfield	No
8	1186	Monterey Bay	Rmc Pacific Materials	Davenport	No
9	498	Yolo-Solano	Halliburton Energy Serv	Woodland	No
10	265	Bay Area	Rmc Pacific Materials I	Redwood City	No
11	77	Sacramento	Nevada Cement Company	Sacramento	No
12	21	Kern County	National Cement Co	Lebec	No
13	20	Kern County	Lehigh Southwest Cement	Monolith	No
14	17	Bay Area	Hanson Permanente Cemen	Cupertino	Yes
15	9	Kern County	California Portland Cem	Mojave	Yes
16	2	Shasta County	Lehigh Southwest Cement	Redding	No

Lime Plants

	FAC ID	DISTRICT	FACILITY NAME	CITY	Further Data Inquiry
1	256	Monterey Bay	Chemical Lime Company	Salinas	No
2	1060	San Joaq.	Chemical Lime Company	Stockton	No

		Valley			
3	61201277	Mojave Desert	Kinne Limestone Product	Lucerne Vall	No
4	17	San Luis Obispo	Lime Mountain Co	Paso Robles	No
5	100	Great Basin Unif.	Panamnit Valley Limestone	Panamint Val	No
6	12700390	Mojave Desert	Partin Limestone Produc	Lucerne Vall	No
7	17	El Dorado County	Spreckles Limestone Agg	Cool	No
8	236	San Joaq. Valley	Valimet Inc	Stockton	No
9	916	San Joaq. Valley	Valimet, Inc	Stockton	No

2.3.1.3 Oregon

Table 32 shows data for plants in Oregon. The plants are listed from the PCA data, and supplemented with data from the Oregon DEQ. The DEQ database contains locations in latitude and longitude for the plants. All the plants were designated for further investigation. Links in the Table lead to the DEQ Internet sites.

Table 32. Oregon cement and lime plants

	Facility/Site Information	OREGON DEQ DATA		
#1	Ash Grove Cement Co 33060 SHIRTTAIL CREEK RD DURKEE , 97905	Cleanup, Haz Waste	Go	Durkee, OR Plant Michael Hrizuk-Plant Manager 33060 Shirttail Creek Road Durkee, OR 97905-0287 Phone: (541) 877-2411 FAX: (541) 877-2246
#2	ASH GROVE CEMENT CO 4098 N PORT CENTER WAY PORTLAND , 97217	Water Discharge Permit	Go >>	**Western Division Office** 6720 SW Macadam Ave, Suite 300 Portland, OR 97219 **Toll-free:** (800) 547-3724 **Phone:** (503) 293-2333 **FAX:** (503) 293-8999

#3	ASH GROVE CEMENT COMPANY 13939 N RIVERGATE BLVD PORTLAND , 97203	Air Discharge Permit, UST, Leaking UST, Haz Waste, Water Discharge Permit	Go >>	Rivergate Lime Plant Gary Wright-Plant Manager 13939 N. Rivergate Blvd. Portland, OR 97203 Phone: (503) 286-1677 FAX: (503) 289-2272
#4	ASH GROVE CEMENT COMPANY MILE POST 348 LIME , 97907	Cleanup, Water Discharge Permit	Go >>	

2.3.2 Natural Gas Processing Data

Limited information on natural gas processing plants was collected from the Energy Information Agency Natural Gas Navigator Internet site: http://tonto.eia.doe.gov/dnav/ng/ng_pp_sum_sca_a_d.htm.

Table 33 presents data for the year 2001 and shows the total volumes of production for the United States.

Table 33. U.S. total natural gas plant processing

Data Series	2001
Natural Gas Processed (Million Cubic Feet)	16,511,427
Total Liquids Extracted (Thousand Barrels)	682,873
Extraction Loss (Million Cubic Feet)	953,984

Table 34 shows similar values for Alaska, and indicates that natural gas processing is a major operation in the State. As currently understood, much of the gas is used internally at the gas and oil fields.

Table 34. Alaska natural gas plant processing

Data Series	2002
Natural Gas Processed (Million Cubic Feet)	2,984,807
Total Liquids Extracted (Thousand Barrels)	30,334

Extraction Loss (Million Cubic Feet)	36,149
Estimated Heat Content of Extraction Loss (Billion Btu)	134,686

Table 35 shows the 2002 data for California.

Table 35. California natural gas plant processing

Data Series	2002
Natural Gas Processed (Million Cubic Feet)	258,271
Total Liquids Extracted (Thousand Barrels)	8,625
Extraction Loss (Million Cubic Feet)	11,060
Estimated Heat Content of Extraction Loss (Billion Btu)	36,055

There was no information for Arizona, Nevada, and Washington in the EIA database. As none of these states are major producers of natural gas, it can be assumed that gas processing is not a significant source of CO_2 in those states.

3 Geologic Sinks

3.1 Characterization Methodology

WESTCARB has focused on sedimentary basins as the initial most-promising targets for geologic sequestration. Our approach for various states has followed similar steps: First, the extent (area) of the basins is determined and entered into a GIS layer. Second, baseline data are collected and preliminary screening is conducted using such criteria as the presence of porous sediments, depth, and restricted access, resulting in a list of basins for which more detailed data on geologic properties are to be obtained. Priority is given to basins in which there are potential value-added benefits from enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coal bed methane recovery (ECBM). Data from reservoirs in these basins form the bulk of the characterization data. The third step entails evaluating CO_2 storage capacity. The final step integrates the characterization data with source and transportation data to evaluate economics and develop supply curves for regional source/sink options.

In California, the California Geologic Survey identified and catalogued sedimentary basins within California's 11 geomorphic provinces. Selected basins included all large or hydrocarbon-producing basins, as well as numerous smaller basins identified from the 1:750,000 scale geologic map of California (Jennings *et al.*, 1977). Where basins extended offshore, only the onshore portions were considered. This resulted in an inventory of 104 basins, 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 to illustrate the distribution of known oil and gas fields. Basins were screened to determine preliminary suitability for potential CO_2 sequestration, with those basins not meeting the screening criteria excluded from further consideration. Screening involved literature searches and analysis of available well logs. Criteria included the presence of significant porous and permeable strata, thick and pervasive seals, and sufficient sediment thickness to provide critical state pressures for CO_2 injection (>800 m—2,625 ft). Accessibility was also considered, with basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs-administered lands, and military installations being excluded. Most of the basins excluded for this reason are located in the arid desert valleys of the Basin and Range and Mojave Desert geomorphic provinces. Structural closure or stratigraphic trapping was not considered a prerequisite for saline aquifers at the screening level.

To identify areas of adequate sedimentary fill, depth-to-basement contour maps were prepared for those basins containing sufficient basement penetrations. This included the Sacramento, San Joaquin, and Salinas basins. In some producing basins, where basement well control is limited or absent, basement contour maps were extrapolated from shallower structure maps (Eel River Basin), or published geophysical depth-to-basement maps were used (Los Angeles, Ventura Basins).

To characterize potential saline aquifers and hydrocarbon reservoirs, oil and gas field and reservoir data were assembled for depleted and producing fields. Data was compiled in field level and reservoir-level databases and attributed to the California oil and gas field GIS layer for manipulation and spatial analysis by other WESTCARB participants. Field-level data included information such as location, depth, field area, cumulative production, and depth-to-base of fresh water. Field-level database parameters are shown in Table 1.

Table 36. Sample content of a Field Table database record

Field Code:	VE024
Field:	Honor Rancho Oil
Discovery Well Operator:	The Texas Co.
Discovery Well:	Honor Rancho A -1
Section:	6
Township:	4N
Range:	16W
Meridian:	SB
Discovery Date:	8/1/1950
Deepest Well Operator:	So. California Gas Co.
Deepest Well:	Wayside Unit 28
Section:	7
Township:	4N
Range:	16W
Meridian:	SB
Depth (ft.)	11,747
Field Area (ac.)	450
Cum. Oil Prod. (MBO)	31,098
Cum. Gas Prod. (MMCF)	52,992
Base Fresh Water:	1,150

Reservoir-specific parameters for producing, abandoned, or shut-in reservoirs in each field were compiled in the reservoir-level database. These data included reservoir fluid (oil, gas, water), zone status (producing, abandoned, shut-in), average depth, average thickness, producing area, porosity, permeability, initial pressure and temperature, formation water salinity, seal thickness, trap type (structural or stratigraphic), and history of secondary and tertiary recovery efforts. A measure of "fracture intensity" was assigned for most reservoirs to instill a general sense of fracturing and/or faulting. This subjective measure was assigned a value of low, medium, or high, based solely on the number of mapped faults illustrated in published California Department of Conservation, Division

of Oil, Gas, and Geothermal Reservoirs (DOGGR) field maps (L = 0–1 fault; M = 2–3 faults; H = 4+ faults). An example of reservoir database parameters is shown in Table 2.

Table 37. Sample content of a Zone Table database record

Field Code:	VE024	Perm. (md):	20
Zone:	Modelo Fm.	Perm. Range Min. (md):	179
Age:	U. Miocene	Perm. Range Max. (md):	
Oil or Gas:	O	Pressure (lb/ft.):	2,962
Date of Discovery:	12/1/1950	Press. Range Min. (lb/ft.):	4,500
Zone Status (P/A/SI):	P	Press. Range Min. (lb/ft.):	190
API Gravity:		Temperature (ºF):	
API Range Min.:	35	Temp. Range Min. (ºF):	
API Range Max.:	39	Temp. Range Max. (ºF):	
GOR:		Salinity (ppm NaCl):	
GOR Range Min.:	220	Sal. Range Min. (ppm NaCl):	11,200
GOR Range Max.:	1,250	Sal. Range Max. (ppm NaCl):	24,800
Sp. Gravity:		TDS (ppm):	20,200
Sp. Gravity Min.:	0.470	TDS Range Min. (ppm):	
Sp. Gravity Max.:	0.765	TDS Range Max. (ppm):	
BTU:	1,066	Seal:	Modelo Fm.
BTU Range Min.:		Seal Thickness (ft.):	
BTU Range Max.:		Seal Thickness Min. (ft.):	5
Cum. Oil (MBO):	29,094	Seal Thickness Max. (ft.):	50
Cum. Gas (MMCF):	47,601	Trap Type:	Stratigraphic
No Pool Breakdown:		Fault Intensity:	L
Depth (ft.):		ERP 1:	Gas Injection
Depth Range Min.:	6,481	ERP 1 Start:	1954
Depth Range Max.:	10,000	ERP 1 Stop:	1956
Thickness (ft.):		ERP 2:	Waterflood
Thickness Range Min. (ft.):	94	ERP 2 Start:	1959
Thickness Range Max. (ft.):	310	ERP 2 Stop:	1966
Producing Area (ac.):	400	ERP 3:	Waterflood
Porosity (%):		ERP 3 Start:	1972
Porosity Range Min. (%):	7	ERP 3 Stop:	1975
Porosity Range Max. (%):	26		

In Nevada, the minimum-basin-depth criterion was taken as 1,000 m (3,300 ft), owing to a generally higher geothermal gradient in the Basin and Range province. The Nevada

Bureau of Mines and Geology (NBMG) developed a GIS-based screening methodology that takes into account the proximity of potential geologic sinks to faults, mineral and geothermal resources, populated areas, other restricted lands, and water resources (Price *et al*., 2005). The NBMG also developed a method, illustrated in Table 3, to interrogate well records for information relevant to geologic sequestration.

Table 38. Information recorded from records of deep wells drilled in Nevada (Hess, 2004)

DEFINITIONS

CO_2 reservoir rock ≡ sandstone, conglomerate, sand, or gravel

Seal rock ≡ shale, mudstone, claystone, mud, clay, halite, gypsum, salt, or nonwelded (possibly clay- or zeolite-altered) ash-flow tuff

NEITHER A CO_2 RESERVOIR ROCK NOR SEAL ≡ limestone, dolomite, fractured volcanic rock, fractured sandstone, quartzite, metamorphic rocks, or granite or other igneous rocks

Data collected from well records, if available, in wells within areas not otherwise excluded for consideration of CO_2

1. Total depth of well.
2. Are there potential CO_2 reservoir rocks in the well below 1 km (3,281 ft) depth? If no, go to next well.
3. Is there a potential seal below 1 km and above that reservoir rock? If no, go to next well.
4. Depth to base of Cenozoic/Tertiary volcanic rocks and alluvium.
5. Depth to base of deepest reservoir rock in pre-Tertiary sedimentary package.
6. How fresh is the water in this deepest reservoir rock? (Total dissolved solids – TDS?)
7. How porous is this deepest reservoir rock? % of porosity?
8. How permeable is this deepest reservoir rock? K in millidarcy?
9. Thickness of the thickest single pre-Tertiary reservoir rock.
10. How fresh is the water in this thickest pre-Tertiary reservoir rock?
11. How porous is this thickest pre-Tertiary reservoir rock?
12. How permeable is this thickest pre-Tertiary reservoir rock?
13. Total thickness of all pre-Tertiary reservoir rocks.
14. Thickness of the thickest single pre-Tertiary seal rock above the deepest reservoir rocks.
15. Total thickness of all pre-Tertiary seal rocks above the deepest reservoir rocks.
16. Depth to base of deepest reservoir rock in Tertiary sedimentary package below 1 km.
17. How fresh is the water in this deepest reservoir rock in Tertiary package?
18. How porous is this deepest reservoir rock in Tertiary package?
19. How permeable is this deepest reservoir rock in Tertiary package?
20. Thickness of the thickest single Tertiary reservoir rock below 1 km.
21. How fresh is the water in this thickest single Tertiary reservoir?
22. How porous is this thickest single Tertiary reservoir?
23. How permeable is this thickest single Tertiary reservoir?
24. Total thickness of all Tertiary reservoir rocks below 1 km.
25. Thickness of thickest single Tertiary seal rock below 1 km.
26. Total thickness of all Tertiary seal rocks below 1 km.
27. Total thickness of all Tertiary seal rocks below 1 km and above shallowest reservoir rock.
28. Thickness of halite beds below 1 km.

FACTORS THAT CAN NOW BE DERIVED FROM THESE NUMBERS

A. Total thickness of potential reservoir rocks = #13 + #24
B. Total thickness of potential seal rocks above the deepest reservoir rock and below 1 km = #15 + #26
C. Reservoir rock to seal rock ratio = #A/#B, ~ sand/shale ratio

In Oregon and Washington, GIS layers were developed that give the location of sedimentary basins. Data on the overall geology of sedimentary basins and the available reservoir properties were assembled. Data from the few available deep wells penetrating the basalt layers in the eastern portions of the states were reviewed to establish the presence of sediments at depths 300 m (1,000 ft) to over 2,700 m (9,000 ft). Information on coal formations as potential sinks was also compiled, including available data on coal rank, percent methane saturation, and sorbtive capacity.

3.2 GIS Database Description

The GIS database for WESTCARB is housed in an Enterprise Geodatabase format using ArcSDE (Spatial Database Engine) from Environmental Systems Research Institute, Inc. (ESRI). This database can be connected directly to any ESRI ArcMap client version 9.0 or greater. The data layers can also be requested from AGRC in a format that can be used in any common GIS software. A complete list of available layers is given with the WESTCARB deliverable associated with Task 1, Item 2 ("GIS-formatted data"). The layers are organized into the main categories of "sedimentary basins," "sources," and "base layers." The sedimentary basin category contains sub-categories of "geologic features" and "supporting data".

An interactive web map has been created to provide access to the data layers via the Internet. This interactive map can be viewed at http://atlas.utah.gov/co2wc. In addition to providing a means by which the GIS data layers can be viewed and queried, this interactive map includes tools that let the user perform some basic analysis operations, such as buffering and linear distance measurement.

In addition to the compilation of the partnership database, the Utah Automated Geographic Reference Center has cooperated with, and will continue to cooperate with the NATCARB (national carbon) database in the modeling and serving of the nationwide distributed carbon atlas. The data layers are served via ESRI's ArcIMS map services, which are harvested by the NATCARB interactive map portal.

References

Hess, R.H., 2004, Nevada Oil and Gas Well Database (NVOILWEL): Nevada Bureau of Mines and Geology Open-File report 04-1, 288 pages and dBASE file, web address: http://www.nbmg.unr.edu/lists/oil/oil.htm.

Jennings, C.W., Strand, R.G., and Rogers, T.H., 1977, Geologic map of California: California Division of Mines and Geology, scale 1:750,000.

Price, J., Hess, R., Fitch, S., Faulds, J., Garside, L., Shevenell, L., and Warren, S., 2005, Preliminary Assessment of the Potential for Carbon Dioxide Sequestration in Geological Settings in Nevada, Nevada Bureau of Mines and Geology, report to Department of Energy, Contract No. DE-FC26-03NT41984.

Appendix II, Final Report

WESTCARB GIS-Formatted Data
Task 1.0, item (2) from SOPO

West Coast Regional Carbon Sequestration Partnership (WESTCARB)
DOE Contract No.: DE-FC26-03NT41984
Contract Period: October 1, 2003–September 30, 2005
Compiler: Barry Biediger, Utah Automated Geographic Reference Center

This document outlines all GIS layer data included in the West Coast Regional Carbon Sequestration Partnership's (WESTCARB's) GIS database. These data are currently housed at the Utah Automated Geographic Reference Center, and many layers are accessible via the online WESTCARB Interactive Map: http://atlas.utah.gov/co2wc/.

SOURCE DATA

Layer: refineries
Point features representing refineries in West Coast Regional Carbon Sequestration Partnership states.

Layer: CementandLimePlants
Point features representing cement and lime plants in West Coast Regional Carbon Sequestration Partnership states.

Layer: GasProcessingPlants
Point features representing oil and gas processing centers in West Coast Regional Carbon Sequestration Partnership states.

Layer: PowerPlants
Point feature class representing power plants in West Coast Regional Sequestration Partnership states.

Layer: AFCLTY_BC:
Oil and Gas Facility locations for British Columbia (Oil and gas Commission data)

GEOLOGIC DATA

Category: Base Layers

Layer: WC_StatesDetailed
This data set portrays the State boundaries of the contiguous states

that are members of the West Coast Carbon Sequestration Partnership.
The original data set was created by extracting
the State boundary polygons from the individual 1:2,000,000-scale State
boundary Digital Line Graph (DLG) files produced by the U.S. Geological
Survey. These files were then merged into a single coverage.

Layer: WC_StatesSimplified
Simplified representation of the boundaries of West Coast Carbon Sequestration Partnership states.

Layers:
AK_Geonames
AZ_Geonames
CA_Geonames
NV_Geonames
OR_Geonames
WA_Geonames
The Geographic Names Information System (GNIS), developed by the U.S. Geological Survey in cooperation with the U.S. Board on Geographic Names (BGN), contains information about physical and cultural geographic features in the United States and associated areas.

Layer: BC_Geonames
Toponymic information is based on the Geographic Names Data Base, containing official standard names approved by the United States Board on Geographic Names and maintained by the National Geospatial-Intelligence Agency.

Layer: AK_ArcticRefuge
The coverage depicts the official legislative boundary of Arctic National Wildlife Refuge

Layer: US_Interstates
This data set portrays the Interstates in the United States

Layer: US_StatesDetailed
U.S. state boundaries

Layer: WC_Railroads
This data set includes railroads in the West Coast Carbon Sequestration Partnership States

Layer: WC_MajorRoads
This data set portrays the major roads in the West Coast Carbon Sequestration Partnership States.

Layer: WC_StreamsWaterBodies
The data set portrays the polygon and line water features of the West Coast Carbon Sequestration Partnership States.

Layer: US_StatesGeneralized
U.S. state boundaries (Generalized).

Layer: WC_BuiltUpAreas

U.S. National Atlas Urbanized Areas represents urban areas in the West Coast Carbon Sequeststration Partnership States derived from the urban areas layer of the Digital Chart of the World (DCW).

Layer: WC_Cities
U.S. Cities represents locations for cities within the West Coast Carbon Sequeststration Partnership States with populations of 10,000 or greater, all state capitals, and the national capital.

Layer: BC_Province
Canada Provinces represents the Canadian provinces and territories as well as coastline, international boundaries, provincial boundaries, and demographics. The boundaries are digitized from CanMap®.

Layer: BC_StreamsWaterBodies
drainage (coastlines, rivers, lakes) in British Columbia

Category: Sedimentary Basins

Layer: AK_SedimentaryBasins
This dataset consists of a polygon coverage and associated attribute data derived from the onshore and offshore portions of the 1994 "Map showing Sedimentary Basins in Alaska" by C.E. Kirschner.

Layer: AZ_SedimentaryBasins

Layer: BC_basins
Layer: basins_bcintersect
Layer: foothills

Layer: BC_Coalfields

Layer: AFDA_BC:
Oil and Gas Fields for British Columbia

Layer: TPDR_NEBC:
Petroleum Developement Roads

Layer: BOGCZ_BC:
OGC Administrative Zones

Layer: AWSH_BC:
Oil and Gas Well Surface locations for British Columbia

Layer: TPDR_NEBC:
Petroleum Developement Roads, British Colimbia

Layer: CA_BASINS
Principle sedimentary basins of California

Layer: CA_BasementMaster

Layer: CA_IsopachMaster

Layer: CA_Oil_and_Gas_Fields
Physical rock properties and production information for California oil and gas fields

Layer: NV_Valley_Fill
Areas of Valley Fill

Layer: NV_Included_Basins
Areas of one kilometer or greater basin-fill

Layer: OR_WA_Sedimentary_Basins

Sub-Category: Geologic Features

Layer: AK_Fault
This digital map database represents the general distribution of major structures, lithologic contacts, faults, folds and gravity anomalies in the state of Alaska and dominant movement along these faults.

Layer: AK_GeologicUnits
A regional summary of geologic formations and units that can be shown cartographically at 1:2,500,000..

Layer: BC_Fault
Digital file containing fault lines for British Columbia. Faults are identified by a type attribute.

Layer: BC_GeologicUnits
Polygon coverage of geology compiled at 1:100,000 scale as part of the B.C. Ministry of Energy & Mines, Geological Survey Branch mineral potential project, 1994-1996.

Layer: CA_HistoricFault

Layer: CA_HoloceneFault

Layer: CA_LateQuaternaryFault

Layer: CA_PreQuaternaryFault

Layer: CA_QuaternaryFault

Layer: OR_500kFaults
This theme shows all known geological faults in Oregon.

Layer: OR_500kGeology

Layer: WA_100kFaults
See Attached pdf for original metadata information.

Layer: WA_500kGeology
Contacts and lithologic units for the geologic map of Washington.

Layer: WA_100kGeology

Layer: WA_100kFolds

Layer: WC_QfaultL_25
This map layer contains locations and information on faults and associated folds, in the West Coast partnership states that are believed to be sources of significant earthquakes (those of magnitude 6 or greater) during the past 1,600,000 years.

Layer: US_GeologicUnits
This data set contains boundaries and tags for major geologic units in the West Coast Carbon Sequestration Partnership states.

Sub-Category: Supporting Data - Pacific Outer Continental Shelf Region (POCSR) Oil and Gas Plays

Layer: POCSR_Growth_FaultPlay
Layer: POCSR_Neogene_ShelfSandstonePlay
Layer: POCSR_Neogene_FanSandstonePlay
Pacific Outer Continental Shelf Region (POCSR) Play outline was digitized to represent the area encompassed by the Neogene Shelf Sandstone (conceptual) Play.

Layer: POCSR_Paleogene_SandstonePlay
Pacific Outer Continental Shelf Region (POCSR) Play outline was digitized to represent the area encompassed by the Growth Fault (conceptual) Play.

Layer: POCSR_Melange_Play
Pacific Outer Continental Shelf Region (POCSR) Play outline was digitized to represent the area encompassed by the Melange Play.

Sub-Category: Supporting Data – OR, WA, Unconsolidated and Consolidated Basins

Layer: Puget_Sound_Quaternary
Polygons representing the thickness of the unconsolidated deposits or depth to bedrock.

Basin outlines:
Layer: Catlow_Basin
Layer: Fort_Rock_Lake
Layer: Kittitas_Basin
Layer: Prineville_Basin
Layer: Selah_Basin
Layer: Summer_Lake_Basin
Layer: Toppenish_Satus_Basin
Layer: Walla_Walla_Basin
Layer: Columbia_R_Basalt

Layer: La_Grande_Basin
Layer: Basin_Umatilla
Layer: Basin_Baker
Layer: LaPine_Subbasin
Layer: Pasco_Basin
Layer: Basin_Quincy
Layer: Spokane_Basin
Layer: Yakima_Basin
Layer: Basin_Willamette_Trough_Q
Layer: Alvord_Pueblo_Basin
Layer: Goose_Lake_Basin
Layer: Klamah_Basin
Layer: Millican_Basin
Layer: Sisters_Basin
Layer: Warner_Lakes_Basin
Layer: ConsolidatedBasin_Astoria_Nahalem
Layer: ConsolidatedBasin_Chiwaukum
Layer: ConsolidatedBasin_Coos
Layer: ConsolidatedBasin_Harney
Layer: ConsolidatedyBasin_Hornbrook
Layer: ConsolidatedBasin_Methow
Layer: ConsolidatedBasin_ Ochoco_Basin
Layer: Puget_Sound_Consolidated
Layer: ConsolidatedBasin_Snake_River
Layer: ConsolidatedBasin_Swauk
Layer: ConsolidatedBasinTofino_Fuca
Layer: ConsolidatedBasin_Tyee_Umpqua
Layer: ConsolidatedBasin_ W_Olympic
Layer: ConsolidatedBasin_Whatcom
Layer: ConsolidatedBasin_ Willapa_Hills

Sub-Category: Supporting Data - OR, WA, 1995 Oil and Gas Play Assessment

Layers:
pr402g
pr452g
pr401g
pr450g
pr1801g
pr1803g
pr1802g
pr403g
pr405g
pr407g
pr410g
pr502g
pr404g
pr406g
pr408g
pr451g
pr501g

pr503g
The fundamental geologic unit used in the 1995 National Oil and Gas Assessment was the play, which is defined as a set of known or postulated oil and or gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. The geographic limit of each play was defined and mapped by the geologist responsible for each province. The play boundaries were defined geologically as the limits of the geologic elements that define the play, such as the limits of the reservoir rock, geologic structures, source rock, and seal lithologies.

Sub-Category: Supporting Data - OR, WA Isopach Maps

Layer: Basin_Base_Spokane
Digital representation of the elevation of the base of the unconsolidated sediments.

Layer: Isopach_Aquifer_Willamette
Digital representation showing thickness of the Willamette aquifer.

Layer: Isopach_CRBG_Geoelectric
Digital representation of Magnetotelluric Survey Data in the Pasco area to determine the Subsurface geometry of the Basalt Waste Isolation Project.

Layer: Isopach_Quincy
Digital representation of contours showing thickness of the overburden.

Layer: Isopach_Sub_CRBG_Geoelectric
Digital representation of Magnetotelluric Survey Data in the Pasco area to determine the Subsurface geometry of the Basalt Waste Isolation Project.

Layer: Isopach_Yakima
Digital representation of contours showing thickness of the overburden.

Layer: Base_Sub_CRBG_Geoelectric
Digital representation of Magnetotelluric Survey Data in the Pasco area to determine the Subsurface geometry of the Basalt Waste Isolation Project.

Layer: Basin_Base_Yakima
Digital representation of the elevation of the base of the unconsolidated sediments.

Layer: Isopach_Consolidated_Puget
Digital representaion of isopahc of Ulatisian and Narizian surface accumulated rocks.

Layer: Isopach_Pasco
Digital representation of contours showing thickness of the overburden.

Layer: Isopach_Silt_Willamette
Digital representation showing thickness of the Willamette Silt unit.

Layer: Isopach_Ulatisian_Narizian
Isopach of Ulatisian and Narizian surface accumulated rocks.

Layer: Top_CRBG_Geoelectric

Digital representation of Magnetotelluric Survey Data in the Pasco area to determine the Subsurface geometry of the Basalt Waste Isolation Project.

Layer: Basin_Base_Quaternary_Willamette
Digital representation showing altitude of the bottom of the basin-fill deposits in the Willamette Lowland

Layer: EdgeofCraton_Sub_CRBG
Digital Representation Edge of Craton

Layer: Isopach_CRBG
Digital representation of thickness of the Columbia River Basalt.

Layer: Isopach_Quaternary_Puget
Polygons representing the thickness of the unconsolidated deposits
or depth to bedrock.

Layer: Isopach_Sub_CRBG
Isopach contours for the CRBG.

Layer: Isopach_Walla_Walla
Digital representation of contours showing thickness of the overburden.

Layer: Top_Sub_CRBG_Geoelectric
Digital representation of Magnetotelluric Survey Data in the Pasco area to determine the Subsurface geometry of the Basalt Waste Isolation Project.

Layer: Alluvium_Base_Yakima
Digital representation of the thickness of the unconsolidated sediments.

Layer: Basin_Base_Umatilla
Digital representation of altitude of top of Saddle Mountains Basalt.

Layer: Isopach_ConfiningUnit_Willamette
Digital representation showing thickness of the Willamette confining unit

Layer: Isopach_Kittitas
Digital representation of contours showing thickness of the overburden.

Layer: Isopach_Selah
Digital representation of contours showing thickness of the overburden.

Layer: Isopach_Toppenish_Satus
Digital representation of contours showing thickness of the overburden.

Layer: Top_Aquifer_Willamette
Digital representation showing altitude of the top of the Willamette aquifer.

Rasters:

Hillshade
Shading for cartographic purposes.

Elevation
Global Land One-km Base Elevation

TERRESTRIAL DATA

baseline_fires_(OR,WA,AZ)

shapefile = all_small_fires_buffered (small fire circle buffered based on size and x, y coordinates in database.)
shapefile = large_fires_from_NDVI (delineated using the AVHRR-NDVI analysis.)

C_supply_afforestation_1 (OR, WA, CA)

accessory (accessory datasets including ownership, counties, land cover)
CA
raster = ca_candmap
shapefile = county_no_water_dissolves
raster = ownership
raster = veg_whr02

PNW_ownership

raster = or_wa_clip
raster = or_wheathay
raster = wa_wheathay
raster = wheat_hay

suitmaps (forest suitability maps)

raster = suit_ca
raster = suit_or_mi
raster = suit_wa_mi

accessory (accessory datasets including ownership, counties, land cover ; affor cost estimates on range and ag lands across 20,40 and 80 year time periods)
raster = ca_rg_dtc20
raster = ca_rg_dtc40
raster = ca_rg_dtc80
raster = or_ag_dtc20
raster = or_ag_dtc40
raster = or_ag_dtc80

raster = or_rg_dtc20
raster = or_rg_dtc40
raster = or_rg_dtc80
raster = wa_ag_dtc20
raster = wa_ag_dtc40
raster = wa_ag_dtc80

C_supply_fuels_reduction CA

raster = csch_3constr (CA high and very high risk forest land suitable for CSCH hazard fuel reduction technique using only 3 factors: slope less than 40%, 0.25mi yarding distance from roads and 50 mi from biomass power plants).

raster = csch_4 (constradditional factor of minimum block size of 80 acres was applied to the above forest lands).

raster = prosa_3constr (Ponderosa pine and mixed coniferous forest suitable for CSCH fuel treatment – 3 factors).

raster = prosa_4constr (Ponderosa pine and mixed coniferous forest suitable for CSCH fuel treatment – 4 factors- slope<= 40%, 0.25mi yarding distance, 50mi haul distance and min block size of 80 acres).

raster = prosa_forest

C_supply_fuels_reduction OR

raster = biomass_csch (available biomass in the CSCH treatable forest)

shapefile = bioplants (bioplants.shp – point for the biomass plans.)

raster = csch_forest

raster = csch_prosa (OR's Ponderosa pine and mixed coniferous forest suitable for CSCH treatment – 3 factors: slope <=40%, yarding distance 0.25mi, hauling distance of 50 mi from biomass plants.)

raster = forest (grid of Or's forest)

raster = hrisk_forest (OR forest with high and moderate fire risk)

raster = prosa_mxf

raster = rank_fccs (OR fuel rank map)

raster = spfr_score (High and moderate forest suitable for CSCH treatment – 3 factors: slope <=40%, yarding distance 0.25mi, hauling distance of 50 mi from biomass plants.)

C_supply_fuels_reduction WA:

raster = bio_cschfor (available biomass in the CSCH treatable forest)

shapefile = bioplants (bioplants.shp – point for the biomass plans.)

shapefile = bioplants_50mi_buffer (50 mi buffer zone from the power plants bioplants.shp – point for the biomass plans.)

raster = csch_forest (grid of WA forests)

raster = hrisk_forest (WA forest with high and moderate fire risk)

raster = prosa_csch (WA Ponderosa pine and mixed coniferous forest suitable for CSCH treatment – 3 factors: slope <=40%, yarding distance 0.25mi, hauling distance of 50 mi from biomass plants.)

raster = prosa_mxc (WA Ponderosa pine and mixed coniferous forest designated with low and mixed-severity fire regimes.)

raster = rank_fccs (WA fuel rank map.)

raster = spfr_scores (High and moderate forest suitable for CSCH treatment – 3 factors: slope <=40%, yarding distance 0.25mi, hauling distance of 50 mi from biomass plants.)

raster = wa_forests (grid of Washington's forests)

C_supply_riparian

shapefile = gapveg_w_stream_lengths_Unio
Reports_Drafts
pdf file = Calif c supply
pdf file = CEC – 500 – 2004-069F
word doc = Draft Baseline Report for Arizona
word doc = Draft Baseline Report for Oregon
word doc = Draft Baseline Report for Washington
word doc = Draft Carbon Supply Report for Oregon
word doc = Draft Carbon Supply Report for Washington

C_supply afforestation

affor cost estimates on range and ag lands across 20,40 and 80 year time periods:
raster = or_ag_dha20

raster = or_ag_dha40
raster = or_ag_dha80

OR_rg_costs:
raster =or_rg_dha20
raster = or_rg_dha40
raster = or_rg_dha80

WA_ag_costs:
raster = wa_ag_dha20
raster = wa_ag_dha40
raster = wa_ag_dha80

OR_rg_costs:
raster = or_rg_dha_20
raster = or_rg_dha40
raster = or_rg_dha80

CA_C_accumulation:
raster = ca_netc20
raster = ca_netc40
raster = ca_netc80

WA_rg_costs:
raster = wa_rg_dha20
raster = wa_rg_dha40
raster = wa_rg_dha80

OR_C_accumulation:
raster = or_20yr
raster = or_40_yr
raster = or_80_yr

WA_C_accumulation:
raster = wa_20yr
raster = wa_40 yr
raster = wa_80 yr

<u>Layers already in SDE database:</u>

estimated carbon stocks on those rangelands identified as candidates in California in 1995:
raster = CAL_BASELINEC

California portion of the West Coast Partnership's carbon supply curve analysis for afforestation of rangelands for 20, 40 and 80 year activities. The units are $/t C sequestered:
raster = CAL_C_COST20R
raster = CAL_C_COST40R
raster = CAL_C_COST80R

The CAL_NET files are those that consider for that baseline and additional growth of the selected woody biomass (trees) from a project over 20, 40 and 80 years. The units are t C/ha:
raster = CAL_NETC20
raster = CAL_NETC40
raster = CAL_NETC80

Appendix III, Final Report

The WESTCARB Interactive Map / Data Sharing with NATCARB

Deliverable associated with Task 1.0, Item 3

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

September 30, 2005

DOE award no. DE-FC26 03NT41984

Submitted by:
Larry Myer
PIER Program
California Energy Commission
1516 Ninth Street, MS-43
Sacramento, California 95814

The following constitutes the required WESTCARB Phase I deliverable associated with Task 1.0, item 3 ("digital data dissemination framework").

State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

The WESTCARB Interactive Map / Data Sharing with NATCARB

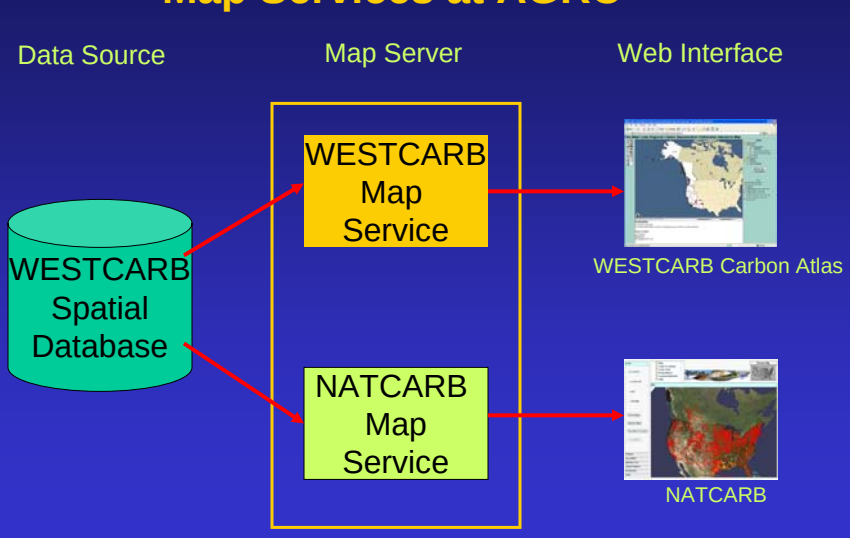
Barry Biediger

November 9, 2005

State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

Map Services at AGRC



State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

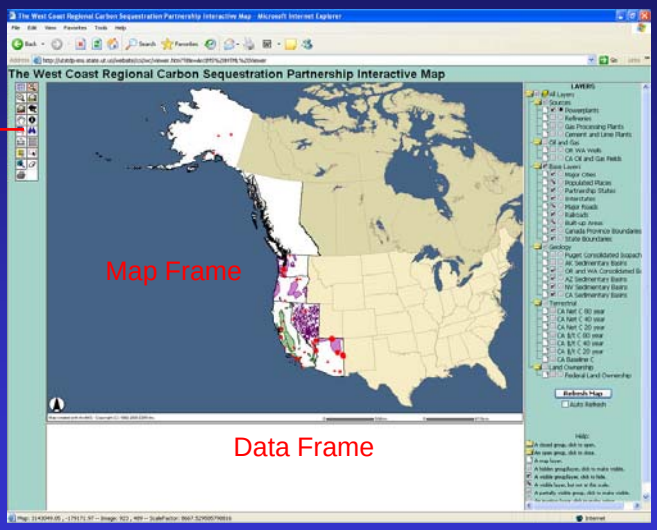
WESTCARB Map Service

- 29 Layers
- Most characterization layers are in the service.
- Any layer that exists as a GIS layer can be added.
- Metadata for each layer will be accessible from the map interface.

State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

WESTCARB Carbon Atlas Interface



State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

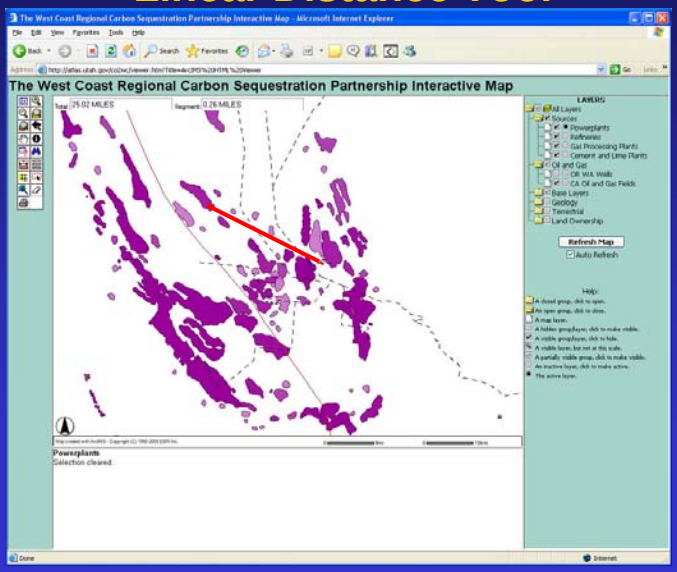
Map Functionality

- Navigation
  - Zoom in, out
  - Pan
  - Zoom to layer
- Create a Printable Map
- Measurement
  - Linear distance
  - Buffer
- Query
  - Identify
  - SQL query
  - Find

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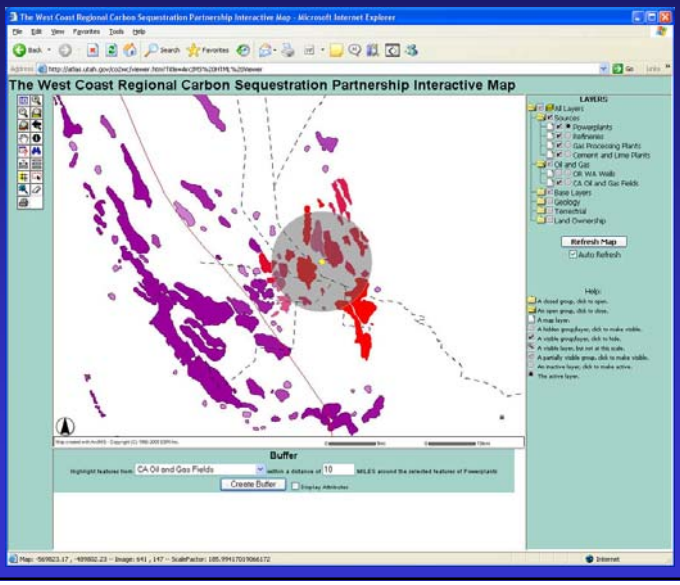
Linear Distance Tool



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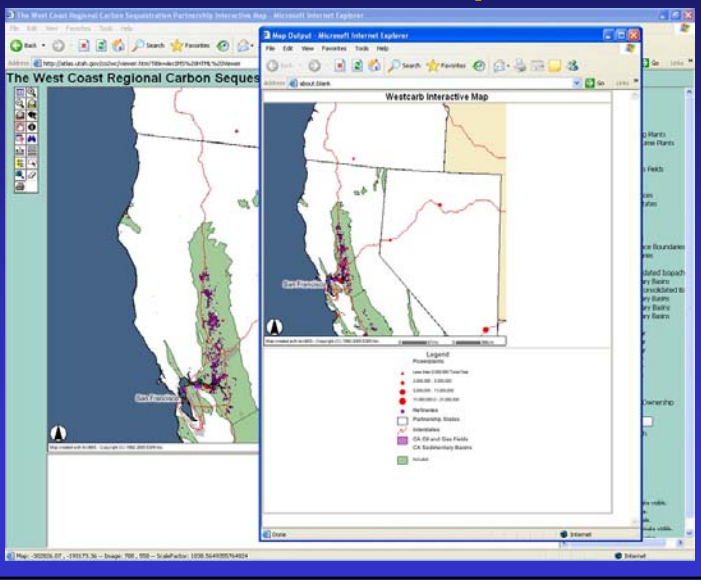
Buffer Tool

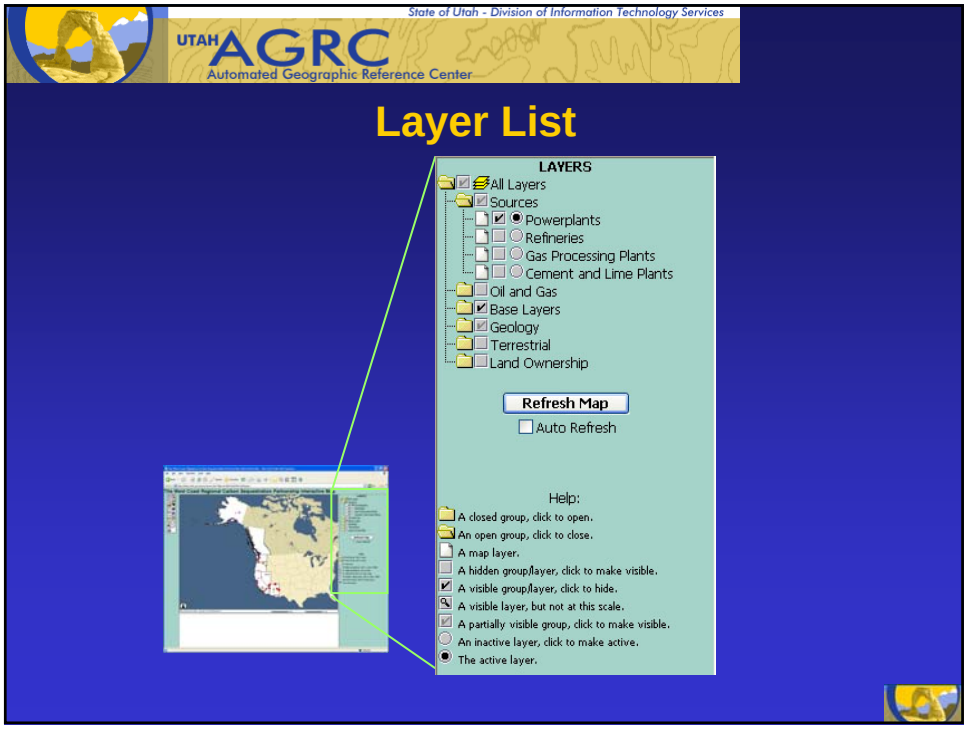


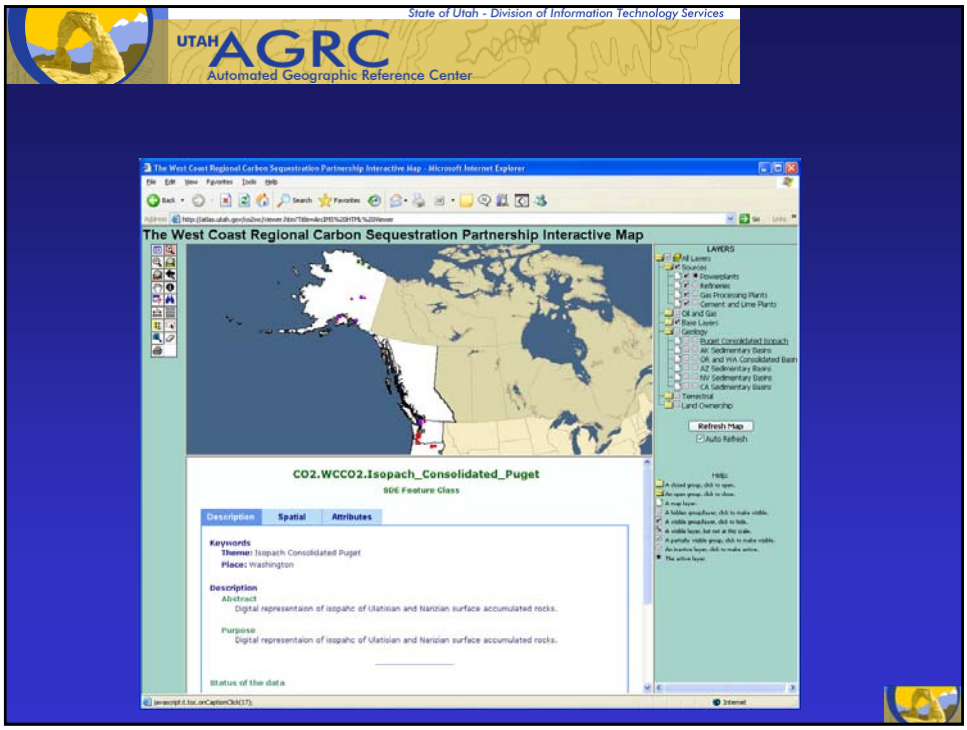
State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

Printable Map



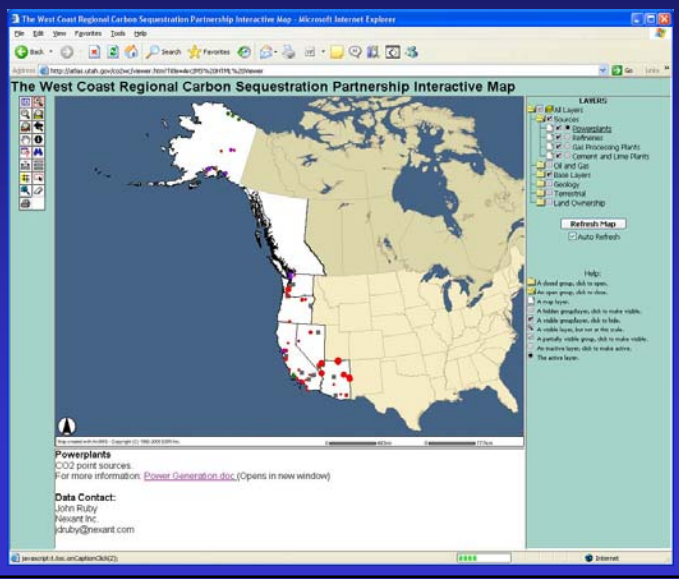

State of Utah - Division of Information Technology Services
UTAH AGRC
Automated Geographic Reference Center
Layer List
LAYERS
All Layers
Sources
Powerplants
Refineries
Gas Processing Plants
Cement and Lime Plants
Oil and Gas
Base Layers
Geology
Terrestrial
Land Ownership
Refresh Map
Auto Refresh
Help:
A closed group, click to open.
An open group, click to close.
A map layer.
A hidden group/layer, click to make visible.
A visible group/layer, click to hide.
A visible layer, but not at this scale.
A partially visible group, click to make visible.
An inactive layer, click to make active.
The active layer.


State of Utah - Division of Information Technology Services
UTAH AGRC
Automated Geographic Reference Center
The West Coast Regional Carbon Sequestration Partnership Interactive Map
CO2.WCCO2.Isopach_Consolidated_Puget
SDE Feature Class
Description
Spatial
Attributes

State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

Custom Metadata



State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

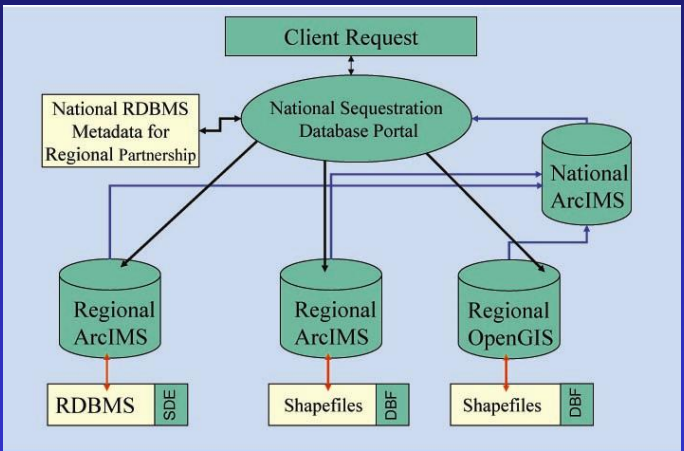
NATCARB Portal

- Nationwide carbon atlas.
- Created and maintained by KGS
- Each partnership is responsible for its own data and metadata.
- Interface provided for the database admins to add layers and metadata.
- IMS services harvested and images drawn together.

State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

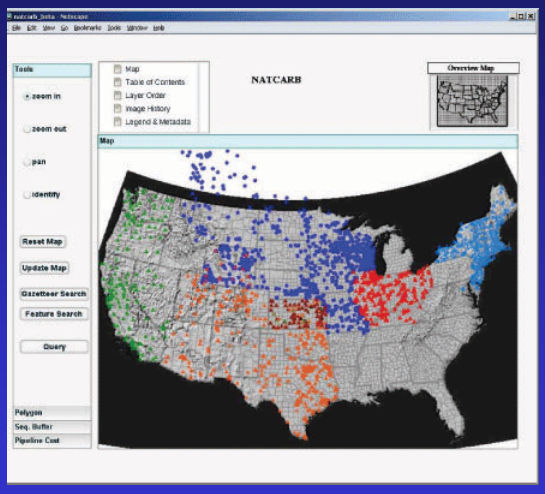
NATCARB Data Harvesting



State of Utah - Division of Information Technology Services

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Map Interface



State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

WESTCARB's Participation in NATCARB

- 7 layers are shared out to NATCARB.
- More layers to be added
- Metadata improvements
- Continued sharing

State of Utah - Division of Information Technology Services

UTAH AGRC Automated Geographic Reference Center

Questions, Comments??

www.westcarb.org/carbonatlas.htm
www.natcarb.org

bbiediger@utah.gov

Appendix IV, Final Report

Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in Arizona, Oregon, and Washington

Deliverable associated with Task 1.0, Item 4

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

September 30, 2005

DOE award no. DE-FC26-03NT41984

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This paper constitutes the required WESTCARB Phase I deliverable associated with Task 1.0, item 4 ("a paper on the terrestrial baselines for the partnership states"). In order to facilitate state-specific review of the paper, it was divided into the following sections:

- Part I: Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in ARIZONA,
- Part II: Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in OREGON, and
- Part III: Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in WASHINGTON.



Part I: Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in ARIZONA

Sandra Brown and John Kadyszewski, Project Coordinators

Winrock International

Citations

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EXECUTIVE SUMMARY

The objective of this paper is to establish the baseline carbon stocks and changes in stocks for the forest and agricultural sectors in the state of Arizona during the most recent 10-year period for which data are available (generally the decade of the 1990s). Such baselines can assist in identifying opportunities where carbon removals (sequestration) in each sector might be increased, or carbon emissions decreased, through changes in land use and management.

BASELINE FOR FOREST LANDS

The baseline for forests is separated into three component parts. A general forests baseline is presented at the State level for all forestlands, based on US Forest Service data, detailing change in forest area and change in carbon stocks, but with no attribution to the causes for the change. Using additional data bases, the specific cases of emissions associated with development and emissions associated with fire are further examined. These components form part of the total detailed in the general forest baseline section and should not be considered separately.

General Forestlands Baseline

Forest area and carbon stocks were derived from USFS published data. Between 1987 and 1997 there is an estimated increase in forest area in Arizona of 0.5 million acres or a mean of 54,000 ac per year (Table S-1). This is equivalent to an increase of 9 $MMTCO_2e$ or 0.92 $MMTCO_2e/yr$ between 1987 and 1997.

Table S-1
Gross change in forest* area and forest carbon stocks in Arizona

	1987	1997	Annual Change 1987-1997
Area (million ac)	19.4	19.9	0.054
Carbon stock ($MMTCO_2e$)	1,229	1,238	0.92

*Includes all forests, federal and non-federal

This sequestration compares with the estimated sequestration in soil and forests reported by the Arizona Climate Change Advisory Group of 6.7 $MMTCO_2e$ in the year 2000. The estimate here is clearly substantially lower. However, some of this divergence can be accounted for by the inclusion of soil carbon sequestration in the Climate Change Advisory Group analysis. In addition, there is some uncertainty on whether the carbon is artificially inflated due to a USFS change in forest definition from 10 % cover to 5 % cover in the study period.

The Advisory Group further estimated the gross emissions for Arizona (excluding sinks) for the year 2000 as 99 $MMTCO_2e$. Sinks, therefore, potentially can offset as much as 7 % of the State's emissions.

Baseline Effect of Development on Forest Lands

The baseline for emissions from development was created using land use data from the National Resources Inventory of the USDA and carbon data derived from the USFS Forest Inventory and Analysis Database for the period 1987 to 1997. Due to data limitations the

analysis is limited non-federal lands and to the gross carbon dioxide emissions from aboveground live tree biomass on conversion of non-federal forestland to developed land uses. As the focus is on non-federal lands the analyses should only be used to explore decisions on private lands.

Between 1987 and 1997 3,499 acres of non-federal forest were converted to development. All of this area was located in the North of the State. This is equal to just 350 ac per year.

For gross carbon emissions two scenarios were considered. Under Scenario 1 all tree biomass in the converted area was immediately emitted as carbon dioxide. Under Scenario 2 for developed areas of less than 10 acres, it was assumed that 50 % of the carbon was retained in the form of residual trees.

Under Scenario 1 an estimated 152,000 t CO_2e were emitted due to development or 15,200 t CO_2e/yr. Under Scenario 2, 145,000 t CO_2e were emitted or 14,500 t CO_2e/yr (Table S-2).

Table S-2
Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development on non-federal forests. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

	Area lost (ac)	Carbon emissions ($MMTCO_2e$)	
		Scenario 1	Scenario 2
Southern	0	0	0
Northern	3,500	0.152	0.145

These emissions compare with the estimated gross sequestration from non-federal forests in Arizona of 0.92 $MMTCO_2e$/yr between 1987 and 1997 (see Table S-1) and gross emissions for the state of 99 $MMTCO_2e$/yr (from Arizona Climate Change Advisory Group). Emissions from deforestation therefore represent a fraction of a percent of the total emissions in the state.

Baseline Effect of Fire on Forest Lands

The emissions from fire were examined through overlaying the wildfire database for Arizona on AVHRR satellite imagery showing change in NDVI (normalized differential vegetation index). (NDVI measures 'greenness' of landscape, greenness decreases immediately after fire). This process determined the location, size and intensity of fires between 1990-1996. Carbon values were applied to these fires using data from the FIA and proportional emissions from the detailed baseline fire analysis for California.

The analysis considered all forests and rangelands in Arizona, federal and non-federal.

Across the seven years analyzed fires with a total area of 437,700 hectares (1.08 million acres) were recorded. This is equivalent to 62,500 ha / yr or 154,000 acres / yr. Emissions totaling

904,000 tons of carbon or 3.3 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. This is equivalent to an emission of 0.47 $MMTCO_2e$ / yr.

Eighty-five percent of the burned area was on rangelands but 42 % of the emissions were from the 15 % of burned area that was forest. Fire incidence varied by year with high emissions in 1993 to 1996 (> 168,000 t C) and low emissions between 1991 and 1992 (< 23,000 t C). Fires occurred throughout Arizona during the study period and there was no apparent geographical relationship between either area burned or carbon emissions from fire and geographic location.

These emissions compare with the estimated gross sequestration from forests in Arizona of 0.92 $MMTCO_2e$/yr between 1987 and 1997 (see above) and gross emissions for the state of 99 $MMTCO_2e$/yr (from Arizona Climate Change Advisory Group). During the analysis period, emissions from fire therefore represented almost 0.5 % of the total emissions in the state.

BASELINE FOR AGRICULTURAL LANDS

This paper presents a general methodology for determining the agricultural baseline. As with other terrestrial carbon baselines, the areas of different land uses and changes in land use are combined with carbon densities of each land use to yield an estimate of the total emissions and removals of carbon associated with land management and/or conversion of lands over a given time period. Estimates of area and changes in area of agricultural and non-agricultural land use types were derived from the National Resource Inventory (NRI) database for the period 1987 to 1997. As the NRI database was used only non-federal land was considered.

Agricultural land area in Arizona amounts to about 1.5% of the total land area. The state lost agricultural land area during 1987-97 through conversion to other land uses, in particular to urban development/transportation and the retiring of agricultural land from cultivation. In some counties, the area of woody cropland actually increased, but these increases were more than offset by decreases in non-woody cropland. Accompanying these losses in area were losses in standing carbon stocks on agricultural land, so that conversion of agricultural land to other uses was responsible for a net annual source (emission) of CO_2 to the atmosphere. Losses of agricultural carbon stocks over the 1987-97 analysis period were estimated at 99,000 tons. The estimated net annual source from Arizona agricultural lands was 0.04 $MMTCO_2eq$ (Table S-3).

Table S-3
Summary of agricultural land area and changes in area, carbon stocks and changes in stocks, for Arizona 1987-97

Parameter	Units	Arizona
Proportion of agricultural land of total land	%	1.5
Change in agricultural land area, 1987-97	Hectares (%)	-30,759 (6.6%)
Change in woody cropland area		+687 (2.3%)

Parameter	Units	Arizona
Change in non-woody cropland area		-31,446 (7.2%)
Total carbon stocks in agricultural land, 1997	$MMTCO_2e$	3.5
Change in carbon stocks in agricultural land,	$MMTCO_2e$	-0.4
Estimated net annual source (emissions) from agricultural lands, disregarding non-CO_2 greenhouse gas emissions	$MMTCO_2e$	-0.04
From woody cropland		-0.02
From non-woody cropland		-0.02
Estimated net annual source from non-CO_2 greenhouse gas emissions, 2000	$MMTCO_2e$	4.2

Emissions of CO_2 from agricultural land conversion, while the primary focus of this paper because of data availability, represent only a portion of the total greenhouse gas emissions attributable to the agricultural sector. The primary non-CO_2 greenhouse gases associated with agricultural activities are nitrous oxide (N_2O; emitted from agricultural soils especially after fertilizer application) with approximately 296 times the global warming potential of CO_2, and methane (CH_4; emitted by livestock and through manure management) with approximately 23 times the global warming potential of CO_2. Examination of data from Arizona indicated that greenhouse gas emissions from N_2O and CH_4 in the agricultural sector dwarf the annual CO_2 source from agricultural land conversion: CO_2 emissions from land conversion represented less than 1 % of the total CO_2 and non-CO_2 greenhouse gas emissions attributable to the agricultural sector.

Chapter 1 – Introduction and Background Information

1.1 General Approach

The purpose of this baseline document is to examine changes in land use and the associated emissions or sequestration of carbon for forest and agricultural lands in the State of Arizona.

Separate baseline analyses are included here for forestlands and agricultural lands. The agricultural land study follows the same principles as the California baseline study (Brown et al. 2004). For forestlands, the California baseline study was based on CA-specific interpreted satellite imagery that detailed the scale of change, vegetation type and cause of change. Because no comparable data is available for Arizona, we instead rely predominantly on two national datasets (see Section 1.2). The consequence of using generalized broad-scale datasets is that the outcome is less certain than we were able to achieve in California.

The forest baseline includes a state-level analysis on the change in area and carbon stocks in all forestland, plus a county-level analysis of changes on non-Federal forestland. Also included are specific case studies on emissions due to development and fire.

1.2 Datasets used in the Analysis

Two datasets are used repeatedly through the baseline analyses:

1.2.1 The National Resources Inventory

The National Resources Inventory (NRI) is conducted by the US Department of Agriculture - National Resources Conservation Service (NRCS). The NRI is a scientifically designed survey of the nation's soil, water, and other related resources with the purpose of assessing conditions and trends. The NRI contains data only on non-Federal lands and water bodies. As noted in the Users' Manual (NRCS 2000), the NRI data are useful in developing estimates of natural resource conditions and in conducting geospatial and temporal analyses of these conditions (however, the location of the survey plots is not given in the data base). In these baseline analyses, NRI data were used for estimates of area because NRI data is available across the WESTCARB States, wide in coverage, and available for multiple points in time and multiple classes of land use.

Because NRI data come from sample surveys, it is important to have a sufficient sample size for a reliable estimate. The NRI Users' Manual does not recommend that the data be used for county-level analysis because of sample size issues. To be conservative, here analyses are reported at the State level. County level results are given for illustrative purposes only.

NRI analyses are for the time period 1987 to 1997. More recently the NRI has switched to annual reporting, but this data is not yet publicly available.

1.2.2 The Forest Inventory and Analysis Database

Forest biomass was estimated using the US Forest Service Forest Inventory and Analysis (FIA) database. Following Acts of Congress in 1928 and 1974, the USFS has been systematically collecting data via the FIA on US forests.

The FIA data is composed of a hierarchy of the following nine tables: SURVEY, COUNTY, PLOT, SUBPLOT, CONDITION, TREE, SEEDLING, SITETREE and BOUNDARY. Examples of plot-level records include: State, County, Plot number, Owner, Forest type, Stand age, Site productivity, and Slope. Examples of tree-level records include: State, County, Plot number, Tree number, Diameter at breast height (DBH), Crown class, Volume, Growth, and Expansion Factors (which allow extension from values per plot to per acre). Diameters are included in the database for all trees with DBH > 1". Creating links between the different hierarchies of the database and utilizing the expansion factors allows the user to explore a variety of topics related to biomass stocks in trees.

In this baseline study, data were downloaded from the FIA website on the scale of individual trees within plots within each county within each state. Using the biomass regressions of Jenkins et al. (2003), diameter at breast height (DBH) was converted to biomass for each tree. Area expansion factors (plot to acre), metric conversions and summation were used to calculate biomass in metric tons per hectare. In the fire baseline, forests are consolidated by forest type which is a plot-level characteristic.

1.3 GEOGRAPHICAL SUBDIVISION OF THE STATE

In the forest baseline, the State is subdivided into two regions. These regions are based on FIA 'units' but are convenient due to climatic, topographic and vegetation similarities within units (Table 1-1). Both the forest and agricultural baselines include county-level analyses; counties in Arizona are shown in Figure 1-1.

Table 1-1
Two Arizona regions with the component counties detailed

Region	Counties
Southern	Cochise, Graham, Greenlee, La Paz, Maricopa, Pima, Pinal, Santa Cruz, Yuma
Northern	Apache, Coconino, Gila, Mohave, Navajo, Yavapai



Figure 1-1
Arizona counties. Source: Digital Map Store, *http://county-map.digital-topo-maps.com/arizona.shtml*

Chapter 2 – Baselines for Forestlands in Arizona

2.1 INTRODUCTION

This chapter presents a baseline for emissions and sequestration in the forests of Arizona. Forest is defined here as land with a greater than 10 % stocking of trees (as in the FIA and NRI).

The forest baseline chapter is presented in three sections.

In Section 2.2 a general forest baseline is presented detailing changes forest area and in stocks in the forests of Arizona with an estimate of annual sequestration/emissions. A State level total is presented for all forests with county level detail only for non-Federal Lands.

The remaining sections present case studies of individual causes of emissions from forests. These case studies should not be considered on top of the general baseline (section 2.2) but as a subset of it. Emissions from fire or development will have formed part of the total emissions from forests that are presented or alternatively will have decreased the total estimated sequestration presented from forests.

In Section 2.3 the case study of emissions caused by development on forestland is presented.

In Section 2.4 the case study of emissions caused by fire on forestland is presented.

2.2 GENERAL FORESTLANDS BASELINE

2.2.1 State Level Analysis for all Forestlands

The USDA Forest Service published a baseline for forests in Arizona between 1987 and 1997 (Birdsey and Lewis 2003). Estimates are based on forest inventory data collected by the Forest Service's Forest Inventory and Analysis (FIA) Unit. Determination of the location of tree measurement plots and changes in land area were assessed using high altitude photography. Where forest inventory was not available, estimates of land use change were derived from the National Resources Inventory.

Between 1987 and 1997 Birdsey and Lewis (2003) estimated a net change in forest area for Arizona from 7.8 million hectares in 1987 to 8.1 million hectares in 1997. This is a total gain of 219,345 hectares (an increase of 2.8 %), which averages out to 21,935 hectares per year (an increase of 0.28%/yr).

Across the state Birdsey and Lewis calculated a mean forest carbon stock density of 42.7 t C/ha in 1987 and 41.9 t C/ha in 1997, or a loss of 0.8 t C/ha over the ten years.

Combining the area data with the carbon density data gives a total stock on forestland in AZ in 1987 and 1997 and a change in stock between the two dates. The stock in 1987 was estimated as 335 million t C and this grew to 337.6 million t C in 1997. This is equal to a total gain of 2.5 million tons of carbon (a gain of 0.75%), which averages out to 251,700 tons of carbon per year (a gain of 0.075%/yr).

2.2.2 Changes in Forest Area on Private Land

The above section gives the overall picture of changes in area and carbon stocks for the whole state, without any reference to the causes of change. Of particular interest in relation to changes in the use and management of forests is the potential to conserve significant quantities of carbon in forests under threat for conversion to other uses, particularly development. It is argued that most forest conversion would come from private lands. It is not expected that widespread deforestation is occurring on public lands though some afforestation may be overlooked. Here is detailed a baseline at the county level for the change in area in privately owned forests in Arizona.

The change in land use associated with forests on private lands in AZ was analyzed from the National Resources Inventory (NRI). Two dates were used that reported data at the county scale of resolution: the most recent publicly available data for 1997 and for 1987. At the State level all land in forest was estimated in 1987 and 1997, plus the broad destination or origin of land that changed from or to forest in the same time period (Table 2-2-1).

Table 2-2-1
Change in area between 1987 and 1997 for nonfederal forestland in Arizona

Area (ha)	Unchanged[1]	Lost to[2]	Gained from[3]
Unchanged	1,644,498		
Development		1,416	
Pasture/Rangeland		102,915	58,803

Strip mines	23,392	
Other	40	
1987 Total		**1,772,262**
1997 Total		**1,703,585**

[1]'Unchanged' refers to areas remaining forest between 1987 and 1997

[2]'Lost to' refers to areas lost from forest to other land use categories between 1987 and 1997

[3]'Gained from' refers to areas becoming forest between 1987 and 1997

In Arizona, forest area decreased by 68,677 hectares in the ten years from 1987 and 1997 or an average of 6,868 ha/yr. Of the total area of forest in 1987, 93.9 % remained unchanged as forest ten years later in 1997. There was a loss of 127,764 hectares principally to rangeland and to strip mining, and a gain of 59,086 ha back from rangeland. Only 1,416 ha of forest were converted to development (see detail below).

County-Level Changes in Forest Area

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Two-thirds of the counties in the State of Arizona contained measured areas of forest. The six most northerly counties (Apache, Coconino, Gila, Mohave, Navajo and Yavapai), which represent 58 % of the area of the State contained 95% of the forest area. Across the State 40 % of counties experienced a loss in forest area between 1987 and 1997 and 20 % gained forest area. Large losses (>10,000 ha) occurred in Apache, Cochise, Coconino and Gila counties, while Navajo County gained almost 20,000 hectares of forest area (Tables 2-2-2, 2-2-3).

Table 2-2-2
Area of nonfederal forestland in Arizona in 1987 and 1997 and change between the two dates

Area (ha)	County Area (ha)	1987	1997	Change
Apache	2,902,050	706,809	690,782	(16,026)
Cochise	1,597,880	12,384		(12,384)
Coconino	4,821,891	189,238	142,819	(46,419)
Gila	1,234,829	100,608	82,316	(18,292)
Graham	1,198,987	70,782	70,782	-
Greenlee	478,371			-
La Paz	1,165,483	1,052	5,990	4,937
Maricopa	2,383,602			-
Mohave	3,447,699	294,217	293,893	(324)

Navajo	2,577,862	396,363	416,113	19,749
Pima	2,379,232			-
Pinal	1,390,719			-
Santa Cruz	320,546		243	243
Yavapai	2,103,925	809	648	(162)
Yuma	1,428,143			-
TOTAL		**1,772,262**	**1,703,585**	**(68,678)**

Table 2-2-3
Area of nonfederal forestland in 1987 and 1997 and change between two dates for two Arizona regions

	Area (ha)		**Change**
	1987	**1997**	**Area**
Northern	1,688,044	1,626,570	**(61,474)**
Southern	84,218	77,014	**(7,204)**

2.2.3 Conclusions

An estimated 219,000 hectares of forest on federal and non-federal lands were gained in Arizona between 1987 and 1997 at a rate of 21,935 ha/yr. These gains are equivalent to 0.28 % of the forest area per year between 1987 and 1997.

A gross sequestration of an estimated 9.2 $MMTCO_2e$ would have occurred between 1987 and 1997 (0.92 $MMTCO_2e$/yr) and 42.7 $MMTCO_2e$ (7.1 $MMTCO_2e$/yr) between 1997 and 2003.

This sequestration compares with the estimated sequestration in soil and forest sinks for the State of Arizona in 2000 of 6.7 $MMTCO_2e$ (Bailie and Lazarus 2005).

The sequestration rate estimated by Bailie and Lazarus (2005) clearly exceeds the rate predicted here. An explanation could be the inclusion of soil organic carbon sequestration and sequestration in the forest floor and in coarse woody debris in the study of Bailie and Lazarus (2005). Alternatively, it is possible that a change in the definition of forest by the USFS from a cover of 10 % to a cover of 5 % could have artificially inflated the forest area during the study, artificially elevating the estimated sequestration.

The gross emissions for Arizona (excluding sinks) for the year 2000 were estimated as 99 $MMTCO_2e$ (Bailie and Lazarus 2005). Sinks, therefore, potentially can offset as much as 7 % of the State's emissions.

For just non-federal lands there is net loss is 69,000 ha. Ninety percent of the loss in area occurs in the Northern counties of the State.

2.3 DEVELOPMENT BASELINE

2.3.1 General Approach

This section provides a baseline for the emissions of carbon attributable to development of forest lands in Arizona. This analysis should be considered a subset of the general forest baseline: the emissions due to development will form part of wider changes in carbon stocks in the State. If this analysis is added to the analysis of the general forest baseline then double counting will occur.

Forest land development is examined only for private lands; it is not expected that widespread development is occurring on public land. Changes in stocks are only changes in aboveground tree biomass, due to uncertainties surrounding both the absolute level of carbon in other carbon pools and whether or not development will cause emissions from these pools.

As in the general forest baseline, changes in forest area due to development were based on NRI data for changes in land use. Carbon stocks and changes in stocks were derived from FIA data. For the purposes of this study, development includes three NRI categories:

- Urban / 10 acres or larger
- Urban / small built-up (< 10 acres). The category 'Urban/small built-up' will be referred to as small-scale development.
- Transportation (e.g. roads, airports etc)

Statistical confidence can only be maintained in results given at the State level, due to the design of the NRI database. Results are given here at the County level merely for illustrative purposes.

2.3.2 Changes in Area at the State and County Level

Between 1987 and 1997, 1,416 hectares of non-federal forest were lost in Arizona due to development, or 142 ha per year. The loss over ten years is equivalent to 0.08 % of the total forest area present in the State in 1987. Of the total area lost to development, 9 % could be considered as small-scale development(Table 2-3-1).

Table 2-3-1
Nonfederal forest area between 1987 and 1997 in Arizona. Area in hectares

	Unchanged[1]	**Lost to[2]**	**Gained from[3]**
Unchanged	1,644,498		
Development		1,416	
% small scale		9%	
Pasture/Rangeland		102,915	58,803
Farmland/Agriculture			283
Strip Mines		23,392	
Other		40	
1987 Total			**1,772,262**
1997 Total			**1,703,585**

[1]'Unchanged' refers to areas remaining forest between 1987 and 1997

[2]'Lost to' refers to areas lost from forest to other land use categories between 1987 and 1997

[3]'Gained from' refers to areas becoming forest between 1987 and 1997

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Losses in non-federal forest area between 1987 and 1997 only occurred in three counties in Arizona (Apache, Coconino, Yavapai), all in the northern portion of the State (Figure 2-3-1, Table 2-3-2). These counties, however, account for 33 % of the area of the State and 49 % of the forested area.

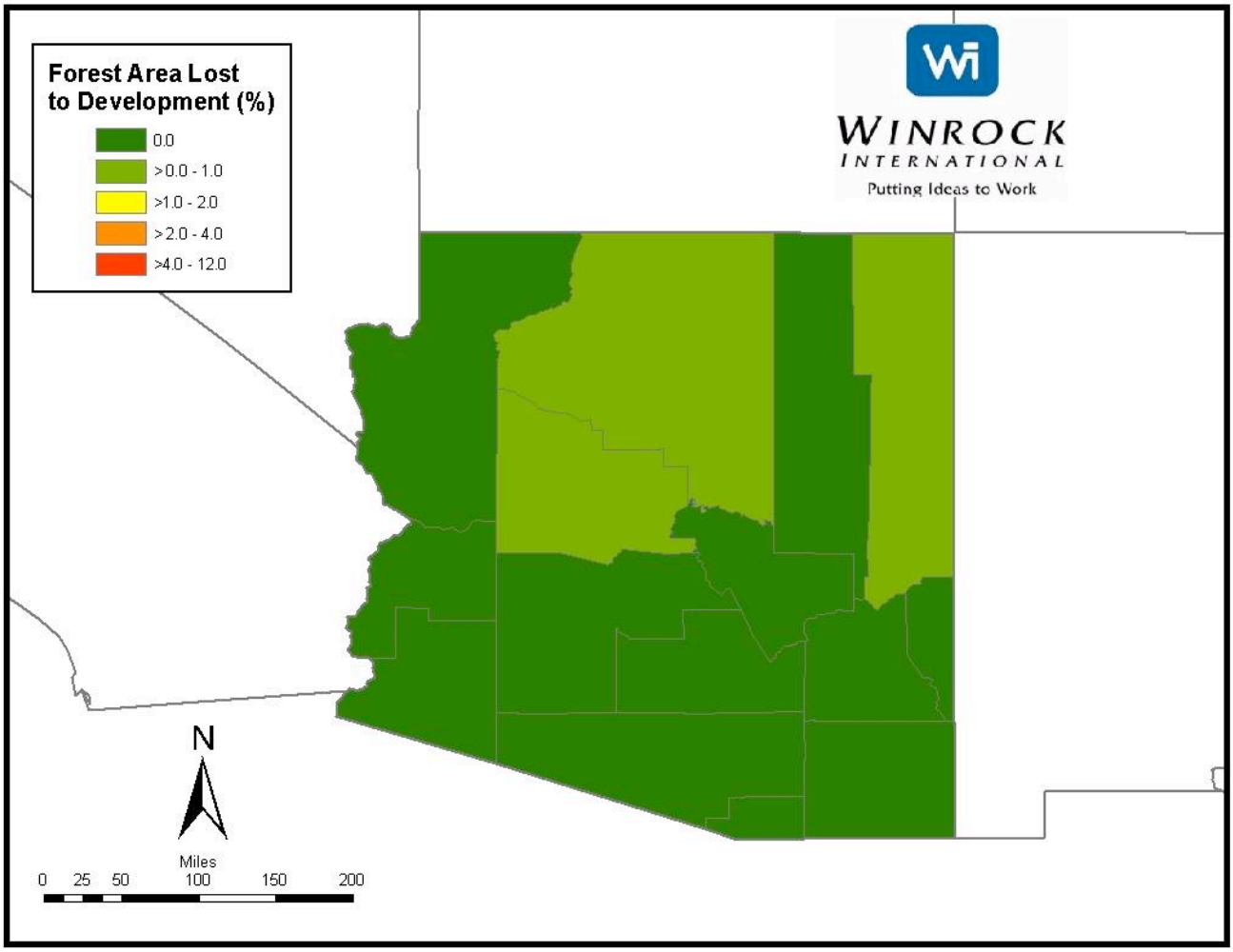


Figure 2-3-1
Loss in non-federal forest area between 1987 and 1997 as a percentage of total non-federal forest area in the county

Table 2-3-2
County level data on area of non-federal forest in 1997, area of forest lost to development between 1987 and 1997 and % of losses that were small-scale

	Population	County Area (ha)	Non-Fed Forest area 1997 (ha)	Area Lost to development (ha)	% small scale
Apache	69,423	2,902,050	690,782	121	
Cochise	117,755	1,597,880			
Coconino	116,320	4,821,891	142,819	1,133	11%
Gila	51,335	1,234,829	82,316	0	
Graham	33,489	1,198,987	70,782	0	
Greenlee	8,547	478,371			
La Paz	19,715	1,165,483	5,990	0	
Maricopa	3,072,149	2,383,602			
Mohave	155,032	3,447,699	293,893	0	
Navajo	97,470	2,577,862	416,113	0	
Pima	843,746	2,379,232			
Pinal	179,727	1,390,719			
Santa Cruz	38,381	320,546	243	0	
Yavapai	167,517	2,103,925	648	162	
Yuma	160,026	1,428,143			
TOTAL			**1,703,585**	**1,416**	9%

2.3.3 Carbon Stocks

Estimates of carbon stocks in live tree biomass were derived from the FIA data base. For AZ, as no FIA data exists for dates representing a midpoint of the analysis period 1987-1997, and the previous inventory in 1985 is considered to be rather out of date for this period, FIA data from the 2003 inventory was used instead.

The FIA data were consolidated at the FIA Unit Level. Biomass carbon estimates were derived from the measurements of tree diameter at breast height for all trees in inventory plots using the

allometric equations of Jenkins et al. (2003), scaled up to a per-ha basis using the plot-area expansion factors (Table 2-3-3).

In order to be conservative, aboveground tree biomass alone was considered. The rate of emission of carbon stored in roots and soil organic matter is slow and poorly understood, especially when it is considered that some of the developed areas will be capped with concrete. Wood products are also not included as it is not clear what proportion of the cut trees would be harvested for products, nor what products would be produced (fire wood and even paper can be rapidly emitted).

Table 2-3-3
Mean aboveground tree carbon stock (from 2003 FIA data) for each region of Arizona with the number of plots and the confidence interval around the stock estimate

	2003			
t C/ha	Mean	95 % CI	# plots	Counties
Southern	18.1	3.31	264	Cochise, Graham, Greenlee, La Paz, Maricopa, Pima, Pinal, Santa Cruz, Yuma
Northern	29.2	2.09	816	Apache, Coconino, Gila, Mohave, Navajo, Yavapai

2.3.4 Carbon emissions from development

Two carbon emission scenarios are considered here. In both cases FIA data from federal and non-federal forests are applied to NRI land cover estimates for non-federal forests.

- Scenario 1 assumes that all carbon present on the land in aboveground tree biomass is lost when development occurs.
- Scenario 2 assumes that when small scale development occurs, a significant proportion of the trees remain during and after the process of development. As examples, these may be trees surrounding residential properties or trees on golf courses. Therefore, in this scenario we assume that for Transportation and Urban/10 acres or larger, all carbon is lost, but for Urban/small built-up, only 50 % of the carbon stocks are emitted.

Emissions discussed here for conversion of forestland to development are gross emissions from aboveground tree biomass only. Total emissions from development over the ten-year period were estimated as 41,300 t C under Scenario 1 and 39,600 t C under Scenario 2. This is equivalent to 4,135 and 3,957 t C per year. The difference is small because only 9% of the total development change is attributed to small-scale development. Emissions by county are summarized below (Figure 2-3-2, Table 2-3-4).

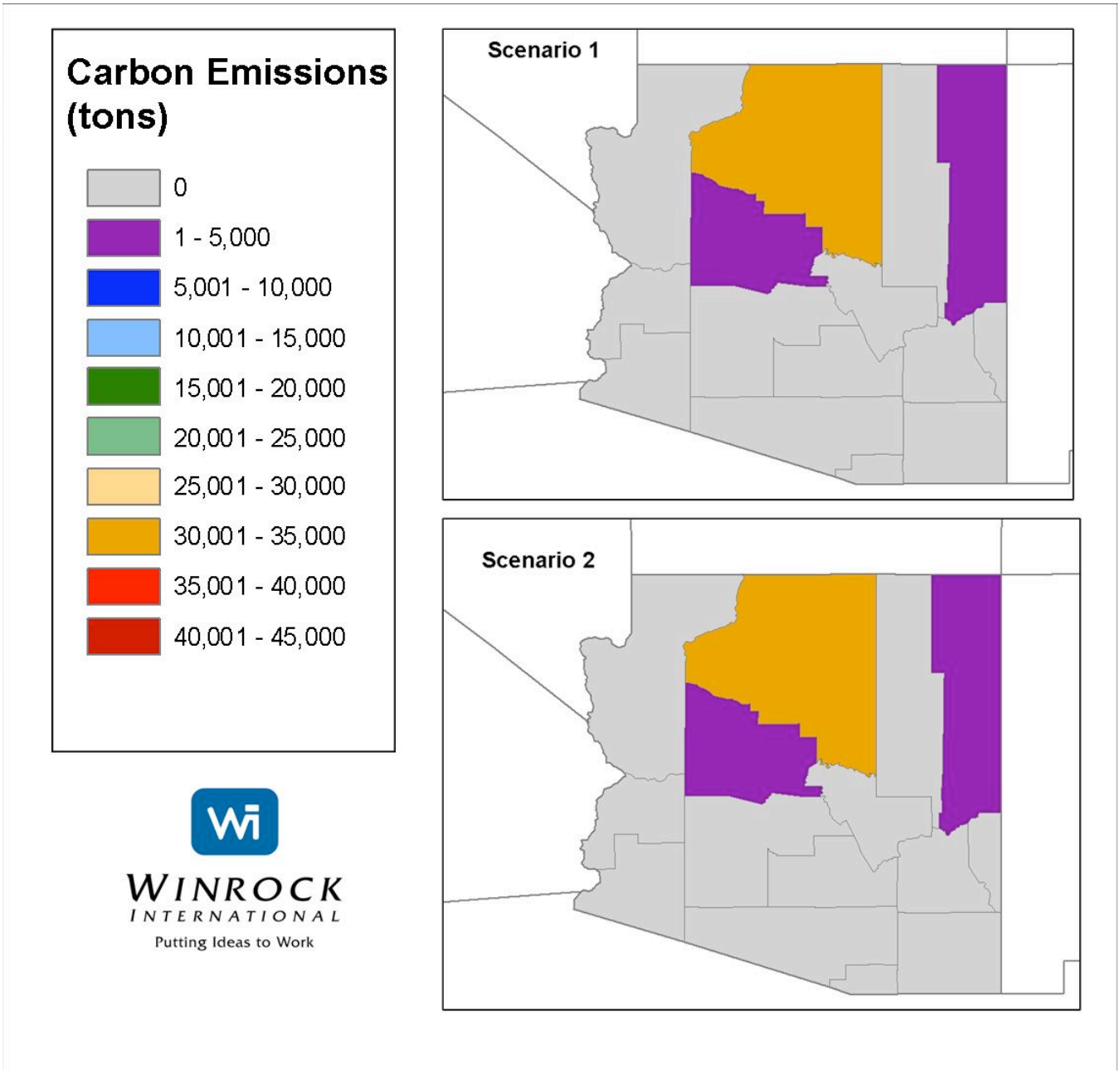


Figure 2-3-2
Carbon emissions under the two scenarios at the county level across the state

Table 2-3-4
County-level estimates on the emissions between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

	Population	County Area (ha)	Non-Fed Forest Area 1997 (ha)	Carbon emissions (t C) Scenario 1	Scenario 2
Apache	69,423	2,902,050	690,782	3,544	3544
Cochise	117,755	1,597,880			
Coconino	116,320	4,821,891	142,819	33,077	31,305
Gila	51,335	1,234,829	82,316		
Graham	33,489	1,198,987	70,782		
Greenlee	8,547	478,371			
La Paz	19,715	1,165,483	5,990		
Maricopa	3,072,149	2,383,602			
Mohave	155,032	3,447,699	293,893		
Navajo	97,470	2,577,862	416,113		
Pima	843,746	2,379,232			
Pinal	179,727	1,390,719			
Santa Cruz	38,381	320,546	243		
Yavapai	167,517	2,103,925	648	4,725	4,725
Yuma	160,026	1,428,143			
TOTAL				**41,346**	**39,574**

The carbon emissions as a result of development mirror the loss in area. All losses occurred in the Northern region of the State (Table 2-3-5). The loss to development over ten years represents less than 0.1 % of the total area of forest land in Arizona, and consequently a low level of emissions for a large State.

Table 2-3-5
Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development

	Area lost (ha)	Carbon emissions (t C)	
		Scenario 1	Scenario 2
Southern	0	0	0
Northern	1,416	41,346	39,574

This is equal to an annual loss in area across the state of just 142 hectares with annual carbon dioxide equivalent emissions of between 14,500 and 15,200 metric tons of CO_2e (Table 2-3-6).

Table 2-3-6
Region-level summary of annual loss in area and carbon dioxide equivalent emissions between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development

	Annual Area lost (ha/yr)	Annual carbon emissions ($MMTCO_2e/yr$)	
		Scenario 1	Scenario 2
Southern	0	0	0
Northern	142	0.0152	0.0145

2.3.5 Additional Considerations

Emissions discussed here for conversion of forestland to development are gross emissions from aboveground tree biomass only.

Gross vs Net Emissions

The analysis presented above represents gross changes. The only consideration was of emissions from losses of forest to development.

Where gains of forest were made from development (none in Arizona), this was not considered.

The destination of biomass upon development is also not considered. The assumption is made that all carbon is immediately emitted. In reality this is unlikely to be the case. Some of the wood is likely to ultimately become fire wood, some will be left to decompose and some may be

used as timber and will have a longer existence as wood products. Regardless, all trees cut for development will ultimately be emitted to the atmosphere as carbon dioxide or carbon dioxide equivalents. Instead of including any delay here the assumption is made of immediate emission.

Other Carbon Pools

Aboveground tree biomass was the only carbon pool considered in this analysis. The reason behind this decision was the uncertainty involved in other pools generally, and specifically in the case of development.

Soil carbon is particularly uncertain. If the land is capped by concrete it is unlikely that soil carbon will be affected at all. If grasses are planted there is even the possibility that development could lead to an increase in soil carbon.

For similar reasons roots are also uncertain. The rate at which roots decompose is very poorly known and even less is known about the diminished rate if the roots are buried beneath concrete or tarmac.

Dead wood and litter are likely to be emitted either immediately upon development or through time as decomposition occurs. However, there is no clear relationship between aboveground tree biomass and these pools and the uncertainty involved with any assumption would be very large.

Non-carbon dioxide greenhouse gas emissions are also unknown. If site preparation occurs through burning, there will be emissions of methane and nitrous oxide (both potent greenhouse gases). If site preparation involves drainage there will be emissions of methane. Without specific site-by-site information it is not possible to make these estimations.

2.3.6 Conclusions

An estimated 1,416 hectares were lost to development in Arizona between 1987 and 1997 at a rate of 142 hectares per year. This forest loss is equivalent to a gross emission of between 0.145 and 0.152 million metric tons of carbon dioxide equivalent or 0.0145 to 0.0152 $MMTCO_2e$ per year.

The emissions were exclusively in the North of the State in the counties of Apache, Coconino and Yavapai.

These emissions compare with the estimated gross sequestration from forests in Arizona of 0.92 $MMTCO_2e/yr$ between 1987 and 1997 (Section 2.2) and gross emissions for the state of 99 $MMTCO_2e/yr$ (Bailie and Lazarus 2005). Emissions from deforestation therefore represent a fraction of a percent of the total emissions in the state.

2.4 FIRE BASELINE

In this fire analysis the emissions caused by fire between 1990 and 1996 are estimated. These emissions are part of the general forest baseline (section 2.2). Without emissions from fire, the general forest baseline would be raised by an amount equal to these emissions.

This baseline, unlike the general forest baseline and the development emissions baseline contains an analysis of rangelands as well as forests.

There are two components to a fire analysis. It is necessary to know both the area that is burnt and the amount of biomass that is volatilized into greenhouse gases per area. Knowledge of these components permits an estimation of total fire-derived emissions.

The period 1990 to 1996 was chosen for this analysis, for (although a partial dataset exists for 1997-2003) these study dates represent the most recent, consistent complete coverage. Complete coverage is essential in order to be able to make State level conclusions on the impact of fire.

2.4.1 Methods for Assessing Biomass Volatilized

2.4.1.1 Background

The effects of fire on carbon stocks are dependent on the intensity of the fire. An intense fire will destroy biomass and release a great proportion of the carbon to the atmosphere, while a less intense fire will even fail to kill the majority of the trees. Here fires are divided into three potential intensities: high, medium and low.

Pre-fire carbon has five potential destinations during and after a fire (Fig. 2-4-1). The first proportion will survive the fire to continue as live vegetation, a second proportion will be volatilized during the fire and immediately released to the atmosphere and the remainder will be divided between the pools of dead wood, soot and charcoal. Soot and charcoal are stable forms of carbon and can remain unchanged for hundreds of years; in contrast dead wood decomposes over time.

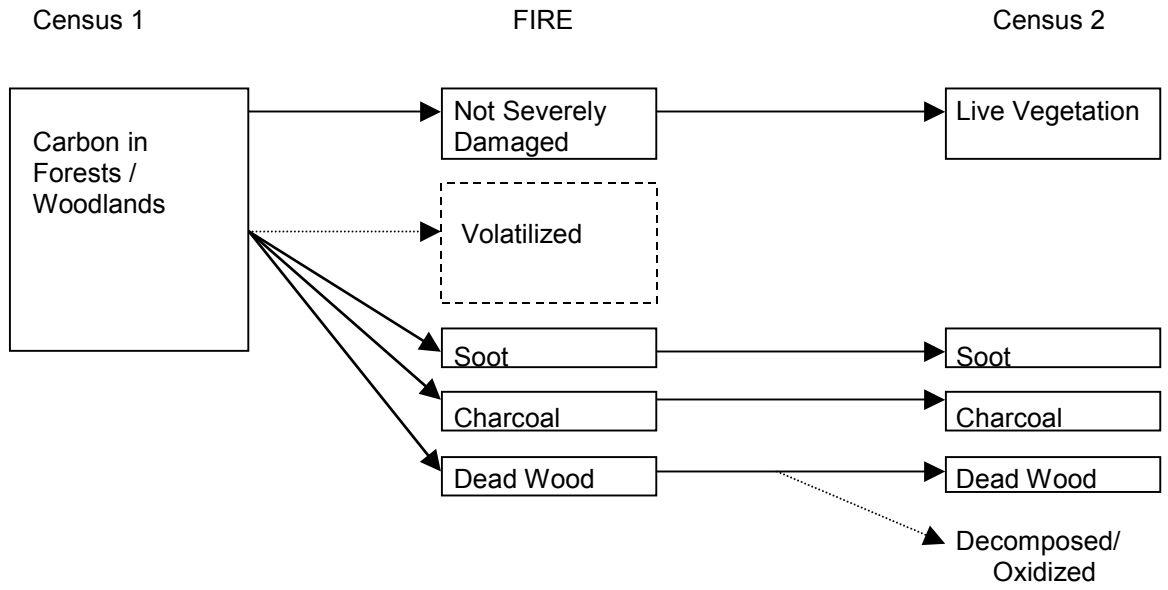


Figure 2-4-1
Flow Diagram Illustrating the Various Destinations of Pre-burn Carbon after a Fire

The basis for this baseline analysis was the detailed study conducted for California (Brown et al. 2004). Under the California baseline analysis changes in canopy coverage (measured from satellite imagery) were recorded through time for forest types and causes including fire were assigned. We assumed (based on expert opinion) that the three intensities are associated with the magnitude of change in crown cover, so that a large decrease in crown cover would be due to a high intensity fire or a small decrease is caused by a low intensity fire.

The midpoint of each decrease in canopy coverage class was assumed to be the proportion of the vegetation killed by the fire. The proportion volatilized is dependent on fire intensity (60 % high intensity fire, 40 % mid-intensity, 20 % low intensity; McNaughton et al. 1998; Carvalho et al. 2001). If the volatilized proportion is subtracted from the midpoint of the decrease then the remaining fraction is the dead wood, soot and charcoal pool. This fraction was divided using the following proportions: 22 % charcoal, 44 % soot, 32 % dead wood (Comery 1981, Raison et al. 1985, Fearnside et al. 1993, Neary et al. 1996).

2.4.1.2 Approach for Calculations

The aim of this study is to determine the loss in biomass as a result of fire in Arizona. In California we had data on the area affected by fire in classes of initial and post fire crown cover and forest type. The degree of reduction in crown cover was used to indicate the intensity of the fire. We also had the biomass associated with each crown cover class and so a change between two cover classes could be represented as a loss in carbon. In contrast, in Arizona available data included only forest type and an indication of fire intensity from fire extent and change in spectral reflectance.

The approach for this study is therefore to use the California data to determine the percentage loss in biomass that occurs as a result of a high, a medium or a low intensity fire in each of the forest types. The percentage loss is then applied to Arizona-specific biomass numbers for comparable forest types.

The source of biomass values is the Arizona 2003 inventory of the FIADB (forest inventory and analysis database). These were split between forest types. In all cases, Arizona FIA data was divided by the five forest/woodland types (Douglas Fir, Fir-Spruce, Other Conifer (typically Ponderosa Pine), Hardwood Forest, Hardwood Rangeland (typically oak savannah and pinyon-juniper); Table 2-4-1) at the county level. The division by forest/woodland type occurred to align the Arizona analysis with the original California study (Brown et al. 2004).

Table 2-4-1
Forest types for fire baseline analysis cross-walked with FIA forest type

California-analysis forest type	FIA forest type
Douglas-fir	Douglas-fir
Fir Spruce	White fir, Red fir, Noble fir, Pacific silver fir, Engelmann spruce, Engelmann spruce / Subalpine fir, Grand fir, Subalpine fir, Blue spruce, Sitka spruce
Other Conifer	Port-Orford cedar, Ponderosa pine, Western white pine, Jeffrey pine / Coulter pine / big cone Douglas-fir, Mountain hemlock, Lodgepole pine, Western hemlock, Western redcedar, Alaska yellow cedar, Western larch, Misc. western softwoods
Hardwoods - forest	Cottonwood, Willow, Oregon Ash, Aspen, Red alder, Bigleaf maple, Tanoak, Giant chinkapin, Pacific Madrone
Hardwood - rangeland	Western juniper, California black oak, Oregon white oak, Canyon live oak / Interior live oak, California laurel, Misc. western hardwood woodlands, Intermountain maple woodland, Juniper woodland, Pinyon juniper woodland, , Rocky mountain juniper, Deciduous oak woodland, Mesquite woodland

The FIA data was further split into regions – Northern and Southern – with the assumption that the climatic variation will lead to variation in biomass that will refine our estimates. The split of counties between regions is listed in Chapter 1.

The mean biomass stocks were calculated from AZ FIA data by region and forest type (Table 2-4-2).

Table 2-4-2
Mean biomass stock by forest type and region

	Mean biomass (t biomass/ha)	
	Northern	Southern
Douglas Fir	175.6	153.8
Fir Spruce	244.2	
Other Conifer	118.6	107.7
Hardwood	159.1	
Range Hardwood	43.8	31.8

2.4.1.3 Biomass Loss through Fire

To calculate the emissions through fire, results from the California analysis (Brown et al. 2004) were used. From the California analysis, the estimated stocks for each forest type at each of the 4 canopy density classes was taken, plus the net emissions for each forest type/canopy density class/fire intensity class. Finally the emissions were calculated as a proportion of the original biomass and the results expressed as a percentage.

As no canopy cover class data exists for Arizona, a mean emission percentage is required excluding canopy cover. This was achieved by weighting the emission percentages by the proportion of forest in each canopy class in the most representative region of California (North Sierra).

The proportions by forest type by region by fire intensity were then multiplied by the biomass by forest type by region to give estimated biomass lost through emissions from fire (Tables 2-4-3, 2-4-4).

Table 2-4-3
Mean emissions from a high, mid and low intensity fire in the Northern Region of Arizona

t CO_2e/ha	High	Mid	Low
Douglas Fir	145.0	62.5	25.1
Fir Spruce	263.5	112.9	45.5
Other Conifer	80.7	53.5	26.6

Hardwood	141.2	61.1	24.6
Range Hardwood	27.4	11.8	4.8

Table 2-4-4
Mean emissions from a high, mid and low intensity fire in the Southern Region of Arizona

t CO_2e/ha	High	Mid	Low
Douglas Fir	126.9	54.8	22.0
Fir Spruce	0.0	0.0	0.0
Other Conifer	73.2	48.6	24.2
Hardwood	0.0	0.0	0.0
Range Hardwood	31.4	13.5	5.4

2.4.1.4 Non-Tree Vegetation

Biomass numbers for non-tree vegetation (primarily shrubs and grasses in rangelands) are taken from the literature and Winrock International experience (Table 2-4-5).

Table 2-4-5
Estimates of pre-fire biomass stocks in non-tree vegetation

Vegetation type	Biomass carbon (t C/ha)	Source
Wet Grasslands	5.9	Prichard et al 2000
Mesic Grasslands	2.4	Brown and Archer 1999
Xeric Grasslands	0.6	Winrock unpublished data
Shrublands	5.1	Martin et al 1981
Desert scrub	2.6	Winrock unpublished data

Here the conservative assumption is made that 50 % of the pre-fire biomass in non-tree vegetation is volatilized to be emitted as carbon dioxide.

2.4.2 Methods for Assessing Area Impacted by Fire and Fire Intensity

Satellite-based analysis is a practical method of quantifying area burned primarily due to the dangerous nature and the wide geographic extent of wildfires. The State reports the location and size of recorded fires but with no measure of fire intensity, nor with the location of the boundaries of the fire. It is necessary to know fire intensity to estimate emissions and the precise location is necessary for a correlation with a database of vegetation species. The approach for this analysis was to estimate the extent of fires at known fire locations, through delineating areas with a change in reflectance on multiple satellite images, i.e. pre-fire and post-fire images.

A common measurement of vegetation from satellite imagery is the Normalized Difference Vegetation Index (NDVI). Very low values of NDVI (0.1 and below) correspond to barren areas of soil without vegetation or of sand, rock or snow. Moderate values represent shrub and grassland (0.2 to 0.3), while high values indicate forests (0.6 to 0.8).

2.4.2.1 Databases

NDVI was calculated from 1.1 km pixel resolution NOAA Advanced Very High Resolution Radiometer (AVHRR) 10 day composite images. The temporal frameset covered the month of September and spanned 1990 – 2003 (except 1994). This encompassed the NOAA 11, 14, 16 satellites. September was chosen for the analysis time frame because it is towards the end of the fire season and the burned areas are not yet affected by regrowth. Only one September 1994 composite was produced for 1994 due to the failure of the AVHRR sensor aboard NOAA-11. As a result, the imagery for 1994 along with fire data was dropped from the analysis due to data inconsistencies in image values and incomplete temporal coverage from sensor failures.

The wildfire database for Arizona encompassed a total of 23,242 occurrences that vary from less than 1 acre to many thousand acres. Fires for the study period with a final size greater than 2,000 acres were identified for NDVI postfire burn detection analysis to quantify area burned. For State lands, 5,602 fires occurred between 1990 and 1996, and for Federal lands, 17,636 fires that occurred between 1990 and 1996. Each fire record included a unique ID with a GPS point location, date, and final extent in acres. There was no GIS polygon representing the extent of the fire in the original database so it was not possible to precisely locate the extent of the fire from these records, so we used the approach described below.

2.4.2.2 Mapping Methods

Fire Identification

This analysis used a postfire burn detection method to quantify area burned by wildfires. NDVI was calculated from the water vapor corrected bands 10, visible (0.58 - 0.68 μm) and band 11, near infrared (0.725 – 1.10 μm).

NDVI = (ch 11 – ch 10)/(ch 11 + ch 10).

In order to obtain a single September NDVI for each year of the study period, three (or in some years four) 10-day composites were averaged into a single image ($NDVI_y$). These September images were then averaged into a 13-year historical NDVI reference image ($NDVI_m$).

NDVI reflectance values are bi-modal, ranging from -1.0 to 1.0. Positive values reflect vegetation or 'greenness', and negative values are indicative of soil or non-vegetated areas. Values close to 1 are 'greener' than values close to 0 and values close to -1 are more barren than values close to 0. When vegetation is burned, a rise in channel 10 reflectance and a decrease in channel 11 reflectance occurs. The degree of change ($NDVI_d$) was measured by subtracting $NDVI_y$ from $NDVI_m$

$NDVI_y - NDVI_m = NDVI_d$

From the reference image each individual annual September image was subtracted and potential fire locations identified. In NDVI difference imagery, positive values indicate an increase in 'greenness' from $NDVI_m$ and negative values a decrease. For burned area-identification purposes, all positive values were removed along with negative values greater than -0.05. The result was an image containing areas of concentrated vegetation decrease. The fire location data was then overlaid to confirm the changes as potential fires.

Fire Extent

The extent of fires listed as having over 2,000 acres in final size were mapped by visual interpretation from the changes seen in $NDVI_d$ with assistance from the fire's GPS location and extent information (Figure 2-4-2).

The wildfire mapping process consisted of creating polygons that represent the extent of the burn area. Fires were first divided into big and small based on final extent. Fires with a final extent of < 2,000 acres or 8 pixels were labeled as small fires. For AVHRR imagery, 1 pixel = 100 hectares = 247.5 acres. Areas of vegetation decrease in $NDVI_d$ greater than 8 pixels and with a corresponding fire greater than 2,000 acres were digitized using the 'heads up method'[1]. The area digitized was then compared with the reported final extent.

All fires with less than 2,000 acres burned were classified too small to display a change in the AVHRR imagery. For these fires, a buffer was calculated and added to the fire point based on the GPS point, which was considered the center of the fire, and the radius; that was derived from the size reported in the original record.

Additionally, if a fire that was larger than 2,000 acres could not be mapped by visual interpretation, it was mapped by the buffering method.

In the case of the fires that occurred in 1994, they were mapped using the images from 1995.

Fire Severity

For the fires that occurred in forested lands, three classes of burn severity were identified: low, medium, and high (Figure 2-4-2). Again, the intensity was evaluated separately depending on the fire mapping method. For the fires that were identified using the imagery, the value of burn severity corresponded with the value of the difference in NDVI. The rationale is that the more

[1] Heads up digitizing refers to on screen digitizing. It is referred to as 'heads up' because the analyst focuses on the screen as opposed to on a digitizing tablet.

negative the difference between the actual NDVI and the mean NDVI, the more severe is the fire. As a result, one fire can include areas with different burn severities. Small fires (< 2,000 acres) were arbitrarily considered to experience a low burn fire severity, since there was no image data to consistently support the estimation.

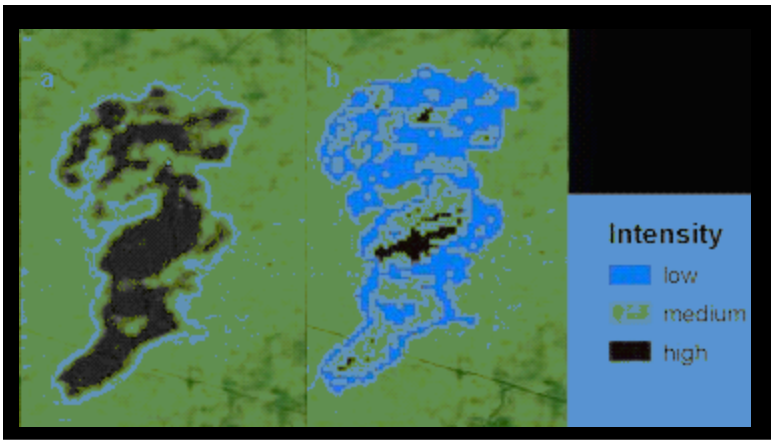


Figure 2-4-2
Illustration of the mapping methodology. In a the point location from the State or Federal database is established, a fire boundary is then created and compared to the fire area reported with the point location; in b the fire intensity through the burn area is calculated using NDVI values

Land Cover Affected by Fire

Finally, the fires map were crossed with the land cover maps, making possible to estimate the amount of land cover type / forest type that was affected by fires.

2.4.3 Results

Across the seven years analyzed fires with a total area of 437,700 hectares (1.08 million acres) were recorded (illustrated in Figure 2-4-3). This is equivalent to 62,500 ha / yr or 154,000 acres / yr.

Emissions totaling 904,000 tons of carbon or 3.3 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. This is equivalent to an emission of 0.47 $MMTCO_2e$ / yr.

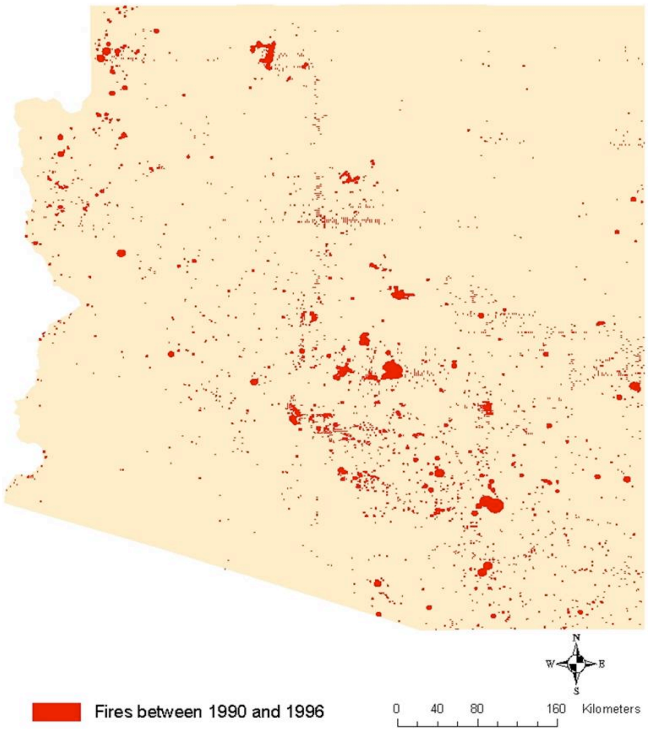


Figure 2-4-3
The location and extent of fires in Arizona between 1990 and 1996

Eighty percent of the fires occurred on rangelands with only 14 % in forests (Table 2-4-6)[2]. Due to the higher biomass loss from forests during fire almost 42 % of the total emissions from fire originated in the 14 % of fire area that was in forest.

Table 2-4-6
Area burned and carbon emissions in forests and in rangeland across the analysis period

	Area burned (ha)	Emissions (t C)
Forest	62,388	375,637
Rangeland	351,891	528,725

The annual emissions ranged between 22,000 tons of carbon and 218,000 tons of carbon (Table 2-4-7, Figure 2-4-3). The lowest emissions occurred in 1991 and 1992 when just 14 and 18,000 hectares were burned. The highest emission was in 1996 when 67,000 ha burned, however the largest area burned in 1993 and 1995 but a greater proportion of these fires occurred in low biomass systems (i.e. rangelands with no trees). The largest fires and highest emission come in

[2] The remaining fire area was on developed, agricultural or barren land

the later years of the analysis but more years of data would be needed to consider whether there is a trend to increase in fire coverage and emissions.

Table 2-4-7
Area burned and carbon emissions per year across the analysis period

YEAR	Area burned (ha)	% Forest	Emissions (t C)
1990	34,909	38	111,273
1991	14,215	10	22,352
1992	17,907	5	22,612
1993	109,510	6	168,611
1994	90,476	16	177,601
1995	103,145	7	183,898
1996	67,490	26	218,014
TOTAL	437,651		904,361

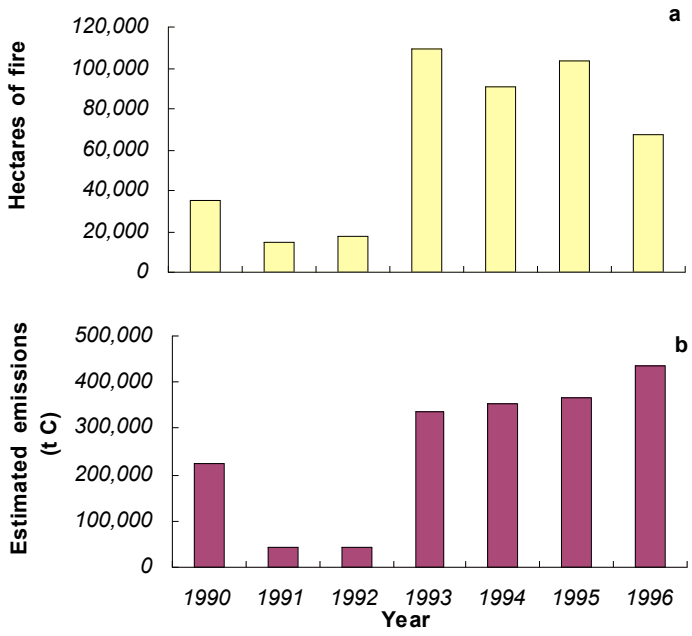


Figure 2-4-4
Area impacted by fire and estimated emissions from fire across the study period

Fires occurred throughout Arizona during the study period and there was no apparent geographical relationship between either area burned or carbon emissions from fire and geographic location (Figures 2-4-4, 2-4-5). The highest emissions occurred in Coconino and Gila Counties (Table 2-4-8). The largest total areas burned were located in Maricopa and Mohave Counties.

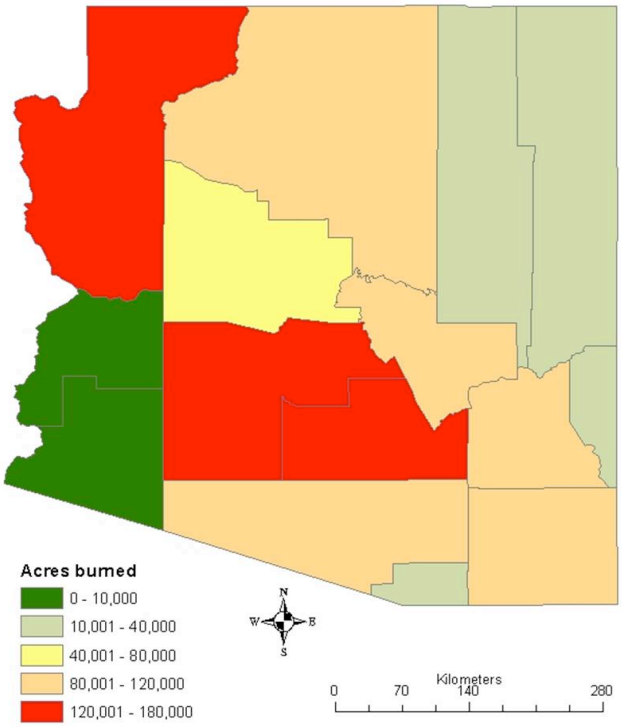


Figure 2-4-5
Area burned (in acres), at the county level, between 1990 and 1996

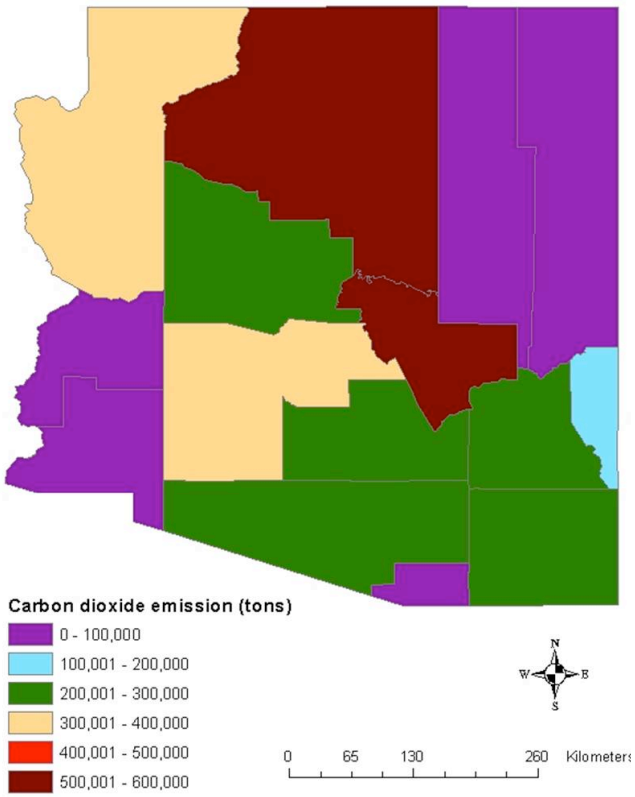


Figure 2-4-6
Metric tons of carbon dioxide emitted, at the county level, between 1990 and 1996

Table 2-4-8
Area burned and carbon emissions per county across the analysis period

COUNTY	County Area (ha)	Area burned (ha)	Emissions (t C)
Apache County	2,902,050	5,723	14,698
Cochise County	1,597,880	36,664	74,279
Coconino County	4,821,891	38,221	137,097
Gila County	1,234,829	35,485	143,832
Graham County	1,198,987	37,391	77,270
Greenlee County	478,371	12,396	50,734
La Paz County	1,165,483	2,334	2,703
Maricopa County	2,383,602	61,479	84,341
Mohave County	3,447,699	71,075	94,615
Navajo County	2,577,862	5,342	24,481
Pima County	2,379,232	48,316	64,908
Pinal County	1,390,719	55,492	73,271
Santa Cruz County	320,546	4,483	4,549
Yavapai County	2,103,925	22,300	56,528
Yuma County	1,428,143	950	1,056
TOTAL		437,651	904,361

2.4.4 Uncertainties

The carbon values to which percentage emission factors are applied are averaged values across all FIA plots in a forest type / region combination. Consequently, the same average value is used to represent forests with very high carbon stocks or very low carbon stocks. Fires will occur in forests regardless of starting carbon stock, yet it is possible that the forests with the very lowest carbon stocks (for example in the year immediately after clear cut logging) may not have enough biomass to sustain a fire. The emissions reported here may therefore be a small *overestimate* for if the very lowest biomass plots are excluded from the FIA analysis the mean will be raised and consequently the estimated emissions.

The calculated emissions presented here are conservatively limited to just aboveground tree biomass and therefore represent an *underestimation* of total emissions. Carbon stored in other pools will combust and be emitted through fire. However, we have no detailed source that will link the region and forest type-specific FIA data on aboveground tree biomass with similar data on other carbon pools.

Fire will directly impact dead wood, litter, shrubs and herbs (though even these pools may not be completely volatilized in low severity fires (e.g. Skinner 2002)). The influence of fire on soil carbon or the carbon stored in roots is less clear. When a tree is killed, the roots will not be burned but will become dead material that will decompose at a rate that is not well understood. A very intense fire will impact soil carbon though it is not fully understood what proportion of soil carbon is volatilized nor what depth the impact penetrates to.

To give an indication of the scale of potential additional emissions for pools not included here, the literature was consulted. Smithwick et al. (2002) took measurements of all carbon pools across 43 stands at seven sites in Washington and Oregon. The authors divided their measurements into three regions – Coastal, Cascades and Eastern. The results from the dry pine forests of Eastern Oregon are presented here to represent the forests in Arizona. Values for roots were not taken from Smithwick et al. (2002); roots were estimated more directly by using the temperate forest allometric equation of Cairns et al. (1997), which calculates belowground biomass from aboveground biomass. The amount of additional biomass carbon as a percentage of aboveground live tree biomass carbon stocks is given in Table 2-4-10.

Table 2-4-10
Relative increase in stocks that would result from adding each of the additional carbon pools to live aboveground trees

	Litter	Dead Wood	Shrubs	Herbs	Roots	Soil Carbon
Arizona	22 %	23 %	0.38 %	0.09 %	25-31 %	43 %

The measurements of Smithwick et al (2002) were in old growth forests. In younger forests lower absolute amounts of dead wood might be expected together with similar quantities of litter, shrubs and herbs. Therefore a lower proportion of dead wood and a higher proportion of litter, shrubs and herbs might be expected in younger forests.

Here, as an indication of potential additions, the values of Smithwick et al. (2002) are used. Adding just litter, dead wood, shrubs and herbs, and assuming that the same proportion of these pools are volatilized as for live aboveground trees, gives an additional emission over the study period equal to 206,936 tons of carbon or an additional 23 %.

2.4.5 Conclusions

Across the seven years analyzed fires with a total area of 437,700 hectares (1.08 million acres) were recorded. This is equivalent to 62,500 ha / yr or 154,000 acres / yr. Emissions totaling 904,000 tons of carbon or 3.3 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. This is equivalent to an emission of 0.47 $MMTCO_2e$ / yr.

Eighty-five percent of the burnt area was on rangelands but 42 % of the emissions were from the 15 % of burned area that was forest. Fire incidence varied by year with high emissions in 1993 to 1996 (> 168,000 t C) and low emissions between 1991 and 1992 (< 23,000 t C). Fires occurred throughout Arizona during the study period and there was no apparent geographical relationship between either area burned or carbon emissions from fire and geographic location.

Chapter 3 – Baseline for Agricultural Lands in Arizona

3.1 GENERAL APPROACH

The goal of this chapter is to quantify the baseline of changes in carbon stocks in the Arizona agricultural sector for the decade of the 1990s. Baselines provide an estimate of the emissions and removals of greenhouse gases caused by changes in the use and management of land. The focus of this paper is on emissions and removals of carbon dioxide and not on non-CO_2 greenhouse gases. Baselines are useful for identifying where, within the landscape of a state, opportunities exist for enhancing carbon stocks and/or reducing carbon sources to mitigate greenhouse gas emissions.

The baseline for the agricultural sector depends on two types of data: (1) the total area of agricultural land, and area of each of the major agricultural land-use types, through time; (2) the carbon stocks in each land-use type. Areas and changes in area of agricultural lands are based primarily on the National Resource Inventory (NRI) database for the period 1987-1997. Carbon stock estimates for various agricultural land-use types were derived from consultation with experts in local universities and from the literature in combination with standard methods. The analysis is conducted for the entire state of Arizona at the county scale of resolution.

3.1.1 Classification of Agricultural Land

In this study, NRI data were used for estimates of area because of the NRI's relative strength in agricultural surveys compared with other sources of data. The coverage of NRI data is wider and is available across the states for multiple points in time and for multiple classes of agriculture.

In this analysis, agricultural land is equated to cropland as defined in the NRI (NRCS 2000). The NRI recognizes two categories of cropland: cultivated and non-cultivated. Cultivated cropland includes small grains and row crops, hay and pasture with cropping history, and horticulture with double cropping (meaning horticulture with crops planted under the trees). Non-cultivated cropland includes horticulture without double cropping, and hay without cropping history. Grazing lands are included under the analyses of rangelands in Chapter 2.

The distinction between cultivated and non-cultivated crops is not useful for the purpose of (aboveground) carbon analysis, which depends instead on biomass models based on the growth form of the vegetation. Therefore, the specific land-use categories from NRI were regrouped for this analysis into categories related to the growth form of the crop. All horticulture lands, with or without double cropping, were reclassified as woody cropland. The rest of the croplands, including hay, row crops and small grains, were considered to be non-woody crops (Table 3-1).

Table 3-1
NRI Categories and Subcategories in Arizona

Broad classification	Detailed classification	NRI classification
INCLUDED AS AGRICULTURE IN THIS CHAPTER		
Perennial woody crops	Fruit orchards	Fruit orchards
	Nut orchards	Nut orchards
	Vineyards	Vineyards
	Bush crops	Bush crops
	Berry crops	Berry crops
	Other horticulture	Other horticulture
Annual non-woody crops	Row / close crops	Row / Corn
		Row / Sorghum
		Row / Soybeans
		Row / Cotton
		Row / Peanuts
		Row / Tobacco
		Row / Sugar beets
		Row / Potatoes
		Row / Other veg / truck crops
		Row / All other row crops
		Row / Sunflower
		Close / Wheat
		Close / Oats
		Close / Rice
		Close / Barley
		Close / All other close grown
		Hay / Grass
		Hay / Legume
		Hay / Legume-grass
		Other crop / Summer fallow
		Other crop / Aquaculture
		Other crop / Other-set-aside etc.
FOCUS OF CHAPTER 2		
Pasture / rangeland	Pasture / rangeland	Pasture / Grass
		Pasture / Legume
		Pasture / Grass-forbs-legumes
		Rangeland
Forest	Forest	Forestland / Grazed
		Forestland / Not grazed
OTHER CATEGORIES		
Urban / transportation	Urban / transportation	Urban / 10 acres or larger
		Urban / Small built-up

		Transportation
Other	Other	Other farmland/Farmsteads Other farmland/Other land Other farmland/CRP land Barren/Salt flats Barren/Bare exposed rock Barren/Strip mines Barren/Beaches Barren/Sand dunes Barren/Mixed barren lands Barren/Mud flats Barren/River wash Barren/Oil wasteland Barren/Other barren land Other rural/Permanent snow-ice Other rural/Marshland All other land Water/Body 2-40 acres Water/Body less than 2 acres Water/Streams per. < 66 ft. wide Water/Streams per. 66-660 ft. wide Water/Large

3.1.2 Limitations of the NRI Database

Despite the general acceptance of NRI for agricultural resource analysis, it is important to note its limitations. First, the samples were taken from non-federal lands only, while in the West Coast states, federal lands occupy half or more of the total land area. Second, the data are not from a complete census, but rather from a statistically sound sampling design. Finally, the NRI's classification of land cover/land use types may not be consistent with other classification schemes commonly used in land cover/land use analysis, e.g. the classification in USGS National Land Cover Classification system.

For the purposes of this chapter of the paper, however, these limitations have virtually no effect on the analysis as the data are only being used for the agricultural sector, where lands are privately owned, easy to classify, and statistically well reported.

The NRI reports a margin of error for the 1997 reporting (equivalent to a 95% confidence interval) of ±9% for its sampling of areas of cultivated cropland.

3.1.3 Area and Change in Area of Agricultural Land

The NRI data for each state were reclassified into the broad classes shown in Table 3-1. The areas for each class for 1987 and 1997 were then calculated. Although data for 1992 were available, a similar analysis for California where the change over two 5-year periods was included (1987-1992 and 1992-1997) indicated that using two periods did not appear to add any

further insights into the dynamics of land-use and carbon stock change (Brown et al. 2004). Thus we only examine the change over the 10-year period 1987 to 1997.

3.1.4 Carbon Density of Agricultural Land

The baseline analysis for the agricultural sector focuses on carbon in vegetation only, including above- and belowground (roots) components. Carbon in vegetation is estimated as 50% of the biomass of the vegetation.

Carbon Stocks for Non-Woody and Woody Crops

A difficulty in estimating the biomass of non-woody annual crops is caused by the seasonal change of the vegetation. During the non-growing season, there is little biomass in annual crops, while at the peak of the growing season just before harvest, biomass can be high. Considering that litter production is usually low in these crops, peak biomass is assumed to be equivalent to the annual primary production of the crops on the land. In many cases the majority of the biomass (or production) is removed from the field at harvest. An approximate temporal average of the biomass was used to derive the carbon stock. The biomass in cultivated non-woody crops was estimated based on three sources of data: crop biomass from the U.S. Department of Agriculture – National Agriculture Statistics Service (USDA NASS, see http://www.usda.gov/nass/sso-rpts.htm), length and timing of harvest cycles, and the relative abundance of each crop type.

Carbon stocks of horticultural crops have less seasonal variation, but data on carbon stocks for these crops are scarce. Yield data from the USDA NASS represents only the biomass of the harvest – a useful estimate of peak biomass for non-woody crops, but only a small portion of the standing biomass for woody crops. Thus estimates were instead derived from consultation with extension agents, university researchers and government officials in combination with literature searches, principally to determine typical stocking densities (number of trees per unit area), tree diameters and tree heights. Biomass can then be estimated from tree diameter and height using a regression equation (Winrock unpublished). The stocking densities were combined with estimates of biomass per plant to arrive at an estimate of biomass carbon density in metric t C/ha. For fruit orchards and bush fruits, multiple crop types were included and the relative abundance of each crop type in the state, derived from USDA NASS, determined the area-weighted mean carbon stock that was used in this analysis (Table 3-2).

Table 3-2
Estimates of the average carbon stock (t C/ha) for each of the crop types in AZ

Crop type	Average C stock (t C/ha)
Fruit orchards	17.3
Nut orchards	10.8
Vineyards	4.3
Bush fruits	-
Berry fruits	-

Other horticulture	4.5
Non-woody crops	1.5

Soil carbon stocks are not included in this paper because we assume that most agricultural land has been under cultivation long enough that changes in soil carbon would be minimal to non-existent under current practices. The stability of soil carbon on cultivated land was confirmed by the study of DeClerck and Singer (2003), who showed that the percent change in soil carbon under row crops in CA remained constant over an approximate period of 50 years. Interestingly, DeClerck and Singer also found the same trend for tree crops, but an increase in soil carbon over the past 50 years for soils under viticulture (about a 1.7-fold increase) and pasture (about a 1.6-fold increase). These results are difficult to apply in baseline determination because the results were reported as an increase in percent carbon with no indication of changes in soil bulk density; calculating changes in carbon stocks requires not only the change in percent carbon but also the change in soil bulk density.

Estimates of the carbon stocks in non-agricultural lands (e.g., urban/transportation, and all the other class) are assumed to be zero. This assumption is probably reasonable for "other" as this contains mostly barren lands, but for urban/transportation there is likely to be more carbon than in non-woody croplands. Urban development often contains significantly more (but unknown) amount of biomass in trees and shrubs that homeowners and local municipalities plant than in the agricultural lands that they replace. This is an area of further research—estimating the amount of carbon in biomass of urban areas as a function of density, etc.

Change in Stocks

When a change in agricultural land use occurred it was assumed in this analysis that the entire carbon stocks in vegetation present before the change would be emitted into the atmosphere as carbon dioxide. This is a reasonable assumption given the necessity to clear the land in order to plant alternative crops or initiate urban development.

For changes in land use to agricultural crops it is assumed that the change occurred at the midpoint of the period under analysis (in 1992), five years before 1997 and five years after 1987. For non-woody crops such as vineyards, bush and berry crops, and other horticulture crops, it is reasonable to assume that in five years, these crop types will have reached their predicted steady-state biomass. The same assumption cannot be applied to orchards, which will take longer than five years to attain their maximal biomass. Instead, the biomass accumulation that might have occurred in five years of growth for fruit and nut orchards respectively was estimated based on conservative estimations of stocking density, tree heights and diameters at five years age (Table 3-3).

Table 3-3
The estimated average biomass carbon accumulation after five years of growth for fruit and nut orchards in AZ (t C/ha)

	Average biomass carbon accumulation
Fruit orchards	1.6
Nut orchards	0.4

In addition, it can be expected that fruit orchards and nut orchards will continue to accumulate biomass for many years. We therefore applied an average biomass accumulation to areas of orchards that remained constant over the ten years of the analysis. The rate of biomass accumulation was determined by estimating the stocks at years 40 and 60 and dividing the difference by 20 to get an annual accumulation. The annual accumulation was multiplied by 10 to give an accumulation for the ten years 1987 to 1997 (Table 3-4).

Table 3-4
The estimated average biomass carbon accumulation over 10 years of growth for fruit and nut orchards in AZ (t C/ha). This growth rate is for existing orchards, i.e. for areas unaffected by land-use change

	Average biomass carbon accumulation
Fruit orchards	3.4
Nut orchards	2.1

3.1.5 Uncertainty

Uncertainty in NRI Data

The estimated margin of error (95 % confidence interval) for the area of cultivated cropland in 1997 is 12.6 % for Arizona (NRCS 2000). For areas presented at finer scales (county level, specific crop) or for changes in area, the margin of error will be significantly higher.

Uncertainty in Carbon Stock Data

To evaluate the confidence in the estimated carbon stocks, ranges were determined (Table 3-5) based on the ranges in diameter, height, biomass and planting density provided by the sources consulted as described in section 3.1.4.

Table 3-5
Estimated ranges in average carbon stock for each crop type in AZ (t C/ha)

Crop type	Range in C stocks (t C/ha)
Fruit orchards	12.9-26.1

Vineyards	2.4-6.7
Bush fruits	-
Berry fruits	-
Other	3.4-5.7
Non-woody	1.0-2.0

Weighting the deviations from the mean by area and carbon stock gave a mean deviation value for carbon stocks of 42 %.

3.2 RESULTS

3.2.1 Statewide Land Use and Land Use Change 1987-1997

The total area of Arizona is 29.53 million ha, of which 57% is covered by the NRI and the remainder is federal land falling outside the scope of the NRI.

In 1997 agricultural land in Arizona, including both perennial woody and annual non-woody lands, was estimated at 438,289 ha or 1.5 % of the land area of the state (Figure 3-1). The area of woody cropland was 6.9 % of the total area under agricultural cultivation.

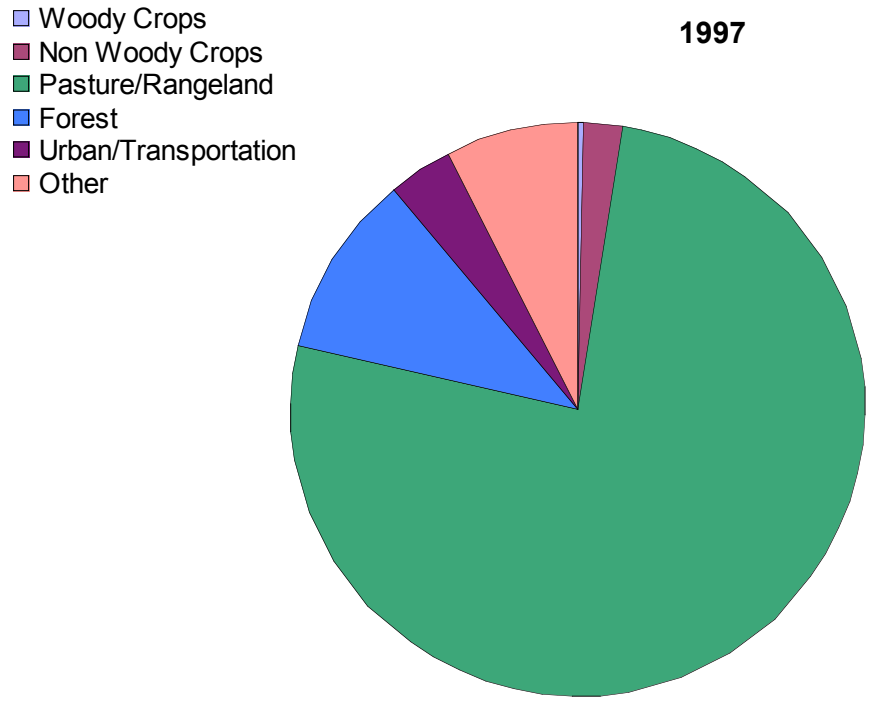


Figure 3-1
Proportional area for land uses in Arizona in 1997, based on NRI data (non-federal lands only)

Table 3-6
Areas (ha) and changes in areas (ha) for lands in Arizona from the NRI dataset

	1987	1997	Change	% Change
Woody crops				
Fruit orchards	16,229	17,766	1,537	+9.5
Nut orchards	8,660	7,648	-1,012	-11.7
Vineyards	4,492	4,654	162	+3.6
Bush crops	-	-	-	-
Berry crops	-	-	-	-
Other horticulture	-	-	-	-
Total woody crops	29,381	30,068	687	+2.3
Non-woody crops				
Row / Close crops	439,667	408,221	-31,446	-7.2
Other land uses				
Pasture / Rangeland	12,991,477	12,906,045	-85,432	-0.7
Forest	1,772,262	1,703,585	-68,677	-3.9
Urban / Transportation	514,536	603,570	89,034	+17.3
Other	1,198,357	1,294,190	95,833	+8.0
TOTAL	16,945,680	16,945,680		

Overall, agricultural land in Arizona experienced a 6.6 % (30,759 ha) loss in area during the 10-year period from 1987-1997. However, this loss included a 7.2 % loss in area of non-woody crops and a 2.3 % increase in area of woody crops (Table 3-6, Figure 3-2). In the same time period there were small decreases in the area of pasture/rangeland (0.7%) and non-federal forest (3.9%) and increases in the area of urban/transportation (17.3 %) and the Other category (8.0 %).

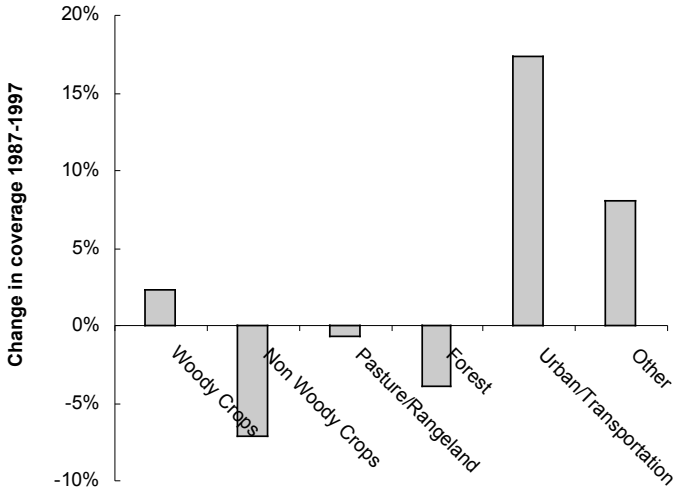


Figure 3-2
Proportional change in area between 1987 and 1997 for broad land uses in Arizona

3.2.2 Changes in Specific Land-use Type

Agricultural land in Arizona is dominated by non-woody crop types (93 %; Figure 3-3). Among the woody crops, fruit orchards make up 59 %, nut orchards 25 % and vineyards 15 %.

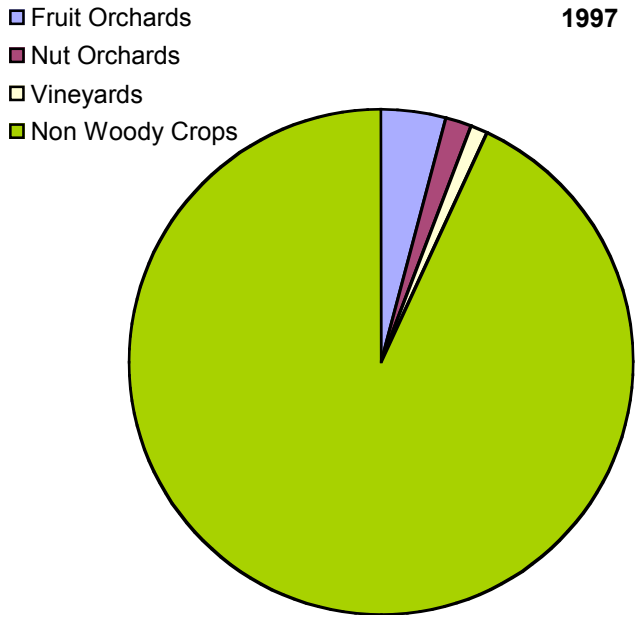


Figure 3-3
Proportional coverage of each agricultural land-use in Arizona in 1997

The 2.3 % increase in area of woody crops between 1987 and 1997 was composed of a 9.5 % increase in fruit orchards (1,537 ha) and a 3.6 % increase in vineyards (162 ha), balanced by a 11.7 % decrease in nut orchards (1,012 ha) (Table 3-6, Figure 3-4).

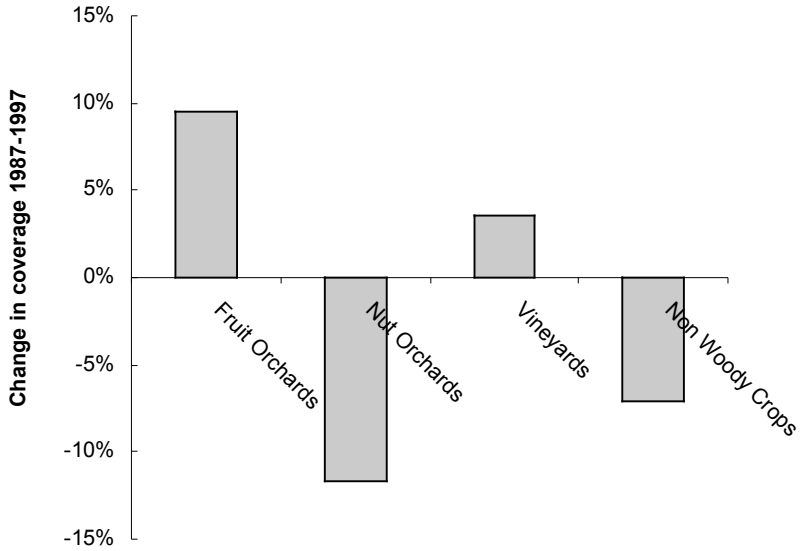


Figure 3-4
Proportional change in area between 1987 and 1997 for agricultural land uses in Arizona

There was a net loss in area in each of the land uses to development, the Urban/Transportation NRI land class (Table 3-7). The greatest loss was from pasture/rangeland to development (65,805 ha), although this was balanced by a loss in forest to pasture/rangeland (44,112 ha). The loss in forest to pasture runs contrary to the sentiment among ranchers that mesquite and juniper are encroaching on grasslands (pers. comm. Melanie Lenart, University of Arizona). However, it should be remembered that NRI classifies oak and juniper woodlands (and any areas with less than 10% crown cover) as rangeland.

The decrease in area of nut orchards resulted in an increase in non-woody crops (202 ha), forest (283 ha) and development (526 ha). Non-woody crops gained area from fruit orchards (81 ha), nut orchards (202 ha) and rangeland (3602 ha) but lost area to development (14,488 ha) and the Other category (20,842 ha).

Table 3-7

Land-use change transition matrix, showing the source and direction of changes in Arizona 1987-1997. The area unchanged between the time periods is listed at left, then the net gain and loss from the land uses listed in the rows to the land uses listed in the columns. A negative sign indicates a net loss of area from the land use in the row to the land use in the column

		Change to (-) / Change from (+)							
	Unchanged	Fruit Orchards	Nut Orchards	Vineyards	Non-Woody Crops	Rangeland	Forest	Urban / Transportation	Other	TOTAL CHANGE
Fruit Orchards	10,198				-81	6,435		-3,238	-1,578	1,538
Nut Orchards	7,649				-202		-283	-526		-1,011
Vineyards	4,492								162	162
Non-Woody Crops	381,834	81	202			3,602		-14,488	-20,842	-31,445
Rangeland	12,768,771	-6,435			-3,602		44,112	-65,805	-53,704	-85,434
Forest	1,644,498					-44,112		-1,416	-23,149	-68,677

3.2.3 *County-Level Estimate of Agricultural Land Area*

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Woody cropland is concentrated in the south of the state, but even in this region it is never a dominant component of the landscape (< 0.5 % by area) (Figure 3-5a). Non-woody crops are also concentrated to the south but are more dominant than woody crops, occupying up to almost 9 % of some counties (Figure 3-5b). The counties with the greatest coverage of non-woody crops include Maricopa and Pinal with 115,900 ha and 124,200 ha respectively in 1997 (Table 3-8).

Only six counties recorded net changes in area of woody crops (Figure 3-6a). Losses in area occurred in Cochise, Graham, Yuma and Pima and gains in Maricopa and Pinal. Losses in area of non-woody crops were recorded in all but two counties (Mohave and Pinal; Figure 3-6b, Table 3-8).

Table 3-8
The county level coverage (ha) for specific agricultural land uses and the change in coverage in Arizona 1987 to 1997

County	High Carbon Crops						Low Carbon Crops			
	Fruit Orchards		Nut Orchards		Vineyards		Non-Woody crops		TOTAL	
	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997
Apache							2,469	2,266	2,469	2266
Cochise	1,052	1,012	445	445			47,876	40,227	49,373	41,684
Coconino							283	243	283	243
Gila							1,214	243	1,214	243
Graham	486	243					18,454	16,350	18,940	16,593
Greenlee							1,497	931	1,497	931
La Paz							28,693	23,756	28,693	23,756
Maricopa	7,285	10,805			728	728	121,653	115,866	129,666	127,399
Mohave							971	1,174	971	1,174
Navajo							1,255	364	1,255	364
Pima			5,787	4,775			12,101	11,251	17,888	16,026
Pinal	2,307	2,307	1,052	1,052	3,764	3,926	123,353	124,162	130,476	131,447
Santa Cruz							1,821	809	1,821	809
Yavapai							2,550	2,104	2,550	2,104
Yuma	5,099	3,399	1,376	1,376			75,477	68,475	81,952	73,250
TOTAL	16,229	17,766	8,660	7,648	4,492	4,654	439,667	408,221	469,048	438,289

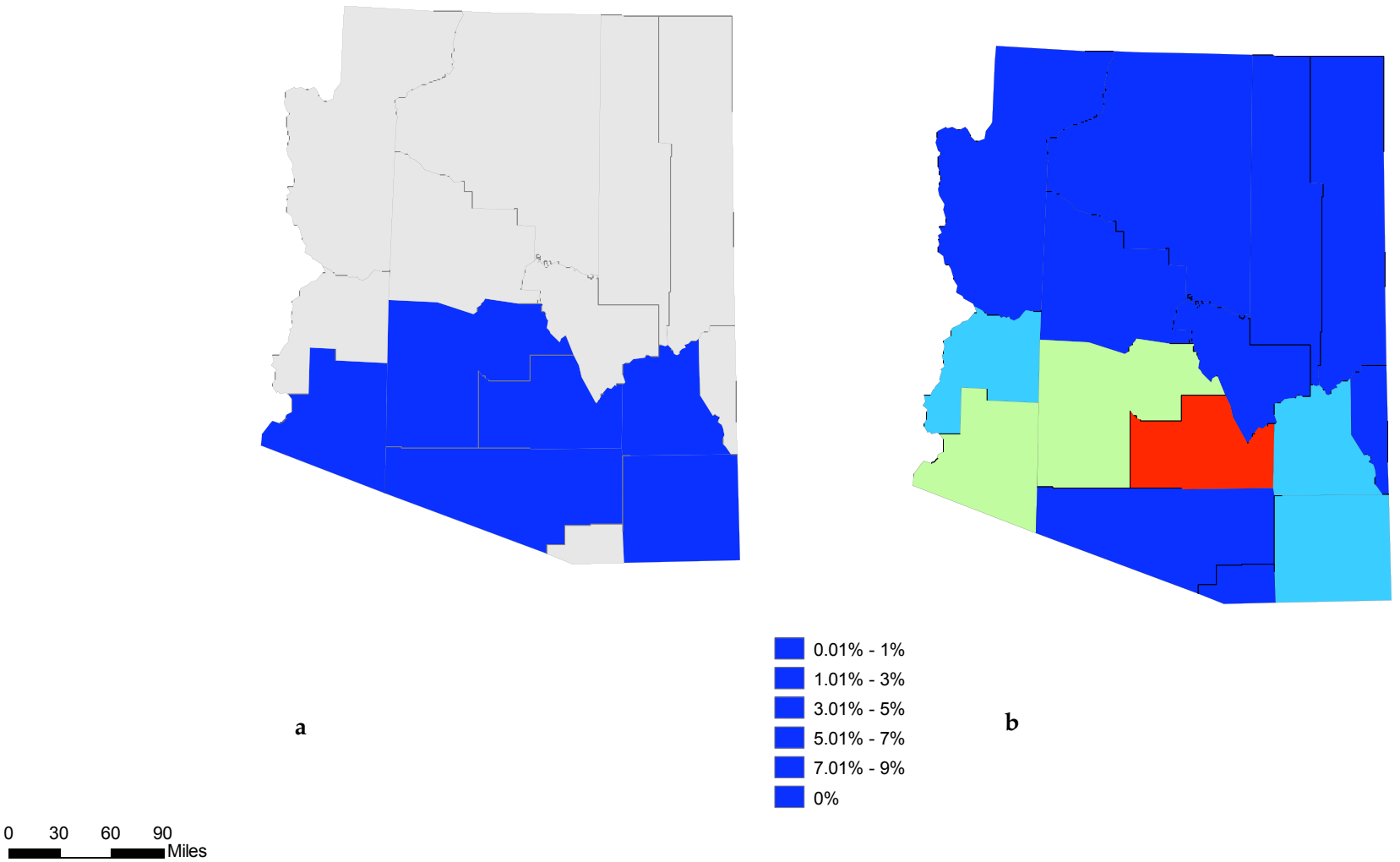


Figure 3-5
Land use by county in AZ, 1997, showing distribution of (a) woody and (b) non-woody cropland. Values indicate the percentage of total land area in each county occupied by each class of agricultural land

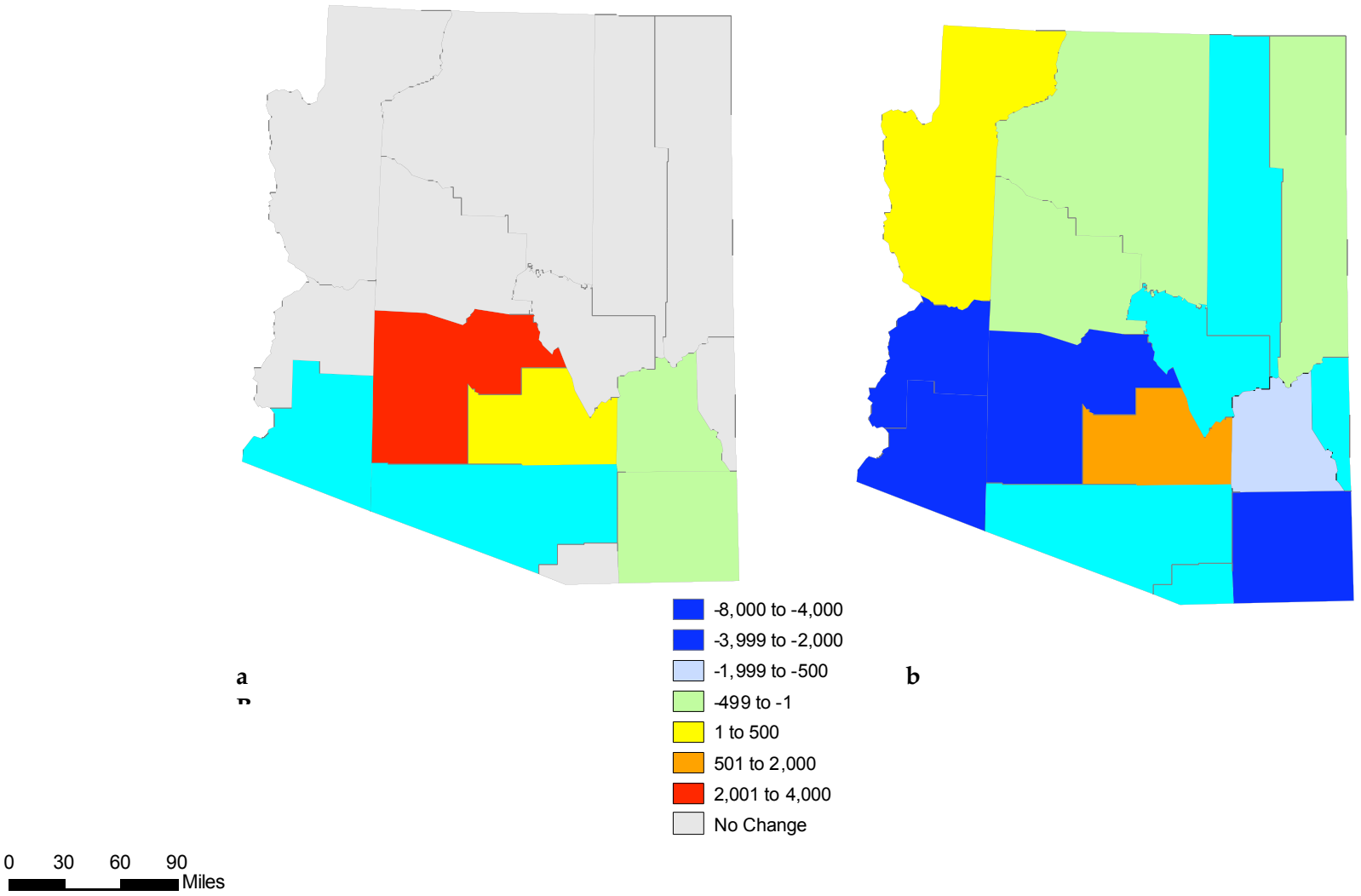


Figure 3-6
Land use change by county in AZ, 1987 to 1997, showing distribution of change in area in (a) woody and (b) non-woody cropland. Values indicate change in hectares; minus sign indicates a loss in area from 1987 to 1997 and plus sign indicates a gain in area in the same period

3.2.4 Carbon Stocks of Agricultural Land During 1987-1997

The total estimated carbon stock in the vegetation of all Arizona agricultural crops is approximately 1 million tons. In the ten-year period between 1987 and 1997, the carbon stock decreased by 98,900 tons caused by the conversion of agricultural land to alternative uses. Of this total, just over 47,000 tons were lost from non-woody crops and 51,700 tons were lost from woody crops (Table 2-4). This represents a loss of 7.2 % of the carbon in non-woody crops and of 13.1 % in carbon in woody crops, for a total loss from agriculture in Arizona proportional to 9.4 % of the carbon stored in 1987. The main source the loss was from fruit orchards (loss of 57,500 t C) that far exceeded small gains in carbon stored in nut orchards and vineyards (Table 3-9, Figure 3-7).

Table 3-9
Carbon stocks (t C) and changes in carbon stocks (t C) for land use types in Arizona

	1987	1997	Change
Woody crops			
Fruit orchards	280,753	223,216	-57,537
Nut orchards	93,534	98,670	5,136
Vineyards	19,316	20,012	697
Bush crops	-	-	-
Berry crops	-	-	-
Other horticulture	-	-	-
Total woody crops	393,603	341,898	-51,705
Non-woody crops			
Row / Close crops	659,501	612,332	-47,169
TOTAL	1,053,103	954,230	-98,874

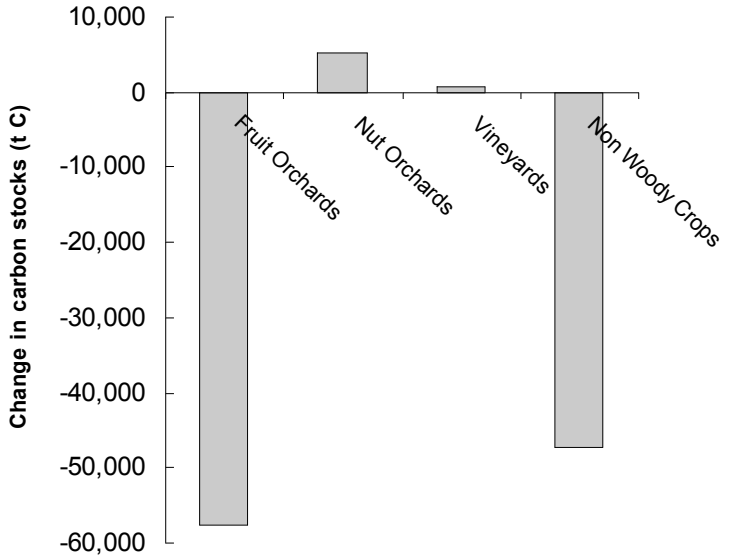


Figure 3-7
Changes in carbon stock (t C) across crop types in Arizona between 1987 and 1997

Large losses in carbon resulted from conversion of cropland to development (83,400 t C) and other (60,900 t C). No changes were recorded from cropland to forestland or vice versa. Gains in carbon in cropland between 1987 and 1987 resulted from the conversion of rangeland to fruit orchards and non-woody crops (11,900 t C). Of the gross gains in carbon in fruit orchards, 74 % was from growth of existing orchards and 26 % was growth in new plantings. There was no expansion in the area of nut orchards and consequently 100 % of the gains in carbon were from growth in existing orchards (Table 3-9).

When converted to carbon dioxide equivalents, the total stocks in 1997 on agricultural land in Arizona are estimated at 3.5 $MMtCO_2eq$ (Table 3-10). There was a net loss of 0.4 $MMtCO_2eq$ between 1987 and 1997. This is equal to an annual source of 0.04 $MMtCO_2eq$. Thirty-six percent of the stocks are estimated to be in woody vegetation. Both woody and non-woody vegetation represented an annual source of 0.02 $MMtCO_2eq$.

Table 3-10
Carbon stocks on agricultural land and their change (million tons of carbon dioxide equivalent, $MMTCO_2e$)

	Agricultural Land	Woody	Non-woody
1987	3.9	1.4	2.4
1997	3.5	1.3	2.2
1987-1997	-0.4	-0.2	-0.2

Table 3-11

The land use origins and destinations of changes in carbon stocks in agriculture in AZ between 1987 and 1997. The growth of existing stands is listed at left, then the net gain and loss in carbon stocks from the land uses listed in the rows to the land uses listed in the columns. A negative sign indicates a net loss of carbon stocks from the land use in the row to the land use in the column

AZ		Change to (-) / Change from (+)							
	Growth of existing stands	Fruit Orchards	Nut Orchards	Vineyards	Non-Woody Crops	Rangeland	Forest	Urban / Transportation	Other	TOTAL CHANGE
Fruit Orchards	34,675				-15,379	6,483		-56,010	-27,305	-57,536
Nut Orchards	16,063				-2,185			-5,682	-3,060	5,136
Vineyards									697	697
Non-Woody Crops		122	303			5,403		-21,732	-31,263	-47,168

3.2.5 Carbon Stocks of Agricultural Land by County

The losses of carbon stocks from non-woody crops were spread through all but two counties in the state (Mohave and Pinal counties). In contrast, the net losses from woody crops were limited to four counties (Graham, Maricopa, Pima and Yuma) with the losses of 29,900 and 34,900 tons of carbon from fruit orchards coming from single counties (Maricopa and Yuma respectively) (Table 3-12, Figure 3-8).

Table 3-12
Change in carbon stocks (t C) between 1987 and 1997 by crop types for counties in Arizona

County	Woody Crops			Non-woody Crops	
	Fruit Orchards	Nut Orchards	Vineyards	Row / Close crops	TOTAL
Apache	0	0	0	-305	-305
Cochise	2,740	935	0	-11,474	-7,798
Coconino	0	0	0	-60	-60
Gila	0	0	0	-1,457	-1,457
Graham	-3,376	0	0	-3,156	-6,532
Greenlee	0	0	0	-849	-849
La Paz	0	0	0	-7,406	-7,406
Maricopa	-29,892	0	0	-8,681	-38,573
Mohave	0	0	0	305	305
Navajo	0	0	0	-1,337	-1,337
Pima	0	-899	0	-1,275	-2,174
Pinal	7,844	2,210	697	1,214	11,964
Santa Cruz	0	0	0	-1,518	-1,518
Yavapai	0	0	0	-669	-669
Yuma	-34,853	2,889	0	-10,503	-42,467
TOTAL	-57,537	5,136	697	-47,169	-98,874

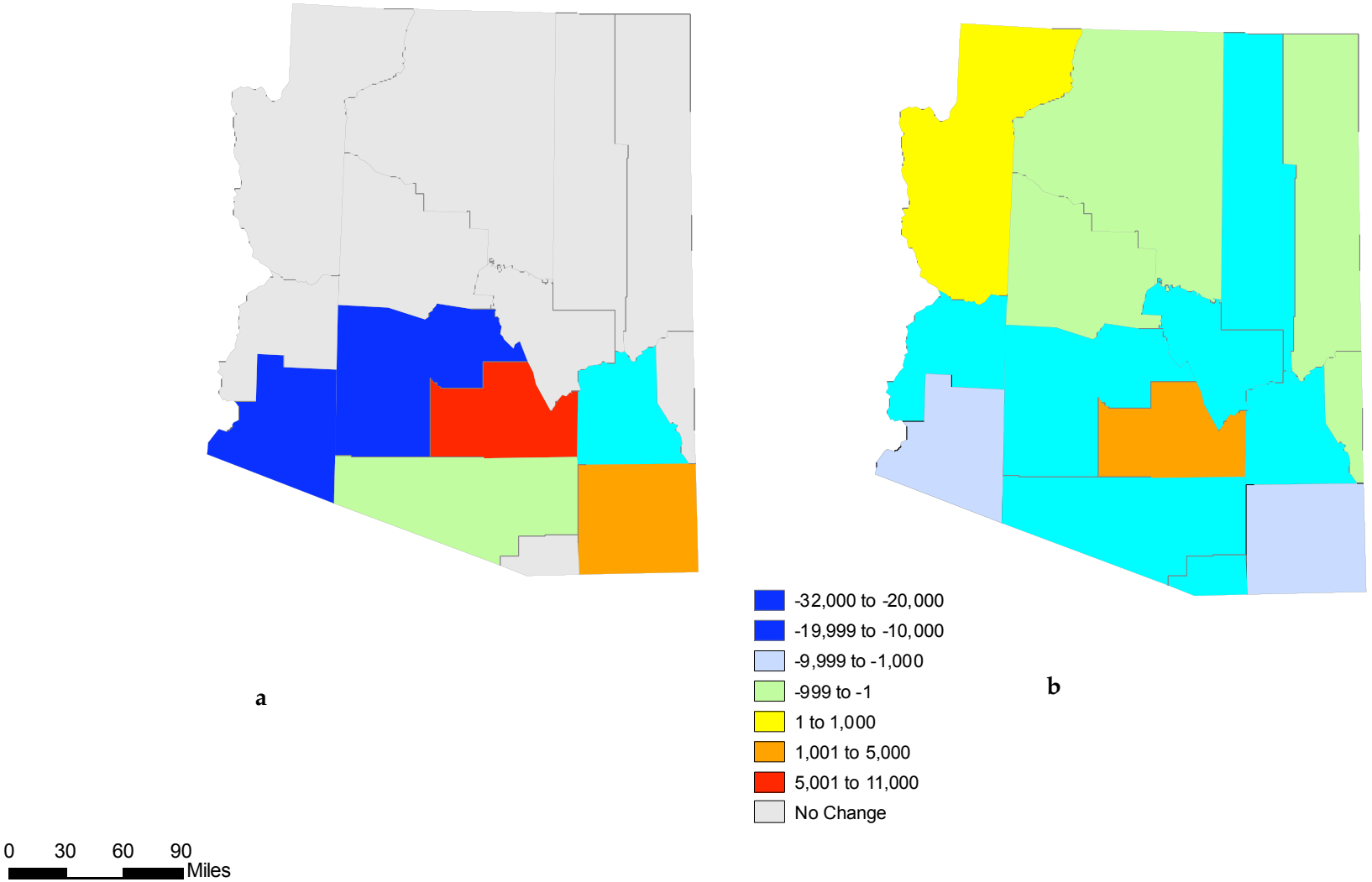


Figure 3-8
county-scale change in carbon stocks, 1987 to 1997, in (a) high-carbon crops (orchards and vineyards, and in (b) low-carbon crops (non-woody crops in Arizona. Values in tons of carbon

3.3 NON-CO_2 GREENHOUSE GAS EMISSIONS

The primary non-CO_2 greenhouse gas emitted from croplands is nitrous oxide, with approximately 296 times the global warming potential of CO_2. Nitrous oxide (N_2O) is emitted from agricultural soils especially after fertilizer application. A second important non-CO_2 gas is methane, with approximately 23 times the global warming potential of CO2. Methane (CH_4) is emitted during manure management and through livestock enteric fermentation.

The Arizona Climate Change Advisory Group (Bailie and Lazarus 2005) report an annual sources from agricultural sources (manure management, fertilizer use, and livestock (enteric fermentation)) of 4.2 $MMTCO_2e$ for the year 2000. This is more than 100 times the total we estimate here for CO_2 emissions attributable to agricultural land conversion (0.036 $MMTCO_2e/yr$). The CO_2 equivalents from nitrous oxide and methane thus make up more than 99 % of the total summed annual sources estimated for Arizona's agricultural sector.

3.4 CHAPTER 3 CONCLUSIONS

Agricultural land in Arizona in 1997 represented 1.5% of the total land area and non-woody crops were 93% of all agricultural land. Both woody and non-woody cropland are concentrated in the southern counties, with non-woody cropland totaling up to 9% of the total land area but woody cropland making up less than 0.5% of the land area in these counties. Statewide, there was a loss of agricultural land of 6.6% between 1987 and 1997, including a 7.2% decrease in non-woody cropland and a 2.3% increase in woody cropland. All land uses lost area over the period through conversion to urban development/transportation.

Total carbon stocks in all agricultural land types in Arizona were estimated at 1 million tons. Between 1987 and 1997, there was a total loss of about 99,000 tons of carbon, or 9.4% of the carbon stored in agricultural lands in 1987 (7.2% loss of the carbon stocks in non-woody crops and 13.1% of the carbon stocks in woody crops). The greatest losses came from conversion of fruit orchards and non-woody crops to urban development, and the greatest gains from conversion of rangeland to fruit orchards and non-woody crops. In CO_2 equivalent terms, total agricultural carbon stocks in Arizona in 1997 were 3.5 million metric tons CO_2 equivalent ($MMTCO_2eq$), and the net loss 1987-97 disregarding non-CO_2 greenhouse gas emissions was 0.4 $MMTCO_2eq$, equivalent to an annual source of 0.04 $MMTCO_2eq$. At the county level of analysis, all but two counties lost carbon through conversion of non-woody cropland to other land uses, but only five lost carbon through conversion of woody cropland. The greatest losses were in Maricopa and Yuma counties.

Non-CO_2 greenhouse gas emissions from N_2O (emitted from agricultural soils after fertilizer application) and CH_4 (from livestock and manure management) dwarf the annual CO_2 source from agricultural land conversion in Arizona.

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Part II: Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in OREGON

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EXECUTIVE SUMMARY

The objective of this paper is to establish the baseline carbon stocks and changes in stocks for the forest and agricultural sectors in the state of Oregon during the most recent 10-year period for which data are available (generally the decade of the 1990s). Such baselines can assist in identifying opportunities where carbon removals (sequestration) in each sector might be increased, or carbon emissions decreased, through changes in land use and management.

Baseline for Forest Lands

The baseline for forests is separated into three component parts. A general forests baseline is presented at the State level for all forestlands, based on USDA Forest Service data, detailing change in forest area and change in carbon stocks, but with no attribution to the causes for the change. Using additional data bases, the specific cases of emissions associated with development and with fire are further examined. These components form part of the total detailed in the general forest baseline section and should not be considered separately.

General Forestlands Baseline

Forest area and carbon stocks were derived from USFS published data for the period 1987-1997. An extrapolation was made from 1997 to 2003 using recently completed USFS inventory data.

Between 1987 and 2003 there was an estimated increase in forest area in Oregon of 2.1 million acres or 94,000 acres per year between 1987 and 1997 and 175, 000ac/yr between 1997 and 2003 (Table S-1).

This is equivalent to an estimated increase of 431 $MMTCO_2e$ between 1987 and 2003 or 23.0 $MMTCO_2e$/yr between 1987 and 1997, and 34.4 $MMTCO_2e$/yr between 1997 and 2003.

Table S-1
Gross change in forest* area and forest carbon stocks in Oregon

	1987	1997	2003	Annual Change 1987-1997	Annual Change 1997-2003
Area (million ac)	28.7	29.7	30.8	0.094	0.175
Carbon stock ($MMTCO_2e$)	3,327	3,557	3,763	23.0	34.4

*Includes all forests, federal and non-federal

The total emissions for Oregon (excluding forests) for the year 2000 were estimated as 67.7 $MMTCO_2e$ (from Governor's Advisory Group on Global Warming). Forest sinks, therefore, potentially can offset as much as 50 % of the State's emissions.

Baseline Effect of Development on Forest Lands

The baseline for emissions from development on non-federal lands was estimated using land use data from the National Resources Inventory of the USDA and carbon data derived from the USFS Forest Inventory and Analysis Database (FIADB), for the period 1987 to 1997. Due to data limitations the analysis is limited non-federal lands and to the gross carbon dioxide emissions from aboveground live tree biomass on conversion of non-federal forestland to developed land uses. As the focus is on non-federal lands the analyses should only be used to explore decisions on private lands.

Between 1987 and 1997, 69,000 acres of non-federal forest were converted to development. This is equal to 6,900 acres per year. Large losses were concentrated in the coastal regions.

For gross carbon emissions, two scenarios were considered. Under Scenario 1 all tree biomass in the converted area was immediately emitted as carbon dioxide. Under Scenario 2 for developed areas of less than 10 acres, it was assumed that 50 % of the carbon was retained in the form of residual trees.

Under Scenario 1 an estimated 15.4 $MMTCO_2e$ were emitted due to development or 1.54 $MMTCO_2e$/yr. Under Scenario 2, 13.9 $MMTCO_2e$ were emitted or 1.39 $MMTCO_2e$/yr. Development was concentrated in the Northwest region of the state where the major city of Portland is located (Table S-2). In this

region 56 % of the emissions under scenario 1, or 58 % of the emissions under scenario 2 occurred, despite the fact that the region represents only 9 % of the area of the State.

Table S-2
Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development on non-federal forests. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

Region	Area lost (ac)	Carbon emissions ($MMTCO_2e$) Scenario 1	Scenario 2
Northwest	35,000	8.6	8.1
West Central	14,200	3.2	2.6
Southwest	15,400	3.1	2.8
Central	4,100	0.51	0.46
Blue	200	0.02	0.02
TOTAL	68,900	15.4	13.9

The emissions from development on non-federal lands of 1.39-1.54 $MMTCO_2e/yr$ represent about 2.3% of the total gross emissions for the state of 63 $MMTCO_2e/yr$ in 1995 (from Governor's Advisory Group on Global Warming). Oregon's forests have a net sequestration of 22 $MMTCO_2e/yr$ between 1987 and 1997 (see Table S-1), after accounting for the emissions from development of about 1.4 $MMTCO_2e/yr$.

Baseline Effect of Fire on Forest Lands

The emissions from fire were examined through overlaying the wildfire database for Oregon on AVHRR satellite imagery showing change in NDVI (normalized differential vegetation index). (NDVI measures 'greenness' of landscape, greenness decreases immediately after fire). This process determined the location, size and intensity of fires between 1990 and 1996[1]. Carbon values were applied to these fires using data from the FIADB and proportional emissions from the detailed baseline fire analysis for northern California.

The analysis considered all forests and rangelands in Arizona, federal and non-federal.

Across the six years analyzed, fires with a total area of 328,000 hectares (0.81 million acres) were recorded. This is equivalent to an average 54,700 hectares per year (135,100 ac/yr) for the period studied. Emissions totaling 25.0 $MMTCO_2e$ were estimated to have occurred from fire during the 6-year period. On an average annual basis this is equal to 1.03 $MMTCO_2e/yr$.

Forty-eight percent of the burned area and 83 % of the emissions were in forest rather than rangeland. Fire incidence varied by year with high emissions in 1996 and low impact in 1993 and 1995. Seventy-nine percent of area burned and 83 % of the emissions were from Federally-owned land, 18 % of the area burned and 13 % of the emissions were from private land. Emissions from fire occurred throughout the State but were markedly lower in the Northwest.

The emissions from fire of 1.03 $MMTCO_2e/yr$ during the 6-year period represented about 1.6% of the total gross emissions for the state of 63 $MMTCO_2e/yr$ in 1995 (from Governor's Advisory Group on Global Warming).

[1] 1994 was excluded due to poor image quality.

Baseline for Agricultural lands

This paper presents a general methodology for determining the agricultural baseline. As with other terrestrial carbon baselines, the areas of different land uses and changes in land use are combined with carbon densities of each land use to yield an estimate of the total emissions and removals of carbon associated with land management and/or conversion of lands over a given time period. Estimates of area and changes in area of agricultural and non-agricultural land use types were derived from the National Resource Inventory (NRI) database for the period 1987 to 1997. As the NRI database was used only non-federal land was considered.

Agricultural land area in Oregon amounts to about 6% of the total land area. The state lost agricultural land area from 1987-97 through conversion to other land uses, in particular to urban development/transportation and the retiring of agricultural land from cultivation. In some counties, the area of woody cropland actually increased, but these increases were more than offset by decreases in non-woody cropland. Accompanying these losses in area were losses in standing carbon stocks on agricultural land, so that conversion of agricultural land to other uses was responsible for a net annual source (emission) of CO_2 to the atmosphere. Losses of agricultural carbon stocks over the 1987-97 period were estimated at 160,000 tons. The estimated net annual source from Oregon agricultural lands was 0.06 $MMTCO_2eq$ (Table S-3).

Table S-3
Summary of agricultural land area and changes in area, carbon stocks and changes in stocks, for Oregon 1987-97

Parameter	Units	Oregon
Proportion of agricultural land of total land	%	5.9
Change in agricultural land area, 1987-97	Hectares (%)	-75,833 (4.8%)
Change in woody cropland area		-2301 (4.1%)
Change in non-woody cropland area		-73,532 (4.8%)
Total carbon stocks in agricultural land, 1997	$MMTCO_2e$	11.6
Change in carbon stocks in agricultural land,	$MMTCO_2e$	-0.6
Estimated net annual source (emissions) from agricultural lands, disregarding non-CO_2 greenhouse gas emissions	$MMTCO_2e$	-0.06
From woody cropland		-0.02
From non-woody cropland		-0.04
Estimated net annual source from non-CO_2 greenhouse gas emissions, 1995	$MMTCO_2e$	-3.8

Emissions of CO_2 from agricultural land conversion, while the primary focus of this paper due to data availability, represent only a portion of the total greenhouse gas emissions attributable to the agricultural sector. The primary non-CO_2 greenhouse gases associated with agricultural activities are nitrous oxide (N_2O; emitted from agricultural soils especially after fertilizer application) with approximately 296 times the global warming potential of CO_2, and methane (CH_4; emitted by livestock and through manure management) with approximately 23 times the global warming potential of CO_2. Examination of data from Oregon indicated that greenhouse gas emissions from N_2O and CH_4 in the agricultural sector dwarf the annual CO_2 source from agricultural land conversion: CO_2 emissions from land conversion represented about 1 % of the total CO_2 and non-CO_2 greenhouse gas emissions attributable to the agricultural sector.

Chapter 1 – Introduction and Background Information

1.1 General Approach

The purpose of this baseline document is to examine changes in land use and the associated emissions or sequestration of carbon for forest and agricultural lands in the State of Oregon.

Separate baseline analyses are included here for forestlands and agricultural lands. The agricultural land study follows the same principles as the California baseline study (Brown et al. 2004). For forestlands, the California baseline study was based on CA-specific interpreted satellite imagery that detailed the scale of change, vegetation type and cause of change. Because no comparable data is available for Oregon, we instead rely predominantly on two national datasets (see Section 1.2). The consequence of using generalized broad-scale datasets is that the outcome is less certain than we were able to achieve in California.

The forest baseline includes a state-level analysis on the change in area and carbon stocks in all forestland, plus a county-level analysis of changes on non-Federal forestland. Also included are specific case studies on emissions due to development and fire.

1.2 Datasets used in the Analysis

Two datasets are used repeatedly through the baseline analyses:

1.2.1 The National Resources Inventory

The National Resources Inventory (NRI) is conducted by the US Department of Agriculture - National Resources Conservation Service (NRCS). The NRI is a scientifically designed survey of the nation's soil, water, and other related resources with the purpose of assessing conditions and trends. The NRI contains data only on non-Federal lands and water bodies. As noted in the Users' Manual (NRCS 2000), the NRI data are useful in developing estimates of natural resource conditions and in conducting geospatial and temporal analyses of these conditions (however, the location of the survey plots is not given in the data base). In these baseline analyses, NRI data were used for estimates of area because NRI data is available across the WESTCARB States, wide in coverage, and available for multiple points in time and multiple classes of land use.

Because NRI data come from sample surveys, it is important to have a sufficient sample size for a reliable estimate. The NRI Users' Manual does not recommend that the data be used for county-level analysis because of sample size issues. To be conservative, here analyses are reported at the State level. County level results are given for illustrative purposes only.

NRI analyses are for the time period 1987 to 1997. More recently the NRI has switched to annual reporting, but this data is not yet publicly available.

1.2.2 The Forest Inventory and Analysis Database

Forest biomass was estimated using the US Forest Service Forest Inventory and Analysis (FIA) database. Following Acts of Congress in 1928 and 1974, the USFS has been systematically collecting data via the FIA on US forests.

The FIA data is composed of a hierarchy of the following nine tables: SURVEY, COUNTY, PLOT, SUBPLOT, CONDITION, TREE, SEEDLING, SITETREE and BOUNDARY. Examples of plot-level records include: State, County, Plot number, Owner, Forest type, Stand age, Site productivity, and Slope. Examples of tree-level records include: State, County, Plot number, Tree number, Diameter at breast height (DBH), Crown class, Volume, Growth, and Expansion Factors (which allow extension from values per plot to per acre). Diameters are included in the database for all trees with DBH > 1". Creating links between the different hierarchies of the database and utilizing the expansion factors allows the user to explore a variety of topics related to biomass stocks in trees.

In this baseline study, data were downloaded from the FIA website on the scale of individual trees within plots within each county within each state. Using the biomass regressions of Jenkins et al. (2003), diameter at breast height (DBH) was converted to biomass for each tree. Area expansion factors (plot to acre), metric conversions and summation were used to calculate biomass in metric tons per hectare. In the fire baseline, forests are consolidated by forest type which is a plot-level characteristic.

1.3 Geographical Subdivision of the State

In the forest baseline, the State is subdivided into five regions. These regions are based on FIA 'units' but are convenient due to climatic, topographic and vegetation similarities within units (Table 1-1). Both the forest and agricultural baselines include county-level analyses; counties in Oregon are shown in Figure 1-1.

Table 1-1
Five Oregon regions with the component counties detailed

Region	Counties
Northwest	Clackamas, Clatsop, Columbia, Hood River, Marion, Multnomah, Polk, Tillamook, Washington, Yamhill
West Central	Benton, Lane, Lincoln, Linn
Southwest	Coos, Curry, Douglas, Jackson, Josephine
Central	Crook, Deschutes, Gilliam, Jefferson, Klamath, Lake, Sherman, Wasco, Wheeler
Blue Mountains	Baker, Grant, Harney, Malheur, Morrow, Umatilla, Union, Wallowa

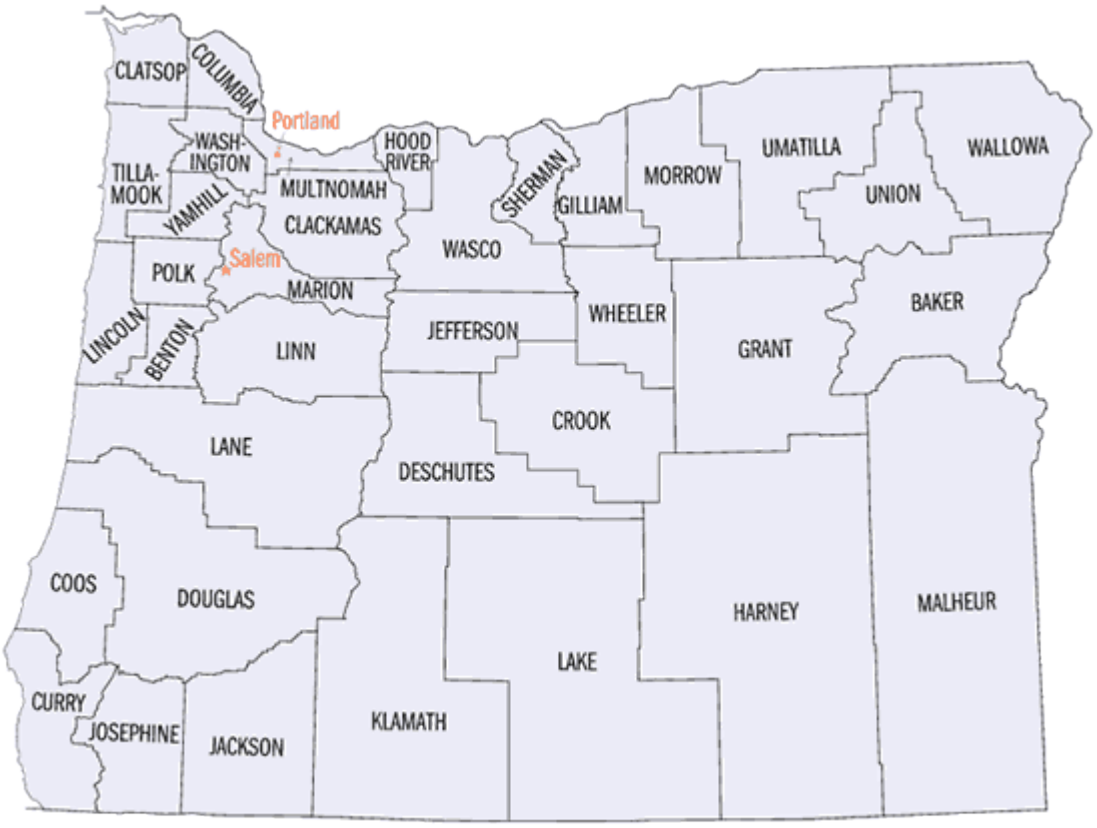


Figure 1-1
Oregon counties. Source: Digital Map Store, http://county-map.digital-topo-maps.com/oregon.shtml

Chapter 2 – Baselines for Forest Lands in Oregon

2.1 Introduction

This chapter presents a baseline for emissions and sequestration in the forests of Oregon. Forest is defined here as land with a greater than 10 % stocking of trees (as in the FIA and NRI).

The forest baseline chapter is presented in three sections.

In Section 2.2 a general forest baseline is presented detailing changes forest area and in stocks in the forests of Oregon with an estimate of annual sequestration/emissions. A State level total is presented for all forests with county level detail only for non-Federal Lands.

The remaining sections present case studies of individual causes of emissions from forests. These case studies should not be considered on top of the general baseline (section 2.2) but as a subset of it. Emissions from fire or development will have formed part of the total emissions from forests that are presented or alternatively will have decreased the total estimated sequestration presented from forests.

In Section 2.3 the case study of emissions caused by development on forestland is presented.

In Section 2.4 the case study of emissions caused by fire on forestland is presented.

2.2 General Forests Baseline

2.2.1 State Level Analysis for all Forestlands

1987-1997

The USDA Forest Service published a baseline for forests in Oregon between 1987 and 1997 (Birdsey and Lewis 2003). Estimates are based on forest inventory data collected by the Forest Service's Forest Inventory and Analysis Unit. Determination of the location of tree measurement plots and changes in land area were assessed using high altitude photography. Where forest inventory was not available estimates of land use change were derived from the National Resources Inventory.

Between 1987 and 1997 Birdsey and Lewis (2003) estimated a net change in forest area for Oregon from 11.6 million hectares in 1987 to 12.0 million hectares in 1997. This is a total gain of 383,245 hectares (an increase of 3.3%), which averages out to 38,326 hectares per year (an increase of 0.33%/yr).

Across the state Birdsey and Lewis calculated a mean forest carbon stock density of 77.9 t C/ha in 1987 and 80.7 t C/ha in 1997, this is a gain of 2.8 t C/ha over the ten years.

Combining the area data with the carbon stock density data gives a total stock on forestland in OR in 1987 and 1997 and a change in stock between the two dates.

The stock in 1987 was estimated as 907 million t C and this grew to 970 million t C in 1997. This is equal to a total gain of 62.7 million tons of carbon (a 6.9% gain), which averages out to 6.3 million tons of carbon per year (a gain of 0.69%/yr).

Beyond 1997

Using the Forest Inventory Mapmaker (version 2.1, http://www.ncrs2.fs.fed.us/4801/fiadb/fim21/wcfim21.asp), an estimated total area of forestland was attained for the year 2003. This area was 12.4 million ha which is equal to a gain of 71,021 ha per year since 1997 (an increase of 0.59%/yr). The rate of gain in forest area has therefore increased by 85 % between 1997 and 2003 over the rate between 1987 and 1997.

To attain carbon stock densities to apply to the areas, an extrapolation was made from the change in stock density between 1987 and 1997.

	1987	1997	2003
t C/ha	77.9	80.7	82.4

This results in a 2003 carbon stock of 1,025 million tons of carbon or an additional 55.8 million t C above the total in 1997 (5.8% gain), which equals a mean accumulation of 9.3 million t C per year (gain of 0.96%/yr). The rate of accumulation increased by 48 % between 1997 and 2003 in comparison with 1987-1997.

2.2.2 Changes in Forest Area on Private Land

This section provides a detailed baseline at the county level for the change in area in privately owned forests in Oregon. Changes are only examined on private land. It is not expected that widespread deforestation is occurring on public lands though some afforestation may be overlooked.

The change in land use associated with forests on private lands in OR was analyzed from the National Resources Inventory (NRI). Two dates were used that reported data at the county scale of resolution: the most recent publicly available data for 1997 and for 1987. At the State level all land in forest was estimated in 1987 and 1997 plus the broad destination or origin of land that changed from or to forest in the same time period (Table 2-2-1).

Table 2-2-1
Change in area (ha) between 1987 and 1997 for nonfederal forestland in Oregon

Category	Unchanged[1]	Lost to[2]	Gained from[3]

Unchanged	5,040,619		
Development		27,884	1,902
Pasture/Rangeland		7,163	55,322
Farmland/Agriculture		6,435	1,578
Other		26,022	3,764
1987 Total			5,108,123
1997 Total			5,103,186

[1]'Unchanged' refers to areas remaining forest between 1987 and 1997
[2]'Lost to' refers to areas lost from forest to other land use categories between 1987 and 1997
[3]'Gained from' refers to areas becoming forest between 1987 and 1997

In Oregon forest area decreased by 4,937 hectares in the ten years between 1987 and 1997, or an average of 494 ha/yr. Of the total area of forest in 1987, 98.7 % experienced no change, in land use, remaining as forest ten years later. There was a loss of 67,504 hectares, principally to development and other (including barren land and water), and a gain of 62,567 hectares, of which 88 % was from pasture/rangeland.

County-Level Changes in Forest Area

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Across the State 58 % of counties lost forest area during the ten-year period and 22 % gained forest area. Large losses (> 4,000 ha) occurred in Lane, Washington, and Harney Counties. Gains in area of a similar magnitude occurred in Lake, Wheeler and Douglas Counties. In Douglas County there was an increase of almost 16,000 ha over the ten-year period (Table 2-2-2).

Table 2-2-2
Area (ha) of nonfederal forestland in Oregon in 1987 and 1997 and change between the two dates

County	Population	County Area (ha)	1987	1997	Change
Baker	16,741	794,639	45,610	45,569	(40)
Benton	78,153	175,203	91,017	89,074	(1,943)
Clackamas	338,391	483,855	154,595	152,734	(1,862)
Clatsop	35,630	214,251	187,376	187,174	(202)
Columbia	43,560	170,090	129,018	129,706	688
Coos	62,779	414,522	261,962	261,517	(445)
Crook	19,182	771,656	95,347	95,307	(40)
Curry	21,137	421,490	133,308	135,332	2,024
Deschutes	115,367	781,698	36,302	35,330	(971)
Douglas	100,399	1,304,480	534,568	550,513	15,945
Gilliam	1,915	311,852	-	-	-
Grant	7,935	1,172,903	158,481	158,400	(81)
Harney	7,609	2,624,779	73,979	69,932	(4,047)
Hood River	20,411	135,287	33,347	32,578	(769)
Jackson	181,269	721,362	268,357	265,524	(2,833)
Jefferson	19,009	461,221	99,961	99,961	-
Josephine	75,726	424,652	137,719	135,817	(1,902)
Klamath	63,775	1,539,537	479,124	478,679	(445)
Lake	7,422	2,107,150	170,783	176,692	5,909
Lane	322,959	1,179,482	376,816	371,029	(5,787)

Lincoln	44,479	253,706	150,346	147,999	(2,347)
Linn	103,069	593,671	220,642	219,590	(1,052)
Malheur	31,615	2,560,745	19,587	9,587	-
Marion	284,834	306,643	70,054	68,961	(1,093)
Morrow	10,995	526,384	42,170	42,129	(40)
Multnomah	660,486	112,724	33,347	30,838	(2,509)
Polk	62,380	191,925	96,076	96,359	283
Sherman	1,934	213,210	-	-	-
Tillamook	24,262	285,454	201,298	198,667	(2,631)
Umatilla	70,548	832,749	144,235	144,235	-
Union	24,530	527,465	98,828	98,828	-
Wallowa	7,226	814,639	130,840	130,840	-
Wasco	23,791	616,688	129,018	130,920	1,902
Washington	445,342	187,450	110,321	105,262	(5,059)
Wheeler	1,547	444,162	115,825	119,953	4,128
Yamhill	84,992	185,330	77,864	78,148	283

The largest losses in area occurred in the Northwest and West Central regions. In the Southwest and Central regions there was a gain in area (Table 2-2-3)(for regions see Chapter 1).

Table 2-2-3
Area (ha) of nonfederal forestland in 1987 and 1997 and change between two dates

Region	1987	1997	Change Area
Northwest	1,093,297	1,080,428	(12,869)
West Central	838,822	827,692	(11,129)
Southwest	1,335,915	1,348,703	12,789
Central	1,126,361	1,136,843	10,482
Blue	713,729	709,520	(4,209)

2.2.3 Conclusions

An estimated 383,000 hectares of forest were gained on federal and non-federal lands in Oregon between 1987 and 1997 at a rate of 38,326 ha/yr. Between 1997 and 2003 an estimated 426,000 additional hectares were gained at a rate of 71,021 ha/yr. These gains are equivalent to 0.33 % of the forest area per year between 1987 and 1997 and 0.59 % of the forest area per year between 1997 and 2003.

A gross sequestration of an estimated 229.9 $MMTCO_2e$ would have occurred between 1987 and 1997 (23 $MMTCO_2e$/yr) and 204.6 MMTCO2e (34 $MMTCO_2e$/yr) between 1997 and 2003.

The emissions for Oregon (excluding forests) for the year 2000 were estimated as 67.7 $MMTCO_2e$ (Governor's Advisory Group on Global Warming 2004). Sinks, therefore, potentially can offset as much as 50 % of the State's emissions.

For just non-federal lands there is net loss is 5,000 ha. This loss is composed of decreases in forest area in the Northwest and West Central (coastal) regions and in the Blue Mountains balanced by gains in forest area in the Southwest (coastal) and in the Central (inland) region.

2.3 Development Baseline

2.3.1 General Approach

This section provides a baseline for the emissions of carbon attributable to development of forest lands in Oregon. This analysis should be considered a subset of the general forest baseline: the emissions due to development will form part of wider changes in carbon stocks in the State. If this analysis is added to the analysis of the general forest baseline then double counting will occur.

Forest land development is examined only for private lands; it is not expected that widespread development is occurring on public land. Changes in stocks are only changes in aboveground tree biomass, due to uncertainties surrounding both the absolute level of carbon in other carbon pools and whether or not development will cause emissions from these pools.

As in the general forest baseline, changes in forest area due to development were based on NRI data for changes in land use. Carbon stocks and changes in stocks were derived from FIA data. For the purposes of this study, development includes three NRI categories:

Urban / 10 acres or larger

Urban / small built-up (< 10 acres). The category 'Urban/small built-up' will be referred to as small-scale development.

Transportation (e.g. roads, airports etc)

Statistical confidence can only be maintained in results given at the State level, due to the design of the NRI database. Results are given here at the County level merely for illustrative purposes.

2.3.2 Changes in Area at the State and County Level

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Between 1987 and 1997 almost 28,000 hectares of non-federal forest were lost in Oregon to development or 2,788 ha per year. The loss over ten years is equivalent to 0.5 % of the total forest area present in the State in 1987. Of the total area lost to development, 20 % could be considered as small-scale development (Table 2-3-1).

Table 2-3-1
Nonfederal forest area (ha) between 1987 and 1997 in Oregon

Category	Unchanged[1]	Lost to[2]	Gained from[3]
Unchanged	5,040,619		
Development		27,884	1,902
% small scale		20%	0%
Pasture/Rangeland		7,163	55,322
Farmland/Agriculture		6,435	1,578
Other		26,022	3,764
1987 Total			5,108,123
1997 Total			5,103,186

[1]'Unchanged' refers to areas remaining forest between 1987 and 1997
[2]'Lost to' refers to areas lost from forest to other land use categories between 1987 and 1997
[3]'Gained from' refers to areas becoming forest between 1987 and 1997

Losses in excess of 2,000 ha occurred in Clackamas, Douglas, Lane, Multnomah and Washington Counties, all of which are in the coastal region of Oregon (Figure, 2-3-1, Table 2-3-2). These five counties represent just 24 % of the area of non-federal forest in 1997, but 53 % of the total area lost to development over the ten-year study period. Across these five counties the mean proportion of small scale development is 14 % as opposed to 20 % across the entire state.

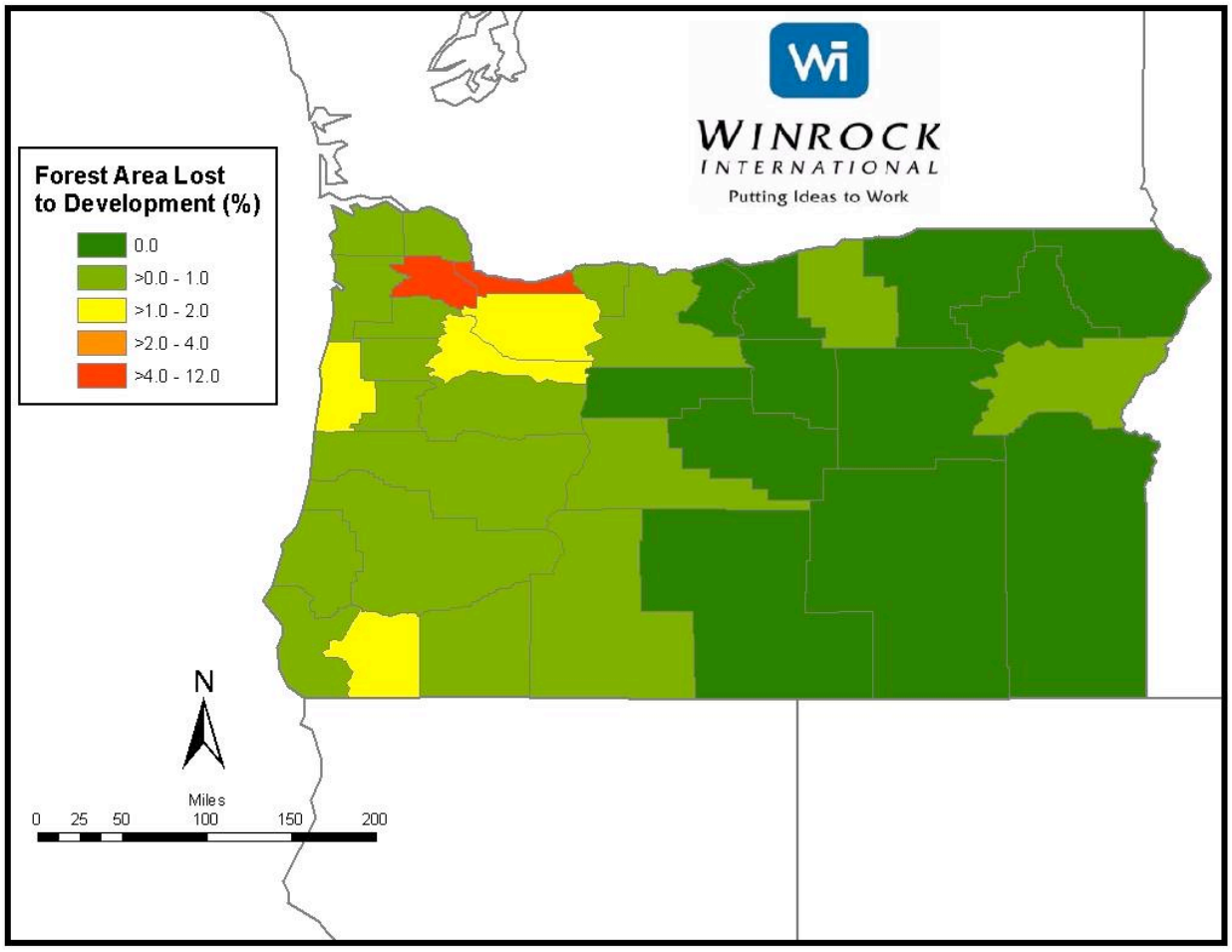


Figure 2-3-1
Loss in non-federal forest area between 1987 and 1997 as a percentage of total non-federal forest area in the county

Table 2-3-2
County-level data on area (ha) of nonfederal forest in 1997, area of forest lost to development between 1987 and 1997 and % of losses that were small-scale

County	Population	County Area (ha)	Non-Fed Forest Area 1997 (ha)	Area Lost to Development	% small scale
Baker	16,741	794,639	45,569	40	100%
Benton	78,153	175,203	89,074	364	11%
Clackamas	338,391	483,855	152,734	2,307	18%
Clatsop	35,630	214,251	187,174	324	63%
Columbia	43,560	170,090	129,706	81	100%
Coos	62,779	414,522	261,517	1,295	41%
Crook	19,182	771,656	95,307	0	
Curry	21,137	421,490	135,332	162	100%
Deschutes	115,367	781,698	35,330	1,012	0%
Douglas	100,399	1,304,480	550,513	2,064	6%
Gilliam	1,915	311,852		0	
Grant	7,935	1,172,903	158,400	0	
Harney	7,609	2,624,779	69,932	0	
Hood River	20,411	135,287	32,578	121	33%
Jackson	181,269	721,362	265,524	931	39%
Jefferson	19,009	461,221	99,961	0	
Josephine	75,726	424,652	135,817	1,781	14%
Klamath	63,775	1,539,537	478,679	364	78%
Lake	7,422	2,107,150	176,692	0	
Lane	322,959	1,179,482	371,029	2,671	38%
Lincoln	44,479	253,706	147,999	1,659	20%
Linn	103,069	593,671	219,590	1,052	69%
Malheur	31,615	2,560,745	19,587	0	
Marion	284,834	306,643	68,961	1,093	7%
Morrow	10,995	526,384	42,129	40	0%
Multnomah	660,486	112,724	30,838	2,792	6%
Polk	62,380	191,925	96,359	486	25%
Sherman	1,934	213,210		0	
Tillamook	24,262	285,454	198,667	1,578	10%
Umatilla	70,548	832,749	144,235	0	
Union	24,530	527,465	98,828	0	
Wallowa	7,226	814,639	130,840	0	
Wasco	23,791	616,688	130,920	283	0%
Washington	445,342	187,450	105,262	4,816	3%
Wheeler	1,547	444,162	119,953	0	
Yamhill	84,992	185,330	78,148	567	57%

2.3.3 Carbon stocks

Estimates of the carbon stocks in live tree biomass are derived from the FIA data base. The FIA databases for 1992/1991 were used as these dates represent a midpoint between 1987 and 1997. FIA data were consolidated at the FIA Unit Level. Biomass carbon estimates were derived from the measurements of tree diameter at breast height for all trees in inventory plots using the allometric equations of Jenkins et al. (2003), scaled up to a per-ha basis using the plot-area expansion factors (Table 2-3-3).

In order to be conservative, aboveground tree biomass alone was considered. The rate of emission of carbon stored in roots and soil organic matter is slow and poorly understood, especially when it is considered that some of the developed areas will be capped with concrete. Wood products are also not included as it is not clear what proportion of the cut trees would be harvested for products, nor what products would be produced (fire wood and even paper can be rapidly emitted).

Table 2-3-3
Mean aboveground tree carbon stock (from 1992 FIA data) for each region of Oregon with the number of plots and the confidence interval around the stock estimate

Region	Mean t C/ha	95 % CI	# plots	Counties included in region
Northwest	165.6	103.9	309	Clackamas, Clatsop, Columbia, Hood River, Marion, Multnomah, Polk, Tillamook, Washington, Yamhill
West Central	151.8	108.6	220	Benton, Lane, Lincoln, Linn
Southwest	136.4	102.7	353	Coos, Curry, Douglas, Jackson, Josephine
Central	83.4	70.7	251	Crook, Deschutes, Gilliam, Jefferson, Klamath, Lake, Sherman, Wasco, Wheeler
Blue Mountains	79.1	49.8	148	Baker, Grant, Harney, Malheur, Morrow, Umatilla, Union, Wallowa

2.3.4 Carbon emissions from development

Two carbon emission scenarios are considered here. In both cases FIA data from federal and non-federal forests are applied to NRI land cover estimates for non-federal forests.

Scenario 1 assumes that all carbon present on the land in aboveground tree biomass is lost when development occurs.

Scenario 2 assumes that when small scale development occurs, a significant proportion of the trees remain during and after the process of development. As examples, these may be trees surrounding residential properties or trees on golf courses. Therefore, in this scenario we assume that for Transportation and Urban/10 acres or larger, all carbon is lost, but for Urban/small built-up, only 50 % of the carbon stocks are emitted.

Emissions discussed here for conversion of forestland to development are gross emissions from aboveground tree biomass only. Total emissions from development over the ten-year period were estimated as 4.2 million t C under Scenario 1 and 3.8 million t C under Scenario 2. This is equivalent to 421,249 and 380,206 t C per year. The difference is small because only 20% of the total development change is attributed to small-scale development. Emissions by county are summarized below (Figure 2-3-2, Table 2-3-4).

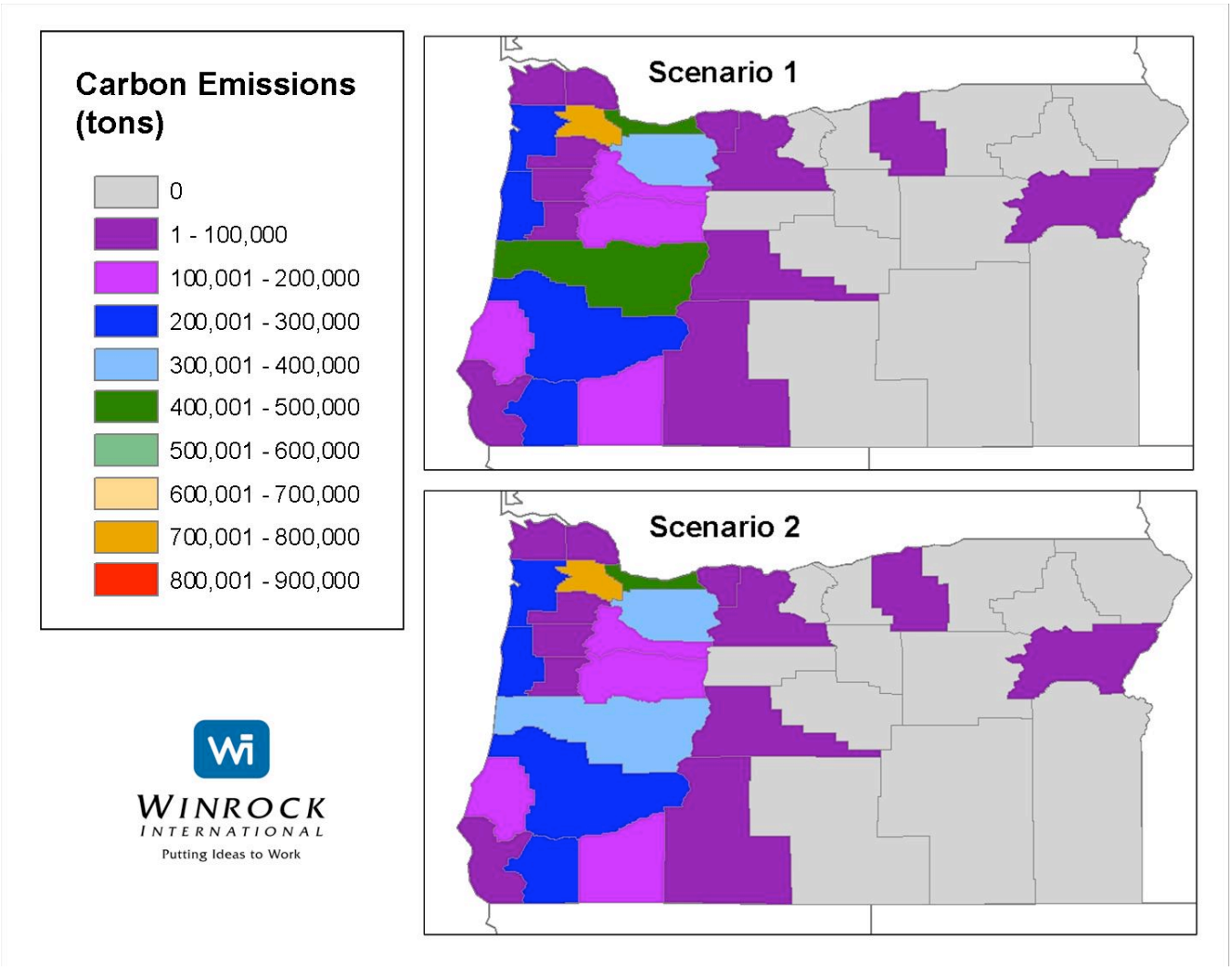


Figure 2-3-2
Carbon emissions under the two scenarios at the county level across the state

Table 2-3-4
County-level estimates on the emissions between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

County	Population	County Area (ha)	Non-Fed Forest Area 1997 (ha)	Carbon emissions (t C) Scenario 1	Scenario 2
Baker	16,741	794,639	45,569	3,199	1,600
Benton	78,153	175,203	89,074	55,272	52,202
Clackamas	338,391	483,855	152,734	381,956	348,451
Clatsop	35,630	214,251	187,174	53,608	36,855
Columbia	43,560	170,090	129,706	13,402	6,701
Coos	62,779	414,522	261,517	176,680	140,792
Crook	19,182	771,656	95,307	-	-
Curry	21,137	421,490	135,332	22,085	11,043
Deschutes	115,367	781,698	35,330	84,392	84,392
Douglas	100,399	1,304,480	550,513	281,584	273,302
Gilliam	1,915	311,852		-	-
Grant	7,935	1,172,903	158,400	-	-
Harney	7,609	2,624,779	69,932	-	-
Hood River	20,411	135,287	32,578	20,103	16,752
Jackson	181,269	721,362	265,524	126,989	102,143
Jefferson	19,009	461,221	99,961	-	-
Josephine	75,726	424,652	135,817	242,935	226,372
Klamath	63,775	1,539,537	478,679	30,381	18,566
Lake	7,422	2,107,150	176,692	-	-
Lane	322,959	1,179,482	371,029	405,330	328,563
Lincoln	44,479	253,706	147,999	251,796	227,230
Linn	103,069	593,671	219,590	159,675	104,403
Malheur	31,615	2,560,745	19,587	-	-
Marion	284,834	306,643	68,961	180,926	174,225
Morrow	10,995	526,384	42,129	3,199	3,199
Multnomah	660,486	112,724	30,838	462,367	448,965
Polk	62,380	191,925	96,359	80,412	70,360
Sherman	1,934	213,210		-	-
Tillamook	24,262	285,454	198,667	261,338	247,936
Umatilla	70,548	832,749	144,235	-	-
Union	24,530	527,465	98,828	-	-
Wallowa	7,226	814,639	130,840	-	-
Wasco	23,791	616,688	130,920	23,630	23,630
Washington	445,342	187,450	105,262	797,416	787,364
Wheeler	1,547	444,162	119,953	-	-
Yamhill	84,992	185,330	78,148	93,814	67,010

The carbon emissions as a result of development mirror the loss in area. The majority of the emissions occurred in the Northwest region – 56 % of total emissions from development under scenario 1 and 58

% under scenario 2 (Table 2-3-5), even though these counties only represent 9 % of the area of the state (but includes the major city of Portland).

Table 2-3-5
Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development

Region	Area lost (ha)	Carbon emissions (t C)	
		Scenario 1	Scenario 2
Northwest	14,165	2,345,341	2,204,621
West Central	5,747	872,074	712,398
Southwest	6,232	850,274	753,652
Central	1,659	138,403	126,588
Blue	81	6,399	4,799

This is equal to an annual loss in area across the state of almost 3,000 hectares with annual carbon dioxide equivalent emissions of between 1.4 and 1.5 million metric tons of CO_2 equivalent (Table 2-3-6).

Table 2-3-6
Region-level summary of annual loss in area and carbon dioxide equivalent emissions between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small-scale development

Region	Area lost per yr (ha/yr)	Annual carbon emissions ($MMTCO_2e$)	
		Scenario 1	Scenario 2
Northwest	1,416	0.86	0.81
West Central	575	0.32	0.26
Southwest	623	0.31	0.28
Central	166	0.051	0.046
Blue Mountains	8	0.002	0.002
TOTAL	2,788	1.54	1.39

2.3.5 Additional Considerations

Emissions discussed here for conversion of forestland to development are gross emissions from aboveground tree biomass only.

Gross vs Net Emissions

The analysis presented above represents gross emissions. The only consideration was of emissions from losses of forest to development.

Where gains of forest were made from development, this was not considered.

The destination of biomass upon development is also not considered. The assumption is made that all carbon is immediately emitted. In reality this is unlikely to be the case. Some of the wood is likely to ultimately become fire wood, some will be left to decompose and some may be used as timber and will have a longer existence as wood products. Regardless, all trees cut for development will ultimately be emitted to the atmosphere as carbon dioxide or carbon dioxide equivalents. Instead of including any delay here the assumption is made of immediate emission.

Other Carbon Pools

Aboveground tree biomass was the only carbon pool considered in this analysis. The reason behind this decision was the uncertainty involved in other pools generally, and specifically in the case of development.

Soil carbon is particularly uncertain. If the land is capped by concrete it is unlikely that soil carbon will be affected at all. If grasses are planted there is even the possibility that development could lead to an increase in soil carbon.

For similar reasons roots are also uncertain. The rate at which roots decompose is very poorly known and even less is known about the diminished rate if the roots are buried beneath concrete or tarmac.

Dead wood and litter are likely to be emitted either immediately upon development or through time as decomposition occurs. However, there is no clear relationship between aboveground tree biomass and these pools and the uncertainty involved with any assumption would be very large.

Non-carbon dioxide greenhouse gas emissions are also unknown. If site preparation occurs through burning, there will be emissions of methane and nitrous oxide (both potent greenhouse gases). If site preparation involves drainage there will be emissions of methane. Without specific site-by-site information it is not possible to make these estimations.

2.3.6 Conclusions

An estimated 28,000 hectares were lost to development in Oregon State between 1987 and 1997 at a rate of 2,788 hectares per year. This forest loss is equivalent to a gross emission of between 13.9 and 15.4 million metric tons of carbon dioxide equivalent or 1.39 to 1.54 $MMTCO_2e$ per year.

The emissions were concentrated in the coastal region and in particular in the Northwest (the region in which Portland is located).

These emissions compare with the estimated gross sequestration from forests in Oregon of 23 $MMTCO_2e/yr$ between 1987 and 1997 (Section 2.2) and gross emissions for the state of 63 $MMTCO_2e/yr$ in 1995 (Governor's Advisory Group on Global Warming 2004). Emissions from deforestation therefore offset between 6 and 7 % of the forest sequestration and represent between 2.2 and 2.4 % of the total emissions in the state.

Comparison with Oregon Department of Forestry Report on Development

The Oregon Department of Forestry and the US Forest Service produced reports on land use change on non-federal land in Oregon (Lettman et al. 2002; 2004). The authors conducted their own sampling based on aerial photographs across the state. The study was split into two reports: one for Western Oregon covering 1973-2000; and one for Eastern Oregon 1975-2001.

The authors report losses in area, from 'Wildland Forest' and 'Mixed Forest Agriculture' to 'Low Density Residential' and 'Urban' land uses, of 56,000 acres in Western Oregon lost between 1982 and 2000, and of 23,000 acres in Eastern Oregon between 1986 and 2001. This produces a total of 79,000 acres of land lost from forest or mixed forest.

In this study we detail a loss of 68,901 acres from forest to developed land uses between 1987 and 1997. This is 10,000 acres fewer but includes 8 fewer years in the Western region and five fewer years in the Eastern region.

It is not easy to directly compare the results of each study because of the overlapping time periods. However, three of the additional years in the Western region and four of the years in the Eastern region are after 1997. The years after 1997 are likely not to be responsible for a significant proportion of deforestation for development, as Lettman et al (2002) showed that the rate of forest loss to development was 90 % lower between 1994 and 2000 in the Western region than between 1982 and 1994. If the pattern of decreasing deforestation through time is consistent, then the five years between 1982 and 1987 in the Western region may, in contrast, be responsible for a significant proportion of the total deforestation for development. If this is the case then the analysis of the NRI database may be producing an overestimate relative to the Oregon-specific study, but without a more direct comparison it is not possible to know.

2.4 Fire Baseline

In this fire analysis the emissions caused by fire between 1990 and 1996 are estimated. These emissions are part of the general forest baseline (section 2.2). Without emissions from fire, the general forest baseline would be raised by an amount equal to these emissions.

This baseline, unlike the general forest baseline and the development emissions baseline contains an analysis of rangelands as well as forests.

There are two components to a fire analysis. It is necessary to know both the area that is burnt and the amount of biomass that is volatilized into greenhouse gases per area. Knowledge of these components permits an estimation of total fire-derived emissions.

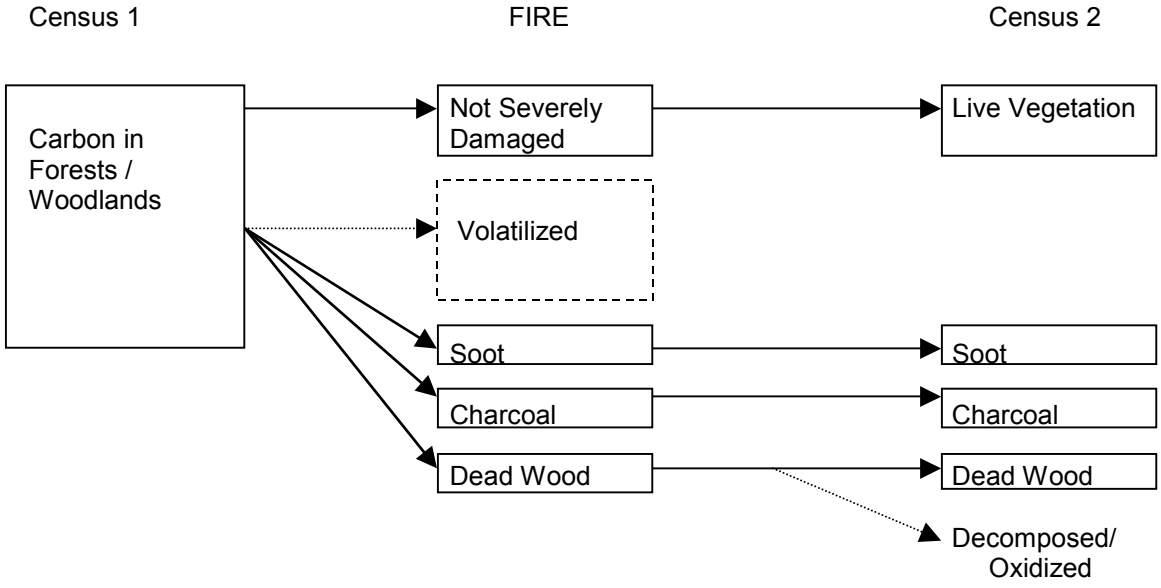
The period 1990 to 1996 was chosen for this analysis, for (although a partial dataset exists for 1997-2003) these study dates represent the most recent, consistent complete coverage. Complete coverage is essential in order to be able to make State level conclusions on the impact of fire.

2.4.1 Methods for Assessing Biomass Volatilized

2.4.1.1 Background

The effects of fire on carbon stocks are dependent on the intensity of the fire. An intense fire will destroy biomass and release a great proportion of the carbon to the atmosphere, while a less intense fire will even fail to kill the majority of the trees. Here fires are divided into three potential intensities: high, medium and low.

Pre-fire carbon has five potential destinations during and after a fire (Fig. 2-4-1). The first proportion will survive the fire to continue as live vegetation, a second proportion will be volatilized during the fire and immediately released to the atmosphere and the remainder will be divided between the pools of dead wood, soot and charcoal. Soot and charcoal are stable forms of carbon and can remain



unchanged for hundreds of years; in contrast dead wood decomposes over time.

Figure 2-4-1
Flow Diagram Illustrating the Various Destinations of Pre-burn Carbon after a Fire

The basis for this baseline analysis was the detailed study conducted for California (Brown et al 2004). Under the California baseline analysis changes in canopy coverage (measured from satellite imagery) were recorded through time for forest types and causes including fire were assigned. We assumed

(based on expert opinion) that the three intensities are associated with the magnitude of change in crown cover, so that a large decrease in crown cover would be due to a high intensity fire or a small decrease is caused by a low intensity fire.

The midpoint of each decrease in canopy coverage class was assumed to be the proportion of the vegetation killed by the fire. The proportion volatilized is dependent on fire intensity (60 % high intensity fire, 40 % mid-intensity, 20 % low intensity; McNaughton et al. 1998; Carvalho et al. 2001). If the volatilized proportion is subtracted from the midpoint of the decrease then the remaining fraction is the dead wood, soot and charcoal pool. This fraction was divided using the following proportions: 22 % charcoal, 44 % soot, 32 % dead wood (Comery 1981, Raison et al. 1985, Fearnside et al. 1993, Neary et al. 1996).

2.4.1.2 Approach for Calculations

The aim of this study is to determine the loss in biomass as a result of fire in Oregon. In California we had data on the area affected by fire in classes of initial and post fire crown cover and forest type. The degree of reduction in crown cover was used to indicate the intensity of the fire. We also had the biomass associated with each crown cover class and so a change between two cover classes could be represented as a loss in carbon. In contrast, in Oregon available data included only forest type and an indication of fire intensity from fire extent and change in spectral reflectance.

The approach for this study is therefore to use the California data to determine the percentage loss in biomass that occurs as a result of a high, a medium or a low intensity fire in each of the forest types. The percentage loss is then applied to Oregon-specific biomass numbers for comparable forest types.

The source of biomass values is the Oregon 2004 inventory of the FIADB (forest inventory and analysis database). These were split between forest types. In all cases, Oregon FIA data was divided by the five forest/woodland types (Douglas Fir, Fir-Spruce, Other Conifer, Hardwood Forest, Hardwood Rangeland; Table 2-4-1) at the county level. The division by forest/woodland type occurred to align the Oregon analysis with the original California study (Brown et al. 2004).

Table 2-4-1
Forest types for fire baseline analysis cross-walked with FIA forest type

California-analysis forest type	FIA forest type
Douglas-fir	Douglas-fir
Fir Spruce	White fir, Red fir, Noble fir, Pacific silver fir, Engelmann spruce, Engelmann spruce / Subalpine fir, Grand fir, Subalpine fir, Blue spruce, Sitka spruce
Other Conifer	Port-Orford cedar, Ponderosa pine, Western white pine, Jeffrey pine / Coulter pine / big cone Douglas-fir, Mountain hemlock, Lodgepole pine, Western hemlock, Western redcedar, Alaska yellow cedar, Western larch, Misc. western softwoods
Hardwoods - forest	Cottonwood, Willow, Oregon Ash, Aspen, Red alder, Bigleaf maple, Tanoak, Giant chinkapin, Pacific Madrone
Hardwood - rangeland	Western juniper, California black oak, Oregon white oak, Canyon live oak / Interior live oak, California laurel, Misc. western hardwood woodlands, Intermountain maple woodland, Juniper woodland, Pinyon juniper woodland, , Rocky mountain juniper, Deciduous oak woodland, Mesquite woodland

The FIA data was further split into regions – Eastern, Central and Coastal with the assumption that the climatic variation will lead to variation in biomass that will refine our estimates. The split of counties

between regions is listed in Chapter 1, though here Northwest, West Central and Southwest are combined into a single Coastal region.

The mean biomass stocks were calculated from OR FIA data by region and forest type (Table 2-4-2).

Table 2-4-2
Mean biomass stock by forest type and region

	Mean biomass (t biomass/ha)		
	Coastal	Central	Eastern
Douglas Fir	326.1	178.0	132.8
Fir Spruce	310.1	242.8	175.0
Other Conifer	285.5	101.1	95.9
Hardwood	158.2	65.7	36.8
Range Hardwood	138.2	26.9	29.8

2.4.1.3 Biomass Loss through Fire

To calculate the emissions through fire, results from the California analysis (Brown et al. 2004) were used. From the California analysis, the estimated stocks for each forest type at each of the 4 canopy density classes was taken, plus the net emissions for each forest type/canopy density class/fire intensity class. Finally the emissions were calculated as a proportion of the original biomass and the results expressed as a percentage.

As no canopy cover class data exists for Oregon, a mean emission percentage is required excluding canopy cover. This was achieved by weighting the emission percentages by the proportion of forest in each canopy class in the most representative region of California (North Coast for Coastal regions and Cascades Northeast for Central and Eastern regions).

The proportions by forest type by region by fire intensity were then multiplied by the biomass by forest type by region to give estimated biomass lost through emissions from fire (Tables 2-4-3, 2-4-4, 2-4-5).

Table 2-4-3
Mean emissions from a high, mid and low intensity fire in the Coastal Region of Oregon

t CO_2e/ha	High	Mid	Low
Douglas Fir	259.8	111.8	45.1
Fir Spruce	298.8	130.9	52.6
Other Conifer	206.6	137.0	68.2
Hardwood	138.2	59.6	24.0
Range Hardwood	121.0	52.1	20.9

Table 2-4-4
Mean emissions from a high, mid and low intensity fire in the Central Region of Oregon

t CO_2e/ha	High	Mid	Low
Douglas Fir	137.0	58.9	23.7
Fir Spruce	231.9	102.3	41.3
Other Conifer	69.7	46.2	23.1
Hardwood	57.2	24.6	9.9
Range Hardwood	30.1	13.6	5.5

Table 2-4-5
Mean emissions from a high, mid and low intensity fire in the Eastern Region of Oregon

t CO_2e/ha	High	Mid	Low
Douglas Fir	102.1	43.8	17.6
Fir Spruce	167.2	73.7	29.7
Other Conifer	66.2	43.8	21.8
Hardwood	32.1	13.8	5.5
Range Hardwood	33.4	15.0	6.1

2.4.1.4 NON-TREE VEGETATION

Biomass numbers for non-tree vegetation (primarily shrubs and grasses in rangelands) are taken from the literature and Winrock International experience (Table 2-4-5).

Table 2-4-5
Estimates of pre-fire biomass stocks in non-tree vegetation

Vegetation type	Biomass carbon (t C/ha)	Source
Wet Grasslands	5.9	Prichard et al 2000
Mesic Grasslands	2.4	Brown and Archer 1999
Xeric Grasslands	0.6	Winrock unpublished data
Shrublands	5.1	Martin et al 1981
Desert scrub	2.6	Winrock unpublished data

Here the conservative assumption is made that 50 % of the pre-fire biomass in non-tree vegetation is volatilized to be emitted as carbon dioxide.

2.4.2 Methods for Assessing Area Impacted by Fire and Fire Intensity

Satellite-based analysis is a practical method of quantifying area burned primarily due to the dangerous nature and the wide geographic extent of wildfires. The State reports the location and size of recorded fires but with no measure of fire intensity, nor with the location of the boundaries of the fire. It is necessary to know fire intensity to estimate emissions and the precise location is necessary for a correlation with a database of vegetation species. The approach for this analysis was to estimate the extent of fires at known fire locations, through delineating areas with a change in reflectance on multiple satellite images, i.e. pre-fire and post-fire images.

A common measurement of vegetation from satellite imagery is the Normalized Difference Vegetation Index (NDVI). Very low values of NDVI (0.1 and below) correspond to barren areas of soil without vegetation or of sand, rock or snow. Moderate values represent shrub and grassland (0.2 to 0.3), while high values indicate forests (0.6 to 0.8).

2.4.2.1 Databases

NDVI was calculated from 1.1 km pixel resolution NOAA Advanced Very High Resolution Radiometer (AVHRR) 10 day composite images. The temporal frameset covered the month of September and spanned 1990 – 2003 (except 1994). This encompassed the NOAA 11, 14, 16 satellites. September was chosen for the analysis time frame because it is towards the end of the fire season and the burned areas are not yet affected by regrowth. Only one September 1994 composite was produced for 1994 due to the failure of the AVHRR sensor aboard NOAA-11. As a result, the imagery for 1994 along with fire

data was dropped from the analysis due to data inconsistencies in image values and incomplete temporal coverage from sensor failures.

The wildfire database for Oregon encompassed a total of 21,625 occurrences that vary from less than 1 acre to many thousand acres. Fires for the study period with a final size greater than 2,000 acres were identified for NDVI postfire burn detection analysis to quantify area burned. Each fire record included a unique ID with a GPS point location, date, and final extent in acres. There was no GIS polygon representing the extent of the fire in the original database so it was not possible to precisely locate the extent of the fire from these records, so we used the approach described below.

2.4.2.2 Mapping Methods

Fire Identification

This analysis used a postfire burn detection method to quantify area burned by wildfires. NDVI was calculated from the water vapor corrected bands 10, visible (0.58 - 0.68 μm) and band 11, near infrared (0.725 – 1.10 μm).

NDVI = (ch 11 – ch 10)/(ch 11 + ch 10).

In order to obtain a single September NDVI for each year of the study period, three (or in some years four) 10-day composites were averaged into a single image ($NDVI_y$). These September images were then averaged into a 13-year historical NDVI reference image ($NDVI_m$).

NDVI reflectance values are bi-modal, ranging from -1.0 to 1.0. Positive values reflect vegetation or 'greenness', and negative values are indicative of soil or non-vegetated areas. Values close to 1 are 'greener' than values close to 0 and values close to -1 are more barren than values close to 0. When vegetation is burned, a rise in channel 10 reflectance and a decrease in channel 11 reflectance occurs. The degree of change ($NDVI_d$) was measured by subtracting $NDVI_y$ from $NDVI_m$

$NDVI_y - NDVI_m = NDVI_d$

From the reference image each individual annual September image was subtracted and potential fire locations identified. In NDVI difference imagery, positive values indicate an increase in 'greenness' from $NDVI_m$ and negative values a decrease. For burned area-identification purposes, all positive values were removed along with negative values greater than -0.05. The result was an image containing areas of concentrated vegetation decrease. The fire location data was then overlaid to confirm the changes as potential fires.

Fire Extent

The extent of fires listed as having over 2,000 acres in final size were mapped by visual interpretation from the changes seen in $NDVI_d$ with assistance from the fire's GPS location and extent information (Figure 2-4-2).

The wildfire mapping process consisted of creating polygons that represent the extent of the burn area. Fires were first divided into big and small based on final extent. Fires with a final extent of < 2,000 acres or 8 pixels were labeled as small fires. For AVHRR imagery, 1 pixel = 100 hectares = 247.5 acres. Areas of vegetation decrease in $NDVI_d$ greater than 8 pixels and with a corresponding fire greater than 2,000 acres were digitized using the 'heads up method'[2]. The area digitized was then compared with the reported final extent.

[2] Heads up digitizing refers to on screen digitizing. It is referred to as 'heads up' because the analyst focuses on the screen as opposed to on a digitizing tablet.

All fires with less than 2,000 acres burned were classified too small to display a change in the AVHRR imagery. For these fires, a buffer was calculated and added to the fire point based on the GPS point, which was considered the center of the fire, and the radius; that was derived from the size reported in the original record.

Additionally, if a fire that was larger than 2,000 acres could not be mapped by visual interpretation, it was mapped by the buffering method.

Fire Severity

For the fires that occurred in forested lands, three classes of burn severity were identified: low, medium, and high (Figure 2-4-2). Again, the intensity was evaluated separately depending on the fire mapping method. For the fires that were identified using the imagery, the value of burn severity corresponded with the value of the difference in NDVI. The rationale is that the more negative the difference between the actual NDVI and the mean NDVI, the more severe is the fire. As a result, one fire can include areas with different burn severities. Small fires (< 2,000 acres) were arbitrarily considered to experience a low burn fire severity, since there was no image data to consistently support the estimation.

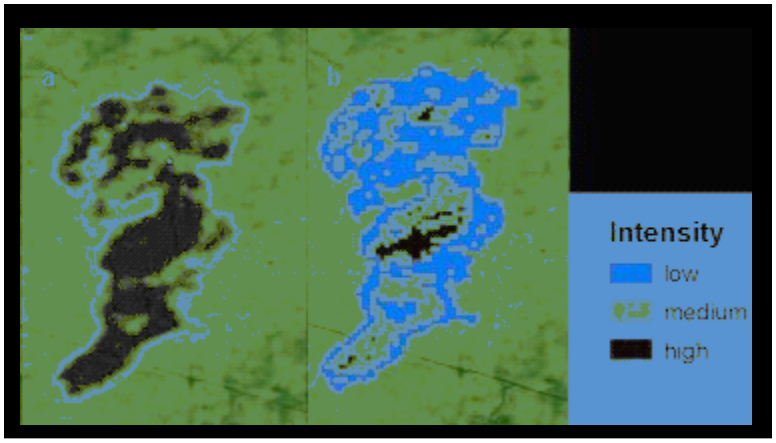


Figure 2-4-2
Illustration of the mapping methodology. In a the point location from the State or Federal database is established, a fire boundary is then created and compared to the fire area reported with the point location; in b the fire intensity through the burn area is calculated using NDVI values

Land Cover Affected by Fire

Finally, the fires map were crossed with the land cover maps, making possible to estimate the amount of land cover type / forest type that was affected by fires.

2.4.3 Results

Across the six years analyzed[3] fires with a total area of 328,000 hectares (0.81 million acres) were recorded (illustrate in Figure 2-4-3). This is equivalent to an average 54,700 hectares per year (135,100 ac/yr) for the period studied.

Emissions totaling 6.8 million tons of carbon or 25.0 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. On an averaged annual basis this is equal to 0.28 million tons of carbon per year (1.03 $MMTCO_2e$/yr).

[3] 1994 was excluded due to poor image quality.

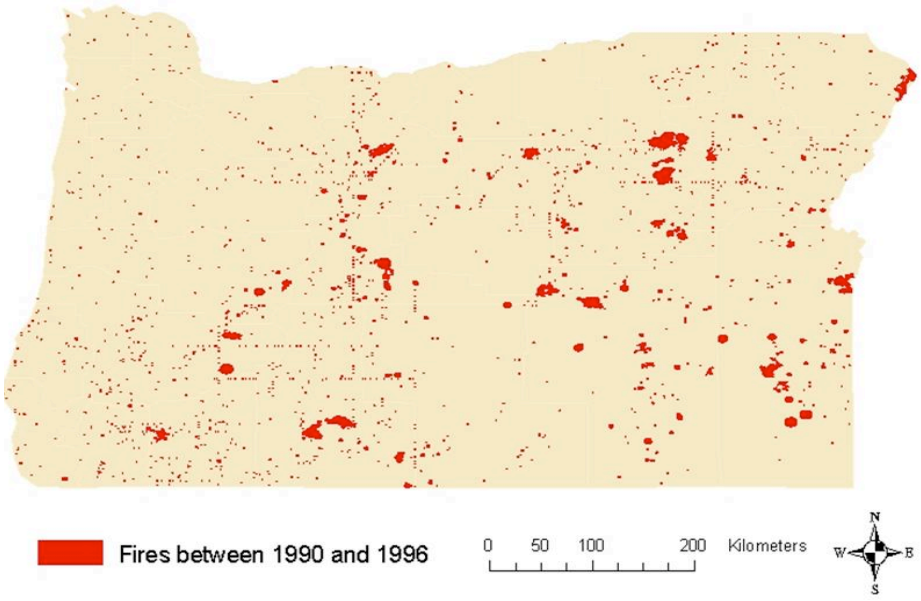


Figure 2-4-3
The location and extent of fires in Oregon between 1990 and 1996

Forty-eight percent of the fires occurred in forests and 46 % in rangeland during the study period (Table 2-4-6)[4]. Due to the higher biomass loss from forests during fire more than 94 % of the total emissions from fire originated in the 48 % of fire area that was in forest.

Table 2-4-6
Area burned and carbon emissions in forests and in rangeland across the analysis period

	Area burned (ha)	Emissions (t C)
Forest	392,296	5,859,967
Rangeland	187,129	363,826

Fires occurred in every year studied, but the area burned and the total carbon emissions varied greatly between years (Table 2-4-7, Figure 2-4-4). As an example, 186,000 hectares were burned in 1996 but just 5,118 hectares burned in 1993. The carbon emissions vary equally widely with 23,500 tons of carbon emitted in 1993 but 1.0 million tons of carbon emitted in 1996. In 1994 no fires were examined due to poor quality imagery.

Table 2-4-7
Area burned and carbon emissions per year across the analysis period

YEAR	Area burned (ha)	Emissions (t C)

[4] The remaining fire area was on developed, agricultural or barren land

1990	45,891	176,199
1991	12,610	111,113
1992	52,560	321,680
1993	5,118	23,538
1994		
1995	26,083	87,434
1996	185,746	1,001,547

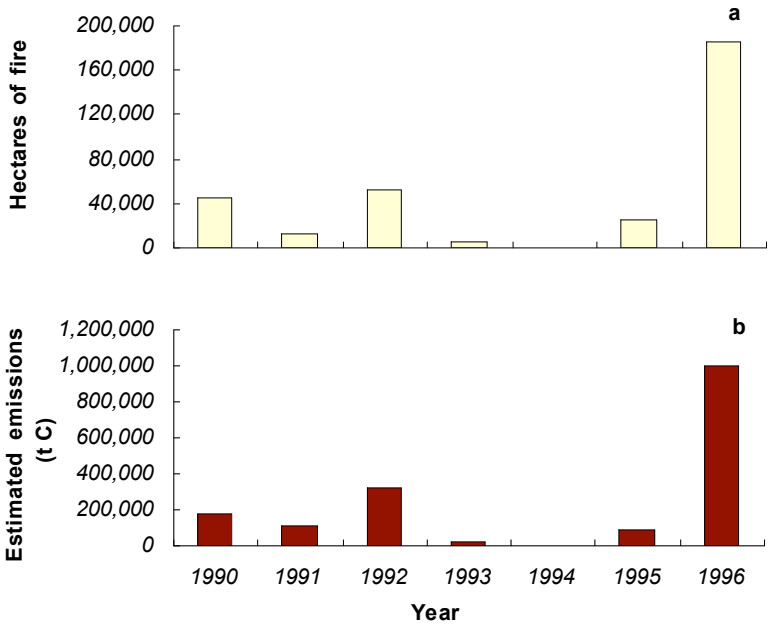


Figure 2-4-4
Area impacted by fire and estimated emissions from fire across the study period

The greatest area of fire and the greatest emissions occurred on Federal Lands with 79 % of the burned area and 83 % of the released carbon (Table 2-4-8). Eighteen percent of the area burned and 13 % of the emissions were from private lands.

Table 2-4-8
Area burned and carbon emissions by ownership across the analysis period

OWNERSHIP	Area burned (ha)	Emissions (t C)
County Government	4	34
Private	110,525	224,237
Private - Conservation	179	863
State Government	5,594	5,997
Tribal	10,655	47,979
US Federal	481,209	1,410,487

Emissions from fire occurred throughout the State of Oregon, however, areas burned and carbon emitted were lowest in the counties in the Northwest of the State (Figures 2-4-5, 2-4-6, Table 2-4-9). In each of Clatsop, Columbia, Tillamook, Washington, Polk, Lincoln, Benton, Marion, Yamhill, and Clackamas the area burned was less than 500 hectares over the 6 years of study (1994 was not examined), and the emissions were less than 7,000 tons of carbon. In contrast, the highest emissions

were in Grant County in the East where 40,000 hectares burned with 250,000 tons of carbon emitted and in Douglas County in the Southwest where 14,000 burned hectares coincided with high carbon stocks producing 105,000 tons of carbon emission.

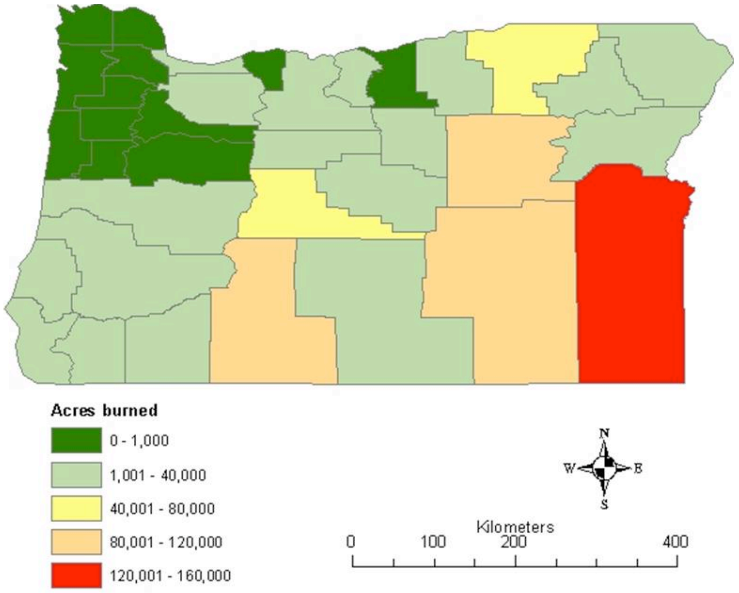


Figure 2-4-5
Area burned (in acres), at the county level, between 1990 and 1996 (excluding 1994)

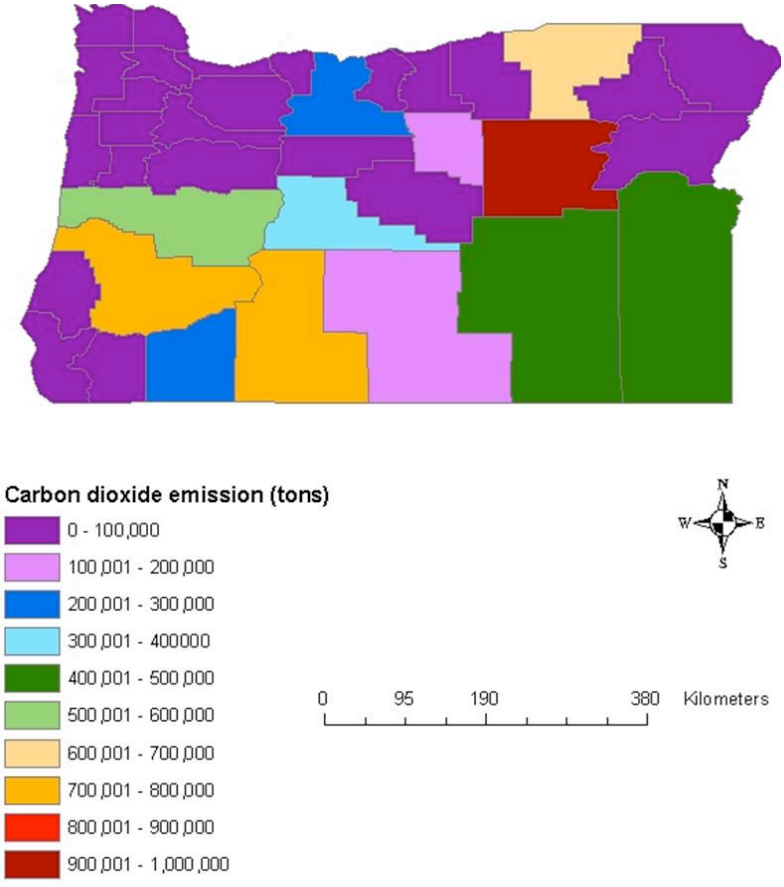


Figure 2-4-6
Metric tons of carbon dioxide emitted, at the county level, between 1990 and 1996 (excluding 1994)

Table 2-4-9
Area burned and carbon emissions per county across the analysis period

COUNTY	County Area (ha)	Area burned (ha)	Emissions (t C)
Baker	794,639	4,541	15,238
Benton	175,203	130	347
Clackamas	483,855	433	6,409
Clatsop	214,251	52	503
Columbia	170,090	27	431
Coos	414,522	655	9,581
Crook	771,656	2,285	12,550
Curry	421,490	1,543	22,279
Deschutes	781,698	30,686	90,465
Douglas	1,304,480	14,137	205,327
Gilliam	311,852	352	420
Grant	1,172,903	39,815	250,308
Harney	2,624,779	47,126	116,020
Hood River	135,287	32	496
Jackson	721,362	6,472	71,701
Jefferson	461,221	5,160	16,837
Josephine	424,652	1,270	17,022
Klamath	1,539,537	33,837	202,307
Lake	2,107,150	8,585	39,618
Lane	1,179,482	9,434	156,502
Lincoln	253,706	90	1,253
Linn	593,671	137	1,114
Malheur	2,560,745	58,496	121,124
Marion	306,643	109	1,759
Morrow	526,384	516	1,320
Multnomah	112,724	1,062	17,217
Polk	191,925	32	81
Sherman	213,210	605	1,432
Tillamook	285,454	55	739
Umatilla	832,749	22,133	179,122
Union	527,465	4,697	22,496
Wallowa	814,639	11,929	10,584
Wasco	616,688	13,291	57,639
Washington	187,450	16	257
Wheeler	444,162	8,221	38,729
Yamhill	185,330	46	373

2.4.4 Uncertainties

The carbon values to which percentage emission factors are applied are averaged values across all FIA plots in a forest type / region combination. Consequently, the same average value is used to represent forests with very high carbon stocks or very low carbon stocks. Fires will occur in forests regardless of starting carbon stock, yet it is possible that the forests with the very lowest carbon stocks (for example in the year immediately after clear cut logging) may not have enough biomass to sustain a fire. The emissions reported here may therefore be a small *overestimate* for if the very lowest biomass plots are excluded from the FIA analysis the mean will be raised and consequently the estimated emissions.

The calculated emissions presented here are conservatively limited to just aboveground tree biomass and therefore represent an *underestimation* of total emissions. Carbon stored in other pools will combust and be emitted through fire. However, we have no detailed source that will link the region and forest type-specific FIA data on aboveground tree biomass with similar data on other carbon pools.

Fire will directly impact dead wood, litter, shrubs and herbs (though even these pools may not be completely volatilized in low severity fires (e.g. Skinner 2002)). The influence of fire on soil carbon or the carbon stored in roots is less clear. When a tree is killed, the roots will not be burned but will become dead material that will decompose at a rate that is not well understood. A very intense fire will impact soil carbon though it is not fully understood what proportion of soil carbon is volatilized nor what depth the impact penetrates to.

To give an indication of the scale of potential additional emissions for pools not included here, the literature was consulted. Smithwick et al. (2002) took measurements of all carbon pools across 43 stands at seven sites in Washington and Oregon. The authors divided their measurements into three regions – Coastal, Cascades and Eastern. Values for roots were not taken from Smithwick et al. (2002); roots were estimated more directly by using the temperate forest allometric equation of Cairns et al. (1997), which calculates belowground biomass from aboveground biomass. The amount of additional biomass carbon as a percentage of aboveground live tree biomass carbon stocks is given in Table 2-4-10.

Table 2-4-10
Relative increase in stocks that would result from adding each of the additional carbon pools to live aboveground trees

	Litter	Dead Wood	Shrubs	Herbs	Roots	Soil Carbon
Coastal	8 %	20 %	0.30 %	0.05 %	23-26 %	79 %
Cascades	8 %	21 %	0.24 %	0.07 %	24-31 %	28 %
Eastern	22 %	23 %	0.38 %	0.09 %	25-31 %	43 %

The measurements of Smithwick et al (2002) were in old growth forests. In younger forests lower absolute amounts of dead wood might be expected together with similar quantities of litter, shrubs and herbs. Therefore a lower proportion of dead wood and a higher proportion of litter, shrubs and herbs might be expected in younger forests.

Here, as an indication of potential additions, the values of Smithwick et al. (2002) are used. Adding just litter, dead wood, shrubs and herbs, and assuming that the same proportion of these pools are volatilized as for live aboveground trees, gives an additional emission over the study period equal to 1,984,952 tons of carbon or an additional 29.6 %.

2.4.5 Conclusions

Across the six years analyzed[5] fires with a total area of 328,000 hectares (0.81 million acres) were recorded. This is equivalent to an average 54,700 hectares per year (135,100 ac/yr) for the period studied. Emissions totaling 6.8 million tons of carbon or 25.0 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. On an averaged annual basis this is equal to 0.28 million tons of carbon per year (1.03 $MMTCO_2e$/yr).

[5] 1994 was excluded due to poor image quality. From analysis of state and federal reporting of fire areas there is no indication that 1994 was a year of high fire incidence so its exclusions will not have dramatically altered the reported results.

Forty-eight percent of the burnt area and 83 % of the emissions were in forest as opposed to rangeland. Fire incidence varied by year with high emissions in 1996 and low impact in 1993 and 1995. Seventy-nine percent of area burned and 83 % of the emissions were from Federally-owned land, 18 % of the area burned and 13 % of the emissions were from private land. Emissions from fire occurred throughout the State but were markedly lower in the Northwest.

The emissions from fire of 1.03 $MMTCO_2e/yr$ during the 6-year period represented about 1.6% of the total gross emissions for the state of 63 $MMTCO_2e/yr$ in 1995 (from Governor's Advisory Group on Global Warming).

Chapter 3 – Baselines for Agricultural Lands in Oregon

3.1 General Approach

The goal of this chapter is to quantify the baseline of changes in carbon stocks in the Oregon agricultural sector for the decade of the 1990s. Baselines provide an estimate of the emissions and removals of greenhouse gases caused by changes in the use and management of land. The focus of this paper is on emissions and removals of carbon dioxide and not on non-CO_2 greenhouse gases. Baselines are useful for identifying where, within the landscape of a state, opportunities exist for enhancing carbon stocks and/or reducing carbon sources to mitigate greenhouse gas emissions.

The baseline for the agricultural sector depends on two types of data: (1) the total area of agricultural land, and area of each of the major agricultural land-use types, through time; (2) the carbon stocks in each land-use type. Areas and changes in area of agricultural lands are based primarily on the National Resource Inventory (NRI) database for the period 1987-1997. Carbon stock estimates for various agricultural land-use types were derived from consultation with experts in local universities and from the literature in combination with standard methods. The analysis is conducted for the entire state of Oregon at the county scale of resolution.

3.1.1 Classification of Agricultural Land

In this study, NRI data were used for estimates of area because of the NRI's relative strength in agricultural surveys compared with other sources of data. The coverage of NRI data is wider and is available across the states for multiple points in time and for multiple classes of agriculture.

In this analysis, agricultural land is equated to cropland as defined in the NRI (NRCS 2000). The NRI recognizes two categories of cropland: cultivated and non-cultivated. Cultivated cropland includes small grains and row crops, hay and pasture with cropping history, and horticulture with double cropping (meaning horticulture with crops planted under the trees). Non-cultivated cropland includes horticulture without double cropping, and hay without cropping history. Grazing lands are included under the analyses of rangelands in Chapter 2.

The distinction between cultivated and non-cultivated crops is not useful for the purpose of (aboveground) carbon analysis, which depends instead on biomass models based on the growth form of the vegetation. Therefore, the specific land-use categories from NRI were regrouped for this analysis into categories related to the growth form of the crop. All horticulture lands, with or without double cropping, were reclassified as woody cropland. The rest of the croplands, including hay, row crops and small grains, were considered to be non-woody crops (Table 3-1).

Table 3-1
NRI Categories and Subcategories in Oregon

Broad classification	Detailed classification	NRI classification
INCLUDED AS AGRICULTURE IN THIS CHAPTER		
Perennial woody crops	Fruit orchards	Fruit orchards
	Nut orchards	Nut orchards
	Vineyards	Vineyards
	Bush crops	Bush crops
	Berry crops	Berry crops
	Other horticulture	Other horticulture
Annual non-woody crops	Row / close crops	Row/Corn
		Row/Sorghum
		Row/Soybeans
		Row/Cotton
		Row/Peanuts
		Row/Tobacco
		Row/Sugar beets

		Row/Potatoes
		Row/Other veg/truck crops
		Row/All other row crops
		Row/Sunflower
		Close/Wheat
		Close/Oats
		Close/Rice
		Close/Barley
		Close/All other close grown
		Hay/Grass
		Hay/Legume
		Hay/Legume-grass
		Other crop/Summer fallow
		Other crop/Aquaculture
		Other crop/Other-set-aside etc.
FOCUS OF CHAPTER 2		
Pasture / rangeland	Pasture / rangeland	Pasture/Grass Pasture/Legume Pasture/Grass-forbs-legumes Rangeland
Forest	Forest	Forestland/Grazed Forestland/Not grazed
OTHER CATEGORIES		
Urban / transportation	Urban / transportation	Urban/10 acres or larger Urban/Small built-up Transportation
Other	Other	Other farmland/Farmsteads Other farmland/Other land Other farmland/CRP land Barren/Salt flats Barren/Bare exposed rock Barren/Strip mines Barren/Beaches Barren/Sand dunes Barren/Mixed barren lands Barren/Mud flats Barren/River wash Barren/Oil wasteland Barren/Other barren land Other rural/Permanent snow-ice Other rural/Marshland All other land Water/Body 2-40 acres Water/Body less than 2 acres Water/Streams per. < 66 ft. wide Water/Streams per. 66-660 ft. wide Water/Large

3.1.2 Limitations of the NRI Database

Despite the general acceptance of NRI for agricultural resource analysis, it is important to note its limitations. First, the samples were taken from non-federal lands only, while in the West Coast states, federal lands occupy half or more of the total land area. Second, the data are not from a complete census, but rather from a statistically sound sampling design. Finally, the NRI's classification of land cover/land use types may not be consistent with other classification schemes commonly used in land cover/land use analysis, e.g. the classification in USGS National Land Cover Classification system.

For the purposes of this chapter of the paper, however, these limitations have virtually no effect on the analysis as the data are only being used for the agricultural sector, where lands are privately owned, easy to classify, and statistically well reported.

The NRI reports a margin of error for the 1997 reporting (equivalent to a 95% confidence interval) of ±9% for its sampling of areas of cultivated cropland.

3.1.3 Area and Change in Area of Agricultural Land

The NRI data for each state were reclassified into the broad classes shown in Table 3-1. The areas for each class for 1987 and 1997 were then calculated. Although data for 1992 were available, a similar analysis for California where the change over two 5-year periods was included (1987-1992 and 1992-1997) indicated that using two periods did not appear to add any further insights into the dynamics of land-use and carbon stock change (Brown et al. 2004). Thus we only examine the change over the 10-year period 1987 to 1997.

3.1.4 Carbon Density of Agricultural Land

The baseline analysis for the agricultural sector focuses on carbon in vegetation only, including above- and belowground (roots) components. Carbon in vegetation is estimated as 50% of the biomass of the vegetation.

Carbon Stocks for Non-Woody and Woody Crops

A difficulty in estimating the biomass of non-woody annual crops is caused by the seasonal change of the vegetation. During the non-growing season, there is little biomass in annual crops, while at the peak of the growing season just before harvest, biomass can be high. Considering that litter production is usually low in these crops, peak biomass is assumed to be equivalent to the annual primary production of the crops on the land. In many cases the majority of the biomass (or production) is removed from the field at harvest. An approximate temporal average of the biomass was used to derive the carbon stock. The biomass in cultivated non-woody crops was estimated based on three sources of data: crop biomass from the U.S. Department of Agriculture – National Agriculture Statistics Service (USDA NASS, see http://www.usda.gov/nass/sso-rpts.htm), length and timing of harvest cycles, and the relative abundance of each crop type.

Carbon stocks of horticultural crops have less seasonal variation, but data on carbon stocks for these crops are scarce. Yield data from the USDA NASS represents only the biomass of the harvest – a useful estimate of peak biomass for non-woody crops, but only a small portion of the standing biomass for woody crops. Thus estimates were instead derived from consultation with extension agents, university researchers and government officials in combination with literature searches, principally to determine typical stocking densities (number of trees per unit area), tree diameters and tree heights. Biomass can then be estimated from tree diameter and height using a regression equation (Winrock unpublished). The stocking densities were combined with estimates of biomass per plant to arrive at an estimate of biomass carbon density in metric t C/ha. For fruit orchards and bush fruits, multiple crop types were included and the relative abundance of each crop type in the state, derived from USDA NASS, determined the area-weighted mean carbon stock that was used in this analysis (Table 3-2).

Table 3-2
Estimates of the average carbon stock (t C/ha) for each of the crop types in OR

Crop type	Average C stock (t C/ha)

Fruit orchards	26.9
Nut orchards	36.1
Vineyards	4.3
Bush fruits	4.1
Berry fruits	1.8
Other horticulture	4.5
Non-woody crops	1.5

Soil carbon stocks are not included in this paper because we assume that most agricultural land has been under cultivation long enough that changes in soil carbon would be minimal to non-existent under current practices. The stability of soil carbon on cultivated land was confirmed by the study of DeClerck and Singer (2003), who showed that the percent change in soil carbon under row crops in CA remained constant over an approximate period of 50 years. Interestingly, DeClerck and Singer also found the same trend for tree crops, but an increase in soil carbon over the past 50 years for soils under viticulture (about a 1.7-fold increase) and pasture (about a 1.6-fold increase). These results are difficult to apply in baseline determination because the results were reported as an increase in percent carbon with no indication of changes in soil bulk density; calculating changes in carbon stocks requires not only the change in percent carbon but also the change in soil bulk density.

Estimates of the carbon stocks in non-agricultural lands (e.g., urban/transportation, and all the other class) are assumed to be zero. This assumption is probably reasonable for "other" as this contains mostly barren lands, but for urban/transportation there is likely to be more carbon than in non-woody croplands. Urban development often contains significantly more (but unknown) amount of biomass in trees and shrubs that homeowners and local municipalities plant than in the agricultural lands that they replace. This is an area of further research—estimating the amount of carbon in biomass of urban areas as a function of density, etc.

Change in Stocks

When a change in agricultural land use occurred it was assumed in this analysis that the entire carbon stocks in vegetation present before the change would be emitted into the atmosphere as carbon dioxide. This is a reasonable assumption given the necessity to clear the land in order to plant alternative crops or initiate urban development.

For changes in land use to agricultural crops it is assumed that the change occurred at the midpoint of the period under analysis (in 1992), five years before 1997 and five years after 1987. For non-woody crops such as vineyards, bush and berry crops, and other horticulture crops, it is reasonable to assume that in five years, these crop types will have reached their predicted steady-state biomass. The same assumption cannot be applied to orchards, which will take longer than five years to attain their maximal biomass. Instead, the biomass accumulation that might have occurred in five years of growth for fruit and nut orchards respectively was estimated based on conservative estimations of stocking density, tree heights and diameters at five years age (Table 3-3).

Table 3-3
The estimated average biomass carbon accumulation after five years of growth for fruit and nut orchards in OR (t C/ha)

	Average biomass carbon accumulation
Fruit orchards	2.1
Nut orchards	1.8

In addition, it can be expected that fruit orchards and nut orchards will continue to accumulate biomass for many years. We therefore applied an average biomass accumulation to areas of orchards that remained constant over the ten years of the analysis. The rate of biomass accumulation was determined by estimating the stocks at years 40 and 60 and dividing the difference by 20 to get an annual accumulation. The annual accumulation was multiplied by 10 to give an accumulation for the ten years 1987 to 1997 (Table 3-4).

Table 3-4
The estimated average biomass carbon accumulation over 10 years of growth for fruit and nut orchards in OR (t C/ha). This growth rate is for existing orchards, i.e. for areas unaffected by land-use change

	Average biomass carbon accumulation
Fruit orchards	3.4
Nut orchards	5.6

3.1.5 Uncertainty

Uncertainty in NRI Data

The estimated margin of error (95 % confidence interval) for the area of cultivated cropland in 1997 is 6.7% for Oregon (NRCS 2000). For areas presented at finer scales (county level, specific crop) or for changes in area, the margin of error will be significantly higher.

Uncertainty in Carbon Stock Data

To evaluate the confidence in the estimated carbon stocks, ranges were determined (Table 3-5) based on the ranges in diameter, height, biomass and planting density provided by the sources consulted as described in section 3.1.4.

Table 3-5
Estimated ranges in average carbon stock for each crop type in OR (t C/ha)

Crop type	Range in C stocks (t C / ha)
Fruit orchards	16.3-44.3
Nut orchards	17.8-69.0
Vineyards	2.4-6.7
Bush fruits	3.2-5.0
Berry fruits	1.4-2.2
Other	3.4-5.7
Non-woody	1.0-2.0

Weighting the deviations from the mean by area and carbon stock gave a mean deviation value for carbon stocks of 42 %.

3.2 Results

3.2.1 Statewide Land Use and Land Use Change 1987-1997

The total area of Oregon is 25.48 million ha, of which 49% is covered by the NRI and the remainder is federal land falling outside the scope of the NRI.

In 1997 agricultural land in Oregon, including both perennial woody and annual non-woody lands, was estimated as 1.51 million ha or 5.9 % of the land area of the state. The area of woody cropland was 3.6 % of the total area under agricultural cultivation (Figure 3-1).

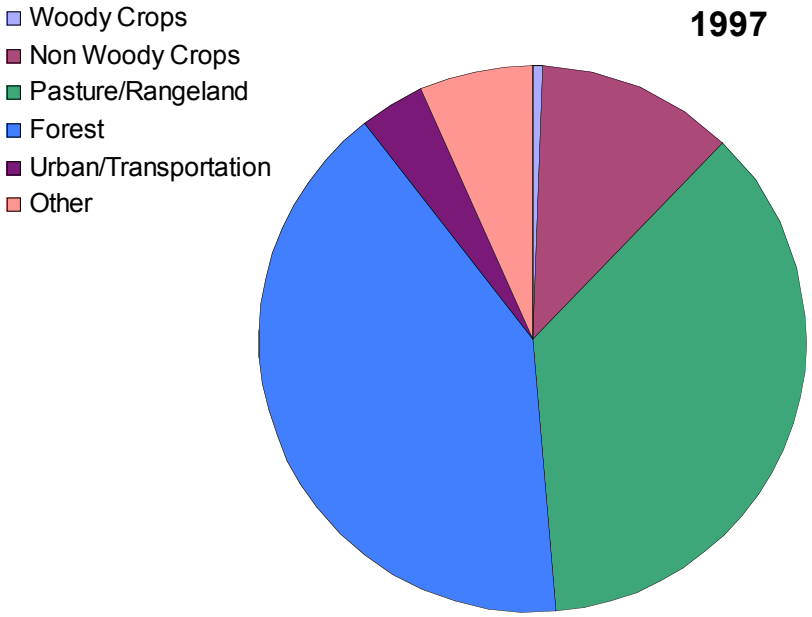


Figure 3-1
Proportional area for land uses in Oregon in 1997, based on NRI data (non-federal lands only)

Table 3-6
Areas (ha) and changes in areas (ha) for land use types in Oregon from the NRI dataset

	1987	1997	Change	% Change
Woody crops				
Fruit orchards	22,218	19,749	-2,469	-11.1
Nut orchards	10,401	10,846	445	+4.3
Vineyards	809	3,764	2,955	+365.3
Bush crops	1,577	2,388	811	+51.4
Berry crops	8,053	11,697	3,644	+45.3
Other horticulture	13,719	6,032	-7,687	-56.0
Total woody crops	56,777	54,476	-2,301	-4.1
Non-woody crops				
Row / Close crops	1,533,813	1,460,281	-73,532	-4.8
Other land uses				
Pasture/Rangeland	4,564,368	4,546,643	-17,725	-0.4
Forest	5,108,123	5,103,186	-4,937	-0.1
Urban/Transportation	422,385	494,503	72,118	+17.1
Other	793,495	819,882	26,387	+3.3
TOTAL	12,478,961	12,478,961		

Overall, Oregon experienced a 4.8 %(75,833 ha) loss in agricultural land area during the 10-year period from 1987-1997. This included a 4.8 % loss in area of non-woody crops and 4.1 % loss in area of woody crops (Table 3-1). In the same time period there were small decreases in the area of pasture/rangeland (0.4%) and non-federal forest (0.1%) and increases in the area of urban/transportation (17.1 %) and the Other category (3.3 %)(Table 3-6, Figure 3-2).

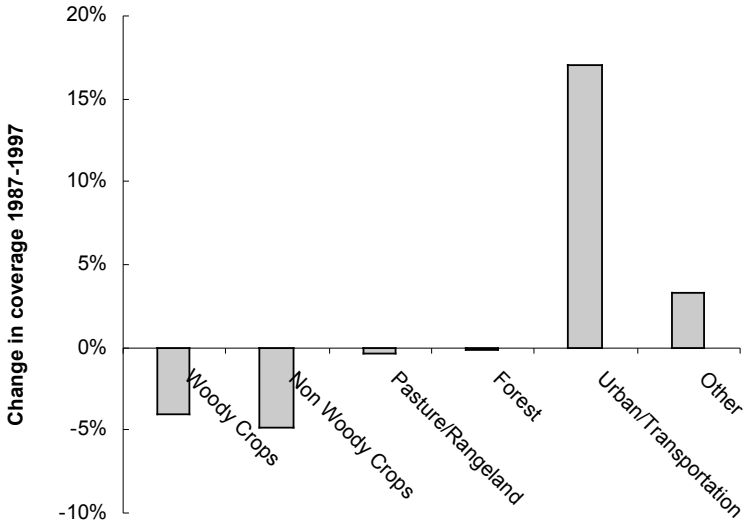


Figure 3-2
Proportional change in area between 1987 and 1997 for broad land uses in Oregon

3.2.2 Changes in Specific Land-use Type

Agricultural area in Oregon in 1997 was dominated by non-woody crops (96 %; Figure 3-3). Among the woody crops, fruit orchards make up 36 %, nut orchards 20 %, vineyards 7 %, bush crops 4 %, berry crops 22 % and other 11%.

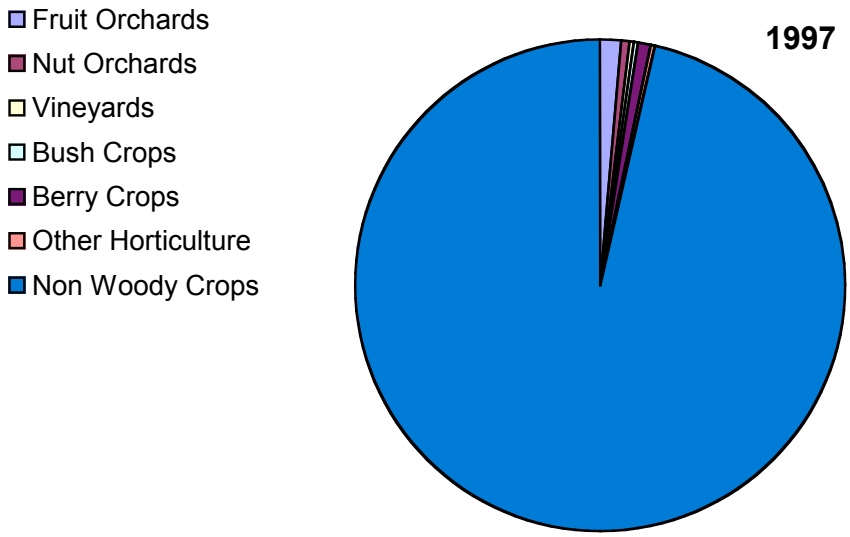


Figure 3-3
Proportional coverage of each agricultural land-use in Oregon in 1997

The 4.1 % loss in area of woody crops between 1987 and 1997 was composed of a 11 % decrease in fruit orchards (2,469 ha) and a 56 % decrease in other horticulture (7,687 ha), partially balanced by a 4 % increase in nut orchards (445 ha), a 365 % increase in vineyards (2,955 ha), a 51 % increase in bush fruits (811 ha) and a 45 % increase in berry fruits (3,644 ha) (Table 3-6, Figure 3-4).

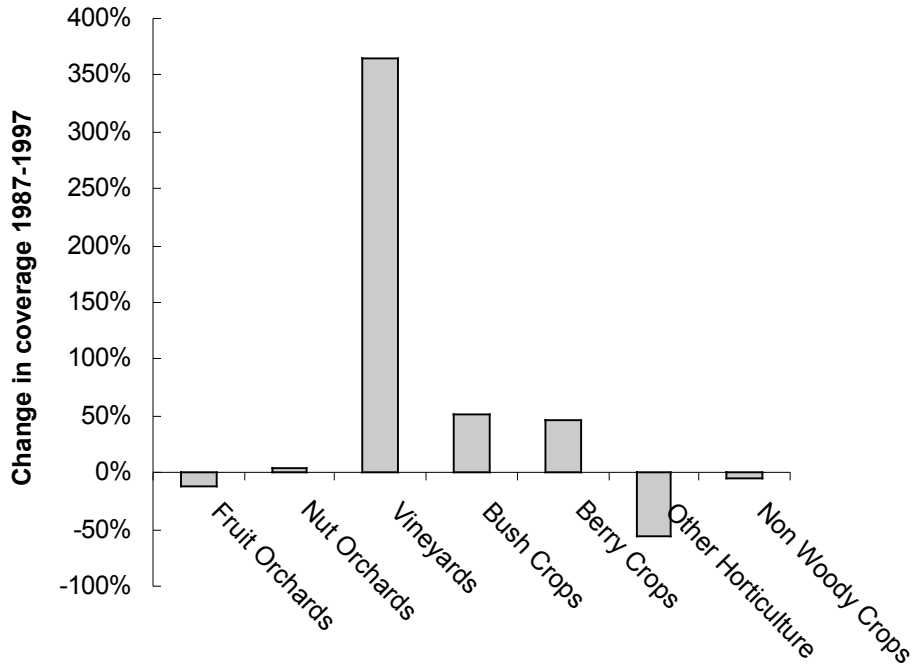


Figure 3-4
Proportional change in area between 1987 and 1997 for agricultural land uses in Oregon

There was a net loss in area in each of the land uses, excluding vineyards, to development. The largest losses to development were 18,698 ha from non-woody crops, 22,946 ha from pasture/rangeland and 26,063 ha from forest. Forest regrowth occurred on 48,159 ha of pasture/rangeland (Table 3-7).

The large gains in area of vineyards and berry crops were at the expense of nut orchards (805 ha), other horticulture (121 ha), non-woody crops (3,076 ha) and rangeland (2,630 ha). The loss in other horticulture was predominantly to non-woody crops (58 %).

Table 3-7

Land-use change transition matrix, showing the source and direction of changes in Oregon 1987-1997. The area unchanged between the time periods is listed at left, then the net gain and loss from the land uses listed in the rows to the land uses listed in the columns. A negative sign indicates a net loss of area from the land use in the row to the land use in the column

		Change to (-) / Change from (+)											
	Unchanged	Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture	Non-Woody Crops	Rangeland	Forest	Urban / Transport-ation	Other	TOTAL CHANGE
Fruit Orchards	19,021							-1,457	-202		-769	-41	-2,469
Nut Orchards	8,296			-405		-405		1,902	283		-324	-607	444
Vineyards	809		405					890	1,497	162			2,954
Bush Crops	1,416							728	243		-162		809
Berry Crops	5,180		405				121	2,186	1,133		-243	41	3,643
Other Horticulture	5,504					-121		-4,492		-567	-567	-1,943	-7,690
Non-Woody Crops	1,382,698	1,457	-1,902	-890	-728	-2,186	4,492		-8,094	1,457	-18,698	-48,443	-73,535
Rangeland	4,376,304	202	-283	-1,497	-243	-1,133		8,094		-48,159	-22,946	48,240	-17,725
Forest	5,040,619			-162			567	-1,457	48,159		-26,063	-25,982	-4,938

3.2.3 County-Level Estimate of Agricultural Land Area

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Woody cropland is primarily concentrated in the western counties (Figure 3-5), west of the Cascade Range, but comprises less than 2% of the total land area with the exception of four counties where up to 8% of the land area is in woody cropland (Washington, Yamhill, Polk and Hood River) (Figure 3-5a). The greatest proportion of non-woody agricultural land is in the northern part of the state along the Columbia River, with several counties having over 8% and two counties over 24% of the total land area in non-woody crops. Much of the drier southeast portion of the state also has some non-woody agricultural land, however (2-8% of the land area) (Figure 3-5b).

Fifteen Oregon counties recorded net changes in area of woody crops (Figure 3-6a). Losses occurred in eight, with one county (Clackamas) losing more than 4,000 ha of berry crops and other horticulture. Most of the conversion was to the Urban/Transportation and Other categories. Seven counties gained in area of woody crops, with Multnomah, Washington and Linn counties gaining the most.

As for non-woody crops, one county (Umatilla) lost more than 15,000 ha and seven more than 4,000 ha. The largest gains in non-woody cropland were in the western and especially southwestern counties, with Douglas, Curry and Josephine counties gaining more than 1,000 ha each (Figure 3-6b, Table 3-8).

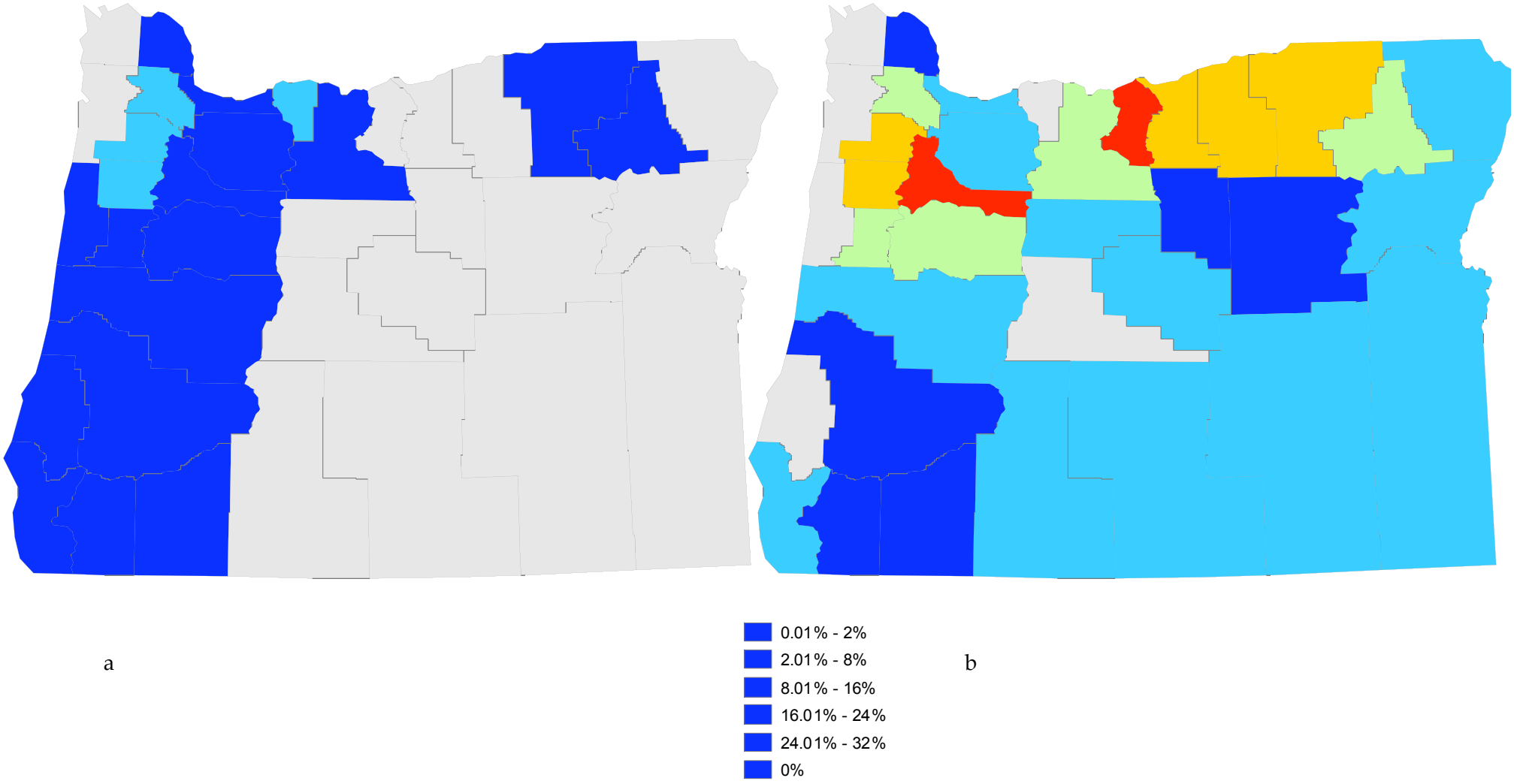


Figure 3-5
Distribution of woody (a) and non-woody (b) cropland by county in Oregon in 1997. Values indicate the percentage of total land area in each county occupied by agricultural land

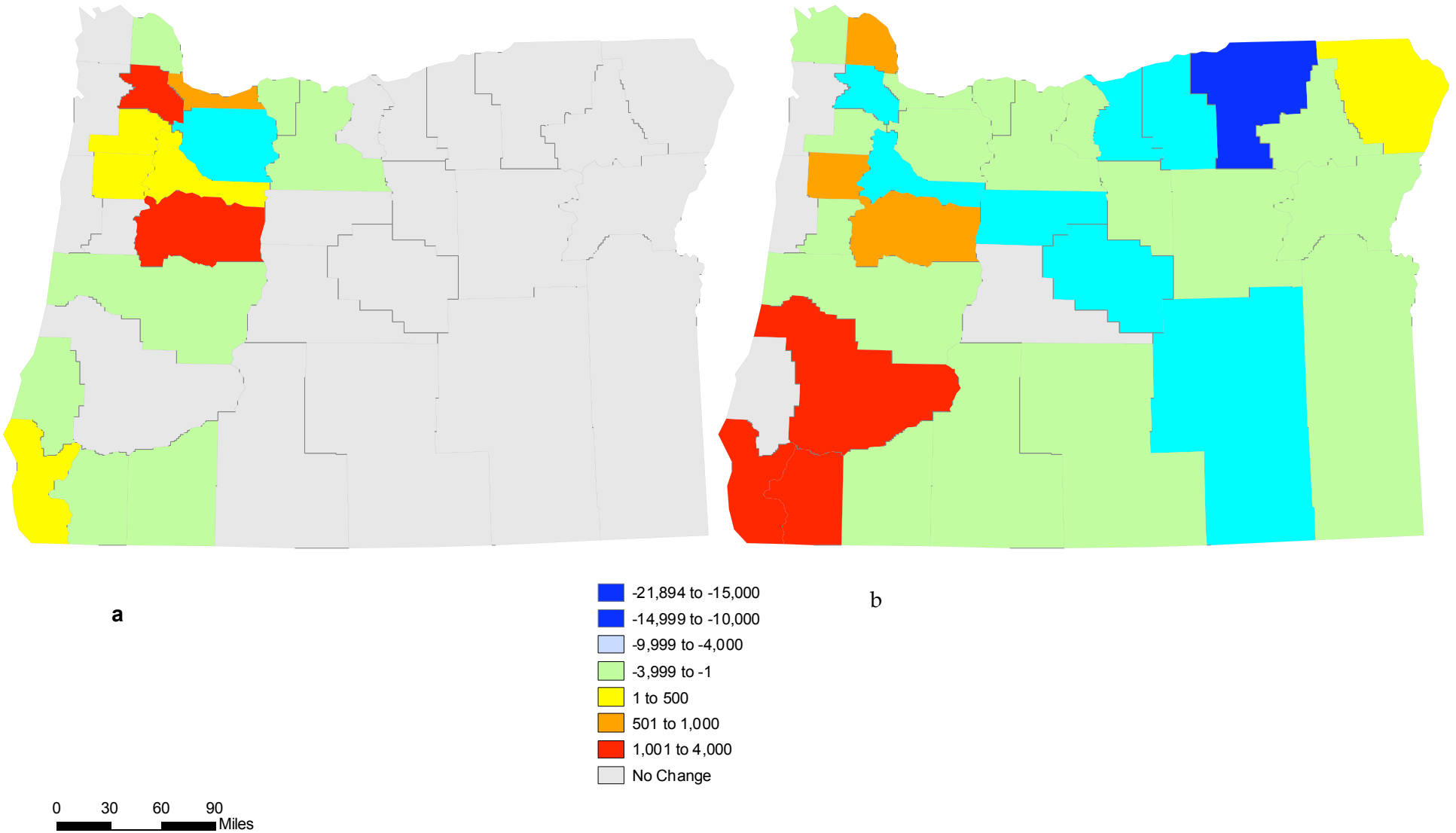


Figure 3-6
Distribution of change in area in woody (a) and non-woody (b) cropland in Oregon by county. Values indicate change in hectares; minus sign indicates a loss in area from 1987 to 1997 and plus sign indicates a gain in area in the same period

Table 3-8
The county level coverage (ha) for specific agricultural land uses and the change in coverage in Oregon 1987 to 1997

	High Carbon Crops												Low Carbon Crops			
	Fruit Orchards		Nut Orchards		Vineyards		Bush Crops		Berry Crops		Other Horticulture		Row / Close crops		TOTAL	
	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997
Baker											0	0	32,174	31,971	32,174	31,971
Benton											648	648	27,277	25,091	27,925	25,739
Clackam			1,214	1,214			445	405	2,226	1,093	3,642	648	27,034	26,913	34,561	30,273
Clatsop													324	0	324	0
Columbi							121	121	769	0	162	162	2,631	3,561	3,683	3,844
Coos									1,659	1,619					1,659	1,619
Crook													27,115	21,287	27,115	21,287
Curry									0	81			11,898	13,315	11,898	13,396
Deschute															0	0
Douglas	445	202					0	243					5,747	9,025	6,192	9,470
Gilliam													88,670	80,616	88,670	80,616
Grant													21,975	21,490	21,975	21,490
Harney													75,477	69,285	75,477	69,285
Hood	6,637	6,273			0	162			243	0	162	162	202	0	7,244	6,597
Jackson	3,197	2,954											8,094	6,313	11,291	9,267
Jefferson													34,845	27,520	34,845	27,520
Josephine					0	486					2,631	0	2,711	6,030	5,342	6,516
Klamath													43,262	43,222	43,262	43,222
Lake													60,543	59,815	60,543	59,815
Lane			1,376	931									44,760	42,615	46,136	43,546
Lincoln									324	324					324	324
Linn			283	283					324	2,914			83,651	84,461	84,258	87,658
Malheur													122,988	119,589	122,988	119,589
Marion	1,174	769	931	931					809	2,590	3,035	1,862	91,705	87,213	97,654	93,365
Morrow													126,590	122,422	126,590	122,422
Multnom							728	1,336					5,302	4,087	6,030	5,423
Polk	3,521	3,197	1,457	2,428	809	1,821			283	0	1,497	567	39,701	40,470	47,268	48,483

	High Carbon Crops												Low Carbon Crops			
	Fruit Orchards		Nut Orchards		Vineyards		Bush Crops		Berry Crops		Other Horticulture		Row / Close crops		TOTAL	
	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997
Sherman													72,886	69,568	72,886	69,568
Tillamoo															0	0
Umatilla	1,174	1,174											240,311	218,417	241,485	219,591
Union	526	526											70,620	69,163	71,146	69,689
Wallowa													24,282	24,768	24,282	24,768
Wasco	3,804	3,764											62,688	62,081	66,492	65,845
Washingt			3,804	3,885			283	283	1,052	3,076	283	0	28,369	22,542	33,791	29,786
Wheeler													6,516	5,383	6,516	5,383
Yamhill	1,740	890	1,336	1,174	0	1,295			364	0	1,659	1,983	43,465	42,048	48,564	47,390
TOTAL	22,218	19,749	10,401	10,846	809	3,764	1,577	2,388	8,053	11,697	13,719	6,032	1,533,813	1,460,281	1,590,590	1,514,757

3.2.4 Carbon Stock of Agricultural Land During 1987-1997

The vegetation of agricultural lands in Oregon contained about 3.2 million tons carbon in 1997. Between 1987 and 1997, conversion of agricultural land was responsible for a total loss of about 160,000 tons of carbon, including 49,800 t C from woody crops and 110,300 t C from non-woody crops (Table 3-9). These losses are equal to 4.9 % of the standing stock in 1987 for woody crops and 4.8 % for non-woody crops, giving a total loss of 4.8 % for all crops combined.

Table 3-9
Carbon stocks (t C) and changes in carbon stocks (t C) for land use types in Oregon

	1987	1997	Change
Woody crops			
Fruit orchards	597,665	577,862	-19,803
Nut orchards	341,146	323,169	-17,977
Vineyards	3,479	16,185	12,707
Bush crops	6,466	9,791	3,325
Berry crops	14,495	21,055	6,559
Other horticulture	61,736	27,144	-34,592
Total woody crops	1,024,986	975,206	-49,781
Non-woody crops			
Row / Close crops	2,300,720	2,190,422	-110,298
TOTAL	3,325,706	3,165,627	-160,079

Contributing to the loss in carbon stocks from woody crops were 19,800 t C from fruit orchards, 18,000 t C from nut orchards and 34,600 t C from other horticulture, principally Christmas trees (Table 3-4). Losses were partially offset by a gain of almost 13,000 t C in vineyards and smaller gains in bush and berry fruits, but these gains were still greatly less than the losses due to conversion of orchards and Christmas tree plantations.

Of the total net loss of carbon from agriculture of 160,000 tons, 63,000 tons were lost to development (urban/transportation). These losses came predominantly from fruit orchards, nut orchards and row/close crops (Table 3-10). There were losses to the expansion of rangelands from fruit orchards (5,400 t C) and row/close crops (12,100 t C), but these were offset by losses in rangeland to nut orchards, vineyards, berry and bush crops. The largest single loss was from row/close crops to the Other category (72,700 t C), including water, marshland, barren land and non-cultivated farmland. It is probable that most of this loss in carbon stocks simply represents agricultural land taken out of cultivation.

Ninety-seven percent of the gross gains in carbon in fruit orchards were from the growth of existing stands as opposed to new plantings; the equivalent percentage for nut orchards was 91 %. For other crop types it is assumed that there are little to no continued gains in carbon beyond the initial years of growth.

Table 3-10

The land use origins and destinations of changes in carbon stocks in agriculture in OR between 1987 and 1997. The growth of existing stands is listed at left, then the net gain and loss in carbon stocks from the land uses listed in the rows to the land uses listed in the columns. A negative sign indicates a net loss of carbon stocks from the land use in the row to the land use in the column

	Growth of existing stands	Change to (-) / Change from (+)											
		Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture	Non-Woody Crops	Rangeland	Forest	Urban / Transport-ation	Other	TOTAL CHANGE
Fruit Orchards	64,671							-56,253	-5,446		-20,684	-2,092	-19,804
Nut Orchards	46,460			-13,274		-24,565		3,424	510		-10,619	-19,911	-17,975
Vineyards			1,740					3,828	6,439	696			12,703
Bush Crops								2,987	996		-664		3,319
Berry Crops			728				219	3,934	2,040		-437	73	6,557
Other Horticulture						-547		-20,215		-2,550	-2,550	-8,742	-34,604
Non-Woody Crops		2,186	-2,853	-1,335	-1,092	-3,279	6,738		-12,141	2,186	-28,047	-72,665	-110,303

When converted to carbon dioxide equivalents, the total stocks in 1997 on agricultural land in Oregon are estimated at 11.6 $MMtCO_2eq$ (Table 3-11). There was a net loss of 0.6 $MMtCO_2eq$ between 1987 and 1997. This is equal to an annual source of 0.06 $MMtCO_2eq$. Sixty-nine percent of the stocks are estimated to be in non-woody vegetation and 69 % of the estimated carbon source arose from these crop types.

Table 3-11
Carbon stocks on agricultural land in Oregon and their change (million tons of carbon dioxide equivalent ($MMtCO_2e$)

	Agricultural Land	Woody	Non-woody
1987	12.2	3.8	8.4
1997	11.6	3.6	8.0
1987-1997	-0.6	-0.2	-0.4

3.2.5 Carbon Stocks of Agricultural Land by County

Three counties had a loss of carbon from conversion of non-woody cropland of over 10,000 tons in the ten years from 1987 to 1997 (Umatilla, Gilliam and Jefferson); Umatilla alone had a loss of almost 33,000 t C. There were lesser but still significant losses of carbon from conversion of non-woody croplands in Crook, Harney, Marion, Morrow and Washington counties (Table 3-12).

In all, 25 counties (69 %) had a loss in carbon from conversion of non-woody cropland to other land uses totaling almost 127,000 t C, partially offset by a total gain of 16,500 t C in seven counties (four counties' carbon stocks remained unchanged). The two counties with the largest carbon accumulation due to expansion of non-woody vegetation, Douglas and Josephine, nonetheless had a net loss of carbon due to losses in area of fruit orchards and other horticulture (Christmas trees) respectively.

As for losses of carbon due to conversion of woody crops, large losses occurred in Yamhill (fruit and nut orchards), Marion and Polk (fruit orchards and other horticulture), Clackamas and Josephine (other horticulture), and Lane, Washington and Yamhill (nut orchards). Large gains occurred in Polk, Yamhill and Josephine (vineyards), Hood River and Wasco (fruit orchards), Multnomah (bush crops), and Linn, Marion and Washington (berry crops).

Figure 3-7a illustrates that the greatest overall losses in carbon stocks from woody croplands in 1987-97 came in Washington, Yamhill, Polk, Clackamas, Lane and Josephine, accounted for primarily by losses of fruit and nut orchards and other horticulture. The greatest gains were in Hood River, Wasco and Linn, accounted for by increases in fruit orchards and berry crops. As for changes in carbon stocks due to conversion of non-woody croplands, the greatest losses were in Gilliam, Morrow, Umatilla, Harney, Crook, Jefferson, Marion and Washington. The greatest gains were in Columbia, Curry, Douglas, Josephine, Linn, Polk and Wallowa, but no county gained more than 6,000 t C (Figure 3-7b).

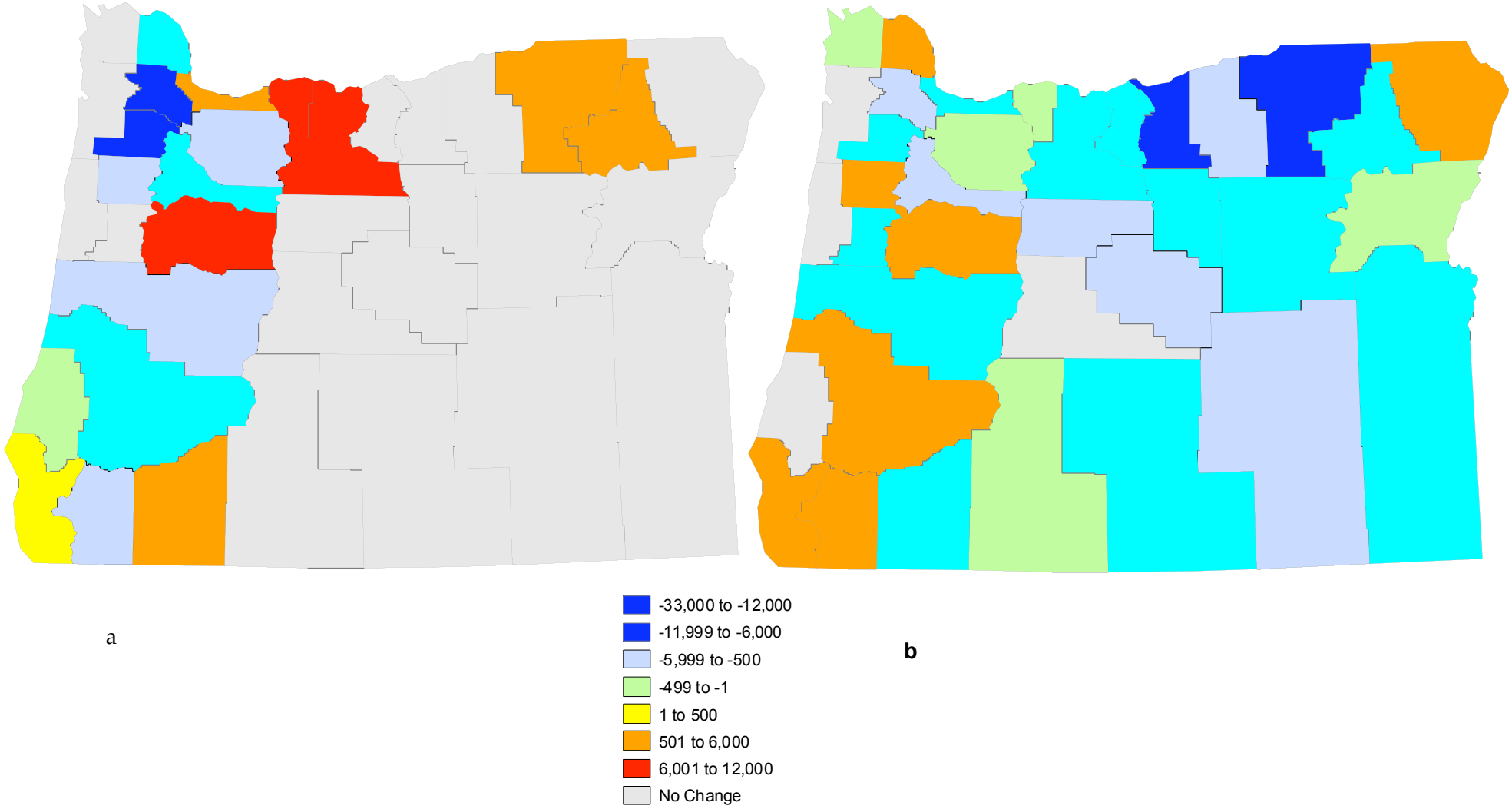


Figure 3-7
county-scale change in carbon stocks, 1987 to 1997, in high-carbon crops (orchards and vineyards, (a)) and in low-carbon crops (non-woody crops, (b)) in Oregon. Values in tons of carbon

Table 3-12
Change in carbon stocks (t C) between 1987 and 1997 across crop types in Oregon

County	Woody Crops						Non-woody Crops	TOTAL
	Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture	Row/Close Crops	
Baker	0	0	0	0	0	0	-305	-305
Benton	0	0	0	0	0	0	-3,279	-3,279
Clackamas	0	6,799	0	-164	-2,039	-13,473	-182	-9,059
Clatsop	0	0	0	0	0	0	-486	-486
Columbia	0	0	0	0	-1,384	0	1,395	11
Coos	0	0	0	0	-72	0	0	-72
Crook	0	0	0	0	0	0	-8,742	-8,742
Curry	0	0	0	0	146	0	2,126	2,271
Deschutes	0	0	0	0	0	0	0	0
Douglas	-5,844	0	0	996	0	0	4,917	69
Gilliam	0	0	0	0	0	0	-12,081	-12,081
Grant	0	0	0	0	0	0	-728	-728
Harney	0	0	0	0	0	0	-9,288	-9,288
Hood River	11,530	0	697	0	-437	0	-303	11,486
Jackson	2,371	0	0	0	0	0	-2,672	-301
Jefferson	0	0	0	0	0	0	-10,988	-10,988
Josephine	0	0	2,090	0	0	-11,840	4,979	-4,771
Klamath	0	0	0	0	0	0	-60	-60
Lake	0	0	0	0	0	0	-1,092	-1,092
Lane	0	-9,389	0	0	0	0	-3,218	-12,607
Lincoln	0	0	0	0	0	0	0	0
Linn	0	1,586	0	0	4,662	0	1,215	7,463
Malheur	0	0	0	0	0	0	-5,099	-5,099
Marion	-8,272	5,212	0	0	3,206	-5,279	-6,738	-11,871
Morrow	0	0	0	0	0	0	-6,252	-6,252
Multnomah	0	0	0	2,493	0	0	-1,823	670
Polk	-17,240	6,945	4,352	0	-509	-4,185	1,154	-9,484
Sherman	0	0	0	0	0	0	-4,977	-4,977
Tillamook	0	0	0	0	0	0	0	0
Umatilla	3,990	0	0	0	0	0	-32,841	-28,851
Union	1,789	0	0	0	0	0	-2,186	-397
Wallowa	0	0	0	0	0	0	729	729
Wasco	11,708	0	0	0	0	0	-911	10,798
Washington	0	-17,062	0	0	3,643	-1,274	-8,741	-23,433
Wheeler	0	0	0	0	0	0	-1,700	-1,700
Yamhill	-19,835	-12,068	5,569	0	-655	1,458	-2,126	-27,657
TOTAL	-19,803	-17,977	12,707	3,325	6,559	-34,592	-110,298	-160,079

3.3 Non-CO_2 Greenhouse Gas Emissions

The primary non-CO_2 greenhouse gas emitted from croplands is nitrous oxide, with approximately 296 times the global warming potential of CO_2. Nitrous oxide (N_2O) is emitted from agricultural soils especially after fertilizer application. A second important non-CO_2 gas is methane, with approximately 23 times the global warming potential of CO2. Methane (CH_4) is emitted during manure management and through livestock enteric fermentation.

The Governor's Advisory Group on Global Warming (2004) for the State of Oregon reports an annual source of nitrous oxide from agricultural soil management in Oregon equal to 3.4 $MMTCO_2eq$ in 1990 and 3.8 $MMTCO_2eq$ in 1995. This is about sixty times the emission we estimate here for CO_2 emissions attributable to agricultural land conversion (0.06 $MMTCO_2eq$/year). The emissions from manure management and enteric fermentation totaled 2.4 $MMTCO_2e$ in 1990 and 2.6 $MMTCO_2e$ in 1995.

The CO_2 equivalents agricultural land conversion are calculated here to be equal to 0.059 $MMTCO_2e$ for the ten year period between 1987 and 1997. Emissions from land conversion therefore make up approximately 1 % of the total emissions for Oregon's agricultural sector.

3.4 Conclusions

Agricultural land in Oregon in 1997 represented 5.9% of the total land area. Non-woody crops were about 96% of all agricultural land; among woody cropland, fruit orchards, nut orchards, and berries represent the largest proportions. Woody crops are concentrated primarily west of the Cascades, but in most counties constitute less than 2% of the total land area, while non-woody crops are concentrated primarily in the northern counties along the Columbia River and constitute up to 24% of the land area. Statewide, there was a loss of agricultural land of 4.8% between 1987 and 1997, coming in approximately equal proportions from conversion of woody and non-woody cropland. The greatest cause of change was conversion to urban development/transportation. Woody cropland increased over the period in seven counties and decreased in eight, while non-woody cropland decreased in eight counties with only small gains in other counties. Vineyards and berry crops increased in area in selected counties, but not to the extent of offsetting the overall loss in agricultural land.

Total carbon stocks in all agricultural land in Oregon were estimated at 3.2 million tons. Between 1987 and 1997, there was a total loss of about 160,000 tons of carbon, or 4.8% of the carbon stored in agricultural lands in 1987. Gains in carbon stocks in vineyards and other woody crops only partially offset the overall loss in carbon in fruit and nut orchards, other horticulture, losses to urban development, and losses to the Other category representing agricultural land taken out of cultivation. In CO_2 equivalent terms, total agricultural carbon stocks in Oregon in 1997 were 11.6 $MMTCO_2eq$, and the net loss 1987-97 disregarding non-CO_2 greenhouse gas emissions was 0.6 $MMTCO_2eq$, equivalent to an annual source of 0.06 $MMTCO_2eq$. Sixty-nine percent of this annual source came from non-woody cropland conversion. At the county level of analysis, the greatest loss of carbon from non-woody cropland came in Umatilla, Gilliam and Jefferson counties, while the greatest loss of carbon from woody cropland was in Yamhill, Marion, Polk, Clackamas, Josephine, Lane and Washington counties. Gains in carbon stocks from increasing area of woody crops in several counties only partially offset the overall loss of carbon stocks from conversion of non-woody cropland.

Non-CO_2 greenhouse gas emissions from N_2O (emitted from agricultural soils after fertilizer application) dwarf the annual CO_2 source from agricultural land conversion in Oregon.

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Part III: Baseline Greenhouse Gas Emissions and Removals for Forest and Agricultural Lands in WASHINGTON

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EXECUTIVE SUMMARY

The objective of this paper is to establish the baseline carbon stocks and changes in stocks for the forest and agricultural sectors in the state of Washington during the most recent 10-year period for which data are available (generally the decade of the 1990s). Such baselines can assist in identifying opportunities where carbon removals (sequestration) in each sector might be increased, or carbon emissions decreased, through changes in the use and management of lands.

Baseline for Forest Lands

The baseline for forests is separated into three components. A general forests baseline is presented at the State level for all forestlands, based on USDA Forest Service data, detailing change in forest area and change in carbon stocks, but with no attribution to the causes for the change. Using additional data bases, the specific cases of emissions associated with development and with fire are further examined. These components form part of the total detailed in the general forest baseline section and should not be considered separately.

General Forestlands Baseline

Forest area and carbon stocks were derived from USFS published data for the period 1987 to 1997. An extrapolation was made for the period 1997 to 2003 using recently completed USFS inventory data.

Between 1987 and 2003 forest area in Washington decreased by 0.9 million acres. Rates of loss between 1987-97 were 62,000 ac per year, and slowed to 49,000 ac/yr between 1997 and 2003 (Table S-1).

This is equivalent to a gross emission of 187 $MMTCO_2e$ or 12.5 $MMTCO_2e$/yr between 1987-97, and 10.1 $MMTCO_2e$/yr between 1997 and 2003.

Table S-1
Gross change in forest* area and forest carbon stocks in Washington

	1987	1997	2003	Annual Change 1987-1997	Annual Change 1997-2003
Area (million ac)	22.5	21.9	21.6	-0.062	-0.049
Carbon stock ($MMTCO_2e$)	3,091	2,965	2,904	-12.6	-10.1

*Includes all forests, federal and non-federal

The values presented here are gross emissions and will be reduced when consideration of the storage in dead wood and wood products pools are included. However, the emissions from forests are undoubtedly a significant proportion of the total emissions for the State of Washington, estimated to be 101 $MMTCO_2e$ in the year 1995.

Baseline for Development on Forest Lands

The baseline for emissions from development was created using land use data from the National Resources Inventory of the USDA and carbon data derived from the USFS Forest Inventory and Analysis Database (FIA). Due to data availability, the period chosen was 1987 to 1997. Due to data limitations the analysis is limited to non-federal forests and to the gross carbon dioxide emissions from

aboveground live tree biomass on conversion of non-federal forestland to developed land uses. As the focus is on non-federal lands the analyses should only be used to explore decisions on private lands.

Between 1987 and 1997, 246,000 acres of non-federal forest were converted to development. Large losses were concentrated in the coastal regions.

For gross carbon emissions, two scenarios were considered. Under Scenario 1 all tree biomass in the converted area was immediately emitted as carbon dioxide. Under Scenario 2 for developed areas of less than 10 acres, it was assumed that 50 % of the carbon was retained in the form of residual trees.

Under Scenario 1, an estimated 70.3 $MMTCO_2e$ were emitted for the 10-year period due to development. Under Scenario 2, 65.4 $MMTCO_2e$ were emitted. Development was concentrated in the Puget Sound region where the major city of Seattle is located (Table S-2). In this region 60 % of the emissions under scenario 1, or 56 % of the emissions under scenario 2 occurred, despite the fact that the region represents only 16 % of the area of the State.

Table S-2
Region-level summary of loss in area and carbon emissions between 1987 and 1997 due to development on non-federal forests. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

	Area lost (ac)	Carbon emissions ($MMTCO_2e$)	
		Scenario 1	Scenario 2
Puget Sound	138,500	42.3	39.4
Olympic	53,800	16.4	15.3
Southwest	30,000	8.2	7.5
Central	20,100	2.9	2.7
Inland Empire	3,300	0.6	0.6
TOTAL	245,700	70.3	65.4

The emissions from development on non-federal lands of 6.5-7.3 $MMTCO_2e/yr$ represent between 52 and 55 % of the total gross emissions from the forest sector (12.6 $MMTCO_2e/yr$ between 1987 and 1997). Compared to total emissions for the state as a whole, 101 $MMTCO_2e/yr$ for the year 1995 (Kerstetter 1999), emissions from deforestation on non-federal land represent more than 5 % of the total in the state.

Baseline Effect of Fire on Forest Lands

Emissions from fire were examined through overlaying the wildfire database for Washington (point data and an estimate of aerial extent) on AVHRR satellite imagery showing change in NDVI (normalized differential vegetation index). (NDVI measures 'greenness' of landscapes, greenness decreases immediately after fire). This process determined the location, size and estimated intensity (based on degree of change in the NDVI) of fires between 1990 and 1996[1]. Carbon values were applied

[1] 1994 was excluded due to poor image quality.

to these areas burned using data from the USDA FIA and proportional emissions from the detailed baseline fire analysis for California.

The analysis considered all forests and rangelands in Arizona, federal and non-federal.

Across the six years analyzed, a total area of 70,800 hectares (0.175 million acres) of fire were recorded. This is equivalent to an average 11,800 hectares per year (29,200 ac/yr) for the period studied. Emissions totaling 1.07 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. On an averaged annual basis this is equal to 0.18 $MMTCO_2e/yr$.

Thirty-three percent of the burned area and 87 % of the emissions were in forest rather than rangeland. No one year dominated fire incidence. Fifty-five percent of area burned and 44 % of the emissions were from private land. Fires covered a greater extent and caused more emissions in the North and Northeast of the State. Incidence was low in the Southeast and Northwest.

Compared to total emissions for the state as a whole, 101 $MMTCO_2e/yr$ for the year 1995, the average annual emissions from fire of 0.18 MMTCO2e represented more than 0.2 % of the total in the state. However, data limitations led to the exclusion of fires from 1994. Unfortunately 1994 was a year with a total area burned that was five times greater than the average annual burn between 1970 and 2003. The inclusion of 1994 would have significantly raised the average annual emissions due to fire.

Baseline for Agricultural lands

A general methodology for determining the agricultural baseline is presented. As with other terrestrial carbon baselines, the areas (acres) of different land uses and changes in land use are combined with carbon densities (tons of carbon per acre) of each land use to yield an estimate of the total emissions and removals of carbon associated with land management and/or conversion of lands over a given time period. Estimates of area and changes in area of agricultural and non-agricultural land use types were derived from the National Resource Inventory (NRI) database for the period 1987 to 1997. As the NRI database was used only non-federal land was considered.

Agricultural land in Washington amounts to almost 15% of the total land area. The state lost agricultural land area from 1987-97 through conversion to other land uses, in particular to urban development/transportation and the retiring of agricultural land from cultivation. In some counties, the area of woody cropland increased, but these increases were more than offset by decreases in non-woody cropland. Accompanying these losses in area were losses in standing carbon stocks on agricultural land, so that conversion of agricultural land to other uses was responsible for a net annual emission of CO_2 to the atmosphere of 0.05 $MMTCO_2eq/yr$ (Table S-3).

Table S-3
Summary of agricultural land area and changes in area, carbon stocks and changes in stocks, for Washington 1987-97

Parameter	Units	Results
Proportion of agricultural land to total land	%	14.6
Change in agricultural land area, 1987-97	Hectares (%)	-234,486 (8%)
Change in woody cropland area		+43,828 (37%)

Change in non-woody cropland area		-278,314 (9.9%)
Total carbon stocks in agricultural land, 1997	$MMTCO_2e$	22.9
Change in carbon stocks in agricultural land,	$MMTCO_2e$	-0.5
Estimated net annual source (emissions) from agricultural lands, disregarding non-CO_2 greenhouse gas emissions	$MMTCO_2e$	-0.05
From woody cropland		+0.1
From non-woody cropland		-0.15
Estimated net annual source from non-CO_2 greenhouse gas emissions, 1995	$MMTCO_2e$	-3.54

Emissions of CO_2 from agricultural land conversion, while the primary focus of this paper due to data availability, represent only a portion of the total greenhouse gas emissions attributable to the agricultural sector. The primary non-CO_2 greenhouse gas associated with agricultural activities, emitted from agricultural soils especially after fertilizer application, is nitrous oxide (N_2O), with approximately 296 times the global warming potential of CO_2. Examination of data from Washington indicated that greenhouse gas emissions from N_2O in the agricultural sector dwarf the annual CO_2 source from agricultural land conversion: CO_2 emissions from land conversion represented about 1.4% of the total CO_2 and non-CO_2 greenhouse gas emissions attributable to the agricultural sector.

Chapter 1 – Introduction and Background Information

1.1 General Approach

The purpose of this baseline document is to examine changes in land use and the associated emissions or sequestration of carbon for forest and agricultural lands in the State of Washington.

Separate baseline analyses are included here for forestlands and agricultural lands. The agricultural land study follows the same principles as the California baseline study (Brown et al. 2004). For forestlands, the California baseline study was based on CA-specific interpreted satellite imagery that detailed the scale of change, vegetation type and cause of change. Because no comparable data is available for Washington, we instead rely predominantly on two national datasets (see Section 1.2). The consequence of using generalized broad-scale datasets is that the outcome is less certain than we were able to achieve in California.

The forest baseline includes a state-level analysis on the change in area and carbon stocks in all forestland, plus a county-level analysis of changes on non-Federal forestland. Also included are specific case studies on emissions due to development and fire.

1.2 Datasets used in the Analysis

Two datasets are used repeatedly through the baseline analyses:

1.2.1 The National Resources Inventory

The National Resources Inventory (NRI) is conducted by the US Department of Agriculture - National Resources Conservation Service (NRCS). The NRI is a scientifically designed survey of the nation's soil, water, and other related resources with the purpose of assessing conditions and trends. The NRI contains data only on non-Federal lands and water bodies. As noted in the Users' Manual (NRCS 2000), the NRI data are useful in developing estimates of natural resource conditions and in conducting geospatial and temporal analyses of these conditions (however, the location of the survey plots is not given in the data base). In these baseline analyses, NRI data were used for estimates of area because NRI data is available across the WESTCARB States, wide in coverage, and available for multiple points in time and multiple classes of land use.

Because NRI data come from sample surveys, it is important to have a sufficient sample size for a reliable estimate. The NRI Users' Manual does not recommend that the data be used for county-level analysis because of sample size issues. To be conservative, here analyses are reported at the State level. County level results are given for illustrative purposes only.

NRI analyses are for the time period 1987 to 1997. More recently the NRI has switched to annual reporting, but this data is not yet publicly available.

1.2.2 The Forest Inventory and Analysis Database

Forest biomass was estimated using the US Forest Service Forest Inventory and Analysis (FIA) database. Following Acts of Congress in 1928 and 1974, the USFS has been systematically collecting data via the FIA on US forests.

The FIA data is composed of a hierarchy of the following nine tables: SURVEY, COUNTY, PLOT, SUBPLOT, CONDITION, TREE, SEEDLING, SITETREE and BOUNDARY. Examples of plot-level

records include: State, County, Plot number, Owner, Forest type, Stand age, Site productivity, and Slope. Examples of tree-level records include: State, County, Plot number, Tree number, Diameter at breast height (DBH), Crown class, Volume, Growth, and Expansion Factors (which allow extension from values per plot to per acre). Diameters are included in the database for all trees with DBH > 1". Creating links between the different hierarchies of the database and utilizing the expansion factors allows the user to explore a variety of topics related to biomass stocks in trees.

In this baseline study, data were downloaded from the FIA website on the scale of individual trees within plots within each county within each state. Using the biomass regressions of Jenkins et al. (2003), diameter at breast height (DBH) was converted to biomass for each tree. Area expansion factors (plot to acre), metric conversions and summation were used to calculate biomass in metric tons per hectare. In the fire baseline, forests are consolidated by forest type which is a plot-level characteristic.

1.3 Geographical Subdivision of the State

In the forest baseline, the State is subdivided into five regions. These regions are based on FIA 'units' but are convenient due to climatic, topographic and vegetation similarities within units (Table 1-1). Both the forest and agricultural baselines include county-level analyses; counties in Washington are shown in Figure 1-1.

Table 1-1
Five Washington regions with the component counties detailed

Region	Counties
Puget Sound	Island, King, Kitsap, Pierce, San Juan, Skagit, Snohomish, Whatcom
Olympic Peninsula	Clallam, Grays Harbor, Jefferson, Mason, Thurston
Southwest	Clark, Cowlitz, Lewis, Pacific, Skamania, Wahkiakum
Central	Adams, Asotin, Benton, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla,
Inland Empire	Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima



Figure 1-1
Washington counties. Source: Digital Map Store, *http://county-map.digital-topo-maps.com/washington.shtml*.

Chapter 2 – Baselines for Forests in Washington

2.1 Introduction

This chapter presents a baseline for emissions and sequestration in the forests of Washington. Forest is defined here as land with a greater than 10 % stocking of trees (as in the FIA and NRI).

The forest baseline chapter is presented in three sections.

In Section 2.2 a general forest baseline is presented detailing changes forest area and in stocks in the forests of Washington with an estimate of annual sequestration/emissions. A State level total is presented for all forests with county level detail only for non-Federal Lands.

The remaining sections present case studies of individual causes of emissions from forests. These case studies should not be considered on top of the general baseline (section 2.2) but as a subset of it. Emissions from fire or development will have formed part of the total emissions from forests that are presented or alternatively will have decreased the total estimated sequestration presented from forests.

In Section 2.3 the case study of emissions caused by development on forestland is presented.

In Section 2.4 the case study of emissions caused by fire on forestland is presented.

2.2 General Forests Baseline

2.2.1 State Level Analysis for all Forestlands

1987-1997

The USDA Forest Service published a baseline for forests in Washington between 1987 and 1997 (Birdsey and Lewis 2003). Estimates are based on forest inventory data collected by the Forest Service's Forest Inventory and Analysis Unit. Determination of the location of tree measurement plots and changes in land area were assessed using high altitude photography. Where forest inventory was not available estimates of land use change were derived from the National Resources Inventory.

Between 1987 and 1997 Birdsey and Lewis (2003) estimated a net change in forest area for Washington from 9.1 million hectares in 1987 to 8.9 million hectares in 1997. This is a total loss of 245,148 hectares (a decrease of 2.7 %), which averages out to 24,515 hectares per year (a decrease of 0.27%/yr).

Across the state Birdsey and Lewis calculated a mean forest carbon stock density of 92.5 t C/ha in 1987 and 91.3 t C/ha in 1997, this is a loss of 1.2 t C/ha over the ten years.

Combining the area data with the carbon stock density data gives a total stock on forestland in WA in 1987 and 1997 and a change in stock between the two dates.

The stock in 1987 was estimated as 843 million t C and this fell to 808.6 million t C in 1997. This is equal to a total loss of 34.5 million tons of carbon (a loss of 4.1%) or an average of 3.4 million tons of carbon per year (a loss of 0.40%/yr).

Beyond 1997

Using the Forest Inventory Mapmaker (version 2.1, http://www.ncrs2.fs.fed.us/4801/fiadb/fim21/wcfim21.asp), a total estimated area of forestland was attained for the year 2003. This area was 8.7 million ha which is equal to a loss of 117,533 ha from the total in 1997 (a decrease of 1.3 %) or a loss of 19,589 ha per year (a decrease of 0.22%/yr). The rate of loss in forest area has therefore decreased by 20 % between 1997 and 2003 in comparison with the rate between 1987 and 1997.

To attain carbon stock densities to apply to the areas an extrapolation was made from the change in stock density between 1987 and 1997.

	1987	1997	2003
t C/ha	92.5	91.3	90.6

This results in a 2003 carbon stock of 791.9 million tons of carbon or a loss of 16.8 million t C from the total in 1997 (a loss of 2.1%), which equals a mean loss of 2.8 million t C per year (a loss of 0.35%/yr). The rate of carbon loss due to loss in forest area decreased by 19 % between 1997 and 2003 in comparison with 1987-1997.

2.2.2 Changes in Forest Area on Private Land

This section provides a detailed baseline at the county level for the change in area in privately owned forests in Washington. Changes are only examined on private land. It is not expected that widespread deforestation is occurring on public lands though some afforestation may be overlooked.

The change in land use associated with forests on private lands in WA was analyzed from the National Resources Inventory (NRI). Two dates were used that reported data at the county scale of resolution: the most recent publicly available data for 1997 and for 1987. At the State level all land in forest was estimated in 1987 and 1997 plus the broad destination or origin of land that changed from or to forest in the same time period (Table 2-2-1).

Table 2-2-1
Change in area (ha) between 1987 and 1997 for private forestland in Washington

Category	Unchanged[1]	Lost to[2]	Gained from[3]
Unchanged	5,139,730		
Development		99,435	1,336
Pasture/Rangeland		21,530	40,106
Farmland/Agriculture		3,278	5,868
Other		6,435	7,082
1987 Total			5,270,408
1997 Total			5,194,122

[1]'Unchanged' refers to areas remaining forest between 1987 and 1997
[2]'Lost to' refers to areas lost from forest to other land use categories between 1987 and 1997
[3]'Gained from' refers to areas becoming forest between 1987 and 1997

In Washington forest area decreased by 76,286 hectares in the ten years between 1987 and 1997, or a mean of 7,628 ha/yr of forest area loss. Of the total area of forest in 1987, 97.5 % of remained unchanged as forest ten years later. There was a loss of 130,678 hectares principally to development and a gain of 54,392 hectares of which 74 % was from pasture/rangeland.

COUNTY-LEVEL CHANGES IN FOREST AREA

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Across the State net losses in forest area occurred in 51 % of counties, with gains in forest area in 28 % of the counties. Losses of more than 7,000 hectares occurred in King, Pierce, Snohomish, Thurston and Kitsap Counties, which are all located in the Coastal region. Gains of > 2,500 ha occurred in Steven, Ferry, Pend Oreille and Okanogan Counties, which are all located East of the Cascades (Table 2-2-2).

Table 2-2-2
Area (ha) of nonfederal forestland in Washington in 1987 and 1997 and change between the two dates

County	Population	County Area	Forest 1987	Forest 1997	Change
Adams	16,428	498,563	-	-	-
Asotin	20,551	164,553	12,141	13,638	1,497
Benton	142,475	441,099	-	-	-
Chelan	66,616	756,631	44,881	46,581	1,700
Clallan	64,525	450,516	211,496	209,716	(1,781)
Clark	345,238	162,709	88,386	81,628	(6,758)
Columbia	4,064	225,022	23,473	25,091	1,619
Cowlitz	92,948	294,907	249,498	244,439	(5,059)

Ferry	7,260	570,829	304,253	307,248	2,995
Franklin	49,347	321,781	-	-	-
Garfield	2,397	184,031	9,308	9,308	-
Grant	74,698	694,392	-	-	-
Grays	67,194	496,471	393,652	388,795	(4,856)
Island	71,558	53,984	34,319	31,607	(2,711)
Jefferson	25,953	469,883	169,367	166,372	(2,995)
King	1,737,034	550,643	265,726	251,521	(14,205)
Kitsap	231,969	102,557	72,482	65,238	(7,244)
Kittitas	33,362	594,969	171,229	170,662	(567)
Klickitat	19,161	484,943	195,470	195,430	(40)
Lewis	68,600	623,575	352,008	351,401	(607)
Lincoln	10,184	598,599	43,343	43,343	-
Mason	49,405	248,913	152,491	149,779	(2,711)
Okanogan	39,564	1,364,423	294,824	297,333	2,509
Pacific	20,984	241,638	211,011	210,727	(283)
Pend Oreille	11,732	362,668	125,781	129,221	3,440
Pierce	700,820	434,837	216,676	201,298	(15,379)
San Juan	14,077	45,305	32,012	31,405	(607)
Skagit	102,979	449,399	174,385	170,743	(3,642)
Skamania	9,872	429,015	82,923	82,276	(648)
Snohomish	606,024	541,065	178,999	167,263	(11,736)
Spokane	417,939	456,780	141,321	142,454	1,133
Stevens	40,066	641,877	402,231	408,949	6,718
Thurston	207,355	188,298	123,231	108,095	(15,136)
Wahkiakum	3,824	68,438	59,248	59,289	40
Walla Walla	55,180	329,059	11,777	13,274	1,497
Whatcom	166,814	548,957	141,564	137,477	(4,087)
Whitman	40,740	559,275	9,146	10,765	1,619
Yakima	222,581	1,112,718	271,756	271,756	-
TOTAL			5,270,408	5,194,122	(76,286)

Losses in forest area over the study period occurred in the three coastal regions, with gains in forest area in the Central and Inland Empire regions (Table 2-2-3)(for definitions of regions see Chapter 1).

Table 2-2-3
Area of nonfederal forestland in 1987 and 1997 and change between two dates

	Area (ha)		Change
	1987	1997	Area
Puget Sound	1,116,163	1,056,550	(59,612)
Olympic Peninsula	1,050,237	1,022,758	(27,479)
Southwest	1,043,074	1,029,759	(13,315)
Central	1,082,775	1,103,293	20,518
Inland Empire	978,160	981,762	3,602

2.2.3 Conclusions

An estimated 245,000 hectares of forest were lost on federal and non-federal lands in Washington State between 1987 and 1997 at a rate of 24,515 ha/yr. Between 1997 and 2003 an estimated 117,500 additional hectares were lost at a rate of 19,589 ha/yr. These losses are equivalent to 0.27 % of the forest area per year between 1987 and 1997 and 0.22 % of the forest area per year between 1997 and 2003.

A gross emission of an estimated 126.5 $MMTCO_2e$ would have occurred between 1987 and 1997 (12.6 $MMTCO_2e$/yr) and 61.6 MMTCO2e (10.3 $MMTCO_2e$/yr) between 1997 and 2003.

These emissions are gross and would be lowered through, for example, consideration of use of harvested timber and the lifetime of these wood products. However, the gross emission between 1997 and 2003 of 10 $MMTCO_2e$ represented approximately 10 % of the total estimated emission from the State of Washington in 1995 of 101 $MMTCO_2e$ (Kerstetter 1999). *(Note, however, emissions / sequestration from forests were not considered by Kerstetter (1999)).*

It is also worth considering that some of the loss in forest area will be replaced with regrowth. For the proportion of the forest area loss that is not permanent, the emissions will still have occurred but over 20-50 years most of these losses will be recouped. Where, for example, development has occurred or the land use has switched to agriculture the losses will be permanent.

For just non-federal lands the net loss is 76,000 ha primarily in the coastal regions and dominantly in the Puget Sound.

2.3 Development Baseline

2.3.1 General Approach

This section provides a baseline for the emissions of carbon attributable to development of forest lands in Washington. This analysis should be considered a subset of the general forest baseline: the emissions due to development will form part of wider changes in carbon stocks in the State. If this analysis is added to the analysis of the general forest baseline then double counting will occur.

Forest land development is examined only for private lands; it is not expected that widespread development is occurring on public land. Changes in stocks are only changes in aboveground tree biomass, due to uncertainties surrounding both the absolute level of carbon in other carbon pools and whether or not development will cause emissions from these pools.

As in the general forest baseline, changes in forest area due to development were based on NRI data for changes in land use. Carbon stocks and changes in stocks were derived from FIA data. For the purposes of this study, development includes three NRI categories:

Urban / 10 acres or larger

Urban / small built-up (< 10 acres). The category 'Urban/small built-up' will be referred to as small-scale development.

Transportation (e.g. roads, airports etc)

Statistical confidence can only be maintained in results given at the State level, due to the design of the NRI database. Results are given here at the County level merely for illustrative purposes.

2.3.2 Changes in Area at the State and County Level

Between 1987 and 1997 almost 99,435 hectares of non-federal forest were lost in Washington State to development, or 9,944 ha per year. The loss over ten years is equivalent to 1.9 % of the total forest area present in the State in 1987. Just over one thousand hectares reverted from developed land to forest. Of the total area lost to development, 14 % could be considered as small-scale development (Table 2-3-1).

Table 2-3-1
Non-federal forest area between 1987 and 1997 in Washington. Area in hectares

	Unchanged[1]	Lost to[2]	Gained from[3]
Unchanged	5,139,730		
Development		99,435	1,336
% small scale		14%	
Pasture/Rangeland		21,530	40,106
Farmland/Agriculture		3,278	5,868
Other		6,435	7,082
1987 Total			5,270,408
1997 Total			5,194,122

[1]'Unchanged' refers to areas remaining forest between 1987 and 1997

[2]'Lost to' refers to areas lost from forest to other land use categories between 1987 and 1997

[3]'Gained from' refers to areas becoming forest between 1987 and 1997

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Major losses in non-federal forest area to development occurred in Clark, King, Pierce, Snohomish and Thurston Counties, all of which are in the coastal region and all of which surround the major cities of Portland, Oregon (Clark) and Seattle, Washington (King, Pierce, Snohomish, Thurston)(Figure 2-3-1, Table 2-3-2). These five counties represent 16 % of the forest area in Washington in 1997, but 58 % of the total area lost to development over the ten-year study period.

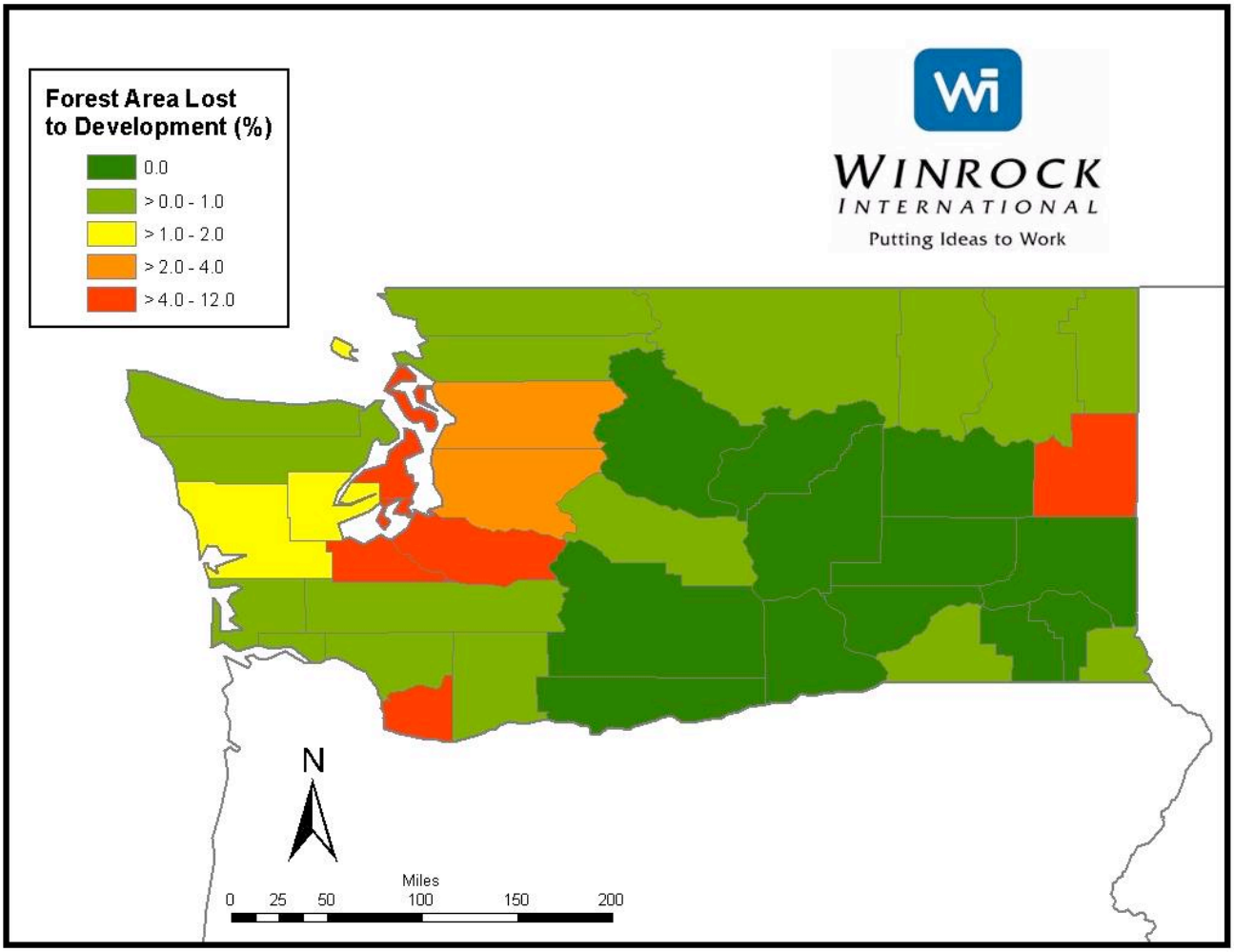


Figure 2-3-1
Loss in non-federal forest area between 1987 and 1997 as a percentage of total non-federal forest area in the county

Table 2-3-2
County level data on area of nonfederal forest in 1997, area of forest lost to development between 1987 and 1997 and % of losses that were small-scale

	Population	County Area (ha)	Non-Federal Forest Area in 1997 (ha)	Area Lost to Development (ha)	% small scale
Adams	16,428	498,563		0	
Asotin	20,551	164,553	13,638	81	50%
Benton	142,475	441,099		0	
Chelan	66,616	756,631	46,581	0	
Clallan	64,525	450,516	209,716	1,619	20%
Clark	345,238	162,709	81,628	6,192	16%
Columbia	4,064	225,022	25,091	0	
Cowlitz	92,948	294,907	244,439	1,740	35%
Douglas	32,603	471,514		0	
Ferry	7,260	570,829	307,248	324	25%
Franklin	49,347	321,781		0	
Garfield	2,397	184,031	9,308	0	
Grant	74,698	694,392		0	
Grays	67,194	496,471	388,795	4,775	3%
Island	71,558	53,984	31,607	2,388	27%
Jefferson	25,953	469,883	166,372	2,833	16%
King	1,737,034	550,643	251,521	13,355	6%
Kitsap	231,969	102,557	65,238	7,244	33%
Kittitas	33,362	594,969	170,662	688	0%
Klickitat	19,161	484,943	195,430	0	
Lewis	68,600	623,575	351,401	3,480	8%
Lincoln	10,184	598,599	43,343	0	
Mason	49,405	248,913	149,779	2,469	23%
Okanogan	39,564	1,364,423	297,333	648	0%
Pacific	20,984	241,638	210,727	202	40%
Pend Oreille	11,732	362,668	129,221	445	55%
Pierce	700,820	434,837	201,298	14,448	10%
San Juan	14,077	45,305	31,405	688	24%
Skagit	102,979	449,399	170,743	1,416	23%
Skamania	9,872	429,015	82,276	405	10%
Snohomish	606,024	541,065	167,263	13,760	12%
Spokane	417,939	456,780	142,454	5,666	2%
Stevens	40,066	641,877	408,949	1,578	15%
Thurston	207,355	188,298	108,095	10,077	15%
Wahkiakum	3,824	68,438	59,289	121	67%
Walla Walla	55,180	329,059	13,274	40	100%
Whatcom	166,814	548,957	137,477	2,752	10%
Whitman	40,740	559,275	10,765	0	
Yakima	222,581	1,112,718	271,756	0	

2.3.3 Carbon stocks

Estimates of the carbon stocks in live tree biomass are derived from the FIA data base. The FIA databases for 1992/1991 were used as these dates represent a midpoint between 1987 and 1997. FIA data were consolidated at the FIA Unit Level. Biomass carbon estimates were derived from the measurements of tree diameter at breast height for all trees in inventory plots using the allometric equations of Jenkins et al. (2003), scaled up to a per-ha basis using the plot-area expansion factors (Table 2-3-3).

In order to be conservative, aboveground tree biomass alone was considered. The rate of emission of carbon stored in roots and soil organic matter is slow and poorly understood, especially when it is considered that some of the developed areas will be capped with concrete. Wood products are also not included as it is not clear what proportion of the cut trees would be harvested for products, nor what products would be produced (fire wood and even paper can be rapidly emitted).

Table 2-3-3
Mean aboveground tree carbon stock (from 1991/1992 FIA data) for each region of Washington with the number of plots and the confidence interval around the stock estimate

t C/ha	Mean	95 % CI	# plots	Counties
Puget Sound	205.8	9.9	676	Island, King, Kitsap, Pierce, San Juan, Skagit, Snohomish, Whatcom
Olympic Peninsula	205.9	11.8	656	Clallam, Grays Harbor, Jefferson, Mason, Thurston
Southwest	183.6	10.6	657	Clark, Cowlitz, Lewis, Pacific, Skamania, Wahkiakum
Central	96.4	15.0	307	Adams, Asotin, Benton, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla,
Inland Empire	113.5	6.5	362	Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima

2.3.4 Carbon emissions from development

Two carbon emission scenarios are considered here. In both cases FIA data from federal and non-federal forests are applied to NRI land cover estimates for non-federal forests.

Scenario 1 assumes that all carbon present on the land in aboveground tree biomass is lost when development occurs.

Scenario 2 assumes that when small scale development occurs, a significant proportion of the trees remain during and after the process of development. As examples, these may be trees surrounding residential properties or trees on golf courses. Therefore, in this scenario we assume that for Transportation and Urban/10 acres or larger, all carbon is lost, but for Urban/small built-up, only 50 % of the carbon stocks are emitted.

Emissions discussed here for conversion of forestland to development are gross emissions from aboveground tree biomass only. Total emissions from development over the ten-year period were

estimated as 19.2 million t C under Scenario 1 and 17.8 million t C under Scenario 2. This is equivalent to 1,918,228 and 1,784,005 t C per year. The difference is small because only 14% of the total development change is attributed to small-scale development. Emissions by county are summarized below (Figure 2-3-2, Table 2-3-4).

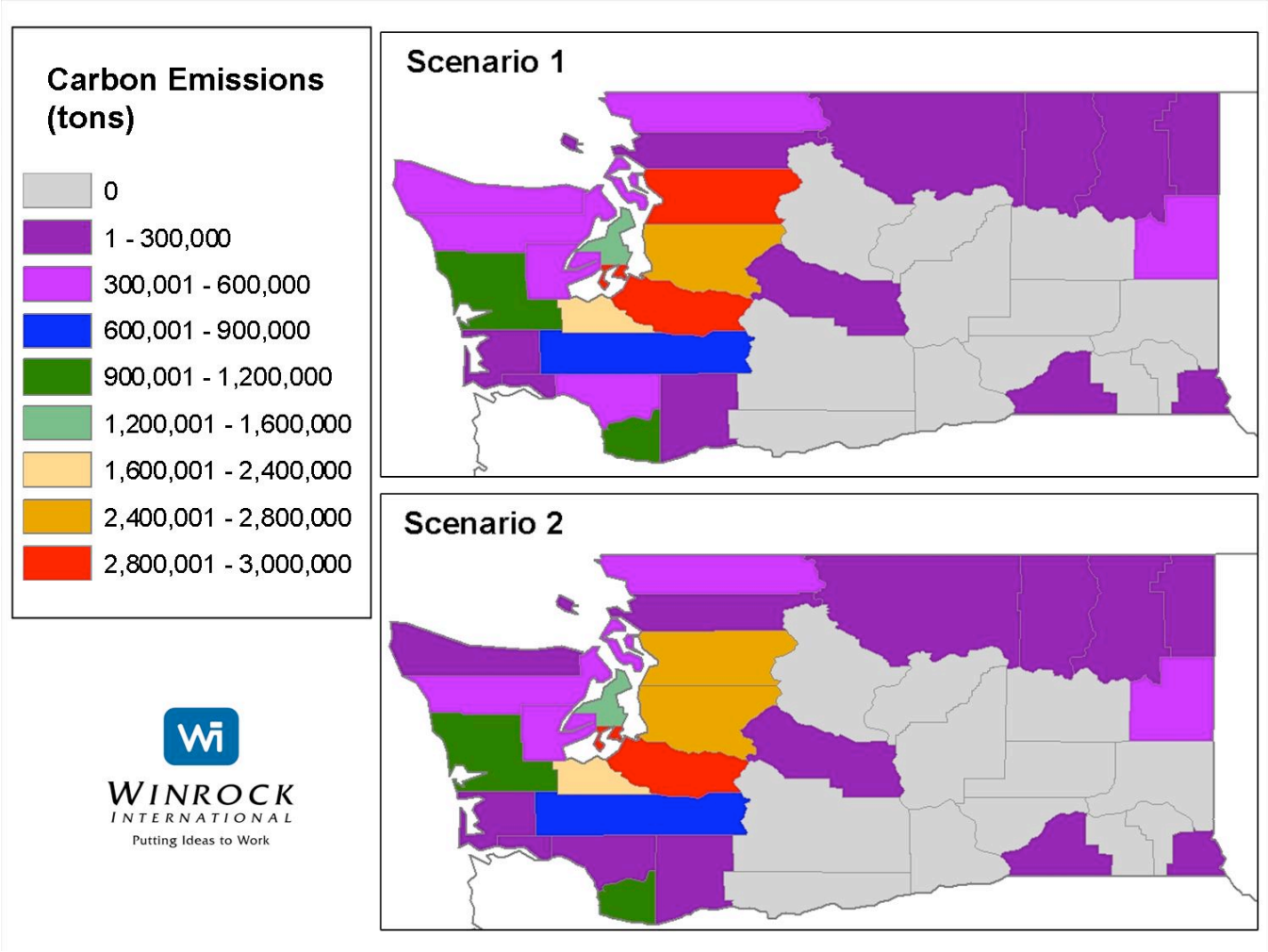


Figure 2-3-2
Carbon emissions under the two scenarios at the county level across the state

Table 2-3-4
County-level estimates on the emissions* between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

	Population	County Area (ha)	Non-Federal Forest Area in 1997 (ha)	Carbon emissions (t C) Scenario 1	Scenario 2
Adams	16,428	498,563		-	-
Asotin	20,551	164,553	13,638	7,806	5,855
Benton	142,475	441,099		-	-
Chelan	66,616	756,631	46,581	-	-
Clallan	64,525	450,516	209,716	333,246	299,921
Clark	345,238	162,709	81,628	1,136,998	1,044,106
Columbia	4,064	225,022	25,091	-	-
Cowlitz	92,948	294,907	244,439	319,549	263,813
Douglas	32,603	471,514		-	-
Ferry	7,260	570,829	307,248	31,225	27,322
Franklin	49,347	321,781		-	-
Garfield	2,397	184,031	9,308	-	-
Grant	74,698	694,392		-	-
Grays	67,194	496,471	388,795	983,074	966,412
Island	71,558	53,984	31,607	491,368	424,741
Jefferson	25,953	469,883	166,372	583,180	537,358
King	1,737,034	550,643	251,521	2,748,327	2,665,045
Kitsap	231,969	102,557	65,238	1,490,759	1,245,075
Kittitas	33,362	594,969	170,662	78,066	78,066
Klickitat	19,161	484,943	195,430	-	-
Lewis	68,600	623,575	351,401	639,097	613,087
Lincoln	10,184	598,599	43,343	-	-
Mason	49,405	248,913	149,779	508,199	449,881
Okanogan	39,564	1,364,423	297,333	73,474	73,474
Pacific	20,984	241,638	210,727	37,157	29,725
Pend	11,732	362,668	129,221	42,935	31,225
Pierce	700,820	434,837	201,298	2,973,190	2,823,282
San Juan	14,077	45,305	31,405	141,580	124,924
Skagit	102,979	449,399	170,743	291,489	258,176
Skamania	9,872	429,015	82,276	74,314	70,598
Snohomish	606,024	541,065	167,263	2,831,610	2,656,716
Spokane	417,939	456,780	142,454	546,439	540,585
Stevens	40,066	641,877	408,949	152,222	140,513
Thurston	207,355	188,298	108,095	2,074,454	1,916,162
Wahkiakum	3,824	68,438	59,289	22,294	14,863
Walla Walla	55,180	329,059	13,274	3,903	1,952
Whatcom	166,814	548,957	137,477	566,322	537,173
Whitman	40,740	559,275	10,765	-	-
Yakima	222,581	1,112,718	271,756	-	-

*Aboveground biomass only considered; assumption of no regrowth.

The highest loss in area due to development (56 % of total loss) and the highest emissions (60 % of total under scenario 1, 56 % under scenario 2) occurred in the Puget Sound region (Table 2-3-5) even though these counties only account for 16 % of the area of the state.

Table 2-3-5
Region-level summary of loss in area and carbon emissions* between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

	Area lost (ha)	Carbon emissions (t C)	
		Scenario 1	Scenario 2
Puget Sound	56,051	11,534,646	10,735,133
Olympic	21,773	4,482,153	4,169,735
Southwest	12,141	2,229,409	2,036,193
Central	8,134	784,531	747,451
Inland Empire	1,336	151,541	151,541

*Aboveground biomass only considered; assumption of no regrowth.

This is equal to an annual loss in area across the state of almost 10,000 hectares with annual carbon dioxide equivalent emissions of between 6.5 and 7 million metric tons of CO_2e (Table 2-3-6).

Table 2-3-6
Region-level summary of annual loss in area and carbon dioxide equivalent emissions* between 1987 and 1997 due to development. Scenario 2 is more conservative assuming that trees are not clearcut during small scale development

	Area lost per yr (ha/yr)	Annual carbon emissions ($MMTCO_2e$)	
		Scenario 1	Scenario 2
Puget Sound	5,605	4.23	3.94
Olympic	2,177	1.64	1.53
Southwest	1,214	0.82	0.75
Central	813	0.29	0.27
Inland Empire	134	0.06	0.06
TOTAL	9,944	7.03	6.54

*Aboveground biomass only considered; assumption of no regrowth.

2.3.5 Additional Considerations

Emissions discussed presented above for conversion of forestland to development are gross emissions from aboveground tree biomass only.

GROSS VS NET EMISSIONS

The analysis here represents gross changes. The only consideration was of emissions from losses of forest to development.

Where gains of forest were made from development, this was not considered.

The destination of biomass upon development is also not considered. The assumption is made that all carbon is immediately emitted. In reality this is unlikely to be the case. Some of the wood is likely to ultimately become fire wood, some will be left to decompose and some may be used as timber and will have a longer existence as wood products. Regardless, all trees cut for development will ultimately be emitted to the atmosphere as carbon dioxide or carbon dioxide equivalents. Instead of including any delay here the assumption is made of immediate emission.

OTHER CARBON POOLS

Aboveground tree biomass was the only carbon pool considered in this analysis. The reason behind this decision was the uncertainty involved in other pools generally, and specifically in the case of development.

Soil carbon is particularly uncertain. If the land is capped by concrete it is unlikely that soil carbon will be affected at all. If grasses are planted there is even the possibility that development could lead to an increase in soil carbon.

For similar reasons roots are also uncertain. The rate at which roots decompose is very poorly known and even less is known about the diminished rate if the roots are buried beneath concrete or tarmac.

Dead wood and litter are likely to be emitted either immediately upon development or through time as decomposition occurs. However, there is no clear relationship between aboveground tree biomass and these pools and the uncertainty involved with any assumption would be very large.

Non-carbon dioxide greenhouse gas emissions are also unknown. If site preparation occurs through burning, there will be emissions of methane and nitrous oxide (both potent greenhouse gases). If site preparation involves drainage there will be emissions of methane. Without specific site-by-site information it is not possible to make these estimations.

2.3.6 Conclusions

An estimated 99,000 hectares were lost to development in Washington State between 1987 and 1997 at a rate of 9,943 hectares per year. This forest loss is equivalent to a gross emission of between 65 and 70 million metric tons of carbon dioxide equivalent or 6.5 to 7.0 $MMTCO_2e$ per year.

The emissions are concentrated in the coastal region and in particular in the Puget Sound (the region in which Seattle is located).

These emissions compare with the estimated gross emission from forests in Washington of 12.6 $MMTCO_2e/yr$ between 1987 and 1997 (Section 2.2) and gross emissions for the state of 101 $MMTCO_2e/yr$ for the year 1995 (Kerstetter 1999). Emissions from deforestation on non-federal land therefore represent between 52 and 55 % of the total gross emissions from the forest sector and more than 5 % of the total emissions in the state. However, Kerstetter (1999) considered neither emissions nor sequestration from forests and so the emissions calculated here would be in addition to the reported annual 101 $MMTCO_2e$.

2.4 Fire Baseline

In this fire analysis the emissions caused by fire between 1990 and 1996 are estimated. These emissions are part of the general forest baseline (section 2.2). Without emissions from fire, the general forest baseline would be raised by an amount equal to these emissions.

This baseline, unlike the general forest baseline and the development emissions baseline contains an analysis of rangelands as well as forests.

There are two components to a fire analysis. It is necessary to know both the area that is burnt and the amount of biomass that is volatilized into greenhouse gases per area. Knowledge of these components permits an estimation of total fire-derived emissions.

The period 1990 to 1996 was chosen for this analysis, for (although a partial dataset exists for 1997-2003) these study dates represent the most recent, consistent complete coverage. Complete coverage is essential in order to be able to make State level conclusions on the impact of fire.

2.4.1 Methods for Assessing Biomass Volatilized

2.4.1.1 BACKGROUND

The effects of fire on carbon stocks are dependent on the intensity of the fire. An intense fire will destroy biomass and release a great proportion of the carbon to the atmosphere, while a less intense fire will even fail to kill the majority of the trees. Here fires are divided into three potential intensities: high, medium and low.

Pre-fire carbon has five potential destinations during and after a fire (Fig. 2-4-1). The first proportion will survive the fire to continue as live vegetation, a second proportion will be volatilized during the fire and immediately released to the atmosphere and the remainder will be divided between the pools of dead wood, soot and charcoal. Soot and charcoal are stable forms of carbon and can remain unchanged for hundreds of years; in contrast dead wood decomposes over time.

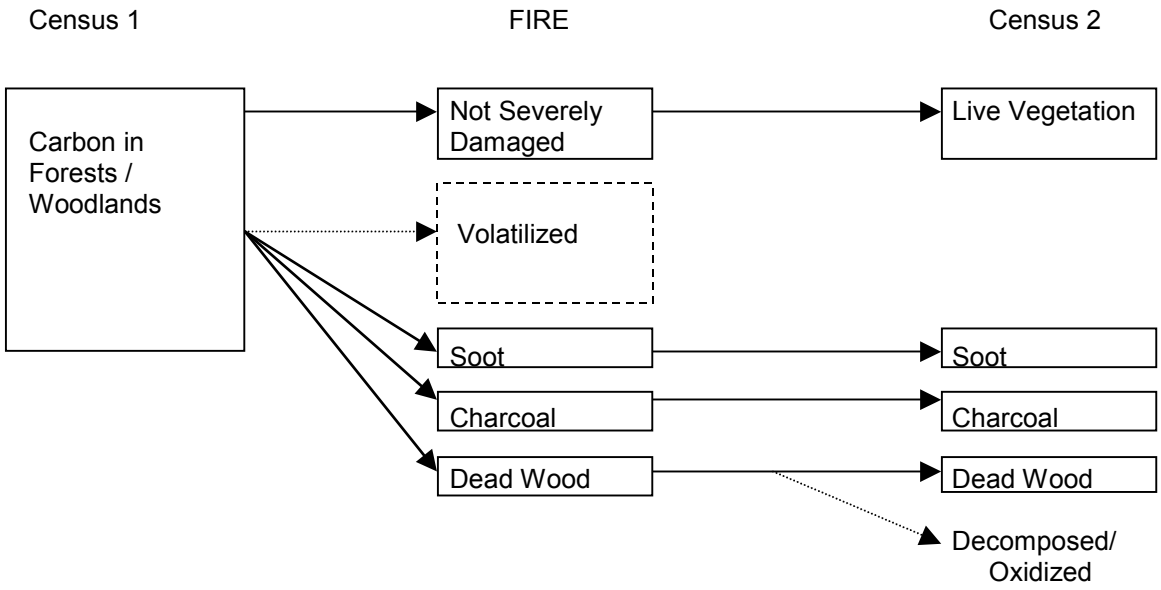


Figure 2-4-1
Flow Diagram Illustrating the Various Destinations of Pre-burn Carbon after a Fire

The basis for this baseline analysis was the detailed study conducted for California (Brown et al. 2004). Under the California baseline analysis changes in canopy coverage (measured from satellite imagery) were recorded through time for forest types and causes including fire were assigned. We assumed (based on expert opinion) that the three intensities are associated with the magnitude of change in crown cover, so that a large decrease in crown cover would be due to a high intensity fire or a small decrease is caused by a low intensity fire.

The midpoint of each decrease in canopy coverage class was assumed to be the proportion of the vegetation killed by the fire. The proportion volatilized is dependent on fire intensity (60 % high intensity fire, 40 % mid-intensity, 20 % low intensity; McNaughton et al. 1998; Carvalho et al. 2001). If the volatilized proportion is subtracted from the midpoint of the decrease then the remaining fraction is the dead wood, soot and charcoal pool. This fraction was divided using the following proportions: 22 % charcoal, 44 % soot, 32 % dead wood (Comery 1981, Raison et al. 1985, Fearnside et al. 1993, Neary et al. 1996).

2.4.1.2 APPROACH FOR CALCULATIONS

The aim of this study is to determine the loss in biomass as a result of fire in Washington. In California we had data on the area affected by fire in classes of initial and post fire crown cover and forest type. The degree of reduction in crown cover was used to indicate the intensity of the fire. We also had the biomass associated with each crown cover class and so a change between two cover classes could be represented as a loss in carbon. In contrast, in Washington available data included only forest type and an indication of fire intensity from fire extent and change in spectral reflectance.

The approach for this study is therefore to use the California data to determine the percentage loss in biomass that occurs as a result of a high, a medium or a low intensity fire in each of the forest types.

The percentage loss is then applied to Washington-specific biomass numbers for comparable forest types.

The source of biomass values is the Washington 2004 inventory of the FIADB (forest inventory and analysis database). These were split between forest types. In all cases, Washington FIA data were divided by the four forest/woodland types (Douglas Fir, Fir-Spruce, Other Conifer, Hardwood Forest; Table 2-4-1) at the county level. The division by forest/woodland type occurred to align the Washington analysis with the original California study (Brown et al. 2004).

Table 2-4-1
Forest types for fire baseline analysis cross-walked with FIA forest type

California-analysis forest type	FIA forest type
Douglas-fir	Douglas-fir
Fir Spruce	White fir, Red fir, Noble fir, Pacific silver fir, Engelmann spruce, Engelmann spruce / Subalpine fir, Grand fir, Subalpine fir, Blue spruce, Sitka spruce
Other Conifer	Port-Orford cedar, Ponderosa pine, Western white pine, Jeffrey pine / Coulter pine / big cone Douglas-fir, Mountain hemlock, Lodgepole pine, Western hemlock, Western redcedar, Alaska yellow cedar, Western larch, Misc. western softwoods
Hardwoods - forest	Cottonwood, Willow, Oregon Ash, Aspen, Red alder, Bigleaf maple, Tanoak, Giant chinkapin, Pacific Madrone

The FIA data was further split into regions – Eastern, Central and Coastal with the assumption that the climatic variation will lead to variation in biomass that will refine our estimates. The split of counties between regions is listed in Chapter 1, with the exception that Puget Sound, the Olympic Peninsula and the Southwest are combined into a single Coastal region.

The mean biomass stocks were calculated from WA FIA data by region and forest type (Table 2-4-2).

Table 2-4-2
Mean biomass stock by forest type and region

	Mean biomass (t biomass/ha)		
	Coastal	Central	Eastern
Douglas Fir	293.4	147.9	201.7

Other Conifer	466.8	127.8	145.8
Hardwood	207.2		

2.4.1.3 BIOMASS LOSS THROUGH FIRE

To calculate the emissions through fire, results from the California analysis (Brown et al. 2004) were used. From the California analysis, the estimated stocks for each forest type at each of the 4 canopy density classes was taken, plus the net emissions for each forest type/canopy density class/fire intensity class. Finally the emissions were calculated as a proportion of the original biomass and the results expressed as a percentage.

As no canopy cover class data exists for Washington, a mean emission percentage is required excluding canopy cover. This was achieved by weighting the emission percentages by the proportion of forest in each canopy class in the most representative region of California (North Coast for Coastal regions and Cascades Northeast for Central and Eastern regions).

The proportions by forest type by region by fire intensity were then multiplied by the biomass by forest type by region to give estimated biomass lost through emissions from fire (Tables 2-4-3, 2-4-4, 2-4-5).

Table 2-4-3
Mean emissions from a high, mid and low intensity fire in the Coastal Region of Washington

t CO_2e/ha	High	Mid	Low
Douglas Fir	233.8	100.5	40.5
Fir Spruce	355.9	155.8	62.7
Other Conifer	337.9	223.9	111.5
Hardwood	181.0	78.1	31.5

Table 2-4-4
Mean emissions from a high, mid and low intensity fire in the Central Region of Washington

t CO_2e/ha	High	Mid	Low
Douglas Fir	113.9	49.0	19.6
Fir Spruce	209.7	92.4	37.2
Other Conifer	88.2	58.5	29.2
Hardwood			

Table 2-4-5
Mean emissions from a high, mid and low intensity fire in the Eastern Region of Washington

t CO_2e/ha	High	Mid	Low
Douglas Fir	155.1	66.7	26.8
Fir Spruce	250.1	110.4	44.4
Other Conifer	100.5	66.6	33.2
Hardwood			

2.4.1.4 NON-TREE VEGETATION

Biomass numbers for non-tree vegetation (primarily shrubs and grasses in rangelands) are taken from the literature and Winrock International experience (Table 2-4-5).

Table 2-4-5
Estimates of pre-fire biomass stocks in non-tree vegetation

Vegetation type	Biomass carbon (t C/ha)	Source
Wet Grasslands	5.9	Prichard et al 2000
Mesic Grasslands	2.4	Brown and Archer 1999
Xeric Grasslands	0.6	Winrock unpublished data
Shrublands	5.1	Martin et al 1981
Desert scrub	2.6	Winrock unpublished data

Here the conservative assumption is made that 50 % of the pre-fire biomass in non-tree vegetation is volatilized to be emitted as carbon dioxide.

2.4.2 Methods for Assessing Area Impacted by Fire and Fire Intensity

Satellite-based analysis is a practical method of quantifying area burned primarily due to the dangerous nature and the wide geographic extent of wildfires. The State reports the location and size of recorded fires but with no measure of fire intensity, nor with the location of the boundaries of the fire. It is necessary to know fire intensity to estimate emissions and the precise location is necessary for a correlation with a database of vegetation species. The approach for this analysis was to estimate the extent of fires at known fire locations, through delineating areas with a change in reflectance on multiple satellite images, i.e. pre-fire and post-fire images.

A common measurement of vegetation from satellite imagery is the Normalized Difference Vegetation Index (NDVI). Very low values of NDVI (0.1 and below) correspond to barren areas of soil without vegetation or of sand, rock or snow. Moderate values represent shrub and grassland (0.2 to 0.3), while high values indicate forests (0.6 to 0.8).

2.4.2.1 DATABASES

NDVI was calculated from 1.1 km pixel resolution NOAA Advanced Very High Resolution Radiometer (AVHRR) 10 day composite images. The temporal frameset covered the month of September and spanned 1990 – 2003 (except 1994). This encompassed the NOAA 11, 14, 16 satellites. September was chosen for the analysis time frame because it is towards the end of the fire season and the burned areas are not yet affected by regrowth. Only one September 1994 composite was produced for 1994 due to the failure of the AVHRR sensor aboard NOAA-11. As a result, the imagery for 1994 along with fire

data were dropped from the analysis due to data inconsistencies in image values and incomplete temporal coverage from sensor failures.

The wildfire database for Washington encompassed a total of 15,994 occurrences that vary from less than 1 acre to many thousand acres. Fires for the study period with a final size greater than 2,000 acres were identified for NDVI postfire burn detection analysis to quantify area burned. Each fire record included a unique ID with a GPS point location, date, and final extent in acres. There was no GIS polygon representing the extent of the fire in the original database so it was not possible to precisely locate the extent of the fire from these records, so we used the approach described below.

2.4.2.2 MAPPING METHODS

Fire Identification

This analysis used a postfire burn detection method to quantify area burned by wildfires. NDVI was calculated from the water vapor corrected bands 10, visible (0.58 - 0.68 μm) and band 11, near infrared (0.725 – 1.10 μm).

NDVI = (ch 11 – ch 10) / (ch 11 + ch 10).

In order to obtain a single September NDVI for each year of the study period, three (or in some years four) 10-day composites were averaged into a single image ($NDVI_y$). These September images were then averaged into a 13-year historical NDVI reference image ($NDVI_m$).

NDVI reflectance values are bi-modal, ranging from -1.0 to 1.0. Positive values reflect vegetation or 'greenness', and negative values are indicative of soil or non-vegetated areas. Values close to 1 are 'greener' than values close to 0 and values close to -1 are more barren than values close to 0. When vegetation is burned, a rise in channel 10 reflectance and a decrease in channel 11 reflectance occurs. The degree of change ($NDVI_d$) was measured by subtracting $NDVI_y$ from $NDVI_m$

$NDVI_y - NDVI_m = NDVI_d$

From the reference image each individual annual September image was subtracted and potential fire locations identified. In NDVI difference imagery, positive values indicate an increase in 'greenness' from $NDVI_m$ and negative values a decrease. For burned area-identification purposes, all positive values were removed along with negative values greater than -0.05. The result was an image containing areas of concentrated vegetation decrease. The fire location data was then overlaid to confirm the changes as potential fires.

Fire Extent

The extent of fires listed as having over 2,000 acres in final size were mapped by visual interpretation from the changes seen in $NDVI_d$ with assistance from the fire's GPS location and extent information (Figure 2-4-2).

The wildfire mapping process consisted of creating polygons that represent the extent of the burn area. Fires were first divided into big and small based on final extent. Fires with a final extent of < 2,000 acres or 8 pixels were labeled as small fires. For AVHRR imagery, 1 pixel = 100 hectares = 247.5 acres. Areas of vegetation decrease in $NDVI_d$ greater than 8 pixels and with a corresponding fire greater than

2,000 acres were digitized using the 'heads up method'[2]. The area digitized was then compared with the reported final extent.

All fires with less than 2,000 acres burned were classified too small to display a change in the AVHRR imagery. For these fires, a buffer was calculated and added to the fire point based on the GPS point, which was considered the center of the fire, and the radius; that was derived from the size reported in the original record.

Additionally, if a fire that was larger than 2,000 acres could not be mapped by visual interpretation, it was mapped by the buffering method.

Fire Severity

For the fires that occurred in forested lands, three classes of burn severity were identified: low, medium, and high (Figure 2-4-2). Again, the intensity was evaluated separately depending on the fire mapping method. For the fires that were identified using the imagery, the value of burn severity corresponded with the value of the difference in NDVI. The rationale is that the more negative the difference between the actual NDVI and the mean NDVI, the more severe is the fire. As a result, one fire can include areas with different burn severities. Small fires (< 2,000 acres) were arbitrarily considered to experience a low burn fire severity, since there was no image data to consistently support the estimation.

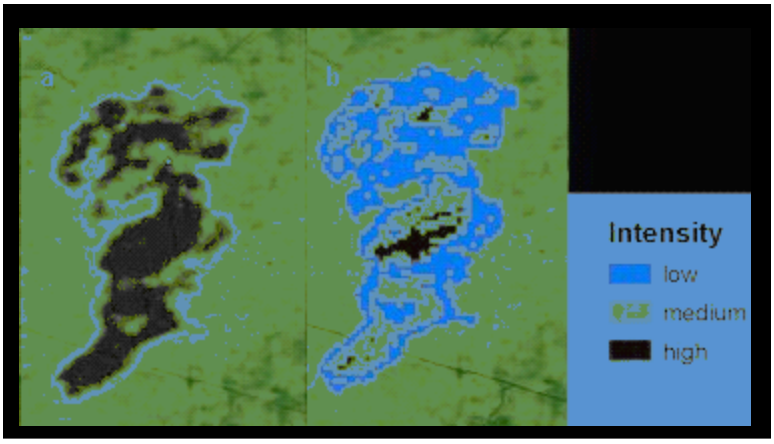


Figure 2-4-2
Illustration of the mapping methodology. In (a) the point location from the State or Federal database is established, a fire boundary is then created and compared to the fire area reported with the point location; in (b) the fire intensity through the burn area is calculated using NDVI values.

Land Cover Affected by Fire

Finally, the fires map were crossed with the land cover maps, making possible to estimate the amount of land cover type / forest type that was affected by fires.

[2] Heads up digitizing refers to on screen digitizing. It is referred to as 'heads up' because the analyst focuses on the screen as opposed to on a digitizing tablet.

2.4.3 Results

Across the six years analyzed, fires with a total area of 70,800 hectares (0.175 million acres) were recorded (illustrated in Figure 2-4-3). This is equivalent to an average 11,800 hectares per year (29,200 ac/yr) for the period studied.

Emissions totaling 0.29 million tons of carbon or 1.07 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. On an averaged annual basis this is equal to 48,600 tons of carbon per year (0.18 $MMTCO_2e$/yr).

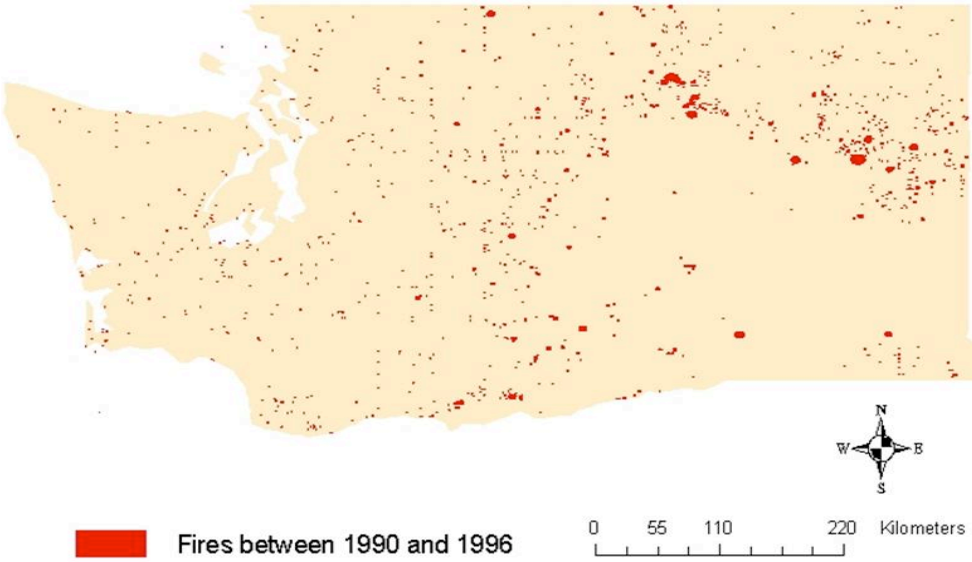


Figure 2-4-3
The location and extent of fires in Washington between 1990 and 1996

Thirty-three percent of the fires occurred in forests and 47 % in rangeland during the study period (Table 2-4-6)[3]. Due to the higher biomass loss from forests during fire more than 87 % of the total emissions from fire originated in the 33 % of fire area that was in forest.

Table 2-4-6
Area burned and carbon emissions in forests and in rangeland across the analysis period

	Area burned (ha)	Emissions (t C)
Forest	23,665	254,594
Rangeland	33,002	37,290

[3] The remaining fire area was on developed, agricultural or barren land

Emissions from fire happened each year of the analysis (Table 2-4-7, Figure 2-4-4). (1994 was not examined due to poor image quality). The largest areas of fire occurred in 1991, 1992 and 1996. In each of the remaining years less than 10,000 hectares were burned and less than 50,000 tons of carbon emitted. The lowest burn year was 1995 when 2,400 hectares burned. The lowest emissions occurred in 1993 with 12,000 tons of carbon released through fire.

Table 2-4-7
Area burned and carbon emissions per year across the analysis period

YEAR	Area burned (ha)	Emissions (t C)
1990	8,144	44,440
1991	20,382	92,703
1992	16,612	63,643
1993	3,191	12,184
1994		
1995	2,371	20,506
1996	20,141	58,415

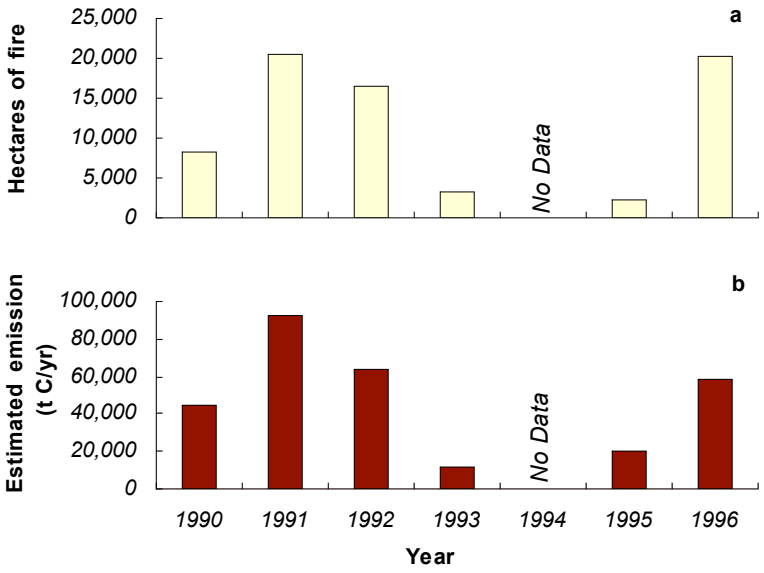


Figure 2-4-4
Area impacted by fire and estimated emissions from fire across the study period

Fifty-five percent of the area burned and 44 % of the emissions from fire occurred on private land (Table 2-4-8).

Table 2-4-8
Area burned and carbon emissions by ownership across the analysis period

OWNERSHIP	Area burned (ha)	Emissions (t C)
City or Municipal Government	3	16
County Government	4	26
Private	31,712	128,700
State Government	5,731	27,748
Tribal	22,035	67,772
US Federal	11,356	67,629

Emissions from fire occurred throughout Washington State. However the areas burned were lowest in the developed Northwest and non-forested Southeast (Figure 2-4-5, Table 2-4-9). The largest areas burned and the greatest quantity of emissions were in the North and Northeast, for example Okanogan had 17,000 hectares of fire during the study period, which caused an estimated emission of 35,600 tons of carbon (Figure 2-4-6, Table 2-4-9).

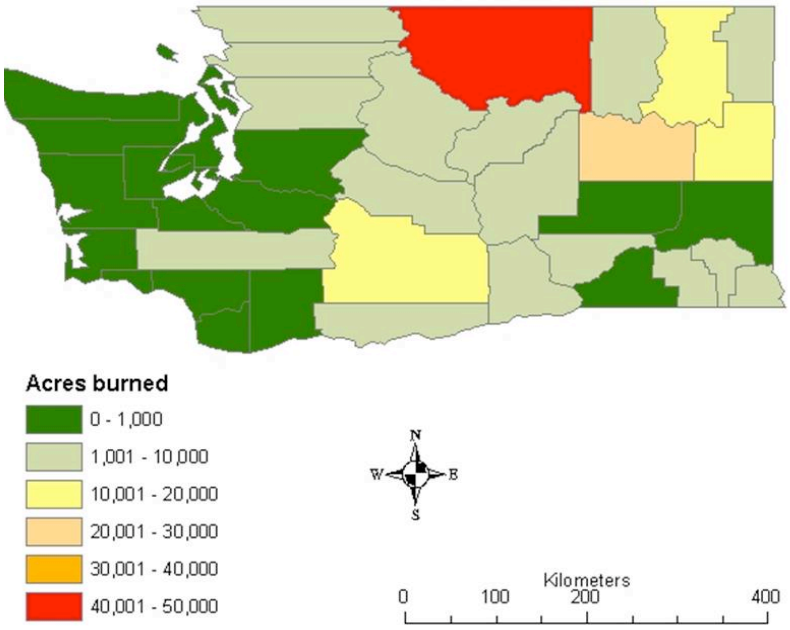


Figure 2-4-5
Area burned (in acres), at the county level, between 1990 and 1996 (excluding 1994)

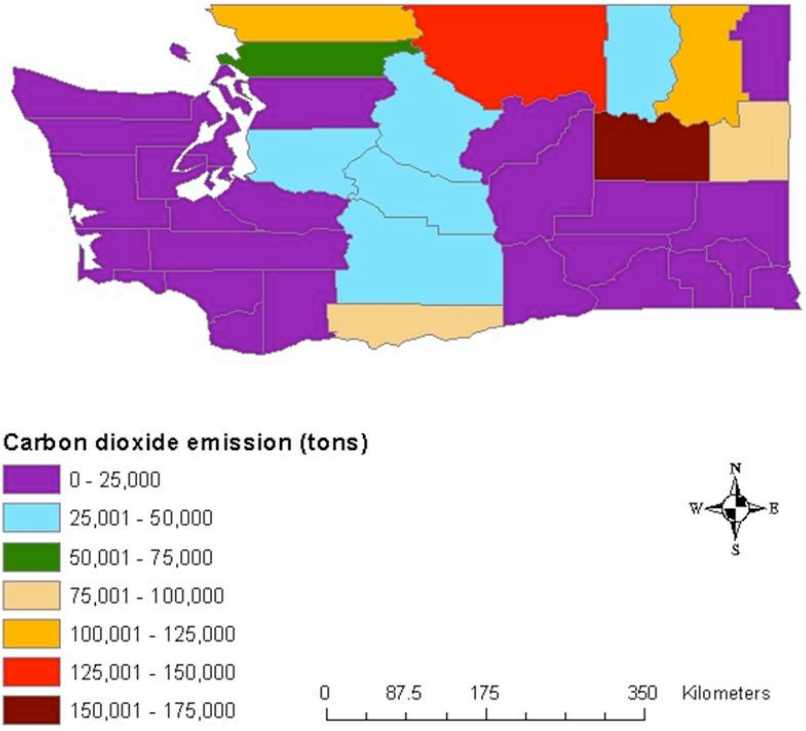


Figure 2-4-6
Metric tons of carbon dioxide emitted, at the county level, between 1990 and 1996 (excluding 1994)

Table 2-4-9
Area burned and carbon emissions per county across the analysis period

COUNTY	County Area (ha)	Area burned (ha)	Emissions (t C)
Adams	498,563	275	239
Asotin	164,553	584	1,102
Benton	441,099	1,542	1,924
Chelan	756,631	3,829	10,976
Clallam	450,516	190	4,454
Clark	162,709	71	536
Columbia	225,022	794	1,480
Cowlitz	294,907	91	635
Douglas	471,514	686	1,245
Ferry	570,829	1,426	10,877
Franklin	321,781	2,714	821
Garfield	184,031	596	306
Grant	694,392	1,141	1,439
Grays	496,471	169	2,331
Island	53,984	30	237
Jefferson	469,883	50	1,226
King	550,643	296	7,016
Kitsap	102,557	20	556
Kittitas	594,969	2,695	7,049
Klickitat	484,943	3,846	24,584
Lewis	623,575	513	4,502
Lincoln	598,599	9,320	42,460
Mason	248,913	207	4,387
Okanogan	1,364,423	16,981	35,610
Pacific	241,638	236	1,802
Pend Oreille	362,668	554	3,110
Pierce	434,837	48	744
San Juan	45,305	1	15
Skagit	449,399	641	17,435
Skamania	429,015	199	1,463
Snohomish	541,065	539	4,978
Spokane	456,780	6,924	25,134
Stevens	641,877	4,832	31,175
Thurston	188,298	141	1,804
Wahkiakum	68,438	1	4
Walla Walla	329,059	12	96
Whatcom	548,957	1,758	29,309
Whitman	559,275	1	0
Yakima	1,112,718	6,886	8,829

2.4.4 Uncertainties

The carbon stocks to which percentage emission factors are applied are averaged values across all FIA plots in a forest type / region combination. Consequently, the same average value is used to represent forests with very high carbon stocks or very low carbon stocks. Fires will occur in forests regardless of starting carbon stock, yet it is possible that the forests with the very lowest carbon stocks (for example in the year immediately after clear cut logging) may not have enough biomass to sustain a fire. The emissions reported here may therefore be a small *overestimate* for if the very lowest biomass plots are excluded from the FIA analysis the mean will be raised and consequently the estimated emissions.

The calculated emissions presented here are conservatively limited to just aboveground tree biomass and therefore represent an *underestimation* of total emissions. Carbon stored in other pools will combust and be emitted through fire. However, we have no detailed source that will link the region and forest type-specific FIA data on aboveground tree biomass with similar data on other carbon pools.

Fire will directly impact dead wood, litter, shrubs and herbs (though even these pools may not be completely volatilized in low severity fires (e.g. Skinner 2002)). The influence of fire on soil carbon or the carbon stored in roots is less clear. When a tree is killed, the roots will not be burned but will become dead material that will decompose at a rate that is not well understood. A very intense fire will impact soil carbon though it is not fully understood what proportion of soil carbon is volatilized nor what depth the impact penetrates to.

To give an indication of the scale of potential additional emissions for pools not included here, the literature was consulted. Smithwick et al. (2002) took measurements of all carbon pools across 43 stands at seven sites in Washington and Oregon. The authors divided their measurements into three regions – Coastal, Cascades and Eastern. No measurements were taken in Eastern Washington so the results from Eastern Oregon are presented here. Values for roots were not taken from Smithwick et al. (2002); roots were estimated more directly by using the temperate forest allometric equation of Cairns et al. (1997), which calculates belowground biomass from aboveground biomass. The amount of additional biomass carbon as a percentage of aboveground live tree biomass carbon stocks is given in Table 2-4-10.

Table 2-4-10
Relative increase in stocks that would result from adding each of the additional carbon pools to live aboveground trees

	Litter	Dead Wood	Shrubs	Herbs	Roots	Soil Carbon
Coastal	6 %	26 %	0.12 %	0.12 %	23-25 %	54 %
Cascades	8 %	26 %	0.25 %	0.07 %	25-26 %	31 %
Eastern	22 %	23 %	0.38 %	0.09 %	24-26 %	43 %

The measurements of Smithwick et al (2002) were in old growth forests. In younger forests lower absolute amounts of dead wood might be expected together with similar quantities of litter, shrubs and herbs. Therefore a lower proportion of dead wood and a higher proportion of litter, shrubs and herbs might be expected in younger forests.

Here, as an indication of potential additions, the values of Smithwick et al. (2002) are used. Adding just litter, dead wood, shrubs and herbs, and assuming that the same proportion of these pools are volatilized as for live aboveground trees, gives an additional emission over the study period equal to 41,253 tons of carbon or an additional 7.4 %.

2.4.5 Conclusions

Across the six years analyzed[4], fires with a total area of 70,800 hectares (0.175 million acres) were recorded. This is equivalent to an average 11,800 hectares per year (29,200 ac/yr) for the period studied. Emissions totaling 0.29 million tons of carbon or 1.07 $MMTCO_2e$ were estimated to have occurred from fire during the analysis period. On an averaged annual basis this is equal to 48,600 tons of carbon per year (0.18 $MMTCO_2e/yr$).

Thirty-three percent of the burnt area and 87 % of the emissions were in forest as opposed to rangeland. No one year dominated fire incidence. Fifty-five percent of area burned and 44 % of the emissions were from private land. Fires covered a greater extent and caused more emissions in the North and Northeast of the State. Incidence was low in the Southeast and Northwest.

Compared to total emissions for the state as a whole, 101 $MMTCO_2e/yr$ for the year 1995, the average annual emissions from fire of 0.18 $MMTCO_2e$ represented more than 0.2 % of the total in the state.

Due to data limitations 1994 was excluded from the analysis. This is unfortunate because across both State and Federal reporting of burned areas in Washington, 1994 represented a burned area that was more than 5 times greater than the long term average (1970-2003 for State reporting, 1986-1996 for Federal reporting). However, even excluding 1994 the mean area burned per year was no different between 1990 and 1996 than in the previous or the succeeding seven year periods, indicating that 1994 represented an unusually devastating fire year. Including 1994 would have undoubtedly significantly raised the calculated emissions caused by fire during the study period.

[4] 1994 was excluded due to poor image quality.

Chapter 3 – Baselines for Agricultural Lands in Washington

3.1 General Approach

The goal of this chapter is to quantify the baseline of changes in carbon stocks in the Washington agricultural sector for the decade of the 1990s. Baselines provide an estimate of the emissions and removals of greenhouse gases caused by changes in the use and management of land. The focus of this paper is on emissions and removals of carbon dioxide and not on non-CO_2 greenhouse gases. Baselines are useful for identifying where, within the landscape of a state, opportunities exist for enhancing carbon stocks and/or reducing carbon sources to mitigate greenhouse gas emissions.

The baseline for the agricultural sector depends on two types of data: (1) the total area of agricultural land, and area of each of the major agricultural land-use types, through time; (2) the carbon stocks in each land-use type. Areas and changes in area of agricultural lands are based primarily on the National Resource Inventory (NRI) database for the period 1987-1997. Carbon stock estimates for various agricultural land-use types were derived from consultation with experts in local universities and from the literature in combination with standard methods. The analysis is conducted for the entire state of Washington at the county scale of resolution.

3.1.1 Classification of Agricultural Land

In this study, NRI data were used for estimates of area because of the NRI's relative strength in agricultural surveys compared with other sources of data. The coverage of NRI data is wider and is available across the states for multiple points in time and for multiple classes of agriculture.

In this analysis, agricultural land is equated to cropland as defined in the NRI (NRCS 2000). The NRI recognizes two categories of cropland: cultivated and non-cultivated. Cultivated cropland includes small grains and row crops, hay and pasture with cropping history, and horticulture with double cropping (meaning horticulture with crops planted under the trees). Non-cultivated cropland includes horticulture without double cropping, and hay without cropping history. Grazing lands are included under the analyses of rangelands in Chapter 2.

The distinction between cultivated and non-cultivated crops is not useful for the purpose of (aboveground) carbon analysis, which depends instead on biomass models based on the growth form of the vegetation. Therefore, the specific land-use categories from NRI were regrouped for this analysis into categories related to the growth form of the crop. All horticulture lands, with or without double cropping, were reclassified as woody cropland. The rest of the croplands, including hay, row crops and small grains, were considered to be non-woody crops (Table 3-1).

Table 3-1
NRI Categories and Subcategories in Washington

Broad classification	Detailed classification	NRI classification
INCLUDED AS AGRICULTURE IN THIS CHAPTER		
Perennial woody crops	Fruit orchards	Fruit orchards
	Nut orchards	Nut orchards
	Vineyards	Vineyards

	Berry crops Other horticulture	Berry crops Other horticulture
Annual non-woody crops	Row / close crops	Row/Corn Row/Sorghum Row/Soybeans Row/Cotton Row/Peanuts Row/Tobacco Row/Sugar beets Row/Potatoes Row/Other veg/truck crops Row/All other row crops Row/Sunflower Close/Wheat Close/Oats Close/Rice Close/Barley Close/All other close grown Hay/Grass Hay/Legume Hay/Legume-grass Other crop/Summer fallow Other crop/Aquaculture Other crop/Other-set-aside etc.
FOCUS OF CHAPTER 2		
Pasture / rangeland	Pasture / rangeland	Pasture/Grass Pasture/Legume Pasture/Grass-forbs-legumes Rangeland
Forest	Forest	Forestland/Grazed Forestland/Not grazed
OTHER CATEGORIES		
Urban / transportation	Urban / transportation	Urban/10 acres or larger Urban/Small built-up Transportation
Other	Other	Other farmland/Farmsteads Other farmland/Other land Other farmland/CRP land Barren/Salt flats Barren/Bare exposed rock Barren/Strip mines Barren/Beaches Barren/Sand dunes Barren/Mixed barren lands Barren/Mud flats

		Barren/Oil wasteland
		Barren/Other barren land
		Other rural/Permanent snow-ice
		Other rural/Marshland
		All other land
		Water/Body 2-40 acres
		Water/Body less than 2 acres
		Water/Streams per. < 66 ft. wide
		Water/Streams per. 66-660 ft. wide
		Water/Large

3.1.2 Limitations of the NRI Database

Despite the general acceptance of NRI for agricultural resource analysis, it is important to note its limitations. First, the samples were taken from non-federal lands only, while in the West Coast states, federal lands occupy half or more of the total land area. Second, the data are not from a complete census, but rather from a statistically sound sampling design. Finally, the NRI's classification of land cover/land use types may not be consistent with other classification schemes commonly used in land cover/land use analysis, e.g. the classification in USGS National Land Cover Classification system.

For the purposes of this chapter of the paper, however, these limitations have virtually no effect on the analysis as the data are only being used for the agricultural sector, where lands are privately owned, easy to classify, and statistically well reported.

The NRI reports a margin of error for the 1997 reporting (equivalent to a 95% confidence interval) of ±9% for its sampling of areas of cropland.

3.1.3 Area and Change in Area of Agricultural Land

The NRI data for each state were reclassified into the broad classes shown in Table 3-1. The areas for each class for 1987 and 1997 were then calculated. Although data for 1992 were available, a similar analysis for California where the change over two 5-year periods was included (1987-1992 and 1992-1997) indicated that using two periods did not appear to add any further insights into the dynamics of land-use and carbon stock change (Brown et al. 2004). Thus we only examine the change over the 10-year period 1987 to 1997.

3.1.4 Carbon Density of Agricultural Land

The baseline analysis for the agricultural sector focuses on carbon in vegetation only, including above- and belowground (roots) components. Carbon in vegetation is estimated as 50% of the biomass of the vegetation.

CARBON STOCKS FOR NON-WOODY AND WOODY CROPS

A difficulty in estimating the biomass of non-woody annual crops is caused by the seasonal change of the vegetation. During the non-growing season, there is little biomass in annual crops, while at the peak of the growing season just before harvest, biomass can be high. Considering that litter production is usually low in these crops, peak biomass is assumed to be equivalent to the annual primary

production of the crops on the land. In many cases the majority of the biomass (or production) is removed from the field at harvest. An approximate temporal average of the biomass was used to derive the carbon stock. The biomass in cultivated non-woody crops was estimated based on three sources of data: crop biomass from the U.S. Department of Agriculture – National Agriculture Statistics Service (USDA NASS, see http://www.usda.gov/nass/sso-rpts.htm), length and timing of harvest cycles, and the relative abundance of each crop type.

Carbon stocks of horticultural crops have less seasonal variation, but data on carbon stocks for these crops are scarce. Yield data from the USDA NASS represents only the biomass of the harvest – a useful estimate of peak biomass for non-woody crops, but only a small portion of the standing biomass for woody crops. Thus estimates were instead derived from consultation with extension agents, university researchers and government officials in combination with literature searches, principally to determine typical stocking densities (number of trees per unit area), tree diameters and tree heights. Biomass can then be estimated from tree diameter and height using a regression equation (Winrock unpublished). The stocking densities were combined with estimates of biomass per plant to arrive at an estimate of biomass carbon density in metric t C/ha. For fruit orchards and bush fruits, multiple crop types were included and the relative abundance of each crop type in the state, derived from USDA NASS, determined the area-weighted mean carbon stock that was used in this analysis (Table 3-2).

Table 3-2
Estimates of the average carbon stock (t C/ha) for each of the crop types in WA

Crop type	Average C stock (t C/ha)
Fruit orchards	24.3
Nut orchards	36.1
Vineyards	4.3
Bush fruits	3.4
Berry fruits	1.8
Other horticulture	4.5
Non-woody crops	1.5

Soil carbon stocks are not included in this paper because we assume that most agricultural land has been under cultivation long enough that changes in soil carbon would be minimal to non-existent under current practices. The stability of soil carbon on cultivated land was confirmed by the study of DeClerck and Singer (2003), who showed that the percent change in soil carbon under row crops in CA remained constant over an approximate period of 50 years. Interestingly, DeClerck and Singer also found the same trend for tree crops, but an increase in soil carbon over the past 50 years for soils under viticulture (about a 1.7-fold increase) and pasture (about a 1.6-fold increase). These results are difficult to apply in baseline determination because the results were reported as an increase in percent carbon with no indication of changes in soil bulk density; calculating changes in carbon stocks requires not only the change in percent carbon but also the change in soil bulk density.

Estimates of the carbon stocks in non-agricultural lands (e.g., urban/transportation, and all the other class) are assumed to be zero. This assumption is probably reasonable for "other" as this contains mostly barren lands, but for urban/transportation there is likely to be more carbon than in non-woody croplands. Urban development often contains significantly more (but unknown) amount of biomass in trees and shrubs that homeowners and local municipalities plant than in the agricultural lands that they replace. This is an area of further research—estimating the amount of carbon in biomass of urban areas as a function of density, etc.

CHANGE IN STOCKS

When a change in agricultural land use occurred it was assumed in this analysis that the entire carbon stocks in vegetation present before the change would be emitted into the atmosphere as carbon dioxide. This is a reasonable assumption given the necessity to clear the land in order to plant alternative crops or initiate urban development.

For changes in land use to agricultural crops it is assumed that the change occurred at the midpoint of the period under analysis (in 1992), five years before 1997 and five years after 1987. For non-woody crops such as vineyards, bush and berry crops, and other horticulture crops, it is reasonable to assume that in five years, these crop types will have reached their predicted steady-state biomass. The same assumption cannot be applied to orchards, which will take longer than five years to attain their maximal biomass. Instead, the biomass accumulation that might have occurred in five years of growth for fruit and nut orchards respectively was estimated based on conservative estimations of stocking density, tree heights and diameters at five years age (Table 3-3).

Table 3-3
The estimated average biomass carbon accumulation after five years of growth for fruit and nut orchards in WA (t C/ha)

	Average biomass carbon accumulation
Fruit orchards	1.6
Nut orchards	1.8

In addition, it can be expected that fruit orchards and nut orchards will continue to accumulate biomass for many years. We therefore applied an average biomass accumulation to areas of orchards that remained constant over the ten years of the analysis. The rate of biomass accumulation was determined by estimating the stocks at years 40 and 60 and dividing the difference by 20 to get an annual accumulation. The annual accumulation was multiplied by 10 to give an accumulation for the ten years 1987 to 1997 (Table 3-4).

Table 3-4
The estimated average biomass carbon accumulation over 10 years of growth for fruit and nut orchards in WA (t C/ha). This growth rate is for existing orchards, i.e. for areas unaffected by land-use change

	Average biomass carbon accumulation
Fruit orchards	3.4
Nut orchards	5.6

3.1.5 Uncertainty

UNCERTAINTY IN NRI DATA

The estimated margin of error (95 % confidence interval) for the area of cultivated cropland in 1997 is 6.5 % for Washington (NRCS 2000). For areas presented at finer scales (county level, specific crop) or for changes in area, the margin of error will be significantly higher.

UNCERTAINTY IN CARBON STOCK DATA

To evaluate the confidence in the estimated carbon stocks, ranges were determined (Table 3-5) based on the ranges in diameter, height, biomass and planting density provided by the sources consulted as described in section 3.1.4.

Table 3-5
Estimated ranges in average carbon stocks for each crop type WA (t C/ha)

Crop type	Range in C stocks (t C/ha)
Fruit orchards	9.5-35.8
Nut orchards	17.8-69.
Vineyards	2.4-6.7
Bush fruits	2.7-4.1
Berry fruits	1.4-2.2
Other	3.4-5.7
Non-woody	1.0-2.0

Weighting the deviations from the mean by area and carbon stock gave a mean deviation value for carbon stocks of 42 %.

3.2 Results

3.2.1 Statewide Land Use and Land Use Change 1987-1997

The total area of Washington is 18.47 million ha, of which 70% is covered by the NRI and the remainder is federal land falling outside the scope of the NRI.

In 1997 agricultural land in Washington, including both perennial woody and annual non-woody lands, was estimated as 2,690,564 ha or 14.6 % of the total land area of the state. The area of woody cropland was 6.1 % of the total area under agricultural cultivation (Figure 3-1).

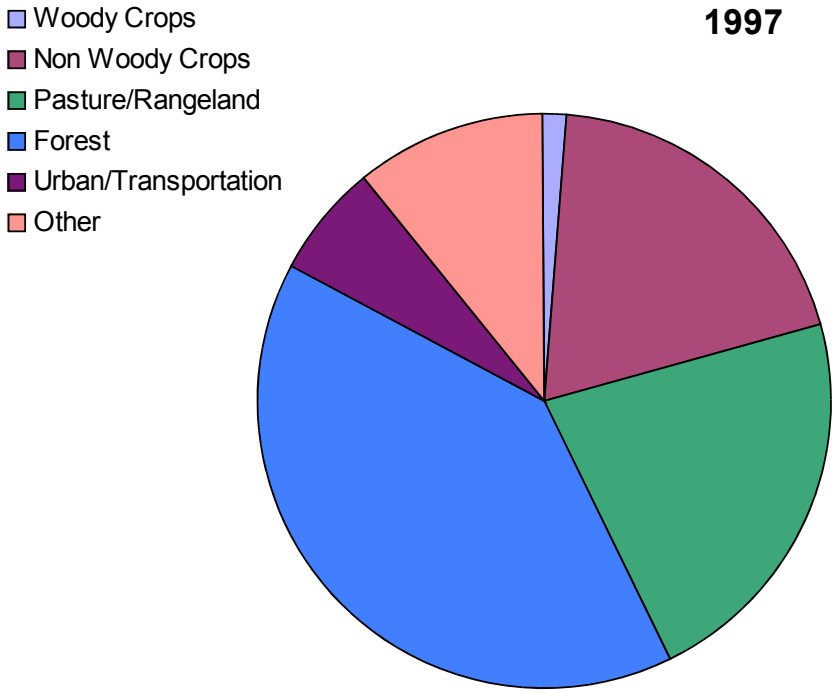


Figure 3-1
Proportional area for land-uses in Washington in 1997, based on NRI data (non-federal lands only)

Table 3-6
Areas (ha) and changes in areas (ha) for land use types in Washington from the NRI dataset

	1987	1997	Change	% Change
Woody crops				
Fruit orchards	82,356	97,371	15,015	+18.2
Nut orchards	728	728	0	0.0
Vineyards	14,084	33,266	19,182	+136.2
Bush crops	850	1,942	1,092	+128.5
Berry crops	2,347	2,144	-203	-8.6
Other horticulture	19,506	28,248	8,742	+44.8
Total woody crops	119,871	163,699	43,828	+36.6
Non-woody crops				
Row / Close crops	2,805,179	2,526,865	-278,314	-9.9
Other land uses				
Pasture/Rangeland	2,978,066	2,856,332	-121,734	-4.1
Forest	5,270,408	5,194,122	-76,286	-1.4
Urban/Transportation	653,064	835,705	182,641	+28.0
				+21.4

TOTAL	12,995,685	12,995,685	

Overall, agricultural land in Washington experienced a 8.0 %(234,486 ha) loss in area during the 10-year period from 1987-1997. However, this loss included a 9.9 % loss in area of non-woody crops and a 36.6 % increase in area of woody crops. Over the same period there were small decreases in the area of pasture/rangeland (4.1%) and forest (1.4%) and increases in the area of urban/transportation (28 %) and the Other category (21.4 %) (Table 3-6, Figure 3-2).

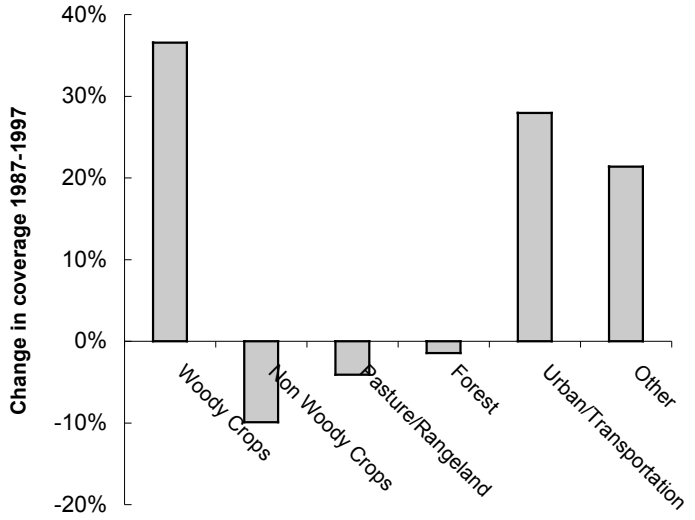


Figure 3-2
Proportional change in area between 1987 and 1997 for broad land uses in Washington

3.2.2 Changes in Specific Land-use Type

Agricultural area in Washington is dominated by non-woody crop types (94 %; Figure 3-3). Among the woody crops, fruit orchards make up 60 %, nut orchards < 1 %, vineyards 20 %, bush crops 1 %, berry crops 1 % and other 17%.

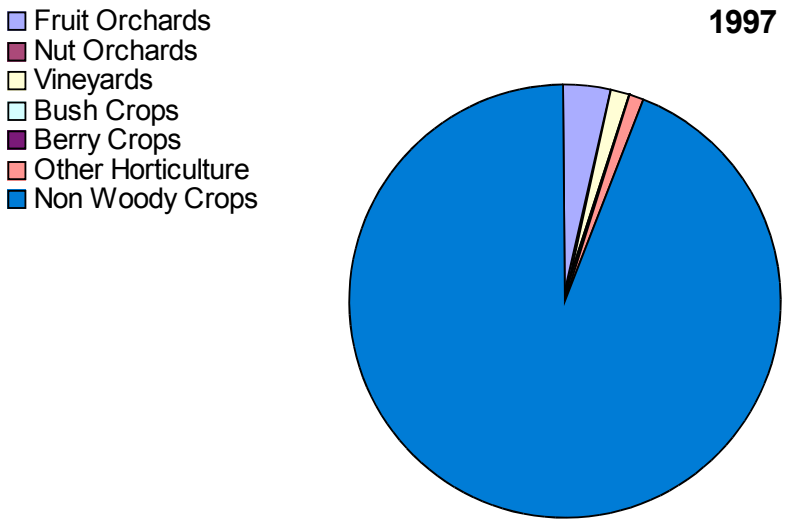


Figure 3-3
Proportional coverage of each agricultural land-use in Washington in 1997

The 36.6 % gain in area of woody crops between 1987 and 1997 was composed of an 18 % increase in fruit orchards (15,015 ha), a 136 % increase in vineyards (19,182 ha), a 129 % increase in berry crops (1,092 ha) and a 45% increase in other horticulture (8,742 ha). A small portion of this gain was offset by a 9 % loss in bush crops (203 ha) (Table 3-7, Figure 3-4).

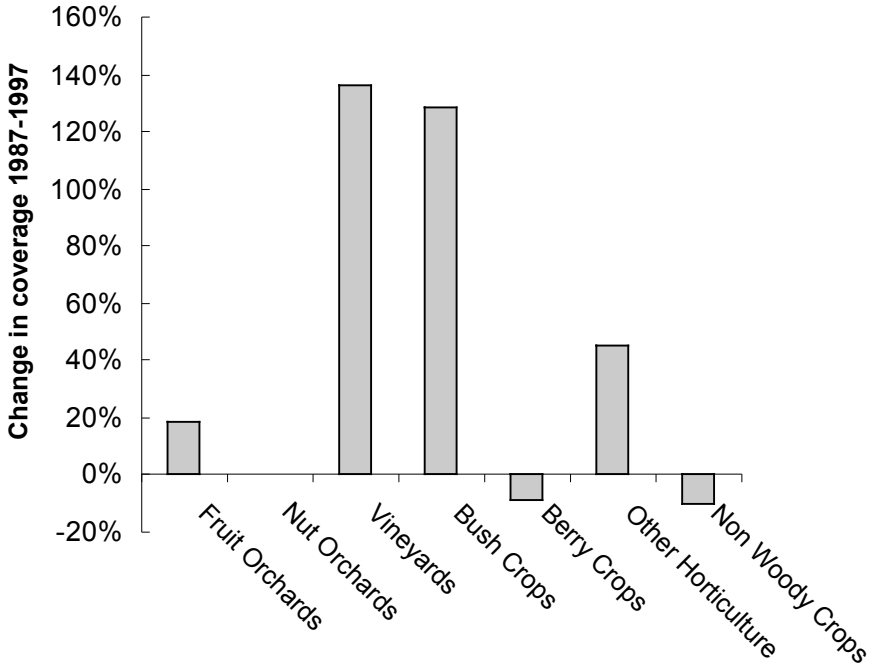


Figure 3-4
Proportional change in area between 1987 and 1997 for agricultural land uses in Washington

Between 1987 and 1997 large net losses to development occurred including 26,750 ha from non-woody crops, 47,350 ha from pasture/rangeland and 98,099 ha from forest. Forest regrowth occurred on 18,576 ha of pasture/rangeland. A large area, almost 248,000 ha, was converted from non-woody crops to the Other category, including water, marshland, barren land and non-cultivated farmland. It is probable that most of this loss in area simply represents agricultural land taken out of cultivation.

The large gains in vineyards were at the expense of non-woody crops (11,412 ha), other horticulture (3,319 ha), fruit orchards (1,012 ha) and pasture/rangeland (1,538 ha). The gains in fruit orchards were predominantly at the expense of non-woody crops (11,898 ha) and pasture/rangeland (5,140 ha). (Table 4-2).

Table 3-7

Land-use change transition matrix, showing the source and direction of changes in Washington 1987-1997. The area unchanged between the time periods is listed at left, then the net gain and loss from the land uses listed in the rows to the land uses listed in the columns. A negative sign indicates a net loss of area from the land use in the row to the land use in the column

		Change to (-) / Change from (+)										
	Unchanged	Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture	Non-Woody Crops	Rangeland	Forest	Urban / Transport-ation	Other	TOTAL CHANGE
Fruit Orchards	76,367			-1,012			445	11,898	5,140		-2,307	850	15,014
Nut Orchards	728												0
Vineyards	11,858	1,012					3,319	11,412	1,538		40	1,862	19,183
Bush Crops	850							1,093					1,093
Berry Crops	1,336							242	-445				-203
Other Horticulture	11,655	-445		-3,319				10,198	971		-81	1,416	8,740
Non-Woody Crops	2,393,517	-11,898		-11,412	-1,093	-242	-10,198		34,561	-3,440	-26,750	-247,838	-278,310
Rangeland	2,741,155	-5,140		-1,538		445	-971	-34,561		-18,576	-47,350	-14,043	-121,734
Forest	5,139,730							3,440	18,576		-98,099	-202	-76,285

3.2.3 County Level Estimate of Agricultural Land Area

NRI data is not designed for use at the county-level, results are given here for illustrative purposes. Figure 3-5 shows the counties of Washington. Although woody cropland is broadly distributed across counties, only one county (Yakima) has more than 2% of its total land area in this land use type (Figure 3-5a). The greatest areas of non-woody cropland are concentrated in Washington's southeastern counties, with 14 counties in which non-woody cropland exceeds 5% of the total land area and 9 in which it exceeds 30% (Douglas, Grant, Lincoln, Adams, Franklin, Whitman, Walla Walla, Columbia and Garfield) (Figure 3-5b).

Multiple counties recorded slight increases in area of woody cropland between 1987 and 1997, but only three counties had more than a 500 ha increase and only one (Yakima) more than a 1,000 ha increase (Figure 3-6a). Most of these increases were due to installation of vineyards and other horticulture (Table 3-8). Four counties lost woody cropland over the period (Challam, Skamania, Chelan and Pierce).

Six counties experienced slight gains in area on non-woody crops. Most counties experienced slight losses; six lost more than 4,000 ha and four (Yakima, Benton, Franklin and Adams) lost more than 15,000 ha of non-woody cropland (Figure 3-6b).

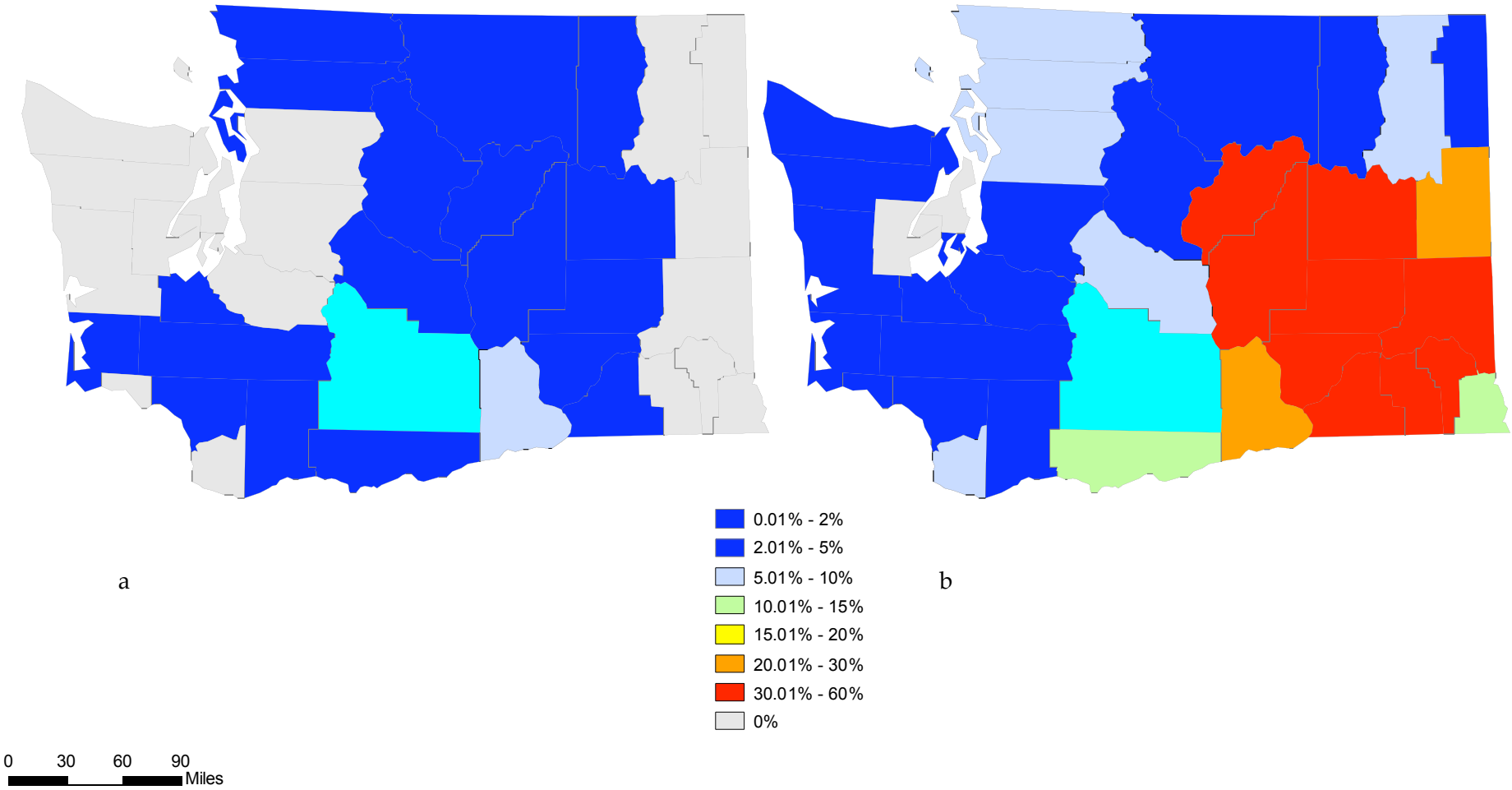


Figure 3-5
Distribution of woody (a) and non-woody (b) cropland by county in Washington in 1997. Values indicate the percentage of total land area in each county occupied by agricultural land

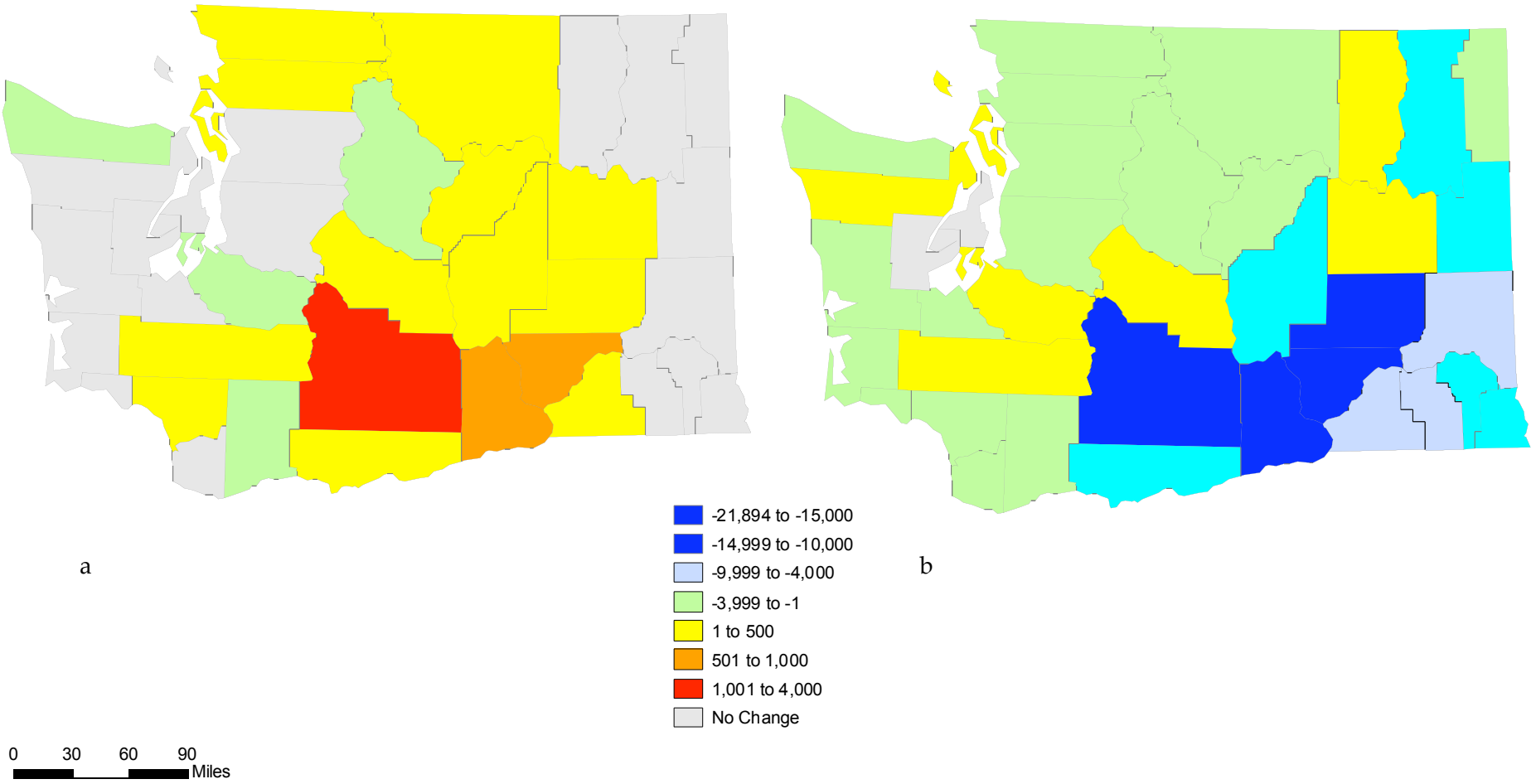


Figure 3-6
Distribution of change in area in woody (a) and non-woody (b) cropland in Washington by county. Values indicate change in hectares; minus sign indicates a loss in area from 1987 to 1997 and plus sign indicates a gain in area in the same period

Table 3-8
The county level coverage (ha) for specific agricultural land uses and the change in coverage in Washington 1987 to 1997

	High Carbon Crops												Low Carbon Crops			
	Fruit Orchards		Nut Orchards		Vineyards		Bush Crops		Berry Crops		Other Horticulture		Row / Close crops		TOTAL	
	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997
Adams	0	648											315,868	262,043	315,868	262,691
Asotin													27,762	21,287	27,762	21,287
Benton	4,249	5,544			6,435	14,286					809	1,497	168,396	133,713	179,889	155,040
Chelan	8,458	7,608											971	890	9,429	8,498
Clallan											283	0	2,833	2,185	3,116	2,185
Clark													13,557	8,742	13,557	8,742
Columbia													90,774	74,748	90,774	74,748
Cowlitz											0	81	3,845	2,833	3,845	2,914
Douglas	8,661	10,118			162	0					445	0	172,078	170,419	181,346	180,537
Ferry	162	162											8,094	9,106	8,256	9,268
Franklin	1,457	5,909			0	809							169,367	137,153	170,824	143,871
Garfield													73,777	64,266	73,777	64,266
Grant	4,007	6,718											300,894	291,101	304,901	297,819
Grays Harbor													7,568	7,123	7,568	7,123

	High Carbon Crops												Low Carbon Crops			
	Fruit Orchards		Nut Orchards		Vineyards		Bush Crops		Berry Crops		Other Horticulture		Row / Close crops		TOTAL	
	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997
Island							0	121					1,781	2,792	1,781	2,913
Jefferson													0	324	0	324
King													4,978	2,792	4,978	2,792
Kitsap															0	0
Kittitas	3,197	3,440											26,751	29,462	29,948	32,902
Klickitat	1,376	2,104											80,940	75,557	82,316	77,661
Lewis											0	890	9,349	10,563	9,349	11,453
Lincoln											1,902	3,602	306,803	307,936	308,705	311,538
Mason															0	0
Okanogan	10,198	14,367											17,483	17,443	27,681	31,810
Pacific									445	445			202	162	647	607
Pend Oreille													6,435	5,990	6,435	5,990
Pierce									243	0			2,550	5,261	2,793	5,261
San Juan													0	445	0	445
Skagit									890	890	405	850	23,230	22,056	24,525	23,796
Skamania	364	81											648	607	1,012	688
Snohomis													17,524	14,650	17,524	14,650

	High Carbon Crops												Low Carbon Crops			
	Fruit Orchards		Nut Orchards		Vineyards		Bush Crops		Berry Crops		Other Horticulture		Row / Close crops		TOTAL	
	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997	1987	1997
h																
Spokane													158,400	145,975	158,400	145,975
Stevens													25,010	17,078	25,010	17,078
Thurston							526	526					4,775	3,804	5,301	4,330
Wahkiakum													648	162	648	162
Walla Walla	0	1,376			1,821	1,821							222,018	197,089	223,839	200,286
Whatcom			728	728			324	1,295	769	809			20,802	16,350	22,623	19,182
Whitman													383,210	366,011	383,210	366,011
Yakima	40,227	39,296			5,666	16,350					15,662	21,328	135,858	98,747	197,413	175,721
TOTAL	82,356	97,371	728	728	14,084	33,266	850	1,942	2,347	2,144	19,506	28,248	2,805,179	2,526,865	2,925,050	2,690,564

3.2.4 Change in Carbon Stock of Agricultural Land During 1987-1997

Conversion of agricultural lands to other land uses was responsible for a net loss of carbon equal to 140,500 t C over the ten years 1987-97. This net loss included a loss in area and consequently of carbon in non-woody cropland of 417,500 t C, partially counterbalanced by a gain from woody crops equal to 277,000 t C (Table 3-9). These carbon stock changes equate to a decrease in non-woody cropland of 9.9 %, a gain in woody cropland of 12.7 %, and a net loss for all agricultural land of 2.2 %.

Table 3-9
Carbon stocks (t C) and changes in carbon stocks (t C) for land use types in Washington

	1987	1997	Change
Woody crops			
Fruit orchards	2,001,262	2,148,970	147,708
Nut orchards	23,893	27,972	4,079
Vineyards	60,561	143,044	82,483
Bush crops	2,890	6,603	3,713
Berry crops	4,225	3,859	-365
Other horticulture	87,777	127,116	39,339
Total woody crops	2,180,608	2,457,564	276,956
Non-woody crops			
Row / Close crops	4,207,769	3,790,298	-417,471
TOTAL	6,388,376	6,247,861	-140,515

The gains in carbon stocks in woody crops come largely from fruit orchards (147,700 t C), vineyards (82,000 t C) and other horticulture (largely Christmas trees – 39,000 t C). A smaller gain was recorded from nut orchards and bush crops, and a small loss from berry crops (Figure 3-7).

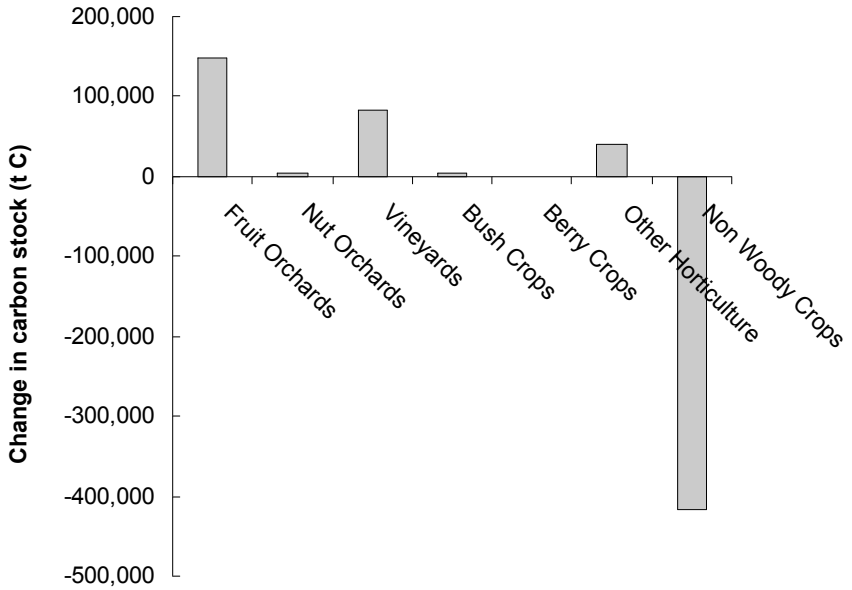


Figure 3-7
Changes in carbon stock (t C) across crop types in Washington between 1987 and 1997

The largest single loss of carbon was from non-woody crops to the Other category (Table 3-10). The Other category includes non-cultivated farmland, so it is likely that this loss of carbon simply represents agricultural land temporarily or permanently taken out of cultivation. Additional large losses occurred between 1987 and 1997 from both woody and non-woody crops to urban development/transportation (98,200 t C). There was a substantial loss from fruit orchards to rangeland, but this was more than balanced by conversion of rangeland to row/close crops. Substantial carbon stocks moved from fruit orchards, vineyards and other horticulture to non-woody crops – a total of 114,000 tons (Table 3-10).

The gross gains in carbon (excluding losses) are dominated by the continued growth of existing stands (88.5 % for fruit orchards, 100 % for nut orchards), as opposed to carbon gained through the planting and initial growth of new orchards. It is assumed that beyond the initial years of growth there is no additional carbon accumulation in the other crop types.

Table 3-10

The land use origins and destinations of changes in carbon stocks in agriculture in WA between 1987 and 1997. The growth of existing stands is listed at left, then the net gain and loss in carbon stocks from the land uses listed in the rows to the land uses listed in the columns. A negative sign indicates a net loss of carbon stocks from the land use in the row to the land use in the column

	Growth of existing stands	Change to (-) / Change from (+)										TOTAL CHANGE
		Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture	Non-woody Crops	Rangeland	Forest	Urban / Transport-ation	Other	
Fruit Orchards	259,648			-28,260			712	19,037	-36,792		-57,892	-8,746	147,707
Nut Orchards	4,079												4,079
Vineyards		4,352					14,272	49,072	6,613		172	8,007	82,487
Bush Crops								3,716					3,716
Berry Crops								436	-801				-365
Other Horticulture		-2,003		-14,936				45,891	4,370		-365	6,372	39,330
Non-Woody Crops		-17,847		-17,118	-1,640	-363	-15,297		51,842	-5,160	-40,125	-371,757	-417,465

When converted to carbon dioxide equivalents the total stocks in 1997 on agricultural land in Washington are estimated at 22.9 $MMtCO_2eq$ (Table 3-11). There was a net loss of 0.5 $MMtCO_2eq$ between 1987 and 1997. This is equal to an annual source of 0.05 $MMtCO_2eq$. Sixty-one percent of the stocks are estimated to be in non-woody vegetation. Non-woody vegetation represented an annual source of 0.15 $MMtCO_2eq$ and woody vegetation represented an annual sink of 0.1 $MMtCO_2eq$.

Table 3-11
Carbon stocks on agricultural land in Washington and their change (million tons of carbon dioxide equivalent ($MMTCO_2e$)

	Agricultural Land	Woody	Non-woody
1987	23.4	8.0	15.4
1997	22.9	9.0	13.9
1987-1997	-0.5	1.0	-1.5

3.2.5 Carbon Stocks of Agricultural Land by County

Seventy-four percent of the counties in Washington had a loss in carbon stocks due to conversion of non-woody cropland between 1987 and 1997 (Table 3-12). For three counties the losses exceed 50,000 t C (Adams, Yakima and Benton). Two counties had no agricultural land at all at either date and eight counties increased their carbon stocks in non-woody crops through land conversion to these crop types.

As for change in carbon stocks on woody cropland, four counties experienced a loss in fruit orchards while 9 counties increased carbon stocks in fruit orchards; the gains greatly exceeded the losses. Changes in vineyards were restricted to three counties with gains in particular in Yakima and Benton counties (46,000 and 34,000 t C respectively). The gain in other horticulture (Christmas trees) of 39,000 t C is dominated by an estimated gain of 25,500 t C in Yakima county.

Figure 3-8a illustrates that the gain in carbon stocks in woody cropland was broadly distributed across counties, with the greatest gains in Okanagan, Douglas, Grant, Benton, Franklin, and Yakima. The greatest loss in carbon from woody crops was in Skamania county. The greatest loss in carbon from conversion of non-woody cropland to other uses came in five counties that lost more than 15,000 t C each (Yakima, Benton, Franklin, Adams and Walla Walla) (Figure 3-8b).

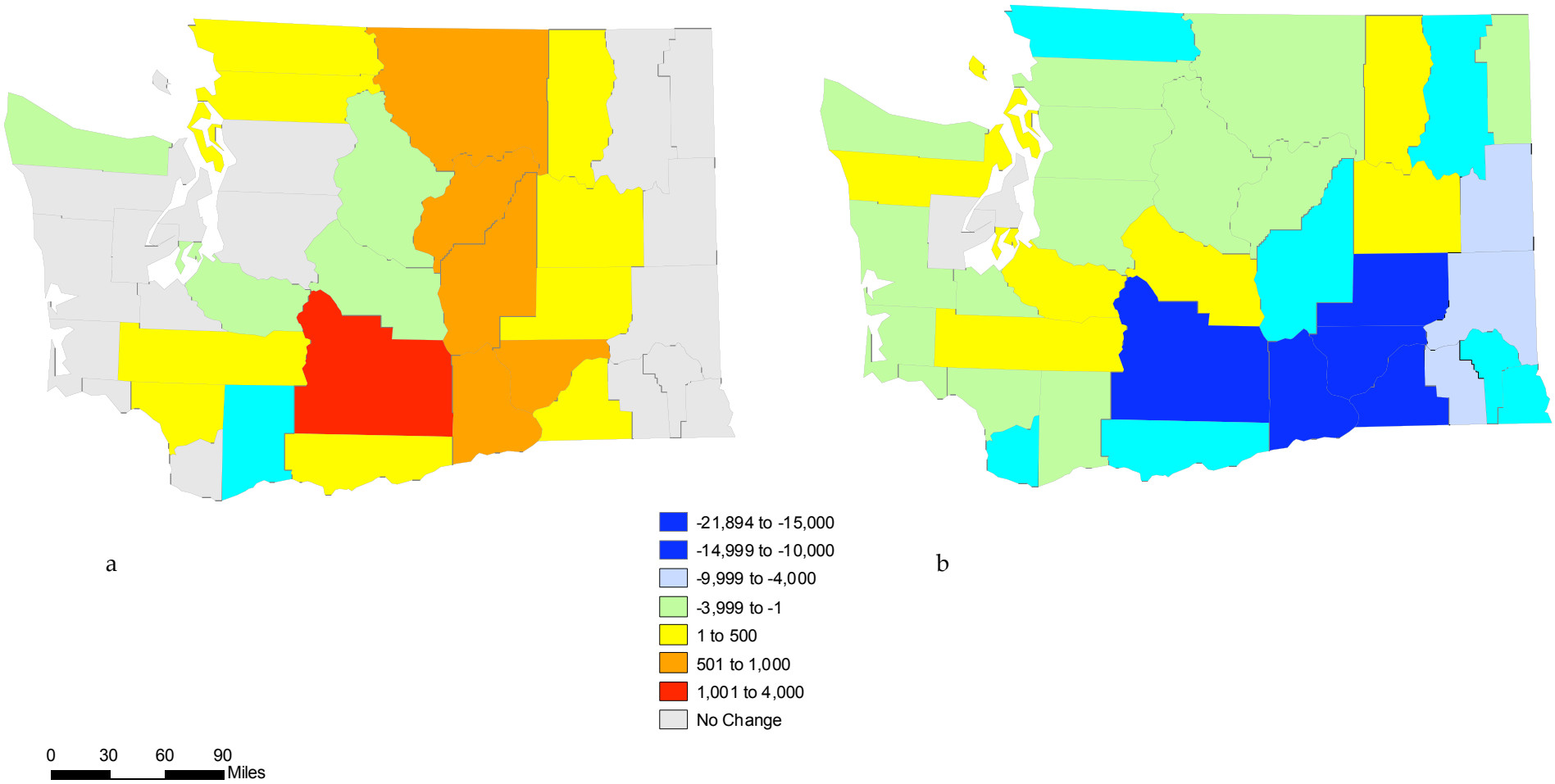


Figure 3-8
county-scale change in carbon stocks, 1987 to 1997, in high-carbon crops (orchards and vineyards, (a)) and in low-carbon crops (non-woody crops, (b)) in Washington. Values in tons of carbon

Table 3-12
Change in carbon stocks (t C) between 1987 and 1997 across crop types in Washington

County	Woody crops						Non-Row / Close	TOTAL
	Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture		
Adams	1,036	0	0	0	0	0	-80,738	-79,702
Asotin	0	0	0	0	0	0	-9,713	-9,713
Benton	-14,112	0	33,759	0	0	3,096	-52,025	-29,281
Chelan	-1,120	0	0	0	0	0	-122	-1,242
Clallan	0	0	0	0	0	-1,274	-972	-2,246
Clark	0	0	0	0	0	0	-7,223	-7,223
Columbia	0	0	0	0	0	0	-24,039	-24,039
Cowlitz	0	0	0	0	0	365	-1,518	-1,154
Douglas	20,157	0	-697	0	0	-2,003	-2,489	14,969
Ferry	550	0	0	0	0	0	1,518	2,068
Franklin	12,077	0	3,479	0	0	0	-48,321	-32,765
Garfield	0	0	0	0	0	0	-14,267	-14,267
Grant	17,960	0	0	0	0	0	-14,690	3,271
Grays Harbor	0	0	0	0	0	0	-668	-668
Island	0	0	0	411	0	0	1,517	1,928
Jefferson	0	0	0	0	0	0	486	486
King	0	0	0	0	0	0	-3,279	-3,279
Kitsap	0	0	0	0	0	0	0	0
Kittitas	-4,585	0	0	0	0	0	4,067	-519
Klickitat	5,844	0	0	0	0	0	-8,075	-2,231
Lewis	0	0	0	0	0	4,005	1,821	5,826
Lincoln	0	0	0	0	0	7,650	1,700	9,350
Mason	0	0	0	0	0	0	0	0
Okanogan	40,288	0	0	0	0	0	-60	40,228
Pacific	0	0	0	0	0	0	-60	-60
Pend Oreille	0	0	0	0	0	0	-668	-668

County	Woody crops						Non-Row / Close	TOTAL
	Fruit Orchards	Nut Orchards	Vineyards	Bush Crops	Berry Crops	Other Horticulture		
Pierce	0	0	0	0	-437	0	4,067	3,629
San Juan	0	0	0	0	0	0	668	668
Skagit	0	0	0	0	0	2,003	-1,761	242
Skamania	-6,609	0	0	0	0	0	-62	-6,671
Snohomish	0	0	0	0	0	0	-4,311	-4,311
Spokane	0	0	0	0	0	0	-18,638	-18,638
Stevens	0	0	0	0	0	0	-11,898	-11,898
Thurston	0	0	0	0	0	0	-1,457	-1,457
Wahkiakum	0	0	0	0	0	0	-729	-729
Walla Walla	2,202	0	0	0	0	0	-37,394	-35,192
Whatcom	0	4,079	0	3,301	72	0	-6,678	774
Whitman	0	0	0	0	0	0	-25,799	-25,799
Yakima	74,020	0	45,941	0	0	25,497	-55,667	89,792
TOTAL	147,708	4,079	82,483	3,713	-365	39,339	-417,471	-140,515

3.3 Non-CO_2 Greenhouse Gas Emissions

The primary non-CO_2 greenhouse gas emitted from croplands is nitrous oxide, with approximately 296 times the global warming potential of CO_2. Nitrous oxide (N_2O) is emitted from agricultural soils especially after fertilizer application.

Kerstetter (2004), writing for the Department of Community, Trade and Economic Development of the State of Washington, reported an N_2O emission for the year 1990 of 4.00 $MMTCO_2eq$ and for the year 1995 of 4.54 $MMTCO_2eq$. This however represents N_2O emissions from all sources, including agriculture, industry, manure and waste. The proportion of the total N_2O emission that would have been attributable to agricultural soil management was estimated from data for Oregon (Governor's Advisory Group 2004). This data showed that in 1990, 77 % of N_2O emissions were from agricultural soil management and in 1995 the proportion was 78 %. This predicts an N_2O emission from agriculture in WA of 3.08 $MMTCO_2eq$ in 1990 and 3.54 $MMTCO_2eq$ in 1995, or an average of 3.3 $MMTCO_2eq$ over a five-year period overlapping with this study. This is about 66 times the estimated CO_2 emissions from agricultural land conversion of 0.05 $MMTCO_2eq$ per year. Stated differently, emissions from N_2O from soil management make up 99 % of the total CO_2eq emissions from agriculture of 3.35 $MMTCO_2eq$ per year.

3.4 Conclusions

Agricultural land in Washington in 1997 represented 14.6% of the total land area. Non-woody crops were about 94% of all agricultural land; fruit orchards constituted 60% of all woody cropland. The greatest areas of non-woody cropland are in the southeastern counties. Although the overall area of woody cropland increased by 37% between 1987 and 1997, due to the greater loss of non-woody cropland to other uses there was an overall loss in agricultural land area of about 234,000 hectares over the period. Most agricultural land area was lost to urban/transportation and the Other category, which gained by 28% and 21% respectively. The 37% increase in woody cropland area was attributable to increases in fruit orchards, vineyards, berry crops, and other horticulture (primarily Christmas trees). The largest losses of non-woody cropland were in Yakima, Benton, Franklin and Adams counties.

Total carbon stocks in all agricultural land in Washington were estimated at 6.2 million tons. Between 1987 and 1997, there was a total loss of about 140,000 tons of carbon, or 2.2% of the carbon stored in agricultural lands in 1987. However, this included an overall increase in carbon stocks in woody croplands of 277,000 tons of carbon (12.7% increase over 1987), exceeded by a decrease in carbon stocks in non-woody croplands of 417,000 tons (9.9% decrease over 1987). In CO_2 equivalent terms, total agricultural carbon stocks in 1997 were 22.9 $MMTCO_2eq$, and the net loss 1987-97 disregarding non-CO_2 greenhouse gas emissions was 0.5 $MMTCO_2eq$, equivalent to an annual source of 0.05 $MMTCO_2eq$. However, because woody croplands increased in area while non-woody croplands decreased, woody croplands represented a net annual carbon sink of 0.1 $MMTCO_2eq$, offset by non-woody croplands as a net annual carbon source of 0.15 $MMTCO_2eq$. At the county level of analysis, 74% of Washington's counties lost carbon stocks between 1987 and 1997 due to conversion of non-woody cropland, with Yakima, Adams and Benton counties losing the greatest number of hectares. The greatest gains in carbon on woody cropland were in Okanagan, Douglas, Grant, Benton, Franklin and Yakima counties, while the greatest losses in carbon on non-woody croplands were in Yakima, Benton, Franklin, Adams and Walla Walla counties.

Non-CO_2 greenhouse gas emissions from N_2O (emitted from agricultural soils after fertilizer application) dwarf the annual CO_2 source from agricultural land conversion in Washington.

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Appendix V, Final Report

An Overview of Geologic Carbon Sequestration Potential in California

CGS Special Report 183

Topical Report

West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

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September 30, 2005

DOE Contract No.: DE-FC26-03NT41984

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Abstract

As part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB), the California Geological Survey (CGS) conducted an assessment of geologic carbon sequestration potential in California. An inventory of sedimentary basins was screened for preliminary suitability for carbon sequestration. Criteria included porous and permeable strata, seals, and depth sufficient for critical state carbon dioxide (CO_2) injection. Of 104 basins inventoried, 27 met the criteria for further assessment. Petrophysical and fluid data from oil and gas reservoirs was used to characterize both saline aquifers and hydrocarbon reservoirs. Where available, well log or geophysical information was used to prepare basin-wide maps showing depth-to-basement and gross sand distribution. California's Cenozoic marine basins were determined to possess the most potential for geologic sequestration. These basins contain thick sedimentary sections, multiple saline aquifers and oil and gas reservoirs, widespread shale seals, and significant petrophysical data from oil and gas operations. Potential sequestration areas include the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins, followed by the smaller Salinas, La Honda, Cuyama, Livermore, Orinda, and Sonoma marine basins. California's terrestrial basins are generally too shallow for carbon sequestration. However, the Salton Trough and several smaller basins may offer opportunities for localized carbon sequestration.

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1 Introduction

As part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB) Phase I effort, the California Department of Conservation, California Geological Survey (CGS) has developed preliminary baseline information concerning geologic options for carbon dioxide (CO_2) sequestration in California. This preliminary screening involved identifying and characterizing porous and permeable rock formations in the numerous sedimentary basins of California and defining areas within these basins that may be geologically suitable for storage of CO_2. This information will be used by other members of WESTCARB in evaluating a variety of potential sequestration options for the WESTCARB region as a whole.

1.1 Background

Over the last several decades, concern has been raised over the potential impacts of anthropogenic greenhouse gasses on global climate (Hansen, 2004). Greenhouse gasses, such as CO_2, trap infrared radiation that would otherwise escape into space and reflect it back to the Earth's surface in a manner similar to how a greenhouse traps infrared radiation that would otherwise be lost to the surrounding environment.

CO_2 is a byproduct of the combustion of fossil fuels such as coal, oil, and natural gas. Its concentration in the atmosphere has been increasing since the Industrial Revolution. The increase in the concentration of CO_2 in the atmosphere is projected to continue as the world's population increases and more countries become industrialized. The United States currently produces about 85% of its commercial energy with fossil fuels (Herzog and Golomb, 2004).

Slowing or reducing anthropogenic CO_2 emissions to the atmosphere will be difficult and it is likely that multiple tactics will be needed to achieve this goal. Possible tactics for slowing or reducing CO_2 emissions include:

- increasing the efficiency of power generation;
- using less carbon-rich fuels such as natural gas in place of oil or coal;
- using alternative energy sources such as solar, wind, or nuclear energy; and,
- carbon sequestration.

Carbon sequestration may play an important role in slowing anthropogenic-made CO_2 emissions to the atmosphere in the near future. Carbon sequestration is the process of collecting CO_2 emissions and isolating them from the atmosphere to prevent buildup of this greenhouse gas and its associated climatic effects. There are two broad categories of sequestration, terrestrial and geologic.

Terrestrial sequestration is achieved when plants absorb CO_2 from the atmosphere during photosynthesis and incorporate the carbon into their structure or transfer it to the soil. Changing the way that forests, rangeland, agricultural lands, and wetlands are managed to either increase the amount of CO_2 removed from the atmosphere and stored as biomass, or decrease the CO_2 emissions from these areas is one way of reducing atmospheric CO_2. Terrestrial sequestration can isolate CO_2 from the atmosphere for decades.

Geologic sequestration involves capturing CO_2 from point sources such as power plants and industrial facilities and storing it in geologic formations. This can be achieved in several ways including injection into depleted or abandoned oil or gas reservoirs or deep saline aquifers; injection into deep, unmineable coal beds; or conversion to carbonate minerals by reaction with ultramafic rocks or serpentinite. Geologic sequestration has the potential to isolate CO_2 from the atmosphere over very long timeframes ranging from hundreds to thousands of years or longer.

1.2 The West Coast Regional Carbon Sequestration Partnership

Myer and Birkinshaw (2005) describe WESTCARB and its goals as follows:

> "The West Coast Regional Carbon Sequestration Partnership is one of seven partnerships that have been established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of the country. The West Coast Region includes Arizona, California, Nevada, Oregon, Washington, and the North Slope of Alaska. Led by the California Energy Commission, West Coast Regional Carbon Sequestration Partnership is a consortium of over 35 organizations, including state natural resource and environmental protection agencies; national laboratories and universities; private companies working on CO_2 capture, transportation, and storage technologies; utilities; oil and gas companies; nonprofit organizations; and policy/governance coordinating organizations. In an 18-month Phase I project, the Partnership will evaluate both terrestrial and geologic sequestration options. Work will focus on five major objectives:
>
> 1. Collect data to characterize major CO_2 point sources, the transportation options, and the terrestrial and geologic sinks in the region, and then compile and organize this data via a geographic information system (GIS) database.
>
> 2. Address key issues affecting deployment of CCS technologies, including storage-site permitting and monitoring, injection regulations, and health and environmental risks.
>
> 3. Conduct public outreach and maintain an open dialogue with stakeholders in CSS technologies through public meetings, joint research, and education work.
>
> 4. Integrate and analyze data and information from the above tasks to develop supply curves and cost-effective, environmentally acceptable sequestration options, both near and long term.
>
> 5. Identify appropriate terrestrial and geologic demonstration projects consistent with the options defined above, and create action plans for their safe and effective implementation."

Additional information on WESTCARB can be found on its web page at http://www.westcarb.org.

2 Executive Summary

As part of the West Coast Regional Carbon Sequestration Partnership, the California Geological Survey (CGS) conducted a preliminary assessment of geologic carbon sequestration potential in California. This involved identifying and characterizing porous and permeable rock formations and defining areas within the state's sedimentary basins that may be geologically suitable for carbon sequestration in saline aquifers or producing or abandoned oil and gas reservoirs. Information was compiled in digital and GIS formats to facilitate spatial analysis and use by other partnership participants.

The CGS identified and cataloged sedimentary basins within California's 11 geomorphic provinces. Inventoried basins included all large or hydrocarbon-producing marine basins, as well as other smaller basins identified from the statewide geologic map of California. The resulting 104 basins were screened to determine preliminary suitability for carbon sequestration. Criteria included the presence of significant porous and permeable strata, seals, and sediment thickness sufficient for critical state carbon dioxide injection. Of the 104 basins, 27 met the criteria for further assessment.

Since saline aquifers have little economic value, no quantitative data is available to measure their capacity for sequestration. To characterize the physical rock and fluid properties of both saline aquifers and hydrocarbon reservoirs, oil and gas field reservoir data was assembled from publications of the California Division of Oil, Gas, and Geothermal Resources and other available sources. Data compiled included location, depth, field area, cumulative production, and depth to base of fresh water. In basins containing oil or gas reservoirs, physical rock and fluid properties for each reservoir unit within each field were compiled. These data included reservoir fluid, zone status, average depth, average thickness, producing area, porosity, permeability, initial pressure and temperature, formation water salinity, seal thickness, trap type, and history of secondary and tertiary recovery efforts. These data were used to characterize rock and fluid properties and evaluated to identify potential saline aquifers and reservoirs for carbon sequestration. Where adequate well bore or geophysical information was available, basin-wide maps showing depth-to-basement and gross sand distribution were prepared to identify promising areas for carbon sequestration.

This preliminary assessment indicates that California's Cenozoic marine sedimentary basins possess the most potential for geologic carbon sequestration. As a group, these basins exhibit a widespread areal distribution, thick sedimentary sections containing multiple widespread saline aquifers and oil and gas reservoirs, thick and laterally persistent shale seals, and an abundance of petrophysical data available through oil and gas development. The most promising basins include the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins. Smaller marine basins, including the Salinas, La Honda, Cuyama, Livermore, Orinda, and Sonoma basins, are also promising but more restricted in terms of size and available geological information. California's terrestrial basins are generally too shallow for carbon sequestration. However, the large Salton Trough and several smaller terrestrial basins may offer some opportunities for localized carbon sequestration and cannot be excluded from consideration given the limited currently available information. Additional geological information and characterization of these basins will be required before their sequestration potential can be more accurately assessed.

3 Experimental

3.1 Scope of Investigation and Project Constraints

The CGS's role in Phase I involved the preliminary screening and inventorying of potential sites for geologic CO_2 sequestration. The goal was to provide baseline geologic data and identify potentially suitable areas for geologic sequestration in California. This involved evaluating the CO_2 sequestration potential of sedimentary rock units within California's many sedimentary basins.

The decision to focus this initial study on the evaluation of California's sedimentary basins was based on the state's geology and the current state of sequestration technology. Currently, three major methods of geologic carbon sequestration are being studied:

- Injection into deep, unmineable coal beds,
- Conversion to carbonate minerals by reaction with ultramafic rocks or serpentinite, and
- Injection of CO_2 into depleted or abandoned oil or gas reservoirs or deep saline aquifers.

While coal has been mined in California in the past, mostly prior to 1900, the state has only scattered coal occurrences. Most are of limited extent and low grade, making them unlikely targets for sequestration.

Ultramafic rock and serpentinite make up approximately 1.4% of the state's area and are most common in the foothills of the Sierra Nevada, the Coast Ranges, and northwestern California. While the processes of converting ultramafic rock or serpentinite to carbonate minerals (mineral carbonation) occur in nature (Hansen and Dipple, 2005) and has been proposed as a means of carbon sequestration (Goff and Lackner, 1998; Eilperin, 2005), a cost effective commercial process for mineral carbonation is still being researched and has yet to be demonstrated.

California has numerous sedimentary basins containing saline aquifers and/or oil or gas fields. An initial evaluation identified 104 sedimentary basins making up approximately 33% of the area of the state. These basins contain 465 oil and gas fields for which varying amounts of subsurface geological and petrophysical information are available to aid in the evaluation of sequestration potential.

California's geology is complex owing to its history as a convergent continental margin. Accordingly, a systematic effort to map the many potential sequestration horizons or associated seals was beyond the scope of this effort. Rather, the goal of the investigation was to provide a timely preliminary screening of California's sedimentary basins.

Subsurface sequestration in sedimentary rocks can be accomplished through CO_2 injection into saline aquifers, or where conditions permit, injection into idle or abandoned oil and gas fields. Carbon dioxide injection as a form of Enhanced Oil Recovery (EOR) in producing oil fields has been in use for many years. In a typical EOR operation, some of the injected CO_2 is recovered at the surface with the oil produced. It is possible that an EOR operation could be designed to increase the amount of CO_2 that would remain in the geologic reservoir while still enhancing the

production of oil, and possibly natural gas.

Saline aquifers have little economic value and are seldom the objective of exploration or production drilling. Hence, while they are of considerable interest for potential CO_2 sequestration, little is known about their direct petrophysical properties on a regional level. Since hydrocarbon accumulations frequently occur in localized structural and/or stratigraphic traps within saline aquifers, information obtained through geophysical logging, coring, and production testing of oil and gas reservoirs gives us our best insights into the potential properties of saline aquifers as a whole. Recognizing that geologic units are heterogeneous and petrophysical properties may vary considerably within a given aquifer, oil and gas reservoir data was used as a surrogate for characterizing stratigraphically correlative saline aquifers for the purposes of this appraisal. Physical rock and fluid data for depleted and producing oil and gas reservoirs used in this investigation were taken largely from publications of the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR).

In most of California's mature hydrocarbon producing basins, geophysical well log control is usually sufficient to identify and map porous and permeable sandstones and sealing shales. However, in some basins where oil and gas production is limited or absent, subsurface control may be limited or absent. This is evident in the nonmarine basins of the Mojave Desert and Basin and Range provinces, where only regional gravity data was available to provide some measure of basin depth in many cases.

3.2 Project Approach and Methods of Work

3.2.1 Basin Inventory and Screening

The CGS identified and cataloged sedimentary basins within California's 11 geomorphic provinces. Selected basins included all large or hydrocarbon producing basins as well as numerous smaller basins identified from the 1:750,000 scale geologic map of California (Jennings *et al.*, 1977). Where basins extended offshore, only the onshore portions were considered. This resulted in an inventory of 104 basins, 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 to illustrate the distribution of known oil and gas fields (Figure 1). Basins were screened to determine preliminary suitability for potential CO_2 sequestration, with those basins not meeting the screening criteria being excluded from further consideration. Screening involved literature searches and analysis of available well logs. Criteria included the presence of significant porous and permeable strata, thick and pervasive seals, and sufficient sediment thickness to provide critical state pressures for CO_2 injection (>800 m or 2,625 ft)). Accessibility was also considered, with basins overlain by national and state parks and monuments, wilderness areas, Bureau of Indian Affairs administered lands, and military installations being excluded. Most of the basins excluded for this reason are located in the arid desert valleys of the Basin and Range and Mojave Desert geomorphic provinces.

Almost all saline aquifers and oil and gas reservoirs in California are relatively young (upper Cretaceous – Pleistocene in age) and exhibit relatively high porosities and a wide range of permeabilities. Therefore, no constraints were placed on these parameters with the exception of fractured saline aquifers or reservoirs, which were considered poor candidates for sequestration.

For this reason, the Santa Maria Basin, in which most porosity and permeability occurs in fractured Miocene shale, was excluded from further consideration at this time.

Finally, structural closure or stratigraphic trapping was not considered a prerequisite for saline aquifers at the screening level. Generally, hydrodynamic forces and fluid residence times within regional saline aquifers may be sufficient to effectively trap CO_2 for hundreds or thousands of years in the larger and more regional aquifers. Reliability of hydrodynamic containment in smaller basins where outcrop recharge areas are nearby may be considerably less.

3.2.2 Oil and Gas Reservoirs and Formation Properties

To characterize potential saline aquifers and hydrocarbon reservoirs, oil and gas field and reservoir data was assembled for depleted and producing fields from publications of the DOGGR and other available sources. Data was occasionally inconsistent or inaccurate. Where it could be determined with certainty, inaccurate data was omitted. Also, rock properties such as porosity and permeability are often reported as measured, average, calculated, or estimated values. No effort was made to standardize these data.

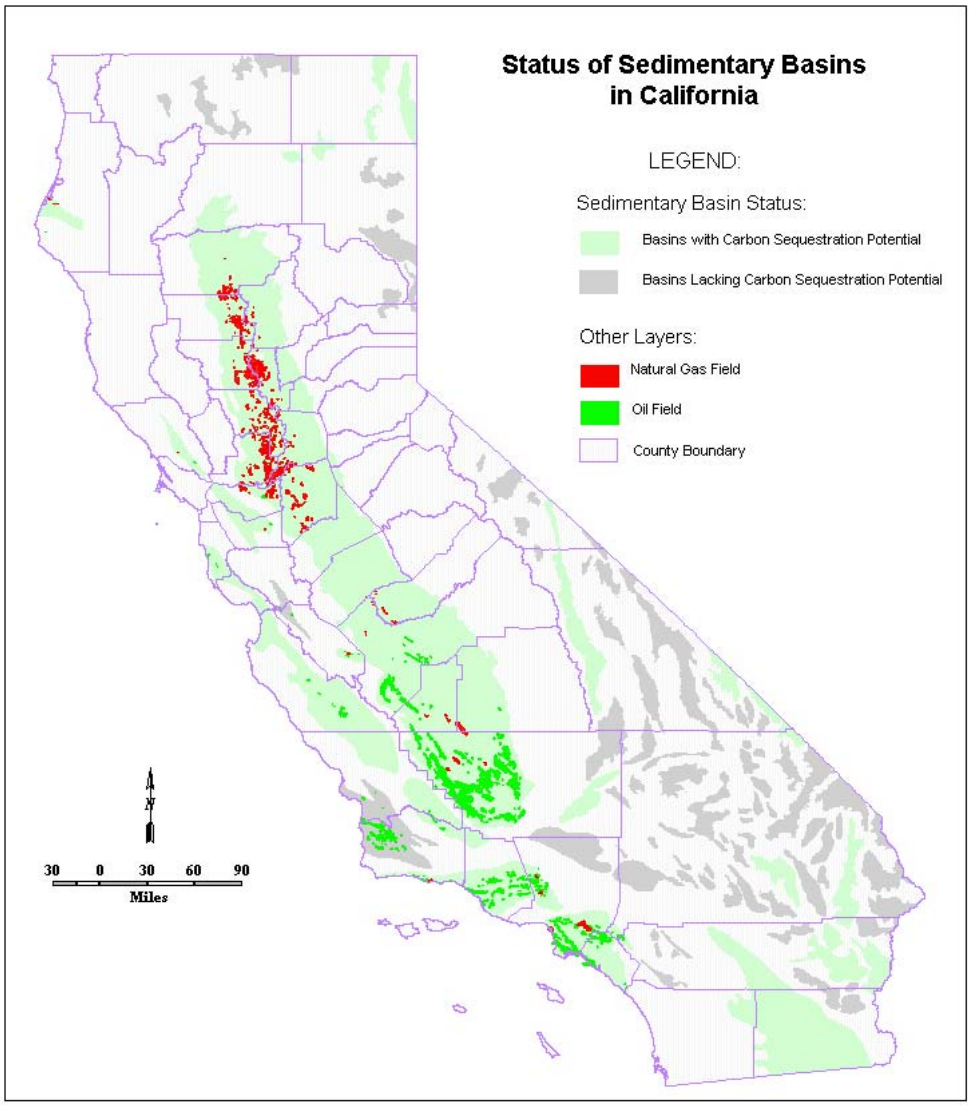


Figure 1. California sedimentary basins with oil and gas fields

Data was compiled in field-level and reservoir-level databases and attributed to the California oil and gas field GIS layer for manipulation and spatial analysis by other WESTCARB participants. Field level data included information such as location, depth, field area, cumulative production, and depth to base of fresh water. Field level database parameters are shown in Table 1.

Reservoir-specific parameters for producing, abandoned, or shut-in reservoirs in each field were compiled in the reservoir level database. These data included reservoir fluid (oil, gas, water), zone status (producing, abandoned, shut-in), average depth, average thickness, producing area, porosity, permeability, initial pressure and temperature, formation water salinity, seal thickness, trap type (structural or stratigraphic), and history of secondary and tertiary recovery efforts. A measure of "fracture intensity" was assigned for most reservoirs to instill a general sense of fracturing and/or faulting. This subjective measure was assigned a value of Low, Medium, and

High, based solely on the number of mapped faults illustrated in published DOGGR field maps (L = 0–1 fault; M = 2–3 faults; H = 4+ faults). An example of reservoir database parameters is shown in Table 2.

Table 1. Sample content of a Field Table database record

Field Code:	VE024
Field:	Honor Rancho Oil
Discovery Well Operator:	The Texas Co.
Discovery Well:	Honor Rancho A -1
Section:	6
Township:	4N
Range:	16W
Meridian:	SB
Discovery Date:	8/1/1950
Deepest Well Operator:	So. California Gas Co.
Deepest Well:	Wayside Unit 28
Section:	7
Township:	4N
Range:	16W
Meridian:	SB
Depth	11,747 ft.
Field Area	450 acres
Cum. Oil Prod. (MBO)	31,098
Cum. Gas Prod. (MMCF)	52,992
Base Fresh Water:	1,150 ft.

3.2.3 Mapping

Sufficient burial depth to ensure critical state injection pressures for carbon dioxide is an important prerequisite for subsurface CO_2 sequestration. The minimum depth is generally accepted to be 800 m (2,625 ft). Some of California's oil and gas producing Cenozoic marine basins contain sufficient well control to allow regional subsurface mapping. To identify areas of adequate sedimentary fill, depth-to-basement contour maps were prepared for those basins containing sufficient basement penetrations. This included the Sacramento, San Joaquin, and Salinas basins. In some producing basins, where basement well control is limited or absent, basement contour maps were extrapolated from shallower structure maps (Eel River Basin) or published geophysical depth-to-basement maps were used (Los Angeles, Ventura Basins). In other producing basins, no deep well log or geophysical data was available, and depth-to-basement maps could not be prepared.

In non-producing basins (generally Cenozoic terrestrial basins), basement well control is rarely available, and depth-to-basement maps were almost exclusively adapted from the published gravity based depth-to-basement maps. Since these maps used a 1-kilometer contour interval, for

the sake of convenience, basins with less than 1 kilometer (rather than 800 meters) of fill were excluded. This had the effect of eliminating a number of remote shallow terrestrial basins that might have slightly more than minimum fill, while retaining those that more clearly contained thicker sedimentary sequences. Gravity depth-to-basement maps were the primary source for depth information in the Salton Trough and the numerous basins of the Mojave Desert and Basin and Range provinces.

Table 2. Sample content of a Zone Table database record

Field Code:	VE024	Perm.:	20 md
Zone:	Modelo Fm.	Perm. Range Min.:	179 md
Age:	U. Miocene	Perm. Range Max.:	
Oil or Gas:	O	Pressure:	2,962 lb/ft^2
Date of Discovery:	12/1/1950	Press. Range Min.:	4,500 lb/ft^2
Zone Status (P/A/SI):	P	Press. Range Min.:	190 lb/ft^2
API Gravity:		Temperature:	
API Range Min.:	35	Temp. Range Min.:	
API Range Max.:	39	Temp. Range Max.:	
GOR:		Salinity:	
GOR Range Min.:	220	Sal. Range Min.:	11,200 ppm NaCl
GOR Range Max.:	1,250	Sal. Range Max.:	24,800 ppm NaCl
Sp. Gravity:		TDS:	20,200 ppm NaCl
Sp. Gravity Min.:	0.470	TDS Range Min.:	
Sp. Gravity Max.:	0.765	TDS Range Max.:	
BTU:	1,066	Seal:	Modelo Fm.
BTU Range Min.:		Seal Thickness:	
BTU Range Max.:		Seal Thickness Min.:	5 ft.
Cum. Oil (MBO):	29,094	Seal Thickness Max.:	50 ft.
Cum. Gas (MMCF):	47,601	Trap Type:	Stratigraphic
No Pool Breakdown:		Fault Intensity:	L
Depth:		ERP 1:	Gas Injection
Depth Range Min.:	6,481 ft.	ERP 1 Start:	1954
Depth Range Max.:	10,000 ft.	ERP 1 Stop:	1956
Thickness:		ERP 2:	Waterflood
Thickness Range Min.:	94 ft.	ERP 2 Start:	1959
Thickness Range Max.:	310 ft.	ERP 2 Stop:	1966
Producing Area:	400 acres	ERP 3:	Waterflood
Porosity (%):		ERP 3 Start:	1972
Porosity Range Min. (%):	7	ERP 3 Stop:	1975
Porosity Range Max. (%):	26		

The reconnaissance nature of this study precluded a systematic effort to map the many potential aquifers, reservoirs, or sealing formations, or, to prepare basin-wide sand-shale ratio maps. Instead, to identify areas of thick sand development in basins with adequate well log control, a single gross sandstone isopach map was constructed for the interval between 800 and 3,050 m (2,625 and 10,000 ft) (or basement if shallower than 3,050 m (10,000 ft)). The upper isopach limit comprises the minimum depth for critical state CO_2 injection, while the lower limit was selected to incorporate a reasonable number of deeper well logs in the larger Sacramento, San Joaquin, Los Angeles, and Ventura basins. While this approach lumps many disparate sand bodies and is not accurate from a rock, time, or sequence stratigraphic standpoint, it does provide a broad measure of the more sand-rich areas.

4 Results and Discussion

4.1 Summary of Basin Screening

Screening and follow-up geologic reviews resulted in 27 of the original 104 basins being identified as having geologic sequestration potential. The remaining 77 basins failed to meet at least one of the screening criteria. Most of these basins are shallow nonmarine basins that lack sufficient fill, are too small, or are overlain by national parks, military installations, or Indian reservations. The majority of these basins are located in the arid desert regions of the Mojave Desert and Basin and Range provinces. A table listing each excluded basin and the basis for each determination is attached as Appendix A.

Of the 27 basins which met the screening criteria, the most promising are the larger Cenozoic marine basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda marine basins. Favorable attributes of these basins include (1) geographic diversity; (2) thick sedimentary fill with multiple porous and permeable aquifers and hydrocarbon reservoirs; (3) thick, laterally persistent marine shale seals; (4) locally abundant geological, petrophysical, and fluid data from oil and gas operations; and (5) numerous abandoned or mature oil and gas fields which might be reactivated for CO_2 sequestration or benefit from CO_2 enhanced recovery operations. Most of these basins contain multiple oil and gas reservoirs and saline aquifers that met the initial screening criteria, the most important of which are discussed in the following sections. The zones were selected for their greater areal distributions and/or thicknesses, significant sealing formations, and hydrocarbon production.

Additionally, a number of nonmarine Cenozoic basins were determined to have variable sequestration potential. Since nonmarine basins are generally hydrocarbon poor, little subsurface well information is available making a stratigraphic or petrophysical assessment of a basin's saline aquifers impossible. However, in most cases, geophysical data was available to ascertain depth-to-basement and identify those basins containing sufficient sedimentary fill to meet the minimum depth requirement. Where available, shallow well or outcrop information was used to supplement the depth determinations, but in general, subsurface geology remains unknown. Much more information is needed to properly assess the sequestration potential of all the identified nonmarine basins, including the large Salton Trough.

Final selection of a sequestration site in any of these basins would require more detailed, site-specific, analysis of the geologic characteristics of the site and subsurface. Additionally, detailed analyses of permitting issues, monitoring system design, potential health and environmental risks, transportation issues, and economics will need to be performed prior to operation of a sequestration project.

The following section describes the 27 basins that met the initial geologic screening criteria in this study.

4.2 Basin Descriptions

4.2.1 Great Valley Province

The Great Valley province is an elongate topographic valley approximately 725 km (450 mi.) long lying between the Sierra Nevada and the Coast Ranges, and extending from the Klamath Mountains in the north to the Transverse Ranges in the south. The Great Valley consists of a large depositional basin that has received sediments almost continuously since the late Jurassic and contains, by some estimates, as much as 12,195 m (40,000 ft) of mostly marine, sedimentary rocks (Magoon and Valin, 1995). In the subsurface, the Great Valley is divided into the Sacramento Basin on the north and the San Joaquin Basin to the south, the point of division being the buried Stockton Arch south of the City of Stockton. Due to Cenozoic regional uplift of the northern Great Valley, Miocene through Pliocene strata has been stripped from all but the southernmost Sacramento Basin.

4.2.1.1 Sacramento Basin

The Sacramento Basin measures approximately 386 km (240 mi.) long and averages about 81 km (50 mi.) wide. In contrast to the oil-prone San Joaquin Basin, the Sacramento Basin is a natural gas-producing basin. It includes the state's largest natural gas field, the Rio Vista Field, which has produced more than 99 Gm^3 gas (3.5 TCFG, or trillion cubic feet of gas).

In conjunction with the northern San Joaquin Basin, the Sacramento Basin formed as part of an upper Jurassic-Paleogene forearc basin between the Sierra magmatic arc and the Franciscan subduction complex to the west. During the upper Jurassic through Cretaceous, the basin filled with a thick sequence of marine slope and submarine fan facies and fringing prograding shelf, deltaic, and nonmarine facies derived largely from the Sierran arc. This sequence is collectively called the Great Valley Sequence. On the eastern side of the basin the rocks are largely shallow marine and deltaic deposits whereas farther basinward, sediments are dominated by deep marine shale and basin plain turbidite deposits.

In its current form, the basin comprises an asymmetric trough with a westerly dipping basement surface ranging from surface exposures in the Sierra foothills to depths estimated to be greater than 6,710 m (22,000 ft) (Figure 2). The western flank is structurally complex, its dominant features being the westerly dipping Coast Range Thrust Fault, numerous associated faults, and steeply dipping beds.

The lowermost upper Cretaceous formations in the basin, the Sites, Guinda, and Dobbins formations, are dominantly basin plain shales in which sandstones are scarce. The oldest sandstones that might be considered for CO_2 sequestration are those of the upper Cretaceous Forbes Formation, which was deposited as a southward prograding, mud rich, basin plain-deep sea fan and slope turbidite system (Imperato *et al.*, 1990). It outcrops on the west side of the basin in the foothills of the Coast Ranges and onlaps Sierran granitic basement to the east. In the southern part of the basin, the Forbes beds plunge below a thickening wedge of younger Cretaceous and Tertiary rocks.

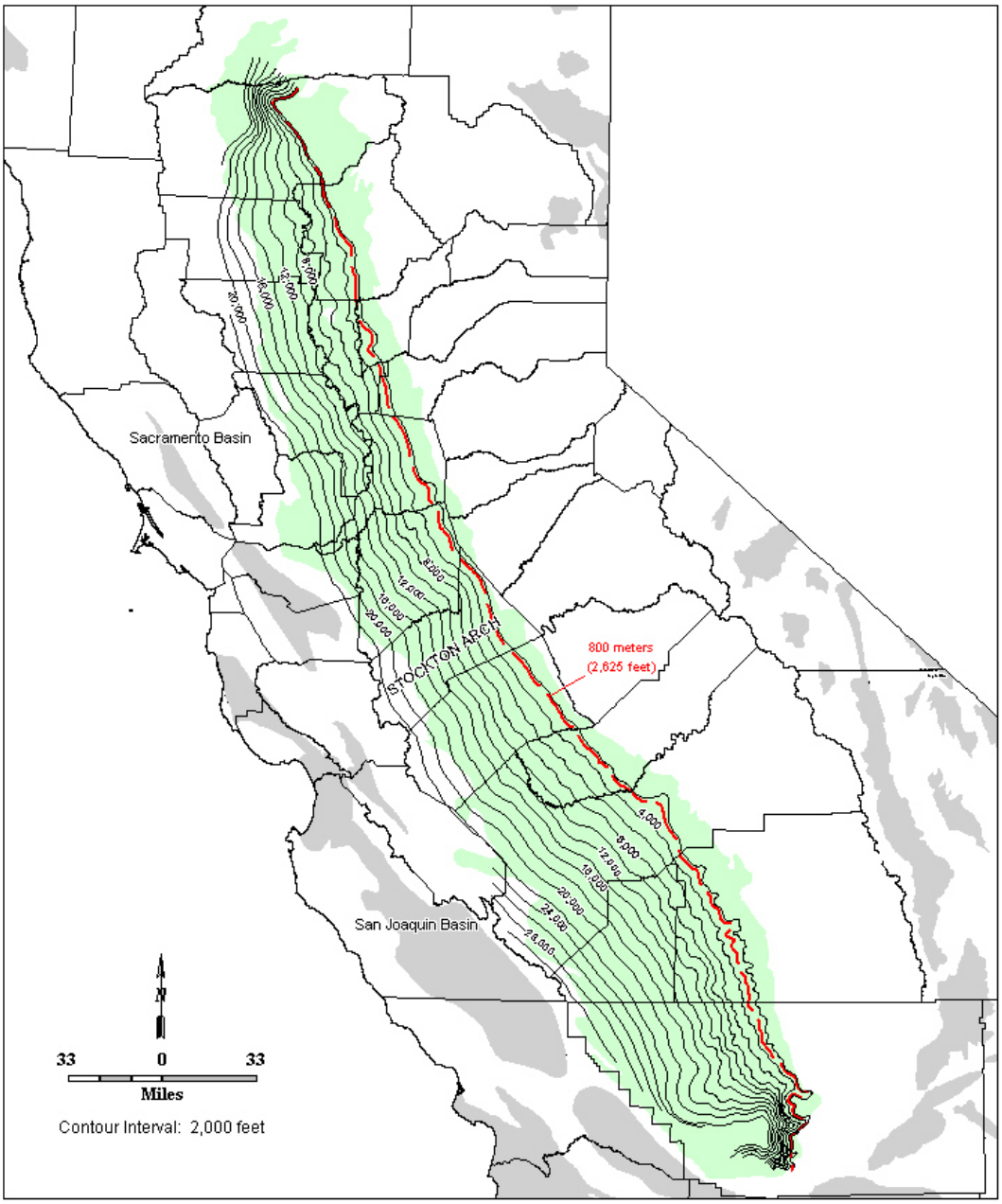


Figure 2. Sacramento and San Joaquin basins – depth-to-basement map.

Forbes Formation sandstones are highly lenticular and erratic in distribution. Sand bodies represent turbidite channel, channel levee, and fan lobes enveloped in surrounding marine shale. Sandstone reservoirs are often measured in tens or hundreds of acres and are frequently absent in closely spaced offsetting wells. Vertical stacking of multiple reservoirs is often responsible for considerable gas reserves. Forbes Formation producing fields include the state's second largest gas field, Grimes Field, in which a number of individual sand bodies have collectively produced over 18.1 Gm^3 gas (638 BCFG, or billion cubic feet of gas). Sandstones are typically a few feet to a few hundred feet) thick. Depths range from about 610 m (2,000 ft) in the north basin and in the vicinity of the Sutter Buttes in Sutter County, to deeper than 3,384 m (11,100 ft) in Solano County. Porosities generally range between 15–30 percent with permeabilities in the range of 15–108 millidarcies (md; DOG, 1983).

The upper Cretaceous Kione Formation consists of a sequence of deltaic sandstones that prograded to the south and west over the Forbes Formation slope and turbidite deposits. Kione sandstones are present throughout much of the basin, but grade southward into distal prodeltaic mud and shale in southern Colusa County. To the north, in parts of Tehama County, the Kione Formation is truncated by regional angular unconformity. Kione sandstones are also absent in a northeast–southwest trend extending from eastern Tehama County through Yolo County where they have been eroded and replaced by mudstone infilling of the Paleocene Princeton Submarine Canyon.

With the exception of a narrow corridor along the basin axis, Kione sandstones are too shallow for carbon sequestration. Sandstone facies reach a maximum depth of between 1,370 and 1,525 m (4,500 to 5,000 ft) in southern Colusa County before shaling out. Individual sandstones range from a few cm (several in.) to over 100 m (several hundred feet) thick with aggregate thicknesses upwards of 600 m (2,000 ft). High porosities between 25–35 percent are common (DOG, 1983). Seals may be thin interbedded Kione shales or the overlying regionally transgressive Sacramento Shale, which can approach 90 m (300 ft) thick. Locally, variable thicknesses of mudstone fill provide seals along the flanks of the Princeton Submarine Canyon.

Gas accumulations in the Kione are generally small and occur in small closures, fault traps, and stratigraphic traps where Kione sandstones have been truncated by regional unconformity or erosion by the Princeton Canyon. The largest field, from a production standpoint, is Wild Goose Gas Field which produced 2.94 Gm^3 gas (104 BCFG) from twelve Kione sandstones on a structural closure of less than 320 acres. The field was converted to a natural gas storage field in 1998.

The upper Cretaceous Lathrop, Winters, Tracy, Blewett, and Starkey formations are genetically related units, sometimes collectively called the Panoche Formation. They record a renewed progradational sequence of basin filling overlying the Sacramento Shale. Each unit is separated by regionally extensive marine shale. The Lathrop, Winters, Blewett, and Tracy formations consist of separate sand-rich submarine fan, slope, and basin plain sediments that were delivered to the shelf edge by multiple prograding Starkey Formation deltaic complexes. The Starkey Formation can be divided into at least six deltaic cycles (Moore and Nilsen, 1990). Lateral migration of the prograding deltas resulted in differing spatial distributions and stratigraphic

position of the submarine fans ranging from the lowermost Lathrop fan through the uppermost Blewett fan.

Lathrop sandstones are time equivalent with the lower Winters sandstones, but occur farther south with little overlap. A lower Starkey delta system provided sands to the Lathrop fans, which were the earliest to be deposited over the Sacramento Shale in the southern Sacramento Basin (Moore and Nilsen, 1990). Lathrop sandstones have a general northeast-southwest trend and are best developed in Southern San Joaquin County where sandstone thickness approaches 760 m (2,500 ft). They pinch out to the north, in the vicinity of northern San Joaquin County. Porosities range from 18–27 percent (DOG, 1983). Permeabilities in the sands in the Lathrop Field average 60 md (Teitsworth, 1964).

Lathrop sands have produced in only three fields in the southern Sacramento Basin. Before conversion to a gas storage field, the Lathrop Field produced 10.2 Gm^3 gas (359 BCFG) from a sequence of sandstones almost 600 m (2,000 ft) thick on a faulted anticline with about 180 m (600 ft) of closure (Teitsworth, 1964). Reservoir depths range from 2,100–2,600 m (6,900–8,500 ft). Much smaller accumulations have been found in French Camp and Lathrop Southeast fields at depths between 2,110–2,170 m (6,925–7,110 ft).

Winters sandstones are best developed approximately 30 km (20 mi.) west-southwest of Sacramento where net sand thickness can exceed 460 m (1,500 ft; Garcia, 1981). Thick sandstone extends for about 160 km (100 mi.), paralleling the basin axis, before gradually thinning to the north into Yolo County and pinching out to the south in southern San Joaquin County. Laterally, the sandstones pinch out eastward toward the shelf edge and thicken basinward. Porosities range from a low of 18 percent in deep sands below 2,900 m (9,500 ft) to a range of 25–38 percent in shallower zones. Permeabilities range from 10–1,700 md (DOG, 1983). Winters and Lathrop sandstones are overlain by the Sawtooth Shale which provides a regional seal ranging from 100–300 m (~300–1,000 ft) thick.

Winters sandstones are important gas reservoirs in the southern Sacramento Basin. Producing depths range from 750 m (2,450 ft) in Dunnigan Hills Field to 2,960 m (9,700 ft) in Union Island Field, where Winters sandstones have produced 7.73 Gm^3 gas (273 BCFG). Other Winters accumulations include the Bunker (2.6 Gm^3 gas (92 BCFG)), River Island (1.6 Gm^3 gas (58 BCFG)), Putah Sink (1.3 Gm^3 gas (47 BCFG)), Winters (1.2 Gm^3 gas (41 BCFG)), and Saxon (0.99 Gm^3 gas (35 BCFG)) fields. Most significant accumulations involve updip normal fault displacement against impermeable shales.

The main Tracy Formation sands are generally confined to the western edge of the southern Sacramento and northern San Joaquin basins between Suisun Bay and the northwestern corner of Fresno County. Upper Tracy sands cover a smaller area, west of Modesto between Contra Costa County and Merced County (Callaway, 1964). Sandstone thickness varies markedly from less than 15 m (50 ft) to over 300 m (1,000 ft) with porosities of 20–28 percent (DOG, 1983). No permeability information was available. Producing sandstone depths range from 1,190 m (3,900 ft) in Tracy Field to over 2,560 m (8,400 ft) in Lathrop Field.

Tracy sandstones are not major reservoirs in the Sacramento Basin but have contributed to the

cumulative production in the Lathrop (10.2 Gm^3 gas (359 BCFG)), Tracy (0.48 Gm^3 gas (17 BCFG)), and French Camp (0.51 Gm^3 gas (18 BCFG)) fields.

Blewett Formation sandstones were deposited contemporaneously with the uppermost Starkey deltaic complexes and are confined to an arcuate trend along the western side of the basin from southern San Joaquin County southward into the northwest corner of Fresno County. Blewett sandstones can range from ~1 m (a few feet) to ~100 m (a few hundred feet) thick with aggregate thicknesses up to 300 m (1,000 ft). Porosity and permeability range from 20–30 percent and 70–597 md, respectively (DOG, 1983).

Blewett sandstones are only present in the southernmost part of the basin and are not major producers. They have, however, contributed to production in the Vernalis (2.92 Gm^3 gas (103 BCFG)), McMullen Ranch (1.8 Gm^3 gas (64 BCFG)), and Tracy (0.48 Gm^3 gas (17 BCFG)) fields.

The undifferentiated Starkey Formation deltaic complexes are more extensive than the marine fans that developed marineward. Starkey sandstones occur throughout the southern Sacramento Basin from southern Colusa and Sutter County where they are truncated by post-Cretaceous angular unconformity, southward into the northern San Joaquin Basin, where they are confined to the eastern half of the basin (Callaway, 1964). Sandstones generally thin westward and are locally absent.

Depths range from about 610 m (2,000 ft) in southern Sutter County to more than 3,050 m (10,000 ft) in southern Solano and Sacramento counties. Individual sandstones range from ~1 m (a few feet) to ~100 m (a few hundred feet) thick with aggregate thicknesses of nearly 460 m (1,500 ft). Porosities of 14–17 percent are typical for sandstones deeper than 2,900 m (9,500 ft) and 30–35 percent for shallower sandstones. Permeability data is scare, the only recorded values ranging from 50–100 md (DOG, 1983). The Starkey Formation is overlain by the H&T Shale, which provides a regional seal 15 to ~100 m (50 to a few hundred feet) thick.

Starkey sandstones are important gas reservoirs in numerous fields with reservoir depths ranging from 690 m (2,250 ft) in Catlett Field to 3,137 m (10,288 ft) in Lindsey Slough Field. Reported gas production is frequently commingled with other reservoirs making production estimates unreliable. Starkey sandstones have produced over 1.1 Gm^3 gas (39 BCFG) in the Sycamore Slough Field and are responsible for a significant portion of the production in the Lindsey Slough (8.75 Gm^3 gas (309 BCFG)) and Millar (4.62 Gm^3 gas (163 BCFG)) fields.

Throughout part of the southern Sacramento Basin, the H&T shale is overlain by the upper Cretaceous Mokelumne River Formation. The formation is progressively truncated to the north by the post-Cretaceous angular unconformity until it pinches out in southern Yolo and Sutter counties. In its northern reaches, it contains interbedded sands and shales interpreted to be delta plain, distributary channel, natural levee, and crevasse splay deposits (Johnson, 1990). The interbedded sandstones grade southward into series of thick sands generally designated the as the Second through Fourth Massive Sands which can achieve thicknesses of over 300 m (1,000 ft) (the Paleocene First Massive Sand is of limited extent). The Massive sands may be locally eroded or wholly absent due to Paleocene – Eocene erosion and downcutting by the Martinez

and Meganos submarine canyons. Depths range from less than 610 m (2,000 ft) in southern Sutter County to over 2,745 m (9,000 ft) in southern Contra Costa County. Porosities range from 15–35 percent and permeabilities 250–1,500 md (DOG, 1983).

Mokelumne River Sandstones are major gas reservoirs. Important Mokelumne sandstone accumulations include the McDonald Island (5.21 Gm^3 gas (184 BCFG)) and East Brentwood (1.3 Gm^3 gas (47 BCFG)) fields. Mokelumne River sandstone pools in the Bunker and River Island fields have produced 2.6 Gm^3 gas (91 BCFG) and 1.2 Gm^3 gas (42 BCFG) respectively. Trap types include fault truncations, stratigraphic traps, and unconformity traps sealed by intervening shales up to 30 m (100 ft) thick and by overlying Martinez and Meganos submarine canyon fill mudstone.

In the southern Sacramento and northern San Joaquin basins, Cretaceous rocks of the Great Valley Sequence are separated from overlying Paleocene and younger beds by a basin-wide unconformity. In the Paleogene, marine and fluvio-deltaic sedimentation resumed in the forearc basin until the emergence of the Stockton Arch in the late Paleogene separated the Sacramento Basin from the San Joaquin Basin.

The most important Paleogene unit in the Sacramento Basin is the Eocene Domengene Formation. It is thought to represent a tide-dominated deltaic system with sediment distribution and geometry complicated by a number of complexities including tectonics and subsidence associated with the Stockton Arch, sediment compaction in the Meganos Gorge, active faulting, and distribution of basin margin uplifts. It includes many facies including channel sands, bars, delta front and shoreline sands, shelf sandstones, and fluvial conglomerate (Cherven, 1983).

Domengine sandstones range from as shallow as 300 m (1,000 ft) in northern Colusa and Sutter counties to over 1,980 m (6,500 ft) deep in southern Solano County. Sandstones range from interbedded stringers to beds over 150 m (500 ft) thick in Contra Costa County. Porosities average 18–32 percent. Permeabilities of 15–70 md are reported in the Domengine sandstone in Galt Field.

The Domengine sandstones are prolific gas producers. They are the primary reservoirs in the Rio Vista Field which has produced 99 Gm^3 gas (3.5 TCFG). It also produces in many other fields but reported production is frequently commingled. Trapping mechanisms include simple fault traps and structural closures through complexly faulted structures and erosional truncation and updip trapping by Markley Submarine Canyon fill. Regionally, the Nortonville Shale overlies the Domengine serving as a seal throughout much of the southern Sacramento and northern San Joaquin basins. Due to a regional unconformity and localized erosion by the Markley Submarine Canyon, its thickness varies widely from a featheredge to upwards of 245 m (800 ft) in the vicinity of the Kirby Hills Field.

A generalized sandstone isopach map of the Sacramento Basin (Figure 3) reveals good sandstone development paralleling the strike of the basin and ranging from over 300 m (1,000 ft) in Tehama County to nearly 1,220 m (4,000 ft) in Stanislaus County. The southward thickening is largely the result of the post-Cretaceous regional unconformity, which progressively truncates the sand-rich Great Valley Sequence formations to the north, leaving only Forbes and Kione

formation sandstones remaining in the northernmost counties.

4.2.1.2 San Joaquin Basin

The San Joaquin Basin comprises the southern half of the Great Valley province. It extends about 350 km (220 mi.) from the Stockton Arch to its southern terminus at the northern Transverse Ranges, and averages 80–110 km (50–70 mi.) wide. It is bounded on the east by the Sierra Nevada and on the west by the Central Coast Ranges and the San Andreas Fault.

The basin is filled with predominantly marine Cretaceous and Cenozoic clastic sedimentary rocks that attain an aggregate thickness of over 9,150 m (30,000 ft) (Figure 2). It also contains the deepest well in the state, which bottomed in Cretaceous siltstone and shale at 7,447 m (24,426 ft) in the Elk Hills Field.

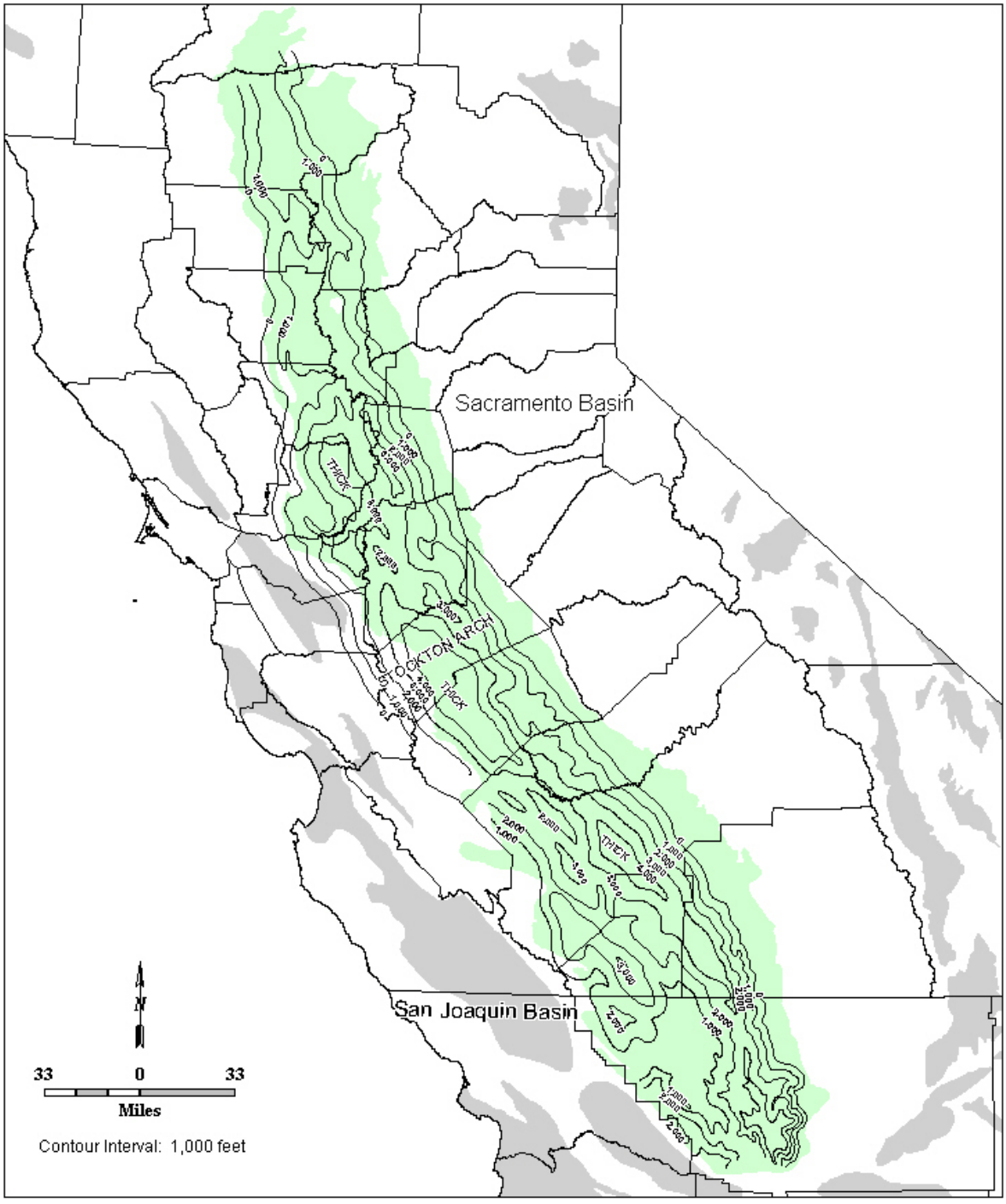


Figure 3. Sacramento and San Joaquin basins – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

During the Mesozoic, the northern San Joaquin and Sacramento basins shared a history of forearc basin sedimentation recorded in the Great Valley Sequence. The Great Valley Sequence thins longitudinally down the axis of the San Joaquin Basin from about 3,050 m (10,000 ft) or more near the Stockton Arch to its pinch out against the north flank of the Bakersfield Arch. Tertiary sedimentation in the San Joaquin Basin records the change from a forearc basin to a wrench related strike-slip basin with multiple sediment sources. Depositional systems filled the basin from sources to the west and south, while prograding shelf deposition continued to infill the basin from the north and east (Callaway, 1990). A thick and complex Neogene marine basin developed in the southern San Joaquin Valley in response to right lateral transform motion along the San Andreas Fault system (Bartow and Nilsen, 1990). This basin received a thick sequence of dominantly marine Miocene and Pliocene aged sediment from which most of the basin's oil is produced. Consequently, the San Joaquin Basin contains many more clastic sequences with geologic carbon sequestration potential than any other California basin.

Only in the northern part of the basin are Cretaceous Great Valley Sequence rocks encountered at reasonable depths. Thick upper Cretaceous sandstones of the Panoche and younger formations produce in several small gas fields in Merced, Madera, and Fresno Counties, which for practical purposes can be considered extensions of the Sacramento Basin and are not reconsidered here.

Important early Tertiary sandstones include the Eocene Gatchell sandstone of the Lodo Formation, and sandstones within the Kreyenhagen Formation. These units are some of the principal stratigraphic and structural reservoirs in the belt of fold-related oil fields along the west side of the basin. Unlike the Sacramento Basin, Domengine sandstones are not well developed in the San Joaquin Basin.

The Gatchell sandstones are confined to the north, northeastern, and western parts of the San Joaquin Basin and pinch out to the east and south. Sandstones are generally ~10 m (a few tens of ft) to ~100 m (hundreds of feet) thick. Depths range from a ~1,000 m (few thousand feet) on the west to over 3,660 m (12,000 ft) in the vicinity of Kettleman North Dome Field in western Kings County. Porosity and permeability in sandstones between 1,980–2,290 m (6,500–7,500 ft) deep in Coalinga East Extension Field average 20 percent and 421 md, and decline to 14–16 percent and 65–75 md at depths between 2,805–3,570 m (9,200 and 11,700 ft) deep. Kreyenhagen Formation shales, which can exceed 365 m (1,200 ft) thick in the Coalinga East Extension Field, form the overlying seal.

The Gatchell sandstone is the primary reservoir in Coalinga East Extension Field where it has produced more than 80.1 million cubic meters (Mm^3) oil (504 MMBO, or million barrels of oil) and 15.4 billion cubic meters (Gm^3) gas (542 BCFG) from an updip pinch out of the Gatchell sandstone between 1,980–2,290 m (6,500–7,500 ft) deep. Gatchell sandstones have also produced 1.6 Mm^3 oil (10 MMBO) and 0.40 Gm^3 gas (14 BCFG) from stratigraphic traps at 3,050 m (10,000 ft) in the Guijarral Hills Field. Equivalent Lodo Formation sandstones have produced more than 3.8 Mm^3 oil (24 MMBO) and 30.78 Gm^3 gas (1,087 BCFG) from structural and stratigraphic traps at 3,050–3,660 m (10,000–12,000 ft) in the Kettleman North Dome Field.

The Eocene Kreyenhagen Formation is continuous throughout much of the basin. In the north it is dominantly marine shale, but thickens south and eastward and interfingers with the Point of

Rocks Sandstone member. The Point of Rocks sandstone is a thick wedge-shaped submarine fan complex that reaches almost 1,525 m (5,000 ft) thick in the vicinity of the Antelope Hills Field and covers much of the southern basin. On the western side of the basin, the Point of Rocks sandstones occur at shallow to moderate depths of 457–1,525 m (1,500–5,000 ft), but deepens dramatically eastward toward the basin center where the Kreyenhagen was encountered at 5,335 m (17,500 ft) in the Coles Levee North Field southwest of Bakersfield.

At shallow to moderate depths, Point of Rocks sandstones exhibit porosities in the range of 20–38 percent and permeabilities of 40 to 4,950 md. Porosity and permeability decline with depth to 12 percent and 10 md at 5,335 m (17,500 ft) deep in Coles Levee North Field (DOGGR, 1998). Where present, upper Kreyenhagen shales can provide seals up to >100 m (several hundred feet) thick. In parts of the basin where the upper shales have been truncated, Point of Rocks sandstone may be unconformably overlain by >100 m (several hundred feet) Oligocene Cymric or Santos shale.

Point of Rocks sandstones produce at shallow to moderate depths at several fields along the southwest margin of the basin. In the Pyramid Hills Field, the Point of Rocks and the lower Kreyenhagen Canoas sandstones have produced more than 4.8 Mm^3 oil (30 MMBO) and 12.3 Mm^3 (433 MMCF) gas from structural and stratigraphic traps at depths of 200–1,495 m (650–4,900 ft). Point of Rocks sandstones have also produced varying amounts from structural traps on faulted anticlines at depths between 183–1,860 m (600–6,100 ft) in the Devil's Den, Belgian Anticline, and Cymric fields. Production data for these fields is commingled.

Oligocene-lower Miocene Vedder sandstones and their equivalents are widespread throughout the south and southeastern part of the basin but are generally absent elsewhere. Vedder sandstones are transgressive marine slope, shelf, and deltaic sands that grade eastward into equivalent nonmarine fanglomerates of the Walker Formation. Sandstones range in thickness from 9 m (30 ft) to >100 m (several hundred feet), but in Tejon North Field multiple Vedder sands comprise an interval more than 610 m (2,000 ft) thick. At moderate depths of 1,525–2,745 m (5,000–9,000 ft), porosities range from 20–40 percent and permeabilities 31–2,400 md, declining to about 12 percent and 15 md at 5,370 m (17,600 ft) in the Semitropic Field (DOGGR, 1998). Vedder sandstones are overlain by siltstone and shale of the Freeman and Jewett formations, which can reach thicknesses of 300 m (1,000 ft) or more.

Vedder sandstones (and Walker Formation equivalents) have produced oil in many fields, primarily in the Bakersfield Arch area and farther south. Producing depths range from as shallow as 430 m (1,400 ft) in the Mount Poso and Round Mountain fields along the eastern basin shelf to as deep as 5,370 m (17,600 ft) in the Semitropic field near the basin center. Production volumes are difficult to ascertain since production records are commingled, but Vedder sandstones are known to have produced 3.3 Mm^3 oil (21 MMBO) and 5.92 Gm^3 gas (209 BCFG) in Tejon North Field. Trapping mechanisms include faulted anticlines, updip pinch outs, and permeability barriers.

In the southeastern basin, Vedder sandstones are overlain by the lower Miocene Jewett and Pyramid Hills sandstones and the Freeman silt. The Freeman silt gradationally overlies and intertongues with the Jewett sandstone and the overlying lower Miocene Olcese Sandstone

(Bartow and McDougall, 1984). The Jewett and Pyramid Hills sandstones are not particularly thick, generally averaging between 3 and 30 m (10 and 100 ft). Producing depths range from 380–490 m (1,250–1,600 ft) in Round Mountain Field to 3,215 m (10,550 ft) in Rio Bravo Field. Porosities between 15–22 percent are typical in sandstones below 3,050 m (10,000 ft) while higher porosities of up to 38 percent occur in shallow sands. Permeabilities range from 6–5,000 md (DOGGR, 1998).

The Jewett and Pyramid Hill sandstones are important oil reservoirs in the southeast San Joaquin Basin. Traps included stratigraphic and permeability pinchouts, faults, and anticlinal closures. In most cases sandstones are encased in or overlain by Freeman and Jewett siltstone and shale >100 m (several hundred feet) thick. Much production is commingled, but in the Round Mountain Field, Jewett and Pyramid Hill sandstones have produced 14 Mm^3 oil (89 MMBO) and 45 Mm^3 (1.6 BCFG) from between 365–580 m (1,200–1,900 ft). In the Greeley Field, Jewett and Vedder sandstones produced 16 Mm^3 oil (98 MMBO) and 0.71 Gm^3 gas (25 BCFG) from 3,445 m (11,300 ft).

The overlying Olcese Sandstone is also confined to the southeastern portion of the basin where the sands were deposited in a marine environment along the basin margin. The unit is dominantly sandstone and reaches a thickness of about 360 m (1,180 ft) near the Round Mountain Field (Bartow and McDougall, 1984). The Olcese grades basinward into the upper Freeman Silt and the overlying Round Mountain Shale which provides a seal roughly 30–90 m (100–300 ft) thick. Olcese sands range in depth from 700 m (2,300 ft) in the Ant Hill Field to 2,715 m (8,900 ft) in the Mountain View Field. Porosities range from 20–34 percent and permeabilities from 150–2,000 md (DOGGR, 1998).

Most reported production is commingled with other reservoirs. However, Olcese sands are reported to have produced more than 0.8 Mm^3 oil (5 MMBO) and 0.37 Gm^3 gas (13 BCFG) from two zones in the Wheeler Ridge Field.

The lower-middle Miocene marine Temblor Formation was deposited on the western basin margin, originating from uplifts associated with initiation of transform motion along the San Andreas Fault zone. It grades eastward into the nonmarine Zilch Formation. The Temblor Formation includes several important sandstones, including the Carneros, Wygal, Phacoides, and Agua sandstones. Sandstones tend to be of multiple environments including estuarine, and shoreline environments to the west and deeper marine turbidite environments farther east and southeast. Individual sandstones are frequently lenticular and discontinuous.

The most widespread is the Carneros sandstone, a large turbidite fan that spread eastward into the central basin. It is well developed in the vicinity of the Elk Hills, Asphalto, Railroad Gap and Northeast McKittrick fields. The Carneros interval correlates to the upper facies of the Freeman-Jewett interval and the Olcese Sand zone along the eastern basin margin.

Most Temblor sandstones range from >1 m (a few feet) to 91 m (300 ft) thick. Locally, aggregate sandstone thickness can approach 150 m (500 ft) (Jalicitos Field) to 305 m (1,000 ft) (Tulare Lake Field). Porosities in shallow to intermediate depth sandstones range from 10–40 percent while permeabilities vary from 7 to 10,000 md. Sandstones greater than 3,050 m (10,000 ft) deep

exhibit porosities of 12–21 percent and permeabilities of 60 to 500 md (DOGGR, 1998).

Intraformational shales provide seals for the Temblor sandstones. The Santos Shale, which can range up to 150 m (500 ft) thick, overlies the lowermost Wygal and Phacoides sandstones. The Upper Santos shale overlies the Agua sand and ranges up to >100 m (several hundred ft) thick. The Media Shale is 60–90 m (200–300 ft) thick and overlies the Carneros Sandstone.

Temblor sandstones are important reservoirs in the San Joaquin Basin and produce throughout much of the western basin from the Coalinga Field in Fresno County southeastward to the Asphalto and Midway Sunset fields in southwestern Kern County. Trapping mechanisms include low relief structural closures, faulted anticlines, updip pinch outs, and permeability barriers. Production has been established from as shallow as 60 m (200 ft) in the Devil's Den Field to 4,210 m (13,800 ft) in Tulare Lake Field. In the Coalinga Field, Temblor sandstones have produced over 140 Mm^3 oil (881 MMBO) and 6.37 Gm^3 gas (225 BCFG) from sandstones between 215 and 1,400 m (700 and 4,600 ft) deep. Other important Temblor fields include the Kettleman North Dome and Belridge fields where Temblor sandstones have produced more than 68.8 Mm^3 oil (433 MMBO) and 52.50 Gm^3 gas (1,854 BCFG), and 10 Mm^3 oil (65 MMBO) and 16.1 Gm^3 gas (569 BCFG), respectively, from depths of 1,830–2,685 m (6,000–8,800 ft).

Nonmarine Zilch sandstones tend to be relatively thin, ranging between 2–30 m (5–100 ft) thick, within an otherwise thick section of interbedded sands, siltstones, and mudstones. Where they produce, they are usually structurally and stratigraphically controlled and range in depth from 825 m (2,700 ft) (Chowchilla Field) to 2,075 m (6,800 ft) (Riverdale Field). Despite the absence of thick individual sandstones, they have produced over 10 Mm^3 oil (64 MMBO) and 1.7 Gm^3 gas (59 BCFG) in the Raisin City, Helm, and Riverdale fields. Porosities range from 24–35 percent and permeabilities from 5 to 771 md (DOGGR, 1998).

During the Upper Miocene, the southern San Joaquin Basin underwent rapid structural changes. Localized uplifts shed sands into the subsiding basin in the form of deep marine turbidite channel and lobe systems which interfingered with deep water, organic rich, porcelanites and siliceous shales of the Monterey Formation and the laterally equivalent Fruitvale Formation on the east side of the basin. While local names are common, Monterey and Fruitvale formation sandstones are collectively called Stevens sandstones. The primary source for the Stevens sandstones was the Gabilan uplift, west of the San Andreas Fault. At the same time, along the eastern basin margin, sediments eroded from the Sierra Nevada were being deposited as submarine fan deposits of the Santa Margarita Formation and nonmarine deposits of the Chanac Formation.

Stevens sandstones are generally medium–fine grained arkosic sands between 2–76 m (5–250 ft) thick. However, thick sections of interbedded sandstone and shale can exceed 5,000 ft) in aggregate thickness. Depths range from less than 60 m (200 ft) on the west side of the basin to over 4,270 m (14,000 ft) in the south central basin. Porosities in sandstones shallower than 3,050 m (10,000 ft) range from 20–35 percent with permeabilities of up to 6,500 md in the shallowest sandstones. Below 3,050 m (10,000 ft), porosity and permeability decline to 10–20 percent and 0.2 to 1,000 md (DOGGR, 1998). Trapping mechanisms include updip pinch outs, structural drape over anticlinal highs, and differential compaction closures. Enclosing Monterey or Fruitvale shales provide the seals.

Stevens sandstones are some of the most important reservoirs in the basin. In Midway-Sunset Field, the nation's fourth largest oil field, they have produced more than 430 Mm^3 oil (2.7 BBO, or billions of barrels) and 16.1 Gm^3 gas (567 BCFG). Other fields with significant Stevens production include Elk Hills (110 Mm^3 oil (691 MMBO) and 37 Gm^3 gas (1.3 TCFG)), Coles Levee North (26.1 Mm^3 oil (164 MMBO) and 6.99 Gm^3 gas (247 BCFG)), Yowlumne (17.0 Mm^3 oil (107 MMBO) and 2.7 Gm^3 gas (94 BCFG)), Buena Vista (14 Mm^3 oil (91 MMBO) and 7.31 Gm^3 gas (258 BCFG)), Paloma (9.7 Mm^3 oil (61 MMBO) and 12.2 Gm^3 gas (432 BCFG)), and Coles Levee South (9.4 Mm^3 oil (59 MMBO) and 12.8 Gm^3 gas (452 BCFG)).

Along the southeastern side of the basin, the Chanac Formation overlies the Santa Margarita Formation in a regressive relationship. Westerly flowing fluvio-deltaic complexes of the Chanac Formation prograded over the Santa Margarita Formation shelf and submarine fan deposits. Chanac sandstones are generally limited to the shallower parts of the eastern basin, but the Santa Margarita marine facies extend farther basinward to greater depths. While individual sandstones may be only ~1 m (a few feet) thick, aggregate sandstone in both the Chanac and Santa Margarita formations can reach over 150 m (500 ft) thick. Porosities in known reservoirs range from 20–40 percent and permeabilities from 1 to 10,000 md (DOGGR, 1998).

Chanac and Santa Margarita sandstones have produced considerable oil from reservoirs between 150 m (500 ft) and 2,470 m (8,100 ft) deep. Stratigraphic and fault traps are common. In most cases, reported production is commingled with that of other reservoirs. However, Chanac sandstones have produced nearly 31.8 Mm^3 oil (200 MMBO) and 0.82 Gm^3 gas (29 BCFG) in the Kern Front Field from an average depth of 700 m (2,290 ft). Santa Margarita sandstones have produced 2.1 Mm^3 oil (13 MMBO) and 800 Mm^3 (1 BCFG), from a shallow faulted anticline in the Wheeler Ridge Field.

The Pliocene Etchegoin Formation overlies the Chanac and Santa Margarita Formations on the east side of the basin and the Monterey and Fruitvale formations in the deeper basin. The San Joaquin Formation, in turn, overlies the Etchegoin Formation. These formations represent the transition from deep marine to nearshore and brackish water environments. The transition to nonmarine conditions was completed in the Pleistocene with the deposition of the Tulare Formation.

The Etchegoin Formation consists largely of sands and mudstones deposited in transitional deltaic, bay, estuary, and shoreface environments throughout much of the west and central basin where it reaches a thickness of about 1,680 m (5,500 ft). Etchegoin sands are poorly indurated andesitic arkoses derived from the Sierran magmatic arc and Franciscan Coast Range sources (Loomis, 1990). Individual sandstones are generally thin, ranging from 2 to over 60 m (5 to over 100 ft) but total sandstone thickness is considerably more. Sandstones are enclosed in, or overlain by, Etchegoin shales ranging from >1 m (a few feet) to over 300 m (1,000 ft) thick. Porosities range from 12–40 percent and permeabilities from 1 to 22,320 md in sandstones up to 2,290 m (7,500 ft) deep, and decline to 17 percent and 200 md at 3,170 m (10,400 ft) in the Yowlumne Field (DOGGR, 1998).

Etchegoin sandstones are important reservoirs and have produced oil from as shallow as 150 m (500 ft) in the Coalinga Field to as deep as 3,170 m (10,400 ft) in the Yowlumne Field at the south end of the basin. Most production is commingled, but Etchegoin sandstones have produced more than 124 Mm^3 oil (782 MMBO) and 20.4 Gm^3 gas (719 BCFG) from between 700–1,280 m (2,300–4,200 ft) in the Buena Vista Field. Trap types include stratigraphic pinch outs, sub-unconformity traps, faults and simple anticlinal closures.

The San Joaquin Formation reaches a maximum thickness of approximately 680 m (2,232 ft) and is composed largely of brackish water sandstone and mudstone derived from the Sierran arc, the Coast Ranges, and the Gabilan Range. The formation is generally shallow ranging from about 150 m (500 ft) in the Midway-Sunset Field on the west side of the basin to 1,400 m (4,600 ft) in the Bowerbank Field nearer the basin center. Sandstones tend to be thin and discontinuous ranging from >1 m (a few feet) to 15 m (50 ft) thick and encased in mudstone and shale. Porosity and permeability in the shallow sands range between 28 to 34 percent, and 135 md, respectively (DOGGR, 1998).

Sandstones in the San Joaquin Formation have produced oil and gas primarily from thin sands on anticlinal closures or flanking stratigraphic pinch outs. Fault truncations are also common. Reported production is usually commingled, but in the Trico Gas Field thin sandstones between 770–983 m (2,525–3,225 ft) deep have produced 5.69 Gm^3 gas (201 BCFG) on a shallow structural closure.

The Plio–Pleistocene Kern River and Pleistocene Tulare formation are the youngest and shallowest units in the basin. They consist of a poorly consolidated terrestrial progradational deposits of conglomerate, alluvial and fluvial sand, silt, and clay, overlain by Holocene alluvium. Sandstones are thin and discontinuous. The Tulare Formation sediments were shed by uplifts to the west, while the Kern River Formation sediments were shed from the Sierra Nevada on the east. The Kern River Formation is not widespread and interfingers basinward with beds of the Etchegoin, San Joaquin, and Tulare formations.

While the Tulare and Kern River formations are important oil reservoirs, having produced over 320 Mm^3 oil (2.0 BBO), they are too shallow for CO_2 sequestration throughout most of their range. Tulare and upper Kern River beds generally range from 61–610 m (200–2,000 ft) deep and only rarely exceed 915 m (3,000 ft) in depth. The Tulare Formation is also an important aquifer in much of the San Joaquin Valley. Only near the basin axis, where they interfinger with the Etchegoin and Santa Margarita formations, do beds of the lower Kern River Formation reach depths of about 2,134 m (7,000 ft). Shallow producing Kern River sandstones above 455 m (1,500 ft) exhibit porosities of 30–40 percent and permeabilities of 1,000 to 5,000 md. Sandstones at 1,494 m (4,900 ft) deep, in the Mountain View Field, average 25 percent and 15 to 80 md.

A gross sandstone isopach map (Figure 3) shows that sandstone occurs in a trend thickening to over 1,220 m (4,000 ft) parallel to the basin axis. Unlike the Sacramento Basin, the isopach interval includes largely Eocene Gatchell Formation through Pliocene San Joaquin Formation sandstones deposited above the post-Cretaceous unconformity. However, some upper Cretaceous Great Valley Sequence sandstones contribute to the isopach in the northern basin, while lower

beds of the Kern River and Tulare formations are included in deeper portion of the southern basin.

4.2.2 Transverse Ranges Province

The Transverse Ranges are an east-west trending series of mountain ranges and valleys extending about 520 km (320 mi.) from Point Arguello eastward to the Mojave Desert. The largest and most important sedimentary basin is the Ventura Basin, a complexly folded and faulted, Cenozoic marine sedimentary basin. The western two thirds of the basin extends offshore to include the Santa Barbara Channel between the Channel Islands and Santa Ynez Mountains. The onshore portion comprises about 4,080 km^2 (1,575 sq. mi.) including the Santa Clara Valley and Oxnard Plain. The onshore basin is bounded by the Santa Ynez and Santa Monica mountains to the north and south respectively, and the San Gabriel Fault to the east.

4.2.2.1 Ventura Basin

The Ventura Basin is the deepest of California's Cenozoic basins, containing more than 17,680 m (58,000 ft) of largely marine sediments (Figure 4). Consequently, the basin includes numerous upper Cretaceous through Pleistocene age sandstones with sequestration potential, and possibly enhanced oil recovery opportunities.

Along the east and northeast margins, basement rocks consist of granodiorite and related plutonic rocks intruded into older gneisses and schists. Along the south rim of the basin, and in outcrops in the Santa Monica Mountains, basement is phyllite and schist intruded by diorite and granodiorite. Franciscan sandstone, shale and chert, intruded by mafic and ultramafic rocks form the basement in the north and northwestern part of the basin.

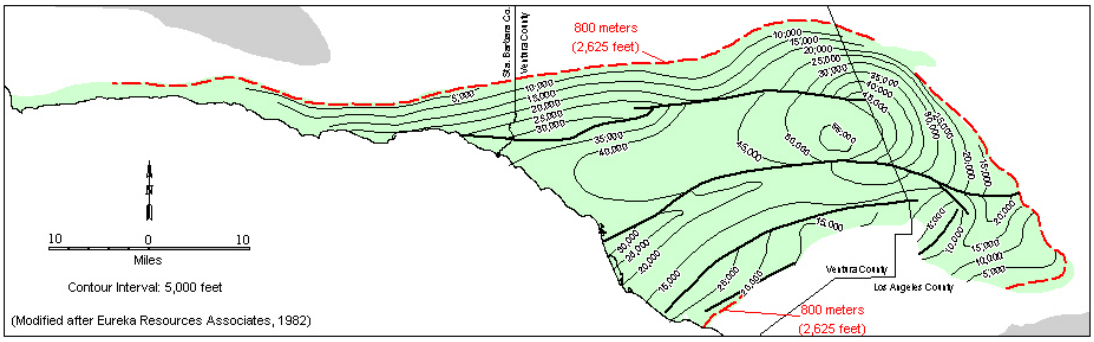


Figure 4. Ventura Basin – depth-to-basement map.

During the late Cretaceous and early Tertiary, sedimentation was in a forearc basin. By the early Miocene, subduction was replaced by crustal stretching, which began the formation of the Ventura and nearby Los Angeles and San Joaquin basins, and allowed the accumulation of thick sections of Miocene sediment. Near the close of the Miocene, accelerated deepening provided for the accumulation of 5,180–6,100 m (17,000–20,000 ft) of Plio–Pleistocene strata, considered to be the world's thickest Plio–Pleistocene section (Bailey, 1954). About mid-Pleistocene, basin

filling ceased and the main Coast Range orogeny occurred. During this time, the basin's structural complexity evolved and most of the intrabasin anticlines, folds and faults formed including the large Oak Ridge, Simi, and Santa Ynez reverse faults with displacements of 1,525–4,575 m (5,000–15,000 ft) or more (Bailey, 1954). The basin is characterized by major east-west trending thrust faults and tightly folded anticlinal trends that contain the majority of the basin's oil reserves.

Cretaceous rocks are poorly understood in the subsurface due to their extreme depth. However, from 915–2,440 m (3,000–8,000 ft) of Cretaceous marine sandstone, conglomerate, and shale are thought to rest on basement. Two oil fields, now abandoned (Horse Meadows and Mission fields), have yielded commercial hydrocarbons from structural and stratigraphic traps in Cretaceous sandstones of the Tuna Canyon and Chico formations at moderate depths of 1,265–2,195 m (4,150–7,200 ft). Porosity and permeability data is not readily available.

Cretaceous rocks are overlain by the lower Eocene Santa Susana Formation and the middle Eocene Llajas and Juncal formations. Sandstones in these formations are not known to be significant hydrocarbon reservoirs, producing only minor amounts of oil and gas from depths of 250–1,980 m (825–6,500 ft). Limited data indicates that these sands have porosities in the range of 22–35 percent and permeability of about 150 md (DOGGR, 1991).

The late Eocene–early Miocene nonmarine Sespe Formation is widespread and consists of up to 2,135 m (7,000 ft) of interbedded sandstones, siltstones, and mudstones deposited in braided stream, meandering river, and fan delta environments. Individual sandstones tend to be thin and lenticular ranging between >1 m (a few feet) to >10 m (several tens of feet) thick, but may reach up to 61 m (200 ft) thick. Aggregate reservoir thicknesses range between 15–915 m (50–3,000 ft). Due to the intense folding and faulting, producing depths vary markedly from as shallow as 30 m (100 ft) to over 3,355 (11,000 ft), but non-producing sandstones may be present to depths greater than 6,100–7,620 m (20,000–25,000 ft) in deeper portions of the Santa Clara Trough (Keller, 1995). Porosities in shallow sandstones above 1,830 m (6,000 ft) range from 18–35 percent with reported permeabilities between 24 and 300 md. Sandstones between 1,830–3,355 m (6,000–11,000 ft) exhibit lower porosities and permeabilities of 15 to 28 percent and 4 to 243 md (DOGGR, 1991).

The combined Sespe and Oxnard fields have produced over 11 Mm^3 oil (72 MMBO) and 2.4 Gm^3 gas (84 BCFG), largely from Sespe sandstones. Numerous smaller fields have produced between 0.8 and 1.6 Mm^3 oil (5 and 10 MMBO). Generally, traps are anticlinal closures or stratigraphic pinch outs with interbedded siltstones and mudstones providing the seals.

The top of the Sespe formation varies from conformable to strongly unconformable. Where present, shallow marine sandstones of the lower Miocene Vaqueros Formation rest conformably on the Sespe Formation. While individual sandstones can be >1 m (a few feet) up to about 91 m (300 ft) thick, aggregate sandstones can approach 152 m (500 ft) thick. In producing oil fields, Vaqueros sandstones range from 335–1,205 m (1,100 to 3,950 ft) deep with porosities between 21 and 30 percent. Permeability of 100 md is reported in several sandstones (DOGGR, 1991). In the deeper basin, depths are similar to those of the Sespe Formation.

Vaqueros sandstones produce in about ten shallow oil and gas fields. Oil production is commingled in most cases, but sandstones in the La Goleta Gas Field have produced 1.3 Gm^3 gas (47 BCFG). Fault traps, complexly faulted structures, simple anticlinal closures, and stratigraphic pinchouts all contribute to trapping. Vaqueros sandstones are overlain by the Rincon shale which provides a regional seal between 152–1,525 m (500–5,000 ft) thick for the Vaqueros and older formations.

Upper Miocene through Pleistocene rocks are some of the most important reservoirs in the Ventura Basin and are represented by oil and gas accumulations in structural and combination traps in sandstone reservoirs. Known traps are largely anticlinal with associated faulting. Stratigraphic traps are rare (Keller, 1995).

The marine upper Miocene Modelo Formation was deposited in the northern part of the Ventura basin at bathyal depths. The Modelo Formation is equivalent in part to the Monterey Formation in the San Joaquin and Los Angeles basins. In the subsurface it reaches a maximum thickness of 3,050 m (10,000 ft), but is absent east of Newhall and Saugus. Producing depths range from about 152 m (500 ft) in the Piru Field to over 4,330 m (14,200 ft) in the Newhall-Potrero Field, but unproductive sandstones extend to greater depth. The deepest well in the basin bottomed in the upper Miocene section at 6,555 m (21,500 ft) (Keller, 1995).

Modelo sandstones range from >10 m (a few tens of feet) to over 152 m (500 ft) thick. In sandstones up to 1,830 m (6,000 ft) deep, porosity ranges from 20–30 percent and permeability from 16 to 480 md. Between 1,830–3,050 m (6,000–10,000 ft), porosity and permeability decline to about 15–23 percent and 8 to 192 md. In the few deep sandstones between 3,050–3,660 m (10,000–12,000 ft) for which data is available, these parameters are further reduced to 12 to 14 percent and 9 to 40 md (DOGGR, 1991).

Modelo sandstones have produced over 200 millions of barrels of oil. Fields in which reported production is not commingled with other zones include the Newhall-Potrero (12 Mm^3 oil (77 MMBO) and 3.20 Gm^3 gas (113 BCFG)), Castaic Junction (4.9 Mm^3 oil (31 MMBO) and 1.6 Gm^3 gas (57 BCFG)), Honor Rancho (4.9 Mm^3 oil (31 MMBO) and 1.5 Gm^3 gas (53 BCFG)), and Ramona (3.7 Mm^3 oil (23 MMBO) and 1.2 Gm^3 gas (43 BCFG)) fields.

The Pliocene Pico Formation is a thick section of neritic to bathyl turbidite and fan deposits that exceeds 3,050 m (10,000 ft) thick in the basin center. It consists of bedded arkosic sandstones and shales, with sandstones ranging from thin stringers to >100 m (hundreds of feet). Sandstone often comprises more than half the formation's thickness. In known oil fields, average reservoir thickness ranges from less than 60 m (100 ft) to 1,525 m (5,000 ft) (Keller, 1995). Depths range from less than 305 m (1,000 ft) in the Newhall Field on the east side of the basin to over 4,575 m (15,000 ft) in the Long Canyon Field in the axial portion of the basin midway between Ventura and Santa Paula. Porosities and permeabilities of 20–35 percent and 67 to 6,000 md are typical of sandstones above 1,830 m (6,000 ft) deep, but decline to 13 to 20 percent and 9 to 82 md in sandstones below 3,050 m (10,000 ft) (DOGGR, 1991).

Pico sandstones are the most important reservoir in the basin having produced well over a billion barrels of oil. In the giant Ventura Field alone, they have produced over 153 Mm^3 oil (963

MMBO) and 60 Gm^3 gas (2.0 TCFG) from ~1,000 m (several thousand feet) sandstone between 1,122–3,660 m (3,680–12,000 ft) on a faulted anticline exhibiting more than 1,050 m (3,450 ft) of relief. The nearby Rincon Field has produced over 25.3 Mm^3 oil (159 MMBO) from Pico sands on a smaller faulted anticline between and 1,035 and 3,960 m (3,400 and 13,000 ft) deep (DOGGR, 1991).

A sandstone isopach map for the Ventura Basin reveals three thick east-west trending sandstone zones, each exceeding 1,220 m (4,000 ft) thick, as well as significant sandstone development exceeding 300 m (1,000 ft) throughout most of the basin (Figure 5). In the deeper parts of the basin, sandstones within the isopach interval include primarily Sespe through Pico formation sandstones. Increasing contributions of Cretaceous strata, at the expense of these Eocene through Pliocene deposits, occupy the isopach interval in the shallower basin margins.

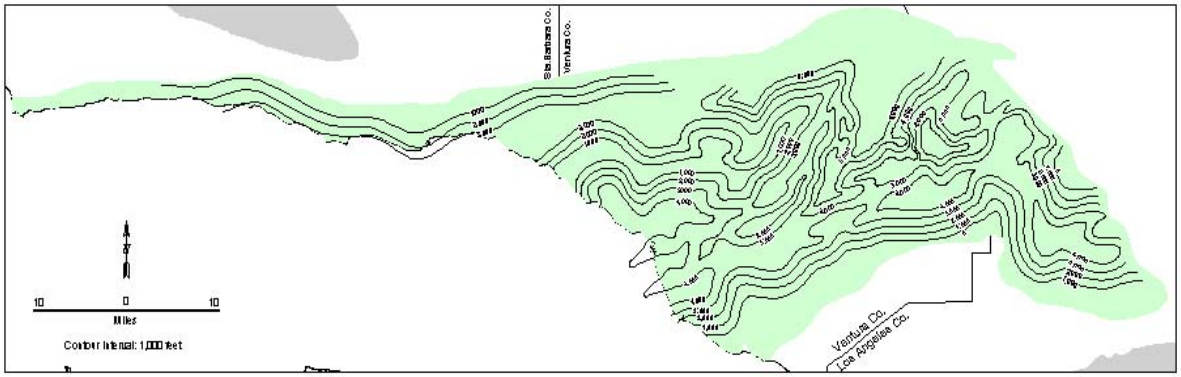


Figure 5. Ventura Basin – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

4.2.3 Peninsular Ranges Province

The Peninsular Ranges are a series of mountain ranges in southwest coastal California characterized by intervening northwest trending valleys sub-parallel to faults branching from the San Andreas Fault zone. The Peninsular Ranges are bordered on the north by the Transverse Ranges, on the west by the Channel Islands, and on the east by the Colorado Desert province.

4.2.3.1 Los Angeles Basin

The Los Angeles Basin is the largest of the Peninsular Range basins and the southernmost of the onshore Cenozoic basins that formed along the continental borderland from the middle Miocene through the Holocene. It covers about 3,885 km^2 (1,500 sq. mi.) and is bordered on the north by the Santa Monica-Hollywood-Raymond Hill Fault Zone and the Santa Monica Mountains; on the northeast by the Sierra Madre Fault and the San Gabriel Mountains; on the east and southeast by the Chino Fault, Santa Ana Mountains, and the San Joaquin Hills; and on the west and southwest by the Palo Verdes Fault. The basin contains a thick section of primarily Miocene and Pliocene sedimentary rocks estimated to be over 8,230 m (27,000 ft) thick (Figure 6). The basin is

considered the world's richest in terms of hydrocarbons per unit volume of sedimentary fill and contains three supergiant fields, the Wilmington, Huntington Beach, and Long Beach fields. Collectively, these three fields contain about 52 percent of the basin's recoverable reserves (Biddle, 1991).

The Los Angeles Basin is a structurally complex basin located within the San Andreas Transform system at the intersection of the Peninsular Ranges and Transverse Ranges. Its evolution commenced with mid-Miocene extension associated with strike-slip and rotation of the Transverses Ranges and persisted through the late Miocene to early Pliocene extension associated with the opening of the Gulf of California (Biddle, 1991). During the late Miocene to early Pleistocene, the basin underwent its principle phase of subsidence and deposition, after which it was subjected to post mid-Pleistocene north-to-south compression resulting in extensive folding and thrust faulting of the Neogene section (Biddle, 1991, Yerkes *et al.*, 1965). In its present form, the basin is broken by many faults and folds, the most important being the Palos Verde, Newport-Inglewood, and Whitier fault zones, which divide the basin into several distinct fault blocks.

The southwestern block is bounded on east by the Newport-Inglewood Fault Zone, a linear trend of extensive folding and faulting which has localized major oil fields along its length. The main structural features of the southwestern block are the anticlinal Palos Verde Hills, uplifted along a steep reverse fault exposing basement Catalina Schist at the surface and forming several basement anticlinal ridges over which younger sediments have been draped, forming important oil pools including the most productive field in the state, the Wilmington Field.

The central block, between the Newport-Inglewood and the Whittier Fault zones, forms the axial trough of the basin. Little is known of the basement rocks in this part of the basin since the deepest well bottomed at a depth of 6,322 m (20,736 ft) in lower Pliocene Repetto Formation beds.

The northeastern block lies between the Whittier Fault Zone and the San Gabriel Mountains. The Whittier Fault is a north dipping reverse right-oblique fault along which several important major oil fields are localized including the Brea-Olinda, Sansinena, and Whittier fields. This block is a deep synclinal basin that contains mostly marine Cretaceous sedimentary rocks.

Sedimentary rocks deposited before the Miocene opening of the Los Angeles Basin are unrelated to the present depositional basin. These rocks include late Cretaceous through Miocene fore-arc basin deposits and volcanic and sedimentary rocks of the Topanga Group. The Topanga Group and earlier rocks are deeply buried and poorly understood throughout most of the Los Angeles Basin. Hence, they are not considered in this survey as potential objective for CO_2 sequestration.

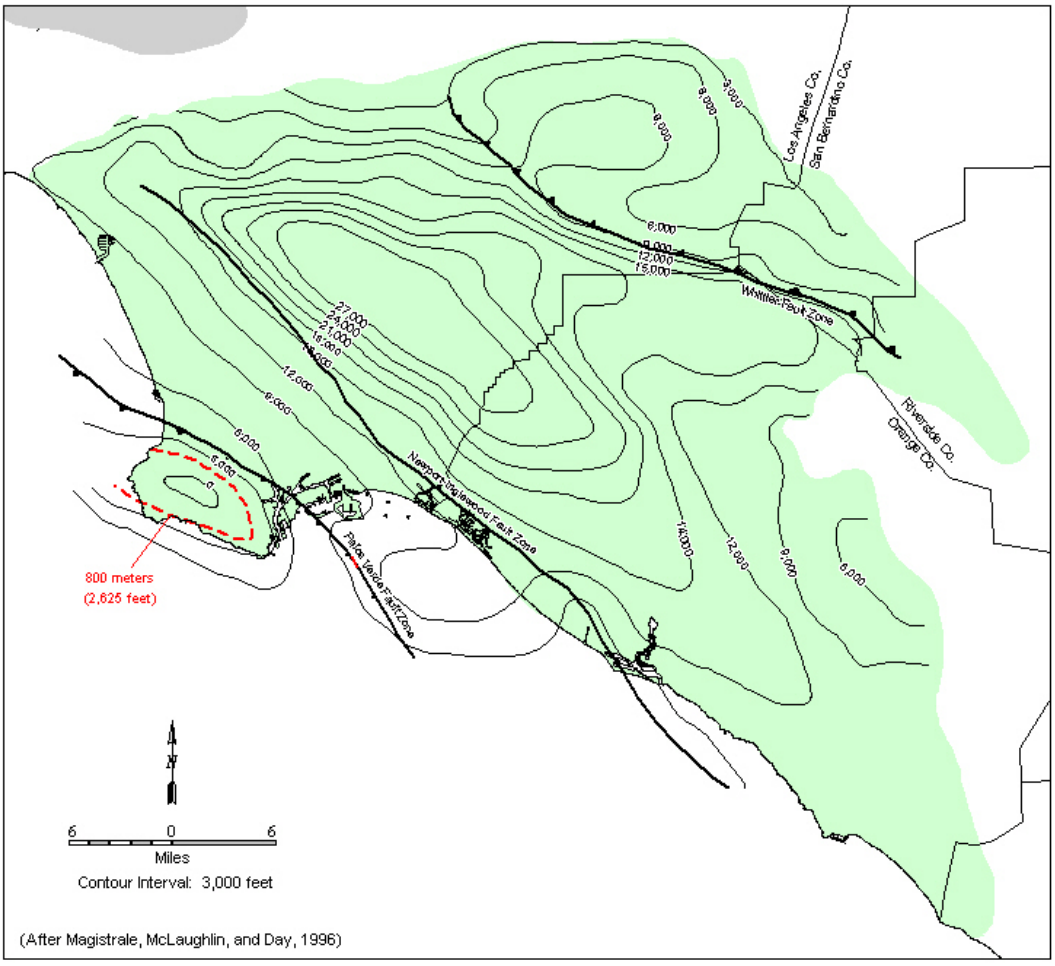


Figure 6. Los Angeles Basin – depth-to-basement map.

Throughout much of the Los Angeles Basin, the Puente Formation overlies the Topanga Formation. The Puente Formation consists of about 2,380 m (7,800 ft) of upper to middle bathyal sediments that can be divided into three general zones—(1) a lower unit (~460 m, or ~1,500 ft) consisting of micaceous and calcareous siltstone and silty medium grained feldspathic sandstone that grades to phosphatic nodular shale in the western part of the basin; (2) a middle zone (~1,160 m, or ~3,800 ft) of medium to coarse feldspathic sandstone interbedded with sandy siltstone and diatomaceous siltstone with lenses of pebble conglomerate; and (3) an upper unit (~760 m, or ~2,500 ft) of fine to coarse grained sandstone interbedded with micaceous sandy siltstone and platy siliceous siltstone with pebble conglomerate (Blake, 1991). Individual sand bodies range from thin stringers to ~100 m (hundreds of feet) in thickness, but sandstone sequences can contain ~1,000 m (thousands of feet) of reservoir sandstone.

Producing sandstones range from 150–3,660 m (500 to almost 12,000 ft) deep in the La Mirada Field. Sandstones above 2,440 m (8,000 ft) average about 20–35 percent porosity with permeabilities between 34 and 1,000 md. Deeper sandstones exhibit porosities and permeabilities on the order of 15 to 18 percent and 10 to 1,500 md (DOGGR, 1991).

Puente sandstones produce in at least 50 fields, but reported production is usually commingled with shallower Repetto and Pico formation reservoirs. Producing fields include the supergiant Wilmington (410 Mm^3 oil (2.6 BBO) and 34 Gm^3 gas (1.2 TCFG)), and Huntington Beach (170 Mm^3 oil (1.1 BBO) and 24.0 Gm^3 gas (846 BCFG)) fields, and the giant Long Beach (148 Mm^3 oil (932 MMBO) and 30.81 Gm^3 gas (1,088 BCFG)), Brea-Olinda (64.2 Mm^3 oil (404 MMBO) and 13.2 Gm^3 gas (467 BCFG)), Inglewood (59.8 Mm^3 oil (376 MMBO) and 7.70 Gm^3 gas (272 BCFG)), and Santa Fe Springs (99.2 Mm^3 oil (624 MMBO) and 23.7 Gm^3 gas (837 BCFG)) fields.

Overlying the Puente Formation is a thick section of Pliocene deposits consisting of a lower unit, the Repetto Formation and an upper unit, the Pico Formation. The lower Pliocene Repetto Formation is the most extensive Pliocene unit in the basin and has previously been identified as an important potential target for CO_2 sequestration (Hovorka *et al.*, 2003).

The Repetto Formation occurs throughout most of the basin at depths of 305 m (1,000 ft) to over 3,050 m (10,000 ft) in the deep central block trough where it exceeds 1,525 m (5,000 ft) thick. It thins to the southeast toward the San Joaquin Hills and to southwest and northeast to less than 305 m (1,000 ft). The Repetto Formation represents the deposits of a southward prograding lower bathyal submarine fan and includes submarine channel sandstones, channel levee sands, and broad lobate fan facies sandstones interbedded with siltstones and mudstones. Southward from the central basin, the Repetto sandstones grade chiefly into distal fan facies. Lateral facies changes can be abrupt with porous sandstones grading rapidly into silty mudstones and abyssal mudstones. While many individual Repetto sandstones range from ~1 m (a few feet) to tens of meters (a few tens of feet) thick, aggregate sandstone thickness within fan deposits can approach ~1000 m (several thousand feet) in the basin center.

Nearly all producing Repetto sandstones occur at depths from 305–2,315 m (1,000–7,600 ft) with porosities of 20 to 34 percent and permeabilities of 40 to 3,220 md. Only in the Potrero and Buena Park East fields do deeper reservoir sandstones occur at depths of 2,490–2,815 m (8,170–9,240 ft) where porosity and permeability of 19 percent and 9 md are reported (DOGGR, 1991).

The Repetto is a major petroleum reservoir in the basin. It has produced in at least 33 fields to various degrees with major commingled production in the aforementioned supergiant and giant Wilmington, Huntington Beach, Long Beach, Brea – Olinda, and Santa Fe Springs fields. Trapping mechanisms are dominantly structural in faulted anticlines and overturned beds along the basin's main fault trends. Smaller stratigraphic traps are not uncommon given the lateral heterogeneity of the turbidite sands. Interbedded siltstones and mudstones provide local seals while overlying Pico Formation shales form a more regional seal up to ~100 m (many hundreds of feet) thick. However, the trapping capacity of the Pico Formation is controlled by Repetto facies distribution and considerable relief on the pre-Pico unconformity that can be on the order of over tens of meters (hundreds of feet) (Henry, 1987). This results in areas where lower Pico shales form upwards of over 245 m (800 ft) of seal for Repetto sandstones and areas where Pico sandstones rest directly upon Repetto sandstones.

The Repetto is unconformably overlain by inner neritic to upper bathyl shales of the upper Pliocene–lower Pleistocene Pico Formation. The Pico Formation consists of submarine fans and shales that continued to fill the basin for the remainder of the Pliocene and most of the Pleistocene. Throughout most of the basin, the Pico Formation is too shallow for CO_2 sequestration. The formation reaches a maximum thickness and depth in a portion of the central trough near Buena Park East and La Mirada fields where the formation ranges from 1,250–1,370 m (4,100–4,500 ft) thick and 2,045–2,440 m (6700–8,000 ft) deep. It thins and rises rapidly to the northeast, northwest, and southwest to only 455–610 m (1,500–2,000 ft) thick with the base of the formation only 610–915 m (2,000–3,000 ft) deep in nearby fields. Where data is available, reported porosities range from 30 to 39 percent and permeabilities from 200 to 5,900 md (DOGGR, 1998).

A few shallow and thin Pico sandstones produce small volumes of oil and gas at depths from 290–915 m (950–3,000 ft), but in all cases production is commingled with Puente and/or Repetto production.

A sandstone isopach map for the Los Angeles Basin indicates that more than 1,525 m (5,000 ft) of sandstone is present within the isopach interval in the central basin and that sandstone thickness generally correlates with relative basement depth (Figure 7). The thicker sandstone reflected in the basin center is dominated by Puente, Repetto, and Pico formation sandstones but in the shallower basin margins, Topanga Formation and older units become locally important in the mapped interval.

4.2.4 Coast Ranges Province

California's Coast Ranges are composed of a series of northwesterly trending coastal mountain ranges and valleys extending southward from the Oregon state line to the Transverse Ranges in Santa Barbara and Ventura counties. To the east, they are bounded by the Coast Range Thrust, along which older Mesozoic rocks are thrust over Cretaceous rocks of the Great Valley Sequence in the Sacramento and San Joaquin basins.

The Coast Ranges include several Cenozoic marine sedimentary basins, some of which have produced significant volumes of oil and natural gas. From north to south, these basins include the Eel River, Livermore, Orinda, Sonoma, La Honda, Salinas, and Cuyama basins. While some of these basins are considerably smaller than other California marine basins, they nonetheless contain thick sequences of marine sands and shales. However, many of these basins are poorly explored and lack deep well control.

4.2.4.1 Eel River Basin

The Eel River Basin, located in Humboldt County, is the onshore expression of a much larger offshore Cenozoic forearc basin. The onshore portion is expressed as a westerly plunging syncline. While the Freshwater Fault technically bounds the basin on the northeast, its northeast margin is more practically defined by the northeasterly dipping Little Salmon Thrust Fault. To the south, the basin is bounded by the Russ Fault, north of which the upturned beds of the Yager Formation and lower Wildcat Group are exposed.

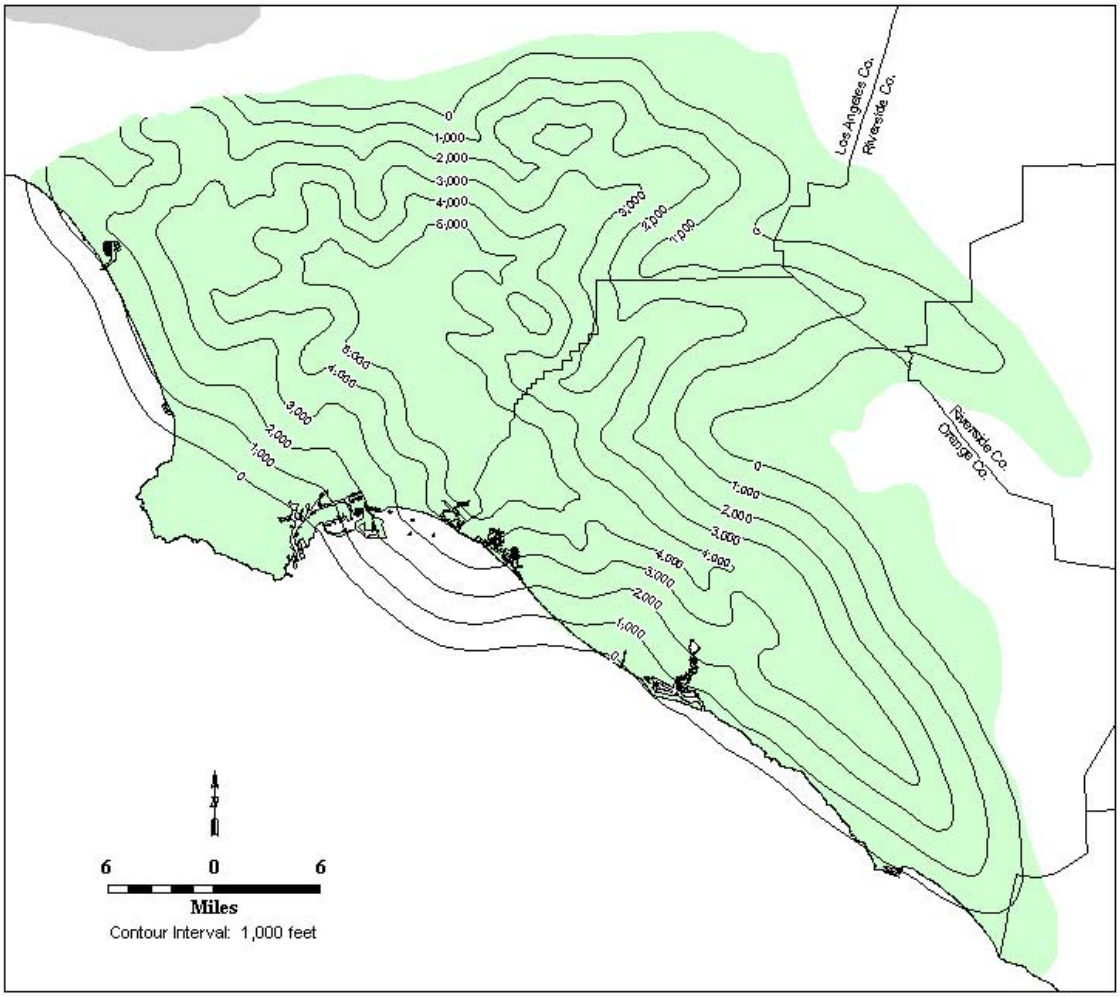


Figure 7. Los Angeles Basin – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

The basin contains more than 3,810 m (12,500 ft) of sedimentary fill including over 3,355 m (11,000 ft) of dominantly Neogene marine, sandstone, siltstone and shale resting on sandstones, conglomerates, and shales of the Cretaceous Yager Formation. In outcrop, the Yager Formation unconformably rests on basement rocks of the Jurassic Franciscan Complex. The basin is only lightly drilled with no wells having penetrated basement. Hence, an extrapolation to basement, adapted from Hopps and Horan's (1983) shallower Eel River Formation structure map, was used to generate a depth-to-basement map which indicates that most of the basin contains sufficient sedimentary fill for potential CO_2 sequestration (Figure 8).

Due to their depth, Yager Formation beds are poorly defined in the subsurface, but outcrops reveal they are dominantly marine shale, mudstone, and siltstone with interbedded graywacke and conglomerate. Ogle (1968) concluded that these rocks were not of hydrocarbon reservoir

quality, except where fractured. Consequently, these beds are considered unlikely candidates for carbon sequestration.

Lower-middle Miocene Bear River beds unconformably overly the Yager Formation, but are confined to the deeper axial portion of the basin. A pronounced unconformity truncates the beds to the north and south along the basin flanks. Due to their depth and distribution, Bear River rocks are less well known than the more extensive overlying upper Miocene and younger units. Where encountered, they consist of bathyl marine units comprised of deep-water sandstones enclosed in siliceous mudstone. Sandstones generally range from 6–37 m (20–120 ft) thick but may reach as much as 610 m (2,000 ft) thick (Hopps and Horan, 1983; Stanley, 1995b). Gas shows have been reported in the Bear River sandstones, but no commercial production has been established.

Bear River beds are unconformably overlain by the Wildcat Group, containing the only commercial hydrocarbon producing reservoirs in the basin. It consists of a lower sequence of marine sandstone, siltstone, and shale 1,890–2,500 m (6,200–8,200 ft) thick and an upper nonmarine sequence of braided delta plain deposits 800–1,000 m (2,625–3,280 ft) thick (Clarke, 1987). In ascending order, the group is composed of the Pullen, Eel River, and Rio Del formations, the Scotia Bluffs Sandstone, and the nonmarine Carlotta Formation (Nilsen and Clarke, 1987).

The Pullen Formation consists of deep-water siliceous clastic sediments. Sandstones are typically 5–6 m (15–20 ft) thick, with porosities of 12–30 percent and permeabilities of more than 300 md (Stanley, 1995b). Gas shows have been reported in the Pullen, but no production has been established.

The Pliocene section consists of prograding deep sea fan to shallow marine sediments of the Eel River and Rio Dell formations (Crouch and Bachman, 1987). Eel River sandstones are as much as 185 m (600 ft) thick with porosities of 15 to 30 percent and permeabilities of 4 to 21 md (Stanley, 1995b). In 1964, gas was discovered in sandstones between 1,370–1,615 m (4,500–5,300 ft) on a small anticline with about 105–135 m (350–450 ft) of closure. The early wells never produced, but these sandstones are receiving renewed attention and is currently undergoing development drilling.

Rio Dell Formation sandstones are deep sea fan channel and lobe deposits with some of the shallower sands being shelf and near shore deposits. Sandstones are lenticular, fine to very fine grained, and range from <1–46 m (1–150 ft) thick but locally may reach as much as 305 m (1,000 ft) thick (Stanley, 1995b). Porosity ranges from 22–28 percent with permeabilities of 1 to 12 md (DOG, 1983).

Since 1937, Tompkins Hill Field has produced more than 3.31 Gm^3 gas (117 BCFG) from middle and lower Rio Dell sandstones between 640–1,770 m (2,100–5,800 ft). Sandstones produce in structural closure and in stratigraphic traps on the flanks of an anticline displaying about 365 m (1,200 ft) of closure (Stanley, 1995b). The main producing sand is about 15 m (50 ft) thick but thickens abruptly to the southeast. In the abandoned Table Bluff Field, gas was discovered in an anticlinal fold in 1960, and abandoned in 1968 after producing only 3 Mm^3 (0.1

BCFG) from Rio Dell sandstones between 640–1,455 m (2,100–4,775 ft). Sandstones are generally <1–3 m (1–10 ft) thick, but net pay zones may be 5–90 m (15–300 ft) thick with porosities of 22–27 percent (DOG, 1983). The Table Bluff anticline has about 610 m (2,000 ft) of closure.

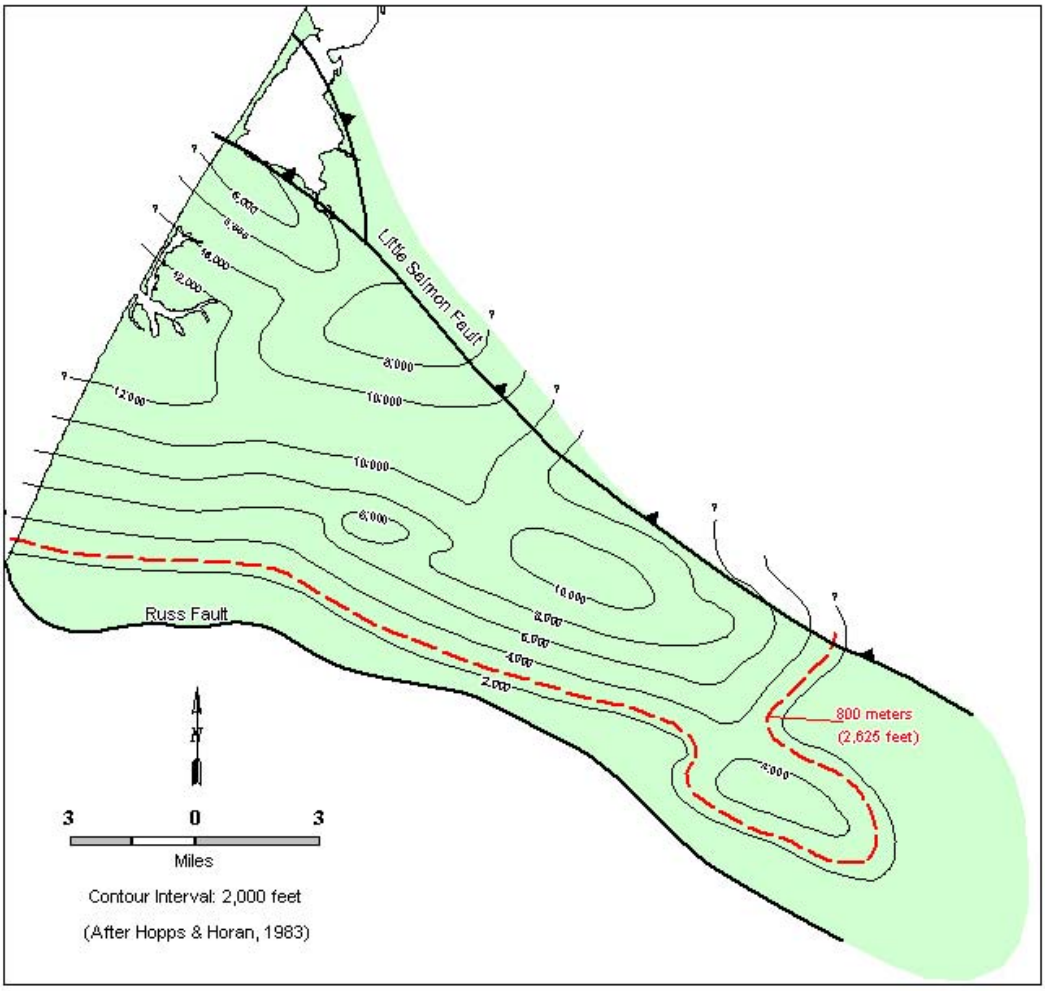


Figure 8. Eel River Basin – depth-to-basement map.

The shallow marine to nonmarine Pleistocene Carlotta and Scotia Bluffs formations, and sediments of the Pleistocene Hookton formation are the youngest units in the basin. With the exception of some lower Carlotta beds near the basin axis, most of these units are too shallow to be considered for potential CO_2 sequestration.

Sandstones in the Bear River Beds through Rio Dell Formation may provide carbon sequestration opportunities in the deeper parts of the basin on anticlinal closures and flanking stratigraphic pinch outs. While individual sandstones are generally thin, a sandstone isopach map reveals a northwesterly trending zone of sandstone, in excess of 760 m (2,500 ft) thick,

paralleling the north flank of the basin (Figure 9). Enclosing siliceous mudstones and shales should provide seals.

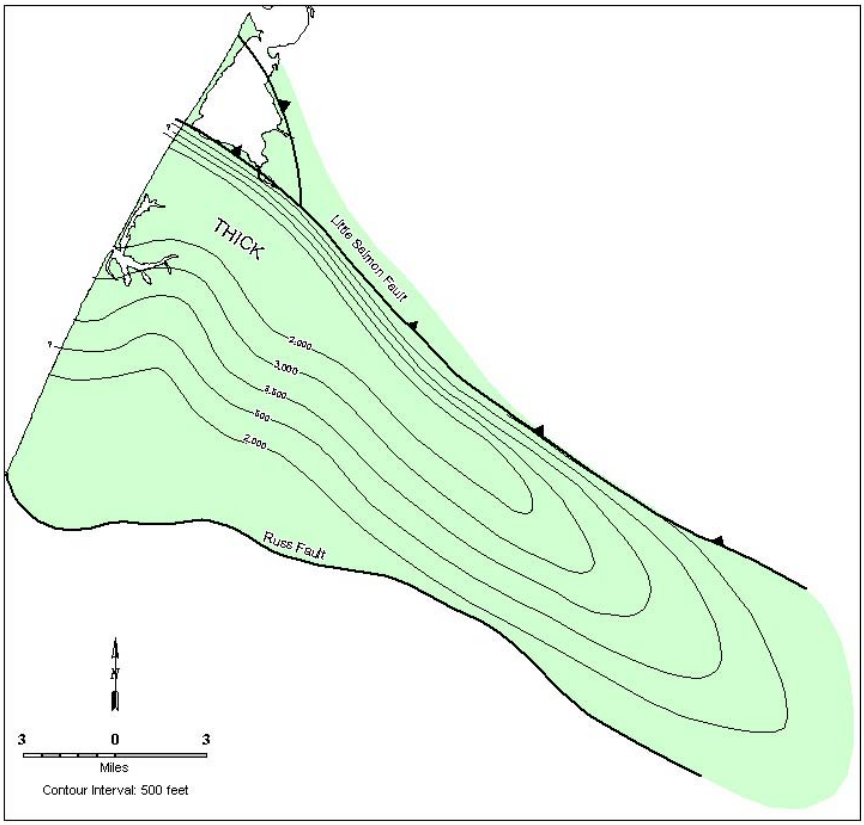


Figure 9. Eel River Basin – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

4.2.4.2 Salinas Basin

The Salinas Basin is one of several hydrocarbon producing Cenozoic marine sedimentary basins west of the San Andreas Fault including the La Honda Basin to the northwest and the Cuyama basin to the southeast. The basin is a narrow, northwest-trending feature extending almost 225 km (140 mi.) from Monterey County southeastward into San Luis Obispo County, and varying in width from less than 16 km (10 mi.) to 48 km (30 mi.). It is bordered on the east by the San Andreas Fault. To the northeast, the basin narrows where Salinian granitic basement rocks are uplifted and exposed in the Gabilan Range. The western basin margin is defined by the Jolan-Rinconda Fault Zone and uplifted granitic and metasedimentary rocks of the Santa Lucia Range.

The structural and lithologic framework of the Salinas Basin consists of a series of tectonic basement blocks assembled during a complex history of subduction and transform motion along plate boundaries. During the Miocene, the plate boundary between the Pacific Plate and the North American Plate evolved into a transform boundary represented by the San Andreas Fault

Zone. Basement rocks representing the subduction phase, and characterized by the Franciscan Complex, are present east of the San Andreas Fault Zone, against which transform motion has juxtaposed allochthonous Cretaceous granitic plutonic rocks and metamorphic basement rocks of the Salinian Terrane to the west. Rocks of the Salinian Terrane are thought to have been transported over 1,600 km (1,000 mi.) northward by transform motion along the San Andreas Fault Zone.

The basin is floored by a complex of Cretaceous granitic plutons and metamorphic rocks that are exposed in the Gabilan Range and dip westward towards the basin axis. Basement is overlain by a thick sequence of Cretaceous marine sediments to Pleistocene marine and nonmarine sedimentary rocks. The deepest well drilled in the basin bottomed in the Monterey Formation at 6,096 m (19,994 ft) (Stanley, 1995b). A generalized depth-to-basement map is shown in Figure 10.

Cretaceous rocks and beds of the lower Miocene Berry Formation, Vaqueros Sandstone, and Sandholt Shale onlap granitic Salinian basement. Little information is available regarding these units but sandstone developments are indicated on well logs. These rocks are overlain by the Monterey Formation, which throughout much of the shallower east flank of the basin, onlaps basement of the Gabilan shelf. The Monterey is conformably overlain by the Miocene Santa Margarita Formation, diatomaceous and silty mudstones of the Pliocene Pancho Rico Formation, and non-marine pebble beds, silica cemented sands and calcareous fresh water clays of the Plio–Pleistocene Paso Robles Formation. The Santa Margarita, Pancho-Rico, and Paso Robles beds are widely exposed throughout the basin in terraces along the lower elevations of the Gabilan Range and are generally too shallow to be considered for potential sequestration purposes.

Where the Monterey Formation onlaps basement, it contains significant sandstone deposits of nearshore, shelf, and turbidite origin which comprise the principal reservoirs in the basins three largest oil fields, the San Ardo, King City, and Monroe Swell fields. Monterey sandstones range in thickness from thin stringers up to 150 m (500 ft), but aggregate sandstone within the formation can total as much as 455 m (1,500 ft). Producing sandstone depths are shallow, ranging from 565–975 m (1,860–3,200 ft), but well control indicates Monterey deposits extend to at least 6,100 m (20,000 ft). Reported porosities in the shallow sands range from 15–39 percent with permeabilities of 500–8,000 md (DOGGR, 1991).

The San Ardo Field is the largest Monterey accumulation, having produced 73.9 Mm^3 oil (465 MMBO) and 2.2 Gm^3 gas (77 BCFG) from offshore bars and shoreline sandstones that onlap a shallow granitic basement ridge (Baldwin, 1950; Colvin, 1963). The King City Field has produced almost 0.3 Mm^3 oil (2 MMBO) and 20 Mm^3 (0.6 BCFG) from the Monterey Thorup Sandstone, a near shore or turbidite deposit along the hingeline between the granitic high on the east and the marine basin to the west. The field area is characterized by numerous northwest – southeast trending faults and anticlines, with many having steep overturned flanks (Church, 1963). The Monroe Swell Field has produced $111x10^3$ m^3 oil (695 MBO) and 3 Mm^3 gas (0.1 BCFG) from structural and stratigraphic traps. Smaller fields such as the Paris Valley, Lynch Canyon, McCool Ranch, and Quinado Canyon fields have produced smaller volumes of oil ranging from $1.6x10^3$ m^3 oil (10 MBO) to $50.1x10^3$ m^3 oil (315 MBO) from shallow Monterey sandstones.

While the Monterey sands in the known oil fields are too shallow for potential sequestration purposes, deeper Monterey sandstones exist farther west in the deeper basin. A gross sandstone isopach map (Figure 11) shows sandstone developments thickening to over 760 m (2,500 ft) to the southwest towards the basin axis. Underlying poorly known lower-middle Miocene and Cretaceous sandstones may also be present at depth.

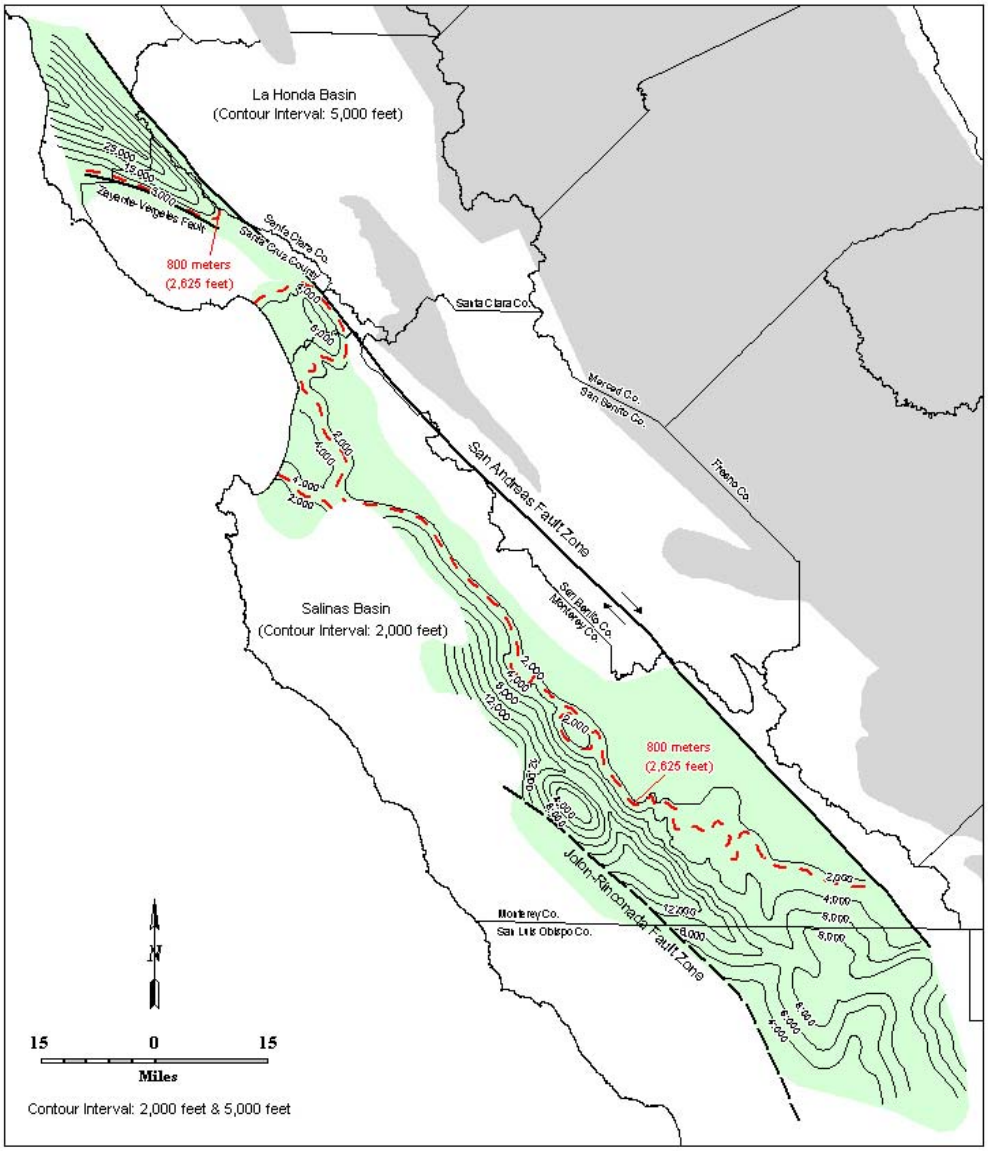


Figure 10. Salinas and La Honda basins – depth-to-basement map.

4.2.4.3 La Honda Basin

The La Honda Basin is located north of the Salinas Basin in Santa Clara and Santa Cruz counties between San Francisco and Monterey Bay. The basin is bounded on the northeast by the San Andreas Fault, on the northwest by granitic rocks of Montara Mountain, on the southwest by the Zayante-Vergeles Fault, and on the west by the San Gregorgio – Hosgri Fault (Stanley, 1995a). The relatively small basin comprises about 930 km^2 (360 sq. mi.) and represents a small sliver of the larger San Joaquin Basin which was displaced approximately 300 km (185 mi.) by right lateral slip along the San Andreas Fault.

It is estimated that as much as 14,635 m (48,000 ft) of Tertiary sedimentary and volcanic strata fill the basin (Figure 10). However, no wells have reached basement near the basin axis. The

basin contains only 4 small shallow oil fields and remains largely unexplored with only about 100 wells drilled to relatively shallow depths. The deeper section is poorly defined or unknown.

Where well logs have revealed the shallow stratigraphy, rocks of the Paleocene Locatelli Formation or overlying lower-middle Eocene Butano Formation rest unconformably on basement. The Locatelli Formation is a poorly understood section identified in outcrop but not positively identified in the subsurface (Stanley, 1995a). Where exposed, it consists of arkosic sandstone, mudstone, and conglomerate thought to be at least 300 m (985 ft) thick and containing both shelf and turbidite sandstones.

The Butano Formation consists of arkosic turbidite sandstone, mudstone, and conglomerate deposited by northward flowing turbidity currents on a deep sea fan (Nilsen, 1979). Individual sandstones may exceed 60 m (200 ft) thick but aggregate sand thickness can exceed 915 m (3,000 ft). Shallow producing sands between 550–760 m (1,800–2,500 ft) deep exhibit porosities between 15–35 percent with permeabilities of 30–40 md, but at depth, these are expected to be considerably reduced. The Butano Formation is conformably overlain by the Twobar Shale and Rices mudstone members of the San Lorenzo Formation which provide a thick overlying seal. The Twobar Shale is widespread and generally ranges from 50–250 m (165–825 ft) thick (Stanley, 1995a). The Rices member is locally as much as 670 m (2,200 ft) thick.

The San Lorenzo Formation is overlain by sandstone of the Vaqueros Formation except where the Vaqueros is locally absent, where the San Lorenzo Formation is overlain by the Zayante Sandstone and Mindego Basalt (Stanley, 1995a). The Vaqueros Formation is mainly sandstone, mudstone, and conglomerate deposited in environments ranging from deep sea fan to shallow marine shelf. The Vaqueros is overlain by the Lambert Shale and the discontinuous Lampico Sandstone.

Throughout much of the eastern basin, the Miocene Monterey Formation has been removed by erosion, but thickens to the southwest and south where it is present in the subsurface under Monterey Bay and along the western flank of the Salinas Basin to the south. Middle to late Miocene sandstones of the Santa Margarita Formation unconformably overlie rocks ranging from Mesozoic granitic basement to the Miocene Monterey Formation, and are themselves conformably overlain by the Santa Cruz mudstone. Unconformably overlying the Santa Cruz mudstone is the upper Miocene–Pliocene Purisima Formation. The Purisima Formation is widespread throughout the basin, resting on granitic basement rocks to rocks as young as the Santa Cruz mudstone (Stanley, 1995a). The Purisima includes arkosic and volcanic sandstones, conglomerate and mudstone. Sandstones are generally lenticular stringers but may reach as much as 30 m (100 ft) thick. Shallow Purisima sandstones between 245–825 m (800 and 2,700 ft) deep exhibit porosities of 22–34 percent and permeabilities of 1–40 md (DOGGR, 1991).

Four small oil fields have produced a total of over 0.27 Mm^3 oil (1.7 MMBO) from shallow sandstones between 100–825 m (330–2,700 ft) deep. The largest, La Honda Field, has produced 0.22 Mm^3 oil (1.4 MMBO) and 42 Mm^3 (1.5 BCFG), primarily from Butano and Purisima sandstones. The Oil Creek Field has produced only $38.3x10^3$ m^3 oil (241 MBO) and 2.2 Mm^3 (79 MMCF) gas from steeply dipping, faulted Butano sandstones. The Moody Gulch and Half Moon Bay fields have collectively produced $25.1x10^3$ m^3 oil (158 MBO) and 2,200 m^3 (76 MCF) from

thin shallow San Lorenzo and Purisima sandstones. Traps include anticlinal closures and stratigraphic traps under the regional sub-Purisima unconformity, and stratigraphic tar seal traps (Stanley, 1995a). The small field size and shallow reservoirs offer little practical opportunity for potential CO_2 sequestration.

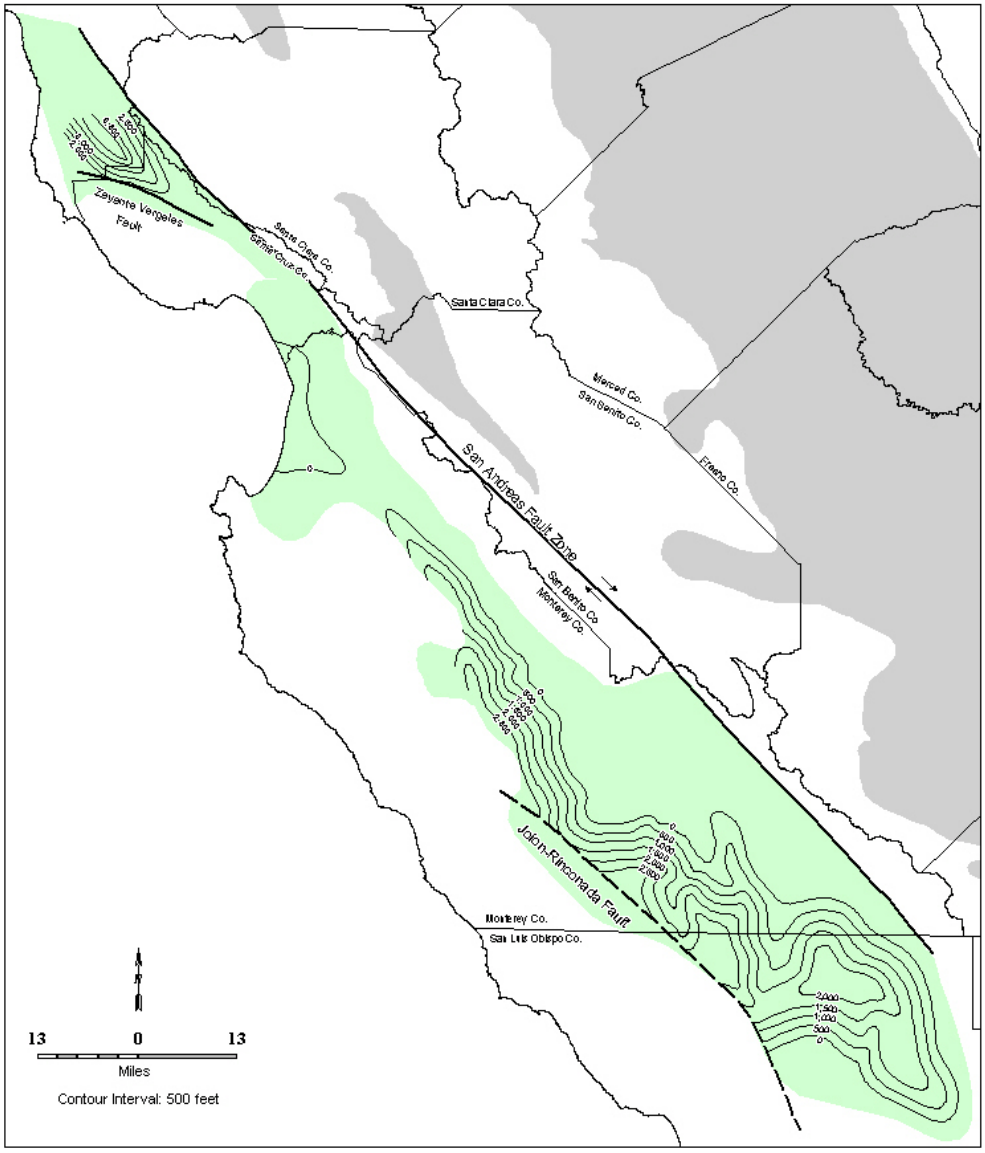


Figure 11. Salinas and La Honda basins – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement)

In the eastern basin, the Butano and Locatelli formations are too shallow to be considered for CO_2 sequestration. Westward, towards the basin center, however, sandstone in the Butano and younger formations thickens markedly (Figure 11). The deepest well in the basin, drilled on the Butano Anticline, bottomed in the Butano Formation at 3,370 m (11,053 ft) and encountered

more than 1,220 m (4,000 ft) of Butano sandstone within the isopach interval. The Vaqueros through Santa Margarita formations are blanketed by the Santa Cruz Mudstone and Purisima Formation, which can attain thicknesses of 2,715 m (8,900 ft) and 2,410 m (7,900 ft) respectively.

4.2.4.4 Cuyama Basin

The Cuyama Basin is a relatively small Cenozoic marine basin near the southern end of the Coast Ranges. It extends approximately 100–120 km (65–75 mi.) in a northwest-southeast direction and varies from 13–29 km (8–18 mi.) wide. It is bounded on the northeast by the San Andreas Fault zone and the Temblor Range, which separate it from the San Joaquin Basin. Its southwest margin is structurally complex and consists of at least two early Miocene wrench faults (Russell and La Panza Faults), which separate the basin from the Sierra Madre Range. The northwest end of the basin is indeterminate, but approaches the southeast end of the Salinas Basin. Its southeastern end is defined by a buried normal fault sub-parallel to the younger Big Pine Fault (Tennyson, 1995).

The basin is located in the southern part of the Salinian block and is floored by granitic and gneissic rocks at considerable depth. Only a handful of wells have encountered deep sub-thrust granitic basement rocks below 5,185 m (17,000 ft) under the Caliente Range east of the basin. The deepest wells in the central basin bottomed just below 3,965 m (13,000 ft) in the Soda Lake member of the Vaqueros Formation (Spitz, 1988). The lack of basement control or published geophysical maps precluded the construction of a depth-to-basement map.

The basin is structurally complex with extensive normal faulting of the pre-Pliocene section followed by later thrust faulting of the basement through Pliocene section burying much of the sedimentary section below complex thrust sheets. Principle thrust faults include the northeasterly dipping Morales, Taylor Canyon, and Whiterock faults.

Nonmarine mudstones, sandstones, and alluvial gravels of the Oligocene Simmler Formation are presumed to unconformably overly basement throughout much of the basin. The overlying lower and middle Miocene section consists of the Vaqueros Formation, Branch Canyon Sandstone, and Monterey Formation. The Vaqueros Formation is a transgressive-regressive sequence consisting of three principal units; 1) basal transgressive shallow marine sandstone of the Quail Canyon member; 2) transgressive deep marine shale of the Soda Lake member; and 3) an upper unit of regressive clastic deltaic and near shore marine facies of the Painted Rock member. No reliable petrophysical data was available for the Vaqueros sandstones.

During the middle and upper Miocene, the western basin was dominated by marine conditions and the deposition of up to 1,370 m (4,500 ft) of Monterey Formation shale. Eastward, the basin plain shales grade shoreward through distal thin-bedded turbidite sands to thicker proximal turbidite sands. Farther shoreward, shallower marine conditions prevailed with the development of a transgressive – regressive shoreline sequence of interfingering Monterey shale and coarser shelf and shallow marine sediments of the Branch Canyon Sandstone, Painted Rock Sandstone, and overlying Santa Margarita Formation. In turn, these units grade landward into nonmarine

rocks of the Caliente Formation (Lagoe, 1984). Shallow marine to nonmarine rocks of the Pliocene Morales Formation unconformably overlie the Santa Margarita Formation.

Branch Canyon sandstones are generally 14–30 m (45–100 ft) thick. Porosity has been reported to be about 19 percent at 2,215 m (7,270 ft). No permeability data was available. Painted Rock sandstones are the primary oil reservoirs in the basin. Sandstones range from 15–91 m (50–300 ft) thick but aggregate sandstones can achieve a thickness of 1,830 m (6,000 ft) (Tennyson, 1995). Porosities and permeabilities in reservoir sandstones at depths of 1,250–2,285 m (4,100–7,500 ft) range from 23–40 percent and 177–400 md, respectively. Reported porosities in shallow Santa Margarita sandstones between 560 and 760 m (1,830 and 2,500 ft) range 30–32 percent, and permeabilities 675–1,300 md. Porosity of 30 percent has been reported in a shallow Morales sandstone at 580 m (1,900 ft) (DOGGR, 1991).

In north central portion of the basin where deep well control exists, a sandstone isopach map (Figure 12) indicates an area of thick sandstone exceeding 1,220 m (4,000 ft) and aligned in a northwest-southeast orientation roughly paralleling the basin axis. Sandstones within the isopach interval include Branch Canyon and Painted Rock sandstones and overlying Santa Margarita sandstones.

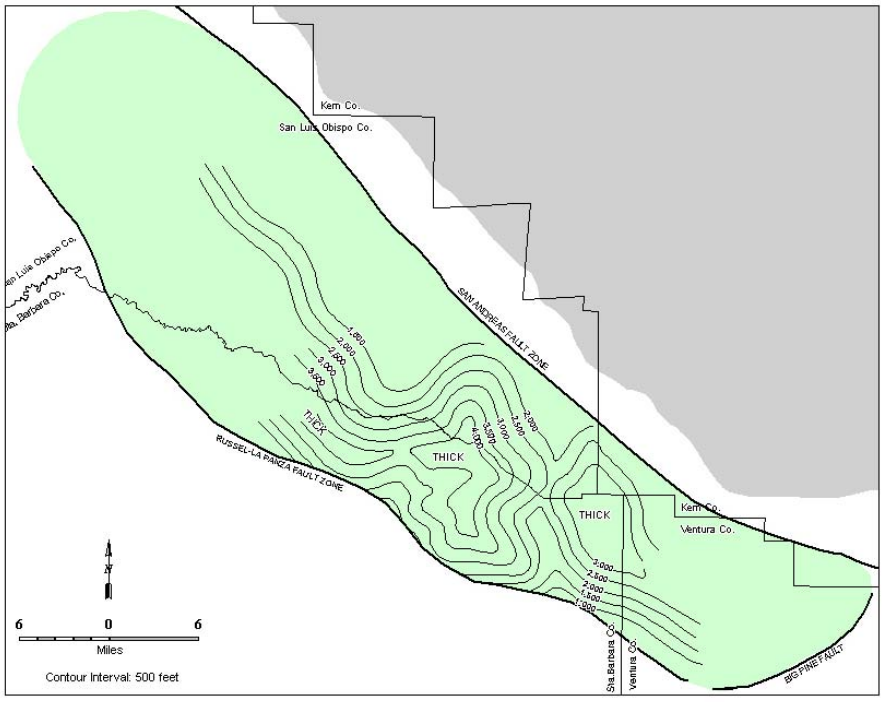


Figure 12. Cuyama Basin – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

Three significant oil fields have been discovered in the basin. The two largest, the South Cuyama Field and the Russell Ranch Field produce from complexly faulted northwest – southeast trending structures. Both fields produce primarily from Painted Rock sandstones. The South

Cuyama Field has produced almost 35.5 Mm^3 oil (223 MMBO) and 2.18 Gm^3 gas (234 BCFG) from sands between 1,250 and 2,285 m (4,100 and 7,500 ft) deep, while the Russell Ranch Field has produced over 11 Mm^3 oil (68 MMBO) and 1.4 Gm^3 gas (49 BCFG) from sands between 795–1,065 m (2,600–3,500 ft) deep. The Morales Canyon Field, has produced 0.40 Mm^3 oil (2.5 MMBO) and 51 Mm^3 (1.8 BCFG) from small sub-thrust structural and stratigraphic traps in Vaqueros Formation sands a 1,770 m (5,800 ft) and a shallow Morales Formation sand at 580 m (1,900 ft).

4.2.4.5 Livermore, Orinda, and Sonoma Basins

The Livermore, Orinda, and Sonoma basins are a related series of deep, linear, Neogene pull-apart basins within the Coast Ranges between San Francisco Bay and the Sacramento Basin. All three basins formed under the influence of extensional stresses after the onset of strike-slip motion along the San Andreas and associated Calaveras and Hayward fault systems during the middle Miocene. Right-slip movement provided the shearing motion to open the basins (Magoon, 1995). Widespread volcanism occurred during the filling of the basins and volcanic rocks are especially prevalent in the shallow Pliocene section in the Sonoma Basin.

The basins are filled with thick sections of Miocene and Pliocene sediments resting on an inferred basement of Jurassic–Cretaceous Franciscan Complex rocks which are exposed in the many uplifts surrounding the basins. No wells have been drilled to basement in the axial portions of these basins and no published geophysical basement maps are available, hence no depth-to-basement maps were prepared for these basins. The Livermore Basin contains the most subsurface control with several wells exceeding 3,050 m (10,000 ft) deep. The Orinda Basin has considerably less well control with only 3 wells exceeding 2,745 m (9,000 ft). Very little control is available in the Sonoma Basin with the deepest well bottoming at 2,470 m (8,105 ft).

The Livermore Basin is approximately 48 km (30 mi.) long by 19 km (12 mi.) wide. It is bounded on the north and east by Mount Diablo and the Diablo Range and on the west and southwest by the Calaveras Fault which separates it from the Orinda Basin. Uplifted Franciscan Complex rocks form its southern end. While the deepest well drilled bottomed at 5,305 m (17,404 ft) in Miocene sediments (Darrow, 1979), outcrop and unpublished geophysical data suggest that the Livermore Basin may be filled with as much as 6,705 m (22,000 ft) of Eocene, Miocene, and Pliocene sediments that have been extensively folded and faulted by later compressional forces caused by motion on the marginal faults. Outcrops of Eocene marine rocks equivalent to the Capay, Domengine, Nortonville, and Markley formations of the Sacramento Basin dip basinward to depths sufficient for CO_2 sequestration. The Miocene section includes the Sobrante, Briones, Cierbo, and Neroly formations. The Sobrante Formation consists of shallow marine sands and pebbly conglomerates. The Briones, Cierbo, and Neroly units make up about 1,370 m (4,500 ft) of shallow marine to brackish water sands, pebbly conglomerates, and tuffaceous sands and shales (Darrow, 1979). The Neroly Formation is overlain by the Pliocene Orinda Formation, a basin-wide nonmarine sequence of sands, conglomerates, shales, and volcanics that may reach a thickness of greater than 4,575 m (15,000 ft) in the major synclinal areas of the basin (Darrow, 1979).

Well logs indicate sandstone intervals separated by laterally persistent shale units that might be suitable seals for potential sequestration purposes. In the basin's single oil field, the Livermore Field, Eocene Tesla Formation (Domengine equivalent) sandstones at 1,615 m (5,300 ft) exhibit porosities of about 23 percent while reported porosity and permeability in the Miocene Cierbo Formation sandstones between 175–610 m (900–2,000 ft) average 26 percent and 250 md, respectively (DOG, 1983). Cumulatively, these zones have produced 0.29 Mm^3 oil (1.8 MMBO) from a folded and faulted anticlinal nose. The combined Tesla-Cierbo sandstone interval, which reaches as much as 490 m (1,600 ft) thick, is overlain by close to 150 m (500 ft) of overlying upper Cierbo Formation shale. Similar Pliocene and Miocene sand and shale relationships are indicated by the deeper well logs.

In the abandoned Hospital Nose Field, near the south end of the basin, over 610 m (2,000 ft) of interbedded upper Cretaceous Panoche Formation sandstone occurs at a depth of 1,525 m (5,000 ft) and is overlain by over 150 m (500 ft) of Moreno Shale. While the distribution of these units is not well known in the basin, these units dip steeply basinward and persist to unknown depth.

A gross sandstone isopach map for the basin depicts an area of thicker sand development exceeding 490 m (1,600 ft) in the south central portion of the basin (Figure 13). Given the complex structural configuration of the basin, steep dips, and fault displacements along the basin margins, the isopach interval includes sandstones of the Cretaceous Panoche through Pliocene Orinda formations.

The Orinda Basin is a narrow linear basin measuring about 80 km (50 mi.) by 11 km (7 mi.) and is bounded on the west by the Hayward Fault and on the east by the Calaveras Fault. Its southern limit is the convergence of the two faults in northern Santa Clara County. Its northern end is taken to San Pablo Bay, past which the Sonoma Basin begins.

Limited well control and outcrop data indicates the Orinda Basin contains a sedimentary section very similar to that of the neighboring Livermore Basin. The deepest well bottomed at 3,048 m (9,997 ft) in the abandoned one-well Pinole Point Field near the north end of the basin. Only two other wells exceeded 2,745 m (9,000 ft) with a handful going to 1,525–2,135 m (5,000–7,000 ft). The available well logs were used to construct a sandstone isopach map of logged section, which suggests a longitudinal thickness of at least 245 m (800 ft) extending from near the basin center to San Pablo Bay (Figure 13).

The Pinole Point Field produced only $2.2x10^3$ m^3 oil (14 MBO) oil and 3.14 Mm^3 (111 MMCF) gas from faulted and poorly developed Orinda Formation sandstones at 1,325 m (4,350 ft) and late Miocene Neroly sandstones at 1,950 m (6,400 ft). No petrophysical properties are reported for either reservoir zone.

The Sonoma Basin measures about 80 km (50 mi.) by 13 km (8 mi.) at its widest. The northerly extension of the Hayward Fault forms its western boundary. The Healdsburg and Rogers Creek faults mark its eastern limit.

Deep subsurface well control is nonexistent in the Sonoma Basin and no depth to basement or sandstone isopach map could be prepared. Only five wells went to depths of more than 1,525 m

(5,000 ft). The deepest well, at the south end of the basin, bottomed at 2,471 m (8,105 ft) and encountered only 70 m (225 ft) of sandstone below 800 m (2,625 ft). In the other four wells, considerably less sand was encountered in the equivalent intervals.

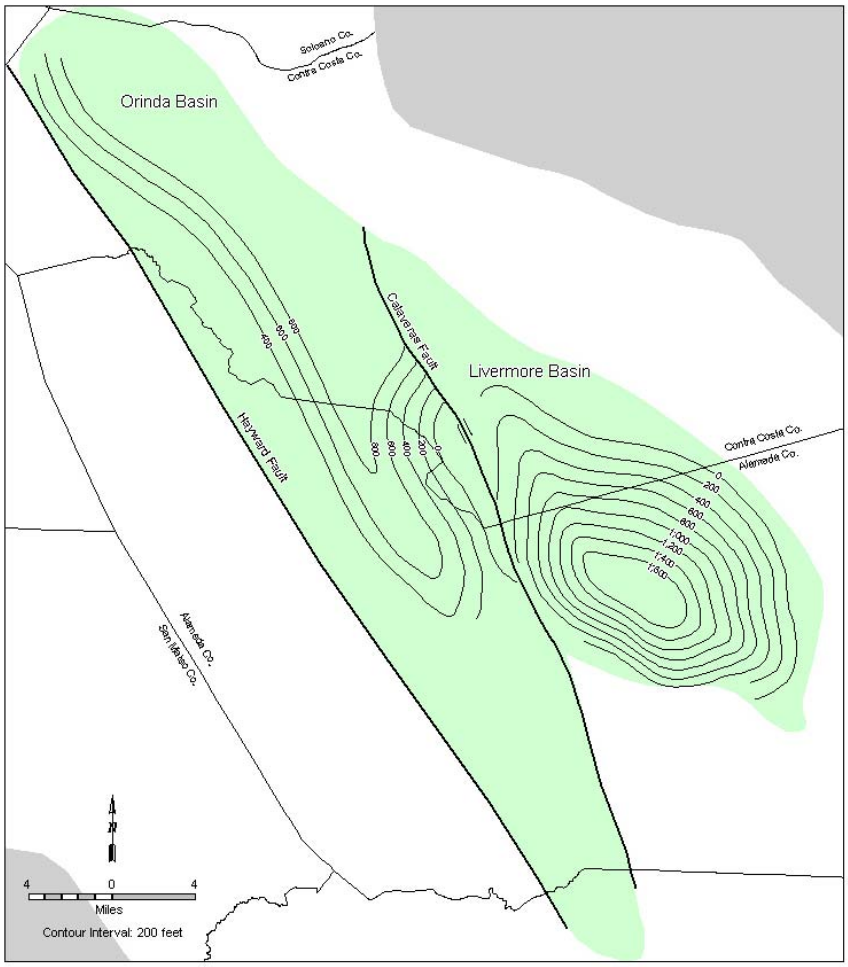


Figure 13. Livermore and Orinda basins – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

Similarly, the only available petrophysical information about basin sandstones comes from sandstones in one of two shallow oil and gas pools that have been discovered. The Petaluma Field, in the south end of the basin, produced 2.2×10^3 m^3 oil (14 MBO) and 37 Mm^3 (1.3 BCFG) from thin Pliocene Petaluma Formation sands at depths of only 185–380 m (600 to 1,240 ft) with reported porosities of 30 percent (DOG, 1983). The one well Cotati Gas Field, on the western fringe of the basin, produced only 17.2 Mm^3 (609 MMCF) gas from an unidentified Pliocene sand at 275 m (900 ft). No other data is available.

Since the Sonoma Basin lacks sufficient well control to adequately assess its subsurface geology, its potential for geologic CO_2 sequestration remains unknown. Its genetic relationship with the Livermore and Orinda basins implies that sandstones and shales equivalent to the Miocene–

Pliocene section in the Livermore and Orinda basins may be present at depth and possibly be suitable for sequestration.

4.2.5 Mojave Desert Province

The Mojave Desert province is a broad interior region in southern California composed of isolated mountain ranges and intervening, fault bounded Cenozoic nonmarine basins with enclosed drainages and numerous playas. It is bounded on the north by the Garlock Fault, to the west by the San Andreas Fault, and to the east by the Colorado River.

Basement rocks exposed in adjacent mountain ranges consist of Proterozoic and Precambrian metamorphic and igneous rocks and limestones, and Mesozoic granitic rocks. Basin fill sediments are primarily nonmarine aggrading alluvial fan sequences derived from adjacent uplands, and interbedded layers of tuff, ash, lacustrine sediments, and evaporates. Volcanic flows and flow breccias are common with andesites and rhyolites characterizing the older extrusives and basaltic flows and cinder cones characterizing younger episodes (Norris and Webb, 1990).

Only six basins in the Mojave Desert province were determined to have CO_2 sequestration potential, including the Bristol, Chuckwalla, Fremont, Palen, Palo Verde, and Ward basins. Aside from shallow water wells and mineral exploration borings, almost no subsurface stratigraphic information in the form of well control exists. Consequently, there are no means to currently assess the stratigraphic sequence for potential sandstone aquifers, sealing units, or trapping configurations. Hence, sandstone isopach maps could not be prepared for these basins. The basins were selected almost entirely on thickness of sedimentary fill derived from the geophysical depth-to-basement maps of Saltus and Jachens (1995) and Blakely and Ponce (2001). In the absence of basin specific data, it was assumed that the nature of sedimentary fill in Mojave Desert basins is ubiquitous and can be characterized by surface and shallow stratigraphic information. While it's relatively clear that these basins contain abundant sands and gravels, the presence of widespread seals and trapping mechanisms is less clear. However, surface and shallow basin center playa deposits, including mudstones and evaporate minerals, under appropriate structural and stratigraphic conditions, may provide localized seals if present at greater depths.

At current levels of knowledge, these basins appear to have considerably less sequestration potential than the larger, deeper, and better understood Cenozoic marine basins. More thorough subsurface characterization would be required before the sequestration potential of these basins could be properly assessed.

4.2.5.1 Bristol Basin

The Bristol basin covers approximately 1,013 km^2 (391 sq. mi.) in south-central San Bernardino County. Gravity data indicates an area of approximately 220 km^2 (85 sq. mi.) near the basin center where over 3,050 m (10,000 ft) sediments may overlie basement (Figure 14). While the nature of the deep beds is unknown, the dry lakebed is actively mined for the mineral halite (salt). The shallow beds include layers of sand, clay, and gypsum. Muds, largely of volcanic ash origin, are found within the salt body. The main salt body averages 2 m (5 ft) thick and is

underlain by 2–3 m (8–10 ft) of lacustrine clay which is underlain by another salt bed approximately 2 m (5 ft) thick. Similar beds at depth could provide seals for deeper saline aquifers under the right structural or stratigraphic circumstances.

4.2.5.2 Ward Basin

Ward Basin is a narrow linear basin in southeastern San Bernardino County. It comprises approximately 1,564 km^2 (604 sq. mi.). In the southern end of the basin, gravity data suggests an area of approximately 260 km^2 (100 sq. mi.), which may contain over 1,525 m (5,000 ft) of sedimentary fill (Figure 14).

4.2.5.3 Palen Basin

Palen Basin is a small basin of about 381 km^2 (147 sq. mi.) in eastern Riverside County. Gravity data indicates a small depression in the southern end of the basin comprising only 60 km^2 (23 sq. mi.) in which sediments may reach close to 1,525 m (5,000 ft) (Figure 14).

4.2.5.4 Chuckwalla Basin

Chuckwalla Basin covers about 1,380 km^2 (533 sq. mi.) in eastern Riverside County. Gravity data suggests that two small sub-basins, which collectively comprise an area of about 236 km^2 (91 sq. mi.), and may contain sediments up to 1,830 m (6,000 ft) thick (Figure 14). No subsurface stratigraphic information is available.

4.2.5.5 Palo Verde Basin

Palo Verde Basin straddles the California – Arizona state line in eastern Riverside County, California and La Paz County, Arizona. The California portion includes approximately 1,062 km^2 (410 sq. mi.), of which about 400 km^2 (155 sq. mi.) may be filled with sediments greater than 800 m (2,625 ft) thick (Figure 14). Two smaller subbasins over 1,525 m (5,000 ft) deep are indicated in the north and south ends of the basin.

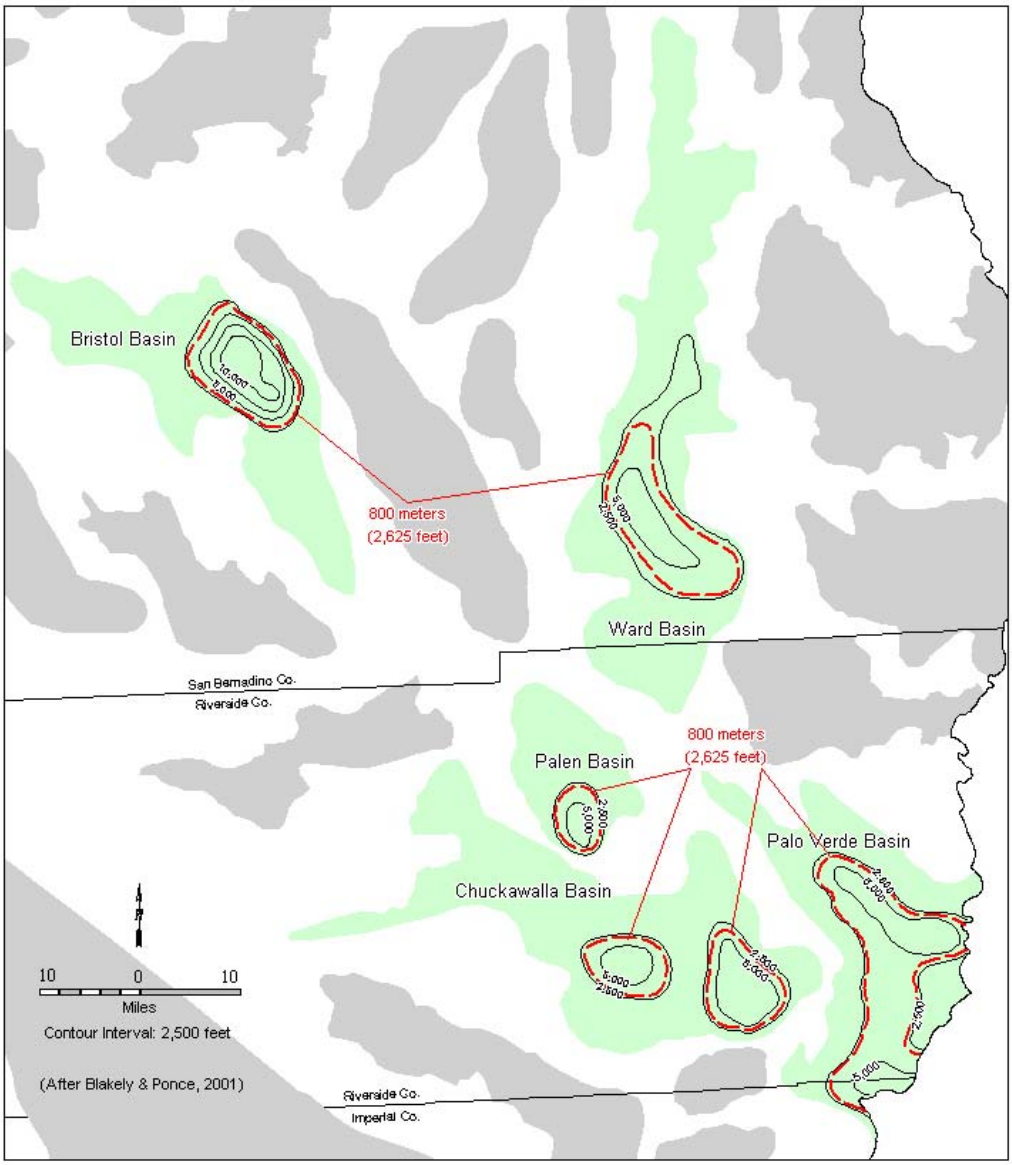


Figure 14. Bristol, Ward, Palen, Chuckwalla, and Palo Verde basins – depth-to-basement map.

4.2.5.6 Fremont Basin

The northern end of the Fremont Valley, in eastern Kern County, is underlain by a small narrow basin of about 325 km^2 (125 sq. mi.) containing some of the thickest known sedimentary fill in the Mojave Desert. The basin is genetically related to the Garlock Fault zone, which forms its northern boundary. Gravity interpretations reveal an area of about 135 km^2 (52 sq. mi.), which may contain sediments over 3,660 m (12,000 ft) thick along the basin axis (Figure 15). An exploratory well drilled in 1926 to a depth of 1,545 m (5,063 ft) encountered interbedded sand, gravel, and clay from surface to total depth. Deeper sediments are likely to be similar with the

possibility of Miocene marine rocks at depth. While this basin may contain saline aquifers with carbon sequestration potential, its proximity to the Garlock Fault may influence that potential.

4.2.6 Basin and Range Province

The Basin and Range province encompasses the westernmost part of the Great Basin which lies largely in neighboring Nevada. The California portion is bounded on the west by the Sierra Nevada Mountains and to the south by the Garlock Fault. It includes most of Inyo and Mono counties, northeastern Kern County, and northern San Bernardino County. A small portion of the Basin and Range extends northward through eastern Lassen and Modoc counties into southeastern Oregon. Bordering the Basin and Range to the west in Lassen and Modoc Counties is the Modoc Plateau province.

The Basin and Range is characterized by north-northwesterly trending fault bounded uplifts and intervening downdropped grabens produced by Cenozoic crustal extension and transform motion. Most basins exhibit interior drainages with ephemeral saline lakes and playas. Of the many basins identified, only seven appear to have sufficient depth and sedimentary fill for potential CO_2 sequestration. These include the Amargosa, Pahrump, Mesquite, and Owens basins in the southern Basin and Range, and the Surprise, Goose Lake, and Alturas basins in the northern Basin and Range.

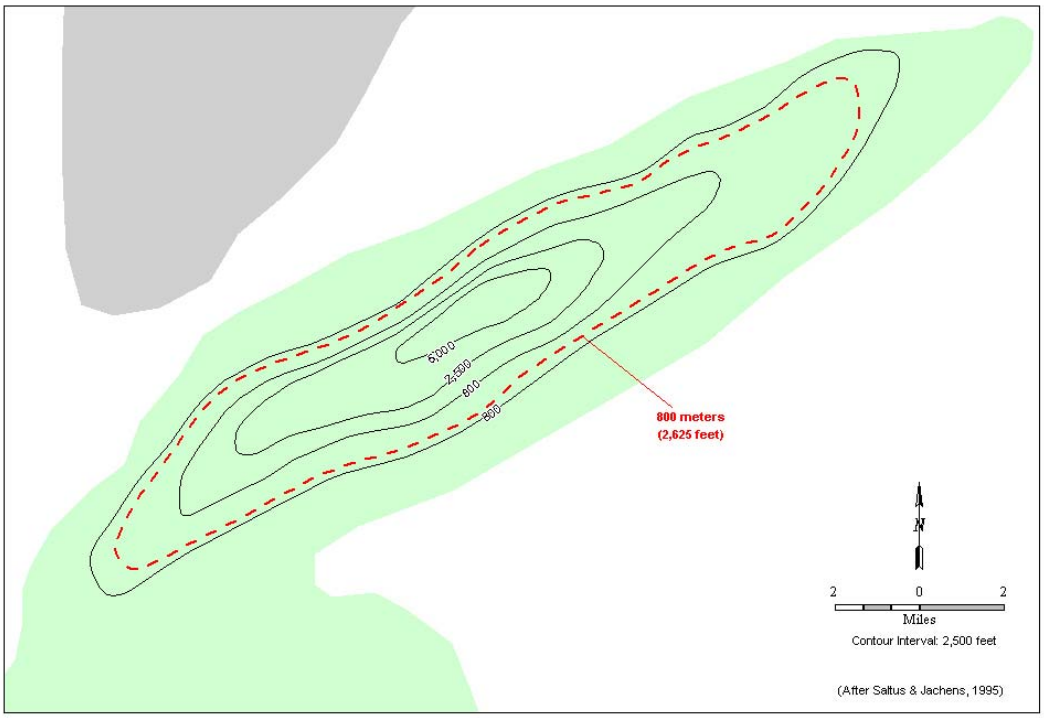


Figure 15. Fremont Basin – depth-to-basement map.

Similar to the Mojave Desert, very little well control exists to evaluate subsurface stratigraphy in the southern part of the province and the depth-to-basement maps of Saltus and Jachens (1995) and Blakely and Ponce (2001) were again used as the primary tool for assessing sediment thickness. In the northern Basin and Range, no geophysical mapping was available. However, the stratigraphy in several geothermal exploratory wells between 1,508 m (4,946 ft) and 2,136 m (7,005 ft) deep in the Surprise Basin was assumed to be similar to that in the neighboring Goose Lake and Alturas basins.

Generally, the basins of the Basin and Range province contain only thin sections of Miocene to Holocene terrestrial sediments and Pliocene to Holocene volcanic rocks. Basin fill tends to be largely coarse alluvial fan material and colluvium shed from bordering uplifts in thick flanking fans and wedges, and possessing no updip stratigraphic seal. Marine sedimentation is absent. Similar to the Mojave Desert, some basins contain Pleistocene lacustrine claystone, mudstone, and evaporate beds which may provide seals for saline aquifers under favorable structural or stratigraphic conditions. For example, in the Searles Valley, where shallow evaporites are solution mined, saline deposits are known to range from 11–24 m (35–80 ft) thick.

4.2.6.1 Amargosa Basin

The Amargosa Basin is one of three northwest trending basins straddling the California – Nevada state line that may contain sufficient sedimentary fill for carbon sequestration. The California portion of the basin, in southeast Inyo County, comprises approximately 710 km^2 (275 sq. mi.), of which approximately 155 km^2 (60 sq. mi.) contain sediments greater than 760 m (2,500 ft) thick (Figure 16). Sediment thickness may reach as much as 1,525 m (5,000 ft) in the west side of the basin.

4.2.6.2 Pahrump Basin

Pahrump Basin straddles the state line about 13–16 km (8–10 mi.) southeast of the Amargosa Basin in Inyo County. About 342 km^2 (132 sq. mi.) lies within California with approximately 130 km^2 (50 sq. mi.) underlain by sediments thicker than 760 m (2,500 ft) (Figure 16). Maximum indicated fill is estimated to exceed 2,285 m (7,500 ft) near the state line.

4.2.6.3 Mesquite Basin

A few kilometers south of the Pahrump Basin is the Mesquite Basin in northeast San Bernardino and northeasternmost Inyo counties. The California portion covers 319 km^2 (123 sq. mi.) of which about 70 km^2 (27 sq. mi.) contains fill estimated to be between 760–2,285 m (2,500–7,500 ft) thick (Figure 16).

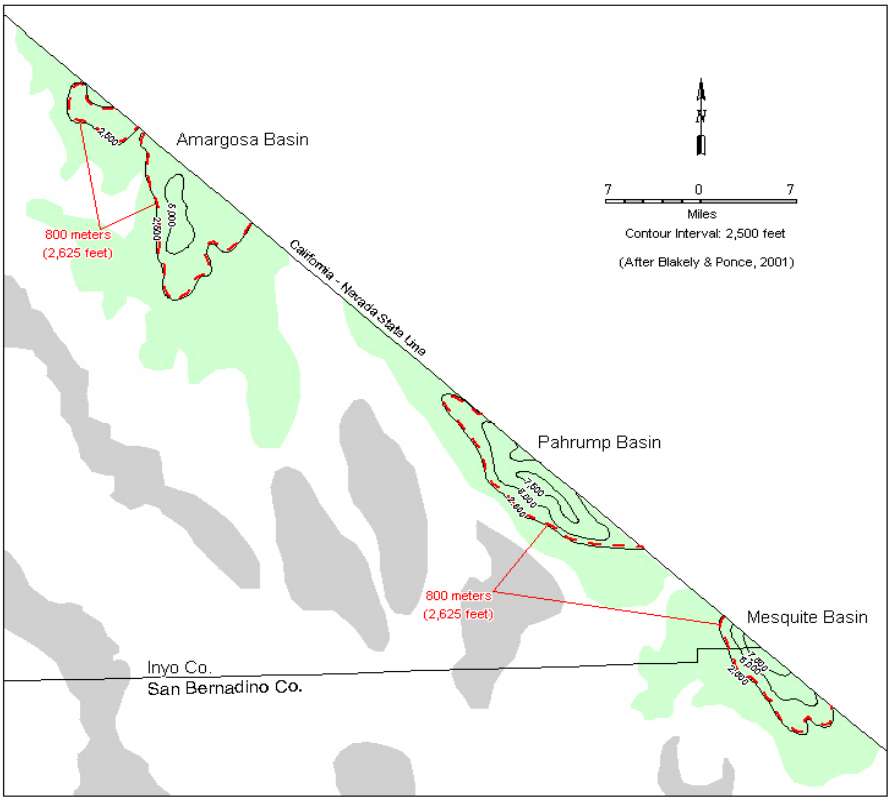


Figure 16. Amargosa, Pahrump, and Mesquite basins – depth-to-basement map.

4.2.6.4 Owens Basin

The Owens basin is the deepest and largest of the identified basins in the Basin and Range province with sequestration potential. A narrow, linear fault bounded graben, it extends from southwestern Inyo County for approximately 225 km (140 mi.) northward through Mono County to the Nevada state line, and ranges in width from as little as 3 km (2 mi.) to over 16 km (10 mi.) at Owens Dry Lake. It lies along the western edge of the Basin and Range geomorphic province, within the Eastern California Shear Zone, where it forms part of the boundary between the Sierra Nevada and Basin and Range provinces. Steeply dipping faults of the Owens Valley and White-Inyo Mountain fault systems separate it from the Sierra Nevada Mountains to the west and the Inyo and White Mountains to the east respectively.

The shallowest sediments consist of unconsolidated Quaternary alluvial fan material deposited along the basin margin which grade into nearshore fluvial and lacustrine sand, silt, clay, and evaporites near the southern basin center. These surficial deposits reach at least 365 m (1,200 ft) thick. In some areas, these strata are interbedded with basalt flows or shallow unconsolidated pumice beds. The only deep control consists of a 2,131 m (6,989 foot) exploratory well drilled on the Owens Lake bed. This well encountered Pliocene to Holocene interbedded muds, clays, sands, and evaporites.

No wells have been drilled to basement, but gravity data indicates two areas of thick basin sediments. The larger of the two, about 20 km (12 mi.) south of Lone Pine and underlying Owens Lake, may contain up to 4,575 m (15,000 ft) of sediments (Figure 17). The smaller of the two lies southeast of Bishop and extends from Big Pine to the Mono County line. It may contain as much as 3,050 m (10,000 ft) of fill.

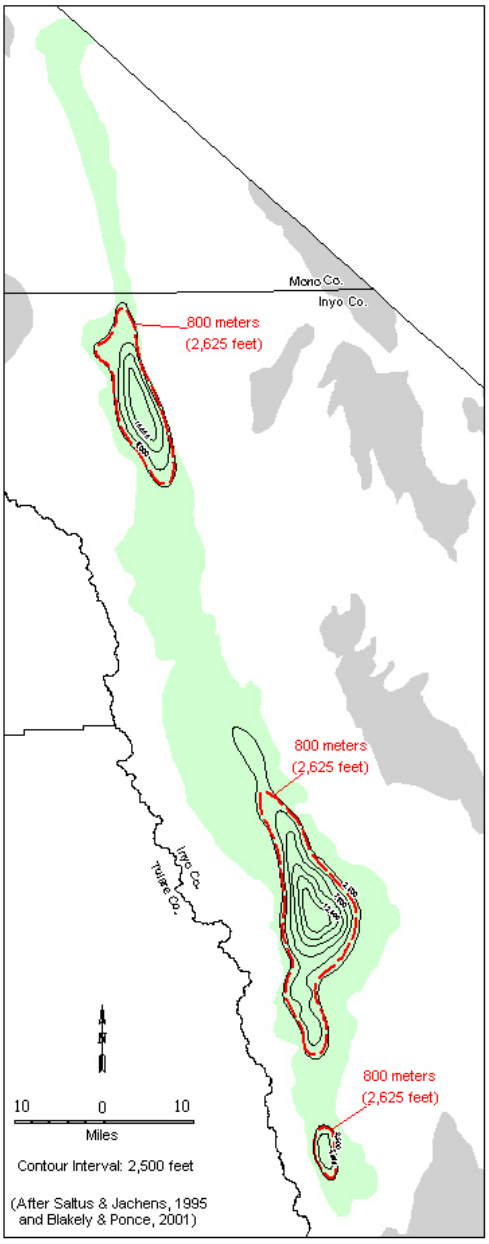


Figure 17. Owens Basin – depth-to-basement map.

The Owens basin is geologically active, which must be taken into consideration. As much as 20 –25 percent of the relative motion between the Pacific and North American plates is

accommodated within the Eastern California Shear Zone, with a significant amount of this along the Owens Valley Fault-White Mountains Fault system (Schroeder *et al.*, 2002). Significant tectonic events along the Owens Valley Fault include the pre-1872, 7.4 magnitude earthquake. Offsets of the Owens Valley Fault indicate at least 2 additional large earthquakes occurred during the Holocene (Smoot *et al.*, 2000) with a cumulative 7 m (23 ft) of vertical displacement and 5 m (16 ft) of horizontal displacement (Sheehan, 1987).

4.2.6.5 Surprise Basin

Surprise Basin is a large complexly faulted graben straddling the Nevada state line in northeast California's Modoc County. The basin is approximately 80 km (50 mi.) long by 20 km (12 mi.) wide, the California portion comprising about 857 km^2 (331 sq. mi.). The valley is bounded on all sides by normal faults including the Surprise Valley Fault on the west and the Hays Canyon Fault on the east. Smaller faults mark its northern and southern ends. Surface deposits are coalesced alluvial fan and nearshore lake deposits. While the depth to bedrock is unknown, several geothermal exploratory wells penetrated a 2,139 m (7,015 foot) thick sequence of interbedded volcanic breccias, tuffs, volcanic sandstones and conglomerates, clays, rhyolite, andesite, and basalt. Sample logs and lost circulation problems while drilling suggest that the igneous rocks may be highly fractured, but lacustrine clay beds and altered argillaceous tuffs might provide seals for underlying sandstones where structural closure or stratigraphic containment could be demonstrated.

4.2.6.6 Goose Lake Basin

Goose Lake Basin is approximately 24 km (15 mi.) northwest of and sub-parallel to Surprise Basin in northern Modoc County. The basin overlaps the Oregon state line to the north. The California portion is approximately 40 km (24 mi.) long by 16 km (10 mi.) wide, comprising approximately 458 km^2 (177 sq. mi.). Similar to Surprise Valley, it consists of a graben bounded by numerous normal faults. Surface deposits consist of alluvium and lake deposits grading laterally into marginal alluvial fans. Basin depth is unknown but its proximity to, and similar structural framework with Surprise Basin suggests it too may contain a thick sequence of interbedded sands, conglomerates, volcanics, and clays.

4.2.6.7 Alturas Basin

The Alturas Basin is located west of Surprise Basin and south of Goose Lake Basin in eastern Modoc County. It occupies an area of 298 km^2 (115 sq. mi.) and is bounded to the east by the Warner Mountains and to the south and west by the Likely Fault and volcanic tablelands. Geologically, the basin is similar to the neighboring Surprise and Goose Lake basins and thought to host an unknown thickness of interbedded sands, conglomerates, volcanics, and clays. Depth to basement is unknown. Lacking data to the contrary, the basin was retained as a potential candidate for CO_2 sequestration.

4.2.7 Modoc Plateau Province

The Modoc Plateau province is a transitional zone between the Cascades, Basin and Range, and Sierra Nevada provinces. It is an undulating plateau composed mostly of Miocene to Holocene basaltic flows. Unlike many of the basins of the Mojave Desert and Basin and Range, little gravity data was available to determine basin depth. Further, deep well control is virtually absent. Published geological information on the basins is also meager. Of the four basins originally identified in the province, only the Big Valley and Fall River basins have indications of sequestration potential.

4.2.7.1 Big Valley Basin

Big Valley Basin is a broad flat plain comprising about 319 km^2 (123 sq. mi.) in southwest Modoc and northwestern Lassen Counties. The basin consists of a series of downthrown grabens surrounded by tilted fault block ridges. To the north, south, ands east are Pleistocene and Pliocene basalt and Tertiary pyroclastic rocks of the Turner Creek Formation, and to the west are Tertiary rocks of the Big Valley Mountain volcanic series.

Basin depth is unknown, but a single geothermal exploratory well drilled near the basin center provides some insight into the basin's stratigraphy. The well encountered 2,134 m (7,000 ft) of interbedded medium to coarse arkosic and volcanic sandstone and conglomerate interbedded with tuffaceous claystone, green-gray claystone, tuff, and siltstone. The lateral extent of these facies is unknown, but the vertical facies relationships suggest that at least aquifers and seals may be present.

4.2.7.2 Fall River Basin

Fall River Basin encompasses about 194 km^2 (75 sq. mi.) in northeast Shasta County, about 25 km (15 mi.) southwest of the Big Valley Basin. No deep wells have been drilled to determine basin fill. However, a single exploratory well encountered at about 282 m (925 ft) of diverse shallow sediments. Deposits include Holocene alluvium and stream channel and floodplain sands, Pleistocene and Holocene volcanic cinders, tuffs, and basalts, and Pleistocene near shore lacustrine clayey silt and sand. The proximity and geologic similarity to the Big Valley Basin suggests the basin may contain over 1,000 m (several thousand feet) of interbedded sandstones and potential seals.

4.2.8 Colorado Desert Province

4.2.8.1 Salton Trough

The Salton Trough is a northeast-southwest elongate Neogene structural trough underlying the Coachella and Imperial Valleys. Its surface expression comprises the Colorado Desert geomorphic province. It extends from the vicinity of Palm Springs in Riverside County, southeastward through Imperial County into Mexico. The US portion of the basin is about 200 km (125 mi.) long by 13–105 km (8–65 mi.) wide. It is bordered on the east by the San Andreas

Fault and uplifted crystalline rocks of the Little San Bernardino and Chocolate Mountain ranges, and on the west by the San Jacinto Mountains and the southern Peninsular Ranges.

The Salton Trough differs from California's other large Cenozoic sedimentary basins in several respects that may adversely impact its potential for geologic CO_2 sequestration. However, its considerable areal extent and depth, in conjunction insufficient existing well control, requires that additional information be obtained before the basin, in whole or in part, is excluded from consideration as a potential sequestration site.

Tectonically, the Salton Trough is one of California's most active basins. It is the northward extension of the Gulf of California, an active rift zone where new crust is being formed by intrusion of mafic igneous rocks at depth. Rifting and magmatic intrusion produces a high heat flow, which has metamorphosed part of the sedimentary section (Fuis *et al.*, 1984). The unusually high geothermal gradients are also responsible for the basin's geothermal energy fields. High temperature water and steam has been harnessed from shallow reservoirs in five geothermal fields ranging from the Salton Sea Geothermal Field at the south end of the Salton Sea to the Heber Geothermal Field near the Mexican Border.

Natural magmatic offgasing has also resulted in shallow high purity CO_2 reservoirs. Lenticular sandstones at depths of less than 300 m (1,000 ft) were commercially exploited during the early to mid-1900s in the now abandoned Imperial Carbon Dioxide Gas Field at the south end of the Salton Sea.

The Salton Trough is filled with a thick sequence of Miocene–Pliocene sedimentary deposits, reaching a thickness of over 5,488 m (18,000 ft) near the Mexican border (Figure 18). In contrast to California's other large Cenozoic marine basins, the Salton Trough is filled largely, if not entirely, with nonmarine sediments. Consequently, no oil or gas production has been established in the basin and deep well control is scarce. While marine sandstones and shales of the Imperial Formation have been identified in bordering outcrops (Dibblee, 1954), the few deep wells encountered only nonmarine rocks, bottoming in terrestrial and lacustrine sediments of the overlying Borrego Formation at depths of over 4,268 m (14,000 ft). Underlying Imperial Formation marine deposits, if present, would likely be metamorphosed in the deep basin, but as yet unidentified marine rocks may occur at shallower depths along the basin margins. Nonetheless, gross sandstone thickness exceeds 1,220 m (4,000 ft) near the basin axis (Figure 19). Like the terrestrial basins of the Mojave Desert and Basin and Range, the prevalence of nonmarine clastic deposits, combined with the lack of widespread marine shales, reduces the basin's potential for large-scale geologic sequestration.

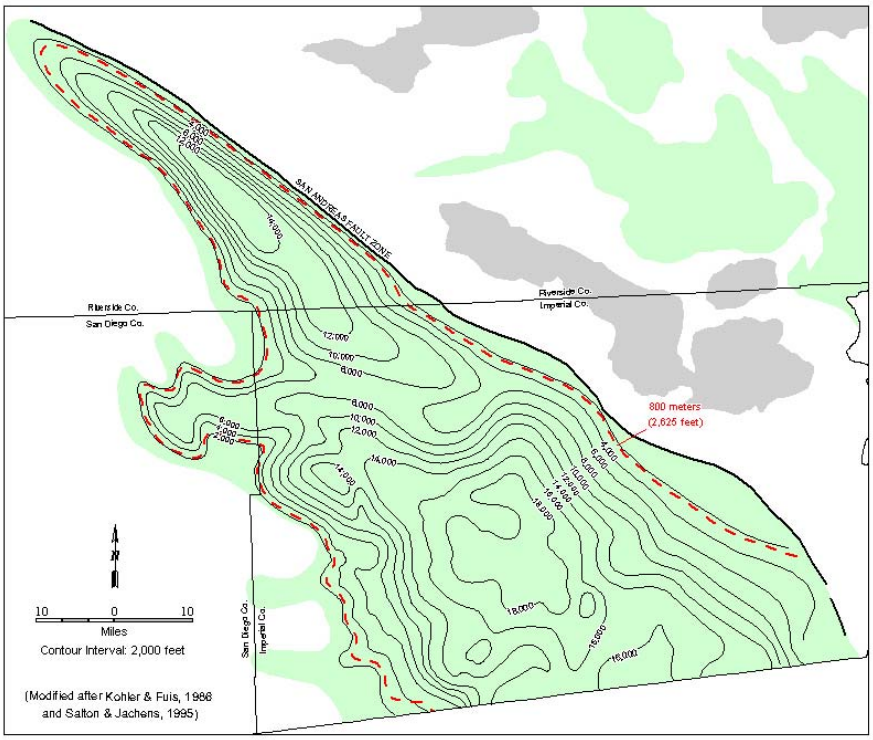


Figure 18. Salton Trough – depth-to-basement map.

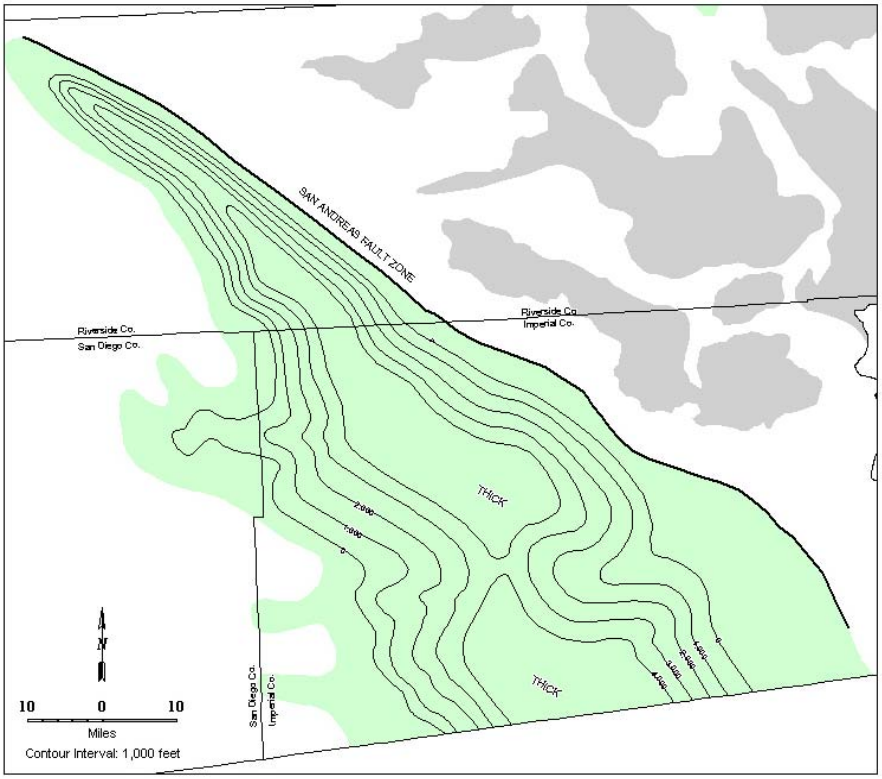


Figure 19. Salton Trough – gross sandstone isopach map for depth interval 800–3,050 m (2,625–10,000 ft; or basement).

5 Conclusions

A preliminary screening of California's sedimentary basins indicates that at least 27 basins possess varying potential for CO_2 sequestration. These basins comprise an aggregate area of more than 98,420 km^2 (38,000 sq. mi.) and range from small, relatively shallow terrestrial basins in the Mojave Desert and Basin and Range geoprovinces to the much larger and deeper Cenozoic marine basins of coastal and central California.

While these basins all appear to meet minimum depth and stratigraphic requirements for CO_2 injection, our current understanding of each basin's suitability is dictated by the amount of available subsurface geological information. Since marine basins tend to be hydrocarbon rich, exploration and development of these resources has provided abundant geological, petrophysical, and fluid data allowing a more objective assessment of a basin's CO_2 sequestration potential. Similar data is nearly, if not completely, absent in California's terrestrial basins where, in some cases, data is limited to geophysical interpretations of depth-to-basement. California's marine sedimentary basins include thick sequences of laterally extensive marine sandstones and shales providing multiple potential sequestration objectives and thick widespread seals. Depths range from shallow to well over 3,050 m (10,000 ft)**.** Additionally, marine basins not only provide opportunities for sequestration in saline aquifers, but also include numerous, well characterized, abandoned and mature oil and gas reservoirs that may provide near-term and future targets for CO_2 sequestration.

Currently, the most promising basins for potential CO_2 sequestration include the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins. Smaller marine basins such as the Salinas, La Honda, Cuyama, Livermore, Orinda, and Sonoma basins are also promising but more restricted in terms of size and available geological information. Several terrestrial basins, including the large Salton Trough, may present some opportunities for CO_2 sequestration and cannot be excluded from consideration given the limited currently available information.

Geological information resulting from this assessment will be used by WESTCARB participants to help identify potential areas for CO_2 sequestration, and to assess CO_2 storage capacity of saline aquifers and hydrocarbon reservoirs in California. Preliminary estimates of CO_2 storage capacity of the ten largest basins identified in this assessment have placed the storage capacity of saline aquifers between 146–840 Gt CO_2 depending on the varying degrees of dissolved phase and separate-phase pore volume storage (Myer *et al.*, 2005). Additional geological information and characterization of these basins, including detailed, formation specific, mapping will be required before their specific potential for CO_2 sequestration can be more accurately assessed.

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8 Glossary

BBO	Billion Barrels of Oil
BCFG	Billion Cubic Feet of Gas
CCS	Carbon Capture and Sequestration
CGS	California Geological Survey
DOE	U.S. Department of Energy
DOG	California Division of Oil and Gas
DOGGR	California Division of Oil, Gas, and Geothermal Resources
EOR	Enhanced Oil Recovery
GIS	Geographic Information Systems
Gt	Gigaton (One Billion Metric Tons)
Gm^3	Giga (Billion) Cubic Meters
MBO	Thousand Barrels of Oil
MMBO	Million Barrels of Oil
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
m^3	Meters squared
m^3	Cubic meters
Mm^3	Mega (Million) Cubic Meters
TCFG	Trillion Cubic Feet of Gas
WESTCARB	West Coast Regional Carbon Sequestration Partnership

Appendix. Excluded Basins

Geoprovince	Basin Name	Reason for Exclusion	References	Comments
Basin & Range	Searles Valley	In China Lake Naval Weapons Station	Blakely & Ponce, 2001	Thick areas only within China Lakes Naval Station
Basin & Range	Indian Wells Valley	In China Lake Naval Weapons Station		> 60% within China Lake Naval Weapons Station
Basin & Range	Panamint Valley	See Comments	Blakely & Ponce, 2001	Too small – Only 12 km² of basin with fill > 1.5 km thick
Basin & Range	Saline Valley	Within Death Valley National Park		90% within Death Valley NP
Basin & Range	Eureka Valley	Within Death Valley National Park		80% within Death Valley NP
Basin & Range	Round Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Basin & Range	Deep Springs Valley	< 1.0 km. of fill	Wilson, D.V., 1975	122 m (400 ft) of valley fill and 427 m (1,400 ft) of alluvial fan material on basement
Basin & Range	Adobe Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Basin & Range	Long Valley Caldera	See Comments	Mukhopadhyay, 2002	Tectonically active with 50–150 tons CO2/day escaping naturally
Basin & Range	Mono Basin	See Comments		Tectonically active and analogous to Long Valley Caldera
Basin & Range	Bridgeport Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Basin & Range	Fish Lake Valley	< 1.0 km. of fill	Blakely & Ponce, 2001	
Basin & Range	Death Valley	Within Death Valley National Park		Entirely within Death Valley NP
Basin & Range	Greenwater Valley	Within Death Valley National Park		> 90% in Death Valley NP
Basin & Range	Chicago Valley	< 1.0 km. of fill	Blakely & Ponce, 2001	Only small area of < 10 sq. km. With 1.0–1.5 km. of fill
Basin & Range	California Valley	< 1.0 km. of fill	Blakely & Ponce, 2001	Only 4–5 sq. km. With 1.0 km. of fill
Basin & Range	Unnamed 12	Small basin with < 0.5 km. of fill	Blakely & Ponce, 2001	Small valley with < 0.5 km. of fill
Basin & Range	Honey Lake Valley	Within Sierra Army Depot	Handman et al, 1990	> 50% in Army Depot; only small area north of Depot > 1.0 km.
Basin & Range	Long Valley	See Comments	TenBrink et al, 2002	No apparent seals; thick sequence of coarse sands & diatomite
Basin & Range	Secret Valley	< 1.0 km. of fill	CDWR, 2003	No deep control. CDWR strat log indicates 762 m (2500 ft.) of sediments
Basin & Range	Madeline Plains	< 0.5 km. Of fill	CDWR, 2003	
Cascades	Shasta Valley	< 1.0 km. of fill	Chesterman & Saucedo, 1984; Mack, 1960	Thin veneer of Cz alluium. & glacial deposits on basement
Coast Ranges	Santa Maria Basin	See Comments		Almost all perm and porosity in fractured Monterey Shale
Coast Ranges	Sargent Hollister Basin	Small active fault controlled basin		Narrow basin bounded by active San Andreas and Calaveras faults
Klamath Mountains	Scott Valley	< 120 m (400 ft)	Mack, 1958	Maximum of 120 m (400 ft) of alluvium on basement
Modoc Plateau	Butte Valley	< 1.0 km. of fill	Wood, 1960; Adam et al, 1994	Basalt/andesite basement overlain by veneer of glacial alluvium and lacustrine sediments
Modoc Plateau	Klamath Valley	< 1.0 km. of fill	Sammel, & Peterson, 1976	Gravity shows portion in Southern Oregon to be up to 2.0 km. Deep, but thins into CA
Mojave Desert	Unnamed 1	< 1.0 km. of fill	Saltus & Jachens, 1995	Small basin with < 1.0 km. fill

Geoprovince	Basin Name	Reason for Exclusion	References	Comments
Mojave Desert	Unnamed 2	Within Chocolate Mt. Gunnery Range		
Mojave Desert	Pinto Basin	Within Joshua Tree National Park		
Mojave Desert	Rice Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Clipper Valley	Within Mojave National Park		
Mojave Desert	Fenner Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	North half in Mojave NP
Mojave Desert	Unnamed 3	Within Mojave National Park		More than 50% in Mojave NP
Mojave Desert	Cadiz Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Unnamed 4	< 0.5 km. of fill	Saltus & Jachens, 1995	Small valley with < 0.5 km.
Mojave Desert	Dale Lake Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Unnamed 5	Within Twentynine Palms Marine Base		60% within Marine base
Mojave Desert	Unnamed 6	Within Twentynine Palms Marine Base		> 50% within Marine base.
Mojave Desert	Unnamed 7	Small basin with < 0.5 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Johnson Valley	Small basin with < 0.5 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Lucerne Valley	Small basin with < 0.5 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	North Lucerne Valley	Small basin with < 0.5 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	El Mirage Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Apple Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Brisbane Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Hinkley Valley	< 1.0 km. of fill	Blakely & Ponce, 2001	
Mojave Desert	Unnamed 8	< 1.0 km. of fill	Blakely & Ponce, 2001	
Mojave Desert	Silurian Valley	< 1.0 km. of fill	Blakely & Ponce, 2001	
Mojave Desert	China Ranch Basin	<1.0–1.5 km. of fill	Blakely & Ponce, 2001	Only about 14 sq. km. with 1.0–1.5 km. of fill
Mojave Desert	Valjean Valley	Small basin with < 0.5 km. of fill	Blakely & Ponce, 2001	
Mojave Desert	Unnamed 9	Within Mojave National Park		> 50% within Mojave NP
Mojave Desert	Unnamed 10	Within Mojave National Park		Entirely within Mojave NP
Mojave Desert	Shadow Valley	Within Mojave National Park		>75 % within Mojave NP and 0% with > 0.5 km. of fill
Mojave Desert	Antelope Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	Large valley with < 0.5 km.
Mojave Desert	Unnamed 11	< 1.0 km. of fill	Blakely & Ponce, 2001	Small basin with <1.0 km.
Mojave Desert	Almond Cove Basin	< 1.0 km. of fill	Saltus & Jachens, 1995	Very small area of 2.0 km fill per Blakely & Ponce (2001)
Mojave Desert	Pilot Knob Valley	In China Lake Naval Weapons Station		Entirely within China Lake Naval Weapons Station
Mojave Desert	Goldstone Basin	In China Lake Naval Weapons Station		> 90% in China Lake Naval Weapons Station
Mojave Desert	Ivanpah Valley	Within Mojave National Park		90% in Mojave NP
Mojave Desert	Lanfair Valley	Within Mojave National Park		
Mojave Desert	Needles Valley	< 1.0 km. of fill in CA	Saltus & Jachens, 1995	Up to 3.5 km. of fill just east of state line in NV

Geoprovince	Basin Name	Reason for Exclusion	References	Comments
Mojave Desert	Chemehuevi Valley	< 1.0 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Vidal Valley	< 0.5 km. of fill	Saltus & Jachens, 1995	
Mojave Desert	Unnamed 13	Within Mojave National Park		Entirely within Mojave NP
Mojave Desert	Unnamed 14	< 1.0 km. of fill	Saltus and Jachens, 1995	Small basin with < 1.0 km. of fill
Mojave Desert	Unnamed 15	< 0.5 km. of fill	Saltus and Jachens, 1995	Very small basin with < 0.5 km. of fill
Mojave Desert	Unnamed 16	< 0.5 km. of fill	Saltus and Jachens, 1995	Very small basin with < 0.5 km. of fill
Mojave Desert	Unnamed 17	< 0.5 km. of fill	Saltus and Jachens, 1995	Very small basin with < 0.5 km. of fill
Mojave Desert	Unnamed 18	< 0.5 km. of fill	Saltus and Jachens, 1995	Very small basin with < 0.5 km. of fill
Mojave Desert	Unnamed 19	Within Twentynine Palms Marine Base		70% within Marine Base
Peninsular Ranges	Moreno Valley	< 0.5 km. of fill	Saltus and Jachens, 1995	
Peninsular Ranges	Perris Valley	< 0.5 km. of fill	Saltus and Jachens, 1995	
Peninsular Ranges	Diamond Valley	< 0.5 km. of fill	Saltus and Jachens, 1995	
Peninsular Ranges	San Jacinto Basin	Small, seismically active basin	Lee et al, 1996; Fett, 1968; Thatcher et al; 1975	Basin in most seismically active part of southern San Andreas Fault system. Only very small area with > 1.0 km. of fill
Peninsular Ranges	Temecula Valley	< 1.0 km. of fill	Saltus and Jachens, 1995	
Sierra Nevada	Sierra Valley	< 1.0 km. of fill	Jackson et al, 1961	Cenozoic deposits at least 760 m (2500 ft) thick in deepest part

Appendix VI, Final Report

Sedimentary Basin Database for Washington and Oregon States for the Geologic Carbon Dioxide Assessment

Topical Report

West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Contract Period: October 1, 2003 - September 30, 2005

Golder Associates Inc.

September 30, 2005

DOE Contract No.: DE-FC26-03NT41984

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Abstract

As part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB), Golder Associates Inc. performed an inventory of sedimentary basins in the states of Oregon and Washington so that others may assess the suitability of these basins for geologic sequestration of carbon dioxide. The results of this inventory include a database (not included) and this report, which summarizes the findings reported in the database. Of particular interest to assessment for geologic sequestration potential are the geometry and physical properties of the basins and saline aquifers in these two states—particularly formations that may serve as reservoirs or seals. Key geologic features that were catalogued in the database and explored in this report include details of recognized and potential oil and gas fields; physical geometries—including areal extent, depth, and thickness; physical properties—such as porosity, permeability, and reservoir yield factors; and geochemistry—notably, the mineralogy of the formation and aqueous quality. The geometry, physical properties, and geochemistry of any capping formations, and also trapping features (such as faults, folds, and stratigraphic features), were also collected.

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1 Introduction

Established in fall 2003, WESTCARB (the West Coast Regional Carbon Sequestration Partnership) is one of seven research partnerships co-funded by the U.S. Department of Energy (DOE) to characterize regional carbon sequestration opportunities and to develop action plans for pilot-scale validation tests. WESTCARB is exploring opportunities in a six-state region (California, Oregon, Washington, Nevada, Arizona and Alaska) for removing carbon dioxide (CO_2) from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted; both will help slow the atmospheric buildup of this greenhouse gas and its associated climatic effects.

A key part of the project is identifying subsurface locations to store the captured CO_2; such sinks are expected to include deep geologic formations (such as oil and gas reservoirs, and saline aquifers) that are essentially leak-proof. These potential sinks will then be matched with the major CO_2 sources such as the main utilities and industrial emitters.

DOE's intention is to combine WESTCARB's findings with those of the other six partnerships to create a national "carbon atlas" to better understand how sequestration technology can help the United States reduce the carbon intensity of its economy and mitigate changes in the climate.

On the basis of the source and geologic characterization, WESTCARB will prioritize geologic sequestration opportunities within the region and will propose pilot-scale projects that combine industrial CO_2 capture, CO_2 transport via pipeline, and injection into geologic formations for storage or enhanced oil recovery.

2 Executive Summary

This report serves as a record of the preliminary characterization of sedimentary basins in the states of Oregon and Washington that Golder Associates Inc. performed for the West Coast Regional Carbon Sequestration Partnership (WESTCARB), and was written with the intent that others may use this information to assess the suitability of these basins for geologic sequestration of carbon dioxide. Three categories of sedimentary basins are described in this study—the western coastal basins of Washington and Oregon, basins east of the Cascade mountain range, and unconsolidated sedimentary basins.

Of particular interest to the assessment of geologic formations for CO_2 storage are the geometry and physical properties of sedimentary basins and saline aquifers. Key geologic features of potential oil and gas fields, capping formations, and trapping features (*e.g.,* faults, folds, stratigraphic features) catalogued in the database and explored in this report include physical geometries (*e.g.,* areal extent, depth, thickness), physical properties (*e.g.,* porosity, permeability, reservoir yield factors); and geochemistry (*e.g.,* mineralogy of the formation, aqueous quality).

Oregon's and Washington's western coastal basins are associated with a major Tertiary sedimentary belt of basins formed in a regional fore-arc environment. They are up to 9,000 m (30,000 feet) deep and are underlain by Eocene oceanic basalt throughout. Many individual

basin boundaries are uncertain at this time. Reviewed basins are as follows: Tofino-Fuca Basin, Western Olympia Basin, Willapa Hills Basin, Puget Trough Basin, Whatcom Basin, Astoria-Nehalem Basin, Tyee-Umpqua Basin, and Coos Basin.

Although basins east of the Cascade Mountains each have some characteristics that are favorable for potential sequestration, exploration and characterization of them are not as comprehensive as that for many of the Western Basins. Reviewed basins are as follows: Sub-Columbia River Basalt Plateau, Ochoco Basin, Methow Basin, Chumstick-Swauk Basin, and Hornbrook Basin.

Oregon's and Washington's unconsolidated sedimentary basins typically consist of Quaternary and Recent alluvium and lacustrine and aolian deposits overlying consolidated basins or volcanic plateau areas. Their relatively shallow character, the absence distinct structural and/or physical traps, and the presence of groundwater make many of these basins less promising for CO_2 storage.

3 Experimental

Golder investigated the following data and information sources for the project:

- Published reports – particularly those produced by the U.S. Geological Survey (USGS), Washington Department of Natural Resources (WA DNR), Oregon Water Resources Department of Water Resources (ODWR), and Oregon Department of Geology and Mineral Industries (ODGAMI);
- A private on-line database, maintained by IHE Energy, that contains hydrocarbon exploration well information;
- On-line abstracts of professional papers; and
- Technical journals and books.

4 Results and Discussion

4.1 Consolidated Geologic Basins of Washington

4.1.1 Western Coastal Basins

Our review of published reports identified several sedimentary basins associated with the western continental margin of Washington State. This section summarizes the character of these basins. The western coast of both states is home to a major Tertiary sedimentary belt of basins that formed in a regional fore-arc environment as the Juan de Fuca plate subducted beneath the North American Plate. The province has been subdivided into several basins, the boundaries of which are uncertain at this time.

These basins are characterized by up to 6,100 m (20,000 feet) of Tertiary sedimentary rocks deposited in embayments and shallow seas; throughout, the basins are underlain by Eocene oceanic basalt. Only in the major downwarp areas (the Puget-Willamette Trough) are the Tertiary sedimentary strata overlain by a significant amount of younger sediments. All of the basins in this region have been explored for hydrocarbon potential; one economically-productive basin that has been in operation for gas extraction (and more recently for gas storage) is in the Chehalis Sub-basin (the Jackson Prairie Gas Field).

4.1.1.1 Tofino-Fuca Basin

Location

The Tofino-Fuca Basin is bounded by the Olympic Mountains to the south, extends beneath the Straits of Juan de Fuca, and is bounded to the north by Vancouver Island. The southern extent of the basin is marked geologically by the major west-east trending Crescent Thrust Fault zone which is between 8 and 13 km (5 and 8 miles) from the shoreline. The northern flank is exposed in a narrow belt of shallow- and deep-water marine Paleogene/Neogene strata along the southern coast of Vancouver Island.

Geology

Snavely *et al.* (1980) described this as a deep Tertiary marginal basin. The sedimentary sequence in the basin consists of more than 5,790 m (19,000 feet) of sandstone, claystone, and coal, which together represent deltaic to deep water depositional settings. The southern flank consists of more than 1,830 m (6,000 feet) of north-dipping middle Eocene to lower Miocene strata consisting of lithic arkosic to lithic turbidite sandstone, deep marine mudstone and subordinate polymict conglomerate and sedimentary breccias. The uppermost strata are deltaic facies (coal bearing) of the Clallam Formation. The basin base is considered to coincide with the top of the Crescent Formation, which is mostly oceanic basalt of early Eocene age.

The generalized sedimentary sequence of onshore rocks above the Crescent Formation (Tcr) is as follows:

- Clallam Formation – L. Miocene, Mn(c) or Tc; nearshore sedimentary rocks (sandstone and conglomerate with minor siltstone).
- Twin River Group - Oligocene-L. Eocene; includes the:
  - Pysth Formation (Tp) – mostly massive mudstone and siltstone;
  - Makah Formation (Tm) – siltstone and sandstone; and
  - Hoko River Formation (Th) – interbedded sandstone and siltstone.
- Lyre Formation – Eocene, Em(2l); marine sandstone and conglomerate.
- Aldwell Formation – Eocene; Em(2a) or Ta; marine siltstone, sandstone and conglomerate.

Onshore, the sedimentary rocks are well exposed and have minimal Quaternary cover material.

Jackson *et al.* (undated) depict the basin in a SW-NE section, showing an asymmetrical syncline with a steeper dipping southern limb and the fold axis positioned about 8 km (5 miles) north of the shoreline.

Exploration

Several deep exploration wells have been drilled on the north coast of the Olympic Peninsula, in two clusters; one cluster is in northeastern Clallam County and another group is further east along the coast. No logs were available in published reports. However, Golder reviewed onshore borehole data for three wells drilled in the 1960s which encountered basement strata at depth of between 1,520 and 1,950 m (5,000 and 6,400 feet). Details for these and other wells in the basin have been included in the database.

Some geophysical (seismic) profiles have been developed across the basin showing the relationship between the sedimentary sequences and basement rocks. The maximum sedimentary rock depth at coastline was about 4,900 m (16,000 feet), reaching as much as 7,600 m (25,000 feet) in the Strait.

Snavely *et al.* (1980) reported the following range of porosity and permeabilities for the Makah Formation based on outcrops:

- Porosity – from 20.4 to 20.7 percent, and
- Permeability – from 2.0×10^{-15} to 7.4×10^{-15} m^2 (2.0 to 7.5 millidarcys, or md).

No geographic or depth information were available for these data. Structural traps onshore are rare; only a few local normal, strike-slip and thrust faults and a few minor faulted anticlines exist. In general, more evidence exists for offshore structural traps.

4.1.1.2 Western Olympic Basin

Location

The Western Olympic Basin is located directly west of the Olympic Mountains in Clallam and northern Jefferson Counties, and extends westwards offshore for at least 64 km (40 miles; Wagner and Batatian, 1985).

Geology and Structure

The onshore geology consists of outcrops of rocks of the Miocene and Eocene marine sedimentary rocks. As with the Tofino-Fuca Basin to the north, the basin basement is formed by the Crescent Formation basalts. The sedimentary rocks are overlain in places by unconsolidated deposits of Quaternary age. The sedimentary strata have an estimated total thickness of at least 2,700 m (9,000 feet), and the recognized formations are:

- Quinault Formation – Pliocene-Miocene (PLMn); up to 1,500 m (5,000 feet) of nearshore sedimentary rocks (siltstone, sandstone and conglomerate).
- Hoh Assemblage – lower-mid Eocene; a sequence of marine rocks accreted to the continental margin:
    - Lincoln Creek Formation - Oligocene-Eocene; up to 2,700 m (9,000 feet) of massive sandstones and tuffaceous siltstones.
    - Skookumchuck Formation – mid-upper Eocene; up to 1,100 m (3,500 feet) of interbedded shallow marine and continental facies (arkosic sandstones and siltstone), and coal in upper and lower member.
    - McIntosh Formation – mid-upper Eocene; up to 1,500 m (5,000 feet) of tuffaceous sedimentary rocks.

Exploration

Golder found information for about 30 exploration wells in the coastal area. The most detailed log information was reported by Rau and McFarland (1982; Sheet 1) for ten wells; all encounter the Hoh Assemblage at depths from 500 to 2,100 m (1,500 to 7,000 feet). However, none of the wells detected basement strata. Limited information was obtained for the remaining wells, with no more than the formation name reported at total drilled depth. Most of these wells report Miocene (Clallam Formation) at a depth of up to 2,300 m (7,500 feet).

Jackson *et al.* (undated) consider the sedimentary units of this basin to have relatively low oil and gas potential, as tectonic activity has disrupted structural traps.

4.1.1.3 Willapa Hills (Grays Harbor) Basin

Location

The Willapa Hills rise to about 950 m (3,100 feet) above sea level and are situated between the Olympic Mountains to the north and the Columbia River to the south. The basin is also thought to extend several km offshore (Wagner and Batatian, 1985; see Section 5.1). The hills contain the most complete section of Tertiary igneous and sedimentary rocks in the state, from the Eocene Crescent Formation basalts (acting as the basement strata), through a thick sequences of Eocene-Miocene sedimentary and interlayered volcanic rocks.

Geology

The basin contains up to 4,600 m (15,000 feet) of late Oligocene to Quaternary strata overlying basement/broken mélange of mid-Miocene to early Oligocene age. Eocene and Oligocene sediments consist predominantly of deep-water siliciclastics, and arkosic sandstones; interbedded volcaniclastic sandstones are contained within thick marine shale sequences.

The recognized geologic formations in the basin above the Crescent Formation are:

- Quinault Formation – Pliocene-Miocene (PLMn); nearshore sedimentary rocks (siltstone, sandstone and conglomerate)
- Montesano Formation – mid-upper Miocene (Mm(2m)); up to 900 m (3,000 feet) of fluvial, lacustrine, brackish water, shallow marine sediments.
- Astoria Formation – lower-mid Miocene, Mm(1a); up to 1,100 m (3,500 feet) of marine sedimentary rocks (carbonaceous, fine-grained sandstone).
- Hoh Assemblage – similar sequence to that in the Western Olympic Basin (Section 2.1.2)
- Cowlitz Formation – Eocene (En(c) or Tco); unconformably overlie Crescent Formation; marine/non-marine siltstone and sandstone.
- Northcraft Formation – Eocene (Evc(n)); up to 460 m (1,500 feet) of volcaniclastic deposits and lavas.

Snavely and Wagner (1982) interpreted a west-east, 48 km (30 mile) long cross-section including three deep, onshore wells and a seismic profile in Grays Harbor County. They show the base of the Skookumchuck Formation reaching a maximum depth of about 2,900 m (9,500 feet).

Exploration

Pauli (2002a) recognized at least four distinct episodes of submarine fan sedimentation in the basin. Two submarine fan sandstones (the basal Cowlitz and basal Lincoln Creek sandstones) correlate with the productive Clark & Wilson Sandstone at the Mist Field in northwestern Oregon (see Section 3.1) and the Zone 2 sandstone reservoir at Jackson Prairie Gas Storage Field (see Section 3.1.4).

Four potential Eocene and Oligocene reservoirs have been identified from oil and gas exploration wells, outcrop studies and seismic interpretations. To date, only eight exploration wells have fully penetrated the Tertiary sedimentary sequence. One well (Union #1 Weyerhaeuser) provides the only subsurface data on porosity and permeability for two of the reservoirs, the basal Lincoln Creek and Cowlitz sandstones. Cores from the well sampled distal turbidites having 26-33 percent porosity with up to $9.4x10^{-14}$ m^2 (95 md) permeability. Intra-Lincoln Creek channel sandstone's have 36-46 percent porosity and $1.0x10^{-13}$ to $9.1x10^{-13}$ m^2 (102–917 md) permeability. Basal McIntosh sandstones sampled along the north flank of the Willapa Hills Uplift have 10–22 percent porosity and $3.9x10^{-16}$ to $6.1x10^{-15}$ m^2 (0.4–6.2 md) permeability.

Some porosity and permeability data were reported for two wells (Milwaukee No.1 and Milwaukee Land Co. No. 1). The results are included in the database and are summarized in Table 1.

Table 1. Summary of porosity and permeability data for Willapa Hills Basin wells

Wells		Porosity (%)	Permeability in m^2 (md)
Milwaukee No.1 and Milwaukee Land Co. No. 1 (33 samples)	Maximum	32.7	$5.2x10^{-13}$ (522)
	Minimum	6.4	$9.9x10^{-16}$ (<1)
	Median	21.4	$1.3x10^{-14}$ (13)

Rau and McFarland (1982) produced a 4-sheet report showing an interpretation of 47 exploration boreholes and wells in the coastal area from Clallam County (Forks River area), Jefferson County, Grays Harbor County and Pacific County (around Willapa Bay). The boreholes mostly encountered the Quinault Formation, Hoh Assemblage, and the basement Crescent Formation at variable depths. The Crescent Formation was only encountered in three wells located in Pacific County. The deepest well (located in coastal Grays Harbor County) described a minimum sedimentary thickness (Quinault and Hoh units) of 2,800 m (9,300 feet).

4.1.1.4 Puget Trough Basin

Location

The Puget Trough Basin is located in northwestern Washington, and occupies the generally low-lying region east of the Olympic Mountains and west of the Cascade Mountains. The southern extent of the basin is defined by the mergence of the Cascade Range and Coastal Range in Lewis and Cowlitz counties.

Geology

The basin was part of the major tectonically active fore-arc basin extending from the Frasier River Valley in British Columbia to Cottage Grove in west central Oregon (Willamette Trough), and varies from 100 to 190 km (60 to 120 miles) wide. The present shape and extent in Washington has resulted from recent tectonic and glacial events in the Tertiary-Quaternary periods. The complex structures principally resulted from the tectonic activity associated with the subduction of the Juan de Fuca plate beneath the North American plate.

The basin consists of up to 1,130 m (3,700 feet) of unconsolidated sediments of Pleistocene age overlying up to 3,050 m (10,000 feet) of Tertiary sedimentary rocks. For the purpose of this assessment, we have included both unconsolidated and consolidated units as part of this basin discussion. However, we have treated the northernmost area (the Whatcom Basin) as a separate basin here (see Section 2.1.5).

The geology of the Puget Trough is complex and interpretation is made difficult by the large volume of mostly glacially-derived, unconsolidated sediments. Faulting and folding is abundant; many active faults are recognized (such as the NW-SE trending Seattle fault zone

and the Whidbey Island faults). The major faults and fold belts are included in the electronic database. At least four major glacial advances and several partial advances recognized that modified the landscape. The unconsolidated sediments consist of Quaternary deposits in four sequences representing glacial periods.

The faulting as resulted in the formation of several major sub-basins:

- Everett Sub-basin – bounded to the north and south by the North and South Whidbey Island Fault Zones, respectively, and attains a maximum thickness of between 3,050 and 4,270 m (10,000 and 14,000 feet), of which as much as 1,100 m (3,600 feet) is considered to be unconsolidated sediments (Jones, 1998).
- Seattle Sub-basin – located south of the South Whidbey Island fault and is bounded to the south by the Seattle fault and uplift; contains up to 4,570 m (15,000 feet) of sedimentary material, of which up to 1,130 m (3,700 feet) is unconsolidated.
- Tacoma Sub-basin – located south of the Narrows Structure; up to 1,830 m (6,000 feet) thick (610 m (2,000 feet) of unconsolidated sediments).
- Chehalis Sub-basin – occupies the southern portion of the Trough, south of the Olympic Gravity Anomaly. The unconsolidated sediment thickness is less than 120 m (400 feet) here.

Everett-Seattle-Tacoma Sub-basin Stratigraphy

Despite the presence of the Quaternary deposits, the Tertiary sedimentary rocks are exposed mostly near the basin margins and have been encountered in some deep exploratory borings. The key sedimentary formations recognized by researchers are:

- Blakeley and Blakeley Harbor Formations – Oligocene-Eocene (OEm(b)); marine sedimentary rocks in the northern Puget Sound area of interbedded volcaniclastic sandstone, siltstone, shale and conglomerate.
- Puget Group – Eocene (Ec(2pg)); continental sedimentary rocks/deposits.
    - Renton Formation (Ec(2r)) - continental sedimentary rocks/deposits (fine-medium grained, massive to cross-bedded arkosic sandstone).
    - Tiger Mountain Formation (Ec(2t)) - continental sedimentary rocks/deposits.
    - Tukmila Formation (Evc(t)) – volcaniclastic rocks/deposits (sandstone, siltstone and conglomerate).

The Crescent Formation is again believed to underlie the Tertiary sedimentary units throughout the western part of the basin. Walsh and Lingley (1991) presented an isopach map showing the thickness of Ulatian and Nazarian (lower-mid Eocene) rock in the subsurface for the entire Puget Trough, based on drilling records, measures sections and outcrop patterns. These contours are included in the database.

Chehalis Sub-basin Stratigraphy

The Chehalis Sub-basin occupies the lowland area between the southern extent of Puget Sound in Thurston County, extending into Lewis County and northernmost Cowlitz County. This sub-basin has special economic significance as it is home to the Jackson Prairie Gas Storage Field; the storage reservoir has a potential capacity in excess of 1.4 billion m^3 (50 billion $ft.^3$) gas and currently houses 0.8 billion m^3 (28 billion $ft.^3$) gas with a daily delivery potential of 24 million m^3 gas/day (850 million $ft.^3$ gas/day).

The geology of the Chehalis consists of Tertiary sedimentary rocks (Eocene to Miocene age) deposited in a fore-arc basin over basaltic rocks. The key sedimentary formations are:

- Wilkes Formation – Miocene (Mc(w)); continental sedimentary rocks.

- Hoh Assemblage – lower-mid Eocene; a sequence of marine rocks accreted to the continental margin; includes the Lincoln Creek, Skookumchuck and McIntosh Formation. Both basal Lincoln Creek Sandstone and Skookumchuck sandstones serve as reservoirs in the Jackson Prairie Gas Storage Field.

Pinotti (2002a,b) reported that the Chehalis gas field's geologic structure was formed by a high angle reverse fault active from mid-Oligocene to Miocene time, trapping minor quantities of native gas. The fault plane over thrust Skookumchuck sand onto Oligocene Lincoln Creek mudstone and forms an elliptical arch around the north and west sides of the field. The fault became inactive at the time of the Miocene Columbia River Basalt flows.

Exploration

Many deep exploration holes have been drilled in the northern Puget Trough area, yet little specific information was available concerning formation thicknesses and engineering properties. About a dozen wells reported the age of the deepest geologic unit encountered; we have included these wells and depths in the database. Much seismic profile and gravity anomaly work has been carried out by government and research groups, with increasing interest following the 2001 Nisqually earthquake.

More than one hundred exploratory holes have been drilled in the Chehalis Sub-basin since the early 1900s, most of which are concentrated in west-central Lewis County. Most drilling terminated in the Eocene strata; the deepest well reached more than 3,050 m (10,000 feet) without encountering the volcanic basement rocks.

Walsh and Lingley (1991) present porosity data for six wells drilled in the Chehalis sub-basin. The porosity ranges from 3 to 39 percent, the highest of which were for a well drilled in the Jackson Prairie field (28 to 39 percent). These data are included in the database. Pauli (2002a) reported porosities for the Tertiary sandstones in the Chehalis Basin as typically exceeding 30 percent, with permeabilities between 9.9×10^{-13} and 3.9×10^{-12} m^2 (1 and 4 darcys). Sharp (2002) reports that Cowlitz and basal Lincoln Creek sands, which store gas at Jackson Prairie Field, have porosities up to 34% and permeabilities up to 3.2×10^{-12} m^2 (3.2 darcys).

Cores collected from the basin's western margin near the Willapa Hills Uplift reportedly encountered numerous Skookumchuck Formation sandstones having excellent reservoir properties (porosity of 30-38 percent, and permeability of $1.3x10^{-13}$ to $3.0x10^{-12}$ m^2 (135-3,030 md)) in a variety of sedimentary facies. Reservoir-quality sandstones have also been documented in oil and gas tests penetrating McIntosh Formation sandstones.

We have included in the database porosity values for core samples collected from several wells in the basin. These are summarized in Table 2.

Table 2. Summary of porosity and permeability data for Chehalis sub-basin wells

Wells		**Porosity (%)**	**Permeability in m^2 (md)**
Jackson Prairie SU909 Hannum No. 2, Pacific Coast Coal No.1, Socal-Schroeder No.1, Socal-Whidbey No.1, Black Diamond No.4-13, Sqaulicum No.1 & Blessing Siler Comm. No.1	Maximum	38.9	$3.9x10^{-12}$ (3,920)
	Minimum	3.7	$3.0x10^{-14}$ (30)
	Median	14.5	$8.1x10^{-14}$ (82)

Much of the economic exploration in the Seattle, Tacoma and Everett Sub-basins has been for groundwater purposes. Well-defined glacial aquifers have hydraulic conductivities in the range of 3 to 210 m/day (10 to 700 ft/day), with most test values in the range of 5 to 15 m/day (15 to 50 ft/day). The higher values are typically associated with coarse sand and gravel outwash or alluvial deposits. Individual aquifer thicknesses are typically from 30 to ~100 m (100 to a few hundred feet) thick, and are generally overlain by low permeable till, clay and silt materials.

4.1.1.5 Whatcom Basin

Location

The Whatcom Basin is located in northwestern Washington, and is the northernmost part of the Puget Trough lowlands (see Section 2.1.4). The exact basin outline is uncertain due the cover of unconsolidated sediments and the complex geology towards the Cascade Range. However, the basin is separated from the Everett sub-basin to the south by the Vedder Mountain-Boulder Creek fault zone.

Geology

The geology of the basin consists of Quaternary glacial and interglacial deposits overlying Tertiary sedimentary rocks and pre-Tertiary rocks of the northwest Cascade Range. The Tertiary rocks consist of mainly those assigned to the Chuckanut and Huntingdon Formations whose deposition were controlled by tectonic activity (uplift and faulting). The upper parts of

the western Cascade Range units, which consist of a stack of oceanic lithologic terranes, are considered for the purpose of this assessment as forming the basin basement. The sedimentary rock units lie above a major tectonic thrust fault (Shusksan) that separates the underlying terranes (Mesozoic metamorphic rocks beneath), forming the basin base.

The Chuckanut Formation (Eocene) consists of up to 6,100 m (20,000 feet) of arkosic sandstone, siltstone, conglomerate and coal deposited in Eocene time. Individual members have maximum thickness of between 910 and 5,490 m (3,000 and 18,000 feet). The depositional environmental was a strike-slip, pull-apart basin that received detritus from local uplifts and distant sources. Deformation has produced broad to tight, N-W and W-E trending folds. The Huntingdon Formation (Oligocene-Eocene) is a moderately- to well-sorted conglomerate, sandstone, siltstone, shale and clay totaling up to 460 m (1,500 feet) of thickness.

The unconsolidated sediments are of Quaternary age, are of glacial origin and are shown by Jones (1998) to be up to 460 m (1,500 feet) thick near the Canadian border. This basin continues into the Fraser Valley of southern British Columbia.

Exploration

There has been a significant amount of exploration of the basin due to the presence of the coal measures which have been economically worked since the 20th century. Methane potential is believed to be relatively good on the eastern basin limb, less so towards the west. We have included data for several exploration wells drilled in the basin. Porosity and permeability data were available for core samples from three wells (formations were not specified). The results are included in the database and are summarized in Table 3.

Table 3. **Summary of porosity and permeability data for Whatcom Basin wells**

Wells		**Porosity (%)**	**Permeability in m^2 (md)**
Squalicum No.1, Ross No. 1 and Hillebrecht No. 1 (13 samples)	Maximum	17.3	$4.5x10^{-14}$ (45.3)
	Minimum	7.0	$9.9x10^{-17}$ (0.1)
	Median	15.0	$8.7x10^{-15}$ (8.8)

4.1.2 Central-Eastern Washington Basins

We have included two major sedimentary basins located between the eastern margin of the Cascade Range and the Columbia Plateau province in this section. We have also included details of the sedimentary rocks known to underlie the thick sequence of the Columbia River Basalt Group (CRBG).

4.1.2.1 Sub-Columbia Basalt Sedimentary Basin

Location

This area is defined as occurring east of the Cascade Mountains in Washington and northern Oregon, and in a geologic sense, west of the ancient cratonic margin. Although the basalt flows are more extensive, we are concerned here with the underlying sedimentary rocks.

Geology

The sedimentary rocks that pre-date the Columbia River Basalt Group (CRBG) are not exposed in the Plateau area and much uncertainty exists to their exact extent and thickness. Most of the existing data have resulted from investigations associated with the Hanford Nuclear Facility in Grant, Benton, and Yakima counties. There is much on-going research work in this province to characterize the basalt for possible natural gas storage (Riedel *et al.*, 2002).

In general, the basin contains up to 4,570 m (15,000 feet) of layered Miocene lava flows (the CRBG) overlying as much as 10,060 m (33,000 feet) mid-Tertiary, non-marine sedimentary strata. The main sub-CRBG sedimentary formations that have been identified are as follows:

- Wenatchee Formation – Oligocene (Oc(h)); up to 300 m (1,000 feet) of fluvial sandstones and shales. Also crops out in the Chiwaukum Basin.
- Wildcat Creek Formation – Oligocene (Ovc(wc)); more than 300 m (1,000 feet) of tuffs and volcaniclastic sandstones.
- Ohanapecosh Formation – Eocene (Ohm(oh)); tuffs and volcaniclastics.
- Roslyn Formation – Eocene (Ec(2r)); more than 4,270 m (14,000 feet) of arkosic sandstones and black shale interbeds.
- Chumstick Formation – Eocene (Ec(2ch)); more than 4,880 m (16,000 feet) of fluvial micaceous sandstone with conglomerate/shale interbeds.
- Swauk Formation – Eocene (Ec(1s)); up to 4,570 m (15,000 feet) of fluvial arkosic sandstone, shale and conglomerate.
- Manatash Formation – Eocene (Ec(1m)); up to 920 m (3,000 feet) of fluvial sandstone, shale and coal.

Reidel *et al.* (2002) recognized the Palouse Slope and Yakima Foldbelt as two key structural features in the Columbia Plateau province in defining the likely extent of the sub-basalt sedimentary strata. The Palouse Slope area overlies a crystalline basement high with a relatively thin (less than 90 m (300 feet)) sediment sequence between the basalt and basement. The underlying basement is metasedimentary rock of late Precambrian to Paleozoic age and is inferred to be part of the old continental craton. The Yakima Foldbelt to the west is underlain by a thick sequence of sediments that have been extensively investigated geophysically.

The western craton edge is estimated to coincide with the Ice Harbor dike swarm near longitude 119° west. Researchers also infer that the southern edge of the craton coincides with the Hite Fault Zone which marks the northern extent of the Blue Mountains province. This arc and the general basin outline have been included in the database.

Exploration

As mentioned, Golder found records for several deep exploration wells that were drilled between 1957 and 1989 through the base of the CRBG. Most of these wells were also drilled through the entire sedimentary sequence and into the crystalline basement. These wells are included in the database, along estimates of depths to the basin base, and thicknesses of the recognized formations. Some geophysical surveys have also yielded information regarding the lateral and vertical extent of the sedimentary units.

Myers and Price (1979) report the results of magnetotelluric survey in the Pasco area conducted to determine the subsurface geometry for the Basalt Waste Isolation Project. The results, which consist of contours of depth to significant horizons and thicknesses, are included in the database.

Walsh and Lingley (1991) present porosity data for three of the deep wells drilled in the basin. Most of the values are for the Roslyn Formation, and range between 4 and 22 percent, with the median about 13 percent. Porosity generally decreases with increasing depth. Some of the samples were of the Ohanapecoch Formation, and range from 13 to 17 percent. These data are included in the database and are summarized in Table 4.

Table 4. Summary of porosity data for sub-CRBG basin sandstones

Formation	Porosity (%)	
Swauk Formation (2 samples)	Maximum	7.9
	Minimum	4.9
	Median	6.4
Ohanapecosh Formation (4 samples)	Maximum	17.0
	Minimum	9.0
	Median	14.9
Wenatchee Formation (7 samples)	Maximum	16.1
	Minimum	9.1
	Median	14.0
Roslyn Formation (61 samples)	Maximum	22.1
	Minimum	3.9
	Median	12.0

The Rattlesnake Gas Field is located in the Yakima Foldbelt and is a low-pressure anticlinal trap in basalts containing natural gas. It is believed that the gas originated from coals in fluvial sediments underlying the basalt.

4.1.2.2 Methow Basin

Location

The Methow Basin is located on the eastern flank of the Cascade Range, and forms part of a more extensive sedimentary basin that extends into southern British Columbia, where it is called the Tyaughton Basin.

Geology

The geology of the basin consists of a thick sequence of Cretaceous sedimentary rocks, bounded by prominent faults; the Chiwack-Pastyn fault is to the northeast and the Ross Lake Fault zone (Hozemeen fault) is to the southwest. The sedimentary rocks are exposed throughout the basin, and the Washington DNR (McGroder *et al.*, 1990) estimated the total sequence thickness (up to 3,960 m (13,000 feet)) based only on outcrops, as no deep exploratory wells have been drilled.

Haugerud *et al.* (2002) identified five Cretaceous-Tertiary sequences:

- Pipestone Canyon Formation - Paleocene, (PAc(p)). Continental siltstone, sandstone, conglomerate, 670 m (2,200 feet) thick at type locality, thinning to the north. Contains substantial vertical jointing.
- Pasayten Group (Cretaceous):
    - Winthrop Sandstone - massive, fine-coarse sandstone, up to 3,960 m (13,000 feet) thick in the Goat Creek syncline).
    - Virginia Ridge Formation – black mudstone, siltstone and chert-lithic sandstone and conglomerate. Up to 3,960 m (13,000 feet) thick near Cady Point. Interfingers with Withrop sandstone.
    - Goat Wall unit - redbeds and volcanics.
- Patterson Lake Conglomerate – Cretaceous (Kcg(p)). Mudstone and interbedded sandstone and conglomerate; massively bedded.
- Harts Pass Formation – L. Cretaceous, (Km(h)). Up to 2,440 m (8,000 feet) of marine sandstone, black shale and conglomerates.
- Newby Group - Jurassic-Cretaceous (KJm(n)). Volcanic lithic sandstone, conglomerate, siltstone, black shale, argillite, carbonate pods and andesitic-dacitic volcanic rocks. Total thickness estimated as at least 1,830 m (6,000 feet). Includes the Twisp Formation (intensely folded argillites and sandstones).

Structure

Structurally, the basin contains a series of parallel thrust faults oriented NW-SE and similar-trending faulting (forming anticlines and synclines). The basin's southeastern extent is marked surficially by the boundary with the younger CRBG sequence. It is likely that the basin's sedimentary sequence extends beneath the basalt flows.

Exploration

As mentioned above, no deep mineral exploration wells have been drilled in the basin, making the thickness and depth of the sedimentary formations difficult to determine. No information was available regarding engineering properties.

4.1.2.3 Chiwaukum and Swauk Basins

Location

The Chiwaukum and Swauk Basins are located on the eastern flank of the Cascade Range in Wenatchee County, and are two adjacent fault-controlled basins.

Geology

The Chumstick Graben forms an erosional lowland and sedimentary basin bounded by the Entiat Fault on the east and the Leavenworth Fault on the west. The sedimentary rocks crop out throughout the basin, and consist of up to 5,790 m (19,000 feet) of non-marine strata of Eocene age.

The main outcropping formation in the Chiwaukum Basin is the Eocene-age Chumstick Formation (Ec(2ch)). This unit is a thick (possibly as much as 1,520 m (5,000 feet)) sequence of continental sandstone and conglomerate, shale and fanglomerate.

The Swauk Basin is located south and west of the Chumstick Basin, and its western boundary is defined by the major north-south Straight Creek Fault. The primary sedimentary unit is the Swauk Formation (lower-mid Eocene) which is considered to be the most extensive sedimentary formation in eastern Washington; it forms a 8 to 16 km (5 to 10 mile) wide belt extending west from the Columbia River along the southern slope of Wentachee Mountain and into the Cascade Range. The strata consist of several facies of conglomerate, arkosic sandstones and shale. The Swauk Formation is also believed to underlie the Chumstick Formation in the Chiwaukum Graben (Gresens, 1983).

As with the Methow Basin, the eastern extents of both basins are masked by the CRBG. Sedimentary rocks outcropping in the basins west of the basalt flow were encountered in deep borings drilled below the base of the CRBG on the western plateau, and it is likely that they extend to the ancient cratonic edge.

Exploration

No deep oil and gas exploration wells have been drilled in the basin, making the thickness and depth of the sedimentary formations difficult to determine. No information was available regarding engineering properties.

4.2 Consolidated Sedimentary Basins of Oregon

For the purpose of this assessment, we have identified several consolidated sedimentary basins in Oregon that belong to the following three geographic provinces:

- Western Tertiary Basins.
- Columbia Plateau Basins.
- Intermontane, Non-marine Tertiary Basins.

The following sections provide summary details of these basins.

4.2.1 Western Tertiary Basins

The Western Tertiary Basins consists, in essence, of a single sedimentary province that evolved as a fore-arc environment in Tertiary time. The province occupies about 51,800 km^2 (20,000 square miles) of mostly marine sedimentary rocks extending from the Oregon coast

to the foothills of the Cascade and Klamath Mountains. The sedimentary sequence consists of up to 6,100 m (20,000 feet) of mostly Eocene age, formed in littoral to deep-marine depositional environments.

Researchers and hydrocarbon prospectors have identified several sedimentary basins in the Coastal Ranges province, namely the Astoria, Nehalem, Tyee, and Coos Basins, for hydrocarbon exploration purposes. The Willamette Basin, which generally coincides with the lowland area, separates the Coastal Range and the Cascade Mountains. Definition of the exact extent of each of these basins is problematic due to the volcanic and sedimentary cover and tectonic deformation. However, the Oregon DOGMI published a series of reports that describe the key characteristics of these economically-important basins using exploration well information as well as outcrop studies.

4.2.1.1 Astoria-Nehalem Basin

Location

The Astoria-Nehalem Basin is located in northwestern Oregon, in western Columbia and eastern Clatsop counties, about 72 km (45 miles) northwest of Portland. The basin contains the only economically-productive gas filed in Oregon (known as the Mist Gas Field), which occupies an area of about 13 km^2 (5 $mi.^2$) and was first produced from in 1979.

Geology

The base of the sedimentary basin coincides with the top of the oldest identified rock unit in the area, the Eocene-age Tillamook Volcanics (which consist of basalts and breccias). The earliest sedimentary unit is the mid-Eocene Yamhill Formation (siltstones and shales); although the sedimentary units interfinger with the volcanics, the Yamhill does contain a prominent sandstone member.

The Cowlitz Formation overlies the Yamhill Formation, and consists of micaceous, arkosic-basaltic marine sandstone, siltstone and mudstone. Of key importance is gas-producing Clark & Wilson Sandstone which is overlain by a thick shale unit.

A sequence of marine sedimentary units overlies the Cowlitz Formation, and consists of thick- to thin-bedded tuffaceous mudstone, siltstone, and sandstone. Key units include the Spencer, Keasey, Pittsburg Bluff, and Astoria Formations (all mid-upper Eocene).
The basin geology is complex due to the extensive folding and faulting. Normal and strike-slip faulting is common, with the predominant fault trend being northwest; some significant east-west and NE-SW faulting also exists. Faulted anticlines are reportedly the most common trap in the Mist Field.

Exploration

This basin has been more extensively drilled and tested than any other basin in Oregon, and records show at least 240 exploratory boreholes and wells in the area; more than half have

descriptive logs and core records. These boreholes were drilled to depths of up to 3,450 m (11,300 feet). Golder obtained (from the OGI reports) records for 15 wells in the area. The logs were interpreted by the authors using Foraminifera correlation. All borings reported Tertiary sedimentary units, and most of the drilling encountered the Tillamook Volcanics at depths between 920 and 2,230 m (3,000 and 7,300 feet). In the Nehalem Basin, some wells encountered up to 1,220 m (4,000 feet) of volcanics beneath the Cowlitz and above the Yamhill Formations.

As mentioned, the Clark and Wilson Sandstone is a gas-containing unit; gas pools are generally small (40 to 160 acres). The gas, which is mostly methane, was not likely generated in-situ, and was most likely generated in the Astoria Basin to the west or the northern Willamette basin to the south, before migration. Jackson *et al.* (undated) considers the Astoria area to have moderate potential for gas, and most of the basin lies offshore.

We have included the stratigraphic details of the available borehole logs in the data base. No isopach maps were discovered in the existing literature, and developing such a map is problematic due to the lack of borings full penetrating the sedimentary sequence. Minimum thickness estimates are provided, however. We have also included some porosity and permeability data for the Clark and Wilson, and Cowlitz Sandstone units from the Texaco 6-1 well (Table 5).

Table 5. Summary of porosity and permeability data for Nehalem Basin sandstones

Unit		**Porosity (%)**	**Permeability in m^2 (md)**
Clark & Wilson Sandstone (33 samples)	Maximum	31.9	$1.4x10^{-12}$ (1,400)
	Minimum	18.9	$1.8x10^{-14}$ (18)
	Median	26.0	$1.9x10^{-13}$ (195)
U. Cowlitz Sandstone (14 samples)	Maximum	38.9	$7.9x10^{-14}$ (80)
	Minimum	25.6	$2.0x10^{-15}$ (2.0)
	Median	29.6	$7.4x10^{-15}$ (7.5)
L. Cowlitz Sandstone (15 samples)	Maximum	13.3	$9.9x10^{-16}$ (1.0)
	Minimum	0.7	$9.9x10^{-16}$ (1.0)
	Median	9.1	$9.9x10^{-16}$ (1.0)

4.2.1.2 Tyee-Umpqua Basin

Location

The Tyee-Umpqua Basin occupies the southern half of the Coastal Range, extending from a latitude near Salem, beyond Roseburg, to the junction of the Coastal Range with the Klamath Mountains. To the west are the younger basinal sediments of the Coos Basin.

Geology and Structure

The basin consists of more than 6,100 m (20,000 feet) of lower-middle Eocene sedimentary strata preserved in the Coastal Range hills. In fact, the basin contains two superimposed basins with different geologic trends and tectonic histories; the NE-SW trending early Eocene Umpqua Basin and the N-S trending Tyee Basin. The Umpqua Basin rocks represent a partially subducted accretionary wedge deposited in a trench or rifted continental margin, overlying and interfingering the lower Eocene Siletz River Volcanics that form basaltic crust. Later and after rotation, a new subduction zone formed to create the fore-arc environment in which the Tyee Basin rocks were deposited.

The main geologic units identified in the basin are:

- Spencer Formations - lower-mid Eocene; up to 150 m (500 feet) of arkosic sandstone (fluvio-deltaic)
- Bateman Formation – mid-upper Eocene; up to 760 m (2,500 feet) of arkosic sandstone (deltaic) and mudstone
- Elkton Formation – mid-Eocene; up to 920 m (3,000 feet) of mostly mudstone and minor sandstone.
- Tyee Formation – mid-Eocene; mostly 1,830 m (6,000 feet) of sandstone, deposited in shallow marine to non-marine deltaic (south) to slope and deep marine basinal margin (in north). The eastern margin is truncated by younger rocks or covered by younger volcanic rocks; the western margin is a passive sill or a seamount terrane of oceanic crust. Contains several recognized members.
- Umpaqua Group – upper Paleocene to lower Eocene; up to 3,050 m (10,000 feet) of mudstone, sandstone and conglomerate (non-marine to deep marine origin). Prominent formations recognized in reports include the Camas Valley White Tail Ridge, Tenmile and Bushnell Rock Formations.

The sedimentary basin basement is formed by the top of the Siletz River volcanics (basalt).

The southern Coastal Range consists of a major, N-S trending syncline with the younger (Elkton Formation) rocks surrounding the older Tyee Formation. Other similar trending folds produce secondary anticlines and synclines, and several NE-SW trending faults exist on the Range fringes.

Exploration

Many hydrocarbon exploration wells have been drilled in the Tyee area, the results for many are included in Niem *et al.* (1992) and Ryu *et al.* (1996). The former report presents a fence diagram containing an interpretation of the depth and thickness of the sedimentary units and, where encountered, the volcanic basement based on well and field exposures. These borings and interpretations are included in the database. The later report also includes some engineering property data (porosity and permeability) for field samples collected from field samples.

Ruy and Niem (1999) report that much of the primary porosity of the Tyee sandstone has been infilled during diagenesis, and that secondary porosity and permeabilities average 10.8 percent and 2.7×10^{-15} m^2 (2.76 md), respectively. We have summarized the porosity and permeability data included in the OGI reports in the database.

4.2.1.3 Coos Basin

Location and Extent

The Coos Basin is located in coastal southwestern Oregon in the Coastal Range Province. The basin extends from the western edge of the Tyee Basin and the Klamath Mountains, and continues offshore.

Geology

The geology of the basin consists of marine sedimentary rocks of Tertiary age that were deposited as continental deltaic margin and deep-sea fan facies. The key units are as follows:

- Bastendorff Formation – upper Eocene to lower Oligocene; up to 880 m (2,900 feet) of thinly-laminated siltstone and mudstone.
- Coaledo Formation – upper Eocene; up to 1,830 m (6,000 feet) of deltaic sandstones, and prominent coal seams.
- Bateman Formation – mid-Eocene; 305 m (1,000 feet) of sandstone (near-shore, deltaic).
- Tyee Formation – similar strata to those in the Tyee Basin; up to 1,520 m (5,000 feet) thick in the Coos Basin.
- Fluornoy Formation – mid-Eocene; between 305 and 1,520 m (1,000 and 5,000 feet) of sandstone and siltstone sequence.
- Looking glass Formation – lower Eocene; basal conglomerate and overlying fine-grained sandstone and siltstone sequence (up to 2,130 m (7,000 feet) thick).
- Roseburg Formation – lower Eocene-upper Paleocene; between 3,050 and 3,660 m (10,000 and 12,000 feet) of rhythmites and submarine basalts.

Exploration

Numerous hydrocarbon exploration borings have been drilled in the basin. McKeel (1984) presented interpretations of several borings for which logs were collected and described. None of the borings, drilled to maximum depths of between 920 and 3,900 m (3,000 and 12,800 feet), encountered non-sedimentary basement material. However, we have included the formational thicknesses and elevations, and overall minimum sedimentary sequence thicknesses in the database. Newton (1980) presented porosity and permeability data for sandstone samples of the lower and upper Coalcedo, Fluornoy and Roseburg Formations, summarized in Table 6

Table 6. Summary of porosity and permeability data for Coos Basin sandstones

Unit		**Porosity (%)**	**Permeability in m^2 (md)**
U. Coalcedo (3 samples)	Maximum	38.3	$6.6x10^{-13}$ (667)
	Minimum	28.2	$5.0x10^{-14}$ (51)
	Median	33.7	$3.3x10^{-13}$ (339)
L. Coalcedo (7 samples)	Maximum	43.2	$1.8x10^{-12}$ (1,788)
	Minimum	18.3	$4.4x10^{-15}$ (4.5)
	Median	30.2	$2.3x10^{-13}$ (232)
Fluornoy (6 samples)	Maximum	38.2	$1.5x10^{-13}$ (154)
	Minimum	25.0	$2.4x10^{-14}$ (24.8)
	Median	32.2	$6.9x10^{-14}$ (70)
Roseburg (4 samples)	Maximum	32.6	$3.8x10^{-13}$ (384)
	Minimum	10.0	$1.5x10^{-14}$ (15.4)
	Median	19.8	$2.4x10^{-14}$ (24)

4.2.2 Columbia Plateau Basins of Central and Eastern Oregon

4.2.2.1 Ochoco Basin

Location

The Ochoco Basin is located in central Oregon, in Crook and Wheeler counties. The precise basin geometry is uncertain as the sedimentary rocks are covered for the most part by the CRBG and exploratory drilling has been limited to four wells.

Geology

Sedimentary rocks of the basin depositionally overlie a diverse assemblage of accreted terranes in the Blue Mountains. Dorsey and Lenegan (2004) describe the Mitchell Inlier, which consists of exposed Cretaceous sedimentary rocks of marine origin:

- Gable Creek Formation – U. Cretaceous, Cenomanian; a fluvio-deltaic conglomerate and sandstone.
- Hudspeth Formation – L. Cretaceous, Albian; a widespread and thick sequence of marine mudstone with subordinate siltstone and sandstone.

Dorsey and Lenegan report the presence of up to 1,520 m (5,000 feet) of pebbly sandstone and conglomerate at one surface exposure. The inlier is surrounded by Tertiary volcanic rocks. The sedimentary units overlie Paleozoic metasedimentary rocks of the Baker Terrane. They also infer the extent of the basin (included in the database here).

Little published data exists on the geology of the area, but based on surface mapping, it has been considered a potential petroleum producing area. No commercial hydrocarbon discoveries have been made, though.

Some research has been performed on the diagenetic history of the Cretaceous sediments during burial beneath the volcanics. Although some low-grade metamorphosis occurred, logging and analysis indicate that some reasonable porosity exists in the deeper parts of the sequence (Summer and Versoub, undated AAPG abstract).

Structure

Given the limited subsurface information, the overall basin structure is difficult to determine. Dorsey and Lenegan report a significant SW-NE trending anticline creating the Mitchell Inlier (described above), exposing the basement rocks and the Cretaceous units. They also report a west-east trending strike-slip fault in the area.

Exploration

Knowledge of the subsurface of the area is provided by four deep exploration holes completed between 1955 and 1981, located between 13 and 23 km (5 and 9 miles) south of Mitchell. The well logs and an interpretation are presented in Thompson *et al.*, 1984. Two additional wells were drilled in Wheeler County (logs available) which encountered crystalline basement rocks at total drilled depth.

4.2.2.2 Hornbrook Basin

Location

The Hornbrook Basin is located in southern Oregon and extends into northernmost California. The defining Hornbrook Formation is one of many widely scattered Cretaceous units that crop out in various parts of Oregon. The rock outcrops form a narrow belt, about 130 km (50 miles) long, from just north of Medford to just south of Yreka in California. The basin's true extent of the formation (and the basin) has been made difficult to determine due to the large separation of outcrop areas, extensive cover of Tertiary volcanic rocks, limited exploratory drilling and extensive deformation. However, some researchers have suggested that the basin may be continuous with the Ochoco Basin in central Oregon (see Section 3.2.1) and the Great Valley in California.

Geology

The Hornbrook, Ochoco and Great Valley sequence of California thought to have been formed as part of the same depositional basin, likely connected at depth beneath cover material. The basin developed along the northeastern margin of the Klamath Mountains, extending further northeast, connecting with the Ochoco Basin in the Mitchell area. Nilsen (1984) infers the likely extent of the Hornbrook-Ochoco Basin as being bounded by upland areas to the north (by the Blue Mountains), east (by the Idaho batholith region) and west and southwest (by the Klamath Mountains). The basin may have been open to the paleo-Pacific Ocean to the northwest.

The Hornbrook Formation strata form three linked valleys in southern Oregon and northern California, defining the eastern edge of the Klamath Mountain province. The Medford-Bear Creek Valley is the only one of these located entirely within Oregon; the Cottonwood Creek Valley straddles the Oregon-California border and is offset from the Medford-Bear Creek Valley by the Siskiyou Summit fault.

The Hornbrook Formation rests unconformably on metamorphic and plutonic, Ordovician to late Jurassic age rocks of the Klamath Mountains. The Hornbrook strata generally dip moderately to the northeast. Tertiary volcanic and sedimentary rocks overlie the Hornbrook Formation to the west.

According to Nilsen (1984), the Hornbrook Formation has a total thickness of about 1,220 m (4,000 feet). He divided the Hornbrook Formation into five members, all of which consistently crop out in the Medford-Bear Creek Valley. The type section is located near the town of Hornbrook, located 13 km (5 mi.) south of the Oregon border in the Cottonwood Creek Valley. The members are (youngest to oldest):

- Blue Ranch Member – mostly mudstone with fine-grained sandstone interbeds. Contains the Rancheria Gulch and Hilt Bed sandstones. Total member thickness is 920 m (3,000 feet).
- Rocky Gulch Member – gray fine-medium grained sandstone. From 150 to 230 m (500 to 750 feet) thick.
- Ditch Creek Member – gray siltstone and fine-grained sandstone. Between 23 and 76 m (75 and 250 feet) thick.
- Osburger Creek Member – marine sandstone unit, includes some conglomerate, siltstone and shale. Between 76 and 152 m (250 and 500 feet) thick.
- Klamath Rover Member – non-marine, clast- and matrix-supported conglomerate; up to 90 m (300 feet) thick.

Exploration

The basin has attracted some attention for petroleum prospects since natural gas discovered east of the outcrop areas in the Cascade Ranges. One well (drilled in 1984 about 48 km (30

miles) northeast of Yreka), encountered 610 m (2,000 feet) of sedimentary rocks with a show of oil or gas.

Kieghin and Law (1984) reported the following engineering properties for sandstone samples collected from the various members in northern California (Table 7).

Table 7. Summary of porosity and permeability data for Hornbrook Basin samples

Unit/Formation	Porosity (%)	Permeability in m^2 (md)
Blue Gulch Sandstone	12.2 – 13.6	$9.9x10^{-18}$ (0.01)
Holt Bed	18.6	$7.9x10^{-16}$ (0.8)
Rocky Gulch Sandstone	6.3 – 12.8	$1.8x10^{-16}$ to $1.2x10^{-15}$ (0.18 – 1.2)
Ditch Creek Siltstone	6.3 – 12.8	$9.9x10^{-18}$ to $4.9x10^{-17}$ (0.01 – 0.05)
Osburger Creek Sandstone	6.7 – 13.1	$9.9x10^{-18}$ to $8.8x10^{-16}$ (0.01 - 0.89)

Law *et al.* (1984) report results for analyses of 62 outcrop samples. They suggest that the nature of the organic matter present (type III kerogen) indicates the rocks have potential to generate gas with little to no oil, and that the rocks are immature to marginally mature with respect to thermal gas generation. However, the effects of weathering of the surface samples means that hydrocarbon potential may be overall slightly higher.

4.2.2.3 Snake River Basin

The Snake River Basin is located in easternmost Oregon, and extends into western Idaho. The basin sediments consist of semi-consolidated to well-consolidated tuffaceous lacustrine shales, siltstones and sandstones, alluvial sandstone and conglomerate, coal, and lava of Miocene-Pliocene age. In many places, the sedimentary rocks are themselves covered by Miocene basalts. According to Dole and Corcoran (1954), the total sedimentary sequence thickness is about 4,570 m (15,000 feet). The sedimentary rocks overlie Mesozoic volcanic rocks.

Several hydrocarbon exploration wells have been drilled in the basin, with oil and gas shows in a few of these boreholes. We have included locations of some of the deeper borings drilled in the basin. Information is limited, although some records indicate the final formation encountered at total depth.

4.2.2.4 Harney Basin

The Harney Basin is located in the northernmost area of the Basin and Range Province. The geology is believed to be similar to that of the Snake River Basin, consisting of thick continental sediments and lavas.

We have included some details for several wells drilled in the basin. Limited geologic information was available, however.

4.3 Unconsolidated Sedimentary Basins

As part of this assessment, we have reviewed literature and information sources for several unconsolidated sedimentary basins in Washington and Oregon. The depositional environments include fluvial, lacustrine, glacial and aeolian. All surficial units exhibit extensive outcrops in these basins.

4.3.1 Unconsolidated Basins of the Columbia Plateau Province (Washington)

4.3.1.1 Walla Walla Basin

The Walla Walla Basin is located in southeastern Washington (in Walla Walla County).

The basin geology consists of unconsolidated alluvial, wind-blown, and flood deposits overlying bedrock consisting of Columbia River Basalt flows.

- Unconsolidated sediments - consist of gravel and clay of Pleistocene age (alluvial fan and flood deposits), loess, and younger and older alluvial materials
- Columbia River Basalt - consists of a thick series of individual flows of the Saddle Mountains Basalt (youngest), Wanapum Basalt, and Grande Ronde Basalt (oldest).

The basalt has been folded and faulted since it was deposited, resulting in several compartmentalized fold- or fault-bounded blocks near the city of Walla Walla. The principal geologic structure is the Walla Walla syncline; the fold axis is roughly parallel to the axis of the Walla Walla valley, and plunges gently to the southwest. The elevation of the top of the basalt is lowest along the axis of the syncline and the thickness of the unconsolidated sediments is greatest to the west along the axis of the syncline.

As part of the database, we have included a map layer showing the interpreted elevation of the base of the unconsolidated sediments (or top of the underlying CRBG strata) in the main part of the valley. The transmissivity of the unconsolidated sand and gravel aquifer in the Walla Walla Basin ranges from about 930 to 5,580 m^2/day (10,000 to 60,000 sq.ft/day) with a hydraulic conductivity of 4 to 200 m/day (13 to 650 ft/day). The basalt aquifer is the most productive aquifer, and contains a number of high-capacity (greater than 3,800 liters/minute (1,000 gallons/minute)) production wells. Groundwater generally occurs in the contacts between basalt flows. The basalt aquifer transmissivity is variable and dependent on the thickness of the interbed zones, the number of interbed zones intersected, and the hydraulic conductivity of the materials in the interbed zones. The transmissivity of the basalt aquifer in the Walla Walla Basin has estimated to average about 750 m^2/day (8,000 sq.ft/day), and rarely exceeds 3,720 m^2/day (40,000 sq.ft/day).

4.3.1.2 Kittatas-Yakima-Selah Basins

These three unconsolidated basin extend eastwards from the foothills of the Cascade Ranges Mountains onto the western edge of the Columbia Plateau Basin. The eastern portion of the basin (east of Cle Elum) transitions into the Yakima fold belt, consisting of structural basins filled with sedimentary and volcaniclastic sediments, and upland areas of volcanic rocks such as basalt.

The Ahtanum-Moxee basin is a synclinal structure bounded on the north by Yakima Ridge and Cowiche Mountain and on the south by Ahtanum Ridge and the Rattlesnake Hills. It is a basin within the larger Yakima River Basin.

An important geologic feature of the basin is the Yakima Fold Belt, which is a series of anticlinal ridges and synclinal valleys that predominantly trend east-west. The Belt covers roughly 14,000 square kilometers of the Columbia Basin, and was formed when basalt flows of the CRBG and interbedded sediments of the Ellensburg Formation were folded and faulted as a direct result of north-south compressional stresses. These structures are clearly exposed along road cuts when driving through the Selah Gap and Union Gap. The tops of the anticlines are represented by Selah Heights and Yakima Ridge on the north side of the valley, and by Ahtanum Ridge and the Rattlesnake Hills on the south side of the valley. The trend of the Yakima Ridge and Ahtanum Ridge anticlines changes east of the Yakima River, where the fold axes trend more northwesterly-southeasterly. Current research suggests that this shift is due to a major structural feature, the Olympic-Wallowa Lineament (OWL), which runs from northeastern Oregon to the tip of the Olympic Peninsula.

The general geology is summarized as:

- Alluvium (Q) - occurs at ground surface with thicknesses that generally range up to 60 m (200) feet.
- Thorp Gravel (Ttg) - underlies the alluvium within the Ahtanum Valley. The thickness of this unit varies up to 12 m (40 feet).
- Upper Ellensburg Formation (Teu) – often sub-divided into an upper coarse-grained member, a middle fine-grained member and a lower coarse-grained member. The Upper Ellensburg Formation is up to 530 m (1,750) feet thick at the axis of the Ahtanum-Moxee basin syncline.

The CRBG and interlayered Lower Ellensburg Formation sediments underlie the Upper Ellensburg Formation. No CRBG thickness information is available in this area.

In the database, we have indicated the general extent of unconsolidated sediments in the valley, and have also included details of the thickness of the unconsolidated sediments and the depth to the top of the CRBG rocks (from Drost and Whiteman, 1986; and Golder, 2002). The basin thickness ranges from zero at the margins to almost 610 m (2,000 feet) at the center of the basin.

We have also included permeability results for several groundwater production wells. The estimated hydraulic conductivity for the Upper Ellensburg Formation ranges over five orders

of magnitude from 0.2 to 0.62 to 690 m/day (2,265 ft/day); the average estimates for the upper and lower members are 4 m/day (13 ft/day) and 18 m/day (60 ft/day), respectively. The transmissivity of Upper Ellensburg Formation sediments ranges from 23 to 7,760 m^2/day (250 to 83,500 sq.ft/day). The basin's permeable units are currently being evaluated for aquifer storage/recharge projects to increase the area's water supply, and improve the quality and reliability.

4.3.1.3 Toppenish-Satus Basin

The Toppenish and Satus Basins lie south of the Yakima Basin, and are separated by the Ahtanum Ridge. The surficial geology is similar to that in the Yakima Basin, and the thickness of unconsolidated sediments exceeded 305 m (1,000 feet) in the center of the Toppenish Basin (Drost and Whiteman, 1986).

4.3.1.4 Pasco Basin

The Pasco Basin is at the eastern edge of the Yakima Fold Belt region, and is bordered to the south by the Columbia River and to the north by the Saddle Mountains. The basin is home to the Hanford Nuclear Reservation. The unconsolidated sediments consist of up to 240 m (800 feet) of Quaternary sediments (Drost and Whiteman, 1986). No specific well information was available in this basin.

4.3.1.5 Quincy Basin

The Quincy Basin is located north of the Pasco Basin, east of the Columbia River. Despite it relatively large areal extent (approximately 1,950 km^2 (750 square miles)), the sediment thickness exceeds 120 m (400 feet) only at the central area (Drost and Whiteman, 1986). No specific well information was available in this basin.

4.3.1.6 Spokane River Basin

The Spokane River Basin is located in eastern Washington and consists of up to 210 m (700 feet) of unconsolidated fluvial and fluvio-glacial sediments. The basin outline included in the database is based on the extent of the unconsolidated sediments. The base of the basin coincides with the top of the continental basement rocks (Precambrian, exposed in a few areas) and the CRBG rocks. The generalized geologic sequence in the region is as follows:

- Unconsolidated (Quaternary) deposits - comprise predominantly sands and gravels with minor amounts of silt and clay; during glacial advances and retreats up to the present day alluvial system.
- Basalt flows and intercalated sediments – consist of basalt rocks comprise Miocene age (Columbia River Basalt Group) flows intercalated with fluvial and lacustrine deposits of the Latah Formation (lacustrine silt and clay beds containing some fluvially-deposited sand and gravel).
- Crystalline basement - comprises Precambrian metamorphics (quartzite, schist and gneiss) and Mesozoic to early-Cenozoic plutonic rocks (granite).

We have included contours of the elevation of the base of the unconsolidated sediments in the database. The thickness ranges from zero where the basalt and crystalline bedrock outcrop to 210 m (700 feet) in the deepest parts of the Spokane River valley.

The unconsolidated sediments in the main Spokane River area (the Spokane Valley-Rathdrum Prairie Aquifer or SVRP) are highly permeable and transmissive, and are heavily pumped heavily for municipal groundwater supplies. Hundreds of shallow groundwater wells have been drilled to extract the generally good quality water. The permeability of the sand and gravel aquifers associated with the flood events can exceed 150 m/day (500 ft/day). Groundwater in the basalt flows is also pumped. Table 8 summarizes the hydraulic properties of the various units.

Table 8. Summary of hydrologic properties for the Spokane River Basin units

Hydrogeologic Unit	**Aquifer Area**	**Transmissivity m^2/day (ft^2/day)**	**Hydraulic Conductivity in m/day (ft/day)**
Flood Sand & Gravel	SVRP	400 –1,020,000 (4,320 – 11,000,000)	150 – 3,660 (500 – 12,000)
	Little Spokane River	930 – 48,200 (10,000 – 518,400)	160 – >190 (530 –>640)
	Deer Park	67 – 24,900 (722 – 267,400)	5 – 1,850 (16 – 6,077)
Lower Flood Sand and Gravel	Little Spokane River	930 – 3,700 (10,000 – 40,000)	30 – 70 (100 – 230)
Basalt	West Plains, Little Spokane River, Five Mile Prairie, Deer Park	2 – 18 (25 – 193)	0.05 – 3.7 (0.18 – 12.1)
Crystalline Basement	North End of Five Mile Prairie	-	0.3 – 26 (1 – 86)

Groundwater in the basin is generally of good to excellent quality. Total dissolved solids (TDS) are generally less than 200 mg/L within the alluvial sediments and less than 250 mg/L within the basalts (Golder, 2003a).

4.3.2 Willamette Lowland Trough

Location

The Willamette Trough is a flat-lying region bounded to the east by the Cascade Mountains, to the west by the Coastal Hills Range, and extends from the Lewis River in Washington to Eugene; both northern and southern extends coincide with upland areas where the Cascade and Coastal hills converge. For the purpose of this assessment, we have used the findings of Gannett *et al.* (1998) to define the basin and geologic properties. The basin includes four broad basins - the Portland Basin, the Tualatin Basin, the Central Willamette Valley and the Southern Willamette Valley. The land surface slopes northwards from about 140 m (450 feet) msl at Eugene to less than 15 m (50 feet) msl near Portland.

Geology

The Willamette Valley consists of up to 610 m (2,000 feet) of unconsolidated basin fill sediments of continental origin (Quaternary age) overlying Columbia River Basalts (in the north) and Tertiary sedimentary and volcanic rocks (in the south). The basin was formed in response to tectonically-induced subsidence in the area between the Coastal Ranges and the Cascade Mountains. The sediments were derived from a number of sources, including the surrounding uplands and the Columbia River; the uppermost basin fill deposits are a result of giant Columbia River floods in late Pleistocene time.

Marine sedimentary rocks and volcanics underlie the basin fill. The former are associated with the Tertiary basins described in Section 3 (such as the Tyee-Upmqua Basin); the latter consist of Columbia River Basalts, and are exposed in the northern part of the basin and separate the four main basin areas. The oldest outcropping rocks in the Basin are the Eocene volcanic rocks (Siletz River and Tillamook volcanics) that also underlie the marine sedimentary basins in the Coastal Range.

Gannet *et al.* (1998) defined the following hydrostratigraphic sequence to develop a regional aquifer system for the basin:

- Willamette Silt Unit – Pleistocene-Holocene; up to 40 m (130 feet) of glacial outburst flood sediment
- Willamette Aquifer – Pliocene-Pleistocene; 6 to 180 m (20 to 600) feet of coarse-grained fan and stream deposits.
- Willamette Confining Unit – Miocene-Pleistocene; up to 490 m (1,600 feet) of fine-grained alluvial fan and river deposits
- CRBG Aquifer – up to 305 m (1,000 feet) of Miocene basalts; underlying the unconsolidated sediments in the northern lowlands
- Basement Unit – includes Tertiary marine sedimentary and Eocene volcanic rocks

Hydraulic properties for these regional units are summarized in Table 9.

Table 9. Summary of hydrologic properties for Willamette Trough units

Unit	Hydraulic conductivity in m/day (ft/day)		
	Median	Range	Modeled
Willamette Silt	0.03 (0.1)	0.03 – 2.4 (0.01 – 8)	0.3 (1)
Willamette Aquifer	2.1 – 73 (7 – 240)	(0.01 – 2,130 (0.03 – 7,000)	61 to 183 (200 – 600)
Confining Unit	0.6 (2)	0.03 – 27 (0.01 – 90)	1.5 (5)
CRBG Aquifer	0.3 (1)	0.0003 – 230 (0.001 – 750)	0.8 (2.5)

McKeel (1984 and 1985) provides some information on the nature of the Tertiary sedimentary and volcanic rocks underlying the basin fill in the northern and southern parts of the basin, respectively. His analysis of borehole cores indicates that as much as 2,900 m (9,500 feet; in the south) and 4,420 m (14,500 feet; in the north) of Tertiary sedimentary rocks overlies basement volcanics. These sedimentary rocks are a continuation of these present in the Cascade Ranges to the west, and overlie the Tillamook Volcanics in the north and the Siletz River Volcanics in the south.

Exploration

Most of the activity in the Willamette Valley Lowlands has been aimed towards water resources. The area is heavily farmed and the unconsolidated and basalt aquifers contain water of excellent quality. More than 30 deep exploratory wells have been drilled in Lane, Linn, Polk, Marion, Yamhill, Washington and Multnomah counties for hydrocarbon exploration. Golder reviewed the interpretation of 18 wells in McKeel (1984, 1985) to estimate depths and thicknesses of the Tertiary sedimentary formations, and depth to economic basement. These data are included in the database.

4.3.3 Unconsolidated Basins of the Columbia Plateau Province in Oregon

4.3.3.1 Umatilla Basin

The Umatilla Basin is located in north-central Oregon (Umatilla and Morrow Counties), immediately south and adjacent to the Columbia River. The basin consists of up to 120 m (400 feet) of unconsolidated sediments deposited by wind and deposited glacially derived fine silt overlies the CRB in much of the basin.

Coarse sediments derived from riverbed, flood and other alluvial deposits occur locally with thicknesses up to ~100 m (several hundred feet). Interflows, consisting of sedimentary units between basalt flows, may be 60 m (200 feet) thick. The entire CRBG sequence may be as much as 1,830 m (6,000 feet) thick in the basin.

Much of the area is under administrative groundwater withdrawal limitations due to excessive irrigation use. Records show that one, 104-m (340-foot) deep exploration well was drilled in 1955 about 6 km (4 miles) northeast of Pendleton. No driller's logs or core records exist for this well, however.

4.3.3.2 Deschutes Basin

The Deschutes Basin is located on the eastern flank of the Cascade Range and occupies the margin with the Basin and Range Province and the High Lava Plains regions. For this assessment, we have considered the more extensive upper Deschutes Basin area, which is a sub-area of the larger Upper Deschutes River watershed (defined in Gannett *et al.*., 2000); in particular, the sub-basins referred to as La Pine, Princeville and Sister.
The geology of the sub-basins consists of Quaternary alluvium, overlying volcanic rocks. The Cascade Range (to the west) and the Tertiary (Miocene) and Quaternary lavas of the Columbia-Deschutes Plateau and Lava Plateau (to the east) form the basin boundaries.

The La Pine Sub-basin is essentially a faulted graben structure, with between 550 and 730 m (1,800 and 2,400 feet) of structural relief. The graben formed a depositional center initially filled with low-permeable material sediment and later coarser alluvium. The La Pine Sub-basin is the largest occurrence of Quaternary alluvium in the region. The sediments generally consist of a lower layer of mostly silt and sand layer (~100 m (several hundred feet) thick) overlain by up to 30 m (100 feet) of silt, sand and gravel. Some local water wells are as deep as 450 m (1,460 feet).

Most of the economically-productive water wells are located in the upper alluvium; these wells yield from 38 to 1,140 liters/minute (10 to 300 gallons/minute), and the sediments have a reported hydraulic conductivity of 27 m/day (88 ft/day). The high organic content in the lower alluvium has been noted as possible source for methane.

The alluvium generally overlies a sequence of fairly permeable volcanic deposits and highly permeable (Miocene-Pliocene) Deschutes Formation which consist of a variety of volcanic and sedimentary units. The Deschutes Formation overlies the low permeable John Day Formation. The John Day Formation consists of ~100 m (several thousand feet) of diagentically-altered volcanic and volcanically-derived sedimentary rocks of Miocene-Eocene age.

Caldwell and Truini (1997) presented groundwater quality data (for general parameters such as specific conductance, general minerals, metals and pH) for more than 20 wells located in the basin. We have included these results in the database. The conductivity ranges from 60 to 866 µS/cm. The report also summarized discharge water quality for seven springs; specific conductance ranges from 60 to 189 µS/cm.

Eight deep exploratory boreholes have been drilled, all located between 3 and 6 km (2 and 4 miles) south and south east of Bend, and were drilled to total depths of between 430 and 1,370 m (1,400 and 4,500 feet). Drilling logs exist for just two of these wells, neither of which was inspected for this project.

4.3.3.3 La Grande and Baker Basins

The La Grande Basin is located in northeastern Oregon, near the cities of La Grande and Elgin in Union county. The basin consist of broad, relatively thin (up to ~100 m (a few 100's of feet)) and relatively continuous surficial alluvial sand and gravel deposited by the Grande Ronde and other braided rivers which flow from the Blue Mountains in the west and the Wallowas in the east onto a broad flat valley floor. Groundwater depth is generally less than 6 m (20 feet) below land surface.

One exploratory borehole has been drilled in the basin is located less than 2 km (one mile) west of Union to a depth of 850 m (2,800 feet), likely terminated in the Tertiary basalts. No log or core records exist, however. The Baker Basin lies several km (a few miles) south of the La Grande Basin

4.3.3.4 Pluvial Lake Basins of the Basin and Range Province

The Basin and Ranges geomorphic province occupies southern Oregon, and is a series of long, narrow north-south trending fault-block mountains alternative with broad sediment-filled basins (Orr and Orr, 1999). We have included in this summary several of the largest basins which are in essence graben structures caused by the extensional tectonics that occurred in this region during Miocene to Pliocene time. The basins were fed water during the relatively wet Pleistocene, resulting in lakes.

The predominant surficial deposits in the basins are alluvium (gravel, sand, silt, and pyroclastic deposits), dune sand, fanglomerates and playa deposits (silt, clay and evaporates). Several basins still contain lakes. The basin floors are typically 1,220 m (4,000 feet) above mean sea level or higher. Many of the basins extend into the northern California and Nevada portions of the Basin and Ranges. The basins defined in this assessment are as follows:

- Klamath Lake Basin
- Fort Rock Basin
- Goose Lake
- Warner Valley
- Summer Lake
- Catlow Valley
- Alvord-Pueblo Valley

The basins typically overlie the Tertiary volcanic rocks which were laid down starting in the Miocene; the total volcanic sequence likely reached up to 3,050 m (10,000 feet). These volcanic rocks were subsequently heavily faulted and fissured. No information was available

for the thickness of the unconsolidated sediments, but they are likely up to ~100 m (several hundred feet) thick.

The Klamath Lake Basin is the most westerly of these basins, and is located on the eastern flank of the Klamath Mountains. The basin contains unconsolidated fluvio-lacustrine deposits of diatomite, water-lain volcanic sediments, and tephra with localized alluvium, alluvial fans, and tallus. Sediments are generally thin (~10 m (tens of feet)) but can be up to ~100 m (hundreds of feet) near fault escarpments. The sediments are generally above the water table, though minor amounts of perched water do occur. The basin also includes a continental sedimentary unit, often referred to as the Yonna Formation. The unit consists of bedded sandstone, siltstone and laminated mudstone, conglomerate and tuff, underlain and overlain by Miocene lava flows. The geologic sections in Sherrod and Pickthorn (1992) illustrate the formation to have a thickness of up to 760 m (2,500 feet).

Hydrocarbon prospectors drilled five wells between 1926 and 1931 in the basin within several km (a few miles) east and south of Klamath Falls; the maximum depth drilled was 1,330 m (4,365 feet). We have included in the data base details for several of these wells. Minimal geologic information was available at this stage, although some borehole logs and cores exist for these and other wells drilled in the basin. Geothermal water was encountered in two of the wells. No engineering properties were available for this basin.

4.4 Petroleum Assessments

4.4.1 1995 Outer Continental Report

In 1995, the U.S. Department of the Interior's Minerals Management Services prepared an assessment of the oil and gas resources of the Pacific Outer Continental Shelf (Dunkel and Piper, 1997). The report defined the Washington-Oregon Assessment Area as consisting of a 48 to 80 km (30 to 50 mile) wide (starting 5 km (3 miles) offshore) by 640 km (400 mile) long region, stretching from Cape Flattery off the northwest coast of the Olympic Peninsula to just south of Cape Blanco in southwestern Oregon.
The assessment also defined six Neogene depositional centers (sub-basins) based on seismic profiles. The offshore geology of the region consists of a Paleocene-Miocene mélange (the Hoh Assemblage discussed in Section 2), overlain by turbidites deposited in a trench and slope environment. Structural features are generally trend north or northwest and include compressional folds and faults, dextral strike-slip faults and extensional faults.

Twelve exploratory wells and three Deep Sea Drilling Project coreholes were drilled in the offshore region. Hydrocarbon shows were encountered in eight of the well sites.

The report also identified five petroleum plays based on reservoir and trapping characteristics; we have included the outlines of these in the database. The following is a brief summary of these plays:

- Growth Fault (conceptual) Play - Miocene-Pliocene sandstones deposited in deltaic and fan systems with growth fault traps. Hydrocarbon accumulations are

expected to occur to about 2,440 m (8,000 feet) below the sea floor. Located off the coast of Washington (from Teawhit Head to the Columbia River mouth).

- Neogene Fan Sandstone (conceptual) Play - Miocene-Pliocene sandstones deposited in deltaic and fan systems with anticlinal, fault and stratigraphic traps. Hydrocarbon accumulations may exist to about 3,660 m (12,000 feet) below the sea floor. Extends from Teawhit Head to Newport in Oregon.
- Neogene Shelf Sandstone (conceptual) Play - Miocene-Pliocene sandstones deposited in deltaic and fan systems on the continental shelf and upper slope, with anticlinal, fault and stratigraphic traps. Hydrocarbon accumulations may exist from 610 to about 3,660 m (2,000 to about 12,000 feet) below the sea floor. Extends from Cape Flattery to Cape Blanco.
- Paleogene Sandstone (frontier) Play – Eocene –Oligocene sandstones deposited in a shelf environment, and incorporate anticlinal, fault and stratigraphic traps. The traps are expected to be between 610 and 6,100 m (2,000 and 20,000 feet) deep. Extends from Grays Harbor to Coos Bay.
- Melange Play – contains oil and associated gas in Eocene-Miocene sandstones, and extends from Cape Flattery to Cape Blanco. The upper part is considered to be turbidites, and the lower part is a tectonic mélange. Equivalent rocks are exposed in the Western Olympics area (see Section 2).

The Eel River Basin lies south of the Washington-Oregon Area basin, and extends a short distance into offshore Oregon waters. None of the associated drilling occurred north of the Oregon-California border. Therefore, for the purpose of this assessment, we have considered this basin to be associated more with California than Oregon.

4.4.2 1995 National Assessment of Oil and Gas Resources

The USGS Central Energy Team provides periodic assessments of the oil and natural gas endowment of the United States. The most recent, completely digital assessment of the entire United States was completed in 1995 and has been archived for your use. The report defined three provinces that either fully or partially fall within the states of Oregon or Washington region. The assessment produced geologic reports and these provinces are:

- Province 4 -Western Oregon-Washington Province. Includes all of Oregon and Washington north of the Klamath Mountains and west of the approximate Cascade Range crest, and extends offshore to the Federal 5-km (3-mile) limit. The province covers an area of 103,600 km^2 (40,000 square miles). The regional geology consists of rocks accreted during the period of Mesozoic subduction. The fore-arc basin strata are as much as 6,100 m (20,000 feet) thick, onlapping the varied pre-Tertiary basement and Paleocene-Eocene volcanic basement.
- Province 5 -Eastern Oregon-Washington Province. This province is bounded on the west by the approximate Cascade Range crest, on the north by the U.S.-Canadian border, on the east by the Idaho state line and on the south by the boundary with the Great Basin Province. The province covers and area of about 155,400 km^2 (60,000 square miles). The regional geology consists of mostly rocks of the Miocene Colombia River Basalt Group (up to 3,350 m (11,000 feet) thick)

overlying Paleozoic and Mesozoic rocks associated with the ancient continental margin. The sedimentary rocks that form the basins and plays are located mostly in the western half of the province, and represent marine sediments deposited on the accretionary complex (Cretaceous) and less continuous, non-marine sediments (Paleocene-Eocene age).

- Province 19 - Western Great Basin Province. This province is essentially the western part of the Great Basin geomorphic province, and occupies a total area of about 336,700 km^2 (130,000 square miles), of which about the northernmost quarter lies within Oregon borders. The regional geology consists of metamorphosed basement rocks of Paleozoic and Mesozoic age, with lacustrine and fluvial sedimentary basins developed in response extensional tectonics in Cretaceous-Cenozoic time. These basins are described in Section 4.4 of this report.

Each province contains individual plays, either conventional (hypothetical) or unconventional. All of the plays consist of one or more of the sedimentary basins described in Sections 2 through 4 of this report.

Only one of the plays (the Cowlitz-Spencer Gas Play in Province 4) is a confirmed play. The report also provides summary ranges of key engineering properties, notably porosity, permeability and total organic carbon, for the significant geologic formations. We have included the outlines of these provinces plus the parameter ranges in the database.

4.4.3 Other Assessments

The American Association of Petroleum Geologists (AAPG) maintains an interactive web site (browser) for worldwide oil and gas fields (http://gisudril.aapg.org/gisdemo/). Golder accessed this site to review the AAPG's data. The browser site includes several basins (both consolidated and unconsolidated) in Washington and Oregon that generally match the sedimentary basins described in earlier sections. No explicit fields were included for any of the basins, though.

5 Conclusions

Golder conducted a preliminary characterization of sedimentary basins in the states of Washington and Oregon as part of Phase I of WESTCARB's Geologic Carbon Dioxide Sequestration Assessment. The following conclusions were drawn based on the work performed and detailed in the report.

5.1 Western Coastal Basins

The study identified several sedimentary basins along the western continental margin of Washington and Oregon states. These basins are associated with a major Tertiary sedimentary belt of basins that formed in a regional fore-arc environment as the Juan de Fuca plate subducted beneath the North American Plate. These basins are characterized by up to 9,000 m (30,000 feet) of Tertiary sedimentary rocks deposited in embayments and shallow

seas; throughout, the basins are underlain by Eocene oceanic basalt. In many cases, the individual basin boundaries are uncertain at this time. Although some basin depth and thickness interpretations were made and engineering properties for key formations exist, no storage volume estimates were attempted at this stage.

- Tofino-Fuca Basin. The Tofino-Fuca Basin occupies the northern edge of the Olympia Peninsula and extends beneath the Strait of Juan de Fuca. The sedimentary sequence consists of up to 7,600 m (25,000 feet) of sandstone, claystone, and coal in an asymmetrical syncline. Reported sandstone permeabilities range from $2.0x10^{-15}$ to $7.4x10^{-15}$ m^2 (2.0 to 7.5 md) and porosities from 20.4 to 20.7 percent. Structural traps onshore are rare and only a few local normal, strike-slip, and thrust faults, and a few minor faulted anticlines, exist. Offshore structural traps appear to be more common.

- Western Olympia Basin. The Western Olympic Basin is located directly west of the Olympic Mountains and extends westwards offshore for at least 60 km (40 mi.). The Miocene and Eocene marine sedimentary rocks have an estimated total thickness of at least 2,700 m (9,000 feet). The Hoh Assemblage, which is the most prominent of these sedimentary rocks, was accreted to the continental margin. All of these units have relatively low oil and gas potential because tectonic activity has disrupted their structural traps.

- Willapa Hills Basin. The Willapa Hills Basin is located south of the Western Olympic Basin and contains up to 4,600 m (15,000 feet) of late Oligocene to Quaternary sedimentary strata overlying oceanic basalt basement. Two notable submarine fan turbidites (the basal Cowlitz and basal Lincoln Creek sandstones) show porosities of 26 to 33 percent and permeabilities up to $9.4x10^{-14}$ m^2 (95 md). The younger McIntosh sandstone exhibit porosities and permeabilities up to 22 percent and $6.1x10^{-15}$ m^2 (6.2 md), respectively. Four potential Eocene and Oligocene reservoirs have been identified from oil and gas exploration wells, outcrop studies, and seismic interpretations in this basin.

- Puget Trough Basin. The Puget Trough Basin occupies the generally low-lying region east of the Olympic Mountains and west of the Cascade Mountains. It consists of up to 1,100 m (3,700 feet) of unconsolidated sediments of Pleistocene age overlying up to 3,000 m (10,000 feet) of Tertiary sedimentary rocks. Faulting and folding is abundant, resulting in the formation of several distinct sub-basins. The Chehalis sub-basin hosts the Jackson Prairie Gas Field—a once-economically productive gas reservoir; this field currently provides temporary storage for natural gas, and so provides a good analog for potential geologic storage of carbon dioxide. Skookumchuck Formation sandstones have excellent reservoir properties (porosity of 30 to 38 percent, and permeability of $1.3x10^{-13}$ to $3.0x10^{-12}$ m^2 (135 to 3,030 md)) in a variety of sedimentary facies.

- Whatcom Basin. Whatcom Basin occupies the northernmost part of the Puget Trough lowlands; however, the true basin outline is uncertain due to unconsolidated sediment cover and complex geology. The basin consists of Quaternary glacial and interglacial deposits overlying Tertiary sedimentary rocks and pre-Tertiary rocks of the northwest

Cascade Range. The notable Chuckanut Formation (Eocene) consists of up to 6,000 m (20,000 feet) of arkosic sandstone, siltstone, conglomerate and coals; individual members have maximum thickness of between 900 and 5,500 m (3,000 and 18,000 feet). Hydrocarbon exploration has been significant, mostly focusing on gas derived from the coal deposits. Reported sandstone porosity and permeability values range up to 17.3 percent and 4.5×10^{-14} m^2 (45.3 md), respectively.

- Astoria-Nehalem Basin. This is located in northwestern Oregon, about 70 km (45 miles) northwest of Portland, and contains the only economically productive gas field (Mist Gas Field) in Oregon. This basin has been explored more than any other in the state. The prominent Cowlitz Formation consists of micaceous, arkosic-basaltic marine sandstone and a siltstone-and-mudstone sequence; this sequence includes the gas-producing Clark & Wilson Sandstone, which is overlain by a thick shale unit. Permeabilities and porosities are up to 1.4×10^{-12} m^2 (1,400 md) and 39 percent, respectively.

- Tyee-Umpqua Basin. This basin occupies the southern half of the Coastal Range in Oregon and consists of two superimposed basins with different geologic trends and tectonic histories. The basin contains more than 6,000 m (20,000 feet) of lower-middle Eocene sedimentary strata. One notable unit in this basin is the Tyee Formation sandstone, which has a total thickness of up to 1,800 m (6,000 feet) and average porosities and permeabilities of 10.8 percent and 2.7×10^{-15} m^2 (2.76 md), respectively.

- Coos Basin. The Coos Basin is located in coastal southwestern Oregon in the Coastal Range Province, extending from the western edge of the Tyee Basin and continuing offshore. The basin consists of up to 4,000 m (13,000 feet) of marine sedimentary rocks of Tertiary age that were deposited as continental deltaic margin and deep-sea fan facies. Prominent sandstones possess porosities and permeabilities up to 43 and 1.8×10^{-12} m^2 (1,800 md), respectively.

5.2 Basins East of the Cascade Range

Our research identified several consolidated basins east of the Cascade Mountains in both Oregon and Washington. Although each basin has some characteristics that are favorable for potential sequestration, exploration and characterization are not as comprehensive as for many of the western basins.

- Sub-Columbia River Basalt Plateau. Several deep exploration boreholes identified a thick sequence of sedimentary rocks underlying the Columbia River Basalt Group. These rocks are not exposed in the Plateau area and much uncertainty exists to their exact extent and thickness. The basin contains up to 4,600 m (15,000 feet) of layered Miocene lava flows overlying as much as 10,000 m (33,000 feet) of mid-Tertiary, non-marine sedimentary strata.

- Ochoco Basin. This basin is located in south-central Oregon and has uncertain lateral extents due to only limited exploration and a thick volcanic cover. The capping is less well known, although the basin is buried beneath younger material.

- Methow Basin. The Methow Basin is located on the eastern flanks of the northern Cascade Range in Washington. The basin is fault-bounded and is believed to contain up to 4,000 m (13,000 feet) of Cretaceous-Tertiary sedimentary strata. Several significant marine sandstone members have been identified based on surface exposures. However, no deep exploration drilling has been performed and the basin has not been well characterized.

- Chumstick-Swauk Basin. This basin is located on the eastern flank of the Cascade Range to the south of the Methow Basin. The basin is a graben feature and contains up to 5,800 m (19,000 feet) of non-marine strata of Eocene age. As with the Methow Basin, no deep oil and gas exploration wells have been drilled in the basin, making the thickness and depth of the sedimentary formations difficult to determine. No information was available regarding engineering properties.

- Hornbrook Basin. The Hornbrook Basin is located in southern Oregon and extends into northernmost California. The basin is a narrow, 80-km (50-mile) long belt containing an undetermined thickness of Cretaceous units. The basin's true extent is uncertain due to the extensive cover of Tertiary volcanic rocks, limited exploratory drilling and extensive deformation. The basin may be continuous with the Ochoco Basin and the Great Valley in California. Some hydrocarbon exploration in the basin encountered oil and gas shows. The limited sandstone porosities and permeabilities vary from 6.3 to 13.6 percent and up to $1.2x10^{-15}$ m^2 (1.2 md), respectively.

5.3 Unconsolidated Sedimentary Basins

Numerous well-defined unconsolidated sedimentary basins were also identified as part of the study. They typically consist of Quaternary and Recent alluvium, lacustrine, and aolian deposits overlying consolidated basins or volcanic plateau areas. However, their relatively shallow character, the absence of a distinct structural and/or physical trap and the reliance of the public for groundwater supplies from many may make them less promising for sequestration purposes.

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Appendix. Geologic formations referenced in this report and database

Symbol[(1)]	Formation/Unit Name	Age	Notes
Western Tertiary Basins - Washington			
Q	Undifferentiated	Quaternary	Unconsolidated sediments
PLM(n)	Quinault Formation	Pliocene	
Mc(w)	Wilkes Formation	Miocene	
Mn(c)	Clallam Formation	Miocene	Tofino-Fuca Basin
OEm(lc)	Lincoln Creek Formation	Oligo-	
OEc(h)	Huntingdon Formation	Oligo-	Whatcom Basin
Em(2tr)	Twin River Group	Oligo-	Tofino-Fuca Basin
En(sk)	Skookumchuck Formation	Eocene	
Ec(c)	Chuckanut Formation	Eocene	Whatcom Basin
Evc(n)	Northcraft Formation	Eocene	
Em(2m)	McIntosh Formation	Eocene	
Em(1h)	Hoh Assemblage	L-M. Eocene	Includes Astoria, Lincoln Creek, Skookumchuck and McIntosh Formations
Ev(c)	Crescent Formation	L-M. Eocene	
Ec(2pg)	Puget Group	Eocene	Puget Trough
Em(b)	Blakely Formation	Eocene	
Km(n)	Nanaimo Formation	Cretaceous	Whatcom Basin
Central-Eastern Washington Basins			
CRBG	Columbia River Basalt	Miocene	
Tsfj	John Day Formation	Mio-Eocene	
Oc(w)	Wenatchee Formation	Oligocene	
Ovc(oh)	Ohanapecosh Formation	Oligocene	
Tct	Clarno Formation	Olig-Eocene	
Ec(1s)	Swauk Formation	Eocene	
Ec(2r)	Roslyn Formation	Eocene	
Western Tertiary Basins - Washington			
Tsd	Undifferentiated	Olio-Eocene	Sedimentary rocks
Tt	Tyee Formation	M. Eocene	
Tco	Cowlitz Formation	M.-U.	
Ty	Yamhill Formation	M.-U.	
Tfe	Eugene Formation	Olio-Eocene	
Tbr	Bushnell Rock Formation	L. Eocene	
Tmst	Marine sedimentary and tuffaceous	Miocene - Eocene	Pittsburg, Smuggler Cove, Northrup Formations

Symbol[(1)]	Formation/Unit Name	Age	Notes
Tmsc	Marine siltstone, sandstone and conglomerate		Roseburg and Camas Valley Formations
Tmsc	Marine siltstone, sandstone and conglomerate		Umpqua Group (includes Lookingglass Formation)
Tu	Umpqua Group		
Tmsm	Marine siltstone, sandstone and conglomerate	L. Eocene	Umpqua Group (Roseburg and Camas Valley
Tss	Tuffaceous siltsones and sandstones	M.-U. Eocene	Coaledo, Bateman, Sager Creek, Keasey Formations)
Ttv	Tillamook Volcanics	M.-U.	
Tsr	Siletz Rover Volcanics	Eocene-Paleocene	
Tes	Spencer Formation	M.-U.	
Tee	Elkton Formation	M. Eocene	Tyee Basin
Tms	Astoria Formation	L.-M.	
Central-Eastern Oregon Basins			
Tcp	Picture Gorge Basalt	M.-L.	
Tca	Carno Formation	Olig-Eocene	
Pz	Metasedimentary basement	Paleozoic	Baker Terrane
Ksc	Gable Creek Formation	U.Cretaceous	Ochoco Basin
Ksa	Hudspeth Formation	L.	Ochoco Basin

Note:
(1) – as used on the Washington 1:100,000 and Oregon 1:500,000 geologic maps

Appendix VII, Final Report

Preliminary Assessment of the Potential for Carbon Dioxide Sequestration in Geological Settings in Nevada

Topical Report

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003 - September 30, 2005

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Abstract

In this report we present a preliminary assessment of the potential for CO_2 disposal by sequestration in geological settings in Nevada using analysis with geographic information systems (GIS). The key assumptions made are that for CO_2 disposal in saline aquifers it is wisest to (1) avoid underground disposal in areas of fractured bedrock and restrict the assessment to parts of alluvial basins that are thick enough to provide a seal against leakage and have sufficient pressure to keep the CO_2 in a condensed phase; (2) stay away from active faults whose fracture zones may allow leakage of CO_2 from underground injection sites; (3) avoid areas that in the foreseeable future have a reasonably high probability of being explored and developed for mineral, geothermal, or water resources; (4) avoid current urban areas and areas that are likely to experience significant population growth during the 21st century; and (5) avoid restricted lands, such as parks and military reservations. The data sets used in the GIS analysis are made available in the electronic version of this report, so that others may reevaluate the approach with different assumptions and data sets.

There appears to be little potential for conventional enhanced oil recovery CO_2 sequestration in Nevada, partly because Nevada's oil fields do not have much associated natural gas. From this we infer that the natural gas has escaped, and so would CO_2 likely escape from these fields if CO_2 were injected into them. Furthermore, Nevada's oil fields are small when compared to fields in other parts of the country, and are at a considerably higher temperature than is ideal for maintaining a dense underground CO_2 phase.

Mined caverns and salt formations in southern Nevada, northwestern Arizona, and southwestern Utah offer some potential for CO_2 storage. Salt deposits in northwestern Arizona offer the highest potential for CO_2 storage, as these deposits are both well described and under investigation for natural gas storage.

Finally, the chemical reaction of CO_2 with mafic and ultramafic rocks has the potential to capture CO_2 in synthetic minerals. These minerals could, in turn, be used to isolate municipal and industrial wastes. Enough of these rocks are exposed in Arizona, California, Nevada, Oregon, and Washington to meet the expected needs for CO_2 sequestration in the region. Reaction of CO_2 with mafic or ultramafic rocks would be a long-term solution requiring considerably more research to design, perfect, and demonstrate the cost-effectiveness of the chemical reactors and associated facilities.

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1 Introduction

A recent report by the U.S. Government (U.S. Climate Change Science Program and the Subcommittee on Global Change Research, 2004) stated:

> "Carbon is important as the basis for the food and fiber that sustain and shelter human populations, as the primary energy source that fuels economies, and as a major contributor to the planetary greenhouse effect and potential climate change. Carbon dioxide (CO_2) is the largest single forcing agent of climate change, and methane (CH_4) is also a significant contributor.
>
> "Atmospheric concentrations of CO_2 and CH_4 have been increasing for about two centuries as a result of human activities and are now higher than they have been for over 400,000 years. Since 1750, CO_2 concentrations in the atmosphere have increased by 30% and CH_4 concentrations in the atmosphere have increased by 150%.
>
> "Approximately three-quarters of present-day anthropogenic CO_2 emissions are due to fossil fuel combustion (plus a small amount from cement production). Land-use change accounts for the rest. The strengths of CH_4 emission sources are uncertain due to the high variability in space and time of biospheric sources. Future atmospheric concentrations of these greenhouse gases will depend on trends and variability in natural and human-caused emissions and the capacity of terrestrial and marine sinks to absorb and retain carbon.
>
> "Decisionmakers searching for options to stabilize or mitigate concentrations of greenhouse gases in the atmosphere are faced with two broad approaches for controlling atmospheric carbon concentrations: 1) reduction of carbon emissions at their source—such as through reducing fossil fuel use and cement production or changing land use and management (e.g., reducing deforestation); and/or 2) enhanced sequestration of carbon—either through enhancement of biospheric carbon storage or through engineering solutions to capture carbon and store it in repositories such as the deep ocean or geologic formations.
>
> "Enhancing carbon sequestration is of current interest as a near-term policy option to slow the rise in atmospheric CO_2 and provide more time to develop a wider range of viable mitigation and adaptation options. However, uncertainties remain about how much additional carbon storage can be achieved, the efficacy and longevity of carbon sequestration approaches, whether they will lead to unintended environmental consequences, and just how vulnerable or resilient the global carbon cycle is to such manipulations."

1.1 Background on the Need to Address CO_2

Large amounts of carbon dioxide (CO_2) are generated from the burning of fossil fuels (coal, natural gas, oil, and products, such as gasoline, derived from them), wood, and other biomass. Worldwide, humans put approximately 6.5 gigatons (6.5 billion metric tons) of carbon into the atmosphere each year from the burning of fossil fuels (Service, 2004). Some handy conversions regarding carbon and CO_2 are listed in Table 1. The U.S. alone burns approximately one gigaton

of coal per year (U.S. Energy Information Administration, 2004) and has vast resources of coal. Service (2004), in interviewing Massachusetts Institute of Technology economist Howard Herzog, stated:

> "Generating electricity with coal and storing the carbon underground still costs only about 14% as much as solar-powered electricity. And unlike most renewable energy, companies can adopt it more easily on a large scale and can retrofit existing power plants and chemical plants. That's particularly important for dealing with the vast amounts of coal that are likely to be burned as countries such as China and India modernize their economies. 'Coal is not going to go away,' Herzog says. 'People need energy, and you can't make energy transitions easily.' Sequestration, he adds, 'gives us time to develop 22nd century energy sources.' That could give researchers a window in which to develop and install the technologies needed to power the hydrogen economy."

Table 1. Carbon and CO_2

Carbon, C (12.0111 grams per mole)
Oxygen, O (15.9994 grams per mole)

Burning carbon:
C [in wood, grass, and fossil fuels – natural gas, petroleum (and its products – gasoline, diesel, and heating oil), and coal] + **O_2** [from the atmosphere] = **CO_2** [into the atmosphere]

With this reaction, one ton of C yields 3.664 tons of CO_2;
1 gigaton of C yields 3.664 gigatons of CO_2.

1 gigaton = 10^9 tons = 1 billion tons

1 gigaton (metric) of water (with a density of 1.0 g/cm^3) occupies a volume of 1 km^3.

Typical density of liquid or supercritical CO_2 at pressure and temperature in the subsurface = 0.5 to 0.75 g/cm^3

One gigaton of liquid or supercritical CO_2 at a density of 0.75 g/cm^3 occupies a volume of 1.33 km^3.

1 ton of CO_2 as a gas at a temperature of 0°C and 1 atmosphere of pressure occupies a volume of 467 m^3.

1 barrel = 42 gallons = 158.76 liters = 0.15756 m^3

1 km^3 = 1 billion m^3 = 6.35 billion barrels

Although no coal is produced in Nevada, coal is the primary source of energy for generation of electricity in Nevada. Thus, burning of coal is the major industrial contributor of CO_2 to the atmosphere from Nevada. Other contributors in Nevada include power plants, homes, businesses, and other facilities that burn natural gas, heating fuel, diesel fuel, and petroleum; cement and lime plants (that heat carbonate rocks, particularly limestone, to drive off CO_2 and produce reactive lime); and aircraft, trains, trucks, and automobiles.

According to the U.S. Energy Information Administration (2004), in 2002 Nevada's coal-fired power plants, which had a capacity of generating 2,658 megawatts of electricity, released 16.6 million metric tons of CO_2 while producing 16.4 million megawatt hours. In the same year Nevada's gas-fired power plants, which had a capacity of generating 1,485 megawatts, released 5.8 million metric tons of CO_2 while producing 12.2 million megawatt hours. Total CO_2 emissions from Nevada power plants in 2002 were 22.4 million metric tons, corresponding to 6.1 million tons of carbon (Table 1).

Despite efforts to limit the burning of carbon, the world economy will almost assuredly continue to use these fuels for heat, generating electricity, and transportation for several decades to come. Concerns about the impacts of CO_2 on global climate and related aspects of weather and ecological and agricultural change have stimulated investigations of ways to sequester CO_2—that is, keep it from either getting into or otherwise removing it from the atmosphere.

1.2 General Logic for Near-Term and Long-Term Solutions

Near-term options for disposal of CO_2 in geological settings involve proven technologies—enhanced oil recovery (EOR) and injection into saline aquifers (Bartlett, 2003; Friedmann, 2003; White and others, 2004). Use of CO_2 in EOR projects has been demonstrated for many years in the Permian Basin of western Texas (Dutton and others, 2005) and elsewhere, but these projects did not attempt to keep the CO_2 in the ground permanently and leakage to the surface does occur (Klusman, 2003). In order to stabilize atmospheric concentrations, leakage of less than 0.01% per year for geological sequestration may be needed (S.M. Benson, personal commun., 2003). A large-scale demonstration project for both EOR and CO_2 sequestration is underway at the Weyburn oil field in Saskatchewan (Friedmann, 2003; White and others, 2004; Service, 2004); CO_2 is piped to the oil field from a plant in Beulah, North Dakota, which uses coal to produce a hydrogen-rich gas.

Demonstration projects are also underway to evaluate CO_2 injection into saline aquifers. A project in the Frio Formation in Texas shows promise for demonstrating disposal in permeable sandstones in states along the Gulf of Mexico (Bartlett, 2003; http://www.beg.utexas.edu/environqlty/co2seq/publications.htm). At the Sleipner West natural gas field in the North Sea, the producing company is injecting co-produced CO_2 into saline aquifers as a means of avoiding a Norwegian tax on CO_2 emissions (Bartlett, 2003; Friedmann, 2003). In a reconnaissance evaluation of possible sites for CO_2 sequestration in saline aquifers in the United States, Hovorka and others (2000) noted little potential in basin-fill sediments and carbonate aquifers in the Basin and Range province of Arizona, California, and Nevada, a conclusion reinforced by this report.

Less proven technologies for CO_2 sequestration include isolation in coal seams, thereby enhancing the recovery of coalbed methane, and oil shales, thereby enhancing oil recovery (Friedmann, 2003; Pinsker, 2003) and chemical reaction with rocks (Goff and Lackner, 1998; Friedmann, 2003; Reed, 2003; Cipolli and others, 2004). Nevada contains little coal or oil shale, but there are abundant exposures of rocks that could be used in chemical reactions.

2 Executive Summary

In 2003, the State of California, in collaboration with the U.S. Department of Energy and the States of Alaska, Arizona, Oregon, and Washington, asked the State of Nevada to participate in a regional analysis of CO_2 sequestration potential, through both terrestrial and geological approaches. The terrestrial approaches involve growing more biomass (particularly trees), and the geological options include proven technologies, such as using CO_2 to enhance recovery from oil fields and disposal of CO_2 in saline aquifers, and more unconventional approaches. As the state with the least amount of annual precipitation, Nevada has little potential for growing substantially more biomass, relative to states along the Pacific Ocean. The Nevada Bureau of Mines and Geology (NBMG) agreed to conduct a preliminary assessment of the potential for geological sequestration in Nevada. This report presents the methodology and results of this assessment.

The NBMG agreed to evaluate the potential for sequestration of carbon dioxide in geological settings in Nevada using geographic information systems (GIS) to combine the following sets of data:

- surface outcropping of bedrock versus alluvium (with the initial assumption that, because of repeated tectonic deformation during the last several hundred million years, including substantial crustal extension during the last 40 million years, areas of bedrock are unlikely to offer significant potential sites for sequestration);
- interpreted geophysical data (largely gravity) suggesting at least 1,000 meters of Quaternary and Tertiary cover over bedrock;
- presence of favorable geological formations (e.g., permeable sands and gravels into which CO_2 could be injected or thick halite beds that could be solution mined to create caverns for storage; thickness and continuity of aquitards to prevent escape of CO_2);
- nearness to extractable geological resources (e.g., mineral, petroleum, natural gas, geothermal, and water resources);
- depth to water table and depth to non-potable water deeper than 800 meters, if known;
- nearness to active faults;
- nearness to large generators of CO_2 (power plants);
- nearness to urban areas and corridors for urban growth;
- nearness to existing transportation routes;
- lands that are potentially off limits (e.g., military reservations, National Parks, National Recreation Areas); and
- other data as appropriate.

There does not appear to be much potential in Nevada for CO_2 sequestration through disposal in saline aquifers. Among the potential deep parts of alluvial basins, few remain after eliminating

areas of potential potable water, geothermal resources, and mineral resources. Within the remaining areas, little is known about porosities, permeabilities, or salinities of aquifers at depths greater than 1 km.

There also does not appear to be much potential in Nevada for conventional approaches to CO_2 sequestration through enhanced oil recovery, in part because the oil fields in Nevada tend not to have much associated natural gas, implying that gas originally associated with the fields has escaped. Injected CO_2 would likely leak to the surface as well. In addition, the oil fields in Nevada are small relative to fields in many other parts of the United States, and some of the Nevada fields are considerably hotter than ideal conditions for maintaining a dense CO_2 phase underground.

There is some potential for disposal of CO_2 in mined caverns in salt formations in basins in southern Nevada, northwestern Arizona, and southwestern Utah. The highest potential for this approach is likely to be in northwestern Arizona, where thick salt deposits are well described and are being investigated for storage of natural gas.

Chemical reaction of CO_2 with mafic rocks (basalt, gabbro) and ultramafic rocks (serpentinite, dunite, peridotite) has the potential to capture CO_2 in synthetic minerals, which, in turn, could be used to isolate municipal and industrial wastes. Enough of these rocks are exposed in Arizona, California, Nevada, Oregon, and Washington to meet the expected needs for CO_2 sequestration in the region. Ultramafic rocks are more favorable than mafic rocks both volumetrically and thermodynamically. Reaction of CO_2 with mafic or ultramafic rocks would be a long-term solution requiring considerable research to design, perfect, and demonstrate the cost-effectiveness of the chemical reactors and associated facilities.

For Nevada to be considered a potential site for significant amounts of CO_2 sequestration in geological settings, considerably more work would need to be done to (a) assess the thicknesses and volumes of salt formations in southern Nevada, (b) demonstrate a cost-effective process for chemical reaction with ultramafic or mafic rocks, and (c) assess the volumes of ultramafic and mafic rocks that are located in optimal areas. Although Nevada occurrences of ultramafic and mafic rocks have the advantage of being remote, considerably larger areas of ultramafic rocks are known in California, Oregon, and Washington, and enormous volumes of basalt occur in eastern Oregon and Washington.

3 Experimental

3.1 General Aspects of the Geology of Nevada

The general geology of Nevada is summarized in Table 2 (modified from Price, 2004, and references therein). Of particular importance to CO_2 sequestration are repeated tectonic events during the Paleozoic, Mesozoic, and Cenozoic eras that have fractured the rocks to such an extent that natural gas generally has escaped to the surface. Ongoing crustal extension is responsible for the current basin-and-range topography in Nevada. Essentially every mountain range is bounded on one or both sides by a fault that has been active in Quaternary time.

Nevada's energy and mineral production (Fig. 1) is closely linked to its tectonic history. Deep circulation of meteoric water along faults helps make geothermal resources abundant. Igneous activity during the Jurassic, Cretaceous, and Tertiary Periods is responsible for the formation of many of the metallic ore deposits scattered throughout the state. Exploration for oil and gas has occurred throughout much of the state (Garside and others, 1988), but oil has been produced commercially from only two localities, Railroad Valley in Nye County and Pine Valley in Eureka County. Minor amounts of natural gas have been produced from some wells, but the amounts are too small to justify building gas pipelines to markets in urban areas. In many cases, oil has also migrated to the surface to form seeps at springs.

We have constructed a conceptual model of oil and potential CO_2 reservoirs and seals in Nevada (Fig. 2). In general, oil occurs in two broad types of reservoirs in Nevada: fractured and permeable Paleozoic sedimentary rocks (mostly limestones but locally also sandstones) and fractured Tertiary ash-flow tuffs. Ideal reservoirs for CO_2 sequestration would be permeable (but unfractured) sandstones. Such sandstones may occur in the Paleozoic section and in the Tertiary valley-fill sequences in the basins. Seals for the oil reservoirs include Paleozoic marine shales, Tertiary lacustrine shales, and the non-welded, clay- or zeolite-altered upper zones of ash-flow tuffs. These rocks could also form seals for CO_2 reservoirs. The best seals appear to be above the Paleozoic-Tertiary unconformity. Some Paleozoic shales may be adequate seals, but these would have to be thoroughly tested if they were to provide the primary deterrent to escape of CO_2 from a potential reservoir.

Table 2. Geologic time scale with major events in Nevada history (modified from Price, 2004)

Million years before present		
	CENOZOIC	
	Quaternary	Modern earthquakes, mountain building, basaltic and rhyolitic volcanism, and geothermal activity are expressions of Basin and Range extension that began in the Tertiary Period. The crust is being pulled apart in Nevada, causing valleys to drop relative to mountains, and right-lateral strike-slip faults in western Nevada accommodate approximately 20% of the motion between the Pacific and North American plates. Prior to 10,000 years ago, ice ages caused glaciers to form in the higher mountains and large lakes to develop in valleys.
1.8		
	Tertiary	Basin and Range extension began about 30 to 40 million years ago. Igneous activity during the Tertiary Period was caused not only by extension but also by subduction (descent of oceanic crust into the Earth's mantle) of oceanic plates beneath the North American Plate and, in northern Nevada, by motion of the crust over the Yellowstone hot spot in the mantle. Numerous Nevada ore deposits, including most major gold and silver deposits and the copper ores near Battle Mountain, formed during this time. Gypsum deposits formed from evaporating lakes in southern Nevada. Tertiary basalts are abundant in several parts of the state.
65		
	MESOZOIC	
	Cretaceous	The Cretaceous Period and Mesozoic Era ended abruptly with the extinction of dinosaurs and many marine species. Numerous granitic igneous intrusions, scattered throughout Nevada, originated from subduction along the west coast of North America. Much of the granite in the Sierra Nevada formed at this time. The igneous activity caused many metallic mineral deposits to form, including the copper-gold-silver-lead-zinc ores near Ely in White Pine County, copper-molybdenum ores north of Tonopah in Nye County, and tungsten ores in several mining districts. In southern and eastern Nevada, sheets of rocks were folded and thrust from the west to the east during the Sevier Orogeny (mountain building), which began in Middle Jurassic time and ended at or beyond the end of the Cretaceous Period.
144		
	Jurassic	A subduction zone to the west caused igneous intrusions (including the gabbroic complex near Lovelock), volcanism, and associated ore deposits (e.g., copper deposits near Yerington). Sandstones, including those in the Valley of Fire, were deposited in southeastern Nevada, and sedimentary gypsum deposits formed in northwestern Nevada.
208		
	Triassic	The general geography of Nevada during the Triassic Period was similar to that during the Jurassic Period—igneous activity in the west and deposition of sedimentary rocks in continental to shallow marine environments to the east. Explosive volcanism produced thick ash-flow tuffs in west-central Nevada. Economically important limestone, gypsum, and silica-sand deposits formed in southern Nevada. The Sonoma Orogeny, which began during Late Permian time and ended in Early Triassic time, moved rocks from the west to the east along the Golconda Thrust in central Nevada. The large marine reptiles at Berlin-Ichthyosaur State Park lived during the Triassic Period.
251		
	PALEOZOIC	
	Permian	Volcanism to the west and deposition of thick limestones to the east were characteristics of much of the Paleozoic Era in the Great Basin. Some marine gypsum deposits formed in southern Nevada.
290		
	Pennsylvanian	The Antler highland, which formed earlier, was eroded and shed sediments into the basins to the east. Carbonate rocks were deposited in eastern and southern Nevada.
320		
	Mississippian	During the Antler Orogeny, from Late Devonian to Early Mississippian time, rocks were folded and thrust from the west to the east. Rocks thrust from the east include fragments of oceanic crust, including some basalts, serpentinites, and deep-water sedimentary rocks. The Roberts Mountains Thrust, below which many of the gold deposits in north-central Nevada occur, formed at this time. Conglomerate, sandstone, siltstone, and shale were deposited in the thick basin of sediments derived from the Antler highland, and carbonate rocks were deposited further east.
360		
	Devonian	Limestone was deposited in eastern Nevada, and shale, chert, and economically important barite were deposited in northeastern and central parts of the state. No record of middle to lower Paleozoic rocks exists in the western part of the state. The quiet, shallow-marine tectonic setting that persisted earlier in the Paleozoic Era began to change, as small land masses from the Pacific Ocean collided with western North America.
418		
	Silurian	Carbonate rocks (dolomite and limestone) in the eastern part of the state and silica-rich rocks (shale, sandstone, and chert) in the central part of the state record similar deposition to that during the rest of the middle to early Paleozoic Era.
438		
	Ordovician	Marine deposition during the Ordovician Period was similar to that during the rest of the early Paleozoic Era, with the exception of basalts (metamorphosed to greenstones) locally interbedded with sedimentary rocks found today in the central part of the state. Some sedimentary barite deposits and copper-zinc-silver ores formed in sea-floor sediments during this time.
490		
	Cambrian	Middle and Upper Cambrian deposition resembled that during much of the Paleozoic Era, with carbonate rocks to the east and shale plus sandstone to the west. Lower Cambrian and uppermost Precambrian rocks are characterized by quartzite and metamorphosed siltstone throughout much of Nevada.
543		
	PRECAMBRIAN	
		The oldest rocks in Nevada (at least 2,500 million years old in the East Humboldt Range in northeastern Nevada and at least 1,700 million years old in southern Nevada) are metamorphic rocks. Precambrian rocks also include granites (about 1,450 million years old) and younger sedimentary rocks. Beginning approximately 750 million years ago, Antarctica and Australia may have rifted away from western North America, setting the stage for the development of a western continental margin that is similar to the Atlantic coast of today. A shallow marine, tectonically quiet setting persisted in eastern Nevada for the next 700 million years.

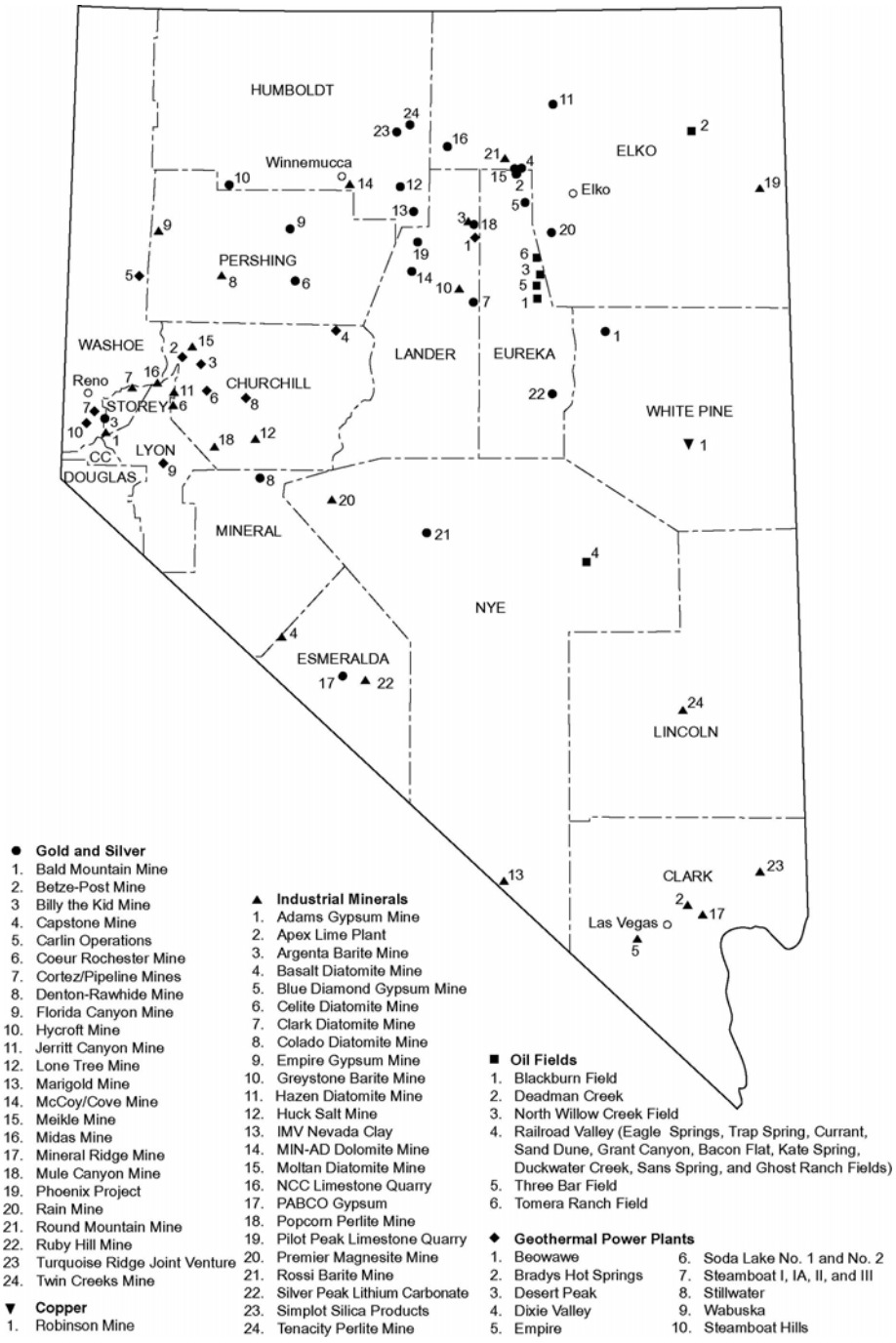


Figure 1. The location of oil fields, major mines, and geothermal power plants in operation in Nevada in 2004

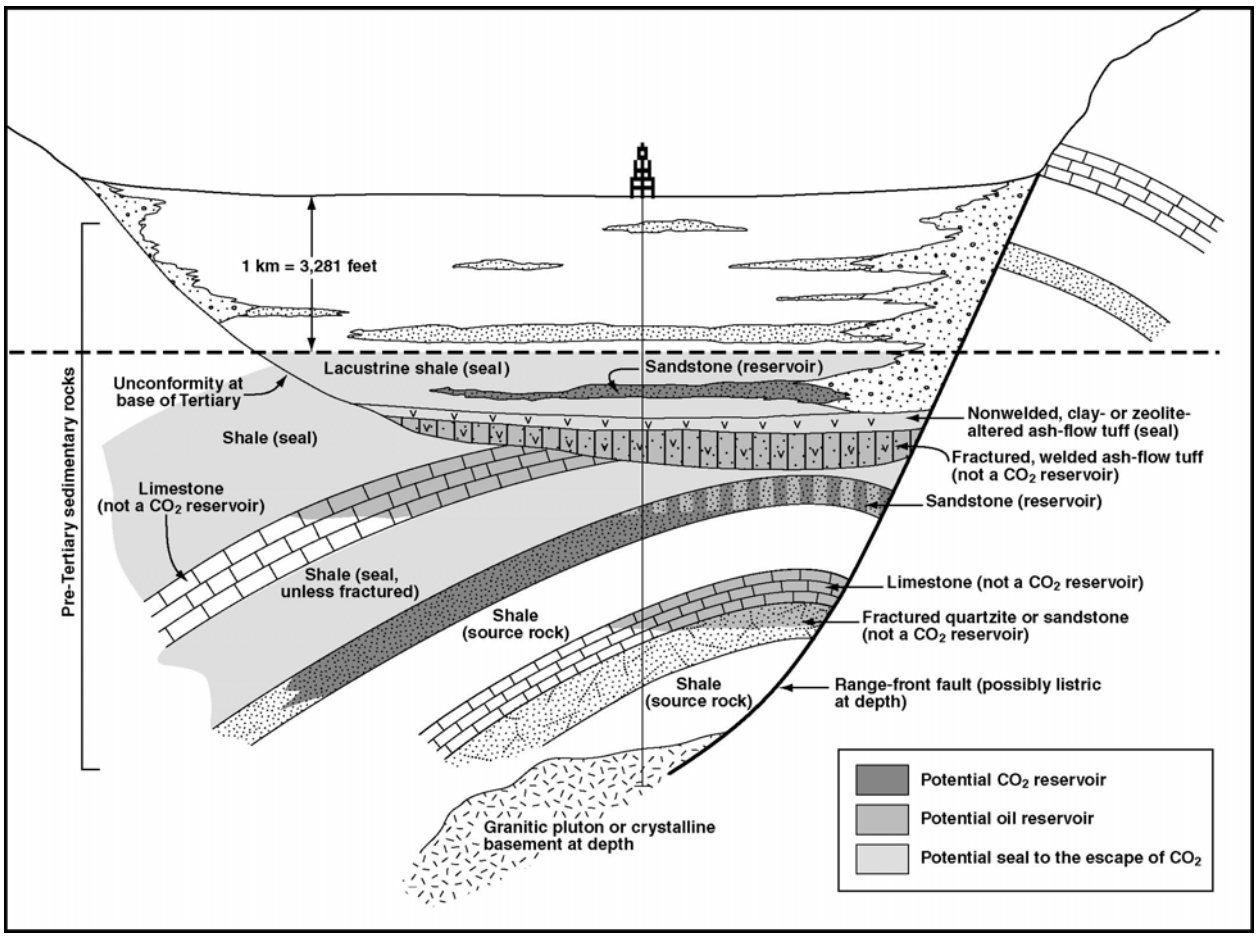


Figure 2. Cross-sectional conceptual model of potential CO_2 reservoirs and seals in Nevada

3.2 Factors and Maps Considered in the Assessment

In this section, we describe the assumptions, factors, and maps considered in assessing areas for possible CO_2 sequestration in saline brine formations in Nevada, and we discuss the potential for CO_2 sequestration through enhanced oil recovery. Details of the analysis methodology using a geographic information system (GIS) are provided in the appendix. Copies of all GIS layers used in the analysis are supplied in the compact disc accompanying this report, so that users may choose other assumptions and approaches in reanalyzing the data. We use a simple, binary approach; that is, in considering each factor, an area is either favorable or not favorable for CO_2 sequestration. In the final analysis, we combine the areas in the GIS to determine remaining areas for possible consideration.

3.2.1 Restriction of Consideration to the Deeper Parts of Alluvial Basins

Areas of bedrock outcrop (Fig. 3) are eliminated from consideration for CO_2 sequestration, because Basin and Range extensional deformation, coupled with earlier fracturing associated with crustal shortening (Table 2), has so thoroughly fractured the bedrock that it is unlikely to contain seals that are adequate to prevent escape of CO_2.

The pressure needed to keep CO_2 in a liquid or dense supercritical state depends on temperature (Fig. 4). The pressure at the critical point is 7.4 megapascals (1,070 pounds per square inch), which corresponds to a depth of 753 m, if one assumes hydrostatic pressure (pressure of a column of water with a density of 1.0 g/cm^3). A minimum depth depth of 800 m for consideration of CO_2 sequestration has been assumed in other studies (eg., Downey and Clinkenbeard, 2005). As illustrated on Figure 4, if temperatures are higher than typical geothermal gradients (25 to 30°C/km) would predict at that depth, the supercritical CO_2 fluid density would be lower, and less CO_2 could be accommodated in the formation than in the preferred case for sequestration. Temperatures in some oil fields in Nevada are considerably higher than would be predicted from typical geothermal gradients (Fig. 4), and abundant hot springs throughout the state attest to shallow, hot rocks in many locations. Given the absence of reliable data on temperature gradients in many areas, we have used a somewhat more conservative figure of 1,000 meters as a minimum depth for consideration of CO_2 sequestration in Nevada.

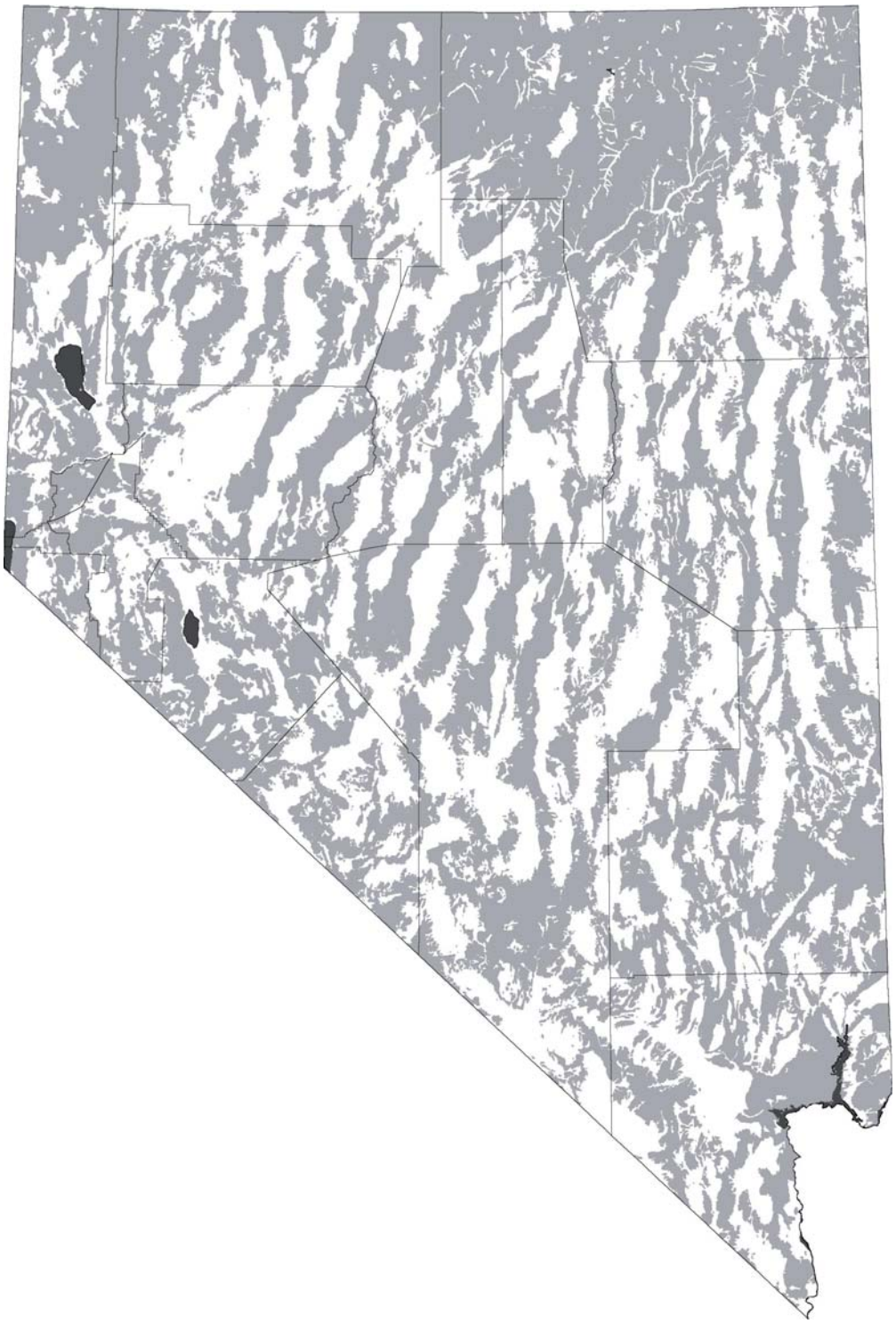


Figure 3. Map showing the distribution of bedrock (gray, representing consolidated rocks of Tertiary and older age) versus Quaternary-Tertiary alluvial deposits (white) in Nevada. Areas of Quaternary glacial drift, which are generally thin and occur mostly in mountains, are included with the bedrock. Major lakes are shown in black.

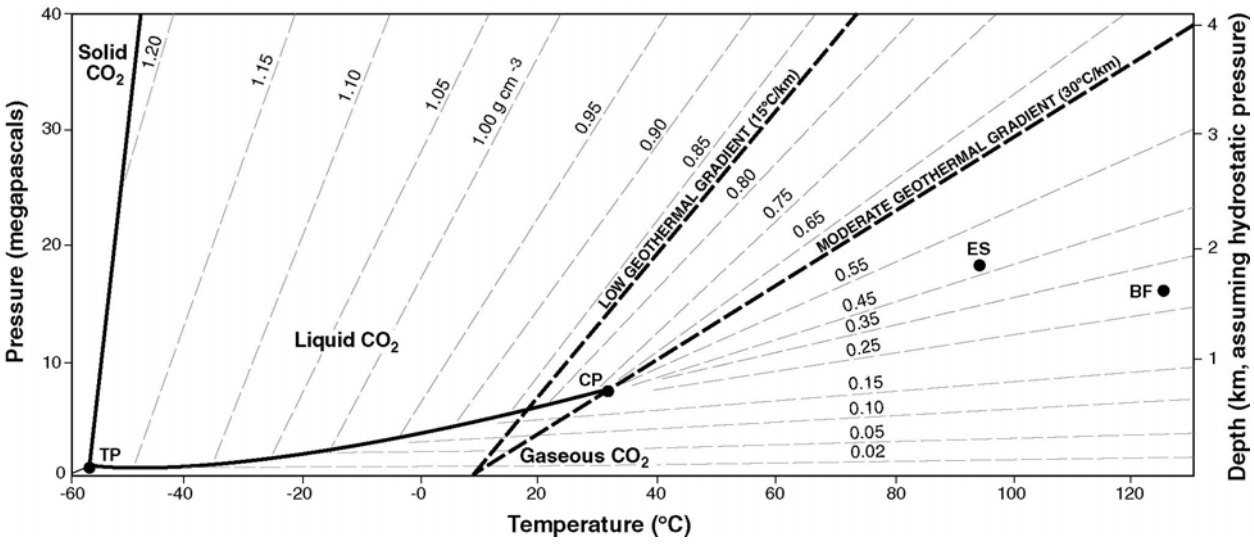


Figure 4. Phase relations, with lines of equal density, for CO_2 (modified from Roedder, 1984). TP = triple point (-56.6°C, 0.5 megapascals), at which solid, liquid, and gaseous CO_2 coexist. CP = critical point (31.0°C, 7.38 megapascals), above which the distinction between gas and liquid cannot be made with increasing pressure or temperature. ES = bottom-hole temperature (93°C at 1,830 m) in the Eagle Springs oil field (Shevenell and Garside, 2005, and http://www.nbmg.unr.edu/geothermal/gthome.htm). BF = reservoir temperature (120-130°C at about 1,625 m) in the Bacon Flat-Grant Canyon oil fields (Hulen and others, 1994).

The United States Geological Survey (USGS) has interpreted publicly available gravity data, calibrated with known depths from exploration drilling, to infer areas that have at least one km of valley fill (Fig. 5). We exclude from consideration any areas that are not considered in this USGS analysis to have at least one km of valley filling sediments and/or volcanic rocks.

The NBMG is the official repository for information about wells drilled for oil and gas and geothermal exploration and development in Nevada. Using the conceptual model of potential CO_2 reservoirs and seals (Fig. 2), we extracted important geologic data from the well records (Table 3). These data are summarized in NBMG Open-File Report 04-1 (Hess, 2004a). These data may be helpful in a more detailed analysis of the potential for CO_2 sequestration at a later time, and they are useful in assessing the potential for CO_2 sequestration using EOR.

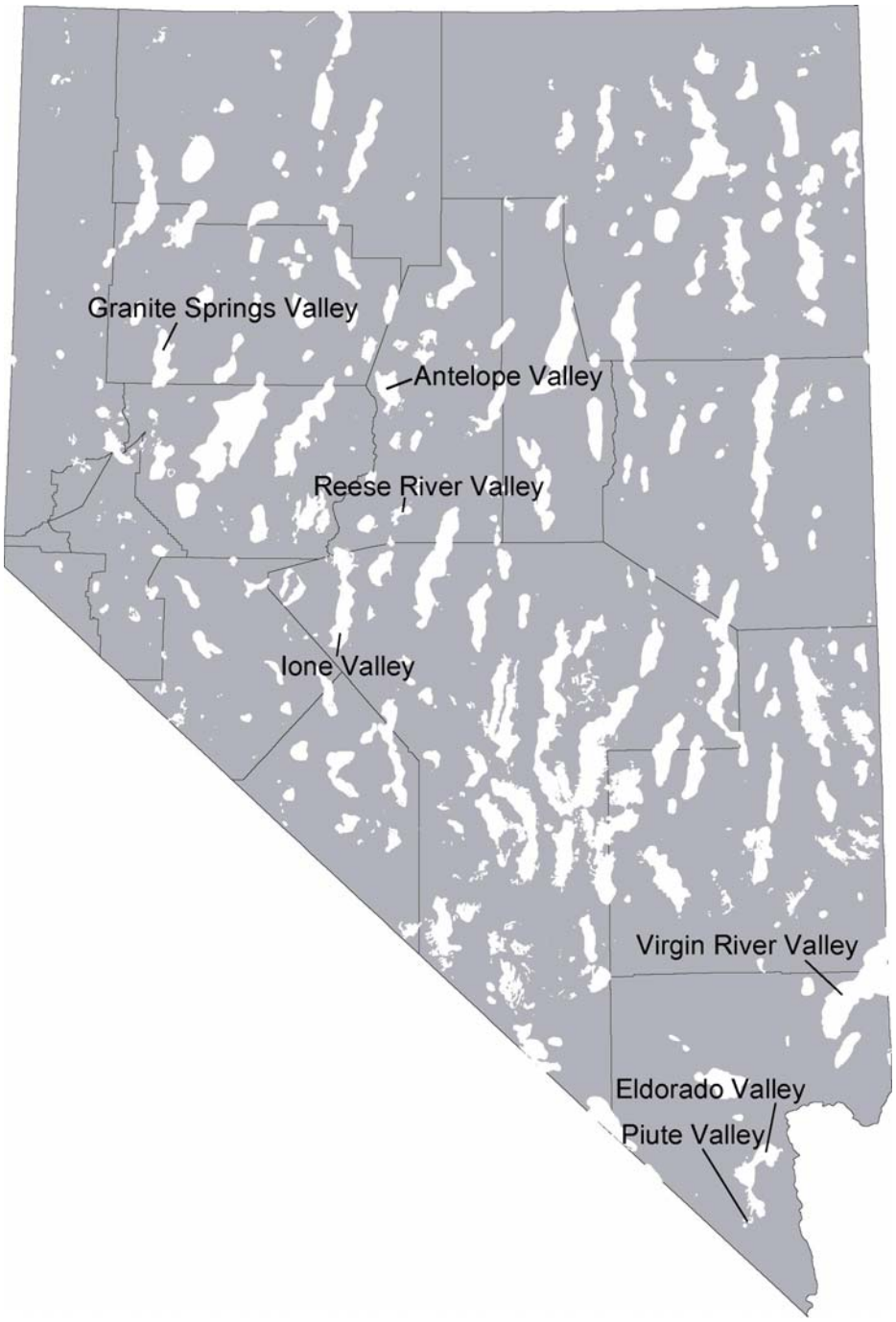


Figure 5. Map showing where valley-filling alluvium and volcanic rocks exceed 1 km in thickness (white areas, modified from Dohrenwend and others, 1996)

Table 3. Information recorded from records of deep wells drilled in Nevada (Hess, 2004)

DEFINITIONS

CO_2 reservoir rock ≡ sandstone, conglomerate, sand, or gravel

Seal rock ≡ shale, mudstone, claystone, mud, clay, halite, gypsum, salt, or nonwelded (possibly clay- or zeolite-altered) ash-flow tuff

NEITHER A CO_2 RESERVOIR ROCK NOR SEAL ≡
limestone, dolomite, fractured volcanic rock, fractured sandstone, quartzite, metamorphic rocks, or granite or other igneous rocks

Data collected from well records, if available, in wells within areas not otherwise excluded for consideration of CO_2

1. Total depth of well.
2. Are there potential CO_2 reservoir rocks in the well below 1 km (3281 ft) depth? If no, go to next well.
3. Is there a potential seal below 1 km and above that reservoir rock? If no, go to next well.
4. Depth to base of Cenozoic/Tertiary volcanic rocks and alluvium.
5. Depth to base of deepest reservoir rock in pre-Tertiary sedimentary package.
6. How fresh is the water in this deepest reservoir rock? (Total dissolved solids – TDS?)
7. How porous is this deepest reservoir rock? % of porosity?
8. How permeable is this deepest reservoir rock? K in millidarcy?
9. Thickness of the thickest single pre-Tertiary reservoir rock.
10. How fresh is the water in this thickest pre-Tertiary reservoir rock?
11. How porous is this thickest pre-Tertiary reservoir rock?
12. How permeable is this thickest pre-Tertiary reservoir rock?
13. Total thickness of all pre-Tertiary reservoir rocks.
14. Thickness of the thickest single pre-Tertiary seal rock above the deepest reservoir rocks.
15. Total thickness of all pre-Tertiary seal rocks above the deepest reservoir rocks.
16. Depth to base of deepest reservoir rock in Tertiary sedimentary package below 1 km.
17. How fresh is the water in this deepest reservoir rock in Tertiary package?
18. How porous is this deepest reservoir rock in Tertiary package?
19. How permeable is this deepest reservoir rock in Tertiary package?
20. Thickness of the thickest single Tertiary reservoir rock below 1 km.
21. How fresh is the water in this thickest single Tertiary reservoir?
22. How porous is this thickest single Tertiary reservoir?
23. How permeable is this thickest single Tertiary reservoir?
24. Total thickness of all Tertiary reservoir rocks below 1 km.
25. Thickness of thickest single Tertiary seal rock below 1 km.
26. Total thickness of all Tertiary seal rocks below 1 km.
27. Total thickness of all Tertiary seal rocks below 1 km and above shallowest reservoir rock.
28. Thickness of halite beds below 1 km.

FACTORS THAT CAN NOW BE DERIVED FROM THESE NUMBERS

A. Total thickness of potential reservoir rocks = #13 + #24
B. Total thickness of potential seal rocks above the deepest reservoir rock and below 1 km = #15 + #26
C. Reservoir rock to seal rock ratio = #A/#B, ~ sand/shale ratio

3.2.2 Proximity of Active Faults to Potential CO_2 Sequestration Sites

We use the Quaternary fault database of the USGS (http://qfaults.cr.usgs.gov/) and the database prepared by Craig M. dePolo (NBMG work in progress) for locations of faults (Fig. 6). The former database has been checked by NBMG earthquake experts. There are two broad types of Quaternary faults in the Basin and Range Province in Nevada – strike-slip faults and normal faults. Some faults have moved with oblique slip (a combination of normal and strike slip). Faults commonly have zones of fracturing, which could allow CO_2 to escape. In fact, it is likely that CO_2 would escape along these faults, because many Nevada petroleum seeps and hot springs occur along faults. We therefore exclude from consideration areas that are close to faults. For normal faults, we exclude an area 1.93 km wide on the hanging wall (down-dip side) of the fault. The 1.93 km figure corresponds to the surface projection of a 60-degree dipping fault to a vertical depth of 3 km plus an additional 200 meters into the hanging wall to account for a zone of fault gouge, breccia, and fractures (Fig. 7A). In the GIS analysis, we actually use a 1.93-km zone on both sides, because the footwall is already excluded as bedrock or as areas of alluvial cover less than one kilometer in thickness. For strike-slip faults, we exclude an area 500 meters on either side of the fault (Fig. 7B). We feel that this is a reasonable minimum number, corresponding to the typical 1-km width of breccia and gouge along the San Andreas fault in California but somewhat less than the 2-km-wide zone of fault splays along well mapped strike-slip faults in Nevada. Before any site in Nevada would be used for CO_2 sequestration in saline brines or EOR, the geological framework of the site would need to be investigated in detail to locate the three-dimensional distribution of fault splays, gouge, and breccias.

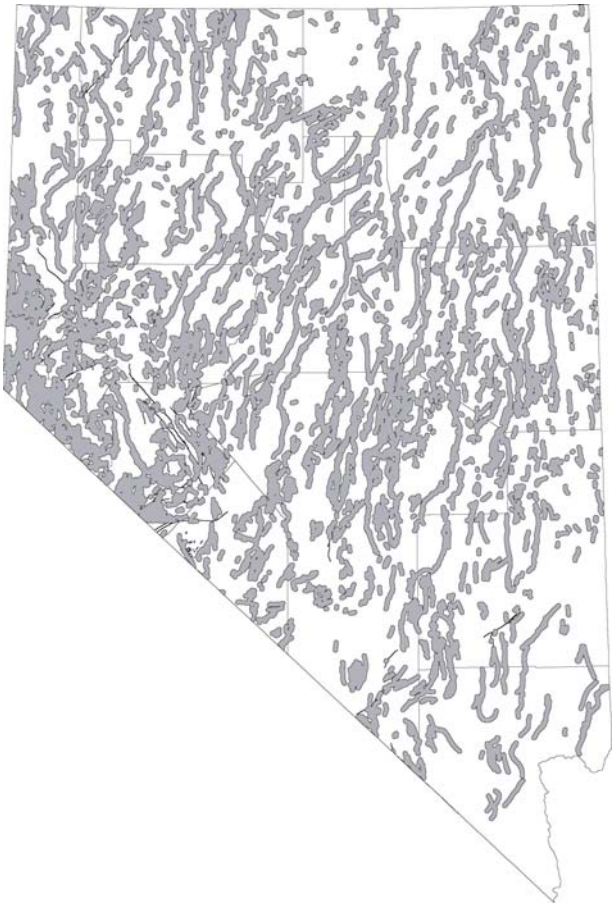


Figure 6. Distribution of Quaternary faults in Nevada with buffered zones next to faults

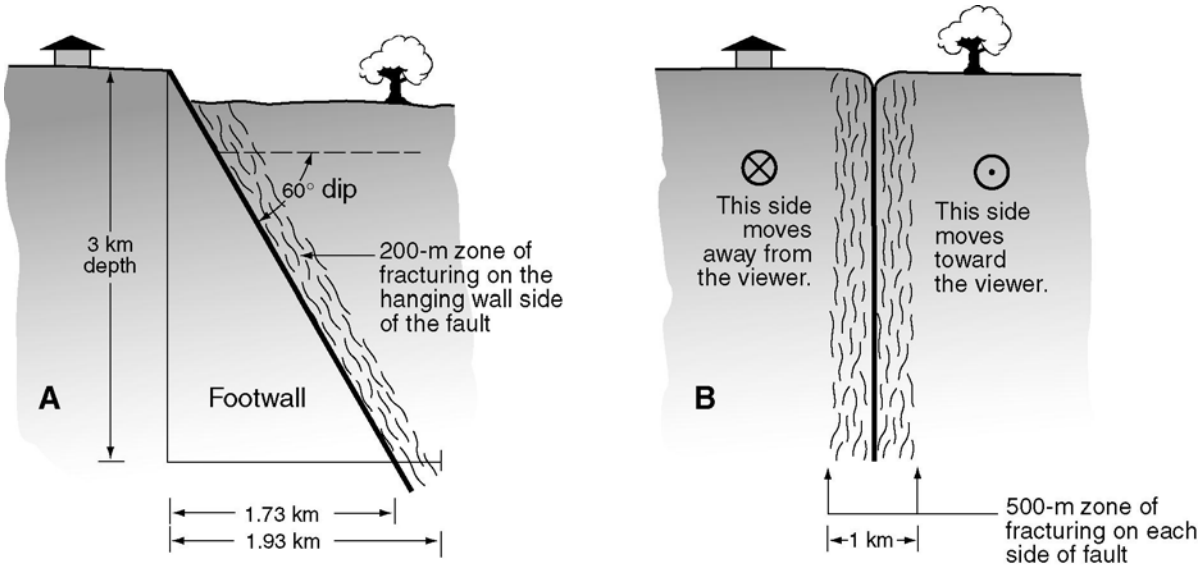


Figure 7. Cross sections of active faults typically found in Nevada. A. Normal fault B. Strike-slip fault.

We use the probabilistic seismic hazard analysis by the USGS to report the expected peak acceleration (expressed as a percentage of the acceleration due to gravity, %g) with 2% probability of exceedance in 50 years (http://eqhazmaps.usgs.gov/html/us2002.html) for the state, including those areas that may be potential CO_2 sequestration sites (Fig. 8). We did not eliminate any areas based on these values of seismic intensity and ground motion. Should sites be chosen, the engineers designing the facility should take into consideration these values and any (deterministic) values based on credible scenarios on nearby faults. Furthermore, should CO_2 pipelines be built across faults in Nevada, care must be taken to design them to accommodate the maximum likely slip resulting from earthquakes on specific faults.

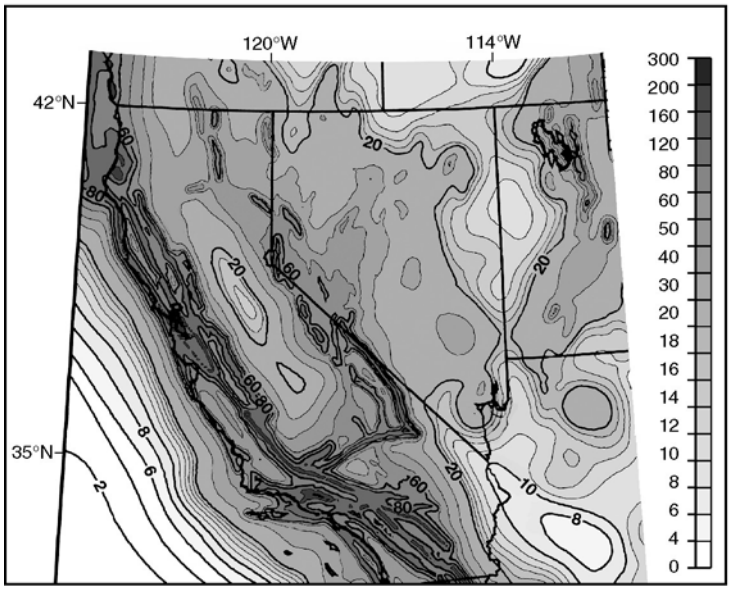


Figure 8. Map showing expected peak acceleration (as percentage of the acceleration due to gravity) with 2% probability of exceedance in 50 years from the USGS probabilistic seismic hazard analysis (http://eqhazmaps.usgs.gov/2002April03/CNU/CNUpga2500v4.gif)

3.2.3 Proximity to Extractable Geological Resources

3.2.3.1 Mineral Resources

Nevada is a major producer of non-fuel mineral resources, generally ranking second or third among the 50 states in recent years in terms of total dollar value of annual production. Nevada production is the reason why we are in the midst of the biggest gold-mining boom in American history (Fig. 9). Gold and silver dominate the mining activity, but many other commodities are currently being mined [barite, copper, magnesite, lithium, the specialty clays, sepiolite and saponite, other clays, construction aggregate (sand, gravel, and crushed stone), lime, diatomite, gypsum, raw materials for cement, silica (industrial sand), dimension stone, semiprecious gemstones, perlite, salt, kalinite (potassium alum), zeolites, and mercury as a by-product of gold and silver processing]. In the past, Nevada has been a major producer of antimony, arsenic, fluorite, iron, lead, manganese, molybdenum, tungsten, and zinc, and resources exist of a number of additional metals, industrial minerals, and uranium. For some of these commodities, Nevada will undoubtedly be a producer again in the future.

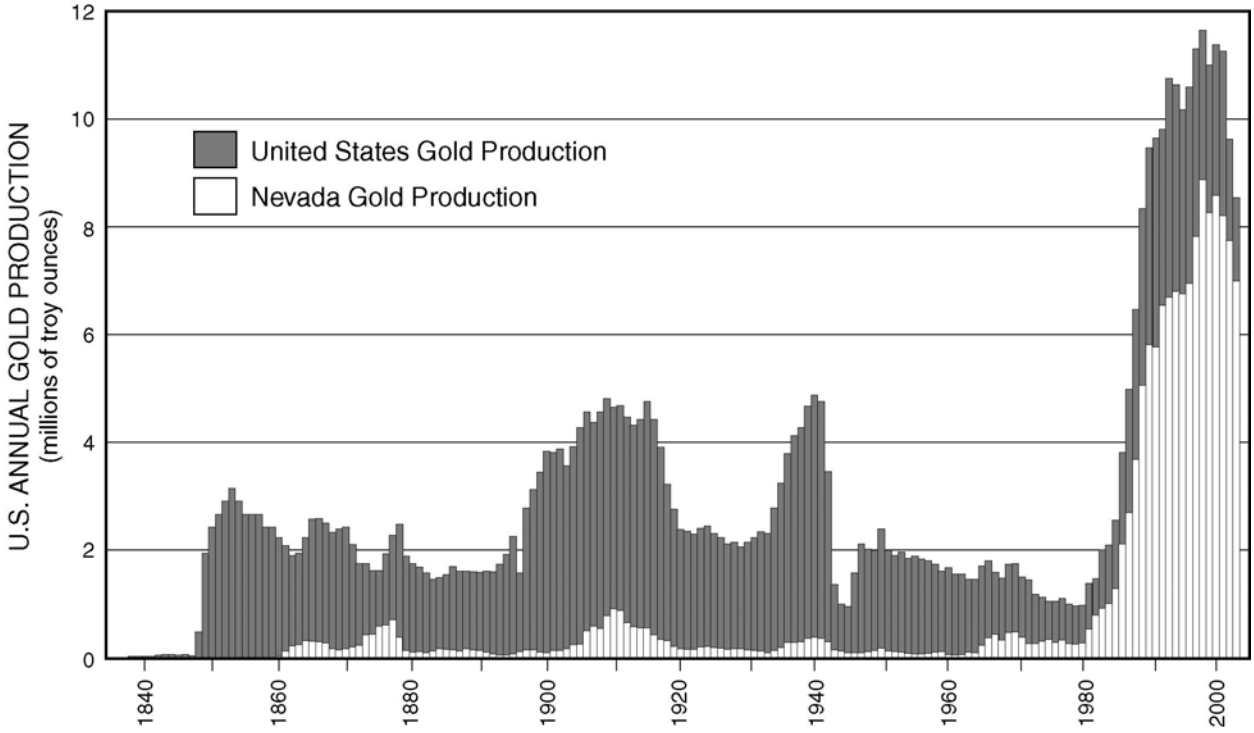


Figure 9. U.S. and Nevada gold production from 1835 through 2004 (Price and Meeuwig, 2005)

Hess (2001) identified over 100,000 point locations of mine shafts, prospect pits, adits, open-pit mines, quarries, sand-and-gravel borrow pits, and other excavations in Nevada (Fig. 10). Although this database was not directly used in the analysis of mineral resources, it illustrates the broad geographic distribution of mineral resources in Nevada.

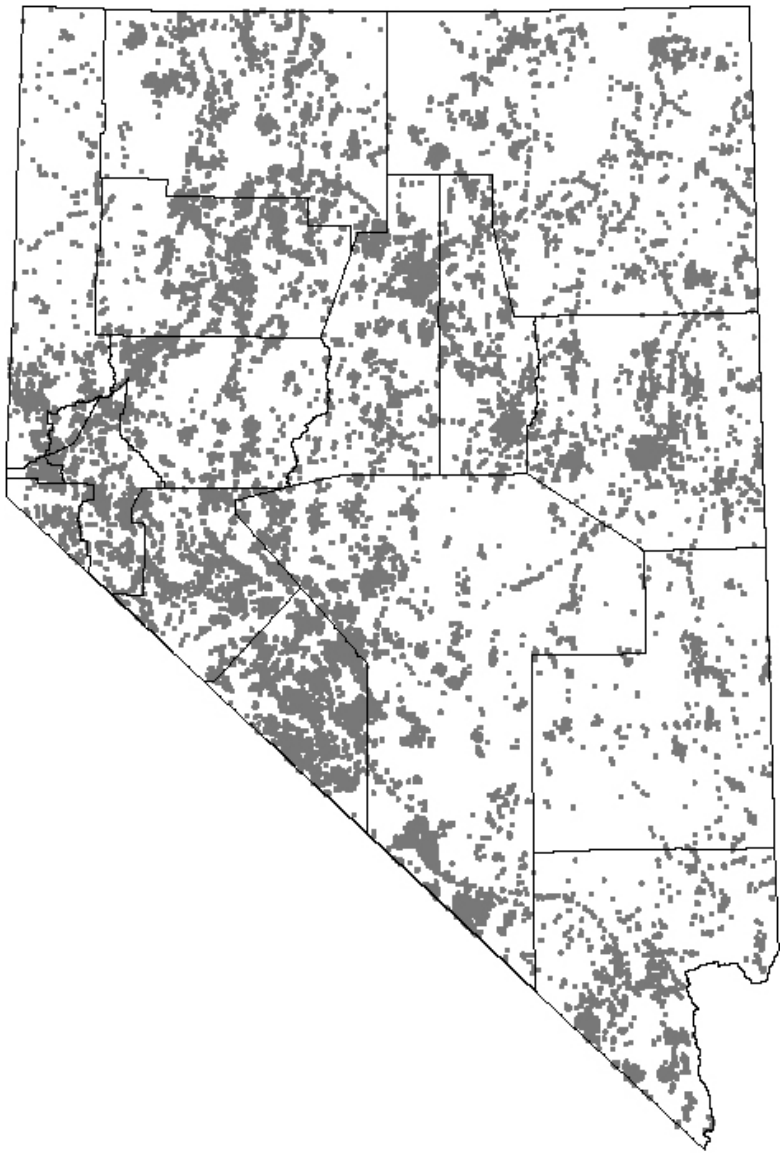


Figure 10. Locations of mine shafts, prospect pits, adits, open-pit mines, quarries, sand-and-gravel borrow pits, and other mineral-resource excavations in Nevada (from Hess, 2001)

We exclude from consideration for potential CO_2 sequestration any areas that are likely to experience mineral production in the future, with the exception of sand and gravel resources, which are mined from shallow (generally less than 100 m deep) quarries and blasting is rarely needed to break the rock. Most of the other mineral commodities are mined from underground workings or large open pits. Deep exploratory drilling, the opening of mine workings themselves, and ground shaking from blasting could adversely affect the integrity of a CO_2 sequestration reservoir.

There are several approaches that could be taken to evaluate areas of potential mineral-resource development. The USGS (Cox and others, 1996a, b, and c) used various geological and GIS approaches to identify tracts of land that they consider permissive for several types of metal deposits, including epithermal deposits (Fig. 11), pluton-related deposits (Fig. 12), and deposit types not directly related to plutonic activity (Fig. 13). When combined, the three USGS maps would eliminate from consideration nearly all of the state (Fig. 14).



Figure 11. Tracts permissive for epithermal deposits (dark areas, Cox and others, 1996b).

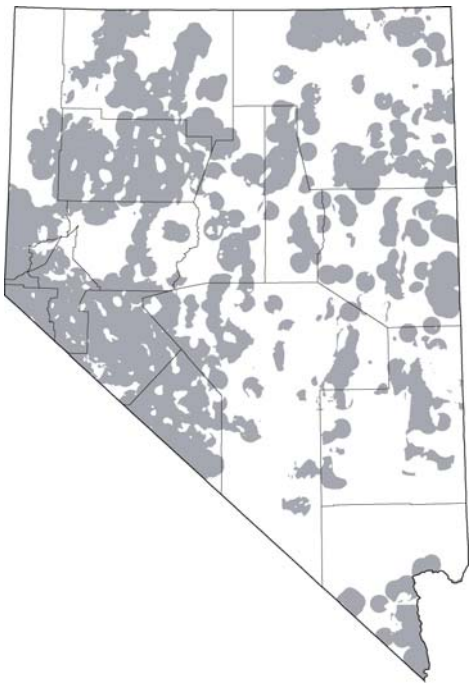


Figure 12. Tracts permissive for pluton-related deposits (dark areas, Cox and others, 1996a).

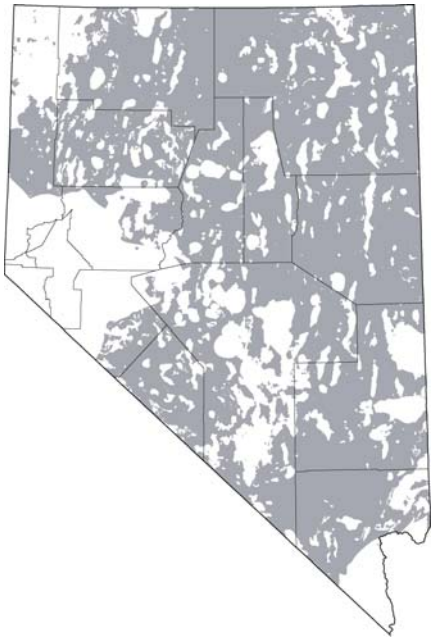


Figure 13. Tracts permissive for deposit types not directly related to plutonic activity (dark areas, Cox and others, 1996c).



Figure 14. Combined tracts permissive for metal-bearing mineral resources (dark areas, derived by combining dark areas from Figs. 11, 12, and 13).

Another approach to evaluating areas of potential mineral-resource development is to use locations of existing mines and prospects. Tingley (1998) outlined mining districts (Fig. 15) using similarities in geological environments and, to a lesser extent, commodities produced. To test how well this map captures known mineral deposits, we compared the mining district outlines with two databases on mineral occurrences in Nevada – (1) the combined Mineral Resource Data System (MRDS) database of the USGS and the Mineral Industry Location System (MILS) database of the former U.S. Bureau of Mines and (2) an NBMG database on gold and silver resources in Nevada (updated from Davis and Tingley, in review). The latter database includes known deposits, mostly with well defined resources, many of which have yet to go into production.

Many MRDS/MILS data points lie outside the mining district outlines (Fig. 16), because these locations often represent single mines for which a district designation was not warranted. Ninety-five percent of the MRDS/MILS data points lie within a buffer of 5 km around the mining district outlines; 99% are within a 12-km buffer; and 100% are within 42 km of the mining district outlines. Most, but not all, of the locations from the NBMG database on gold and silver resources in Nevada fall within the outlines of the mining districts (Fig. 17).

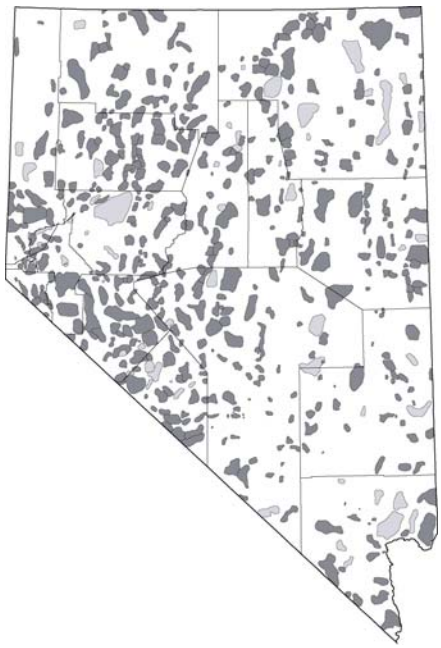


Figure 15. Locations of mining districts (Tingley 1998). Metal-mining districts are shown with dark shading; districts that produced only industrial minerals are shown with light shading.

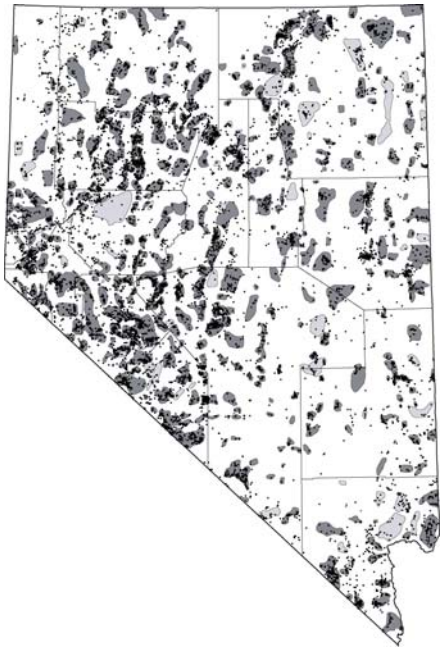


Figure 16. Locations of points (individual mines) in the combined MRDS/MILS database (Source: USGS and U.S. Bureau Mines) superimposed on the outlines of mining districts (Fig. 15).

We compared the MRDS/MILS data points with the NBMG database. With few exceptions, the bulk of the deposits in the NBMG database fall within 5 km of a MRDS/MILS location (Fig. 18). A combination of these maps provides us with our best estimate of the areas likely to experience

mineral-resource development; these are areas to be excluded from consideration for CO_2 disposal (Fig. 19). We chose to include features from three databases:

(1) a 5-km buffer around the MRDS/MILS locations,
(2) a 5-km buffer around the NBMG database of known gold and silver resources, and
(3) outlines of mining districts.

We chose not to add a buffer around the mining districts because the 5-km buffer around the other locations largely covers those outlines and because many of the outlines for industrial minerals reasonably cover the area that is likely to experience production.



Figure 17. Locations of points (individual gold and silver deposits) in the NBMG database on gold and silver resources superimposed on the outlines of mining districts (Fig. 15).

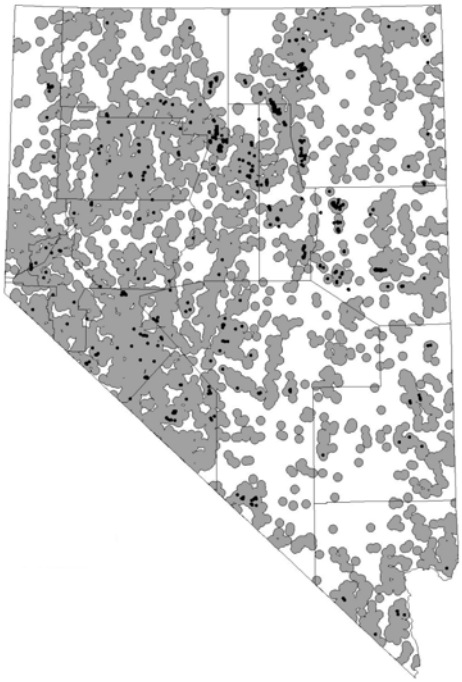


Figure 18. Locations of points (individual gold and silver deposits) in the NBMG database on gold and silver resources superimposed on the 5-km buffers around locations (individual mines) in the combined MRDS/MILS database.

Although we can use this approach to predict the most likely areas for metallic mineral-resource exploration, it is not possible to predict where everyone may choose to explore in the future. As an example, the Carlin trend, a belt of gold deposits in north-central Nevada, which accounts for 12% of all the gold ever mined in the United States and a bit more than 1% of all the gold ever mined in the world (Price and Meeuwig, 2005), had little activity before the discovery of the Carlin deposit in 1961. Since then, many Carlin-type gold deposits have been discovered along the Carlin trend and the subparallel Battle Mountain-Eureka trend, areas which before 1961 would have been beyond the 5-km buffers of known deposits.

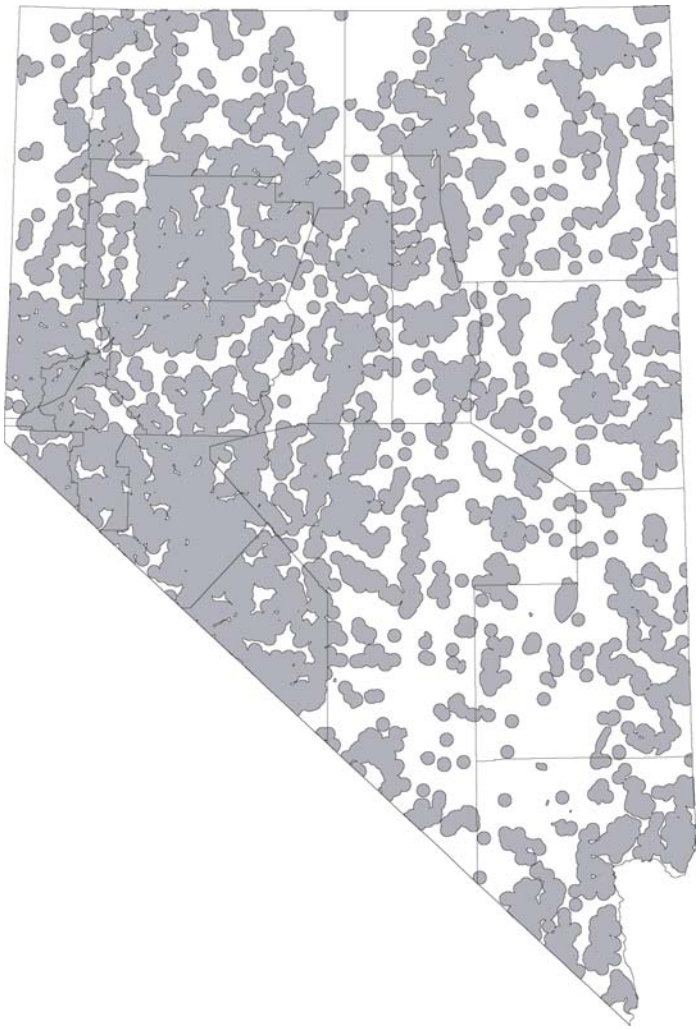


Figure 19. Areas likely to experience mineral-resource development, with the exception of sand and gravel in Nevada (dark areas). This map combines a 5-km buffer around the MRDS/MILS locations with a 5-km buffer around the NBMG database of known gold and silver resources, and outlines of mining districts. Note that a broader area is indicated by the USGS in their analysis of tracts permissive for metal-bearing mineral resources (Fig. 14).

3.2.3.2 Petroleum and the Potential for CO_2 Sequestration through Enhanced Oil Recovery

Significant production of oil in Nevada has come only from Railroad and Pine Valleys (Fig. 20). There is, however, considerable excitement about the potential for oil and gas discovery in deep zones below thrust faults. We do not attempt to eliminate any areas of potential oil and gas discovery from consideration for CO_2 sequestration (unless those areas are eliminated for other reasons), because such areas may be ideal for use of CO_2 in enhanced oil recovery. Before any enhanced oil recovery using CO_2 would be undertaken, however, care must be taken to ensure that the reservoirs would not leak beyond the limits required for effective long-term

sequestration. We suspect that the reservoirs would, in general, be leaky, because the active extensional tectonic environment in Nevada has probably limited natural gas accumulations.

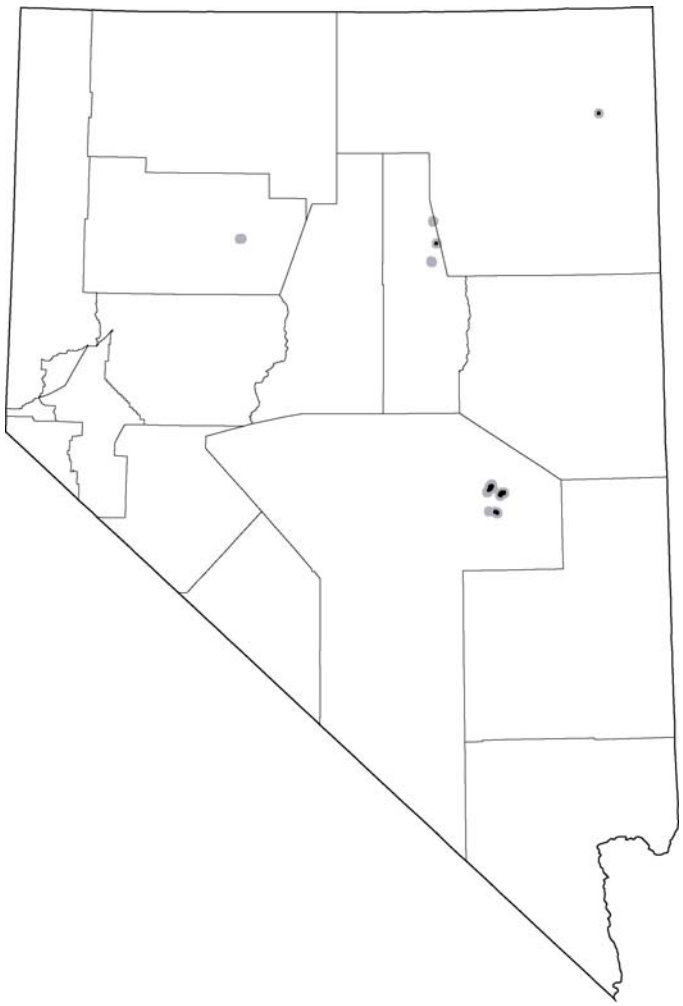


Figure 20. Gray shading indicates areas of reported oil production in Nevada. Black dots indicate oil production wells with greater than 1 km of Quaternary-Tertiary valley fill.

There is some potential for use of CO_2 in enhanced oil recovery in Nevada, but the ability for the Nevada oil reservoirs to trap and retain the CO_2 is questionable. Some of the oil fields are hot, and the amount of CO_2 sequestered would therefore be less than in an equal volume of reservoir rock at the same depth in a cooler area (Fig. 4). The fields are also small, relative to many fields in the United States. Only two Nevada fields have produced over 10 million barrels, and cumulative production from all 15 fields is only 48 million barrels (Davis, 2004). To put this in perspective, one gigaton of CO_2 at a density of 0.75 g/cm^3 would occupy a volume of 8.5 billion barrels. That is, much larger oil fields than those discovered thus far in Nevada will be needed for significant CO_2 sequestration. Some of the fields (particularly in Pine Valley) are shallower than the minimum depth of 800 m for liquid or supercritical CO_2. The potential for CO_2 sequestration through enhanced oil recovery in Nevada is also likely to be further limited

because of leakage. These oil fields tend not to have much associated natural gas, implying that gas that was probably associated with the fields has largely escaped. We do know that gas was associated with these oil fields, because small amounts of gas have been reported in some of the fields, and one well in Huntington Valley (Jiggs No. 10-1 of Wexpro Co.) discovered significant quantities of gas but was too far from market to be economic. Injected CO_2 would likely leak to the surface as well, although the time scale for such leakage is not known. The timing of oil and gas generation in Nevada is not well known, and it almost assuredly occurred at different times at different places, given the repeated history of thrusting and intrusion (Table 2). The fact that some source rocks near the producing oil fields in Nevada are immature and the hot temperatures of some of the fields imply that oil and gas may be generated today, in which case leakage of natural gas has likely been fairly rapid.

In addition, the larger fields in Railroad Valley, one of which (the Kate Spring Field) does have a small amount of natural gas (Davis, 2004), are distant from any natural gas pipelines and major industrial sources of CO_2. A relatively close source could arise in the future, however, if the 1,600-megawatt coal-fired power plant proposed in White Pine County (Public Utilities Commission of Nevada, 2005) comes on line as expected by 2010 or shortly thereafter.

3.2.3.3 Geothermal Resources

Nevada is a significant producer of electrical energy from geothermal resources (worth on the order of $100 million per year; Hess, 2004b). Geothermal resources are also used in Nevada for space heating and other industrial purposes, notably for drying garlic and onions. Hot springs and wells (with water warmer than 37°C) and warm springs (with water warmer than 20°C and 10°C above the average annual surface temperature) occur throughout the state (Shevenell and Garside, 2005), but most of the commercial geothermal developments have been in the northern part of the state (Fig. 1). Known geothermal areas are likely to be problematic for CO_2 sequestration because densities of the supercritical CO_2 will be lower than is optimal for economical sequestration (Fig. 4).

The Great Basin Center for Geothermal Energy at the University of Nevada, Reno has analyzed the potential for geothermal development in Nevada, largely using regional heat flow and state of stress as deduced from geodetic observations (Fig. 21, Coolbaugh and others, 2005, in press). Primarily using locations of known hot and warm springs and wells, Trexler and others (1983) outlined broad areas in Nevada as having potential for geothermal resource development (Fig. 22a). Blackwell and Richards (2004a and 2004b) used a combination of data from bottom-hole temperatures and heat-flow measurements of various petroleum and geothermal exploration wells to estimate temperatures at 4 km below the surface. As an additional comparison, areas with temperatures greater than 150°C at 4 km are considered by Blackwell and Richards (2004b) to have the most potential (Fig. 22b).

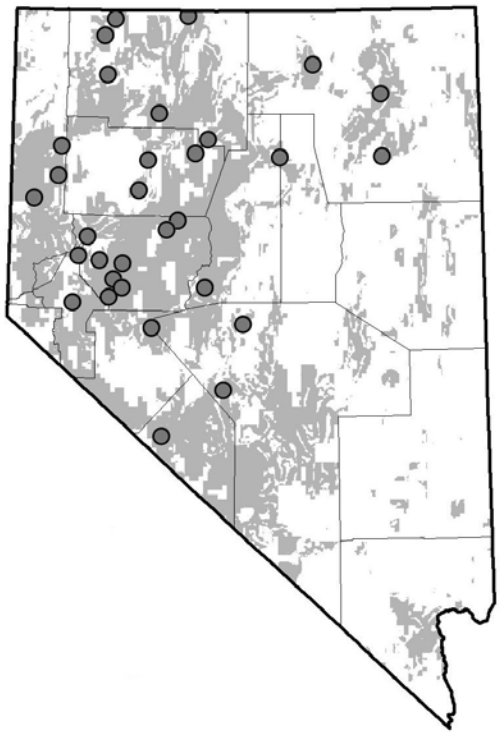
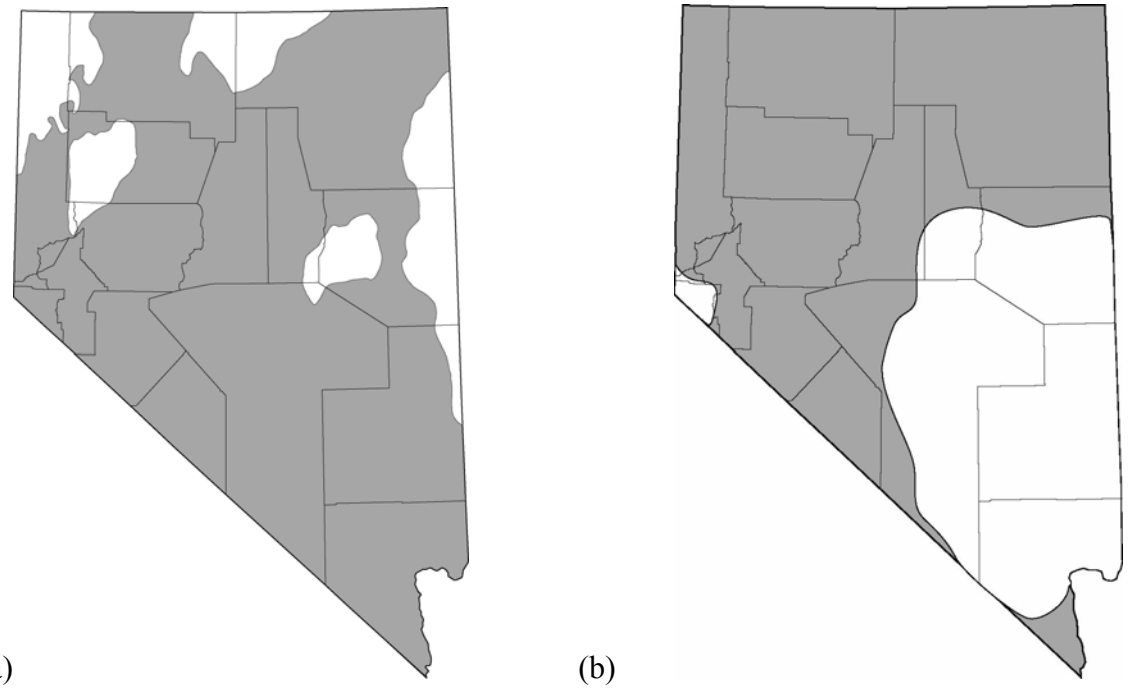


Figure 21. Simplified geothermal potential map of Nevada, adapted from Coolbaugh and others (in press). Gray areas have a higher than average probability of hosting high-temperature (greater than or equal to 150°C) geothermal resources compared to the rest of the Great Basin. Circles are known geothermal systems with estimated reservoir temperatures greater than or equal to 150°C.



(a) (b)

Figure 22. (a) Areas of potential for geothermal development (gray) according to Trexler and others (1983). (b) Areas of potential for geothermal development (gray) according to Blackwell and Richards (2004b), using their areas with temperatures in excess of 150°C at 4 km depth.

In comparing the locations of known geothermal anomalies (hot and warm springs, hot and warm wells, and holes with measured moderate and high heat flow from Shevenell and Garside (2005) with Figures 21 and 22, we note that a buffer of 20 km from these geothermal anomalies includes nearly all the high and moderate potential areas shown on Figures 21 and 22a. We have therefore chosen a buffer of 20 km from these known geothermal anomalies for the areas to exclude from consideration for CO_2 sequestration on the basis of potential geothermal resources (Fig. 23). Although a more sophisticated approach may have been to elongate the buffer zones along faults that control the geothermal systems, we know too little about the controlling faults to do this throughout the state (Faulds and others, 2004).

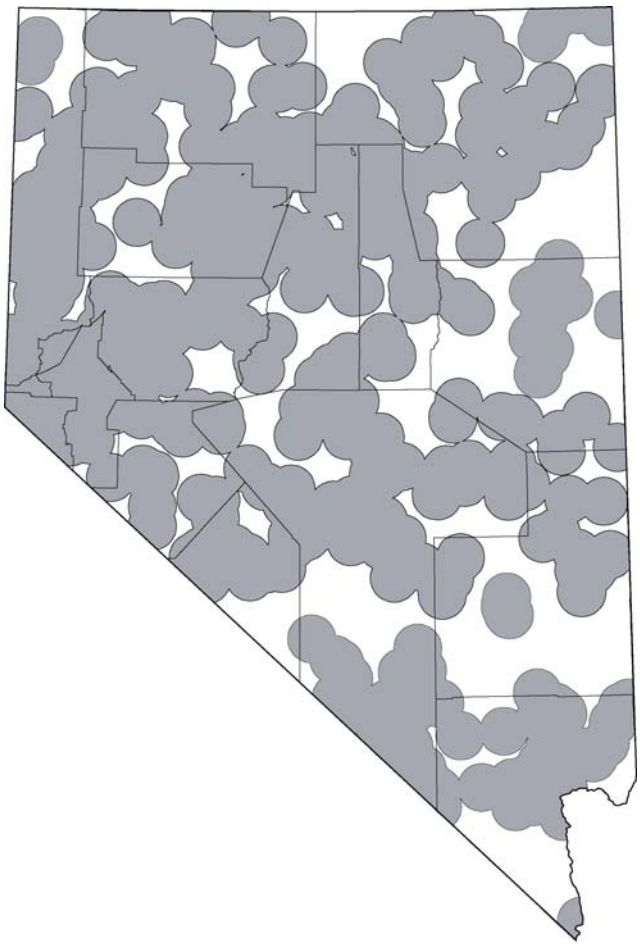


Figure 23. Areas excluded from consideration for CO_2 sequestration on the basis of potential geothermal resources. This map uses a buffer of 20 km from the locations of known hot and warm springs, hot and warm wells, and moderate to high heat flow wells shown on NBMG Map 141 (Shevenell and Garside, 2005).

3.2.3.4 Water

Nevada is the driest state in the nation in terms of average annual precipitation. Water is a precious resource for many reasons—industrial and urban sustainability and growth, ecological health, agriculture, recreation, and other cultural values. Sustaining adequate water resources is vital for Nevada's future. One of the principal aquifers in the state is the Deep Carbonate Aquifer of eastern Nevada (Thomas and others, 1986; Fig. 24). It is broadly defined to include the entire package of Paleozoic carbonate rocks stretching from the northeastern part of the state south-southwestward into California, with a general drop in the elevation of the potentiometric surface in that direction. The aquifer is recharged primarily through rain and snowmelt in the high mountains. The carbonate rocks underlie many of the valleys as well. For example, the water co-produced with petroleum in carbonate rocks in Railroad Valley is dominantly fresh water and is considered a resource for future use. This aquifer feeds important springs and wetlands in the region. We eliminate areas potentially underlain by the Deep Carbonate Aquifer from consideration for CO_2 sequestration.

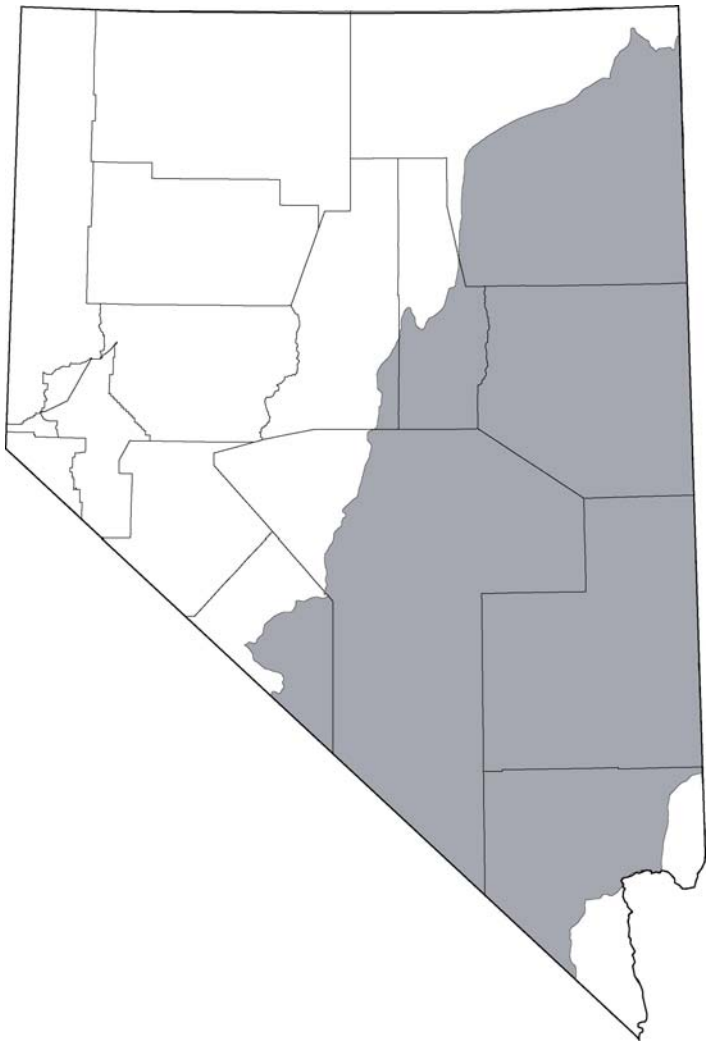


Figure 24. Distribution of the Deep Carbonate Aquifer, the principal deep aquifer in eastern and southern Nevada

By eliminating all areas potentially underlain by the Deep Carbonate Aquifer, we are also eliminating the possibility of using deep (> 1 km) saline aquifers that may occur above the Deep Carbonate Aquifer in the Tertiary basins of eastern and southern Nevada. We anticipate that such situations are rare, because the Deep Carbonate Aquifer, itself recharged by rain and snowmelt high in the mountains, tends to recharge the overlying Tertiary aquifers, as in Las Vegas Valley. There are two major reasons for eliminating these areas: (1) drilling through any deep saline aquifers in search of potable water in the Deep Carbonate Aquifer could hinder the integrity of a CO_2 sequestration site; and (2) depending on the density of the brine-CO_2 fluid and the relative heads of the brine and the deeper aquifer, the brine could sink into and contaminate the Deep Carbonate Aquifer.

There are other areas of significant potable groundwater resources outside the Deep Carbonate Aquifer. For example, some large gold-mining operations in northern Nevada pump substantial

quantities (tens to hundreds of thousands of liters per minute) of high-quality water from alluvial and bedrock aquifers. Before any project to dispose of CO_2 in saline aquifers were to be undertaken, the local hydrogeology would need to be investigated in detail to understand impacts on useable water resources.

3.2.4 Proximity to Urban Areas and Areas of Future Urban Growth

We do not feel that it would be wise to build a CO_2 sequestration facility near urban areas. We have therefore eliminated from consideration areas that are currently densely populated or may be developed during the 21st century (Fig. 25). We eliminate from consideration a 30-km buffer around current urban areas (as mapped from 2000 data of the U.S. Census Bureau), a 10-km buffer around current towns not classified as urban areas, and a 10-km buffer along major highways connecting urban areas (specifically, U.S. Highway 395, I-15, I-80, U.S. Highway 50 from Lake Tahoe to Fallon, U.S. Highway 95 from Indian Springs to Laughlin, U.S. Highway 93 from Apex to Hoover Dam, and Nevada Route 160, which goes through Pahrump). These buffers are reasonable given the remarkable urban growth in Nevada during the 20th century. For example, Las Vegas was not an urban area at the beginning of the 20th century, but by the beginning of the 21st century, nearly the entire 20x30-km valley had been converted to urban and suburban development.

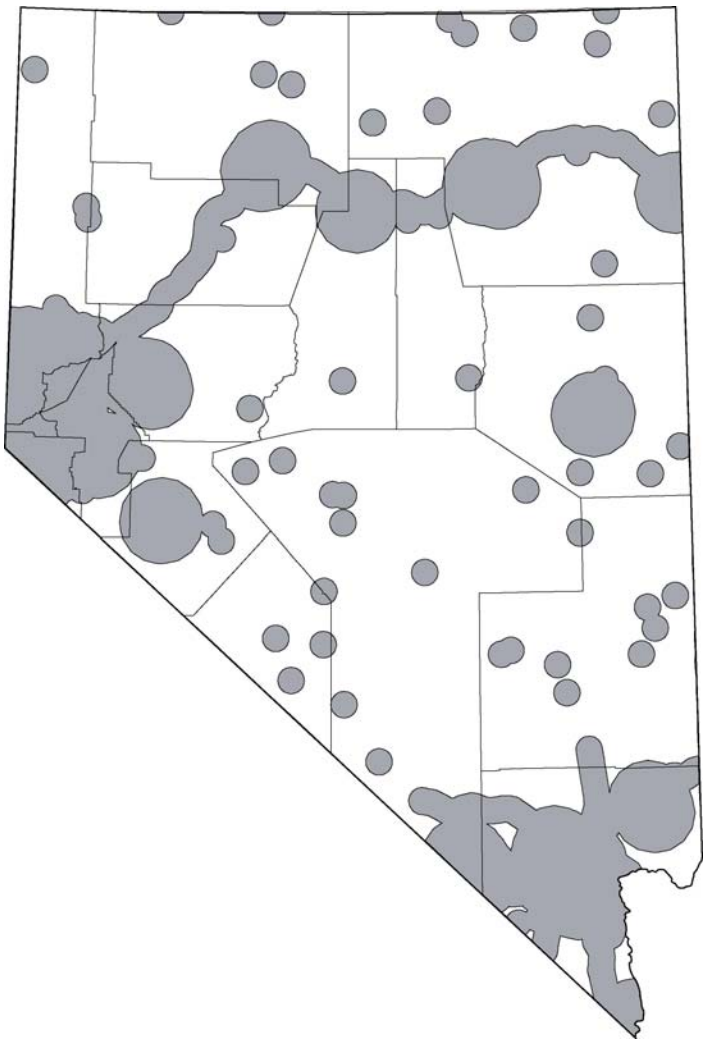


Figure 25. Areas of current high population density and areas likely to be developed during the 21st century. The gray areas include a 30-km buffer around major current population centers and a 10-km buffer around highways along which significant development has been taking place.

3.2.5 Restricted Lands

Approximately 86% of Nevada is managed by the federal government, largely by the Bureau of Land Management (BLM), the U.S. Forest Service, the National Park Service, the Department of Defense, and the Department of Energy. Nevada contains many areas in which a CO_2 sequestration facility could not be permitted, in part because of the difficulty of building a pipeline into the facility. These include National, Regional, and State Parks; National Recreation Areas; Wilderness Areas (but not Wilderness Study Areas); Military Reservations; and the Nevada Test Site. These areas have been eliminated from consideration (Fig. 26), because it is unlikely that permission for building a CO_2 sequestration facility would be granted by the controlling agencies. We did not consider the possibility of directional drilling into these restricted lands, nor did we consider the possibility that Congress could act to allow CO_2

sequestration in these areas as a general benefit to the public. Permission might be granted in some other reserved lands, such as BLM Areas of Critical Environmental Concern, National Conservation Areas, Indian Reservations, and National Wildlife Refuges. Should further consideration be given to specific areas, care should be taken to avoid areas that may be converted to a restricted status.

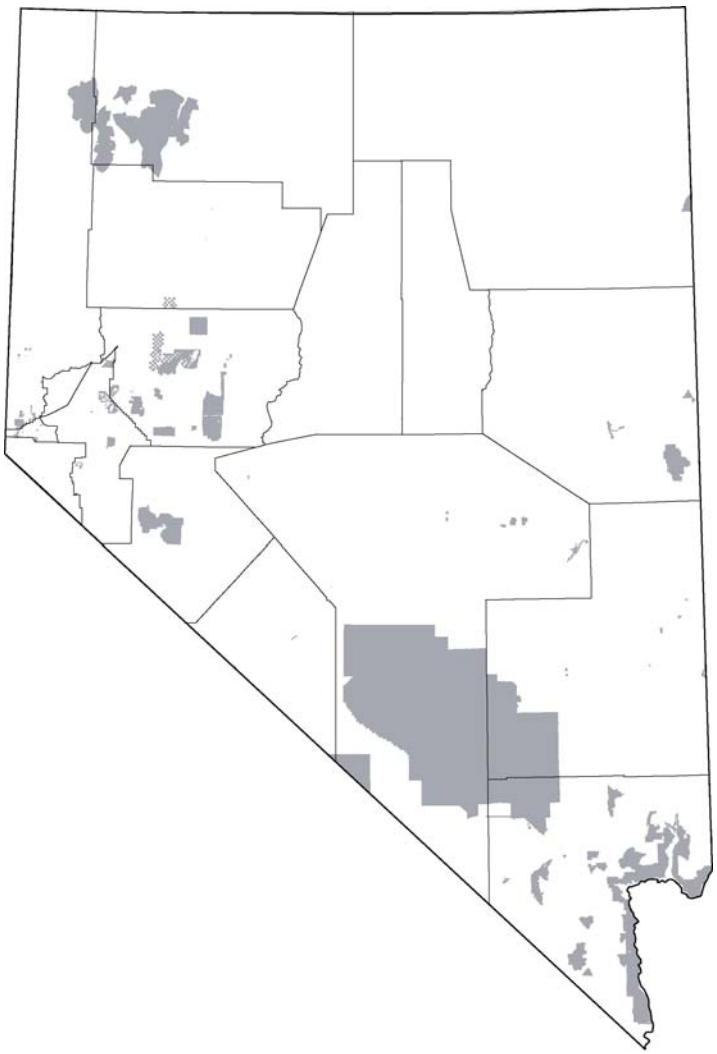


Figure 26. National, Regional, and State Parks, National Recreation Areas, Wilderness Areas, Military Reservations, and the Nevada Test Site

3.2.6 Other Data Considered

3.2.6.1 CO_2 Generators

Ideally, a sequestration site will be located close to the site of CO_2 generation. The largest generators of CO_2 are generally power plants, refineries, and lime and cement plants (Fig. 27). In Nevada, large coal-fired power plants are located near Battle Mountain (Valmy plant, Humboldt

County), Laughlin (Mohave plant, Clark County), and Moapa (Reid Gardner plant, Clark County). New coal-fired power plants have been proposed in the Gerlach area in northern Washoe County in the northwestern part of the state (Sempra Energy's Granite Fox project), in White Pine County in the eastern part of the state (White Pine Energy Associates), and in Boulder Valley in Eureka County in the northern part of the state (Newmont Mining Company), and Sierra Pacific Power has proposed expanding the Valmy operation.

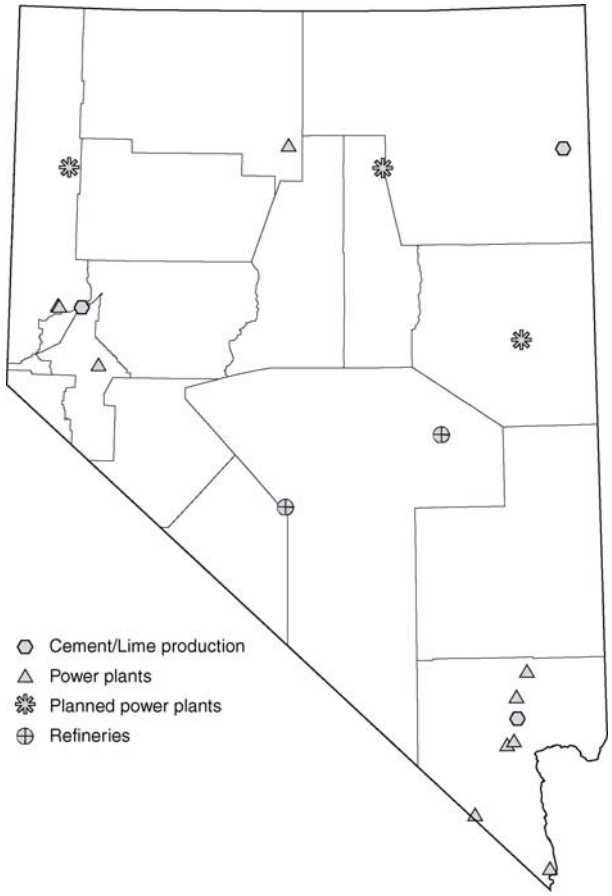


Figure 27. Location of major generators of CO_2 in Nevada [coal- and natural gas-fired power plants (triangles); proposed coal-fired power plants (stars); cement and lime plants (hexagons); and refineries (circles with crosses)]

Nevada also has several natural gas-fired (and oil-fired) power plants; among the largest are the Clark Station in Las Vegas Valley in Clark County, the Fort Churchill plant in Lyon County, the El Dorado plant southwest of Boulder City in Clark County, and the Tracy plant near Reno-Sparks in Washoe County. Additional gas-fired plants came into service in 2003 and 2004 at Apex, North Las Vegas, and Primm in Clark County, and others have been proposed to the Public Utilities Commission of Nevada (http://www.puc.state.nv.us/) to meet the demands of the region's increasing population. Natural gas is also burned in the production of wallboard from gypsum in Clark and Washoe Counties.

The only significant, albeit small, oil refinery in Nevada is in Railroad Valley. Much of Nevada's petroleum is trucked or railed to the Salt Lake City area for refining. A small refinery near Tonopah in Nye County is no longer in operation.

The only major operating cement plant in Nevada (with production over 500,000 short tons per year) is at Fernley in Lyon County. Another plant near Logandale in Clark County produced intermittently in recent years, and development is underway to start a new plant near Interstate 80 in Pershing County (Castor, 2004). Major lime plants operate in the Toano Range near West Wendover in Elko County, and at Apex, near Las Vegas in Clark County. Small amounts of lime are also produced at a plant in Henderson near Las Vegas (Castor, 2004). The major existing CO_2-generating facilities are located on Figure 27.

3.2.6.2 Transportation Infrastructure

Constructing a CO_2 pipeline would be facilitated if it follows current pipelines and transportation routes, along which rights of way may be easier to obtain than in remote areas. Figure 28 has locations of current major gas and petroleum-product (gasoline, jet fuel, diesel fuel) pipelines, electrical transmission lines, highways, and railroads. Major storage facilities for petroleum products in Nevada are currently in and near urban areas and on military bases.

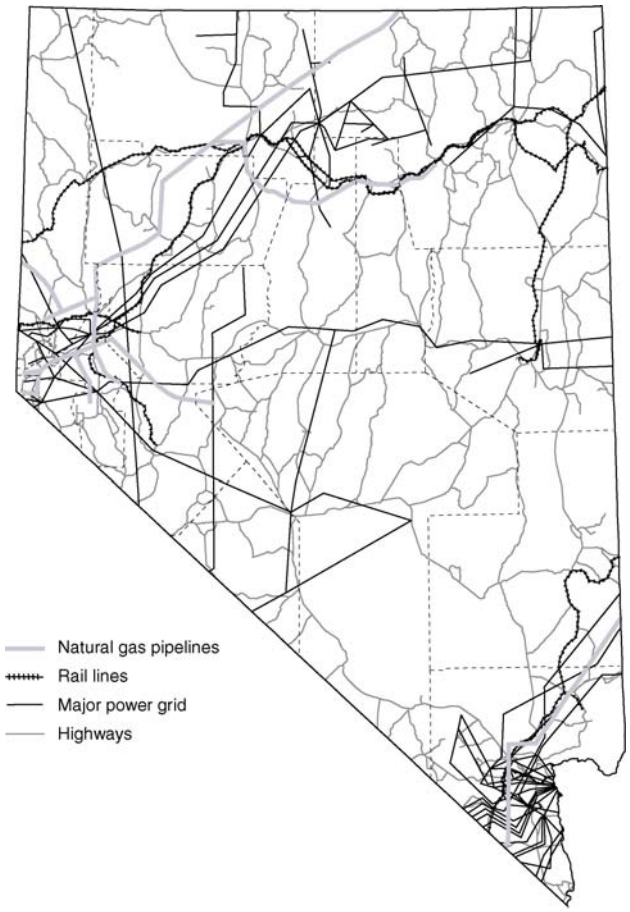


Figure 28. Major pipelines for petroleum products and natural gas, electrical transmission lines, highways, and railroads

4 Results and Discussion

The binary (yes-no) approach of GIS analysis used in this report (Appendix) to assess the potential for CO_2 disposal in saline aquifers boils down to the following key assumptions or criteria: (1) avoid underground disposal in areas of fractured bedrock and restrict the assessment to parts of alluvial basins that are thick enough to provide a seal against leakage and have enough pressure to keep the CO_2 in a condensed phase; (2) stay away from active faults whose fracture zones may allow leakage of CO_2 from underground injection sites; (3) avoid areas that in the foreseeable future have a reasonably high probability of being explored and developed for mineral, geothermal, and water resources; (4) avoid current urban areas and areas that are likely to experience significant population growth during the 21st century; and (5) avoid restricted lands, such as parks and military reservations. After combining the relevant GIS data sets, a few areas that meet all the criteria remain (Fig. 29).

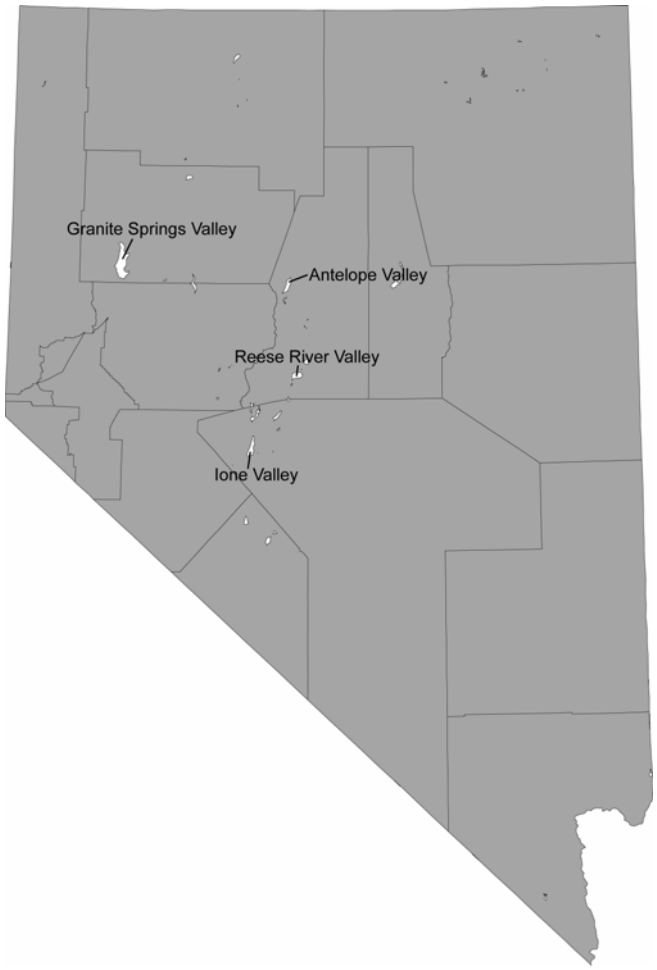


Figure 29. Areas that have the potential for CO_2 waste disposal through geological sequestration in possibly saline aquifers in Nevada. This map is a combination of maps in Figures 3 (eliminating areas in which consolidated rocks of Tertiary age and older crop out), 5 (eliminating areas with less than 1 km of valley fill), 6 (eliminating areas close to Quaternary faults), 19 (eliminating areas likely to experience mineral-resource development), 23 (eliminating areas that are likely to be developed for geothermal resources), 24 (eliminating areas potentially underlain by the Deep Carbonate Aquifer), Population (eliminating current and likely future urban areas), and 26 (eliminating areas in which permission is not likely to be granted).

The valleys with the largest areas of potential for CO_2 sequestration by injection into saline aquifers are Granite Springs Valley in Pershing County, Antelope and Reese River Valleys in Lander County, and Ione Valley in Nye County. Each contains 30 km^2 or more area. The NBMG has no records of deep (>1,000 m) wells in any of these areas. The type of information listed in Table 3 would be needed to more fully evaluate the potential for CO_2 sequestration in these areas. In particular, information is needed on the porosity, permeability, thickness, and salinity of deep aquifers in these areas. Although no data are available in the immediate areas shown to be potentially favorable for CO_2 sequestration on Figure 29, we can hypothesize the existence of

favorable aquifers on the basis of nearby wells and the expectation that most deep alluvial basins will contain some permeable sandy aquifers and clay-rich seals.

A further complication is that some of the areas shown as thick basins are likely filled with thick accumulations of Tertiary volcanic rocks rather than mostly sediments. Because the differences in density between sediments and volcanic rocks, particularly tuffs, is small, the zones shown on Figure 5, interpreted from gravity data, actually show combined thickness of basin-filling sediments and volcanic rocks. For example, the upper part of a well near the thickest part of Antelope Valley (Arco Exploration's Antelope Valley No. 1 well, a wildcat drilled in late 1984 and early 1985 in Lander County) contains basin-filling sands, gravels, silt, and clay, but from 212 to 890 m, the well penetrated mostly tuff and clay-rich tuffaceous sediments. All four areas with 30 km^2 or greater area in Figure 29 are likely to contain significant accumulations of Tertiary volcanic rocks; that is, the basin-filling sediments may not be as thick as desired.

The total area identified with potential for CO_2 disposal in Figure 29 is 524 km^2. If further investigation indicated that thick, permeable sandstones with saline water do indeed exist in these areas, it is possible that significant amounts of CO_2 could be sequestered. Assuming a porosity of 10% in the subsurface sandstone formation, 1 gigaton of CO_2 at a density of 0.75 g/cm^3 would require a volume of 13.3 km^3. Assuming the sandstone thickness to be 100 m, this would require a surface area of 133 km^2. One gigaton of CO_2 is a reasonable expectation for a full-scale CO_2 sequestration project associated with a large power plant. A 2,000+-megawatt plant that burned 5 million metric tons of carbon per year for 50 years would produce 0.9 gigaton of CO_2. Clearly, more data would be needed on the subsurface geology in these areas remaining after the GIS analysis before proceeding with a CO_2 sequestration project.

The largest of the areas identified with potential for CO_2 sequestration in Figure 29 is Granite Springs Valley. Although little is known about the subsurface geology in this valley, based on regional comparisons, it is possible that the area has potential for geothermal development, and the subsurface temperatures may be too high for cost-effective sequestration. Richards and Blackwell (2002a) rated the Trinity Mountains, immediately east of Granite Springs Valley, as one of the top 15 areas for geothermal development in Nevada, based in part on estimated heat loss (Richards and Blackwell, 2002b). Should further investigation of Granite Springs Valley be warranted, particular care should be taken to evaluate its geothermal potential.

5 Alternative Approaches to CO_2 Sequestration in Geological Settings

Although enhanced oil recovery and deep disposal in non-potable aquifers are two proven technologies for CO_2 sequestration, opportunities for these approaches appear to be limited in Nevada. There are, however, alternative approaches. We explore two such alternatives here. Storage of CO_2 in mined caverns in salt formations would take advantage of existing technologies for storage of natural gas in these formations. Chemical reaction with mafic and ultramafic rocks is an unproven technology that has much promise for long-term, permanent disposal of CO_2 without the leakage concerns associated with underground injection.

5.1 Storage in Mined Caverns in Salt Formations

One possible approach to CO_2 sequestration is to develop repositories in thick salt deposits. Caverns within salt are excavated through dissolution of salt with fresh water (i.e. solution mining). This process produces significant quantities of brine, which can be reinjected into saline aquifers proximal to the salt deposit. In some cases, solution mining is used to produce industrial salt. For example, Morton Salt operates a solution mine in thick salt deposits near Phoenix, Arizona (Rauzi, 2002). Volatile materials, such as liquefied petroleum gas (LPG), have been safely stored in salt-solution caverns in many parts of the country. Two LPG facilities presently exist in Arizona and several others are currently or have recently been under investigation (e.g., Federal Energy Regulatory Commission, 1982).

The Basin and Range province hosts several unusually thick Cenozoic salt deposits, including some of the thickest in the world (Fig. 30; Peirce, 1976; Faulds and others, 1997). Most of the salt resides in Cenozoic basins produced by basin-and-range extension. Halite deposits are particularly thick in some of these basins and may have significant economic potential for storage of natural gas (Rauzi, 2002).

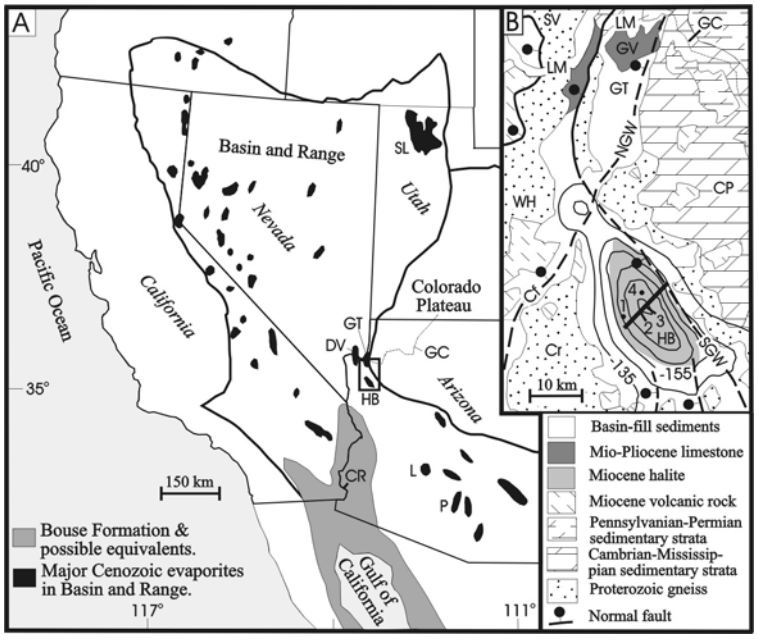


Figure 30. (a) Major Cenozoic evaporite deposits in the Basin and Range (from Faulds and others, 1997). (b) Generalized geologic map of the Hualapai basin area showing Bouguer gravity contours (10 mgal intervals; from Davis and Conradi 1981) and location of drill holes and cross section (Fig. 31). Cf, Cerbat Range fault; CP; Colorado Plateau; Cr, Cerbat Range; CR, Colorado River; DV, Detrital and southern part of Virgin River depression; GC, Grand Canyon; GT, Grand Wash trough; GV, Grapevine Mesa; HB, Hualapai basin; L, Luke basin; LM, Lake Mead; NGW, northern Grand Wash fault; P, Picacho basin; SGW, southern Grand Wash fault; SL, Great Salt Lake; SV, South Virgin Mountains; WH, White Hills.

The basins containing the thick salt deposits owe their origin to a relatively complex history of tectonism and drainage evolution. Large-magnitude crustal extension in middle Tertiary time gave way to more widely distributed east-westerly extension and block faulting in the late Miocene (typically ~10 Ma in much of the province). Localized deep basins developed in the hanging walls of steeply dipping northerly striking normal faults. Basin-and-range block faulting that accompanied deposition of post mid-Miocene basin fill locally produced steep basin margins and prominent escarpments (Dickinson, 1991), which served to accentuate development of some regional depressions or sinks. In the western Great Basin, northwest-striking right-lateral faults contributed to development of some basins.

By late Miocene time, a reduction in extensional strain rates promoted widespread aggradation (building up) of sediments within composite basins. Basin-fill sedimentation ultimately buried a rugged mid-Tertiary paleogeography of corrugated tilt blocks (Dickinson, 1991). Facies patterns in late Tertiary basin fill are congruent with modern topography and reflect construction of alluvial fans derived from flanking ranges. The alluvial fans interfinger with and give way to floodplain, lacustrine, and continental playa environments toward the basin floors.

Reduced strain rates and regional aggradation in late Tertiary time facilitated the evolution of regional drainage systems that ultimately integrated large networks of basins. In eastern parts of the Basin and Range, major drainages emanated from the relative highlands of the Colorado Plateau, and vast quantities of fresh water began flowing into regional sinks in late Tertiary time. Many basins also became regional sinks for groundwater flow systems. Prior to development of through-going drainage systems to the Gulf of California in Pliocene time (~3 to 5 Ma), thick nonmarine evaporite deposits (halite, anhydrite, and gypsum) accumulated in these sinks. Evaporite deposition was focused in the younger basins associated with high-angle basin-and-range faulting, either within the lower parts of the sinks or in satellite basins proximal to major river systems. The thickest known salt deposit of this vintage is the 2.5-km-thick Red Lake salt in the Hualapai basin of northwest Arizona just south of Lake Mead (Fig. 31; Faulds and others, 1997).

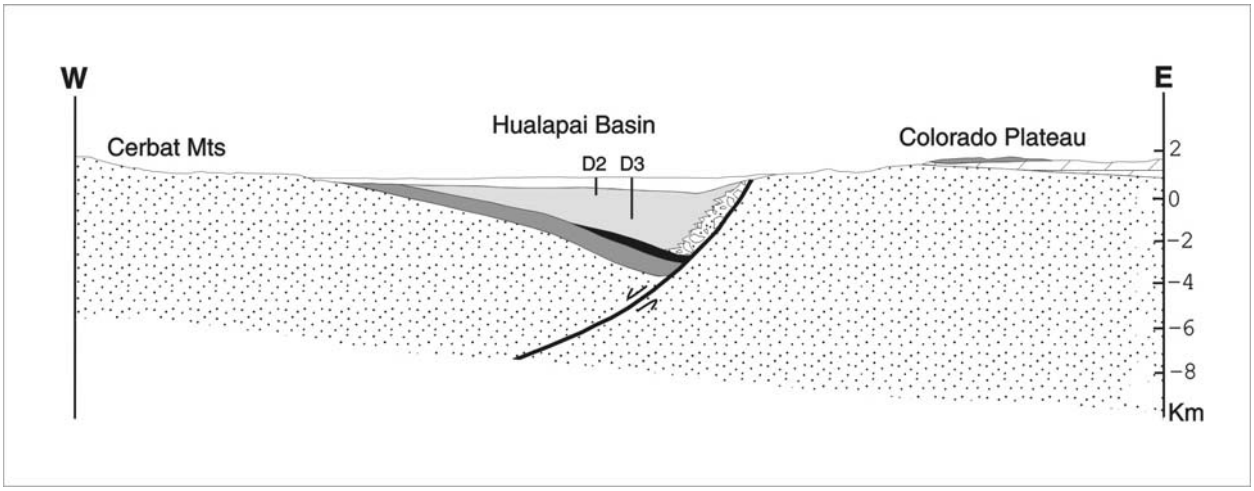


Figure 31. 1:1 cross section showing the Red Lake salt deposit in the Hualapai basin, northwest Arizona (view is toward the north; from Faulds and others, 1997). Unit patterns: stippled, Proterozoic gneiss; cross-hatched, Paleozoic sedimentary strata; dark gray, Miocene volcanic rocks; black, Miocene sedimentary rocks; light gray, late Miocene-early Pliocene salt deposit; gravel pattern along fault, alluvial fan deposits; white, early Pliocene to recent silt and sand deposits, with minor anhydrite and gypsum at base.

Because the geologic setting of southern Nevada is similar to that of northwest Arizona, several northerly trending basins within southern Nevada probably host thick salt deposits. These include the Virgin River depression and Eldorado and Piute basins (Fig. 5). Mannion (1974) documented ~500 m of late Tertiary salt in the southern part of the Virgin River depression, specifically in the Overton Arm area of Lake Mead. In addition, high TDS (total dissolved solids) characterizes wells in the northern part of Eldorado Valley and the deeper levels (~300 m) of some wells in the Mesquite area (M. Johnson, Virgin Valley Water District, personal commun., 2004). Maximum basin depth and thickness of basin-fill sediments generally ranges from ~2 to 6 km in Nevada (e.g., Bohannon and others., 1993; Langenheim and Schmidt, 1996; Langenheim and others, 2001). However, the eastern part of the Virgin River depression exceeds 8 km in depth in the northwest corner of Arizona (Langenheim and others, 2001). Although thick salt has not been documented in the northern and eastern parts of the Virgin River depression, it is important to note that the deeper parts of this basin have not been penetrated by drill holes. Considering the location of the Virgin River depression at both the mouth of the Virgin River Canyon and near the confluence of the Virgin and Colorado Rivers, as well as the presence of thick salt in the shallower southern part of the basin (Mannion, 1974), it is likely that thick evaporite deposits reside in the deep eastern part of the basin. Most of the potential salt-bearing basins in southern Nevada are relatively quiet tectonically, with little activity on range-bounding faults over the past several million years. One exception to this is the northern part of the Eldorado basin, where the Black Hills fault shows evidence of rupturing in a sizeable earthquake in the past 10,000 years (Fossett and Taylor, 2003).

Considering the rapid population growth and related recent construction of natural gas power plants near Las Vegas, presence of the coal-fired Mohave Generating Station (MGS) at Laughlin, relative tectonic quiescence, and proximity of thick salt deposits, the southern Nevada region

may be a favorable location for a CO_2 sequestration project. This may be particularly relevant for the MGS, a 1,580-megawatt coal-fired power plant located approximately 120 km southwest of the Grand Canyon and only 65 km southwest of the 2.5-km-thick Red Lake salt deposit. The MGS began operations in 1971 and is one of the largest sources of air pollution in the West (emitting up to 40,000 short tons of sulfur dioxide, SO_2, per year), contributing significantly to visibility impairment at the Grand Canyon (U.S. Environmental Protection Agency, 1999). In fact, once controls are installed at the Centralia Power Plant in Washington State, as scheduled in the next few years, the MGS will be the largest source of SO_2 in the West. The MGS is operated by Southern California Edison, the majority owner of the plant. The Los Angeles Department of Water and Power, Nevada Power Company, and Salt River Project also own interests in the plant. This facility is the only coal-fired, base-loaded power plant in the United States that receives coal through a slurry pipeline, which originates 440 km to the east at Black Mesa in northern Arizona. Carbon dioxide emissions from the MGS could possibly be contained within a solution cavern within the nearby Red Lake salt deposit. However, the MGS may shut down in the near future due to the costs of necessary pollution control retrofits and repairs to the coal-slurry pipeline that transports coal from northeastern Arizona, in which case the MGS may no longer be a major source of CO_2 (Edwards, 2005).

The volume of caverns needed to hold the CO_2 exhaust from a major power plant is substantial. Using the factors in Table 1, a plant that burns 250 million metric tons of carbon in coal over its lifetime (approximately a 2,000-megawatt plant operating for 50 years) would need 1.2 km^3 of underground storage space. For such an operation, only sedimentary basins with thick, extensive salt formations would be practical.

5.2 Chemical Reaction with Mafic and Ultramafic Rocks

The principal means by which CO_2 is naturally sequestered in rocks is through the alteration of calcium- and magnesium-rich rocks, ultimately forming carbonates (rocks composed primarily of calcite, $CaCO_3$, the major mineral in limestone, and dolomite, $CaMg(CO_3)_2$). The Earth contains abundant calcium and magnesium in basalts (volcanic rocks commonly erupted at ocean ridges on the seafloor, in volcanic islands, such as Hawaii, and in certain continental areas, such as the Columbia River Plateau east of the Cascade Range in Oregon and Washington) and gabbros (intrusive equivalents of basalts). These rocks are termed mafic to describe their high magnesium and iron (ferrous) contents.

One approach to permanent CO_2 sequestration would be to speed up the natural process. Minerals in these rocks can react with CO_2 to produce various carbonates, silica, and alumina as reaction products. As indicated in Table 4, in terms of volume of material required for the reactions and volume of materials produced, rocks with high concentrations of the mineral forsterite (Mg_2SiO_4), the magnesium end member of the olivine group, would be most favored. One gigaton of carbon, approximately the amount of coal burned annually in the United States, would require reaction with 5.86 gigatons of forsterite (approximately 1.82 km^3 of dunite, a rock composed mostly of Mg-rich olivine) and would produce 9.52 gigatons of product composed of 7.02 gigatons of magnesite plus 2.50 gigatons of quartz. Assuming 20% porosity in the waste product, this would be 2.92 km^3 of magnesite product and 1.18 km^3 of quartz product, for a total of 4.10 km^3 of waste product. Reaction of CO_2 with other minerals would require considerably

more volume of reactant and would produce considerably more waste product than reaction with Mg_2SiO_4, although reaction with serpentinite, a rock composed mostly of serpentine minerals, such as antigorite, $Mg_6Si_4O_{10}(OH)_8$, is nearly as favorable volumetrically as reaction with olivine (Table 4). Coincidentally, the reaction of CO_2 with Mg_2SiO_4 is also favorable thermodynamically; heat generated from the reaction could be used to provide energy needed to pulverize the rock, thereby speeding up the kinetics of the reaction.

Goff and Lackner (1998) describe the potential use of ultramafic rocks for CO_2 sequestration. These are particularly Mg-rich igneous rocks, including dunite, serpentinite, and peridotite, a rock composed mostly of olivine and pyroxenes, minerals composed primarily of $(Mg,Fe,Ca)SiO_3$. They describe a scenario in which the ultramafic rocks would be reacted with hydrochloric acid to facilitate reactions with CO_2. Unfortunately, although ultramafic rocks are abundant in California, Oregon, and Washington, Nevada contains only small amounts of these types of rocks near the surface. Nevada does, however, have abundant basalt and other mafic rocks (Fig. 32). The volume requirements for reactions with basalts are considerably less favorable than for reactions with ultramafic rocks, such that any use of basalts in Nevada would have to deal with large volumes of waste products. For example, using the hypothetical basalt composition in Table 4, 5.2 km^3 of basalt would need to be mined to react with one gigaton of carbon, and 8.5 km^3 of waste would be generated from the reaction, more than enough to refill the hole from which the basalt would be mined.

A hypothetical scenario for permanent CO_2 sequestration would be to site a CO_2-generating power plant near a large amount of ultramafic rock or basalt, which would be mined and used in chemical reactors. The waste products from the reactions could be used to isolate municipal and other waste materials, which would refill the holes dug in the mining operations. Because of the volume considerations (Table 4), additional landfills would be required, or artificial hills would be constructed near where the ultramafic rock or basalt had been mined. Ideally, such an industrial ecology facility would be located close to railroads (to bring coal from Wyoming and other sources and waste from cities) or perhaps ports (to bring coal from Alaska and possibly oil or natural gas from any location), electrical transmission lines, and cities that use the electricity and generate the municipal waste.

The locations of large outcrops of mafic rocks in Nevada are plotted with locations of current railroads, piplelines, electrical transmission lines, and major CO_2 generators in Figure 32. Should such a scenario be pursued, volumes of mafic rocks would need to be assessed. It is likely that sufficient volumes of basalt and ultramafic rocks occur in the western states to meet the CO_2 sequestration needs of the region (Goff and Lackner, 1998). In Nevada, Tertiary basalts crop out in many parts of the state, and a large gabbroic complex occurs near Lovelock in northern Churchill and southern Pershing Counties. Serpentinite, presumably altered pieces of dunite- or peridotite-rich oceanic crust thrust onto the North American continent during Paleozoic and Mesozoic mountain-building events (Stewart, 1980), occurs in small bodies in Mineral, northwestern Nye, and eastern Humboldt Counties.

Table 4. Theoretical weights and volumes of reactants and products in reactions between CO_2 and various rocks and minerals (data from Weast, 1971, Roberts and others, 1974, and Robie and Hemingway, 1995).

Mineral reactant	Ratio of weights of mineral reactant to C	Volume of mineral reactant (m^3/t of C)	Ratio of weights of solid products to C	Volume of solid products (m^3/t of C) assuming 20% porosity in products
1. Mg_2SiO_4 (forsterite)	5.86	1.82	9.52	4.10
2. Fe_2SiO_4 (fayalite)	8.48	1.93	12.15	4.24
3. $Mg_6Si_4O_{10}(OH)_8$ (antigorite)	7.69	2.98	10.36	4.49
4. $MgSiO_3$ (enstatite)	8.36	2.62	12.02	5.28
5. $FeSiO_3$ (ferrosilite)	10.98	2.75	14.65	5.42
6. $CaSiO_3$ (wollastonite)	9.67	3.32	13.34	6.20
7. $CaAl_2Si_2O_8$ (anorthite)	23.16	8.39	26.83	11.22
8. $NaAlSi_3O_8$ (albite)	43.66	16.67	47.33	21.18
9. Hypothetical basalt	16.32	5.21	19.98	8.50

1. Mg_2SiO_4 (forsterite in olivine) + $2CO_2$ (gas, captured from power plant) = $2MgCO_3$ (magnesite) + SiO_2 (quartz or other silica compound)
2. Fe_2SiO_4 (fayalite in olivine) + $2CO_2$ (gas) = $2FeCO_3$ (siderite) + SiO_2 (quartz)
3. $Mg_6Si_4O_{10}(OH)_8$ (antigorite) + $6CO_2$ (gas) = $6MgCO_3$ (magnesite) + $4SiO_2$ (quartz) + 4H2O (water)
4. $MgSiO_3$ (enstatite in pyroxenes) + CO_2 (gas) = $MgCO_3$ (magnesite) + SiO_2 (quartz)
5. $FeSiO_3$ (ferrosilite in pyroxenes) + CO_2 (gas) = $FeCO_3$ (siderite) + SiO_2 (quartz)
6. $CaSiO_3$ (wollastonite in pyroxenes) + CO_2 (gas) = $CaCO_3$ (calcite) + SiO_2 (quartz)
7. $CaAl_2Si_2O_8$ (anorthite in plagioclase) + CO_2 (gas) = $CaCO_3$ (calcite) + Al_2O_3 (alumina or corundum) + $2SiO_2$ (quartz)
8. $2NaAlSi_3O_8$ (albite in plagioclase) + CO_2 (gas) = Na_2CO_3 (sodium carbonate) + Al_2O_3 (alumina or corundum) + $6SiO_2$ (quartz)
9. The composition of this hypothetical basalt is calculated with the following assumptions:

Hypothetical Basalt	Mole Fraction	Chemical composition	Weight %
Mg_2SiO_4 (in olivine)	0.15	SiO_2	48.6
Fe_2SiO_4 (in olivine)	0.05	Al_2O_3	19.2
$CaSiO_3$ (in pyroxenes)	0.07	MgO	11.5
$MgSiO_3$ (in pyroxenes)	0.23	FeO	7.8
$FeSiO_3$ (in pyroxenes)	0.10	CaO	11.2
$CaAl_2Si_2O_8$ (in plagioclase)	0.30	Na_2O	1.7
$NaAlSi_3O_8$ (in plagioclase)	0.10	TOTAL	100.0
TOTAL	1.00		

With the exception of reaction 8, all reactions are thermodynamically favorable (with respect to calculated negative Gibbs free energies of reaction at 25°C).

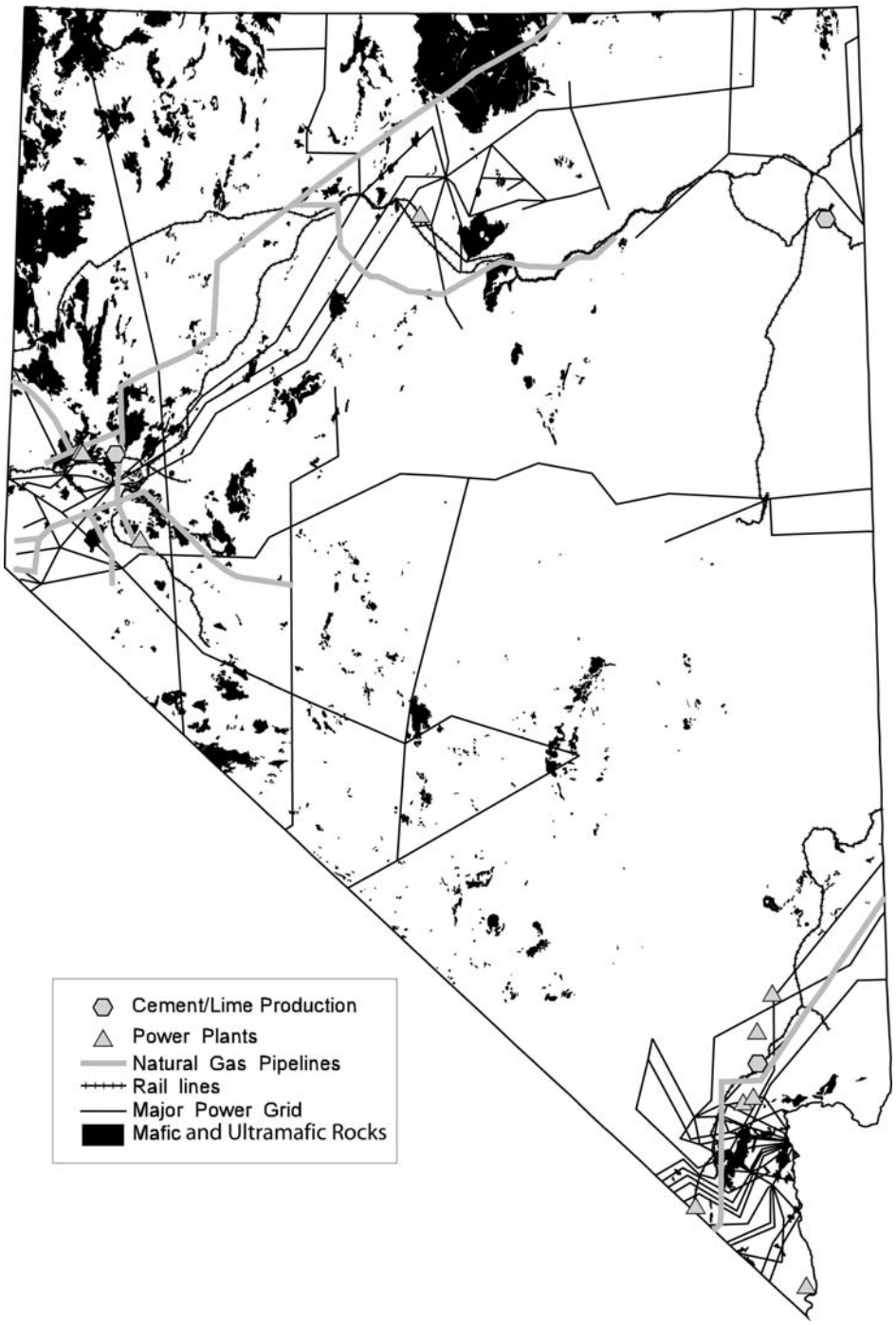


Figure 32. Distribution of mafic (magnesium- and iron-rich) rocks (black), major power plants (gray triangles), cement and lime plants (gray hexagons), major electric power transmission lines, pipelines, and rail lines in Nevada.

Using the factors in Table 4, a large coal-fired power plant (burning 5 million metric tons of carbon in coal per year and generating on the order of 2,000 megawatts) would need to mine

approximately 14.9 million m^3 of serpentinite or 26.1 million m^3 of basalt per year and would generate approximately 22.5 or 42.5 million m^3, respectively, of solid waste per year. Over a 50-year life, the solid waste would amount to approximately 1.1 or 2.1 km^3, depending on whether serpentinite or basalt, respectively, were used for the chemical reactions. These numbers are comparable to the sizes of large-scale copper and gold mines in Nevada (e.g., the Robinson and Yerington copper mines and the Carlin and Betze-Post gold mines) and other parts of the western United States.

Depending on the chemical reactor design (using supercritical, liquid, or gaseous CO_2 versus an aqueous solution as described by Goff and Lackner, 1998), considerable water may be needed for the process. Interestingly, reaction of CO_2 with serpentinite, which is more abundant in California than in Nevada, would produce approximately one ton of water for each ton of carbon sequestered, thereby perhaps eliminating the need to consume existing water resources. A further advantage of serpentinite is that it is locally considered a nuisance, because of commonly contained asbestos, which would be destroyed upon reaction with CO_2. Commercial-scale sequestration by reaction with rocks, although highly attractive as a means of permanently disposing of the CO_2, is likely to be far in the future, because the chemical reactors and overall power generation-mining-waste disposal systems would need to be designed, perfected, and demonstrated to be cost-effective.

6 Conclusions

We have presented an approach to a preliminary assessment of the potential for CO_2 disposal by sequestration in geological settings in Nevada using GIS analysis. The key assumptions made are that for CO_2 disposal in saline aquifers it is wisest to (1) avoid areas of fractured bedrock and restrict the assessment to parts of alluvial basins that are deep enough to provide a thick, relatively impermeable seal against leakage and have sufficient pressure to keep the CO_2 in a condensed phase; (2) stay away from active faults whose fracture zones may allow leakage of CO_2 from underground injection sites; (3) avoid areas that in the foreseeable future have a reasonably high probability of being explored and developed for mineral, geothermal, and water resources; (4) avoid current urban areas and areas that are likely to experience significant population growth during the 21st century; and (5) avoid restricted lands, such as parks and military reservations. The data sets used in the GIS analysis are readily available through references provided in this report or are made available in the electronic version of this report, so that others may reevaluate the approach with different assumptions and data sets.

There does not appear to be much potential in Nevada for CO_2 sequestration through disposal in saline aquifers. Among the potential deep parts of alluvial basins, few remain after eliminating areas of potential potable water, geothermal resources, and mineral resources. Within the remaining areas, little is known about porosities, permeabilities, or salinities of aquifers at depths greater than 1 km.

There also does not appear to be much potential in Nevada for conventional approaches to CO_2 sequestration through enhanced oil recovery, in part because the oil fields in Nevada tend not to have much associated natural gas, implying that gas that was associated with the fields has escaped. Injected CO_2 would likely leak to the surface as well, although the time scale may be

quite long. In addition, the oil fields in Nevada are small relative to fields in many other parts of the United States, and some of the Nevada fields are considerably hotter than ideal conditions for maintaining a dense CO_2 phase underground.

There is some potential for disposal of CO_2 in mined caverns in salt formations in basins in southern Nevada, northwestern Arizona, and southwestern Utah. The highest potential for this approach is likely to be in northwestern Arizona, where thick salt deposits are well described and are being studied for storage of natural gas.

Chemical reaction of CO_2 with mafic rocks (basalt, gabbro) and ultramafic rocks (serpentinite, dunite, peridotite) has the potential to capture CO_2 in synthetic minerals, which, in turn, could be used to isolate municipal and industrial wastes. Enough of these rocks are exposed in Arizona, California, Idaho, Nevada, Oregon, and Washington to meet the expected needs for CO_2 sequestration in the region. Ultramafic rocksare more favorable than mafic rocks both volumetrically and thermodynamically. Chemical reaction with mafic or ultramafic rocks would be a long-term solution requiring considerable research to design, perfect, and demonstrate the cost-effectiveness of the chemical reactors and associated facilities.

For Nevada to be considered a potential site for significant amounts of CO_2 sequestration in geological settings, considerably more work would need to be done to (a) assess the thicknesses and volumes of salt formations in southern Nevada, (b) demonstrate a cost-effective process for chemical reaction with ultramafic or mafic rocks, and (c) assess the volumes of ultramafic and mafic rocks that are located in optimal areas. Although Nevada occurrences of ultramafic and mafic rocks have the advantage of being remote, considerably larger areas of ultramafic rocks are known in California, Oregon, and Washington, and enormous volumes of basalt occur in eastern Oregon and Washington.

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Appendix: Geographic Information System Analysis

The GIS data sets used in this assessment are included in the compact disk (CD) version of this report. Included on the CD are metadata files for each data set. Further descriptions of the metadata and the assumptions made in deciding how to use each data set are given in this section. Should further consideration be given to CO_2 sequestration in Nevada, others may wish to reevaluate our approach, make different assumptions, or use different data sets.

A. Software and Projection Information

All coverages in this project are in UTM, zone 11, meters, NAD 27 projection. Original data coverages that were not in this projection were projected using the projection wizard in Arcview 3.3. Coverages that extended beyond the Nevada State line were clipped to exclude areas outside of the State prior to final modeling. Arcview 3.3 and ARCGIS 9.0 were used for data development, editing, analysis, and modeling. All data layers are designed to be used at a scale of 1:1,000,000 or smaller. Minor edits were performed on some preliminary coverages to remove line work errors and close polygons.

B. The Binary Model

We used a binary model for the GIS analysis. A binary model is, simply put, a series or stack of data layers that are attributed in such a way as to show where data of interest, per layer, are and where they are not. Typically, values used include zero or one, yes or no, or a unique number per map layer if the feature is present and no value or a null value where it is not present. In this approach, for any data layer being considered, an area is either acceptable for subsurface CO_2 sequestration or eliminated from consideration. We considered other approaches, such as assigning different weights to different layers and applying distance-probability distributions (e.g., to handle nearness to urban areas or known mineral deposits), but for this preliminary assessment of CO_2 sequestration, we considered the binary model to be the most justifiable and easiest to understand.

In our binary model, we assign a “no” value to areas of bedrock and to shallow parts of alluvial basins that are not thick enough to provide a seal against leakage or have sufficient pressure to keep the CO_2 in a condensed phase. We assign a “no” value to areas close to active faults where CO_2 may easily leak from underground injection sites and to areas that in the foreseeable future have a reasonably high probability of being explored and developed for mineral, geothermal, and water resources. We also assign a “no” value to current urban areas and areas that are likely to experience significant population growth during the 21st century, as well as to restricted lands, such as parks and military reservations. In the final GIS analysis, areas assigned an attribute of “no” in any of these GIS layers are combined spatially (unioned) to create the overall area eliminated from further consideration. The remaining area, which was assigned “yes” on every GIS layer, remains as having potential for CO_2 sequestration by disposal in deep brine aquifers.

In this preliminary assessment of the potential for CO_2 disposal by sequestration in geological settings, we use the entire state as the spatial extent. There are two near-term opportunities for CO_2 sequestration in Nevada: EOR and injection into saline aquifers. There are limited opportunities for EOR in oil fields with past production (see section on Petroleum above), and

these are not considered in the GIS analysis. The GIS binary model is restricted to areas that may be amenable to injection into saline aquifers. Alternative approaches for geological sequestration are discussed separately from the GIS binary model.

The primary question asked of the binary model is "where should consideration be given to CO_2 disposal in saline aquifers?" Another way of asking the question is "what areas should be eliminated from consideration for CO_2 disposal in saline aquifers?"

C. Primary Map Layers (Coverages) for the Binary Model

C.1 Nevada State and County Boundaries

The digital 1:1,000,000-scale Nevada State and County boundary coverage, 2nd edition, 1998, produced by the Nevada Bureau of Mines and Geology was extensively used for graphic presentation of data results, primarily on plot maps and graphics used in this report, and as the layer that all of the data sets were clipped to for the special extent of the binary model.

C.2 Geology

We used the digital version of the Stewart and Carlson (1978) Geologic Map of Nevada (Raines and others, 2003) to produce a map that indicates areas of valley fill versus bedrock in Nevada. The original paper map was printed as a single sheet at a scale of 1:500,000, then reprinted as two sheets in 1991. The database by Raines and others (2003), which is reproduced in this report, supercedes earlier published digital versions (Turner and others, 1991, Raines and others, 1996). This database can be queried in many ways to produce a variety of maps. This database is not meant to be used or displayed at any scale larger than 1:500,000 (for example, 1:100,000). Attributes that were selected from the Stewart and Carlson map that indicated areas of valley fill included alluvium, lake deposit, landslide, and playa. These selected attributes were exported into a shape file called "Val_fill" and became the model layer for areas of valley fill. With the exception of alluvium, lake deposit, landslide, playa and water features, all other units were selected and exported as the shape file "Bedrock." This shape file became the model layer for areas of bedrock (Fig. 3). In the binary model, areas of bedrock were not considered for CO_2 sequestration.

C.3 Areas with Greater than One Kilometer of Valley Fill

The U.S. Geological Survey has interpreted gravity data in terms of thickness of valley fill, including alluvium and some Tertiary volcanic rocks (Dohrenwend and others, 1996). We use the 1-km contour in Plate 8 of Dohrenwend and others (1996) to locate deep basins in Nevada, which we define as equal to or more than 1 km in depth. The NBMG Open-File Report from which this coverage came is a large compilation of various data sets that were designed to expand the knowledge base on mineral deposits in Nevada with the end goal of presenting a series of mineral deposit permissive maps for Nevada. The gravity dataset is one of the preliminary coverages that was developed to complete the permissive maps. Because of limitations such as data availability, uneven distribution of data, and model grid size, the overall accuracy of this data set is believed to be plus/minus 250 m (Dohrenwend and others, 1996). The

shape file (Depth_1k.shp) was used to generate Figure 5. In the binary model, only areas greater than 1 km of valley fill were considered for CO_2 sequestration.

The coverage developed in the preceeding step was used to produce a layer showing areas of shallow valley fill. This was done by combining the greater then 1 km of valley fill map with the alluvial cover map, developed earlier in this process from the Stewart and Carlson (1978) Geologic Map of Nevada (Raines and others, 2003). The areas of valley fill that fell outside of the area of greater then 1 km depth were selected and exported to a new shape file (Vf_Shallow.shp). The map layer showing areas with less then 1 km versus greater than or equal to one kilometer of valley fill was then utilized in the model (Fig. 5).

C.4 Faults

Locations of faults that have moved during the Quaternary Period (the last 1.6 million years) were taken from the USGS Quaternary Fault (USGS_QF) database (U.S. Geological Survey, 2004) and NBMG Quaternary Fault (NBMG-QF) database (dePolo, 1999). We used NBMG-QF to identify strike-slip faults that were not attributed as such in the USGS-QF database. This was accomplished by selecting those faults that were within 500 m of identified strike-slip faults within the NBMG-QF database. Faults that fell within 500 m but were attributed as normal faults in the USGS-QF data were not included on the list of strike-slip faults. The strike-slip faults so identified in the USGS-QF database plus those already attributed as strike-slip in the original USGS-QF database, plus those faults shown as strike-slip in the NBMG-QF database were plotted with a 500-m buffer. All other faults from both quaternary fault data sets were plotted with a 1,930-m (1.93-km) buffer. All the buffer maps were then merged into one coverage to create a map layer showing the distribution of areas potentially affected by Quaternary faults in Nevada. A graphic plot of these data showing the buffer areas around the faults combined with the actual location of the faults shown as lines was produced (Fig. 6). In the binary model, areas within these buffers near faults are excluded from consideration for CO_2 sequestration.

C.5 Mineral Resources

The mineral resources layer is a compilation of four data sets. The first data set (Mining_Districts) is the "Mining Districts of Nevada" 2nd edition by Tingley (1998). This is a digital polygon coverage of mining districts in Nevada.

The second data set (NV_MRDS) is the USGS Mineral Resource Data System (MRDS) database from "Nevada Abandoned Mines Database Compilation Update" by Hess (2001). A subset of MRDS data contained in this report was used as a point coverage indicating sites that have had some type of mineral exploration, development, or production. The original MRDS database was created and is still maintained by the USGS. Sand and gravel locations were removed before these data were used.

The third data set (MILS2000) is the Mineral Inventory Lands System (MILS) database from Hess (2001). A subset of MILS data contained in this report was used as a point coverage indicating sites that have had some type of mineral exploration, development, or production. The

original MILS data base was created by the U.S. Bureau of Mines and is no longer being updated. Sand and gravel locations were removed before these data were used.

The fourth data set (Map_120_e) is the "Gold and silver resources in Nevada" database by Davis and Tingley (in review). This map shows locations of deposits with a noted or implied gold and/or silver resource or reserve discovered since 1930. Base-metal and industrial-mineral deposits that contain a significant amount of gold or silver are also shown. This point coverage was used to show locations of known precious metal resources. Significant pre-1930 gold and silver deposits are captured in the second and third data sets.

The second, third, and fourth data sets, all point coverages, were plotted with a 5-km buffer, which takes into account potential location inaccuracies, necessary space to develop a large surface or subsurface mine, and the potential for additional discoveries associated with the known resource. Five kilometers is also within the effective distance of large hydrothermal systems responsible for the formation of most ore deposits in Nevada. Once the point coverages were buffered, all three were combined with the mining district coverage using the union command. Internal polygons were dissolved by aggregating all areas that fell within a buffer or mining district area into single polygons. Portions of those polygons that fell outside of Nevada were clipped to the Nevada State boundary. This became the mineral resource coverage for the model (Fig. 19). In the binary model, areas within the 5-km buffer of known deposits or within a defined mining district were excluded from consideration for CO_2 sequestration.

C.6 Geothermal Resources

The geothermal resource layer is based on the identified geothermal springs and wells found on the Nevada geothermal resources map of Shevenell and Garside (2005). The well and spring locations are available for download as an Excel spreadsheet file. This file was generated into a point shape file and projected to UTM, zone 11, meters, NAD 27 projection. A 20-km buffer was then created around all of the geothermal sites. Twenty kilometers was chosen because this buffer map visually correlated well with previously published resource potential outlined by Trexler and others (1983), and it included most of the moderate to high potential areas suggested by Blackwell and Richards (2004a and 2004b) and Coolbaugh and others (2005, in press). Areas within the 20-km buffer (Fig. 23) were excluded from consideration for CO_2 sequestration in the binary model.

C.7 Deep Carbonate Aquifer

We used the approximate extent of the carbonate-rock province (Deep Carbonate Aquifer) in eastern Nevada as outlined by Thomas and others (1986) in their study of groundwater levels in the Great Basin region of Nevada, Utah, and adjacent states. A shape file was created showing the area identified as being underlain by carbonate rocks and then utilized in the binary model (Fig. 24), wherein areas underlain by the Deep Carbonate Aquifer are excluded from consideration for CO_2 sequestration in saline aquifers.

C.8 Areas of Population

The areas of population layer was developed from three data sets. The first data set, consisting of roads in Nevada, 1998 edition (Roads_10k_buffer.shp), was digitized by the Nevada Bureau of Mines and Geology from 1:500,000-scale source materials. The coverage contains interstate highways, U.S. highways, state highways, and some minor roads. From this coverage, major highways such as Interstates 80 and 15 and sections of United States and State highways near urban areas were selected (see section on Proximity to Urban Areas and Areas of Future Urban Growth). These features were exported to a shape file. A 10-km buffer was created around the selected highways. This selection was made because ongoing rapid growth in Nevada's urban areas tends to follow the major transportation corridors outward from existing communities.

The second data set, showing urban areas as of 2000 (Nv_urban_utm27.shp), was developed by the U.S. Census Bureau. The Nevada data were downloaded as a polygon shape file from the ESRI Web Site (http://www.esri.com/data/download/census2000_tigerline/index.html). All urban areas identified in Nevada where selected and a 30-km buffer was produced around the urban polygons. This was done to include areas of possible future development during the 21st century.

The third data set (Cities.shp) includes digitized point locations for the center of 101 communities in Nevada. This includes many smaller communities not included in the urban areas coverage. A 10-km buffer was developed around these communities.

All three of the above coverages were combined using the union command to form the urban area coverage (People.shp) for use in the model. This combined coverage includes the Las Vegas and Reno-Carson City urban areas, major towns along Interstate 15 and 80, and the communities of Yerington, Ely, Austin, Eureka, and other small Nevada towns (Fig. 25). In the binary model, these areas are excluded from consideration for CO_2 sequestration.

C.9 Restricted Lands

The restricted lands layer was developed from two data sets. The first data set is the "Nevada Lands Status Coverage" developed by the U.S. Bureau of Land Management (2003a). This was designed to display the distribution of land ownership throughout Nevada. It was originally captured for the Bureau of Land Management by the University of Utah, for use with the U.S. Fish and Wildlife GAP Program. The data were updated using the Geographic Coordinate Data Base (GCDB) in 2003. From this data set we selected areas identified as being managed by Department of Defense, Department of Energy (Nevada Test Site), National Park Service, Nevada State lands, and regional parks. These select areas were then exported to a shape file.

The second data set is the "Wilderness Lands of Nevada" developed by the U.S. Bureau of Land Management (2003b). These data represent designated wilderness areas in Nevada administered by the U.S. Department of the Interior - Bureau of Land Management. Late in 2004 the President signed a new law passed by Congress to designate additional land in Lincoln County as wilderness. It is not included in this data set and has not been included in the project analysis. The wilderness lands data set was combined with the shape file created in the step above and

used as the restricted lands coverage for the model (Fig. 26). These restricted lands were excluded from consideration in the binary model.

D. Construction of Model Shape File

All the map layers developed above were merged together using a union command. When supplied with two input shape files (map layers), the union command merges the data so that all the attribute data that are present in the coverages remain spatially intact in the new output shape file. Where the various polygons overlap and the boundaries stay the same, the data are attributed from both data sets to the existing polygon. Where the polygon boundaries do not overlap or only partially overlap, new polygons covering only the area of difference are created in the output shape file and attributed with the data from the specific coverage for that particular area. The first two shape files to be unioned were bedrock and shallow valley fill. These two shape files were then unioned with the Quaternary faults layer followed by the mineral resource layer. This combined file of four layers was then unioned with the carbonate rocks layer and the areas of population layer. This combined layer was then unioned with the restricted lands layer and the geothermal resources layer. This combined shape file was then unioned to the final layer, the one kilometer or greater basin fill coverage.

Typical Boolean operators for query statements include AND, OR, and NOT. Other operators that can be used in query expressions include equals (=), great than (>), less than (<), not equal to (<>), greater than or equal to (>=), and less than or equal to (<=). The final areas identified for potential CO2 sequestration were identified by applying the following compound query: areas **not equal** to BEDROCK and **not equal** to SHALLOW VALLEY FILL and **not equal** to QUATERNARY FAULTS and **not equal** to MINERAL RESOURCES and **not equal** to CARBONATE ROCKS and **not equal** to POPULATION and **not equal** to RESTRICTED LANDS and **not equal** to GEOTHERMAL RESOURCES and **equal** to ONE KILOMETER OR GREATER OF VALLEY FILL.

The above query selected 98 polygons out of a database total of 37,690 polygons (Fig. 29). These 106 polygons collectively have an area of 524 km^2 or less than 0.2 % of the total area of the state's 285,987 km^2. Only four of the 98 polygons are 30 square kilometers or greater in area.

E. Other Coverages

E.1 Oil and Gas Well Database

The Nevada Oil and Gas Well Database (Hess, 2004a) was updated and used to generate a shape file for checking some basin depth information.

E.2 Nevada Abandoned Mines Database Compilation Update.

The Nevada Abandoned Mines Database Compilation Update (file name NV_PTS) contains the digitized locations of mine shaft, prospect, mine tunnel and cave, quarry, and gravel-sand-clay or borrow pit locations from all Nevada 7.5-minute U.S. Geological Survey topographic quadrangles plus sites identified by the Nevada Division of Minerals as hazardous mine site

locations. Each location has an associated record that identifies the map name; symbol type; mining district name determined from Tingley (1998), if within a district; Division of Minerals serial number (for their sites only); land management code, which identifies the site as being on federally managed or private land (location data merged from digital land status coverage supplied by BLM); and UTM (zone 11, NAD27) location coordinates.

This coverage was used during the model definition phase as a possible alternate or additional additive layer indicating areas of potential mineral resources. There are over 100,000 points identified in this data set. Attempts at building this layer into the model, either as a density grid, point coverage, or buffered point coverage, was not practical due to a lack of associated attribute information such as size of workings, production, commodity, reserve, or resource information. We decided not to utilize this data set in the final model. It was, however, used to produce Figure 10, indicating areas of past mineral development and exploration.

E.3 Tracts Permissive for Ore Deposits

The U.S. Geological Survey's analysis of Nevada's metal-bearing mineral resources (Cox and others, 1996a, b, and c) was tested for potential model layers. Specifically, we compared their maps of tracts permissive for three broad types of deposits: epithermal deposits (Fig. 11), pluton-related deposits (Fig. 12), and deposit types not directly related to plutonic activity (Fig. 13).

E.4 Geothermal Resource Maps

We examined the maps of potential geothermal resources by Trexler and others (1983), which was digitally converted by the Idaho National Engineering & Environmental Laboratory (2003), Blackwell and Richards (2004a and 2004b), and Coolbaugh and others (2005, in press). The former map (Fig. 22a) shows the regions favorable for the discovery of thermal water at shallow depth (<1000 m) of sufficient temperature for direct heat applications. This map was reproduced in the Geothermal section of The Nevada Mineral Industry 2003 (Hess, 2004a). Trexler and others (1983) cautioned that although only small areas of this region may be underlain by such thermal water; the region represents that part of the state that deserves further exploration. Local sources of thermal water may be discovered in areas of Nevada not identified in this coverage. Existing data do not document the presence or lack of usable thermal water at shallow depths. The original published map also included data on geothermal well and spring temperatures and known geothermal resource area (KGRA) boundaries that were not included in the digital conversion data set. The Blackwell and Richards (2004a and 2004b) maps (Fig. 22b) rely primarily on bottom-hole temperatures and heat-flow measurements in wells, and the Coolbaugh and others (in press) maps (Fig. 21) is created by combining several GIS layers in a manner that attempts to optimize areas favorable for discovery of geothermal reservoirs capable of being exploited for power generation.

E.5 Power Grid, Power Plant, Pipeline, and Cement and Lime Plant Data

The power grid, power generation, and pipeline data were put together from parts of various data sets supplied by Sierra Pacific Power Company, the Federal Energy Information Administration, the Nevada Public Utilities Commission, and the Western Governors' Association. These data

can be used to identify potential sites within proximity to existing electrical generation or transmission facilities and to generate page size graphics. The cement and limestone production coverage (Cement.shp) was developed from information in the Nevada Mineral Industry 2003 (Castor, 2004) publication. Major CO_2 generators are plotted on Figures 27 and 32, and pipelines and electrical transmission lines are plotted on Figures 28 and 32.

E.6 Railroads and Highways

The railroad coverage was developed and provided by the Nevada Department of Transportation (NDOT). This coverage is an advance draft version; it is part of a larger digital conversion project which is still in the review process and has not been released. The original line coverage with which NDOT started was from the USGS transportation-rail digital line graphs (DLG) for Nevada. NDOT provided additional data and locational update edits from USGS 1:24,000-scale topographic maps in the form of digital raster graphic (DRG) files, USGS digital orthophoto quads (DOQ), and other historical maps georeferenced to the DRGs or DOQs. The NDOT coverage includes active rail lines as well as historic, dismantled, planned, and proposed rail routes. For this project, only active rail lines were utilized in Figures 28 and 32.

Highways (Roads_10k_buffer.shp) were digitized by the NB M G from 1:500,000 scale source materials (1998 version, which is still valid today). These are plotted on Figure 28.

E.7 Mafic and Ultramafic Rocks

Map layers were developed to show areas with potential for chemical reaction of CO_2 with minerals in mafic and ultramafic rocks. We used the digital version of the Stewart and Carlson (1978) Geologic Map of Nevada (Raines and others, 2003) to identify areas associated with mafic rocks. Attributes that were selected from the Stewart and Carlson map included Qtb (Quaternary basalt flows), Tb (Tertiary basalt flows), Tba (Tertiary andesite and basalt flows), Tbg (Tertiary Banbury Formation), Tob (Tertiary older basaltic rocks), Jgb (middle Jurassic gabbroic complex), and Pzsp (serpentinite). These selected units were exported into a shape file (mafic.shp) and became a layer for areas of mafic rocks. Although this layer was not used in the binary analysis, it was used, along with locations of major sources of CO_2 (electric power generation plants and cement and lime plants), major electrical transmission lines, major gas pipelines, and active rail lines, to create Figure 32.

Figure 11. Tracts permissive for epithermal deposits (dark areas, Cox and others, 1996b) .....

Figure 12. Tracts permissive for pluton-related deposits (dark areas, Cox and others, 1996a)

Figure 13. Tracts permissive for deposit types not directly related to plutonic activity (dark areas, Cox and others, 1996c)

Figure 14. Combined tracts permissive for metal-bearing mineral resources (dark areas, derived by combining dark areas from Figs. 11, 12, and 13)

Figure 15. Locations of mining districts (Tingley 1998). Metal-mining districts are shown with dark shading; districts that produced only industrial minerals are shown with light shading

Figure 16. Locations of points (individual mines) in the combined MRDS/MILS database (Source: USGS and U.S. Bureau of Mines) superimposed on the outlines of mining districts (Fig. 15)

Figure 17. Locations of points (individual gold and silver deposits) in the NBMG database on gold and silver resources superimposed on the outlines of mining districts (Fig. 15)

Figure 18. Locations of points (individual gold and silver deposits) in the NBMG database on gold and silver resources superimposed on the 5-km buffers around locations (individual mines) in the combined MRDS/MILS database.

Figure 19. Areas likely to experience mineral-resource development, with the exception of sand and gravel in Nevada (dark areas). This map combines a 5-km buffer around the MRDS/MILS locations with a 5-km buffer around the NBMG database of known gold and silver resources, and outlines of mining districts. Note that a broader area is indicated by the USGS in their analysis of tracts permissive for metal-bearing mineral resources (Fig. 14)

Figure 20. Gray shading indicates areas of reported oil production in Nevada. Black dots indicate oil production wells with greater than 1 km of Quaternary-Tertiary valley fill

Figure 21. Simplified geothermal potential map of Nevada, adapted from Coolbaugh and others (in press). Gray areas have a higher than average probability of hosting high-temperature (greater than or equal to 150°C) geothermal resources compared to the rest of the Great Basin. Circles are known geothermal systems with estimated reservoir temperatures greater than or equal to 150°C.

Figure 22. (a) Areas of potential for geothermal development (gray) according to Trexler and others (1983). (b) Areas of potential for geothermal development (gray) according to Blackwell and Richards (2004b), using their areas with temperatures in excess of 150°C at 4 km depth

Figure 23. Areas excluded from consideration for CO_2 sequestration on the basis of potential geothermal resources. This map uses a buffer of 20 km from the locations of known hot and warm springs, hot and warm wells, and moderate to high heat flow wells shown on NBMG Map 141 (Shevenell and Garside, 2005)

Figure 24. Distribution of the Deep Carbonate Aquifer, the principal deep aquifer in eastern and southern Nevada

Figure 25. Areas of current high population density and areas likely to be developed during the 21st century. The gray areas include a 30-km buffer around major current population centers and a 10-km buffer around highways along which significant development has been taking place

Figure 26. National, Regional, and State Parks, National Recreation Areas, Wilderness Areas, Military Reservations, and the Nevada Test Site

Figure 27. Location of major generators of CO_2 in Nevada [coal- and natural gas-fired power plants (triangles); proposed coal-fired power plants (stars); cement and lime plants (hexagons); and refineries (circles with crosses)]

Figure 28. Major pipelines for petroleum products and natural gas, electrical transmission lines, highways, and railroads

Figure 29. Areas that have the potential for CO_2 waste disposal through geological sequestration in possibly saline aquifers in Nevada. This map is a combination of maps in Figures 3 (eliminating areas in which consolidated rocks of Tertiary age and older crop out), 5 (eliminating areas with less than 1 km of valley fill), 6 (eliminating areas close to Quaternary faults), 19 (eliminating areas likely to experience mineral-resource development), 23 (eliminating areas that are likely to be developed for geothermal resources), 24 (eliminating areas potentially underlain by the Deep Carbonate Aquifer), Population (eliminating current and likely future urban areas), and 26 (eliminating areas in which permission is not likely to be granted)

Figure 30. (a) Major Cenozoic evaporite deposits in the Basin and Range (from Faulds and others, 1997). (b) Generalized geologic map of the Hualapai basin area showing Bouguer gravity contours (10 mgal intervals; from Davis and Conradi 1981) and location of drill holes and cross section (Fig. 31). Cf, Cerbat Range fault; CP; Colorado Plateau; Cr, Cerbat Range; CR, Colorado River; DV, Detrital and southern part of Virgin River depression; GC, Grand Canyon; GT, Grand Wash trough; GV, Grapevine Mesa; HB, Hualapai basin; L, Luke basin; LM, Lake Mead; NGW, northern Grand Wash fault; P, Picacho basin; SGW, southern Grand Wash fault; SL, Great Salt Lake; SV, South Virgin Mountains; WH, White Hills

Figure 31. 1:1 cross section showing the Red Lake salt deposit in the Hualapai basin, northwest Arizona (view is toward the north; from Faulds and others, 1997). Unit patterns: stippled, Proterozoic gneiss; cross-hatched, Paleozoic sedimentary strata; dark gray, Miocene volcanic rocks; black, Miocene sedimentary rocks; light gray, late Miocene-early Pliocene salt deposit; gravel pattern along fault, alluvial fan deposits; white, early Pliocene to recent silt and sand deposits, with minor anhydrite and gypsum at base

Figure 32. Distribution of mafic (magnesium- and iron-rich) rocks (black), major power plants (gray triangles), cement and lime plants (gray hexagons), major electric power transmission lines, pipelines, and rail lines in Nevada

Appendix VIII, Final Report

"Other Emissions" Analysis Spreadsheet: Paper Print-Out

Deliverable associated with Task 2.0, Item 1

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

John Ruby

September 30, 2005

DOE award no. DE-FC26-03NT41984

Prepared by:
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The following constitutes a paper version of the spreadsheet (41984_Task2-Item1.xls) that satisfies the required WESTCARB Phase I deliverable associated with Task 2.0, item 1 ("'other emissions' analysis"). The data and formulae in this spreadsheet are explained in the WESTCARB paper "Life Cycle Assessment of Power Generation Emissions When CO_2 Removal Is Applied".

Select: PLANT, STATE, REGION, FUEL

		PLANT	STATE	REGION	FUEL
		AGUA FRIA	Washington	WESTCARB	Natural Gas
EXISTING					
NET GENERATION CAPACITY MWe		613	1,954	35,921	24,606
GROSS GENERATION CAPACITY, MWe		632	2,056	37,332	25,345
PLANT CAPACITY FACTOR		0.380	0.73	0.51	0.39
ANNUAL GENERATION MWh		2,043,449	12,422,893	159,979,349	84,014,545
PLANT HEAT RATE, Btu/kWh		10,996	10,493	10,565	10,340
INSTALLED CONTROL EQUIPMENT					
SO2 CONTROL, % OF GEN. CAPACITY		0%	0%	20%	0%
NOx CONTROL, % OF GEN. CAPACITY		0%	25%	84%	93%
PRIMARY FUEL		Natural Gas	Portions Below	Portions Below	Natural Gas
COAL		Not Applicable	82.9%	46.0%	Not Applicable
OIL		Not Applicable	1.4%	0.4%	Not Applicable
NATURAL GAS		Not Applicable	15.7%	53.6%	Not Applicable
SO2 EMISSION	Tons Per Year	82	83,777	225,678	847
NOX EMISSION	Tons Per Year	6,103	20,638	202,063	44,783
MERCURY	Lb Per Year	N/A	578	2,554	-
CO2 EMISSION	Tons Per Year	1,333,532	12,102,561	134,300,588	52,171,849

		PLANT	STATE	REGION	FUEL
		AGUA FRIA	Washington	WESTCARB	Natural Gas
RETROFIT					
NET GENERATION CAPACITY MWe		493	1,513	28,432	19,770
GROSS GENERATION CAPACITY, MWe		542	1,699	31,519	21,726
PLANT CAPACITY FACTOR		0.380	0.726	0.512	0.394
ANNUAL GENERATION MWh		1,641,925	9,618,277	129,391,779	72,105,348
PLANT HEAT RATE, Btu/kWh		13,686	13,553	13,063	12,235
INSTALLED CONTROL EQUIPMENT					
SO2 CONTROL, % OF GEN. CAPACITY		0%	0%	20%	0%
NOx CONTROL, % OF GEN. CAPACITY		0%	25%	84%	93%
PRIMARY FUEL		Natural Gas	Portions Below	Portions Below	Natural Gas
COAL		Not Applicable	82.9%	46.0%	Not Applicable
OIL		Not Applicable	1.4%	0.4%	Not Applicable
NATURAL GAS		Not Applicable	15.7%	53.6%	Not Applicable
SO2 EMISSION	Tons Per Year	41	4,269	12,623	423
NOX EMISSION	Tons Per Year	6,103	20,638	202,063	44,783
MERCURY	Lb Per Year	N/A	578	2,554	-
CO2 EMISSION	Tons Per Year	133,353	1,210,256	13,430,059	5,217,185

		PLANT	STATE	REGION	FUEL
		AGUA FRIA	Washington	WESTCARB	Natural Gas
REPLACE LOST CAPACITY					
Net Capacity Lost by Addition of CO2 Removal	MWe	120	440	7,490	4,840
Replacement MWh Required	MWh	401,524	2,804,616	30,587,570	11,909,197
Replacement with Existing GTCC Power	MWe	120	220	3,745	40
Replacement with Existing Pulverized Coal Power	MWe	0	220	3,750	4,800
Replacement Power Emissions					
SO2 EMISSION	Tons Per Year	0	925	10,102	7,791
NOX EMISSION	Tons Per Year	56	1,890	20,637	14,285
MERCURY	Lb Per Year	0	48	525	405
CO2 EMISSION	Tons Per Year	236,743	2,390,235	26,091,035	13,225,760

		PLANT	STATE	REGION	FUEL
		AGUA FRIA	Washington	WESTCARB	Natural Gas
DELTA EMISSIONS					
EXISTING - RETROFIT + REPLACEMENT					
SO2 EMISSION	Tons Per Year	(40)	(78,580)	(202,950)	7,370
NOX EMISSION	Tons Per Year	60	1,890	20,640	14,280
MERCURY	Lb Per Year	N/A	48	525	405
CO2 EMISSION	Tons Per Year	(963,400)	(8,502,100)	(94,779,500)	(33,728,900)

Note: Delta Emissions and some other values are rounded.

		WESTCARB Half NG, Half Coal	WESTCARB All Natural Gas	
REPLACE LOST CAPACITY				
Net Capacity Lost by Addition of CO2 Removal	MWe	7,490	7,490	
Replacement MWh Required	MWh	30,587,570	30,587,570	
Replacement with Existing GTCC Power	MWe	3,745	7,490	
Replacement with Existing Pulverized Coal Power	MWe	3,750	0	
Replacement Power Emissions				**CURRENT**
SO2 EMISSION	Tons Per Year	10,102	0	225,678
NOX EMISSION	Tons Per Year	20,637	4,266	202,063
MERCURY	Lb Per Year	525	0	2,554
CO2 EMISSION	Tons Per Year	26,091,035	18,034,724	134,300,588
DELTA EMISSIONS EXISTING - RETROFIT + REPLACEMENT				
SO2 EMISSION	Tons Per Year	(202,950)	(213,050)	
NOX EMISSION	Tons Per Year	20,640	4,270	
MERCURY	Lb Per Year	525	-	
CO2 EMISSION	Tons Per Year	(94,779,500)	(102,835,800)	

POINT SOURCE	TPY	STATE	
Navajo Generating Station	20,458,265	Arizona	
Centralia	10,484,141	Washington	
Mohave	10,153,106	Arizona	
Cholla	8,350,688	Arizona	
Springerville Generating Station	6,451,073	Arizona	
EGRID Data Power Generation			
BP West Coast Products LLC	2,169,143	California	
Chevron U.S.A. Inc.	2,169,143	California	
BP West Coast Products LLC	1,877,143	Washington	
Chevron U.S.A. Inc.	1,877,143	California	
Williams Alaska Petro Inc.	1,651,285	Alaska	
Estimated From Production Capacity Petroleum Refining			
CEMEX	4,679,282	California	2126.946
Hanson Permanente Cement	2,493,576	California	1133.444
Mitsubishi Cement Corp.	2,624,548	California	1192.976
California Portland Cement Co.	2,199,867	Arizona	999.9397
California Portland Cement Co.	2,093,855	California	951.7524
Estimated From Production Capacity Cement Production			

Select: PLANT, STATE, REGION, FUEL

	PLANT	STATE	REGION	FUEL
	AES ALAMITOS LLC	Washington	WESTCARB	Natural Gas

EXISTING					
NET GENERATION CAPACITY MWe		2,129	1,954	35,921	24,606
GROSS GENERATION CAPACITY, MWe		2,193	2,056	37,332	25,345
PLANT CAPACITY FACTOR		0.347	0.73	0.51	0.39
ANNUAL GENERATION MWh		6,473,582	12,422,893	159,979,349	84,014,545
PLANT HEAT RATE, Btu/kWh		10,279	10,493	10,565	10,340
INSTALLED CONTROL EQUIPMENT					
SO2 CONTROL, % OF GEN. CAPACITY		0%	0%	20%	0%
NOx CONTROL, % OF GEN. CAPACITY		100%	25%	84%	93%
PRIMARY FUEL		Natural Gas	Portions Below	Portions Below	Natural Gas
COAL		Not Applicable	82.9%	46.0%	Not Applicable
OIL		Not Applicable	1.4%	0.4%	Not Applicable
NATURAL GAS		Not Applicable	15.7%	53.6%	Not Applicable
SO2 EMISSION	Tons Per Year	20	83,777	225,678	847
NOX EMISSION	Tons Per Year	1,274	20,638	202,063	44,783
MERCURY	Lb Per Year	N/A	578	2,554	-
CO2 EMISSION	Tons Per Year	3,957,192	12,102,561	134,300,588	52,171,849
SOLID WASTE	Tons Per Year	na	na	na	na
RETROFIT					
NET GENERATION CAPACITY MWe		1,711	1,513	28,432	19,770
GROSS GENERATION CAPACITY, MWe		1,880	1,699	31,519	21,726
PLANT CAPACITY FACTOR		0.347	0.726	0.512	0.394
ANNUAL GENERATION MWh		5,200,610	9,618,277	129,391,779	72,105,348
PLANT HEAT RATE, Btu/kWh		12,794	13,553	13,063	12,235
INSTALLED CONTROL EQUIPMENT					
SO2 CONTROL, % OF GEN. CAPACITY		0%	0%	20%	0%
NOx CONTROL, % OF GEN. CAPACITY		100%	25%	84%	93%
PRIMARY FUEL		Natural Gas	Portions Below	Portions Below	Natural Gas
COAL		Not Applicable	82.9%	46.0%	Not Applicable
OIL		Not Applicable	1.4%	0.4%	Not Applicable
NATURAL GAS		Not Applicable	15.7%	53.6%	Not Applicable
SO2 EMISSION	Tons Per Year	10	4,269	12,623	423
NOX EMISSION	Tons Per Year	1,274	20,638	202,063	44,783
MERCURY	Lb Per Year	N/A	578	2,554	-
CO2 EMISSION	Tons Per Year	395,719	1,210,256	13,430,059	5,217,185
SOLID WASTE	Tons Per Year	na	na	na	na
REPLACE LOST CAPACITY					
Net Capacity Lost by Addition of CO2 Removal	MWe	420	440	7,490	4,840
Replacement MWh Required	MWh	1,272,972	2,804,616	30,587,570	11,909,197
Replacement with Existing GTCC Power	MWe	120	220	3,745	40
Replacement with Existing Pulverized Coal Power	MWe	300	220	3,750	4,800
Replacement Power Emissions					
SO2 EMISSION	Tons Per Year	600	925	10,102	7,791
NOX EMISSION	Tons Per Year	1,149	1,890	20,637	14,285
MERCURY	Lb Per Year	31	48	525	405
CO2 EMISSION	Tons Per Year	1,228,177	2,390,235	26,091,035	13,225,760
SOLID WASTE	Tons Per Year	na	na	na	na
DELTA EMISSIONS					
EXISTING - RETROFIT + REPLACEMENT					
SO2 EMISSION	Tons Per Year	590	(78,580)	(202,950)	7,370
NOX EMISSION	Tons Per Year	1,150	1,890	20,640	14,280
MERCURY	Lb Per Year	N/A	48	525	405
CO2 EMISSION	Tons Per Year	(2,333,300)	(8,502,100)	(94,779,500)	(33,728,900)
SOLID WASTE	Tons Per Year	na	na	na	na

Note: Delta Emissions and some other values are rounded.

EPRI/DOE REPORT		Natural Gas Combined Cycle Case 1A, 90% CO2 Removal	Case 1C, Without CO2 Removal	Factor	
STEAM CYCLE					
Throttle Pressure	psia	1,800	1,800		
Throttle Temperature	F	1,050	1,050		
Reheat Outlet Temperature	F	1,050	1,050		
GROSS POWER SUMMARY	kWe				
Gas Turbine Power		334,892	334,892		
Steam Turbine Power		120,037	194,198	0.143	
Generator Loss		(8,062)	(9,724)		
Gross Plant Power		446,867	519,366	-14.0%	
AUXILIARY LOAD SUMMARY,	kWe				
Condensate Pumps		320	320		
High Pressure Boiler Feed Pump		2,270	2,280		
Misc Balance of Plant		500	500		
Gas Turbine Auxiliaries		600	600		
Steam Turbine Auxiliaries		200	200		
Circulating Water Pumps		1,700	2,810		
Cooling Tower Fans		960	1,600		
					kWe per kWe Gross Plant Power
Flue Gas Blower		22,410	NA	0.043	
MEA CO2 Removal		1,440	NA	0.003	
CO2 Compression and Drying		16,220	NA	0.031	
Transformer Loss		1,370	1,650		
TOTAL AUX POWER REQUIREMENT		47,990	9,960	0.092	
NET PLANT POWER	kWe	398,877	509,406	-22%	
PLANT EFFICIENCY	kWe				
Net Efficiency	%LHV	43.6%	55.6%		
Net Heat Rate	LHV, Btu/kWh	7,839	6,138		
Net Efficiency	%HHV	39.2%	50.1%		
Net Heat Rate	HHV, Btu/kWh	8,699	6,811		
Natural Gas Comsumption	lb/h	158,986	158,986		
Natural Gas LHV	Btu/lb	19,666	19,666		
Natural Gas HHV	Btu/lb	21,824	21,824		
EMISSIONS					
SO2		Negligible	Negligible		
SO2, Unit Rate	lb/MWh				
NOx @ 65% Capacity	tons/year	325	270		
NOx @ 85% Capacity	tons/year	381	360		
NOx, Unit Rate	lb/MWh	0.280	0.190		
CO2 @ 65% Capacity	tons/year	112,266	1,165,200		
CO2 @ 85% Capacity	tons/year	146,809	1,523,740		
CO2, Unit Rate	lb/MWh	98.86	803.20		
REPLACE LOST CAPACITY GTCC					
Net Heat Rate	HHV, Btu/kWh	10,000			
SO2	lb/MWh	-			
NOx	lb/MWh	0.279			
CO2	lb/MWh	1,179			
MERCURY	lb/MWh	-			

Since so coal specific, regional average used. Zero for Natural Gas.

		Case 7A, 90% CO2 Removal	Case 7C, Without CO2 Removal	Factor	
STEAM CYCLE					
Throttle Pressure	psia	3,500	3,500		
Throttle Temperature	F	1,050	1,050		
Reheat Outlet Temperature	F	1050/1050	1050/1050		
GROSS POWER SUMMARY	kWe				
Gas Turbine Power		NA	NA		
Steam Turbine Power		408,089	498,319	0.184	
Generator Loss		(5,835)	(7,211)		
Gross Plant Power		402,254	491,108	-18.1%	
AUXILIARY LOAD SUMMARY,	kWe				
Solids Handling		1,310	1,310		
Pulverizers		1,860	1,860		
Ash Handling		1,670	1,670		
Primary Air Fans,		1,220	1,220		
Forced Draft Fans		970	970		
Induced Draft Fans		19,880	5,050	0.030	kWe per kWe Gross Plant Power
SCR		100	100		
Seal Air Blowers		50	50		
Precipitators		1,000	1,000		
FGD Pumps and Agitators		3,450	3,450		
Condensate Pumps		300	590		
BFW Booster Pump		3,090	2,670		
Misc BOP		2,000	2,000		
Steam Turbine Auxiliaries		400	400		
Circulationg Water Pumps		1,950	3,540		
Cooling Tower Fans		1,110	2,030		
MEA Unit		1,940	NA	0.004	kWe per kWe Gross Plant Power
CO2 Compressor		29,730	NA	0.061	
Transfomer Loss		930	1,140		
TOTAL AUX POWER REQUIREMENT		72,960	29,050	0.089	
NET PLANT POWER	kWe	329,294	462,058	-29%	
PLANT EFFICIENCY	kWe				
Net Efficiency	%LHV	na	na		
Net Heat Rate	LHV, Btu/kWh	na	na		
Net Efficiency	%HHV	28.9%	40.5%		
Net Heat Rate	HHV, Btu/kWh	11,816	8,421		
Coal Comsumption	lb/h	333,542	151,295		
Coal LHV	na	na	na		
Coal HHV	Btu/lb	11,666	11,666		
EMISSIONS					
SO2 @ 85% Capacity	tons/year	1,243	1,243		
SO2, Unit Rate	lb/MWh	1.010	1.010		
NOx @ 65% Capacity	tons/year	1,745	1,745		
NOx @ 85% Capacity	tons/year	2,282	2,282		
NOx, Unit Rate	lb/MWh	1.85	1.85		
CO2 @ 65% Capacity	tons/year	223,303	2,245,430		
CO2 @ 85% Capacity	tons/year	292,011	2,936,330		
CO2, Unit Rate	lb/MWh	237	1,707		
REPLACE LOST CAPACITY PC PLANT					
Net Heat Rate	HHV, Btu/kWh	11,000			
SO2	lb/MWh	1.32			
NOx	lb/MWh	2.42			
CO2	lb/MWh	2,230			
MERCURY	lb/MWh	0.0000343			

Appendix IX, Final Report

Health, Safety, and Environmental Screening and Ranking Framework Spreadsheets: Paper Print-Out

Deliverable associated with Task 2.0, Item 2

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Curtis M. Oldenburg

September 30, 2005

DOE award no. DE-FC26-03NT41984

Prepared by:
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Earth Sciences Division 90-1116
Lawrence Berkeley National Laboratory
Berkeley, CA 94720

Submitted by:
Larry Myer
PIER Program
California Energy Commission
1516 Ninth Street, MS-43
Sacramento, California 95814

The following constitutes a paper version of the spreadsheets (41984_HSE-SRF-RioVista.xls and 41984_HSE-SRF-Ventura.xls) that satisfy the required WESTCARB Phase I deliverable associated with Task 2.0, item 2 ("a risk assessment framework (and related FEPs) for the region"). The data and formulae in this spreadsheet are explained in the WESTCARB paper "Health, Safety, and Environmental Screening and Ranking Framework for Geologic CO_2 Storage Site Selection".

README…..README…..README…..README…..README…..README

Thank you for your interest in the HSE Screening and Ranking Framework (SRF) spreadsheet. We are in a development phase with the framework, and we would very much appreciate feedback of all kinds on this work. As an early user and tester, please send your comments directly to us. All comments, criticisms, suggestions, etc. will be appreciated. Our goal is to improve and extend the spreadsheet to make it as useful as possible.

To get started, open up the spreadsheet in Excel and read the comments under "Basis…" and "Instructions…" on the Summary sheet. User input is expected in light-blue cells. Two already-filled-in spreadsheets are provided as examples to guide you in filling out the spreadsheet for your own site(s).

Thanks in advance for your interest and comments.

-Curt Oldenburg

cmoldenburg@lbl.gov

Geologic Carbon Sequestration HSE Screening and Ranking Framework
Version 1.0

9/24/04 **C.M. Oldenburg (LBNL)** **Last update: 9/20/2005**

Basis... Funded by...

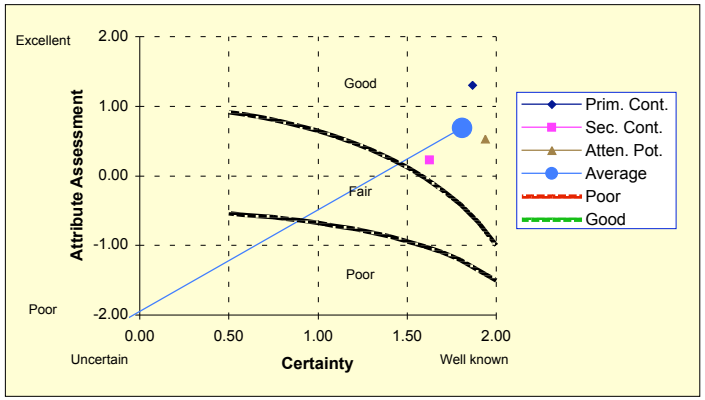
Instructions... Reference...

Disclaimer... Copyright...

Site: Rio Vista Gas Field

Operator: Rosetta Resources

Evaluator (name): Curtis Oldenburg
Affiliation: LBNL
Date: 8/18/04
Revision: 2.0



Contact: Curt Oldenburg
cmoldenburg@lbl.gov

Acknowledgments

Chart Details

Total Average Certainty:	1.81
Total Average Attribute:	0.68
Magnitude of Total Average:	3.24
Prim. Cont. Weighting factor:	1
Sec. Cont. Weighting factor:	1
Atten. Pot. Weighting factor:	1

	Primary Containment		Secondary Containment		Attenuation Potential	
Average of attributes:	1.30	(2 = excellent site; -2 = poor site	0.22	(2 = excellent site; -2 = poor site	0.52	(2 = excellent site; -2 = poor site)
Average certainty:	1.87	(2 = well known; 0.1 = poorly kr	1.63	(2 = well known; 0.1 = poorly kn	1.94	(2 = well known; 0.1 = poorly known)
Overall score:	2.49	(4 = excellent site; -4 = poor site	0.51	(4 = excellent site; -4 = poor site	0.92	(4 = excellent site; -4 = poor site)

Summary comments:

This site has good primary containment. Secondary containment is not as good, but attenuation potential is good. The site is very well characterized.

Sources:

Graham, S.A., ed., Field guide to the mesozoic-cenozoic converg. Margin. Of northern California, Pac. Sec. AAPG, 1981.
Johnson, D.S., Rio Vista Gas Field-USA, in Foster, N.H. and E.A. Beaumont, eds., Atlas of oil and gas fields, Struct. Traps III, AAPG Treatise of Petrol. Geol., Atlas of Oil and Gas Fields, Tulsa, OK, 1990.
Burroughs, E., Rio Vista Gas Field, Summary of Calif. Oil fields, 53, No. 2-Part 2, State of Calif., Dept. of Cons., Div. Oil and Gas, 25, 1967.

8/18/04 **Rio Vista Gas Field** **Revision: 2.0**

Primary Containment

Overall score for this sheet: **2.49**

Average of the weighted assessments of attributes: **1.30**

Average certainty: **1.87**

Attribute	Weight (10 = most importar, 1 = least)	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk (2 = excellent (positive attribute), 0 = neutral (fair attribute), -2 = poor (negative attribute))	Weighted Assessment of Attribute	Certainty Factor (2.0 = Very well known, 1.0 = Generally accepted, 0.1 = Poorly known)
Primary Seal			**Description**				
Thickness	10	0.48	100 m		0	0.00	2
Lithology	5	0.24	Shale		2	0.48	2
Demonstrated sealing	5	0.24	Good seal		2	0.48	2
Lateral continuity	1	0.05	Large areal extent of gas		2	0.10	2
	21	1.00		Average:	1.50	1.05	2.00
Depth			**Description**				
Distance below ground	10	1.00	some v. shallow, but most 1000 m - 3000		2	2.00	2
	10	1.00		Average:	2.00	2.00	2.00
Reservoir			**Description**				
Lithology	1	0.07	Sandstone		2	0.13	2
Perm., poros.	2	0.13	5-1800 mD, 20-34%		2	0.27	2
Thickness	1	0.07	150 m		2	0.13	2
Fracture or primary poros.	1	0.07	Primary		2	0.13	2
Pores filled with...	1	0.07	latural gas and low-TDS water		2	0.13	1
Pressure	1	0.07	Hydrostatic to depleted		1	0.07	1
Tectonics	2	0.13	Growth faults, but not v. active		0	0.00	2
Hydrology	2	0.13	Water drive		0	0.00	1
Deep wells	2	0.13	Many deep wells		-2	-0.27	2
Fault permeability	2	0.13	Trapping faults (low k)		2	0.27	1
	15	1.00		Average:	1.10	0.87	1.60

8/18/04 **Rio Vista Gas Field** **Revision: 2.0**

Secondary Containment

Overall score for this sheet	Average of weighted assessments of attributes	Average certainty
0.51	**0.22**	**1.63**

Attribute	Weight 10 = most importar 1 = least	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk 2 = excellent (positive attribute) 0 = neutral (fair attribute) -2 = poor (negative attribute)	Weighted Assessment of Attribute	Certainty Factor 2.0 = Very well known 1.0 = Generally accepted 0.1 = Poorly known
Secondary Seal			**Description**				
Thickness	10	0.38	150 m (Sidney Flat shale)		0	0.00	2
Lithology	5	0.19	Shale		2	0.38	2
Demonstrated sealing	1	0.04	Gas prod. from multiple horiz.		1	0.04	2
Lateral continuity	5	0.19	Laterally continuous		1	0.19	2
Depth	5	0.19	Sidney Flat shale ~800 m		0	0.00	2
	26	1.00		Average:	0.80	0.62	2
Shallower Seals			**Description**				
Thickness	10	0.33	Thin mudstone		-1	-0.33	1
Lithology	5	0.17	Mudstone		0	0.00	1
Lateral continuity	5	0.17	Extensive		1	0.17	1
Evidence of seepage	10	0.33	Historic gas seeps		0	0.00	2
	30	1.00		Average:	0.00	-0.17	1.25

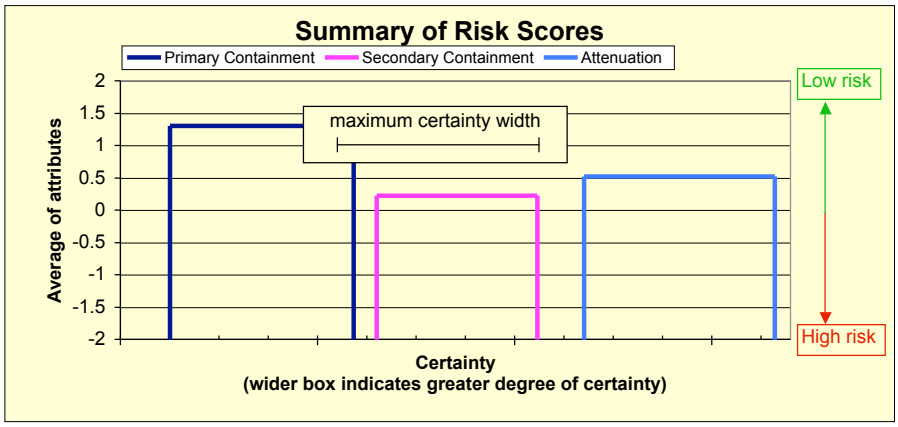
8/18/04 **Rio Vista Gas Field** **Revision: 2.0**

Attenuation Potential

Overall score for this sheet	Average of weighted assessments attributes	Average certainty
0.92	**0.52**	**1.94**

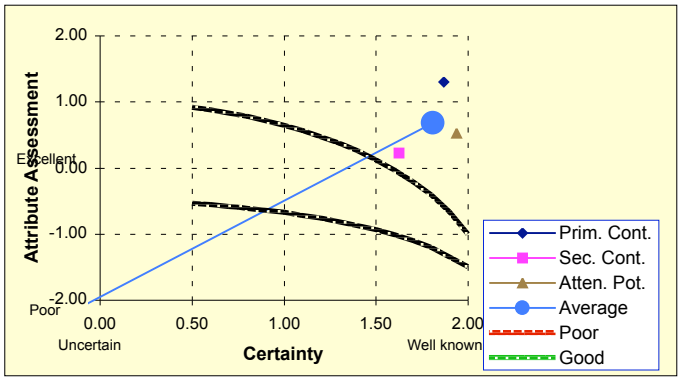
Attribute	Weight (10 = most importar, 1 = least)	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk (2 = excellent (positive attribute), 0 = neutral (fair attribute), -2 = poor (negative attribute))	Weighted Assessment of Attribute	Certainty Factor (2.0 = Very well known, 1.0 = Generally accepted, 0.1 = Poorly known)
Surface Characteristics			**Description**				
Topography	5	0.15	Flat		2	0.30	2
Wind	10	0.30	Windy		2	0.61	2
Climate	2	0.06	Sub-humid		-1	-0.06	2
Land use	4	0.12	Farmland/wetlands		1	0.12	2
Population	10	0.30	Rural		1	0.30	2
Surface water	2	0.06	Perennial wetlands exist		-2	-0.12	2
	33	1.00		Average:	0.50	1.15	2.00
Groundwater Hydrology			**Description**				
Regional flow	6	0.32	/ariable, away from Mont. Hills		1	0.32	2
Pressure	7	0.37	Hydrostatic		0	0.00	2
Geochemistry	2	0.11	Fresh, slightly alk.		2	0.21	2
Salinity	4	0.21	Very low TDS		2	0.42	2
	19	1.00		Average:	1.25	0.95	2.00
Existing Wells			**Description**				
Deep wells	5	0.25	Many deep wells		-2	-0.50	2
Shallow wells	4	0.20	Numerous shallow gw wells		-2	-0.40	2
Abandoned wells	10	0.50	Many abandoned wells.		-2	-1.00	2
Disposal wells	1	0.05	Water is re-injected.		-2	-0.10	2
	20	1.00		Average:	-2.00	-2.00	2.00
Faults			**Description**				
Tectonic faults	10	0.59	No permeable tectonic faults		2	1.18	2
Normal faults	1	0.06	Normal faults form traps		2	0.12	2
Strike-slip faults	1	0.06	Few strike-slip faults		2	0.12	1
Fault permeability	5	0.29	0% of gas plays are fault traps		2	0.59	2
	17	1.00		Average:	2.00	2.00	1.75

0	-2	2.1	-2	4.2	-2
0	1.30	2.1	0.22	4.2	0.52
1.87	1.30	3.73	0.22	6.14	0.52
1.87	-2	3.73	-2	6.14	-2



	uncert.	attrib.	Weighting Factor
prim.	1.87	1.30	1
sec.	1.63	0.22	1
atten.	1.94	0.52	1
			3.00

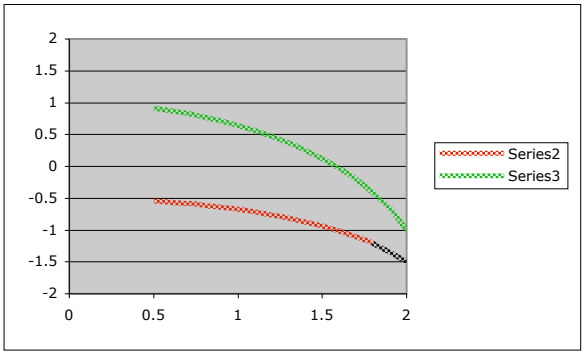
	x(uncert.)	y(attrib.)
centroid	1.81	0.68
	-0.1	-2.1
mag	3.24	



x,y points of arcs or radius r.

r	x	y formula
1.5	0.5	-0.542262
1.5	0.6	-0.561251
1.5	0.7	-0.58402
1.5	0.7499	-0.596852
1.5	0.8	-0.610756
1.5	0.9	-0.641692
1.5	1	-0.677124
1.5	1.1	-0.717424
1.5	1.2	-0.763068
1.5	1.3	-0.814673
1.5	1.4	-0.873057
1.5	1.5	-0.93934
1.5	1.6	-1.015114
1.5	1.7	-1.102782
1.5	1.8	-1.206275
1.5	2	-1.5

1.5	0	-0.5
1.5	0.1	-0.501668
1.5	0.2	-0.506682
1.5	0.3	-0.515076
1.5	0.4	-0.526908



3	0.5	0.915476
3	0.6	0.877499
3	0.7	0.83196
3	0.8	0.778489
3	0.9	0.716616
3	1	0.645751
3	1.1	0.565151
3	1.2	0.473863
3	1.3	0.370654
3	1.4	0.253886
3	1.4999	0.121462
3	1.6	-0.030228
3	1.7	-0.205564
3	1.8	-0.412549
3	1.9	-0.665834
3	2	-1

3	0	1
3	0.1	0.996665
3	0.2	0.986637
3	0.3	0.969848
3	0.4	0.946184

Geologic Carbon Sequestration HSE Screening and Ranking Framework
Version 1.0

9/24/04 **C.M. Oldenburg (LBNL)** **Last update: 9/20/2005**

Basis… Funded by…

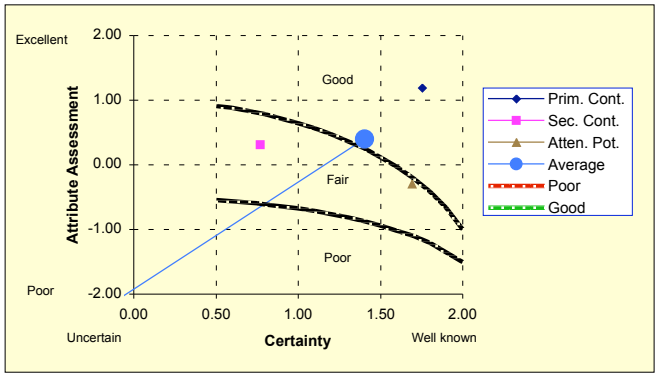
Instructions… Reference…

Disclaimer… Copyright…

Site: Ventura Basin Oil Fields

Operator: AERA, et al.

Evaluator (name): Curtis Oldenburg
Affiliation: LBNL
Date: 8/18/04
Revision: 2.0



Contact: Curt Oldenburg
cmoldenburg@lbl.gov

Acknowledgments

Chart Details

Total Average Certainty:	1.41
Total Average Attribute:	0.40
Magnitude of Total Average:	2.78
Prim. Cont. Weighting factor:	1
Sec. Cont. Weighting factor:	1
Atten. Pot. Weighting factor:	1

	Primary Containment		Secondary Containment		Attenuation Potential	
Average of attributes:	1.19	(2 = excellent site; -2 = poor sit	0.31	(2 = excellent site; -2 = poor sit	-0.29	(2 = excellent site; -2 = poor site)
Average certainty:	1.75	(2 = well known; 0.1 = poorly k	0.77	(2 = well known; 0.1 = poorly kr	1.69	(2 = well known; 0.1 = poorly known)
Overall score:	2.23	(4 = excellent site; -4 = poor sit	0.20	(4 = excellent site; -4 = poor sit	-0.72	(4 = excellent site; -4 = poor site)

Summary comments:

This site has fair attenuation potential, but good primary containment if CO2 is put into existing oil reservoirs. Secondary containment is fair, but not very certain.

Sources:

Sylvester, A.G., and G.C. Brown, Santa Barbara and Ventura Basins, Coast Geol. Soc. Guidebook 64, April 1988.
Link, M.H., Ventura Basin: Geol. Intro. And field trip guidebook, AAPG Pacific Section, 1988.
Harden, D.R., California Geology, Prentice Hall, 479 pp., 1997.

8/18/04 **Ventura Basin Oil Fields** **Revision: 2.0**

Primary Containment

Overall score for this sheet	Average of the weighted assessments of attributes	Average certainty
2.23	**1.19**	**1.75**

Attribute	Weight (10 = most importar, 1 = least)	Normalized Weight	Property/Value	Assessment of Attribute Property Relative to HSE Risk (2 = excellent (positive attribute), 0 = neutral (fair attribute), -2 = poor (negative attribute))	Weighted Assessment of Attribute	Certainty Factor (2.0 = Very well known, 1.0 = Generally accepted, 0.1 = Poorly known)
Primary Seal			**Description**			
Thickness	10	0.48	200 m	1	0.48	2
Lithology	5	0.24	Shale	2	0.48	2
Demonstrated sealing	5	0.24	Good seal where oil is present	2	0.48	1
Lateral continuity	1	0.05	Extensive folding/faulting makes seal loca	0	0.00	2
	21	1.00	Average:	1.25	1.43	1.75
Depth			**Description**			
Distance below ground	10	1.00	some v. shallow, but most 1000 m - 3000	2	2.00	2
	10	1.00	Average:	2.00	2.00	2.00
Reservoir			**Description**			
Lithology	1	0.07	Sandstone	1	0.07	2
Perm., poros.	2	0.13	100 mD, 35%	2	0.27	2
Thickness	1	0.07	50 m	1	0.07	2
Fracture or primary poros.	1	0.07	Primary	2	0.13	2
Pores filled with…	1	0.07	Brine	0	0.00	1
Pressure	1	0.07	Overpressured prior to exploit.	-2	-0.13	1
Tectonics	2	0.13	Very active tectonics	-2	-0.27	2
Hydrology	2	0.13	Not known	0	0.00	0.1
Deep wells	2	0.13	Many deep wells	-2	-0.27	2
Fault permeability	2	0.13	Trapping faults (low k)	2	0.27	1
	15	1.00	Average:	0.20	0.13	1.51

8/18/04 **Ventura Basin Oil Fields** **Revision: 2.0**

Secondary Containment

Overall score for this sheet: **0.20**

Average of weighted assessments of attributes: **0.31**

Average certainty: **0.77**

Attribute	Weight (10 = most importar, 1 = least)	Normalized Weight	Property/Value	Assessment of Attribute Property Relative to HSE Risk (2 = excellent (positive attribute), 0 = neutral (fair attribute), -2 = poor (negative attribute))	Weighted Assessment of Attribute	Certainty Factor (2.0 = Very well known, 1.0 = Generally accepted, 0.1 = Poorly known)
Secondary Seal			**Description**			
Thickness	10	0.38	200 m	0	0.00	1
Lithology	5	0.19	Shale	2	0.38	1
Demonstrated sealing	1	0.04	Oil prod. from multiple horiz.	1	0.04	0.2
Lateral continuity	5	0.19	:ing/folding diminish lateral cont.	-1	-0.19	0.5
Depth	5	0.19	Deep sec. seals are present	2	0.38	0.5
	26	1.00	Average:	0.80	0.62	0.64
Shallower Seals			**Description**			
Thickness	10	0.33	200 m	0	0.00	0.1
Lithology	5	0.17	Shale	2	0.33	1
Lateral continuity	5	0.17	Extensive	2	0.33	0.5
Evidence of seepage	10	0.33	Widespread seepage	-2	-0.67	2
	30	1.00	Average:	0.50	0.00	0.9

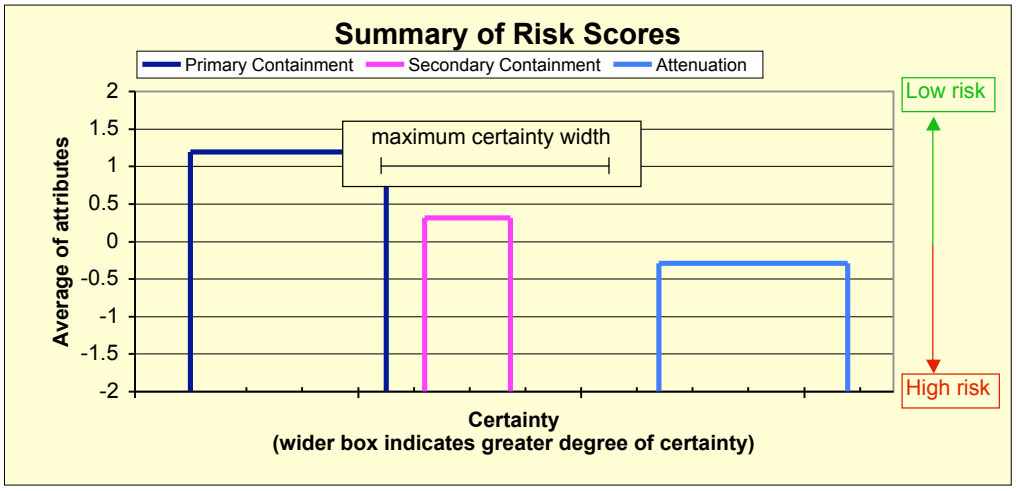
8/18/04 **Ventura Basin Oil Fields** **Revision: 2.0**

Attenuation Potential

Overall score for this sheet	Average of weighted assessments attributes	Average certainty
-0.72	**-0.29**	**1.69**

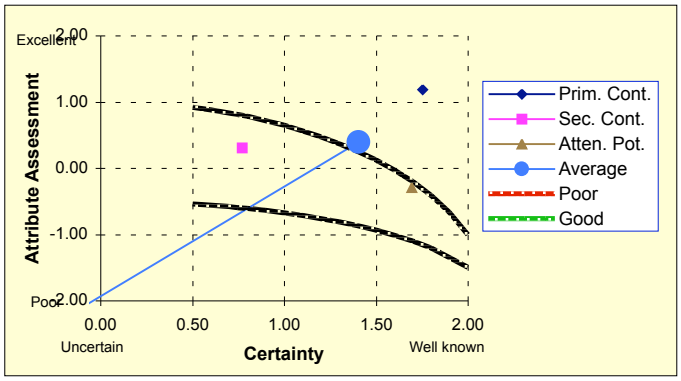
Attribute	Weight (10 = most importar, 1 = least)	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk (2 = excellent (positive attribute), 0 = neutral (fair attribute), -2 = poor (negative attribute))	Weighted Assessment of Attribute	Certainty Factor (2.0 = Very well known, 1.0 = Generally accepted, 0.1 = Poorly known)
Surface Characteristics			**Description**				
Topography	5	0.15	Mountainous		-2	-0.30	2
Wind	10	0.30	Moderately windy		0	0.00	2
Climate	2	0.06	Semi-arid		1	0.06	2
Land use	4	0.12	Open range		2	0.24	2
Population	10	0.30	Rural		1	0.30	2
Surface water	2	0.06	Dry except in streams		2	0.12	2
	33	1.00		Average:	0.67	0.42	2.00
Groundwater Hydrology			**Description**				
Regional flow	6	0.32	To the southwest		0	0.00	1
Pressure	7	0.37	Hydrostatic		0	0.00	0.1
Geochemistry	2	0.11	Alkaline		2	0.21	1
Salinity	4	0.21	Low		1	0.21	1
	19	1.00		Average:	0.75	0.42	0.78
Existing Wells			**Description**				
Deep wells	5	0.25	Many deep wells		-2	-0.50	2
Shallow wells	4	0.20	Few shallow gw wells		2	0.40	2
Abandoned wells	10	0.50	Many abandoned wells.		-2	-1.00	2
Disposal wells	1	0.05	No disposal wells.		-2	-0.10	2
	20	1.00		Average:	-1.00	-1.20	2.00
Faults			**Description**				
Tectonic faults	10	0.59	Tectonic faults present		-2	-1.18	2
Normal faults	1	0.06	Many normal faults		-2	-0.12	2
Strike-slip faults	1	0.06	Many strike-slip faults		-2	-0.12	2
Fault permeability	5	0.29	Trapping faults (low k)		2	0.59	2
	17	1.00		Average:	-1.00	-0.82	2.00

0	-2	2.1	-2	4.2	-2
0	1.19	2.1	0.31	4.2	-0.29
1.75	1.19	2.87	0.31	5.89	-0.29
1.75	-2	2.87	-2	5.89	-2



	uncert.	attrib.	Weighting Factor
prim.	1.75	1.19	1
sec.	0.77	0.31	1
atten.	1.69	-0.29	1
			3.00

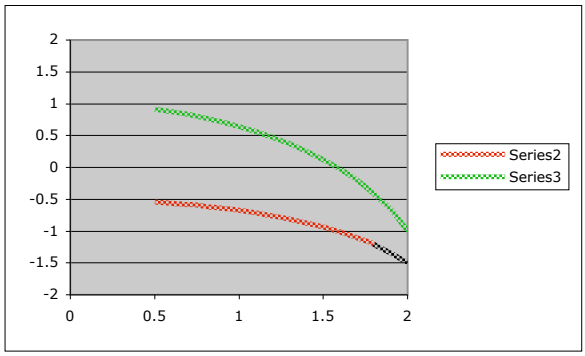
	x(uncert.)	y(attrib.)
centroid	1.41	0.40
	-0.1	-2.1
mag	2.78	



x,y points of arcs or radius r.

r	x	y formula
1.5	0.5	-0.542262
1.5	0.6	-0.561251
1.5	0.7	-0.58402
1.5	0.7499	-0.596852
1.5	0.8	-0.610756
1.5	0.9	-0.641692
1.5	1	-0.677124
1.5	1.1	-0.717424
1.5	1.2	-0.763068
1.5	1.3	-0.814673
1.5	1.4	-0.873057
1.5	1.5	-0.93934
1.5	1.6	-1.015114
1.5	1.7	-1.102782
1.5	1.8	-1.206275
1.5	2	-1.5

1.5	0	-0.5
1.5	0.1	-0.501668
1.5	0.2	-0.506682
1.5	0.3	-0.515076
1.5	0.4	-0.526908



3	0.5	0.915476
3	0.6	0.877499
3	0.7	0.83196
3	0.8	0.778489
3	0.9	0.716616
3	1	0.645751
3	1.1	0.565151
3	1.2	0.473863
3	1.3	0.370654
3	1.4	0.253886
3	1.4999	0.121462
3	1.6	-0.030228
3	1.7	-0.205564
3	1.8	-0.412549
3	1.9	-0.665834
3	2	-1

3	0	1
3	0.1	0.996665
3	0.2	0.986637
3	0.3	0.969848
3	0.4	0.946184

Appendix X, Final Report

Permitting and Regulatory Issues Compilation

Deliverable associated with Task 2.0, Item 3

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

September 30, 2005

DOE award no. DE-FC26-03NT41984

Submitted by:
Larry Myer
PIER Program
California Energy Commission
1516 Ninth Street, MS-43
Sacramento, California 95814

The following constitutes the required WESTCARB Phase I deliverable associated with Task 2.0, item 3 ("a Web-based compilation of regulations and permits"). This hyperlinked document is available on the WESTCARB web site: http://www.westcarb.org/pdfs/PermitRegIssues.pdf.



Permitting and Regulatory Issues Compilation

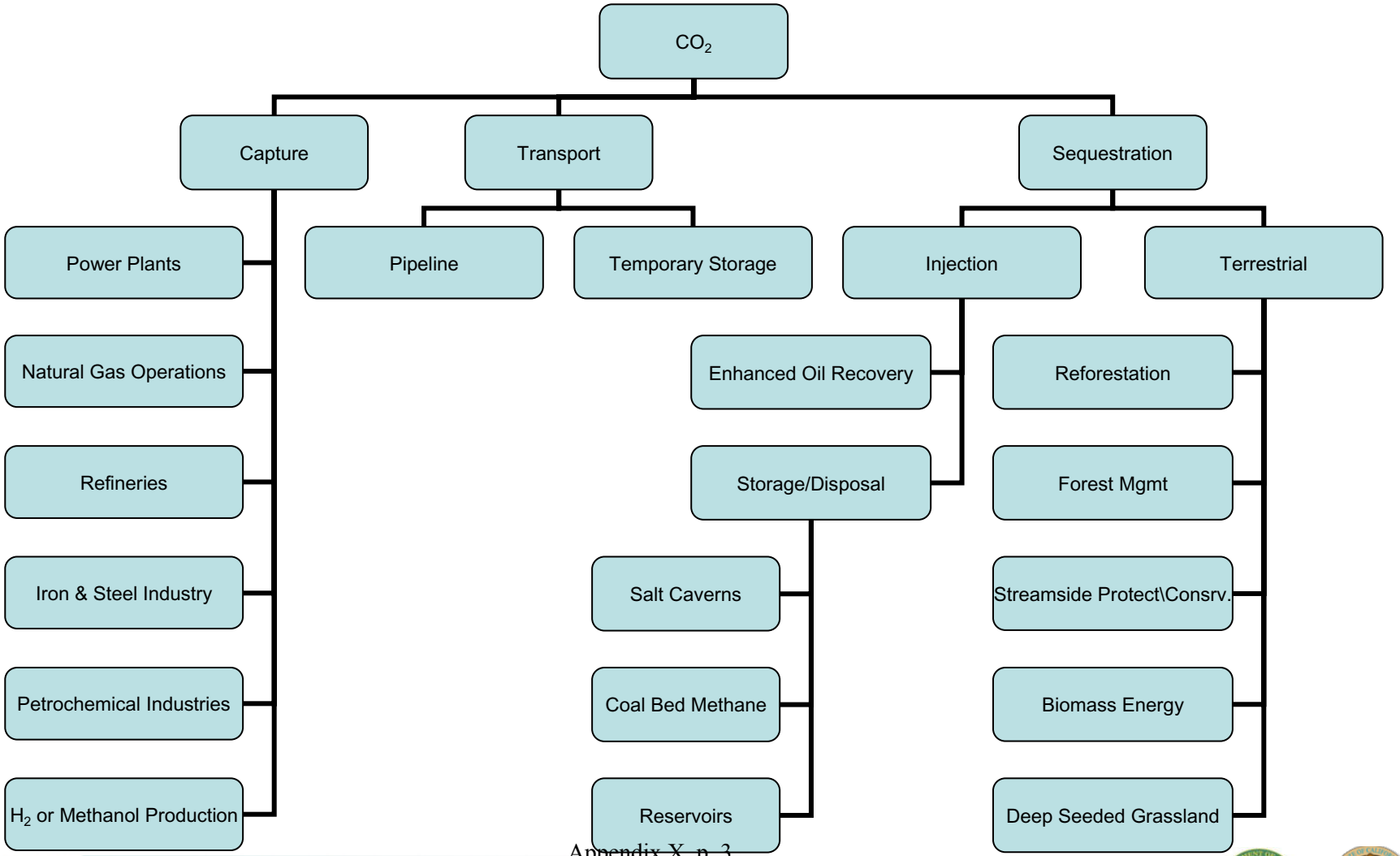
State-by-State Analysis for Geologic (Transportation and Injection) and Terrestrial Sequestration

Jean Young, Mike Bruno
Terralog Technologies USA, Inc.
Arcadia, CA

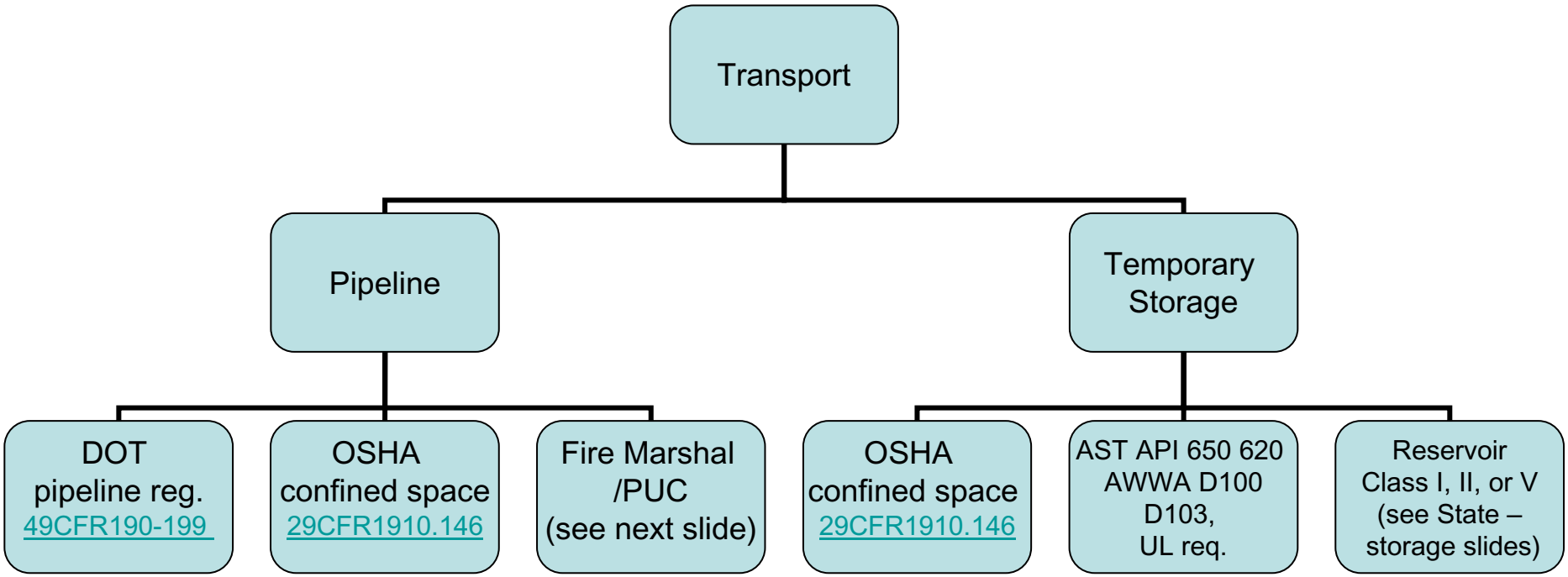
August 2005

CO_2 From Capture to Sequestration

West Coast Regional Carbon Sequestration Partnership



CO_2 Transport



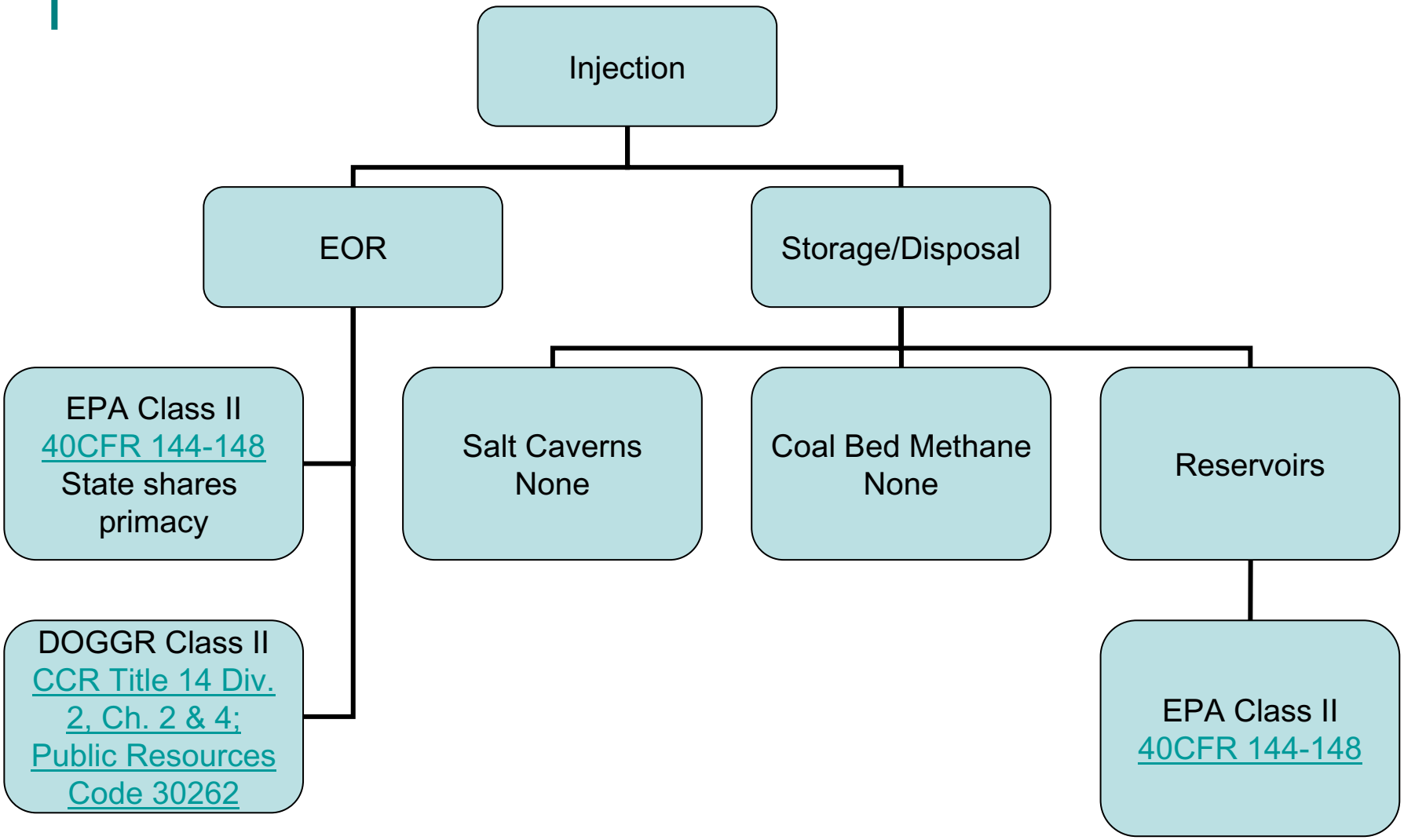
Fire Marshal/PUC State Regulations

- AK defers to DOT 49CFR 195
- AZ ACC, R14-5-201 to R14-5-205
- CA Fire Marshal Gov Code Sec 51010 to 51019.1, AB 592, DOG Pipeline regulations
- NV PSC NAC 704.455 to 704.465, DOT 49CFR 195
- OR PUC Div 31 860-031-0001 to 860-031-0040, DOT 49CFR 195
- WA UTC ESSHB 2420 Ch 191 Laws of 2000, RCW Ch 81.11, DOT 49CFR 195

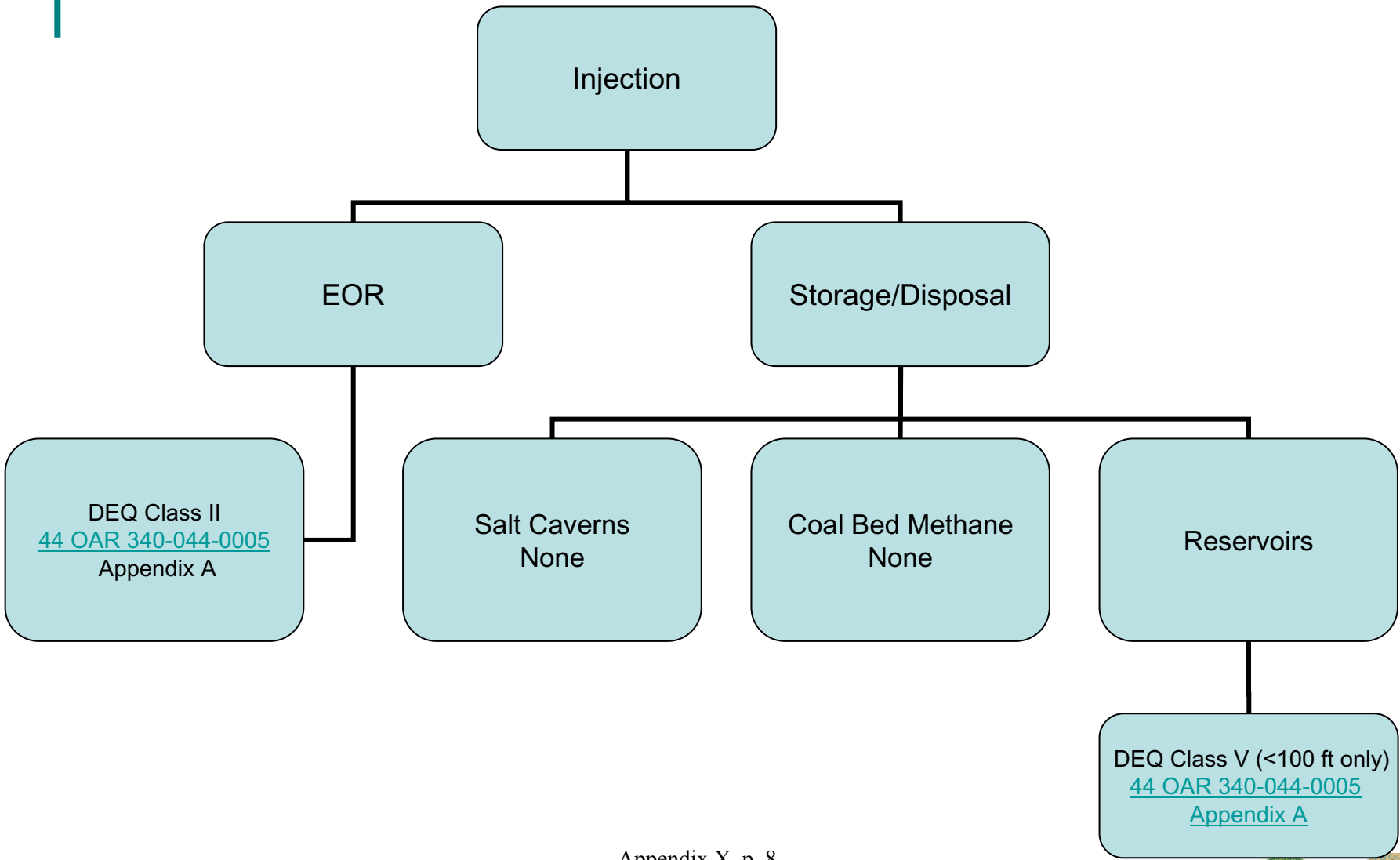
CO_2 Injection Classification Definition

- Definition of CO_2 as waste or product to be decided by EPA and states. Classification is of lesser importance than regulatory operations concern.
- EOR wells as Class II – classified as product in 6 states
- Salt Cavern – AZ Class I
- Coalbed Methane (not related to EOR)– AZ Class I
  AK Class V
  WA Class V

California Injection Options



Oregon Injection Options



Arizona Salt Deposits

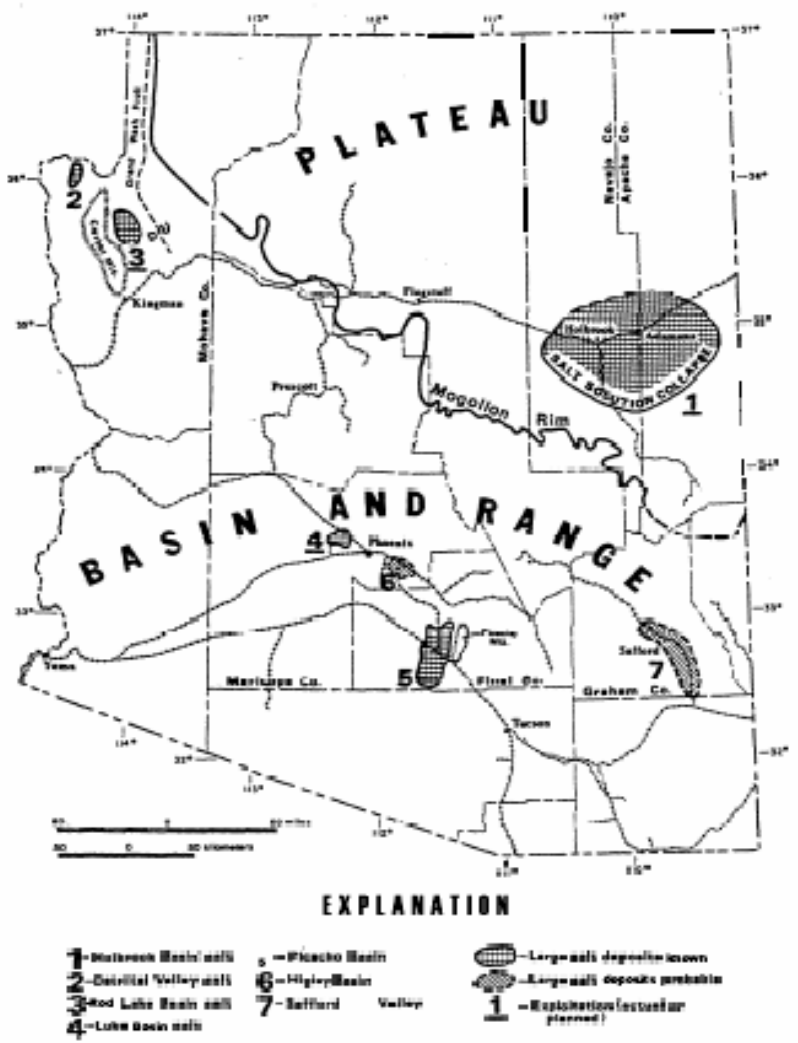
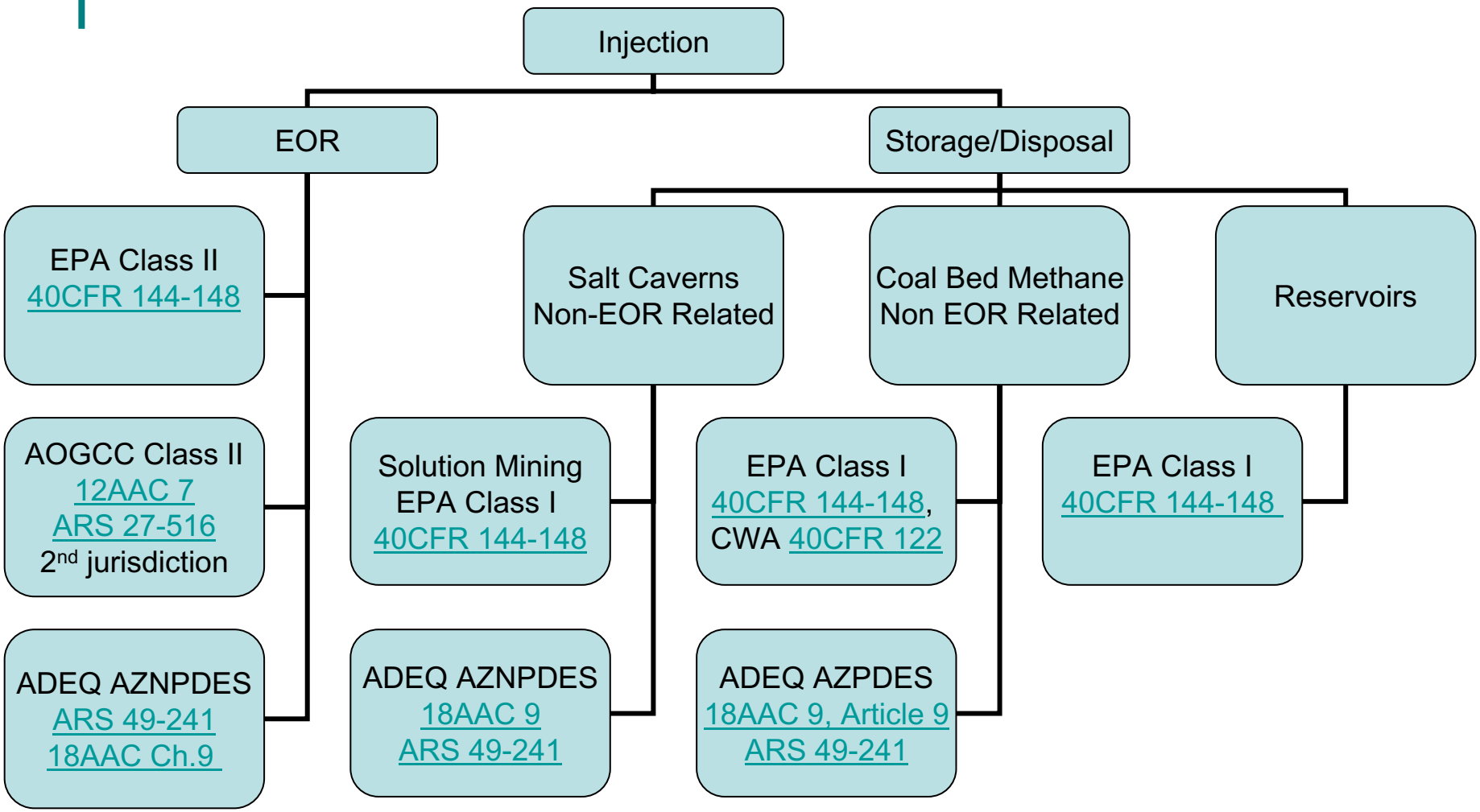


Figure 1. Index to Arizona Salt Deposits and Location of Railroads.

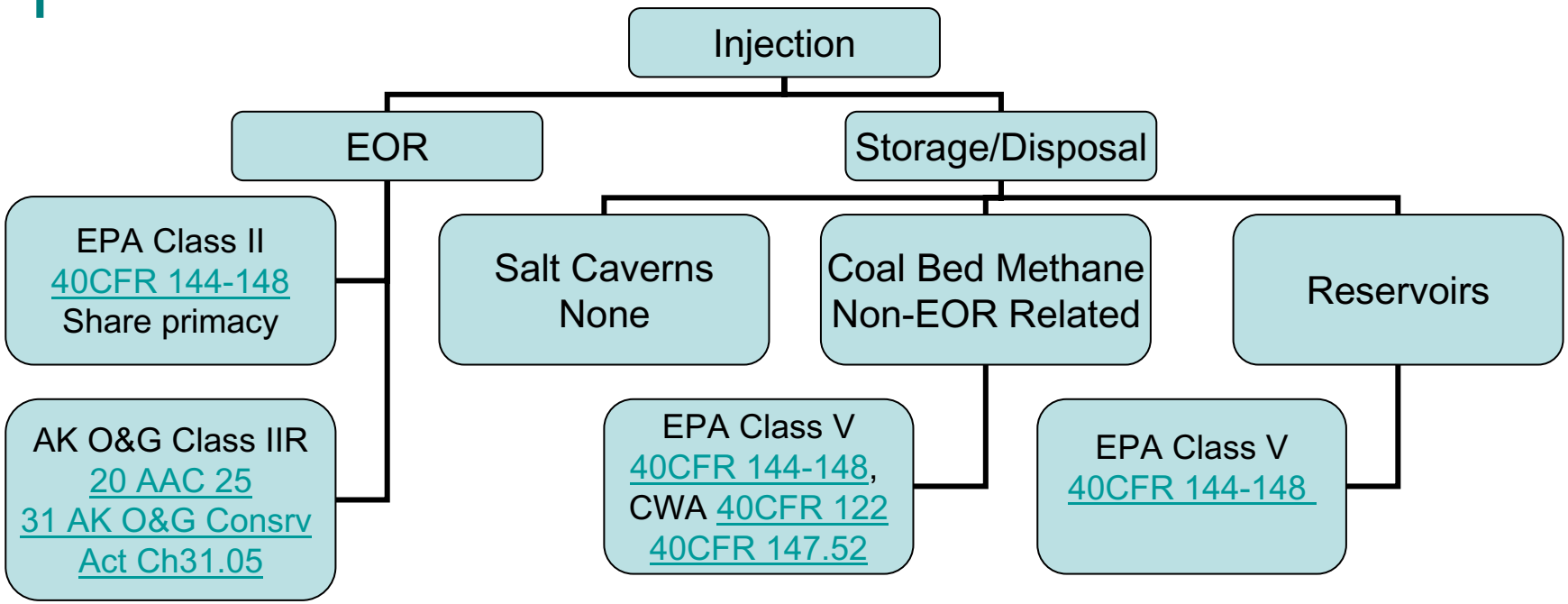
Source: Neal, J.T., 1996, Storage Opportunities in AZ Bedded Evaporites,

SMRI

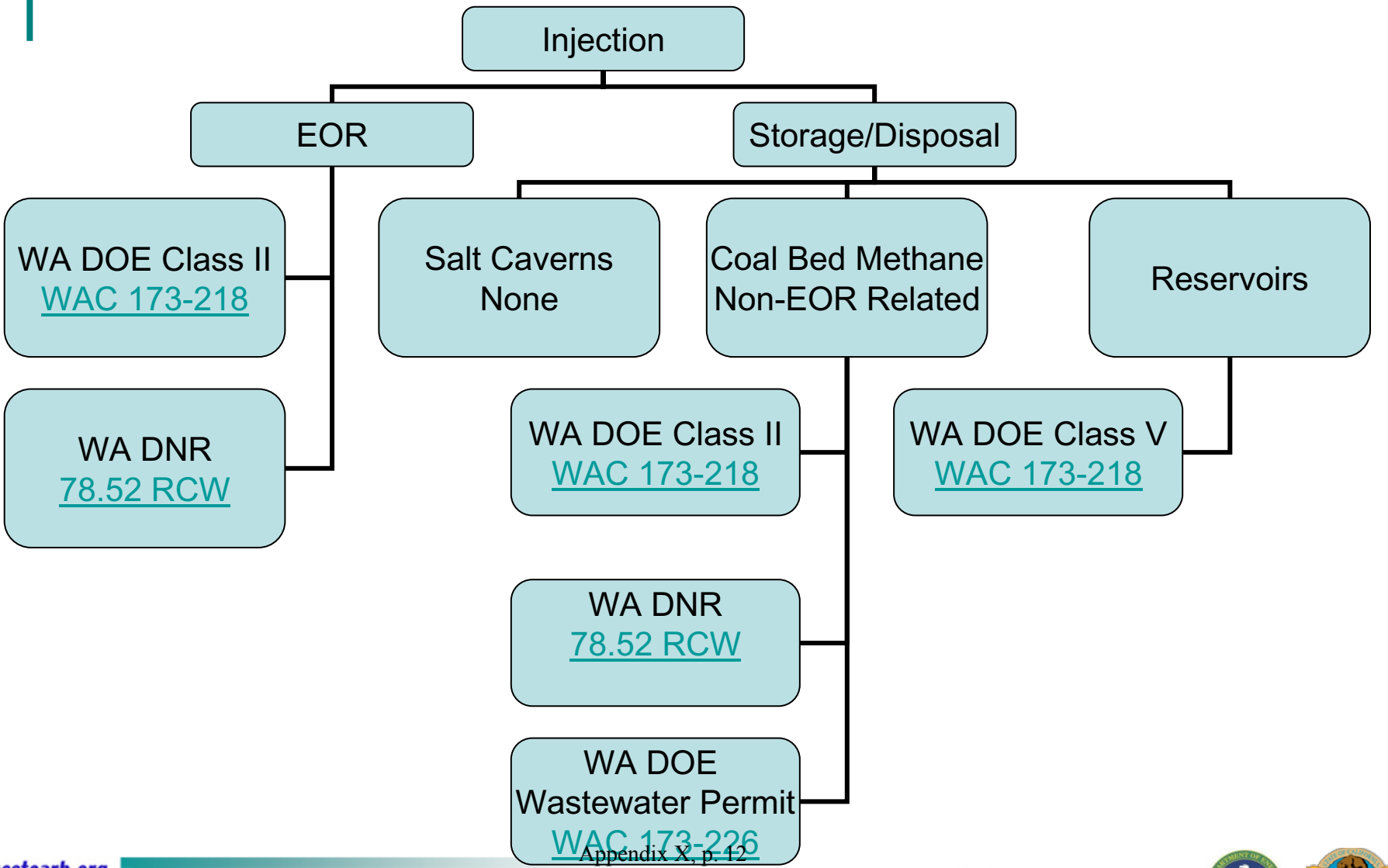
Arizona Injection Options



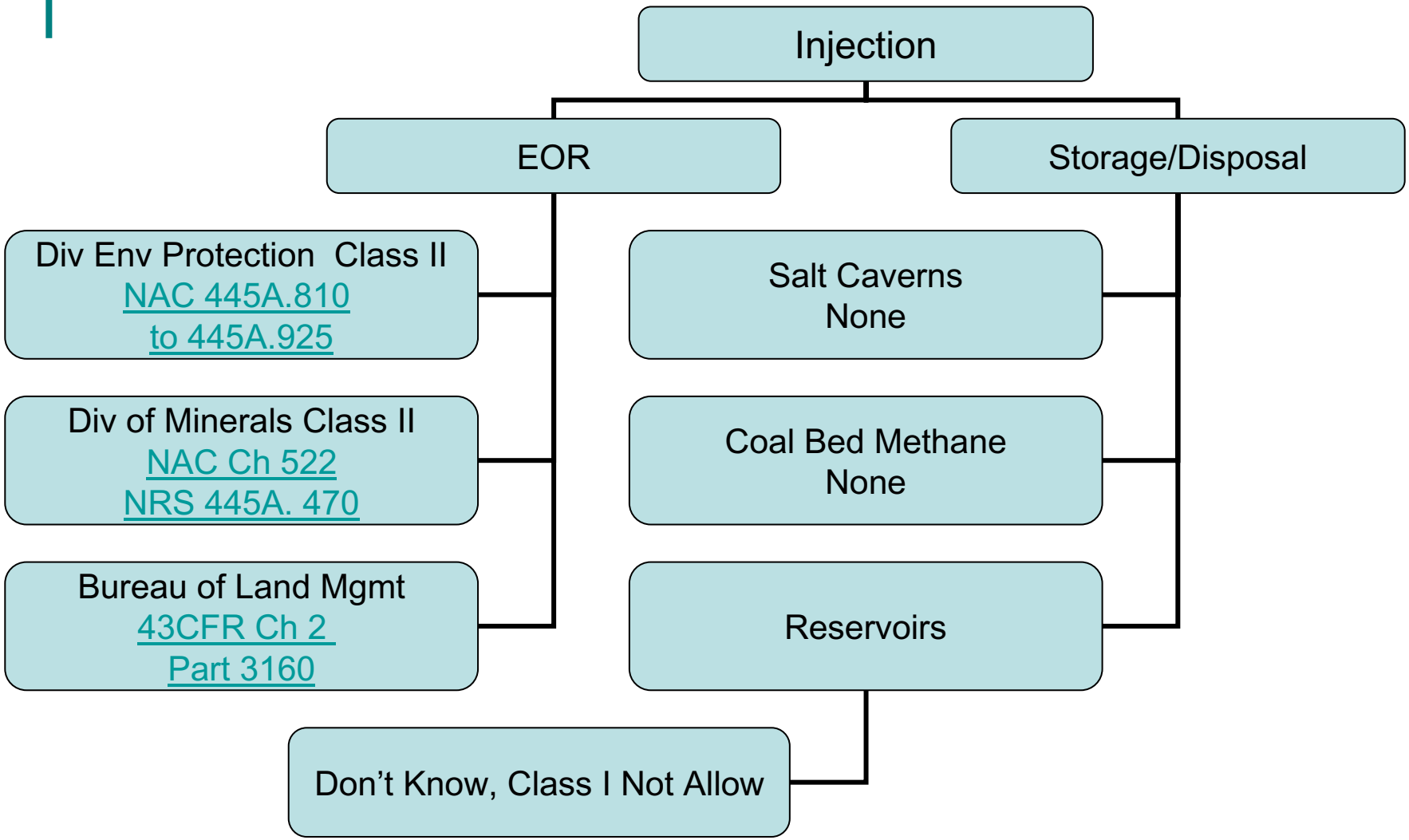
Alaska Injection Options



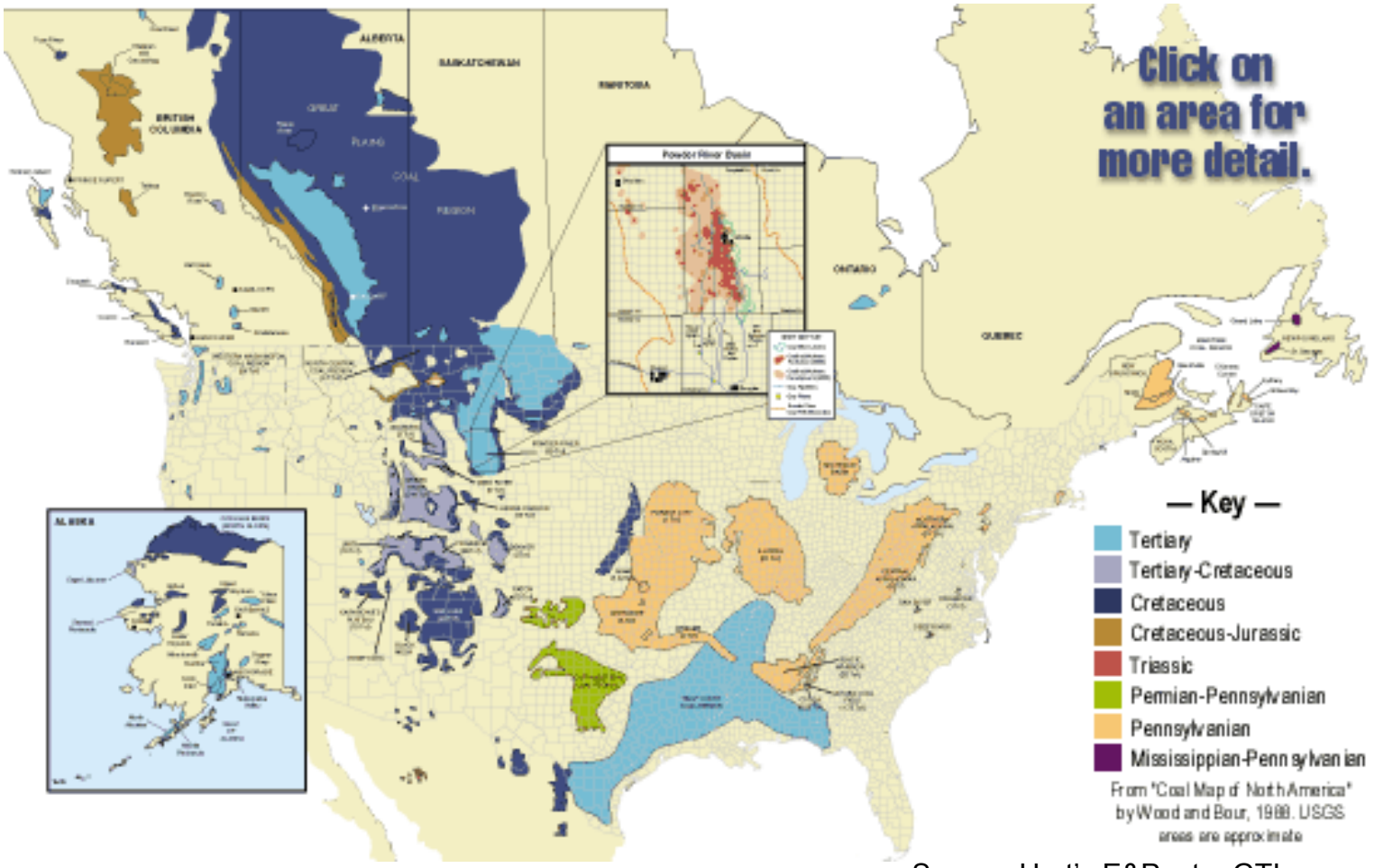
Washington Injection Options



Nevada Injection Options



North America Coal Bed Methane Resource Map



Source: Hart's E&Pnet – GTI
www.eandpnet.com/cbm

Terrestrial CO_2 Strategies

- Carbon conservation
  - Maintain forest land base (e.g., forest reserves and conservation)
  - Reduced deforestation
  - Modified forest management (e.g., extending rotation)
  - Reduced degradation (e.g., protect forests from fires and pests)
- Carbon substitution
  - Biomass for energy generation
  - Substitution for fossil-fuel-based products
  - Urban forestry (e.g., energy conservation)
- Carbon sequestration and storage
  - Afforestation/reforestation
  - Urban forestry (e.g., carbon storage through tree growth)
  - Agroforestry
  - Forest management (include commercial forestry)

Source: Vine, Edward, 2003, Regulatory Constraints to Carbon Sequestration in Terrestrial Ecosystems and Geologic Formations: A California Perspective

Top 4 Terrestrial CO_2 Sequestration Options

- Reforestation of under-producing lands (include streamside forest restoration)
- Forest management
- Forest protection and conservation
- Hazard wildfire fuel treatments/Biomass energy

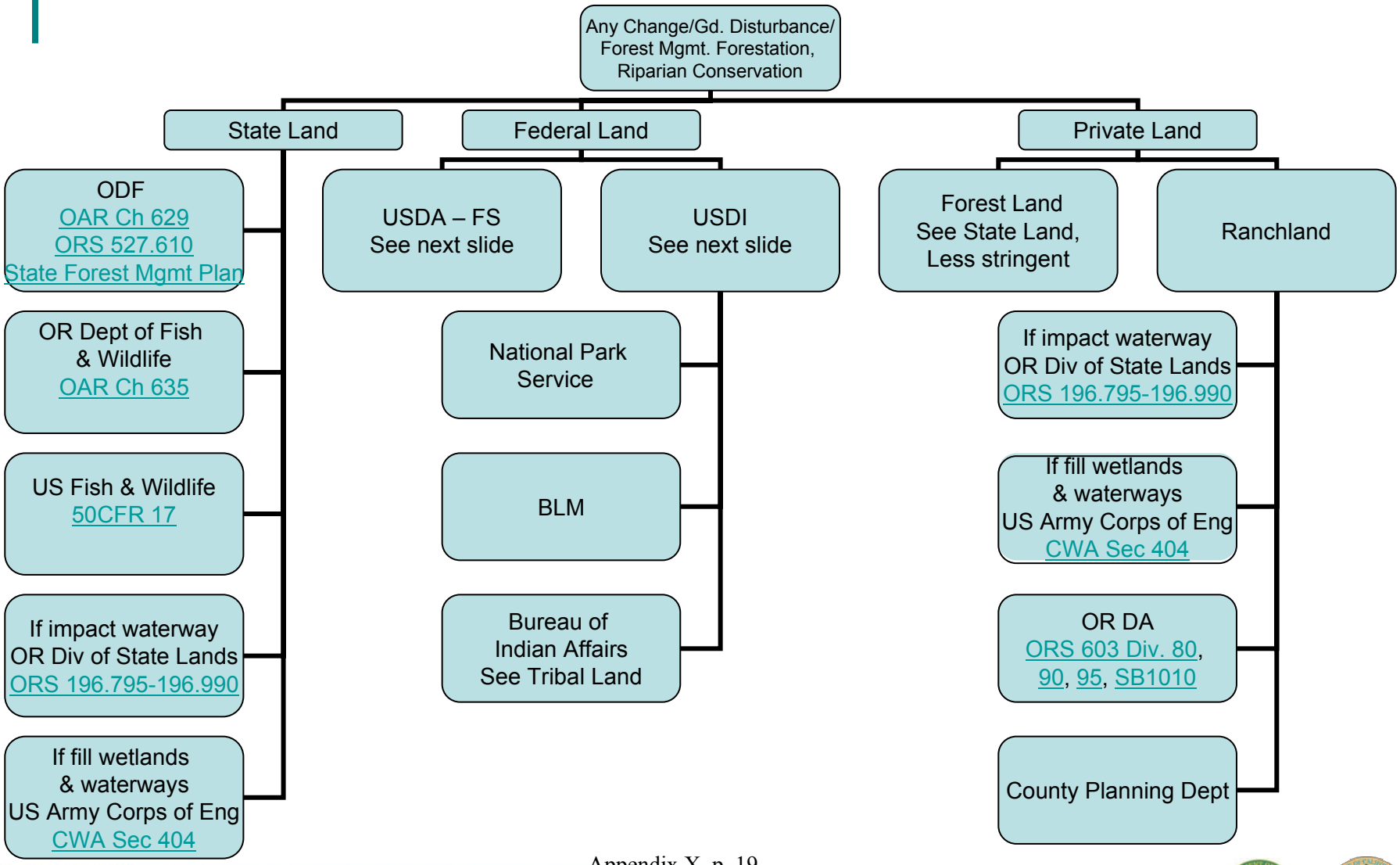
Federal Land Management

- U.S. Dept. of Agriculture
  - Forest Service
- U.S. Dept. of Interior
  - Bureau of Land Management
  - National Park Service

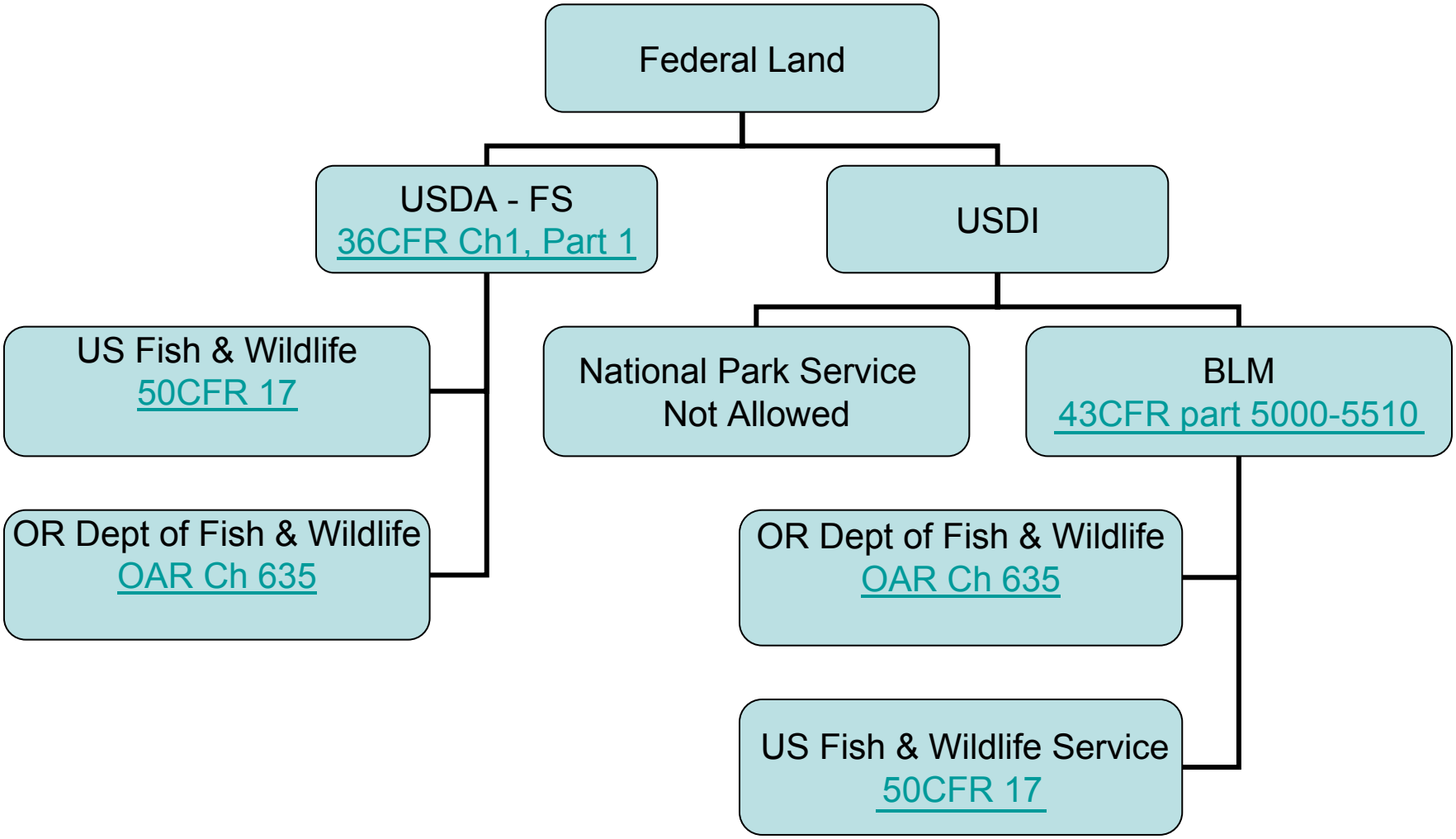
Tribal Land Management

- Sovereign Tribal Government
- U.S. Dept. of Interior
  - Bureau of Indian Affairs

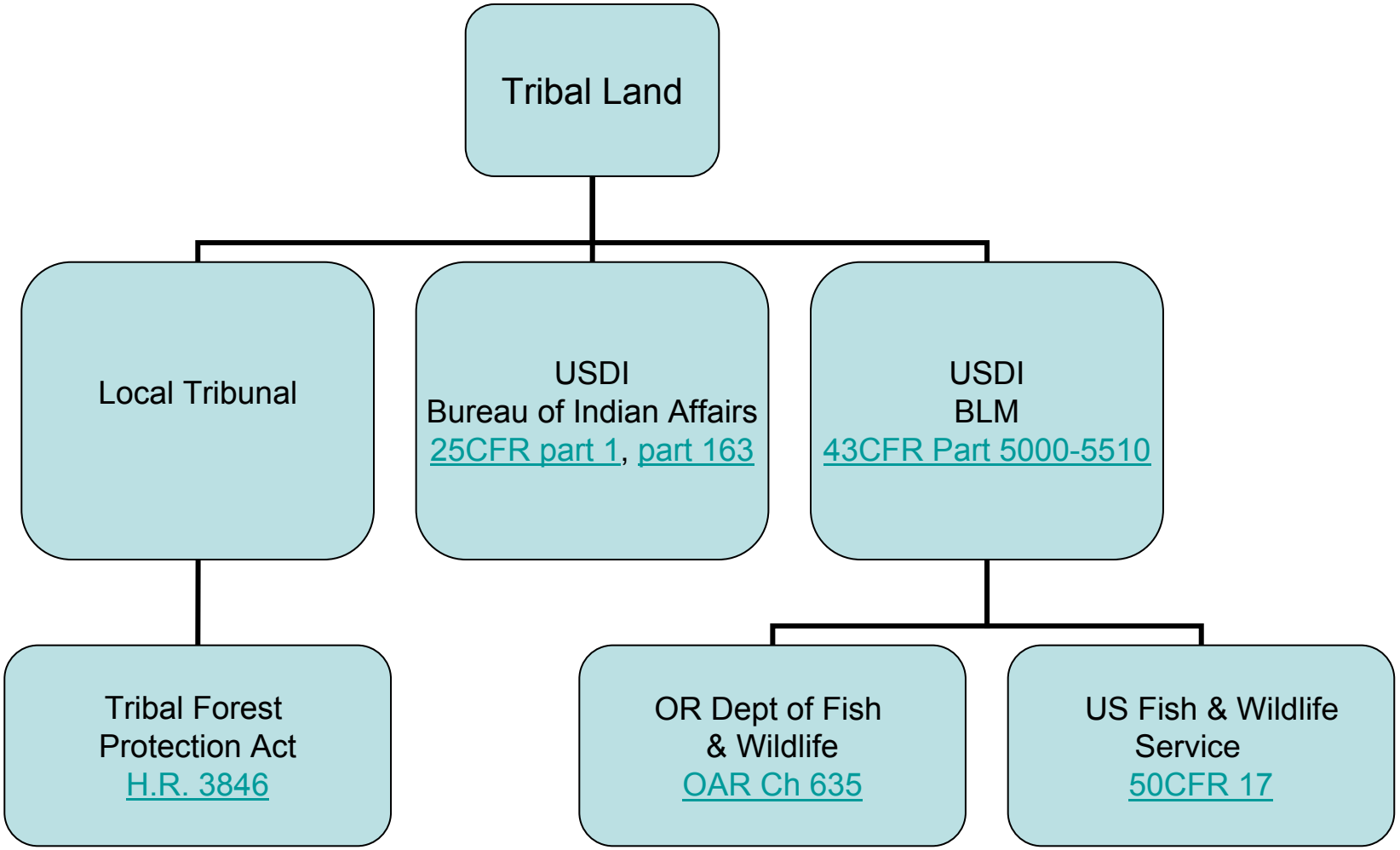
Oregon Terrestrial Options



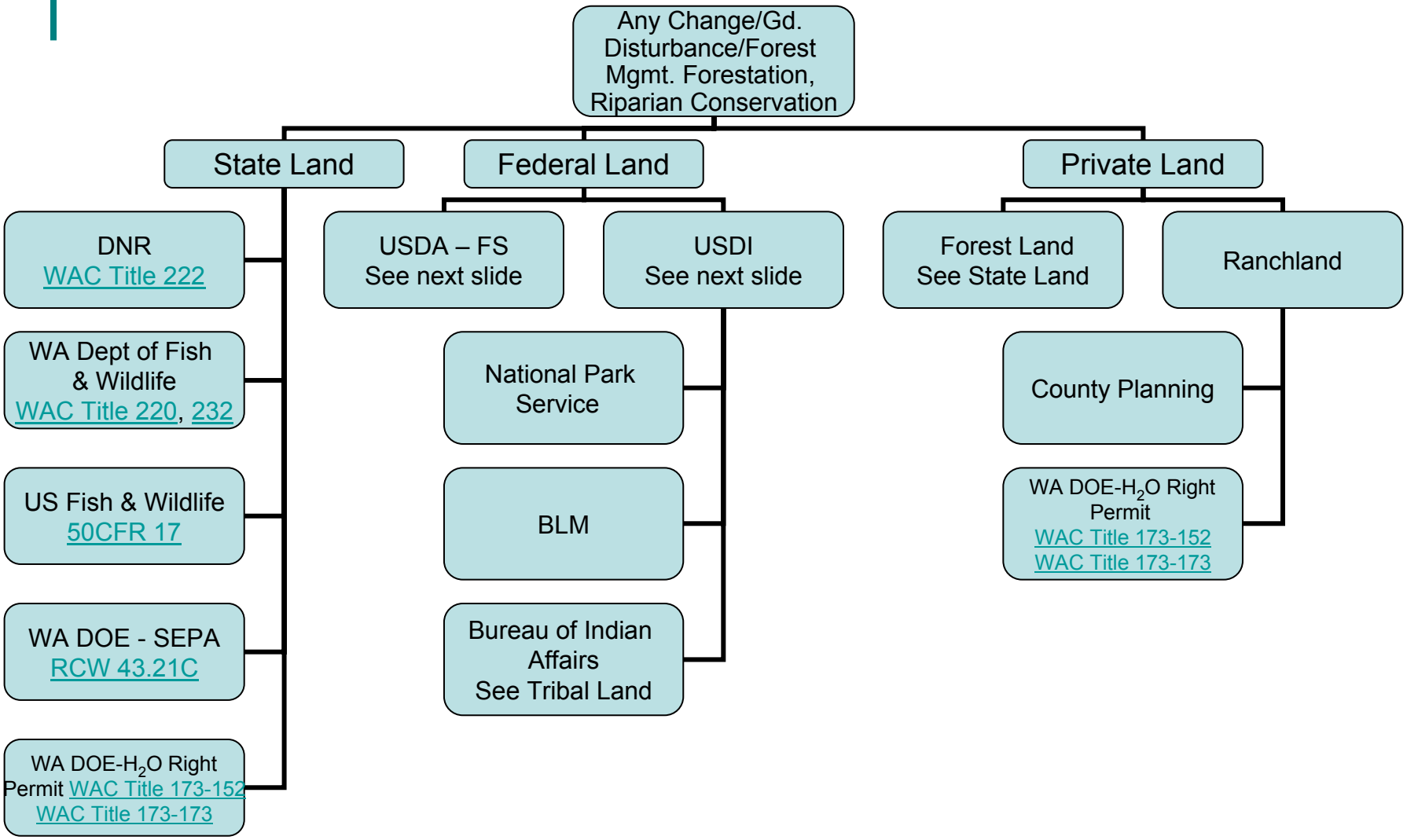
Oregon Federal Land



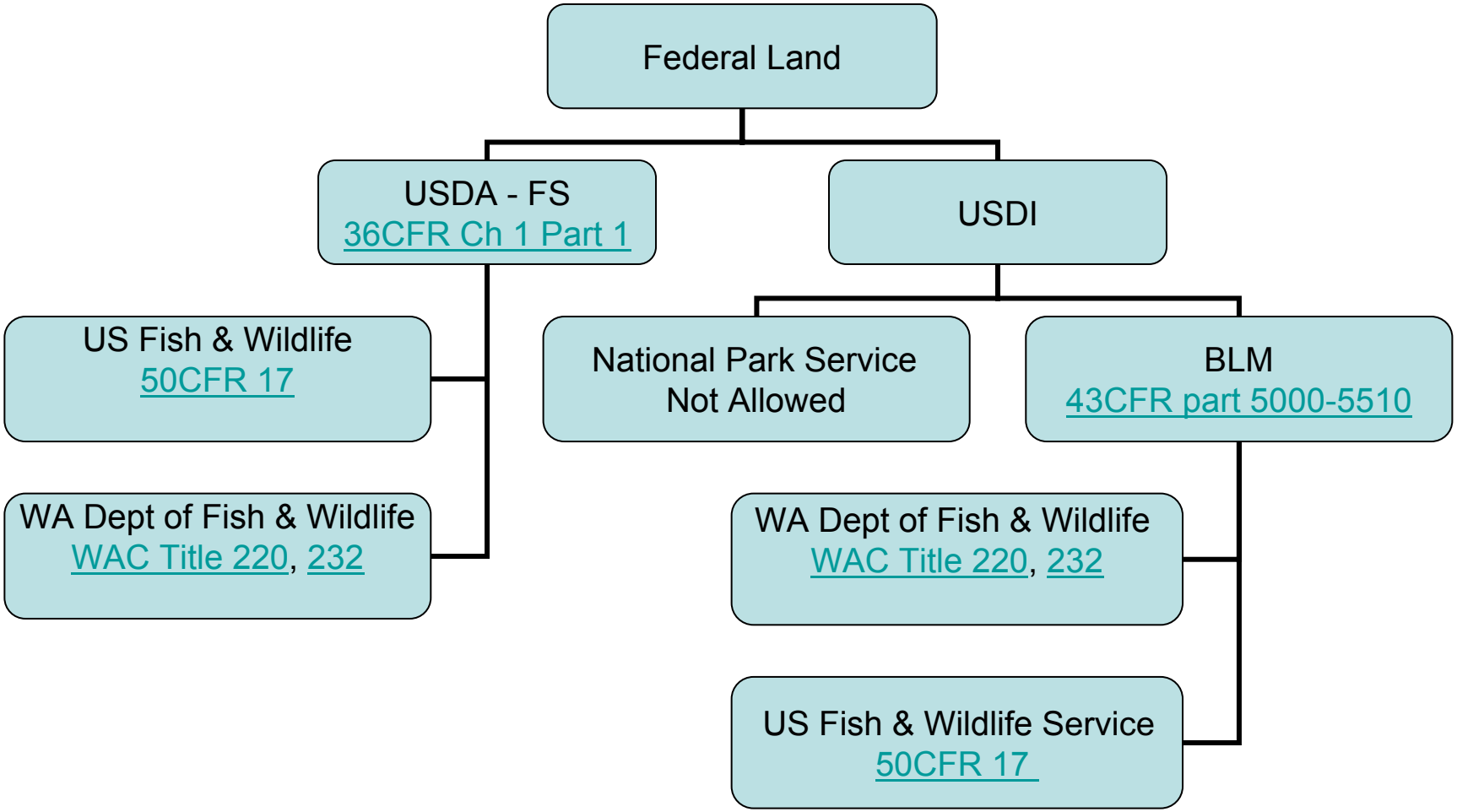
Tribal Land


Tribal Land
Local Tribunal
USDI
Bureau of Indian Affairs
25CFR part 1, part 163
USDI
BLM
43CFR Part 5000-5510
Tribal Forest
Protection Act
H.R. 3846
OR Dept of Fish
& Wildlife
OAR Ch 635
US Fish & Wildlife
Service
50CFR 17

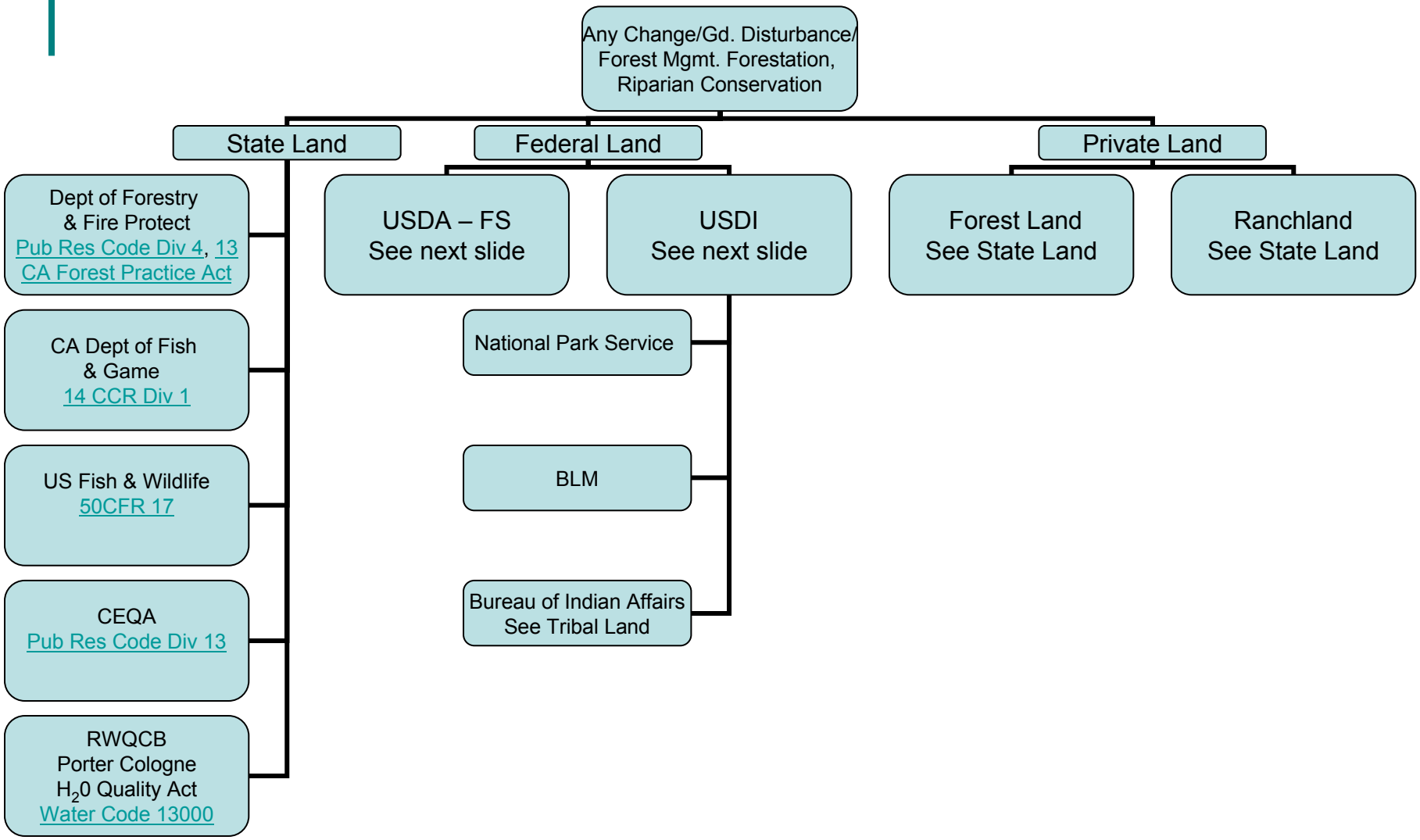
Washington Terrestrial Options



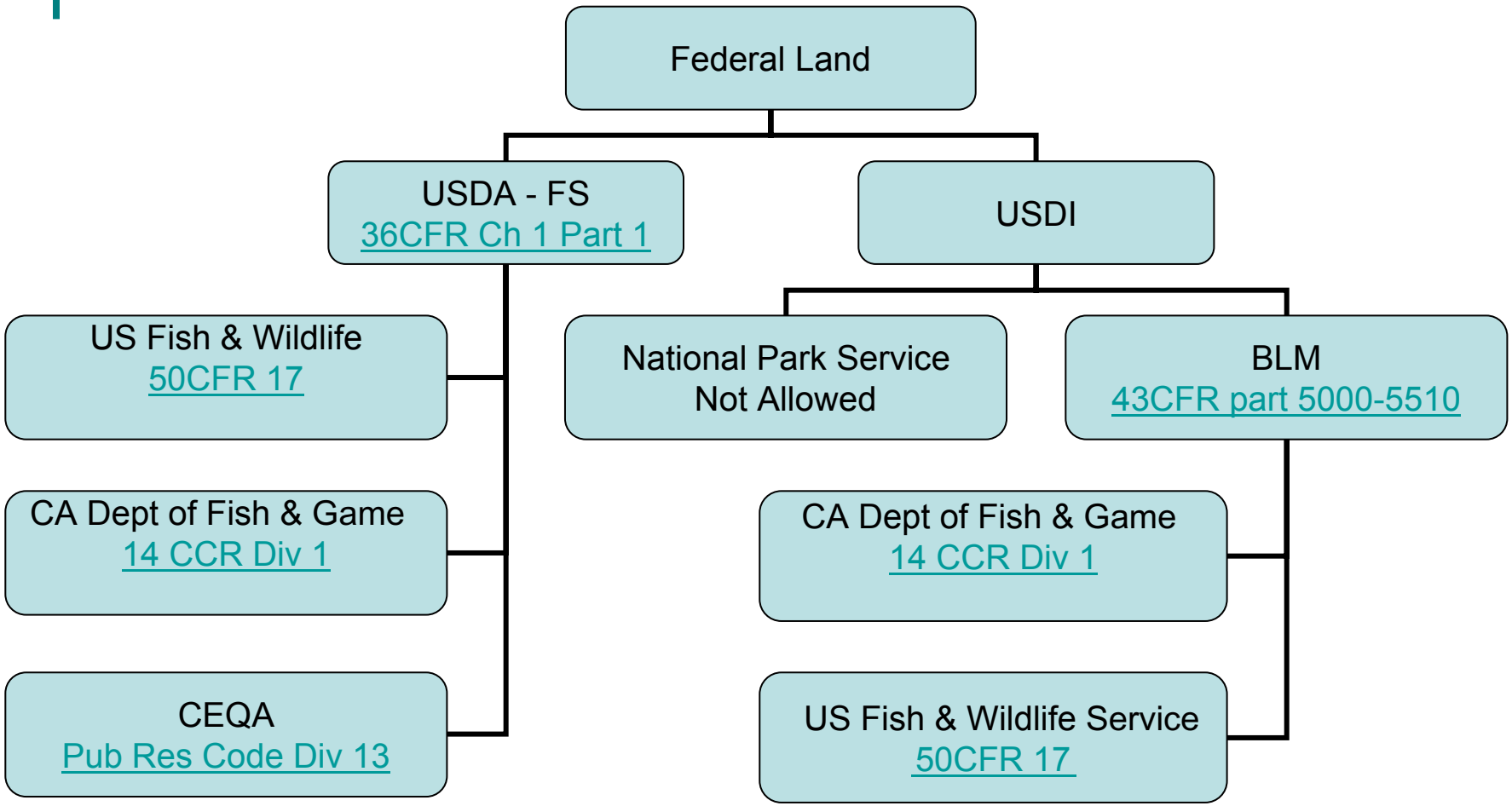
Washington Federal Land



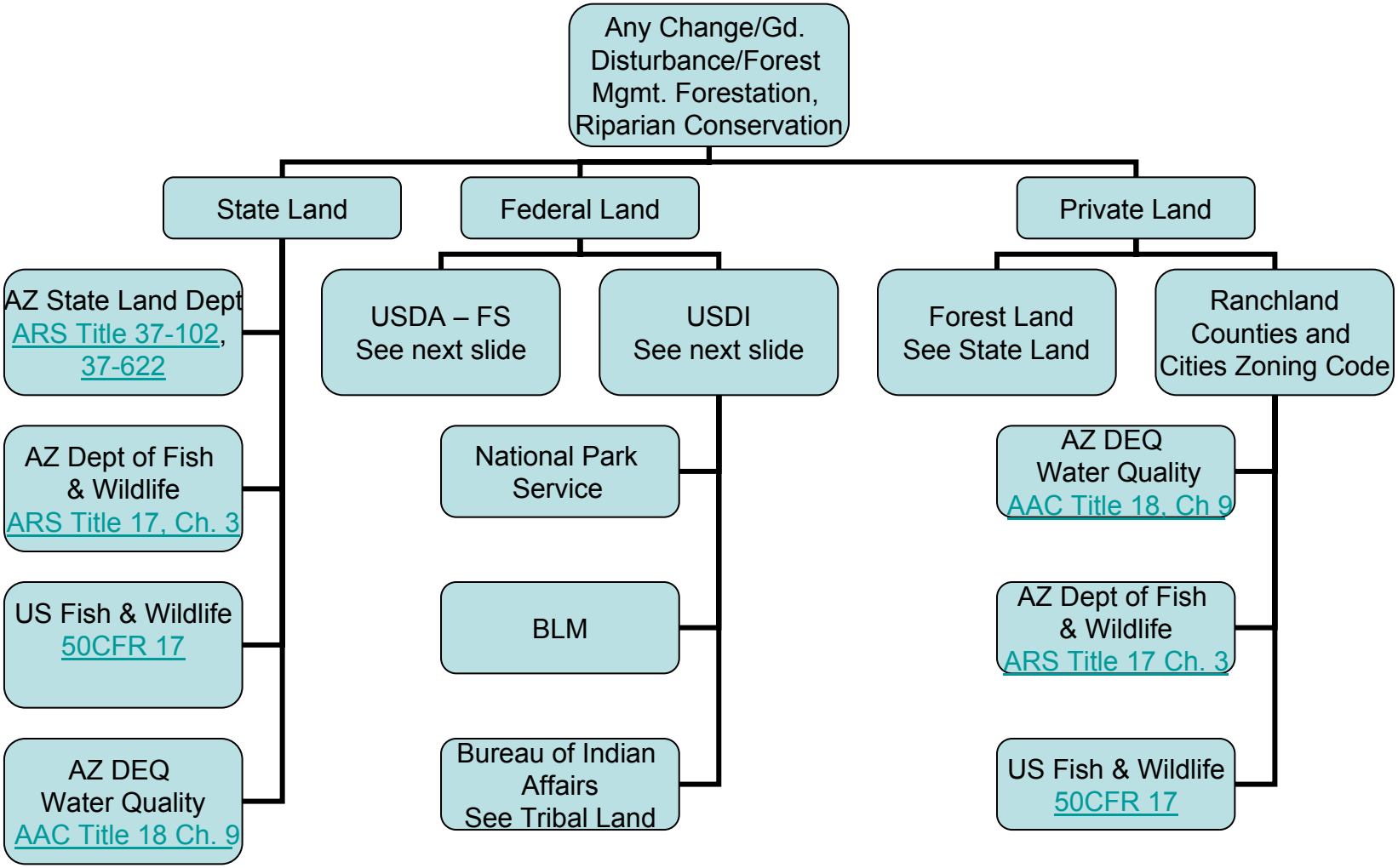
California Terrestrial Options



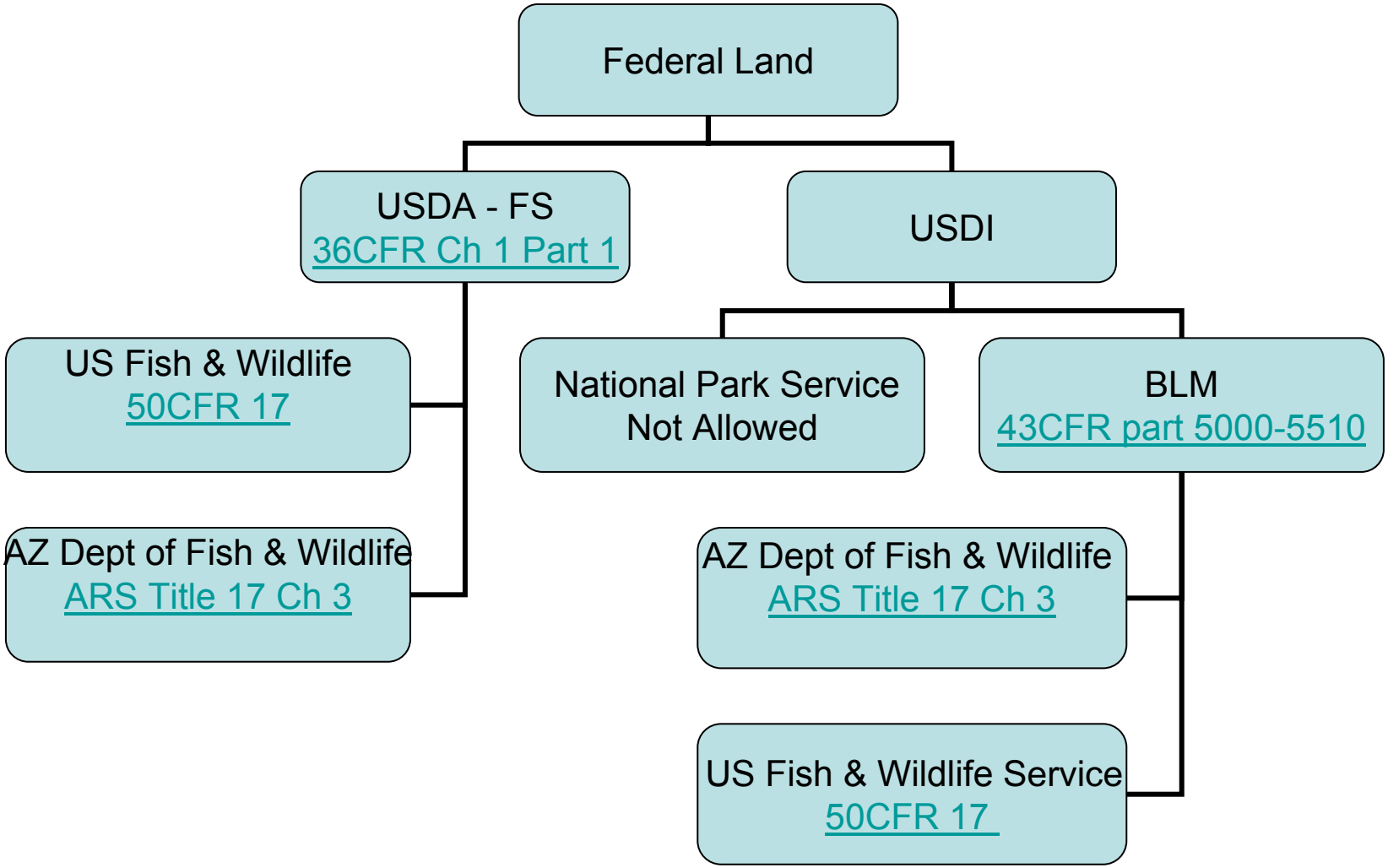
California Federal Land



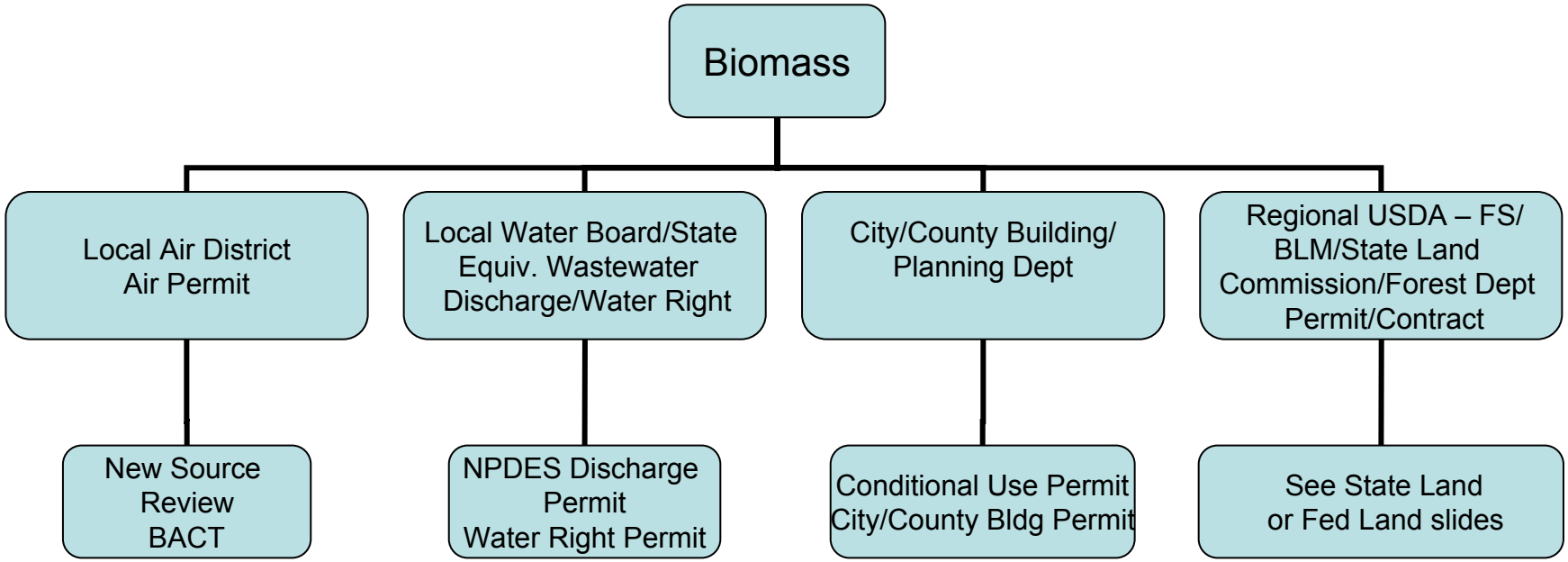
Arizona Terrestrial Options



Arizona Federal Land



WA, OR, CA, AZ Biomass



Appendix XI, Final Report

Life Cycle Assessment of Power Generation Emissions When CO_2 Removal Is Applied

Deliverable associated with Task 2.0, Item 4

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

John Ruby

September 30, 2005

DOE award no. DE-FC26-03NT41984

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The following constitutes part of the required WESTCARB Phase I deliverable associated with Task 2.0, item 4 ("paper on the 'other emissions' analysis"). The LCA spreadsheet explained in this report is entitled 41984_Task2-Item1.xls.

This paper is in support of Nexant Task 3 of the WESTCARB project. The original task statement is reproduced below.

> Task 3 Western Region Life Cycle Assessment
> Nexant shall lead the preparation of life cycle assessments (LCA) for the regional sequestration. The LCA will examine currently existing conditions and estimated future conditions. The assessments will be computer-based to allow evaluation of a large number of sources-to-sequestration options. The LCA work will include major point-source pollutants in addition to CO_2. A task report shall be prepared to document the LCA work and report the results. Nexant shall assist EPRI/CEC and the team to formulate the scenario definitions and to set criteria for preliminary screening. Nexant shall assist the preparation of a detailed methodology for scenario evaluation and ranking. Nexant shall prepare recommendations for future research and testing and longer-term planning by industry and government in the Western Region.

Emission data was only available for power generation point sources of CO_2. As described in other reports, data for other industries: cement and lime manufacturing, petroleum refining, and natural gas processing was very limited and requests for data from industry were not successful. The present paper documents the basis for LCA and provides samples of reports that may be used to examine issues such as: If a specified number of power plants have CO_2 removal installed, what is the estimate of changes for emissions of SO_2, NO_x, mercury and CO_2 at the plant, state, and regional levels. The LCA spreadsheet also provides a means to estimate the changes by fuel type.

Background

The emission and performance data use for the LCA are from the U. S. Environmental Protection Agency's EGRID system with minor additions from other sources. The EGRID data is for the year 2000 and includes the following elements selected for the LCA work.

- Boiler capacity (MMBtu/hr)
- 2000 SO2 (scrubber) control device for utilities
- 2000 NOx control device for utilities
- State abbreviation
- Plant name
- Plant operator name
- Plant county name
- Plant latitude
- Plant longitude
- Number of generators
- Plant primary fuel
- Plant capacity factor
- Utility plant boiler capacity (MMBtu/hr)
- Plant generator capacity (MW)
- Plant 2000 annual heat input (MMBtu)
- Plant 2000 annual net generation (MWh)
- Plant 2000 annual NOx emissions (tons)
- Plant 2000 annual SO2 emissions (tons)
- Plant 2000 annual CO2 emissions (tons)
- Plant 2000 annual mercury emissions (lbs)
- Plant 2000 nominal heat rate (Btu/kWh)
- Plant 2000 annual coal net generation (MWh)
- Plant 2000 annual oil net generation (MWh)
- Plant 2000 annual gas net generation (MWh)

The raw data was sorted into a number of tables that could be accessed by the spreadsheet created to manipulate the data and examine "what if" questions. The spreadsheet allows the user to select and specify the value of several variables to see how emission estimates are changed. The spreadsheet is not intended to be a product for wide distribution, i.e. it is not completely "user friendly", but is for internal partnership use by people familiar with the background and work of the project.

Before discussing the LCA spreadsheet applications, it is noted that even in the EGRID database some of the data values are incomplete. Where possible data has been added and overall it is judged that the completeness of data is sufficient for WESTCARB to evaluate carbon capture options. Finally, while data for oil-fired plants is included, the level of completeness is relatively poor, and with the small number of plants in the region it is recommended that individual assessments of oil-fired plants not use the spreadsheet. If these plants become a concern for evaluation, they need to be examined individually.

LCA Spreadsheet Model

The spreadsheet will be described in four parts. All four are included in a single workbook, but hopefully the discussion will be more easily understood and the model used by stepping through the four main sections. The first part is shown as Exhibit 1 where the data for existing conditions (the EGRID year 2000 information) is presented. At the top of the page there are 4 boxes where the user may select a plant, state, or fuel. When the designated cell is selected, a pull-down list appears for selection of a plant, one of the states in WESTCARB, or a fuel (coal, oil, or natural gas). The 3rd column's box titled "Region" only has that one entry.

The 4 columns are independent of each other so any plant, regional state, or fuel choice can be shown at the same time. The first 5 data elements are familiar industry standards:

- NET GENERATION CAPACITY, MWe
- GROSS GENERATION CAPACITY, MWe
- PLANT CAPACITY FACTOR
- ANNUAL GENERATION, MWh
- PLANT HEAT RATE, Btu/kWh

The SO_2 and NO_x items under the heading INSTALLED CONTROL EQUIPMENT are weighted percentage calculations of the units with and without emission controls installed based on the generation capacity of the units.

The remaining data items are the types of fuels and the emissions for the 4 columns. There was no data available for solid wastes from any of the plants, but it may be useful to collect and input this data at some later time.

Exhibit 2 presents the estimated results for emissions and performance if a plant, the state, the region, or a fuel type is retrofitted to remove carbon. The basis for how the values are estimated and other spreadsheet calculations are documented in later sections.

Exhibit 1, Part 1 of the Spreadsheet Model – Existing Data

			PLANT	STATE	REGION	FUEL
Select: PLANT, STATE, REGION, FUEL			AGUA FRIA	Washington	WESTCARB	Oil
EXISTING						
NET GENERATION CAPACITY MWe			613	1,954	35,921	193
GROSS GENERATION CAPACITY, MWe			632	2,056	37,332	199
PLANT CAPACITY FACTOR			0.380	0.73	0.51	0.20
ANNUAL GENERATION MWh			2,043,449	12,422,893	159,979,349	339,034
PLANT HEAT RATE, Btu/kWh			10,996	10,493	10,565	12,644
INSTALLED CONTROL EQUIPMENT						
SO2 CONTROL, % OF GEN. CAPACITY			0%	0%	20%	0%
NOx CONTROL, % OF GEN. CAPACITY			0%	25%	84%	0%
PRIMARY FUEL			Natural Gas	Portions Below	Portions Below	Oil
COAL			Not Applicable	82.9%	46.0%	Not Applicable
OIL			Not Applicable	1.4%	0.4%	Not Applicable
NATURAL GAS			Not Applicable	15.7%	53.6%	Not Applicable
SO2 EMISSION		Tons Per Year	82	83,777	225,678	2,130
NOX EMISSION		Tons Per Year	6,103	20,638	202,063	1,726
MERCURY		Lb Per Year	N/A	578	2,554	-
CO2 EMISSION		Tons Per Year	1,333,532	12,102,561	134,300,588	342,195
SOLID WASTE		Tons Per Year	na	na	na	na

Exhibit 2, Part 2 of the Spreadsheet Model – Retrofit Estimates

	RETROFIT						
	NET GENERATION CAPACITY MWe		493	1,513	28,432	155	
	GROSS GENERATION CAPACITY, MWe		542	1,699	31,519	170	
	PLANT CAPACITY FACTOR		0.380	0.726	0.512	0.201	
	ANNUAL GENERATION MWh		1,641,925	9,618,277	129,391,779	272,351	
	PLANT HEAT RATE, Btu/kWh		13,686	13,553	13,063	15,740	
	INSTALLED CONTROL EQUIPMENT						
	SO2 CONTROL, % OF GEN. CAPACITY		0%	0%	20%	0%	
	NOx CONTROL, % OF GEN. CAPACITY		0%	25%	84%	0%	
	PRIMARY FUEL		Natural Gas	Portions Below	Portions Below	Oil	
	COAL		Not Applicable	82.9%	46.0%	Not Applicable	
	OIL		Not Applicable	1.4%	0.4%	Not Applicable	
	NATURAL GAS		Not Applicable	15.7%	53.6%	Not Applicable	
	SO2 EMISSION	Tons Per Year	41	4,269	12,623	1,065	
	NOX EMISSION	Tons Per Year	6,103	20,638	202,063	1,726	
	MERCURY	Lb Per Year	N/A	578	2,554	-	
	CO2 EMISSION	Tons Per Year	133,353	1,210,256	13,430,059	34,219	
	SOLID WASTE	Tons Per Year	na	na	na	na	

Exhibits 3 and 4 show the other parts of the LCA model. In Exhibit 3 the user selects between two options for replacing the power generation lost by adding CO_2 removal to existing power plants, and compressing the CO_2 for pipeline transport. The actual transportation and sequestration of the CO_2 is not included with the energy estimates, but will be relatively small.

The net capacity lost by plant, state, region or fuel is shown in the first line of Exhibit 3. The model user needs to select (in the yellow cells) how much of the lost power will be replaced by a gas turbine combined cycle (GTCC) power plant. The model assumes that the remaining lost power will be replaced by coal-fired plants and calculates that value. Based on the proportion of gas and coal replacement power generation the spreadsheet estimates emissions from the replacement power operations.

The basis for estimating the gas or coal replacement power and the emissions is the performance of existing plants. Thus it is supposed that any replacement power would come from operating existing gas or coal plants at a higher capacity factor, and the level of emissions would be the same as coming from plants not retrofitted with carbon capture systems. Other options for replacement power can certainly be envisioned such as new plants with or without CO_2 removal. The current calculation criterion bases the estimates on existing plants and existing performance, i.e. the EGIRD data.

Exhibit 4 presents the part of the spreadsheet model that reports LCA delta emissions. These are the emissions from a plant, state, the region or a fuel type calculated after the user has input an amount of GTCC replacement power. The LCA emissions include those from the retrofitted plant with CO_2 removal and the selected replacement power plant emissions. These emissions are deducted from the existing (pre-retrofit) EGRID data to obtain a negative or positive difference.

In the Exhibit 4 example when the replacement power is all GTCC, as in the first column, all emissions are reduced. For other cases where coal is included with the repowering mix and depending on the existing conditions emissions may increase. For the cases examined to test the model, CO_2 is always reduced.

Exhibit 3, Part 3 of the Spreadsheet Model – Replacement of Lost Generation Capacity

REPLACE LOST CAPACITY					
Net Capacity Lost by Addition of CO2 Removal	MWe	120	440	7,490	40
Replacement MWh Required	MWh	401,524	2,804,616	30,587,570	66,683
Replacement with Existing GTCC Power	MWe	120	220	3,745	40
Replacement with Existing Pulverized Coal Power	MWe	0	220	3,750	0
Replacement Power Emissions					
SO2 EMISSION	Tons Per Year	0	925	10,102	0
NOX EMISSION	Tons Per Year	56	1,890	20,637	9
MERCURY	Lb Per Year	0	48	525	0
CO2 EMISSION	Tons Per Year	236,743	2,390,235	26,091,035	39,317
SOLID WASTE	Tons Per Year	na	na	na	na

Exhibit 4, Part 4 of the Spreadsheet Model, Estimates of LCA Emissions Caused by Retrofit Actions

DELTA EMISSIONS					
EXISTING - RETROFIT + REPLACEMENT					
SO2 EMISSION	Tons Per Year	(40)	(78,580)	(202,950)	(1,060)
NOX EMISSION	Tons Per Year	60	1,890	20,640	10
MERCURY	Lb Per Year	N/A	48	525	-
CO2 EMISSION	Tons Per Year	(963,400)	(8,502,100)	(94,779,500)	(268,700)
SOLID WASTE	Tons Per Year	na	na	na	na
Note: Delta Emissions and some other values are rounded.					

Reporting and Evaluation Examples

Examples of reports or comparisons that may be useful in future evaluations of CO_2 sequestration scenarios are presented next. Obviously, other reports can be generated from the data and spreadsheet model.

Exhibit 5 shows the existing, retrofit and delta emissions data for the States and the Region.

Exhibit 6 presents the same type of comparison for fuel types.

The examples are for the criteria specified in notes 1 – 4 about the proportion of gas and coal used for replacement power. Other criteria would, of course result in other values. It is interesting to note that for the Regional case where all plants are retrofit with CO_2 control, and replacement power is split 50/50 between GTCC and coal, the CO_2 and SO_2 emissions are reduced but the NOx and mercury are increased. This is due to the criteria set for the retrofits, which are thought to be reasonable, but certainly have a range of alternative conditions.

Exhibit 5, Report Example for the States and the Region

		Alaska			Arizona		
		Existing	Retrofit	Delta Emissions1	Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		905	726		7,977	6,166	
GROSS GENERATION CAPACITY, MWe		933	798		8,406	6,932	
PLANT CAPACITY FACTOR		0.42	0.42		0.63	0.63	
ANNUAL GENERATION MWh		3,353,621	2,687,518		44,187,217	37,607,268	
PLANT HEAT RATE, Btu/kWh		10,671	13,315		11,327	13,309	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		77.41%	77.41%	
NOx CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		89.34%	89.34%	
PRIMARY FUEL		Portions Below	Portions Below		Portions Below	Portions Below	
COAL		0.06	0.06		0.92	0.92	
OIL		0.10	0.10		0.00	0.00	
NATURAL GAS		0.84	0.84		0.08	0.08	
SO2 EMISSION	Tons Per Year	2,712	1,117	(1,600)	71,316	3,605	(65,530)
NOX EMISSION	Tons Per Year	7,477	7,477	90	93,877	93,877	4,460
MERCURY	Lb Per Year	13	13	-	1,432	1,432	113
CO2 EMISSION	Tons Per Year	2,288,594	228,859	(1,667,000)	49,146,500	4,914,650	(38,603,800)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

1. Assumes all replacement power is supplied by GTCC units.
2. Assumes 50% of replacement power is supplied by GTCC units and 50% by coal units.

		California			Nevada		
		Existing	Retrofit	Delta Emissions1	Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		18,713	15,035		4,604	3,592	
GROSS GENERATION CAPACITY, MWe		19,274	16,522		4,825	4,016	
PLANT CAPACITY FACTOR		0.38	0.38		0.66	0.66	
ANNUAL GENERATION MWh		62,564,201	50,267,597		26,607,155	20,644,562	
PLANT HEAT RATE, Btu/kWh		10,456	13,014		10,253	13,214	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		19.08%	19.08%	
NOx CONTROL, % OF GEN. CAPACITY		100.00%	100.00%		45.22%	45.22%	
PRIMARY FUEL		Portions Below	Portions Below		Portions Below	Portions Below	
COAL		-	-		0.71	0.71	
OIL		0.00	0.00		0.00	0.00	
NATURAL GAS		1.00	1.00		0.29	0.29	
SO2 EMISSION	Tons Per Year	312	156	(160)	53,100	2,715	(48,400)
NOX EMISSION	Tons Per Year	19,891	19,891	1,720	46,883	46,883	4,050
MERCURY	Lb Per Year	-	-	-	366	366	103
CO2 EMISSION	Tons Per Year	38,598,164	3,859,816	(27,488,200)	24,766,010	2,476,601	(17,174,900)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

		Oregon			Washington		
		Existing	Retrofit	Delta Emissions1	Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		1,768	1,399		1,954	1,513	
GROSS GENERATION CAPACITY, MWe		1,838	1,551		2,056	1,699	
PLANT CAPACITY FACTOR		0.70	0.70		0.73	0.73	
ANNUAL GENERATION MWh		10,844,263	8,566,558		12,422,893	9,618,277	
PLANT HEAT RATE, Btu/kWh		8,908	11,276		10,493	13,553	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%		0.00%	0.00%	
NOx CONTROL, % OF GEN. CAPACITY		100.00%	100.00%		25.27%	25.27%	
PRIMARY FUEL		Portions Below	Portions Below		Portions Below	Portions Below	
COAL		0.35	0.35		0.83	0.83	
OIL		0.00	0.00		0.01	0.01	
NATURAL GAS		0.65	0.65		0.16	0.16	
SO2 EMISSION	Tons Per Year	14,461	762	(13,700)	83,777	4,269	(78,580)
NOX EMISSION	Tons Per Year	13,298	13,298	320	20,638	20,638	1,890
MERCURY	Lb Per Year	165	165	-	578	578	48
CO2 EMISSION	Tons Per Year	7,398,759	739,876	(5,315,900)	12,102,561	1,210,256	(8,502,100)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

		WESTCARB		
		Existing	Retrofit	Delta Emissions2
NET GENERATION CAPACITY MWe		35,921	28,432	
GROSS GENERATION CAPACITY, MWe		37,332	31,519	
PLANT CAPACITY FACTOR		0.51	0.51	
ANNUAL GENERATION MWh		159,979,349	129,391,779	
PLANT HEAT RATE, Btu/kWh		10,565	13,063	
INSTALLED CONTROL EQUIPMENT				
SO2 CONTROL, % OF GEN. CAPACITY		19.64%	19.64%	
NOx CONTROL, % OF GEN. CAPACITY		84.03%	84.03%	
PRIMARY FUEL		Portions Below	Portions Below	
COAL		0.46	0.46	
OIL		0.00	0.00	
NATURAL GAS		0.54	0.54	
SO2 EMISSION	Tons Per Year	225,678	12,623	(202,950)
NOX EMISSION	Tons Per Year	202,063	202,063	20,640
MERCURY	Lb Per Year	2,554	2,554	525
CO2 EMISSION	Tons Per Year	134,300,588	13,430,059	(94,779,500)
SOLID WASTE	Tons Per Year	na	na	na

Exhibit 6, Report Example for Types of Fuel

		Coal			Natural Gas		
		Existing	Retrofit	Delta Emissions3	Existing	Retrofit	Delta Emissions4
NET GENERATION CAPACITY MWe		11,709	8,956		24,606	19,770	
GROSS GENERATION CAPACITY, MWe		12,412	10,132		25,345	21,726	
PLANT CAPACITY FACTOR		0.73	0.73		0.39	0.39	
ANNUAL GENERATION MWh		74,539,530	57,014,080		84,014,545	72,105,348	
PLANT HEAT RATE, Btu/kWh		11,136	14,559		10,340	12,235	
INSTALLED CONTROL EQUIPMENT							
SO2 CONTROL, % OF GEN. CAPACITY		56.04%	56.04%		0.00%	0.00%	
NOx CONTROL, % OF GEN. CAPACITY		66.54%	66.54%		93.05%	93.05%	
PRIMARY FUEL		Coal	Coal		Natural Gas	Natural Gas	
COAL		Not Applicable	Not Applicable		Not Applicable	Not Applicable	
OIL		Not Applicable	Not Applicable		Not Applicable	Not Applicable	
NATURAL GAS		Not Applicable	Not Applicable		Not Applicable	Not Applicable	
SO2 EMISSION	Tons Per Year	222,709	11,135	(200,010)	847	423	(420)
NOX EMISSION	Tons Per Year	155,693	155,693	21,180	44,783	44,783	1,660
MERCURY	Lb Per Year	2,554	2,554	601	-	-	-
CO2 EMISSION	Tons Per Year	83,351,430	8,335,143	(55,477,300)	52,171,849	5,217,185	(39,932,900)
SOLID WASTE	Tons Per Year	na	na	na	na	na	na

3. Assumes all replacement power is supplied by coal units.
4. Assumes all replacement power is supplied by GTCC units.

		Oil		
		Existing	Retrofit	Delta Emissions4
NET GENERATION CAPACITY MWe		193	155	
GROSS GENERATION CAPACITY, MWe		199	170	
PLANT CAPACITY FACTOR		0.20	0.20	
ANNUAL GENERATION MWh		339,034	272,351	
PLANT HEAT RATE, Btu/kWh		12,644	15,740	
INSTALLED CONTROL EQUIPMENT				
SO2 CONTROL, % OF GEN. CAPACITY		0.00%	0.00%	
NOx CONTROL, % OF GEN. CAPACITY		0.00%	0.00%	
PRIMARY FUEL		Oil	Oil	
COAL		Not Applicable	Not Applicable	
OIL		Not Applicable	Not Applicable	
NATURAL GAS		Not Applicable	Not Applicable	
SO2 EMISSION	Tons Per Year	2,130	1,065	(1,060)
NOX EMISSION	Tons Per Year	1,726	1,726	10
MERCURY	Lb Per Year	-	-	-
CO2 EMISSION	Tons Per Year	342,195	34,219	(268,700)
SOLID WASTE	Tons Per Year	na	na	na

Spreadsheet Model Basis

The 48 regional power plants selected during the data collection work are included in the model. The regional partnership states include Alaska, Arizona, California, Nevada, Oregon and Washington. Coal, natural gas, and oil are the fossil fuels used at the model plants.

The following items are the major sources of data and basis for estimates used for the LCA.

Existing Conditions

- Data from the year 2000, the latest reported by the EPA's EGRID database is used.
- Existing emission control, % of generating capacity is the percent of installed capacity with and without SO_2 or NO_x controls. Distinctions among types of controls or degree of emission control are not made.
- The proportion of fuels used is calculated from EGRID data on the amounts of power generated at the plants by each fuel type.

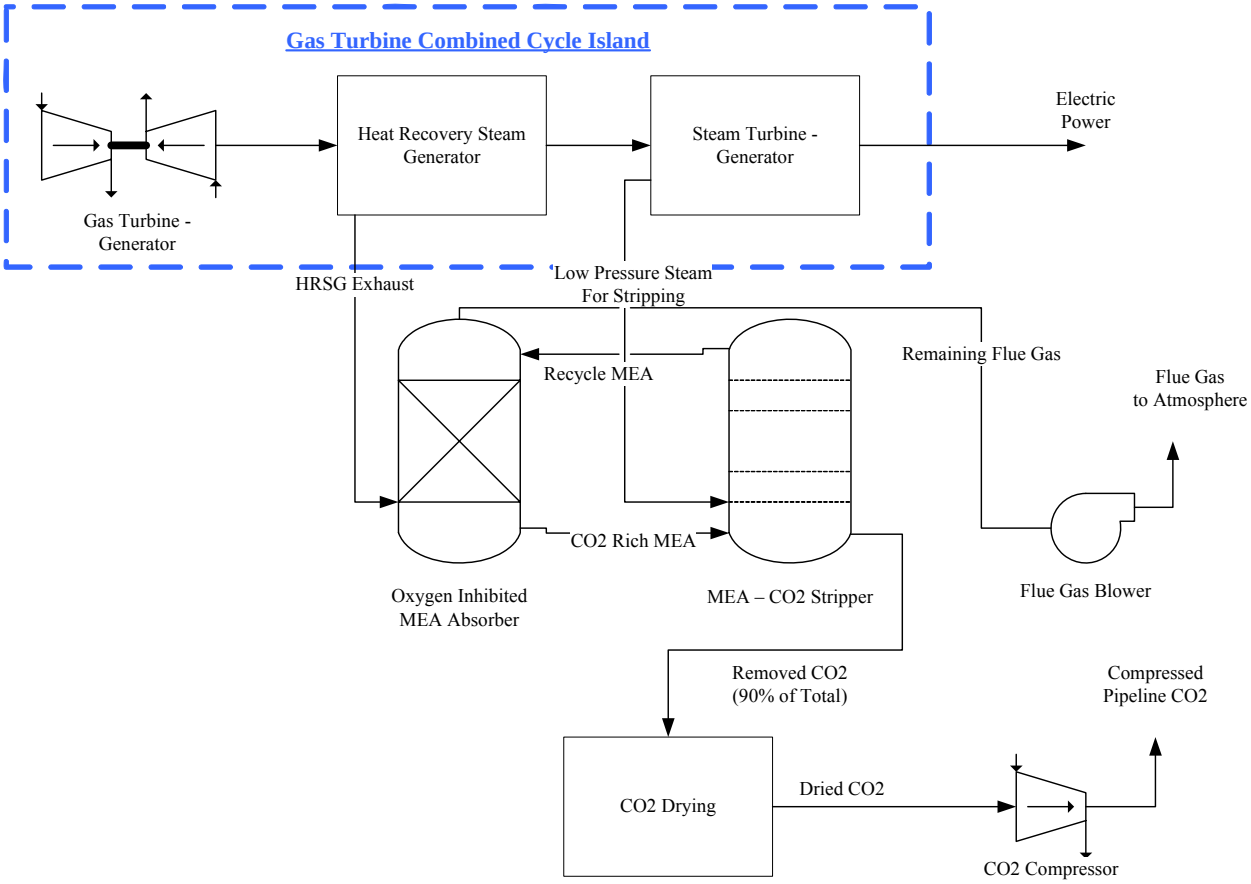
Retrofit Conditions GTCC

- The existing natural gas plant gross capacity is reduced by 14.3% to account for the steam used to operate the amine CO2 capture system.
- The new (retrofit) gross capacity is further reduced by 7.7 % to account for increased auxiliary power requirements by the addition of flue gas blowers and for the amine system and CO_2 compression for pipeline transport.

- CO_2 emissions are reduced by 90%. An oxygen inhibited amine and stripper process is the basis for carbon capture.
- NO_x emissions are unchanged from existing conditions. While the retrofit may offer opportunities to reduce NO_x along with CO_2, the energy and cost penalties are likely to be very large, and thus adding NO_x removal is not included.
- Even though SO_2 emissions are small, and for many existing units "negligible", a 50% removal factor is applied to GTCC to account for the sensitivity of amine systems to sulfur poisoning.
- Mercury emissions are not changed for the retrofit condition.

Exhibit 7 shows the general concept for the retrofit plant schematically.

Exhibit 7, Simplified Diagram of the Retrofit Gas Turbine Combined Cycle Plant



Retrofit Conditions Coal

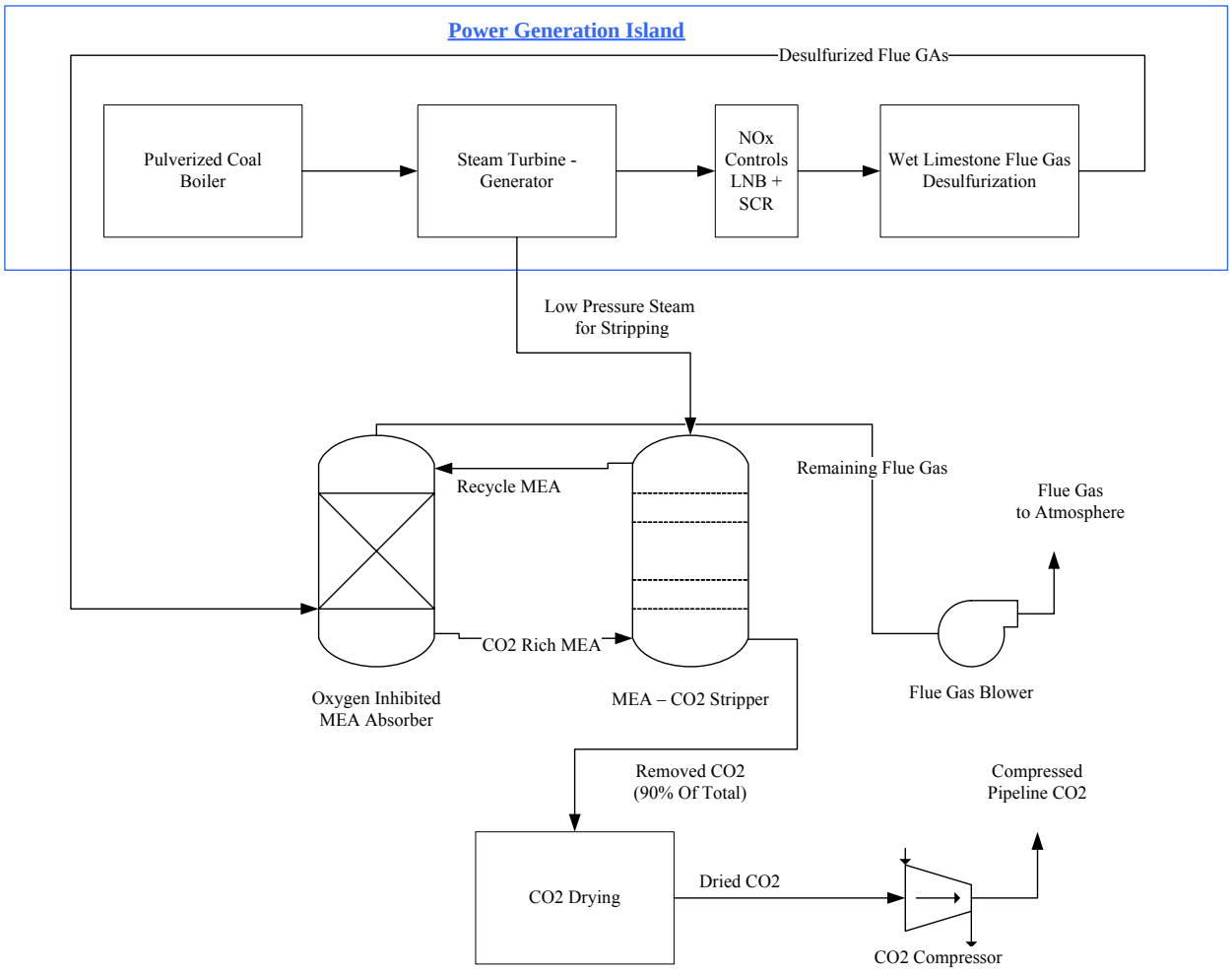
- Similarly for the coal plants, the existing gross capacity was reduced 18.4 % to account for amine steam requirements.
- The retrofit gross capacity was then reduced by 9.5 % to account for auxiliary power used by the induced draft fan, the amine system, and CO_2 compression.
- The plant capacity factor was unchanged from existing to retrofit calculations.
- The fuel/energy input is the same for existing and retrofit.
- The annual generation and heat rates retrofit values are calculated from the new estimates bulleted above.
- The proportion of emission control equipment was not changed from existing plant data.

The amounts of gross and net capacity reductions used to calculate the changes to existing plants that are retrofit with amine CO_2 capture systems are estimates from the literature and in-house data. The US DOE – EPRI report, Cost and Performance Estimates for fossil Fuel Power Plants with CO_2 Removal, was a major source for selecting the capacity reductions.

- CO_2 emissions are reduced by 90%. An oxygen inhibited amine and stripper process is the basis for carbon capture.
- NO_x emissions are unchanged from existing conditions.
- SO_2 emissions are reduced by 95% from existing emission levels as a measure to prevent amine catalyst poisoning.
- Mercury emissions are not changed for the retrofit condition.

Exhibit 8 shows the simplified process diagram for the retrofit coal-fired power plant.

Exhibit 8, Simplified Diagram of Retrofit Coal-Fired Power Plant



Replacement of Lost Generation Capacity

As described above, the generation capacity lost because plants add a CO_2 capture and compression ability must be replaced for full LCA accounting of emissions. The criteria selected for the replacement power calculations are based on data for the region and unit emission levels for typical gas and coal plants. The basic assumption for the near term is that any lost generation would be replaced by operating existing plants in the region for more hours of the year. The

spreadsheet does not estimate and account for potential increased auxiliary power requirements from added or improved sulfur or NO_x removal systems installed to support the amine process, or for emission control enhancements.

For GTCC replacement power:

- A general heat rate of 10,000 Btu/kWh is used.
- $S0_2$ emissions are zero.
- NO_x emissions are 0.28 lb per MWh.
- CO_2 emissions are 1,179 lb per MWh
- Mercury emissions are zero.

For coal-based replacement power:

- A heat rate of 11,000 Btu/kWh is used.
- SO_2 emissions are 1.32 lb per MWh.
- NO_x emissions are 2.42 lb per MWh
- CO_2 emissions are 2,230 lb per MWh
- Mercury emissions are 0.0000343 lb per MWh.

Delta Emissions

The final emissions accounting is to calculate the change in emissions after retrofit compared to the existing emission. Adding the retrofit and replacement power emissions and subtracting that value from the existing plant emissions yields the delta results. The results depend on criteria used in the model and the distribution of replacement power selected by the "what if" question posed by the spreadsheet user.

Appendix XII, Final Report

Health, Safety, and Environmental Screening and Ranking Framework for Geologic CO_2 Storage Site Selection

Topical Report

West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Curtis M. Oldenburg

September 30, 2005

DOE Contract No.: DE-FC26-03NT41984

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Abstract

This report describes a screening and ranking framework (SRF) developed to evaluate potential geologic carbon dioxide (CO_2) storage sites on the basis of health, safety, and environmental (HSE) risk arising from possible CO_2 leakage. The approach is based on the assumption that HSE risk due to CO_2 leakage is dependent on three basic characteristics of a geologic CO_2 storage site: (1) the potential for primary containment by the target formation, (2) the potential for secondary containment if the primary formation leaks, and (3) the potential for attenuation and dispersion of leaking CO_2 if the primary formation leaks and secondary containment fails. The framework is implemented in a spreadsheet in which users enter numerical scores representing expert opinions or general information available from published materials along with estimates of uncertainty to evaluate the three basic characteristics in order to screen and rank candidate sites. Application of the framework to the Rio Vista Gas Field, Ventura Oil Field, and Mammoth Mountain demonstrates the approach. Refinements and extensions are possible through the use of more detailed data or model results in place of property proxies. Revisions and extensions to improve the approach are anticipated in the near future as it is used and tested by colleagues and collaborators.

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1 Introduction

In order to minimize the possibility that carbon dioxide (CO_2) storage projects will result in health, safety, and environmental (HSE) impacts due to CO_2 leakage and seepage, it is essential that sites be chosen to minimize HSE risk. This is particularly important for early pilot studies for which leakage and seepage for any reason could be perceived as a failure of the general approach of geologic CO_2 storage. Apart from site-specific operational choices once a given CO_2 pilot injection project is underway, the best way to avoid unintended leakage and seepage is to choose a good site at the outset.

This report describes a spreadsheet-based Screening and Ranking Framework (SRF) for evaluating multiple sites on the basis of their potential for HSE risk due to CO_2 leakage and seepage. The results of comparisons can be used to help select the best CO_2 injection sites from a number of candidate sites through screening and ranking. Although designed to be used in the early stages of site selection or for pilot CO_2 injection studies, the approach with extensions may find application in full geologic CO_2 storage site development. This report describes the philosophy behind the approach and its basic elements, and presents three case studies to demonstrate the use and applicability of the framework. Revisions and extensions are anticipated as feedback is received from colleagues and collaborators.

Before describing the framework, it is useful to clarify some terminology. The term *leakage* refers to migration of CO_2 away from the intended target formation. *Seepage* is slow or diffuse CO_2 migration across an interface in the near-surface environment such as the ground surface or the bottom of water body such as a lake. The *near-surface environment* is defined loosely as ±10 m from the ground surface. The term *flux* is used in its formal sense to refer to mass per unit area per unit time (e.g., kg m^{-2} s^{-1}), in contrast to *flow* which refers to mass per unit time (e.g., kg s^{-1}) with no area specified. A *plume* of CO_2 is a large relatively concentrated volume of CO_2 either in the subsurface or above ground. The word *impact* refers to consequences or effects of a given high CO_2 concentration on people and the biota for a given time. *Risk* is often defined as the product of probability of occurrence and consequence in order to reflect both the elements of likelihood and impact, and this same definition is used here. However, rather than treating likelihood in any kind of formal probabilistic sense, the SRF is qualitative with respect to risk and uses subsurface properties as general proxies for processes and features as described in the following section, “Executive Summary”.

2 Executive Summary

In order to reduce the possibility that geologic carbon dioxide (CO_2) storage projects will result in health, safety, and environmental (HSE) impacts due to CO_2 leakage and seepage, it is essential that sites be chosen to minimize HSE risk. Here we present a spreadsheet-based Screening and Ranking Framework (SRF) for evaluating multiple sites on the basis of their potential for HSE risk due to CO_2 leakage and seepage. Application of the framework to three California sites (Rio Vista Gas Field, Ventura Oil Field, and the Mammoth Mountain natural analog site) demonstrates the approach. Although

designed to be used in the early stages of site selection, the SRF approach, with extensions, may find application in full geologic CO_2 storage site risk assessment.

The HSE effects of concern are caused by persistent high concentrations of CO_2 in the near-surface environment where humans, plants, and other living things reside. To minimize HSE effects, it is necessary either to (1) prevent CO_2 from leaking away from the primary target formation, (2) prevent CO_2 leakage from reaching the near-surface environment, or (3) attenuate the leakage flux or disperse the CO_2 if it should reach the near-surface environment. With this understanding of the underlying origin of HSE impact, the SRF was formulated to evaluate three fundamental characteristics of a geologic CO_2 storage site:

1. Potential for long-term primary containment by the target formation,

2. Potential for secondary containment should the primary formation leak, and

3. Potential of the site to attenuate and/or disperse leaking CO_2 should the primary formation leak and secondary containment fail.

The SRF spreadsheet is designed to provide an independent assessment of each of these three characteristics through an evaluation of the properties of various attributes of the three characteristics. For example, the attributes of Primary Containment are given by the properties of the caprock and the reservoir, including reservoir depth. Similarly, Secondary Containment is determined by the properties of secondary and shallower seals, and Attenuation Potential is determined by surface characteristics, hydrology, and the presence and nature of existing wells and faults. These attributes are scored by the user based on suggested ranges of properties and values given in the spreadsheet. Arbitrary weights can be used to express the importance of some properties over others. Many of the properties and values of attributes are actually proxies for uncertain and undetermined quantities that could eventually be measured or modeled with additional site characterization effort.

The expected users of the SRF are geoscientists or hydrologists with some general knowledge of the site and/or access to published information in reference books or maps. It is expected that one user or group of users will evaluate all of the sites in a given screening or ranking process, thereby ensuring a measure of consistency in each assessment. The system is sufficiently simple and transparent that anyone can review the assessments done by other users and re-do the assessment if there is disagreement. Simplicity and transparency are key design features of the SRF spreadsheet
Uncertainty in the SRF is defined broadly and includes parameter uncertainty and variability. Uncertainty is kept separate from the scores for the characteristics and is a primary graphical output along with the attribute assessment for each of the three characteristics. The primary output graphic of the SRF spreadsheet is a plot of attribute assessment for each of the three characteristics on the *y*-axis, and certainty on the *x*-axis. A demonstration of the SRF approach through comparison of two potential CO_2 storage sites (Rio Vista and the Ventura Oil Field) along with a leaking natural analogue site

(Mammoth Mountain, California) is presented. Primary Containment at Rio Vista is expected to be very good, while secondary containment is not as favorable. Dispersion of leaking CO_2 is expected to be effective because of low topographic relief and fairly consistent winds. The Ventura Oil Field site ranks lower than Rio Vista, while the natural analogue site Mammoth Mountain ranks by far the lowest the three sites as we would expect.

A framework for screening and ranking candidate sites for geologic CO_2 storage on the basis of HSE risk has been developed based on three fundamental characteristics of a geologic CO_2 storage site. We emphasize that this is a screening and ranking tool intended to guide the selection of the most promising sites for which more detailed risk assessment would be carried out. Example applications of the framework show that plausible comparative evaluations of prospective sites with limited characterization data can be accomplished based on the potential for CO_2 leakage and seepage and related HSE risk.

3 Experimental

3.1 Philosophy Behind the Approach

Although leakage and seepage are unlikely in the case of pilot studies involving small amounts of CO_2 injection, there is always the possibility that injected CO_2 will migrate away from the intended target formation. The wide variety of recognized potential pathways for leakage and seepage to the near-surface environment is shown schematically in Figure 1. Note that all of the leakage pathways involve the potential for secondary entrapment at higher levels in the system, that is, leakage pathways may not result directly in seepage. Furthermore, all of the pathways involve the potential for attenuation or dispersion. In particular in the near-surface environment, for example where the CO_2 plume is shown mixing with air in a ground plume, the potential for CO_2 to disperse and mix with water, air, or other fluids and gases is always present.

The HSE effects of CO_2 that are of concern are caused by persistent high concentrations of CO_2 in the near-surface environment where humans, plants, and other living things reside. For example, high concentrations in soil gas can lead to root respiration limitations and corresponding plant stress or death (e.g., Farrar *et al.*, 1995; Qi *et al.*, 1994). In potable groundwater aquifers, high concentrations can lead to leaching of heavy metals that could adversely affect water quality (Wang and Jaffe, 2005). In the above-ground environment or in basements and houses, high CO_2 concentrations can lead to health effects ranging from dizziness to death in humans and other animals (Benson *et al.*, 2002). To minimize HSE effects, it is necessary either to (1) prevent CO_2 leakage, (2) prevent CO_2 leakage from reaching the near-surface environment, or (3) attenuate the leakage flux or disperse the CO_2 if it should reach the near-surface environment so that CO_2 never builds up to persistent high concentrations at which it is an HSE risk.

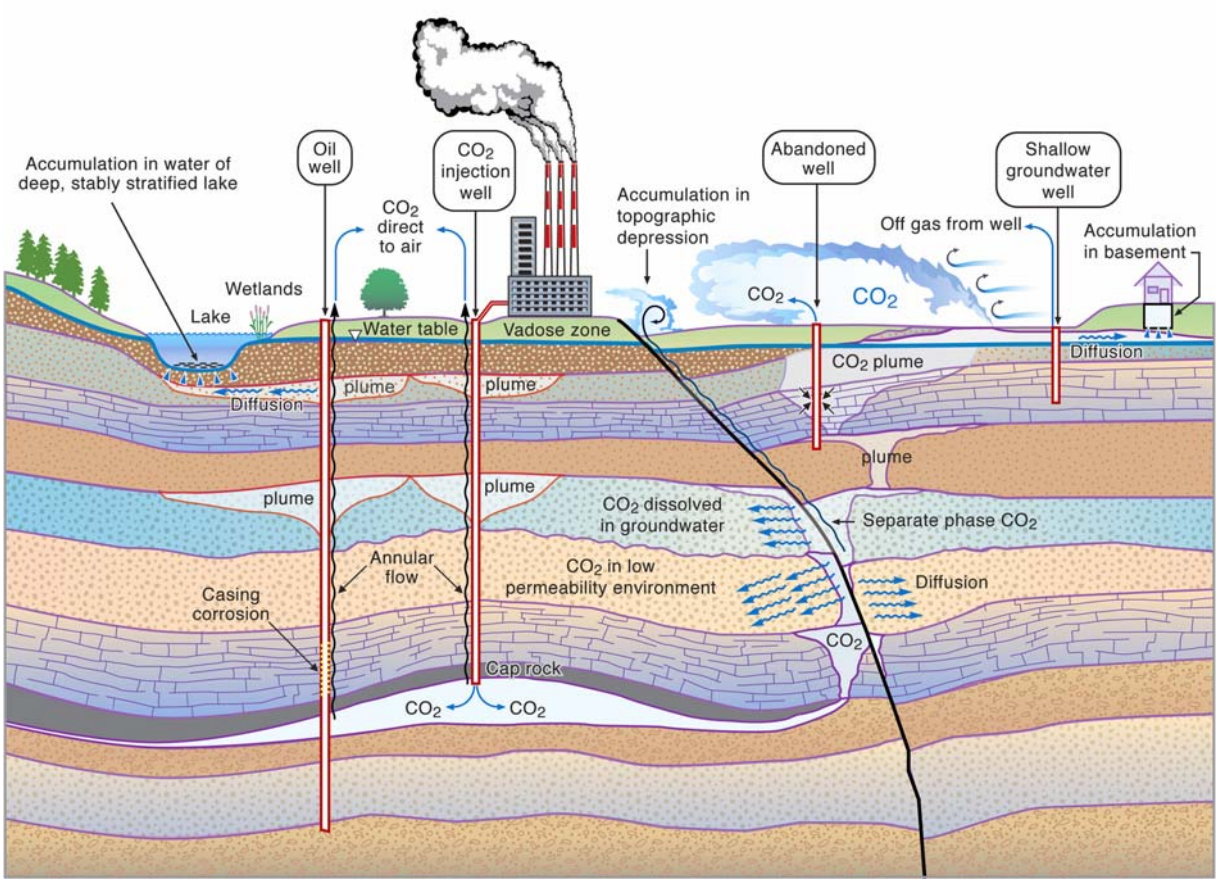


Figure 1. Schematic of various leakage and seepage pathways and processes for CO_2 from a geologic storage site

It is with this understanding of the underlying origin of HSE impact that the SRF for evaluating the potential for HSE impact was formulated. Specifically, the approach stems from the realization that potential HSE impact is related to three fundamental characteristics of a geologic CO_2 storage site:

1. Potential of the target formation for long-term containment of CO_2,

2. Potential for secondary containment should the primary target site leak, and

3. Potential of the site to attenuate and/or disperse leaking CO_2 should the primary formation leak and secondary containment fail.

The SRF spreadsheet was designed to provide a qualitative and independent assessment of each of the three characteristics through an evaluation of the properties of various attributes of these three characteristics. The SRF is designed so that it can be applied to sites with limited data. This is considered appropriate for early site selection or for pilot study sites when multiple sites are under consideration and where detailed site-characterization data will be lacking. Many of the properties and values of attributes that

the user will input into the SRF spreadsheet are actually proxies for uncertain and undetermined quantities that could eventually be measured or modeled with additional site characterization effort. However, because of the lack of data that will be the norm for most site-selection processes (especially in the early phases), uncertainty has been made a fundamental input and output of the SRF that is kept separate from the scores for the characteristics. Uncertainty in the SRF is defined broadly and includes parameter uncertainty (e.g., how well known a given property is) and variability (e.g., how variable a given property is). Uncertainty is handled by the SRF as a primary graphical output along with the qualitative risk score for each of the three characteristics. The overall uncertainty reflects the user's confidence in how well the characteristics are known. Users can utilize this graph to compare sites, taking into account both the expectation of HSE risk and some estimate of how well-known is that risk. The comparison of sites in this context can be used for screening or ranking of sites based on the HSE risk criterion.

The SRF relies on input by a user who either already knows something about the site, has opinions about the site based on general information, or who has gained knowledge from published information about the site. As discussed above, the reason for the choice to use relatively qualitative and/or opinion-based information rather than hard data and/or modeling results is that detailed site-characterization information—especially for pilot CO_2 injections—will rarely be available. The expected users of the SRF are geoscientists or hydrologists with some general knowledge of a site and/or access to limited published information about the site in reference books or maps. It is expected that one user or group of users will evaluate all of the sites in a given screening or ranking exercise, thereby ensuring a measure of consistency in each assessment. The system is sufficiently simple and transparent that anyone can review the assessments done by other users and even redo the assessment if there is disagreement. Simplicity and transparency are key design features of the SRF spreadsheet.

The methods behind the SRF differ from other approaches such as the Features, Events, and Processes (FEP) approach (e.g., Wildenborg *et al*., 2005), and the probabilistic approach (e.g., Rish, 2003). In the FEP approach, a comprehensive list of FEPs is developed and codified in a database that is then used to define scenarios for leakage and seepage, or any other performance-affecting event. Modeling is then used to evaluate the consequences of that scenario in terms of CO_2 impact due to high concentrations and long residence times, for example. The FEPs have subjective probabilities associated with them, and risk can be calculated from the product of consequence as simulated in the scenario and probability as assigned to the FEPs. The FEP scenario approach is laborious and requires significant site-specific information to be carried out effectively. In the probabilistic approach of Rish (2003), probabilities of events are input and the likelihood of various detrimental events is calculated. The probabilistic approach relies upon accurate probability distributions—something that will be difficult at best to estimate for multiple sites especially during the early phases of site selection.

In the SRF approach, there is no modeling and simulation nor are probabilities assigned. The reason for this approach is that detailed site-characterization information, especially for pilot CO_2 injections, is not expected to be sufficient to undertake a FEP-scenario

analysis, nor to assign probabilities for a probabilistic analysis. Instead the SRF uses qualitative pieces of information, for example as gleaned from general reports or an expert's knowledge of an area, as proxies for potential FEPs and consequences combined. By this approach, the analysis is greatly simplified and includes explicitly the level of confidence that the user assigns to the assessments as a primary output. In short, the SRF is designed to answer the question "From a choice of several potential sites, and based on existing information, which site has the lowest HSE risk?" In "Screening and Ranking Framework" (below), the SRF approach and its input and output are described in detail.

3.2 Screening and Ranking Framework

The SRF approach is based on an independent evaluation of the three fundamental characteristics of a site that control the HSE risk of CO_2 leakage and seepage. Although developed based on past experience with CO_2 storage rather than with the formality of decision analysis, the approach falls loosely under the category of multi-attribute utility theory (e.g., Keeney and Raiffa, 1976; Keeney, 1980). The three scores that are evaluated for each site are proxies for combinations of impact and likelihood (i.e., risk) of leakage, secondary entrapment, and attenuation. The utility function in this case would be a measure of tendency for minimal HSE impact while injecting a maximum amount of CO_2. The SRF approach was not developed using any formal guidelines, and some unconventional aspects are included for the case of subsurface environments about which very few hard facts will be known. The input required by the SRF is quite general and may rely primarily on expert opinion depending on the degree of characterization and/or published information available for the sites.

The assessment made in the framework is based on four classes of information: (1) site characteristics which are defined by (2) attributes, which are defined by (3) properties which are defined by (4) values input by the user. Table 1 shows the relationship between characteristics, attributes, and properties, and what properties these proxies represent. For example, Table 1 shows that the three attributes of the potential for the target formation to contain CO_2 for long periods are (1) the nature of the primary caprock seal, (2) reservoir depth, and (3) reservoir properties. The properties of the primary caprock seal attribute are thickness, lithology, demonstrated sealing capacity, and lateral continuity. The far right-hand column shows that these four properties are proxies for (1) likely effectiveness of the seal, (2) permeability and porosity of the seal, (3) the probability of leakage through the seal, and (4) the integrity of the seal against CO_2 spreading that could exceed the spillpoint. Properties and proxies for all of the attributes are shown in Table 1.

Table 1. Characteristics, attributes, properties, and proxies

Characteristics	Attributes	Properties	Proxy for…
Potential for primary containment	Primary seal	Thickness Lithology Demonstrated sealing Lateral continuity	Likely sealing effectiveness Permeability, porosity Leakage potential Integrity and spillpoint
	Depth	Distance below surface	Density of CO_2 in reservoir
	Reservoir	Lithology Permeability and porosity Thickness Fracture or primary porosity Pore fluid Pressure Tectonics Hydrology Deep wells Fault permeability	Likely storage effectiveness Injectivity, capacity Areal extent of injected plume Migration potential Injectivity, displacement Capacity, tendency to fracture Induced fracturing, seismicity Transport by groundwater Likelihood of well pathways Likelihood of fault pathways
Potential for secondary containment	Secondary seal	Thickness Lithology Demonstrated sealing Lateral continuity Depth	Likely sealing effectiveness Permeability, porosity Leakage potential Integrity and spillpoint Density of CO_2
	Shallower seals	Thickness Lithology Lateral continuity Evidence of seepage	Likely sealing effectiveness Permeability, porosity Integrity and spillpoint Effectiveness of all seals
Attenuation Potential	Surface characteristics	Topography Wind Climate Land use Population Surface water	CO_2 plume spreading Plume dispersion Plume dispersion Tendency for exposure Tendency for exposure Form of seepage
	Groundwater hydrology	Regional flow Pressure Geochemistry Salinity	Dispersion/dissolution Solubility Solubility Solubility
	Existing wells	Deep wells Shallow wells Abandoned wells Disposal wells	Direct pathway from depth Direct pathway Direct pathway, poorly known New fluids, disturbance
	Faults	Tectonic faults Normal faults Strike-slip faults Fault permeability	Large permeable fault zones Seal short-circuiting Permeable fault zones Travel time

The first thing the SRF spreadsheet user must do in evaluating the attributes of one of the three characteristics is decide the importance of a given property through the specification of weighting factors for each of the *j* properties of each attribute. The weighting factors (w_j) are normalized by the spreadsheet as

$$\sum_j w_j = 1 \tag{1}$$

so any arbitrary scale can be used. The weighting option allows the user great latitude in applying his/her judgment to the evaluation. For example, if the user feels strongly that caprock seal thickness is the overriding property controlling leakage and seepage, then a large number can be assigned for the weight of that property and the caprock thickness value will dominate the assessment of the attribute Primary Seal. Figure 2 shows an example of the Primary Containment worksheet from the SRF spreadsheet. The light blue cells indicate those that require user input. As shown, the weight of the seal thickness property is assigned a value of 10 out of a total of 21 making approximately one-half of the weight of the primary seal attribute and its uncertainty rest on the seal thickness value. For comparing sites in the process of screening or ranking, the use of different weighting factors for the properties of different sites should be carefully considered. In the test cases presented below, constant weighting factors are used for consistency.

8/18/2004	Rio Vista Gas Field	Revision: 2.0		Overall score for this sheet		Average of the weighted assessments of attributes		Average certainty
	Primary Containment			2.49		1.30		1.87
	Attribute	Weight 10 = most import 1 = least	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk 2 = excellent (positive attribute) 0 = neutral (fair attribute) -2 = poor (negative attribute)	Weighted Assessment of Attribute	Certainty Factor 2.0 = Very well known 1.0 = Generally accepted 0.1 = Poorly known
	Primary Seal			**Description**				
	Thickness	10	0.48	100 m		0	0.00	2
	Lithology	5	0.24	Shale		2	0.48	2
	Demonstrated sealing	5	0.24	Good seal		2	0.48	2
	Lateral continuity	1	0.05	Large areal extent of gas		2	0.10	2
		21	1.00		Average:	1.50	1.05	2.00
	Depth			**Description**				
	Distance below ground	10	1.00	some v. shallow, but mos	t 1000 m -	2	2.00	2
		10	1.00		Average:	2.00	2.00	2.00
	Reservoir			**Description**				
	Lithology	1	0.07	Sandstone		2	0.13	2
	Perm., poros.	2	0.13	5-1000 mD, 20-34%		2	0.27	2
	Thickness	1	0.07	150 m		2	0.13	2
	Fracture or primary poros.	1	0.07	Primary		2	0.13	2
	Pores filled with...	1	0.07	ural gas and low-TDS water		2	0.13	1
	Pressure	1	0.07	Hydrostatic to depleted		1	0.07	1
	Tectonics	2	0.13	wth faults, but not v. active		0	0.00	2
	Hydrology	2	0.13	Water drive		0	0.00	1
	Deep wells	2	0.13	Many deep wells		-2	-0.27	2
	Fault permeability	2	0.13	Trapping faults (low k)		2	0.27	1
		15	1.00		Average:	1.10	0.87	1.60

Figure 2. Example worksheet from the SRF spreadsheet for the characteristic Primary Containment

The second thing the user of the SRF spreadsheet does is assign a numerical value (a_j) to the properties based on suggestions in pop-up comments in the spreadsheet. Examples of property values can be seen in Figures 2–4, which show the worksheets for Primary Containment, Secondary Containment, and Attenuation Potential. The numerical values are chosen as integers ranging from –2 (poor) to +2 (excellent) with 0 considered neutral (neither good nor bad). Broad ranges of values are offered for various conditions in the pop-up comments to guide the user in selecting an integer between –2 and +2. Real numbers can also be used in cases when the user feels it is warranted.

8/18/2004	Rio Vista Gas Field	Revision: 2.0		Overall score for this sheet		Average of weighted assessments of attributes		Average certainty
	Secondary Containment			0.51		0.22		1.63
	Attribute	Weight 10 = most import. 1 = least	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk 2 = excellent (positive attribute) 0 = neutral (fair attribute) -2 = poor (negative attribute)	Weighted Assessment of Attribute	Certainty Factor 2.0 = Very well known 1.0 = Generally accepted 0.1 = Poorly known
	Secondary Seal			**Description**				
	Thickness	10	0.38	150 m (Sidney Flat shale)		0	0.00	2
	Lithology	5	0.19	Shale		2	0.38	2
	Demonstrated sealing	1	0.04	s prod. from multiple horiz.		1	0.04	2
	Lateral continuity	5	0.19	Laterally continuous		1	0.19	2
	Depth	5	0.19	Sidney Flat shale ~800 m		0	0.00	2
		26	1.00		Average:	0.80	0.62	2
	Shallower Seals			**Description**				
	Thickness	10	0.33	Thin mudstone		-1	-0.33	1
	Lithology	5	0.17	Mudstone		0	0.00	1
	Lateral continuity	5	0.17	Extensive		1	0.17	1
	Evidence of seepage	10	0.33	Historic gas seeps		0	0.00	2
		30	1.00		Average:	0.00	-0.17	1.25

Figure 3. Example worksheet from the SRF spreadsheet for the characteristic Secondary Containment

8/18/2004	Rio Vista Gas Field	Revision: 2.0						
				Overall score for this sheet		Average of weighted assessments attributes		Average certainty
	Attenuation Potential			0.92		0.52		1.94
	Attribute	Weight	Normalized Weight	Property/Value		Assessment of Attribute Property Relative to HSE Risk	Weighted Assessment of Attribute	Certainty Factor
		10 = most import				2 = excellent (positive attribute)		2.0 = Very well known
		1 = least				0 = neutral (fair attribute)		1.0 = Generally accepted
	Surface Characteristics			**Description**		-2 = poor (negative attribute)		0.1 = Poorly known
	Topography	5	0.15	Flat		2	0.30	2
	Wind	10	0.30	Windy		2	0.61	2
	Climate	2	0.06	Sub-humid		-1	-0.06	2
	Land use	4	0.12	Farmland/wetlands		1	0.12	2
	Population	10	0.30	Rural		1	0.30	2
	Surface water	2	0.06	Perennial wetlands exist		-2	-0.12	2
		33	1.00		Average:	0.50	1.15	2.00
	Groundwater Hydrology			**Description**				
	Regional flow	6	0.32	riable, away from Mont. Hills		1	0.32	2
	Pressure	7	0.37	Hydrostatic		0	0.00	2
	Geochemistry	2	0.11	Fresh, slightly alk.		2	0.21	2
	Salinity	4	0.21	Very low TDS		2	0.42	2
		19	1.00		Average:	1.25	0.95	2.00
	Existing Wells			**Description**				
	Deep wells	5	0.25	Many deep wells		-2	-0.50	2
	Shallow wells	4	0.20	Numerous shallow gw wells		-2	-0.40	2
	Abandoned wells	10	0.50	Many abandoned wells.		-2	-1.00	2
	Disposal wells	1	0.05	Water is re-injected.		-2	-0.10	2
		20	1.00		Average:	-2.00	-2.00	2.00
	Faults			**Description**				
	Tectonic faults	10	0.59	o permeable tectonic faults		2	1.18	2
	Normal faults	1	0.06	Normal faults form traps		2	0.12	2
	Strike-slip faults	1	0.06	Few strike-slip faults		2	0.12	1
	Fault permeability	5	0.29	6 of gas plays are fault traps		2	0.59	2
		17	1.00		Average:	2.00	2.00	1.75

Figure 4. Example worksheet from the SRF spreadsheet for the characteristic Attenuation Potential

The third thing the user must do is enter a value for the confidence with which each property is known (2 is very certain; 0.1 is highly uncertain). This confidence information will be carried along and plotted with attribute assessments for each of the three characteristics. The worksheets depicted in Figures 2–4 show that there are three attributes ($i = 3$) for the Primary Containment characteristic, two attributes ($i = 2$) for the Secondary Containment characteristic, and four attributes ($i = 4$) for the Attenuation Potential characteristic. These reflect the current version of the SRF and are subject to change in future revisions.

From this user input, a variety of averaged quantities is generated by the spreadsheet. The fundamental calculation the spreadsheet does is to add up the weighted property assessments and average them across the attributes to arrive at a score for each of the three fundamental characteristics. This is done for each of the j properties shown in Table 1, and then averaged over i attributes ($i = 3$ for Primary Containment and $i = 2$ for Secondary Containment, and $i = 4$ for Attenuation Potential (see Table 1)). The score (S) for site n is a function of the j properties and values (a)

$$S_n = \frac{1}{i}\sum_{1}^{i}\left[\sum_{j} w_j a_j\right]_i . \qquad (2)$$

For site n, the overall confidence (C) for the j properties and values is averaged over i attributes as follows:

$$C_n = \frac{1}{i}\sum_{1}^{i}\left[\frac{1}{j}\sum_{j} c_j\right]_i . \tag{3}$$

The results are summarized and displayed graphically in the plot on the Summary worksheet, an example of which is shown in Figure 5 for the Rio Vista Gas Field.

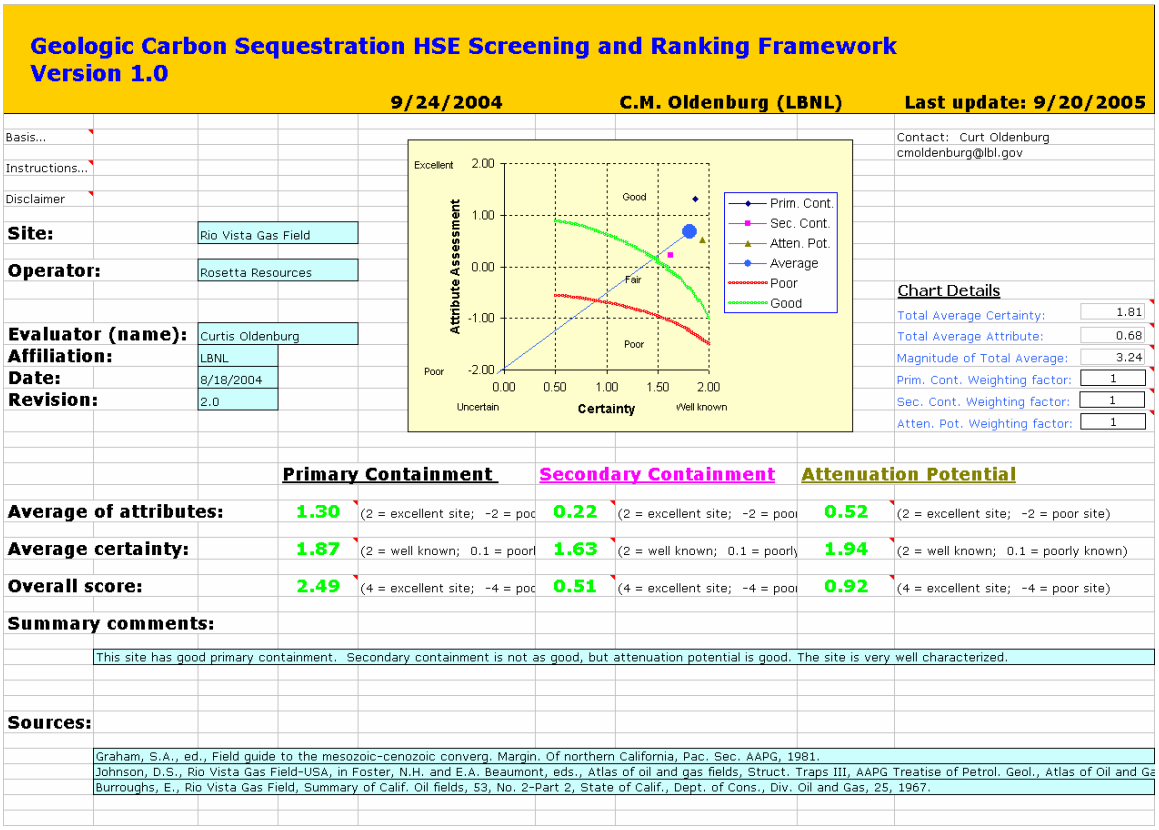


Figure 5. Summary graphic showing the attribute assessment (*y*-axis) and uncertainty (*x*-axis) of the three fundamental characteristics along with qualitative regions of poor, fair, and good HSE risk for the Rio Vista Gas Field

There are additional display elements of the Summary worksheet worthy of note. To the right of the plot in Figure 5 is a table ("Chart Details") containing numerical values of the averages of the three characteristics and certainties as shown by the large circle symbol in the plot. The third number—"Magnitude of Total Average"—in the "Chart Details" table is the distance from the lower-left-hand corner of the plot (lowest assessment, least certainty) to the average point. This distance is a measure of the overall quality of a site, taking into account both the average scores and average uncertainty. The three numbers

below the table are additional weighting factors that users can assign for the purpose of weighting the importance of the three characteristics, heretofore assumed to be of equal importance, and which are assigned default values of one. Additional scores of the three characteristics are displayed along the bottom of the plot and defined in comments. These scores are automatically colored based on the scores (red implies poor, green implies good). The overall score ranges from –4 to +4 and is a product of the assessments and uncertainties. The low end –4 would be a site that the user is very certain is very poor, while a +4 would be a site that the user is very certain is very good. Because the overall score collapses expected behavior and certainty together into one number, it is neither emphasized nor plotted, but rather included simply as additional information. The summary worksheet graphic displays tentative screening curves delineating Good, Fair, and Poor regions on the summary graphic. These screening curves are entirely provisional and arbitrary and may be modified in future versions.

It is important to emphasize that the relative assessments of different sites are not necessarily linearly related to their relative physical behaviors. For example, a site that scores a 1.0 for the primary containment characteristic does not necessarily leak 50% more than a site that scores 1.5 for primary containment. In fact, such sites could be orders of magnitude different in their ability to contain CO_2. The assessment scores simply represent relative rankings of the sites without indicating absolute performance.

4 Results and Discussion

4.1 Rio Vista Gas Field

The Rio Vista Gas Field is located in the delta region of the Sacramento-San Joaquin Rivers in the Sacramento Basin of California, approximately 75 km (47 mi) northeast of San Francisco. The Rio Vista Gas Field is the largest on-shore gas field in California, and has been producing gas since 1936 from reservoirs in an elongated dome-shaped structure extending over a 12 km by 15 km (7.5 mi by 9.3 mi) area. The largest production has been from the Domengine sands in fault traps at a depth of approximately 4,500 ft (1,400 m) with sealing by the Nortonville shale. Details of the field can be found in Burroughs (1967) and Johnson (1990).

We have used published materials and our knowledge of the geology of the area to fill in values in the SRF spreadsheet and arrive at overall attribute assessments and certainties for the Rio Vista Gas Field under the assumption that it would be used as a geologic CO_2 storage site. As shown in the Summary worksheet in Figure 5, the high attribute score displayed by the SRF spreadsheet reflects the very effective primary containment expected at Rio Vista. Secondary containment is not expected, as sealing formations above the Nortonville shale are largely absent; however, the attenuation potential is excellent at Rio Vista due largely to steady winds and flat topography. As shown in Figure 5, confidence in the attribute assessments is quite high for subsurface and surface characteristics at Rio Vista because of the long history of gas production at the site. The

high score and certainty at this site suggest that Rio Vista Gas Field is a good candidate for geologic CO_2 storage.

4.2 Ventura Oil Field

The Ventura Oil Field taps reservoirs in young folds and fault traps of marine sediments in the tectonically active coastal area northwest of Ventura, California. The primary structure is the Ventura Anticline, a dramatic fold that is visible in outcrop in the deeply incised canyons of the area. Natural oil seeps and tar are widely found in the area. Using geological information from published references (Sylvester and Brown, 1988; Harden, 1997) and our own knowledge of the site, we assigned values appropriate for the Ventura Oil Field to assess attributes and uncertainty for HSE risk if the site were to be used for geological CO_2 storage.

As shown in Figure 6, the Ventura Oil Field comes out worse on average than the Rio Vista Gas Field (Figure 5). The very significant oil accumulations at Ventura indicate that good traps exist, but the evidence of widespread oil and tar seepage along with the lack of significant natural gas accumulation suggest that pathways to the surface also exist. As for secondary containment, some of the oil reservoirs in the area are quite shallow, suggesting that secondary containment may occur but there is a high degree of uncertainty, especially in light of the abundant seepage. As for attenuation potential, the Ventura area is highly dissected with steep canyons that do not promote dispersion of seeping CO_2. There is also considerable population and agriculture to the southeast which could be exposed to seeping CO_2. Therefore, attenuation potential is also judged worse at Ventura than at Rio Vista.

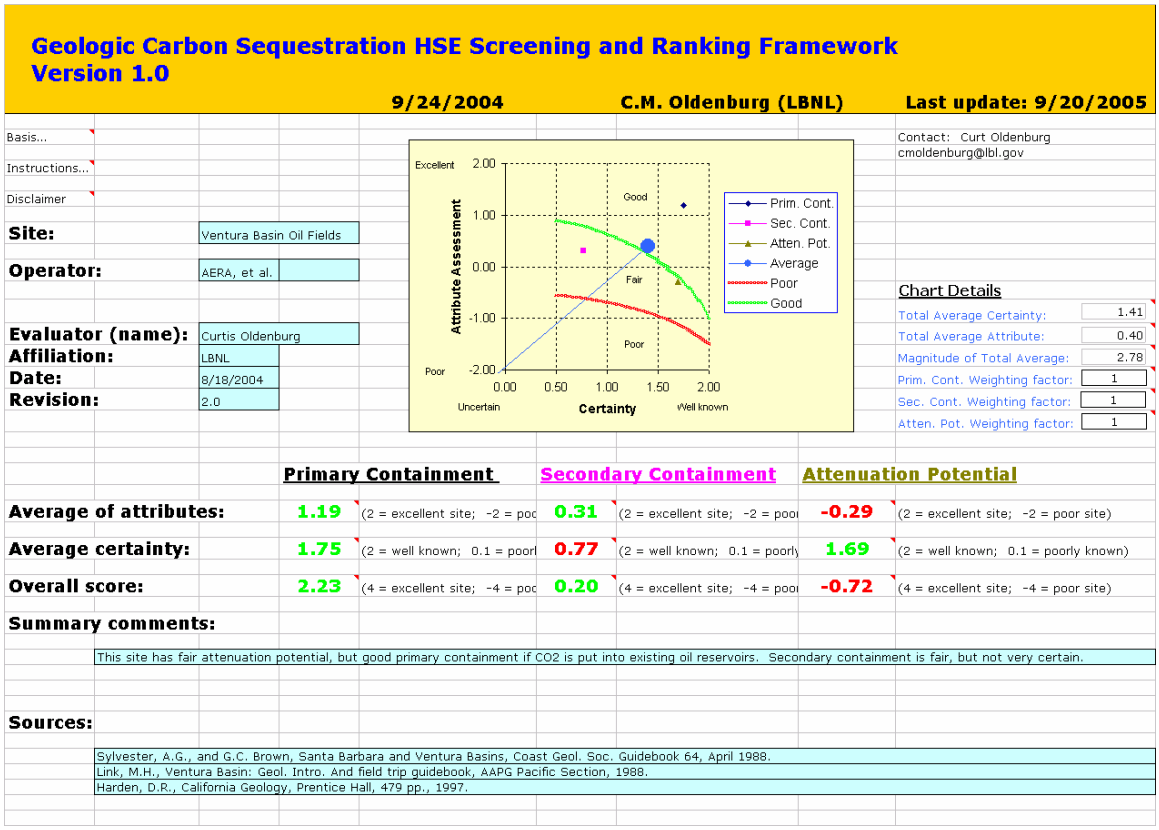


Figure 6. Summary worksheet showing the attribute assessment (*y*-axis) and uncertainty (*x*-axis) of the three fundamental characteristics for the Ventura Oil Field

4.3 Mammoth Mountain

Finally, this study ran an example of a naturally leaking site to see how it compares using the SRF. Mammoth Mountain, California, is a 200,000 year-old dormant volcano with active springs and geothermal anomalies. Carbon dioxide seeps out of the ground and has built up high enough concentrations in some areas in soil to kill native trees. For this purely academic analysis of the potential HSE effects of deliberate CO_2 injection, we assumed that the area under consideration was comparable to Rio Vista and Ventura in terms of size by considering the entire Mammoth Mountain area, not simply the Horseshoe Lake tree-kill area where natural CO_2 seeps from the ground.

Using published information from Farrar *et al.* (1995) and Sorey *et al.* (1999), we filled in values and properties of the SRF spreadsheet. Many of the properties are given the lowest values because they simply do not apply at Mammoth Mountain. For example, as evidenced by the extensive seepage, we concluded that there is no effective seal present, and therefore scored those properties with the lowest values. Other properties are not very well known and we scored them accordingly. As shown in Figure 7, the Mammoth Mountain site scored badly as expected in primary and secondary containment. The site

does better on attenuation potential because it is fairly windy there and the population is relatively sparse. Nevertheless, the SRF spreadsheet demonstrates what we knew *a priori*, namely, that Mammoth Mountain has natural CO_2 HSE risk and would not be a good place to store CO_2 in the subsurface.

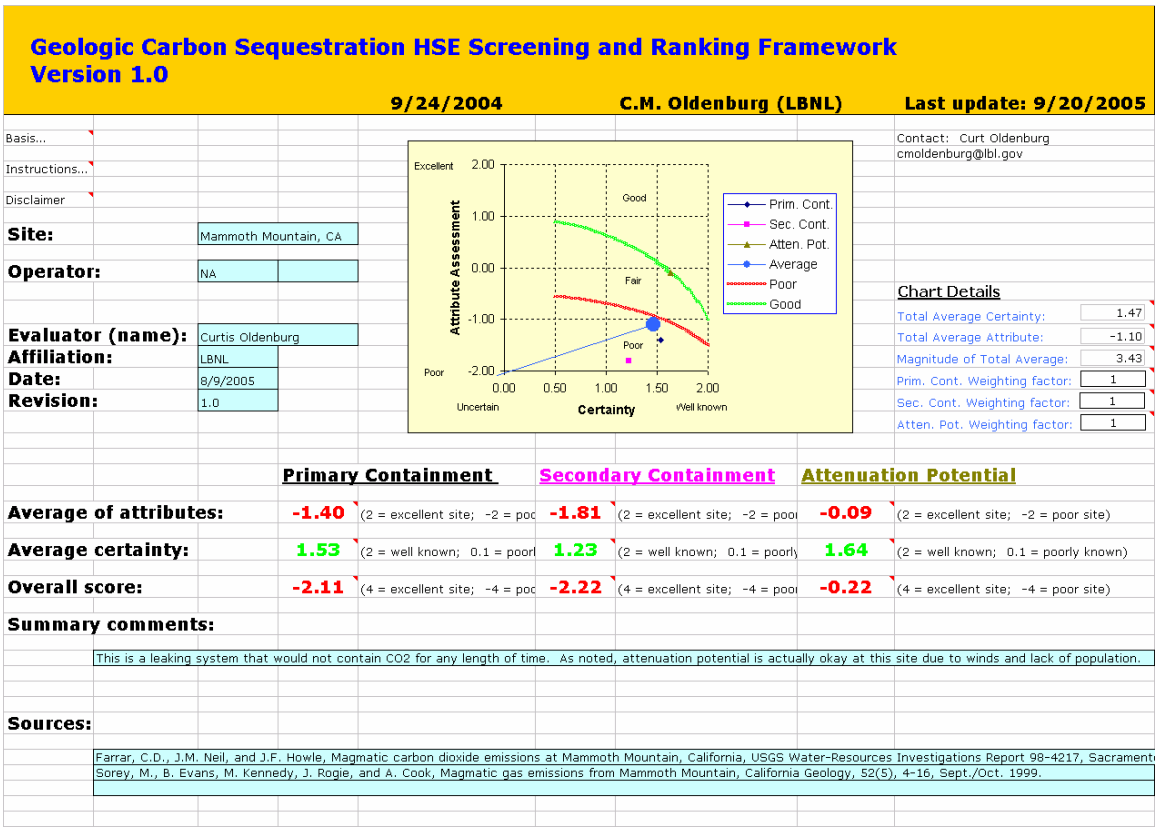


Figure 7. Summary graphic showing the attribute assessment (*y*-axis) and uncertainty (*x*-axis) of the three fundamental characteristics for the natural analog site Mammoth Mountain, California

5 Results and Discussion

The preceding demonstration of the SRF cannot formally be called a validation because no one has injected CO_2 into any of these sites and evaluated the three characteristics directly. Nevertheless, the results are consistent with our general knowledge and expectation of these three sites. The benefit of the SRF is that this knowledge and expectation is now formally expressed in a way that others can review, criticize, revise, or affirm. There is a large degree of arbitrariness allowed in the system by allowing the user to weight the importance of various properties. In the above examples, the weighting factors were the same for all three analyses. In the case that weighting functions are changed for various sites under comparison, it will be more difficult to defend direct comparisons. Nevertheless, the transparency of the system and simplicity will allow a critic or reviewer to alter the weighting functions and do the analysis again to compare

the effect. Group efforts with multiple people evaluating the same sites may prove especially useful because this strategy would tend to capture a large range of opinions while simultaneously bringing uniformity to comparisons. As with any tool, misuse is possible and the SRF assumes an underlying integrity of the users. Because of the transparency and simplicity of the system, there is little possibility to hide abuses.

Several extensions of the system are possible. First, as more data become available, distributions—rather than single values—could be input by the user where such distributions are known. This approach would add a component of variability to the outcome, and potentially better represent the range of performance of a site rather than a worst-case, best-case, or average performance.

As shown in Table 1, the values and properties entered by the user combine to represent proxies for site characterization data that may not be known precisely. For example, for the Primary Containment attribute "Primary Seal", lithology is a proxy for permeability and porosity. The idea here is that permeability and porosity may not have been measured but that the known lithology of the seal provides a fair representation of these properties. This proxy representation also occurs at the scale of the attribute. For example, the primary seal attribute is evaluated by assigning values and properties (e.g., thickness, lithology) to describe it. The combination of these values and properties is a proxy for the expected effectiveness of the seal. This proxy could be replaced by data or model results that represent seal effectiveness in more detail, e.g., by quantitative prediction of CO_2 flux. In this way, the SRF can be extended if more site characterization data are available to include more quantitative measures of performance. On the value and property scale, quantitative data or distributions could be input and evaluated if these data were available. On the attribute scale, model simulations or experimental data could be input and evaluated for sites undergoing more detailed levels of site characterization.

6 Conclusions

A framework for screening and ranking candidate sites for geologic CO_2 storage on the basis of HSE risk has been developed based on three fundamental characteristics of a CO_2 sequestration site. The framework allows users to arbitrarily weight and assign uncertainty to the properties of the attributes of the fundamental characteristics to evaluate and rank two or more sites relative to each other. We emphasize that this is a screening and ranking risk assessment tool intended to guide the selection of the most promising sites for which more detailed risk assessment would be carried out. Example applications of the framework show that comparative evaluations of prospective sites with limited characterization data can be accomplished based on potential for CO_2 leakage and seepage and related HSE risk. Testing and further development of the SRF are underway.

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Appendix XIII, Final Report

Regulatory and Permitting Issues

Topical Report

West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Terralog Technologies USA, Inc.

September 30, 2005

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Abstract

As part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB), Terralog Technologies USA, Inc., reviewed current state and federal regulations related to carbon dioxide capture and storage within geologic formations and enhanced carbon uptake in terrestrial ecosystems. We have evaluated and summarized the current and possible future permitting requirements for the six states that comprise the West Coast Regional Partnership. Four options exist for CO_2 injection into appropriate geologic formations, including storage in: (1) oil and gas reservoirs, (2) saline formations, (3) unmineable coal beds, and (4) salt caverns. Terrestrial CO_2 sequestration involves improved carbon conservation management (*e.g.* reduction of deforestation), carbon substitution (*e.g.,* substitution for fossil fuel-based products, energy conservation through urban forestry, biomass for energy generation), and improved carbon storage management (*e.g.,* expanding the storage of carbon in forest ecosystems). The primary terrestrial options for the West Coast Region include: (1) reforestation of under-producing lands (including streamside forest restoration), (2) improved forest management, (3) forest protection and conservation, and (4) fuel treatments for the reduction of risk of uncharacteristically severe fires (potentially with associated biomass energy generation). The permits and/or contracts required for any land-use changes/disturbances and biomass energy generation that may occur as part of WESTCARB's activities have been summarized for each state.

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1 Executive Summary

In 1997, the U.S. Department of Energy (DOE) started the Carbon Sequestration Program. Carbon dioxide (CO_2) is a potent greenhouse gas. Carbon dioxide capture and storage within geologic formations and enhanced carbon uptake in terrestrial ecosystems are the two main sequestration options. Seven Regional Carbon Sequestration Partnerships were formed; Terralog Technologies belongs to the West Coast Regional Carbon Sequestration Partnership (WESTCARB) and is responsible for reporting on the regulatory and permitting issues for CO_2 sequestration.

Carbon dioxide generated from industrial activities can be sequestered through capturing, transporting, and injecting it into appropriate geologic formations, or through uptake by terrestrial ecosystems. For injection into appropriate geologic formations, options include storage in:

- Oil and gas reservoirs,
- Saline formations,
- Unmineable coal beds, and
- Salt caverns.

Injection of CO_2 into geologic formations requires an Underground Injection Control (UIC) permit from the U.S. Environmental Protection Agency (EPA). EPA has delegated primary regulatory authority to state agencies that have demonstrated an ability to implement UIC programs that meet EPA requirements. These states are referred to as "primacy states". In states that have not received primacy status, the responsible permitting agency is EPA. Currently, EPA does not differentiate between CO_2 storage and CO_2 disposal in any geologic formation, but is endeavoring to ensure a universal standard and perhaps classification to which all agencies will adhere. The permit requirements for each of the above options have been documented and their respective regulations cited. We suggest that EPA should promulgate the ruling with input from the states and standardize the different regulations that exist for different states.

Terrestrial CO_2 sequestration involves improved carbon conservation management (*e.g.* reduction of deforestation), carbon substitution (*e.g.,* substitution for fossil fuel-based products, energy conservation through urban forestry, biomass for energy generation), and improved carbon storage management (*e.g.,* expanding the storage of carbon in forest ecosystems). Terrestrial options available to the WESTCARB partnership are:

- Reforestation of under-producing lands (including streamside forest restoration),
- Improved forest management,
- Forest protection and conservation, and
- Fuel treatments for the reduction of risk of uncharacteristically severe fires (potentially with associated biomass energy generation).

The required permit/contract for any land use changes/disturbances and biomass energy generation have been summarized for each state. To date, biomass energy generation is not economically feasible without some form of government subsidy or tax credit.

2 Experimental

No experiment was performed for this report. All regulatory reviews and CO_2 sequestration options are described in detail under their respective headings (see Table of Contents).

3 Results and Discussion

3.1 Regulatory Overview

Carbon dioxide (CO_2) generated from industrial activities can be sequestered by capturing, transporting, and injecting it into appropriate geologic formations, or through uptake by terrestrial ecosystems. It is generated by power plants, natural gas operations, refineries, iron and steel industry, petrochemical industries, and hydrogen or methanol production (Herzog *et al.*, 1997). CO_2 is not currently listed as hazardous waste, and it is not regulated under the Clean Water Act (68FR52922-52933).

Injection of CO_2 into appropriate geologic formations requires an Underground Injection Control (UIC) permit from the U.S. Environmental Protection Agency (EPA). The UIC Program was established under the provisions of the Safe Drinking Water Act of 1974 to protect underground sources of useable water. Under this program, five classifications of wells were established:

- Class I – wells used to inject liquid hazardous wastes, industrial non-hazardous liquid, and municipal wastewater beneath the lowermost drinking-water reservoir;
- Class II – wells used to dispose of fluids associated with the production of oil and natural gas, enhanced oil recovery, and storage of liquid hydrocarbon;
- Class III – wells used to inject fluids for the extraction of minerals;
- Class IV – wells used to dispose of hazardous or radioactive wastes into or above drinking water. EPA has banned the use of these Class IV wells; and
- Class V – wells not included in the other classes used to generally inject non-hazardous fluid into or above drinking water.

See "Classification of Wells for Injection of CO_2" (below) for a discussion of permitting of underground CO_2 injection under existing UIC regulations.

EPA has delegated primary regulatory authority to state agencies that have demonstrated an ability to implement UIC programs that meet EPA requirements. These states are referred to as "primacy states". In many of these states, more than one state agency has primary regulatory authority for one or more classes of injection wells. In states that have not received primacy, the responsible agency is EPA.

3.2 Pipeline Transportation

The most economical means of transporting captured CO_2 is by pipelines. Depending on supply and demand, the transportation of CO_2 may involve temporary storage in either some storage tanks or geological reservoirs before the CO_2 is permanently disposed of within geologic formations.

Pipelines are regulated by U.S. Department of Transportation (DOT), Occupational Safety and Health Administration's (OSHA's) confined space regulation, and each State's Fire Marshall or Public Utility Commission (PUC). In addition, pipelines from wellhead to lease property may be regulated by each State's equivalent of a Division of Oil and Gas. Table 1 (below) shows the regulations cited by Federal authorities and the responsible state agencies.

Table 1. Federal and state pipeline regulations. (See Appendix I for an explanation of acronyms.)

STATE/ FEDERAL	REGULATING AGENCY	REGULATIONS CITED
Federal	DOT OSHA (confined space) FERC (construction)	49CFR190-199 29CFR1910.146 18 CFR part 1- 399
Alaska	Defer to DOT	49CFR195
Arizona	Arizona Corporate Commission	ACC R14-5-201 to R14-5-205
California	Fire Marshall DOGGR	Gov. Code Sec 51010 to 51019.1, AB592 DOGGR Pipeline regulations
Nevada	Public Service Commission	NAC 704.455 to 704.465
Oregon	PUC	PUC Div.31, 860-031-0001 to 860-031-0041
Washington	UTC	House Bill 2420, Ch191, Laws of 2000, RCW Ch81.11

CO_2 may also be temporary stored in Aboveground Storage Tanks (AST) and transported via pipeline to its final sequestered location at some later time. There is no regulation for CO_2 in aboveground tanks; however, AST is subjected to American Petroleum Institute

standards, Underwriters Laboratories Inc. requirements, and American Water Works Association guidelines.

3.3 Classification of Wells for Injection of CO_2

All six western States belonging to WESTCARB (*i.e.,* Alaska, Arizona, California, Nevada, Oregon, and Washington) define CO_2 as a product when used with enhanced oil recovery (EOR) projects; hence, CO_2 can be injected into a well classified as Class II. For CO_2 injection not related to EOR, the classification of CO_2 as a product or a waste will influence the type of injection well as well as the regulating agency.

The regulations on CO_2 injection wells are currently in flux. It has been suggested by some that CO_2 injection wells should be classified in EPA UIC Class II category (IOGCC, 2005). As of the writing of this report, the authors understand that EPA will probably make no distinction between storage and disposal into any medium such as oil and gas reservoirs, saline formations, coal beds, or salt, nor will EPA distinguish whether the CO_2 is in gaseous or liquid phase. EPA Region X, which includes Alaska, Oregon, and Washington, will probably permit CO_2 injection wells as Class V regardless of whether they are for storage or disposal with permit conditions similar to Class I. However, EPA Region IX will probably permit these well as Class I. EPA needs to ensure that injection wells will have the same standard, regardless of the well classification, and should ensure a universal standard to which all primacy-state agencies will adhere. Ultimately EPA, with input from the States, will have to decide on the proper classification of CO_2.

3.4 Sequestration Options

CO_2 can either be injected into suitable geologic formations or be captured through uptake by terrestrial ecosystems.

3.4.1 Geologic Sequestration Options

Currently, the only permits issued for CO_2 injection within the six States belonging to WESTCARB are for EOR-related injection. The States and the Federal government make no clear distinction between CO_2 storage and CO_2 disposal and, at this time, it appears that EPA will probably treat the storage and disposal of CO_2 by injection in the same category. The responsible agency involved with permitting depends on whether the injection is located on State, Federal or Indian lands and if the state has primacy status with EPA.

For injection on Indian lands, EPA will be the permitting agency. As of the writing of this report, no Indian Nation has primacy status; however, the Navajo Nation is close to obtaining primacy status. For injection on Federal lands, EPA will also be the regulatory agency, and will notify the corresponding state agency and the Bureau of Land Management of the injection. For injection on State lands, the responsible agency will depend on whether or not the state has primacy status with EPA.

The options for geologic sequestration of CO_2, including storage in:

- Oil and gas reservoirs,
- Saline formations,
- Unmineable coal beds, and
- Salt caverns.

Are outlined in the following sections.

3.4.1.1 Oil and Gas Reservoirs

CO_2 injected into oil and gas reservoirs for enhanced oil recovery (EOR) is currently classified as Class II by all 6 western States. CO_2 is classified as a product to enhance the recovery of hydrocarbons in depleted fields. In places where states have primacy, the agencies involved (see Table 2) have control over the Class II well. In states where EPA shares primacy, e.g. Alaska and California; EPA and the state will jointly administer the Class II program. In California, the Division of Oil, Gas, and Geothermal Resources (DOGGR) will issue a Class II well permit. In Alaska, the Oil and Gas Conservation Commission (OGCC) will issue a Class IIR (Enhanced Recovery) well permit for the EOR well. Arizona has no primacy status, so EPA will issue a Class II well permit. However, Arizona OGCC has secondary jurisdiction and an Aquifer Protection Permit is also required from the Department of Environmental Quality (DEQ). A well permitted by EPA may start out as Class II when there is EOR activity, but when EOR activity stops, the well will be reclassified as either Class I or V depending on which EPA jurisdiction it falls within.

Table 2. Federal and state EOR permit requirements. (See Appendix I for an explanation of acronyms.)

STATE	REGULATING AGENCY	WELL/PERMIT TYPE	REGULATIONS CITED
Alaska	EPA OGCC share primacy w/EPA	Class IIR	40CFR144-148 20AAC25; 31 AK O&G Consvr. Act Ch31.05
Arizona	EPA no primacy w/state OGCC DEQ	Class II 2nd jurisdiction Aquifer Protection Permit	40CFR144-148 12AAC7; ARS 27-516 ARS 49-241; 18AAC,Ch9
California	EPA DOGGR share primacy w/EPA	Class II	40CFR144-148 14CCR Div2, Ch2, 4; Public Resources Code 30262
Nevada	DEP DOM BLM	Class II (Interagency Cooperation between 3 agencies)	NAC445A.810 to 445A.925 NAC Ch522; NRS 445A.470 43CFR Ch2 Part3160
Oregon	DEQ DOGAMI	Class II Interagency cooperation	40CFR144-148; 44OAR340-044-0005 and Appendix A OAR Ch.632 Div. 10; ORS 520
Washington	Dept. of Ecology DNR	Class II (joint control)	40CFR144-148; WAC173-218 78.52 RCW

Currently, all CO_2 injection into oil and gas reservoirs is associated with EOR. The permitting situation for injection into depleted oil and gas reservoirs that will not be related to EOR or enhanced gas recovery (EGR) will likely be similar to that for saline formation. See the section on Saline Formations (below) for a discussion of how agencies might permit this type of injection.

3.4.1.2 Saline Formations

Regulations of CO_2 injection in saline formations are not yet well defined and are not consistent between states. For example, Nevada, Oregon, and Washington prohibit Class I wells. In Oregon and Washington, EPA Region X will probably classify CO_2 injection wells as Class V; however, Oregon only allows shallow Class V wells—less than 30 m (100 ft.) deep—because of subsurface conditions. In EPA Region IX, which includes

Arizona, California, and Nevada, CO_2 injection wells will most probably be classified as Class I; however, similar to Oregon, Nevada prohibits Class I wells because of subsurface conditions. It should be noted that the different classifications of CO_2 wells is of lesser importance when compared to operational requirements (based on criteria, standards, geology, for example) for each CO_2 injection application.

In Alaska, the OGCC permits disposal (including CO_2) as Class IID wells. This classification depends on the fluid stream and a compatibility demonstration; for example, kitchen and compound wastes can be disposed of using Class IID well if the disposal is used for flooding purposes. Table 3 (below) summarizes permit conditions and regulations for CO_2 injection not related to EOR.

Table 3. Federal and state potential permit requirements for CO_2 injection NOT related to EOR. (See Appendix I for an explanation of acronyms.)

STATE	REGULATING AGENCY	WELL/PERMIT TYPE (If not EOR related)	REGULATIONS CITED
Alaska	EPA OGCC share Class II primacy w/EPA	Class V	40CFR144-148 20AAC25; 31 AK O&G Consvr. Act Ch31.05
Arizona	EPA no primacy w/state OGCC	Class I	40CFR144-148 12AAC7; ARS 27-516
California	EPA DOGGR share Class II primacy w/EPA	Class I	40CFR144-148 14CCR Div2, Ch2, 4; Public Resources Code 30262
Nevada	DEP DOM BLM joint interagency cooperation	Unknown, Class I prohibited	NAC445A.810 to 445A.925 NAC Ch522; NRS 445A.470 43CFR Ch2 Part3160
Oregon	DEQ DOGAMI	Class V, <30 m (100 ft.) well only Interagency cooperation	44 OAR 340-044-0005 and Appendix A OAR Ch.632 Div. 10; ORS 520
Washington	Dept. of Ecology	Class V	40CFR144-148; WAC173-218

3.4.1.3 Methane-Bearing Coal Beds

Regulations for CO_2 injection into coal beds for enhanced coal-bed methane (ECBM) recovery vary among the three WESTCARB states (Alaska, Arizona, and Washington) that have sizable deposits (Hart's E&Pnet, see Figure 1). Washington (primacy status) has permitted one Class II injection well for ECBM. Since ECBM deals with hydrocarbon recovery, it appears that CO_2 injection for ECBM would lead to a Class II classification. CO_2 injection for ECBM can be thought of as a form of EGR. Alaska OGCC will jointly administer Class II well with EPA (share primacy) for EGR injection. Because Arizona has no primacy status, EPA will administer the Class II well program for EGR in this state. For non-EGR-related injection in states without primacy, EPA Region X most probably will permit the CO_2 injection regardless if it is for storage or disposal as Class V well with permit conditions similar to Class I. EPA Region IX will most probably permit ECBM-related wells as Class I.

Storage of CO_2 in ECBM produces a significant amount of water during the initial injection phase, and the disposal of the water produced may require a National Pollutant Discharge and Elimination System (NPDES) permit (Veil, 2002).

Table 4. Federal and state potential coal-bed methane permit requirements. (See Appendix I for an explanation of acronyms.)

STATE	REGULATING AGENCY	WELL/PERMIT TYPE	REGULATIONS CITED
Alaska	EPA OGCC share primacy w/EPA	Class V non EGR related Class II for EGR	40CFR144-148; CWA 40CFR 122, 40CFR147.52 20AAC25; 31 AK O&G Consvr. Act Ch31.05
Arizona	EPA no primacy w/state DEQ	Class II for EGR Class I non EGR related Aquifer Protection Permit	40CFR144-148; CWA 40CFR 122; 40CFR147.52 ARS 49-241; 18AAC Ch9
Washington	Dept. of Ecology DNR	Class II Waste Water Permit Class II (joint control with Dept. of Ecology	40CFR144-148; CWA 40CFR 122, 40CFR147.52; WAC173-218 WAC173-226 78.52 RCW

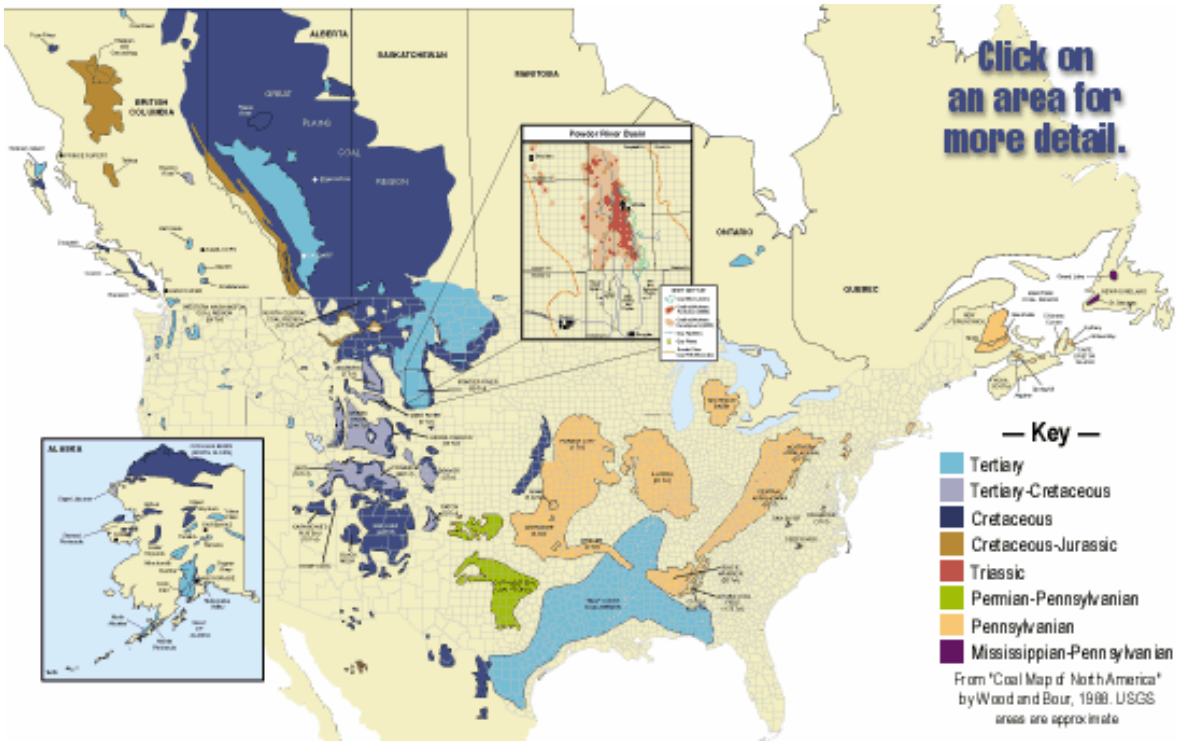


Figure 1. North America coal-bed methane resource map
Source: Hart's E&P Magazine

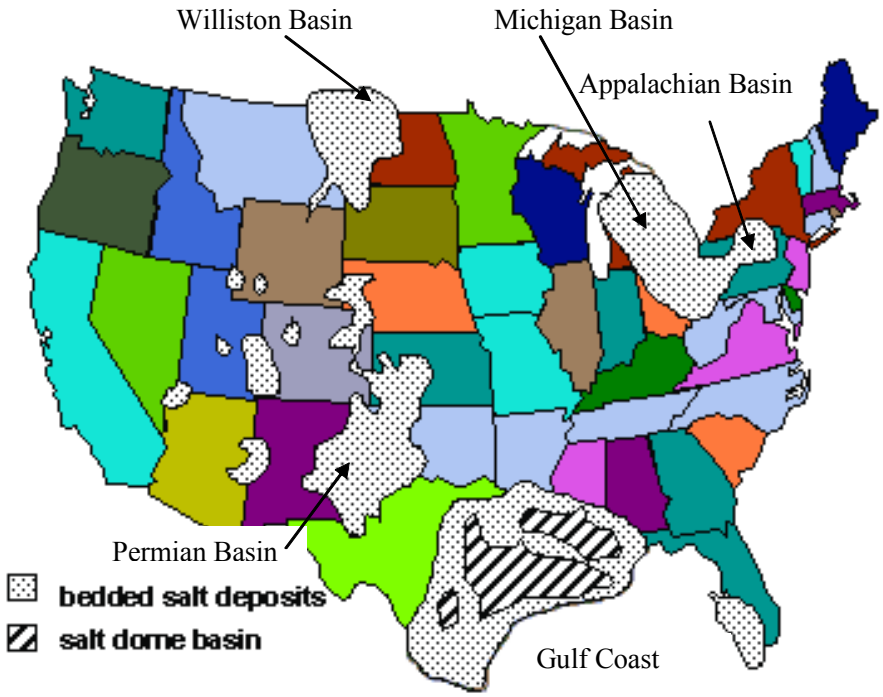
3.4.1.4 Salt Caverns

Arizona is the only state within the West Coast Regional Carbon Sequestration Partnership that has sizable salt deposits (Figure 2). In Arizona, two classes of well are defined for this type of reservoir: (1) a Class I well permit is required to solution-mine salt deposits, and (2) a Class II well permit is required for the injection of CO_2 into the caverns for EOR purposes. An Aquifer Protection Permit is also required. If CO_2 injection is not related to EOR and is to be disposed or stored into salt cavern, a Class I permit will be maintained.

Table 5 shows the potential permit requirements for salt -cavern storage of CO_2.

Table 5. Potential salt cavern permit requirements. (See Appendix I for an explanation of acronyms.)

STATE	REGULATING AGENCY	WELL/PERMIT TYPE	REGULATIONS CITED
Arizona	EPA OGCC DEQ	Class I (solution mining of salt and non EOR related) Class II (for EOR related 2nd jurisdiction for Class II Aquifer Protection Permit	40CFR144-148 12AAC Ch7 ARS 49-241; 18AAC,Ch9



Source: National Petroleum Technology Office

Figure 2. Major salt basins in the U.S.

3.4.2 Terrestrial Options

Terrestrial CO_2 sequestration options applicable to the WESTCARB region include carbon conservation, carbon substitution, and carbon storage. Carbon conservation deals with maintaining the forestland base, reducing deforestation, reducing forest degradation by protecting forests from fires and pests, and modifying forest management through

extended rotation (as well as other techniques). Carbon substitution deals with substitution for fossil fuel-based products, energy conservation through urban forestry (*e.g.,* reducing fossil fuel consumption by using shade trees to keep buildings cool), and biomass for energy generation. Carbon storage deals with afforestation (forestation of previously unforested land), tree growth, agroforestry, and commercial forestry management (Vine, 2003). The primary terrestrial options in the WESTCARB states of Arizona, California, Oregon, and Washington are:

- Reforestation of under-producing lands (including streamside forest restoration),
- Improved forest management,
- Forest protection and conservation, and
- Fuel treatments for the reduction of the risk of uncharacteristically severe fires (potentially with associated biomass energy generation).

Both Federal and State agencies will require a permit for any land-use changes or disturbances including improved forest management, forestation, and riparian conservation. The top three options mentioned above all involve some form of land-use changes or disturbances, and hence will have the same set of permitting requirements. Terrestrial sequestration options will be discussed in two separate categories: (1) land-use changes or disturbances and (2) biomass energy generation.

3.4.2.1 Land-Use Changes or Disturbances

There are three types of land ownership pertinent to terrestrial CO_2 sequestration: Federal, State, and private. Tables below define the terrestrial CO_2 sequestration permit/contracts requirements for the WESTCARB states of Arizona (Table 6), California (Table 7), Oregon (Table 8) and Washington (Table 9). Federal land can be managed by either the U.S. Department of Agriculture, U.S. Department of Interior (UDSI) through the National Park Services, Bureau of Land Management (BLM), or Bureau of Indian Affairs. Regulations affecting private land management depend on whether the land is classified as private forest land or private ranchland.

Table 6. Potential Arizona permits/contracts for land-use changes or disturbances. (See Appendix I for an explanation of acronyms.)

TYPE OF LAND		REGULATING AGENCY	REGULATIONS CITED
State land		State Land Dept. Dept. of Fish & Wildlife DEQ (Water Quality) U.S. Fish and Game	ARS Title 37-102 and 37-622 ARS Title 17 Ch3 AAC Title 18 Ch9 50CFR17
Federal land	USDA	USDA Dept. of Fish and Game U.S. Fish and Game	36CFR Ch1 part 1 ARS Title 17 Ch3 50CFR17
	USDI – National Parks	Not allowed	
	USDI – BLM	BLM Dept. of Fish and Game U.S. Fish and Game	43CFR part 5000-5510 ARS Title 17 Ch3 50CFR17
	USDI – Tribal land	USDI BLM Local tribunal	25CFR part1 and 163 All BLM regulations HR3826 (Tribal Forest Protection Act); local tribunal laws
Private land	Forest land	Same as State land	State land regulations
	Ranch land	County/city planning DEQ (Water Quality) Dept. of Fish and Game U.S. Fish and Game	Various county/city zoning codes AAC Title 18 Ch9 ARS Title 17 Ch3 50CFR17

Table 7. Potential California permits/contracts for land-use changes or disturbances. (See Appendix I for an explanation of acronyms.)

TYPE OF LAND		REGULATING AGENCY	REGULATIONS CITED
State land		Dept. of Forestry & Fire Protection Dept. of Fish and Game CEQA RWQCB U.S. Fish and Game	Pub Resource Code Div4 and 13; California Forest Practice Act 14CCR Div 1 Pub Resource Code Div 13 Water Code 13000 (Porter Cologne Water Quality Act) 50CFR17
Federal land	USDA	USDA Dept. of Fish and Game U.S. Fish and Game CEQA	36CFR Ch1 part 1 14CCR Div 1 50CFR17 Pub Resource Code Div 13
	USDI – National Parks	Not allowed	
	USDI – BLM	BLM Dept. of Fish and Game U.S. Fish and Game	43CFR part 5000-5510 14CCR Div 1 50CFR17
	USDI – Tribal land	USDI BLM Local tribunal	25CFR part1 and 163 All BLM regulations HR3826 (Tribal Forest Protection Act); local tribunal laws
Private land	Forest land	Same as State land	State land regulations
	Ranch land	Same as State land	State land regulations

Table 8. Potential Oregon permits/contracts for land-use changes or disturbances. (See Appendix I for an explanation of acronyms.)

TYPE OF LAND		REGULATING AGENCY	REGULATIONS CITED
State land		ODF Dept. of Fish and Game Div. of State Lands (if impact waterways) U.S. Army Corps of Engineers (if fill wetlands or waterways) U.S. Fish and Game	OAR Ch629; ORS 527.610, State Forest Management Plan OAR Ch635 ORS 195.795-196.990 CWA Sec404 50CFR17
Federal land	USDA	USDA Dept. of Fish and Game U.S. Fish and Game	36CFR Ch1 part 1 OAR Ch635 50CFR17
	USDI – National Parks	Not allowed	
	USDI – BLM	BLM Dept. of Fish & Game U.S. Fish & Game	43CFR part 5000-5510 OAR Ch635 50CFR17
	USDI – Tribal land	USDI BLM Local tribunal	25CFR part1 and 163 All BLM regulations HR3826 (Tribal Forest Protection Act); local tribunal laws
Private land	Forest land	Same as State land	State land regulations except less stringent
	Ranch land	ODA (agriculture water quality review) Div. of State Lands (if impact waterways) U.S. Army Corps of Engineers (if fill wetlands or waterways) County planning dept.	ORS603 Div 80, 90 and 95; SB1010 ORS 195.795-196.990 CWA Sec404 Various county planning regulations

Table 9. Potential Washington permits/contracts for land-use changes or disturbances. (See Appendix I for an explanation of acronyms.)

TYPE OF LAND		REGULATING AGENCY	REGULATIONS CITED
State land		DNR Dept. of Fish and Game Dept. of Ecology (SEPA requirements) (Water Right Permit) U.S. Fish and Game	WAC Title 222 WAC Title 220 and 232 RCW43.21C WAC Title 173-152 and 173-173 50CFR17
Federal land	USDA	USDA Dept. of Fish and Game U.S. Fish and Game	36CFR Ch1 part 1 WAC Title 220 and 232 50CFR17
	USDI – National Parks	Not allowed	
	USDI – BLM	BLM Dept. of Fish and Game U.S. Fish and Game	43CFR part 5000-5510 WAC Title 220 and 232 50CFR17
	USDI – Tribal land	USDI BLM Local tribunal	25CFR part1 and 163 All BLM regulations HR3826 (Tribal Forest Protection Act); local tribunal laws
Private land	Forest land	Same as State land	State land regulations
	Ranch land	County planning dept. Dept. of Ecology (water right permit)	Various county planning regulations WAC Title 173-152 and 173-173

3.4.2.2 Biomass Energy Generation

Arizona, California, Oregon, and Washington all have the same permitting requirements for the biomass CO_2 sequestration option. Besides the State or Federal requirements discussed in the previous section, local air district, water board, and county/city planning department rules will be applicable.

Biomass is not yet economical, but can be if government will provide subsidies or tax credits. Beside local county/city planning department regulations, building of power plant for biomass energy generation will require local air district approval as well as an NPDES permit from the water board for the effluent discharge. Dead wood removal also requires a contract/permit from the land owner.

Table 10. Biomass permit contract requirements

REGULATING AGENCY	REGULATIONS CITED
State or Federal	See existing State land or Federal land regulations
Local air district	New source review (BACT); air permit
Water board	NPDES permit; water right permit
City/county planning dept.	Conditional use permit; City/county planning building permit

4 Conclusions and Recommendations

In order for CO_2 sequestration to be viable, EPA will first have to standardize injection regulations and government will possibly need to give some tax incentive or credit.

Carbon dioxide generated from industrial activities can be captured, transported and sequestered either by injecting into appropriate geologic formations, or capturing through carbon intake into the terrestrial ecosystems. EPA will probably make no distinction between storage and disposal into any medium, nor if in gaseous or liquid phase. For injection into appropriate geologic formations, options include storage in:

- Oil and gas reservoirs,
- Saline formations,
- Unmineable coal beds, and
- Salt caverns.

The permit requirements for each of the above options have been documented and their respective regulations cited. It is not yet clear how the classification of CO_2 as product or waste will influence the type of injection well or the regulating agency. EPA will most probably not differentiate between storage and disposal. Regardless of the well classification, the well will have the same standard; EPA is endeavoring to ensure a universal standard and perhaps classification to which all agencies will adhere. Ultimately, EPA, with the States' input will have to decide on the proper classification of CO_2. The classification is of lesser importance than the regulatory operational concerns such as the requirements based on criteria, standards, geology, etc., for each CO_2 injection well.

Terrestrial CO_2 sequestration involves carbon conservation, substitution and storage. The primary terrestrial options for the West Coast Regional Partnership states of Arizona, California, Oregon, and Washington are:

- Reforestation of under-producing lands (including streamside forest restoration),
- Improved forest management,
- Forest protection and conservation, and
- Fuel treatments for the reduction of risk of uncharacteristically severe fires (potentially with associated biomass energy generation).

The required permit/contract for any land use changes/disturbances and biomass energy generation have been summarized for each state. To date, biomass energy generation is not feasible without some form of government subsidy or tax credit.

Table 11 (below) shows the relative efforts in obtaining the required permits for CO_2 sequestration for the different injection and terrestrial options pertinent to the WESTCARB region. Injection of CO_2 for EOR-related projects is allowed by all states and therefore the permit is relatively easy to obtain. States with primacy will control the Class II well injection through their respective state agencies and EPA for those states without the primacy status. For the relative efforts involved in obtaining terrestrial CO_2 permits, most terrestrial options fall between two extreme cases: (1) already-in-operation (*e.g.*, EOR), to (2) not permitted (*e.g.*, harvesting in National Parks).

Table 11. Table of relative efforts

OPTIONS (from easy to difficult)	**REASONS**
EOR	In operation Class II wells for State with primacy, EPA without primacy
U.S. Dept. of Agriculture – Forest Service	Permit from U.S. Department of Agriculture, Forest Service U.S. Fish and Game (endangered species review) State Fish and Game (State endangered species review)
U.S. Dept. of Interior – BLM	Permit from BLM U.S. Fish and Game (endangered species review) State Fish and Game (State endangered species review)
State forestlands	Permit from State Forest and Fire Dept. State Dept. of Fish and Game U.S. Fish and Game Water right or usage permit U.S. Army Corps of Engineers (Oregon only if fills wetlands or waterways) Div. of State Lands (Oregon only if impacts waterways) CEQA (CA) SEPA (WA) review
Private forestlands Private ranchlands	Permit from State Forest and Fire Dept. State Dept. of Fish and Game U.S. Fish and Game Water right or usage permit County planning dept. (Oregon and Washington only) U.S. Army Corps of Engineers (Oregon only if fills wetlands or waterways)

	Div. of State Lands (Oregon only if impacts waterways) CEQA (CA) SEPA (WA) review
U.S. Dept. of the Interior – Indian Lands	Permit from BLM U.S. Fish and Game (Endangered species review) State Fish and Game (State endangered species review) Local tribunal laws
Subsurface Storage and Disposal	Uncertain depending on classification of CO_2 as product or waste
Biomass	Local air permit (BACT, new source review) NPDES permit County planning dept. Permit from State forest and fire dept. State Dept. of Fish and Game U.S. Fish and Game Water right or usage permit U.S. Army Corps of Engineers (Oregon only if fills wetlands or waterways) Div. of State Lands (Oregon only if impacts waterways) CEQA (CA) SEPA (WA) review Uneconomical without tax credit or government subsidy
U.S. Dept. of Interiors – National Parks	No harvesting allowed

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Appendix

AB	Assembly Bill
ACC	Alaska Administrative Code
ACC	Arizona Administrative Code
ARS	Arizona Revised Statues
AST	Aboveground storage tank
BACT	Best Available Control Technology
BLM	Bureau of Land Management
ECBM	Enhanced Coal-Bed Methane
CCR	California Code of Regulations
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DNR	Department of Natural Resources
DOGGR	California Division of Oil, Gas and Geothermal Resources
DOM	Division of Minerals
DOT	Department of Transportation
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
HR	House Rule
FERC	Federal Energy Regulatory Commission
NAC	Nevada Administrative Code
NPDES	National Pollutant Discharge and Elimination System
NRS	Nevada Revised Statutes
OAR	Oregon Administrative Rule
ODA	Oregon Department of Agriculture
ODF	Oregon Department of Forestry
OGCC	Oil and Gas Conservation Commission
OSHA	Occupational Safety and Health Administration
PUC	Public Utility Commission
RWQCB	Regional Water Quality Control Board
SEPA	State Environmental Protection Act
USDA	U.S. Department of Agriculture
USDI	U.S. Department of Interior
UIC	Underground Injection Control
UTC	Utilities and Transportation Commission
WAC	Washington Administrative Code

Appendix XIV, Final Report

Geophysical Techniques for Monitoring CO_2 Movement During Sequestration

Topical Report

West Coast Regional Carbon Sequestration Partnership (WESTCARB)
Contract Period: October 1, 2003 - September 30, 2005

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September 30, 2005

DOE Contract No.: DE-FC26-03NT41984

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Abstract

The relative merits of the seismic, gravity, and electromagnetic (EM) geophysical techniques are examined as monitoring tools for geologic sequestration of carbon dioxide (CO_2). This work does not represent an exhaustive study, but rather demonstrates the capabilities of a number of geophysical techniques for two synthetic modeling scenarios. The first scenario represents combined CO_2 enhanced oil recovery (EOR) and sequestration in a producing oil field, the Schrader Bluff field on the north slope of Alaska, USA. EOR/sequestration projects in general and Schrader Bluff in particular represent relatively thin injection intervals with multiple fluid components (oil, hydrocarbon gas, brine, and CO_2). This model represents the most difficult end member of a complex spectrum of possible sequestration scenarios. The time-lapse performance of seismic, gravity, and EM techniques are considered for the Schrader Bluff model. The second scenario is a gas field that in general resembles conditions of Rio Vista reservoir in the Sacramento Basin of California. Surface gravity, and seismic measurements are considered for this model.

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1 Executive Summary

This report considers the application of a number of different geophysical techniques for monitoring geologic sequestration of CO_2. The relative merits of seismic, gravity, and electromagnetic (EM) geophysical techniques are considered for monitoring. Numerical modeling has been done on flow simulations based on a proposed CO_2 sequestration project in the Schrader Bluff field on the North Slope of Alaska as well as a gas field that in general resembles conditions of Rio Vista reservoir in the Sacramento Basin of California.

The time-lapse performance of seismic, gravity, and EM techniques are considered for the Schrader Bluff model. This model represents the most difficult end member of a complex spectrum of possible sequestration scenarios because of thin injection intervals with multiple fluid components (oil, hydrocarbon gas, brine, and CO_2). The spatial variations in the changes in the vertical component of gravity as well as the vertical gradient of the vertical component of gravity directly correlate with the spatial variations in the net density changes within the reservoir. Although the magnitude of the signals measured on the surface is in the noise level of the field survey, borehole measurements just above the reservoir do produce measurable change in the vertical component of gravity that could be used to map lateral distributions of injected CO_2. The difference in both the borehole gravity response and the vertical gravity gradient measured in vertical profiles within boreholes clearly identifies the position of the reservoir. There is a clear change in seismic amplitude associated with the reservoir caused by the changes in water and CO_2 saturation (S_w and S_{CO2}, respectively). In addition, there is a change in the seismic amplitude variation with offset (AVO) effects. Both seismic amplitude and AVO can be exploited to make quantitative estimates of saturation changes. There is a direct one-to-one correspondence with the change in S_w and the change in the electric field amplitude. While this signal level is low, it can be measured given the signal-to-noise ratio of the data. While this represents a potential low-cost monitoring technique, it is best suited for CO_2-brine systems where there is a one-to-one correlation between the change in water saturation and the change in CO_2 saturation (since $S_w + S_{CO2} = 1$). In petroleum reservoirs such as Schrader Bluff, the presence of hydrocarbons as additional fluids eliminates the one-to-one correlation between changes in S_w and changes in S_{CO2}.

The seismic and gravity responses were simulated for a simplified flow simulation model of the Rio Vista gas field in Sacramento Basin, California. Models were used to calculate anticipated contrasts in seismic velocity, density, and impedance in gas-saturated rock when CO_2 is introduced. Numerical simulations were performed to evaluate whether a CO_2-CH_4 front can be monitored using seismic and/or gravity. For the gas field used in this study, the change in reservoir properties are very small and neither gravity nor seismic methods would provide information necessary for monitoring of CO_2 movement.

2 Experimental

2.1 On-Shore Enhanced Oil Recovery Project – Schrader Bluff, Alaska

A joint industry project comprising BP, ChevronTexaco, Norsk Hydro, Shell, Statoil, and Suncor was formed with the goal of developing technologies to enable cost-effective CO_2 capture and sequestration. One site being considered for this project is the Schrader Bluff reservoir on Alaska's North Slope (Figure 1). Preliminary evaluations show that CO_2-based enhanced oil recovery could increase oil recovery by up to 50% over waterflooding (Hill *et al.*, 2000). Furthermore, the studies concluded that up to 60% of the CO_2 injected as part of the EOR scheme would remain in the reservoir. A schematic geological cross-section through the Schrader Bluff Formation is shown in Figure 2.

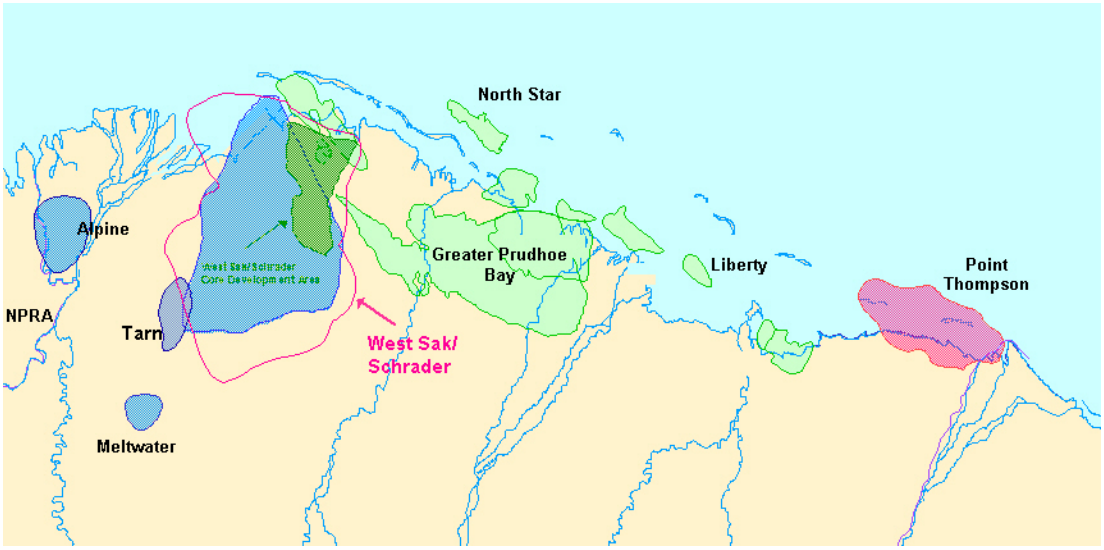


Figure 1. Location of Schrader Bluff reservoir on Alaska's North Slope

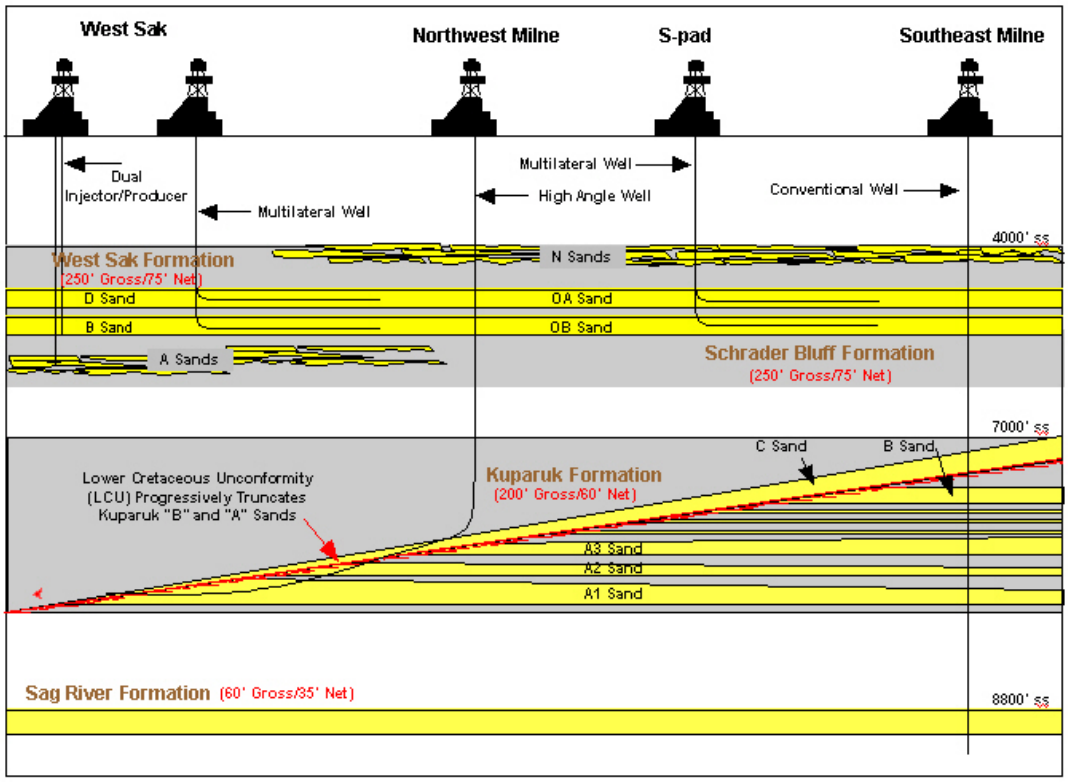


Figure 2. A schematic geological cross-section through the Schrader Bluff Formation

In order to compare the spatial resolution and sensitivity of various geophysical techniques being considered for CO_2 sequestration monitoring, a three-dimensional (3-D) flow simulation model of the reservoir provided by BP was used in conjunction with rock-properties relations developed from log data to produce geophysical models from the flow simulations. The Schrader Bluff reservoir is a sandstone unit that is between 25 and 30 m (82 and 98 ft) thick at a depth of 1,100–1,400 m (3,600–4,600 ft). Figure 3 shows a 3-D view of the portion of the reservoir under consideration for a CO_2 sequestration test. The reservoir unit gently dips to the east with major faulting running mainly north-south. Two faults with offsets in excess of 75 m (250 ft) cut the reservoir with several smaller sub-parallel faults present. Time-lapse snapshots of the reservoir at initial conditions and 5-year increments out to 2035 were used. A water-after-gas (WAG) injection strategy is considered which produces complicated spatial variations in both CO_2 and water saturation within the reservoir over time.

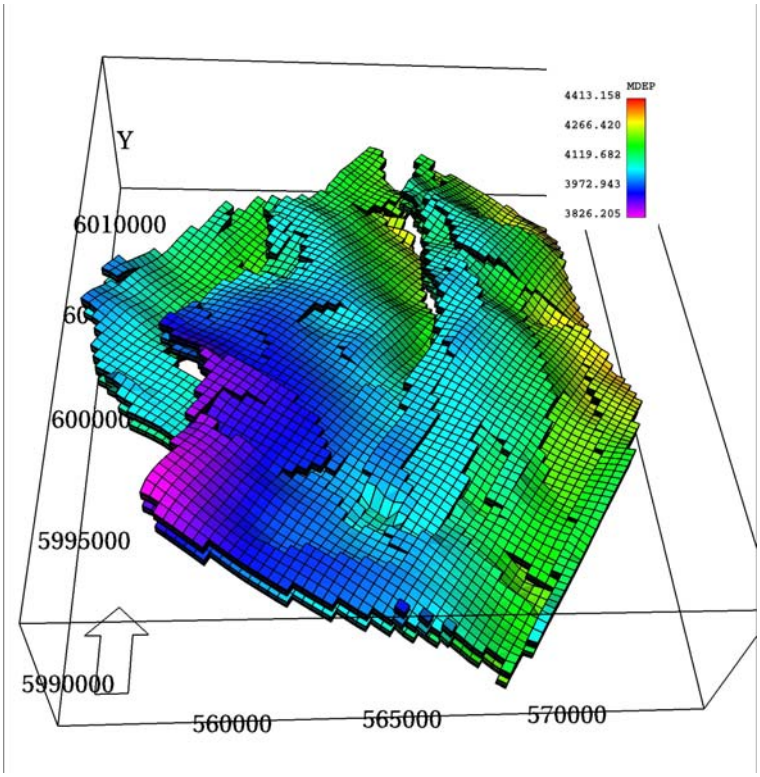


Figure 3. Three-dimensional view of the portion of the reservoir under consideration for CO_2 sequestration test at Schrader Bluff. Depths range between 1,158 and 1,341 m (3,800 and 4,400 feet) true vertical depth.

2.1.1 Rock Properties Models

Rock properties models were developed from log data for the reservoir. These models relate reservoir parameters to geophysical parameters and are used to convert the flow simulation model parameters to geophysical use format from another document parameters (V_P, V_S, density, and electrical resistivity). A description of the rock-properties modeling process is given by Hoversten *et al.* (2003). Electrical resistivity as a function of porosity and water saturation using an Archie's law formulation is used. Seismic properties are modeled as shown in Figure 4. The predicted V_p, V_s, and density from the derived model based on log data from the MSP-15 well are shown.

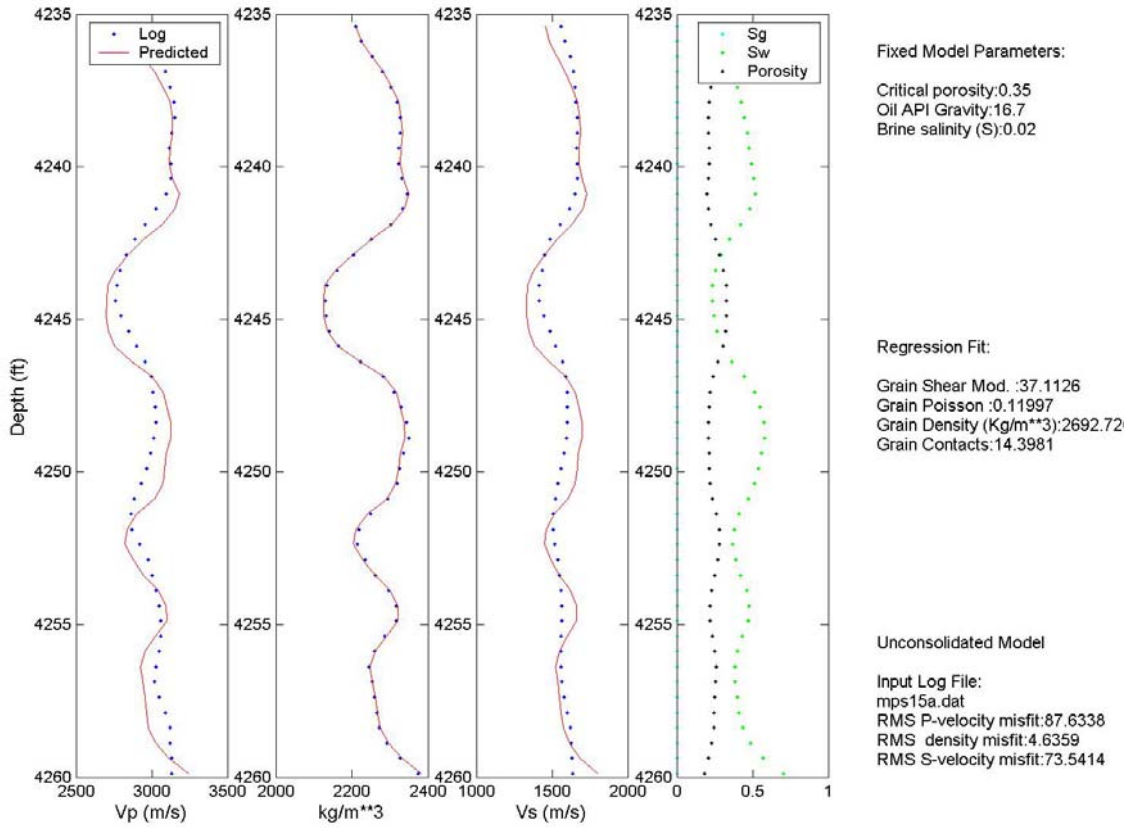


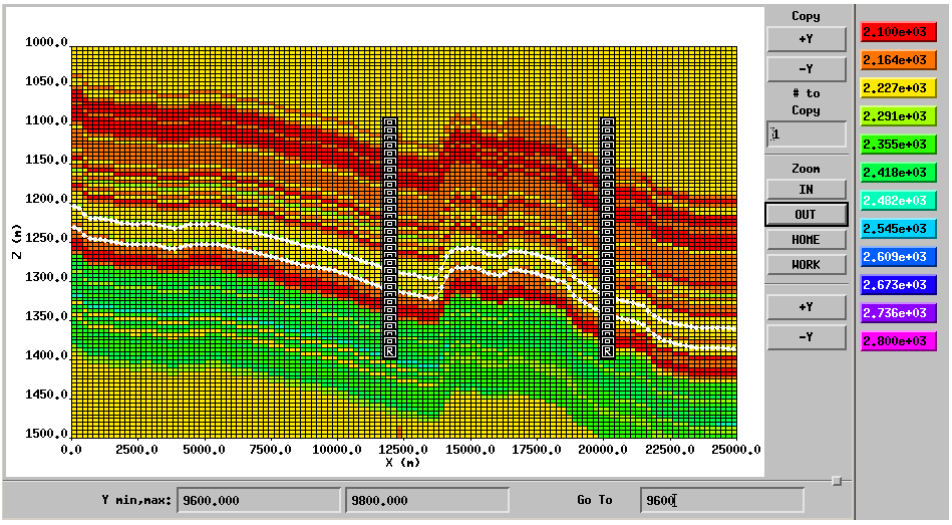
Figure 4. Rock properties model based on un-consolidated sandstone model (Dvorkin & Nur, 1996). Measured log values are shown as blue dots. Parameters (right side) are derived from a simplex minimization of the misfit between observed and calculated V_p, V_s, and density logs. Predicted V_p, V_s, and density are shown as red lines.

A critical porosity of 35%—appropriate for sandstone—is assumed. Oil API gravity and brine salinity are taken from measured values. The regression-determined values of the grain shear modulus and Poisson ratio are appropriate for quartz grains. The model parameters are determined for the reservoir interval in the logs. The full geophysical models are built by interpolating available well logs in 3-D using the seismic reservoir surfaces as a spatial guide. This produces a background model in V_p, V_s, density, and resistivity. The reservoir flow simulations, which only cover the reservoir interval, are then filled in at the time intervals where flow simulations were done. The model shown in Figure 4, along with Archie's law, is used to convert the porosity, water saturation, oil saturation, gas saturation, CO_2 saturation, pressure and temperature from the flow simulation to V_p, V_s, density and electrical resistivity.

2.1.2 Gravity Modeling

A snapshot of the model at initial conditions, before CO_2 injection begins, is shown in Figure 5. Figure 5a is a cross-section of bulk density as a function of depth and horizontal distance between a pair of injection wells. In this figure, gravimeters are located in two wells roughly 8 km (5 mi) apart. The reservoir interval is outlined in white on Figure 5a. Figure 5b is a plan view of the density at initial conditions at a depth of 1,200 m (3,936 ft) with positions of 23 injecting wells taken from the reservoir simulation. The positions of the gravimeters are indicated by black squares. Spacing between the gravimeters in depth (z) is 10 m (33 ft) outside of the reservoir and 5 m (16 ft) inside of the reservoir. The white circle in the upper part of Figure 5b indicates a well for which borehole gravity responses are shown in Figure 11 and 12.

(a)



(b)

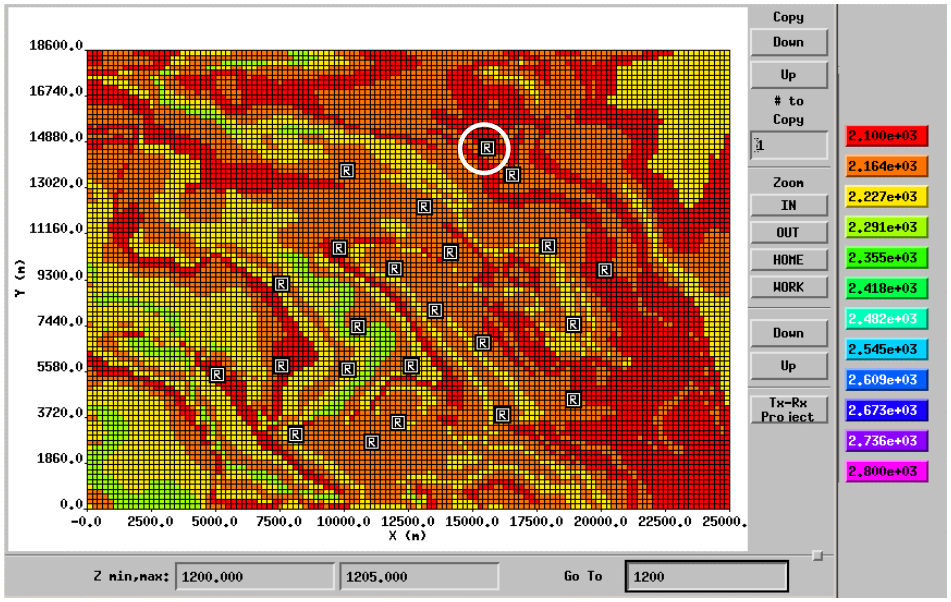


Figure 5. (a) Cross-section of a density field (kg/m^3) as a function of depth and horizontal position. (b) Plan view of a density (kg/m^3) field at a depth z = 1,200 m (3,936 ft). The white circle indicates the well location used for borehole gravity calculations shown in Figures 11 and 12.

The surface gravity response was calculated on a grid of stations with 1 km (0.6 mi) spacing from 2,000 m to 22,000 m (6,560 ft to 72,160 ft) in the x direction and from 2,000 m to 16,000 m (6,560 ft to 52,480 ft) in the y direction. In general, since CO_2 is less dense (at reservoir conditions) than either oil or water, addition of CO_2 to the reservoir will cause a reduction in the measured gravitational attraction either at the surface or in a borehole.

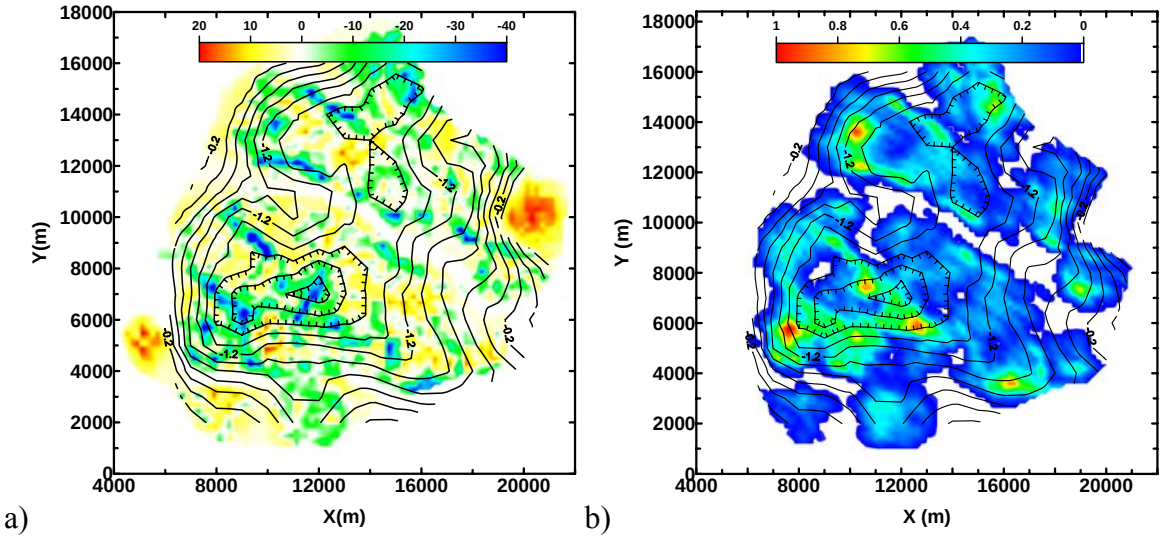


Figure 6. (a) Plan view of the net change in density (kg/m^3) within the reservoir. (b) Plan view of the net changes in CO_2 saturation within the reservoir. The change in G_z at the surface for the same time period is shown as black contours with hatch marks indicating decreasing G_z values.

The change in the vertical attraction of gravity (G_z) at the ground surface between 2020 and initial conditions is overlaid as black contours in Figure 6a on the net density changes within the reservoir. The peak-to-peak change in G_z is on the order of 2 μgal, which would be in the noise level of a field survey using current technology (Hare *et al.*, 1999). The changes in the vertical gradient of gravity (dG_z/dz) between 20 years into CO_2 injection and initial conditions (not shown) are approximately 0.01 Eötvos units (EU), and also below the noise level of current instruments. The high spatial variations of the net density changes within the reservoir are expressed as a filtered response at the surface and only show the average changes on a larger scale. It should be noted that petroleum reservoirs in general, and this reservoir in particular, are thinner (30 m, or 98 ft) than most brine formations considered for CO_2 sequestration (100–200 m, or 328–656 ft). This difference means that while the calculated response for Schrader Bluff at the surface are below current technology repeatability, brine formations at the same depths would produce measurable responses. This is the experience at the Sleipner CO_2 project (Nooner *et al.*, 2003) for a gravity survey conducted in 2002 and not yet published. These results suggest future analysis to determine the maximum sensitivity of G_z and dG_z/dz that could be obtained by permanent emplacement of sensors with continuous monitoring coupled with surface deformation measurements to reduce noise levels.

Figure 6b shows the change in surface gravity G_z as black contours overlaid on the net change in CO_2 saturation within the reservoir. Because the density changes within the reservoir are caused by a combination of CO_2, water, and oil saturation changes as the WAG injection proceeds, there is not a one-to-one correlation in space between either the

net change in density and the change in G_z or the net change in CO_2 saturation (S_{CO2}) and the change in G_z. There is correlation between the change in surface G_z and the net change in S_{CO2} on a large scale. For example, the largest changes in S_{CO2} occur in the south-west quadrant of the image (Figure 6b) where the largest change in G_z occurs. This scenario, injecting CO_2 into an oil reservoir with multiple fluid components, is a worst case for the use of gravity to directly map changes in S_{CO2}. In a CO_2 injection into a brine formation there would only be water and CO_2; in this case the net changes in density within the reservoir would directly correlate with the net changes in S_{CO2}, as would the change in G_z at the surface.

Access to boreholes allows the gravity measurement to be made closer to the reservoir, thus strengthening the signal compared to observations made on the surface. Figure 7a shows the change in G_z (2020 minus initial) at a depth of 1,200 m (3,936 ft, just above the reservoir in this section of the field), while Figure 7b is a change in dG_z/dz at the same depth. In both figures, the data are calculated on the same grid of 1 km-by-1 km (0.6 mi-by-0.6 mi) site locations as on the surface. The color images in Figures 7a and 7b are the net density changes in the reservoir from Figure 7a. The changes in G_z and dG_z/dz respectively, correlate directly with the maximum density changes. The magnitude of the changes in both G_z and dG_z/dz is larger than for surface measurements, although only the change in G_z would be measurable in the boreholes with current commercial technology. It should be noted however that work on more sensitive borehole G_z and dG_z/dz meters is ongoing and has the potential to significantly lower the sensitivity of such devices in the near future (Thomsen *et al.*, 2003).

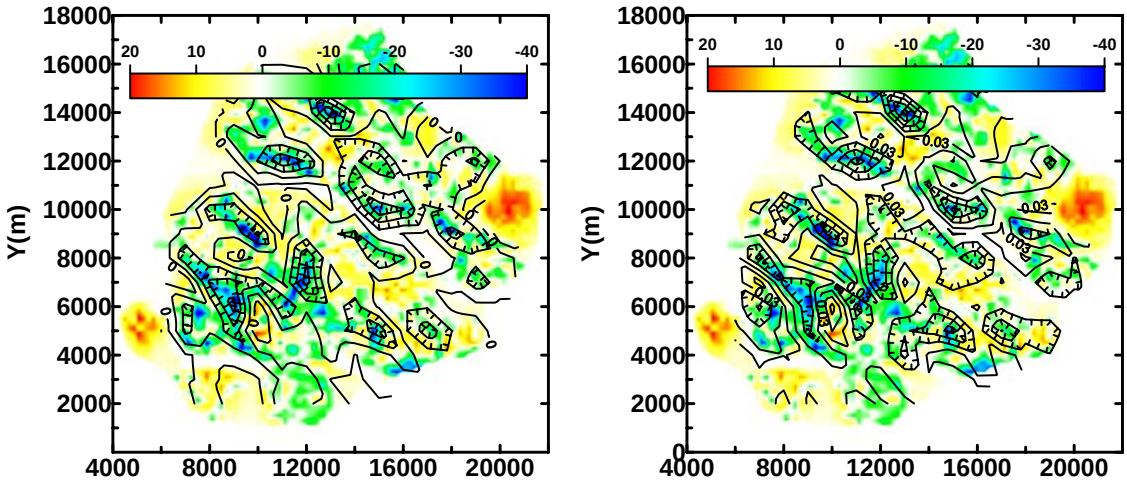
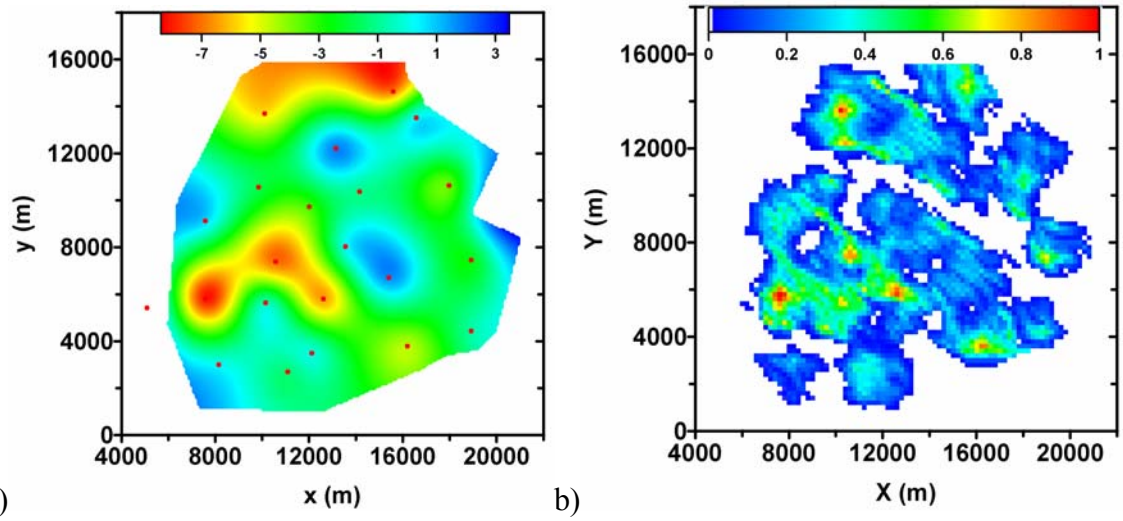


Figure 7. (a) Plan view of the color-coded net change in density within the reservoir (2020-initial). The change in G_z (μGal) at a depth of 1,200 m (3,936 ft) is overlaid as black contours. The peak-to-peak change in G_z is approximately 10 μGal. (b) The change in dG_z/dz (EU) at a depth of 1,200 m (3,936 ft) laid over the net change in density. The peak-to-peak change in dG_z/dz is approximately 0.25 EU.

While Figure 7 illustrated the potential resolution by measuring close to the reservoir, access though the existing injection wells would substantially reduce the data coverage. Figure 8a shows a map of contoured changes in G_z measured only in the 23 boreholes at a depth of 1,200 m (3,936 ft). Figure 8b is a net change of CO_2 saturation for comparison. Figure 8a was generated using a minimum curvature algorithm for data interpolation; however, it is representative of the general features present in all of the other types of interpolation tested. In general, interpretation of the interpolated G_z changes from the boreholes would lead to an overestimate of the CO_2 saturation changes in the reservoir. This problem is particularly evident at the north end of the field where increased CO_2 saturation at two isolated wells produces an interpolated image that would be interpreted as increased CO_2 between the wells where none exists.

Borehole measurements would have to be used in conjunction with some form of surface measurement to guide the interpolation between wells. Alternatively, pressure testing between wells could provide estimates of spatial variations in permeability that could be used to condition, in a statistical sense, interpolation of the borehole gravity data. Many possibilities exist for combining the borehole data with other information in order to produce more accurate maps of change within the reservoir. This is an area where further work could be done.



a) b)

Figure 8. (a) Plan view of the change in G_z (μGal) at a depth of 1,200 m (3,936 ft) between 20 years into CO_2 injection and initial conditions using 23 wells indicated by red dots. (b) Plan view of the net change in S_{CO2} within the reservoir between 20 years into CO_2 injection and initial condition.

In addition to considering spatial variations in G_z and dG_z/dz on both the surface and at a constant depth within boreholes, the response of G_z and dG_z/dz in vertical profiles down boreholes has been considered. Figure 9 is the change in S_w between 2020 and initial conditions along a vertical slice through the reservoir at an injection well indicated by a white circle in Figure 5b. Figure 10 shows the change in S_{CO2} between 2020 and initial

conditions. At the top of the reservoir near the injection well, S_w decreases while S_{CO2} increases. At the bottom of the reservoir, both S_{CO2} and S_w increase slightly. G_z measured in the borehole, shown in Figure 11a, reflects this change by a decrease in the response at the top of the reservoir, and an increase in the response at the bottom. The change in G_z is ±8 μGal. The reservoir interval is between 1,325 and 1,350 m (4,346 and 4,428 ft) at this location. The change in G_z between 2020 and initial conditions (Figure 11b) clearly identifies the position of the reservoir. The sign of the change reflects the changes in the local densities caused by the combined changes in all fluids (oil, water, and CO_2). The reservoir is outlined by the shaded blue area.

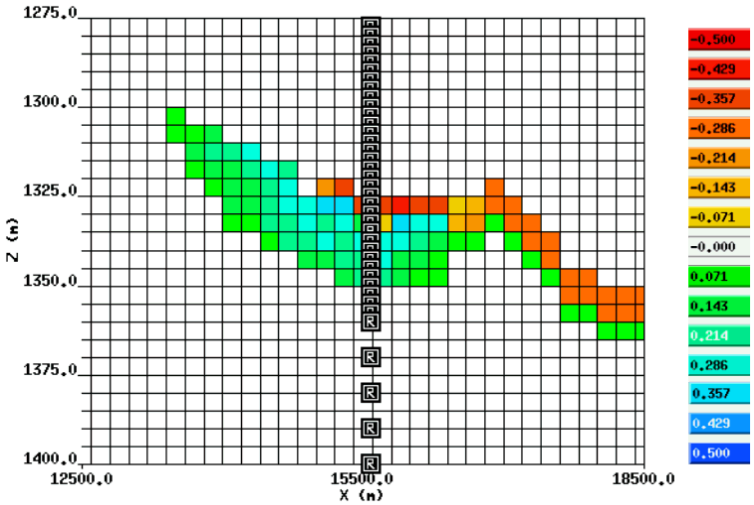


Figure 9. Change in S_w between 2020 and initial conditions. Greens and blues are an increase in S_w, yellows and reds are a decrease.

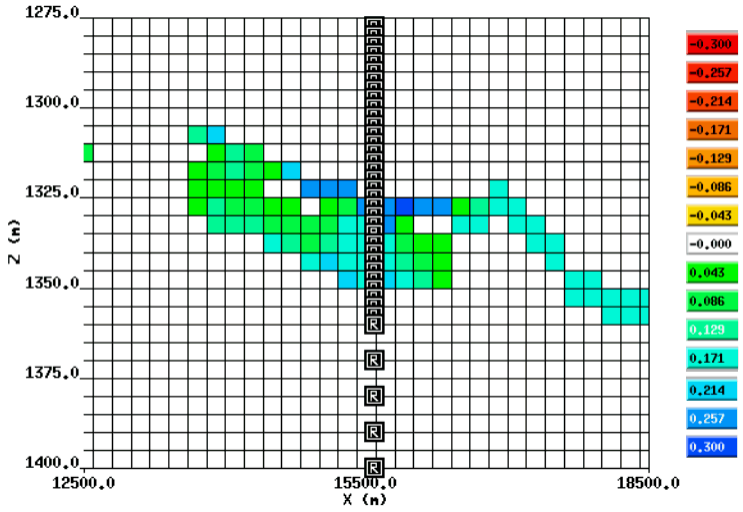
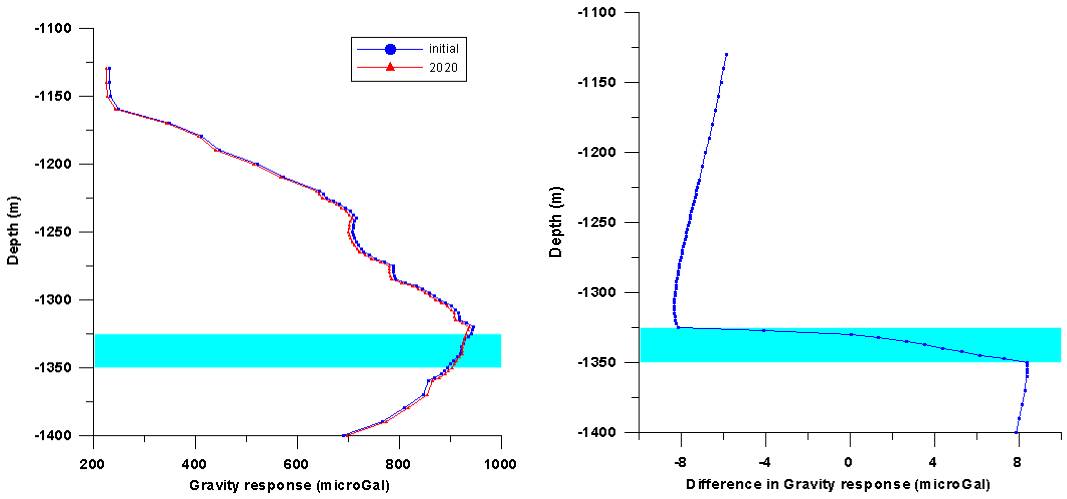


Figure 10. Change in S_{CO2} between 2020 and initial conditions. Greens and blues are an increase in S_{CO2}, yellows and reds are a decrease.



(a) (b)

Figure 11. (a) Borehole G_z for initial conditions (dark blue line) and 2020 (red line). (b) Change in G_z between 2020 and initial conditions. The reservoir interval is indicated by the light blue area.

The vertical gradient response (dG_z/dz) is shown in Figure 12a, and the change between 2020 and initial conditions is shown in Figure 12b. The change in the response is about 0.1 EU, which is not measurable with current technology.

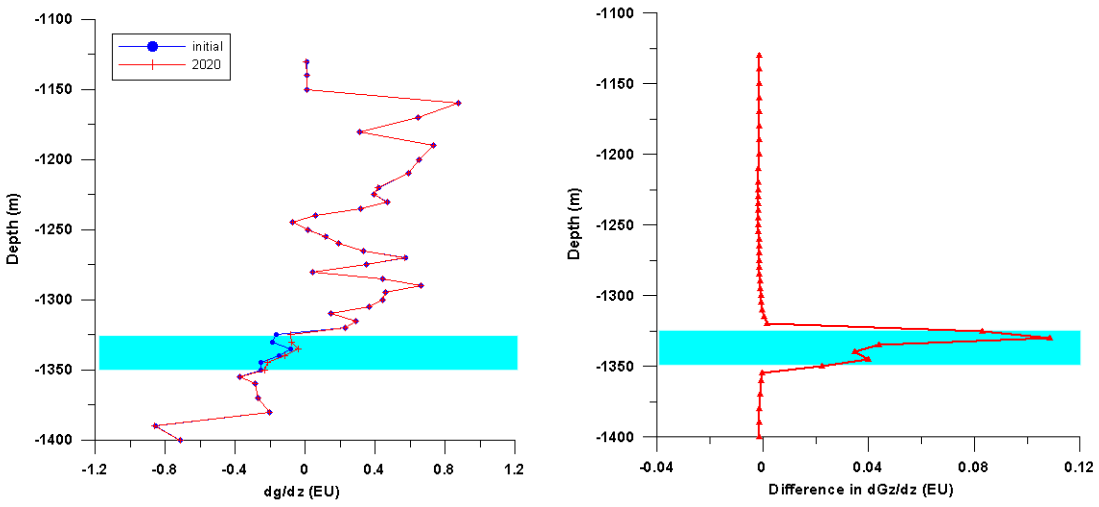


Figure 12. (a) Borehole vertical gradient response (dG_z/dz) for initial conditions (dark blue line) and 2020 (red line). (b) Change in dG_z/dz between 2020 and initial conditions. The reservoir interval is indicated by the light blue area.

Popta *et al.* (1990) showed that a geological structure with a sufficient density contrast can be detected by borehole gravity measurements if the observation well is not further away than one or two times the thickness of the zone of density contrast. Figure 13 shows a CO_2 wedge of 250 m (820 ft) radius and density of 2,260 kg/m^3 (141.0 lb/ft^3, representing 20% CO_2 saturation in 20% porosity) inside of 100 m (328 ft) thick sand layer with a density of 2,285 kg/m^3 (142.6 lb/ft^3) at the depth of 1 km (0.6 mi). The background density is 2,160 kg/m^3 (134.8 lb/ft^3). The borehole gravity response as a function of distance from the right edge of the wedge is shown in Figure 14a. The maximum response at the edge of the CO_2 wedge is 10 μGal (due to 1% change in density). The responses decrease with distance away from the wedge. 50 m (164 ft) away from the wedge the response is 6 μGal, 100 m (328 ft) away the response decreases to 4.4 μGal, and 200 m (656 ft) away it is down to 2.5 μGal. The borehole vertical gradient response for the same model is shown in Figure 14b. The response changes from 7 EU at the edge of the CO_2 wedge to 1 EU 50 m (164 ft) away from the edge.

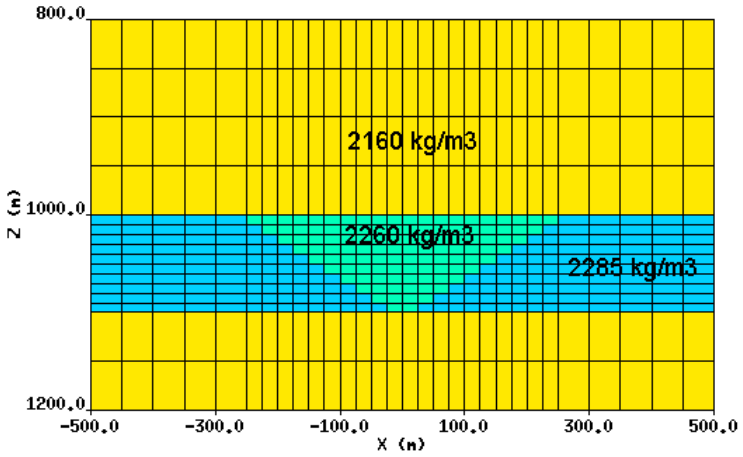
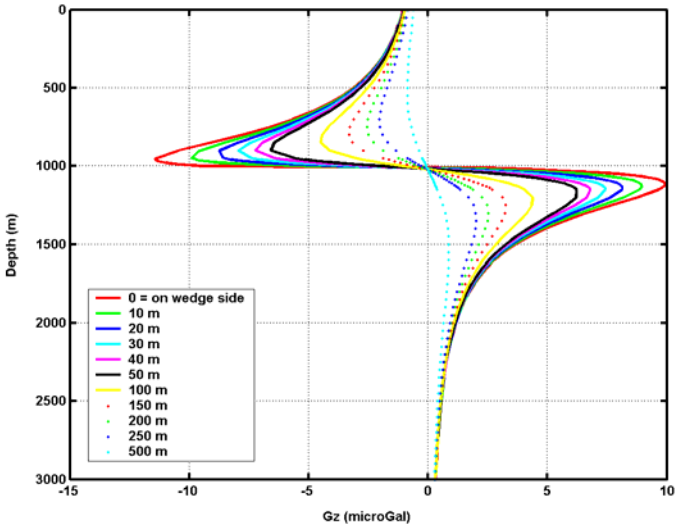
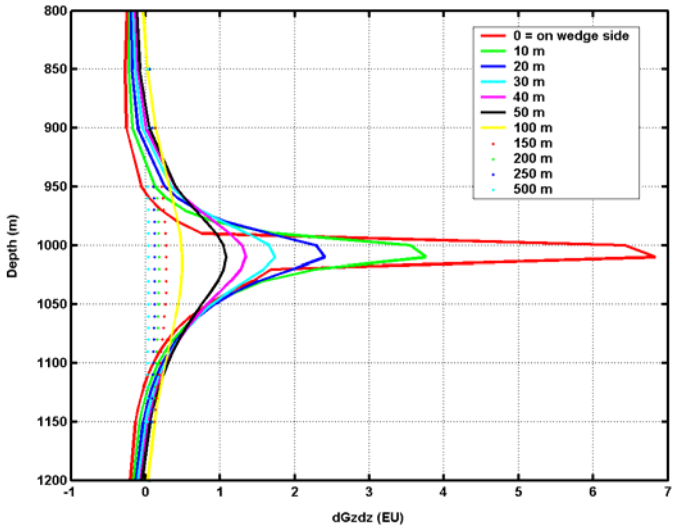


Figure 13. CO_2 wedge model



(a)



(b)

Figure 14. (a) Borehole gravity response of the model in Figure 13 as a function of distance from the wedge edge. (b) Borehole vertical gradient gravity response of the model in Figure 13 as a function of distance from the wedge edge.

Current borehole gravimeter technology has a repeatability of around 5 μGal for G_z. This means that, with current technology, borehole measurements are sensitive to changes in a zone up at distances equal to the zone thickness away from the zone edge.

2.1.3 Seismic Modeling

Results from flow simulation models for Schrader Bluff have been converted to acoustic velocity, shear velocity, and density. A simulated seismic line has been calculated running approximately N45°E across the reservoir, and the elastic response to a 50 Hz

Ricker wavelet was calculated. The general increase in S_{CO2} in portions of the reservoir near injection wells produces an approximately 20% decrease in seismic velocity as shown in Figure 15 (change in P-wave velocity between 2020 and 2005). The S_{CO2} and S_w changes are shown in Figures 16 and 17, respectively. The seismic pressure responses, for a single shot located at 7,500 m (24,600 ft, covering the area of the reservoir with maximum change in S_{CO2}) on the 2-D profile, for 2005 and 2020 are shown in Figure 18 with the difference shown in Figure 19. There is a significant class 3-type amplitude variation with offset (AVO) effect as S_{CO2} increases in the reservoir.

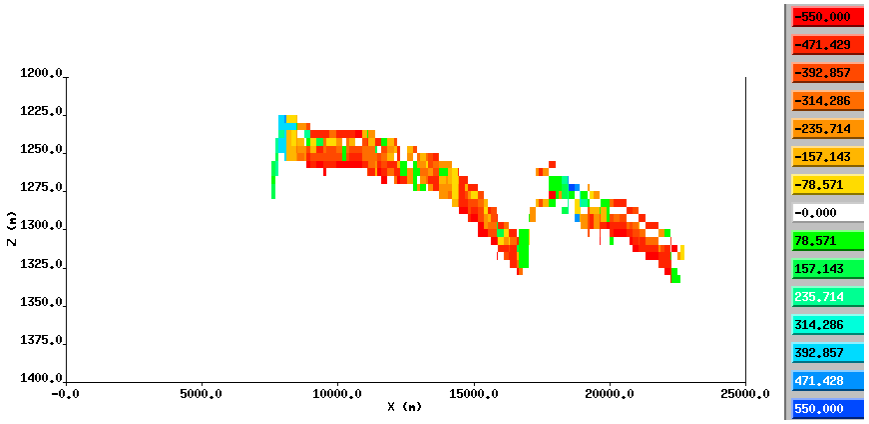


Figure 15. Change in the acoustic velocity (Vp) between 2020 and 2005 along a 2-D profile extracted form the 3-D model volume. The profile runs N45°E across the 3-D model. Note the significant decrease in acoustic velocity associated with the increase in S_{CO2} (Figure 16).

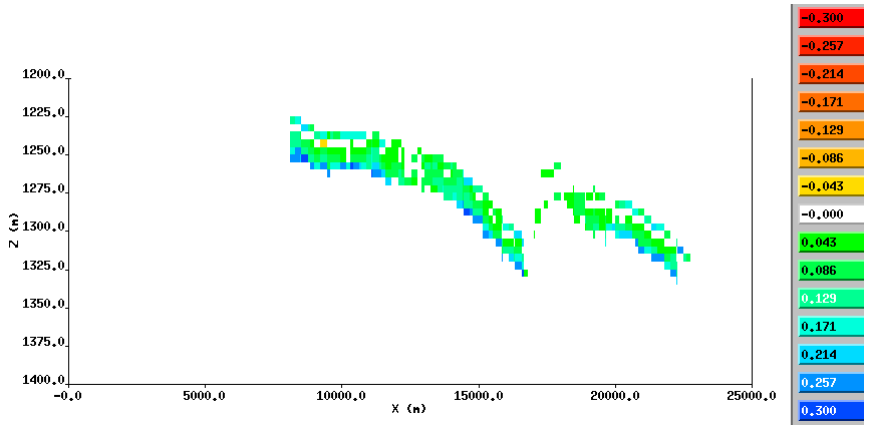


Figure 16. Change in S_{CO2} between 2020 and 2005

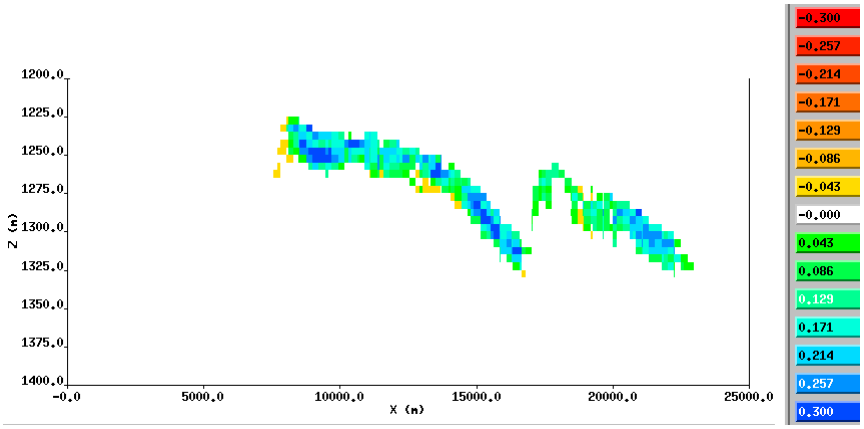


Figure 17. Change in S_w between 2020 and 2005

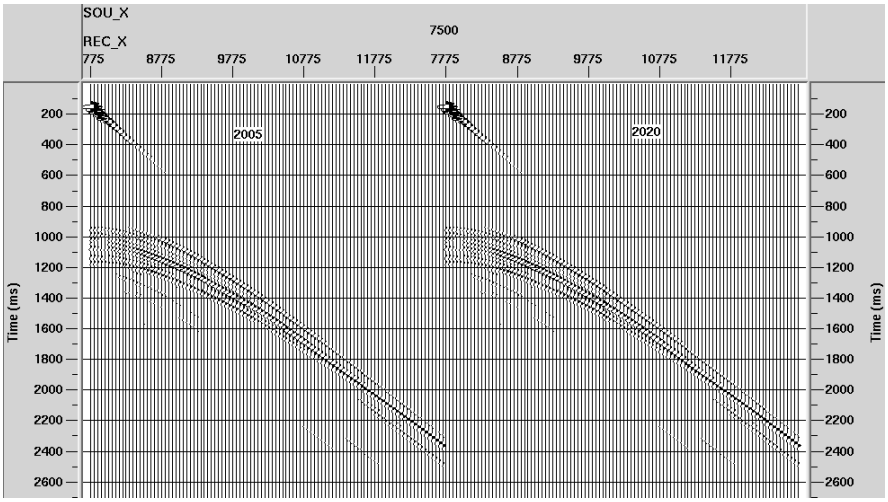


Figure 18. Seismic pressure response (shot gather) for 2005 (left) and 2020 (right)

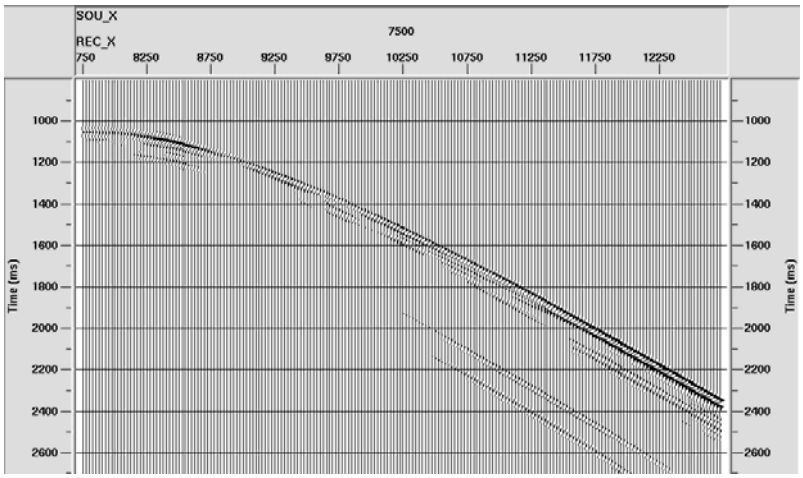


Figure 19. Change in pressure response (shot gather) between 2020 and 2005. Note amplitude change and AVO effects associated with S_w and S_{CO2} changes in the reservoir.

The pressure response was sorted to common-depth-point (CDP) gathers, normal move-out (NMO) corrected, and stacked to produce the sections for 2005 and 2020 shown in Figure 20. The red line is a constant time horizon within the reservoir for reference. The 30 m (98 ft) reservoir interval is not uniform and is comprised of 5 m (16 ft) thick substrata, each of which has reflection coefficients at their top and base that vary with S_{CO2}. These sub-strata are all below the seismic tuning thickness. This produces a seismic response without a clear top and base reflector. There is a significant increase in S_{CO2} to the right of CDP 8412.5, producing the large change in the stacked sections shown in Figure 20.

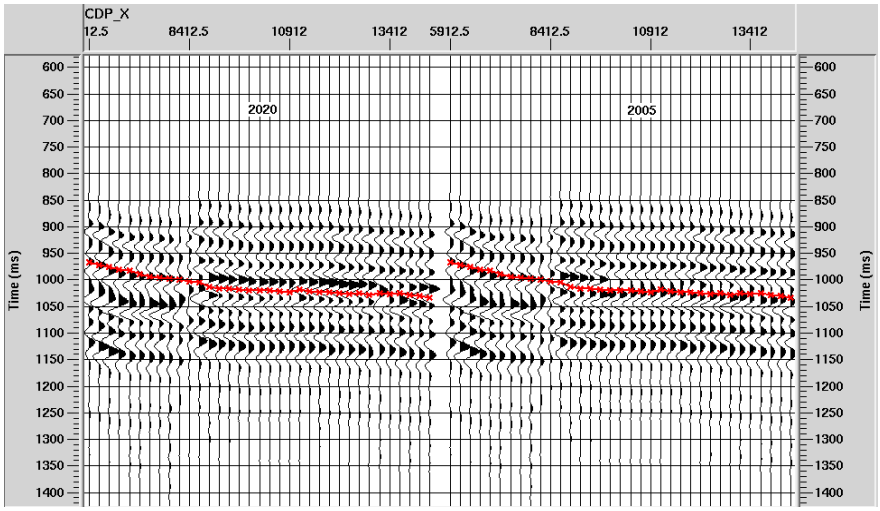


Figure 20. Stacked section for 2005 and 2020

The change in the stacked sections between 2020 and 2005 is shown in Figure 21. Below the areas of major change in the reservoir (to the right of CDP 8412.5), the decrease in the velocity of the reservoir produces a time shift in the 2020 seismic responses below the reservoir, resulting in the events around 1,100 ms that do not reflect CO_2 saturation changes at this depth, only the time shift from CO_2 above.

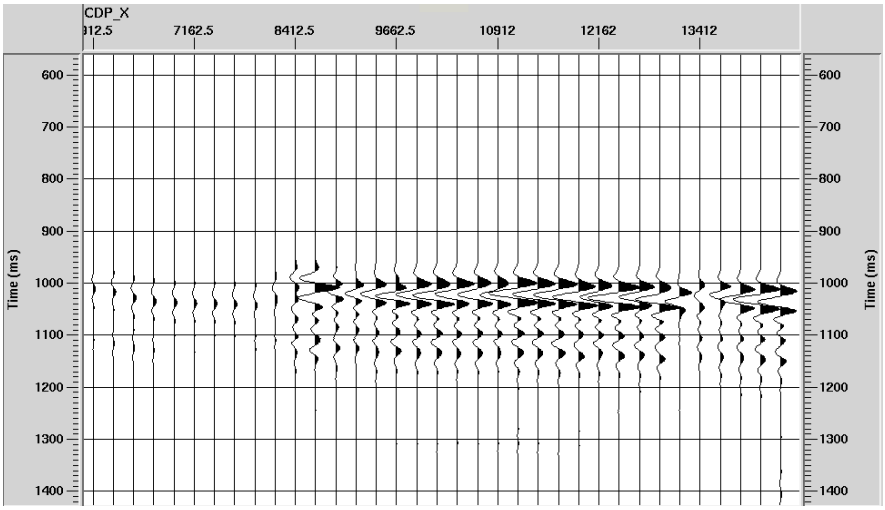


Figure 21. Change in the stacked sections between 2020 and 2005 (2020-2005)

There is a large, and easily measurable, change in the stacked trace amplitude associated with the reservoir caused by the changes in S_w and S_{CO2}. In addition, there is a change in the AVO effects as seen in Figure 19. Both amplitude and AVO can be exploited to make quantitative estimates of saturation changes under certain conditions. Forward calculations using the Zoeppritz equation for both the 2005 and 2020 models provide insight into the AVO dependence on model parameters. The forward modeling creates a synthetic seismic gather from a given set of elastic parameters V_P, V_S, and density as a function of depth. The full Zoeppritz equation is used to compute the acoustic-to-acoustic (pp) reflection coefficient Rpp(θ) for each angle and at each layer boundary. Synthetic seismic CDP gathers are calculated by convolving the angle-dependent reflection coefficients with a 50 Hz Ricker wavelet. The convolution model assumes plane-wave propagation across the boundaries of horizontally homogeneous layers, and takes no account of the effects of geometrical divergence, inelastic absorption, wavelet dispersion, transmission losses, mode conversions, and multiple reflections.

The changes in V_P, V_S, and density within the reservoir (between 1,250 and 1,275 m, or 4,100 to 4,182 ft) are shown in Figure 22.

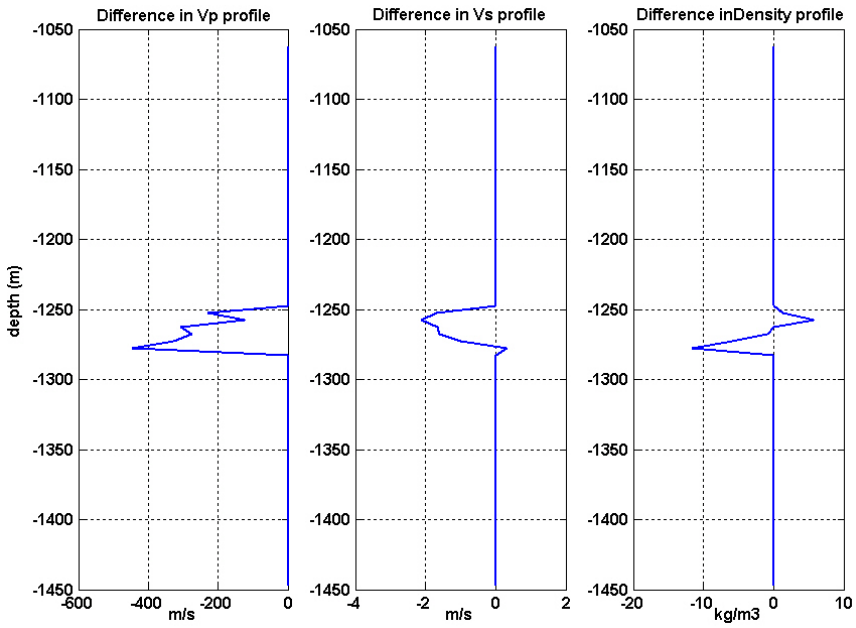
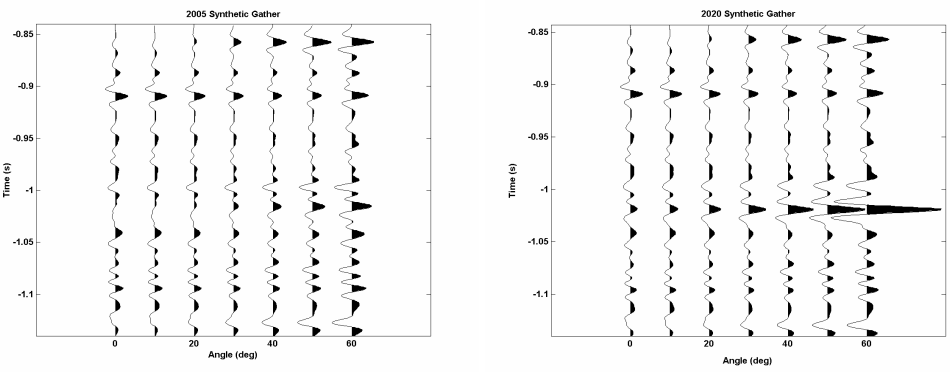


Figure 22. Difference in V_P, V_S, and density profiles between 2020 and 2005 for the Schrader Bluff model at the center of maximum CO_2 saturation increase

The synthetic CDP gathers as a function of angle are shown in Figures 23a and 23b for 2005 and 2020, respectively. The change in reflection amplitude between 2020 and initial conditions is shown in Figure 24. The AVO response of the composite reflections from the reservoir interval shows increasing negative amplitude with offset, a typical Class 3 gas response. The negative trough (associated with the top of the reservoir) increases its magnitude with offset and is followed by an increasing peak amplitude with offset



(a) (b)

Figure 23. Synthetic gather for (a) 2005 and (b) 2020

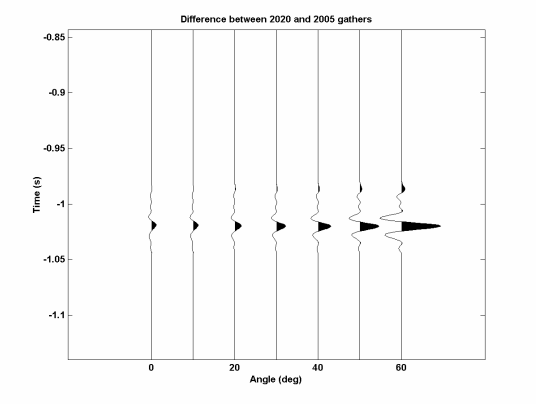


Figure 24. Difference between 2020 and 2005 gathers

2.1.3.1 Use of AVO in Fluid Saturation Prediction

The AVO attributes of reflections from the reservoir can be used to estimate fluid saturations under certain circumstances. AVO data can be used to estimate the acoustic and shear impedance of the reservoir (Castagna *et al*., 1998). When used in a time-lapse sense, these data can provide estimates of the change in water saturation and pressure within the reservoir (Landro, 2001). The ability to predict changes in water saturation and pressure within a reservoir is illustrated in Figure 25. In Figure 25 the rock properties model derived for the North Sea sands of the Troll reservoir (Dvorkin and Nur, 1996) is used to calculate the changes in shear and acoustic impedance of the reservoir as the water saturation and pore pressure for two cases of oil saturation as CO_2 is introduced. The first case (open circles) has initial oil and water saturation of 50% each; as CO_2 is introduced it replaces water. The second case has an initial oil saturation of 60% and 40% water, with CO_2 replacing water. In both cases S_{CO2} ranges from 0 to 30%. Each point in the figure represents a unique value of S_W and S_{CO2} with the oil saturation held fixed at either 50% or 60%. S_{CO2} values increase in increments of 0.015% from right to left on the figure, and pore pressure increases and decreases (indicated by arrows) from the reference pressure of 24.24 MPa by increments of 0.7 MPa.

Figure 25 illustrates three important points; 1) if the oil saturation is known, the changes in shear and acoustic impedance of the reservoir can determine the change in pressure and CO_2 saturation, 2) the changes in the shear impedance required to make the estimates is quite small and would require extremely good shear data, and 3) an uncertainty in the oil saturation level of 10% in this example has only a small effect on the estimated values of changes in S_{CO2} and almost no effect on the estimates of pressure change.

An uncertainty on the value of oil saturation has limited effects in these calculations because of the relative similarity of the bulk modulus and density of oil compared to water when either is compared to the properties of CO_2. The situation is significantly different if there is hydrocarbon gas (such as methane) in the reservoir. In this case (due to the extreme differences between the properties of methane and water) even a small uncertainty in the hydrocarbon gas saturation leads to very large uncertainties in the estimated values of

pressure and CO_2 saturation changes, making this technique essentially unusable unless an independent estimate of water saturation or gas saturation can be obtained from other methods (Hoversten *et al.*, 2003).

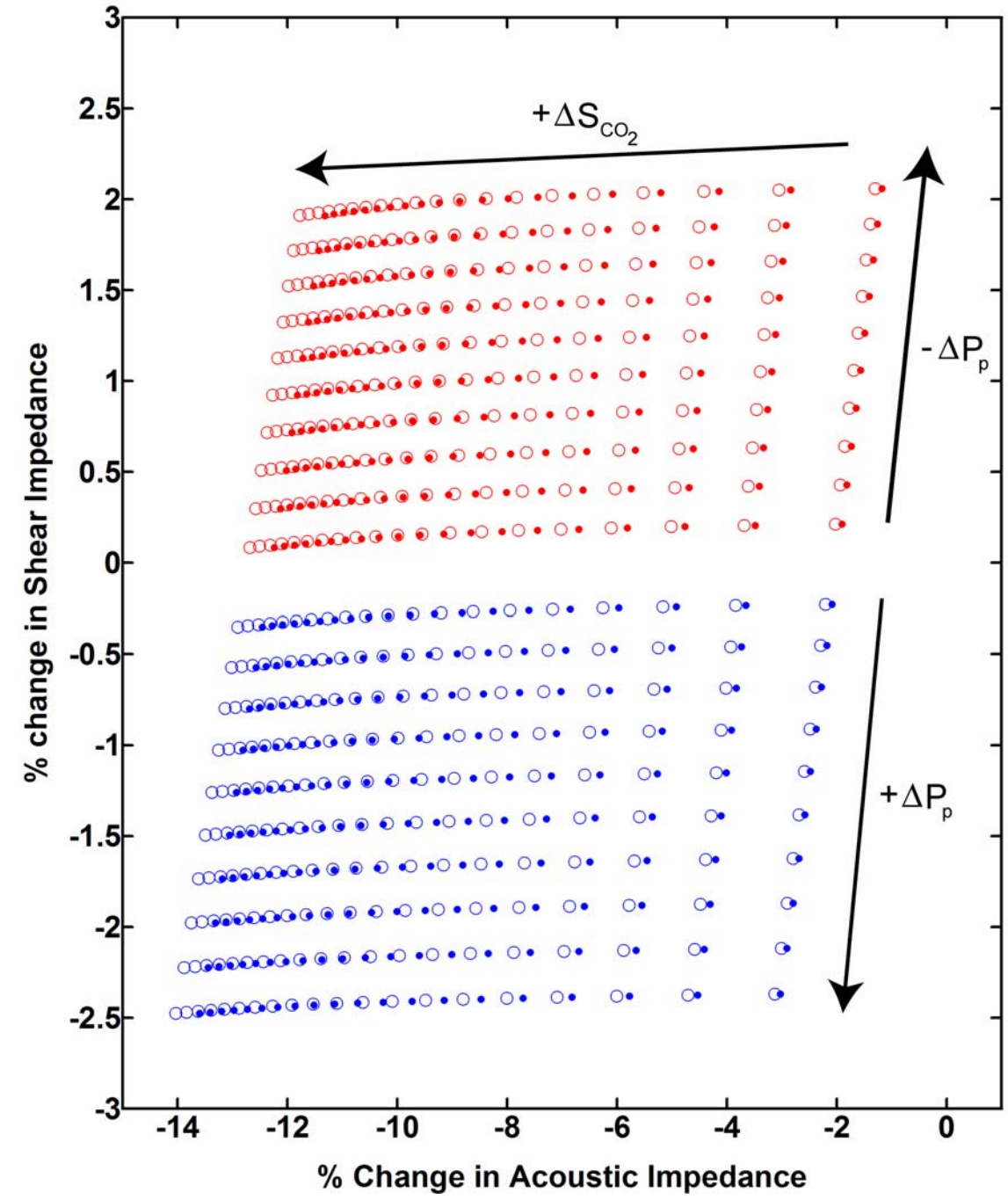


Figure 25. Each point represents a unique value of changes in pore pressure (ΔP_p) and CO_2 saturation (ΔS_{CO2}) as a function of changes in the shear and acoustic impedance of the reservoir. Open circles represent oil saturation of 50% with CO_2 replacing water. Filled dots represent oil saturation of 60% with CO_2 replacing water. Initial pore pressure is 25.24 MPa, and initial S_{CO2} is 0%. S_{CO2} increments are 0.015% and pressure increments are 0.7 MPa.

While estimation of changes in fluid saturation using AVO is complicated by the multiple fluid components in oil or gas reservoir, the situation is simpler in a brine reservoir. For cases were CO_2 is injected into a brine reservoir, there are only two fluid components (brine and CO_2) and the added constraint that their saturation levels sum to one. In this case, AVO information can more easily be used to estimate the level of CO_2 in the reservoir. The following example illustrates this process: An unconsolidated North Sea sand of the Troll reservoir (Dvorkin and Nur, 1996) that is encased in shale is assumed to contain 50% brine and 50% CO_2 as the reference point for these calculations. Pressure and temperature are such that the CO_2 is in the liquid state. The values of CO_2 (and hence water) saturation and pore pressure are varied about this starting point and the acoustic and shear velocities as well as density are calculated.

The reflection coefficient at the top of the reservoir can be approximated (Shuey, 1985) by:

$$R(\theta) \approx A + B\sin^2(\theta) + C\sin^2(\theta)\tan^2(\theta), \tag{2}$$

where θ is the average of the reflection and transmission angle for a plane wave hitting the interface. The constants A and B are referred to as the intercept and slope, respectively, in the AVO literature. The constants A, B, and C are functions of the velocity and density of the media on either side of the reflecting interface and are given by:

$$A = 1/2(\Delta V_p / \langle V_p \rangle + \Delta\rho / \langle \rho \rangle \tag{3}$$

$$B = 1/2(\Delta V_p / \langle V_p \rangle - 2(\langle V_s \rangle / \langle V_p \rangle)^2 (2\Delta V_s / \langle V_s \rangle + \Delta\rho / \langle \rho \rangle) \tag{4}$$

$$C = 1/2(\Delta V_p / \langle V_p \rangle , \tag{5}$$

where ΔV_p is the change in acoustic velocity across the interface; $\langle V_p \rangle$ is the average acoustic velocity across the interface, ΔV_s; and $\langle V_s \rangle$, $\Delta\rho$, and $\langle \rho \rangle$ are changes and averages for shear velocity and density, respectively. If time lapse seismic data are acquired, and A and B are estimated from the AVO data and used to calculate ΔA and ΔB, the associated ΔS_{CO2} and ΔP_p can be estimated from model-based calculations such as those illustrated in Figure 26.

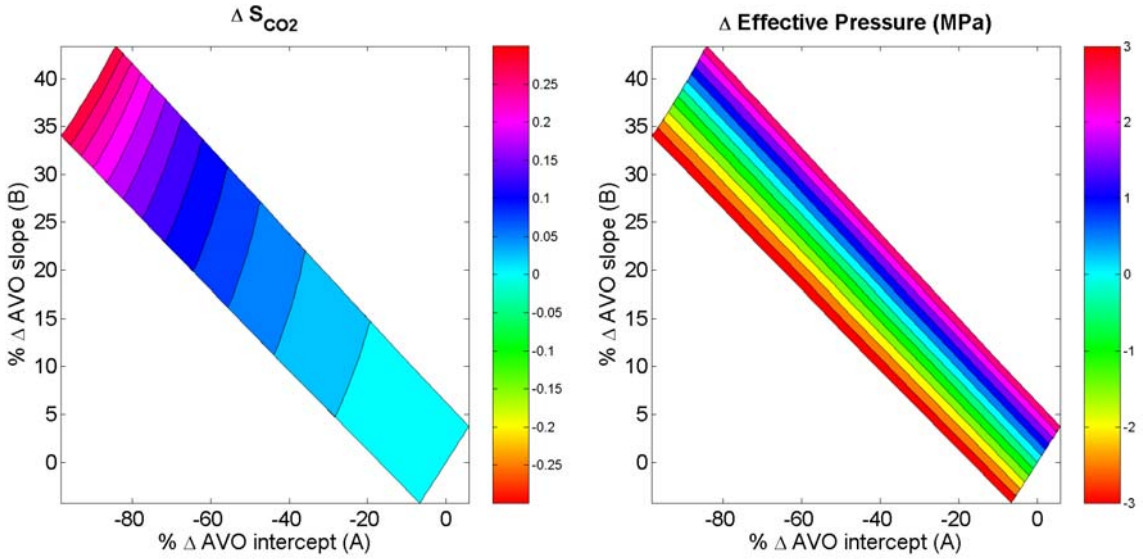


Figure 26. Contours of the change in CO_2 saturation (left panel) and effective pressure (lithostatic – pore pressure) (right panel) as function of the change in the AVO intercept (A) and slope (B) for an unconsolidated sand surrounded by shale

This example illustrates a theoretical case without noise in the seismic data; in practice, the estimation of the "slope" (B) is the most difficult. Extremely high signal-to-noise (S/N) seismic data would be required for accurate estimates of B and hence accurate estimates of pressure and saturation changes.

2.1.4 Electromagnetic Modeling

The electrical resistivity of reservoir rocks is highly sensitive to changes in water saturation. This can be seen from Archie's Law (Archie, 1942), which has been demonstrated to accurately describe the electrical resistivity of sedimentary rocks as a function of water saturation, porosity, and pore fluid resistivity. Figure 27 shows the rock bulk resistivity (Ωm) as a function of gas saturation (1–water saturation) for a reservoir with brine resistivity equivalent to that of seawater ($\rho_{brine} = 0.33$) with 25% porosity. All petroleum fluids (oil, condensate, and hydrocarbon gas) as well as CO_2 are electrically resistive, hence the relation shown in Figure 27 is appropriate for any combination of oil, hydrocarbon gas, condensate, or CO_2.

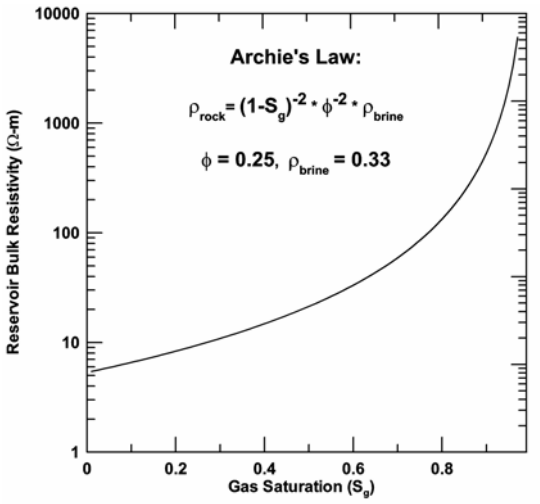


Figure 27. Reservoir bulk resistivity as a function of gas saturation (Sg); porosity = 25%

The bulk resistivity in Figure 27 is plotted on a log scale to span the large range of resistivity values as a function of the gas saturation (S_g). This high sensitivity to water saturation in a reservoir can be exploited by electromagnetic (EM) techniques where the response is a function of Earth's electrical resistivity. Of all the possible combinations of EM sources and measured EM fields, one system combines both relative ease of deployment with high sensitivity to reservoirs of petroleum scale and depth. This technique uses a grounded electric dipole that is energized with an alternating current at a given frequency to produce time-varying electric and magnetic fields that can be measured on the earth's surface. The electric dipole can consist of two steel electrodes (1 m^2—or 11 ft^2—plates or sections of drill pipe) buried at a shallow depth (1–10 m, or 3–33 ft), separated by 100 m (328 ft), and connected by cable to a low-power generator (a portable 5,000 W generator is sufficient). The measured data would consist of the electric field at a given separation from the transmitter acquired on the surface or in the near surface.

To simulate such an EM system we have calculated the electric field on the surface of the Schrader Bluff model using 100 m (328 ft) electric dipoles operating at 1 Hz and measuring the resulting electric field at a separation of 2 km (1.2 mi) in-line with the transmitting dipole. Figure 28 shows the amplitude of the generated EM field at 2 km (1.2 mi) separation and 1 Hz together with the natural background electric field generated from worldwide thunderstorms and pulsations in the earths ionosphere (the source field for the magnetotelluric method). The significance of Figure 28 is that the generated electric field for the Schrader Bluff model, using only a small portable generator (producing a 10 A current in the source dipole) is an order of magnitude above the background electric field (noise) at the operating frequency of 1 Hz. This means that synchronous detection of the signal combined with stacking can recover signal variations to better than 1%.

Figure 29 shows the net change in water saturation within the reservoir (vertically integrated ΔS_w) between 2020 and initial conditions. The change in the electric field

amplitude for the same interval is overlaid as black contour lines, with peak-to-peak amplitude of 1.2%. There is a direct one-to-one correspondence with the change in S_w and the change in the electric field amplitude. While this signal level is low, it can be measured given the signal-to-noise ratio of the data (Figure 28). While this represents a potential low-cost monitoring technique, it is best suited for CO_2-brine systems where there is a one-to-one correlation between the change in water saturation and the change in CO_2 saturation (since $S_w + S_{CO2} = 1$). In petroleum reservoir such as Schrader Bluff the presence of hydrocarbons as additional fluids eliminates the one-to-one correlation between changes in S_w and changes in S_{CO2}. This is illustrated in Figure 30, where the same changes in electric field amplitude are overlaid on the net change in the CO_2 saturation within the reservoir between 2020 and initial conditions. In this case, we see that the correlation between changes in S_{CO2} and changes in the electric field amplitude are not as good as seen between changes in S_w and the electric field data.

This type of EM technique has not yet been employed as a monitoring tool within the petroleum industry; however, EM technology is currently the subject of a significant upsurge in industry interest. Several commercial contractors are now offering this technique as a survey tool, most notably in the offshore environment where it is currently being used as an exploration tool (Ellingsrud *et al.*, 2002). The equipment and service providers exist to apply this technique for monitoring in the future.

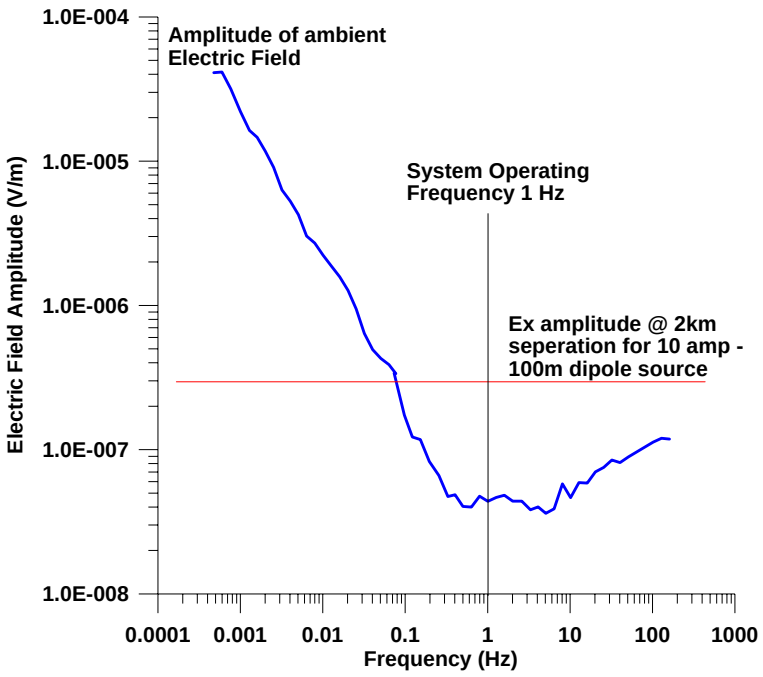


Figure 28. Amplitude of naturally occurring electric field as a function of frequency (Gasperikova *et al.*, in review), that would be considered noise to that electromagnetic system considered here for monitoring, shown as blue curve. The horizontal red line represents the signal amplitude at a source-receiver separation of 2 km (1.2 mi) at an operating frequency of 1 Hz for a 100 m (328 ft) electric dipole energized with 10 A of current.

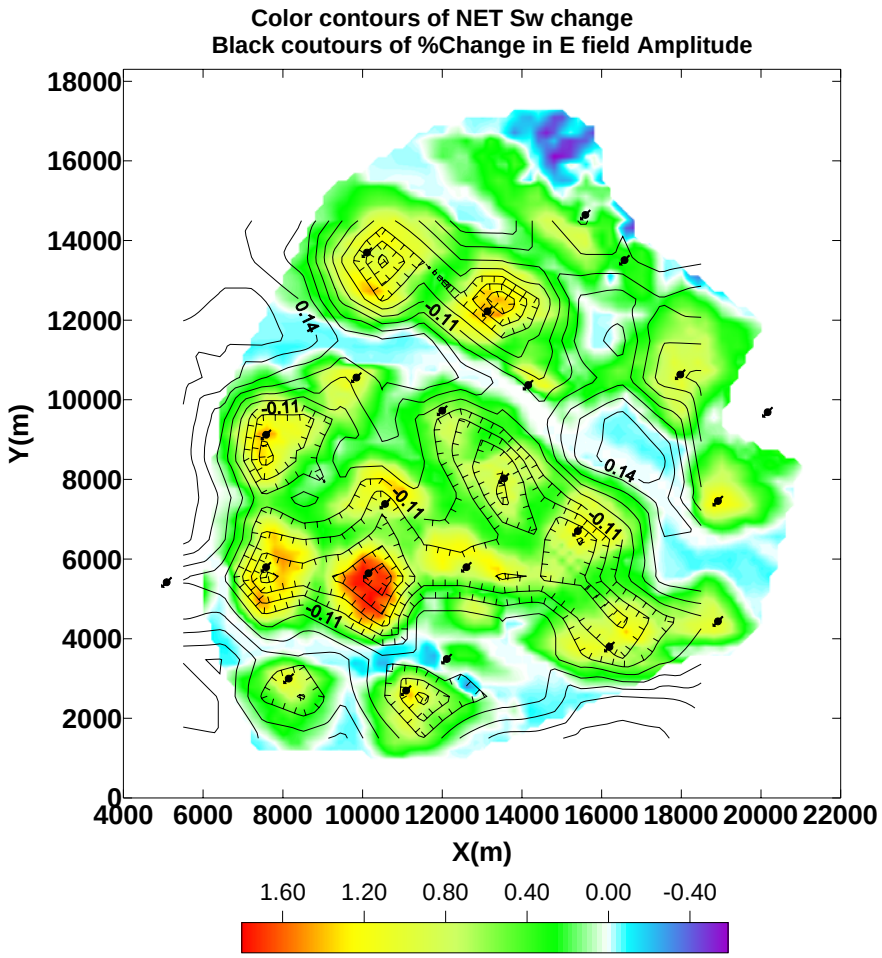


Figure 29. Color contours of the net change in water saturation over the vertical interval of the reservoir between 2020 and initial conditions. The change in the amplitude of the electric field from an electric dipole source at a separation of 2 km (1.2 mi) is overlaid as black contours. The peak-to-peak change is electric field amplitude is 1.2%. Note the direct correlation between decreases in the electric field amplitude and increases in water saturation (decreased electric resistivity of the reservoir). The locations of injection wells are shown by black circles with arrows through them.

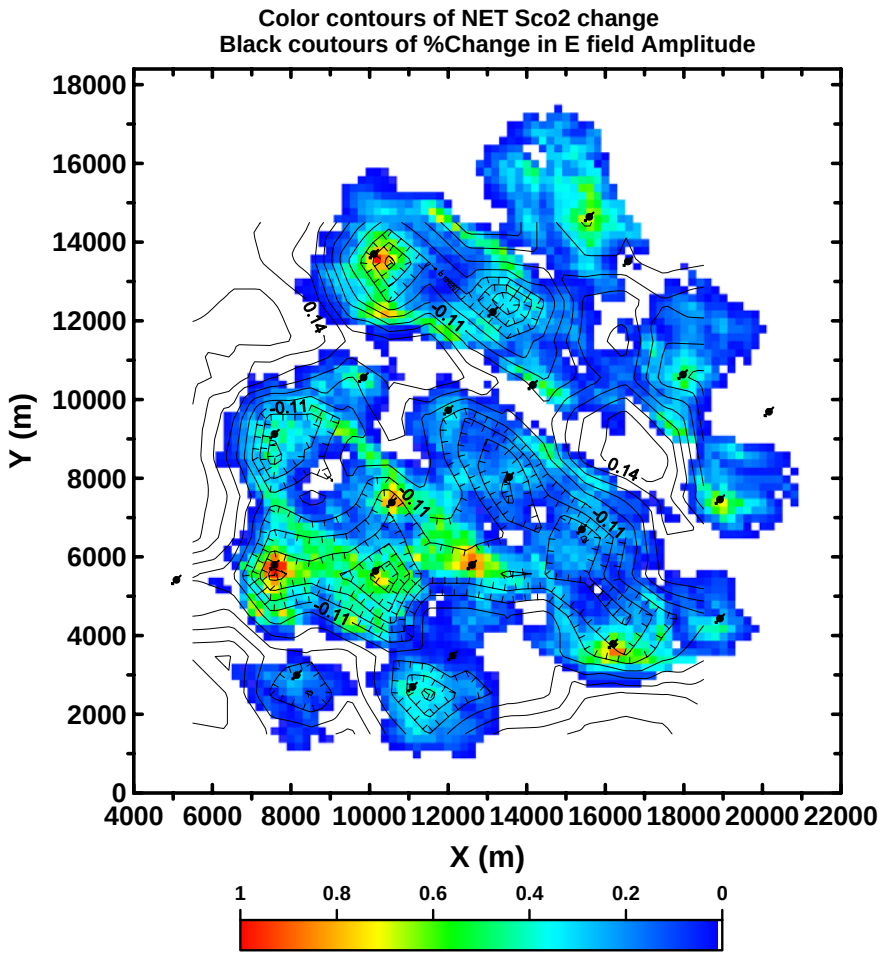


Figure 30. Color contours of the net change in CO_2 saturation (ΔS_{CO2}) over the vertical interval of the reservoir between 2020 and initial conditions. The change in the amplitude of the electric field from an electric dipole source at a separation of 2 km (1.2 mi) is overlaid as black contours. The peak-to-peak change in electric field amplitude is 1.2%. The locations of injection wells are shown by black circles with arrows through them.

2.2 On-Shore EGR Project – Rio Vista Gas Field, California

It is natural to consider geophysical techniques for monitoring of CO_2 movement within hydrocarbon reservoirs whether the CO_2 is introduced for enhanced oil/gas recovery or for geologic sequestration because of the large body of experience in their application in the petroleum industry. Among geophysical techniques, seismic methods are by far the most highly developed. Due to cost considerations, other less-expensive techniques are being considered for monitoring. This part of the report considers the use of surface gravity and seismic as a means of monitoring the movement of CO_2 within a gas reservoir.

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

Gravity methods sense changes in density, and seismic methods depend on both density and elastic stiffness. These physical properties are known for CO_2, typical reservoir fluids, and their mixtures (Batzle and Wang, 1992; Magee and Howley, 1994; NIST, 1992) so assessments can be made of expected changes in geophysical properties.

2.2.1 Rock Properties Model

One of the scenarios we studied was a gas field that, in general, resembles conditions of the Rio Vista reservoir in the Sacramento Basin, California. The field size is about 15 km x 15 km (9 mi x 9 mi), and the zone of interest is at about 1,300 m (4,260 ft) depth. The unit is Eocene in age and is called the Domengine Sandstone. The average thickness of the reservoir is about 50 m (165 ft). Contacts with the underlying Capay Shale and overlying Nortonville Shale are conformable (Johnson, 1990). The unit consists of series of interbedded marine sands and shales, with sand being a predominant lithology. The Domengine sand is poorly consolidated.

We have used a reservoir simulation (Oldenburg *et al.*, 2004) where the CO_2 injection well is in the center of the field and four production CH_4 wells are at the corners about 800 m (2,624 ft) away from the injection well (Figure 31b). This is only one five-spot simulation domain; there are 25 CO_2 injection wells, 16 CH_4 production wells, and 8 monitoring wells placed over the central part of the gas field (Oldenburg *et al.*, 2004), as shown in Figure 31a. CO_2 injection begins at the base of the 50 m (165 ft) thick reservoir interval. The porosity is 0.30, permeability is 10^{-12} m^2 (1 Darcy), residual brine saturation is 0.20, and reservoir temperature is 75 °C (167 °F). Reservoir pressure at the start of CO_2 injection is 5 MPa, and at the end of the last simulation (15 years) is 6 MPa. CH_4 density is 29.0 kg/m^3 (1.81 lb/ft^3) at pressure of 5.0 MPa and temperature of 75 °C (167 °F). The density of CO_2 under the same conditions is 90.5 kg/m^3 (5.65 lb/ft^3). The CO_2 injection rate is 3 kg/s (260 t/day) and CH_4 production rate is 0.56 kg/s (48 t/day).

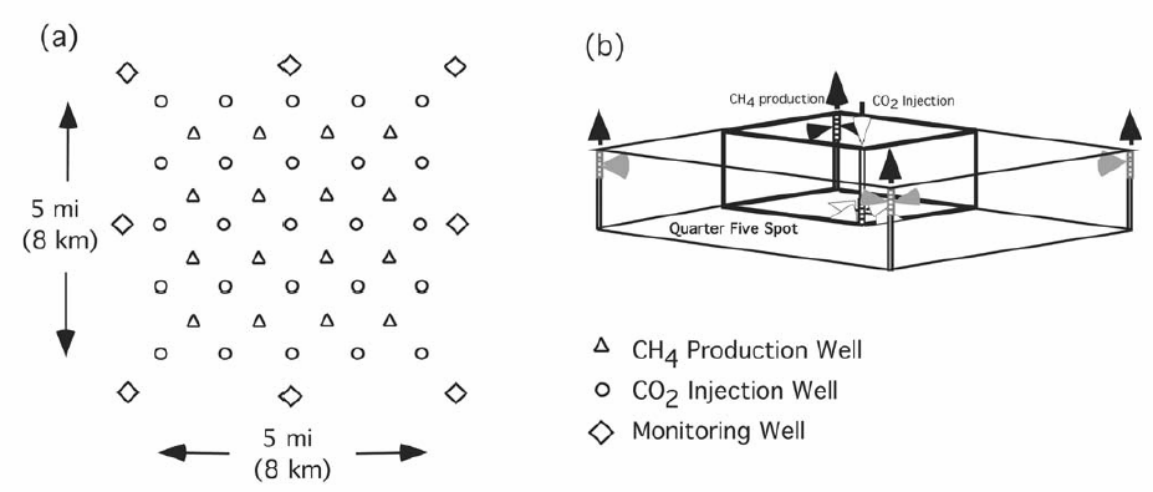


Figure 31. (a) Schematic of well pattern for a CO_2 sequestration/enhanced gas recovery simulation with well spacing of 1.6 km (1 mi). (b) Perspective view of quarter five-spot simulation domain (after Oldenburg *et al.*, 2004).

The properties (density and bulk modulus) of the CO_2 are calculated assuming hydrostatic pressure and a temperature of 75°C (167 °F) at 1,300 m (4,264 ft) using the NIST14 code (Magee and Howley, 1994). The bulk rock density D_{bulk} of the reservoir is calculated using

$$D_{bulk} = (1 - S_w - S_{CO_2})D_{grain} + S_w D_{brine} + S_{CO_2} D_{CO_2}, \quad (1)$$

where S_w is the brine saturation, S_{CO2} is the CO_2 saturation, D_{grain} is the grain density, D_{brine} is the brine density, and D_{CO2} is the CO_2 density. The density effect of CO_2 dissolved in the brine is neglected. Quartz sand grains (D_{grain} = 2,650 kg/m^3 = 165.4 lb/ft^3) are assumed.

Four time steps were considered – initial conditions, 5 years, 10 years, and 15 years into the CO_2 injection. Using these flow simulations, geophysical models were created to study the gravity- and seismic-methods responses to changes in the reservoir due to the CO_2 injection.

Figure 32 is a plane view of CO_2 saturation in the reservoir at the depth of 1,325 m (4,346 ft) after 10 years of CO_2 injection. The CO_2 injection well is at (0,0) and CH_4 production wells are at the corners of the grid: (-800, -800), (800, -800), (-800, 800), and (800, 800).

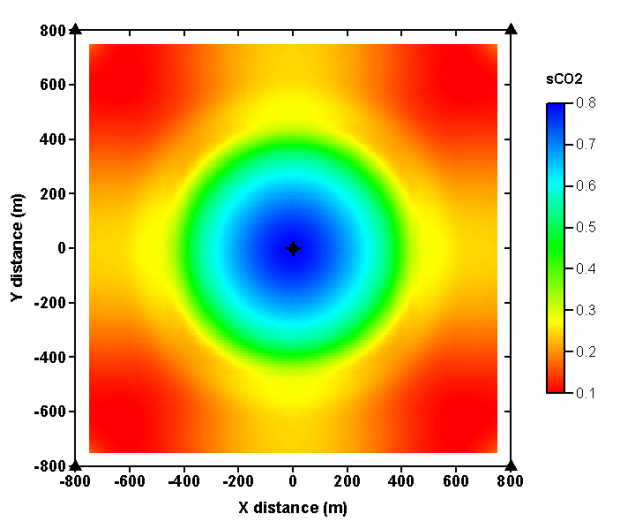


Figure 32. Plan view of CO_2 saturation at the depth of 1,325 m (4,346 ft) as a function of x and y coordinates after 10 years of injection

Figure 33 is a cross-section of CO_2 saturation through the center of the reservoir after 10 years of CO_2 injection. The injector is at the bottom of the reservoir (depth of 1,350 m, or 4,346 ft) at x = 0 m.

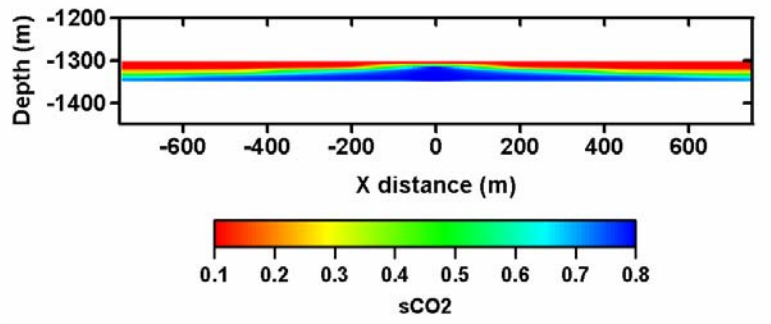


Figure 33. A cross-section of CO_2 saturation in the center of the reservoir after 10 years of CO_2 injection as a function of depth and horizontal position

Figures 34-36 are cross-sections of Vp-velocity, Vs-velocity, and density (respectively) through the center of the reservoir after 10 years of CO_2 injection. All these figures indicate a symmetric pattern between the injection and production wells and relatively small changes both in velocity and density.

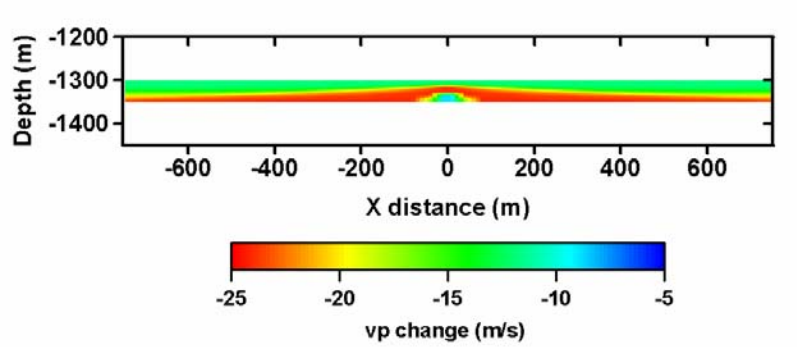


Figure 34. Vp-velocity change between initial conditions and 10 years into the CO_2 injection as a function of depth and horizontal position

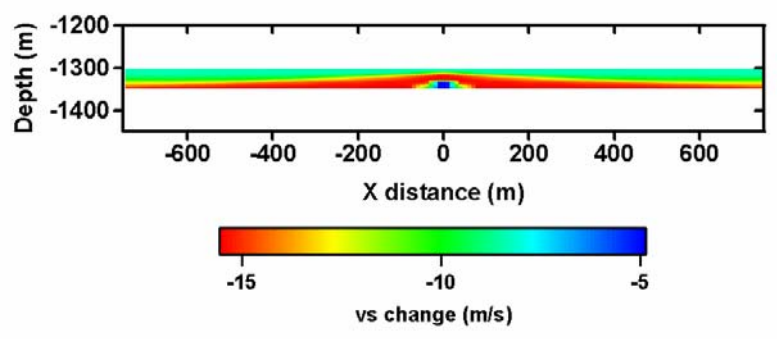


Figure 35. Vs-velocity change between initial conditions and 10 years into the CO_2 injection as a function of depth and horizontal position

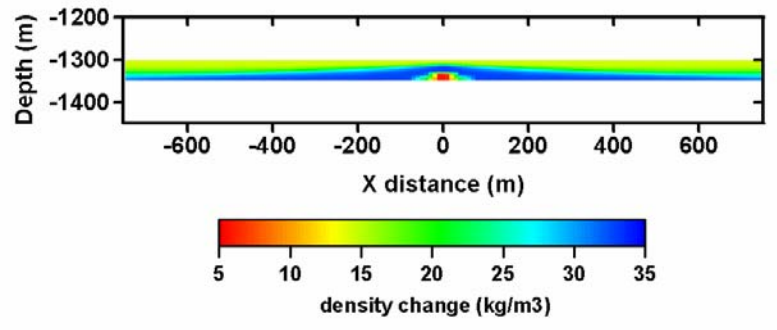


Figure 36. Density change between initial conditions and 10 years into the CO_2 injection as a function of depth and horizontal position

2.2.2 Gravity Modeling and Inversion

The vertical component of the surface gravity response of the model after 5 years, 10 years, and 15 years of CO_2 injection is shown in Figures 37, 38, and 39, respectively. CO_2 has higher density than CH_4 under reservoir conditions; therefore, by injecting CO_2 into the reservoir, density increases, which in turn causes an increase in the gravity response. The peak surface gravity response is about 2 μGal, 3.5 μGal, and 5 μGal after 5, 10, and 15 years of injection, respectively. Signals for 5 and 10 years are very close to the limits of current survey technologies and might not be measurable in the field. The response after 15 years of CO_2 injection should be measurable in the field. Brown *et al.* (2002) reported repeatability of 3.5 μGal for a gravity survey at Prudhoe Bay, Alaska. Nooner *et al.* (2003) reported repeatability of 2.5 μGal and a detection threshold for time-lapse changes of 5 μGal for a time-lapse gravity survey of the Sleipner CO_2 sequestration site in the North Sea.

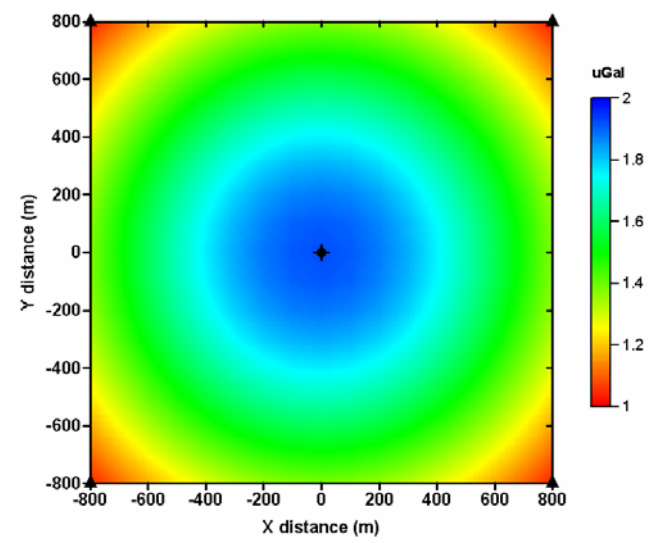


Figure 37. Vertical component of the surface gravity response of the model after 5 years of CO_2 injection as a function of x and y coordinates

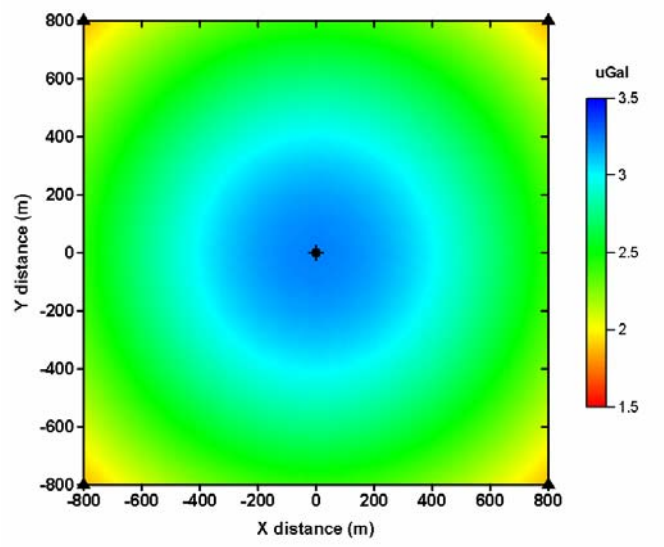


Figure 38. Vertical component of the surface gravity response of the model after 10 years of CO_2 injection as a function of x and y coordinates

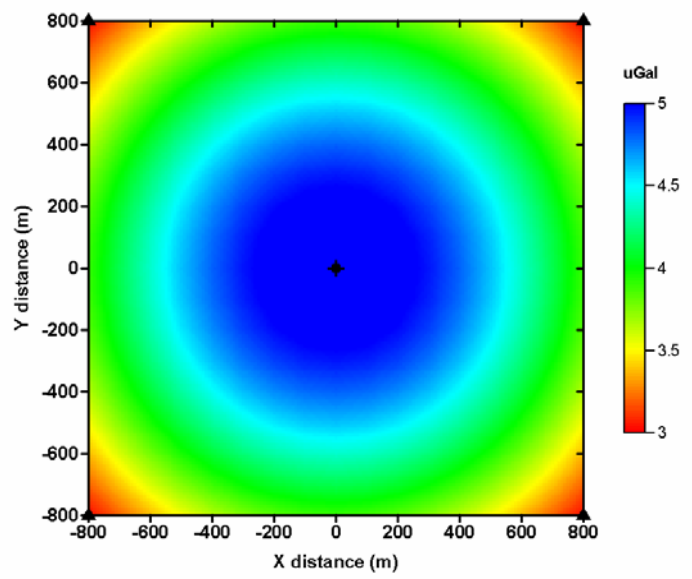


Figure 39. Vertical component of the surface gravity response of the model after 15 years of CO_2 injection as a function of x and y coordinates

The inversion of gravity data is very important since construction of density contrast models significantly increases the amount of information that can be extracted from the gravity data. However, a principal difficulty with the inversion of the gravity data is the inherent non-uniqueness and that there is no inherent depth resolution. This difficulty can be overcome by introduction of prior information. Some authors prescribe the density variations and invert for the geometrical parameters of the model (*e.g.*, Oldenburg, 1974),

while others assume a constant density contrast and invert for the position of a polyhedral body from isolated anomalies (*e.g.*, Pedersen, 1979). Li and Oldenburg (1998) developed another approach where gravity data are inverted directly by minimizing an objective function of the density model subject to fitting the observations. This approach also incorporates prior information via a reference model and depth weighting. We adopted Smith *et al.*'s (1999) approach described for magnetotelluric data inversion, in which the top and base of the reservoir are known and we invert for a density variation inside the reservoir. The inversion result is a cumulative density change in the reservoir as a function of x and y coordinates. Because the model space and inversion domain space can be different, one needs to calculate a parameter—a product of a cumulative cell density change and its volume—that is equal in both of these domains in order to compare inversion results with a true model.

The gravity inversions of the vertical component of the surface gravity response for each time are shown in Figures 40, 41, and 42, respectively.

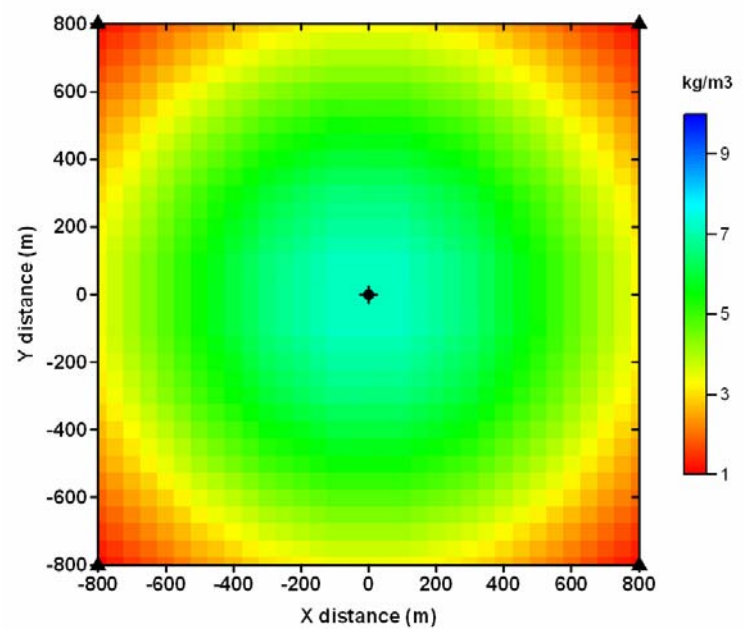


Figure 40. Density change (in kg/m^3) recovered by inversion of the vertical component of the surface gravity response of the model after 5 years of CO_2 injection as a function of x and y coordinates

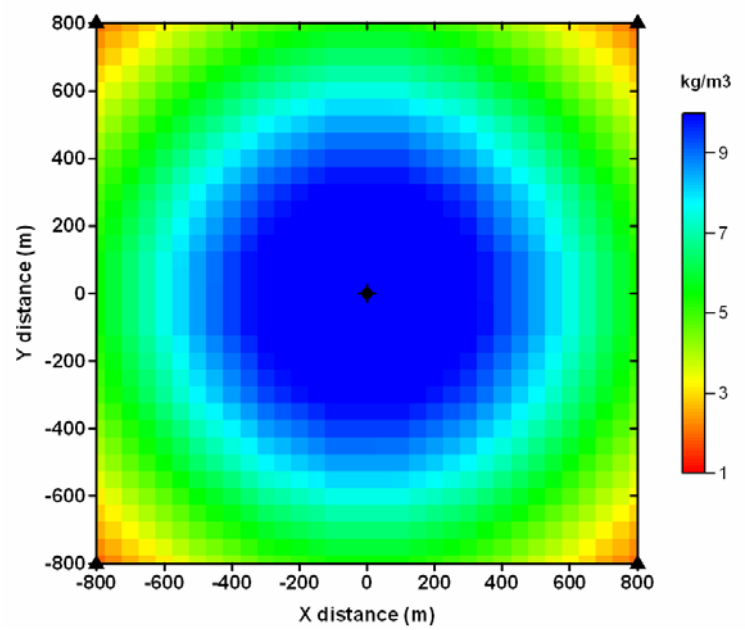


Figure 41. Density change (in kg/m^3) recovered by inversion of the vertical component of the surface gravity response of the model after 10 years of CO_2 injection as a function of x and y coordinates

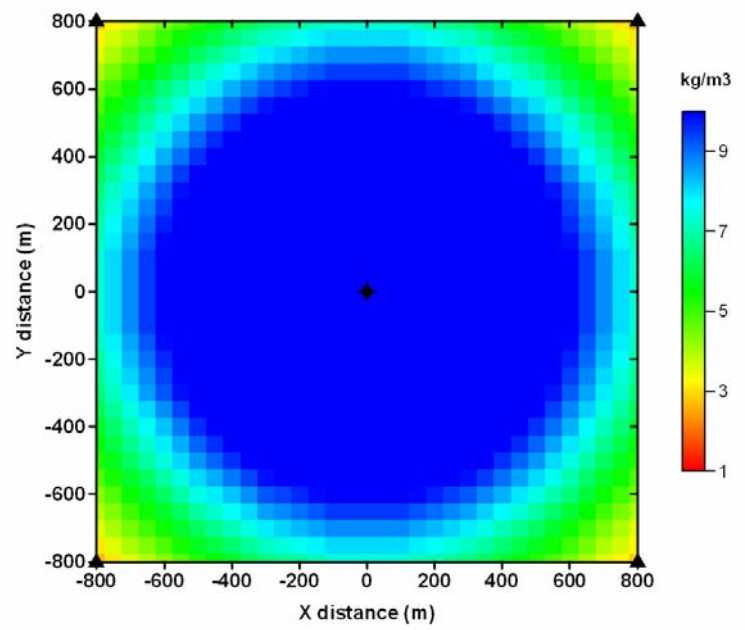


Figure 42. Density change (in kg/m^3) recovered by inversion of the vertical component of the surface gravity response of the model after 15 years of CO_2 injection as a function of x and y coordinates

Figures 40, 41, and 42 show that CO_2 is replacing CH_4 further and further from the injection well (0, 0) with time and therefore the CO_2-CH_4 contact moves away from the injection well. Since the five-point simulation area is centered over the CO_2 injection well and CH_4 production wells contributed only partially, the gravity high is centered on the injection well. To evaluate how much change in the response is due to one injection well (0,0) and one production well (800, 800), we modified the model after 15 years of CO_2 injection to reflect that; the gravity response of this model is shown in Figure 43. Figure 44 shows the inversion results for this model overlaid on the true density model. The gravity inversion used in this study is solving for density changes between the top and bottom of the reservoir. The inversion result is a cumulative density change in the reservoir as a function of x and y coordinates. Because the model space and inversion domain space are different, in order to compare inversion results with a true model we need to calculate a parameter that is equal in both of these domains and a product of a cumulative cell density change and its volume. The true model is displayed in color, and the inversion results are displayed as red contours. The true model shows that density near the injection well is higher than that near the production well. The inversion finds a broad, smooth anomaly centered between the injection and production wells.

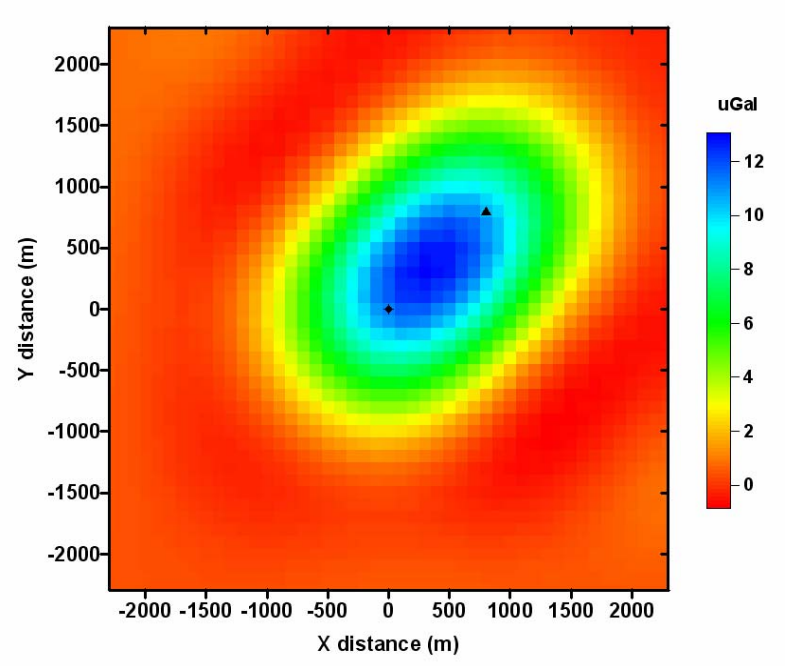


Figure 43. Vertical component of the surface gravity response of a modified model after 15 years of CO_2 injection with an injection well at (0,0) and a production well at (800,800) as a function of x and y coordinates

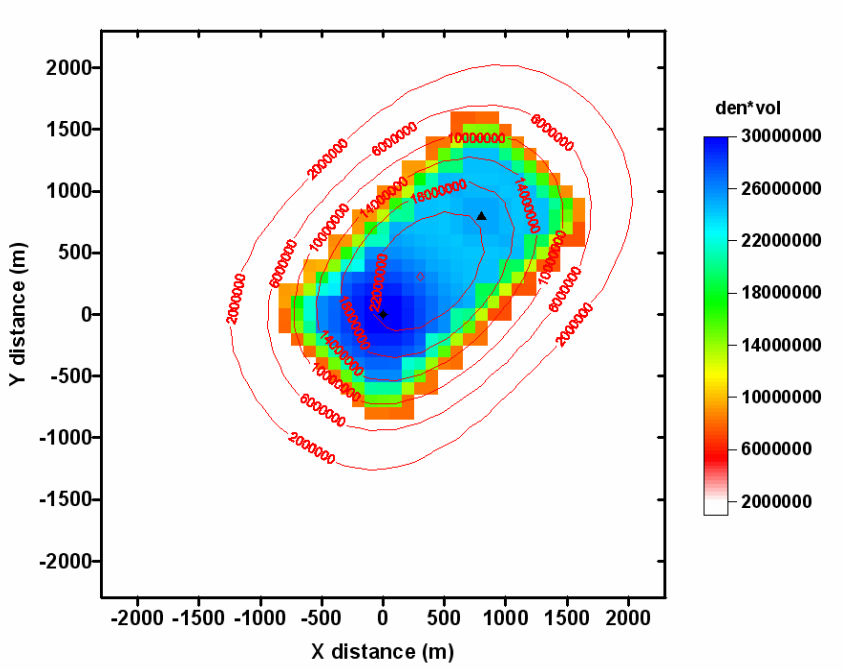


Figure 44. True density model overlaid by contours of the inversion results as a function of x and y coordinates

2.2.3 Seismic Modeling

NMO CDP stack sections of the model after 5 years, 10 years, and 15 years of CO_2 injection are shown in Figures 45, 46, and 47, respectively. The reservoir produces weak anomalies associated with the changes in CO_2 saturation. Seismic velocities change only 1–2%. The seismic amplitudes are small and therefore seismic is not a reliable monitoring tool of CO_2 movement under present reservoir conditions.

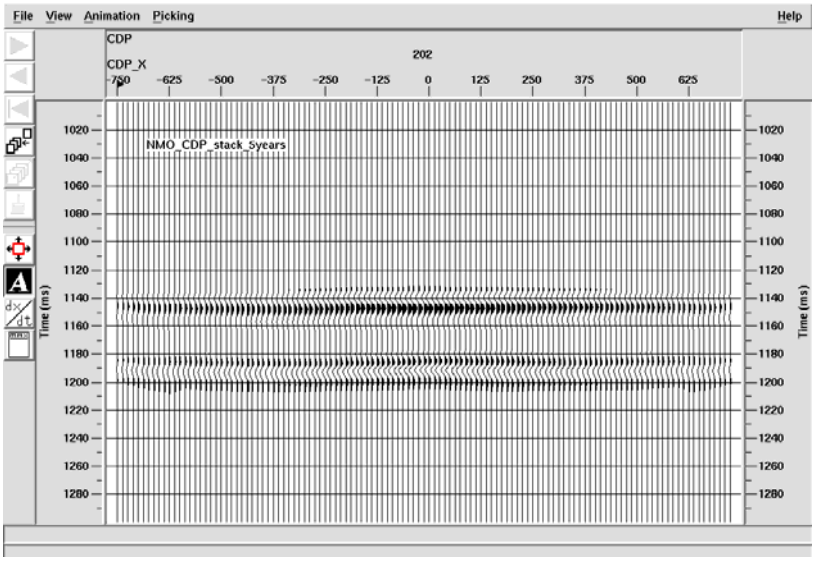


Figure 45. NMO CDP stacked section of the model after 5 years of CO_2 injection

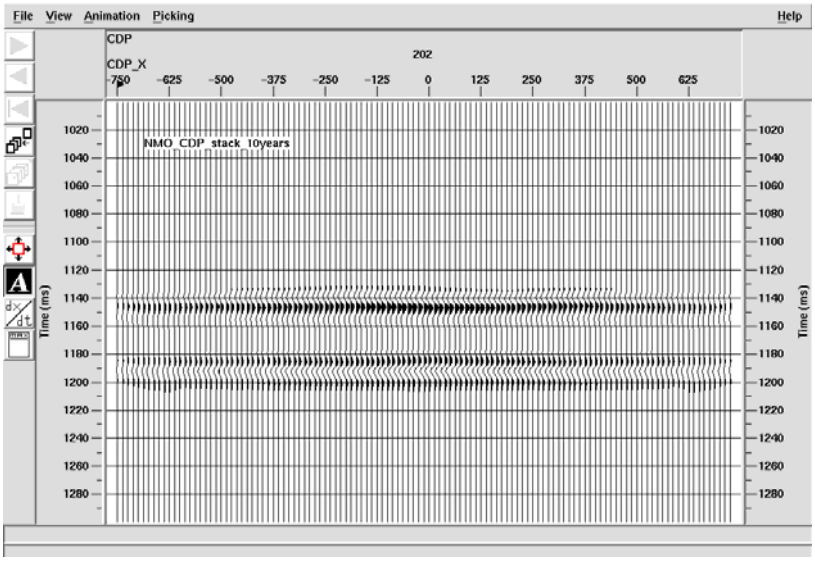


Figure 46. NMO CDP stacked section of the model after 10 years of CO_2 injection

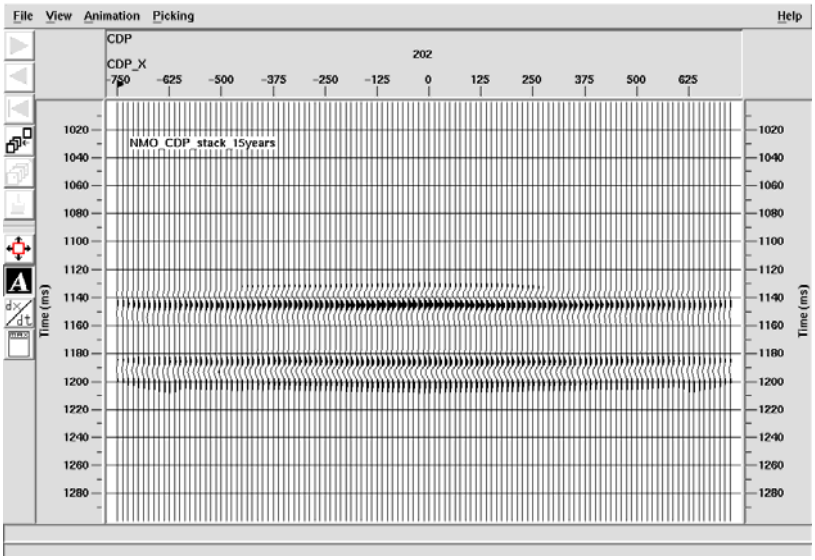


Figure 47. NMO CDP stacked section of the model after 15 years of CO_2 injection

Figure 48 shows the NMO section as function of offset centered 300 m (984 ft) away from the injection well for the model after 10 years of CO_2 injection. Figure 49 shows amplitude at the top of the reservoir at the same location (x= -300 m = -984 ft), as a function of offset after 5, 10, and 15 years of CO_2 injection. There is less than a 2% change for models after 5 and 10 years of CO_2 injection, and about 3% for model after 15 years of CO_2 injection. Figure 50 shows predicted Rpp amplitude as a function of offset for the reservoir properties used in this study. All three figures (Figures 48–50) confirm that the change in the amplitude as a function of offset is on the edge of detectability to be able to predict the CO_2 saturation from AVO measurements for this model. Assuming normal S/N ratios and changes present over many traces, 2–5% change both in amplitude and AVO should be detectable in the field data (T. Daley, personal communication).

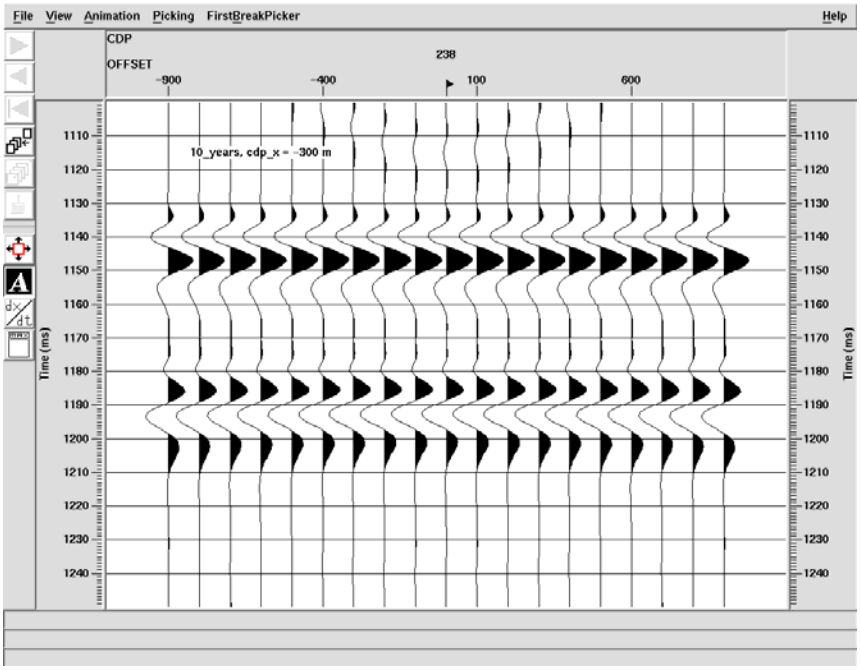


Figure 48. NMO section for CDP 238 (x = -300 m = -984 ft) showing seismic amplitude as a function of offset of model after 10 years of CO_2 injection

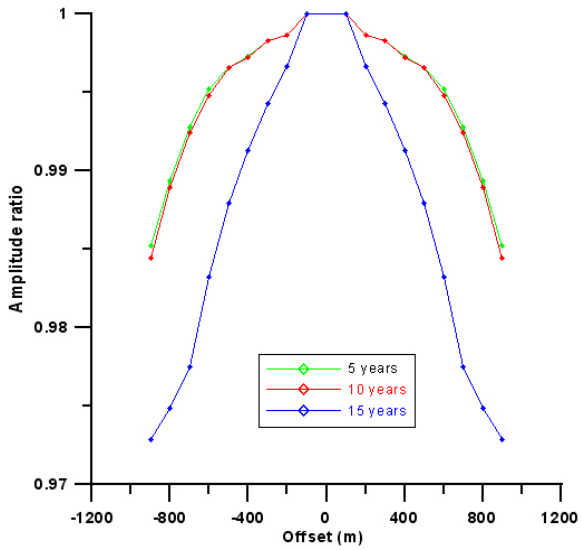


Figure 49. AVO amplitude ratio as a function of offset for CDP 238, which is 300 m (984 ft) away from the injection well

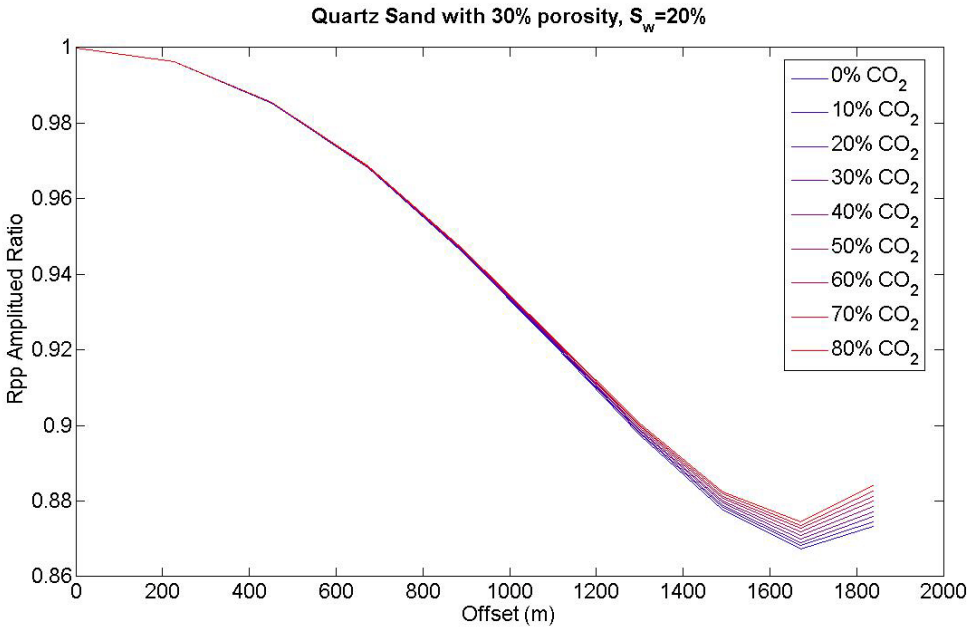


Figure 50. Model AVO results–Rpp amplitude as a function of offset for quartz sand of 30% porosity and 20% water saturation

2.3 Ventura Oil Field

The Ventura Field is located in the center of the Ventura Basin, 105 km (65 mi) west and north of Los Angeles. The basin is filled with tertiary sediments. The Pliocene section is about 6,000 m (19,680 ft) thick and crops out within the Ventura Field. This section of deep-water fan sediments consists of many interbedded sandstones and shales. Mid-Pleistocene stresses compressed the basin, folded the sediments, and formed a complexly faulted, east-west trending, asymmetric structure known as the Ventura Anticline. The Ventura Field produces from a Pliocene unit at depths of 1,000 m (3,280 ft) to over 4,000 m (13,120 ft). Five major fault blocks (A, B, C, D, and N) have been identified during development. Blocks B, C, and D, between 1,500 and 3,000 m (4,920 and 9,840 ft) depth, are candidates for CO_2 sequestration.

Using average reservoir properties we calculated a response in seismic amplitude (Figure 51) and density change (Figure 52) due to the change in CO_2 saturation. The values used in these calculations are: depth to the top of the reservoir = 2,500 m (8,200 ft), porosity = 14%, reservoir temperature = 87.8 °C (190 °F), reservoir pressure = 22 MPa, GOR ~ 100 l/l, oil gravity = 30° API, water saturation = 0.6, and oil saturation = 0.4.

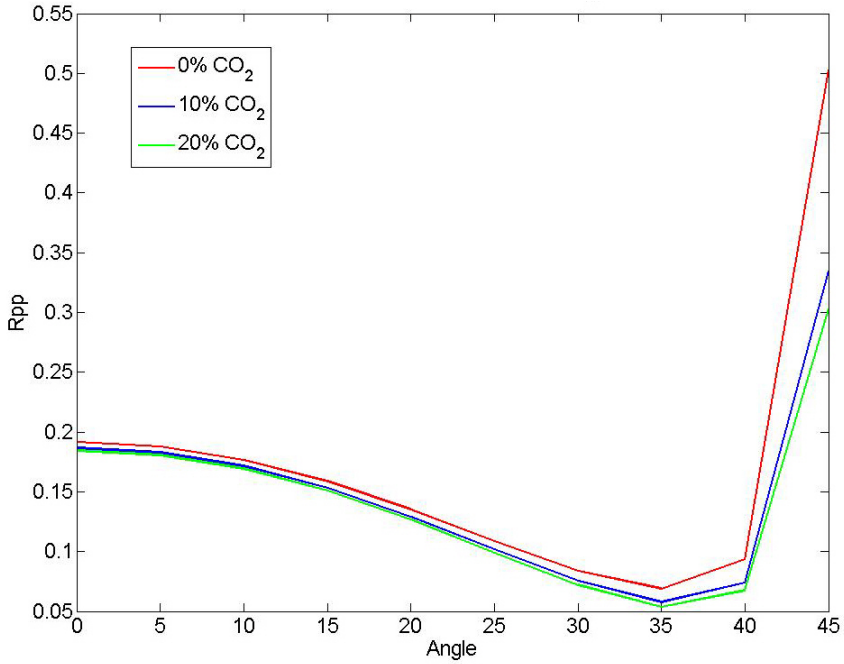


Figure 51. Seismic amplitude as a function of angle (offset) for a hypothetical model for the Ventura Oil Field

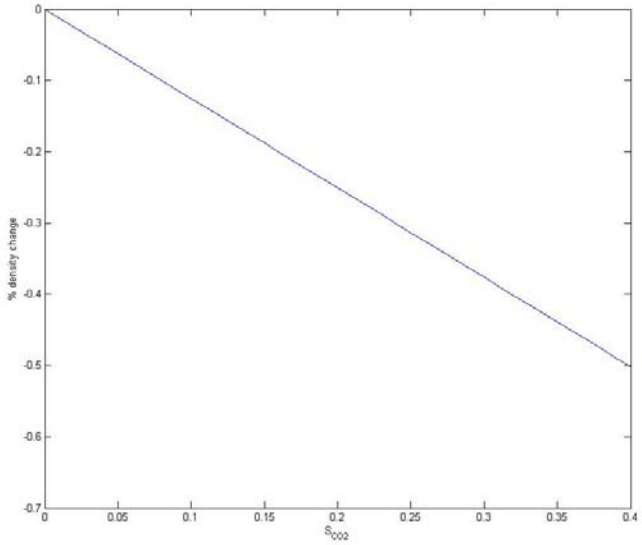


Figure 52. Density change due to a change in CO_2 saturation for a hypothetical model for the Ventura Oil Field

Based on the signal levels in Figures 51 and 52, neither the seismic nor gravity methods would be able to monitor changes in the reservoir due to CO_2 saturation change for conditions used in this hypothetical model.

3 Results and Discussion

The difference in the vertical component of gravity (G_z) on the surface caused by CO_2 injection over a 20-year period for the Schrader Bluff model is on the order of 2 μGal, which is in the noise level of the field survey (Hare *et al.*, 1999). The negative change in the response is caused by increased CO_2 saturations reducing the bulk density of the reservoir. The spatial variations in the changes in G_z as well as the vertical gradient of the vertical component of gravity (dG_z/dz) directly correlate with the spatial variations in the net density changes within the reservoir. Again, the magnitude of the signal measured in the field (2–10 EU) is above the gradiometer accuracy (0.5–1 EU), but the difference between initial conditions and 20 years into CO_2 injection is very small (~0.1 EU). If the noise levels of measurements of the changes in dG_z/dz could be reduced by permanent sensor emplacement and continuous monitoring of gravity and gradient measurements may offer a tool for monitoring.

Borehole measurements of gravity just above the reservoir do produce measurable change in the vertical component of gravity that could be used to map lateral distributions of injected CO_2. The changes in dG_z/dz measured in the borehole are below the ability of current technology to distinguish. However, current work on borehole gravity tools may change this situation within the next few years. The difference in both the borehole gravity response and the vertical gravity gradient (dG_z/dz) measured in vertical profiles within boreholes clearly identifies the position of the reservoir, and the sign of the change reflects the changes in the local densities caused by either water or CO_2.

There is a clear change in seismic amplitude associated with the reservoir caused by the changes in water and CO_2 saturation. In addition, there is a change in the seismic AVO effects: both seismic amplitude and AVO can be exploited to make quantitative estimates of saturation changes. Forward calculations made using the Zoeppritz equation for both 2005 and 2020 models support this argument.

The electrical resistivity of reservoir rocks is highly sensitive to changes in water saturation. This high sensitivity to water saturation in a reservoir can be exploited by electromagnetic (EM) techniques where the response is a function of the electrical resistivity of the formation. Of all the possible combinations of EM sources and measured EM fields, one measurement method combines both relative ease of deployment with high sensitivity to reservoirs of petroleum scale and depth. This technique uses a grounded electric dipole that is energized with an alternating current at a given frequency to produce time varying electric and magnetic fields that can be measured on the earth's surface. To simulate such an EM system, we have calculated the electric field on the surface of the Schrader Bluff model using 100 m (328 ft) electric dipoles operating at 1 Hz and measuring the resulting electric field at a separation of 2 km (1.2 mi) in-line with the transmitting dipole. The electric field for the Schrader Bluff model—generated using only a small portable generator—is an order of magnitude above the background electric field (noise) at the operating frequency of 1 Hz; this means that synchronous detection of the signal combined with stacking can recover signal variations to better than 1 percent. There is a direct one-to-one correspondence with the change in S_w and the change in the electric field amplitude. While this signal level is low, it can be measured given the

signal-to-noise ratio of the data. While this represents a potential low-cost monitoring technique it is best suited for CO_2-brine systems where there is a one-to-one correlation between the change in water saturation and the change in CO_2 saturation (since $S_w + S_{CO2} = 1$). In petroleum reservoirs such as Schrader Bluff, the presence of hydrocarbons as additional fluids eliminates the one-to-one correlation between changes in S_w and changes in S_{CO2}. This type of EM technique has not yet been employed as a monitoring tool within the petroleum industry; however, EM technology is currently the subject of a significant upsurge in industry interest. Several commercial contractors are now offering this technique as a survey tool—most notably in the offshore environment where it is used as an exploration tool (Ellingsrud *et al.,* 2002). The equipment and service providers exist to apply this technique to future monitoring.

For the gas field used in this study, the changes in reservoir properties were very small and neither gravity nor seismic methods would provide the information necessary for monitoring of CO_2 movement.

Not enough information was available to create a representative model of the Ventura Oil Field, California; however, preliminary calculations made using average reservoir properties suggest that neither gravity nor seismic methods will be able to give sufficient information about CO_2 saturation change.

4 Conclusions

Both surface and borehole gravity measurements have been modeled for Schrader Bluff on the North Slope of Alaska. The injection of CO_2 produces a bulk density decrease in the reservoir that in turn produces a reduction in the gravitational attraction from the reservoir. The spatial pattern of the change in the vertical component of gravity (G_z), as well as the vertical gradient of gravity (dG_z/dz), is directly correlated with the net change in density of the reservoir. The difference in G_z on the surface caused by CO_2 injection over a 20-year period is on the order of 2 μGal, which is below the level of repeatability of current field surveys (Hare *et al.*, 1999); however, measurements made in boreholes just above the reservoir interval (1,200 m—or 3,936 ft—depth) are sensitive enough to observe measurable changes in G_z as CO_2 injection proceeds. Such measurements made in numerous wells could map the areas of net density changes caused by injected CO_2 and water within the reservoir. The time-lapse changes in the borehole G_z and dG_z/dz clearly identify the vertical section of the reservoir where fluid saturations are changing.

Model results show a clear change in seismic amplitude associated with the reservoir due to the changes in water and CO_2 saturation. Moreover, there is a change in the seismic AVO effects. Both seismic amplitude and AVO can be used to make quantitative estimates of saturation changes, subject to modeling assumptions.

The electrical resistivity of rocks is primarily a function of porosity and water saturation (S_w). When the porosity is known, or can reasonably be assumed to have small spatial variation, the changes in electrical resistivity are directly related to the changes in water saturation, and EM techniques can be used to map such spatial variations in electrical

resistivity. An EM field system that combines relative ease of deployment with high sensitivity to petroleum reservoirs generated an electric field for the Schrader Bluff model that was an order of magnitude above the background electric field (noise) at the operating frequency of 1 Hz. This means that synchronous detection of the signal combined with stacking can recover signal variations to better than 1 percent. The change in the electric field amplitude is directly proportional to the change in S_w. While this signal level is low, it can be measured given the high signal-to-noise ratio of the data. This potential low-cost monitoring technique is best suited for CO_2-brine systems where there is a one-to-one correlation between the change in water saturation and the change in CO_2 saturation. In petroleum reservoirs such as Schrader Bluff, the presence of hydrocarbons as additional fluids eliminates this one-to-one correlation.

Because the changes in reservoir properties for the gas field used in this study are very small, neither gravity nor seismic methods would provide information necessary for monitoring of CO_2 movement.

Not enough information was available to create a representative model of the Ventura oil field. Preliminary calculations made using average reservoir properties suggest, however, that neither gravity nor seismic methods will be able to provide sufficient information about CO_2 saturation change.

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Appendix XV, Final Report

Action Plan for Addressing Phase II Technology Deployment Issues

Deliverable associated with Task 2.0, Item 5

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Prepared by:
Richard J. Myhre, P.E.

March 14, 2005
with editor's notes from July 2006

DOE award no. DE-FC26-03NT41984

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Deliverable Mapping

This action plan constitutes the required WESTCARB Phase I deliverable associated with Task 2.0, Identify and Address Technology Deployment Issues, Item 5 (“an action plan”). Note that there are companion action plans for Phase II public outreach and implementation of Phase II pilot projects.

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Introduction

The West Coast Regional Carbon Sequestration Partnership (known as WESTCARB) is one of seven partnerships established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of North America.



Accordingly, WESTCARB is exploring the opportunities in six Western states and one Canadian province for removing CO_2 from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted, both of which will help slow the atmospheric buildup of this greenhouse gas.

WESTCARB is identifying the major sources of man-made CO_2 in its territory; assessing the status and cost of technologies for separating CO_2 from process and exhaust gases at large industrial plants; determining the potential for storing captured CO_2 in leak-proof geologic formations; establishing the extent to which changes in the management of forests, rangelands, and agricultural lands could increase carbon storage by plants and soil; assessing the logistics and costs of building pipelines to move CO_2 from the points of capture to the points of storage; and summing the results of cost estimates for capture, transportation, and storage to create carbon storage "supply curves."

Led by the California Energy Commission, WESTCARB's Phase I partners include about 50 organizations from state and provincial resource management and environmental protection agencies; national laboratories and research institutions; colleges and universities; conservation non-profits; oil and gas companies; power companies; pipeline companies; trade associations; vendors and service firms; and consultants.

One of WESTCARB's six primary goals is to resolve technology deployment issues, such as uncertainties in regulatory status and permitting procedures and validity and cost of techniques for measurement, monitoring, and verification (MMV). These issues are most readily addressed through pilot field tests to validate the feasibility, safety, and efficacy of promising geologic and terrestrial carbon sequestration solutions.

Specific WESTCARB pilot projects, developed in Phase I, and to be conducted during Phase II include:

- Conducting two CO_2 storage pilot tests at a gas reservoir leased by Calpine and the underlying saline formation. [Editor's Note: Rosetta Resources became our industrial match partner for this project with the acquisition of Calpine Rio Vista area gas rights in mid-2005.] In addition to information on the safety and viability of these sequestration options, they will provide valuable data on monitoring and verification technologies, permitting in California, and the efficacy of public outreach efforts.

- Conducting a CO_2 storage pilot test in northern Arizona (site TBD, but expected to be near a Salt River Project coal-fired power plant) to demonstrate the safety and feasibility of CO_2 storage in saline formations in Arizona's portion of the vast Colorado Plateau region, obtain data on monitoring and verification technologies, and gain experience with regulatory permitting and public outreach associated with CO_2 storage in a saline formation in Arizona.

- Conducting two pilot projects in Lake County, OR, and Shasta County, CA, that will test the following options for terrestrial sequestration: afforestation of once-forested lands now used for agriculture or grazing, forest fuel load reduction for improved fire management (i.e., reducing the probability of uncharacteristically severe wildfires and accompanying massive CO_2 releases), and improved forest conservation management.

This action plan describes WESTCARB's approach to successfully securing permits and keeping regulatory authorities apprised of progress (and compliance) on these pilot projects.

Permitting Strategy for Geologic Pilot Projects

For applications other than enhanced oil recovery, regulatory structures are generally not yet established for large-scale injection of CO_2 for sequestration. In Phase I, WESTCARB compiled the current regulations that could be applicable in each state of its territory (see Appendix A). This included regulations for injection into oil and gas reservoirs, injection into coal formations, injection for natural gas storage, and injection for disposal purposes.

In WESTCARB's Phase II Northern Arizona pilot, we will work with Salt River Project, U.S. EPA Region 9, Arizona Department of Environmental Quality (ADEQ), and possibly the Navajo Nation EPA, to identify the appropriate regulatory process for a well to inject CO_2 into a saline formation. Our initial approach to permitting the pilot project will be to request a permit for a Class V experimental well. A phased approach will be considered, in which a Temporary Aquifer Protection Permit is first obtained from the ADEQ for a stratigraphic testing well.

In California, WESTCARB investigators will work with Calpine, EPA Region 9, and the California Department of Oil, gas, and Geothermal Resources (DOGGR) to identify the appropriate regulatory process for the planned saline formation and gas reservoir pilot tests. [Editor's Note: Rosetta Resources became our industrial match partner for this project with the acquisition of Calpine Rio Vista area gas rights in mid-2005.] In light of the planned injection into and below a depleted gas reservoir, we plan to request a permit for a Class II oil and gas production-related well. Both EPA Region 9 and DOGGR are WESTCARB participants.

MMV Strategy for Geologic Pilot Projects

Our approach to measurement, monitoring, and verification (MMV) of the geologic pilot tests is based on the experience we gained as a result of our participation in the Frio Brine Pilot Injection Test, the Lost Hills (California) CO_2 EOR pilot test, and the Weyburn Project. To ensure that project goals, permitting requirements, and safety controls are achieved, we will use the process outlined in Figure 1. At the heart of our approach, is a careful requirements definition phase, followed by the repeated use of detailed simulations of flow and transport, coupled to a geophysical imaging code. The repeated use of these tools over the project phases—requirements definition, pre-permitting, permitting and operations—allows us meet project goals, while minimizing costs, by optimizing the injection and observation well spacing, the quantity of CO_2 injected and the suite of monitoring techniques used for the pilot tests.

Simulation of the CO_2 injection and storage will begin with a detailed, site-specific hydrogeological model of the pilot test site. After assembling the hydrogeological model from all of the available data, subsurface flow and transport simulations

will be carried out with TOUGH2 and TOUGHREACT (Pruess et al. 1999; Xu et al. 2004). The output of the flow and transport model is then imported to a geophysical simulator. The geophysical simulator allows us to calculate the geophysical response for seismic techniques, electrical and electromagnetic methods and gravity—and to evaluate whether they have sufficient detection limits to meet the project objectives. These detailed simulations also provide the basis for determining the distance between the injection and observation wells (where a two-well project design is used) and the amount of CO_2 that needs to be injected to ensure breakthrough at the observation well.

For each pilot test, a comprehensive set of monitoring techniques will be evaluated and deployed as part of the tests, aimed at monitoring CO_2 movement in the storage formation as well as detecting any leakage outside the primary storage formation. Based on our best current understanding, a combination of surface seismic reflection, Vertical Seismic Profiling (VSP), and cross-well seismic imaging will be the primary techniques used to track migration of CO_2 and to detect leakage from the storage formation. Injection rates will be monitored continuously. Wellhead and formation pressures will be monitored to assure that injection pressures remain within the permitting guidelines. Fluid and gas composition will be monitored using samples collected during the CO_2 injection. To ensure the safety of workers on the site, surface CO_2 sensors and an alarm system will be positioned at the wellheads, near the injection pumps, and at any other location where leakage from surface facilities may occur. In addition, all of the subsurface and surface measurements listed in Table 1 will be evaluated on a site-specific basis to determine which will be most effective for tracking CO_2 movement before deciding which methods and monitoring configurations to deploy.

In addition to the general approach outlined above, site-specific requirements will be addressed. For example, seismic methods may not be sufficiently sensitive for tracking CO_2 migration in a natural gas reservoir, therefore, the multilevel fluid sampling system will be utilized to track migration and allow careful evaluation of flow and transport processes that affect success of carbon sequestration enhanced gas recovery (CSEGR).

For the Northern Arizona Saline Formation CO_2 Storage Pilot, the “Frio approach” will be modified to account for the likelihood that the permeability of the formation is much lower than the permeability of the Frio formation (or Thornton saline formation). One of the most significant modifications will be to include passive seismic monitoring, to determine if any micro-seismic events are induced by pressure buildup and temperature changes. In addition, because only one well will be drilled, we will rely on VSP, and possibly only surface seismic, to track migration of the injected CO_2 (see Figure 2). VSP proved to be a very cost-effective technique for monitoring CO_2 migration at the Frio Brine Pilot Test. Not only did it have a high sensitivity for detecting the presence of CO_2, it provided wider area coverage than cross-well imaging methods. For this reason, we are

confident that we can obtain a sufficient amount of information to meet the test objectives with a single well test.

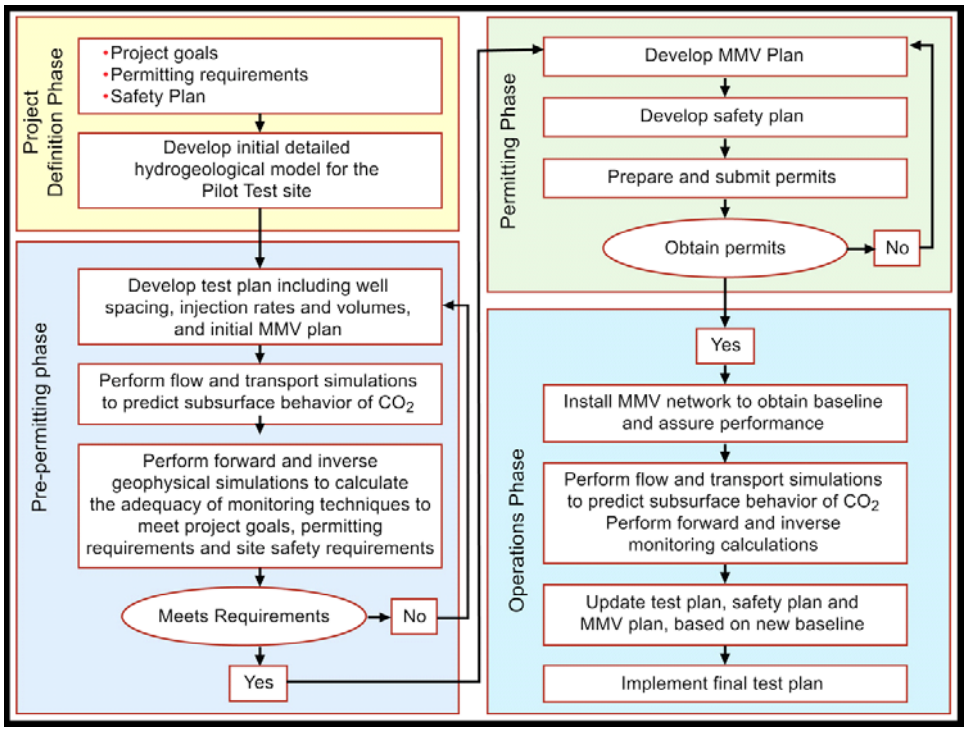
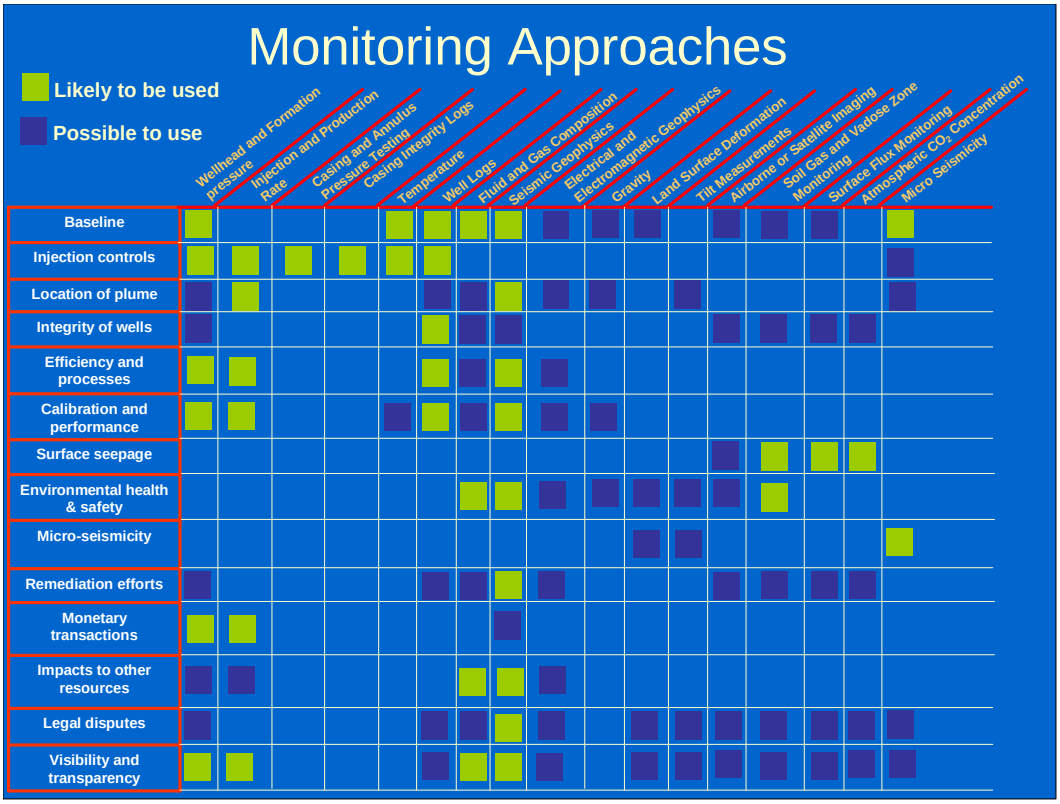


Figure 1. Illustration of the process used to ensure the MMV plan satisfies the goals of the project, permitting requirements, environmental, and safety issues.

Table 1. Potential monitoring methods that could be employed for the monitoring program at the WESTCARB CO_2 Storage Pilot Projects (modified from Benson et al. 2004)



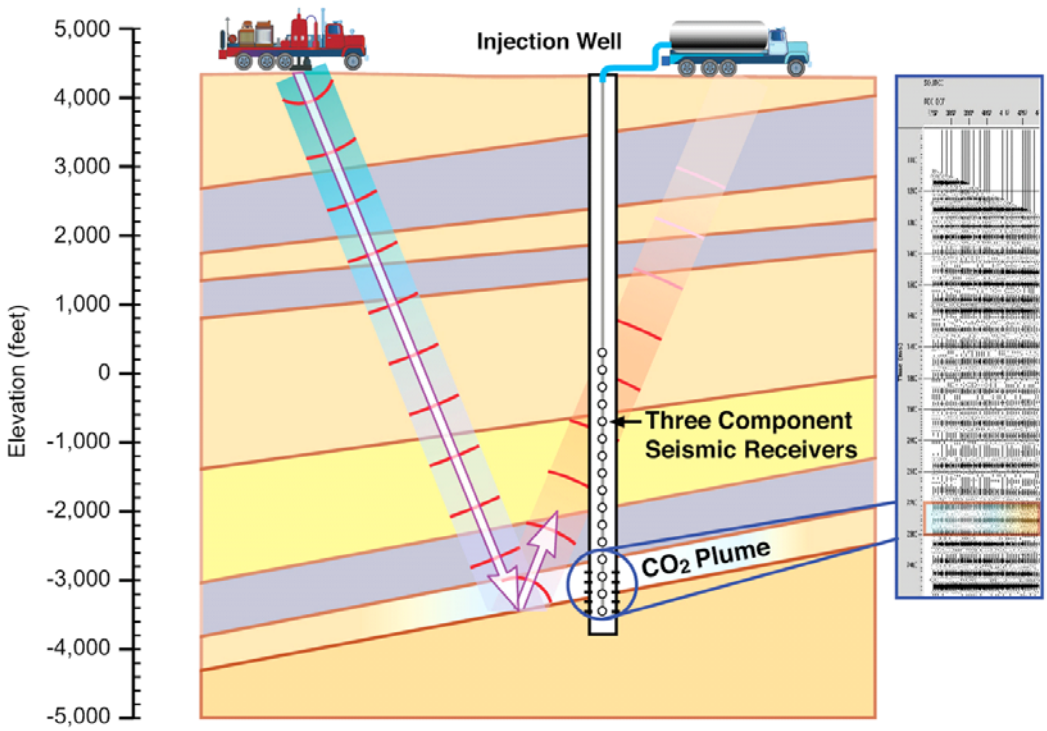


Figure 2. Schematic showing the Northern Arizona Saline Formation CO_2 Storage Pilot and the use of VSP (Vertical Seismic Profiling) to detect CO_2 migration

Permitting Strategy for Terrestrial Pilot Projects

WESTCARB's Phase I evaluations identified applicable or potentially applicable regulations for forest-based terrestrial sequestration state by state (see Appendix B). Measurement, monitoring, and validation activities on public lands will take place on projects for which the federal and state partners have already met applicable environmental review requirements (i.e., NEPA requirements for projects on federal lands and corresponding state regulations for projects on state forest land).

On private lands, all measurement, monitoring, and validation activities will conform to either the California or Oregon Forest Practices Acts. For the treatment of fuels and for site preparation where the landowner receives an economic gain, such as through selling fuels for power generation, the activities will also conform to state forestry regulations. For all treatment activities, analyses will assure compliance with endangered species and water quality regulations.

MMV Strategy for Terrestrial Pilot Projects

WESTCARB will base its modeling and MMV of terrestrial carbon sequestration on the peer-reviewed methods summarized by Brown et al. (2004) and MacDicken (1997) and on baselines established for California (Brown et al. 2004) and Oregon. These methods apply to afforestation, change in forest management, and forest conservation project activities—at virtually any scale—and produce accurate, cost-effective measurements of the total change in carbon stocks in dead and live biomass and in soil to a standard of precision of 10% of the mean with 95% confidence.

WESTCARB member Winrock International will work with other partners, including Oregon State University, the USDA Forest Service Pacific Wildland Fire Sciences Laboratory and Pacific Southwest Research Station, and the California and Oregon departments of forestry, to review fire models and collect data to validate models. All carbon sequestration will be reported to CCAR and will meet the standards of the Registry. As noted, established methodologies for measuring the carbon benefits of forest fuel management do not exist. In the course of our pilot projects, we aim to develop and test new methodologies for quantifying these carbon benefits, and to work with CCAR to seek their approval.

NEPA Compliance Documentation

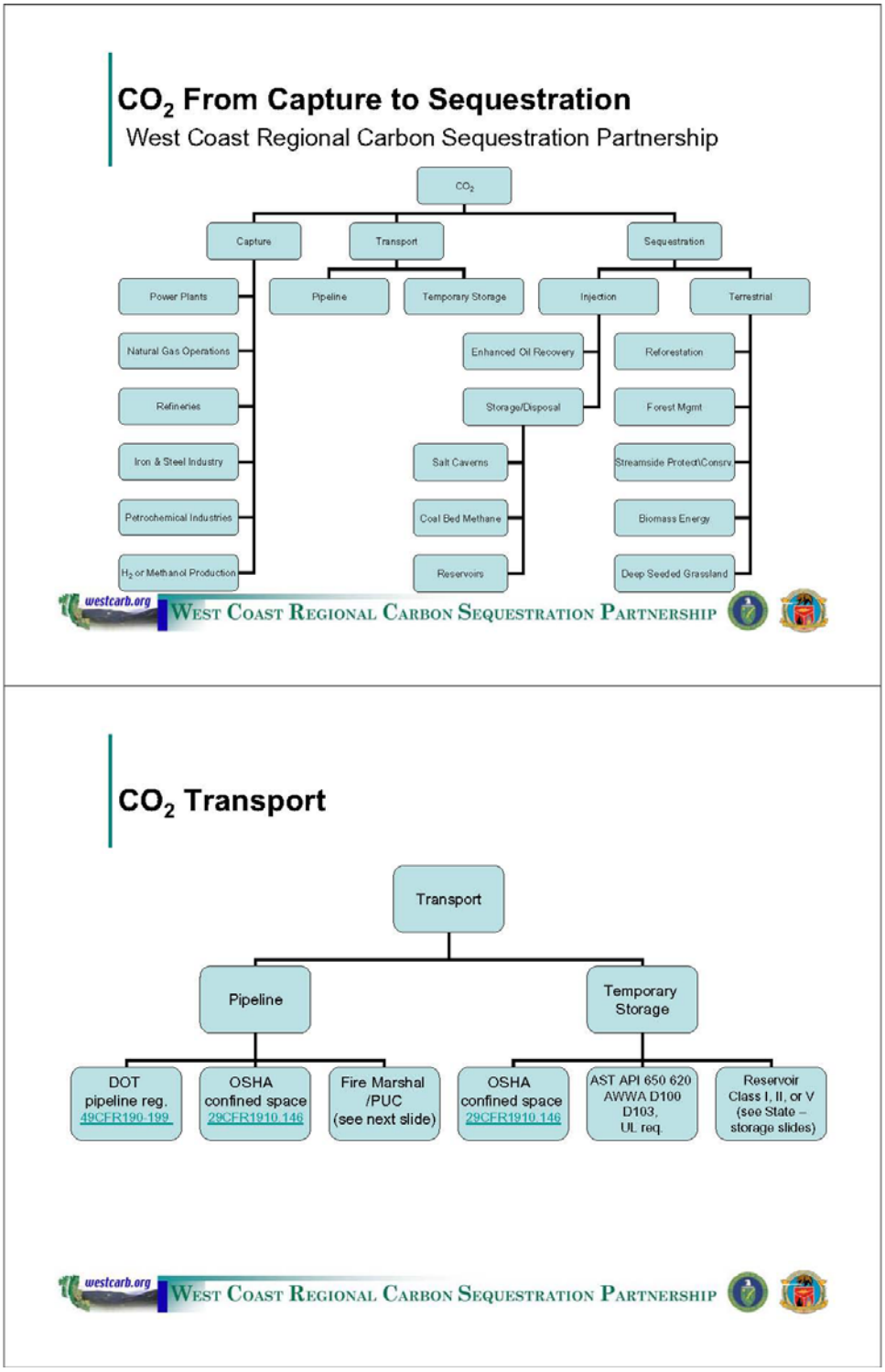
WESTCARB will prepare National Environmental Policy Act (NEPA) compliance documentation for its Phase II activities. At present, we plan to prepare individual NEPA compliance documentation for each of our two geologic pilot and two terrestrial pilot sites. We expect that each of these projects will be appropriately covered by an Environmental Assessment, and that they may yield a Finding-of-No-Significant-Impact. In some cases, a categorical exclusion, based on the small-scale experimental nature of the project, or association with ongoing commercial oil and gas operations, may be appropriate. However, we are not assuming such a determination.

We plan to work closely with DOE and other Regional Partnerships to develop a consistent approach to NEPA compliance, using the resources of Lawrence Berkeley National Laboratory in this effort. In California, geologic and terrestrial pilot projects may also require California Environmental Quality Act (CEQA) documentation. [Editor’s Note: In Fall 2005, the consulting firm Aspen Environmental, which works extensively with the California Energy Commission, was contracted to prepare NEPA and, where applicable, CEQA documentation for our geologic and terrestrial pilot projects.]

Permitting Schedule

The schedule for permitting activities is linked to the schedules for the individual pilot projects and is governed by their overall progress. In general, California geologic permitting activities will take place in 2006–07 and Arizona permitting activities will take place in 2007–08. For most terrestrial pilot activities, permits are being obtained independently by landowners and/or managers.

Appendix A: Potential CO_2 Transportation and Geologic Storage Regulations

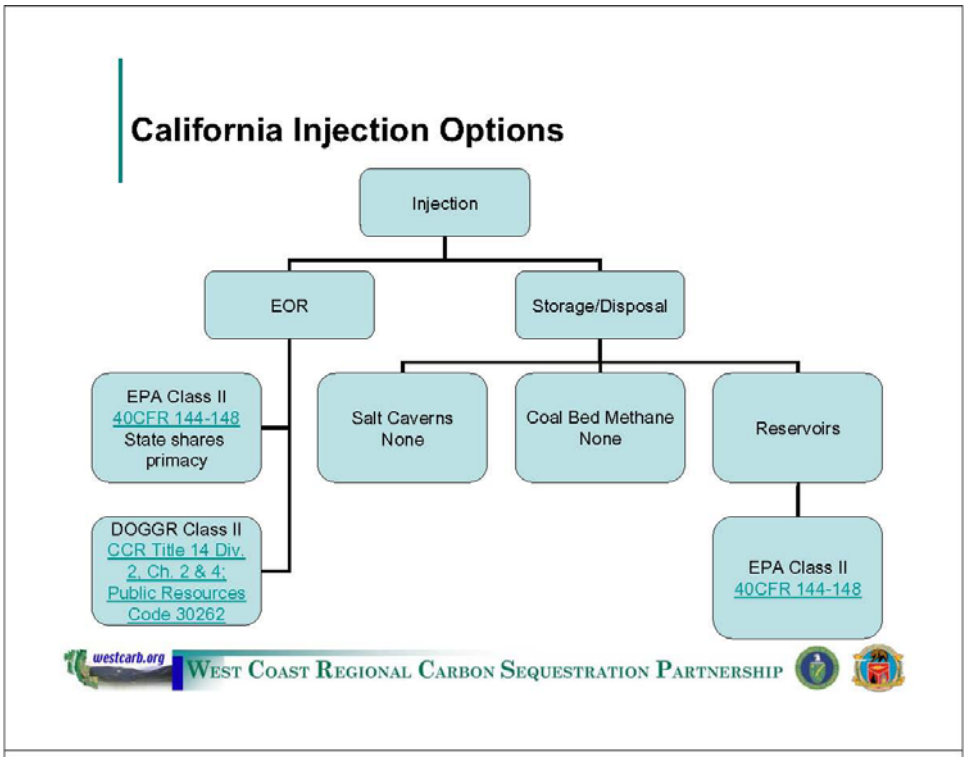


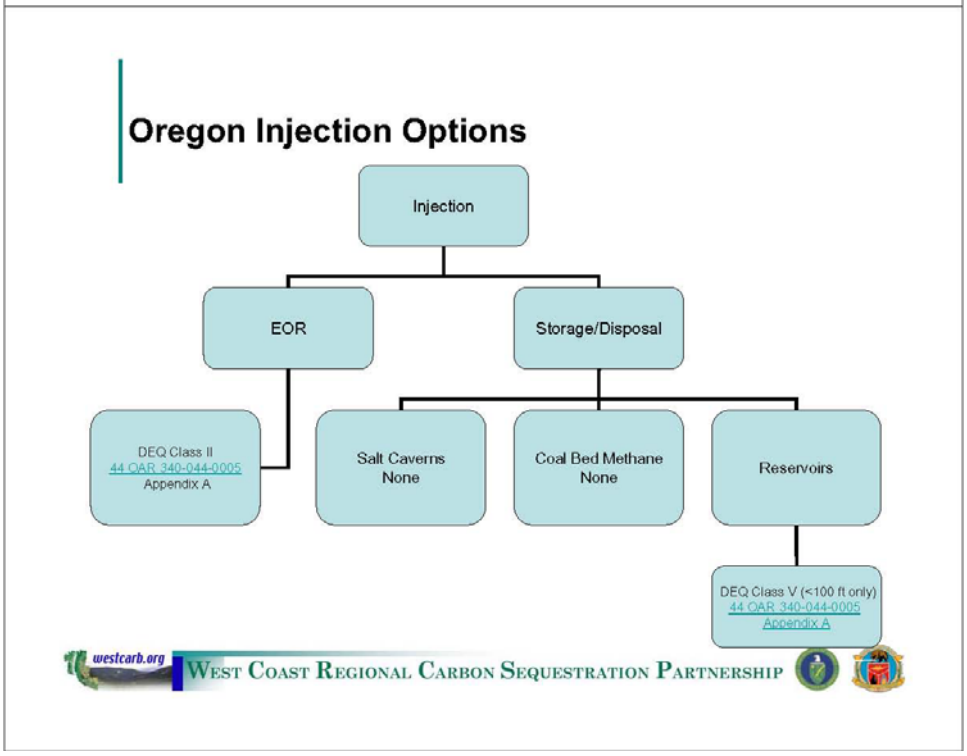
Fire Marshal/PUC State Regulations

- AK defers to DOT 49CFR 195
- AZ ACC, R14-5-201 to R14-5-205
- CA Fire Marshal Gov Code Sec 51010 to 51019.1, AB 592, DOG Pipeline regulations
- NV PSC NAC 704.455 to 704.465, DOT 49CFR 195
- OR PUC Div 31 860-031-0001 to 860-031-0040, DOT 49CFR 195
- WA UTC ESSHB 2420 Ch 191 Laws of 2000, RCW Ch 81.11, DOT 49CFR 195

CO_2 Injection Classification Definition

- Definition of CO_2 as waste or product to be decided by EPA and states. Classification is of lesser importance than regulatory operations concern.
- EOR wells as Class II – classified as product in 6 states
- Salt Cavern – AZ Class I
- Coalbed Methane (not related to EOR)– AZ Class I
  AK Class V
  WA Class V


California Injection Options
Injection
EOR
Storage/Disposal
EPA Class II
40CFR 144-148
State shares primacy
DOGGR Class II
CCR Title 14 Div. 2, Ch. 2 & 4; Public Resources Code 30262
Salt Caverns
None
Coal Bed Methane
None
Reservoirs
EPA Class II
40CFR 144-148
westcarb.org
West Coast Regional Carbon Sequestration Partnership


Oregon Injection Options
Injection
EOR
Storage/Disposal
DEQ Class II
44 OAR 340-044-0005
Appendix A
Salt Caverns
None
Coal Bed Methane
None
Reservoirs
DEQ Class V (<100 ft only)
44 OAR 340-044-0005
Appendix A
westcarb.org
West Coast Regional Carbon Sequestration Partnership

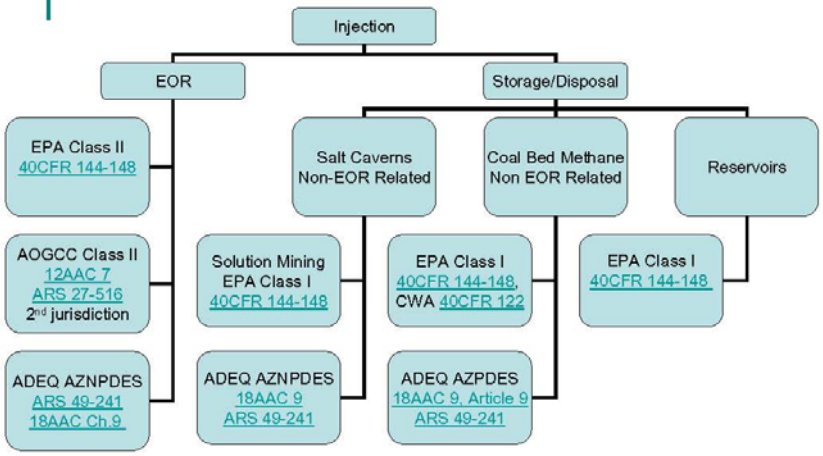
Arizona Salt Deposits



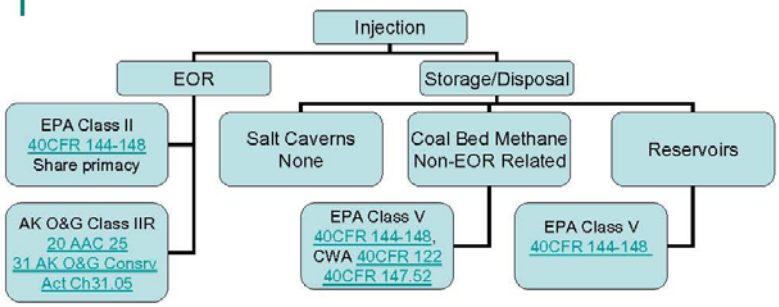
Source: Neal, J.T., 1996, Storage Opportunities in AZ Bedded Evaporites,

SMRI

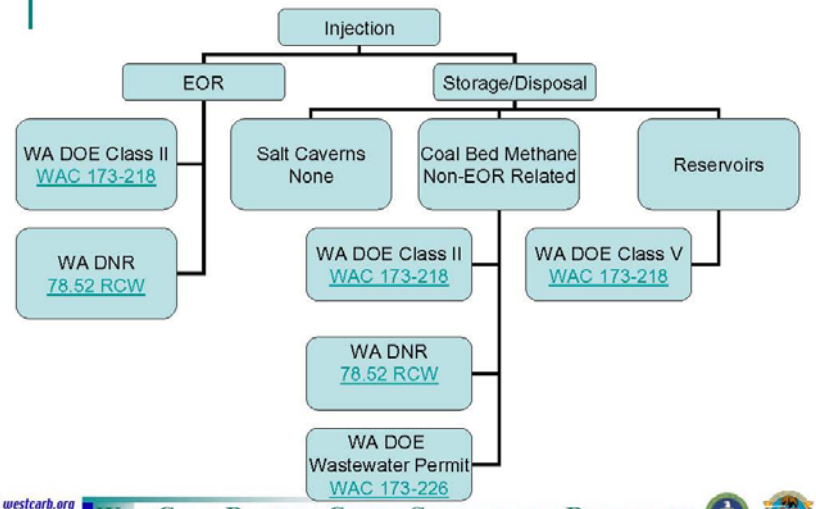
Arizona Injection Options



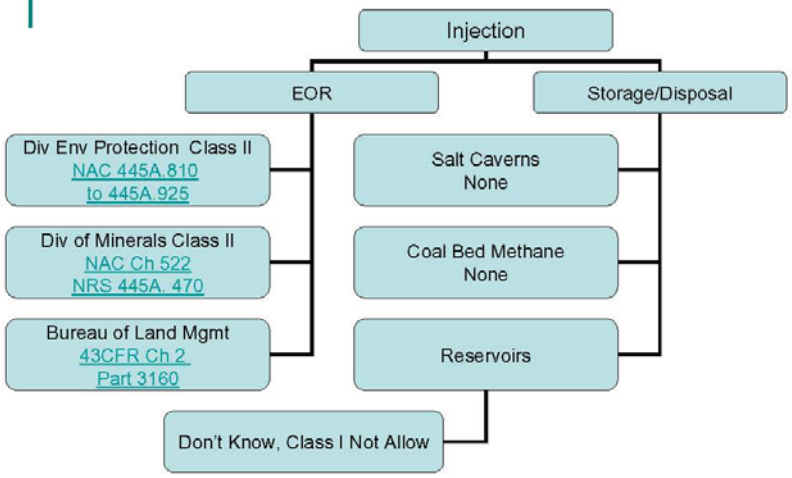
Alaska Injection Options



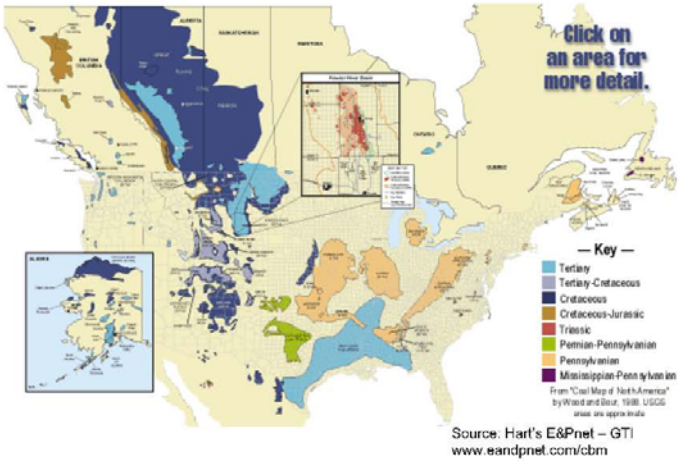
Washington Injection Options



Nevada Injection Options

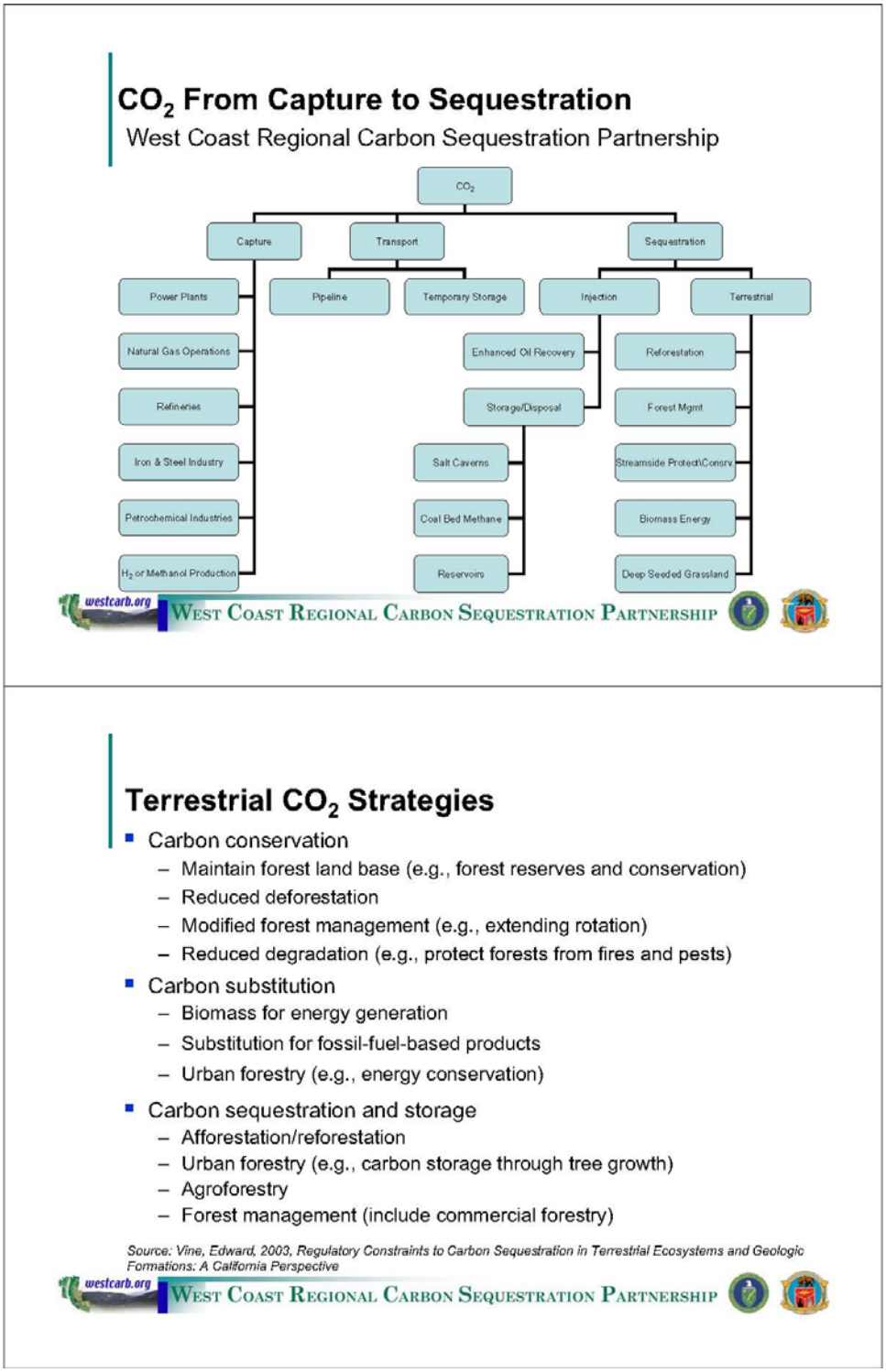


North America Coal Bed Methane Resource Map



Source: Hart's E&Pnet – GTI
www.eandpnet.com/cbm

Appendix B: Potential Terrestrial Sequestration Regulations



Top 4 Terrestrial CO_2 Sequestration Options

- Reforestation of under-producing lands (include streamside forest restoration)
- Forest management
- Forest protection and conservation
- Hazard wildfire fuel treatments/Biomass energy

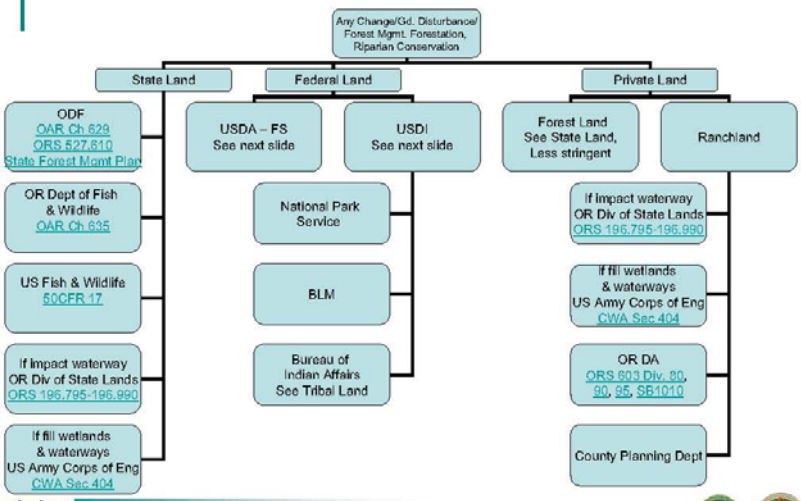
Federal Land Management

- U.S. Dept. of Agriculture
  - Forest Service
- U.S. Dept. of Interior
  - Bureau of Land Management
  - National Park Service

Tribal Land Management

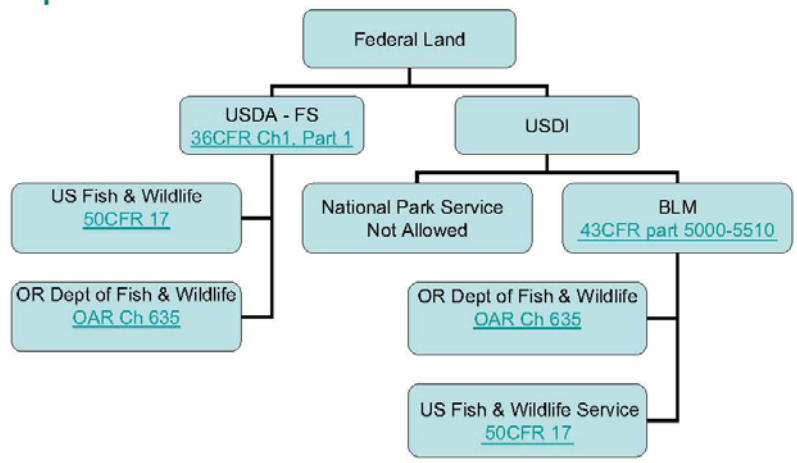
- Sovereign Tribal Government
- U.S. Dept. of Interior
  - Bureau of Indian Affairs

Oregon Terrestrial Options

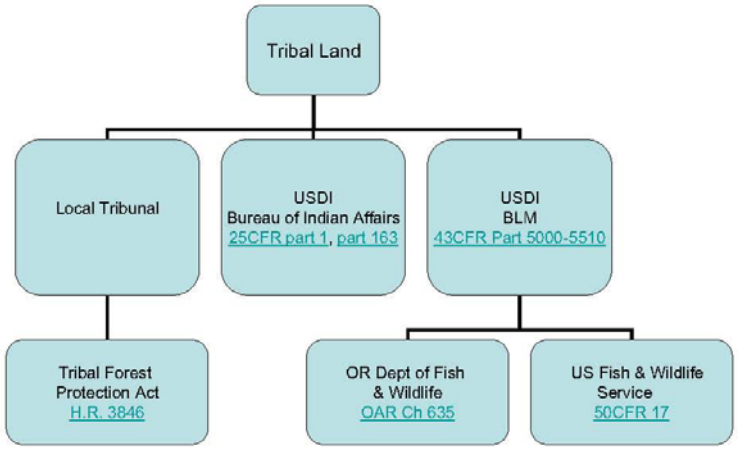


westcarb.org WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP

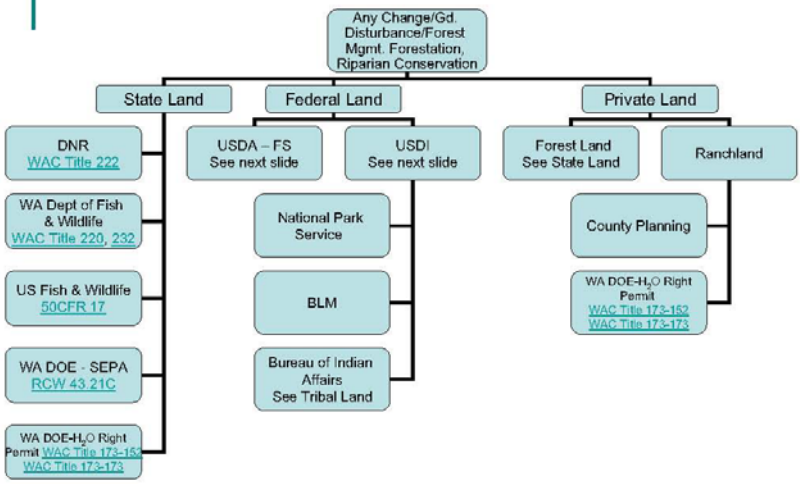
Oregon Federal Land



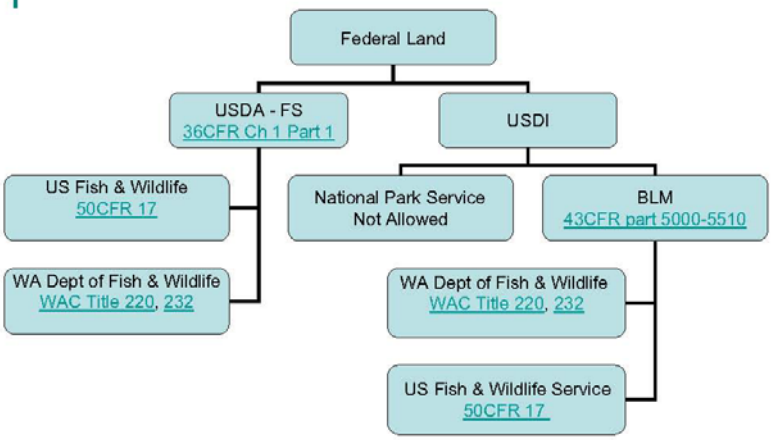
Tribal Land

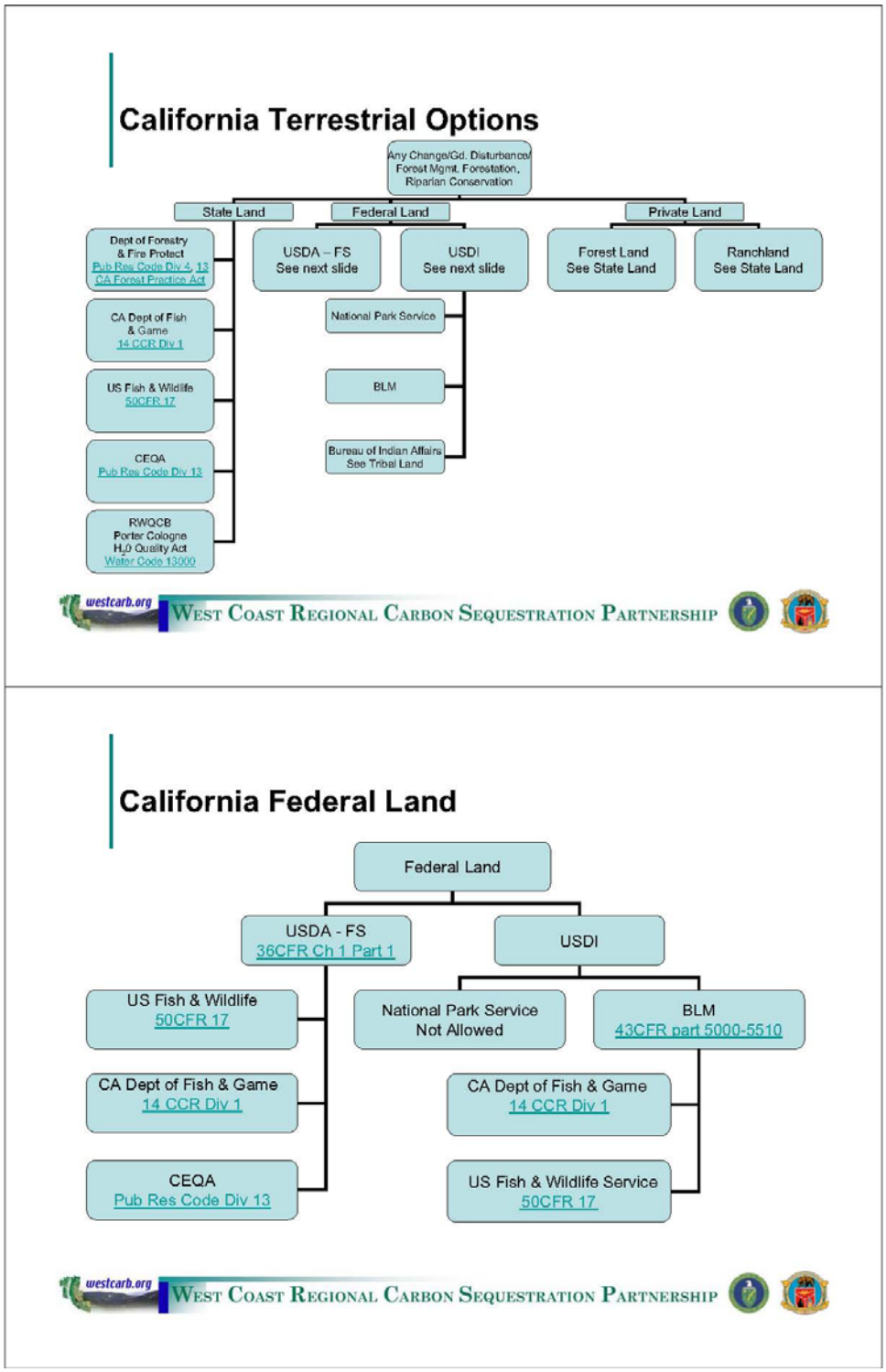


Washington Terrestrial Options

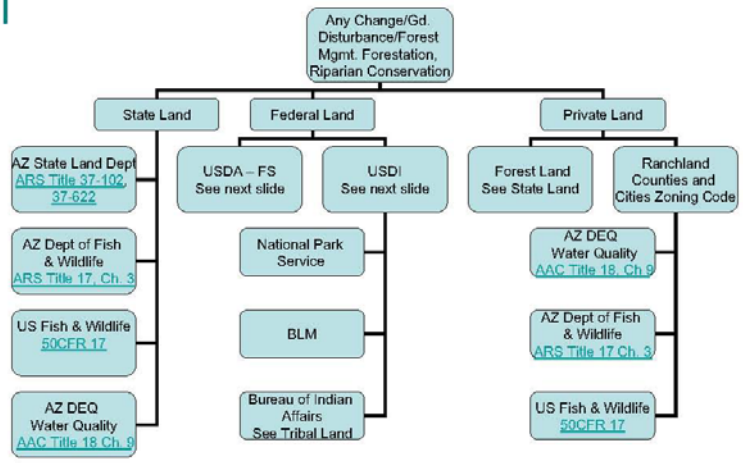


Washington Federal Land

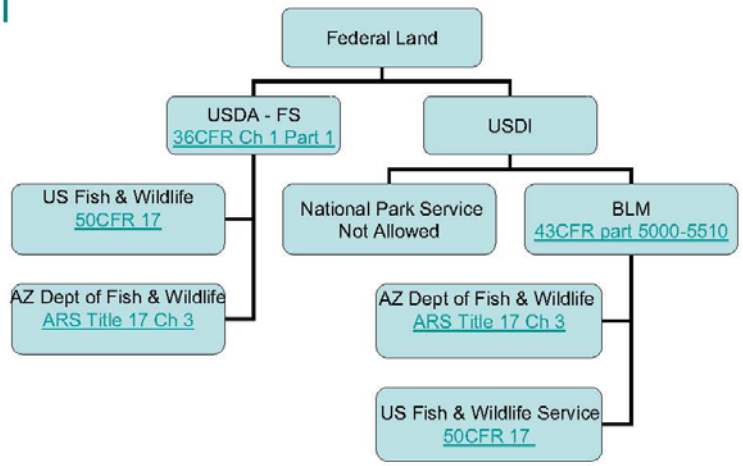


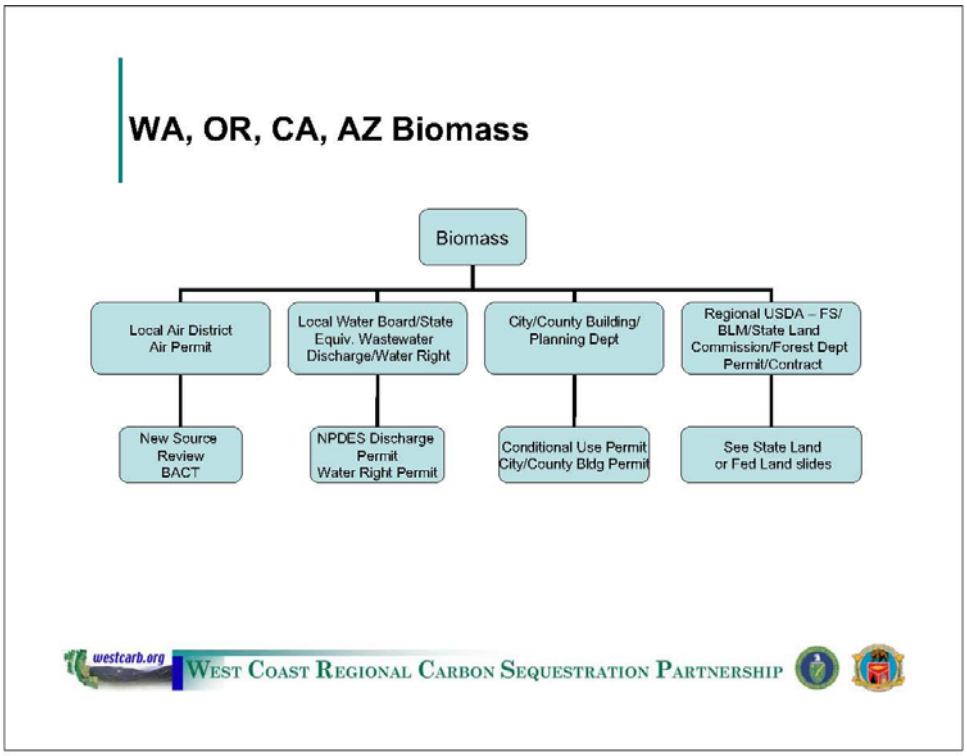

California Terrestrial Options
Any Change/Gd. Disturbance/ Forest Mgmt, Forestation, Riparian Conservation
State Land
Federal Land
Private Land
Dept of Forestry & Fire Protect
Pub Res Code Div 4, 13
CA Forest Practice Act
USDA – FS
See next slide
USDI
See next slide
Forest Land
See State Land
Ranchland
See State Land
CA Dept of Fish & Game
14 CCR Div 1
National Park Service
US Fish & Wildlife
50CFR 17
BLM
CEQA
Pub Res Code Div 13
Bureau of Indian Affairs
See Tribal Land
RWQCB
Porter Cologne
H2O Quality Act
Water Code 13000
westcarb.org
West Coast Regional Carbon Sequestration Partnership
California Federal Land
Federal Land
USDA - FS
36CFR Ch 1 Part 1
USDI
US Fish & Wildlife
50CFR 17
National Park Service
Not Allowed
BLM
43CFR part 5000-5510
CA Dept of Fish & Game
14 CCR Div 1
CA Dept of Fish & Game
14 CCR Div 1
CEQA
Pub Res Code Div 13
US Fish & Wildlife Service
50CFR 17
westcarb.org
West Coast Regional Carbon Sequestration Partnership

Arizona Terrestrial Options



Arizona Federal Land




WA, OR, CA, AZ Biomass
Biomass
Local Air District Air Permit
Local Water Board/State Equiv. Wastewater Discharge/Water Right
City/County Building/ Planning Dept
Regional USDA – FS/ BLM/State Land Commission/Forest Dept Permit/Contract
New Source Review BACT
NPDES Discharge Permit Water Right Permit
Conditional Use Permit City/County Bldg Permit
See State Land or Fed Land slides
westcarb.org
West Coast Regional Carbon Sequestration Partnership

Appendix XVI, Final Report

Public Outreach Education Materials

Deliverable associated with Task 3.0, Item 1

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Prepared by:
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Produced in 2004–05
Assembled July 27, 2006

DOE award no. DE-FC26-03NT41984

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Deliverable Mapping

This set of carbon sequestration and WESTCARB project educational materials constitutes the required WESTCARB Phase I deliverable associated with Task 3.0, Implement Public Outreach, Item 1 (“education materials”).

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Introduction

The West Coast Regional Carbon Sequestration Partnership (known as WESTCARB) is one of seven partnerships established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of North America.



Accordingly, WESTCARB is exploring the opportunities in six Western states and one Canadian province for removing CO_2 from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted, both of which will help slow the atmospheric buildup of this greenhouse gas.

WESTCARB is identifying the major sources of man-made CO_2 in its territory; assessing the status and cost of technologies for separating CO_2 from process and exhaust gases at large industrial plants; determining the potential for storing captured CO_2 in leak-proof geologic formations; establishing the extent to which changes in the management of forests, rangelands, and agricultural lands could increase carbon storage by plants and soil; assessing the logistics and costs of building pipelines to move CO_2 from the points of capture to the points of storage; and summing the results of cost estimates for capture, transportation, and storage to create carbon storage "supply curves."

Led by the California Energy Commission, WESTCARB's Phase I partners include about 50 organizations from state and provincial resource management and environmental protection agencies; national laboratories and research institutions; colleges and universities; conservation non-profits; oil and gas companies; power companies; pipeline companies; trade associations; vendors and service firms; and consultants.

One of the WESTCARB's six primary goals is to promote public participation and education. Accordingly, an important WESTCARB Phase I activity was to develop basic educational materials introducing carbon sequestration and the WESTCARB project to a wide audience.

Public Outreach Education Materials

During Phase I, WESTCARB established a partnership website, westcarb.org, and produced numerous communications materials, including a fact sheet and meeting flyer, technical reports and papers, posters, news releases, and numerous PowerPoint presentations. WESTCARB also established Web access to some of its GIS-based maps of CO_2 emission sources, geologic formations suitable for CO_2 storage, and terrestrial carbon storage baselines and supply curves for various timeframes.

All of these communication materials contribute to overall education on climate change issues, the potential role of carbon sequestration technology in mitigating adverse impacts, and WESTCARB's role in advancing our understanding of carbon sequestration opportunities. Within this body of materials, however, were several documents and webpages specifically developed as tutorials on these topics intended for general audiences. Appendices A through D contain a selection of those WESTCARB-produced tutorials.

Appendix A: WESTCARB Fact Sheet

WESTCARB "Key Facts" Fact sheet.



KEY FACTS

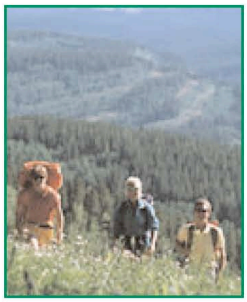
The West Coast Regional Carbon Sequestration Partnership (known as WESTCARB) is a collaborative research project bringing together more than 40 public agencies, private companies, and non-profits to identify the best regional opportunities for keeping CO_2 out of the atmosphere and thereby reducing mankind's impact on the climate.

WESTCARB is one of seven research partnerships co-funded by the **U.S. Department of Energy (DOE)** to characterize regional carbon sequestration opportunities and to develop "action plans" for pilot-scale validation tests. Actual testing will take place in a second work phase, which is not yet funded. The WESTCARB region consists of six states—Alaska, Arizona, California, Oregon, Nevada, and Washington. The **California Energy Commission (CEC)** manages the WESTCARB team and has contributed nearly $1 million to the project.

Carbon Sequestration—A Vital Option for Curbing CO_2 Emissions

Slowing, and ultimately reducing, man-made CO_2 emissions is a complex challenge that will require multiple solutions, including more efficient energy use, alternative fuels, electric-drive transportation, electricity from non-CO_2-emitting energy sources, and **carbon sequestration**.

Carbon sequestration refers to "capturing" CO_2 and storing it away from the atmosphere for periods ranging from decades to millennia. Sequestration allows society to reduce the carbon intensity of the economy while continuing the use of economical fossil fuels, thereby "buying" time and resources for developing and constructing affordable non-CO_2-emitting energy systems.



Two Major Approaches To Carbon Sequestration

WESTCARB is examining regional opportunities for two major types of carbon sequestration projects: **terrestrial** and **geologic**.

Terrestrial sequestration involves changing the management of forests, rangelands, agricultural lands, and wetlands to remove more CO_2 from the air via photosynthesis and/or to reduce CO_2 emissions from these ecosystems.



Geologic sequestration involves collecting CO_2 from fuel or exhaust gases at industrial "point sources," such as refineries and power plants, transporting it via pipelines, and injecting it into leak-proof geologic formations. Because this sequestration approach involves industrial CO_2 separation processes and long-term geologic storage, it is also known as "carbon capture and storage."

Both sequestration approaches offer economic, as well as environmental, benefits. Terrestrial sequestration, for example, can increase timber values or provide new venues for outdoor recreation. CO_2 captured at industrial facilities can be injected into producing oil fields to "loosen" residual oil and enhance recovery.

Finding the Best Regional Sequestration Opportunities

WESTCARB's objective is to characterize and rank regional carbon sequestration options—both geologic and terrestrial—in terms of capacity, technical feasibility, deployment timeframe, public acceptance, and cost.

To accomplish this task, WESTCARB will map the region's major sources of man-made CO_2, pipeline rights-of-way, and geologic formations capable of CO_2 storage. On the basis of their proximity and logistical factors, WESTCARB will prioritize geologic sequestration options and develop plans for pilot-scale validation projects.



In parallel, WESTCARB will assess terrestrial sequestration options in four states and rank them by cost to create carbon storage "supply curves." Plans for pilot-scale terrestrial validation projects will also be developed.



Results of geologic and terrestrial sequestration opportunity characterizations will be reported via widely used geographic information system (GIS) data formats and made available to the public. DOE will combine WESTCARB results with those from other regional partnerships to create a national "carbon atlas."

WESTCARB will also analyze "real world" issues pertaining to pilot-scale and full-scale sequestration projects, such as regulatory and permitting requirements; potential health, safety, and environmental impacts; storage site disruption risks; and monitoring and verification protocols.

Community Connection

WESTCARB is committed to engaging communities throughout the region as part of the process of characterizing carbon sequestration opportunities and identifying pilot-scale validation projects.

This effort will encompass "town hall" meetings in communities where pilot projects may be proposed, joint efforts with regional and national educational organizations to design curricula and classroom materials on carbon sequestration and its impacts and benefits, and co-hosting of a public meeting with DOE on a programmatic environmental impact statement suitable for regional carbon sequestration projects.

For More Information

Please visit our website at www.westcarb.org.

You may also e-mail WESTCARB's project manager, Larry Myer, at Larry.Myer@ucop.edu.

MAY 2004

The WESTCARB Team

Members of the West Coast Regional Carbon Sequestration Partnership are listed below alphabetically:

Advanced Resources International
Aera Energy
Argonne National Laboratory
Bevilacqua-Knight
British Petroleum
California Climate Action Registry
California Department of Forestry and Fire Protection
California Department of Oil, Gas, and Geothermal Resources
California Energy Commission
California Environmental Protection Agency
California Geologic Survey
California Institute for Energy Efficiency
California Polytechnic State University
California State University–Bakersfield
ChevronTexaco
Clean Energy Systems
ConocoPhillips
Electricity Innovation Institute
EPRI (Electric Power Research Institute)
KinderMorgan
Lawrence Berkeley National Laboratory
Lawrence Livermore National Laboratory
Massachusetts Institute of Technology
National Council for Air and Stream Improvement
Nevada Bureau of Mines and Geology
Nexant
Occidental Petroleum
Oregon Department of Forestry
Pacific Forest Trust
Pacificorp
Salt River Project
San Francisco Department of the Environment
Science Strategies
SFA Pacific
Shell International
Sierra Pacific Resources
Stanford Global Climate Energy Project
Terralog Technologies
Transalta Centralia Generation
University of Alaska–Fairbanks
University of California–Davis
U.S. Department of Energy, National Energy Technology Laboratory
Utah Automated Geographic Reference Center
Washington Department of Natural Resources
Western Governors' Association
Western States Petroleum Association
Winrock International

Appendix B: Web-Based Sequestration Tutorial

"What Is Sequestration?" Tutorial from WESTCARB website (6 webpages integrated into a "poster").

What Is Sequestration?

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP
westcarb.org

Carbon Sequestration Introduction

CO_2 Is a Greenhouse Gas

Carbon dioxide, or CO_2, in the atmosphere reflects the Earth's infrared radiation back to the surface, causing heat to be trapped, as in a greenhouse. The amount of CO_2 in the air had been relatively constant for ten thousand years until the Industrial Revolution in the 1800s. Since then, the world's population has grown tremendously, as has the combustion of fossil fuels, especially coal, oil, and natural gas. Because CO_2 is a primary product of combustion, the atmospheric concentration of CO_2 has been on the rise. At the same time, average temperatures throughout much of the world have inched up and other climatic changes have been documented, indicating the connection between our use of fossil fuels and climatic effects.

There's No "Silver Bullet" for Curbing Global CO_2 Emissions

Slowing and ultimately reducing man-made CO_2 emissions is a complex challenge that will require multiple solutions—including more efficient energy use, alternative fuels, electric-drive transportation, electricity from non-CO_2-emitting energy sources, and carbon sequestration.

Carbon sequestration refers to the "capture" of CO_2 and long-term storage away from the atmosphere. Indeed, it is sometimes called "carbon capture and storage" (CCS). CO_2 can be captured in two basic ways—by enhancing natural processes that remove it from the air and by applying industrial processes that remove it from fuel gas or exhaust gas at major "point sources," such as power plants, oil refineries, and cement plants. No practical means are known for capturing CO_2 from the exhaust of "mobile sources," such as automobiles.

CO_2 Capture, Transportation, and Geologic Storage

CO_2 captured at industrial facilities needs to be stored in a location where it won't escape to the atmosphere or interfere with human activities and the environment. Typically this means injecting it deep underground into leak-proof geologic formations, such as oil and gas reservoirs, unminable coal beds, or saline formations (porous sands filled with saltwater). There it may remain for centuries or millennia. In some cases, injected CO_2 may be used to enhance oil and natural gas production. Pipelines can be used to transport CO_2 from the point of capture to the point of storage.

Terrestrial Sequestration

Plants absorb CO_2 from the air during photosynthesis and ultimately metabolize and store carbon as tissue (biomass) or transfer it to soil. Changing the way that forests, rangelands, agricultural lands, and wetlands are managed can increase the amount of carbon stored by plant and soil matter. Known as terrestrial sequestration, this approach builds carbon storage capacity over time and can hold carbon intact for decades or centuries.

R&D and Validation Projects Are Urgently Needed

Neither terrestrial nor geologic carbon sequestration is currently a commercial technology; hence the need for the WESTCARB research partnership and lots of work by others). Terrestrial sequestration appears to be simpler and less expensive than industrial capture and geologic storage, but its capacity will likely be smaller and it may require more management to prevent inadvertent CO_2 releases. The economics of geologic storage improve when the captured CO_2 is used for enhanced oil and natural gas recovery; these are expected to be initial applications.

While helping stem global increases in CO_2 concentrations, terrestrial and geologic sequestration could also affect local and regional economies, public safety, and the environment. These effects may be beneficial or adverse. WESTCARB will seek public input and will evaluate potential socio-economic and environmental issues in conjunction with technical issues as it characterizes regional carbon sequestration capacity.

WESTCARB's comprehensive analysis of its six-state and one-province territory is establishing an inventory of carbon sequestration opportunities and projects for pilot-scale validation tests. To assure the effectiveness of sequestration technology and associated monitoring and verification techniques, we are working to commence field validation projects as soon as possible.

Carbon Dioxide (CO_2) Capture

CO_2 and water vapor are the primary products of fossil fuel combustion. CO_2 capture involves the separation of CO_2 from combustion exhaust gases, or in some cases from fuel gases before combustion, at an industrial facility such as a refinery, power plant, or cement plant. This type of CO_2 separation is energy-intensive and expensive and is not commercially practiced today.

CO_2 separation processes are used commercially in the food and beverage industry—for soft drink carbonation, for example—and in the petrochemical industry. These processes may be adaptable for CO_2 capture from industrial-scale combustors. This is currently the subject of considerable research.

Researchers are also exploring completely new, or novel, approaches to CO_2 capture, in hopes of creating processes that don't use so much energy, don't require so much space, are less costly, or yield a final product that is easier to store (such as a limestone-like solid).

Because technology breakthroughs can't be predicted, however, and because proving the viability of carbon sequestration requires the combined demonstration of CO_2 capture, transport, and geologic storage, WESTCARB is proceeding to identify candidate sites for pilot-scale carbon capture validation tests on the basis of the current industrial methods for CO_2 separation.

Transportation

Normally, CO_2 captured at an industrial facility will need to be transported to a separate location for injection into an underground reservoir for long-term storage. Pipelines appear to be the only practical way to transport CO_2 at any substantial scale by compressing it to a dense, supercritical state. (Note that transportation is not a relevant topic for terrestrial sequestration, in which CO_2 is removed directly from the atmosphere.)

CO_2 pipelines are already in commercial use, with over 1000 miles of underground pipe bringing CO_2 from natural reservoirs in Colorado and Utah to west Texas and Oklahoma for injection into oil fields to enhance production. Shorter piping runs are used in other locations in beverage and chemical manufacturing facilities. These pipelines and industrial piping runs have operated for years without significant safety incidents.

CO_2 pipeline technology is similar to that used for natural gas; accordingly, a robust construction, operation, and maintenance infrastructure is in place. And because of the Texas and Oklahoma enhanced oil recovery applications, CO_2-related regulatory issues have been addressed in at least some states.

WESTCARB will build on this foundation of knowledge in evaluating the routing options and costs for CO_2 pipelines linking industrial plants to geologic sequestration sites.

Geologic Storage

Although the idea of intentionally storing CO_2 underground for extended periods is new, nature has in fact been doing it for millions of years. There are numerous natural CO_2 reservoirs throughout the Rocky Mountain states in geologic "domes" and "traps." Over the last 30 years, some of this CO_2 has been extracted for use by the oil industry, making room for CO_2 captured from industrial facilities. The overall capacity of these natural reservoirs, however, is far less than the storage capacity needed if industrial CO_2 capture is to be practiced on any meaningful scale.

Fortunately, many other geologic formations are capable of storing injected CO_2 for centuries or more. Depleted natural gas reservoirs are an excellent example, as they have trapped methane—which is less dense than CO_2 and thus can escape more easily—for geologic time periods.

The practice of injecting gases and liquids underground for storage is also well established. For example, natural gas companies routinely use depleted gas reservoirs for storing gas received via pipeline, prior to its distribution.

Although health, safety, and environmental problems aren't expected from geologic storage of CO_2, validation tests and demonstrations are needed to ascertain real-world site management needs.

Most experience to date for CO_2 injection comes from the oil industry, which has used it to "loosen" residual oil in mature producing fields. Known as enhanced oil recovery (EOR), this practice represents an excellent opportunity for initial geologic sequestration projects because of its economic value and established technical and regulatory procedures. But like the natural CO_2 reservoirs, EOR sites are ultimately too few and too geographically isolated to accommodate the quantity of CO_2 from large-scale industrial CO_2 capture operations.

Terrestrial Storage

Terrestrial carbon sequestration involves changing the management of forests, rangelands, agricultural lands, and wetlands to either remove more CO_2 from the air or reduce CO_2 emissions from these ecosystems. To be effective in curbing the rise in atmospheric CO_2 concentrations, these changes must persist for decades or longer.

Terrestrial sequestration can be illustrated by looking at four types of measures:

First, land management practices can be altered to decrease the decomposition of organic matter which releases CO_2 and to sustainably increase the rate of plant photosynthesis per acre. Examples include reforesting cleared or mined lands, switching crops to those that require little or no tillage, and planting long-lived tree species.

Second, trees can be used to produce long-lasting products, such as high-quality furniture, that can keep captured CO_2 out of the atmosphere for many years.

Third, forests that are choked with brush or are otherwise unhealthy can be managed to reduce "fire fuels" by removing this material for renewable biomass power production. This approach helps avoid severe wildfires and the associated potential for large CO_2 emissions. Electricity from biomass power production also displaces fossil fuel use and its CO_2 emissions.

Fourth, land use decisions can be influenced to promote uses that tend to remove CO_2 from the atmosphere, such as parklands and greenbelts, and to discourage uses that tend to increase CO_2 emissions, such as "sprawling" suburban development.

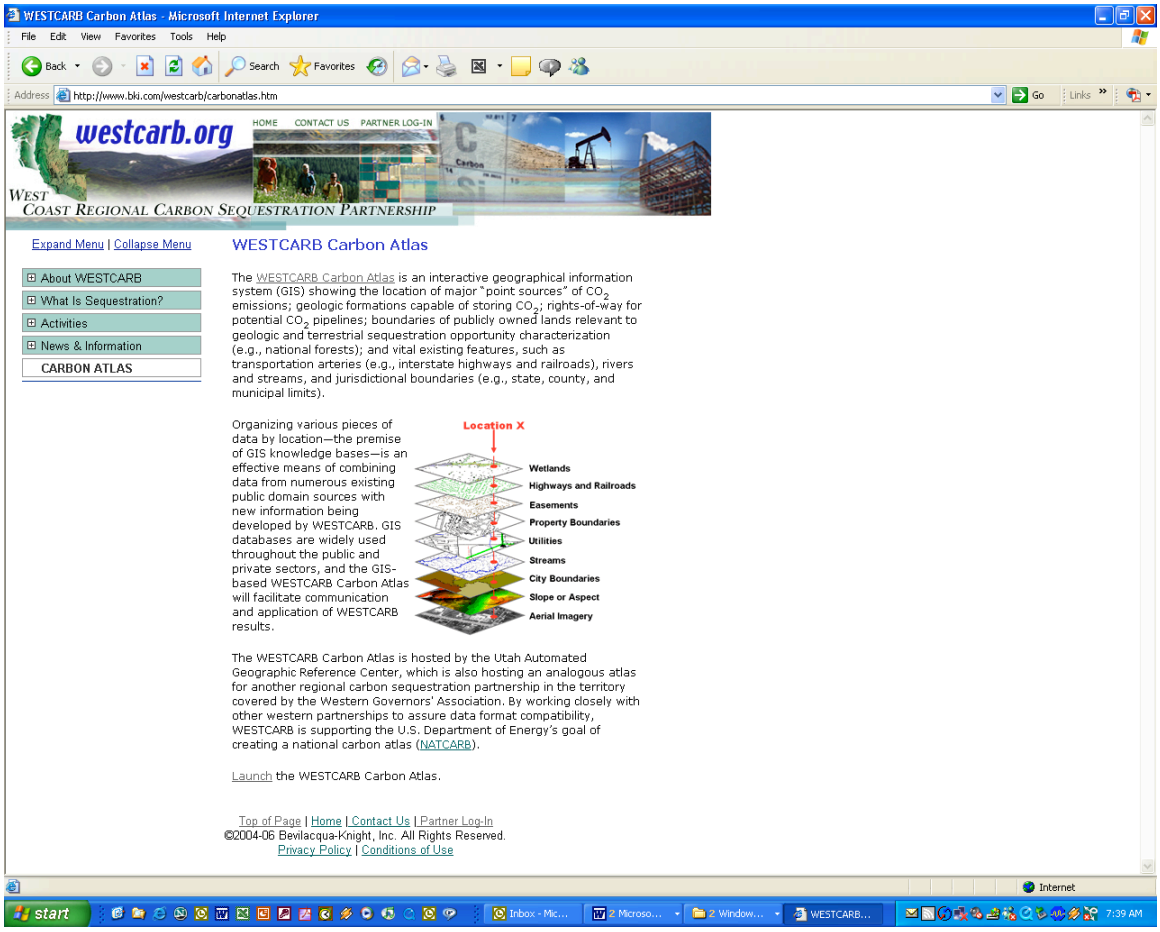
Measuring the amount of carbon stored through terrestrial sequestration is not always straightforward. Establishing "baselines" of current carbon stocks and changes that would normally take place over time are a vital first step. In addition, terrestrial sequestration validation tests must address not only the effectiveness of proposed land management practices, but also the accuracy and repeatability of the associated carbon measurement methods.

One of the attractions of terrestrial sequestration is its lower initial cost (relative to other CO_2 storage options) coupled with the potential for significant environmental, economic, and aesthetic co-benefits. These may include:

- Improving forest health
- Creating new wildlife habitat
- Preventing soil erosion and stream sedimentation
- Boosting local and regional economies
- Reclaiming poorly managed soils
- Increasing the recreational value of lands

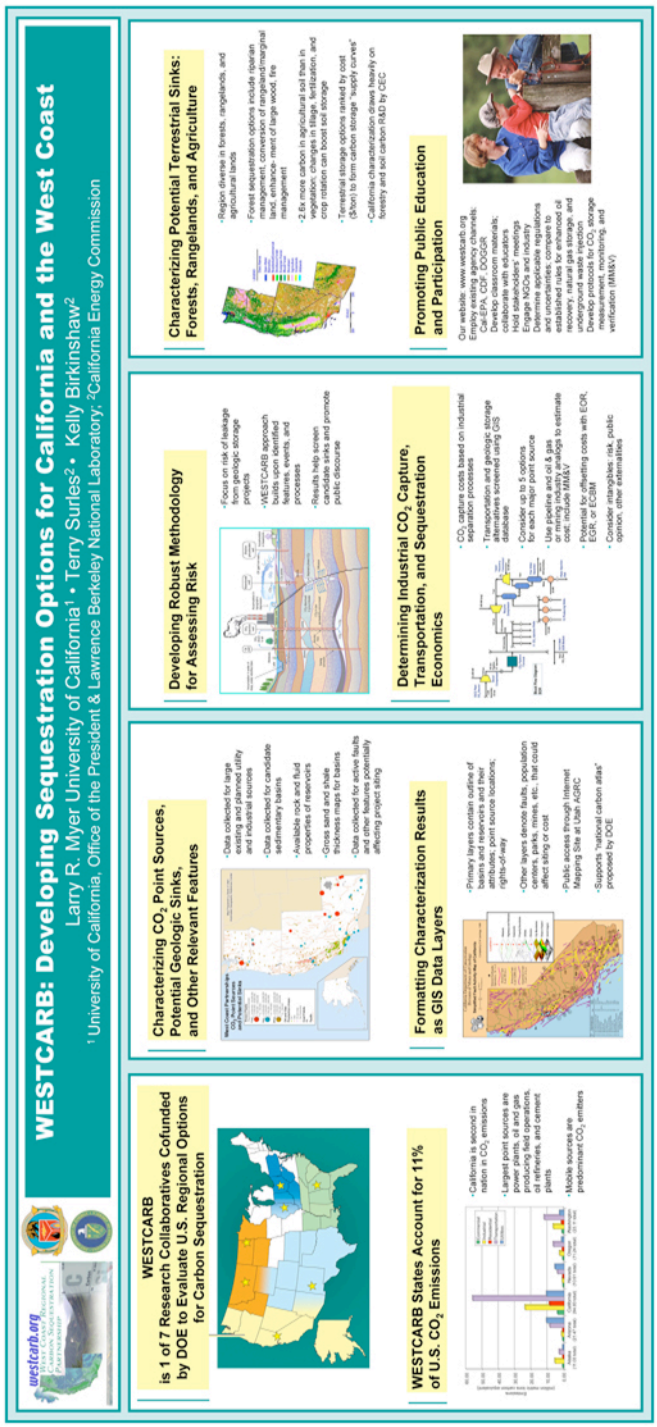
Appendix C: GIS Tutorial Webpage

WESTCARB webpage explaining Geographic Information System based data storage as an introduction to our WESTCARB Carbon Atlas.



Appendix D: WESTCARB Conference Poster

WESTCARB conference poster displayed at the California Energy Commission's First Annual Climate Change Conference.



Appendix XVII, Final Report

Stakeholder Public Meeting Summary

Deliverable associated with Task 3.0, Item 2

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Prepared by:
Richard J. Myhre, P.E.

Public Meeting Date: October 27, 2004
Summary Assembled July 27, 2006

DOE award no. DE-FC26-03NT41984

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Deliverable Mapping

This meeting summary constitutes the required WESTCARB Phase I deliverable associated with Task 3.0, Implement Public Outreach, Item 2 ("a summary of the stakeholder meeting").

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Introduction

The West Coast Regional Carbon Sequestration Partnership (known as WESTCARB) is one of seven partnerships established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of North America.



Accordingly, WESTCARB is exploring the opportunities in six Western states and one Canadian province for removing CO_2 from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted, both of which will help slow the atmospheric buildup of this greenhouse gas.

WESTCARB is identifying the major sources of man-made CO_2 in its territory; assessing the status and cost of technologies for separating CO_2 from process and exhaust gases at large industrial plants; determining the potential for storing captured CO_2 in leak-proof geologic formations; establishing the extent to which changes in the management of forests, rangelands, and agricultural lands could increase carbon storage by plants and soil; assessing the logistics and costs of building pipelines to move CO_2 from the points of capture to the points of storage; and summing the results of cost estimates for capture, transportation, and storage to create carbon storage "supply curves."

Led by the California Energy Commission, WESTCARB's Phase I partners include about 50 organizations from state and provincial resource management and environmental protection agencies; national laboratories and research institutions; colleges and universities; conservation non-profits; oil and gas companies; power companies; pipeline companies; trade associations; vendors and service firms; and consultants.

One of the WESTCARB's six primary goals is to promote public participation and education. Along those lines, an important WESTCARB Phase I activity was to conduct a public meeting with a broad array of stakeholders.

Public Meeting Summary

WESTCARB held a “public forum” in Portland, Oregon, on October 27, 2004, targeted to public and private sector professionals, researchers, community leaders, and conservation/environmental groups. The half-day forum featured presentations in two panel sessions interspersed with Q&A time. The first panel addressed climate change science, its regional implications, technology/policy response options, and emerging initiatives in Oregon and Washington. This outstanding panel was composed of internationally known scientists and economists, senior representatives in state government, and a power company program manager. Their talks provided context for the second panel, comprised of WESTCARB members, who offered an overview of geologic and terrestrial sequestration and the DOE and WESTCARB programs.

About 55 people attended the forum (of which about 50 registered; see Appendix A). This exceeded our expectations and nearly filled the room to capacity. About half were from WESTCARB member organizations, and half from our non-member target audience. Audience questions ranged from clarifying queries on basic climatic understanding to knowledgeable comments on current research. No contentious debate took place.

Pre-Meeting Publicity

Preparations for the meeting involved audience segmentation, communication channel analysis, and crafting of direct mail and media outreach activities to reach target audiences (see Appendix B). Pre-meeting publicity included mailing a professional-looking flyer to more than 1000 people matching our target audience profile (see Appendix C), and preparing news releases for local media (see Appendix D).

Public Meeting Agenda and Presentations

Agenda

October 27, 2004
WESTCARB Public Forum
Multi-stakeholder panel sessions and Q&A time to engage public and private sector professionals in a discussion of carbon sequestration opportunities and issues

1:00–1:05 **Local Host Welcome**
Jim Cathcart, Oregon Department of Forestry;
WESTCARB Team Leader for Terrestrial Sequestration

1:05–2:20 **Panel 1: Climate Change in the Pacific Northwest and Societal Response to Possible Impacts**
(Moderator: Martha Krebs, Science Strategies)
- Climate Science—Alan Mix, Oregon State University
- Technology Response—Jae Edmonds, Pacific Northwest National Laboratory
- Oregon Public Perspective—Sam Sadler, Oregon Department of Energy
- Western States Public Perspective—Carol Jolly, Washington Governor's Office (no slides)
- Pacific Northwest Energy Business Perspective—Virinder Singh, PacifiCorp (a WESTCARB partner)

2:20–3:00 **Discussion and Break**

3:00–4:15 **Panel 2: Terrestrial and Geologic Sequestration Opportunities in the Pacific Northwest and the DOE/WESTCARB Research Partnership**
(Moderator: Kelly Birkinshaw, California Energy Commission; WESTCARB Executive Director)
- A View of DOE's Carbon Sequestration R&D Program—David Hyman, DOE National Energy Technology Laboratory
- Geological Sequestration—Lynn Orr, Stanford University
- Terrestrial Sequestration—John Kadyszewski, Winrock International
- Developing Sequestration Options for the West Coast—Larry Myer, University of California, Office of the President, and Lawrence Berkeley National Laboratory; WESTCARB Technical Director

4:15–4:45 **Discussion**

4:45 **Adjourn**



westcarb.org
West Coast Regional Carbon Sequestration Partnership

Panel 1 Introduction

Martha Krebs
Science Strategies
Portland, Oregon
October 27, 2004

Carbon Sequestration: A Response to Climate Change

- Climate Change: How real? How large a change?
- Technology Response: Which ones? How fast? At what cost?
- The View from the Pacific Northwest: Public policy needs? At what cost?
- The View from the Pacific Northwest: Private sector opportunities? At what cost?

westcarb.org West Coast Regional Carbon Sequestration Partnership

Panel 1 Speakers

- Alan Mix – College of Ocean and Atmospheric Science
- Jae Edmonds – Pacific Northwest National Laboratory
- Sam Sadler – Oregon Department of Energy
- Carol Jolly – Governor's Office, State of Washington
- Virinder Singh - PacifiCorp

westcarb.org West Coast Regional Carbon Sequestration Partnership

The Science of Climate Change

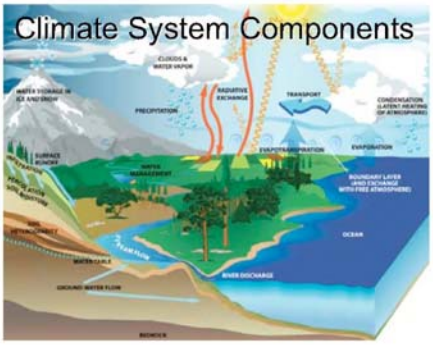


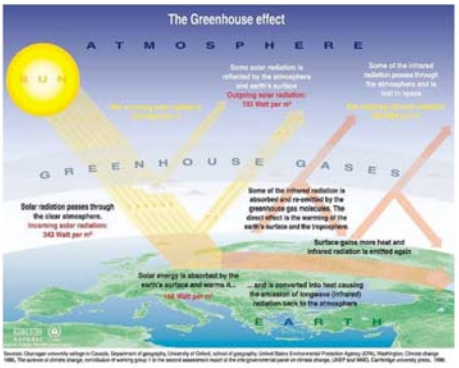
From the Globe to the Pacific Northwest

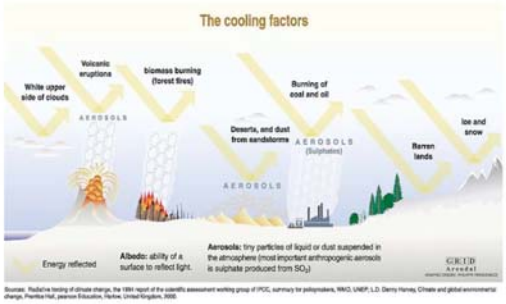
Alan C. Mix, Oregon State University

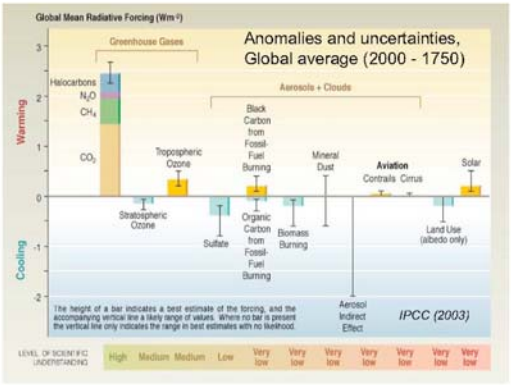
27 October 2004, WESTCARB, Portland Oregon

Climate System Components





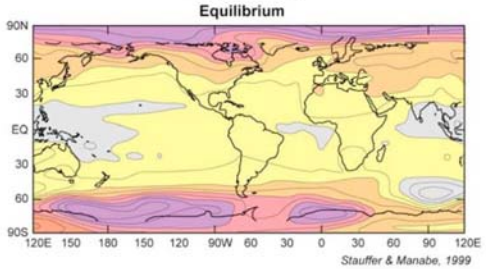




Predicted Temperature Changes

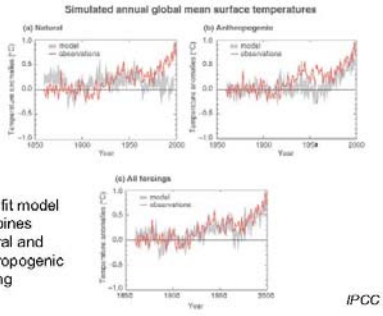
CO_2 Doubling

Equilibrium



Stauffer & Manabe, 1999

Test Models by Simulating History

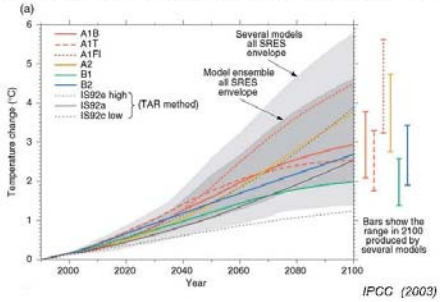


Best fit model combines natural and anthropogenic forcing

IPCC (2003)

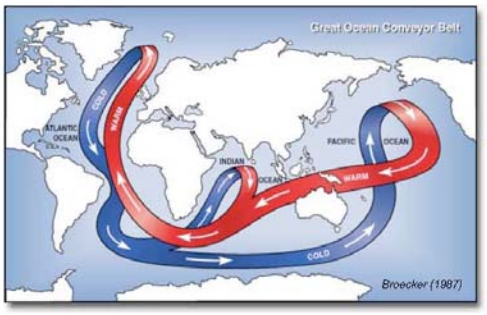
Future Global Predictions

Uncertainties reflect emissions scenarios and model disagreements.

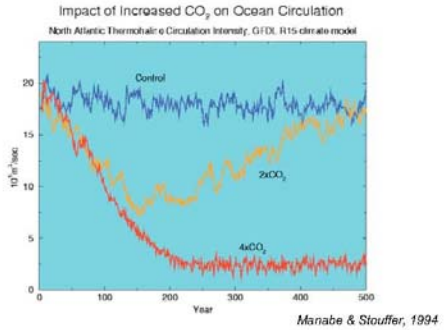


IPCC (2003)

The Oceanic Wild Card



Is the ocean system stable to CO_2 change? Perhaps not.

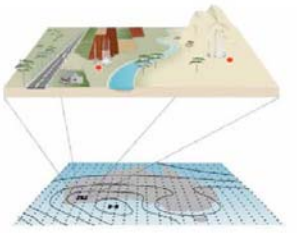


Manabe & Stouffer, 1994

The Challenge of Regional Predictions: "Downscaling" Global Models

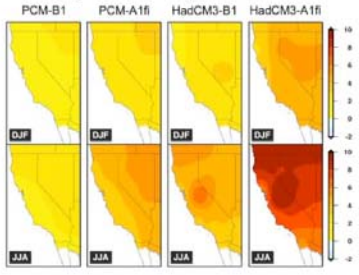
a) Statistical downscaling

b) Embedded regional models



Charles & Timbal (2004)

Downscaled Prediction of 21st Century Warming in California



Hayhoe et al. 2004

Downscaling Pacific Northwest Impacts

Consensus Statement of Climate Change Impacts on the Pacific NW.
http://inr.oregonstate.edu -- download PDF report.

Variable	Prediction	Uncertainty
Temperature	2.7°F by 2030 (average).	intermediate
Precipitation	Winter rain, summer drought.	uncertain
Snowpack	April-1 snowpack decline.	uncertain
Land ecosystems	Drought stress, fire, insects.	uncertain
Marine ecosystems	Coastal upwelling increase.	likely
	More anoxic events?	uncertain
Sea Level	Continued rise - regional	certain

Research Priorities

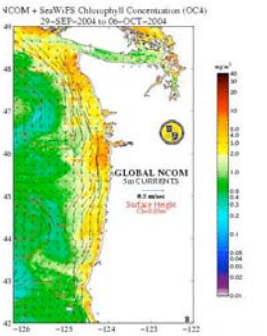
- Improved observations over the long term (paleo, historical, future).
- Experiments to understand processes and dynamic linkages.
- Improved coupled regional models, including ecological responses.
- Science to inform policy analysis, consider economic impacts.

Pac. N.W. Ocean Impacts

Possible Feedbacks

- Continental warming…
  leads to…
- Stronger summer winds…
  leads to…
- Stronger coastal upwelling..
  leads to…
- Nearshore cooling
  will this…
- Mitigate Warming?
  will this…
- Increase Bio-Production?
  – Better fisheries?
  or….
  – Anoxic Fish kills?

We don't know at present.



Example of real-time monitoring, Kindle, 2004

Summary - What do we know?

- The climate system is complex
  - includes physical, chemical and biological feedbacks
  - some are poorly known.
- Future climate will change - both natural and anthropogenic causes. Surprises possible due to climate "wild cards" - ocean thermohaline circulation, etc.
- Future global-average warming is reasonably certain,
- Some regional climate predictions remain uncertain.
- Regional climate impacts and linkages need study.

Alan C. Mix
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Energy Technology, Stabilizing Climate Change, and CO_2 Capture and Storage

WestCarb

Public Outreach Meeting

Jae Edmonds
27 October 2004
Joint Global Change Research Institute
Portland, OR

Thanks to the WestCarb

U.S. Department of Energy

EPRI

California Energy Commission

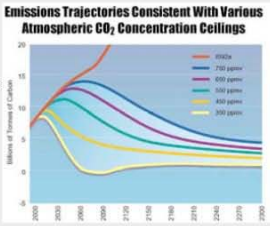
Other Sponsors of the Global Energy Technology Strategy Program

Some Major Points

- Climate change is a long-term issue—century to millennium scale—with implications for today.
- Energy is central. A broad portfolio including energy efficiency, renewable energy, and nuclear power is essential to manage the risk of climate change.
- Several potential additions to the technology portfolio could dramatically reduce the cost of stabilizing CO_2 concentrations—e.g. CO_2 Capture and Storage.
- CCS could not only enable the continued large scale use of fossil fuels, but also enable H_2 to reduce CO_2 emissions and in conjunction with commercial biomass creates the potential for a negative emission energy technology!
- The scale of technology deployment, e.g. carbon capture & storage, could be HUGE.

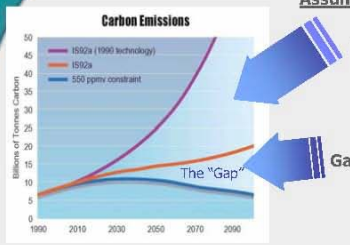
Stabilizing CO_2 Concentrations

- Stabilization of greenhouse gas **concentrations** is the goal of the Framework Convention on Climate Change
- Stabilizing the concentration of CO_2 is a very long term problem



- Stabilization means that GLOBAL emissions must peak in the decades ahead and then decline indefinitely thereafter.

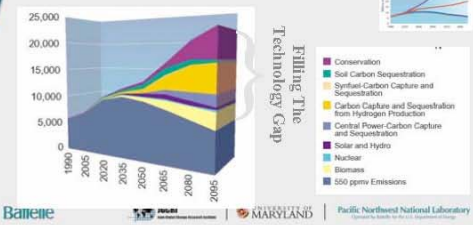
Stabilizing CO_2 Base Case and "Gap" Technologies



Assumed Advances In
- Fossil Fuels
- Energy intensity
- Nuclear
- Renewables

Gap technologies
- E.g. CCS

Technology Breakthroughs Are Essential to Stabilizing Concentrations and Controlling Costs. For Example ...



There Are No "Silver Bullets" When It Comes to Stabilization

- Energy Intensity Improvements
  - Industry
  - Buildings
  - Transportation
- Wind and Solar
- Biotechnology
  - Soils
  - Biomass crops
  - Advanced biotechnology
- Nuclear
  - Fission
  - Fusion
- Carbon Dioxide Capture and Storage
  - Geologic
  - Terrestrial (soils, trees)
- Advanced Transformation Systems
  - Electricity
  - Hydrogen
  - Bio-derivative fuels
- Non-CO_2 Greenhouse Gases

Battelle | JGCRI | Maryland | Pacific Northwest National Laboratory

Carbon capture and storage already exists.



Battelle | JGCRI | Maryland | Pacific Northwest National Laboratory

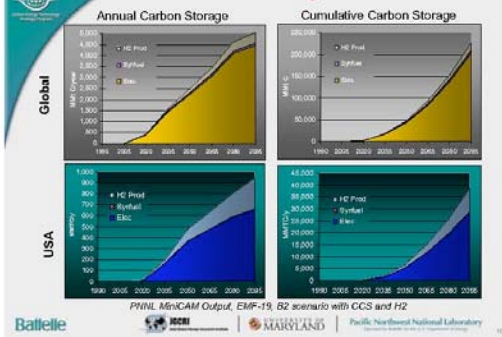
CCS Pathways

CO_2 capture and storage can be combined with technologies that reach across the economy.

- Capture from power plants,
- Capture in the production of H_2, and
- Capture from commercial biomass.
  - Since biomass obtained its carbon from the air, it has no net effect of the concentration in the atmosphere, but
  - If the carbon is removed and stored, either in the production of electricity or production of H_2, then the biomass energy actually removes carbon on net from the atmosphere!

Battelle | JGCRI | Maryland | Pacific Northwest National Laboratory

How Big?



PNNL MiniCAM Output, EMF-19, B2 scenario with CCS and H2

Battelle | JGCRI | Maryland | Pacific Northwest National Laboratory

Is There Storage Available?

Carbon Storage Reservoir	Range (PgC)
Deep Saline Reservoirs	*87 to 2,727*
Depleted Gas Reservoirs	*136 to 300*
Depleted Oil Reservoirs	*41 to 191*
Unminable Coal	*>20*
Basalt Formations	*>1,000*
Deep Ocean	*1,400 to 27,000*

Source: Herzog et al. (1997), Freund and Ormerod (1997), PNNL (2001)

Battelle | JGCRI | Maryland | Pacific Northwest National Laboratory

Recent Work Has Looked at the USA and Canada

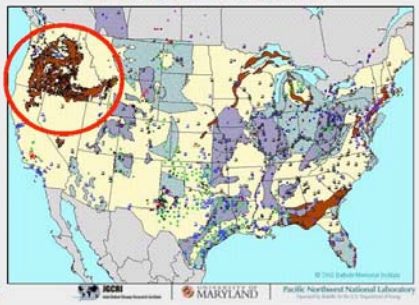
Where Is the Storage Reservoir Capacity?



- **3,800 GtCO2 US and Canadian Geologic CO_2 Storage Reservoirs Theoretical Capacity**
  - **3730 GtCO2in deep saline formations (DSF),**
  - **65 GtCO2 in deep unminable coal seams,**
  - **40 GtCO2 in depleted gas fields, and**
  - **13 GtCO2 in depleted oil fields with potential for enhanced oil recovery (EOR)**

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Potential Storage in the Pacific Northwest—Basalt Flows

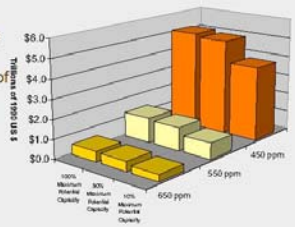


Cost Estimates for CCS

Costs component	Cost range $/tCO$_2$ avoided ($/tC avoided)	Potential for cost reduction up to 2020
Capture (including separation and compression)	$13 – $74 ($48 - $272)	20 - 30 %
Capture from industrial sources (including separation and compression)	$0 - $116 ($0 - $426)	Limited
Geological or ocean storage (including measurement, monitoring and verification)	$5 – $10 ($18 – $37)	Considerable for new technologies, limited for commercially viable injection

What's It Worth?

Technology is the largest lever we have on the cost of stabilizing greenhouse gas concentrations—*The Value of Capture & Sequestration*



Summing Up

- Climate change is a long-term issue—century to millennium scale—with implications for today.
- A broad portfolio including energy efficiency, renewable energy, and nuclear power is essential to manage the risk of climate change.
- Several potential additions to the technology portfolio could dramatically reduce the cost of stabilizing CO_2 concentrations—e.g. CO_2 Capture and Storage.
- CCS could not only enable the continued large scale use of fossil fuels, but also enable H_2 to reduce CO_2 emissions and in conjunction with commercial biomass creates the potential for a negative emission energy technology!
- The scale of technology deployment, e.g. carbon capture & storage, could be HUGE.

END

Will the Problem Go Away on Its Own?

Won't the limited conventional oil and gas resource force a transition in the near term to a world based on energy efficiency and renewable and nuclear energy forms?

FOSSIL FUEL RESOURCES

Atmosphere 750 PgC

Vegetation 610 PgC

Oil 130 PgC | Gas 120 PgC

Coal

5,000 to 8,000 PgC

Unconventional Liquids and Gases

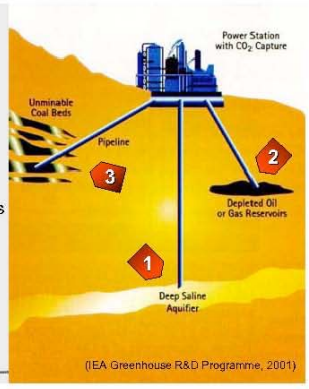
40,000 PgC

Cost of CCS Will Depend on Many Factors

- Technology for Capture
  - Retrofit versus new capacity
  - Add-on to an existing pulverized coal plant or a new integrated gasification combined cycle plant designed from the outset to capture CO_2.
  - Coal or Gas plant?
- Storage Opportunities
  - Are the reservoirs near by?
  - Enhanced oil recovery?
  - Coalbed methane production?
  - Deep saline reservoir?
- The National and Regional Market

Geologic Disposal

1. Deep saline formations
2. Oil & gas reservoirs
3. Unmined coal beds



(IEA Greenhouse R&D Programme, 2001)

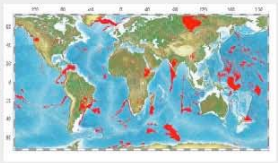
Geologic Disposal

There are other reservoirs that need to be explored…

Deep Basalt Flows

Ex situ Mineralization





Ocean Disposal

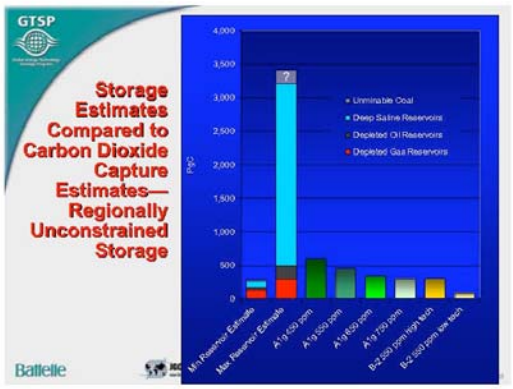
Important Research Is Needed to Answer Key Questions About CO_2 Capture and Storage

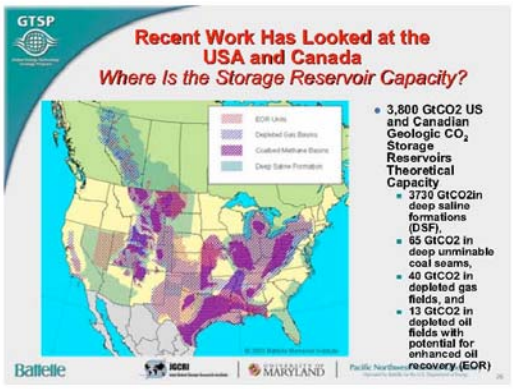
- How much will CO_2 capture cost? How much can costs be lowered?
- Where to store the CO_2?
- Will the CO_2 remain where it is put?
- How much does CCS lower the cost of meeting an environmental goal?

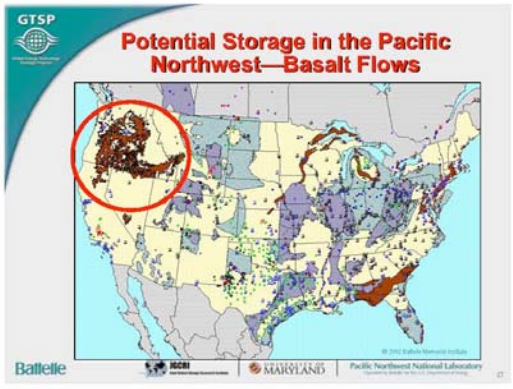
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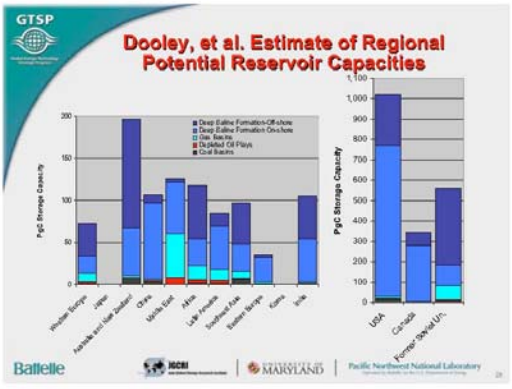
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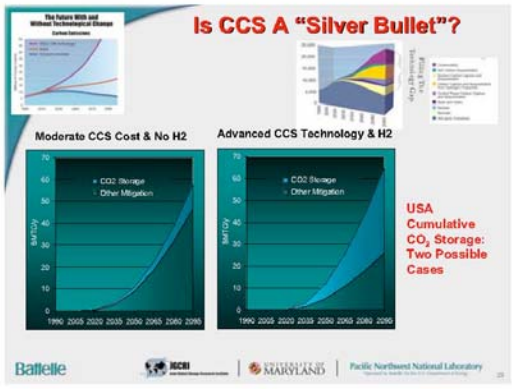
Source: Herzog et al. (1997), Freund and Ormerod (1997), PNNL (2001).


GTSP
Storage Estimates Compared to Carbon Dioxide Capture Estimates—Regionally Unconstrained Storage
Unminable Coal
Deep Saline Reservoirs
Depleted Oil Reservoirs
Depleted Gas Reservoirs
Battelle


GTSP
Recent Work Has Looked at the USA and Canada
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Battelle


GTSP
Potential Storage in the Pacific Northwest—Basalt Flows
Battelle


GTSP
Dooley, et al. Estimate of Regional Potential Reservoir Capacities
Battelle


Is CCS A "Silver Bullet"?
Moderate CCS Cost & No H2
Advanced CCS Technology & H2
CO2 Storage
Other Mitigation
USA Cumulative CO2 Storage: Two Possible Cases
Battelle



WESTCARB Annual Meeting

Portland, Oregon

October 27, 2004
Sam Sadler

OREGON DEPARTMENT OF ENERGY

- **Climate Change Activities**
- Governor's Advisory Group on Global Warming
- Draft "Oregon Strategy for Greenhouse Gas Reductions" posted on Web:

  www.energy.state.or.us/climate/Warming/Draft_Intro.htm
- Oregon's CO_2 standard for new energy facilities

Governor's Advisory Group on Global Warming

Governor's Advisory Group

- Appointed by the Governor in early 2004
- Public and private representation (28 members) with support from technical subcommittees
- Final Advisory Group decisions in December
- Final report to Governor in January 2005

Governor's Advisory Group on Global Warming

Major Draft Recommendations

- New Goals: 10% below 1990 levels by 2020

  75% below 1990 by 2050
- Meet Northwest Power and Conservation Council target of capturing at least 960 aMW of electricity savings and comparable savings of gas and oil.
- Develop about 130 aMW of renewable generation by 2006 and comparable or greater amount each biennium thereafter.

Governor's Advisory Group on Global Warming

Major Draft Recommendations

- Convene task force to recommend to the 2007 Legislature a carbon content standard for delivered energy (electricity, gas, oil) on a schedule consistent with state goals.
  - A renewable portfolio standard an alternate approach for electricity, with an assumption that it would be at least 25%.

Governor's Advisory Group on Global Warming

Major Draft Recommendations

- Convene task force to recommend to the Governor, Environmental Quality Commissions and the 2007 Legislature a proposal for adopting greenhouse gas emission standards for new vehicles.
- Achieve waste disposal and recovery goals adopted in statute.
- Convene an Advisory Group in 2005 to address adaptation to climate change

Governor's Advisory Group on Global Warming

Draft Recommendations for Biological Sequestration

- Reduce wildfire risk by creating a market for woody biomass from forests.
  - 3.2 MMTCO$_2$E in reductions in 2025 in addition to reductions in emissions from electricity mix
- Consider greenhouse gas effects in farm and forest land decisions.
  - 0.6 MMTCO$_2$E in reductions in 2025
- Increase forestation of under-producing lands.
  - 0.5 MMTCO$_2$E in reductions in 2025

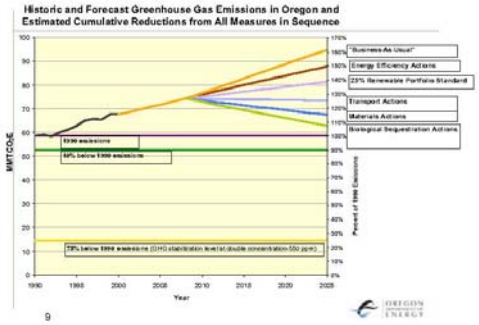
7

Governor's Advisory Group on Global Warming

Draft Recommendations for Biological Sequestration

- Expand application of water-erosion reducing practices for cereal production.
  - 0.2 MMTCO$_2$E in reductions in 2025
- Leverage the Conservation Reserve Program to expand reserved acreage.
  - 0.2 MMTCO$_2$E in reductions in 2025
- Establish a municipal street tree restoration program.
  - 0.1 MMTCO$_2$E in reductions in 2025

8



9

Oregon CO_2 Standard for New Energy Facilities

- Adopted by Legislature in 1997
- Performance standard of 0.675 lbs. CO_2/kWh net emissions
- Monetary Path:
  - $0.85 per ton excess emissions at 100% capacity factor over 30 years
  - Payable to The Climate Trust
  - All facilities have used this method

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Oregon CO_2 Standard for New Energy Facilities

- The Climate Trust has purchased offsets from several bio-sequestration projects:
  - Deschutes Riparian Reforestation Project
  - Lummi Indian Tribe Preservation of 1,600 acres of forest land in Washington
  - Rainforest Reforestation in Ecuador
- Direct $1.5 million to the Oregon Forest Resource Trust from an earlier proceeding

11

Contact

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fax: 503.373.7806
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www.energy.state.or.us

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PACIFICORP

Reducing Greenhouse Gas Emissions

Virinder Singh
Environmental Policy

October 27, 2004

About PacifiCorp

- 1.5 million customers
  - Oregon, Utah, Wyoming, Washington, Idaho and California
- Owned by ScottishPower
- 8,200 MW of power generation
  - Predominantly coal
  - Growing gas portfolio
  - Push for more renewables

PACIFICORP

About Regulated Utilities

- We are obligated to serve customers reliably and as cost-effectively as possible
- As a monopoly, we are overseen by public utility commissions
- As a result, most of our actions require approval by PUCs for cost recovery
- Thus, we cannot act unilaterally without PUC approval
  - This makes us different from many companies in setting internal policies

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The ScottishPower Connection

- Our UK colleagues face real regulations on greenhouse gas emissions and renewable energy
  - Lots of thought and work going into reducing emissions in the generation fleet and tracking policy developments in UK and European Union
- In the US, we face federal disinterest and mild state interest in tackling emissions
  - U.S. Congress moving slowly
  - Oregon and Washington have plant siting laws
  - Other states, such as California and Massachusetts, are setting limits on vehicles and power plants
- Nevertheless, climate change can translate into financial risk since regulations can materialize in the future
  - The UK experience shows that even after 2 decades of Thatcher and Major, regulations can suddenly happen when you least expect it!

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Our Climate Strategy

- Planning
  - Incorporate carbon risk value in our resource modeling
- Procurement
  - Apply carbon risk value to bid evaluations in our RFPs for new generation
- Accounting
  - Joined California Climate Action Registry
- Policy
  - Support well-crafted policies that mitigate emissions growth
    - Renewables
    - Efficiency
    - Offsets
    - GHG Accounting

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Incorporating Climate Change into Planning

- Integrated Resource Plan: 10-yr, least-cost plan
- We included $ adders for CO2 plus NOx and SOx
  - CO2 is a challenge since there are virtually no regulations to reference
  - Worries that a wrong estimate could lead to financial penalties from our regulators
    - But is the alternative - $0/ton - better? We thought "no"
  - Extensive process - consulted experts, environmental representatives, internal managers
  - Settled on $8/ton of CO2 starting in 2009

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Clean Energy in Our 10-Year Procurement Plan

- 4,000 MW of new resources
  - 1,400 MW of renewables (wind, geothermal)
    - 340,000 homes
    - Will require "learning by doing" for integrating intermittent wind into our grid
  - 450 aMW of energy conservation
    - 330,000 homes
  - Other resources will be fossil fuel
    - Balance between minimizing environmental risk and providing low-cost power to customers
- Contingent on bids from developers that meet our price requirements

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Comments on the Plan

- "…the most sophisticated and most consequential IRP that has been prepared in the region in the last five to 10 years."
  - Natural Resources Defense Council
- "This is one of the most impressive integrated resource plans I've seen."
  - Oregon Office of Energy staff
- "PacifiCorp is really leading the way."
  - Renewable Northwest Project
- Everyone (environmentalists, industrial customers, etc.) recognizes elements they do not prefer in the plan - which probably means we're doing something right…
- The commenters above recognize that a plan does not equal implementation - we all have a lot more work to do…

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Tracking emissions

- Important to establish common rules on counting GHGs
  - Avoid accounting games
  - Helps build a foundation for early action credit and offsets
- We currently report GHG emissions in Environmental and Social Impact Report
  - http://www.scottishpower.plc.uk/pages/aboutus_environment
- We have joined the California Climate Action Registry
  - Derived from WRI/WBCSD standards, CCAR should reflect emerging global norms for GHG accounting
  - Registry to focus on both owned generation and purchased power
  - Currently working together to set detailed rules on data certification, emissions factors, T&D losses, etc.

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Support Policies

- Supported a proposed federal renewable portfolio standard, requiring 10% of power to come from renewables in 2020
- Supported federal energy efficiency standards for appliances and equipment
- Engaged in West Coast Governors' Global Warming Initiative
  - Concerned about push for state-mandated CO2 limits
  - States ideally positioned to incent new, clean supply
  - CA, OR, and WA should share best practices
    - Regional Renewable Portfolio Standard?
    - Common efficiency standards?
    - Transportation pilots?
    - GHG Accounting?
    - Siting standard?

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Challenges Are Stiff

- Demand for electricity is rising dramatically
- Supply trends are ambiguous
  - Long-term natural gas supply in question
  - Plentiful, low-cost coal available
  - Cost of wind has dropped dramatically
    - But will new wind farms be permitted by weekending urban liberals?
  - Are we facing a coal-renewables future?
- We see little national leadership
  - Many utilities are interested in policy certainty
- There's a need for further development of technology
  - Utilities typically underinvest in R&D
  - Federal government sending discouraging signals on willingness to deploy technologies in the marketplace

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Other Utility Approaches

American Electric Power

- Largest CO_2-emitting utility in the US
- Faced intense pressure from shareholder groups, environmental groups, and now state AGs on criteria air emissions and greenhouse gas emissions
- Produced a study of McCain-Lieberman's impact on costs – proprietary modeling tool to weigh resource options
- Committed to "proactive" advocacy of "positive policy options", including support for McCain-Lieberman
- Determined that modest GHG reductions can occur over coming years
- Reductions do not change investment plan to conventional pollutants
- Actively pursuing IGCC for its next round of coal investment

Texas Utilities

Shareholders generally would be well served by reducing carbon dioxide.

- The time value of money and the likelihood that there would be sufficient time to adopt cost-effective measures
- The likelihood that costs incurred in advance of mandatory controls would be absorbed by shareholders
- The possibility that later advances in technology will reduce the cost of reducing carbon emissions
- The current inability to target its activities to reflect the specific requirements
- The inability to use the flexibility of the cap-and-trade program
- The danger that early actions would decrease the number of initial allowances, effectively penalizing the company and its shareholders

PACIFICORP

westcarb.org
West Coast Regional Carbon Sequestration Partnership

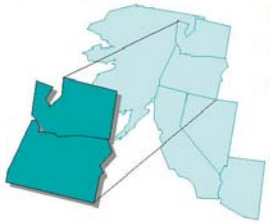
WESTCARB Research Partnership

Developing Sequestration Options for the Pacific Northwest

Kelly Birkinshaw
Executive Director
West Coast Regional Carbon Sequestration Partnership

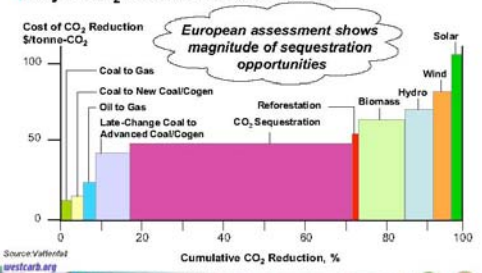
Portland, Oregon
October 27, 2004

WESTCARB Has Active Pacific Northwest Participation



- Public agencies
- Industry
- Conservation/ environmental organizations
- Stakeholder input via public meetings

Carbon Sequestration Can Potentially Achieve Major CO_2 Emissions Reductions



Source:Valfenfat

Carbon Sequestration Is a Bridge to CO_2-Free Energy Systems



Panel Discussion of Sequestration Options and R&D Programs

- **U.S. DOE:** Federal R&D and the Role of Regional Carbon Sequestration Partnerships
- **Geologic Sequestration:** Storage in Natural Underground Reservoirs
- **Terrestrial Sequestration:** Land and Soil Management, Afforestation, Biomass
- **WESTCARB:** Geologic and Terrestrial Sequestration Opportunities and Issues for the Pacific Northwest

A View of DOE's Carbon Sequestration R&D Program



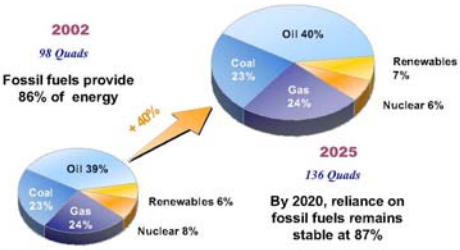
"Pathways to Sustainable Use of Fossil Energy"

Fossil Energy - America's Energy Foundation

2002

98 Quads

Fossil fuels provide 86% of energy



2025

136 Quads

By 2020, reliance on fossil fuels remains stable at 87%

Technological Carbon Management Options

Reduce Carbon Intensity	Improve Efficiency	Sequester Carbon
• Renewables • Nuclear • Fuel Switching	• Demand Side • Supply Side	• Capture & Store • Enhance Natural Sinks

All options needed to:
- **Affordably meet energy demand**
- **Address environmental objectives**



What is Carbon Sequestration?

Capture and storage of CO_2 and other Greenhouse Gases that would otherwise be emitted to the atmosphere

Capture can occur:
- at the point of emission
- when absorbed from air

Storage locations include:
- underground reservoirs
- dissolved in deep oceans
- converted to solid materials
- trees, grasses, soils, or algae



Sequestration Options

Direct Sequestration



Capture and storage

- Oil & Gas Reservoirs
- Unmineable Coal Seams
- Saline Formations
- Oceans

Indirect Sequestration



Remove CO_2 from atmosphere

- Forestation
- Mineralization
- Agricultural Practices
- Ocean Fertilization

Advanced Concepts

Convert CO_2

- Stable Solids
- Useful Products
- Fuels

Major Sequestration Issues…

- **Health, safety, and environmental risks**
- **Permanence and large-scale verification**
- **Capacity evaluation**
- **Infrastructure**
- **Uncertain regulatory frameworks**
- **Protocols for identifying amenable storage sites**
  - Direct CO_2 storage
  - Enhanced natural sinks

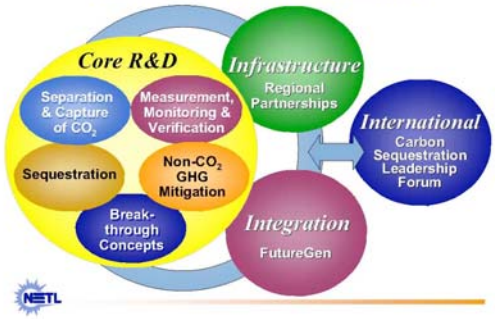


Requirements for Sequestration

- **Environmentally acceptable**
  - No legacy for future generations
  - Respect existing ecosystems
- **Safe**
  - No sudden large-scale CO_2 discharges
- **Verifiable**
  - Ability to verify amount of CO_2 sequestered
- **Economically viable**



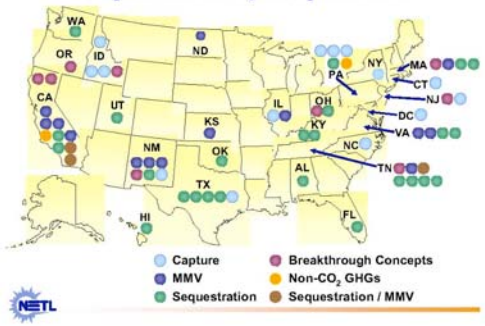
Sequestration Program Organization



Major Technology R&D Pathways

Capture	• Post-combustion Capture • Oxygen combustion • Pre-combustion capture • Chemical looping
Sequestration	• Depleting oil reservoirs • Unmineable coal seams • Saline formations • Enhanced terrestrial uptake • Ocean (injection, fertilization)
MM&V	• Advanced soil carbon measurement • Subsurface measurements • Remote sensing/above-ground MMV • Fate and transport models
Breakthrough Concepts	• Advanced Capture • Bio-accelerated sequestration • Niches

Sequestration Projects Span Nation



Separation & Capture of CO_2

Issue

- Demonstrated technology is costly

Pathways

- Pre-combustion capture
- Post-combustion capture
- Oxygen-fired combustion
  - Chemical looping
- Optimized engineering



Measurement, Monitoring & Verification

Issue

- Proving CO_2 fate

Pathways

- Surface and subsurface CO_2 leak detection and mitigation tools
- Atmospheric detection systems
- CO_2 fate and transport studies
- Protocols for accounting and permanence



Digital Aerial Imagery to Estimate Carbon Stocks in Above-Ground Vegetation

Sequestration

Issues:

- Health, safety, and environmental risks
- Uncertain regulatory framework
- Site selection

Pathways:

- Field experiments / demos
- Protocols for identifying amenable storage sites
- Capacity evaluation studies
- Underlying science



Diverse U.S. Industrial Conditions and Geologic Environments Require a Regional (Re)Orientation for Sequestration Technology Deployment



Regional Carbon Sequestration Partnerships

Developing Infrastructure for Wide-Scale Deployment

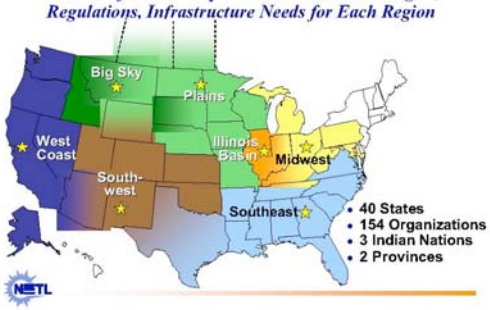
- Baseline region for sources and sinks
- Address regulatory, environmental, outreach issues
- Establish monitoring and verification protocols
- Validating sequestration technology & infrastructure
  - Phase 1 – Planning
  - Phase 2 – Proof of Concepts
- Determine benefits of sequestration to region

These partnerships - 4 to 10 across the country, each made up of private industry, universities, and state and local governments - will become the centerpiece of our sequestration program. They will help us determine the technologies, regulations, and infrastructure that are best suited for specific regions of the country.

Energy Secretary Spencer Abraham
November 21, 2002

Seven Regional Partnerships

Network of Partnerships to Determine Technologies, Regulations, Infrastructure Needs for Each Region



- 40 States
- 154 Organizations
- 3 Indian Nations
- 2 Provinces

Partnership Program has a Two-Phased Approach…



Current Phase I (Planning)

- 7 Projects
- 18-24 months
- ~$1.5 million per project
- Overall ~ 40% cost share
- 2 exceed 50% cost share



Proposed Phase II (Proof-of-Concepts)

- about 8 years duration
- up to about $4 million/year-project
- 20% cost share (minimum)

Regional Partnerships Phase I Outcomes…

- Regional Carbon Sequestration Atlases: Sources, transportation, and sinks
- Regional Project Implementation Plans: Identify the most promising technologies/ approaches to sequester carbon directly or indirectly and/or capture carbon in the region
- Action Plan for Regulatory Compliance
- Action Plan for Public Outreach and Education
- Implementation Plan for a proposed Phase II

Proposed Phase II Approach…

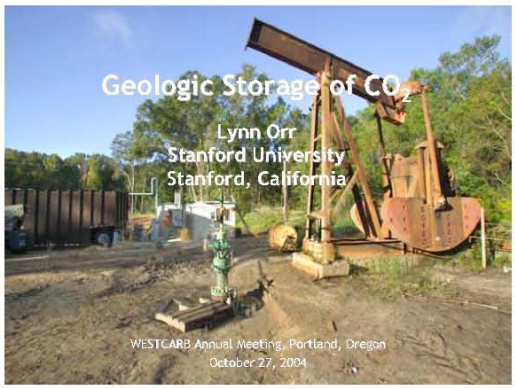
- Not a technology development program.
- Perform proof-of-concept field tests for technology & infrastructure concepts
- Continue characterization efforts for source and sinks; determine appropriate capture methods
- Establish wide-scale deployment opportunities
- Establish and implement Measurement, Monitoring & Verification protocols
- Establish and implement accounting & regulatory approaches
- Implement outreach mechanisms

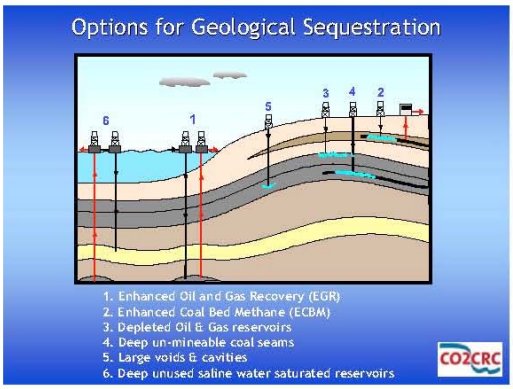
Visit the NETL Sequestration Website…
www.netl.doe.gov/coal/Carbon%20Sequestration/

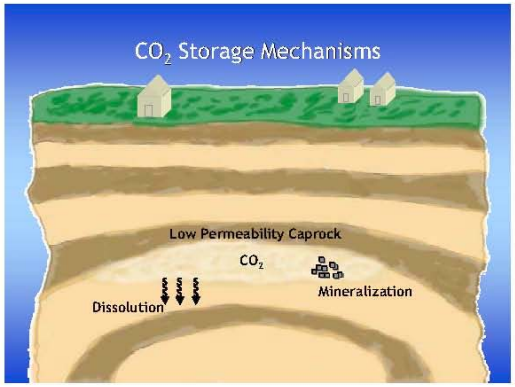


Carbon Sequestration E-mail Newsletter









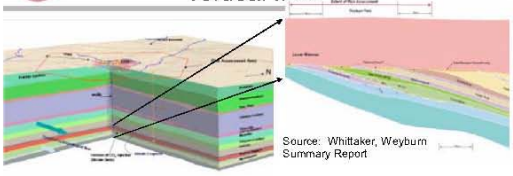


CO_2 for EOR

- Proven technology – 70 projects in west Texas
- Use of CO_2 for oil recovery is limited by gas supply
- 1998 production ~ 180,000 B/D
- 1998 CO_2 injection (natural CO_2) ~ 7.5 million t/yr C ~ 0.6% of fossil fuel emission



Weyburn: multiple barriers to vertical flow

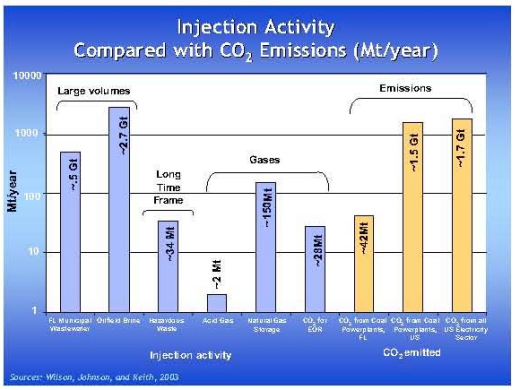


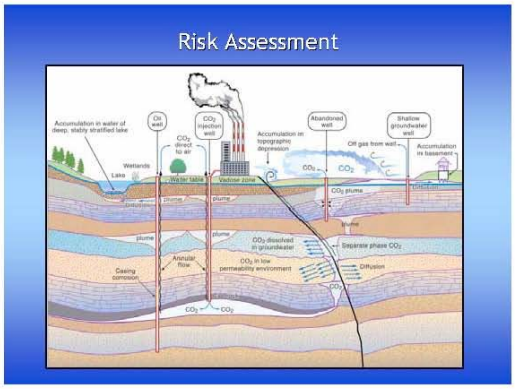
Source: Whittaker, Weyburn Summary Report

The deep formations containing oil and salt water are separated from the surface by thick formations that prevent flow of oil, gas, or water.

Even if the oil were not present at Weyburn, it would be a good place to store CO_2.

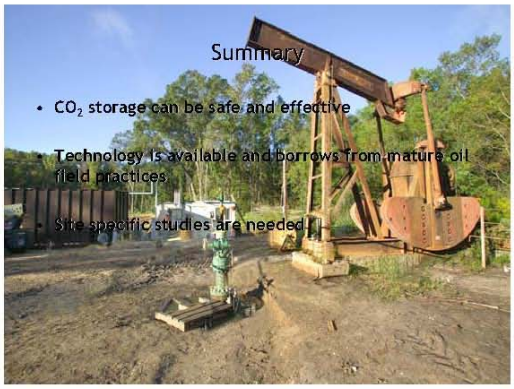






Monitoring Options

	Basic Monitoring	Additional Measurements for Enhanced Monitoring
Pre-operational Monitoring	• Well logs • Wellhead pressure • Formation pressure • Injection and production rate testing • Seismic survey • Atmospheric CO_2 monitoring	• Gravity survey • Electromagnetic survey • CO_2 flux monitoring • Pressure and water quality above the storage formation
Operational Monitoring	• Wellhead pressure • Injection and production rates • Wellhead atmospheric CO_2 monitoring • Microseismicity • Seismic surveys	• Well logs • Gravity survey • Electromagnetic survey • Continuous CO_2 flux monitoring at 10 stations • Pressure and water quality above the storage formation
Closure Monitoring	• Seismic survey	• Gravity survey • Electromagnetic survey • Continuous CO_2 flux monitoring at 10 stations • Pressure and water quality above the storage formation • Wellhead pressure monitoring for 5 yeas, after which time the wells will be abandoned



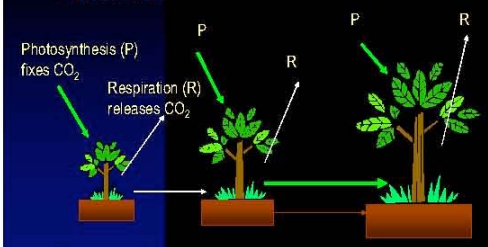
West Coast Carbon Partnership
Annual Meeting

What is Terrestrial Carbon Sequestration?

John Kadyszewski
Winrock International
Portland, Oregon
October 27, 2004



How do Ecosystems Sequester Carbon?



Photosynthesis exceeds respiration, resulting in storage of carbon

©Winrock International

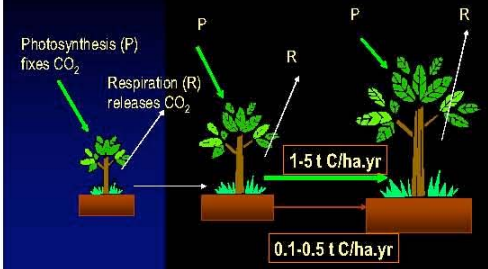
Where is Carbon Sequestered?

- Live biomass
  - Trees
  - Understory
  - Roots
- Dead biomass
  - Standing
  - Down
    - Coarse
    - Fine
- Wood products
- Soil

"Carbon Pools"

©Winrock International

At What Rate Does Carbon Accumulate?



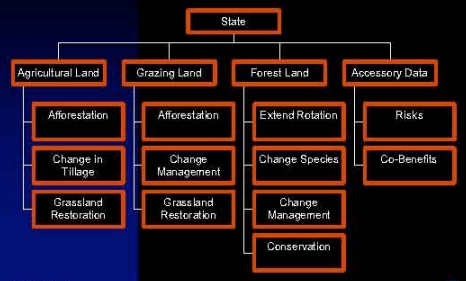
©Winrock International

What is a Terrestrial Carbon Sequestration Project?

- Activity focused on ecosystems resulting in less greenhouse gases (primarily CO2) in the atmosphere
  - Avoid new emissions
  - Remove CO2 from the atmosphere
- Project-based carbon benefits are the difference between the selected "carbon pools" in the with-project and without-project cases

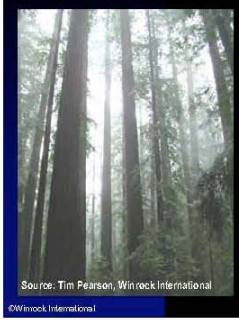
©Winrock International

Terrestrial Sequestration Options



©Winrock International

Conserve Forests


Source: Tim Pearson, Winrock International

- Stop forest conversion to non-forest
- Sierra Mixed Conifer (150 year old forest)
  - 376 tC/ha
- Redwood (150 year old forest)
  - 478 tC/ha

©Winrock International

Afforestation

- Convert agricultural or grazing land back to forest
  - Return to native forest
  - Convert to forest land for timber production




Source: Tim Pearson, Winrock International

Mixed Conifers

©Winrock International

Reforest Degraded Land

- Rate of Carbon Sequestration for Douglas Fir
  5 tC/ha yr x 20 yrs
  =100 tC/ha


Source: Tim Pearson, Winrock International

©Winrock International


Source: Jon Johnson, Washington State University

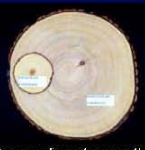
Afforestation

- Convert to forest land with fast-growing species

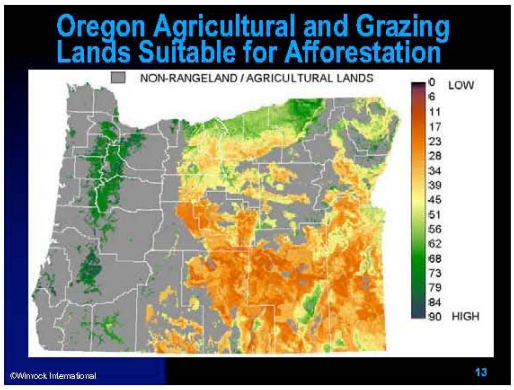
Hybrid Poplar
28 years old
110 feet tall
32 in. dbh

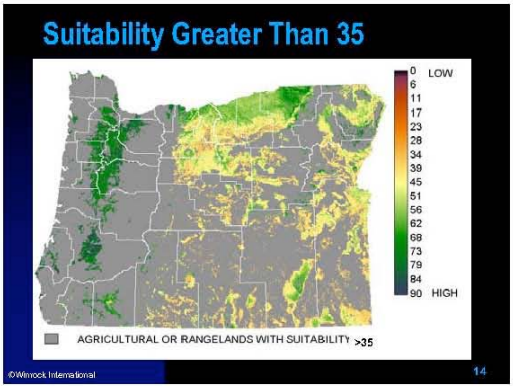
Growth Rates for Trees

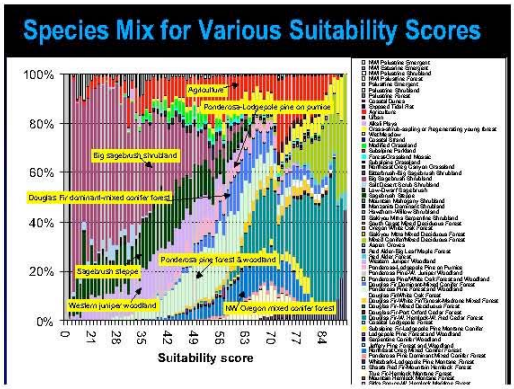
- Douglas Fir 4 dry t/acre/yr
  ~50 year rotation
- Hybrid Poplar 10 dry t/acre/yr
  6-8 year rotation


9 years diameter growth

Source: Jon Johnson
Associate Professor
Washington State University


Oregon Agricultural and Grazing Lands Suitable for Afforestation
NON-RANGELAND / AGRICULTURAL LANDS
0 LOW
6
11
17
23
28
34
39
45
51
56
62
68
73
79
84
90 HIGH
©Winrock International
13

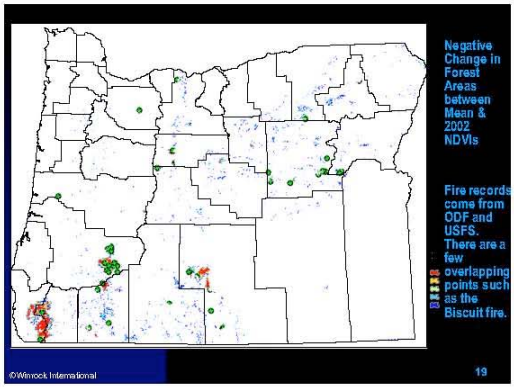

Suitability Greater Than 35
0 LOW
6
11
17
23
28
34
39
45
51
56
62
68
73
79
84
90 HIGH
AGRICULTURAL OR RANGELANDS WITH SUITABILITY >35
©Winrock International
14


Species Mix for Various Suitability Scores
100%
80%
60%
40%
20%
0%
Agriculture
Ponderosa-Lodgepole pine on pumice
Big sagebrush Shrubland
Douglas Fir dominant-mixed conifer forest
Ponderosa pine forest &woodland
Sagebrush steppe
Western juniper woodland
NW Oregon mixed conifer forest
0 21 28 35 42 49 56 63 70 77 84
Suitability score


Fuels and Fire Management
Not all fires are the same
Source of Photos: Dr. Sam Sandberg, USDA Forest Service PacificWildland Fire Sciences Laboratory


Potential Sequestration Benefits from Improved Fire Management
Source: Dr. Sam Sandberg, USDA Forest Service PacificWildland Fire Sciences Laboratory
Reduce net GHG emissions from combustion
Reduce loss of carbon stocks from large trees
Reduce loss of carbon stocks from duff
Maintain carbon accumulation rates during recovery
Avoid ecosystem-changing fires
©Winrock International
17


Ecosystem Conversion
San Francisco Peaks, AZ
Fire can change forest ecosystems to non-forest ecosystems
Source: Dr. Sam Sandberg, USDA Forest Service PacificWildland Fire Sciences Laboratory
18



Change Logging Practices

30 Mg C/ha living biomass removed → 15.6 Mg C/ha slash (non stemwood + collateral mortality) → Oxidized at 8% per year

14.4 Mg C/ha stemwood extracted

6.8 Mg C/ha oxidized in near term (bark, sawdust, short-lived products)

7.6 Mg/ha derived LWPs (paper and sawnwood in long-term use) → Oxidized at 1% per year

©Winrock International 20

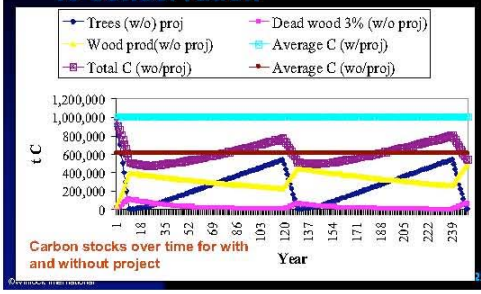
Change From Logging to Conservation



- Collect data on logging
  - Rotation length
  - Growth rates
  - Slash left in forest
  - Volume logged
- Determine decomposition rates
- Assess wood products
  - Quantity
  - Type
  - Turnover
- Simulate over 2-3 rotations

©Winrock International 21

Accounting model for changes in forest management: logging to conservation



Carbon stocks over time for with and without project

Inputs to accounting model for changes in forest management

Empirical data from project area—based on measurements

Activity	Conservation of forest by prevention of logging		
	Area suitable for logging		ha/yr
Inputs	Area harvested per year		ha/yr
	Amount of abovground biomass in forest		t/ha
	Slash		t biomass
	Total biomass removed = slash plus extracted wood		t/ha.yr
	Decomposition rate of wood		per year
	Decomposition rate of wood		per year
	Fraction biomass removed		
	Fraction converted to wood products		
	Wood product decomposition rate		per year
	Regrowth rates: period 1		t/ha.year
	period 2		t/ha.year
	period 3		t/ha.year
	Rotation period		years

Can these activities make a difference?

Global estimates of the potential amount of land available and potential amount of C that could be sequestered and conserved by forest management practices on this land between 1995 to 2050.

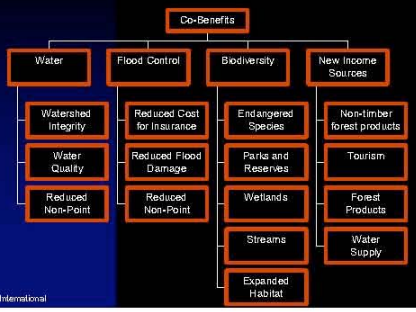
Latitudinal belt	Practice	Area (Mha)	C sequestered & conserved (billion tons)	
Boreal	Forestation	95	2.4	
Temperate	Forestation	113	11.8	
	Agroforestry	7	0.7	14
Tropics	Forestation	67	16.4	
	Agroforestry	63	6.3	
	Regeneration	217	11.5-28.7	
	Slow deforestation	138	10.8-20.8	46-73
Total		700	60-87	

*The amount of C conserved and sequestered here is equivalent to 12-15% of the business-as-usual fossil fuel emissions over the same time period

From Brown et al. 1996, Second Assessment Report of IPCC; Kauppi and Sedjo 2000, Third Assessment Report, IPCC

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Multiple Additional Environmental Benefits



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Project Issues

- Baselines
- Leakage
- Reversibility (Permanence)
  - Duration
  - Risk of Loss
- Additionality
- Measurement and Monitoring

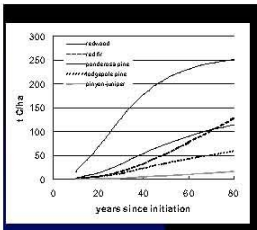
©Winrock International 26

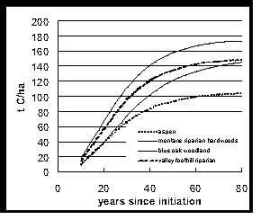
Baselines

- Setting a baseline requires projecting future activities in the absence of a project
- Baseline has two components—land use/cover and corresponding carbon
- Land use component:
  - for afforestation activities simplest approach is a base year
  - for changes in forest management, need projection of practices prior to a base year
  - for conservation from threat of deforestation, need projection of existing practice into future (how far?)

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Growth Curves





©Winrock International

Leakage

- Leakage is the unanticipated loss or gain in carbon benefits outside of the project's boundary as a result of the project activities
  - Carbon emissions from leakage could offset gains from a carbon project, resulting in a reduction of the carbon "credits"

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Leakage can be divided into two types:

- Activity shifting occurs when the activity causing carbon loss in the project area is displaced outside project boundary—primary leakage
  - e.g. stopping logging at one site may stimulate logging at another site.
- Market effects occur when project activities change supply and demand equilibrium—secondary leakage
  - e.g. if demand is unmet because a project reduces supply (timber supply) or it increases demand (plantation projects may depress the price of wood, causing nearby plantations to be replaced with low-biomass land uses).
  - e.g. a reduction in price of timber may reduce pressure on native forests for timber supply, in essence having a spillover effect

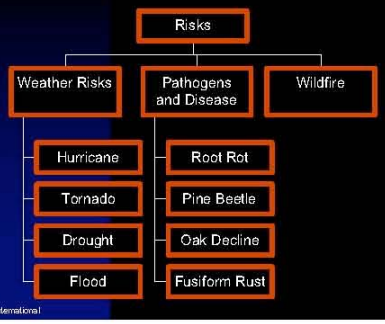
14

Duration and Risk of Loss (Permanence)

- Land-based systems are subject to reversal by human and natural disturbances
- Risk increase with project duration
  - Credits can be permanent or temporary
- Risk of loss
  - Quantify potential loss for range of risks
  - Manage risk with insurance methods internal or external to the project

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Risks



©Winrock International

Additionality

- A project activity is additional if the activity would not have taken place in the absence of the sale of carbon credits
  - Financial additionality
  - Environmental additionality

©Winrock International

Decide which carbon pools to measure and monitor

- Carbon pools: aboveground biomass, belowground biomass, litter, dead wood, and soil organic carbon
- Can choose not to monitor all of them if evidence provided that they are not a source of GHG
  - E.g. soil can be more expensive to measure and changes are often small and in an afforestation activity on degraded lands soil is unlikely to be a source of GHGs

©Winrock International

Which carbon pools to include in a project?

Project type	Carbon pools						
	Live biomass			Dead biomass			Wood
	Trees	Understory	Roots	Fine	Coarse	Soil	products
Avoid emissions							
•Stop logging and protect	Y	M	R	M	Y	N	Y
•Change forest management	Y	M	R	M	Y	N	Y
Sequester carbon							
•Restore native forests	Y	M	R	R	Y	R	N
•Plantations for timber	Y	N	R	M	M	R	Y
•Agroforestry	Y	Y	R	N	N	R	M
•Short-rotation plantations	Y	N	M	N	N	Y	*

*Stores carbon in unburned fossil fuels
Y=yes, R=recommended, M=maybe, N=not recommended

No "one size fits all"—different project types can select to measure different pools

Modified from IPCC Special Report on LULUCF/Draft GPG

Questions or Comments:

John Kadyszewski
Winrock International
(703) 525-9430,ext 618
Jkadyszewski@winrock.org

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westcarb.org
West Coast Regional Carbon Sequestration Partnership

Developing Sequestration Options for the West Coast

Larry R. Myer
University of California Office of the President
California Institute for Energy and Environment

WESTCARB Is One of Seven in DOE Program

- Partnership is evaluating terrestrial and geologic options for CO_2 sequestration in the region
- Partnership has broad stakeholder representation
- California Energy Commission is lead organization for WESTCARB



WESTCARB Has Engaged A Strong Multi-Sectoral Team

- **Policy and Coordination** (Western Governor's Association)
- **State Resource Management, Environmental Protection, and Regulation** (CA Dept. of Forestry and Fire Protection, CA Dept. of Oil, Gas and Geothermal Resources, CA Geologic Survey, CAL EPA, OR Dept. of Forestry, Nevada Bureau of Mines and Geology, Region 9 EPA, WA Dept. of Natural Resources)
- **Oil and Gas Companies** (AERA, BP, Chevron Texaco, ConocoPhillips, Occidental Petroleum, Shell)
- **NGO's** (Pacific Forest Trust)
- **Utilities** (Pacific Corp., Salt River Project, Sierra Pacific Resources, TransAlta)
- **National Lab and Research Institutions** (Electricity Innovation Institute, Kearney Foundation, LBNL, LLNL, MIT, Stanford-GCEP, Winrock)
- **Engineering Companies** (Advanced Resources International, Clean Energy Systems, Golder Associates, KinderMorgan, Nexant, SFA Pacific, Terralog)
- **Public Outreach/Education** (American Petroleum Institute, Cal State Bakersfield, Cal Poly, SF Dept. of Environment, Science Strategies, Western State Petroleum Association)

WESTCARB Is Addressing 4 Major Questions in a Two-Phase Program

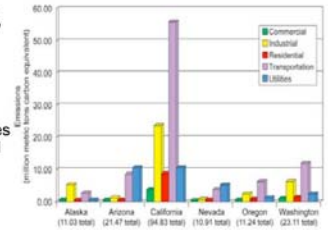
- Where are the sources of CO_2 and how much is there?
- Where can it be stored?
- How much will it cost?
- Will it be safe?

- Phase I will address these at the regional level while Phase II will address them at the local level

Where are the CO_2 sources and how much is there?

WESTCARB States Account for 11% of U.S. CO_2 Emissions

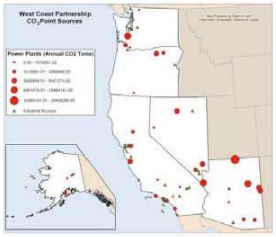
- Within WESTCARB, transportation accounts for 53%, utilities 13%, and industry 23% emissions
- Largest point sources are power plants, oil and gas producing field operations, oil refineries, and cement plants



Data Source: EPA CO_2 emission inventories for 1999 fossil fuel combustion

Major Point Sources of CO_2 Have Been Identified for Study in WESTCARB

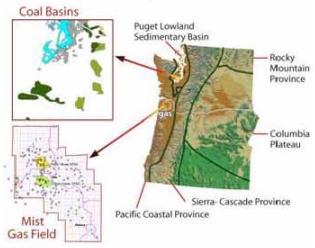
- Sources account for about 80% of total industrial and utility sector emissions
- CO_2 emissions and plant operating data are being collected
- Information is stored in a Geographic Information System (GIS) format



Where can the CO_2 be stored?

Large Sedimentary Basins Offer the Best Geologic Storage Sites

Potential for offsetting costs if gas fields or coal beds are used



WESTCARB Offers Major Terrestrial Storage Opportunities

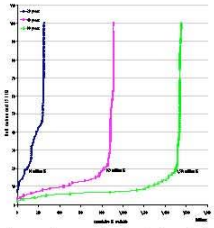
- Region diverse in forests, rangelands, and agricultural lands
- Forest sequestration options include riparian management, conversion of rangeland/marginal land, enhancement of large wood, fire management
- Baseline analyses define carbon emissions and/or sequestration for forest, rangeland, and agricultural sectors



How much will it cost to store the CO_2?

Supply Curves Quantify Major Terrestrial Storage Options

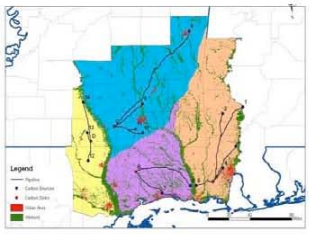
- Identify areas of current use
- Determine areas suitable for change
- Estimate additional carbon stored
- Include risk, other externalities
- Estimate opportunity, conversion, MMV costs
- Field check carbon storage estimates



Carbon supply curves for afforestation activities on candidate rangelands at 20, 40 and 80 years.

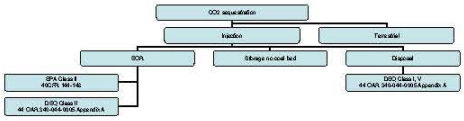
Costs are Calculated for Point Source-Geologic Site Combinations

- Costs include capture and separation, compression, pipeline transportation, injection
- Cost offsets for additional oil or gas production taken if feasible
- Analyses carried out using GIS-based system



Example of source-sink matching using GIS system

Regulatory and Permitting Requirements Are Compiled and Assessed



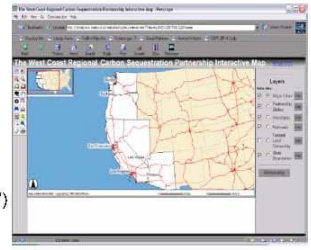
Is CO_2 storage safe?

Security Against Leakage Is an Important Factor in Geologic Site Selection

- Geologic sites are screened for adequate depth; isolation from potable water; multiple, continuous seals (e.g., shale layers); distance from active faults
- Spreadsheet model for scoring possible health, safety and environmental risks help in screening
- Evaluation of available monitoring technology being carried out for example geologic site locations in WESTCARB

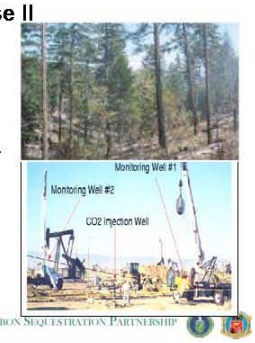
Transparency Is Essential

- Broad stakeholder participation
- Public meetings, education materials
- Public access to information through web site and Internet Mapping Site at Utah AGRC (go to WESTCARB.org and click on "carbon atlas")



Field Pilot Demonstrations Will Be Proposed for Phase II

- Pilots will be representative of best sequestration options, unique technologies and approaches, in region
- At least one terrestrial and one geologic pilot will be proposed for a five year study
- Pilots involve site-specific focus for
  - Testing technologies
  - Defining costs
  - Testing regulatory requirements
  - Validating monitoring methods
  - Assessing leakage risks
  - Gauging public acceptance



Conclusions

- WESTCARB has been designed to advance the practical application of carbon sequestration
- Regional source/sink information is an important basis for decision-making at state and national level
- Phase I work is about half finished; new participants are still welcome
- Phase II field pilots are being developed – suggestions are welcome



Appendix A: Meeting Registrants

Registrants for the WESTCARB Public Meeting in Portland, OR, on October 27, 2004.

Name	Title	Organization	Address	City,State Zip	Telephone	Fax	Email
Austin, David	Managing Director	Greenwood Resources	P.O. Box 5905	Portland, OR 97202	503-274-0438	503-478-0751	daustin@greenwoodresources.com
Beidiger, Barry	GIS Specialist	State of Utah AGRC	5130 State Office Bldg	Salt Lake City, UT 84114	801-537-7078		bbeidiger@utah.gov
Benson, Gary	PFSC	Pacific NW Research Station	620 S.W. Main Street, Ste 400	Portland, OR 97205	503-808-2191		gbenson@fs.fed.us
Bicker, Steve		NW Natuarl	220 NW Second Ave	Portland, OR 97209	503-220-2369		stephen.bicker@nwnatural.com
Birkinshaw, Kelly	Program Manager	California Energy Commission	1516 9th Street	Sacramento, CA 95814	916-654-4542		kbirkins@energy.state.ca.us
Brown, Mark	Forester	Bureau of Indian Affairs	911 NE 11th Ave	Portalnd, OR 97232	503-231-2273		
Browning, Arnold	Forester	Bureau of Indian Affairs	911 NE 11th Ave	Portland, OR 97232	503-231-6205		
Bruno, Mike		Terralog Technologies	332 E Foothill Blvd	Arcadia, CA			msbruno@terralog.com
Bushek, Jim			6915 SW 8th Ave	Portland, OR 97219	503-246-9556		jabuschek@cs.com
Carrow, Vince		Carrow,LLC Consulting	4477 Medina Lane SE	Salem, OR 97301	503-399-7807		carrhome@worldnet.att.net
Cathcart, Jim		Oregon Department of Forestry	2600 State Street	Salem, OR	503-945-7493	503-945-7490	jcathcart@odf.state.or.us
Chakravarti, Shrikar	Manager	Purification R&D	175 East Park Drive	Tonawanda, NY 14150	716-879-4760		shikar_chakravarti@praxair.com
Clinkenbeard, John	Senior Geologist	California Geological Survey	801 K Street, MS 13-40	Sacramento, CA 95814	916-323-7696		john.clinkenbeard@conservation.ca.gov
Cloughesy, Mike		OFRI	317 SW 6th Ave, Ste 400	Portland, OR 97204	503-229-6718		cloughesy@ofri.com
Cross, Joe	Research	Conoco Phillips	370a PL	Bartlesville, OK 74004	918-661-3285	918-662-5203	joe.b.cross@conocophillips.com
DeBolt, Richard		Transalta	913 Big Hanaford Road	Centralia, WA 98531	330-8118		Richard_Debolt@transalta.com
Evans, Amy	Counsel	WA State House of Representatives	408 John L. O'Brien Bldg	Olympia, WA 98504	360-786-5262		evans_am@leg.wa.gov
Gagliano, Troy	Sr. policy Associate	Renewable NW Project	917 SW Oak #303	Portland, OR 97205	503-223-4544		troy@rnp.org
Green, Dominc	Specialist	Portland General Electric	121 SW Salmon 1 WTC 0302	Portland, OR 97204	503-464-8533		dominic.green@pgn.com
Hemelstrand, Mike		PG&E	121 SW Salmon	Portland, OR 97204	503-464-8195		
Hirl, MJ	Director Business Development	KM			713-369-8716		
Hym, David	Geologist	USDOE	P.O. Box 10940	Pittsburgh, PA			
Ifie, Tony		Department of Natural Resource	1111 Washington St. SE	Olympia, WA 98513	360-902-1019	360-902-1776	tonyifie@aol.com
Johnson, James	Research Geochemist	LLNL	7000 East Ave, L-221	Livermore, CA 94550	925-423-7352	925-422-7438	jwjohnson@llnl.gov
Jolly, Carol	Executive Policy Coordinator	WA Governor's Office	P.O. Box 43113	Olympia, WA 98504	360-902-0639		carol.jolly@ofm.wa.gov
Kadyszewski, John	Task Leader	Winrock International	1621 N Kent St., Suite 1200	Arlington, VA 22209	703-525-9430		jkadyszewski@winrock.org
Lee, Arthur		Chevron Texaco Corporation	6001 Bollinger Canyon	San Ramon, CA 94583	925-842-7421	925-842-7447	rlas@chevrontexaco.com
Long, David	EX Officer	CIBC	P.O. Box 5102	Fullerton, CA	951-683-7349	714-578-0417	cjec@earthlink.net
Meyer, Jack	Geologist	NW Natural	220 NW Second Ave	Portland, OR	503-226-4211	503-220-2595	h2m@nwnatural.com
Mix, Alan	Professor	Oregon State University	College of Oceanic & Admin	Corvallis, OR 97330	541-737-5212		amix@coas.oregonstate.edu
Morgan, Rhidian	Managing Partner	Plas Newyad	P.O. Box 428	Ridgefield, WA 98642	360-887-3531		plasnewyad@dslnorthwest.net
Myhre, Rich	Vice President	Bevilcqua Knight, Inc	100 Broadway Suite 410	Oakland, CA 94607	510-444-8707	510-463-2690	rmyhre@bki.com
Oldenburg, Curt	Staff Scientist	LBNL	1 Cyloton Road	Berkeley, CA 94720	510-486-7419	510-486-5686	crnoldenburg@lbl.gov
Orr, Lynn		Stanford University	550, Rm 556B	Stanford, CA 94305	650-725-6270	650-725-9190	fmorr@stanford.edu
Paik, Mike		Southern California Edison	6000 N. Irwindale Ave, Ste E	Irwindale, CA 91702	626-812-7398		mike.paik@sce.com
Poe, Edgar	Regional Water Resource Scientist	Bureau of Indian Affairs	911 NE 11th Ave	Portland, OR 97232	503-872-2741		
Price, Jonathan	State Geologist	Neveda Bureau of Mines and Geology	University of Neveda Reno, MS 17	Reno, NV 89557	775-784-6691	775-784-1709	jprice@unr.edu
Pronske, Keith		Clean Energy Systems, Inc.	11330 Sunco Drive, Suite A	Rancho Cordova, CA 95670	916-379-9143		kpronske@cleanenergysystems.com
Raney, Ron		USDA, NRCS	101 SW Main	Portland, OR	503-414-3263		ron.raney@or.usd.gov
Robin, George		US Environmental Protection Agency	75 Hawthorne St, WTR-9	San Francisco, CA 94105	415-972-3532	415-972-3549	robin.george@epa.gov
Sadler, Sam	Senior Analyst	Oregon Department of Energy	625 NE Marin St	Salem, OR 97201	503-373-1034	503-375-7806	samuel.r.sadler@state.or.us
Seluga, Dave	Portland Business Line Manager	Shaw Environment	10300 SW nimbus Ave., Ste B	Tigard, OR 97223	503-603-1075		dave.seluga@shawgrp.com
Shine, Joe		Praxair		Danbury, CT 08110			joe.shine@praxair.com
Simbeck, Dale		SFA Pacific, Inc.	444 Castro St., Suite 720	Mountain View, CA 94041	650-969-8876	650-969-1317	simbeck@sfapacific.com
Sterner, Michael		Interforest,LLC	721 NW 9th Ave, Ste 227	Portland, OR 97209	503-478-0800		msterner@iforest.com
Stevens, Scott	Vice President	Advanced Resources Int'l Inc	4501 Fairfax Drive, Ste 910	Arlington, VA 22203	703-528-0439		sstevens@adv-res.com
Virinder, Singh	Enivornmental Policy	Pacificorp	825 NE Multnomah, Suite 2000	Portland, OR 97232	503-813-7276	503-813-7251	virinder.singh@pacificorp.com
Walls, Jim	Executive Director	Lake Coutny Resources Institute	25 North E St.	Lakeview, OR 97630	541-947-5461	541-947-5461	jwalls@goooselake.com
Wickizer, Doug		California Department of Forestry and Fire	1416 Ninth Street	Sacramento, CA 95814	916-653-5602	916-653-8957	doug.wickizer@fire.ca.gov
Wimberly, Bamson	Industrial Engineer	NW Natural	220 NW Second Avenue	Portland, OR	503-721-2479		b3w@nwnatural.com
Zipper, Diane		Renewable NW Project	917 SW Oak #303	Portland, OR 97205	503-223-4544	503-223-4554	diane@RNP.org

Appendix B: Target Audience Segmentation Analysis

WESTCARB October 2004 Public Meeting: Audience Segment Analysis (for Planning Discussion)
R. Myhre DRAFT, 8/20/04

Audience Segment	Likely Interest	Likely Perspective or Concern	Our Current Program "Fit"	Likely Attendance	Keys to Successful Engagement	Mailing List Sources
Professionals in relevant public agencies: forestry, agriculture, geologic survey, climate task forces	How sequestration technologies/ markets affect agency goals and operations	Creating workable programs with nascent technologies and legal/reg structures	Good, but some may want info planned for business meeting	Moderate	• Inviting participation of agency heads • Good advance notification • Q&A/announcement opportunities	• Cathcart OR list • Ifie WA list
Relevant industry professionals	Prospect of significant new regulations or business opportunities	Potential for cofunding of project meeting their interests; concern over adverse regulations or business impacts	Moderate, but too futuristic for some, with no near-term opportunity or threat on the table	Uncertain	• Inviting participation of executives • Emphasis on future project cofunding opportunities	• Trade association and regulatory agency lists • Cathcart's business websites Commercial SIC code lists
General business community	Prospect of impending regulations or business opportunities/ threats	Concern over adverse regulations or business impacts	Potentially too futuristic; no near-term opportunity or threat is on the table	Low	• Emphasis on how sequestration technology/markets could generate new business	• Chambers of Commerce • Cathcart's business websites
Academia/Students	Regional characterization data sets, analytical methods, and results; potential Phase	What are future joint research/ funding opportunities?	Public meeting may be too general; business meeting better technically, but won't have	Uncertain	• Perception of meeting as technically significant and objective • Emphasis on future joint research opportunities	• Researchers known to WESTCARB members • Key program faculty/alumni lists

Audience Segment	Likely Interest	Likely Perspective or Concern	Our Current Program "Fit"	Likely Attendance	Keys to Successful Engagement	Mailing List Sources
	II projects		papers and maybe not enough Q&A		• Promotion by professors	
Environmental Groups	How sequestration projects affect local communities/ environment	Opposition to projects not aligned with current mission (e.g., old growth/habitat preservation and limited timber harvest)	Potentially too general; no specific policy initiative or project is on the table	Uncertain	• Creating sense their input is sought and matters	• OR lists from Cathcart, Lehmann, others • Ifie WA list
"Inquisitive" public	Prospect of impending project or adverse climate-related change in their community	Affect on their quality of life and property value	Potentially too futuristic; no specific threat or project is on the table	Low	• Convey relevance	• Website listservers?
Media	"Event coverage" story for metro page; "feature" story for science page	Local implications	Too futuristic; media thrives on immediacy of action	Uncertain	• Participation by well-known local officials or student/civic groups • Good press release/media kits; active follow-up • Potential for controversy	• Local WESTCARB members • Standard commercial sources

Appendix C: WESTCARB Meeting Flyer

WESTCARB distributed copies of its public meeting flyer via direct mail to targeted lists developed with key partners. Partner organizations also distributed the flyers through internal channels. Overall, more than 1000 were sent out.



Climate Change in the Pacific Northwest

A Forum on Opportunities for Managing Impacts through Carbon Sequestration

Portland, Oregon
October 27, 2004 1:00–4:45 p.m.

Purpose

This informational forum will characterize climate change projections for the Pacific Northwest as well as technical and policy measures that could help temper or manage any adverse impacts. Particular emphasis will be given to "carbon sequestration," a collection of technologies and land management techniques that reduces net emissions of CO_2, the predominant "greenhouse gas."

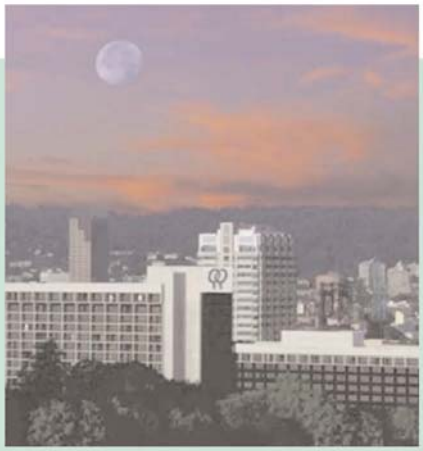
Speakers will represent a diverse set of Northwest perspectives and will include scientists, policymakers, government agencies, and businesses. The meeting's panel discussion format will allow ample time for audience questions and discussion. Results will help the West Coast Regional Carbon Sequestration Partnership (WESTCARB) assess Pacific Northwest carbon sequestration opportunities and issues for the U.S. Department of Energy.

Who Should Attend

- Community leaders, legislators, and other decisionmakers
- Energy, agriculture, range, and forest interests
- Conservation and environmental groups
- Natural resource and environmental protection agencies
- Researchers, university faculty and students
- Other interested citizens

How to Register

Anyone is welcome to attend the meeting, free of charge, with or without advance registration. However, to help the meeting planners assure an effective room arrangement, we encourage you to register in advance by e-mailing your name, full business address, and phone number to Richard Zabel at **richard@westernforestry.org.** Alternatively, you may call Richard at (503) 226-4562.



LOCATION

DoubleTree Hotel & Executive Meeting Center—Portland Lloyd Center
1000 NE Multnomah
Portland, OR 97232
Hotel phone: (503) 281-6111

For directions to the hotel, follow the "Directions and Transportation" link on www.doubletree.com/en/dt/hotels/index.jhtml?ctyhocn=RLLC-DT

Parking is available at the structure adjacent to the hotel. Bring your parking "ticket" into the meeting to be validated for free parking.

WESTCARB Climate Change Forum Q&A:

Q: Why should I come to this meeting?

A: Climate change could potentially affect the whole world, including the Pacific Northwest. Computer simulations developed by scientists suggest that regional changes may include more winter rain, earlier spring snowmelt in the mountains, hotter and drier summers with smoggier air, water shortages, greater coastal storm surge and erosion, and added stress on salmon.

The magnitude of human-induced climate change will depend, in part, on decisions made by people in the Pacific Northwest and by others around the world. Education and public discourse are vital to informed decision-making.

Q: What is carbon sequestration?

A: Carbon sequestration involves capturing and permanently isolating carbon dioxide (CO_2) that might otherwise contribute to global climate change. Affordable and environmentally safe techniques for sequestering carbon could help stabilize atmospheric levels of CO_2 without premature large-scale and potentially costly changes to our energy infrastructure.

Q: Who are the speakers?

A: Our panelists include scientists working on climate change from universities and national laboratories in the Pacific Northwest, representatives from Oregon and Washington state government, a program manager for the U.S. Department of Energy, a PacifiCorp executive, and a consultant.

Q: Who organized this forum?

A: This forum was organized by the West Coast Regional Carbon Sequestration Partnership. WESTCARB is a collaborative research venture, led by the California Energy Commission, bringing together scientists and engineers at more than 40 public agencies, private companies, and nonprofits. Our local host, the Oregon Department of Forestry, is a WESTCARB member.

Q: Is this forum part of a legal process to obtain a construction permit or authorize a timber harvest?

A: No. Our objective is to increase public awareness—and feedback—on the potential role of carbon sequestration in curbing CO_2 emissions and on WESTCARB's characterization of carbon sequestration opportunities and issues in the Pacific Northwest.

The U.S. Department of Energy (DOE) developed the regional carbon sequestration partnerships program (WESTCARB is one seven partnerships across the country). DOE is currently planning a second phase of work that will involve field validation tests of carbon sequestration technologies.

DOE is also preparing a programmatic Environmental Impact Statement that will cover its future carbon sequestration research, development, and demonstration activities, including "geologic" and "terrestrial" sequestration projects.

When DOE issues its request for Phase II proposals, WESTCARB plans to submit a responsive proposal featuring both a geologic and a terrestrial sequestration application within its six-state territory. Specific projects and locations have yet to be determined.

Q: What if I can't attend the climate change forum?

A: The October 27th forum in Portland is the only meeting planned this year in the six-state WESTCARB territory. After the meeting, the panelists' presentations will be posted on our website, www.westcarb.org. You'll find other background and project-specific information there as well. We invite you to review the website and write to us with any questions or comments.

WESTCARB is committed to seeking broad input to its characterization of carbon sequestration opportunities for the Pacific Northwest and to finding the best types of projects to validate carbon sequestration technologies, both technically and in terms of community support.

For More Information

Please visit our website at www.westcarb.org.

You may also e-mail WESTCARB's technical director, Larry Myer, at Larry.Myer@ucop.edu.

10/5/04

Appendix D: Media Contacts and News Releases

The following WESTCARB News Release, Business Calendar Listing, and Invitation to Cover, were sent to the following media contacts:

The Oregonian (Portland)
Environmental Reporter: Michael Milstein, (503) 294-7689, michaelmilstein@news.oregonian.com
Business Reporter: Dylan Rivera, (503) 221-8532. dylanrivera@news.oregonian.com

Statesman Journal (Salem)
Environmental Reporter: Beth Casper, (503) 589-6994, bcasper@statesmanjournal.com
Business Editor: Don Currie, (503) 399-6677, dcurrie@statesmanjournal.com

Register Guard (Eugene)
Environmental Reporter: Diane Dietz, (541) 338-2376, ddietz@guardnet.com
Business Team Leader (editor): Christian Wihtol, (541) 338-2381, cwihtol@guardnet.com

OPB (Oregon Public Broadcasting, Portland)
Environmental Reporter: Ley (pronounced 'lee') Garnett, (503) 293-1986, ley_garnett@opb.org
News and Public Affairs Director: Morgan Holm, (503) 293-1975, opbnews@opb.org

The Business Journal (business weekly, Portland)
Managing Editor: Dan McMillan, (503) 219-3418, dmcmillan@bizjournals.com

Daily Journal of Commerce (Portland)
Construction/Law Reporter: Stephanie Basalyga ('boss-uh-league-uh'), (503) 226-1311x246, stephanie.basalyga@djc-or.com

Capital Press (Agricultural weekly, based in Salem)
Reporter: Mitch Lies (pronounced 'lease'), (503) 371-0552, mlies@capitalpress.com

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP



NEWS RELEASE

FOR IMMEDIATE RELEASE

October 18, 2004

Climate Change in the Pacific Northwest—A Forum on Opportunities for Managing Impacts Through Carbon Storage

October 27, 2004, 1:00–4:45 p.m.
DoubleTree Hotel—Portland Lloyd Center

Media Contacts: Dan Postrel, Oregon Dept. of Forestry, (503) 945-7420
Jim Cathcart, Oregon Dept. of Forestry, (503) 945-7493
Rich Myhre, BKi (consultant), (510) 444-8707, x220

Public Invited to Free Portland Forum on Oct. 27 to Hear Experts Discuss Climate Change—Challenges and New Solutions

Scientists agree that climate change (also called global warming) has begun in the Pacific Northwest and that it will continue—and possibly speed up—over the next several decades. Some of the climate changes projected by scientists are more winter rain, earlier spring snowmelt in the mountains, hotter and drier summers, and increased sea level and storm surge. As a result, we could see more summer smog, water shortages, coastal erosion, and added stress on salmon.

In response, scientists, public officials, businesses, and conservation groups have teamed to work on solutions that will slow climate change and mitigate adverse impacts. This research team, known as the West Coast Regional Carbon Sequestration Partnership (WESTCARB; see www.westcarb.org), will hold a free public forum in Portland on October 27th so that people can learn about their work and can ask questions.

(MORE)

Task Leader for Terrestrial Storage: Oregon Department of Forestry
2600 State Street, Salem, Oregon 97310

NEWS RELEASE

The meeting will focus on "carbon storage," a set of new, safe technologies and land management practices that can capture and isolate carbon dioxide (CO_2) that would otherwise end up in the atmosphere and contribute to climate change. Carbon storage is also called "carbon sequestration." Carbon storage projects could become a source of revenue for public and private entities. Other benefits could include healthier forests, protection against wildfires, and increased energy production. WESTCARB members want the public to know more about carbon storage technologies so that they can better participate in public hearings and other venues discussing potential projects.

The October 27th, 1:00–4:45 p.m., event will be held at the DoubleTree Hotel—Lloyd Center, 1000 NE Multnomah, Portland. Parking will be free at the hotel's adjacent parking structure if you bring your "ticket" to the meeting for validation.

Led by the California Energy Commission, WESTCARB is one of seven research partnerships funded in part by the U.S. Department of Energy to describe regional carbon sequestration opportunities and to develop plans to test carbon storage on a limited scale. WESTCARB comprises more than 40 organizations from the public, private, and nonprofit sectors working together to keep carbon dioxide out of the atmosphere and thereby reduce mankind's impact on the climate. The Oregon Department of Forestry is leading WESTCARB's work to store more carbon in plants and soil (known as "terrestrial storage").

# # #

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP

Task Leader for Terrestrial Storage: Oregon Department of Forestry
2600 State Street, Salem, Oregon 97310

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP



NEWS RELEASE

FOR IMMEDIATE RELEASE

October 18, 2004

BUSINESS CALENDAR LISTING

Climate Change in the Pacific Northwest—A Forum on Opportunities for Managing Impacts Through Carbon Storage

October 27, 2004, 1:00–4:45 p.m.
DoubleTree Hotel—Portland Lloyd Center

Media Contacts: Dan Postrel, Oregon Dept. of Forestry, (503) 945-7420
Jim Cathcart, Oregon Dept. of Forestry, (503) 945-7493
Rich Myhre, BKi (consultant), (510) 444-8707, x220

A team of scientists, public officials, businesses, and conservation groups, known as the West Coast Regional Carbon Sequestration Partnership (WESTCARB; see www.westcarb.org), will hold a free public forum so that people can learn about "carbon storage," a set of new, safe technologies and land management practices that can capture and isolate carbon dioxide (CO_2) that would otherwise end up in the atmosphere and contribute to climate change (also known as global warming). Carbon storage is also called "carbon sequestration." The October 27th, 1:00–4:45 p.m., event will be held at the DoubleTree Hotel—Lloyd Center, 1000 NE Multnomah, Portland. Advance registration is not required. Parking will be free at the hotel's adjacent parking structure if you bring your "ticket" to the meeting for validation.

Led by the California Energy Commission, WESTCARB is one of seven research partnerships funded in part by the U.S. Department of Energy to describe regional carbon sequestration opportunities and to develop plans to test carbon storage on a limited scale. WESTCARB comprises more than 40 organizations from the public, private, and nonprofit sectors working together to keep carbon dioxide out of the atmosphere and thereby reduce mankind's impact on the climate. The Oregon Department of Forestry is leading WESTCARB's work to store more carbon in plants and soil (known as "terrestrial storage").

###

Task Leader for Terrestrial Storage: Oregon Department of Forestry
2600 State Street, Salem, Oregon 97310

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP



NEWS RELEASE

FOR IMMEDIATE RELEASE

October 18, 2004

INVITATION TO COVER

Climate Change in the Pacific Northwest—A Forum on Opportunities for Managing Impacts Through Carbon Storage

October 27, 2004, 1:00–4:45 p.m.
DoubleTree Hotel—Portland Lloyd Center

Media Contacts: Dan Postrel, Oregon Dept. of Forestry, (503) 945-7420
Jim Cathcart, Oregon Dept. of Forestry, (503) 945-7493
Rich Myhre, BKi (consultant), (510) 444-8707, x220

WHO: A team of scientists and engineers from more than 40 organizations in the public, private, and nonprofit sectors—known as the West Coast Regional Carbon Sequestration Partnership (WESTCARB; see www.westcarb.org)—working to keep carbon dioxide (CO_2) out of the atmosphere and thereby reduce mankind's impact on the climate. The Oregon Department of Forestry is leading WESTCARB's work to store more carbon in plants and soil (known as "terrestrial storage").

WHAT: A free public forum where people can learn about "carbon storage," a set of new, safe technologies and land management practices that can capture and isolate carbon dioxide that would otherwise end up in the atmosphere and contribute to climate change (also called global warming). Carbon storage is also called "carbon sequestration." Speakers include scientists from universities and national laboratories, representatives from the Washington governor's office and the Oregon Dept. of Energy, a program manager from the U.S. Department of Energy, a PacifiCorp executive, and a consultant.

(MORE)

Task Leader for Terrestrial Storage: Oregon Department of Forestry
2600 State Street, Salem, Oregon 97310

NEWS RELEASE

WESTCARB members want the public to know more about carbon storage technologies so that they can better participate in public hearings and other venues discussing potential carbon storage projects.

WHEN: Wednesday, October 27th, 1:00–4:45 p.m.

WHERE: DoubleTree Hotel & Executive Meeting Center—Portland Lloyd Center, 1000 NE Multnomah, Portland. Parking will be free at the hotel's adjacent parking structure if you bring your "ticket" to the meeting for validation.

WHY: Scientists agree that climate change has begun in the Pacific Northwest and that it will continue—and possibly speed up—over the next several decades. This could result in more summer smog, water shortages, coastal erosion, and added stress on salmon. In response, WESTCARB is working on solutions that will slow climate change and mitigate adverse impacts.

# # #

WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP

Task Leader for Terrestrial Sequestration: Oregon Department of Forestry
2600 State Street, Salem, Oregon 97310

Appendix XVIII, Final Report

Action Plan for Phase II Public Outreach

Deliverable associated with Task 3.0, Item 3

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Prepared by:
Richard J. Myhre, P.E.

March 14, 2005
with editor's notes from July 2006

DOE award no. DE-FC26-03NT41984

Submitted by:
Larry Myer
PIER Program
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Prepared by:
Richard J. Myhre, P.E.
Bevilacqua-Knight, Inc.
1000 Broadway, Suite 410
Oakland, CA 94607

Deliverable Mapping

This action plan constitutes the required WESTCARB Phase I deliverable associated with Task 3.0, Implement Public Outreach, Item 3 (“an action plan”). Note that there are companion action plans for implementation of Phase II pilot projects and identification and resolution of Phase II technology deployment issues.

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Introduction

The West Coast Regional Carbon Sequestration Partnership (known as WESTCARB) is one of seven partnerships established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of North America.



Accordingly, WESTCARB is exploring the opportunities in six Western states and one Canadian province for removing CO_2 from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted, both of which will help slow the atmospheric buildup of this greenhouse gas.

WESTCARB is identifying the major sources of man-made CO_2 in its territory; assessing the status and cost of technologies for separating CO_2 from process and exhaust gases at large industrial plants; determining the potential for storing captured CO_2 in leak-proof geologic formations; establishing the extent to which changes in the management of forests, rangelands, and agricultural lands could increase carbon storage by plants and soil; assessing the logistics and costs of building pipelines to move CO_2 from the points of capture to the points of storage; and summing the results of cost estimates for capture, transportation, and storage to create carbon storage "supply curves."

Led by the California Energy Commission, WESTCARB's Phase I partners include about 50 organizations from state and provincial resource management and environmental protection agencies; national laboratories and research institutions; colleges and universities; conservation non-profits; oil and gas companies; power companies; pipeline companies; trade associations; vendors and service firms; and consultants.

One product of WESTCARB's Phase I public outreach activities is a plan for the Phase II public outreach activities, both generally and in relation to geologic and terrestrial sequestration pilot projects.

Specific WESTCARB pilot projects, developed in Phase I, and to be conducted during Phase II include:

- Conducting two CO_2 storage pilot tests at a gas reservoir leased by Calpine and the underlying saline formation. [Editor's Note: Rosetta Resources became our industrial match partner for this project with the acquisition of Calpine Rio Vista area gas rights in mid-2005.] In addition to

information on the safety and viability of these sequestration options, they will provide valuable data on monitoring and verification technologies, permitting in California, and the efficacy of public outreach efforts.

- Conducting a CO_2 storage pilot test in northern Arizona (site TBD, but expected to be near a Salt River Project coal-fired power plant) to demonstrate the safety and feasibility of CO_2 storage in saline formations in Arizona's portion of the vast Colorado Plateau region, obtain data on monitoring and verification technologies, and gain experience with regulatory permitting and public outreach associated with CO_2 storage in a saline formation in Arizona.

- Performing an in-depth assessment of the storage potential for two additional geologic formations with significant storage potential in the WESTCARB region.

- Conducting two pilot projects in Lake County, OR, and Shasta County, CA, that will test the following options for terrestrial sequestration: afforestation of once-forested lands now used for agriculture or grazing, forest fuel load reduction for improved fire management (i.e., reducing the probability of uncharacteristically severe wildfires and accompanying massive CO_2 releases), and improved forest conservation management.

- Identifying candidate sites for future terrestrial pilot projects in Washington and Arizona.

This action plan describes WESTCARB's approach to successfully communicating results of these pilot projects and continued regional characterization activities.

Public Outreach Strategy for Geologic Pilot Projects

In preparation of the detailed project management plan for each pilot, and in conjunction with planning for environmental review and permitting, members of WESTCARB's Public Outreach Committee will meet with technical and public affairs representatives from the pilot host organization(s) to develop public outreach objectives, strategies, roles and responsibilities, activities, and points of contact for the project. Such plans will seek to gain stakeholder "buy in" for the project, and knowledge of local communities and any relevant histories or sensitivities will be key to successful outreach planning.

Communication activities are expected to include development of straightforward summaries of the project's goals/rationale, activities, timetable, possible impacts, associated safety precautions, and benefits (in both broad terms and to the local community). These materials will be disseminated to residents, elected and safety officials, clergy, chambers of commerce, union stewards, civic group leaders, publishers of local media, employees of the pilot host, landowners, educators, and other stakeholders and concerned parties. We also expect that speaking engagements and exhibition opportunities at local venues will figure prominently in the outreach plans.

Opinion leaders will be identified and engaged in dialogue early in the process—through face-to-face meetings wherever possible. Such sessions will be designed not just to inform, but also to find areas of mutual interest (e.g., expansion of local job opportunities), and to assure that all safety concerns are clearly understood by pilot project planners. WESTCARB will seek opportunities to show that the project is responsive to community concerns, ideally in ways that don't increase cost or hinder the project schedule (e.g., routing of CO_2 transporter deliveries to minimize inconvenience due to traffic congestion or noise). Where advisable, WESTCARB and the pilot host organizations may engage locally trusted "key stakeholder communication facilitators" to assure effective dialogue with community leaders and/or participate in negotiations regarding permit terms and conditions.

Local pilot outreach activities will be complemented by WESTCARB's general Phase II outreach activities, such as Web communications, creation of handout and mailing materials, annual Partnership meetings, major market and capital city media relations, etc.

To obtain an objective assessment of its public outreach activities (and to guide their refinement), WESTCARB will support independent university researchers conducting interviews and surveys to measure public perception of carbon sequestration in communities near Rio Vista, CA (i.e., with a local geologic pilot) vs. similar "control" communities without pilot projects, and the effectiveness of outreach materials (or endorsements by others) in educating the public, addressing their concerns, and influencing their opinion.

Public Outreach Strategy for Terrestrial Pilot Projects

In many regards, public outreach planning for the terrestrial pilots will be analogous to the geologic pilots. One key difference, however, is that terrestrial projects involve a suite of activities on multiple lands owned by multiple types of entities with varying objectives. Thus, their view of co-benefits and carbon-offset market values may differ as well. Accordingly, WESTCARB plans to engage industry associations to help prepare and disseminate project materials to the forest products industry and private commercial forest owners. [Editor's Note: Our candidates for this work are the Oregon Forest Resources Institute and the California Forest Products Commission, but contracts have not yet been awarded.]

Pilot project activities will be reported to the California Climate Action Registry. The Registry will use the pilot projects to "road test" the forest protocols it has developed for afforestation and conservation and may use the fuel treatment pilot activities to facilitate development of new protocols for fire management. Although the ultimate aim of the pilot projects is to register certified marketable emission reductions with the Registry, WESTCARB is generally seeking to demonstrate that the applicable forest protocols are practical and functionally effective. Validation by the Registry provides public visibility for project activities and responds to the concerns and interests of a broad range of stakeholders.

The Climate Trust in Oregon will also review WESTCARB's pilot projects, applying the additional "screening criteria" of a purchaser of carbon credits. Because the Climate Trust makes purchases using funds originating from companies satisfying regulatory requirements in Oregon, any activities submitted for actual credit sales must also satisfy Oregon regulatory requirements.

General Public Outreach

During Phase I, WESTCARB established a partnership website, westcarb.org, and produced numerous communications materials, including a fact sheet and meeting flyer, technical papers and posters, news releases, and PowerPoint presentations. WESTCARB also established Web access to some of its GIS-based maps of CO_2 emission sources, geologic formations suitable for CO_2 storage, and terrestrial carbon storage baselines and supply curves for various timeframes.

WESTCARB plans to continue all of these activities in Phase II and, as noted above, expand their scope to accommodate new information from the geologic and terrestrial sequestration pilot projects as well as continued characterization of the region. One area WESTCARB plans to step-up, in particular, is communications with executives and policymakers, assuring awareness of our activities and their potential benefits. We will build upon our successful

interaction with the Western Governors' Association to include other policy-influencing groups. We also plan to track climate-change-related initiatives within our region (both public and private sector) and any appointed boards or commissions studying issues that could affect public perception of carbon sequestration or the processes governing sequestration project permitting and/or carbon credit validation. Where appropriate, we will offer to provide technical information.

During Phase I, WESTCARB held a successful public meeting in Portland, OR, in conjunction with its annual business meeting for partners. Preparations for the meeting involved audience segmentation, communication channel analysis, and crafting of communications and media relations activities to reach target audiences. Post-meeting analyses suggested opportunities for improving key audience participation in future meetings. In Phase II, WESTCARB plans to hold four additional annual public meetings. Meeting locations could coincide with pilot locations, or they may be held in major metropolitan areas or capital cities of the various WESTCARB states (to broaden exposure and facilitate education of the public and affiliated professionals). [Editor's Note: Given that most pilot projects are in rural locations, WESTCARB annual business meetings will be held in major metropolitan areas within the region to reduce travel time and expense. Pilot-project-specific public meetings will be held in communities where the pilots are located.]

With the approval of DOE NETL and the California Energy Commission, WESTCARB will issue news releases and "invitations to cover" to select media in advance of the business and/or public meetings, and may host media events. WESTCARB may also submit op/ed pieces to selected media at appropriate times during Phase II and avail our Technical Director and other key personnel to reporters. [During Phase I, the publicity surrounding release of the movie *The Day After Tomorrow* gave our Technical Director a chance to be interviewed on TechTV and explain carbon sequestration as a climate change solution.]

WESTCARB will coordinate its outreach activities with other Regional Partnerships through the Outreach Working Group, select joint projects, and other venues. As noted, WESTCARB is also sponsoring independent public perception research, which will also be coordinated with other Regional Partnerships.

Public Outreach Committee

A Public Outreach committee will report to Technical Director Dr. Larry Myer during Phase II (see Table 1).

Table 1. Public Outreach Committee Members

Public Outreach Committee Members		
Name	**Organization**	**Role**
Sally Benson	LBNL	Public Interface, Committee Chair
Martha Krebs	CEC PIER	Strategy
Reid Edwards	LBNL	Strategy/Policy Issues
Barry Biediger	Utah AGRC	GIS Web Tools/NATCARB
Rich Myhre	BKi	Presentation Materials, Website, Committee Coordinator
Chico Hunter	SRP	Northern Arizona Pilot Permitting/Outreach
Other Pilot Host Public Affairs Representatives	TBD	Strategy/Local Implementation

[Editor's Note: The current SRP public outreach committee representative is John Keane, not Chico Hunter.]

Public Outreach Schedule

Many public outreach activities are ongoing in nature (e.g., website maintenance, responding to inquiries) or recurring (e.g., WESTCARB annual meeting, quarterly and semi-annual progress reports to DOE). Other activities are linked to the schedules for pilot projects and are governed by overall progress on the pilots. Appendix A lists the activities as described in the Phase II Statement of Project Objectives (SOPO).

Appendix A: Public Outreach Activities in Phase II SOPO

Subtask 1.4 Public Outreach

Public outreach activities will center on partnership-level communications. Core activities will include communications will include developing specific plans for pilot projects, informing press and key government contacts of WESTCARB activities, maintaining and improving the WESTCARB website and related resources, considering opportunities to partner with universities to develop educational materials on sequestration, and holding annual stakeholder meetings. The 2nd-level subtasks describing this work appear in Table A-1.

Table A-1. 2nd-level subtasks associated with Subtask 1.4

Subtask	Description
Subtask 1.4.1	**Partnership-level external communications.** Develop Phase II public outreach plan establishing strategic goals, linkage of activities to goals, schedule/budget, and metrics for success; maintain content on westcarb.org website; expand website to include sections on each pilot; coordinate with pilot hosts; track/recommend submission of technical papers by WESTCARB members to appropriate scientific, business/trade, and policy journals; track/recommend major market media relations activities by WESTCARB members and pilot hosts; edit and/or refine graphics for WESTCARB member articles/presentations, as directed by the WESTCARB Technical Director; support DOE PEIS public meetings and related DOE RCSP program-level outreach
Subtask 1.4.2	**WESTCARB annual public/business meetings (4).** Program content planning; logistical planning and on-site support; presentation and handout materials; results documentation; publicity and media relations (strategy development, flyers/mailings, news releases, op/ed articles/interviews)
Subtask 1.4.3	**DOE Outreach Working Group participation.** Prepare for and participate in monthly conference calls; participate in joint activities (e.g., discussions with topical experts, RCSP-wide standard communications development, conference papers, etc., as determined by the group); participate in annual meetings of the group (e.g., at DOE Carbon Capture and Sequestration Conference)
Subtask 1.4.4	**Pilot-specific public outreach planning.** Advise pilot host public affairs reps during their development of strategy for gaining public acceptance and satisfying NEPA requirements for public notification/involvement; advise host reps during formulation of their plan for communications over the course of the pilot (e.g., media events/interviews; speeches to local chapters of technical, business, and civic organizations; activities/tours for local K-12 schools and community colleges); provide partnership-level communications material to support hosts' plans; advise host reps on plans to document pilot project successes (e.g., video footage) to build public outreach tools for use in subsequent expansion phases or other projects.

Subtask	Description
Subtask 1.4.5	**Key stakeholder communications facilitation.** Facilitate discussions with influential stakeholder groups regarding pilot permit approval and public acceptance; communicate WESTCARB (DOE/CEC) results/accomplishments and their benefits to opinion leaders and policymakers; track emerging climate change policy studies/deliberations to assure opportune communication of WESTCARB accomplishments, plans, and collaboration possibilities
Subtask 1.4.6	**Public perception research.** Support independent university researchers conducting interviews and surveys to measure public perception of carbon sequestration in communities with geologic pilot facilities vs. those without, and the effectiveness of outreach materials (or endorsements by others) in educating the public, addressing their concerns, and influencing their opinion.

Appendix XIX, Final Report

Computer Algorithms for Data Analysis

Deliverable associated with Task 4.0, Item 1

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Principal Author:
Howard J. Herzog

September 30, 2005

DOE award no. DE-FC26-03NT41984

Submitted by:
Larry Myer
PIER Program
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1516 Ninth Street
Sacramento, CA 95814

Prepared by:
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Laboratory for Energy and the Environment
Massachusetts Institute of Technology
77 Massachusetts Avenue, Room E40-455
Cambridge, MA 02139-4307

This "read-me" document outlines the files on CD-ROM "41984-Task4-Item1". These computer files satisfy the required WESTCARB Phase I deliverable associated with Task 4.0, item 1 ("computer algorithms for data analysis"). Table 1 (below) lists the computer programs developed by Massachusetts Institute of Technology (MIT) for WESTCARB's CO_2 capacity analysis, properties calculations, and source-sink matching,. Tool documentation and descriptions of these analyses can be found both under the CD-ROM directory "Tool Documentation" (note: this documentation was performed under DOE contract DE-FC26-02NT41622 but is included here for the user's information) as well as in

the WESTCARB topical report entitled "West Coast Regional Carbon Sequestration Partnership CO_2 Sequestration GIS Analysis". Computer codes and spreadsheet are located under the directory "Tool".

Table 1. Computer programs by MIT

Tool	**Format on CD**
CO_2 Property Calculator	Computer Codes
CO_2 Storage Capacity Calculator	Computer Codes based on ArcGIS Software, Documentation
CO_2 Source-Sink Matching	Computer Codes based on ArcGIS Software, Documentation
CO_2 Capture Cost Modeling	Spreadsheet, Documentation

Appendix XX, Final Report

West Coast Regional Carbon Sequestration Partnership
CO_2 Sequestration GIS Analysis

Topical Report

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

Principal Author:
Howard J. Herzog

September 30, 2005

DOE Contract No.: DE-FC26-03NT41984

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Abstract

This report presents the Geographic Information System (GIS) analysis part of the Phase I study of the West Coast Regional Carbon Sequestration Partnership (WESTCARB). In this report, GIS software and other tools were used to characterize the WESTCARB region and assess its carbon sequestration potential. The WESTCARB member states include Alaska, Arizona, California, Nevada, Oregon, and Washington.

In this report, we present:

- A summary of stationary carbon dioxide (CO_2) sources and the levels of emissions within the WESTCARB region,
- A first-order scoping analysis to determine the maximum CO_2 storage capacity of the carbon sinks within the WESTCARB region (except for Alaska),
- Methods for determining the CO_2 capture costs from the types of CO_2 sources included in the study,
- A methodology for estimating the requirements and costs of transporting CO_2 from the sources to the storage reservoirs,
- An initial matching between CO_2 sources and sinks in the WESTCARB region (except for Alaska) based on minimum straight-line distance, and
- A detailed source-sink matching analysis that is used to develop CO_2 sequestration marginal abatement cost curves. This analysis is restricted to California due to the limited availability of more expansive datasets. This type of analysis will be expanded to the entire WESTCARB region in Phase II.

It must be emphasized that this is only an initial analysis. It was based on the best information available during Phase I of the regional partnerships. This effort will be continued and improved in Phase II using more sophisticated tools and more detailed data sets.

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1 Executive Summary

This report presents the Geographic Information System (GIS) analysis part for the Phase I study of the West Coast Regional Carbon Sequestration Partnership (WESTCARB) in characterizing the CO_2 sequestration potential for the region. The following three components of carbon dioxide (CO_2) sequestration are evaluated in the study:

1. CO_2 source analysis,
2. CO_2 storage capacity estimation, and
3. CO_2 source-sink matching and sequestration cost.

As a first step, the study analyzed the information regarding the stationary CO_2 sources in the WESTCARB region. The data was compiled and stored as a database in the WESTCARB GIS server. The database includes information for 77 facilities from four categories with total annual CO_2 emissions of 159 million metric tonnes (Mt). Table ES-1 summarizes the CO_2 emissions from major stationary sources in the WESTCARB region by facility type and by state, respectively. The CO_2 emissions from power plants are actual 2000 CO_2 emissions from the eGRID database. Annual CO_2 emissions from cement plants and refineries are estimates based on production capacities. While the production capacities for gas processing facilities are all missing from the database, no CO_2 emissions are estimated for these facilities. Power plants are the single largest source of CO_2 emissions, accounting for more than 80 percent of the emissions from the stationary sources in the database. California has the highest annual CO_2 emissions in the region, representing over one-third of the regional total emissions, followed closely by Arizona.

Table ES-1. CO_2 emissions from stationary sources by facility type and state

	Power Plants		Cement		Gas Processing[d]		Refineries		Total	
State	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)	# of Facilities	CO_2 Emiss (Mt)
AK	6	2.3	0	0.0	3	0	3	2.6	12	4.9
AZ	7	48.3	2	1.4	0	0	0	0.0	9	49.7
CA	18	36.5	6	6.0	2	0	7	11.3	33	53.8
NV	6	24.8	3[a]	0.0	0	0	0	0.0	9	24.8
OR	3	7.4	2[b]	0.6	0	0	0	0.0	5	8.0
WA	3	12.1	3[c]	0.8	0	0	3	4.4	9	17.3
Total	**29**	**131.3**	**16**	**8.8**	**5**	**0**	**13**	**18.4**	**77**	**158.5**

[a]The WESTCARB database contains no production capacity data for cement in Nevada.
[b]Only one cement plant in Oregon has production data.
[c]Only two cement plants in Washington have production data.
[d]No production capacity data or CO_2 emission data is available for gas processing facilites.

The WESTCARB database contains two types of potential geological storage sinks for CO_2 sequestration: hydrocarbon (oil & gas) reservoirs and saline aquifers. For hydrocarbon reservoirs, the storage capacity estimation methods in the JOULE II report (Holloway *et al.*, 1996) were adapted as the baseline model in estimating the CO_2 storage capacity. The baseline model was

modified to accommodate the data deficiency problem in the database. The modified models were then applied to estimate the CO_2 storage capacity for each candidate hydrocarbon CO_2 sink based on the currently available information. However, the information for saline aquifers in the WESTCARB database is not complete enough to estimate the CO_2 storage capacity of these aquifers. Therefore, only the theoretical models for calculating the CO_2 storage capacity of saline aquifers were presented for future reference and no such capacities were actually calculated for candidate aquifer sinks.

After identifying the CO_2 sources and candidate sinks, the study then evaluated the CO_2 sequestration potential in the WESTCARB region by analyzing the matching between sources and sinks. Figure ES-1[1] shows the distribution of CO_2 sources and sinks that were considered in the source-sink matching analysis. After limiting to CO_2 sources in the contiguous-U.S. part of the WESTCARB region and excluding sources without CO_2 emission data, a total of 58 CO_2 sources were studied in the source-sink matching analysis. These 58 CO_2 sources include 10 coal-fired power plants, 27 gas-fired power plants, 11 cement plants and 10 refineries, with an annual amount of 184 Mt CO_2 to be sequestered[2].

As a preliminary analysis, the study performed a straight-line distance-based matching for the entire contiguous-U.S. part of the WESTCARB region, connecting each source to its closest sink in terms of straight-line distance. In this preliminary exercise, neither the optimal pipeline path nor the sink's storage capacity constraints were considered. The straight-line distance matching analysis was performed for each of the three different groups of eligible sinks and a combination of them altogether (see Tables ES-2 and ES-3). Given that the WESTCARB server lacked sufficient data to evaluate the CO_2 sequestration potential for Nevada, the matching exercises were performed under two scenarios: with and without Nevada saline aquifers. Table ES-2 and Table ES-3 summarize the matching results under the two scenarios in terms of annual CO_2 storage capacity by marginal straight-line distance. If enhanced oil recovery (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 50 km (31 mi) away while about one half of the sources could be matched with a sink that is less than 250 km (155 mi) away. If all sink types, including Nevada sinks, were considered for sequestration, however, more than four-fifths of CO_2 sources could be matched with appropriate sinks within 50 km (31 mi). However, there are still some sources that cannot be matched to any sinks that is within 250 km (155 mi) from the sources.

[1] All the maps presented in this report include all WESTCARB member states except Alaska.

[2] The annual amount of CO_2 to be sequestered differs to the 159 Mt annual emissions reported previously. The 184 Mt $CO_2$was estimated under the following three assumptions: (1) an 80% operation capacity for power plants; (2) full production capacity for non-power stationary CO_2 sources; and (3) a capture efficiency of 90% for all sources.

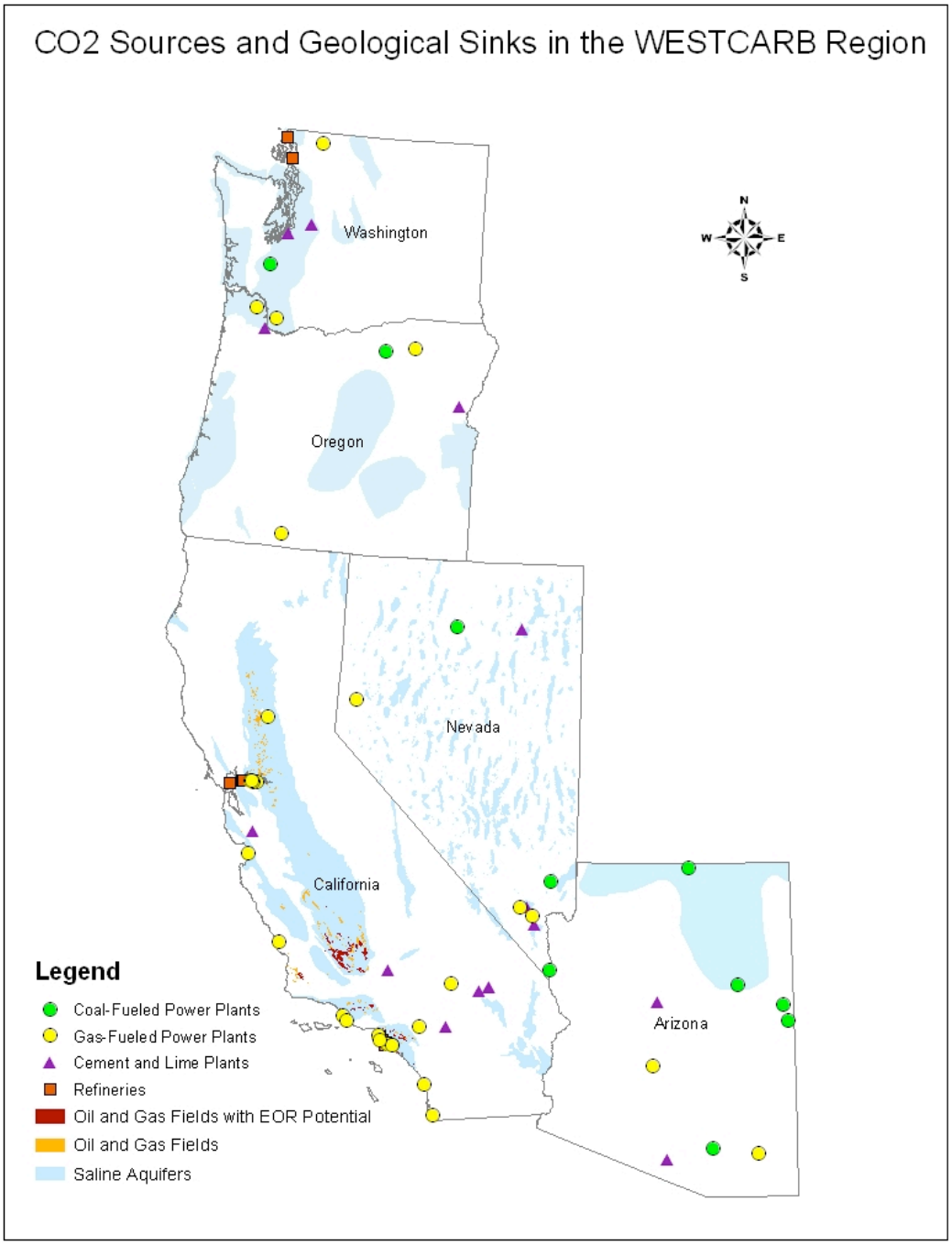


Figure ES-1. CO_2 sources and sinks in the WESTCARB region

Table ES-2. CO_2 storage capacity (Mt/yr) by marginal straight-line distance to nearest sink; Nevada aquifers included

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in WC Region	154	174	176
All Sinks	154	174	176

Note: The CO_2 storage rate was 184 Mt/yr.

Table ES-3. CO_2 storage rate (Mt/yr) by marginal straight-line distance to nearest sinks; Nevada aquifers excluded

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km or less	100 km or less	250 km or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in WC Region Excluding Navada	139	168	176
All Sinks	139	168	176

Note: The CO_2 storage rate was 184 Mt/yr.

This study further presented a GIS-based method of matching sources and sinks considering the optimal pipeline route selection and sink's capacity constraint. The pipeline construction costs vary considerably according to local terrains, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks. In order to account for such obstacles, the locations and characteristics of these obstacles were loaded into the spatial database and were used to construct a single aggregate transportation obstacle layer. In contrast to the distance-based matching analysis, this least-cost matching analysis links each CO_2 source to a least-cost geological sink based on the sum of the transportation costs associated with the least-cost path and the injection cost subject to the sink's capacity constraint. An iterative algorithm was used to approximate an optimal system solution. Due to the limited availability of detailed sink data for the WESTCARB region, this least-cost matching analysis was only performed for California where the sink data set is relatively rich.

The least-cost source-sink matching analysis for California was conducted in two stages. In the first stage, only 35 EOR sites with storage capacity over 20 Mt[3] were included as candidate sinks, which results in an overall storage capacity of 3.2 giga metric tonnes (Gt). The amount of CO_2 that needs to be sequestered from the 31 CO_2 sources in California over 25 years was estimated

[3] Most of the CO_2 sources will emit more than 20 Mt CO_2 over the 25-year project lifetime.

to be 2.1 Gt. The cost calculation assumed a credit of $16/metric tonne (t) CO_2 for EOR injection and omitted the injection cost. With the assumption of a constant CO_2 credit, the optimization algorithm only considers minimizing the overall transportation of the network system. Figure ES-2 shows the marginal per-tonne CO_2 transportation cost by annual CO_2 storage rate in oil fields with EOR potential. As the CO_2 storage capacity in the EOR sinks was larger than the 25-year CO_2 flow, all the sources were connected to their corresponding least-cost EOR sinks. The transportation costs for most of the sources are below $10/t CO_2 except for a few outliers.

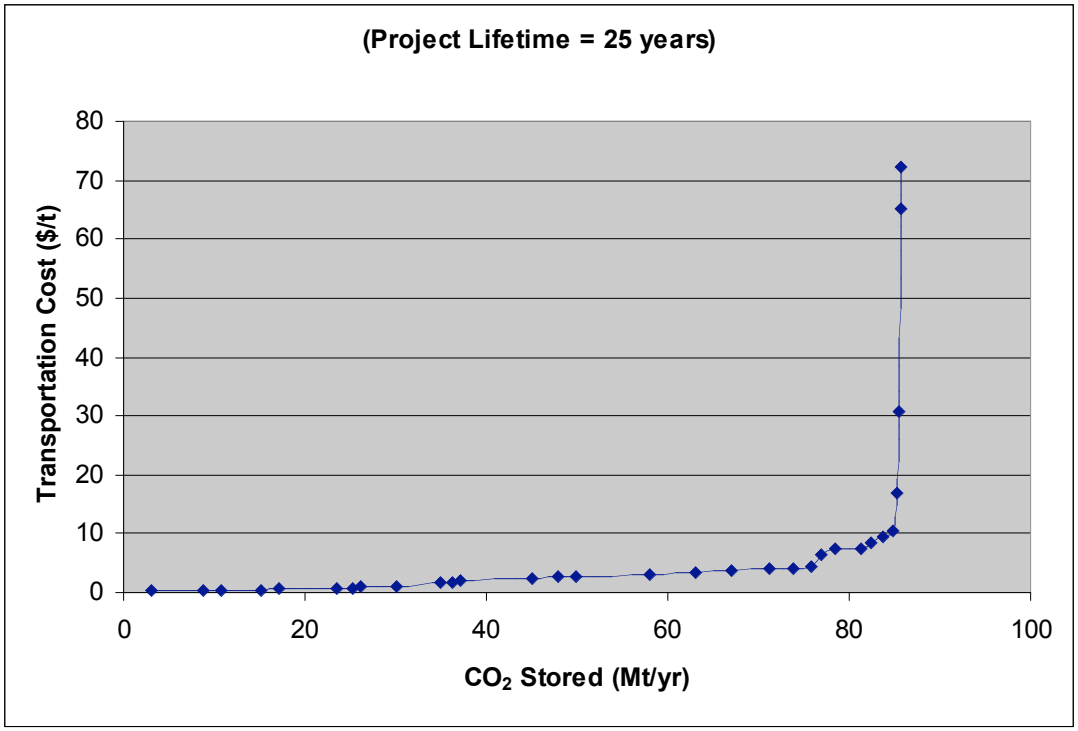


Figure ES-2. Marginal transportation cost by annual CO_2 storage rate in oil fields with EOR potential, California

Only four sources had transportation costs to the closest EOR site greater than the credit value of $16/t CO_2. For the second stage of least-cost source-sink matching analysis for California, a new round of source-sink matching was applied to these four sources with the same algorithm as before, but using the oil and gas fields without EOR potential and saline aquifers suitable for CO_2 storage in California as the sink layer instead. A final check was run to conduct a full-cost comparison to decide whether they should be matched to EOR or non-EOR sinks. Except for the source with transportation to EOR site of $16.8/t CO_2 that remained to be connected to its EOR destination, the other three sources were reassigned to saline aquifers instead because of the lower full costs.

Figure ES-3 shows the marginal full sequestration cost by annual CO_2 storage rate. For sources matched with EOR sites, the full cost estimate included costs for capture and transportation, net

of an EOR credit. For sources matched with non-EOR hydrocarbon fields or aquifers, the full cost estimate included costs for capture, transportation, and injection. The results of the full cost sequestration analysis in California indicate that 20, 40, or 80 Mt of CO_2 per year could be sequestered in California at a cost of $31/t, $35/t, or $50/t, respectively.

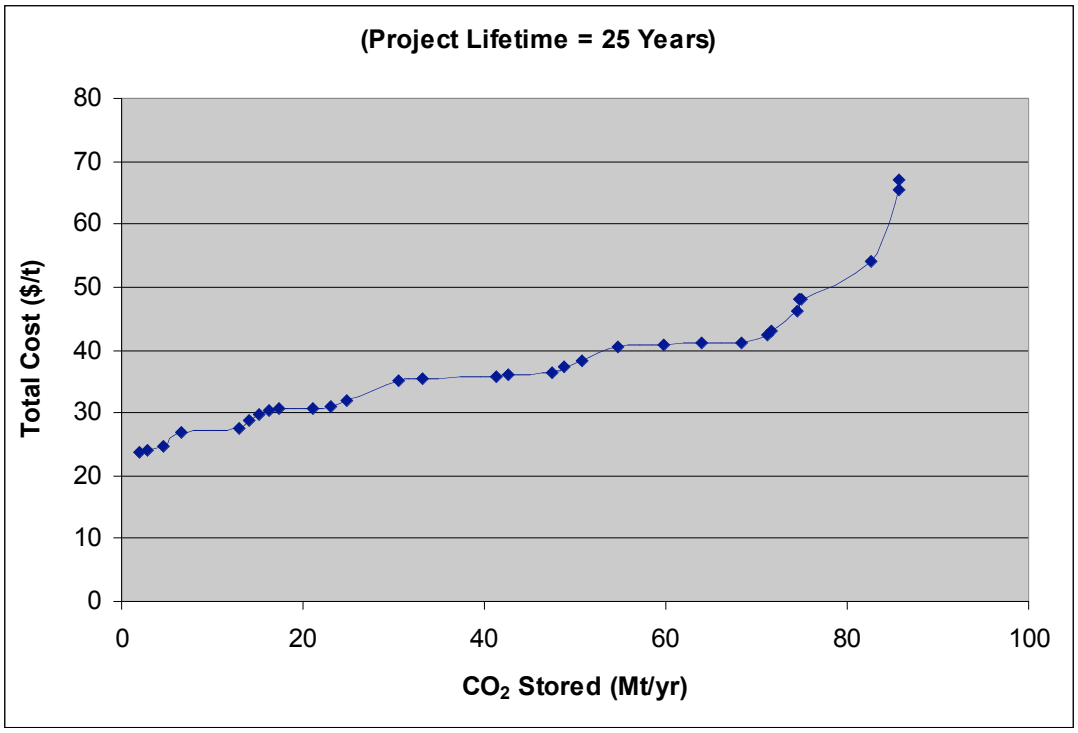


Figure ES-3. Marginal total cost by annual CO_2 storage rate, California

2 Experimental

This project involves computer modeling and there is no laboratory work associated with this project.

3 Results and Discussions

3.1 Stationary CO_2 Sources in the WESTCARB Region

This report summarizes the CO_2 source database contained in the WESTCARB database. The database contains the location and capacities of the major stationary sources of CO_2 in the WESTCARB study area.

The database contains the following four major types of stationary sources:

- Power plants,

- Cement plants,
- Gas processing facilities, and
- Refineries.

3.1.1 Fossil-Fuel Power Plants

The WESTCARB database used for analysis contains information regarding fossil-fuel power plants in the member states for the year 2000. The database contains information about each facility including location, ownership, generating capacity, fuel type, annual electricity production, and annual emissions. The capacity and CO_2 emissions data are from the eGRID database and are for the year 2000. Table 1 summarizes the fossil-fuel power plants in the WESTCARB region by state. In the database, Alaska is the only state in the WESTCARB region with oil-fired power production facilities. Figure 1 plotted these fossil power plants in the contiguous-U.S. part of the WESTCARB region by type, location, and annual CO_2 emissions. As can be seen in the map, all the power generation facilities in California power in the database are gas-fired.

Table 1. Power generation capacity and CO_2 emissions by fuel and state (2000)

	Gas			Oil			Coal		
State	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)	Number	Capacity (MW)	CO_2 Emissions (Mt)
AK	2	684	1,686	3	193	342	1	28	261
AZ	2	1,173	4,931	0	0	0	5	5,745	43,394
CA	18	17,973	36,450	0	0	0	0	0	0
NV	3	1,835	4,575	0	0	0	3	2,769	20,191
OR	2	1,207	3,400	0	0	0	1	560	3,999
WA	2	494	1,758	0	0	0	1	1,460	10,345
Total	**29**	**23,366**	**52,800**	**3**	**193**	**342**	**11**	**10,562**	**78,189**

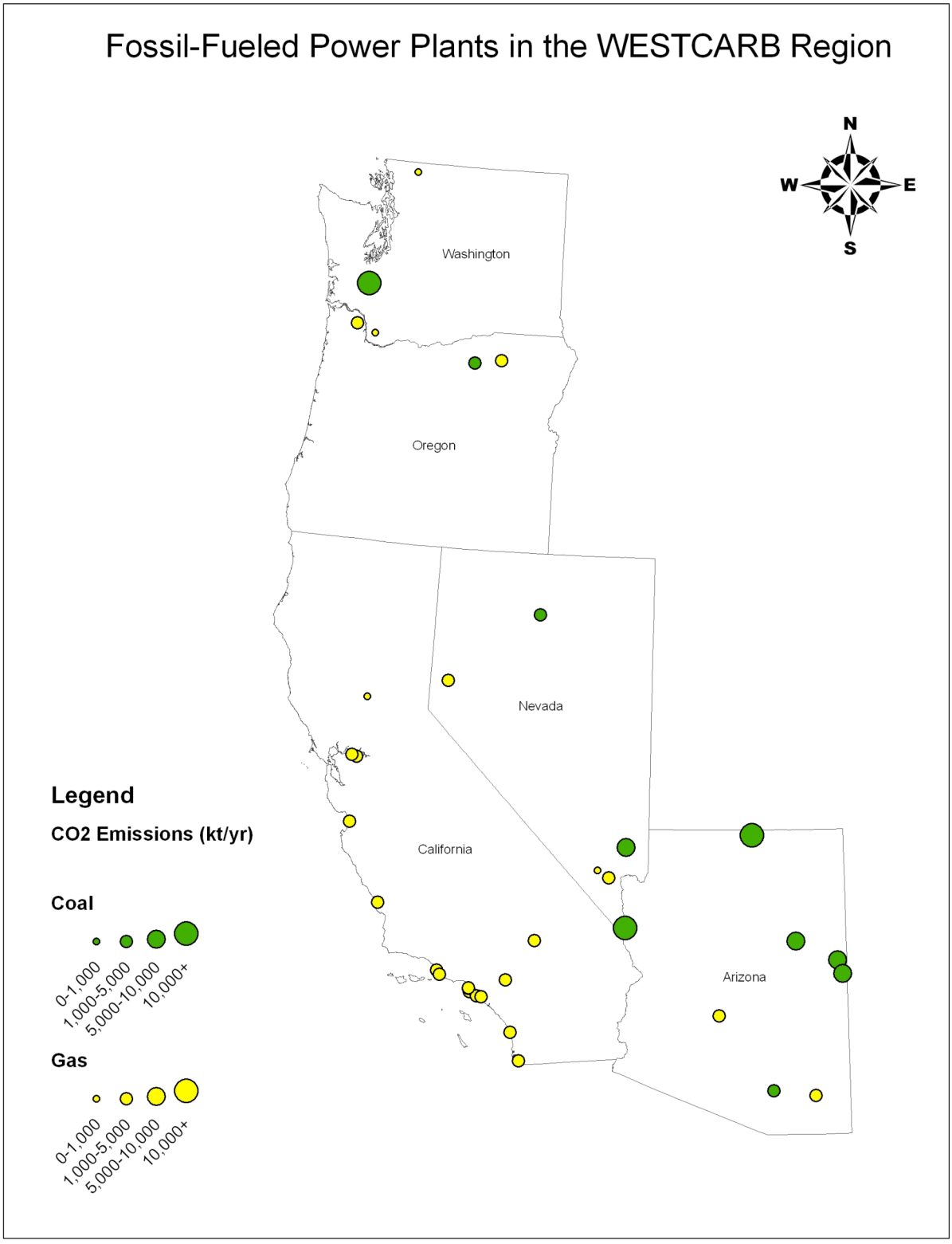


Figure 1. Fossil-fueled power plants in the WESTCARB region

3.1.2 Non-Power Stationary CO_2 Sources

The WESTCARB database contains three major non-power stationary CO_2 sources: cement plants, gas processing facilities, and refineries. Figure 2 shows the geographical distribution of these non-power stationary CO_2. This section briefly summarizes each type of these non-power stationary CO_2 sources in the database.

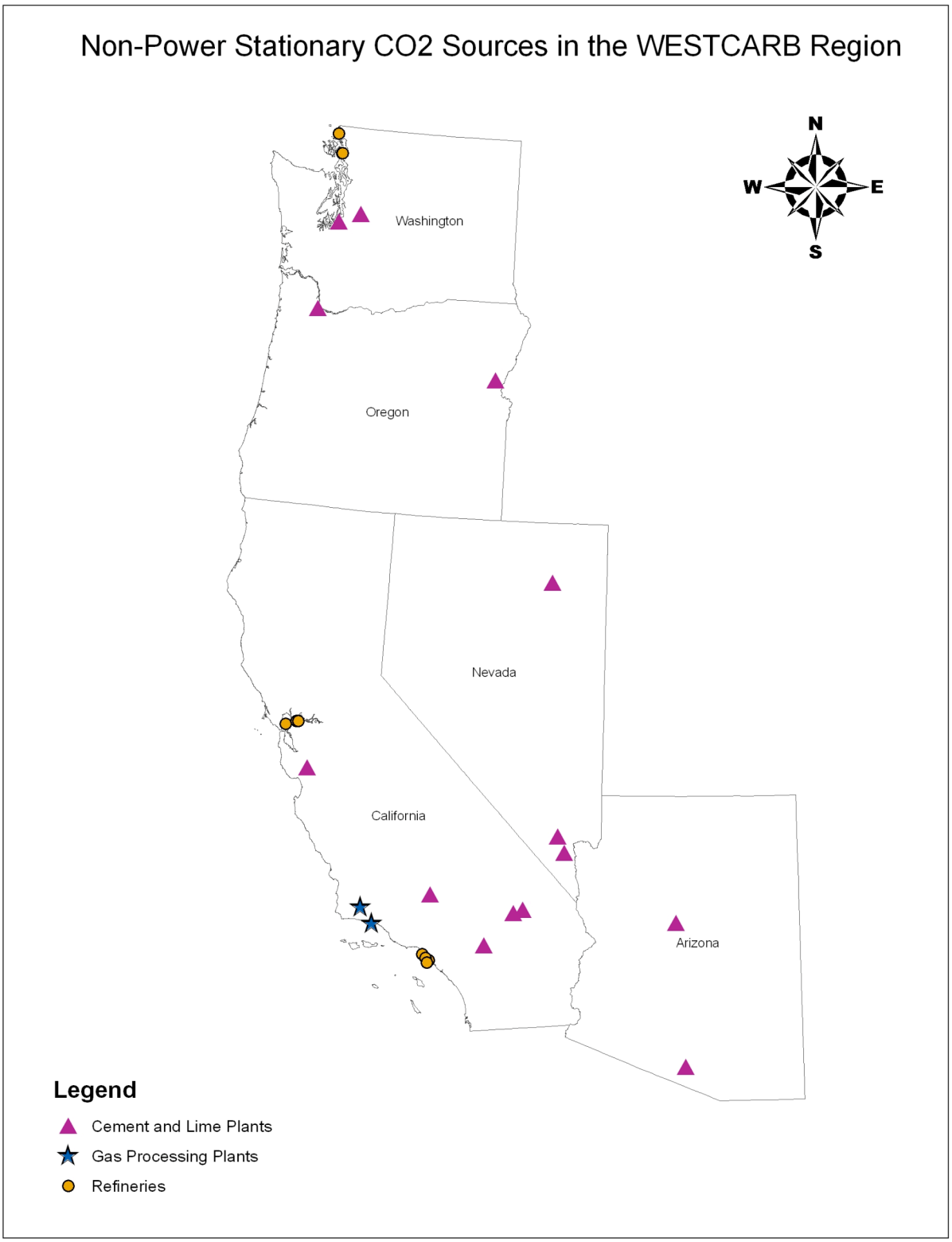


Figure 2. Non-power CO_2 Sources in WESTCARB region

3.1.2.1 Cement Plants

Table 2 summarizes the data for cement plants in the WESTCARB database by state. The database contains information for 16 facilities. California has the most production facilities with 6,650 kt of annual cement production capacity with total estimated emissions of 6,016 kt of CO_2.

Table 2. Cement and lime plant capacity and estimated CO_2 emissions by state

State	Number	Capacity (kt/yr)	Estimated CO_2 Emissions(kt/yr)
AK	0	0	0
AZ	2	1,574	1,424
CA	6	6,650	6,016
NV	3[a]	0	0
OR	2[b]	660	597
WA	3[c]	855	774
Total	**5**	**9,739**	**8,811**

[a]The WESTCARB database contains no production capacity data for cement in Nevada.
[b]Only one cement plant in Oregon has production data.
[c]Only two cement plants in Washington have production data.

3.1.2.2 Gas Processing Facilities

Table 3 summarizes the data for gas processing facilities in the WESTCARB database by state. To date, the WESTCARB database only contains five gas-processing facilities in two states. But even for these facilities, no data on production capacity or CO_2 emissions is available.

Table 3. Gas processing capacity and estimated CO_2 emissions by state

State	Number	Capacity (MMCFD)[a]	Estimated CO_2 Emissions (kt/yr)[a]
AK	3	0	0
AZ	0	0	0
CA	2	0	0
NV	0	0	0
OR	0	0	0
WA	0	0	0
Total	**5**	**0**	**0**

[a] No production capacity data or CO_2 emission data is available in in the WESTCARB database.

3.1.2.3 Refineries

Table 4 summarizes the data for refineries in the WESTCARB database by state. The database also lists refineries for Alaska, California, and Washington, with California having the largest share of production capacity and CO_2 emissions in refineries.

Table 4. Refinery capacity and estimated CO_2 emissions by state

State	Number	Capacity (1000 barrels / stream day)	Estimated CO_2 Emissions (kt/yr)
AK	3	317	2,642
AZ	0	0	0
CA	7	1,356	11,312
OR	0	0	0
NV	0	0	0
WA	3	485	4,046
Total	**13**	**2,158**	**18,000**

3.2 WESTCARB CO_2 Storage Capacity Analysis

This section presents the theoretical principles supporting the baseline estimation of CO_2 storage capacity in the WESTCARB region. Methods were developed to estimate the CO_2 storage capacity of three different types of geological sinks:

- Hydrocarbon (oil & gas) reservoirs,
- Saline aquifers, and
- Coalbeds.

These methods were integrated into software tools for use with ArcGIS modeling software. These standardized capacity tools were then used with the collected WESTCARB data to estimate the CO_2 storage capacity of the geological sinks in the study region. Due to data availability, this Phase I study only evaluates the CO_2 storage capacity in hydrocarbon reservoirs in the state of California. It will be extended to saline aquifers and coalbeds in Phase II when more detailed data sets are available.

The storage capacity estimation methods in the JOULE II report (Holloway *et al.*, 1996) were adapted as the baseline models in estimating the CO_2 storage capacity for hydrocarbon reservoirs and saline aquifers, while the methodology developed by Reeves (2003) was used as the baseline model in estimating the CO_2 storage capacity for coalbeds. These baseline models were modified to accommodate the availability of information.

3.2.1 CO_2 Storage in Hydrocarbon Reservoirs

3.2.1.1 CO_2 Storage Capacity of Hydrocarbon Reservoirs

A significant amount of pore space is vacated in underground hydrocarbon reservoirs when hydrocarbons are produced from the reservoir. CO_2 can be stored in the pore space left vacant by the hydrocarbon production. The CO_2 storage capacity of each reservoir depends on the amount of hydrocarbon fuel produced from the reservoir, with the total expected future storage capacity dependant on the total expected hydrocarbon production. In order to estimate storage capacity, an assumption was made in this study that the entire underground volume of the hydrocarbons produced from a reservoir can be replaced by CO_2. Therefore, the future CO_2 storage capacity of a hydrocarbon reservoir can be calculated from *the underground volume of the ultimately recoverable oil and gas*.

Not every hydrocarbon reservoir is suitable for CO_2 storage, and reservoirs were only analyzed for CO_2 storage if the initial pressure and temperature were above the critical point of CO_2. If the pressure and temperature of the reservoir were unknown, the reservoirs were only analyzed if they were at a depth of 3,000 feet (915 meters) or greater. The generalized theoretical formula adopted in estimating the CO_2 storage capacity of a hydrocarbon field with depth over 3,000 ft (915 m) can be expressed as:

$$Q_{CO2} = (V_{Uoil} + V_{Ugas}) * \rho_{CO_2}, \quad (1)$$

where Q_{CO2} = CO_2 storage capacity (Mt CO_2),
V_{Uoil} = underground volume of the ultimately recoverable oil (km^3),
V_{Ugas} = underground volume of the ultimately recoverable gas (km^3), and
ρ_{CO_2} = CO_2 density at the reservoir conditions (kg/m^3).

The CO_2 density at the reservoir conditions was calculated using correlations from Altunin (1975) that assume that the CO_2 density is a function of the pressure and temperature of the reservoir[4].

The underground volumes of oil and gas in equation (1) are calculated from the standard volumes of oil and gas based on the following conversion formula:

$$V_{Uoil} = V_{oil(st)} * B_o, \text{ and} \quad (2)$$

$$V_{Ugas} = V_{gas(st)} * B_g, \quad (3)$$

where $V_{oil(st)}$ = volume of oil at standard conditions (km^3),
$V_{gas(st)}$= volume of gas at standard conditions (km^3),
B_o = oil formation volume factor, and

[4] The CO_2 density was calculated using a computer code developed by Victor Malkovsky of the Institute of Geology of Ore Deposits, Petrography, Mineralogy and Geochemistry (IGEM) of the Russian Academy of Sciences, Moscow. We converted his FORTRAN code into Visual Basic.

B_g = gas formation volume factor.

In this study, a default B_o of 1.2 is applied for oil. B_g is estimated using the following equation:

$$B_g = (4.8\,P + 93.1)^{-1}, \quad (4)$$

where P = the reservoir pressure (MPa).

Data on the underground volume of the ultimately recoverable oil and gas in a field is generally not available, so equation (1) usually cannot be directly applied to estimate the CO_2 storage capacity of hydrocarbon fields. But in cases information on the amount of original oil in place (OOIP) or original gas in place (OGIP) is known, the ultimately recoverable oil or gas can be estimated as a proportion of OOIP or OGIP:

$$V_{Uoil} = V_{OOIP} * p_{oil}, \text{ and} \quad (5)$$
$$V_{Ugas} = V_{OGIP} * p_{gas}, \quad (6)$$

where V_{OOIP} = underground volume of original oil in place (km^3),
V_{OGIP} = underground volume of original gas in place (km^3), and
$p_{oil/gas}$ = volume percentage of OOIP/OGIP that are recoverable (%).

According to the JOULE II report, the average underground volumes of the ultimately recoverable oil and gas are approximately 35% of OOIP and 80-90% of OGIP, respectively. Therefore, when OOIP and OGIP information is available, equation (1), together with equations (5) and (6), gives the formula to estimate the CO_2 storage capacity in hydrocarbon fields.

3.2.1.2 The Adopted "Conservative" Approach

In most cases, information on the OOIP and OGIP for a reservoir is also not available. The best data that is available is the cumulative oil and gas production up to the date when the data was collected. To make use of this data, the cumulative production of oil and gas was used to replace the ultimately recoverable oil and gas in equation (1). This methodology will result in an underestimation of the CO_2 storage capacity, particularly for fields that are in early stages of production. However, this approach provides the ability to calculate consistent estimates of the CO_2 storage capacity for most of the oil and gas fields using available data. Using this methodology, equation (1) can be rewritten as:

$$\widetilde{Q}_{CO2} = (\widetilde{V}_{Uoil} + \widetilde{V}_{Ugas}) * \rho_{CO_2}, \quad (7)$$

where $\widetilde{Q}_{CO2}$ = CO_2 storage capacity (Mt CO_2),
$\widetilde{V}_{Uoil}$ = underground volume of the cumulative oil production (km^3), and
$\widetilde{V}_{Ugas}$ = underground volume of the cumulative gas production (km^3).

Equation (7) was then used as the baseline formula in estimating the CO_2 storage capacity for hydrocarbon reservoirs.

3.2.1.3 Categorizing the CO_2 Storage Potential for Hydrocarbon Reservoirs

Oil and gas reservoirs were classified into different types in terms of their depths and API gravities. Reservoirs that are at least 3000 ft[5] deep are under enough pressure for supercritical CO_2 injection, so this depth is used as an initial criterion for determining whether hydrocarbon fields have CO_2 storage potential. The API gravity, a measurement of oil density which indicates CO_2 miscibility, is used to determine the EOR potential for oil fields. Oil fields with API gravity more than 25^o are classified as fields with miscible CO_2-EOR potential. Oil fields with API gravity between 17.5^o and 25^o are classified as fields with immiscible CO_2-EOR potential. Based on these criteria, the oil fields can be divided into five categories:

1. Fields with miscible CO_2-EOR potential (depth > 3000 ft, API > 25),
2. Fields with immiscible CO_2-EOR potential (depth > 3000 ft, 17.5 < API < 25),
3. Fields with CO_2 storage potential but no EOR potential (depth > 3000 ft, API < 17.5),
4. Fields without CO_2 storage potential (depth < 3000 ft), and
5. Undetermined fields (depth or API missing).

The gas fields are classified into three categories based on the depth information:

1. Fields with CO_2 storage potential (depth > 3000 ft),
2. Fields without CO_2 storage potential (depth < 3000 ft), and
3. Undetermined fields (unknown depth).

3.2.1.4 CO_2 Capacity Estimation Results

The methods presented above were used to estimate the CO_2 storage capacity for oil and gas reservoirs included in the WESTCARB Phase I database (see Figure 3). The database only hosts complete oil and gas field data for the State of California, so we limited our capacity analysis to the state of California.

Panel A of Table 5 summarizes the CO_2 storage capacity for oil fields aggregated by the five categories mentioned above. There are 121 oil fields in California with miscible CO_2 EOR potential and 18 oil fields with immiscible CO_2 EOR potential. These fields with CO_2 EOR potential have a CO_2 storage capacity of 3.4 Gt. The storage capacity of non-EOR oil fields is trivial, amounting to roughly 0.2 Gt.

The CO_2 storage capacity of gas fields, screened by depth, was also estimated using the expression in equation (7). Panel B of Table 5 shows the storage capacity for gas fields aggregated by the three categories mentioned above. The result yielded 128 gas fields with a combined CO_2 storage capacity of 1.7 Gt.

[5] 3,000 ft (approx. 914 m) is chosen as a conservative depth threshold. Some studies suggest using 800 m as depth threshold. The result does not differ much from using 800 m as the depth threshold as few fields have depth between 800 m and 914 m.

Table 5. Estimates of CO_2 storage capacity in oil fields and gas fields, California

Fields Group	Number of Fields	Estimated Total Storage Capacity (Mt)
A: Oil Fields		
Oil fields with CO_2 storage potential	176	3,563
Oil fields with miscible CO_2-EOR potential	*121*	*3,186*
Oil fields with immiscible CO_2-EOR potential	*18*	*178*
Oil fields with CO_2 storage capacity but no EOR potential[a]	*37*	*199*
Oil fields without CO_2 storage potential	55	0
Oil fields without depth information	61	0
B: Gas Fields		
Gas fields with CO_2 storage potential	128	1,666
Gas fields without CO_2 storage potential	36	0
Gas fields without enough information	33	0

[a] Oil fields that lack API data are also included.

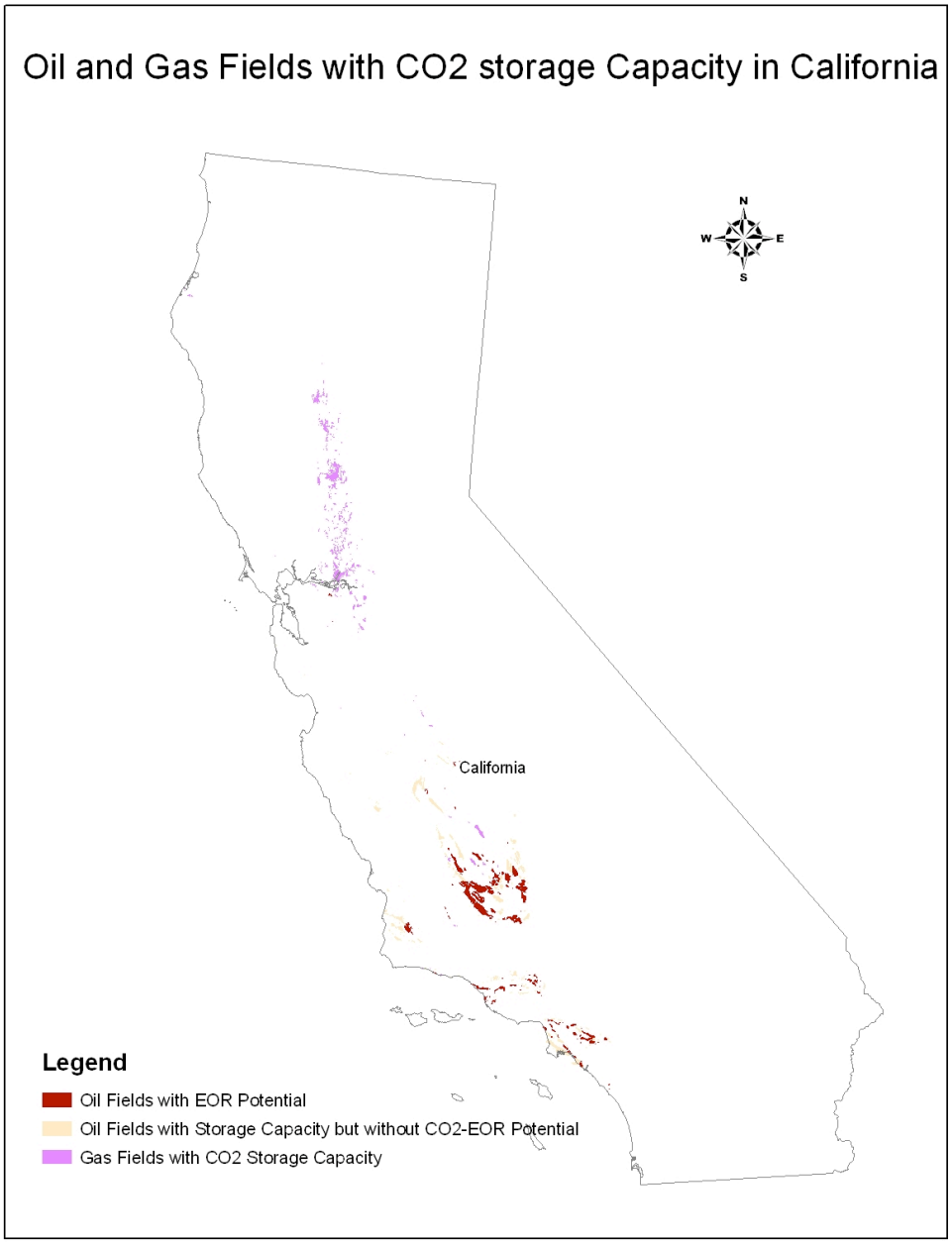


Figure 3. Oil and gas fields with CO_2 storage capacity in Phase I database

3.2.2 CO_2 Storage in Saline Aquifers

The WESTCARB database did not contain complete information for saline aquifers; therefore we are unable to estimate the CO_2 storage capacity of these aquifers in this report. Nonetheless, we include the theoretical model for calculating the CO_2 storage capacity of saline aquifers below.

Deep saline aquifers have the greatest CO_2 sequestration potential since they are the most common and most voluminous type of reservoirs. Two preliminary screening criteria are used to evaluate the CO_2 storage suitability of saline aquifers. The first screening criterion is similar to hydrocarbon reservoirs that the depth of the aquifer needs to be more than 800 m (2,624 ft) to ensure that the injected CO_2 can be kept at the supercritical phase. Second, the aquifer needs to have good seal properties so that the injected CO_2 can be sufficiently trapped in the aquifer.

If the above two screening criteria are satisfied, the CO_2 storage capacity of a saline aquifer can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO_2}, \quad (8)$$

where Q_{aqui} = storage capacity of entire aquifer (Mt CO_2),
V_{aqui} = total volume of entire aquifer (km^3),
p = reservoir porosity (%),
e = CO_2 storage efficiency (%), and
ρ_{CO_2} = CO_2 density at reservoir conditions (kg/m^3).

If accurate spatial data is available for an aquifer, the aquifer volume used in equation (8) can be calculated as an integral of the surface area and the thickness of the aquifer:

$$V_{aqui} = \sum_i S_i T_i, \quad (9)$$

where S_i is the area of the raster cell, and
T_i is the thickness of the cell.

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For the "closed" aquifer, the storage efficiency is assumed to be 2% (Holloway *et al.*, 1996).

The model will be applied to the WESTCARB region to estimate the CO_2 storage capacity of the saline aquifers when more detailed data is available in Phase II.

3.2.3 CO_2 Storage in Coalbeds

The WESTCARB database of Phase I did not contain enough detailed information for coalbeds to estimate the CO_2 storage capacity in the coalbeds. Nonetheless, we include the theoretical model for calculating the CO_2 storage capacity of coalbeds below. In Phase II of the study, efforts will be put into collecting detailed data to apply to the model.

The CO_2 storage capacity of coalbeds used for CO_2-enhanced coalbed methane recovery (ECBMR) operations can be estimated using a methodology based on work by Reeves (2003). The original methodology developed by Reeves is useful for estimates of storage capacity at the basin level. In this study, Reeves's methodology was adapted for use with data collected at the coalfield level.

The principle idea of the CO_2 disposal in coalbeds is that CO_2 can be adsorbed more readily onto the coal matrix than methane. Therefore, the CO_2-ECBMR operation involves absorbing the injected CO_2 at the expense of methane. The displaced methane can be recovered as a free gas at production wells.

The CO_2 storage potential of coalbed results from the two primary mechanisms listed below:

1. Storage capacity via methane replacement: In this process, the primary methane production is assumed to create a voidage in the coal reservoir which can be replaced by CO_2 up to the original pressure of the coal reservoir.
2. Incremental storage capacity via ECBMR: The secondary methane production through CO_2 injection produces additional methane which enables some additional CO_2 storage capacity.

Coalfields are categorized as either "commercial" or "non-commercial" according to the economic feasibility of producing methane from the field. "Non-commercial" areas are areas where ECBMR and CO_2 storage are technically feasible, yet unprofitable. "Commercial" coalfields are those where ECBMR operations are both technically and financially feasible. "Non-commercial" areas are usually deeper, have thinner coals, and are less permeable than the "commercial" areas. The storage capacity of "commercial" coalfields results from both primary and incremental methane replacement, whereas the capacity of "non-commercial" coalfields is from incremental methane replacement. Accordingly, different parameters are used to calculate the storage capacity of the two types of fields via ECBMR. The following two sections discuss details of the methodology for estimating the CO_2 storage capacity for "commercial" methane fields and "non-commercial" methane fields, respectively.

3.2.3.1 CO_2 Storage in "Commercial" Methane Fields

Storage Capacity via Methane Replacement

CO_2 storage capacity available due to methane displacement can be estimated using a coal-rank based ratio that specifies the ratio of the volume of CO_2 that can be injected per volume of CH_4 produced and the primary recovery factor of methane. Due to concerns about reservoir over-pressurization or the ability to gain adequate reservoir access, a voidage replacement efficiency factor (e) is used to reflect the percentage of void space occupied by CO_2.

$$Q_{replacement} = r * e * V_{OGIP} * PRF * \rho_{CO_2}, \qquad (10)$$

where $Q_{replacement}$ = CO_2 storage capacity via methane replacement,
r = CO_2/CH_4 ratio,
e = voidage replacement efficiency,
V_{OGIP} = original gas in place (volume in standard condition),
PRF = primary recovery factor of methane (%), and
ρ_{CO_2} = CO_2 density (in standard condition).

According to Reeves (2003), the baseline value of *e* is 0.75 and the baseline value of *PRF* is 65%. Column (2) of Table 6 gives the CO_2/CH_4 ratio based on the coal rank.

Incremental Storage Capacity via ECBMR

Additional CO_2 storage capacity due to the incremental methane production is estimated using a coal-rank based ratio and the ECBM recovery factor (expressed as a percentage of in-place resource at the start of CO_2 injection).

$$Q_{ECBM} = r * e * V_{OGIP} * (1 - PRF) * ERF * \rho_{CO_2}, \qquad (11)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery,
r = CO_2/CH_4 ratio,
e = voidage replacement and ECBMR efficiency factor,
V_{OGIP} = original gas in place (volume in standard condition),
PRF = primary recovery factor,
ERF = ECBM recovery factor, and
ρ_{CO_2} = CO_2 density (in standard condition).

The baseline values for *e* and *PRF* are 0.75 and 65%, respectively, while the *ERF* depends on the coal rank. Column (3) of Table 6 gives the ECBM recovery factor for each type of coal rank.

Overall Storage Capacity for "Commercial" Methane Fields

The overall CO_2 storage capacity for "commercial" methane fields is the sum of equation (10) and equation (11):

$$Q_{CO_2} = Q_{replacement} + Q_{ECBM}, \qquad (12)$$

Table 6. Coal rank, CO_2/CH_4 ratio, and ECBM recovery factors

(1) Coal Rank	(2) CO_2/CH_4 Ratio	(3) ECBM Recovery Factor ("Commercial" Methane Fields)	(4) ECBM Recovery Factor ("Non-Commercial" Methane Fields)
Low-volatile (LV)	1:1	50%	25%
Medium-volatile (MV)	1.5:1	55%	32%
High-volatile A (HVA)	3:1	61%	37%
High-volatile (HV)	6:1	67%	42%
Sub-bituminous (Sub)	10:1	100%	74%

3.2.3.2 CO_2 Storage in "Non-Commercial" Methane Fields

"Non-commercial' methane fields, though not economically viable for primary methane production, can generate room for CO_2 storage via CO_2-ECBMR. By substituting a zero for the PRF in equation (11), a modified version of the equation (13) can be used to estimate the CO_2 storage capacity for "non-commercial" methane fields.

$$Q_{ECBM} = r * e * V_{OGIP} * ERF * \rho_{CO_2}, \quad (13)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery,
R = CO_2/CH_4 ratio,
e = accessible portion of 'non-commercial' area,
V_{OGIP} = original gas in place (volume in standard condition),
ERF = ECBM recovery factor (%), and
ρ_{CO_2} = CO_2 density (in standard condition).

The default value for e for "non-commercial" methane fields is 0.5 (unlike 0.75 for "commercial" fields). Column (4) of Table 7 gives the ECBM recovery factor for "non-commercial" methane fields by coal rank, which is less than the corresponding ECBM recovery factor for "commercial" methane fields within each coal rank type.

3.2.3.3 The "Adopted" Approach to Estimate the CO_2 Storage Capacity for "Commercial" Methane Fields

Equations (10) and (13) use data on the original gas in place in order to estimate the CO_2 storage capacity of methane fields. Just like the case with hydrocarbon fields, however, this data is generally unavailable. For "commercial" methane fields, however, data usually available refer to the cumulative gas production to date. This cumulative gas production data is used as a lower bound of the ultimately recoverable gas—equivalent to the term "V_{OGIP}*PRF" in equation (10). By using this lower bound value of the ultimately recoverable gas, equation (14) gives a very conservative estimate of the CO_2 storage capacity for "commercial" methane fields. Since little data is available for "noncommercial" methane fields, equation (13) is used to estimate the CO_2 storage capacity:

$$Q_{ECBM} = r * e * \widetilde{V}_{CGP} * [\frac{PRF + (1 - PRF) * ERF}{PRF}] * \rho_{CO_2}, \quad (14)$$

where Q_{ECBM} = CO_2 storage capacity via incremental methane recovery,
r = CO_2/CH_4 ratio,
e = voidage replacement and ECBMR efficiency factor,
$\widetilde{V}_{CGP}$ = cumulative gas production (volume in standard condition),
PRF = primary recovery factor,
ERF = ECBM recovery factor, and
ρ_{CO_2} = CO_2 density (in standard condition).

Equation (14) was used to estimate the CO_2 storage capacity of "commercial" methane fields using cumulative gas production data. The limitation of this approach was that it underestimated the CO_2 storage capacity for "commercial" methane fields, particularly for those in their early stage of production. Moreover, it could not be applied to "noncommercial" methane fields since these fields have no gas production. In Phase II of the study, effort will be put into collecting original gas in place data for methane fields so that the theoretically more sound formulas (12) and (13) can be used for both "commercial" and "noncommercial" methane fields.

3.3 CO_2 Capture Cost Estimation

3.3.1 Methodology

This study uses the "*Generic* CO_2 *Capture Retrofit*" spreadsheet prepared by SFA Pacific, Inc., as the basis for calculating the CO_2 capture cost for stationary CO_2 sources in the WESTCARB region (see Figure 4). These estimates vary according to three key input variables: (1) the flue gas flow rate (in tonnes per hour), (2) the flue gas composition (volume share or weight share of CO_2 in flue gas), and (3) the annual load factor.

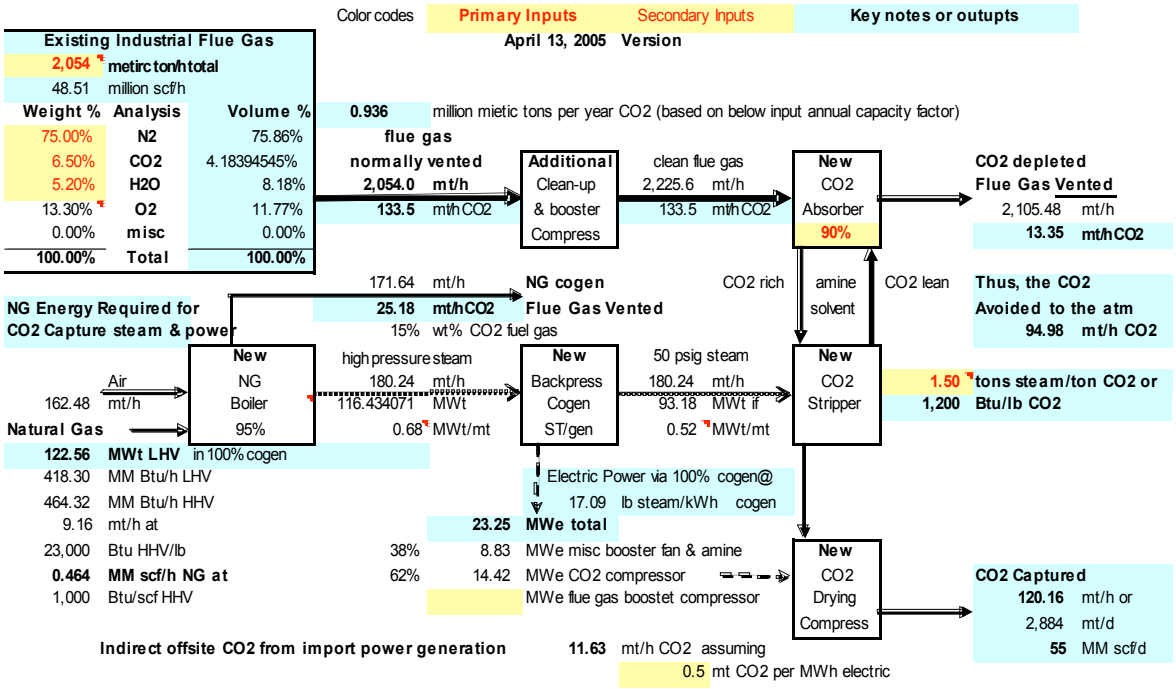
The SFA Pacific spreadsheet provides estimates of capture cost in terms of both CO_2 captured and CO_2 avoided. CO_2 captured is the amount of CO_2 captured by the absorber and kept out of the atmosphere—assumed to be 90% of the CO_2 in the flue gas. However, since the CO_2 capture process requires energy for purification and compression, the "CO_2 avoided" term subtracts the CO_2 emitted producing this process energy from the total amount of CO_2 captured. The two terms are used differently in CO_2 sequestration analysis. The "CO_2 captured" term is used for calculations involving the amount of CO_2 being handled, such as for pipeline transportation costs, while the "CO_2 avoided" term is used for calculations involving the amount of CO_2 withheld from the atmosphere and therefore eligible for possible CO_2 emissions credits.

According to these two measurements, there are also two definitions on the per-unit CO_2 capture cost. To avoid ambiguity, this report uses "CO_2 capture cost" to refer to the capture cost measured in per tonne CO_2 captured while "CO_2 avoidance cost" to refer to the capture cost measured in per tonne CO_2 avoided.

Generic Industrial CO2 Capture for Any Large CO2 Flue Gas Stream

April 2005 working draft by Dale Simbeck at SFA Pacific, Inc

Key assumption is that NG is use as the added energy source to make the steam & power required for CO2 capture
This avoides the loss of capacity or increased off-site CO2 emission of supplying additional electric power
Also the high demand of low pressure stripping steam for the amine CO2 stripper, favors a NG cogen boiler



Capital Costs	Unit cost basis at		cost/size factors	Actual unit cost at		millions of $ 2003 dollars	Notes
	60	mt/h CO2		120	mt/h CO2		
NG boiler	$ 15	/lb/hr steam	75%	$13	/lb/hr steam	5.0	
cogen ST gen	$ 500	/kWe	75%	$420	/kWe	9.8	
Additional cleanup	$ -	mt/h flue gas	75%	$0	mt/h flue gas	-	if SO2, NOx cleanup
Booster compressor	$ 800	/kWe	75%	$672	/kWe	-	needed in many cases
CO2 absorber	$ 25,000	mt/h flue gas	75%	$21,015	mt/h flue gas	46.8	
CO2 Stripper	$ 200,000	mt/h CO2	75%	$168,124	mt/h CO2	20.2	
CO2 Compressor	$ 1,000	/kW	75%	$841	/kW	12.1	
				Total process units		93.9	
General Facilities		20%	of process units			18.8	20-40% typical
Eng. Permitting & Startup		10%	of process units			9.4	10-20% typical
Contingencies		10%	of process units			9.4	10-20% typical
Working Capital, Land & Misc.		5%	of process units			4.7	5-10% typical
				U.S. Gulf Coast Capital Costs		136.1	
Site specific factor	110%	of US Gulf Coast		Total Capital Costs		149.7	CA costs are likely higher than Gulf Coast

CO2 Costs				$/Mscf CO2 MM $/yr	$/mt CO2 Cost Capture	$/mt CO2 Cost Capture	$/mt CO2 Cost Avoided	Notes
	80%	ann load factor						high ann load is critical to cost
Variable Non-fuel O&M	1.0%	/yr of capital		1.5	0.09	1.78	2.25	0.5-1.5% typical
Natural Gas	$ 5.00	/MMBtu HHV		16.3	1.02	19.32	24.44	$4- 7/MM Btu industrial rate
Carbon Tax	$ 10.00	/ton Carbon		0.3	0.02	0.30	0.38	all electric power made onsite
Total Variable Operating Cost				18.0	1.13	21.40	27.08	
Fixed Operating Cost	5.0%	/yr of capital		7.5	0.47	8.89	11.25	4-7% typical for refining
Capital Charges	15%	/yr of capital		22.5	1.40	26.67	33.74	15-25% typical for private investment
			Total CO2 Costs	48.0	3.00	56.97	72.07	including return on investment

Note that the difference between capture and avoided CO2 costs is due to the energy required for CO2 capture steam & power

Source SFA Pacific, Inc. April 13, 2005

Figure 4. SFA Pacific CO_2 capture cost tool

3.3.2 CO_2 Capture Cost for Fossil Fuel Power Plants

In order to use the SFA Pacific capture cost tool with fossil fuel power plants, an assumption was made that the CO_2 capture cost for such plants varied only as a function of fuel type, design capacity, and operating factor. A further assumption was made *that power plants would operate at 80% of their designed capacity once the capture facility has been installed.* So for each fuel type the CO_2 capture cost only varies based on the plant's design capacity. The fossil power plants were grouped into three categories by fuel type: coal-fired, gas-fired, and oil-fired.

Table 7 provides summary statistics for the fossil power plants in the WESTCARB region by fuel type. The WESTCARB database contains 43 power plants[6]. Eleven of these power plants are coal-fired, 29 are gas-fired, and 3 are oil-fired. The actual total CO_2 emissions for these facilities in year 2000 were 131 Mt, while the adjusted (under the assumption of 80% capacity factor) annual CO_2 emissions were 183 Mt.

Table 7. Fossil fuel power plants (PP) by fuel type

Fuel Type	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Plants	11	29	3
Total Design Capacity (MWe)	10,562	23,366	193
2000 Average Operating Factor[b]	0.79	0.47	0.20
Actual 2000 Total CO_2 Emissions (Mt)[c]	77	53	0.3
Adjusted Total Annual CO_2 Emissions (Mt)[d]	81	100	1.6

Note: [a]Weighted (by design capacity) average operating factor
[b]eGRID-published 2000 CO_2 emission based on the actual plant operating factor
[c]Estimated plant CO_2 emissions at 80% operating factor

Two key input variables needed to estimate the CO_2 capture cost for the fossil power plants are the flue gas flow rate and the flue gas composition. Since this specific information was unavailable for all of the power facilities, two further assumptions were used to derive reasonable values for these variables. The two flue gas assumptions were that: (*1) the flue gas flow increases linearly with the design capacity of a power plant; (2) within each fuel-type category, the flue gas composition is independent of the design capacity.* Table 8 provides the flue gas flow rate and composition used in the data for each type of fossil fuel power plant.

[6] The study restricts to power plants that are also contained in the eGRID database and have information on design capacity and 2000 CO_2 emissions.

Table 8. Flue gas flow rate and composition for coal-, gas-, and oil-fired power plants (PP)

		Coal-fired PP	Gas-fired PP	Oil-fired PP[1]
Flow Rate (mt/h per 100MW design capacity)		4.06	5.14	4.6
Flue Gas Composition (% in Volume)				
	N_2	73.81%	75.86%	74.84%
	CO_2	15.15%	4.18%	9.67%
	H_2O	8.33%	8.18%	8.26%
	O_2	2.54%	11.77%	7.16%
	misc	0.16%	0.00%	0.08%

Note: [1]Data about oil-fired power plants are MIT Carbon Capture and Sequestration Technologies Program estimates. Others are from SFA Pacific's *"Generic CO_2 Capture Retrofit"* and *"Existing Coal Power Plant CO_2 Migration"* spreadsheets.

Using data derived from the SFA Pacific capture cost estimation tool, Figure 5 plots both the CO_2 capture cost and avoidance cost for coal-fired power plants as functions of the plant design capacity. The relationship between CO_2 capture and avoidance costs and the design capacity of the coal-fired power plant can be represented by the following two power functions (with R^2 close to 1):

$$yc = 78.57 * x^{-0.1168}, \text{ and} \quad (15)$$

$$ya = 99.40 * x^{-0.1168}, \quad (16)$$

where yc = cost per tonne of CO_2 captured ($/t),
ya = cost per tonne of CO_2 avoided ($/t), and
x = design capacity of the coal-fired power plant (MWe).

Taking derivatives on both sides of Equation (15), the CO_2 capture/avoidance cost elasticity with respect to plant design capacity is $\frac{dy/y}{dx/x} = -0.1168$. In practical terms, this means that, due to economies of scale, the per-unit CO_2 capture/avoidance cost decreases by 0.1168 percent for every 1 percent increase in power plant design capacity.

Figures 6 and 7 plot the relationship between the CO_2 capture and avoidance costs and plant design capacity for gas-fired and oil-fired power plants, respectively. Table 9 summarizes the estimated formula for CO_2 capture and avoidance costs as functions of power plant design capacity for each fuel type category.

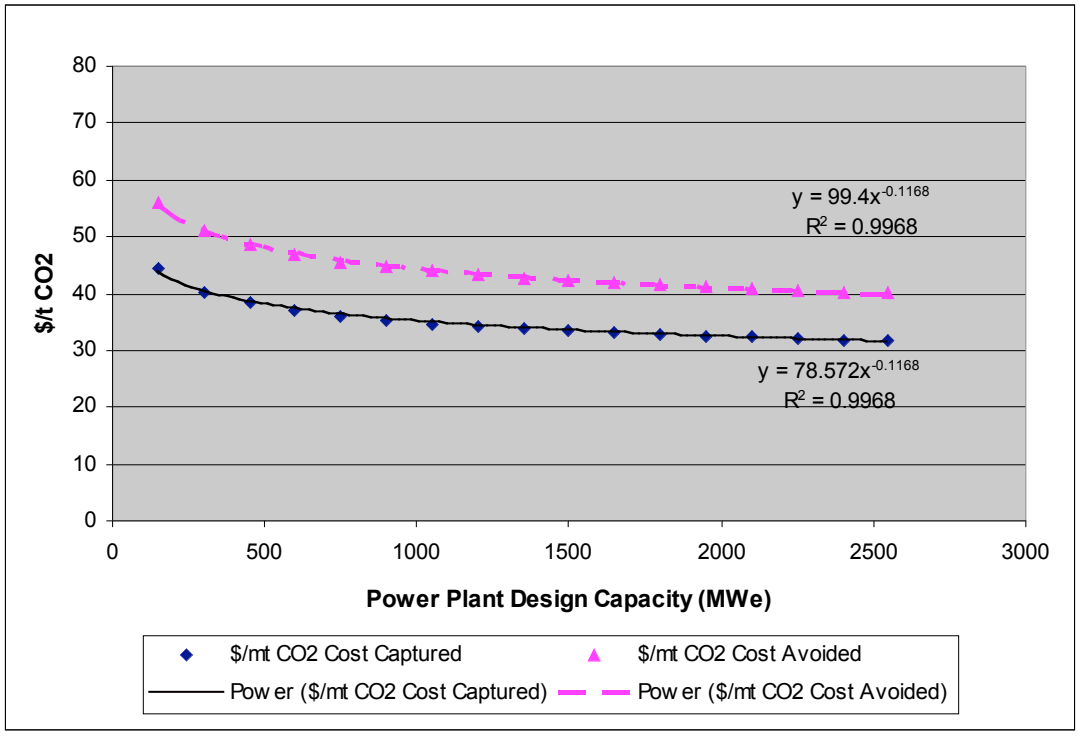


Figure 5. Estimated CO_2 capture and avoidance costs for coal-fired power plants

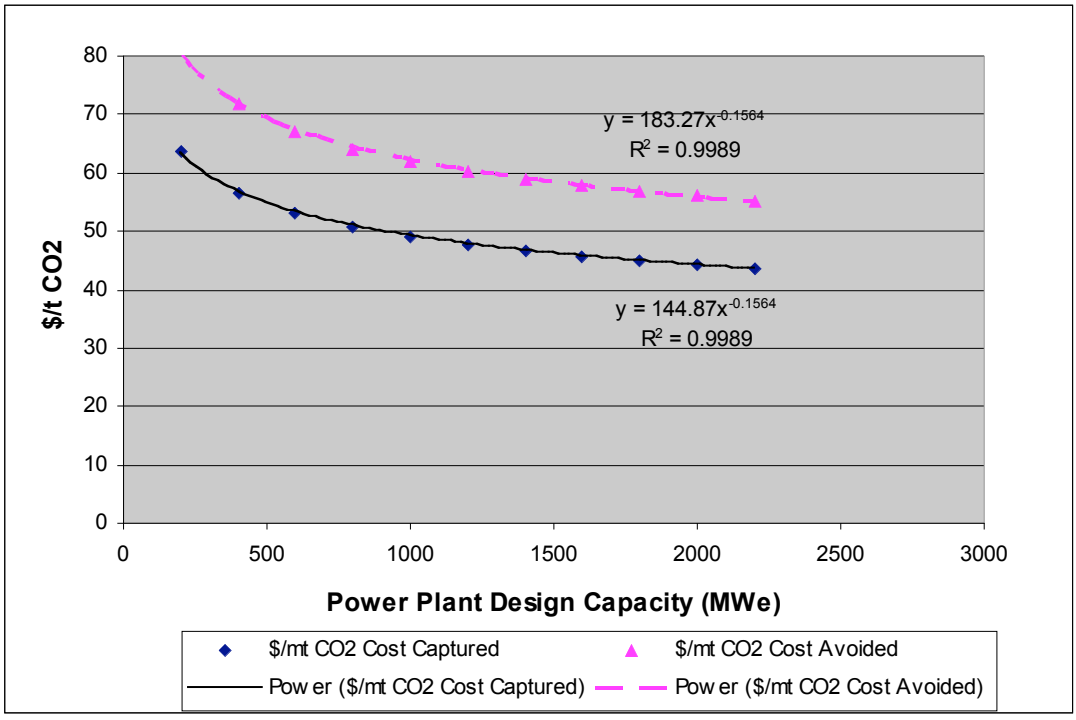


Figure 6. Estimated CO_2 capture and avoidance costs for gas-fired power plants

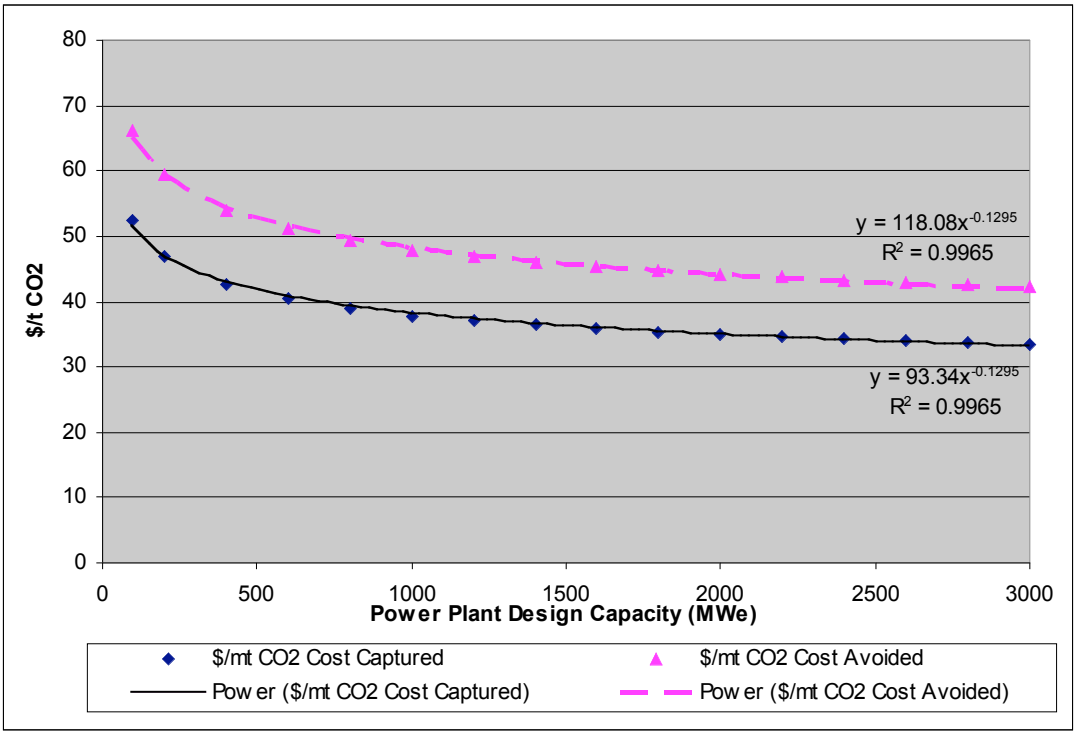


Figure 7. Estimated CO_2 capture and avoidance costs for oil-fired power plants

Table 9. Formula and range of per-tonne CO_2 capture and avoidance cost for power plants

Category	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP
# of Facilities	11	29	3
Capacity Range	28~2,409 MWe	50~2,129 Mwe	112~2951 Mwe
$/t CO_2 Captured Formula	$78.57x^{-0.1168}$	$144.87x^{-0.1564}$	$93.34\ x^{-0.1295}$
$/t CO_2 Avoided Formula	$99.40x^{-0.1168}$	$183.27x^{-0.1564}$	$118.08x^{-0.1295}$
Capture Cost Range ($/t CO_2 captured)	$31.6~$53.4	$44.3~$79.3	$49.7~$62.2
Avoidance Cost Range ($/t CO_2 avoided)	$40.0~$67.5	$56.1~$100.3	$62.9~$78.6

Note: x is the power plant design capacity in MWe.

The study applies the above methodology to the fossil fuel power plants contained in the WESTCARB database. Column (9) and column (10) in Appendix C present CO_2 capture cost and avoidance cost for these power plants when operated at 80% of design capacity. The capture cost varies from $31.6 per tonne for a 2,409 MWe coal plant to $79.3 per tonne for a 50 MWe gas plant. The avoidance cost varies from $40.0/t to $100.3/t for these same facilities. The capacity-weighted average CO_2 capture cost for fossil fuel power plants analyzed is $43.1/t, while the capacity-weighted average CO_2 avoidance cost is $54.6/t.

3.3.3 CO_2 Capture for Non-power Stationary Sources

The capture cost estimation tool from SFA Pacific was adapted so that it could be used with the non-power sources in the WESTCARB region. In the "Methodology" section, three key variables were needed for the estimation: (1) the flue gas flow rate, (2) the flue gas composition, and (3) the annual load factor. The WESTCARB database includes three types of non-power stationary sources: cement plants, gas processing facilities, and refineries. CO_2 emission data are only available for cement plants and refineries[7], so this study only analyzed the CO_2 capture from these two non-power stationary sources.

Table 10. Assumed flue gas component and load factor for cement plants and refineries

Facility Type	Flue Gas Component (volume)	Annual Load Factor
Cement	25% CO_2, 75%N_2	100%
Refineries	10% CO_2, 90% N_2	100%

Table 10 lists the assumed flue gas composition and the annual load factor used for cement plants and refineries evaluated. The actual flue gas flow rates were unknown, but they were estimated based on plant capacity, the CO_2 emissions factor, and the flue gas composition. Using these assumptions with the generic SFA CO_2 capture model, Figures 8 and 9 plot the per-unit CO_2 capture cost and avoidance cost as power functions of facility capacity for cement plants and refineries, respectively.

[7] The CO_2 emission data for cement plants and refineries were estimated by John Ruby, Nexant, Inc. (email communication with Larry Myer, California Energy Commission and Lawrence Berkeley National Laboratory).

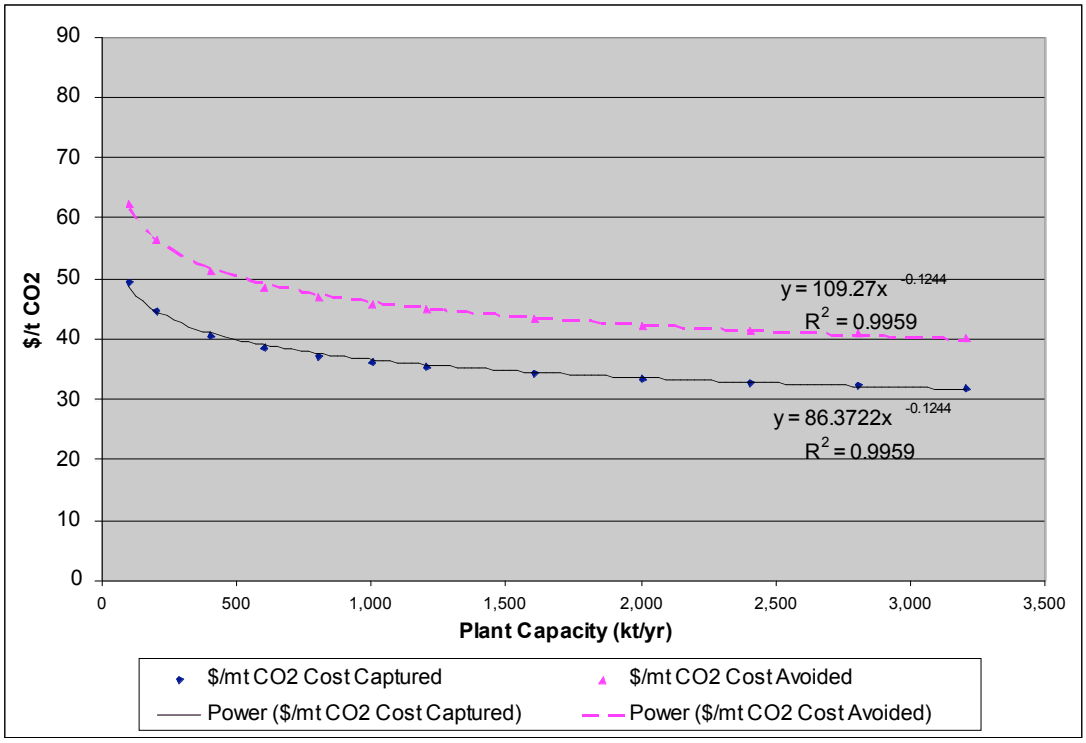


Figure 8. Estimated CO_2 capture and avoidance costs for cement plants

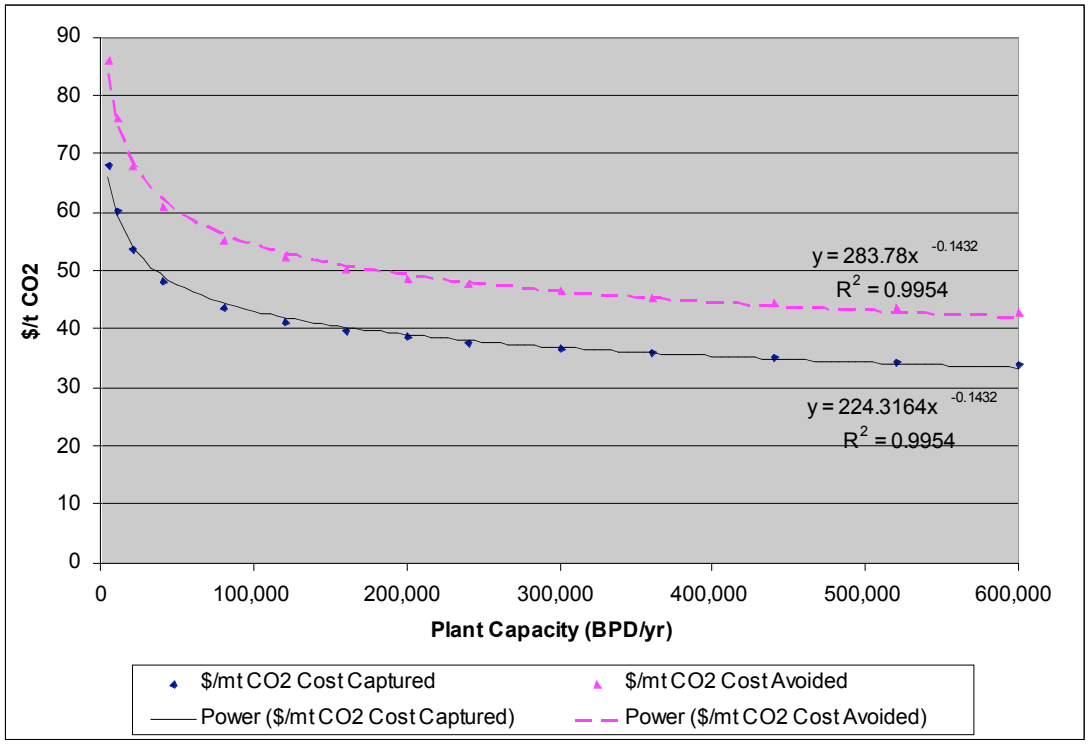


Figure 9. Estimated CO_2 capture and avoidance costs for refineries

Columns (6) and (7) in Appendices D and E show the estimated per-tonne CO_2 capture and avoidance costs for the cement plants and refineries in the region. Table 11 summarizes the range of production capacity, CO_2 capture and avoidance costs for cement plants and refineries evaluated in this study.

Table 11. Range of per-tonne CO_2 capture and avoidance costs for cement plants and refineries

Category	Cement[a]	Refineries
# of Facilities	11	13
Capacity Range	100~2,540 kt	5,400~557,000 BPD
Capture Cost Range ($/t CO_2 captured)	$48.8~$32.6	$65.5~$33.7
Avoidance Cost Range ($/t CO_2 avoided)	$61.7~$41.2	$82.9~$42.7

[a]Five cement plants in the WESTCARB database were excluded due to the lack of production capacity data.

3.4 CO_2 Pipeline Transportation Costs

In cases where the CO_2 source is not co-located with an appropriate sink, large quantities of CO_2 will need to be transported from the source to the sink for sequestration. Underground pipelines are considered the most economical means of transporting such large quantities of CO_2, and a pipeline network would be necessary for carbon sequestration to be feasible. Pipeline construction entails significant capital costs, and this section presents models and methods to estimate the CO_2 pipeline transportation costs based on key pipeline variables.

3.4.1 Transport Pipeline Design Capacity

The pipeline design capacity is one of the first design criteria needed for cost estimation. Pipeline capacity is a factor of both pipeline diameter and operating pressure, and pipelines need to be appropriately sized for the CO_2 transportation requirements of their corresponding CO_2 emissions sources. For pipelines originating at cement plants and refineries, the pipeline design capacity is set equal to the 2000 CO_2 emissions multiplied by a default capture efficiency (90%). For power plants, the pipeline design capacity is calculated as follows:

$$VC_{CO2} = \frac{VE_{CO2}^{2000}}{OE^{2000}} * CE_0 \quad , \tag{17}$$

where VC_{CO2} = maximum CO_2 flow rate (t/yr),
VE_{CO2}^{2000} = 2000 annual CO_2 emission (t),
OE^{2000} = 2000 plant operating factor, and
CE_0 = default CO_2 capture efficiency (90%).

Equation (17) gives the maximum CO_2 flow rate (in terms of tonnes/yr) for a power plant operating at its full design capacity. The required pipeline capacity is an overestimate since plants usually operate below their maximum design capacity.

3.4.2 Pipeline Diameter Calculation

Figure 10 plots the relationship between the maximum mass flow rate and the pipeline diameter. A power function closely models this relationship. In this study it is assumed that standard type gas industry pipelines will be used for CO_2 transportation (True, 1998). Based on the power function in Figure 10, Table 12 gives the breakdown of the CO_2 flow rate for each pipeline standard diameter within the range from 4 to 36 inches (10 to 91 cm). For any given maximum CO_2 flow rate, Table 12 provides a look-up table to determine the appropriate pipeline diameter. Column (5) of Appendix B provides the corresponding transport pipeline diameter for all sources located in California used in the detailed source-sink matching analysis in the "Least-Cost Path Source-Sink Matching and Full Costing Analysis (California)" section of this paper.

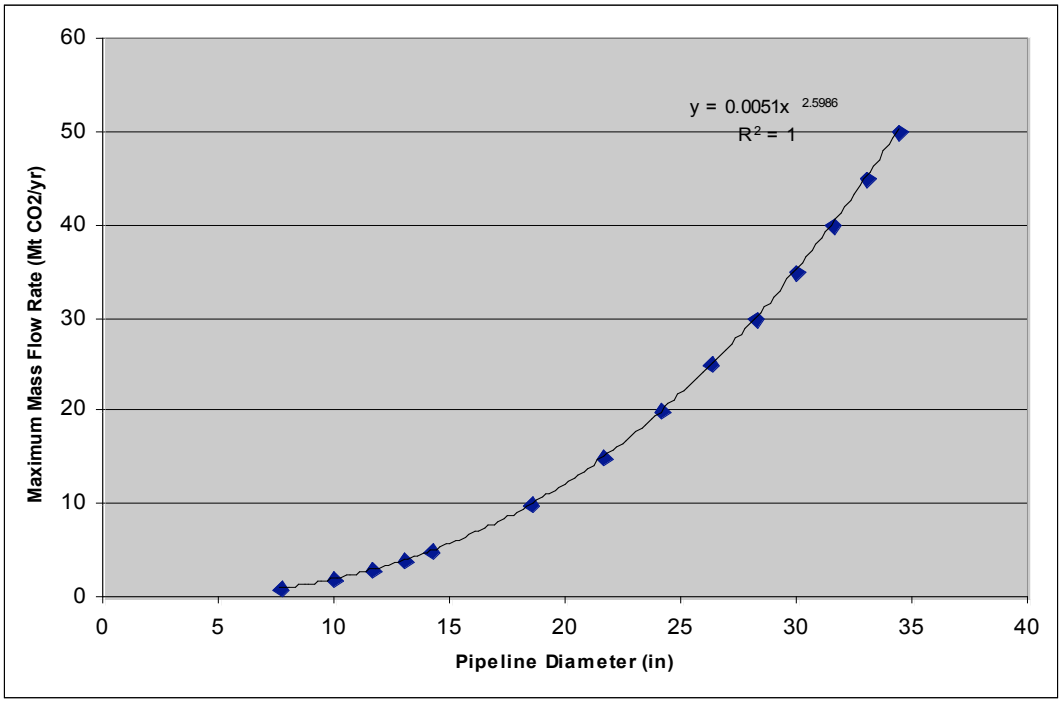


Figure 10. Maximum mass CO_2 flow rate as a function of pipeline diameter

Table 12. Pipeline diameter and the CO_2 flow rate range

Pipeline Diameter (in)	CO_2 Flow Rate (Mt/yr)	
	lower bound	upper bound
4		0.19
6	0.19	0.54
8	0.54	1.13
12	1.13	3.25
16	3.25	6.86
20	6.86	12.26
24	12.26	19.69
30	19.69	35.16
36	35.16	56.46

3.4.3 Obstacle Layer Construction

In addition to the diameter and capacity, the terrain being traversed by a pipeline is another significant pipeline construction cost variable. These costs vary considerably according to the local terrain and are also affected by the presence of buildings or infrastructure. Pipeline construction is more expensive in hilly areas than on flat plains. In order to reduce complications

and costs, a pipeline's route should avoid passing through populated places[8], wetlands, and national or state parks. In order to account for such obstacles in the study, the locations and characteristics of these obstacles were loaded into Geographic Information System (GIS) software. Using the GIS software, the costs for traversing such obstacles during pipeline construction were combined into a single obstacle data layer. This obstacle layer reflected three types of general obstacles: land slope, protected areas, and crossings of three line-type obstacles (waterways, railroads, and highways).

In order to use this land obstacle data to help calculate optimal pipeline routes, the continuous obstacle data layer was rasterized into 1 km–by–1 km cells. If there were no transportation obstacles contained within a given 1 km^2 cell, then the construction costs of a pipeline traversing the cell was assumed to be "1". From this base case construction cost, relative weights were then assigned to each obstacle in Table 13 according to the difficulty of traversing the obstacle. These relative weights were then added to the base case construction cost to form a combined pipeline construction cost factor.

Table 13. Estimated relative construction cost factor

Construction Condition		Cost Factor
Base Case		1
Slope		
	10-20%	0.1
	20-30%	0.4
	>30%	0.8
Protected Area		
	Populated Area	15
	Wetland	15
	National Park	30
	State Park	15
Crossing		
	Wateway Crossing	10
	Railroad Crossing	3
	Highway Crossing	3

Note: The relative weights are calculated as the ratios of the additional construction costs to cross those obstacles and the base-case construction cost for an 8-inch pipeline.

The total pipeline construction cost factor for a cell is then the sum of the base case cost factor and the cost factors of all of the obstacles that exist in that cell. For example, the relative cost of an 8-inch pipeline crossing a river in the national park would be 41: 1 (base case) + 30 (national park) + 10 (river crossing). Using the weighted cost layer calculated above, the spatial analysis function in ArcGIS was used to determine the least-cost pipeline path for connecting each source and sink.

[8] The populated places data is from U.S. Land Use and Land Cover (LULC) data set, which adopts the census definition of "populated place areas" that include census designated places, consolidated cities, and incorporated places within United States identified by the U.S. Bureau of the Census.

3.4.4 Pipeline Transport Cost Estimation

The model decomposes the pipeline construction cost into two components: the basic pipeline construction cost (diameter-dependent) and the additional obstacle cost (diameter-independent). The basic pipeline construction cost is estimated to be $12,000/in/km[9] ($7,602/cm/mi). The additional obstacle cost was calculated as the product of the relative weight assigned in Table 13 and the basic construction cost of an 8-inch pipeline[10]. The additional obstacle cost does not vary with the pipeline diameter, since the amount of site preparation required for pipeline construction does not vary according to pipeline size. The cumulative pipeline construction cost was then calculated as the sum of the basic construction cost and the additional obstacle cost.

For pipeline operations the pipeline operations and maintenance (O&M) costs were estimated to be $3,100/km ($4,991/mi) per year, regardless of pipeline diameter (Heddle *et al.*, 2003). A capital charge of 0.15 was used to annualize the construction cost over the operating life of the pipeline so that the annual pipeline transportation was 0.15 of its construction cost plus the annual O&M cost.

[9] Heddle *et al.* (2003) estimate that the average pipeline construction cost (including obstacle crossing cost) is $20,989/in/km. For sparsely populated areas average pipeline construction costs are estimated to be $12,400/in/km.

[10] For a 100-km, 8-inch pipeline with 6 waterway crossings, 1 railroad crossing, 1 highway crossing, and 1 wetland crossing, the estimated construction cost is ($12,000/in/km)*(8 in)*(100 km) (base case construction) + $960,000*6 (waterway crossing) + $288,000 (railroad crossing) + $288,000 (highway crossing) + $1,440,000 (wetland crossing) = $17,376,000, which is similar to the average number provided by Heddle: ($20,989/in/km)*(8 in)*(100 km) = $16,791,200.

3.5 Distance-Based Source-Sink Matching

This section presents the methodology developed to estimate the distance from each CO_2 source to its nearest sink. This methodology was applied to sources and sinks in the WESTCARB region in order to estimate the transportation requirements for captured CO_2 and to study how these requirements changed as a function of the sink set included in the analysis. The results from this analysis provide estimates of the distance between sources and their closest sinks, but do not consider the transportation costs or optimal pipeline routing when matching, as will be considered in "Least-Cost Path Source-Sink Matching and Full Costing Analysis (California)" section.

The source-sink matching in the WESTCARB region considers 37 power producing CO_2 sources and 21 non-power producing CO_2 sources. Over an assumed 25-year project lifetime, 4.6 Gt of CO_2 would need to be sequestered[11]. The regional CO_2 storage capacity was estimated to be at least 5.2 Gt. Since the estimated CO_2 storage capacity was larger than the amount of captured CO_2, an assumption was made in this analysis that all sources could be transported and stored in the nearest sinks. The sink storage capacity constraint was considered in the analyses presented in the following section.

3.5.1 Methodology

This analysis was used to calculate the straight-line distance from each CO_2 source to the nearest sink and provides an estimate of the CO_2 storage potential within a given distance from the CO_2 sources. The analysis was performed using GIS software tools. The "Straight-Line Distance" function in the spatial analyst extension of ArcMap was used to calculate the shortest straight-line distance from each source in the study area to the nearest geological sink. The output from this analysis was a raster layer where the cell values were equal to the straight-line distance from each cell to the nearest sink.

3.5.2 Straight-Line Distance-Based Source-Sink Matching in WESTCARB Region

The CO_2 sources without emission data were excluded from the source-sink matching analysis. We also limited our analysis to the contiguous-U.S. part of the WESTCARB region and excluded the CO_2 sources located in Alaska. Fifty-eight CO_2 sources in WESTCARB region, including 10 coal-fired power plants, 27 gas-fired power plants, 11 cement plants and 10 refineries, are included in analysis. The total annual CO_2 emission for these sources is about 184 Mt.

The distance matching analysis was performed for each of the four groups of eligible sinks: 1) oil and gas fields with EOR potential, 2) all oil and gas fields, 3) saline aquifers, and 4) all geological sinks. Since the WESTCARB server lacked sufficient data to evaluate the CO_2 sequestration potential in Nevada saline aquifers, we performed the source-sink matching analysis under two scenarios, either with (Scenario One) or without (Scenario Two) including

[11] The CO_2 emissions were estimated under an operation capacity of 80% for power plants and full production capacity for non-power stationary CO_2 sources. A capture efficiency of 90% is also assumed for all the CO_2 except for the pure CO_2 sources.

Nevada saline aquifers. Figure 11 presents a map of all the sources and sinks considered in this section.

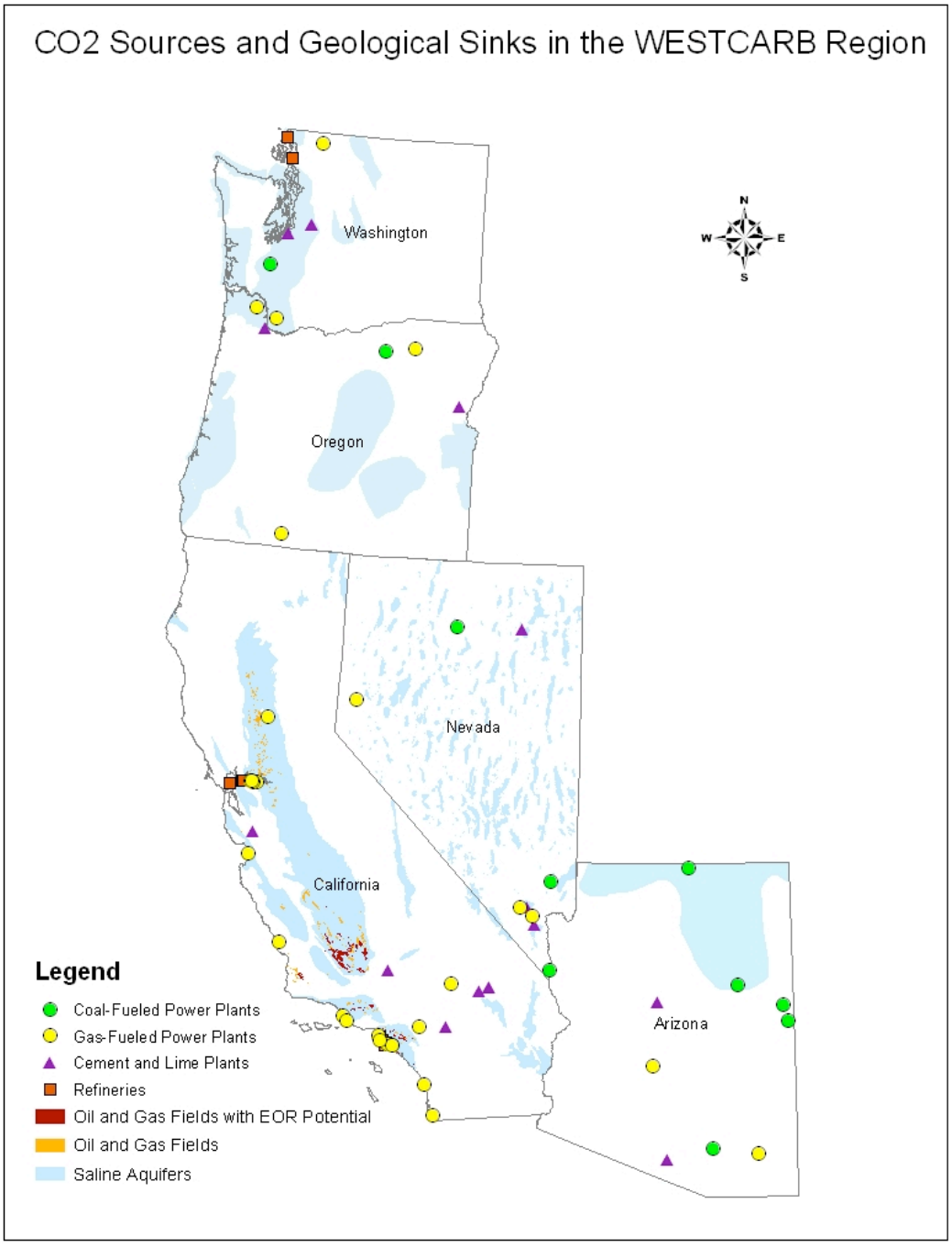


Figure 11. CO_2 sources and sinks considered in straight-line distance matching

3.5.2.1 Scenario One: Nevada Aquifers Included

Table 14, Figure 12, and Figure 13 show the results for the source-sink matching in the WESTCARB region when the Nevada aquifers are included. Appendix C to Appendix E presents the detailed results with the straight-line distance to nearest EOR site, oil & gas field, and aquifer, respectively, for each CO_2 source. It's interesting to note that the cases with the hydrocarbon reservoirs needed much larger transportation distances than the cases with the saline aquifers. This is probably due to the limited amount of hydrocarbon data for states other than California. Also, performing the analysis with all sinks is identical to the aquifer-only cases since many hydrocarbon fields are geographically located within the bounds of aquifers.

Table 14. Annual CO_2 storage capacity (Mt) by marginal straight-line distance to nearest sink; Nevada aquifers included

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km (31 mi) or less	100 km (62 mi) or less	250 km (93 mi) or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in Region	154	174	176
All Sinks	154	174	176

Note: The annual CO_2 storage rate was 184 Mt.

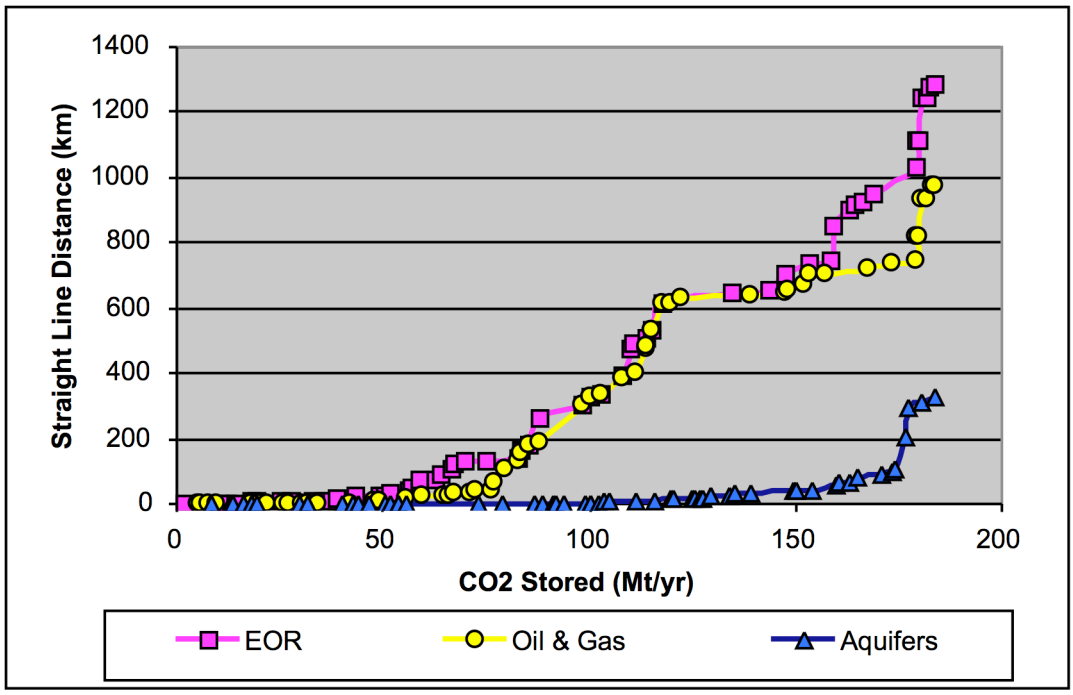


Figure 12. Marginal straight-line distance from CO_2 source to sink by annual CO_2 storage rate; Nevada aquifers included

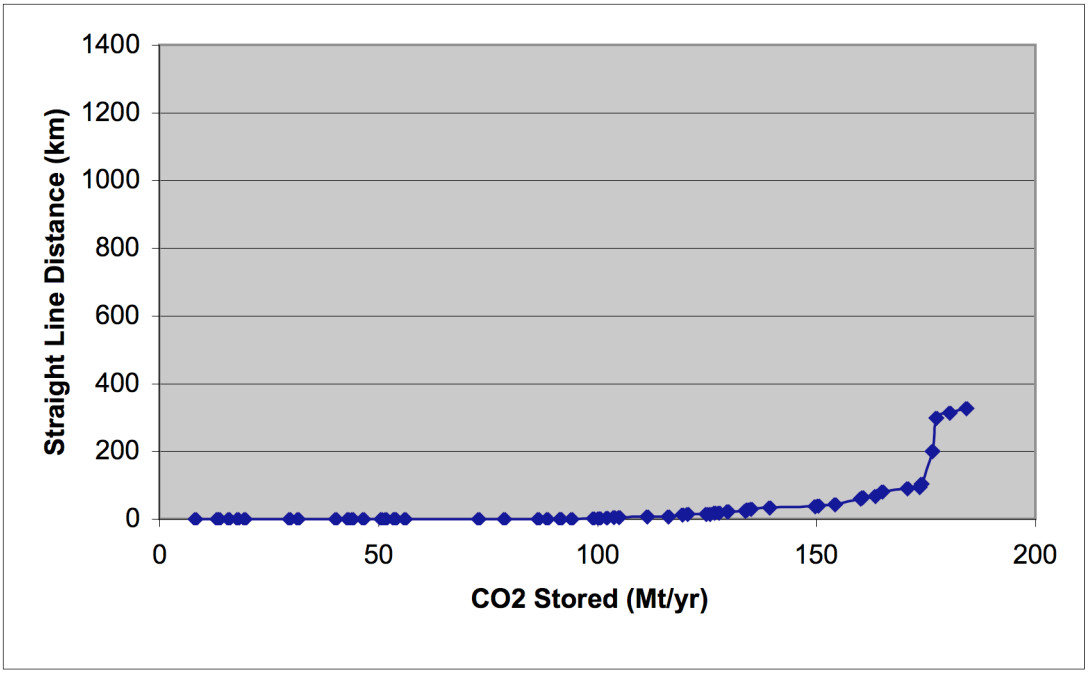


Figure 13. Marginal straight-line distance from CO_2 source to all sinks by annual CO_2 storage rate; Nevada aquifers included

3.5.2.2 Scenario Two: Nevada Aquifers Excluded

Table 15, Figure 14, and Figure 15 present the results for the case when the Nevada aquifers are excluded. It's interesting to note that the exclusion of the Nevada saline aquifers did not appear to have any significant effect on the results.

Table 15. Annual CO_2 storage rate (Mt/yr) by marginal straight-line distance to nearest sinks; Nevada aquifers excluded

Sink Type	Straight-Line Distance to Nearest Sinks		
	50 km (31 mi) or less	100 km (62 mi) or less	250 km (93 mi) or less
Oil & Gas Fields with EOR Potential	59	64	86
Oil & Gas Fields	76	77	88
Aquifers in Region Excluding Nevada	139	168	176
All Sinks	139	168	176

Note: The annual CO_2 storage rate was 184 Mt.

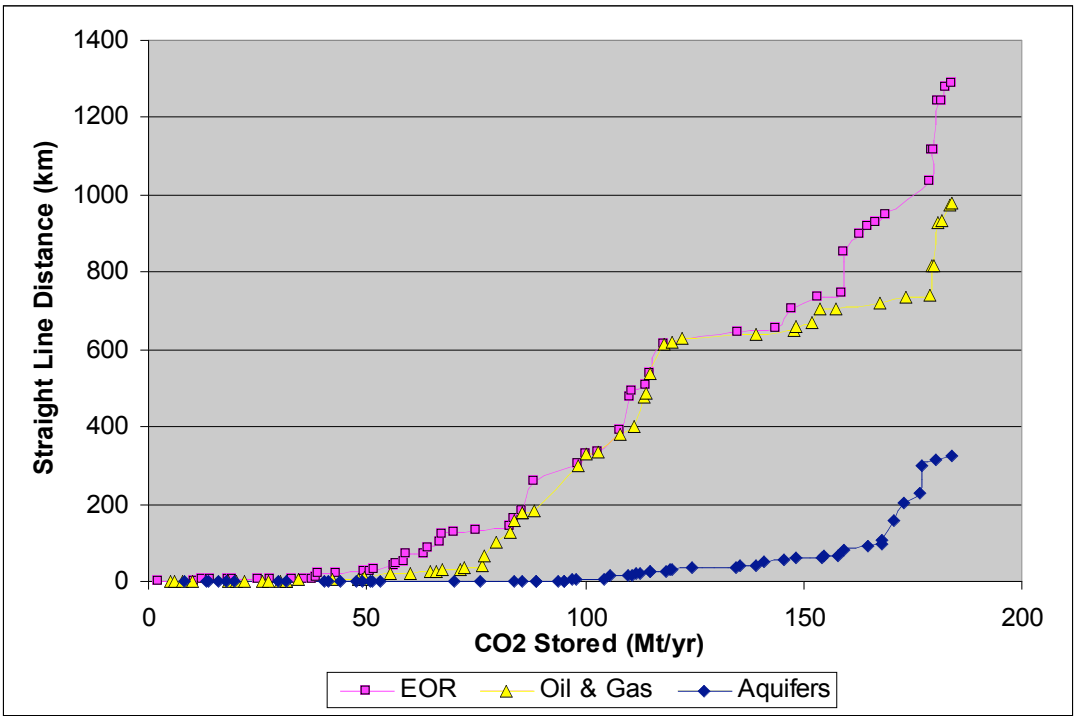


Figure 14. Marginal straight-line distance from CO_2 source to all sinks by annual CO_2 storage rate; Nevada aquifers excluded

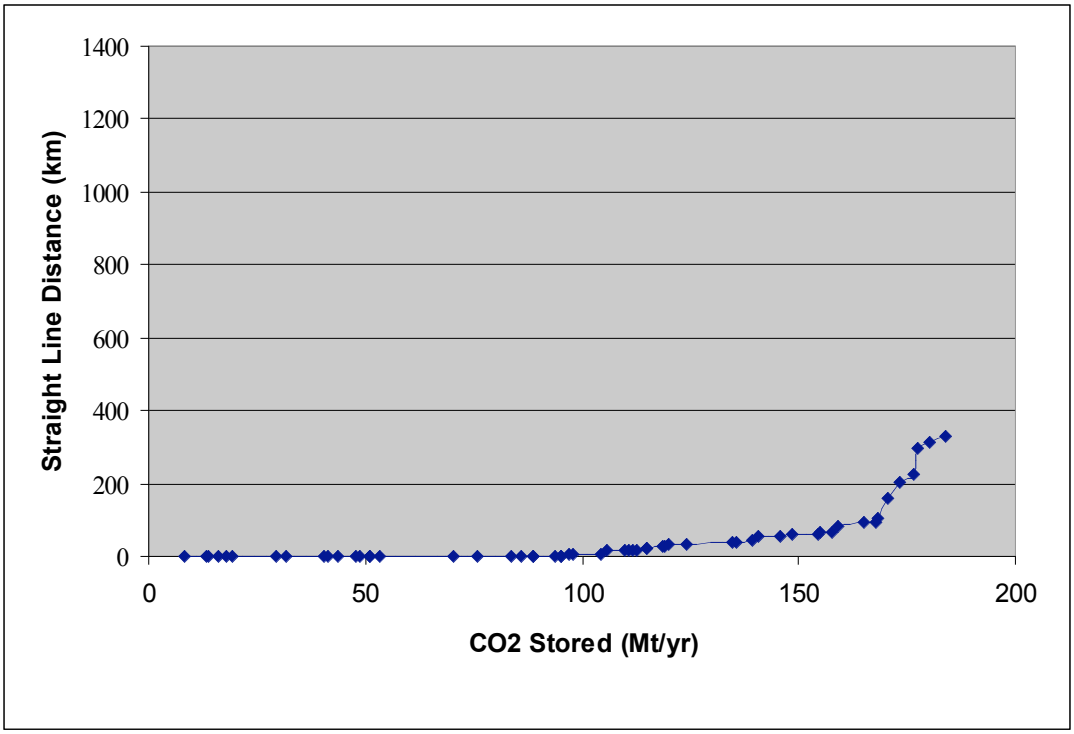


Figure 15. Marginal straight-line distance from CO_2 source to nearest sinks by annual CO_2 storage rate; Nevada aquifers excluded

3.5.3 Source-Sink Matching Discussion

This section presents results from analyses of the straight-line distance between sources and sinks in the WESTCARB region. While these results are not an accurate representation of the total cost for carbon capture and storage (CCS; also called carbon sequestration) within the WESTCARB region, the results do provide a sense of the CCS transportation requirements for cases where there is insufficient information for a full-cost evaluation. If EOR sites in the WESTCARB region were the only sinks available for sequestration, only less than half of the CO_2 sources by volume could be matched with a sink that were less than 250 km (155 mi) from the source; and, for some sinks in Washington State, the closest EOR sinks would be over 1000 km (621 mi) away. If all sink types were considered for sequestration, however, more than 95% of the CO_2 sources could be matched with appropriate sinks within 250 km (155 mi) of the source. More than 75% of the sources (by volume) would find their nearest sinks within 50 km (31 mi) of the source. Approximately 50% of the sources were actually co-located with an appropriate sink, which was usually a saline aquifer. It's also interesting to note that the exclusion of the Nevada saline aquifers did not appear to have any significant effect on the results. The actual transportation distance requirements would be larger if sink capacity constraints and transportation obstacles were considered. These analyses are presented in the following section.

3.6 Least-Cost Path Source-Sink Matching and Full Costing Analysis (California)

In this section, estimates of the total cost of carbon capture and storage are calculated by combining the methods presented in both the "CO_2 Capture Cost Estimation" section and the "CO_2 Pipeline Transportation Costs" section for calculating capture and transportation costs with a more detailed method of calculating pipeline paths. Whereas in the previous section pipeline paths were calculated according to the shortest distance, in this section the pipeline paths were calculated using an iterated GIS-based least-cost path algorithm that considers typography as well as social and political data for the study region. This more-cumulative sequestration cost analysis, which consists of capture, transport, and injection costs, was performed only for the State of California due to the limited availability of detailed data for the entire WESTCARB region. As more detailed data is collected for the other WESTCARB states in Phase II, this least-cost path source-sink matching and full capture-cost analyses will be extended to the entire WESTCARB region.

3.6.1 Methodology

In contrast to the distance-based matching analysis performed in the "Distance-Based Source-Sink Matching" section, this section presents a method of matching sources and sinks based on least total cost. For this analysis, each CO_2 source in California was linked to a least-cost geological sink based on a least-cost transportation route and an estimated injection cost. The linking algorithm also considered reservoir storage capacity and ensured that each linked sink had sufficient storage capacity for all sources matched with it.

The list of sinks used in the matching analysis included hydrocarbon fields with EOR potential, hydrocarbon fields without EOR potential, and saline aquifers[12]. While all of these sinks are suitable for sequestration, the cost of sequestration varies for each sink type. The sinks can be grouped into two basic categories: (1) oil fields with EOR potential that are eligible for oil production credits, and (2) non-EOR hydrocarbon fields and saline aquifers that will have to bear the full cost for CO_2 transportation, compression, and injection. Projects were assumed to have 25-year lifetimes, and sources were only matched up to a sink if its remaining storage capacity exceeded the source's 25-year CO_2 flow.

The linking analysis was conducted in two stages, first considering cheaper sinks before proceeding to sinks with higher storage costs. In this first stage, EOR sites were included as potential sinks since they would purchase CO_2 from a provider. After allocating the EOR storage capacity to the appropriate sources, if there were still unmatched CO_2 sources, the matching algorithm was rerun with the regular hydrocarbon fields and saline aquifers included in the list of potential sinks. An algorithm flow chart is shown in Figure 16.

[12] There are no coalbed methane fields included in the sink set for California.

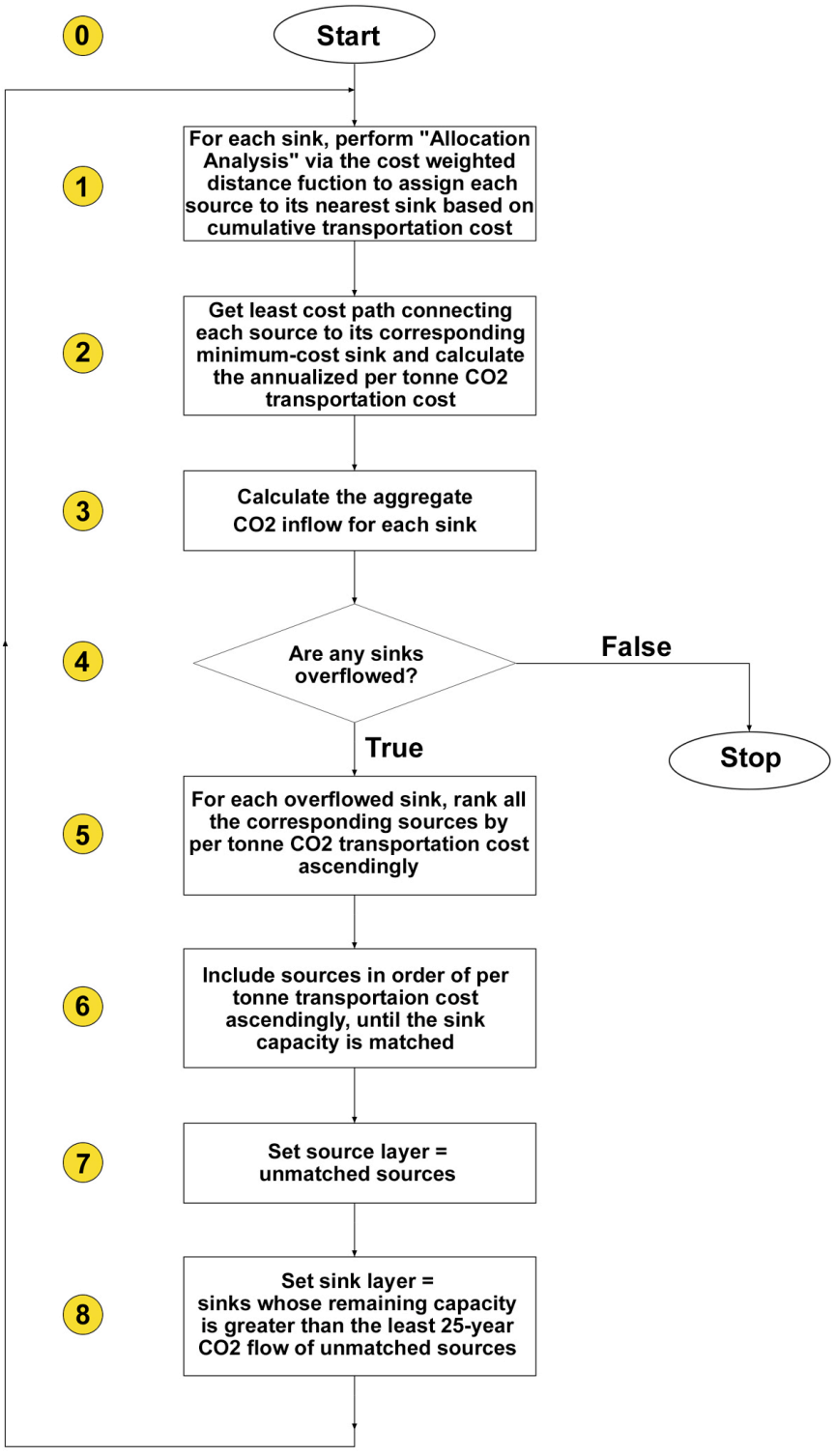


Figure 16. Flow chart of the least-cost path CO_2 source-sink matching algorithm

An iterative algorithm was developed to "optimize" the source-sink matching using the ArcGIS "spatial analysis" tool. Figure 16 depicts the flow chart for this iterative matching algorithm using an example of a stage-1 matching process when only transportation-cost needs are considered:

- In the first step, the ArcGIS "Allocation Analysis" function was used to assign each source to its nearest sink based on the transportation cost as calculated in the "CO_2 Pipeline Transportation Costs" section. The allocation result provided a picture of how the sources would be optimally linked to the sinks within the region if there were no restrictions on the storage capacity of each sink.

- In the second step, the ArcGIS "Least Cost Path" function was used to obtain the least-cost path linking each source to its corresponding least-cost sink. Using the transportation cost estimation algorithm discussed in the "CO_2 Pipeline Transportation Costs" section, the capital cost and maintenance cost were calculated as the cost-per-tonne of CO_2 transported.

- In the third step, the 25-year CO_2 flow volumes from all sources assigned to each sink in step 1 were summed up to get the aggregate 25-year CO_2 flow.

- In step 4, the aggregate 25-year CO_2 flow calculated in step 3 was compared to the estimated CO_2 storage capacity for each sink.

    - If none of the sinks were over capacity, then the iteration ended with an approximately "optimal" matching outcome.

    - If some of the sinks were over capacity, the program continued to step 5 to evaluate which sources should be excluded from the "overfilled" sinks.

- In step 5, for each "overfilled" sink, the associated sources were ranked in ascending order by the transportation cost per tonne of CO_2.

- In step 6, the ordered sources for each "overfilled" sink were re-added to the sink's "matched source set" in ascending order of CO_2 transportation cost. Sources were added until the sink's remaining storage capacity was less than the 25-year CO_2 flow of the smallest source assigned to this sink in step 1 that had not been added to the "matched source set."

- In step 7, all of the sources that were not included in "matched source set" for any sinks were set as the new "source layer".

- In step 8, all sinks with remaining CO_2 storage capacity exceeding the 25-year CO_2 flow of the smallest source in the new "source layer" defined in step 7 was set as the new "sink layer". The program then went back to step 1 and reran the source-sink matching algorithm until all sources were matched and no sinks were "overfilled."

While the matching algorithm described above was capable of determining a near-optimal solution, the algorithm might not find the absolute least-cost solution. Since the algorithm did not evaluate whether assigning one source to a relatively more costly sink could reduce overall system cost, the optimization was not truly optimal. Even though the matching algorithm used in this analysis was not "truly optimal," this is a typical problem in system optimization and the algorithm produces a reasonable result. The complexity of a "true" system optimization algorithm was beyond the scope of the Phase I analysis, but efforts in Phase II will focus on improving the algorithm functionality.

3.6.2 Least-Cost Path Source-Sink Matching

This analysis was conducted using the CO_2 sources located in California, which included power plants, refineries, and cement and lime plants. Gas processing plants were excluded from the analysis since the server lacked CO_2 emissions data for these facilities. In total, 31 sources were included in the source-sink matching process. The project lifetime was assumed to be 25 years. Total source CO_2 flow over 25 years was approximately 2.1 Gt. Table 16 shows the CO_2 flow rate by source type.

Table 16. CO_2 flow rate by plant type in California

Plant Type	Number of Plants	Annual CO_2 Flow (Mt)	25-year CO_2 Flow (Mt)
Cement and Lime Plant	6	5	135
Power Plant	18	70	1,754
Refinery	7	10	255
All sources	31	86	2,144

Oil fields with EOR potential are chosen as the geological sinks in the matching process. There are 139 oil fields with EOR potential in California. 121 of these fields, or 3.4 Gt of the capacity, were favorable for miscible EOR operations. 18 of the fields, or 0.2 Gt of the capacity, were categorized as immiscible EOR reservoirs. After screening out fields with storage capacity less than 20 Mt[13], 35 sinks with an overall storage capacity of 3.2 Gt were included in the first stage of the analysis. Since the CO_2 storage capacity in EOR sinks was larger than the 25-year CO_2 flow, we expected to link all the sources to their least-cost EOR sinks. Nevertheless, regular hydrocarbon fields and saline aquifers were also prepared as the back-up sink layer in case there would be some unmatched CO_2 sources in the first stage.

The cost surface used in this study is an aggregate transportation cost layer generated using the method presented in the "CO_2 Pipeline Transportation Costs" section. The value of each cell in this layer is the obstacle cost factor plus the construction cost factor for an 8-inch pipeline crossing this cell. The raw data source of each type of obstacle is listed in Table 17.

[13] Most of the CO_2 sources will emit more than 20 Mt CO_2 over the 25-year project lifetime.

Table 17. Data sources of transportation barrier layers

Barrier Layer	Raw Data Source
Slope	ESRI Digital Elevation Model Data
Populated area	ESRI Data & Maps
Wetland	USGS LULC Data
National Park	ESRI Data & Maps
State Park	ESRI Data & Maps
Waterway	ESRI Data & Maps
Railway	ESRI Data & Maps
Highway	ESRI Data & Maps

Figure 17 shows all the CO_2 sources, geological sinks, and transportation cost factors used in the least-cost path analysis. After the first stage of the source-sink matching analysis, all the 35 sources were linked to EOR sites as expected.

The transportation cost (including construction cost, obstacle-crossing cost, and O&M cost) of each source can be calculated using the method presented in the "CO_2 Pipeline Transportation Costs" section. Table 18 shows the results of the source-sink matching and the transportation cost analysis in California. CO_2 sources are sorted in ascending order by the transportation cost.

Figure 18 plots the marginal transportation distance by annual CO_2 storage rate for sources transported to the oil fields with EOR potential. Figure 19 plots the marginal transportation cost by annual CO_2 storage rate for sources transported to EOR oil fields.

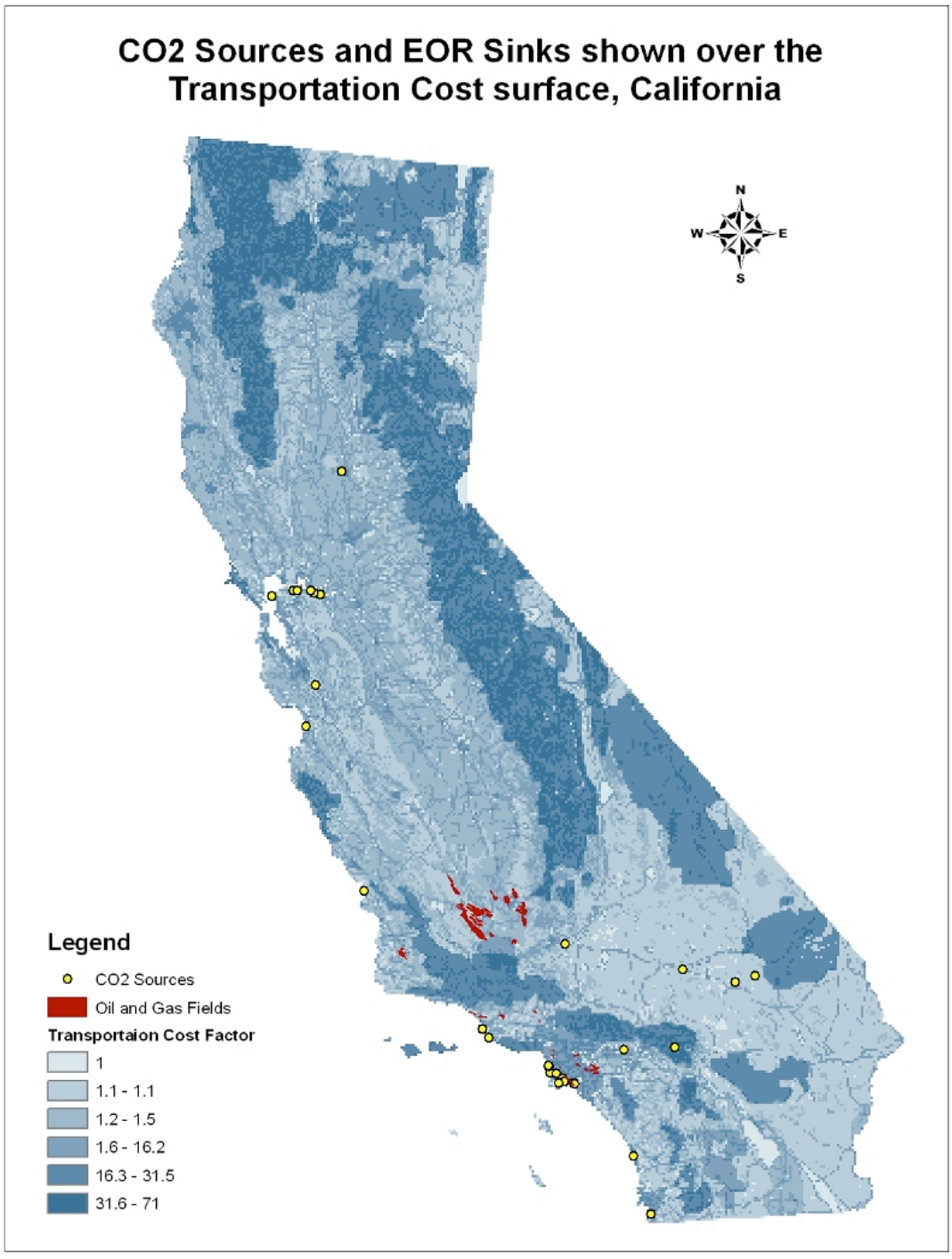


Figure 17. CO_2 sources and sinks shown over the transportation cost surface, California

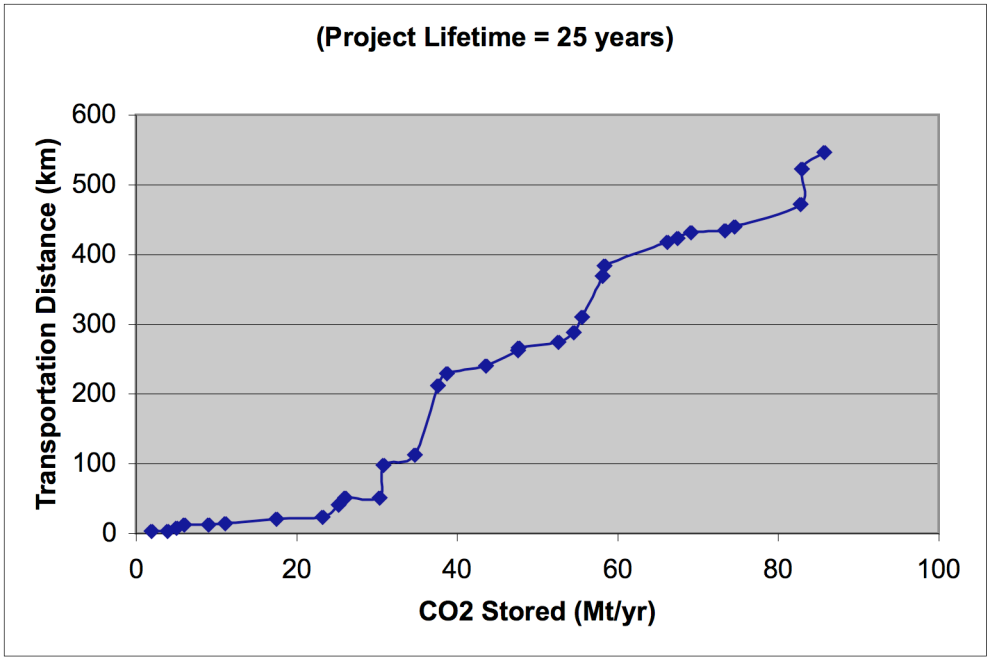


Figure 18. Marginal transportation distance by annual CO_2 storage rate in oil fields with EOR potential, California

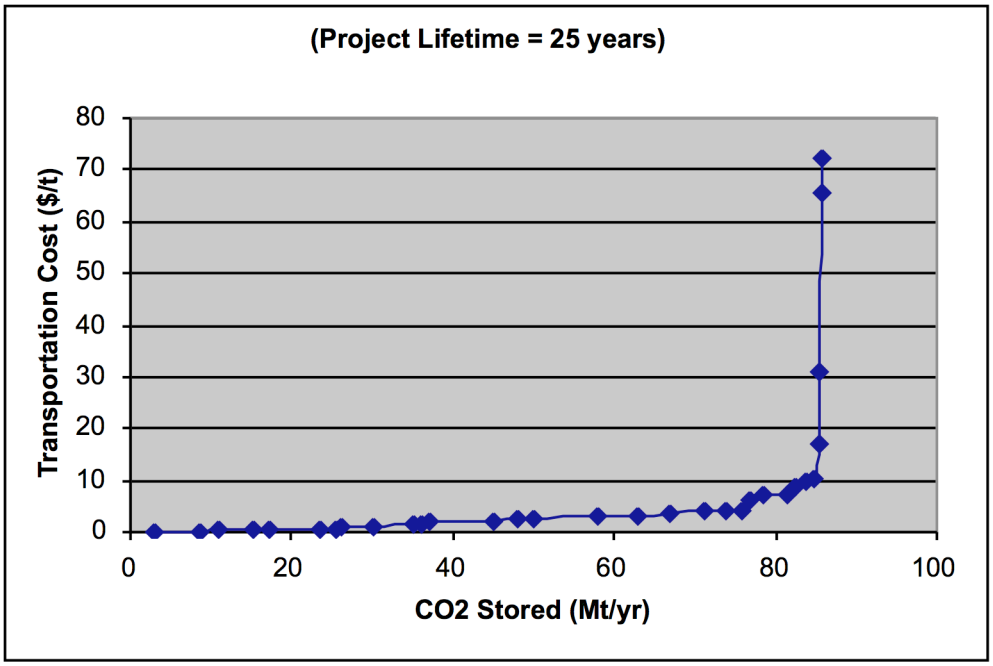


Figure 19. Marginal transportation cost by annual CO_2 storage rate in oil fields with EOR potential, California

Table 18. Least-cost path analysis for CO_2 sources transported to oil fields with EOR potential, California

Facility Name	Plant Type	Destination Fieldcode	Pipeline Diameter (inch)	25-year CO2 Flow (Mt)	Length (km)	Construction Cost (M $)	Crossing Cost (M$)	Annual O&M Cost (M$)	Transportation Cost ($/ton)
Scattergood Generating Station	POWER PLANT	LA021	16	74.69	13	2.51	0.83	0.04	0.18
Ormond Beach Generating Station	POWER PLANT	VE076	20	144.52	24	5.78	3.55	0.07	0.25
Mandalay Generating Station	POWER PLANT	VE076	12	52.59	15	2.17	2.58	0.05	0.36
Etiwanda Generating Station	POWER PLANT	LA006	16	106.64	52	9.91	2.82	0.16	0.49
BP WEST COAST CARSON REFINERY	REFINERY	LA030	12	48.8	3	0.49	6.05	0.01	0.51
Haynes Gen Station	POWER PLANT	LA054	20	158.83	21	5.10	19.36	0.07	0.59
Harbor Generating Station	POWER PLANT	LA030	12	48.09	4	0.55	7.08	0.01	0.60
CALIFORNIA PORTLAND CEMENT CO. M	CEMENT	SJ087	8	21.42	51	4.90	0.48	0.16	1.13
Morro Bay Power Plant, LLC	POWER PLANT	SJ012	16	98.13	113	21.73	5.93	0.35	1.15
Moss Landing	POWER PLANT	SJ012	16	122.47	241	46.19	5.15	0.75	1.72
EXXONMOBIL TORRANCE REFINERY	REFINERY	LA045	12	27.97	8	1.16	11.97	0.03	1.78
CONNACOPHILLIPS, WILMINGTON PLANT	REFINERY	LA030	12	25.65	13	1.85	11.29	0.04	1.96
Pittsburg Power Plant (CA)	POWER PLANT	SJ082	20	196.17	418	100.37	12.13	1.30	2.32
Coolwater Generating Station	POWER PLANT	SJ066	16	71.9	212	40.67	6.40	0.66	2.68
CHEVRONTEXACO EL SEGUNDO REFINERY	REFINERY	LA036	12	48.8	41	5.92	30.11	0.13	2.83
AES Alamitos	POWER PLANT	SJ016	20	205.27	472	113.30	34.79	1.46	2.88
AES Redondo Beach	POWER PLANT	SJ046	16	124.45	274	52.70	50.33	0.85	3.28
El Segundo	POWER PLANT	SJ046	16	99.49	263	50.46	40.06	0.81	3.62
Cabrillo Power I (Encina)	POWER PLANT	SJ066	16	105.88	434	83.42	17.63	1.35	3.90
Contra Costa Power Plant	POWER PLANT	SJ011	12	64.03	370	53.24	9.18	1.15	4.10
CEMEX - BLACK MOUNTAIN QUARRY	CEMENT	SJ066	12	47.86	288	41.53	7.00	0.89	4.27
MITSUBISHI CEMENT 2000, LUCERNE	CEMENT	VE002	12	26.84	230	33.12	7.38	0.71	6.32
CHEVRON RICHMOND REFINERY	REFINERY	SJ080	12	42.23	432	62.16	10.85	1.34	7.28
Duke Energy South Bay	POWER PLANT	SJ046	16	71.35	547	104.93	25.77	1.69	7.46
HANSON PERMANENTE CEMENT	CEMENT	SJ008	12	25.49	311	44.76	7.23	0.96	8.59
TESORO AVON REFINERY MARTINEZ	REFINERY	SJ082	12	31.16	424	61.04	10.08	1.31	9.61
SHELL OIL PRODUCTS, MARTINEZ	REFINERY	SJ016	12	29.9	440	63.34	11.02	1.36	10.47
CALIFORNIA PORTLAND CEMENT	CEMENT	LA006	8	11.84	98	9.40	41.68	0.30	16.82
Delta Energy Center, LLC	POWER PLANT	SJ012	6	5.43	384	27.65	8.94	1.19	30.75
Sutter Energy Center	POWER PLANT	SJ012	6	3.97	523	37.66	20.68	1.62	65.30
TXI RIVERSIDE CEMENT	CEMENT	SJ087	8	1.91	267	25.61	5.62	0.83	72.13

In this analysis, \$16/t of CO_2 was used as an assumed EOR credit value, meaning that a CO_2 source could receive \$16/t of CO_2 used for EOR. If the transportation cost from a CO_2 source to an EOR site was less than \$16/t, then the CO_2 was allocated to that EOR site instead of an alternative non-EOR sink. If the transportation costs to the closest EOR site were greater than \$16/t, then the CO_2 source should be double-checked whether to link to the EOR sink or non-EOR sink depending on the total costs.

Only four of the sources in this analysis had transportation costs to the closest EOR site that were greater than the credit value of \$16/t CO_2. A final check was run to compare final cost calculations for these sources to the alternative option of a non-EOR sink to decide which option represents the true least-cost matching. For these four sources, a new round of source-sink matching was applied with the same algorithm as before, but using the oil and gas fields without EOR potential and saline aquifers suitable for CO_2 storage in California as the sink layer instead[14]. In addition to transportation cost, sources were allocated while considering the injection costs for gas fields or saline aquifers at the second stage.

Table 19 shows the transportation and injection costs for the alternative option. The algorithm resulted in all four sources matching to saline aquifers instead of non-EOR hydrocarbon fields. The comparison of the total cost[15] to the EOR sink and non-EOR sink options confirms that the alternative options to the saline aquifers represent the true least-cost matching for three of the four sources. However, the California Portland Cement plant should remain matched to the EOR sink (LA006) since the total cost of transportation to the aquifer would be much higher than to the EOR field.

Table 19. Comparisons of alternative options for sources with EOR transportation costs over \$16/t CO_2

Facility Name	Plant Type	25-year CO_2 Flow (Mt)	Pipeline Diameter (inch)	Alternative Option			to EOR Sink	
				Destination	Transportation Cost (\$/t)	Injection Cost (\$/t)	Transportation Cost (\$/t)	EOR Credit (\$/t)
Delta Energy Center, LLC	POWER PLANT	5.43	6	Aquifer	0.00	1.95	30.75	16.00
Sutter Energy Center	POWER PLANT	3.97	6	Aquifer	0.00	2.66	65.30	16.00
TXI Riverside Cement	CEMENT	1.91	8	Aquifer	6.22	5.54	72.13	16.00
California Portland Cement	CEMENT	11.84	8	Aquifer	15.16	0.89	16.82	16.00

Appendix B presents the source-sink matching results for each of the CO_2 sources listed in this section. Thirty-three out of the 35 CO_2 sources were linked to oil fields with EOR potential, while the remaining 3 sources could find their least-cost sinks in saline aquifers.

[14] The WESTCARB database lacked sufficient detailed information to estimate the storage capacity in saline aquifers. It is assumed that the saline aquifers have enough capacity to hold all the CO_2 inflow; *i.e.*, there is no storage capacity constraint for saline aquifers.

[15] For the option "to EOR sink", total cost is calculated as transportation cost minus EOR credit (\$16/t). For the option "to non-EOR sink", total cost is calculated as the sum of transportation cost and injection cost.

In contrast to the results from the previous section, the results from the least-cost path source-sink matching provide an optimized pipeline arrangement based on construction cost criteria. In many cases this transportation distance will be longer than the straight-line distance calculated in the previous section. But, since transportation obstacle costs are included, the overall transportation cost will be less. If EOR fields were the only sequestration sinks considered, most of the sources could be linked to an appropriate sink. However, some of these sinks were more than 400 km (248 mi) away from the CO_2 source. The total transportation costs for most sources linked to EOR sinks were less than \$10/t CO_2. In reality, the transportation costs might be less since in some cases sources and sinks in the same region could share pipelines or pipeline routes. This would likely decrease transportation costs below the estimates presented here.

3.6.3 CO_2 Sequestration Full-Cost Estimation

For sources matched with EOR sites, the full cost estimate included costs for capture, transportation, and an EOR credit. For sources matched with gas fields or aquifers, the full-cost estimate included capture cost, transportation cost, and injection cost.

The injection cost analysis was based on methods used by Heddle *et al.* (2003). The Heddle injection cost model requires inputs for surface injection pressure, downhole injection pressure, CO_2 flow rate, and reservoir properties. Heddle *et al.* (2003) defined a base case, a high-cost case, and a low-cost case derived from an analysis of typical data for aquifers and gas fields. Since there is no aquifer property data available in the WESTCARB data set, the reservoir properties in the base case of Heddle's spreadsheet are used in this analysis. The surface injection pressure was assumed to be 10.30 MPa. Using the spreadsheet shown in Figure 20, the injection cost was calculated using the source CO_2 flow rate. A power plant with a 25-year CO_2 emission of 67.4 Mt was used as a reference case in the spreadsheet. In this reference case, the injection cost was estimated to be \$0.16 per tonne of CO_2.

Figure 21 and Appendix B show the results of the CO_2 sequestration full-cost estimation. The results of the full-cost sequestration analysis in California indicate that 20, 40, or 80 M tonnes of CO_2 per year could be sequestered in California at a cost of \$31/t, \$35/t, or \$50/t, respectively.

		AQUIFER - Base Case			
Inputs					
Surface inj. pressure	(MPa)	**10.30**			
Downhole inj. pressure	(MPa)	**21.30**	17.08	18.25	**17.92**
CO_2 mass flow rate	(t/d)	7,389			
	(kg/s)	86			
Reservoir properties					
Reservoir pressure	(MPa)	8.4			
Thickness	(m)	171			
Depth	(m)	1239			
Permeability	(md)	22			
Temperature	(deg C)	46.0			
Viscosity calculation					
Intermediate pressure	(MPa)	14.85	12.74	13.33	13.16
Viscosity	(mPa.s)	0.050	0.042	0.044	0.044
Well number calculation					
CO_2 mobility	(md/mPa.s)	242.4	286.8	272.6	276.5
CO_2 injectivity	(t/d/m/MPa)	5.042	5.966	5.670	5.751
CO_2 injection rate per well	(t/d)	11123	8856	9555	9363
Number wells required		0.7	0.8	0.8	**0.8**
Cost calculation					
Site screening & evaluation	($M)	1.69			
Injection equipment	($M)	0.04	0.04	0.04	0.04
Well drilling cost	($M)	0.24	0.24	0.24	0.24
Total capital cost	($M)	1.97	1.97	1.97	1.97
Normal daily expenses	($M/yr)	0.01	0.01	0.01	0.01
Consumables	($M/yr)	0.02	0.02	0.02	0.02
Surface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Subsurface maintenance	($M/yr)	0.01	0.01	0.01	0.01
Total O&M costs	($M/yr)	0.04	0.04	0.04	0.04
Annual total cost	($M)	0.34	0.34	0.34	0.34
$/tonne CO_2		0.16	0.16	0.16	**0.16**
Pressure change calculation					
CO_2 temperature	(deg C)	25			
CO_2 density	(kg/m^3)	822			
Gravity head					
Elevation change	(m)	-1239			
Pressure change	(MPa)	9.99			
Friction loss					
Well diameter	(m)	0.1200			
Viscosity	($N.s/m^2$)	6.06E-05			
Reynolds number	unitless	2.26E+07	1.80E+07	1.94E+07	1.90E+07
Roughness	(ft)	0.00015			
Friction factor	unitless	0.00395	0.00395	0.00395	0.00395
Well length	(m)	1239			
Velocity	(m/s)	13.85	11.03	11.90	11.66
Pressure change	(MPa)	3.21	2.04	2.37	2.28
Downhole pressure	(MPa)	17.08	18.25	17.92	18.02

Figure 20. Injection cost estimation spreadsheet

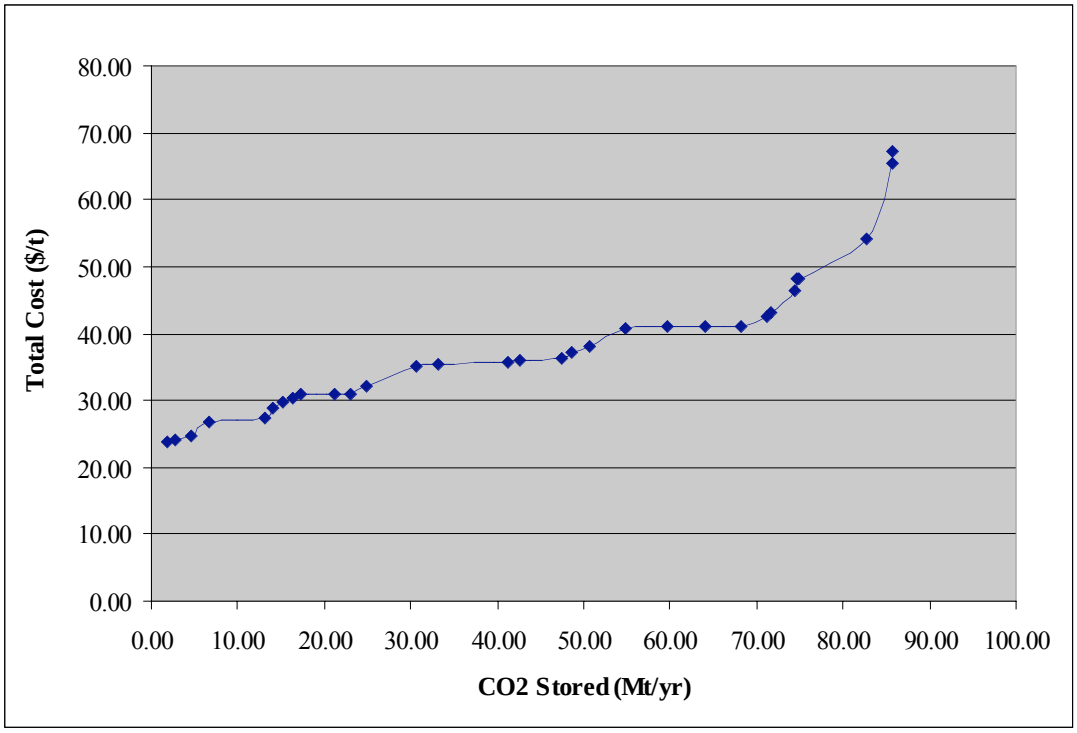


Figure 21. Marginal total cost by annual CO_2 storage rate, California

4 Conclusions

This study was conducted to highlight opportunities for carbon capture and storage in the WESTCARB region. The study provided preliminary estimates of the CO_2 emissions from major stationary sources, CO_2 storage capacity in oil and gas fields, and transportation requirements from the straight-line distance-based source-sink matching. The 77 major stationary CO_2 sources in the WESTCARB database have total annual CO_2 emissions of 159 Mt. A conservative estimation of the CO_2 storage potential in the oil and gas fields in the WESTCARB region is 5.2 Gt. The straight-line distance-based source-sink matching results showed that if all sinks, including Nevada sinks, were considered for sequestration, more than four-fifths of CO_2 sources could be matched with appropriate sinks within 50 km (31 mi). A more advanced GIS-based least-cost source-sink matching method was applied to analyze sources and sinks in California, which also takes into account the CO_2 storage capacity constraint of the sinks. For most CO_2 sources in California, the transportation costs to the corresponding EOR site are below \$10/t CO_2, less than the assumed \$16/t CO_2 credit for EOR injection. A full sequestration costing analysis, which includes capture cost, transportation cost, and injection cost (or net of EOR credit if matched to an EOR site), was also conducted for CO_2 storage in California. The results of the full sequestration cost analysis indicate that 20, 40, 80 Mt of CO_2 per year could be sequestered in California at a cost of \$31/t, \$35/t, or \$50/t, respectively.

As a preliminary approach, the study has some limitations. First, the CO_2 storage capacity in EOR sites is underestimated under the current method because of the use of cumulative oil production and gas production as proxies for original oil in place and original gas in place. Second, the study didn't estimate the CO_2 storage capacity in coalbeds and saline aquifers due to the lack of data. Third, the transportation model and the source-sink matching algorithm can be improved by adopting updated pipeline costing data and a more comprehensive optimization approach. Finally, the least-cost source-sink matching analysis was limited to California only. Phase II studies will be targeted to address these limitations and expand the least-cost source-sink matching-based full sequestration cost to the entire WESTCARB region.

5 References

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Appendices

Appendix A. List of Acronyms

Abbreviation	Meaning
BPD	barrels per day
CO_2	carbon dioxide
DOE	United States Department of Energy
ECBMR	enhanced coalbed methane recovery
eGRID	Emissions and Generation Resource Integrated Database
EOR	enhanced oil recovery
ERF	ECBM recovery factor
GIS	Geographic Information System
Gt	giga metric tonnes
HV	high-volatile
HVA	high-volatile A
IGEM	Institute of Geology of Ore Deposits, Petrography, Mineralogy & Geochemistry
LFEE	Laboratory for Energy and the Environment (at MIT)
LULC	land use and land cover
LV	low-volatile
MIT	Massachusetts Institute of Technology
MMCFD	millions of cubic feet per day
Mt	million metric tonnes
MV	moderate-volatile
MWe	megawatt electrical
OGIP	original gas in place
O&M	operations and maintenance
OOIP	original oil in place
PRF	primary recovery factor
Sub	sub-bituminous
tonne	metric ton
USGS	United States Geological Survey
WESTCARB	West Coast Regional Carbon Sequestration Partnership

Appendix B. CO_2 Sequestration Full Cost Estimation, California

(1) Facility Name	(2) Plant Type	(3) Pipeline Diameter (inch)	(4) 25-year CO2 Flow (Mt)	(5) Transportation Cost ($/t)	(6) Capture Cost ($/t)	(7) EOR Credit ($/t)	(8) Injection Cost ($/t)	(9) Total Cost ($/t)
AES Alamitos	POWER PLANT	20	205.27	2.88	48.81	16.00		35.70
AES Redondo Beach	POWER PLANT	16	124.45	3.28	53.65	16.00		40.93
BP WEST COAST CARSON REFINERY	REFINERY	12	48.8	0.51	40.03	16.00		24.54
Cabrillo Power I (Encina)	POWER PLANT	16	105.88	3.90	53.11	16.00		41.00
CALIFORNIA PORTLAND CEMENT	CEMENT	8	11.84	16.82	42.20	16.00		43.02
CALIFORNIA PORTLAND CEMENT CO. M	CEMENT	8	21.42	1.13	39.05	16.00		24.18
CEMEX - BLACK MOUNTAIN QUARRY	CEMENT	12	47.86	4.27	35.45	16.00		23.72
CHEVRON RICHMOND REFINERY	REFINERY	12	42.23	7.28	40.79	16.00		32.07
CHEVRONTEXACO EL SEGUNDO REFINERY	REFINERY	12	48.8	2.83	40.03	16.00		26.86
CONNACOPHILLIPS, WILMINGTON PLANT	REFINERY	12	25.65	1.96	43.64	16.00		29.60
Contra Costa Power Plant	POWER PLANT	12	64.03	4.10	47.19	16.00		35.29
Coolwater Generating Station	POWER PLANT	16	71.9	2.68	59.58	16.00		46.26
Delta Energy Center, LLC	POWER PLANT	6	5.43	0.00	46.16		1.95	48.11
Duke Energy South Bay	POWER PLANT	16	71.35	7.46	51.03	16.00		42.49
El Segundo	POWER PLANT	16	99.49	3.62	52.98	16.00		40.60
Etiwanda Generating Station	POWER PLANT	16	106.64	0.49	56.48	16.00		40.97
EXXONMOBIL TORRANCE REFINERY	REFINERY	12	27.97	1.78	43.12	16.00		28.90
HANSON PERMANENTE CEMENT	CEMENT	12	25.49	8.59	38.21	16.00		30.80
Harbor Generating Station	POWER PLANT	12	48.09	0.60	46.35	16.00		30.95
Haynes Gen Station	POWER PLANT	20	158.83	0.59	42.86	16.00		27.45
Mandalay Generating Station	POWER PLANT	12	52.59	0.36	53.84	16.00		38.20
MITSUBISHI CEMENT 2000, LUCERNE	CEMENT	12	26.84	6.32	37.96	16.00		28.28
Morro Bay Power Plant, LLC	POWER PLANT	16	98.13	1.15	45.67	16.00		30.81
Moss Landing	POWER PLANT	16	122.47	1.72	50.70	16.00		36.42
Ormond Beach Generating Station	POWER PLANT	20	144.52	0.25	50.71	16.00		34.97
Pittsburg Power Plant (CA)	POWER PLANT	20	196.17	2.32	67.71	16.00		54.03
Scattergood Generating Station	POWER PLANT	16	74.69	0.18	81.24	16.00		65.42
SHELL OIL PRODUCTS, MARTINEZ	REFINERY	12	29.9	10.47	42.72	16.00		37.19
Sutter Energy Center	POWER PLANT	6	3.97	0.00	45.53		2.66	48.19
TESORO AVON REFINERY MARTINEZ	REFINERY	12	31.16	9.61	42.48	16.00		36.09
TXI RIVERSIDE CEMENT	CEMENT	8	1.91	6.22	55.41		5.54	67.17

Appendix C. CO_2 Capture Cost Estimation and Straight-Line Distance Source-Sink Matching for Fossil-Fuel Power Plants, WESTCARB Region

(1) Facility ORIS Code	(2) State	(3) Design Capacity (Mwe)	(4) EGRID 2000 Electricity Production (MWh)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emission (t)	(7) Estimated Annual CO2 Emission at 80% Capacity (t)	(8) Fuel Type	(9) CO2 Capture Cost ($/t CO2 Captured)	(10) CO2 Avoid Cost ($/t CO2 Avoided)	(11) Dist to Nearest EOR O&G Fields (km)	(12) Dist to Nearest Oil & Gas Fields (km)	(13) Dist to Nearest Aquifer,w/ Nevada (km)	(14) Dist to Nearest Aquifer,w/o Nevada (km)	(15) Dist to Nearest Sink (km)
6288	AK	28	185,277	0.77	260,535	271,002	Coal	53.35	67.50					
8224	NV	521	4,011,243	0.88	3,998,874	3,641,547	Coal	37.84	47.87	506	403	14	227	14
126	AZ	559	1,639,965	0.34	1,455,424	3,473,565	Coal	37.53	47.48	614	614	315	315	315
6106	OR	561	3,790,921	0.77	3,998,677	4,143,170	Coal	37.52	47.46	897	668	43	43	43
2324	NV	612	4,238,122	0.79	5,343,704	5,407,923	Coal	37.13	46.98	390	382	8	55	8
6177	AZ	822	6,276,187	0.87	7,113,187	6,528,105	Coal	35.88	45.39	737	733	61	61	61
8223	AZ	850	5,876,943	0.79	6,245,526	6,327,788	Coal	35.74	45.21	744	741	91	91	91
113	AZ	1,105	6,795,289	0.70	8,441,969	9,624,591	Coal	34.66	43.84	652	649	0	0	0
3845	WA	1,460	9,400,803	0.74	10,345,031	11,259,898	Coal	33.55	42.44	1034	718	0	0	0
2341	NV	1,636	10,769,396	0.75	10,848,287	11,549,946	Coal	33.10	41.88	303	301	37	37	37
4941	AZ	2,409	18,096,243	0.86	20,137,721	18,789,569	Coal	31.64	40.03	643	641	0	0	0
10349	CA	50	349,219	0.81	177,484	176,294	GAS	79.25	100.26	124	2	0	0	0
54001	CA	74	434,076	0.67	202,072	241,425	GAS	74.47	94.21	19	9	2	2	2
54537	WA	246	1,935,850	0.90	953,258	847,812	GAS	61.86	78.26	n.a	n.a	n.a	n.a	n.a
7605	WA	248	n.a.	n.a.	804,272	n.a.	GAS	61.77	78.15	926	618	0	0	0
6559	AK	266	882,084	0.38	436,343	923,233	GAS	61.10	77.29	n.a	n.a	n.a	n.a	n.a
399	CA	293	985,252	0.38	1,024,155	2,137,553	GAS	60.19	76.14	7	0	0	0	0
96	AK	418	1,947,226	0.53	1,249,521	1,880,040	GAS	56.98	72.09	n.a	n.a	n.a	n.a	n.a
160	AZ	559	3,459,141	0.71	3,597,610	4,075,457	GAS	54.48	68.92	706	706	327	327	327
345	CA	573	2,555,413	0.51	1,486,659	2,337,514	GAS	54.27	68.65	0	0	0	0	0
8073	OR	586	2,837,242	0.55	1,725,588	2,498,589	GAS	54.08	68.42	948	628	0	0	0
141	AZ	613	2,043,449	0.38	1,333,532	2,805,220	GAS	53.70	67.94	475	475	201	201	201
54761	OR	621	4,216,100	0.77	1,674,494	1,729,179	GAS	53.60	67.81	920	705	82	82	82

Appendix C. (Continued)

(1) Facility ORIS Code	(2) State	(3) Design Capacity (Mwe)	(4) EGRID 2000 Electricity Production (MWh)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emission (t)	(7) Estimated Annual CO2 Emission at 80% Capacity (t)	(8) Fuel Type	(9) CO2 Capture Cost ($/t CO2 Captured)	(10) CO2 Avoid Cost ($/t CO2 Avoided)	(11) Dist to Nearest EOR O&G Fields (km)	(12) Dist to Nearest Oil & Gas Fields (km)	(13) Dist to Nearest Aquifer, w/ Nevada (km)	(14) Dist to Nearest Aquifer, w/o Nevada (km)	(15) Dist to Nearest Sink (km)
55077	NV	632	2,102,946	0.38	857,735	1,806,708	GAS	53.46	67.63	331	329	3	53	3
228	CA	676	2,769,971	0.47	1,664,108	2,845,844	GAS	52.90	66.93	6	3	0	0	0
329	CA	727	2,634,295	0.41	1,652,392	3,195,343	GAS	52.31	66.18	129	127	68	68	68
310	CA	729	2,276,565	0.36	1,413,186	3,171,246	GAS	52.29	66.15	103	103	95	95	95
2322	NV	790	3,691,787	0.53	2,033,845	3,049,814	GAS	51.64	65.33	335	333	0	60	0
404	CA	823	1,830,310	0.25	1,053,156	3,319,639	GAS	51.32	64.92	5	1	0	0	0
302	CA	1,000	3,226,385	0.37	2,165,749	4,705,593	GAS	49.79	62.99	41	41	34	34	34
331	CA	1,049	2,631,760	0.29	1,696,714	4,739,425	GAS	49.43	62.53	22	21	16	16	16
259	CA	1,056	5,262,644	0.57	3,101,024	4,361,496	GAS	49.38	62.46	73	30	25	25	25
356	CA	1,303	3,273,678	0.29	1,983,637	5,531,230	GAS	47.80	60.47	6	0	0	0	0
260	CA	1,404	8,048,763	0.65	4,452,297	5,442,906	GAS	47.25	59.77	133	23	1	1	1
350	CA	1,500	4,002,319	0.30	2,445,546	6,422,971	GAS	46.77	59.17	5	5	0	0	0
400	CA	1,606	3,568,531	0.25	2,238,622	7,059,115	GAS	46.28	58.55	23	19	7	7	7
271	CA	1,984	6,838,839	0.39	4,288,462	8,718,601	GAS	44.79	56.66	141	3	0	0	0
315	CA	2,129	6,473,582	0.35	3,957,192	9,123,209	GAS	44.30	56.05	1	1	0	0	0
2336	NV	413	1,793,661	0.50	1,683,565	2,714,333	GAS	57.10	72.23	261	185	0	157	0
330	CA	996	2,285,397	0.26	1,447,083	4,421,948	GAS	49.82	63.03	5	1	0	0	0
79	AK	23	67	0.00	45	121,229	Oil	66.15	78.63	n.a	n.a	n.a	n.a	n.a
6286	AK	40	3,054	0.01	6,537	608,060	Oil	61.53	73.14	n.a	n.a	n.a	n.a	n.a
6285	AK	129	335,913	0.30	335,613	906,143	Oil	52.92	62.90	n.a	n.a	n.a	n.a	n.a

Note: All sources in Alaska are not matched.

Appendix D. CO_2 Capture Cost Estimation and Straight-Line Distance Source-Sink Matching for Refineries, WESTCARB Region

(1) ID	(2) Plant Name	(3) State	(4) Design Capacity (BPD)	(5) Estimated Annual CO2 Emission (t)	(6) CO2 Capture Cost ($/t CO2 Captured)	(7) CO2 Avoid Cost ($/t CO2 Avoided)	(8) Dist to Nearest EOR O&G Fields (km)	(9) Dist to Nearest Oil & Gas Fields (km)	(10) Dist to Nearest Aquifer,w/ Nevada (km)	(11) Dist to Nearest Aquifer,w/o Nevada (km)
12	PETROSTAR VALDEZ	AK	46,000	390,000	51.12	64.67	n.a.	n.a.	n.a.	n.a.
13	TESORO ALASKA PETROLEUM CO KENAI	AK	72,000	601,000	47.86	60.55	n.a.	n.a.	n.a.	n.a.
9	TESORO NORTHWEST, ANACORTES	WA	110,000	959,000	44.71	56.57	1244	930	16	16
10	CONNACOPHILLIPS, WILMINGTON PLANT	CA	131,000	1,140,000	43.64	55.21	9	0	0	0
6	PUGET SOUND REFINING CO. ANACORTES	WA	145,000	1,210,000	43.28	54.75	1245	932	19	19
5	EXXONMOBIL TORRANCE REFINERY	CA	149,000	1,243,000	43.12	54.55	5	1	0	0
7	SHELL OIL PRODUCTS, MARTINEZ	CA	160,000	1,329,000	42.72	54.05	29	6	5	5
8	TESORO AVON REFINERY MARTINEZ	CA	166,000	1,385,000	42.48	53.75	25	1	1	1
11	FLINT HILLS NORTH POLE	AK	197,000	1,651,000	41.49	52.49	n.a.	n.a.	n.a.	n.a.
1	BP, CHERRY POINT	WA	223,000	1,877,000	40.79	51.60	1288	972	0	0
3	CHEVRON RICHMOND REFINERY	CA	225,000	1,877,000	40.79	51.60	50	29	5	5
2	BP WEST COAST CARSON REFINERY	CA	260,000	2,169,000	40.03	50.64	3	1	0	0
4	CHEVRONTEXACO EL SEGUNDO REFINERY	CA	260,000	2,169,000	40.03	50.64	3	1	0	0

Note: It is assumed that the flue gas comprises of 10% of CO2 and 90% of N2 in volume.
Refineries at Alaska are not matched to corresponding Sinks

Appendix C. (Continued)

(1) Facility ORIS Code	(2) State	(3) Design Capacity (Mwe)	(4) EGRID 2000 Electricity Production (MWh)	(5) EGRID 2000 Operating Factor	(6) EGRID 2000 CO2 Emission (t)	(7) Estimated Annual CO2 Emission at 80% Capacity (t)	(8) Fuel Type	(9) CO2 Capture Cost ($/t CO2 Captured)	(10) CO2 Avoid Cost ($/t CO2 Avoided)	(11) Dist to Nearest EOR O&G Fields (km)	(12) Dist to Nearest Oil & Gas Fields (km)	(13) Dist to Nearest Aquifer, w/ Nevada (km)	(14) Dist to Nearest Aquifer, w/o Nevada (km)	(15) Dist to Nearest Sink (km)
55077	NV	632	2,102,946	0.38	857,735	1,806,708	GAS	53.46	67.63	331	329	3	53	3
228	CA	676	2,769,971	0.47	1,664,108	2,845,844	GAS	52.90	66.93	6	3	0	0	0
329	CA	727	2,634,295	0.41	1,652,392	3,195,343	GAS	52.31	66.18	129	127	68	68	68
310	CA	729	2,276,565	0.36	1,413,186	3,171,246	GAS	52.29	66.15	103	103	95	95	95
2322	NV	790	3,691,787	0.53	2,033,845	3,049,814	GAS	51.64	65.33	335	333	0	60	0
404	CA	823	1,830,310	0.25	1,053,156	3,319,639	GAS	51.32	64.92	5	1	0	0	0
302	CA	1,000	3,226,385	0.37	2,165,749	4,705,593	GAS	49.79	62.99	41	41	34	34	34
331	CA	1,049	2,631,760	0.29	1,696,714	4,739,425	GAS	49.43	62.53	22	21	16	16	16
259	CA	1,056	5,262,644	0.57	3,101,024	4,361,496	GAS	49.38	62.46	73	30	25	25	25
356	CA	1,303	3,273,678	0.29	1,983,637	5,531,230	GAS	47.80	60.47	6	0	0	0	0
260	CA	1,404	8,048,763	0.65	4,452,297	5,442,906	GAS	47.25	59.77	133	23	1	1	1
350	CA	1,500	4,002,319	0.30	2,445,546	6,422,971	GAS	46.77	59.17	5	5	0	0	0
400	CA	1,606	3,568,531	0.25	2,238,622	7,059,115	GAS	46.28	58.55	23	19	7	7	7
271	CA	1,984	6,838,839	0.39	4,288,462	8,718,601	GAS	44.79	56.66	141	3	0	0	0
315	CA	2,129	6,473,582	0.35	3,957,192	9,123,209	GAS	44.30	56.05	1	1	0	0	0
2336	NV	413	1,793,661	0.50	1,683,565	2,714,333	GAS	57.10	72.23	261	185	0	157	0
330	CA	996	2,285,397	0.26	1,447,083	4,421,948	GAS	49.82	63.03	5	1	0	0	0
79	AK	23	67	0.00	45	121,229	Oil	66.15	78.63	n.a	n.a	n.a	n.a	n.a
6286	AK	40	3,054	0.01	6,537	608,060	Oil	61.53	73.14	n.a	n.a	n.a	n.a	n.a
6285	AK	129	335,913	0.30	335,613	906,143	Oil	52.92	62.90	n.a	n.a	n.a	n.a	n.a

Note: All sources in Alaska are not matched.

Appendix XXI, Final Report

Carbon Sequestration through Changes in Land Use in Oregon and Washington: Costs and Opportunities

Deliverable associated with Task 4.0, Item 3

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

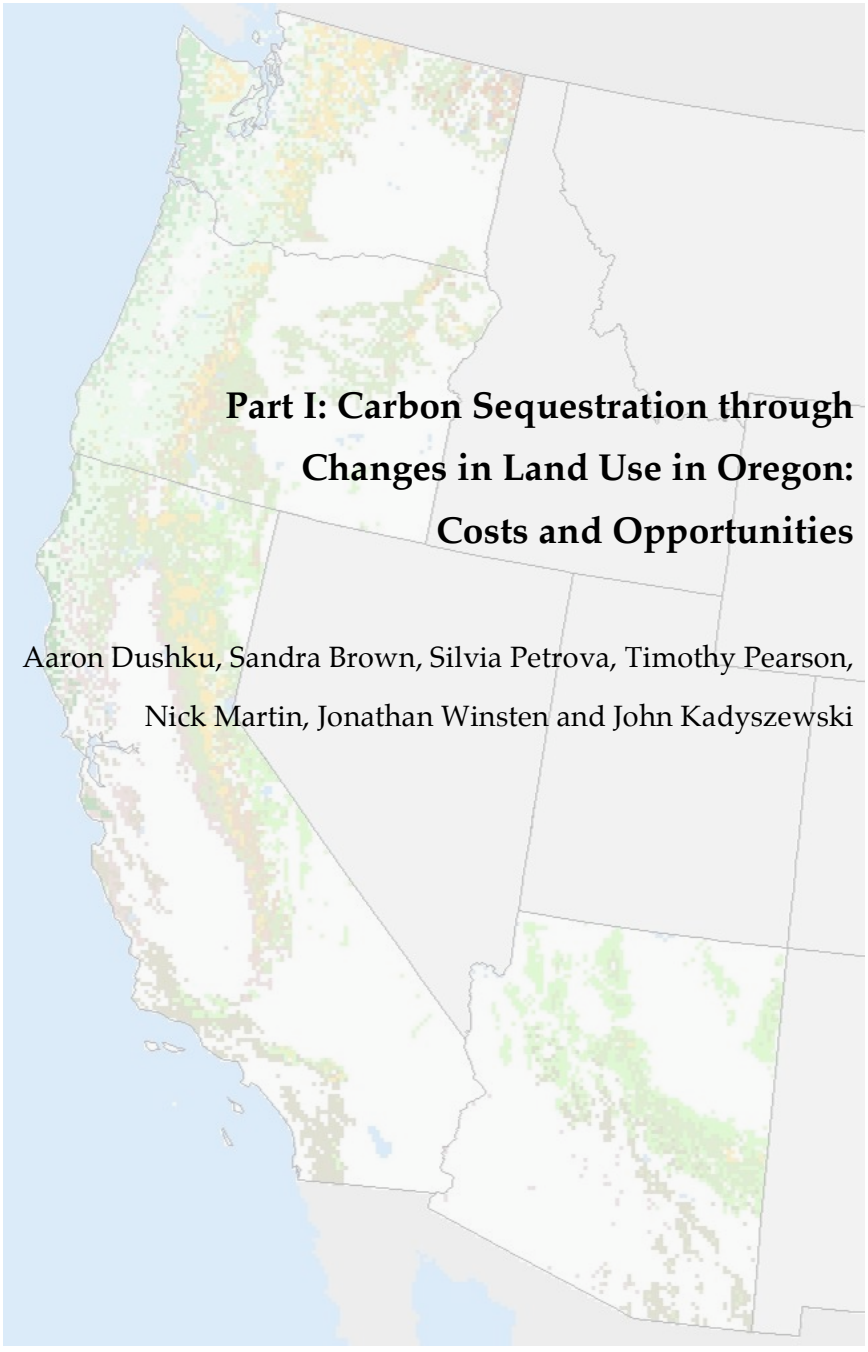
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This paper constitutes the required WESTCARB Phase I deliverable associated with Task 4.0, item 3 ("a paper on terrestrial supply curves."). In order to facilitate state-specific review of the paper, it was divided into the following sections:

- Part I: Carbon Sequestration through Changes in Land Use in Oregon: Costs and Opportunities, and
- Part II: Carbon Sequestration through Changes in Land Use in Washington: Costs and Opportunities.



Part I: Carbon Sequestration through Changes in Land Use in Oregon: Costs and Opportunities

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Abstract

This paper presents potential carbon supply from several classes of activities in Oregon forest, range and agricultural lands: afforestation of rangelands, afforestation of crop lands, changes in forest management including extending rotations and widening riparian buffers, and hazardous fuel reduction to reduce emissions from wildfire in fire-prone forest ecosystems. For each activity, methods and results are presented for estimating the total quantity of carbon that could be sequestered, followed by an economic analysis summarizing total costs of converting lands or changing management to sequester carbon. Carbon supply curves are presented illustrating the total area of land that would be converted or put under different management, and total quantity of carbon thus sequestered, at different assumed prices of carbon. The paper concludes with a summary of next steps and further refinements for the second phase of the West Coast Regional Carbon Sequestration Partnership.

Keywords: carbon sequestration, afforestation/reforestation, forest management, hazardous fuel reduction

Executive Summary

Introduction

Of late there have been several estimates of the terrestrial carbon storage potential in regions of the United States based on biological and technical criteria coupled with coarse-scale consideration of the economic costs associated with changing land management practices. Recent work by Winrock International for California, and for all the states under the US Department of Energy's Southeast Regional Carbon Sequestration Partnership, has focused on adding more detailed analysis of opportunities on both agricultural and forest lands; biological rates of carbon sequestration, taking into consideration variations in site conditions across the landscape; and incorporating more detailed analysis of all costs. Consideration of the varying carbon sequestration potential of different land classes and other economic factors yield more realistic estimates of carbon storage potential and associated costs. Realistic assessments of the potential for carbon sequestration from changes in land use can help policy makers and the private sector prepare for an uncertain regulatory future by providing estimates of the quantity of carbon credits that might be available at different price points for different classes of activities.

Purpose

The broad purpose of the project entitled "BASELINES, CARBON SUPPLY CURVES AND PILOT ACTIONS FOR TERRESTRIAL CARBON SEQUESTRATION" is to quantify terrestrial carbon sequestration opportunities across the West Coast Partnership Region (Arizona, California, Oregon, and Washington) and estimate the quantity of carbon credits that might be available at different price points.

Project Objectives

Methodologies developed by Winrock International in previous research will be applied to develop carbon supply curves for the major classes of potential land-use and forest-based activities in Oregon. Specifically:

- Prepare carbon supply estimates for different classes of potential terrestrial project activities, including afforestation of cropland, afforestation of rangeland, and changes in management of forestland.
- Assess the potential for hazardous fuel removal from forests with high fuel loads as a carbon sequestration activity.

Project Outcomes

The state of Oregon's lands are classified into three main groups: forests, rangelands, and agricultural lands. Forests (about 26.1 million acres) include conifers, hardwoods, and mixed classes; rangelands (about 27 million acres) include a variety of non-woody and woody ecosystems; and agricultural lands (about 6.4 million acres) include a wide range of non-woody crops such as wheat and hay and woody crops such as vineyards and orchards.

For rangelands and croplands (lands growing wheat and hay), the potential carbon sequestration was estimated for afforestation using native species with no subsequent

harvesting—i.e for restoration. Historical evidence suggests that in many areas, large tracts of forest may have once stood where grazing and agricultural lands now do. The general approach was to identify and locate existing rangelands and croplands where biophysical conditions could favor forests, estimate rates of carbon accumulation for the forest types projected to grow, and assign values to each contributing cost factor. The carbon supply is estimated for three time durations: 20 years, 40 years and 80 years of forest growth, to reflect the impact of activity duration on the likely supply and to provide an assessment for the near–term and longer-term planning horizons.

For forestlands, potential carbon supply was estimated for three alternatives: (1) allowing timber to age past economic maturity (lengthening rotation time); (2) increasing the riparian buffer zone by an additional 200 feet; and (3) hazardous fuel reduction in forests to reduce catastrophic fires, and subsequent use of fuels in biomass power plants. For estimating the costs of allowing timber to age and the costs of enhanced riparian zone management, estimates are based on specific counties for public and private landowners, and then extrapolated to all counties throughout the state. For the fuel reduction alternative, the analysis used a "Suitability for Potential Fuel Reduction (SPFR)" score on forest landscapes where potential exists for significant carbon loss from wildfires. Suitability scores for potential fuel reduction with highest suitability were assigned to areas with gentle grades of slope that are close to roads and biomass power plants.

Although the whole range of costs and potential carbon available are presented in this paper, Table ES-1 summarizes the amount of carbon and the area available for afforestation of rangelands and croplands at three price points: ≤ \$2.40/t CO_2 (\$8.81/t C), ≤ \$10.00/t CO_2 (\$36.67/t C), and ≤\$20.00/t CO_2 (\$73.33/t C).

At a price of ≤ \$2.40/t CO_2, the no carbon can be sequestered after 20 years by afforesting rangelands and croplands, but after 80 years about 732 MMT CO_2 could be sequestered on rangelands (Table ES-1). If prices per t CO_2 rose to \$20 it is possible to convert more productive range and crop lands with higher opportunity costs and sequestering almost 280 MMT CO_2 carbon even with a 20-year time duration, and the total amount rises sharply to more than 1,813 MMT CO_2 at 40 years and approximately 4,203 MMT CO_2 at 80 years (Table ES-1). Converting this total amount at 40 years to an approximate annual rate results in about 45 MMT CO_2/yr.

Although Oregon has substantial areas of forests, 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. If all of the private and non-federal public land nearing the economically optimal rotation period (790 thousand acres) were contracted to increase rotation ages up to 15 years, 35.6 MMT CO_2 could be sequestered for average costs of \$37/t CO_2.

The potential area of mature forests where the riparian buffer zone could be increased by an additional 200 feet was estimated at 20,700 acres. The additional carbon that could be stored on these lands if the forests were conserved is 1.25 MMT CO_2 at an average cost of \$40/t CO_2.

Table ES-1. Summary of the quantity of carbon (million metric tons CO_2 [MMT CO_2]) and area (million acres) available at selected price points for afforestation on existing rangelands and croplands of Oregon over 20-year, 40-year, and 80-year durations.

	Quantity of C—MMT CO_2			Area available—million acres		
Activity	**20 years**	**40 years**	**80 years**	**20 years**	**40 years**	**80 years**
Rangelands-Afforestation						
≤$2.40	0.0	0.489	732.2	0.0	0.001	1.4
≤$10.00	0.195	337.3	2,156	0.001	1.42	12.3
≤$20.00	117.7	1,336	2,827	1.40	15.6	19.1
Croplands-Afforestation						
≤$2.40	0.0	0.0	0.0	0.0	0.0	0.0
≤$10.00	0.279	457.2	997.9	0.002	1.91	1.93
≤$20.00	162.0	477.2	1,376	1.91	2.15	5.06

From the forest hazardous fuel reduction analysis, the area of Oregon forests with historically low and mixed severity fire regimes, yet mapped today as containing high quantities of hazardous fuel, is estimated to be 10.3million acres. A commonly used potential hazardous fuels treatment is "Cut-Skid-Chip-Haul" (CSCH), a treatment in which hazardous fuel is harvested in the woods, bunched and skidded to a landing, chipped into a chip van, and hauled to a biomass energy facility for electricity and/or heat generation. The area of forestlands with historically low and mixed severity fire regimes in the state to which this treatment could be applied is approximately 2.9 million acres. Two removal scenarios were analyzed: HFR removal of 4 bone dry tons (BDT)/acre on these lands would yield 12 million BDT biomass fuel for use in energy facilities, while removal of 8 BDT/acre would yield 23 million BDT. Total estimated costs and potential revenue from these removals were analyzed. During moderate to intense fires, 10-70% of the biomass stock burns and is emitted as CO_2. A preliminary analysis suggested that considering the differences in CO_2 emissions between high-, medium- and low-intensity fires, HFR treatments that reduced fire intensity would avoid sufficient emissions to be able to cover, at commonly used prices for carbon of $2.40/t CO_2 and $10/t CO_2, the subsidies needed to pay for CSCH – adding support to the argument for qualifying fuel reduction activities as carbon offset projects.

Conclusions

The key conclusions from this work are:

- The largest terrestrial sequestration opportunity, both in terms of absolute quantity and costs, is afforestation of rangelands.
- Changes in forest management by lengthening rotation age beyond the economical rotation, has limited potential both in terms of quantity and costs.

- Forest fire appears to be the most important management issue to address and hazardous fuel removal has the potential to avoid substantial carbon dioxide emissions.
- Forest conservation, such as extending riparian buffers, is limited in scope and tends to be expensive.

Recommendations

It is recommended that further work focus on refinements to the analysis of fuel load reduction on wildfire-prone forests, and on afforestation using fast-growing species such as hybrid poplar or native species for timber production.

Recommended next steps for fuel load reduction include the analysis of other fuel removal treatment types and how the constraints on each affect the amount of forest land that could be treated; and the development of baselines for various wildfire-prone forest types. Such baselines need to include field data and models to quantify the likelihood of fires occurring (e.g. fire-return interval) as well as the effects of fire on greenhouse gas emissions from forests under different intensities of fire (how much of the forest's carbon stock in different pools is emitted under different fire intensities and stand structures). More detailed economic analysis is also needed to determine if fuel removal produces sufficient emissions reductions to pay for currently uneconomic treatments.

The work on afforestation of rangelands and croplands considered only the planting of native species for forest restoration. However, it is possible that forest could be grown for timber and non-timber products using both native and fast-growing species. Simulating the growing of trees for products affects two components of the carbon supply analysis: the quantity of carbon sequestered and the costs. How changes in carbon sequestration and costs affect total carbon supply needs to be investigated across the region.

1. Introduction

1.1 Objectives of study

Of late there have been several estimates of the terrestrial carbon storage potential in regions of the United States based on biological and technical criteria coupled with coarse-scale consideration of the economic costs associated with changing land management practices. Recent work by Winrock International, including for California and for all the states under the US Department of Energy's Southeast Regional Carbon Sequestration Partnership, has focused on adding more detailed analysis of opportunities on both agricultural and forest lands; biological rates of carbon sequestration, taking into consideration variations in site conditions across the landscape; and incorporating more detailed analysis of all costs. Consideration of the varying carbon sequestration potential of different land classes and other economic factors will yield more realistic estimates of carbon storage potential. Realistic assessments of the potential for carbon sequestration from changes in land use can help policy makers and the private sector prepare for an uncertain regulatory future by providing estimates of the quantity of carbon credits that might be available at different price points for different classes of activities.

The main goal of this study is to generate estimates of potential carbon supply, including total amount, $/t CO_2 (dollars per ton of carbon dioxide) , and location, from changes in the use and management of three classes of land in Oregon: rangelands, croplands, and forest lands. The remainder of this paper is divided into the following sections: Section 2 on carbon sequestration potential through afforestation of rangelands and croplands, Section 3 on potential changes in forest management to sequester additional carbon, and Section 4 on fuel load reduction in wildfire-prone areas to reduce emissions and/or sequester carbon.

2. Afforestation of rangelands and croplands

2.1. Background

Over 100 years ago, when Oregon's booms in timber, gold and silver had not yet attracted thousands of people into the region to exploit its forest resources, historical evidence suggests that in many places, tracts of forest may have once stood where human populations, agriculture and grazing lands now do. We hypothesize that a significant proportion of today's woodland, shrub and grassland vegetation types on Oregon's rangelands and much of its agricultural lands were once either closed forests or similar woodlands but with significantly higher biomass than they currently contain.

Oregon's cattle and calves industry is the state's second largest agricultural sector. Hay is the third and dairy production is the fifth (USDA-NASS 2004). Oregon is the twenty-first leading beef cow producing state in the U.S. and the state has a total of over 1.4 million head of cattle. Oregon ranks within the nation's top ten states for sheep, ewes and market sheep and lambs inventories (USDA-NASS 2004). There are approximately 6.5 million acres of agricultural land in Oregon (Karl et al 1999). The top grossing agricultural commodities in Oregon are greenhouse and nursery products and grass seed. Lower value crops include hay and wheat. Hay was produced on over 1 million acres and wheat on approximately 1 million acres of Oregon agriculture land in 2003 (USDA-NASS 2004).



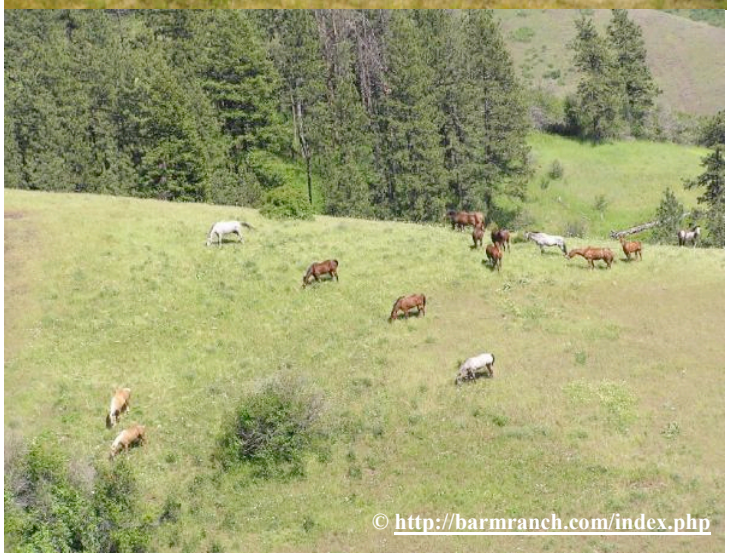




Figure 2-1. The variety of Oregon rangelands.

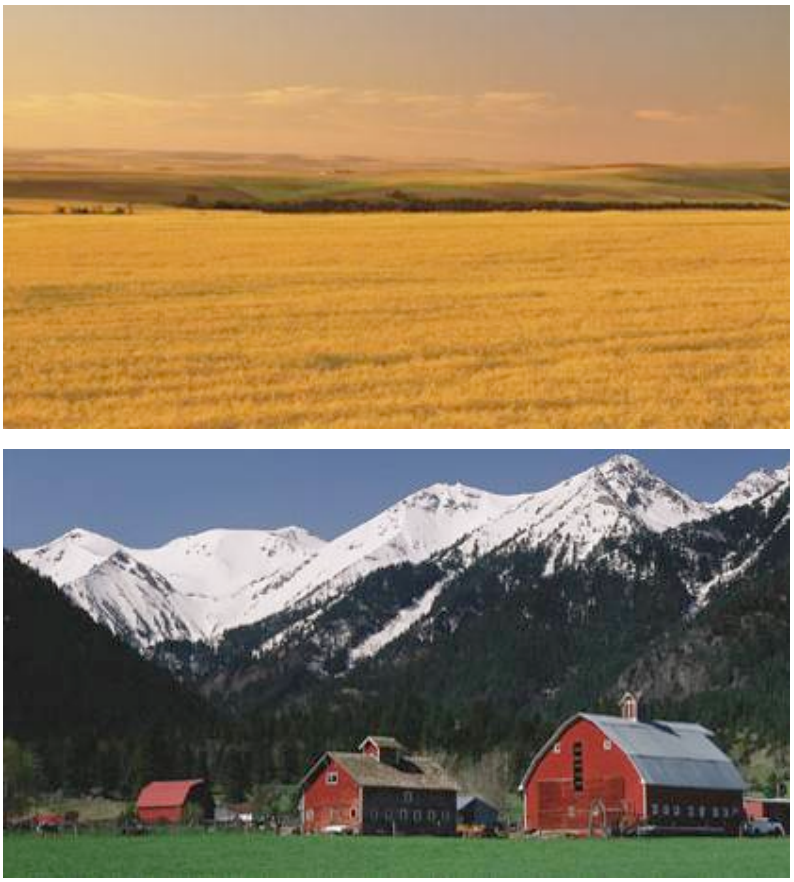


Figure 2-2. The variety of Oregon agricultural lands (Photos by J.L. Torretta and D. Jensen - http://www.eova.com/).

Presently in Oregon, on lands that were once forestland, wheat and hay farms occupy the majority of the agricultural lands and ranching takes place on the rangelands (Figure 2-1 & 2-2).

2.2. Approach

Unless otherwise noted, the methods applied in this section are identical to those of a previous Winrock study by Brown et al. (2004—Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California). In addition to rangelands in Oregon, potential opportunities also occur on crop lands. Methods used for analyzing costs on crop lands are practically the same as those used in a previous Winrock International study for the Southeast Regional Carbon Sequestration Partnership (Brown & Kadyszewski 2005a).

The analyses take the following steps to assess the quantity and cost of potential carbon sequestration:

- Identify the area and current use and cover of lands that have the potential to be managed for carbon sequestration—referred to as "candidate lands," including rangelands and selected crop lands.
- Estimate the area and geographic location of candidate lands that could be afforested and the rates of carbon sequestration on them.

- Estimate the total cost of afforesting candidate lands, including opportunity cost, conversion cost, maintenance costs, and measurement and monitoring costs.
- Combine the estimated quantities of carbon per unit area with the corresponding area and cost to produce estimates of the total quantity of carbon that can be sequestered for given range of costs, in $/ton CO_2.
- Determine the geographic distribution of available carbon at various prices.

The analysis is performed in a geographic information system (GIS) to superposition the diversity of existing land cover, rates of carbon sequestration, and costs in the analyses. As a result, not only are more realistic estimates of the potential supply of carbon produced, but the use of GIS shows where the least to most expensive carbon credits will most likely be found.

For agricultural lands, high-value crop producing areas are unlikely to be converted for carbon sequestration activities due to high opportunity costs. The value of hay production per acre is significantly more than the value of open rangeland, often by 10 times or more. However, in certain places hay production may provide good opportunities for affordable carbon sequestration activities because the overall value per acre is still generally low. Also, with average yields of 50-60 bushels per acre, wheat-producing land has a production value of generally less than $250 per year (USDA-NASS 2004), making wheat land also an attractive candidate for carbon projects.

This study used a wide variety of spatial and non-spatial data sets. The spatial data include:

- National Elevation Dataset 30m DEM grids, developed by USGS (2004a);
- National Land Cover Dataset (NLCD), developed by USGS (2004b);
- NRCS STATSGO soil survey maps and databases and resultant analyses by non-NRCS researchers (Schwarz and Alexander 1995; Miller et al. 1998);
- DAYMET Mean Annual Temperature map (Thornton et al. 1997);
- Oregon Geospatial Data Clearinghouse precipitation maps (derived from USGS);
- Northwest Regional Gap Analysis land cover dataset (Karl et al 1999).

Non-spatial data include, for example, regression equations for converting US Forest Service Forest Inventory and Analysis (FIA) data to biomass carbon, forest growth models, published literature, experience from other Winrock activities, and state and county reports of agricultural statistics. The details of all of these data and their applications are given in the appropriate sections below.

The carbon supply for afforestation options is estimated for three time durations – 20 years, 40 years and 80 years – to reflect the impact of activity duration on supply and to provide an assessment for the near–term and longer-term planning horizons. Several key assumptions of the analysis are shown in Figure 2-3 with the corresponding steps of the analysis.

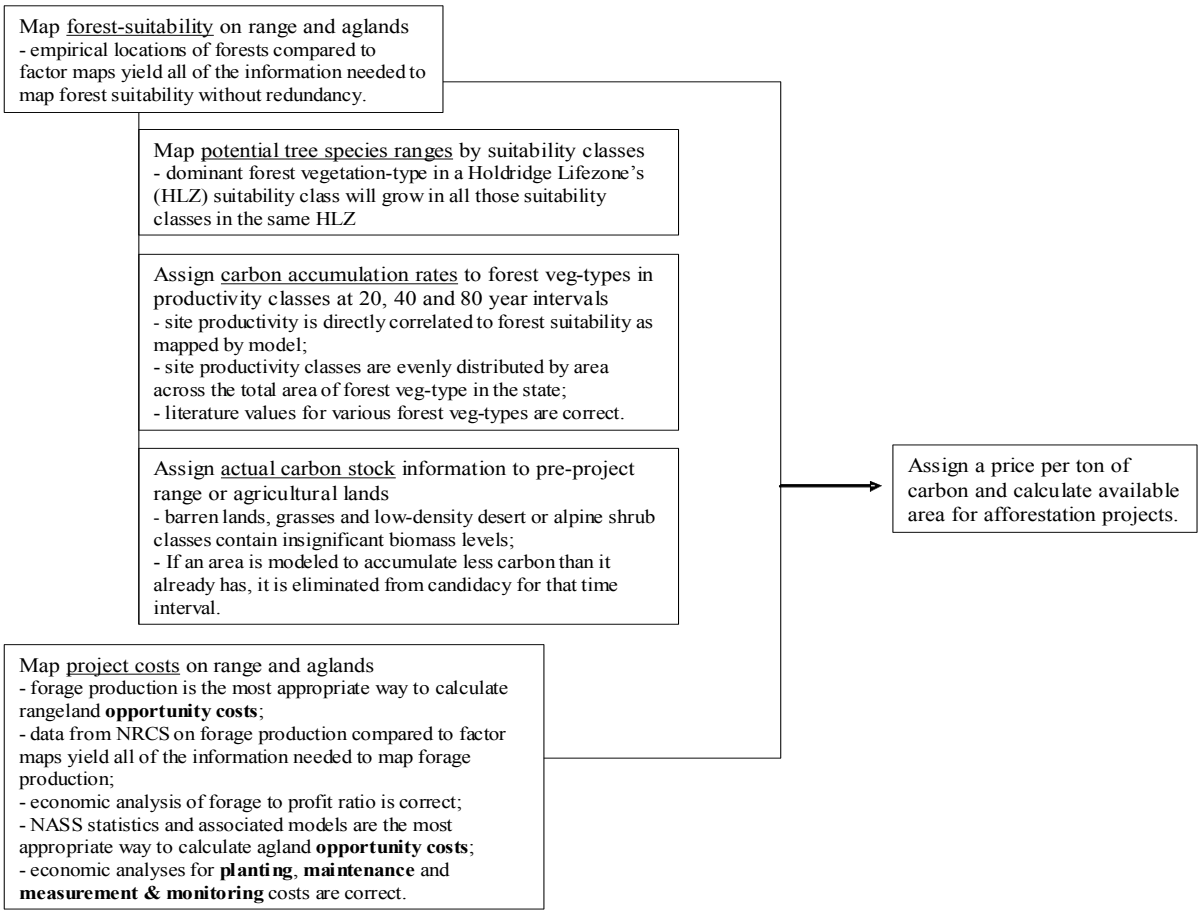


Figure 2-3. Flowchart of carbon supply curve analysis with key assumptions listed below each step.

2.2.1 Scale of analyses

This study aims to estimate the amount of carbon that can be sequestered on the selected areas through afforestation. The level of resolution used in this analysis is the same as that used by NLCD (30 meter pixels) and by the Oregon GAP Analysis in their land cover map product. GIS software used in the analyses was ESRI's ArcGIS 9.0 suite and ArcView 3.3, with Idrisi Kilimanjaro and ERDAS Imagine also used intermittently.

2.2.2 Oregon land cover characterization

The 30-meter resolution, NW Regional Gap Analysis land-cover map (Karl et al 1999) was used as the base for vegetation mapping because it allowed for more resolution between forest and rangeland classes than the USGS NLCD and because it offered a uniform vegetation classification system for comparison with a concurrent analysis for the state of Washington. Although the Oregon map was produced in 1999, the majority of the data used to create it came from Landsat satellite imagery gathered from 1991 to 1993. Much inquiry and investigation was made into the incorporation of other, more recent datasets into this analysis although all assembled datasets were eventually rejected due to incomplete coverage or incompatible land

cover classification systems. Several well-known Landsat satellite imagery-based examples follow with the justification for not using them:

- The Interagency Vegetation Mapping Project (IVMP) was an initiative that mapped the forest types and attributes of the coastal areas of the Pacific Northwest from 1998 to 2002. The project mapped only forest land cover types and no agricultural or rangelands and did not cover the entire state. http://www.or.blm.gov/gis/projects/ivmp_data.asp
- The National Land Cover Dataset (NLCD) from the USGS mapped land-cover in 1992. Although it did include 3 agricultural land cover classes that the GAP Analysis did not have, all other classes were too coarse for making species-specific discriminations. http://landcover.usgs.gov/nlcd/show_data.asp?code=OR&state=Oregon
- ODF's Atterbury Consultants non-industrial private forestland (NIPFL) dataset. This dataset mapped Western Oregon's NIPFL in great detail in the early 1990's although it only mapped one ownership class, for just the Western half of the state.
- The Northwest Habitat Institute's vegetation maps used slightly more recent Landsat imagery than the GAP Analysis or NLCD to map vegetation communities in Oregon, but the classes were more mixed in their species types with a larger variety of biomass levels within each one as compared to the GAP analysis. http://www.nwhi.org/NHI/default.asp?pageurl=books/booklist.asp
- The updated GAP Analysis dataset from Oregon State University (not compiled into one data set) would have taken considerable effort to patch together with other datasets and then to reconcile inevitable vegetation classification differences within them. Moreover, these classes had not been cross-walked into the Karl et al (1999) classification system also used in the state of Washington.

For individual land cover types or specific regions of the state, some of these other datasets may have provided a better idea of the actual characteristics of the land today. Nevertheless, the regional GAP analysis map compiled by Karl et al (1999) from the original Oregon GAP analysis of Kagan et al (1999b) is the most up-to-date and detailed land-cover data available *for the entire state* of Oregon that exists at this time.

Through consultation with Oregon Natural Heritage Information Center (J. Kagan, *pers. comm.* 2004), the vegetation classes present in the land cover dataset were combined into three discrete classes: rangelands, forests and 'other' (Table 2-1). The 'other' class included agricultural lands, urban and residential development and water bodies.

The three broad classes are shown in the map in Figure 2-4. The area of rangelands (27 million ac) in Oregon is about the same as that for forests (26 million ac). Any inconsistency in these numbers with other published data may be due to the inclusion of the generally low-biomass 'Western Juniper' areas in the rangelands class instead of forests. Agriculture lands cover about 6.4 million ac or about one-fourth the area of forests or of rangelands (Table 2-1).

Table 2-1. Land cover classification, areas and class generalization in Karl et al. (1999) GAP Analysis. Actual cover is for the period 1991-1993.

GAP Analysis Vegetation Class	Broad Landuse category	Hectares	Acres	%of total
Mixed Mesic Coniferous Forest	FOREST	3,822,481	9,441,529	15.4
Mixed Xeric Coniferous Forest	FOREST	2,284,232	5,642,053	9.2
Ponderosa Pine	FOREST	1,887,820	4,662,916	7.6
Xeric Douglas-fir	FOREST	1,026,754	2,536,081	4.1
Mesic Mixed Forest	FOREST	496,367	1,226,027	2.0
Mixed Subalpine Coniferous Forest	FOREST	289,280	714,522	1.1
Xeric Mixed Forest	FOREST	145,272	358,821	0.5
Mixed Coastal Forest	FOREST	143,129	353,530	0.5
Mesic Deciduous Forest	FOREST	141,441	349,358	0.5
Mountain Hemlock	FOREST	133,607	330,009	0.5
Lodgepole Pine	FOREST	103,233	254,984	0.4
Xeric Deciduous Forest	FOREST	46,525	114,916	0.1
Jeffrey Pine	FOREST	21,561	53,256	0.0
Deciduous Forested Riparian	FOREST	11,942	29,496	0.0
Subtotal		**10,553,643**	**26,067,498**	**42.6**
Agricultural	Agriculture	**2,597,234**	**6,415,169**	**10.4**
Water	OTHER	327,918	809,957	1.3
Urban/Developed	OTHER	227,667	562,338	0.9
Lava/exposed rock	OTHER	63,278	156,297	0.2
Ice/Snow	OTHER	62,618	154,666	0.2
Estuarine Emergents	OTHER	13,631	33,669	0.0
Tidal Flats	OTHER	1,065	2,630	0.0
Sand	OTHER	138	341	0.0
Subtotal		**3,293,549**	**8,135,066**	**13.3**
Big Sagebrush	RANGELAND	7,072,243	17,468,441	28.5
Western Juniper	RANGELAND	1,525,921	3,769,024	6.1
Xeric Grasslands	RANGELAND	1,278,158	3,157,050	5.1
Shrub Dominated Riparian	RANGELAND	403,203	995,912	1.6
Salt-desert Shrub	RANGELAND	281,302	694,816	1.1
Other Sagebrush	RANGELAND	174,819	431,804	0.7
Subalpine Meadow	RANGELAND	74,075	182,966	0.3
Bitterbrush	RANGELAND	61,764	152,558	0.2
Graminoid/Forb Riparian	RANGELAND	27,358	67,574	0.1
Upland Shrublands	RANGELAND	22,491	55,553	0.0
Wet Meadow	RANGELAND	1,175	2,902	0.0
Mountain Mahogany	RANGELAND	554	1,369	0.0
Subtotal		**10,923,064**	**26,979,969**	**44.1**

Candidacy for afforestation on agricultural lands was not based on the GAP analysis' 'agriculture' class. As specified earlier, this analysis aimed at identifying cost-effective afforestation projects and from early analysis of NASS data, it was evident that opportunity costs on high-value agricultural lands in Oregon would make afforestation prohibitively expensive.

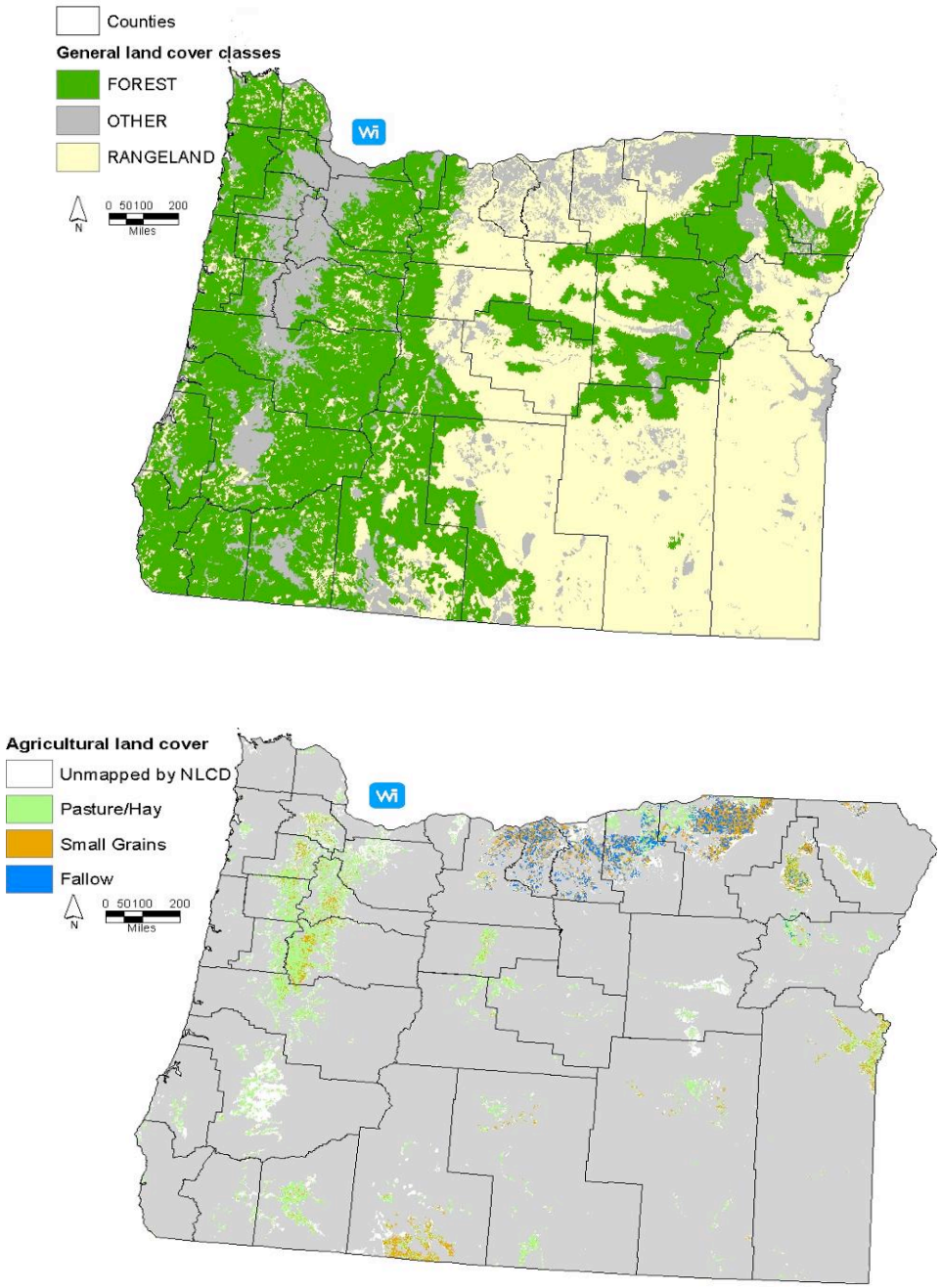


Figure 2-4. Broad land-cover classes from NW Regional GAP analysis (top) and cropland cover classes from the NLCD map (bottom).

Lands targeted by this study were wheat and hay fields but given the lack of any resolution within the GAP analysis' 'agriculture' vegetation class, another data source was tapped. The USGS NLCD dataset (USGS 2004b) disaggregates agriculture into 'small grains', 'row crops', 'pasture/hay' and 'fallow'. The two datasets were combined to create a new layer of agricultural land cover candidates wherein anything that was mapped by NLCD as 'pasture/hay', 'small grains' or 'fallow', plus any lands mapped as agriculture by the GAP analysis and not by NLCD, were made candidates for afforestation (Figure 2-4). The decision to put into candidacy the 'fallow' and unmapped agricultural lands is based upon the fact that most agricultural lands in the state are pastures, hay or wheat (USDA-NASS 2004).

2.2.3 Mapping suitability for afforestation with native species

To map the suitability for a non-forested landscape to grow trees, certain variables in the STATSGO state soils databases ('sitind', 'woodprod', etc.) have been successfully used in eastern sates of the US (e.g. Southeast States; Brown and Kadyszewski, 2005a). In more arid landscapes, where forests are not the dominant vegetation type, there are complications with using these databases because they lack data in the areas of sparser forest cover or areas that have not been under forest cover in recent memory. In Oregon, as in California (Brown et al 2004), data in the Oregon STATSGO soils datasets for the 'woodprod' (Mean Annual Increment) variable were incomplete across the state (Figure 2-5).

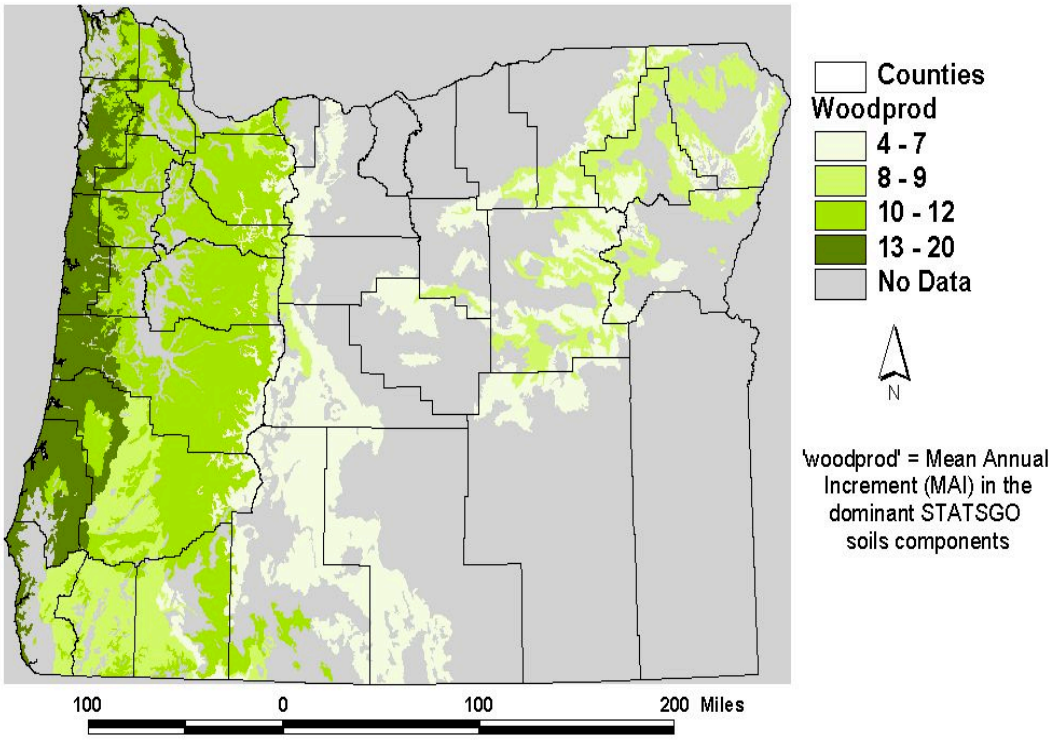


Figure 2-5 Map showing dominant soils components with available STATSGO 'woodprod' data.

To derive suitability for any area that was not mapped for 'woodprod' by STATSGO, a multi-criteria evaluation of pertinent factors was conducted whereby areas of current forest vegetation were used to calibrate a model and predict a score indicating whether or not an area

was suitable for growing trees (suitability score). The methods used to derive this suitability score were identical to the methods used the carbon supply report for California (Brown et al 2004) except that the factor aspect was included in the set of biophysical drivers for Oregon. The factors, used to map suitability for forest growth in Oregon, were soil available water content (AWC), elevation, slope, mean annual temperature and annual precipitation.

In this analysis, a constraint was introduced whereby lands that fell into a category of any one of the factor maps where there were no areas of current forests were eliminated as candidate lands for afforestation. In other words, the concept of limiting factors was used. For example, a constrained site might be one where the mean annual precipitation class is one in which forests commonly exist across the state, but there are no forests growing in areas with mean annual temperature values as low as the site in question. In this example, the site would be constrained from candidacy for afforestation because of the prohibiting factor of mean annual temperature despite meeting the suitability constraint for mean annual precipitation. Elevation was another factor that acted as a constraint at some of the state's higher points.

The suitability score was based on the proportion of each factor map's class that is forested throughout the state. For any given cell in a factor map, this proportion value across all of the factor maps was averaged to produce an overall suitability map for forest growth. More details on how suitability scores are calculated using GIS can be found in the California report (Brown et al 2004) or in conventional GIS suitability analysis discussions such as those found in the Idrisi Kilmanjaro users' manual (Eastman 2003) and with ESRI products in Wayne (2003a & 2003b). In this study, no weighting of factors with respect to each other was used (cell values were averaged) but empirical data on forest area locations were used to weigh the classes in each factor map. This technique is used frequently in land use change modeling (Brown et al. *in press*; Pontius et al 2001; Hall et al 1995).

The suitability scores for forests cross-referenced to existing land cover classes in Oregon are shown in Figure 2-6. It can be seen from this figure that there are relatively large areas of agricultural land and rangeland classes that have high forest suitability scores. To illustrate the case for rangelands in more detail, Figure 2-7 shows the distribution, in acres, of existing rangelands within the forest suitability classes.

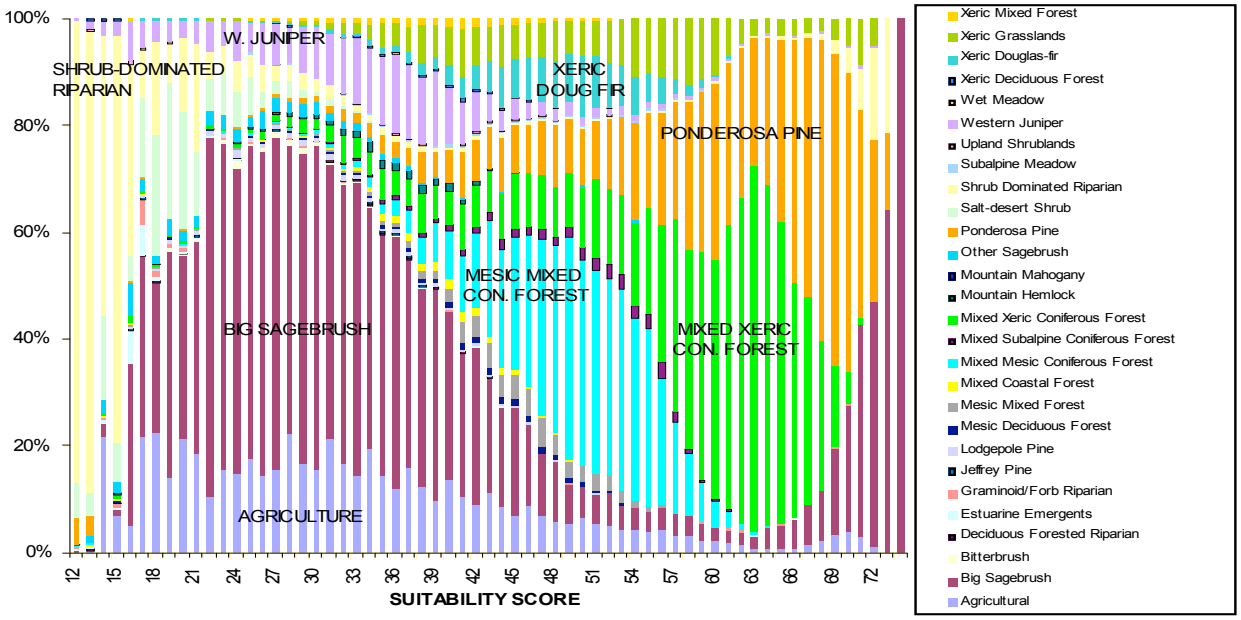


Figure 2-6. Forest suitability scores cross-referenced to land cover classes in Oregon. The higher the score the more suitable the site is for forests and vice versa.

It is clear that a substantial area of existing rangelands have high forest suitability scores and when compared to Figure 2-6, these scores correspond to those for mixed mesic coniferous forest, mixed xeric coniferous forests and ponderosa pine forests. This overlap implies that rangelands could be afforested with species typical of these forest types. In most cases, when overlaps occur for a forest type in a wide range of suitability scores (from low to high), this is reflected in the modeling of the biomass productivity of an afforestation project and is described below. As explained above, in factor map classes where forests do not currently exist in Oregon, these classes were flagged and excluded from suitability analysis. Due to the fact that this constraint was introduced, no minimum threshold cut-off in the suitability scores for afforestation candidacy was applied as in the California report (Brown et al 2004).

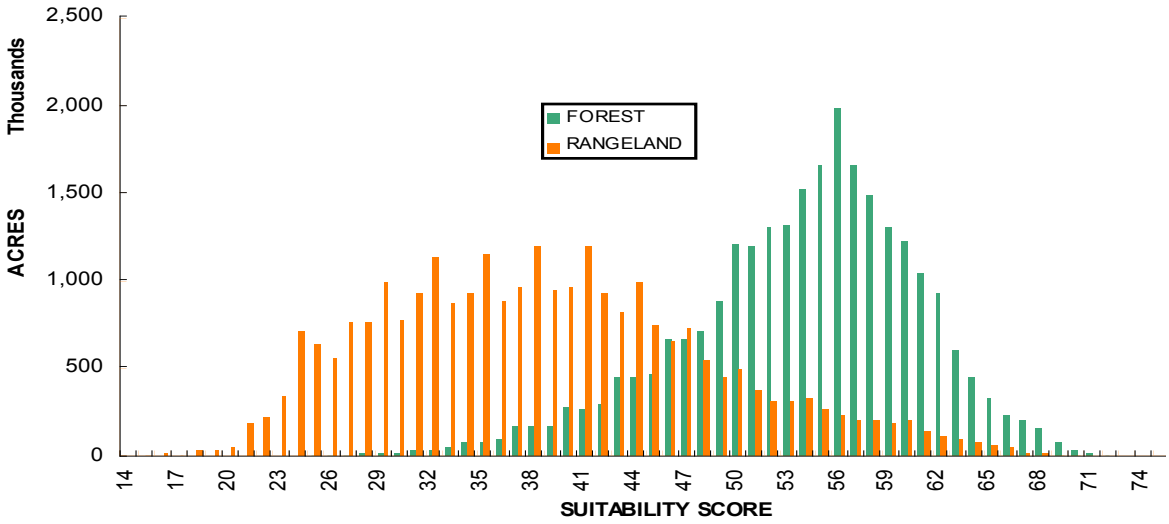


Figure 2-7. Distribution of existing rangelands and all forest classes within the forest suitability classes

2.2.4 Species selection analysis

The carbon sequestration potential for any given grid cell was developed by first identifying the dominant forest vegetation types that exist in those suitability classes in other areas of the state. This illustrated the tree species that would most successfully be planted on candidate sites. This analysis needed to be constrained because if sites in the Blue Mountains are in the same suitability class as ones in the Cascades, they could be assigned the same dominant forest vegetation type, even if this would not be the case in reality. To prevent this, we constrained the species selection step with a map of Holdridge Life Zone classes of the state (Lugo et al. 1999 –Figure 2-8). In this way, the dominant forest vegetation type was mapped for all suitability classes in each Holdridge Life Zone.

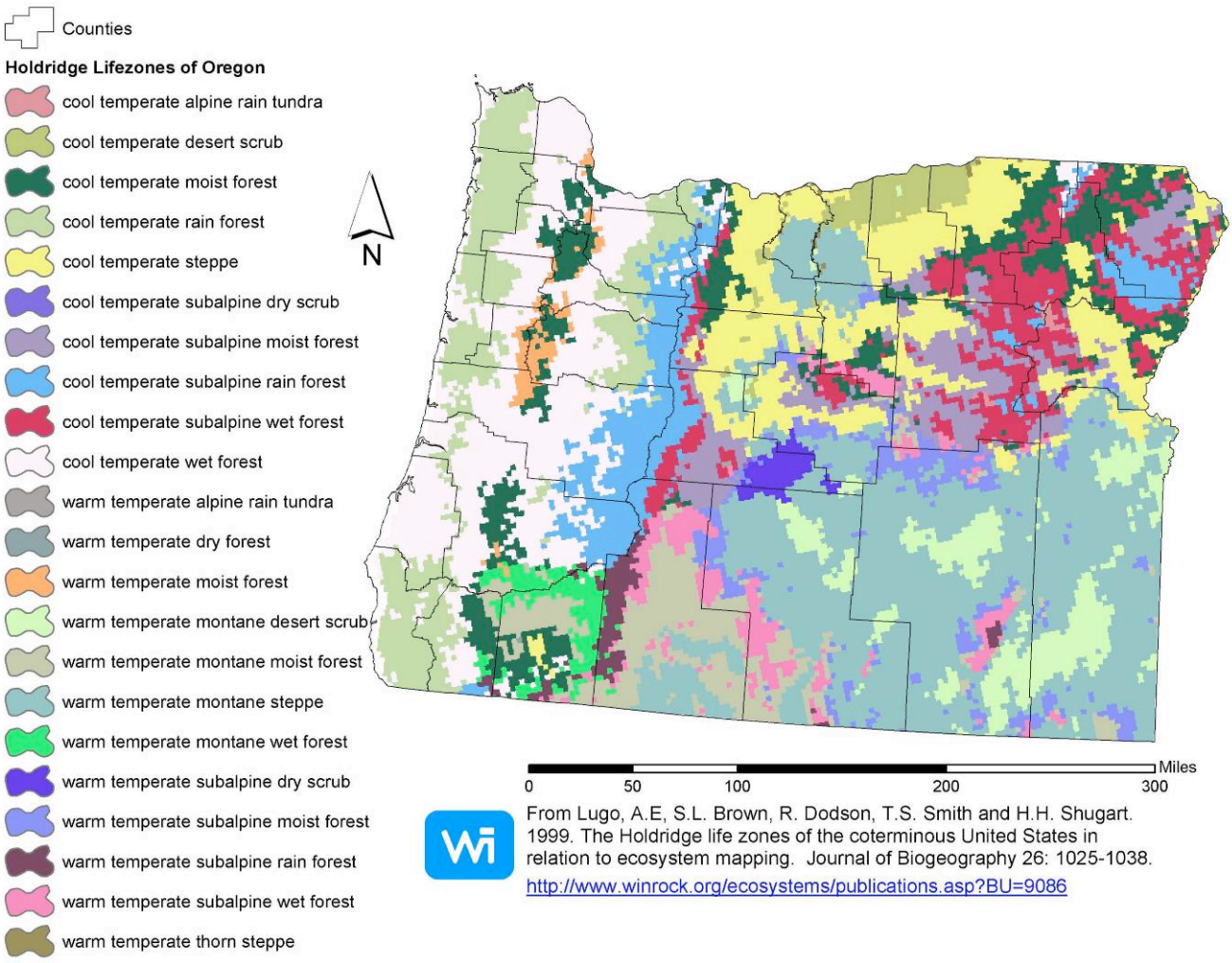


Figure 2-8 Map of Holdridge Life Zones of Oregon (from Lugo et al. 1999).

Using the Holdridge Life Zone map to stratify the lands also allows for another constraint to be applied in the estimation of the suitability of sites as described in 2.2.3. If a suitability class in a Holdridge Life Zone had no dominant forest species when dominant forest species were extracted (meaning that it actually has no forest) even though the suitability class might have forests in other Life Zones, all of these areas were eliminated from candidacy.

2.2.5 Modeling forest carbon sequestration potential

Existing models of forest growth were considered, including CRYPTOS and CACTOS models developed at U.C. Berkeley (Wensel et al. 1986) and Forest Vegetation Simulator developed by the U.S. Forest Service. Given the data requirements for these models, they were deemed to be less useful for application to the large scale of this effort (both in Oregon *and* in the Washington study). Therefore, models were developed to estimate directly rates of forest carbon accumulation on a per unit area basis, and that would require a manageable suite of inputs: forest type and forest suitability class. To simplify, other factors influencing forest growth (e.g. site preparation, planting density, and management) were held constant.

The carbon accumulation numbers applied to this analysis were prepared to be conservative yet fully transparent and supported. Where possible the values are taken from the US Department of Energy's 1605b greenhouse gas reporting program's look-up tables (http://www.pi.energy.gov/pdf/library/AppendixPartIForestry0321.pdf).

Where look-up table values were not applicable, carbon accumulation data was taken from the published literature. For the analysis, carbon stock densities are required for years 20, 40 and 80, so literature values were used in a growth model to derive values for these years.

The Chapman-Richards function (Richards 1959; Pienaar and Turnbull 1973), a popular sigmoid-shaped biological growth model, has been used in related reports and found to be appropriate as it is simple to use, transparent, and data are available for parameterization. The Chapman-Richards function of the following form was chosen to model biomass carbon accumulation over time:

$$yield = a \times (1 - e^{(-k \times age)})^{1/(1-m)}$$

Parameters for Chapman-Richards models were estimated to tailor carbon yield curves for each vegetation class, and passing through the previously determined age:biomass/ha points.

- "yield" is expressed in metric tons of biomass
- "age" is expressed in years
- "a" (asymptote) determined from literature
- "m" parameter set iteratively at 0.7 (fraction of asymptote (final yield) at which growth rate peaks),
- back calculation for "k" (rate at which the asymptote is approached)

The age at which mean annual increment (MAI) peaks, roughly the age at which stand volume begins to level off (here assumed to be the age at which yield = 80% of the asymptote) was determined in consultation with Josephson (1962), referencing empirically-derived yield tables, and the USFS Silvics of North America (Burns and Honkala 1990).

All values reported here include the carbon in above- and belowground live biomass.

Where a single forest class had significant coverage across a wide range of forest suitability classes (>10 classes) in a Holdridge Life Zone, the forest class was further broken down into productivity classes (high, medium, and low productivity). The cumulative distribution of the areas across the life zone's suitability classes was then divided into equal area low, medium and high productivity classes. The carbon sequestration estimates are shown in Table 2-2.

Table 2-2. Estimated rates of carbon sequestration of selected forest vegetation types.

Forest type	Dominant NW Regional Gap Analysis Categories	Example Species	Prod. Class	Biomass carbon (t C/ha) at age:			Source
				20	40	80	
Subalpine forest	Subalpine fir Engelmann spruce Mixed subalpine coniferous forest	Engelmann spruce, Subalpine fir	High	50.65	85.7	159.5	1605b
			Mid	40.85	62.75	114.65	
Mixed coastal forest	Coastal coniferous forest Coastal lodgepole pine Mixed coastal forest Grand fir	Grand fir, Douglas fir, Sitka spruce, lodgepole pine		116	285	501	Smithwick et al.2002, Chapman-Richards
Jeffrey Pine	Jeffrey pine	Jeffrey Pine		38.42	134.87	254.09	Burns and Honkala 1990, Smith et al. 2003, Cairns et al.1997
Lodgepole Pine	Lodgepole pine	Lodgepole Pine		25.2	53.3	95	1605b
Ponderosa Pine	Ponderosa pine	Ponderosa Pine		28.8	46	76.1	1605b
Douglas fir	Mesic Douglas fir	Douglas fir	High	49.6	180.7	391.4	1605b
			Mid	39.5	132.5	315.5	
			Low	29.3	84.2	239.5	
Western Hemlock	Western Hemlock	Western hemlock	High	65.5	231	467.7	1605b
			Mid	51.6	173	399	
			Low	37.7	115	329	

Forest type	Dominant NW Regional Gap Analysis Categories	Example Species	Prod class	Biomass carbon (t C/ha) at age: 20	40	80	Source
Mixed mesic forest	Mountain Hemlock Western Redcedar Mixed mesic coniferous forest Coniferous forested riparian Deciduous forested riparian Whitebark pine Mesic mixed forest Miixed riparian	Douglas fir, Moutain hemlock, Western redcedar		57	161	350	Smithwick et al. 2002, Chapman-Richards
Mixed xeric forest	Mixed xeric coniferous forest Western Larch Xeric Deciduous Forest Xeric Douglas Fir Xeric Mixed Forest	Ponderosa pine, western larch, Douglas fir		22	55	96	Smithwick et al.2002, Chapman-Richards
Mesic deciduous forest	Mesic deciduous forest Deciduous forested riparian	Bigleaf maple, cottonwood, aspen		50.2	84.5	161.5	1605b

2.2.6 Carbon stock baselines in non-tree vegetation

The rangeland vegetation classes from the Northwest regional gap analysis were combined into categories based on biomass. Biomass values for each of the categories were obtained from Forest Inventory and Analysis data (USFS) and from the literature.

The biomass carbon values and the sources of the data are given in Table 2-3.

Table 2-3. Biomass carbon stocks in rangeland vegetation classes.

Vegetation type	Northwest Regional Gap Analysis Categories	Biomass carbon	Source

		(t C/ha)	
Wet Grasslands	Alpine meadow Wet meadow	5.9	Prichard et al. 2000
Mesic Grasslands	Subalpine meadow Gramminoid/Forb Riparina	2.4	Brown and Archer 1999
Xeric Grasslands	Xeric grasslands	0.6	Winrock unpublished data
Shrub/Tree	Pinyon pine Moutain mahogany Utah juniper Western juniper	25.5	FIA analysis
Shrub	Big sagebrush Shrub-dominated riparian Bitterbrush Other sagebrush Rabbitbrush salt-desert shrub Upland shrubland	5.1	Martin et al. 1981

These carbon stocks on existing rangelands represent the baseline that is not considered attributable to afforestation activities on those lands.

2.2.7 Economic analyses

All economic decisions involve trade-offs. If activity X is forgone in order to undertake activity Y, then the value of undertaking activity X must be considered as the opportunity cost of undertaking activity Y. Simply put, the opportunity cost is the most highly valued alternative to the activity being considered. In this case, the activity being considered is afforestation of range and crop land in Oregon. Therefore, the profitability per hectare in Oregon represents the opportunity cost of producing carbon on that land (i.e. afforestation). The ultimate cost of producing carbon through afforestation of crop or range land is going to differ from site to site and county to county, primarily based on the quality of the soil and growing conditions, which directly influences both crop or range yields (i.e. opportunity forgone) and carbon yields (i.e. afforestation).

In the economic analysis, the "price" a farmer/rancher would need to receive to take a parcel of land out of agriculture/rangeland and put it in forestland use for increased carbon sequestration needs to be estimated. That "price" must be equal to or greater than the return the farmer/rancher is currently receiving from the agricultural or range use of that land. For a landowner to consider taking an acre of agricultural or range land out of that use for the purpose of afforestation, the "price" will have to be equal to the marginal return to the farmer from that parcel of land under consideration. That marginal return is the estimated revenue less the input costs for the agricultural enterprise in question for putting that last acre into

agricultural or range production. Only the variable costs of agricultural or range production are used in this analysis because it is unlikely that a farmer will enroll all land in a carbon sequestration program, but only a smaller proportion thereof. As a result, the allocation of fixed costs over the amount of unit area remaining in agricultural or range land use remains about the same and can be ignored.

The economic analysis methodology for estimating the opportunity costs of afforestation projects on range and crop land is based on widely available data on prices, costs, and yields of the major crops produced in the state. We have intentionally designed this methodology to be easily replicable across states. In doing so we have foregone some degree of local specificity regarding costs and prices of crop production, but we feel that the simplicity and replicability of this approach outweighs the small margins of error caused by using regional cost and price data.

To calculate the total cost of afforesting rangeland and cropland, the variables considered were opportunity costs, one-time conversion costs, management, costs and measurement and monitoring costs. The economic analysis for rangelands is practically identical to that used for California (Brown et al. 2004) and that for croplands the same as that for the Southern States regional partnership (Brown and Kadyszewski, 2005a). Here we briefly describe the approaches for estimating total costs and the local values used in the analyses.

Rangelands

The most highly valued alternative to afforestation is cattle ranching. (An alternative to afforestation of rangelands could be conversion to urban development, and depending upon the price of real estate, the opportunity cost for this alternative could be high. We did not consider this alternative in our analysis.) Therefore, the profitability per acre of cattle ranching in Oregon represents the opportunity cost of producing carbon (i.e. afforestation).

The profitability of cattle ranching varies greatly from year to year and from ranch to ranch. This is due primarily to weather conditions and cyclical fluctuations in the price of beef. Unfortunately annual enterprise budgets for cattle ranching, which indicate profitability, are not officially kept in Oregon. Because of this, we used input from recent Cattle-Fax publications and from personal communication with rangeland extension specialists[1] to calculate an average annual profitability value for Oregon cattle ranching (Table 2-4). The revenue estimates that reported in Table 2-4 reflect long-term average prices received for cattle. After subtracting total costs of production from revenue, an average annual profit per cow is estimated to be $94.75.

Table 2-4. Revenue and costs associated with cattle ranching in Oregon (data from Cattle-Fax and T. Hudson and D. Nelson, Washington State University, 2005, pers. comm.).

Economics of Ranching in Oregon

1 From personal communication with Don Nelson 2005. Washington State University, Extension Beef Specialist for Pacific Northwest; and Tip Hudson 2005. Washington State University Rangeland Extension Specialist.

Revenue			
	Total	$/animal	Assumption
Calf	$600.00	$510.00	85% wean rate
Cull cows	$425.00	$63.75	15% cull rate
Total Revenue		**$573.75**	
Costs in $/animal			
Pasture		$130.00	
Supplemental feed		$151.00	
Other operating and fixed costs		$198.00	
Total Costs		**$479.00**	
Mean annual profit/animal (Revenue – Costs)		**$94.75**	

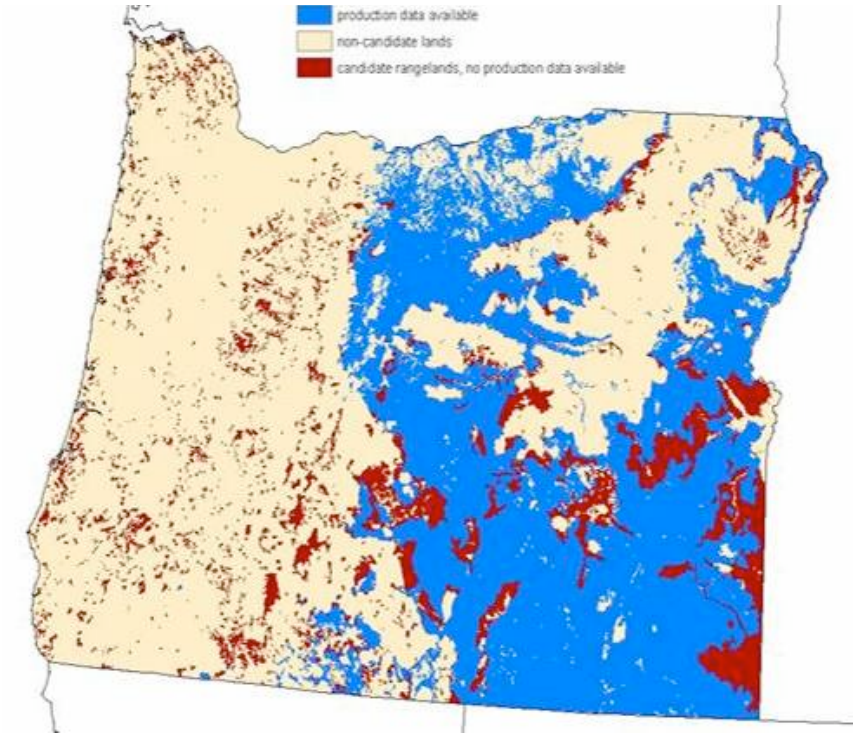
Other than the wide swings in the price received for cattle, the most critical variable in determining ranching profitability is the forage production potential of the rangeland. Forage production determines the carrying capacity of the land. Higher forage production can support more cows per acre and therefore results in higher profits per acre. Moisture and soil conditions are the primary predictors of rangeland productivity and are the drivers of the methodology described below.

Western rangeland specialists use an average of 791 lbs. of forage dry matter (DM) to represent the monthly requirements for cattle being fed on rangeland forages (L. Metz 2003, USDA-NRCS, Davis, CA, pers. comm.). This monthly requirement is termed an animal unit month (AUM) and it is used as a measure of the carrying capacity of a parcel of rangeland. Therefore, if one acre of rangeland produces 791 lbs. of forage DM over the course of one month, that acre is said to produce one AUM of forage. This translates into an annual per cow forage requirement of 9,492 lbs. DM (12 times the AUM). This forage requirement estimate (i.e. AUM of 791 lbs.) and the average annual per cow profitability of $94.75 was used to estimate the profitability potential (i.e. opportunity cost) for all Oregon rangelands, as explained next.

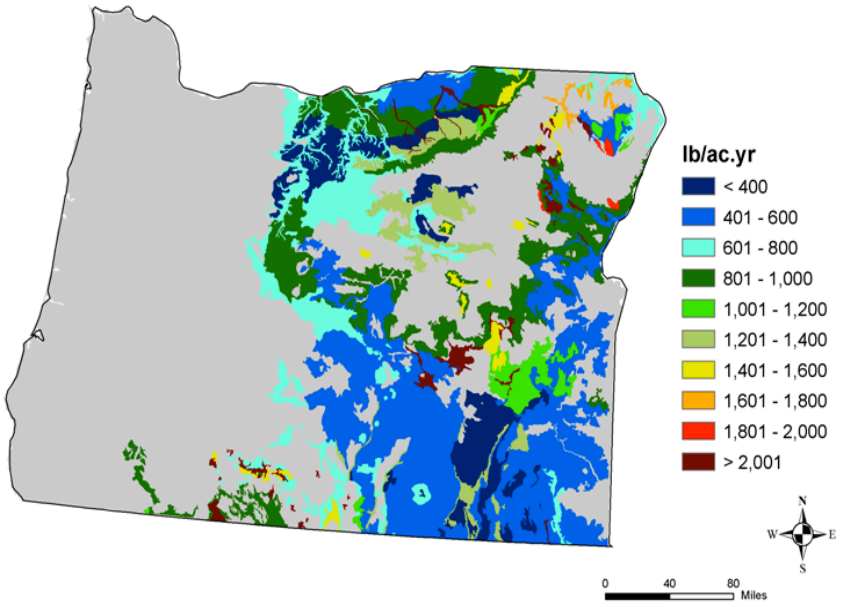
For rangeland that produces only 100 lbs. of forage DM per acre, almost 95 acres will be required to support one head of cattle for a year. The annual per acre profitability of this low-producing rangeland is estimated to be only $1.00 (i.e. $94.75/95). High producing rangeland of 2,000 lbs. DM per acre per year will require only 4.75 acres to support one head. In this case the annual per acre profitability is $19.96 (i.e. $94.75/4.75). The relationship between annual average per cow profitability and annual average per cow forage DM requirements yields a constant relationship indicating that each lb of forage DM is equal to $ 0.009982 in ranch profits. This average profitability figure per lb of forage production is used to project the profitability of all Oregon rangelands. The model used to estimate the forage DM production for each pixel of Oregon rangeland is described in the following section.

The modeling methodology that was developed to estimate forage production for all Oregon rangelands used forage production estimates from the State Soil Geographic Database (STATSGO). The forage production estimates were then translated into a livestock carrying capacity for the land and combined with the average per cow profitability (Table 2-4) to estimate the average annual opportunity cost of afforestation for each pixel of rangelands on the map.

Because forage production from STATSGO was not available for the full extent of a state's rangelands, a multivariate regression was run using the variables of aspect, slope, elevation, mean annual precipitation, mean annual temperature and soil available water content (based on the approach developed for California). These data were extracted from 5180 sample locations where STATSGO data were available for the dominant soil components and a highly significant relationship as reflected in low P values (8.3×10^{-147}) was derived. Figure 2-9a shows areas where forage production data were unavailable from STATSGO and where the regression analysis was used to fill in the gaps. And Figure 2-9b shows the range of forage production in areas where STATSGO data were available. Most of the mapped rangelands have low productivity (less than 600 lb/ac.yr) and would require about 16 acres to support one animal.



(a)



(b)

Figure 2-9. (a) Map showing dominant soils components with available STATSGO 'rsprod' (range productivity) data (maroon areas were filled with regression results); and (b) estimates of forage production for areas with 'rsprod' data.

Conversion costs represent the estimated cost for planting trees on rangelands in Oregon. Based on information from timber companies in California, the one-time conversion cost for planting trees varies from $300 to $600 per acre. The variability stems mostly from the moisture, soil texture, and slope of the site. The Oregon Department of Forestry give estimates at $550 per acre (J. Cathcart pers. comm.) that was used for this analysis ($1360/ha). Another cost included in the analysis is an expected maintenance cost that is projected to be incurred for a period of 5 years from the beginning of the activities to ensure that enough tree seedlings survive to establish a well-stocked stand. Activities expected (depending upon local conditions) include replanting seedlings that died, weeding (or herbicide application), possibly fertilizing and adequate fencing to control livestock incursion until the trees get established. Annual maintenance costs to establish a "free-to-grow" stand are estimated to be approximately $70/ac.yr during the first 5 years of activities ($173/ha.yr) (Table 2-5).

Table 2-5 Assumptions in per-acre cost breakdown for afforestation projects [NOTE: for croplands, 'Site prep' was reduced by 50%]

one-time conversion costs		establishment costs	
Site Prep	$250	Vegetation Management	$130
Seedling Costs (436 trees/acre @ 10' by 10' spacing)	$150	Interplantiing/Contingencies (seedlings and labor)	$120
Planting Labor Costs	$120	Final Release	$90
Administration	$30	Additional administration costs	$10
	$550		$350
		per year of first 5 years	*$70*

The final cost category is the costs of measuring and monitoring the carbon production over the life of the activity. The average annual M&M costs associated with carbon production contracts is estimated to equal $1.60/ac for 20-year projects, $1.08/ac for 40-year projects, and $0.80/ac for 80-year projects, based on Winrock's experience with measuring and monitoring many afforestation activities throughout the US. Several factors affect the magnitude of the cost including which pools are measured and monitored (in this case we assume only aboveground biomass), frequency of monitoring (once every five years over duration of project), area, and whether the lands are contiguous or dispersed (assumed here to be contiguous). The area of the activity is an important factor and economies of scale exist for M&M costs; therefore, per-acre M&M costs may be significantly higher for smaller activities.

Because the economic analysis is considering afforestation activities that are 20, 40, and 80 years in duration, the annual opportunity cost estimates must be projected into the future (20, 40, and 80 years) and then discounted to obtain a present value (PV) estimate of the annual stream of profits from farming that would be foregone to allow for afforestation. The real discount rate used in this analysis is 4 percent (6% discount rate minus 2% inflation rate). The costs that are incurred only at the beginning of the project are not discounted. These include the conversion cost and the contract cost (currently assumed to be zero because data are not available) and are added to the total present value costs. The resulting numbers represent the present value of all of the current and future (for the life of the carbon project) costs associated with sequestering carbon on rangelands through afforestation (Table 2-6).

Table 2-6. Present value of costs associated with sequestering carbon on Oregon rangelands through afforestation.

Forage production Lbs/acre.yr	20 year	40 year	80 year
100	$2,310	$2,325	$2,329
500	$2,444	$2,520	$2,565
1000	$2,612	$2,764	$2,860
1500	$2,779	$3,008	$3,155
2000	$2,947	$3,252	$3,450

Crop lands

The economic analysis for croplands involves estimating the profitability of crop production for the major relevant crops of Oregon using USDA county-level area and yield data. The crops

that are selected to be included in the analysis are the crops that meet both of the following criteria: (1) represent a significantly large area in the state, and (2) have an average profitability that is low enough to allow carbon projects to be a possible alternative (i.e. commodity as opposed to high-value crops). The two crops that meet these criteria for Oregon are wheat and hay. Another reason that the higher-value crops were not included in this analysis is that they tend to cover smaller areas and are not distinguished clearly on any land-use or land-cover maps and thus are difficult to identify.

The area and the average yield for each county within Oregon were collected from the USDA National Agricultural Statistics Service (NASS) for the years 2000-2004. NASS's annual program focuses on agricultural production for mainstream crops, livestock and associated inventories. The program is based on a series of sample surveys to collect farm-level data to produce the State and U.S. crop forecasts and estimates published in the NASS Agricultural Statistics Board reports.

In a given year, net returns (NR) to the land, per area of land can be calculated with the expression,

$NR = PY - CY + G;$

where P is the price per unit for each commodity received by the farmer, Y is the expected yield of that crop, C is the variable cost of production per unit, and G is the amount of money received as government payments or subsidies for producing that crop. Estimates of the total price (P) received by the farmer are based on estimates of future market prices for the year 2005 through 2014. Estimates of future prices for the major U.S. crops are published by the Food and Agriculture Policy Research Institute (FAPRI). The mean of the actual and projected prices for the years 2005-2014 are used as the price in the opportunity cost calculations for this analysis.

Similar to what was done for the analysis of rangelands, the costs of production for each of the major crops in each county are calculated by multiplying the reported average yield for the crop by the variable costs of production. Fixed costs of production were ignored.

The variable costs of production for each of the major crops are taken from the enterprise budgets prepared by the Oregon State University extension specialists for each crop. The yield used for each crop in each county is the average of the reported county yields for the years 2000 through 2004. As mentioned above, these data come from the USDA-NASS database. The county-specific yields for each crop generate the variability in estimated profitability associated with crop production across the state.

For most of the major Oregon crops included in this analysis, wheat and hay, government payments (G) are applicable only to wheat. For wheat, like other subsidized crops, G consists of up to three components. These are loan deficiency payments received per unit of production, counter-cyclical payments per unit of production, and direct payments per area of production. The loan deficiency payment and counter-cyclical payment are conditional based on the price received for the crop. The direct payment is received regardless of price or yield. The standard formulae for calculating each of the government payments and the total G are applied in this analysis.

Any given area of cropland is likely to have a rotation of crops produced on it over a number of years for agronomic and economic reasons. This analysis has used USDA-NASS data on planted area for each crop in each county to calculate the average percentage of hectares planted to both wheat and hay from 2000-2004. This average for each county is used to estimate a weighted average profitability for crop production in each county. By using county-specific yield and area data, combined with prices and per unit costs that are constant across the region, this analysis is able to produce relatively specific estimates of opportunity costs with a simplified and replicable analytical framework.

The profitability (i.e. opportunity cost) estimates for each crop in each county are then weighted by the average percentage of cropland planted to each crop in each county from 2000 through 2004. This averaging process is necessary to account for the frequency of crop rotations on agricultural land. Each county then ends up with a unique opportunity cost for foregoing crop production for afforestation. This estimated opportunity cost could be viewed as the minimum amount of return necessary to induce landowners to afforest agricultural land.

Added to the opportunity cost are the costs of converting the land to trees, managing the land for afforestation, and measuring and monitoring carbon production on that land as was done for rangelands and described above. Finally, a present value analysis is performed using the same time intervals and discount rates as for rangelands described above. The results of this analysis, in terms of present value of the total costs for afforesting crop lands in Oregon, are shown in Table 2-7.

Table 2-7. Present value of the total costs for afforesting crop lands in Oregon after different time intervals.

	20 years	40 years	80 Years
Mean	$3,706	$4,499	$5,020
Median	$3,725	$4,526	$5,053
Minimum	$2,913	$3,343	$3,623
Maximum	$4,199	$5,216	$5,887

2.3. Results: carbon supply for rangelands and croplands

2.3.1 Carbon sequestration potential

Based on the analyses of carbon sequestration potential and productivity across suitability and Holdridge Life Zone classes, carbon sequestration grids were derived for all rangelands and croplands. On candidate areas, new grids of additional carbon that could be sequestered were obtained by subtracting the current carbon stocks (Table 2-3) from the potential carbon stocks after different time intervals (Table 2-2). The amount of carbon sequestered at any of the time intervals is always lower in the drier east side of the state than in the moister west side (Figures 2-10 and 2-11). Even after 80 years, the maximum carbon stocks that can be attained by afforestation of rangelands and croplands in the eastern part of the state range between 50 to 100 t C/ha. In contrast, this value is attained within 20 years on lands in the western, more humid part of the state.

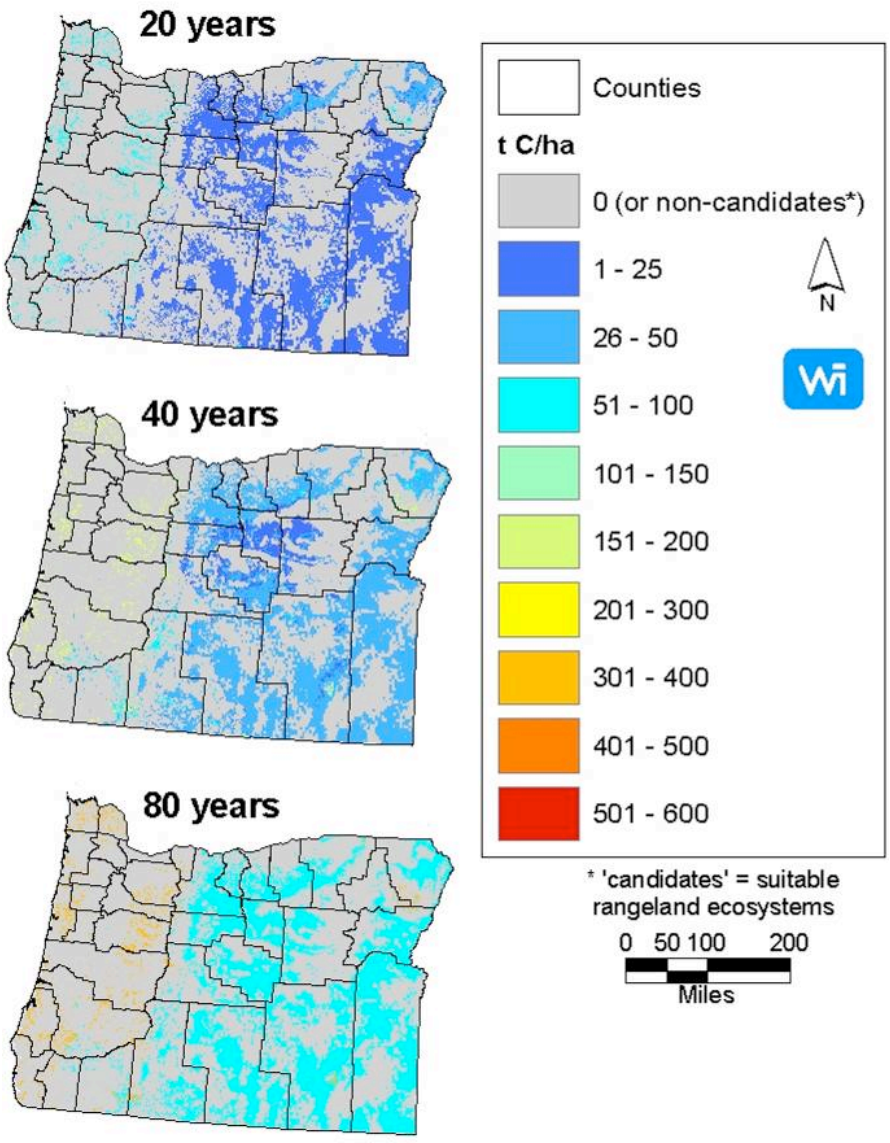


Figure 2-10. Map showing additional carbon sequestration potential of rangelands in Oregon.

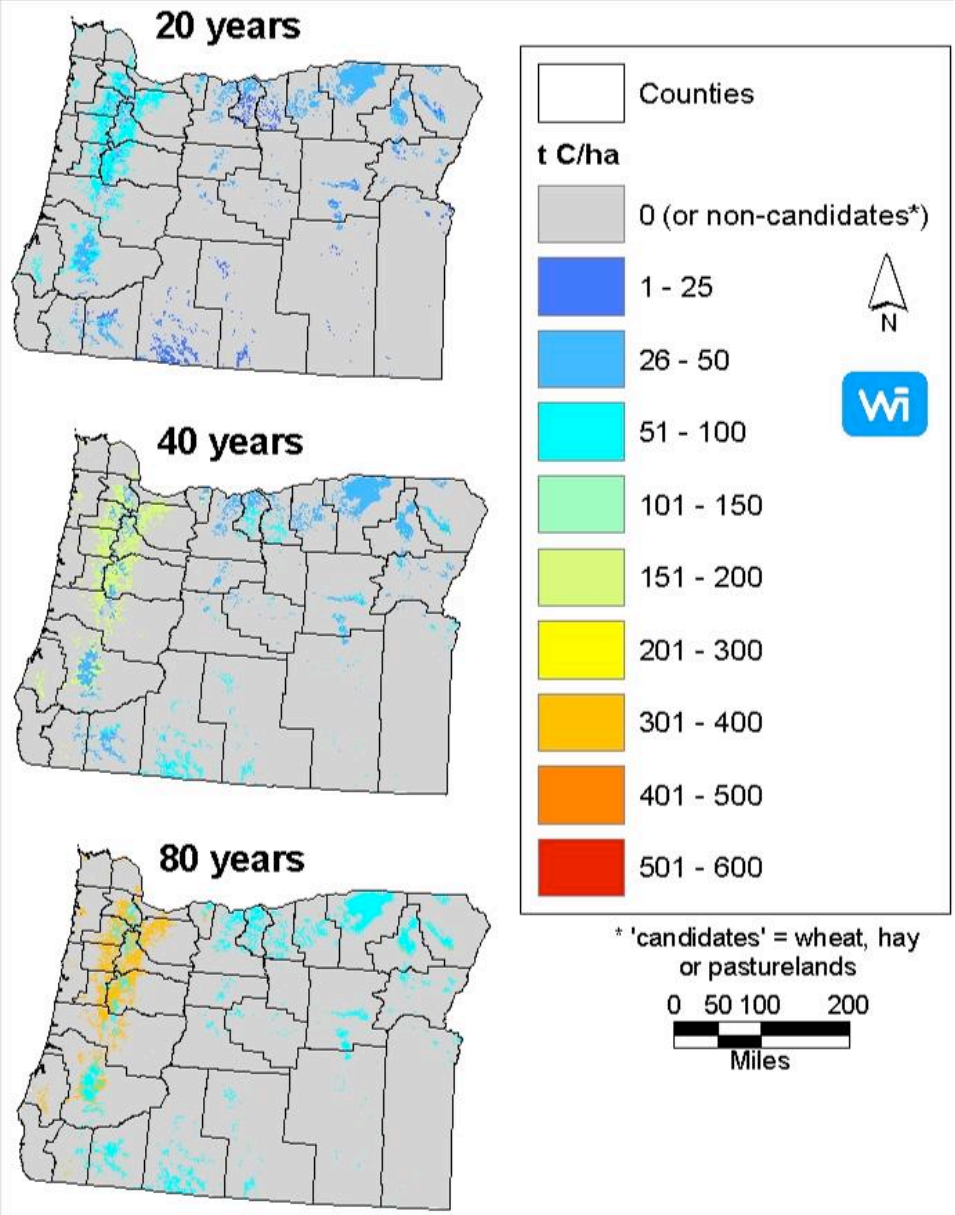


Figure 2-11. Map showing carbon sequestration potential of candidate crop lands in Oregon.

2.3.2 Total present value of costs

The total costs in $/ha for afforesting rangelands and croplands are mapped in Figures 2-12 and 2-13. The present value of the costs is higher for the longer duration scenarios because there is a longer period of time where the rangeland opportunity has been forgone. The present value of the cost hurdle on rangelands tend to be less than $3,000/ha for the 40-year duration period. For a project lasting 80 years duration, the present value of the cost hurdle is generally below $3,250/ha, except for a few areas where costs reach up to and above $3,500 /ha (Figure 2-12)

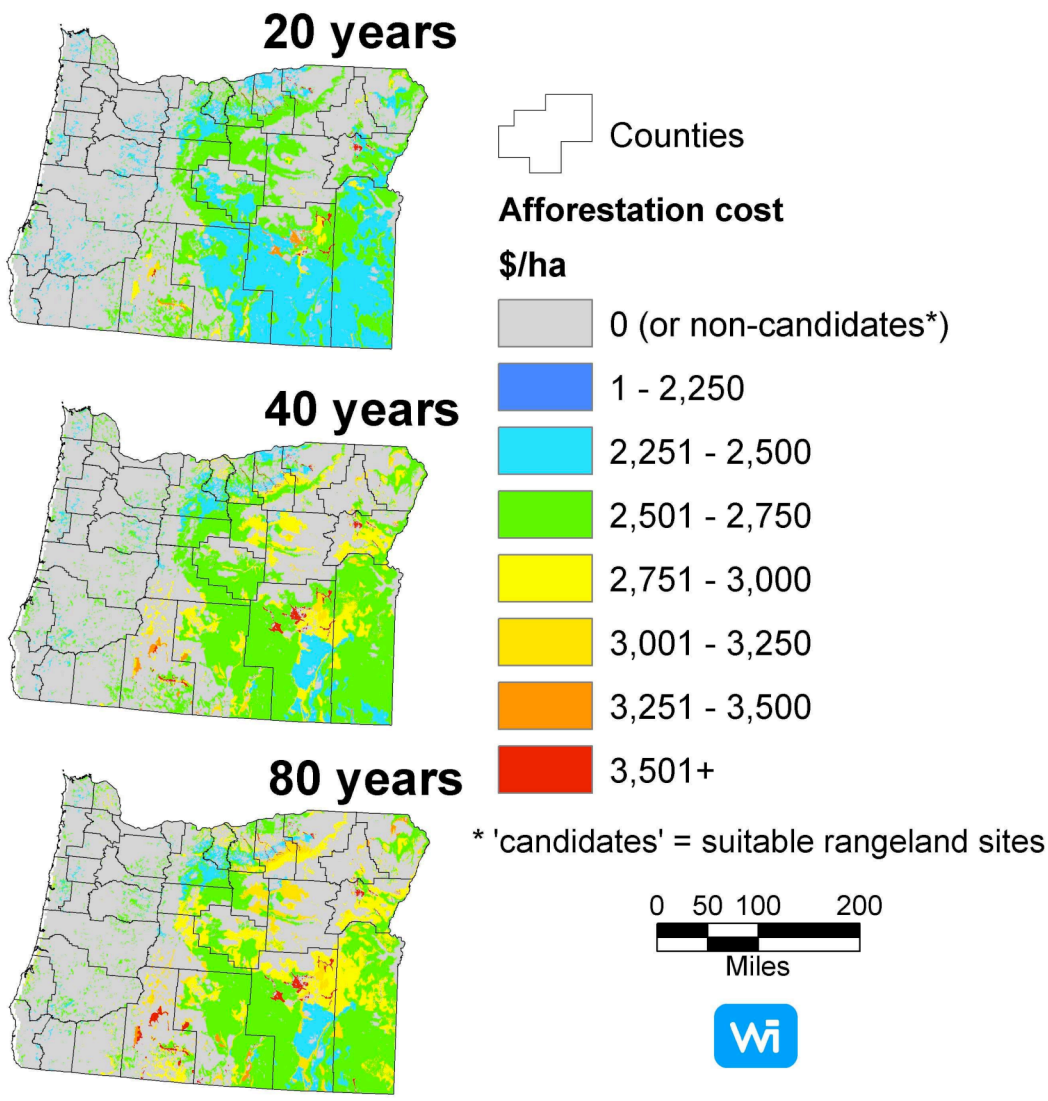


Figure 2-12. The present value of the total cost ($/ha; to convert to $/ac divide by 3.7) to afforest candidate rangeland. E.g. the highest cost is $3,501/ha or $1,417/acre.

The present value for costs of sequestration for croplands is considerably higher than for rangelands as expected (Figure 2-13). Very few cropland areas have cost of less than $3,500/ha, and much of the cropland has cost in the range of $3,500-$5,500/ha up to 40 years. After 80 years, costs go as high as $5,500/ha and sometimes over $6,000/ha.

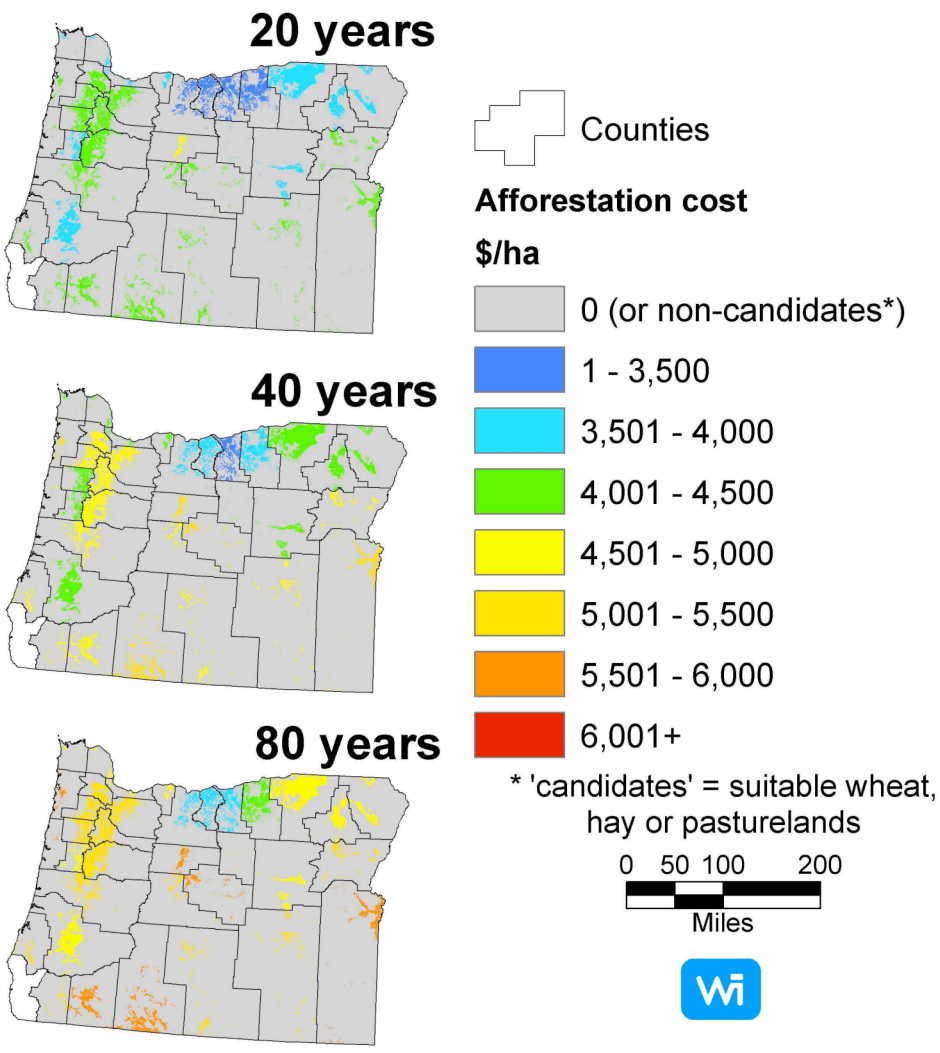


Figure 2-13. The present value of the total cost ($/ha; to convert to $/ac divide by 3.7) to afforest candidate croplands (NOTE: different scale from previous figure). The highest cost of more than $6,000/ha is $2,430/acre.

2.3.3 Carbon supply for afforestation of range and crop lands

Figures 2-14 and 2-15 show the spatial distribution (at 30 m resolution) of the cost per t C for afforesting rangelands and croplands for activities lasting 20, 40, and 80 years, respectively. After 20 years, much of the rangeland available for afforestation supplies carbon at costs of more than $76/t C. However, for longer project activities, the costs per t C decrease because the initial afforestation costs are now spread over more years of sequestration so that the amount of carbon storage is increased due to tree growth. For an 80 year duration, most of the rangeland could be afforested and supply carbon at costs of less than $75/t C (or <$20/t CO_2), though large amounts in eastern and south-central Oregon appear available for <$35/t C (or <$10/t CO_2) and for <$10/t C (or <$3/t CO_2) in western Oregon.

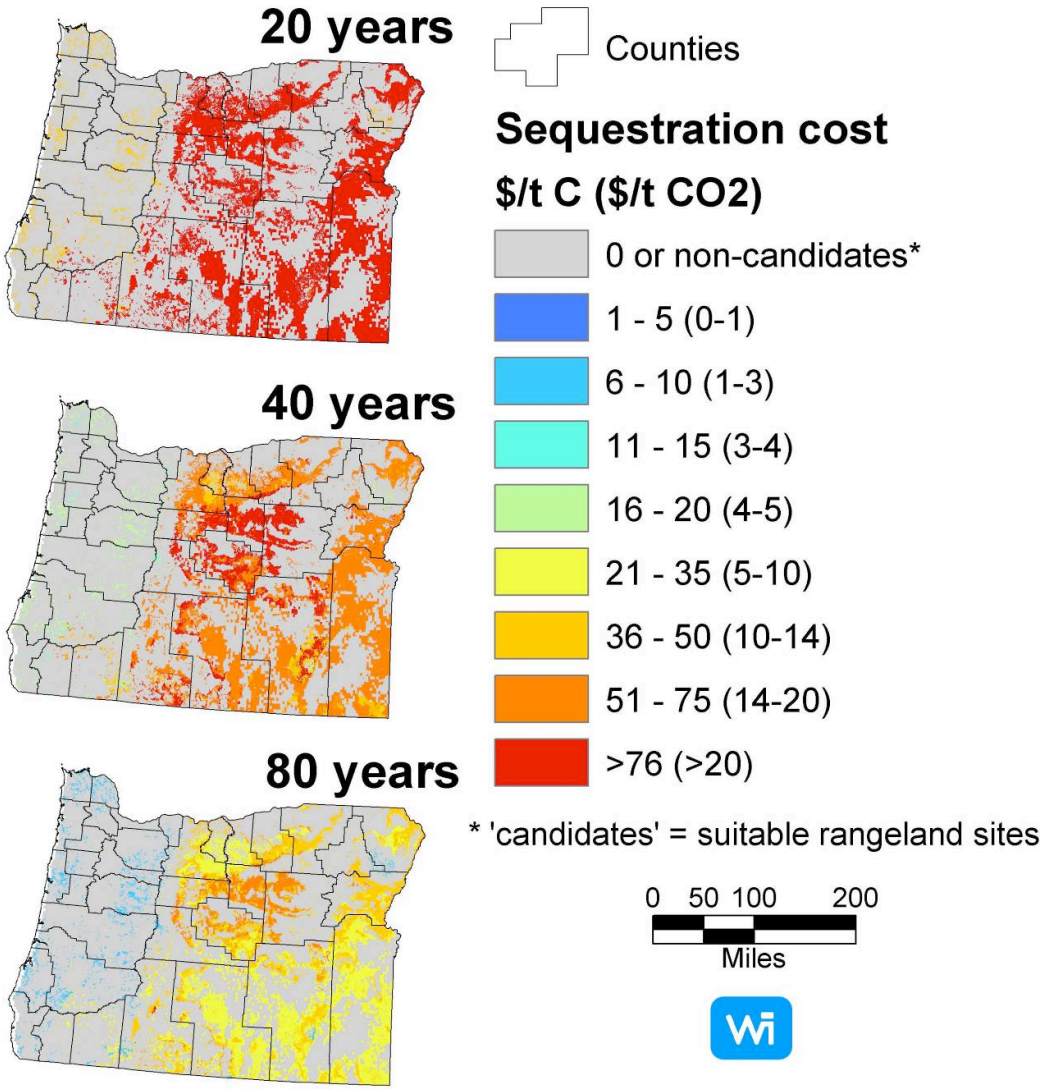


Figure 2-14. Costs of carbon sequestration through afforestation of suitable rangelands of Oregon.

Similar to the case for rangelands, after 20 years, much of the cropland available for afforestation supplies carbon at costs of more than \$76/t C (>\$20/t CO_2 -Figure 2-16). The costs per t C decrease somewhat for longer periods, especially in the Willamette Valley region (north-west to western part of the state), where afforestation of most croplands could supply carbon at costs of less than \$20/t C (<\$5/t CO_2) after 80 years and in some areas in Douglas County, as low as \$11/t C (\$3/t CO_2). Much of the cropland in the eastern part of the state has the potential to supply carbon mostly in the \$36-75/t C range after 80 years.

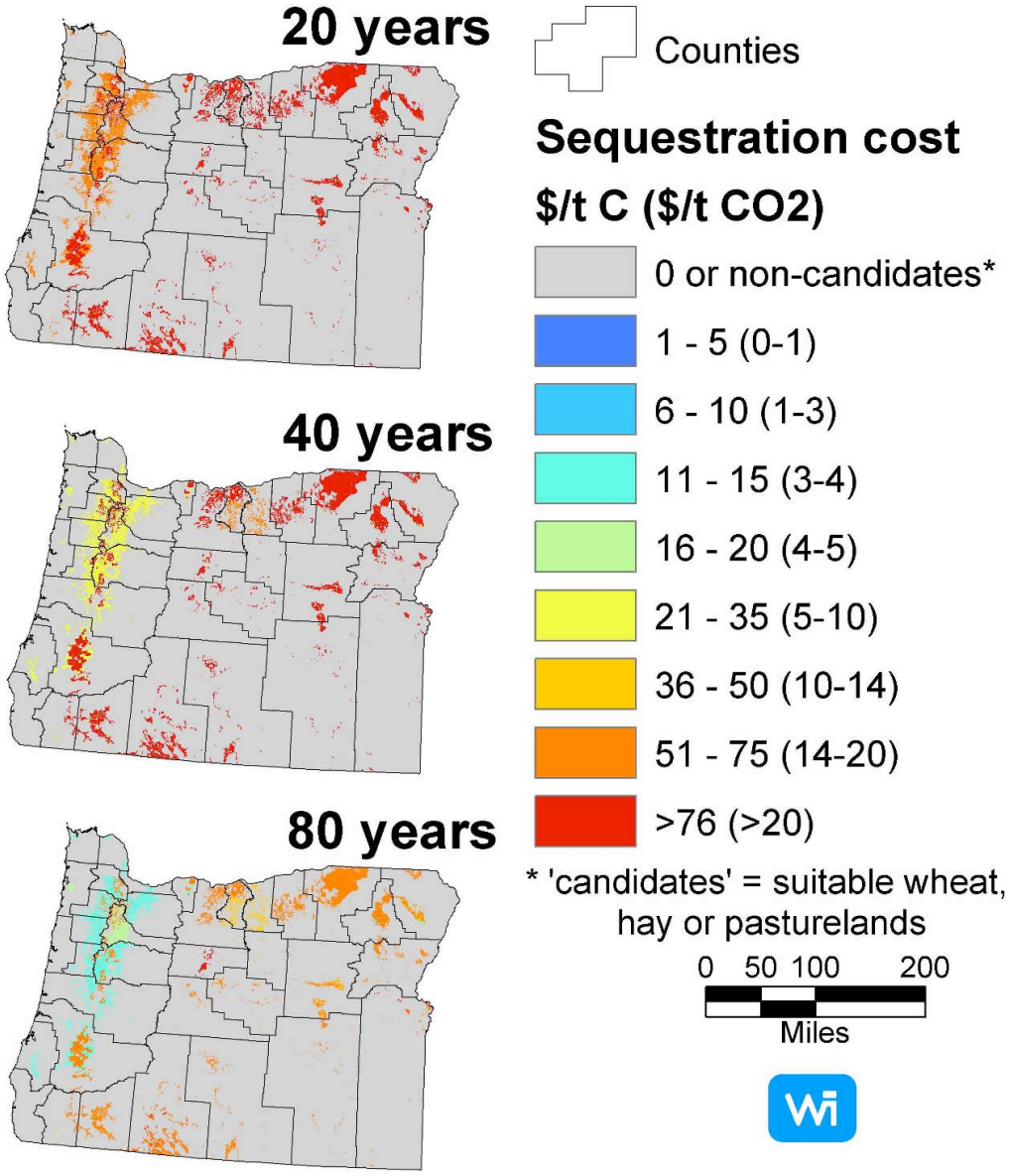


Figure 2-15. Costs of carbon sequestration through afforestation of suitable croplands of Oregon.

The area of rangeland available for afforestation increases up to about 8 million ha at gradually increasing costs for all project durations (Figure 2-16, top). The quantity of carbon available from afforestation of rangelands at different price points below $100/t C and time periods is shown in Figure 2-16 (bottom). At a common carbon price of $36/t C or $10/t CO_2, afforestation of rangelands could only supply about 53,000 t C after 20 years, but could potentially supply 93 million t C for projects lasting 40 years, and 590 million t C for projects lasting 80 years.

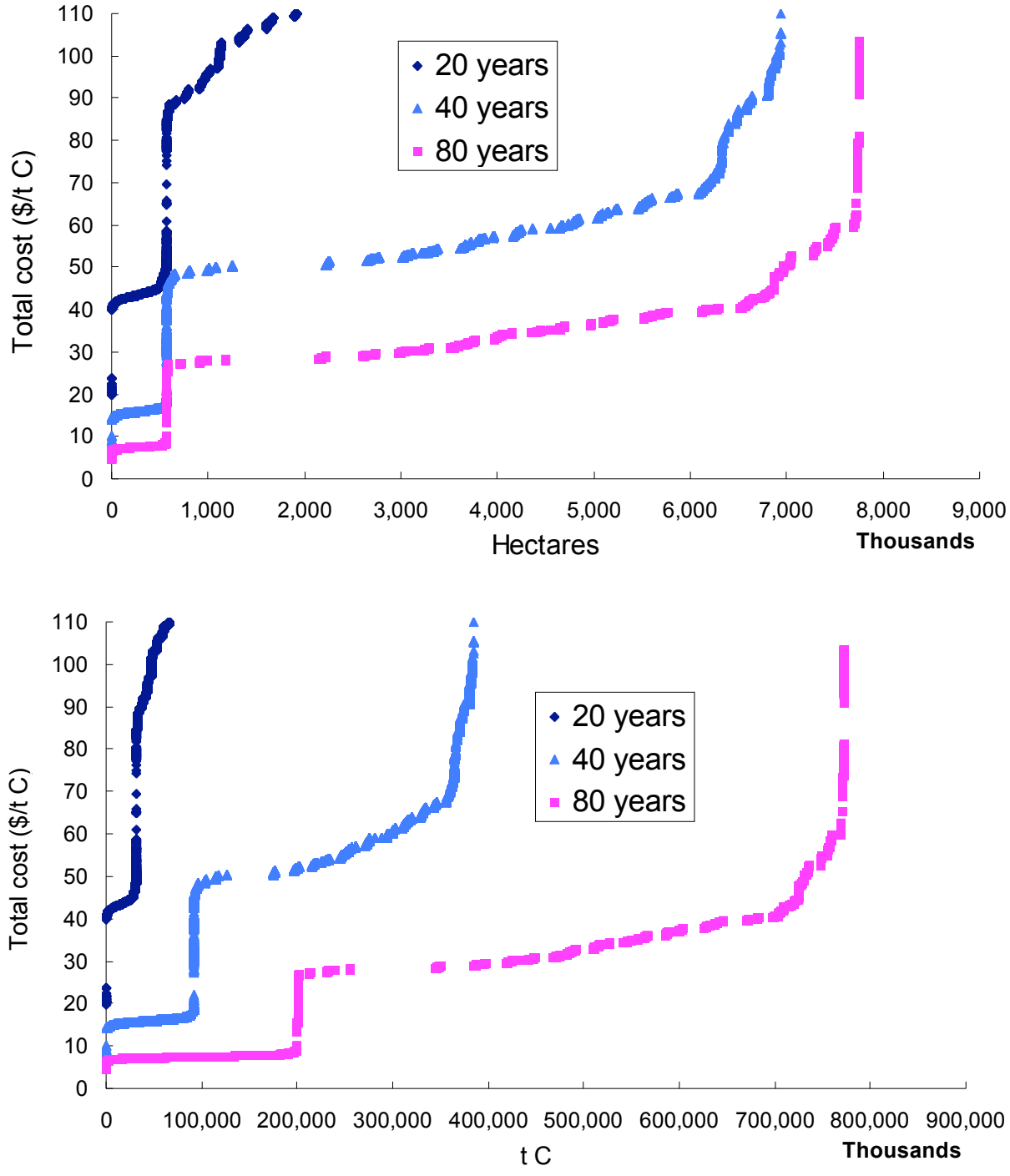


Figure 2-16. Carbon supply curves for afforestation of suitable rangelands in Oregon: (top) areas available and (bottom) quantity available at different costs per ton carbon.

The noticeable rise in the cost of carbon after approximately 700,000 hectares (1,730,000 acres) of lower-cost candidates have been planted is due to the exhausting of highly productive

rangelands west of the Cascade Mountains and in the 'cool temperate sub-alpine rain forest' Holdridge Life Zone in the vicinity of Wallowa-Whitman National Forest in Wallowa, Union and Baker Counties.

The total amount of carbon that could be sequestered by afforestation of rangelands is highest at all three time periods in the counties in the south-central and southeastern part of the state (Figure 2-17). Counties in the northwestern part of the state have the lowest potential. Most of the southeastern and southern counties have the potential to sequester more than 30 million t C after 80 years, with the two most southeastern sequestering more than 100 million t C.

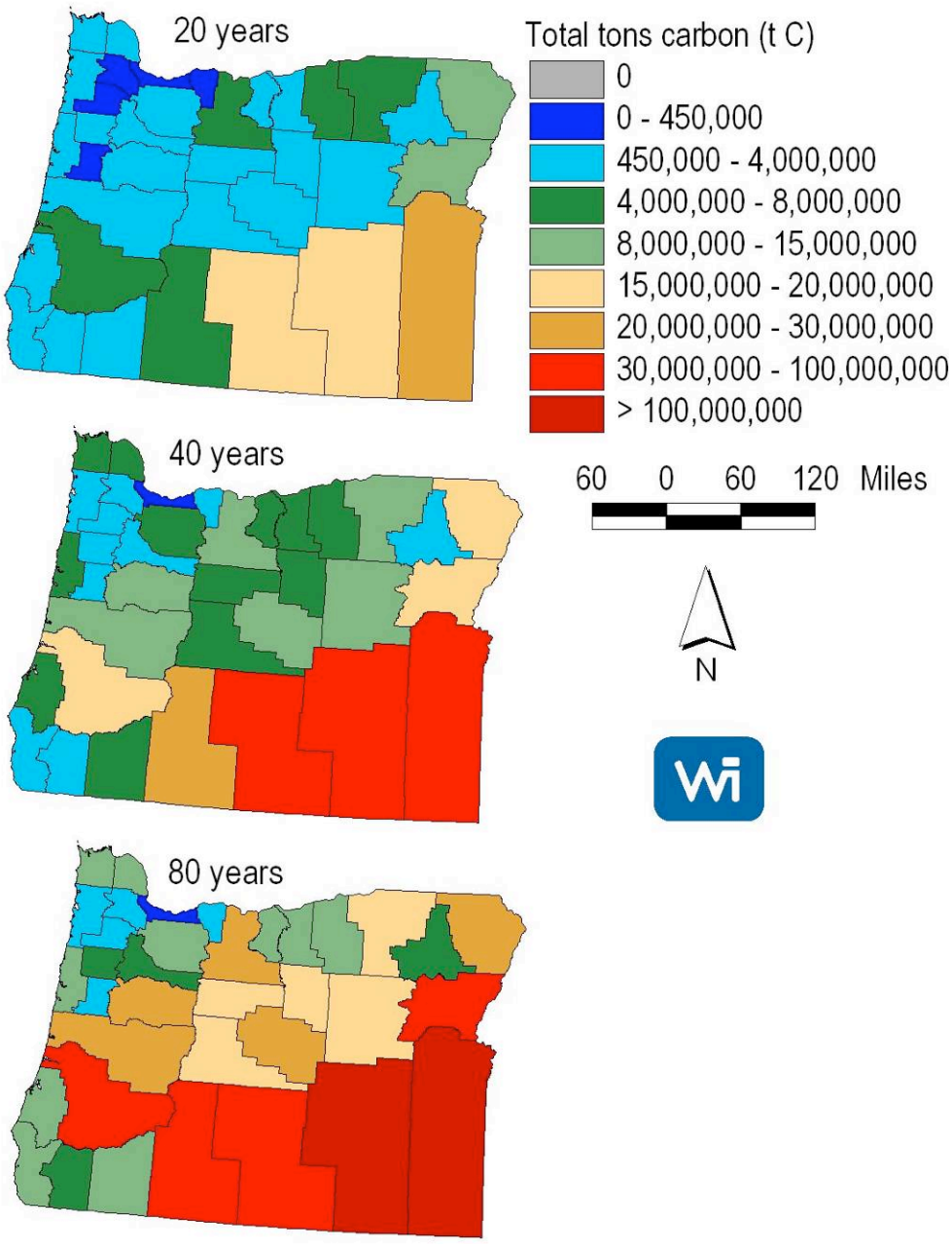


Figure 2-17. Spatial distribution, at the county scale of resolution, of the total amount of carbon that could be sequestered by afforestation of rangelands after 20, 40, and 80 years.

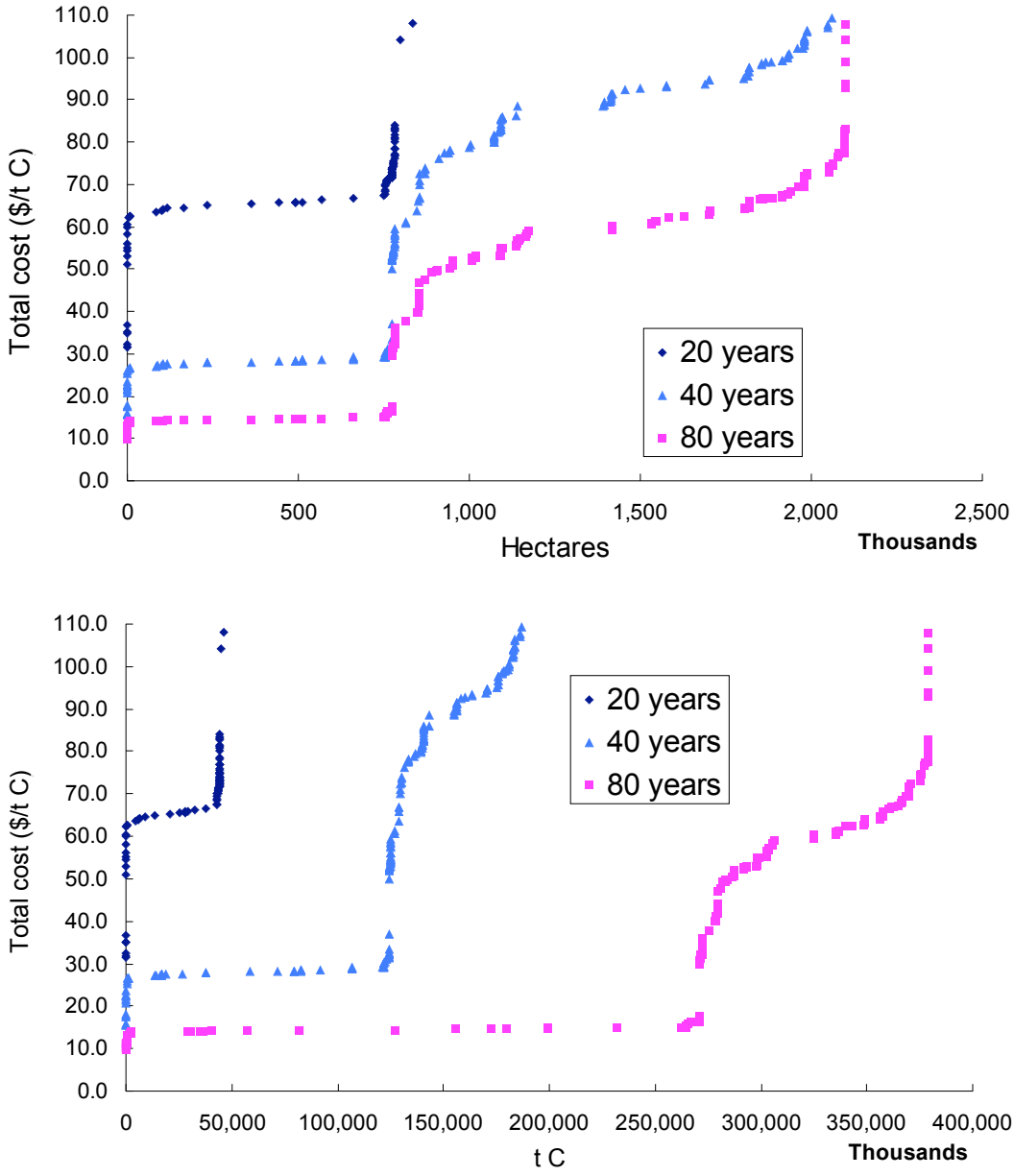


Figure 2-18. Carbon supply curves for afforestation of suitable crop lands in Oregon: (top) areas available and (bottom) quantity available at different costs per ton carbon.

The area of cropland available for afforestation increases up to about 2.1 million ha at gradually increasing costs for all project durations (Figure 2-18, top). The noticeable rise in the cost of carbon after approximately 770,000 hectares (1,900,000 acres) of lower-cost candidates have been planted would be due to the exhausting of highly productive wheat and hay lands in the Willamette Valley. The next best options for low-cost opportunities on croplands are in Sherman and Gilliam Counties alongside the Columbia River.

The quantity of carbon available from afforestation of croplands at different price points below $100/t C and time periods is shown in Figure 2-18 (bottom). At a common carbon price of

$36/t C ($10/t CO_2), afforestation of croplands would supply almost no carbon after 20 years, but could potentially supply 125 million t C for projects lasting 40 years, and 273 million t C for projects lasting 80 years.

The total amount of carbon that could be sequestered by afforestation of croplands is highest at all three time periods in the counties between the coastal ranges and the Cascades, potentially sequestering up 8 million t C after 20 years to 20-40 million t C after 80 years (Figure 2-19). Most of the central and eastern counties have the lowest potential to sequester carbon, generally not exceeding 4 million or so t C after 80 years.

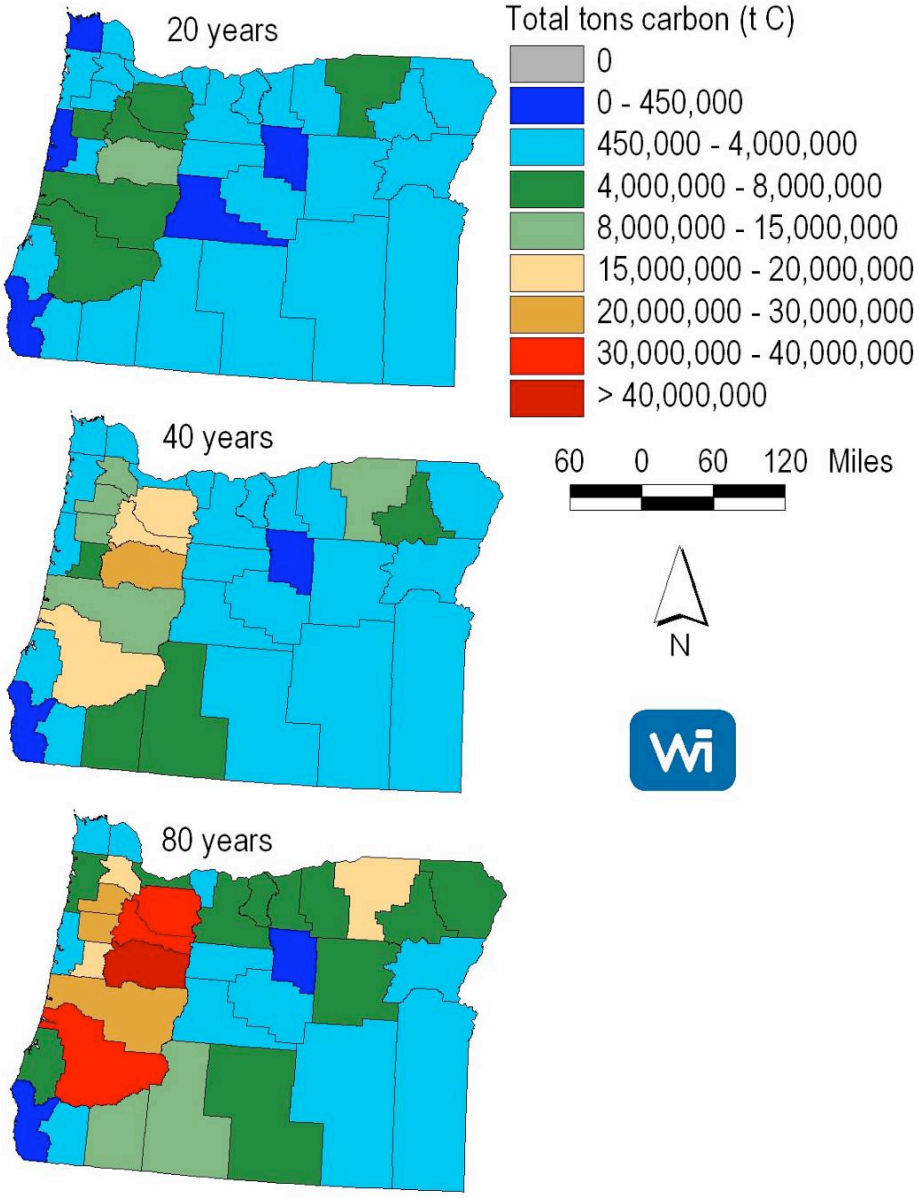


Figure 2-19. Spatial distribution, at the county scale of resolution, of the total amount of carbon that could be sequestered by afforestation of croplands after 20, 40, and 80 years.

3. Changes in forest management

3.1. Background

The potential for, and costs of, carbon sequestration through two potential changes in forest management were investigated: increasing rotation ages and increasing the area of riparian zones along streams in Oregon. A model is presented describing how optimal rotation ages are affected by changes in the value of sequestered carbon. The model is used to estimate the marginal costs of increasing rotation ages 5, 10, and 15 years beyond currently optimal rotation ages. The model is also used to estimate the costs of holding land indefinitely in riparian zones. Estimates of marginal costs are developed for a range of species, site classes, and timber pricing regions in Oregon. These costs are then applied to US Department of Agriculture Forest Service Forest Inventory and Analysis (FIA) data to estimate the spatial distribution of carbon sequestration.

The results indicate that there are around 284,000 hectares of private timberland nearing optimal rotation age in Oregon. Up to 8.4 million t C could be stored in 15-year rotation extensions on this land. The average cost per ton would be around $136 per t C, or about $4,000 per hectare. For expanding riparian zone management, there appear to be around 8,400 hectares of land nearing the optimal rotation age, with the potential to store 0.3 million t C for an average cost of $146 per t C.

This section is organized as follows: Section 3.2 describes the methodology used to estimate carbon sequestration costs through aging timberland, and presents estimates of the 5, 10, and 15 year extension periods for Oregon forests. Section 3.3 describes the approach, data used and results for setting aside timberland in extended riparian zones.

3.2. Extending forest rotations

3.2.1 Approach

Previous estimates of carbon sequestration costs through aging timberland have been developed for Winrock International for several Southern states (Brown & Kadyszewski 2004, 2005a) and for California (Brown et al 2004). The methods used to estimate the costs of carbon sequestration through aging in this paper are updated and revised relative to these earlier reports. This paper estimates marginal costs for permanent sequestration of carbon through aging timber, and for permanently setting aside riparian zones along streams.

Several important assumptions underlie this analysis. First, prices for all products and carbon are assumed to be constant over time. Second, for financial analysis, the value of carbon sequestration is discounted, and when calculating potential carbon storage, additional tons gained over time are also discounted. The issue of carbon discounting is discussed in more detail below.

To estimate the marginal costs of carbon sequestration in forests through aging, the optimal rotation period with and without value assigned to carbon storage is calculated. Optimal rotation periods for a range of carbon prices, and the additional (permanent) carbon stored for the alternative rotation periods are calculated. The carbon prices that achieve 5, 10, or 15 year aging periods are thus the marginal costs of sequestering carbon, assuming that carbon and timber prices are constant.

To calculate optimal rotation periods under alternative carbon and timber prices, the following function is maximized:

(1) Stand Value =

$$W(a) = \frac{(P_S\phi_S + P_P\phi_P)V(a)e^{-ra} + P_C\alpha V(a)e^{-ra} + rP_C\int_0^a \beta(n)V(n)e^{-rn}dn - C}{(1-e^{-ra})}$$

Where:

P_S = price of sawtimber products (stumpage, $/ft3)

P_p = price of pulpwood products is (stumpage, $/ft3)

P_C = price of sequestering a ton of carbon forever

$V(a)$ = biomass yield, or growing stock volume (ft3 per hectare)

ϕ_S = proportion of biomass used for sawtimber

ϕ_P = proportion of biomass used for pulpwood

α = conversion factor converting harvested biomass into "permanently" stored carbon.

$\beta(t)$ = conversion factor converting biomass yield into carbon.

C = harvesting costs

r = interest rate

a = rotation period.

The first part of equation (1) represents the value of harvesting the stand and selling products in markets, $(P_S\phi_S + P_P\phi_P)*V(a)e^{-ra}$. The second part of Eq.1 is the value of storing carbon permanently in markets $[P_C\alpha V(a)e^{-ra}]$. The term α is calculated as the present value of initial storage in market products less the present value of decay (or replacement rate of products):

$$\alpha = \gamma\phi_S(0) - \int_0^\infty \delta_S\gamma\phi_S(n)e^{-rn}dn + \gamma\phi_P(0) - \int_0^\infty \delta_P\gamma\phi_P(n)e^{-rn}dn$$

The term γ accounts for wood density and converts wood biomass into carbon. The term α therefore accounts for the proportion of the harvested volume that is carbon as well as the proportion stored permanently in marketed products. Permanent storage is valued at the market price for carbon sequestration, P_C. The term $[rP_C\int_0^a \beta V(n)e^{-rn}dn]$ accounts for the value of carbon sequestered on the stump. Carbon on the stump is rented annually at the rate of rP_C. Because the volume of carbon on the stump grows over time, the annual value of rental

payments for carbon sequestration will increase over time. Consequently, within each rotation, the present value of rental payments must be calculated with the integral in (1). The term □*(n)* converts timber volume into carbon. As noted in Smith et al. (2003), carbon per unit of timber volume changes over time, so the carbon conversion factor for timber on the stump is a function of time.

For this analysis, Eq.1 is solved numerically for each timber type and pricing region in the state over a set of constant carbon prices (ranging from $0 - $750 per t C). This allows us to determine the optimal rotation age, given timber prices and carbon prices. The carbon price, as shown in Eq.1, represents the marginal cost of carbon storage in forests. For each carbon price (or marginal cost), the optimal additional aging period is calculated.

The additional carbon stored when forests are aged is calculated separately for each aging period. For this analysis, a 300 year period is used to assess carbon gains. Carbon stocks are calculated across this 300 year period for the baseline, and for each increment in rotation ages. The carbon benefit calculated for aging timber is estimated as the net present value of the annual change in the difference in carbon stocks (both in products and stored on the stump) during this period. The annual difference in carbon stocks is given as:

(2a) $CSD_t = CS_t^{ER} - CS_t^{B}$

(2b) $S_t = CSD_t - CSD_{t-1}$

(2c) $NPV(Carbon) = \sum_{0}^{300} S_t (1+r)^{-t}$

where CS^{ER} is the carbon stock in each time period under the extended rotation, and CS^{B} is the carbon stock in each time period under the baseline. Stands are assumed initially to be at the optimal rotation period (the baseline rotation period, "*B*"). In the baseline scenario, stands are assumed to be continuously harvested at the economically optimal rotation age. In the scenario of extended rotations with carbon prices, stands are also assumed to be harvested continuously at optimal rotations, but the optimal rotations will be longer due to carbon prices.

Throughout this study, present value techniques are used to discount carbon flows. While most economists recognize the importance of discounting monetary flows over time, equations (2a – 2c) above discount a non-monetized flow of carbon, rather than carbon values. Discounting carbon flows like this is appropriate for benefit cost analysis under the following conditions.

Suppose a company considers investing in a project that has a stream of costs, C_t, a stream of annual carbon sequestration, S_t, and a stream of the benefits of sequestering a ton of carbon in each year, P^c_t. P^c_t is the price of carbon that would evolve in a carbon market, thus it represents the marginal costs of abating carbon in the next best alternative for the company, i.e. it is the opportunity cost for sequestering carbon. A company would choose to invest in projects where the following condition holds (where *r* is the discount rate):

(3) $\sum_{0}^{X} C_t (1+r)^{-t} < \sum_{0}^{X} P_t^c S_t (1+r)^{-t}$

Assuming that the price of carbon rises at a rate of *g* over time, this equation becomes:

(3a) $$\sum_{0}^{X} C_t(1+r)^{-t} < \sum_{0}^{X} P_0^c(1+g)^t S_t(1+r)^{-t}$$

(3b) $$\sum_{0}^{X} C_t(1+r)^{-t} < P_0^c \sum_{0}^{X} S_t\left(\frac{(1+g)}{(1+r)}\right)^t$$

Under this assumption, one would invest in the project if the discounted costs divided by the net discounted carbon gains are less than the current price of carbon.

(4) $$\frac{\sum_{0}^{X} C_t(1+r)^{-t}}{\sum_{0}^{X} S_t\left(\frac{(1+g)}{(1+r)}\right)^t} < P_0^c$$

Note that for this analysis, no salvage value is assumed, thus the landowner retains the rights to the carbon. Further, the company that purchased the sequestration over the period of time in question must continue to hold sequestered tons beyond the project period, X, equal to the undiscounted stream of S_t. Companies may choose to renegotiate their contracts with existing landowners, purchase new contracts, or abate carbon on their own, depending on the relative costs of other alternatives, at the end of the term of the contract.

As can be seen in equation (4), if g is 0, carbon flows can be discounted at financial discount rates and the costs per ton can be compared to the current opportunity costs of carbon sequestration. Alternatively, one could assume that carbon is discounted with social discount rates to determine the present value of carbon. Social discount rates for carbon could be appropriate for long term problems like climate change where damages occur in the very far distant future. The carbon analysis uses a social discount rate of 3% for carbon. Costs are discounted at 6%.

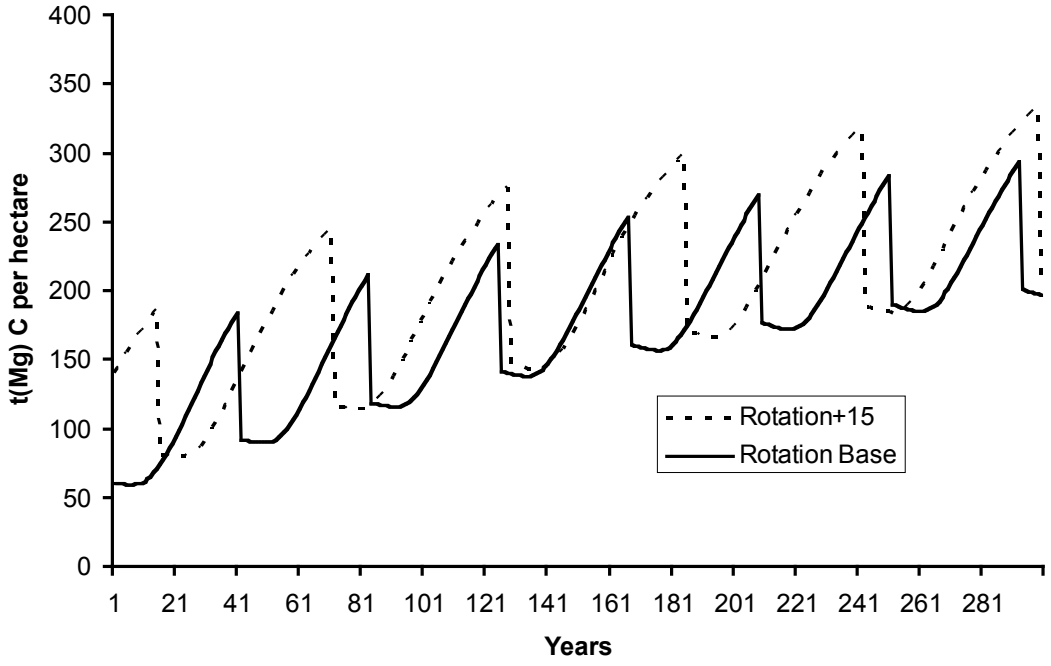


Figure 3-1. Comparison of total carbon storage on the landscape and in forest products over a 300-year period for a high site Douglas Fir stand in western Oregon.

To get a sense for the potential carbon flows associated with projects that might arise in Oregon, Figure 3-1 compares the baseline rotation with the 15-year extended rotation for a high-site Douglas Fir stand in western Oregon. Carbon gains are calculated by comparing the differences in the stocks with these two rotations, and then calculating the annual change in this difference. This credits the lengthened rotation for maintaining the stock initially and avoiding an emission, and it credits future storage of timber products. It also debits the lengthened rotation for delaying the faster earlier growing period, and for emitting some carbon at harvest time. The stream of incremental carbon gains or losses are discounted to determine the net present value of the gain in carbon associated with aging a forest additional years.

3.2.2 Data used in the analysis

3.2.2.1 Inventory and yield function parameters

These data are obtained from the USDA Forest Service Forest Inventory and Analysis database (USDA Forest Service, FIA), FIA Mapmaker version 1.7. The most recent complete periodic inventory for Oregon is used, namely, data from cycle 4 collected in 1999. Data were downloaded on the age class distribution of forest types and the proportion in different site classes.

Individual yield functions for RPA timber types in the region are estimated based from information on growing stock and acres in different age classes. RPA timber types are aggregates based on dominant species. Many stands will contain additional species. The values of these additional species can have important effects on site value, thus corrections for the mix of species present in each RPA timber type are carried out when the marginal value of

stands (i.e. the price) is calculated. All yield information is originally estimated in m^3 per hectare. The functional form of the yield function is assumed to be as follows:

(5) Yield (m^3/hectare) = exp(a – b/age)

Yield function parameters for Oregon estimated for this analysis are shown in Table 3-1.

Table 3-1. Estimated yield function parameters or Oregon. Yield at 120 years using the parameters and the maximum yield observed in FIA data is shown.

Forest type	Parameter a	Parameter b	Yield at 120 yrs. from param.	Maximum Yield in FIA data
			m3/ha	
Douglas Fir High	7.40	60	992.3	1125.4
Douglas Fir Medium	6.75	60	518.0	495.9
Douglas Fir Low	6.00	65	234.7	226.7
Ponderosa Pine Med	5.70	70	166.8	334.9
Ponderosa Pine Low	5.35	60	127.7	121.7
Fir/Spruce Med	5.70	50	197.0	304.0
Fir/Spruce Low	5.50	60	148.4	179.6
Hemlock/Spruce High	6.90	45	682.0	969.5
Hemlock/Spruce Med.	6.85	50	622.2	648.1
Hemlock/Spruce Low	6.40	55	380.6	394.2
Lodgepole Average	5.90	70	203.7	242.5
Hardwood Average	6.15	35	518.0	918.2

Table 3-2. Parameters used to calculate sawtimber proportion of stands for Oregon.

	Parameters		
Forest type	A	B	C
Douglas fir	2	0.052	10
Pond. Pine	3	0.03	20
Fir/Spruce	2.5	0.03	20
Hemlock/Spruce	3	0.03	20
Lodgepole	2.5	0.02	20
Hardwood	1	0.02	20

In addition to determining the growing stock volume, it is important to estimate the proportion of growing stock used for sawtimber and pulpwood. For this, we utilize USDA Forest Service FIA data that defines the proportion of growing stock that is sawtimber quality to develop the relationship between stand age and sawtimber proportion. The relationship used in this analysis is:

(6) Sawtimber % = 0 if Age < C

= A*(1-EXP(-B*(Age-C)))^4 if Age > C

In addition to the information presented in equation (6), we impose an additional constraint that the sawtimber proportion cannot exceed 85%. Parameters used to estimate the sawtimber proportion for this analysis are given in Table 3-2.

3.2.2.2 Price data

Prices were obtained from the Oregon Department of Forestry (Oregon DOF, Log Price Information). Prices were obtained for 4 different regions within the state, and averaged for the year 2004. Prices are available for a number of different species, and for a range of grades. For this analysis, we assume that an average price for each species is approximated by grade "3S." To determine stumpage prices, we assume that logging and hauling costs are $200 per thousand board feet (MBF; approximately $34 per m^3). As noted above, the analysis is based on RPA timber types, which are often composed of multiple species. That is, stands are likely to have multiple species within them, although they may be classified into a "dominant type." Because we have prices for individual species, we estimated weighted average prices for RPA timber types by using information on the proportion of each species within each RPA timber type. The resulting weighted average prices for Oregon RPA timber types are shown in Table 3-3.

Table 3-3. Timber prices for RPA timber types in Oregon (2004)

	R1 (NW)	R2 & R3 (SW)	R4 (SC)	R5 (east-side)
		$ per m^3		
Douglas fir & Larch	$62.98	$64.70	$66.23	$45.34
Ponderosa Pine	$63.22	$63.35	$88.64	$36.53
Fir - Spruce	$37.20	$37.41	$40.31	$31.79
Hemlock-Sitka	$45.11	$46.61	$45.09	$42.08
Lodgepole	$23.31	$23.35	$25.23	$21.04
Red Alder	$66.16	$66.32	$67.17	$59.41
Other HWDS	$66.11	$66.26	$67.11	$59.37
Pulp and Miscell.	$1.83	$1.83	$1.83	$1.83

3.2.2.3 Cost data

Costs for regeneration and timberland management in Oregon are estimated to be approximately $1,396 per hectare on average for industrial and non-industrial private land (Jim Cathcart, 2005, pers comm). Specific cost categories are shown in Table 3-4.

Table 3-4. Regeneration cost estimates for Oregon

	$$/acre	$$/ha
Private Industrial		
Site Prep	$90	$222
Seedlings	$110	$272
Planting Labor	$110	$272
Veg. Mgmt	$130	$321
Interplanting/Contingencies	$10	$25
Administration	$20	$49
TOTAL	$470	$1,161
Private non-Industrial	$660	$1,630
Average	$565	$1,396

3.2.2.4 Taxes

Two types of taxes are relevant for Oregon. First, Oregon levies a property tax on forestland. The property tax rate depends on the quality of the land. In addition, there is a special assessment for fire protection. The rate of this assessment depends on the location of the forest. We have accounted for site quality differences and locational differences in the special fire tax assessment by developing the tax rates to be applied to different site qualities in different regions in Table 3-5.

Table 3-5. Tax rates to be used in Oregon ($ per hectare per year)

Site Class	Northwest Oregon	Southwest Oregon	Eastern Oregon
High	$15.81	$16.55	$17.02
Med	$7.47	$8.21	$8.68
Low	$3.21	$3.95	$4.42

In addition to the property tax in Oregon, there is a harvest tax applied when stands are harvested. This harvest tax is applied to all timber equally. The current harvest tax is $0.48 per m^3 of harvested wood.

3.2.2.5 Biomass/carbon data

Biomass conversion factors from Smith et al. (2003) are used in this analysis. Only aboveground carbon in live biomass is counted in the analysis. The functional form used to estimate biomass is (parameters for the equation for different species are given in Table 3-6):

$$\text{Carbon (tons/hectare)} = 0.5*(E*(F+(1-EXP(-\text{Yield}/G))))$$

Table 3-6. All parameters are specific to the RPA type for all of Oregon, although specific site classes are used to calculate growing stock volume (GSV) and carbon at 70 years.

Forest type	Parameters E	F	G	GSV at 70 years	Carbon at 70 years
				m^3/ha	t/hectare
Douglas fir (Med)	984.2	0.0185	1251.5	362.4	132.8
Pond. Pine (Med)	312.80	0.02	331.20	109.9	46.9
Fir/Spruce (Med)	658.80	0.02	757.60	146.3	63.2
Hemlock/Spruce (Med)	658.80	0.02	757.60	462.1	155.7
Lodgepole (Med)	303.40	0.02	390.50	134.3	47.1
Hardwood (Med)	2318.00	0.01	4085.20	284.3	90.8

Carbon stocks in products are tracked using rates suggested by Row and Phelps (1996) and Winjum et al. (1998). First, we assume that when a softwood stand is harvested, 43% enters products and 57% is emitted immediately, either on-site through decomposition of deadwood or through use in the energy sector. Second, solidwood products are assumed to turn over at a rate of 0.5% per year and release carbon, while pulpwood turns over at a rate of 1% per year.

3.2.3 Results: estimated marginal costs of carbon sequestration through extending rotations

Table 3-7 presents the marginal costs, and the carbon gains associated with holding carbon for 5, 10 or 15 years longer than the optimal rotation period for permanent changes in rotations. The results are shown for all site classes and a single pricing region in Oregon. Differences in marginal costs arise from differences in initial rotation ages, prices, and yield functions for different site classes and species. The total amount of carbon available for sequestration on private timberland in Oregon is shown in Table 3-8. The total is derived by summing the marginal costs and t C/ha for each site class and timber type in each county. Only softwood timberland that is 40 – 60 years old according to the USDA Forest Service FIA database is included in the analysis. Future contracts could be established on younger stands, but currently merchantable age classes are deemed to be the most appropriate for aging at the current time.

Table 3-7. Net carbon sequestered (t C/ha) and $ per ton for increasing rotation ages 5, 10 and 15 years beyond economically optimal rotation ages in Oregon Region 1 (west-side of Cascades)

	Net sequestered			$ per t C		
	5 years	10 years	15 years	5 years	10 years	15 years
Doug. Fir Hi	21.9	39.1	52.4	$130	$150	$170
Doug. Fir Med	13.0	23.3	31.4	$110	$130	$140
Doug. Fir Low	6.5	11.6	15.7	$80	$95	$110
P. Pine Hi*	5.9	10.5	14.1	$125	$135	$140
P. Pine Med.*	4.8	8.5	11.3	$135	$140	$145
Fir/Spruce Hi	7.5	12.9	17.1	$85	$90	$92
Fir/Spruce Low	5.9	10.3	13.7	$75	$75	$80
Hem/Spr. Hi*	18.2	31.4	41.5	$185	$190	$195
Hem/Spr. Med*	17.6	30.4	40.3	$160	$165	$170
Hem/Spr. Low*	12.4	21.7	28.9	$130	$135	$135
Lodgepole	6.9	11.9	15.7	$10	$15	$60
Red Alder	7.6	13.2	17.4	$20	$20	$20

*P. pine=ponderosa pine; Hem/Spr. = Hemlock/Spruce

Briefly, the results indicate that 283,670 hectares of private land in Oregon are nearing the economically optimal rotation period. If all of this land were contracted to increase rotation ages by 15 years, 8.4 million t C could be sequestered for an average cost of $136 per t C. The calculation for public land in Oregon does not include USDA Forest Service land (no national inventory on thee lands in the FIA data base), but indicates that 36,368 hectares of public land

are nearing economically optimal rotation ages and could be contracted for extending rotations. Contracts for 15-year extensions on these lands could provide up to 1.3 million additional tons of carbon for similar average costs.

Table 3-8. Aggregate estimated carbon potential with holding timber past economically optimal rotation periods for Oregon.

	Extension of rotation		
	5 yr	**10 yr**	**15 yr**
Private Land Potential Hectares	283,670		
Million Tons	3.6	6.3	8.4
Million $	$394	$787	$1,150
Average $ per ton	$111	$125	$136
Average $ per hectare	$1,388	$2,775	$4,053
Average Tons per hectare	12.5	22.2	29.7
Non-Federal Public Land Potential Hectares[1]	36,368		
Million Tons	0.6	1.0	1.3
Million $	$63	$129	$193
Average $ per ton	$111	$125	$136
Average $ per hectare	$1,735	$3,544	$5,304
Average Tons per hectare	15.4	27.4	36.7

[1] Note that public land omits Federal USDA Forest Service lands.

A marginal cost curve for carbon sequestration through forest aging is presented for private lands in Figure 3-2. There are relatively few opportunities for less than $50 per t C. Most of these opportunities in Oregon are in counties that have large areas of Red Alder nearing economically optimal rotation ages. Lower cost opportunities after 15-year rotation extensions tend to occur on the east side of the Cascades due to relatively lower site values for forests overall (Figure 3-3).

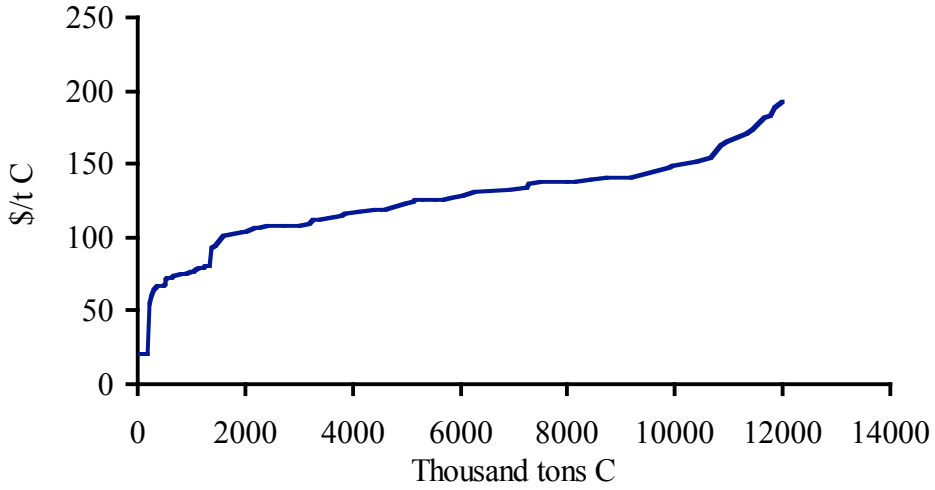


Figure 3-2. Marginal cost curves for carbon sequestration through aging, including 5, 10, and 15 year rotation extension periods.

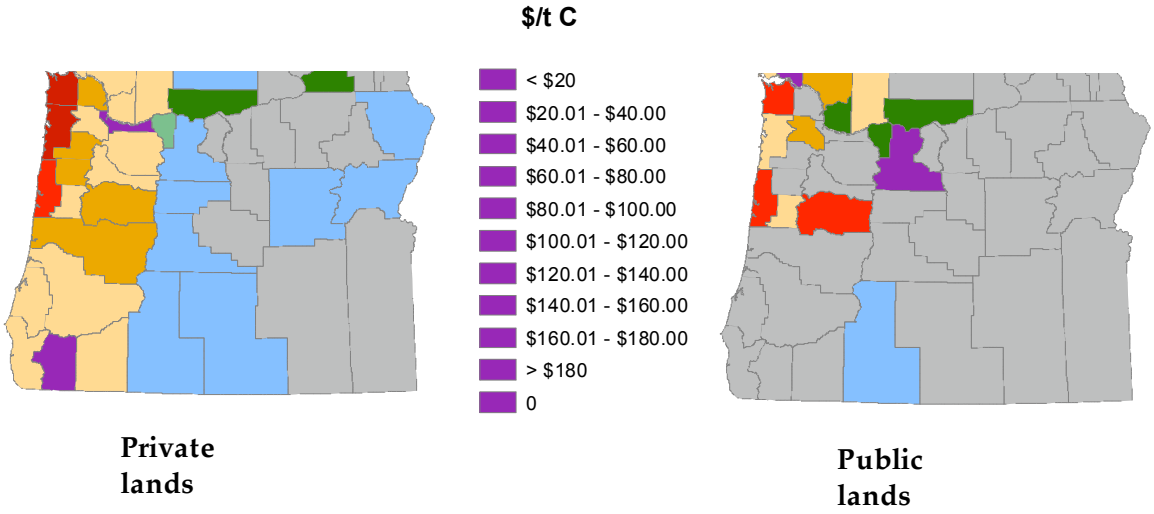


Figure 3-3. Distribution of the costs of carbon sequestration for extending rotations 15 years in Oregon (and parts of neighboring Washington).

3.3 Conservation of timber land in extended riparian buffers

3.3.1 Methods and analyses

This section examines the potential for riparian zone management to increase carbon sequestration. For this analysis, we assume that 200' riparian buffers are required on all timberland in Oregon. We estimate the costs of excluding currently mature timber in these buffers from harvest for the indefinite future. This means that the new riparian zones are treated as set-asides, and we only consider economically mature timber at the current time.

The potential carbon sequestration associated with setting aside timberland can be seen in Figure 3-4 below. The figure presents the carbon balance for a riparian zone set-aside (red line) versus harvesting that stand in the same rotation period indefinitely (blue line). For a stand that is initially near the rotation age of 50 years, if the stand is set aside, carbon accumulates along the red line from the year of the set-aside forward. If the stand is harvested, some carbon is stored in wood products and some is emitted initially. Over the first several rotations, the set-aside stand holds more carbon than is held by the harvested stand. Over the longer run, however, the harvested stand accumulates on average similar quantities of carbon as the set-aside stand due to carbon storage in wood products.

In this analysis, we discount the carbon, such that early carbon gains are more valuable than future carbon gains. Thus, the set-aside stand holds more "present value" carbon than the harvested stand, even though these stands have similar average carbon storage in the longer run (i.e., > 400 years). The set-aside stand shown in Figure 3-4 is estimated to hold approximately 100 t of "present value" carbon.

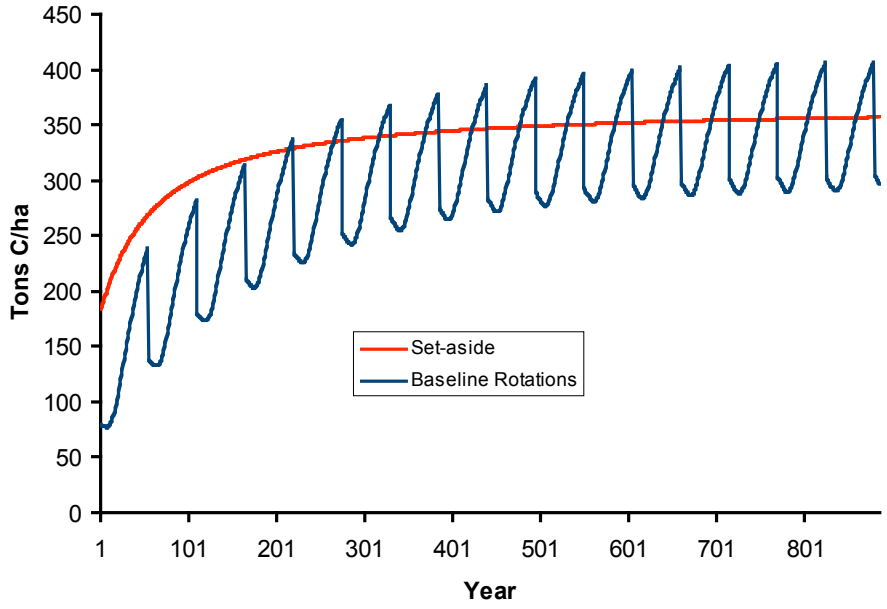


Figure 3-4. Tons carbon per hectare stored in above-ground biomass and products for the baseline (blue) and set-aside (red) for high site Douglas Fir stands in Oregon region 1.

The total costs per hectare of setting aside timberland are estimated as the current stumpage value of mature timber on each hectare, assuming the timber is near the optimal rotation age, plus the present value of bare land. These estimates provide a lower bound estimate of what it would cost individuals interested in purchasing set-asides to negotiate with landowners for the rights to hold the timber on the land indefinitely, for example through a conservation easement. The costs per ton are estimated by dividing total tons gained into the total costs.

Table 3-9. Net carbon sequestered (t C/ha) and $ per ton for setting aside mature forests in riparian zones in Oregon.

	Net sequestered	$ per t C			
	All Regions	Region 1	Region 2	Region 4	Region 5
Douglas Fir Hi	99.9	$213	$220	$225	$148
Douglas Fir Med	64.7	$172	$177	$181	$119
Douglas Fir Low	35.0	$130	$134	$137	$89
Pond. Pine Hi	25.8	$187	$187	$269	$101
Pond. Pine Med	19.8	$202	$202	$290	$108
Fir/Spruce Hi/Med	28.0	$113	$113	$122	$93
Fir/Spruce Low	24.0	$99	$99	$107	$81
Hem/Sp Med	59.9	$266	$275	$266	$248
Hem/Sp Med	61.5	$229	$236	$228	$213
Hem/Sp Low	48.0	$179	$185	$179	$166
Lodgepole	27.0	$46	$46	$50	$43
Red Alder	25.4	$72	$71	$72	$64

Table 3-9 presents estimates of the tons of carbon gained and the costs for riparian zone protection in Oregon. These estimates assume that the land would otherwise be harvested at economically optional rotation ages, and they assume that the harvests would occur in the relatively near future (i.e. the next 5 – 10 years). Carbon gains depend only on the site class, and thus are the same for each region (assuming the same site classes). The estimates of costs, however, differ due to differences in stumpage prices estimated for the different regions.

It is also useful to estimate how much land is available in riparian areas for protection. To accomplish this, stream lengths through different types of land uses in each county were estimated. The stream lengths through forested areas were extracted from these data, and used to estimate the total area of land in a set-aside encompassing an additional 100 feet of land on each side of the stream. The data included information on the types of forests, allowing us to attach the economic value and carbon sequestration estimates from the tables above directly to specific stream segments.

The estimates of costs and carbon sequestration assume that land is currently of merchantable age, however, the riparian area data did not distinguish age classes. We therefore assumed that the riparian zones have the same distribution of age classes as the rest of forests in each county. Thus, the total stream length within in each county was adjusted to reflect the proportion in the county that is merchantable, according to the USDA Forest Service FIA data.

3.3.2 Results: marginal costs of carbon conservation in riparian buffers

The results of the analysis of potential costs of sequestering carbon through riparian zone set-asides are shown in Table 3-10. Currently, it is estimated that there are 8,392 hectares of mature forests in riparian zones within Oregon. If these areas were set aside, the estimated costs would be approximately $5,899 per hectare, or $49.5 million in total. Approximately 340,000 t C could be sequestered with this action, for an average cost of $146 per t C. The distribution of costs by county is shown in Figure 3-5. As with holding timber longer than optimal rotation periods, costs tend to be lower in counties on the east-side of the Cascades due to lower overall site values.

Table 3-10. Estimated total area of riparian zones and total cost of protecting currently mature areas in Oregon

	Oregon
Riparian Stream lengths (million meters)	26.2
Total Potential Area (hectares)	159,795
Mature Potential Area (hectares)	8,392
Total Carbon (million tons)	0.34
Total Cost (million $$)	$49.5
Average Cost per ton ($ /t C)	$145.84
Average Cost per hectare ($ / hectare)	$5,899

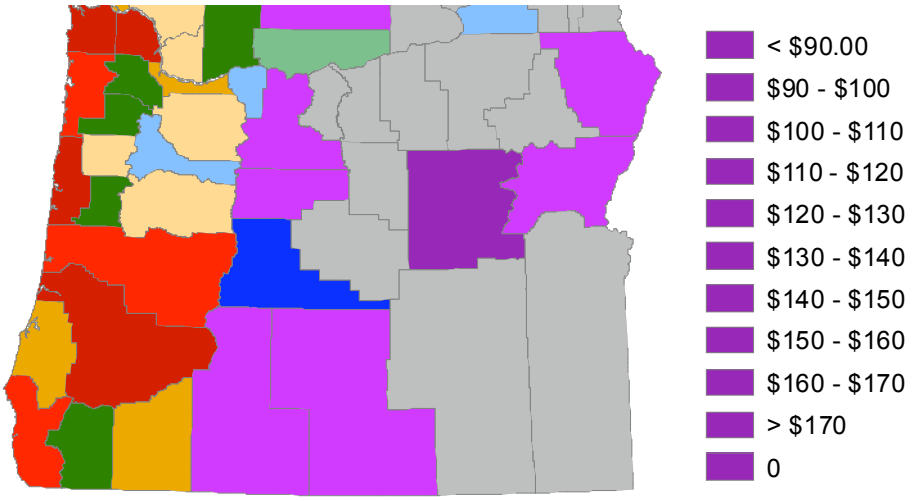


Figure 3-5. Costs of sequestering carbon through expanding riparian zones in Oregon (and parts of neighboring Washington).

4. Fuel load reduction on wildfire-prone areas

4.1. Introduction

Fires have a significant effect on carbon stocks in forests. Fire management techniques that reduce carbon emissions by reducing the risk of wildfire through removal of biomass fuels potentially offer an opportunity to reduce emissions and thus provide carbon dioxide emission reduction credits (henceforth, carbon credits) . Not only would reductions in catastrophic forest fires reduce carbon and non-CO_2 GHG emissions from burning, but the use of the biomass to generate electricity would offset emissions from fossil fuel-generated energy. The objective of this section is to produce a first-order approximation of the areas and carbon stocks of forests suitable for fuel reduction to reduce their fire risk, and their location relative to existing power plants.

4.1.1. Magnitude of the problem

The last century has seen the transformation of many western forest ecosystems from relatively open, healthy forests in which periodic low-intensity ground fire played an important ecosystem function, to densely stocked, fire-prone forests in which catastrophic crown fires burn hundreds of thousands of acres each fire season. This has resulted in escalating fire suppression budgets, loss of timber, wildlife, recreational and ecosystem values, lost property values, skyrocketing insurance costs, and loss of life. Fires appear to be increasing in size and intensity, resulting in greater losses of forest area and billions of tax dollars spent each year for fire control. As reported by the National Interagency Fire Center, 103,387 fires consumed 4.5 million acres in 1960; by the year 2000, 122,827 fires burned almost twice as much—8.4 million acres—while federal expenditures rose from $845 million in 1994 to $1.7 billion in 2002 (Figure 4-1).

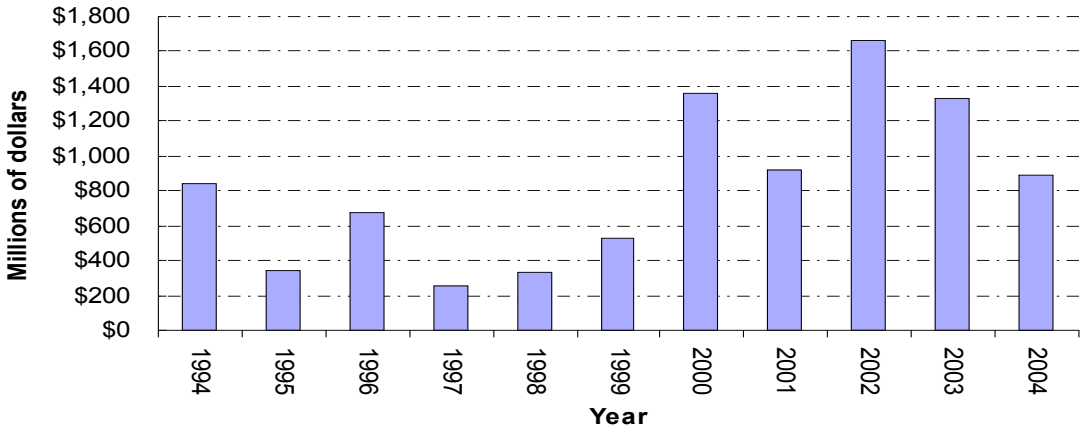


Figure 4-1. National Interagency Fire Center statistics showing federal expenditures in millions of dollars from 1994 to 2004.

The USDA Forest Service (USFS) in 1937 adopted policy of "fast, energetic and thorough suppression of all fires in all locations" (Chase 1989). A more recent scientific consensus suggests that low-intensity ground fire played a natural and important role in many Western forest ecosystems (e.g. Schoennagel et al. 2004). Instead of having a healthy fire return interval of 15 or 20 years depending on forest type, a combination of logging, fire suppression and other factors have altered fire regimes and resulted in a fundamentally different forest landscape in which accumulated woody fuels create conditions for infrequent but intense and large-scale fires that can permanently alter ecosystems (Pyne et al. 1996). This has led to a debate among landowners and public land managers about how to manage fire across boundaries, and how to return natural low-intensity fire to these forest ecosystems – starting from a present condition of accumulated fuels that makes it impossible simply to forego fire suppression, let fires burn, or introduce prescribed fire without first undertaking treatments to reduce fuel loads. A national consensus is beginning to develop among government, industry, community and environmental stakeholders that something must be done to reduce fuel loads and return forests to more natural fire regimes; nonetheless, the problem is complex and the barriers to a large-scale solution are political, administrative, environmental, and perhaps most significantly economic. The necessary fuel reduction treatments tend to be labor-intensive and very costly, the value of the material removed relatively low, and agency budgets to pay for treatment increasingly constrained. Creative utilization strategies for understory biomass and small-diameter timber are needed, together with a broad portfolio of approaches and sources of revenue to offset the costs of fuel treatment.

A recent assessment of forests across 15 Western states, conducted under the auspices of the National Fire Plan, found that approximately 67 million acres are at moderate to high risk of wildfire (Fire Regime Condition Class 2 and 3) and 28 million acres at the highest risk level (FRCC 3) [2]. These figures include only those acres considered accessible for some type of treatment to reduce hazardous fuels. The 28 million acres in FRCC 3 could yield 345 million bone dry tons (BDT) in removals, with the greater proportion (70%) of the volume in larger diameter classes (over 7" considered merchantable sawtimber), but the greater number of stems in the < 7" submerchantable biomass category (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003). This hints at both the scale of the wildfire risk/hazardous fuels problem in the West, and one of the key economic barriers: a huge quantity of submerchantable material requiring treatment and/or removal to reduce fire risk, but constituting relatively little volume or value to pay the high cost of handling such a large number of stems.

In Oregon alone, 12.2 million acres in FRCC 2 and 3 require hazardous fuel reduction and would yield an estimated 291 million BDT, of which 5.6 million acres are in FRCC 3 and would

[2] Fire Regime Condition Class (FRCC) is a measure of how much a forest has departed from natural wildland fire conditions (Schmidt et al 2002). The fire regime in Class 2 areas is moderately altered from the historical range; moderate levels of restoration treatments such as fire or mechanical treatments would be required to begin managing a more natural fire cycle. In Class 3 areas, fire regimes have been significantly altered and there is a high risk of losing key ecosystem components in a wildfire. Due to high fuel loadings, mechanical treatments are expected to be needed before the reintroduction of fire (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003).

yield an estimated 91 million BDT (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003).

4.1.2. Approach and analysis of hazardous fuel reduction treatments

Decades of fire suppression practices, resulting in unnatural fuel accumulation and severe wildfire in western forests, are particularly associated with the dry ponderosa pine forest type (Schoennagel et al 2004). According to Schoennagel et al, dry ponderosa pine forests are in urgent need of ecological restoration and fire mitigation. Historically, frequent and low-intensity fire maintained open stands in low-elevation ponderosa pine; the surface fuel layer, dominated by grasses and needles, usually dries easily, resulting in frequent low-intensity surface fires (low-severity fire regime). Disturbing this historical fire regime in these forests through fire suppression has resulted in build-up of ladder fuels at intermediate heights that carry ground fires into the crowns, where they can lead to large, catastrophic fires. Mixed-severity fire regimes occur mostly at mid elevation, in forest stands with variable tree species and densities defined as mixed conifer forests. For these forests accumulated fuel and climate affect the frequency, severity and size of fires. The impact of suppression practices on fuel loads in these forests varies depending on the tree composition of the forest stand. To restore historical stand structure of ponderosa pine and mixed conifer forests, mechanical HFR treatments are recommended.

A broad range of hazardous fuel reduction (HFR) treatments and technologies is available to address the fire risk problem. Prescribed fire is a relatively low-cost way to reduce fuel loading and ultimately perhaps the preferred treatment if the goal is to reintroduce fire into forest ecosystems. Prescribed fire is fairly constrained in its use today because of the potential for fire escape (especially at the wildland-urban interface), relatively short windows of appropriate conditions, and air quality and sediment yield concerns. Indeed, to treat FRCC 3 forest lands, prescribed fire is probably an option only following some mechanical treatment to reduce fuel loads (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003). One could envision a range of available HFR treatments, each with different constraints, costs, yield of merchantable and submerchantable material and thus revenues, air quality impacts, ground impacts, and greenhouse gas emission impacts (Figure 4-2, Table 4-1).

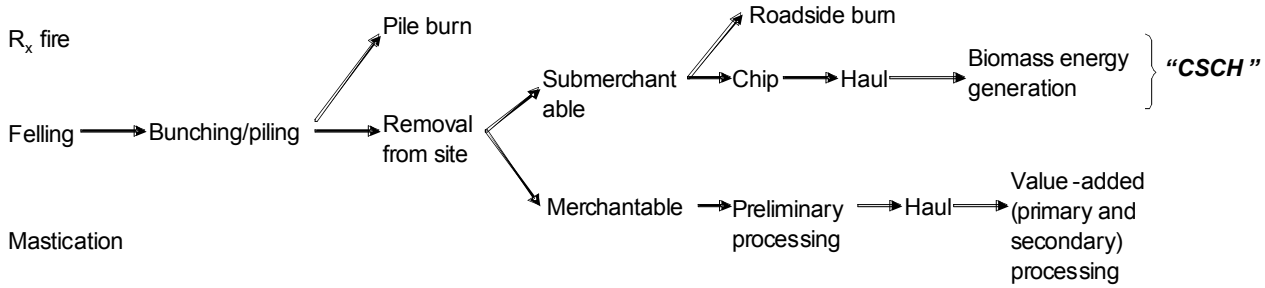


Figure 4-2. Schematic of potential HFR treatments (adapted from USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003).

Table 4-1. Benefits, constraints and representative costs for HFR treatments.

Hazardous fuels reduction treatment	Product yield	Benefits	Constraints	Representative costs
R_x fire	No	Less expensive, re-introduces fire	Air quality, ground impacts, fire escape (WUI), seasonal restrictions, immediate CO_2 emissions to atmosphere	$35-300/acre, average $92/acre[3] $23-223/acre[4]
Masticate – leave on site	No	Efficient, useful for less accessible sites where fuel removal not a goal	Leaves fuel on site, gradual CO_2 emissions to atmosphere	$100-1,000/acre[2]
Cut-pile-burn	No	Less expensive, can be used on inaccessible or steep sites	Leaves fuel on site, air quality, immediate CO_2 emissions to atmosphere	$100-750/acre[2]
Cut-lop-scatter	No	Less expensive, can be used on inaccessible or steep sites	Leaves fuel on site, gradual CO_2 emissions to atmosphere	$105-280/acre[5]
Cable yarding for biomass removal	Yes	Makes less accessible or steeper sites treatable	Expensive, ground impacts	$80-130/CCF[4]
Cut-skid-chip-haul (for submerchantable biomass) ***"CSCH"***	Yes	Removes fuel from site; some product value to offset costs; allows renewable energy generation; greatest CO_2	More expensive; limited to gentler slopes, areas closer to roads for removal, limited haul distance to biomass plant	$34-48/BDT + haul cost $0.35/BDT.mile[1] $560-1,634/acre[6]

[3] USDA Forest Service Research & Development/Western Forestry Leadership Coalition, 2003.

[4] Chalmers and Hartsough, no date.

[5] Fight et al. 2004, Barbour et al 2004.

		benefit		
Cut-skid-process-load-haul (for merchantable)	Yes	Greatest product value to offset costs; removal of merchantable material may be necessary to reduce fire risk (Crowning Index) and meet spacing or forest health goals	More expensive; limited to gentler slopes, areas closer to roads for removal, limited haul distance to processing facility; environmental controversy / frequent litigation	Variable

The present analysis is confined to a single HFR treatment – cut-skid-chip-haul, or "CSCH" because this appears to be the practical way to remove fuel from the forest while at the same time being available for transportation to a biomass energy power plant. We attempt to estimate the total area of Oregon forest lands with low-severity and mixed-severity fire regimes, how much of this area meets a series of constraints making it feasible to treat using CSCH, how much biomass could be removed from this area using CSCH and be available to existing biomass power plants, and what might be the economics of using CSCH on those forested acres. Thus the focus is primarily on submerchantable biomass, and the use of forest fuels for generating heat and power in biomass energy facilities.

The approach chosen here is necessarily a simplification of the reality of HFR as practiced today, in which a variety of treatments can be applied for different locations, terrain, slope or other conditions. Perhaps most importantly, most HFR prescriptions call for a mix of submerchantable and merchantable material removal, both for economic reasons and to target a desired future forest condition that is defined in terms of residual spacing or basal area, residual fuel loading, reduced ladder fuels to prevent ground fires from moving into the crown, and reduced crown density or crown-touching to prevent crown fires from being sustained or spreading over long distances (Fried et al 2003). While diameter limits are sometimes applied, it is rarely appropriate to exclude all merchantable material to meet these desired future conditions. Accordingly, different treatment types, technologies, and product yield mean different economics of HFR and different types of sites that become treatable either in technical terms (e.g. treatments available for steep slopes) or in economic terms (e.g. treatments that yield more merchantable material, offsetting costs and allowing the contractor to remove more submerchantable biomass to reduce ladder fuels or treat lands on the margin of the maximum haul distance from a biomass energy facility). There is a large literature focused on the economics of different treatments, models to estimate costs of treatment (STHARVEST and others), and models to estimate quantities of biomass available from a given area or the best locations to site biomass energy facilities (FIA Biosum, Coordinated Resource Offering Protocol,

[6] Fried et al 2003.

and others) (Fight et al 2003, 2004; Fried, Barbour and Fight 2003; Fried et al 2002, 2003; Barbour et al 2001, 2004; Christensen et al 2002; Chalmers and Hartsough, no date; Mater 2005).

4.1.3. Objectives

The four primary objectives of this study are:

1) Identify areas of forestland in the state with historically low-severity and mixed-severity fire regimes (HLS-HMS fire regimes—ponderosa pine and mixed conifer forests).

2) Conduct a multi-criteria evaluation to identify forestlands HLS-HMS fire regimes suitable for fuel removal. This analysis assigns a Suitability for Potential Fuel Reduction (SPFR) score to all forested areas, based on criteria affecting the feasibility of treating these lands, removing and transporting fuels for biomass energy generation.

3) Identify forested areas with HLS-HMS fire regimes that could be treated with "Cut-Skid-Chip-Haul" HFR treatment to mitigate potential extreme fire behavior and to restore these forests to their historical fire regime.

4) Assess how much biomass fuel this "Cut-Skid-Chip-Haul" HFR treatment might generate for use in power plants, and at what cost.

4.2.Results: forested land with low-severity and mixed-severity fire regimes

The first step in this analysis was to identify forest areas with HLS-HMS fire regimes that are suitable for fuel removal to restore the historical fire regimes in these forests. Forested areas were extracted from the Oregon GAP analysis layer (USGS, GAP Analysis Program 2005). There were 17 forest types recognized in the GAP dataset, dominated by mixed mesic coniferous, mixed xeric coniferous, ponderosa pine and xeric coniferous forests. Considering the areas of Oregon forests within a 50-mile radius of biomass-fueled electric power plants, mixed mesic coniferous forest predominate (Table 4-2; Figure 4-3).

Table 4-2. Distribution of forest area (ha) by forest type.

Forest type	Northwest Regional GAP Analysis category	Area (ha) statewide
Mixed Mesic	Mixed Mesic Coniferous Forest	3,840,400
	Mesic Mixed Forest	556,700
	Mountain Hemlock	135,100
	Deciduous Forested Riparian	12,800
	Mixed Riparian	400
Mixed Xeric	Mixed Xeric Coniferous Forest	2,289,200
	Xeric Douglas-fir	1,025,800
	Xeric Mixed Forest	143,600
	Xeric Deciduous	45,800
Ponderosa Pine	Ponderosa Pine	1,891,600
Subalpine	Mixed Subalpine Coniferous Forest	285,400
Mixed Coastal	Mixed Coastal Forest	194,300
Mesic Deciduous	Mesic Deciduous	143,700
Lodgepole Pine	Lodgepole Pine	106,000
Jeffrey Pine	Jeffrey Pine	21,400
Shrub/Tree	Mountain Mahogany	600

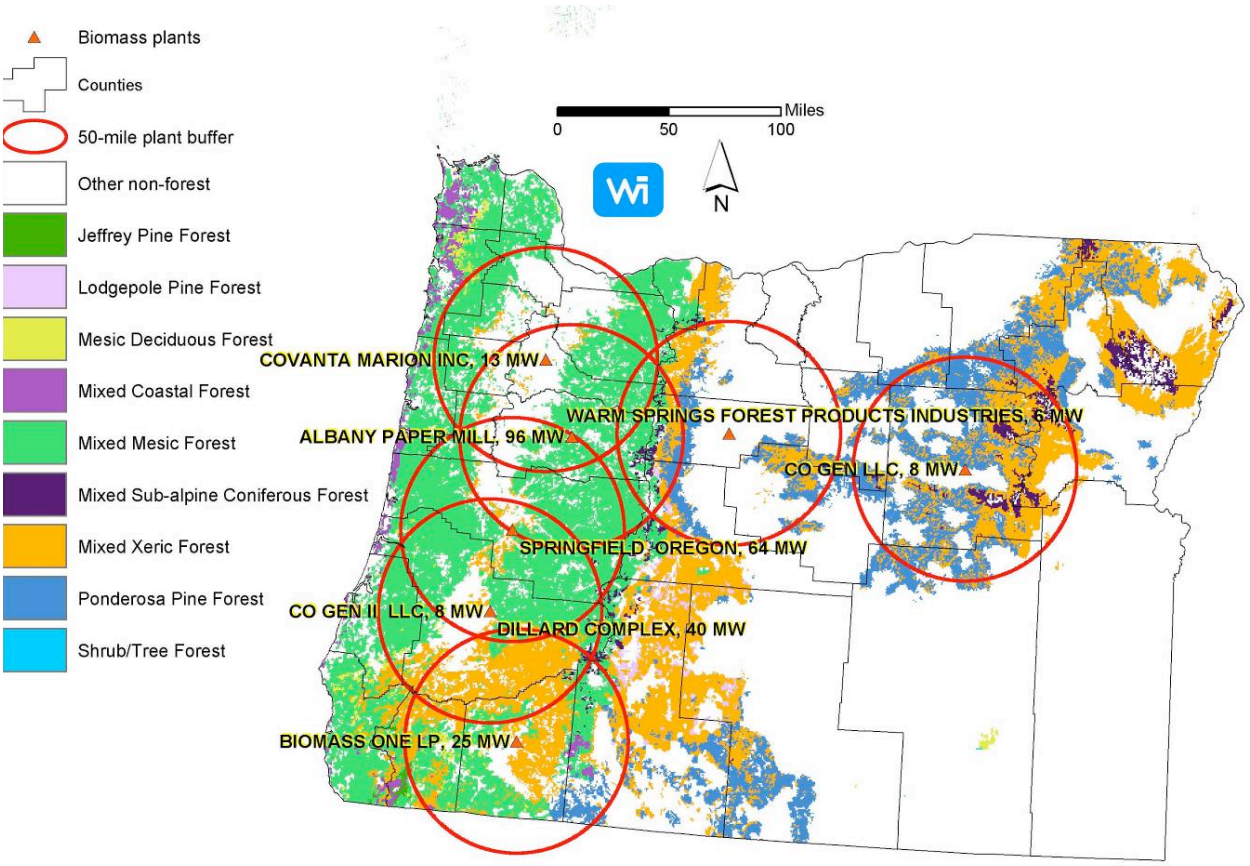


Figure 4-3. Map showing the forest classes for this analysis and names of Oregon's biomass power plants and their electric power outputs (in MW).

For this analysis, forest areas with HLS-HMS regimes were identified based on a re-classification of the NW Regional GAP's classification used above. Two forest categories were recognized from the GAP analysis data: ponderosa pine forest and mixed xeric coniferous forest as HLS-HMS fire regime forests. The total area of ponderosa pine and mixed xeric coniferous forests in Oregon was estimated at approximately 4.2 million hectares (Figure 4-4).

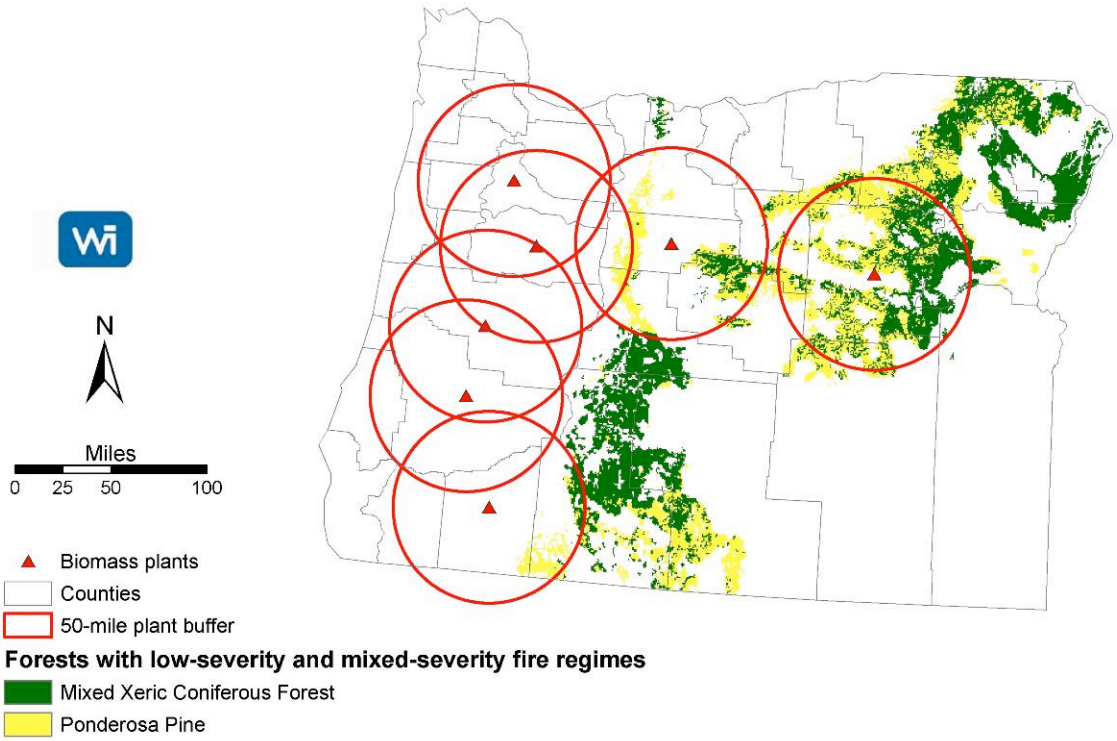


Figure 4-4. Map showing forestlands with historically low-severity and mixed-severity fire regimes and locations of the biomass power plants in Oregon.

4.3. Results: suitability for potential fuel reduction

A multi-criteria evaluation was conducted to identify forestlands suitable for fuel removal. Three factor maps were used in the decision support tool for a Multi-Criteria Evaluation module (MCE): distance from roads, distance from power plants, and slope. The analysis was constrained to a radius of 50 miles from existing power plants, representing a general rule-of-thumb for maximum hauling distance for low-value biomass fuel. These factor maps were combined to create a single raster map showing Suitability for Potential Fuel Removal (SPFR) scores.

The first factor analyzed was distance from roads. A road layer for the Census 2000 TIGER Line was downloaded from the ESRI web site[7], including all major state, interstate highways and local roads statewide. Also, a railroad layer at scale 1:24,000 was downloaded from Oregon Geospatial Data Clearinghouse (Oregon Geospatial Enterprise Office (GEO) 2005). Both transportation layers were combined to create a layer representing all roads. The Euclidean distance module in ArcView was used to create a distance map from the linear features of all roads. This map was standardized into a range from 0 to 255 using the "FUZZY" module in GIS software Idrisi Kilimanjaro (Eastman 2003), so that the starting point for most suitable areas was 100 meters away from the roads to avoid a risk of fire close to roads. The greatest travel distance

[7] http://arcdata.esri.com/data/tiger2000/tiger_download.cfm

to reach a road was assigned the lowest suitability score (0), and the least travel distance the highest suitability score (255), indicating that as yarding distance increases, cost of removal increases and suitability for fuel removal thus decreases (Figure 4-5).

The second factor analyzed was slope. A slope map in degrees was derived from a 30m DEM. Slope ranges between 0.0 and 27.79 degrees for the state of Oregon, and was standardized with a fuzzy classifier to range of 0 to 255, with 255 representing the gentlest slope (easiest access and least ground impact from fuel removal, thus most suitable) and 0 the steepest slope (least suitable) (Figure 4-5).

The third factor analyzed was distance from existing power plants. Locations of electricity generating facilities within the state of Oregon with greater than 0 MWh annual biomass/wood net generation in 2000 were obtained from the Emissions & Generation Resource Integrated Database ('eGrid' -U.S. Environmental Protection Agency, 2003). A point file was created using the latitude and longitude information for each plant, then the Euclidean distance module in ArcView was used to create a distance map from the point locations of electricity generating plants. The distance map was standardized to a scale of 0 to 255, with the greatest travel distance to reach a power plant assigned the lowest suitability score (0) and the least travel distance the highest suitability score (255), indicating that as the distance to the nearest power plant increases, cost of hauling fuel increases and suitability for fuel removal thus decreases (Figure 4-5).

All three factor maps were used as inputs for the MCE module, a GIS decision making tool in Idrisi Kilimanjaro software. The output of this module was a SPFR score map on a standard scale from 0 to 255, where 0 represents the least suitable areas and 255 the most suitable areas for potential fuel reduction accounting for distance to roads, slope and distance to power plants (Figure 4-5).

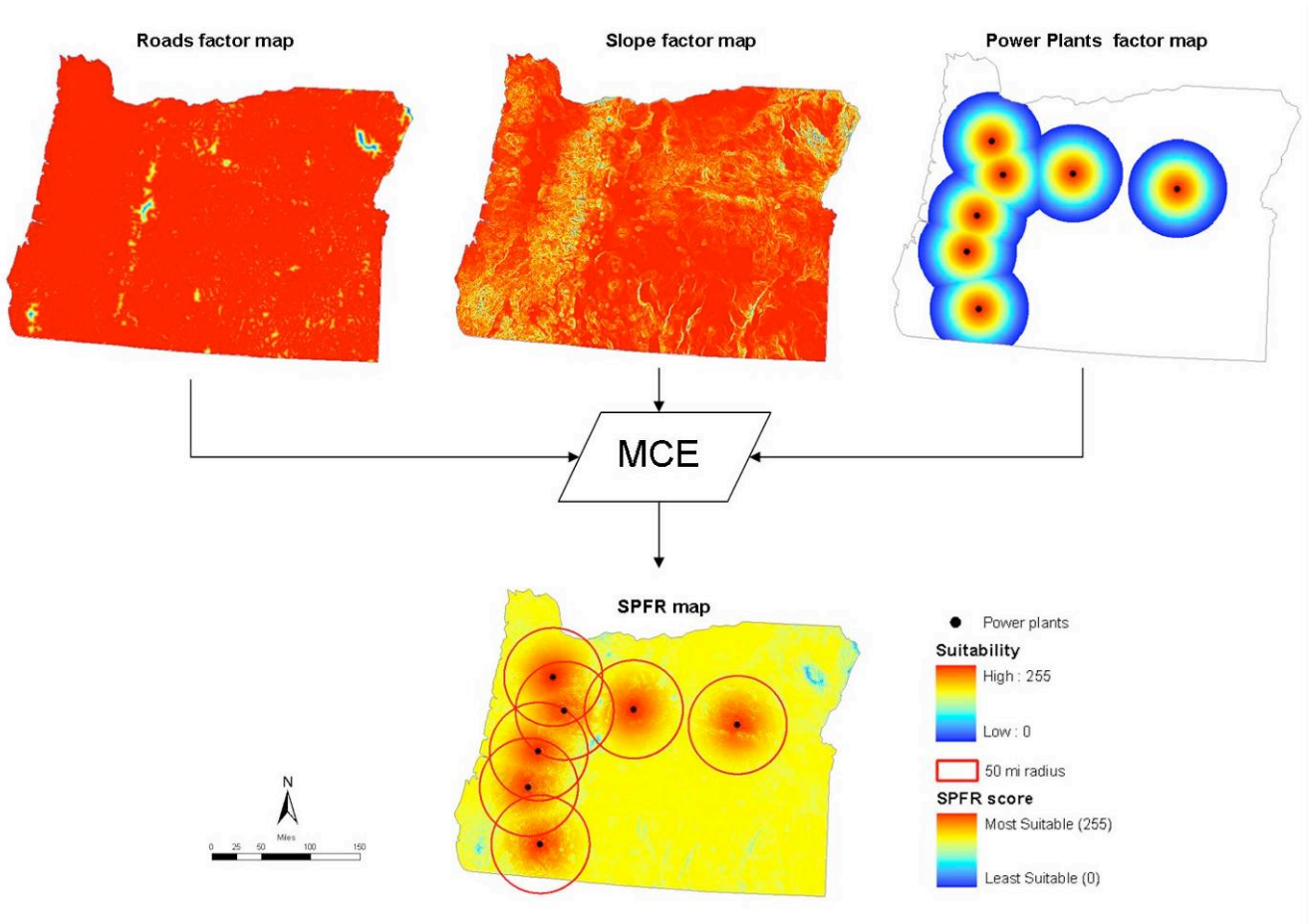


Figure 4-5. Suitability for Potential Fuel Removal (SPFR) scores for Oregon, with highest suitability assigned to areas close to roads, on gentle slopes, and close to existing power plants.

The ranges of the SPFR scores for the forests with HLS-HMS fire regimes, and locations of the existing power plants in Oregon and their buffer zone of 50 miles are shown in Figure 4-6. The SPFR scores for Oregon forests with HLS-HMS fire regimes indicated the suitability for treating these forestlands, removing and transporting the fuels to biomass energy generation facility, based on three factors: slope, distance from roads, and maximum distance of 50 miles from power plants. The highest suitability is assigned to forest close to roads and power plants, and on gentle slopes.

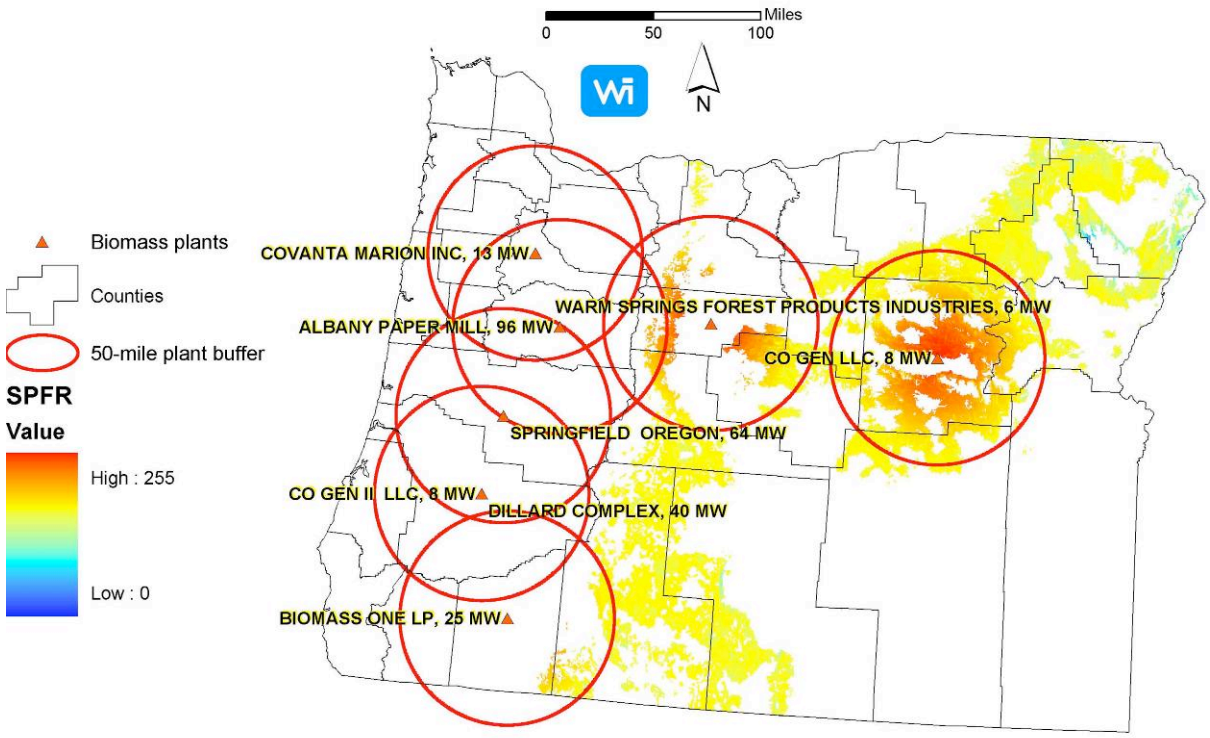


Figure 4-6. Suitability for Potential Fuel Reduction (SPFR) scores for Oregon's forests with historically low-severity and mixed-severity fire regime [NOTE: 50–mile radii and power outputs of existing biomass power plants].

4.4. Results: historically low-severity and mixed-severity fire regime forests treatable with "CSCH"

4.4.1. Estimated biomass yield

In the third component of this analysis, we looked in more detail at one potential hazardous fuels treatment, "Cut-Skid-Chip-Haul" (CSCH), a treatment in which hazardous fuel is harvested in the woods, bunched and skidded to a landing, chipped into a chip van, and hauled to a biomass energy facility for electricity and/or heat generation. The objective was to assess the area of HLS-HMS fire regime forestlands in the state to which this treatment could be applied, how much biomass fuel this might generate for use in power plants, and at what cost.

In this analysis, the following crucial constraints for CSCH treatment were considered to identify the area of HLS-HMS fire regime forestlands available for CSCH:

- Maximum slope constraint. Assumes only lands of < 40% slope may be treated with CSCH (Fight et al 2003; Fried et al 2002; Fried et al 2003; Fried, Barbour and Fight 2003). Steeper slopes may be treated in other ways (e.g. cut-pile-burn), but do not allow CSCH due to machinery and equipment access, ease of removal, and ground impacts from harvest and skidding.
- Maximum yarding distance constraint. Assumes only lands within 0.25 miles (400 meters) of existing roads may be treated with CSCH. This is used as a general rule of thumb for the maximum distance low-value material would be skidded to a landing

where a chipper and chip van is parked (Bob Rynearson, WM Beaty & Associates, pers. comm. September 2005).

- Maximum haul distance constraint. Assumes only lands within 50 miles of existing power plants may be treated with CSCH due to transport cost. This maximum haul distance may be considerably affected by the volume/value of merchantable material in the prescription, but for a simplified CSCH treatment targeting only low-value submerchantable material, it is assumed that haul distance cannot exceed 50 miles.
- Minimum block size to justify move-in costs of equipment and personnel. A general rule of thumb is that a treatment block must be at least 80-100 acres to justify move-in costs, although this number may be slightly less if equipment is already sited nearby for another project (Bob Rynearson, WM Beaty & Associates, pers comm. September 2005).

Constraints were applied sequentially so that only lands meeting all constraints were available for CSCH treatment. Forests with HLS-HMS fire regimes were superimposed on a slope map and all forestlands of > 40 % slope were excluded (Figure 4-7 A). To meet the requirement of maximum 0.25 miles yarding distance, a buffer layer was created, rasterized and overlain with the HLS-HMS fire regime forests on gentle slopes to exclude any lands further than 0.25 miles from roads (Figure 4-7 B). Finally, the constraint map of 50 mile radii from existing power plants was overlain on the earlier maps to exclude forests beyond this haul distance (Figure 4-7 C).

The fourth constraint of minimum block size proved difficult to apply when the analysis was conducted. In theory it would be possible to exclude as uneconomic all lands, meeting the three above constraints, but without sufficient contiguous area to meet a minimum 80- or 100-acre minimum treatment block constraint. However, the 1,000-meter level of resolution that the analysis was originally conducted at meant that a single pixel represented 100 hectares or 247 acres, so it was not possible to exclude blocks of only 80-100 acres. Only at a later date would the 1,000-meter pixel data be eliminated from the analysis[8] allowing 30-meter resolution analysis. The WESTCARB Phase II project anticipates application of this constraint in further characterization of opportunities at the finer-scale analyses of the pilot project sites.

Applying sequential factors of slope, yarding distance and 50-mile radius from existing power plants to forestlands with HLS-HMS fire regimes, resulted in an estimate of approximately **1.2 million hectares** of dry ponderosa pine and mixed coniferous xeric forests that would be available for CSCH treatment (Figure 4-7).

[8] A 1,000-meter grid cell 'fuel characteristic class system' (FCCS) GIS layer, developed by the Fire and Environmental Research Applications team (FERA) of the USDA Forest Service - Pacific Northwest Research Station - Pacific Wildland Fire Sciences Laboratory, was originally used to identify fuel beds that had moderate and high fire behavior potential and were at high wildfire risk. Subsequent and later reviews indicated that assumptions about forest species compositions as supported by Schoennagel et al (2004) were sufficient for mapping fire risk.

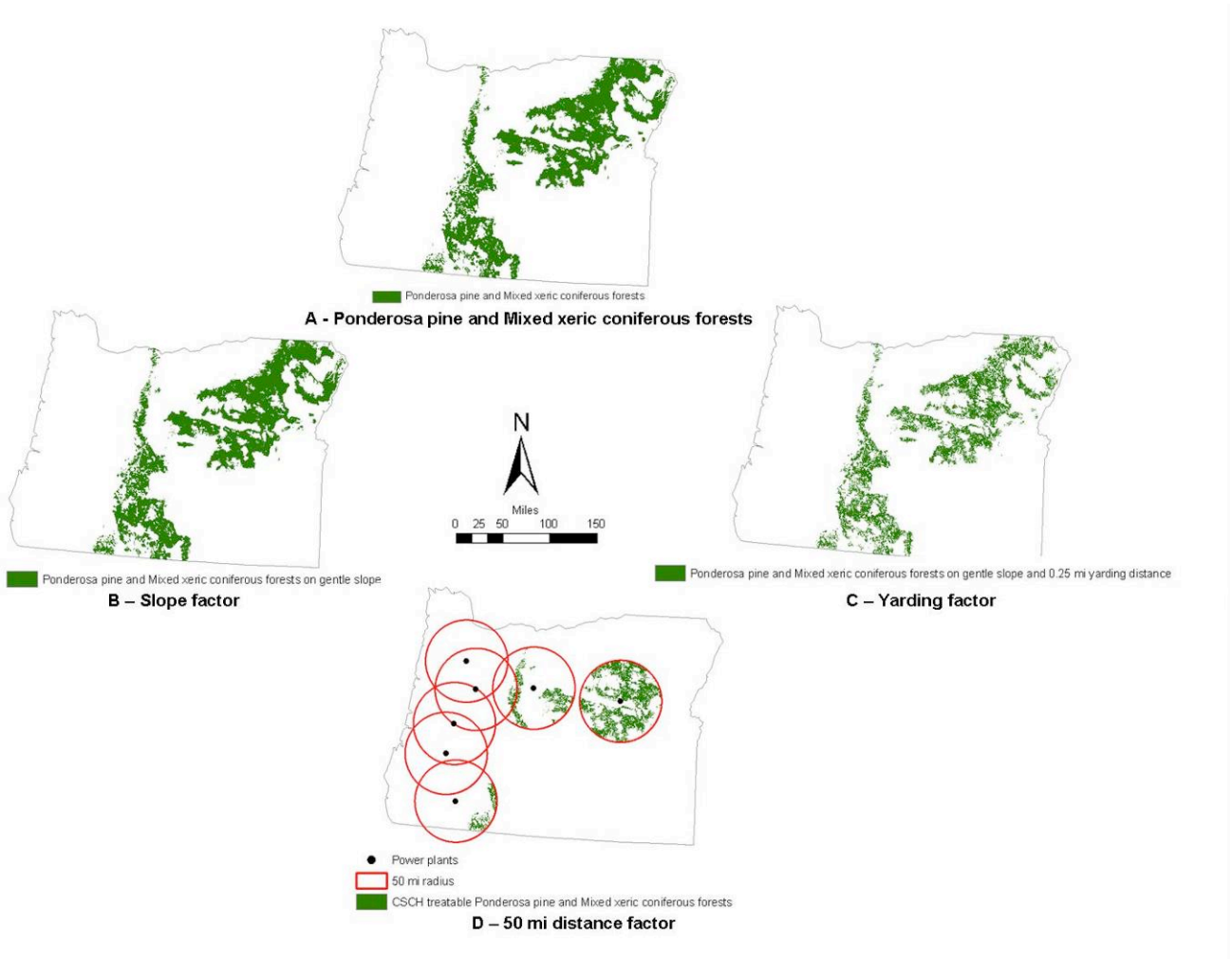


Figure 4-7. Critical factors to determine forest lands with historically low-severity and mixed-severity fire regimes, suitable for CSCH fuel treatment: A – Ponderosa pine and mixed xeric coniferous forest in Oregon; B – Slope less than 40%; C- Yarding distance less than 0.25mi; D- Distance from existing biomass power plants less than 50 miles.

Considering only lands meeting all these constraints, the total area accessible for CSCH across Oregon's forest lands with HLS-HMS fire regimes would be approximately **1.2 million hectares**. Available biomass (short tons/acre) for each fuelbed was calculated from the FCCS data set using the available fuel potential index (dimension/scaled) multiplied by 10 (David Sandberg, USDA Forest Service - Pacific Northwest Research Station, pers. comm. August 2005). The available biomass (short tons/acre) was multiplied by 1.016 to convert to metric tons, and then divided by 0.4 to convert to available biomass (BDT/ha)[9]. The total biomass stocking, including trees, on Oregon forest lands at fire risk and accessible for CSCH treatment, would be approximately 109 million BDT. This value represents estimated total biomass stocking in the forests with HLS-HMS fire regimes based on the Fire Behavior Potential index.

[9] All numbers are reported in hectares. To convert ha to acres, multiply by 2.47..

The total fuel available for removal would be much less than this quantity, as not all biomass on the land will be removed through treatment. Actual percent removal will be highly variable by stand, pre-treatment condition and desired future condition (D. Goehring and D. McCall, PG&E Natural Resources, pers. comm. September 2005), making it difficult to assign a percent removal across a broad scale such as a state or region. Over the landscape as a whole, more than 50% removal of the pre-treatment fuel loading may be needed to significantly reduce fire hazard (Torching Index and/or Crowning Index; Fried et al. 2002, 2003). Furthermore, more than 50% removal, as a landscape average, is likely to be needed to reach a stand-level residual basal area of 80-125 ft^2/acre, often used in HFR prescription scenarios (Fried et al. 2002). A 15-state strategic assessment of fuels reduction assumed a removal prescription of reducing stand density to 30% of maximum Stand Density Index (SDI) for a given stand, or averaged across the landscape, 70% reduction in SDI (USDA Forest Service Research & Development/ Western Forestry Leadership Coalition 2003).

Given the uncertainty in fuel available for removal, two scenarios were considered to help understand the relationship between potential fuel removal and the subsequent carbon benefits associated with that removal. The first scenario assumed that regardless of pre-treatment condition and desired future condition of the forest stand, CSCH treatment will remove 10 BDT biomass per hectare (4 BDT/ac). The second scenario assumed that 20 BDT biomass per hectare (8 BDT/ac) will be removed.

In the first scenario, biomass of **approximately 12 million BDT** would be available to biomass energy facilities in Oregon from CSCH treatments to reduce fire hazard on approximately 1.2 million ha forest lands. This implies an initial loss of forest carbon due to HFR treatment of approximately 6 million t C [10] -- although this initial loss is obviously offset by potentially great savings in CO_2 and non-CO_2 greenhouse gas emissions due to reduction in the probability, severity and extent of wildfire attributable to the HFR treatment. The second scenario results in **approximately 23 million BDT** available biomass associated with approximately 11.5 million t C initial removals. The total carbon stocks for these Oregon forests with low-severity and mixed-severity fire regimes are estimated to be approximately 55 million t C.

4.4.2. Economic analysis and potential role of carbon emission reduction credits

Costs for CSCH range widely depending on the treatment prescription, presence or absence of merchantable material in the prescription, region of the country, and the factors identified above (slope, yarding distance, haul distance, etc.). Here we use as a guide the values quoted in a recent broad-scale strategic assessment covering 15 states and a wide range of experience with HFR: the treatment analogous to CSCH had a cost range of $34-48/BDT (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003). Assuming from above that biomass of approximately 12 million BDT would be removed from the forest lands in scenario 1, treating all these forest lands would have a total cost of approximately $397 million (low) to approximately $560 million (high). Treating these forest lands in scenario 2 would have a cost of approximately $794 million (low) to approximately $1.1 billion (high).

[10] Carbon stocks are calculated as 50% of biomass.

The value of this biomass for purchase by biomass facilities may be estimated at $36/BDT (Fried et al 2003), although market prices for fuel will vary somewhat by region depending on the number of biomass plants in operation and thus competition for fuel. For both scenarios, we estimate the amount of revenue that CSCH on the forest lands in question would generate, and/or subsidy required, to remove the available biomass to biomass energy facilities.

In the first scenario, with removal of approximately 12 million BDT biomass from Oregon forest lands with HLS-HMS fire regimes, the fuel would have a total value of approximately $420 million, and thus range from generating a small net revenue of approximately $23 million (if value = $36/BDT and cost = $34/BDT), to requiring a total subsidy of approximately $140 million to treat all these lands (if value = $36/BDT and cost = $48/BDT). In the second scenario, with removal of approximately 23 million BDT biomass, the fuel would have a total value of approximately $840 million, and thus range from generating a net revenue of approximately $47 million (if value = $36/BDT and cost = $34/BDT), to requiring a total subsidy of approximately $280 million to treat all these lands (if value = $36/BDT and cost = $48/BDT).

To investigate whether removal of hazardous fuel that results in reduced fire intensity and reduced carbon emissions (i.e. conservation of forest carbon stocks) makes economic sense, the following first-order calculations are presented. Assuming the higher costs for biomass removal as described above, to treat the 1.2 million ha estimated to be treatable using CSCH would require a per-hectare subsidy of $117 ($140 million total subsidy divided by 1.2 million ha) for removal of 10 BDT/ha, or $233 ($280 million divided by 1.2 million ha) for removal of 20 BDT/ha. Assuming commonly used prices of CO_2, would emissions reductions attributable to HFR activities be sufficient so that the sale of carbon credits from these projects could cover the per-hectare subsidy required?

Depending upon the price of carbon assumed (two commonly used values are $2.4/t CO_2 and $10/t CO_2), the quantity of carbon emissions that would need to be reduced through HFR in order to cover the per-hectare subsidies needed – essentially, to make high-cost CSCH a break-even activity – varies from as little as about 3.2 t C/ha to as much as 26.5 t C/ha (Table 4-3). Whether HFR could produce this order of magnitude of emissions reductions depends on baseline emissions from fires of varying intensities, and whether HFR prior to fire reduces the intensity of fires. In an analysis conducted for this project, the differences between net carbon emissions from medium-intensity fires and low-intensity fires across all forest types in Oregon ranged from 3 to 21 t C/ha (Brown and Kadyszewski, 2005b). In other words, if HFR resulted in low-intensity forest fires rather than medium-intensity fires, there would be a reduction in carbon emissions attributable to HFR of 3-21 t C/ha; if the reduction was from high-intensity to low-intensity fires, the reduction in emissions would be even greater. The reduction in emissions attributable to HFR in order to cover the per-hectare subsidies required, 3.2-26.5 t C/ha, is generally within the same range. Thus it appears, in a preliminary analysis, that the order of magnitude in emissions reductions attributable to HFR, assuming commonly used prices for carbon offsets, is within the realm of practicality to cover subsidies needed for HFR – adding support to the argument for qualifying fuel reduction activities as carbon offset projects. It should be emphasized that this preliminary analysis needs further research and discussion, including collection of additional data on emissions from wildfires of varying severity, and what reductions in fire intensity and/or emissions should be attributable to pre-fire HFR treatment.

Table 4-3. Quantity of CO_2 emissions reductions (t CO_2/ha and t C/ha) that would need to be produced by HFR activities in order to cover estimated per-hectare subsidies needed for CSCH.

Subsidy	$2.4/t CO_2		$10/t CO_2	
	t CO_2/ha	t C/ha	t CO_2/ha	t C/ha
$117/ha	48.8	13.3	11.7	3.2
$233/ha	97.1	26.5	23.3	6.4

5. Next steps

This paper has presented the results of carbon supply analyses for several potential activities in Oregon: afforestation of rangelands, afforestation of crop lands, changes in forest management including extending rotations and widening riparian buffers, and hazardous fuel reduction to reduce emissions from wildfire in fire-prone forest ecosystems. The final section outlines further characterization work that is needed, both to refine these analyses and to evaluate additional carbon sequestration opportunities for the state and region. We focus in particular on refinements to the analysis of fuel load reduction, and on afforestation using fast-growing species such as hybrid poplar as a means to sequester carbon and/or provide fuel for biomass energy generation.

5.1. Refinements to the analysis of carbon supply from fuel load reduction

The preliminary analysis presented in Section 4 highlights needs further research, policy discussion, and consensus-building among the diverse stakeholders with an interest in forests and fire. Further research and analysis is needed, particularly in the following two areas.

5.1.1 Refinement #1: Analysis of other HFR treatment types

In reality a much greater range of treatment types than only CSCH (as used in this paper) is available for fuel reduction and/or removal. Each treatment type has its own ideal conditions for use, constraints on use, costs, product yield and thus revenue to offset costs, and environmental (air quality, sedimentary, and greenhouse gas emission) implications. Some treatments leave the fuel on site or simply change its form, but may be applied on sites that are relatively more inaccessible either from a technical (terrain, slope, distance to roads) or economic (hauling distance) point of view. Thus a more comprehensive model is needed to answer the questions:

- What factors in addition to slope, yarding distance, distance to biomass plants determine the choice of treatment type and technology—minimum size of treatment block to justify move-in costs, mix of diameter classes to be removed, volume and number of stems in the submerchantable and merchantable categories, distance to processing facilities for merchantable material, other factors?
- What is an appropriate decision rule for each factor? In treating the slope factor, this analysis assumed CSCH could be applied on slopes < 40%. An analysis based on meeting constraints ignores the other side of each decision rule: excluding lands of > 40% slope or > 0.25 miles yarding distance only means these lands are not available for

CSCH, not that they are excluded from all HFR treatment. On slopes > 40% or at greater distance from roads, other treatments might be available that leave fuel on site but still reduce fire hazard (cut-pile-burn, cut-lop-scatter, prescribed fire etc.).

- What are commonly accepted cost ranges for each treatment type and technology, in $/acre or $/bone dry ton (BDT) for submerchantable material and $/MBF or $/CCF for merchantable?
- What revenues are available from utilization of submerchantable and merchantable material from these projects, and what effects do revenues have on the factors and decision rules used to select treatments? For example, by how much will a greater volume of merchantable material in the prescription increase the yarding distance or distance to a processing facility that is economically feasible?

Most HFR treatments in fact involve a mix of submerchantable and merchantable material, with the value of merchantable material sometimes "subsidizing" the high cost of removing a large number of submerchantable stems, and both submerchantable and merchantable being part of the prescription to achieve a desired condition of spacing, residual basal area per acre, improved forest health, improvement in Torching Index and Crowning Index, etc. Including merchantable material would make more acres accessible for treatment. Thus the estimates here, focusing only on one objective and a single treatment targeting the submerchantable biomass fuel, can be taken as conservative.

5.1.2. Refinement #2: GHG emissions from wildfire, and eligibility of HFR as a carbon offset activity

The suggestion that HFR might produce sufficient emissions reductions to pay for currently uneconomic CSCH treatments, if these emissions reductions were marketable at commonly used prices for CO_2 credits, is a starting point for further study. This suggestion was based on first-order estimates of the difference in CO_2 emissions between low-, medium- and high-intensity fires, and the assumption that HFR treatment might be credited with turning what would have been a high- or medium-intensity (perhaps crown) fire into a low-intensity (perhaps ground) fire. If so, the emission reductions could be credited to the HFR treatment and potentially marketed as a carbon-offset project.

To substantiate this hypothesis, several areas of study are needed. First, work is needed to develop baselines for various wildfire-prone forest types. These baselines will serve as the reference case against which activities to reduce fires would be compared to estimate the potential carbon credits. Such baselines need to include field data and models to quantify the likelihood of fires occurring (e.g. fire-return interval) as well as the effects of fire on greenhouse gas emissions for the forests under different intensities of fire (how much of carbon stock is burned by fire intensity and stand structure). Field data might include measurements of post-fire forest carbon stocks for comparison to unburned areas; measurements in past fires of varying intensities; measurements of areas where fuel loads were reduced prior to fire to quantify how much treatment reduced the loss of carbon stocks; and evaluation of non-CO_2 greenhouse gas emissions such as CH_4 and N_2O, also likely to be released in wildfires though to varying extents depending on the type and intensity of fires.

Second, further scientific research as well as policy discussion and consensus-building are needed around the question of what reductions in fire intensity and/or greenhouse gas

emissions should be attributable to pre-fire HFR treatment. Intuitively reducing ladder fuels or crown density should reduce the probability, intensity, and extent of wildfires and thus the loss of forest carbon stocks and other greenhouse gas emissions; but by how much? With a probabilistic phenomenon such as fire, it is not possible to demonstrate that an area treated with HFR would have burned in the absence of treatment, and released X tons of CO_2 equivalent to the atmosphere; nor in the with-treatment scenario is the goal necessarily to avoid fire and its associated emissions, only to reduce the intensity of fire or its extent. Many fire models are currently in use to evaluate probability and impacts of fire under different assumptions, but these models produce highly variable outputs and consensus among models is lacking, and most do not address greenhouse gas emissions from fire. Therefore the process of deciding what types of HFR treatments should be eligible to qualify as carbon offset projects, and assigning values to the greenhouse gas emission reductions attributable to HFR, will involve considerable scientific as well as political consensus-building – even among stakeholders who more or less agree it would be desirable to reduce fuel loads and treat more acres by improving the overall economics of HFR through qualifying these projects for CO_2 credit markets.

Bringing this refinement together with the last, different HFR treatments and technologies could be evaluated in terms of their greenhouse gas emission impacts: for example, "CSCH" would be assigned a triple emission reduction benefit through reduced emissions from wildfire, reduced emissions from fossil fuel-generated electricity due to electricity generation in biomass facilities, and enhanced carbon sequestration in the residual forest stand. Prescribed fire or cut-pile-burn could be assigned a quantifiable benefit for reducing the incidence or intensity of wildfires, but would still put a greater portion of the forest carbon removed in the treatment into the atmosphere.

When potential utilization of both submerchantable biomass and merchantable material from HFR treatments is considered, emissions reduction credits become one of a set of values – along with merchantable material, biomass fuel value, green power incentives, and even other marketed ecosystem services enhanced by these treatments -- that would improve the overall economics of HFR and help federal, state and private landowners to mount a more effective response to the wildfire problem.

Finally, further work would then be needed to develop carbon accounting methods and field protocols for actually quantifying the potential carbon credits for a variety of fuel treatments by forest types. This calculation would include the reduction in greenhouse gas emissions from displacing some quantity (MWh) of electricity that would otherwise be generated using fossil fuels. Such methods and protocols would need to be cost effective, transparent, and reproducible.

These refinements will be addressed through additional field data collection, modeling, analysis, and stakeholder discussions in the second phase of the West Coast Regional Carbon Sequestration Partnership.

5.2 Evaluation of carbon sequestration potential through afforestation using fast-growing species and other forest management methods.

In the first phase of this work, the analysis of afforestation potential on rangelands and croplands looked only at the use of planting native species for forest restoration (see Section 2

above). Two other possibilities exist that will be investigated in Phase 2 of the West Coast Regional Carbon Sequestration Partnership.

5.2.1. Use of fast-growing species

Instead of considering only native species for afforestation activities, fast growing tree species such as hybrid poplar will be investigated. Land suitable for planting such species will be assessed based on existing data, other publications in the region, and partners. Hybrid poplar is already being grown in parts of Oregon and Washington and its extent could be increased. Plantations of hybrid poplar grow fast with up to about 100 t C/ha after 10 years. The potential carbon supply for planting fast growing species on rangelands and crop lands will be investigated including estimating the opportunity costs (as described above), the costs for planting and managing the plantations, and the revenues from the products (pulp, timber, or biomass fuel) plantations. The analysis will be done in a GIS as done for native species and a comparison of the carbon supply from native versus fast-growing species will be preformed.

5.2.2. Other forest management methods

In phase 1 of this work, afforestation of rangelands and croplands considered only the planting of native species for forest restoration. However, it is possible that forest could be grown for timber products. Simulating the growing of trees for timber production affects two components of the carbon supply analysis: the quantity of carbon sequestered and the costs. The effects on the quantity of carbon and the costs will be investigated across the region in phase 2.

The quantity of carbon sequestered in the living component of forests grown for timber production will be less than that for forest grown for restoration. However this decrease in the long term average in living trees can be made up in part by the carbon in the harvested wood that is converted to long term wood products. The balance between these two main pools of live and wood products will vary by forest type and will be investigated in detail in phase 2. Cost will also be different between forests grown for timber and for restoration. When grown for timber, there will be revenues from the sale of timber as well as for the carbon. The analysis of the potential carbon sequestration for the region by afforestation for timber species will incorporate all these factors to arrive at new estimates of the carbon supply and the results compared to those generated in this paper.

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Part II: Carbon Sequestration through Changes in Land Use in Washington: Costs and Opportunities

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Abstract

This paper presents potential carbon supply from several classes of activities in Washington's forest, range and crop lands: afforestation of rangelands, afforestation of croplands, changes in forest management including extending rotations and widening riparian buffers, and hazardous fuel reduction to reduce emissions from wildfire in fire-prone forest ecosystems. For each activity, methods and results are presented for estimating the total quantity of carbon that could be sequestered, followed by an economic analysis summarizing total costs of converting lands or changing management to sequester carbon. Carbon supply curves and maps are presented illustrating the total area of land that would be converted or put under different management, and total quantity of carbon thus sequestered, at different prices of carbon. The paper concludes with a summary of next steps and further refinements for the second phase of the West Coast Regional Carbon Sequestration Partnership.

Keywords: carbon sequestration, afforestation, forest management, hazardous fuel reduction

Executive Summary

Introduction

Of late there have been several estimates of the terrestrial carbon storage potential in regions of the United States based on biological and technical criteria coupled with coarse-scale consideration of the economic costs associated with changing land management practices. Recent work by Winrock International for California, and for all the states under the US Department of Energy's Southeast Regional Carbon Sequestration Partnership, has focused on adding more detailed analysis of opportunities on both agricultural and forest lands; biological rates of carbon sequestration, taking into consideration variations in site conditions across the landscape; and incorporating more detailed analysis of all costs. Consideration of the varying carbon sequestration potential of different land classes and other economic factors yield more realistic estimates of carbon storage potential and associated costs. Realistic assessments of the potential for carbon sequestration from changes in land use can help policy makers and the private sector prepare for an uncertain regulatory future by providing estimates of the quantity of carbon credits that might be available at different price points for different classes of activities.

Purpose

The broad purpose of the project entitled "BASELINES, CARBON SUPPLY CURVES AND PILOT ACTIONS FOR TERRESTRIAL CARBON SEQUESTRATION" is to quantify terrestrial carbon sequestration opportunities across the West Coast Partnership Region (California, Oregon, and Washington) and estimate the quantity of carbon credits that might be available at different price points.

Project Objectives

Methodologies developed by Winrock International in previous research will be applied to develop carbon supply curves for the major classes of potential land-use and forest-based activities in Oregon. Specifically:

- Prepare carbon supply estimates for different classes of potential terrestrial project activities, including afforestation of cropland, afforestation of rangeland, and changes in management of forestland.
- Assess the potential for hazardous fuel removal from forests with high fuel loads as a carbon sequestration activity.

Project Outcomes

The state of Washington 's lands are classified into three main groups for the analyses presented here: forests, rangelands, and agricultural lands. Forests (about 20.2 million acres) include conifers, hardwoods, and mixed classes; rangelands (about 11.7 million acres) include a variety of non-woody and woody ecosystems; and agricultural lands (about 9.6 million acres) include a wide range of non-woody crops such as wheat and hay and woody crops such as vineyards and orchards.

For rangelands and croplands (lands growing wheat and hay), the potential carbon sequestration was estimated for afforestation using native species. Historical evidence suggests that in many areas, large tracts of forest may have once stood where grazing and agricultural lands now do. The general approach was to identify and locate existing rangelands and croplands where biophysical conditions could favor forests, estimate rates of carbon accumulation for the forest types projected to grow, and assign values to each contributing cost factor. The carbon supply is estimated for three time durations: 20 years, 40 years and 80 years of forest growth, to reflect the impact of activity duration on the likely supply and to provide an assessment for the near–term and longer-term planning horizons.

For forestlands, potential carbon supply was estimated for three alternatives for 20-year and/or permanent contract periods: (1) allowing timber to age past economic maturity (lengthening rotation time); (2) increasing the riparian buffer zone by an additional 200 feet; and (3) hazardous fuel reduction in forests to reduce catastrophic fires, and subsequent use of fuels in biomass power plants. For estimating the costs of allowing timber to age and the costs of enhanced riparian zone management, estimates are based on specific counties for public and private landowners, and then extrapolated to all counties throughout the state. For the fuel reduction alternative, the analysis used a "Suitability for Potential Fuel Reduction (SPFR)" score on forest landscapes where potential exists for significant carbon loss from moderate to high intensity wildland fires. The SPFR scores were created in a GIS using slope, distance to biomass plants, and distance from roads as equal weighted factors in the decision-making process.

Table ES-1 summarizes the amount of carbon and the area available for afforestation of range and crop lands at three commonly used price points: ≤ \$2.40/t CO_2 (\$8.81/t C), ≤ \$10.00/t CO_2 (\$36.67/t C), and ≤\$20.00/t CO_2 (\$73.33/t C). At a price of \$2.40/t CO_2, no carbon could be sequestered by afforesting rangelands and croplands at 20 and 40 years but the amount reaches about 1,399 MMT CO_2 at 80 years (Table ES-1). If prices per t CO_2 rose to \$20 it is possible to convert more productive range and crop lands with higher opportunity costs and sequestering almost 289 MMT CO_2 carbon even with a 20-year time duration, and the total amount rises sharply to more than 1,233 MMT CO_2 at 40 years and approximately 3,176 MMT CO_2 at 80 years (Table ES-1). Converting this total amount at 40 years to an approximate annual rate results in about 31 MMT CO_2/yr.

Although Washington has substantial areas of forests, 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. All of the carbon available at prices of less that \$10/t CO_2 for extending rotations by 5 years is located on non-federal public lands; only when prices reach between \$10-20/t CO_2 do private lands generate potential carbon credits. If all of the private and non-federal public land nearing the economically optimal rotation period (1.46 million acres) were contracted to increase rotation ages by up to 15 years, 61.6 MMT CO_2 could be sequestered for average costs of \$37/t CO_2.

The potential area of mature forests where the riparian buffer zone could be increased by an additional 200 feet was estimated at 34,9000 acres. The additional carbon that could be stored on these lands if the forests were conserved is 2.2 MMT CO_2 at an average cost of \$33.3/t CO_2.

Table ES-1. Summary of the quantity of carbon (million metric tons CO2 [MMT CO2]) and area (million acres) available at selected price points ($/t CO2) for afforestation of existing rangelands and croplands over 20-year, 40-year, and 80-year durations.

	Quantity of C—MMT CO_2			Area available—million acres		
Activity	20 years	40 years	80 years	20 years	40 years	80 years
Rangelands-Afforestation						
≤$2.40	0.0	0.0	1,399	0.0	0.0	3.1
≤$10.00	0.0	877.9	2,153	0.0	4.3	6.2
≤$20.00	279.4	1,178	2,450	4.2	8.8	8.9
Croplands-Afforestation						
≤$2.40	0.0	0.0	14.4	0.0	0.0	0.0
≤$10.00	0.0	0.0	140.5	0.0	0.3	0.3
≤$20.00	9.8	54.9	725.9	0.1	1.4	5.5

From the forest hazardous fuel reduction analysis, the area of Washington forests with historically low-severity and mixed-severity (HLS-HMS) fire regimes is estimated to be 3.3 million acres. A commonly used potential hazardous fuels treatment is "Cut-Skid-Chip-Haul" (CSCH), a treatment in which hazardous fuel is harvested in the woods, bunched and skidded to a landing, chipped into a chip van, and hauled to a biomass energy facility for electricity and/or heat generation. The area of forestlands with HLS-HMS fire regimes in the state to which this treatment could be applied is approximately 1.2 million acres. Two removal scenarios were analyzed: HFR removal of 4 BDT/acre on these lands would yield 5 million BDT biomass fuel for use in energy facilities, while removal of 8 BDT/acre would yield 10 million BDT. Total estimated costs and potential revenue from these removals was analyzed. During moderate to intense fires, 10-70% of the biomass stock burns and is emitted as CO_2. A preliminary analysis suggested that considering the differences in CO_2 emissions between high-, medium- and low-intensity fires, HFR treatments that reduced fire intensity would avoid sufficient emissions to be able to cover, at commonly used prices for carbon of $2.40/t CO_2 and $10/t CO_2, the subsidies needed to pay for CSCH – adding support to the argument for qualifying fuel reduction activities as carbon offset projects.

Conclusions

The key conclusions from this work are:

- The largest terrestrial sequestration opportunity, both in terms of absolute quantity and costs, is afforestation of rangelands.
- Changes in forest management by lengthening rotation age beyond the economical rotation, has limited potential both in terms of quantity and costs.

- Forest fire appears to be the most important management issue to address and hazardous fuel removal has the potential to avoid substantial carbon dioxide emissions.
- Forest conservation, such as extending riparian buffers, is limited in scope and tends to be expensive.

Recommendations

Further characterization work is needed to refine the analyses done to date and to evaluate additional carbon sequestration opportunities for the state and region. It is recommended that further work focus in particular on refinements to the analysis of fuel load reduction on wildfire-prone forests, and on afforestation using fast-growing species such as hybrid poplar or native species for timber production or biomass energy.

Recommended next steps for fuel load reduction include the analysis of other fuel removal treatment types and how the constraints on each affect the amount of forest land that could be treated; and the development of baselines for various wildfire-prone forest types. Such baselines need to include field data and models to quantify the likelihood of fires occurring (e.g. fire-return interval) as well as the effects of fire on greenhouse gas emissions from forests under different intensities of fire (how much of the forest's carbon stock in different pools is emitted under different fire intensities and stand structures). More detailed economic analysis is also needed to determine if fuel removal produces sufficient emissions reductions to pay for currently uneconomic treatments.

Afforestation of rangelands and croplands could be planted with trees for timber and non-timber products using both native and fast-growing species. Simulating the growing of trees for products affects two components of the carbon supply analysis: the quantity of carbon sequestered and the costs. How changes in carbon sequestration and costs affect total carbon supply needs to be investigated across the region.

1. Introduction

1.1 Objectives of study

Many past studies estimate the terrestrial carbon storage potential in regions of the United States based on biological and technical criteria coupled with coarse-scale consideration of the economic costs associated with changing land management practices. Recent work by Winrock International, including for California and for all the states under the US Department of Energy's Southeast Regional Carbon Sequestration Partnership, has focused on adding more detailed analysis of opportunities on both agricultural and forest lands; biological rates of carbon sequestration, taking into consideration variations in site conditions across the landscape; and incorporating more detailed analysis of all costs. Consideration of the varying carbon sequestration potential of different land classes and other economic factors will yield more realistic estimates of carbon storage potential. Realistic assessments of the potential for carbon sequestration from changes in land use can help policy makers and the private sector prepare for an uncertain regulatory future by providing estimates of the quantity of carbon credits that might be available at different price points for different classes of activities.

The main goal of this study is to generate estimates of potential carbon supply, including total amount, $/t CO_2 (dollars per ton of carbon dioxide), and location, for changes in the use and management of three classes of land in Washington: rangelands, croplands, and forest lands. The remainder of this paper is divided into the following sections: Section 2, carbon sequestration potential through afforestation of rangelands and croplands, Section 3 on potential changes in forest management to sequester additional carbon, and Section 4 on hazardous fuel load reduction in wildfire-prone areas to reduce emissions and/or sequester carbon.

2. Afforestation of rangelands and croplands

2.1 Background

Over 100 years ago, when Washington had not yet attracted thousands of people into the region to exploit its forest resources, historical evidence suggests that in many places, tracts of forest may have once stood where human populations, agriculture and grazing lands now do. We hypothesize that a significant proportion of today's woodland, shrub and grassland vegetation types on Washington's rangelands and much of its agricultural lands were once either closed forests or similar woodlands but with significantly higher biomass than they currently contain.

Washington's cattle and calves industry is the state's fifth largest agricultural sector. Hay is the sixth and dairy production is the second (USDA-NASS 2004). Washington is the 29th leading beef cow producing state in the U.S. and the state has a total of over 1.1 million head of cattle. Washington ranks within the nation's top ten states for milk production (USDA-NASS 2004).

There are approximately 16.0 million acres of agricultural land in Washington (Karl et al 1999). The top grossing non-orchard, agricultural commodities in Washington are greenhouse and nursery products, cranberries, hops and potatoes. Lower value crops include hay and wheat. Hay was produced on over 810,000 acres of Washington agriculture land in 2003 and wheat on approximately 2.3 million acres (USDA-NASS 2004). Washington is the nation's fifth largest wheat producer.

Presently in Washington, on lands that were once forestland, wheat and hay farms occupy the majority of the crop lands and ranching takes place on the rangelands (Figures 2-1 and 2-2).



Figure 2-1. Photographs of Washington crop lands (Photo credits: WA State Tourism, John Marshall).



Figure 2-2. Photographs of Washington rangelands (Photo credits: www.mckuster-ranch.com , WA State Tourism).

2.2 Approach

Unless otherwise noted, the methods applied in this section are identical to those of a previous Winrock study by Brown et al. (2004—Carbon Supply from Changes in Management of Forest, Range, and Agricultural Lands of California). In addition to rangelands in Washington, potential opportunities also occur on crop lands. Methods used for analyzing costs on crop lands are practically the same as those used in a previous Winrock International study for the Southeast Regional Carbon Sequestration Partnership (Brown & Kadyszewski 2005).

The analyses take the following steps to assess the quantity and cost of potential carbon sequestration:

- Identify the area and current use and cover of lands that have the potential to be managed for carbon sequestration—referred to as "candidate lands," including rangelands and selected crop lands.
- Estimate the area and geographic location of candidate lands that could be afforested and the rates of carbon sequestration on them.
- Estimate the total cost of afforesting candidate lands, including opportunity cost, conversion cost, maintenance costs, and measurement and monitoring costs.
- Combine the estimated quantities of carbon per unit area with the corresponding area and cost to produce estimates of the total quantity of carbon that can be sequestered for given range of costs, in \$/ton CO_2.

- Determine the geographic distribution of available carbon at various prices.

The analysis is performed in a geographic information system (GIS) to superposition the diversity of existing land cover, rates of carbon sequestration, and costs in the analyses. As a result, not only are more realistic estimates of the potential supply of carbon produced, but the use of GIS shows where the least to most expensive carbon credits will most likely be found.

For agricultural lands, high-value crop producing areas are unlikely to be converted for carbon sequestration activities due to high opportunity costs. The value of hay production per acre is significantly more than the value of open rangeland, often by 10 times or more. However, in certain places hay production may provide good opportunities for affordable carbon sequestration activities because the overall value per acre is still generally low. Also, with average yields of 59.4 bushels of wheat per acre, wheat-producing land has a production value of generally less than $250 per year (USDA-NASS 2004), making wheat land also an attractive candidate for carbon projects.

This study used a wide variety of spatial and non-spatial data sets. The spatial data include:

- National Elevation Dataset 30m DEM grids, developed by USGS (2004a);
- National Land Cover Dataset, developed by USGS (2004b);
- NRCS STATSGO soil survey maps and databases and resultant analyses by non-NRCS researchers (Schwarz and Alexander 1995; Miller et al. 1998);
- DAYMET Mean Annual Temperature map (Thornton et al. 1997);
- DAYMET Mean Annual Precipitation map (Thornton et al. 1997);
- Northwest Regional Gap Analysis land cover dataset (Karl et al 1999).

Non-spatial data include, for example, regression equations for converting US Forest Service Forest Inventory and Analysis (FIA) data to biomass carbon, forest growth models, published literature, experience from other Winrock activities, and state and county reports of agricultural statistics. The details of all of these data and their applications are given in the appropriate sections below.

The carbon supply for afforestation options is estimated for three time durations -- 20 years, 40 years and 80 years -- to reflect the impact of activity duration on supply and to provide an assessment for the near–term and longer-term planning horizons. Several key assumptions of the analysis are shown in Figure 2-3 with the corresponding steps of the analysis.

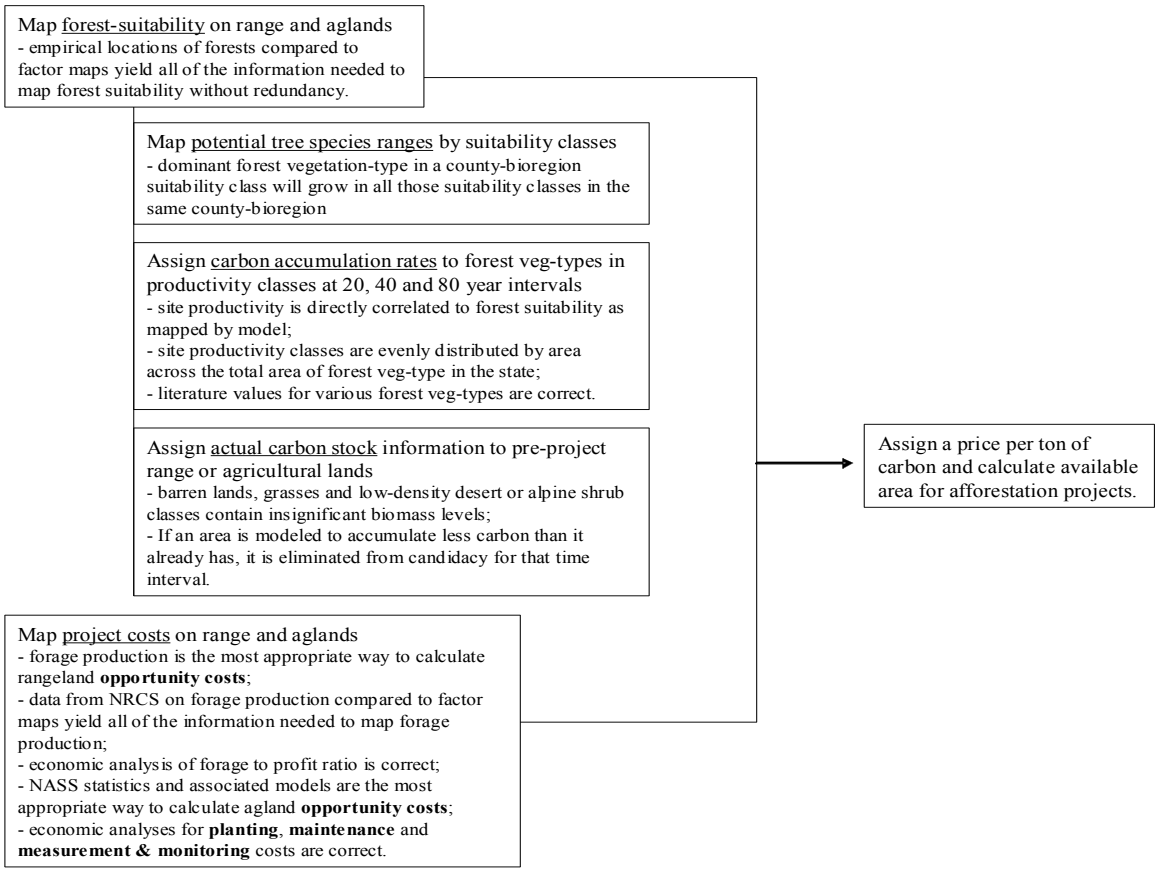


Figure 2-3. Flowchart of carbon supply curve analysis with key assumptions listed below each step.

2.2.1. Scale of analyses

This study aims to estimate the amount of carbon that can be sequestered on the selected areas through afforestation. The level of resolution used in this analysis is the same as that used by NLCD (30 meter pixels) and by the Washington GAP Analysis in their land cover map product. GIS software used in the analyses was ESRI's ArcGIS 9.0 suite and ArcView 3.3, with Idrisi Kilimanjaro and ERDAS Imagine also used intermittently.

2.2.2. Washington land cover characterization

The 30-meter resolution, NW Regional Gap Analysis land-cover map (Karl et al 1999) was used as the base for vegetation mapping because it allowed for more resolution between forest and rangeland classes than the USGS NLCD and because it offered a uniform vegetation classification system for comparison with a similar analysis for the state of Oregon. Although the Washington portion of the map was produced in the late 1990's, the majority of the data used to create it came from Landsat satellite imagery gathered from the early 1990's. Much inquiry and investigation was made into the incorporation of other, more-recent datasets into this analysis although all assembled datasets were eventually rejected due to incomplete coverage or incompatible land cover classification systems. Several well-known Landsat satellite imagery-based examples follow with the justification for not using them:

- The Interagency Vegetation Mapping Project (IVMP) was an initiative that mapped the forest types and attributes of the coastal areas of the Pacific Northwest from 1998 to 2002. The project mapped only forest land cover types and no agricultural or rangelands and did not cover the entire state. http://www.or.blm.gov/gis/projects/ivmp_data.asp
- The National Landcover dataset (NLCD) from the USGS mapped land-cover in 1992. Although it did include 3 agricultural land cover classes that the GAP Analysis did not have, all other classes were too coarse for making species-specific discriminations. http://landcover.usgs.gov/nlcd/show_data.asp?code=WA&state=Washington
- The Northwest Habitat Institute's vegetation maps used slightly more recent Landsat imagery than the GAP Analysis or NLCD to map vegetation communities in Washington but the classes were more mixed in their species types with a larger variety of biomass levels within each one as compared to the GAP analysis. http://www.nwhi.org/NHI/default.asp?pageurl=books/booklist.asp
- Various other datasets at the National Forest or County level.

For individual land cover types or specific regions of the state, some of these other datasets may have provided a better idea of the actual characteristics of the land today. Nevertheless, the regional GAP analysis map compiled by Karl et al (1999) from the original Washington GAP analysis (Cassidy et al 1999) is the most up-to-date and detailed land-cover data available *for the entire state* of Washington that exists at this time.

The vegetation classes present in the land cover dataset were combined into four discrete classes: agriculture, rangelands, forests and 'other'. The 'other' class included urban and residential development and water bodies. The full classification rules are shown in Table 2-1. The three broad classes are shown in the maps in Figure 2-4. Forests cover the largest area of Washington State at 47% of the total area, followed by rangelands at 27%, and agriculture at 22%, with "other" occupying the remaining 4% (Table 2-1).

The three broad classes are shown in the map in Figure 2-4. The area of rangelands (12 million ac) in Washington is less than that for forests (20 million ac). Any inconsistency in these numbers with other published data may be due to the inclusion of the generally low-biomass 'Western Juniper' areas in the rangelands class instead of forests. Agriculture lands cover about 9.5 million ac or about half the area of forests and three quarters that of rangelands (Table 2-1).

Table 2-1. Land cover classification, areas and class generalization in Karl et al (1999) GAP Analysis.

GAP Analysis Vegetation Class	Broad Landuse category	Hectares	Acres	% of total
Mixed Mesic Coniferous Forest	FOREST	3,107,941	7,676,614	17.70%
Mesic Douglas-fir	FOREST	1,308,695	3,232,477	7.46%
Ponderosa Pine	FOREST	1,103,451	2,725,524	6.29%
Mesic Mixed Forest	FOREST	703,169	1,736,828	4.01%
Mixed Subalpine Coniferous Forest	FOREST	620,319	1,532,188	3.53%
Deciduous Forested Riparian	FOREST	335,469	828,609	1.91%
Xeric Douglas-fir	FOREST	293,264	724,363	1.67%
Mixed Xeric Coniferous Forest	FOREST	237,510	586,649	1.35%
Mixed Coastal Forest	FOREST	169,016	417,470	0.96%
Xeric Mixed Forest	FOREST	111,853	276,276	0.64%
Mesic Deciduous Forest	FOREST	68,746	169,803	0.39%
Mixed Riparian	FOREST	66,484	164,215	0.38%
Xeric Deciduous Forest	FOREST	31,775	78,485	0.18%
Subalpine Fir	FOREST	20,904	51,632	0.12%
Coniferous Forested Riparian	FOREST	4,497	11,108	0.03%
Other	FOREST	11	28	0.00%
Subtotal		**8,183,105**	**20,212,269**	**46.6%**
Agriculture	**Agriculture**	**3,867,456**	**9,552,616**	**22.03%**
Urban/Developed	OTHER	433,556	1,070,884	2.47%
Water	OTHER	259,804	641,716	1.48%
Ice/Snow	OTHER	55,769	137,750	0.32%
Estuarine Emergents	OTHER	5,639	13,927	0.03%
Exposed Rock	OTHER	3,708	9,159	0.02%
Tidal Flats	OTHER	1,043	2,576	0.01%
Subtotal		**4,626,975**	**11,428,628**	**26.4%**
Xeric Grasslands	RANGELAND	1,872,706	4,625,585	10.67%
Upland Shrublands	RANGELAND	1,208,207	2,984,271	6.88%
Big Sagebrush	RANGELAND	868,378	2,144,894	4.95%
Subalpine Meadow	RANGELAND	707,320	1,747,081	4.03%
Shrub Dominated Riparian	RANGELAND	37,455	92,515	0.21%
Alpine Meadow	RANGELAND	22,266	54,997	0.13%
Graminoid/Forb Riparian	RANGELAND	17,499	43,223	0.10%
Salt-desert Shrub	RANGELAND	8,938	22,078	0.05%
Other Sagebrush	RANGELAND	1,336	3,299	0.01%
Subtotal		**4,744,106**	**11,717,941**	**27.0%**

Candidacy for afforestation on agricultural lands was not based on the GAP analysis' 'agriculture' class. Lands targeted by this study were wheat and hay fields but given the lack of any resolution within the GAP analysis' 'agriculture' vegetation class, another data source was tapped. The USGS NLCD dataset (USGS 2004b) disaggregates agriculture into 'small grains', 'row crops', 'pasture/hay' and 'fallow'. The two datasets were combined to create a new layer

of agricultural land cover candidates wherein anything that was mapped by NLCD as 'pasture/hay', 'small grains' or 'fallow', plus any lands mapped as agriculture by the GAP analysis and not by NLCD, were made candidates for afforestation (Figure 2-5). The decision to put into candidacy the 'fallow' and unmapped agricultural lands is based upon the fact that most agricultural lands in the state are pastures, hay or wheat (USDA-NASS 2004).

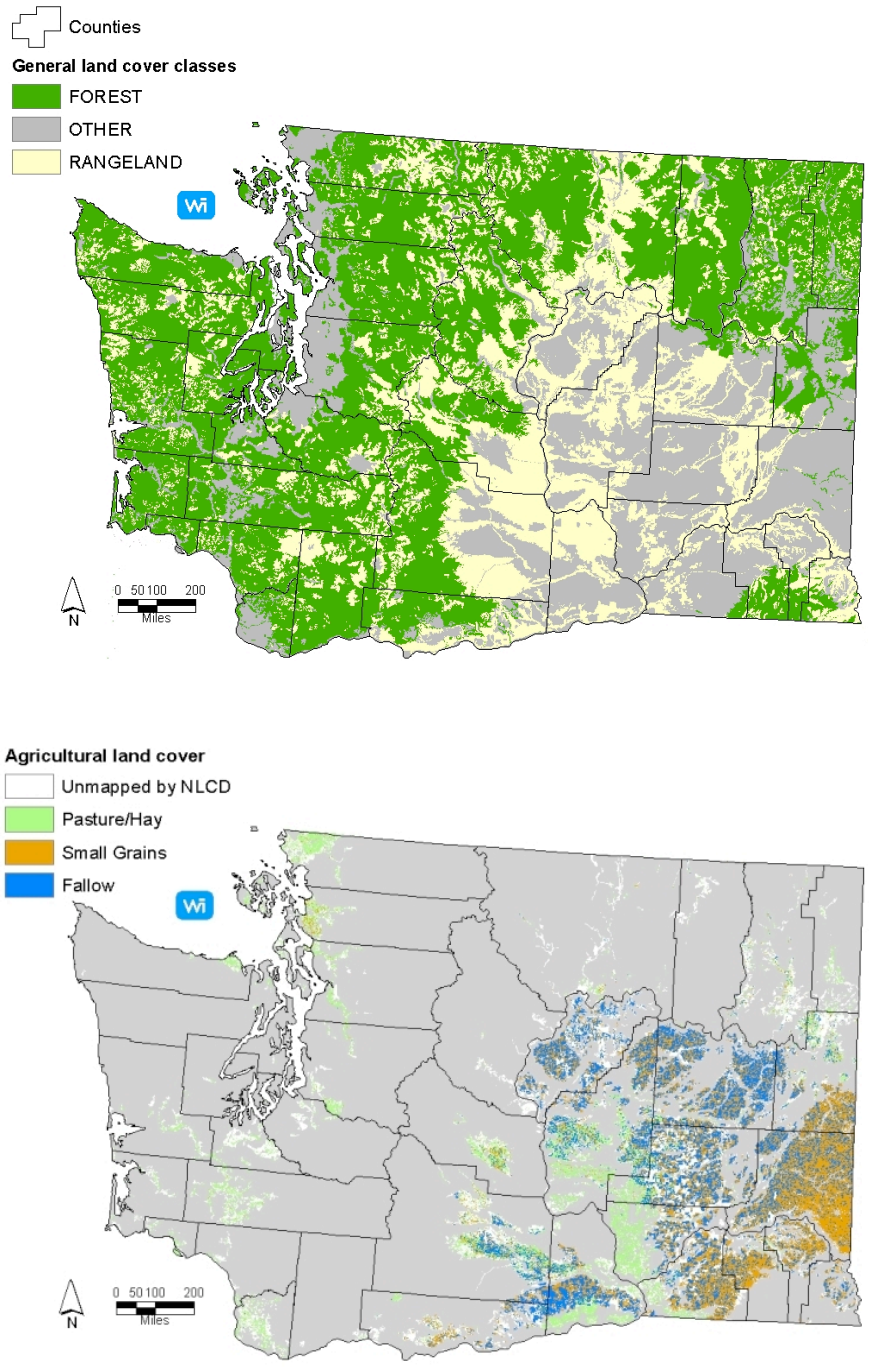


Figure 2-4. Broad land cover classes from NW Regional GAP analysis (top) and cropland cover classes from the NLCD map (bottom).

2.2.3. Mapping suitability for afforestation with native species

To map the suitability for a non-forested landscape to grow trees, certain variables in the STATSGO state soils databases ('sitind', 'woodprod', etc.) have been successfully used in eastern sates of the US (e.g. Southeast States; Brown and Kadyszewski, 2005a). In more arid landscapes, where forests are not the dominant vegetation type, there are complications with using these databases because they lack data in the areas of sparser forest cover or areas that have not been under forest cover in recent memory. In Washington, as in California (Brown et al 2004), data in the Washington STATSGO soils datasets for the 'woodprod' (Mean Annual Increment) variable were incomplete across the state (Figure 2-5).

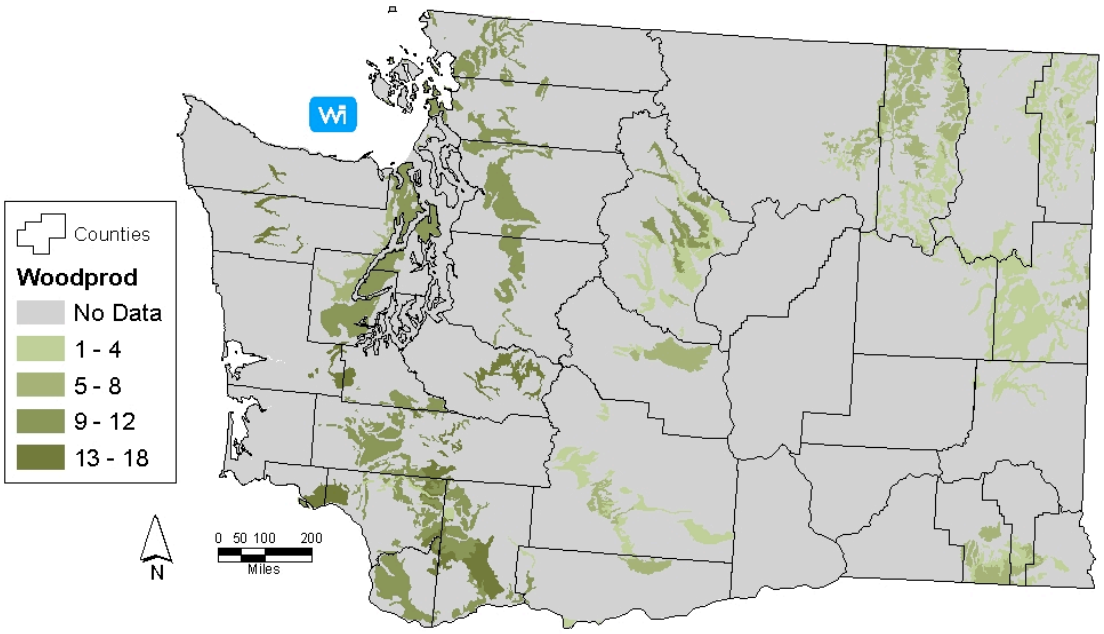


Figure 2-5. Map showing dominant soils components with available STATSGO 'woodprod' data.

To derive suitability for any area that was not mapped for 'woodprod' by STATSGO, a multi-criteria evaluation of pertinent factors was conducted whereby areas of current forest vegetation were used to calibrate a model and predict a score indicating whether or not an area was suitable for growing trees (suitability score). The methods used to derive this suitability score were identical to the methods used the carbon supply report for California (Brown et al 2004) except that the factor aspect was included in the set of biophysical drivers for Washington. The factors, used to map suitability for forest growth in Washington, were soil available water content (AWC), elevation, slope, mean annual temperature and annual precipitation.

In this analysis, a constraint was introduced whereby lands that fell into a category of any one of the factor maps where there were no areas of current forests were eliminated as candidate lands for afforestation. In other words, the concept of limiting factors was used. For example, a constrained site might be one where the mean annual precipitation class is one in which forests commonly exist across the state, but there are no forests growing in areas with mean annual temperature values as low as the site in question. In this example, the site would be constrained

from candidacy for afforestation because of the prohibiting factor of mean annual temperature despite meeting the suitability constraint for mean annual precipitation. Elevation was another factor that acted as a constraint at some of the state's higher points.

The suitability score was based on the proportion of each factor map's class that is forested throughout the state. For any given cell in a factor map, this proportion value across all of the factor maps was averaged to produce an overall suitability map for forest growth. More details on how suitability scores are calculated using GIS can be found in the California report (Brown et al 2004) or in conventional GIS suitability analysis discussions such as those found in the Idrisi Kilmanjaro users' manual (Eastman 2003) and with ESRI products in Wayne (2003a & 2003b). In this study, no weighting of factors with respect to each other was used (cell values were averaged) but empirical data on forest area locations were used to weigh the classes in each factor map. This technique is used frequently in land use change modeling (Brown et al *In Press*; Pontius et al 2001; Hall et al 1995).

The suitability scores for forests cross-referenced to existing land cover classes in Washington is shown in Figure 2-6. It can be seen from this figure that there are relatively large areas of agricultural land and rangeland classes that have high forest suitability scores. To illustrate the case for rangelands in more detail, Figure 2-7 shows the distribution, in acres, of existing rangelands within the forest suitability classes.

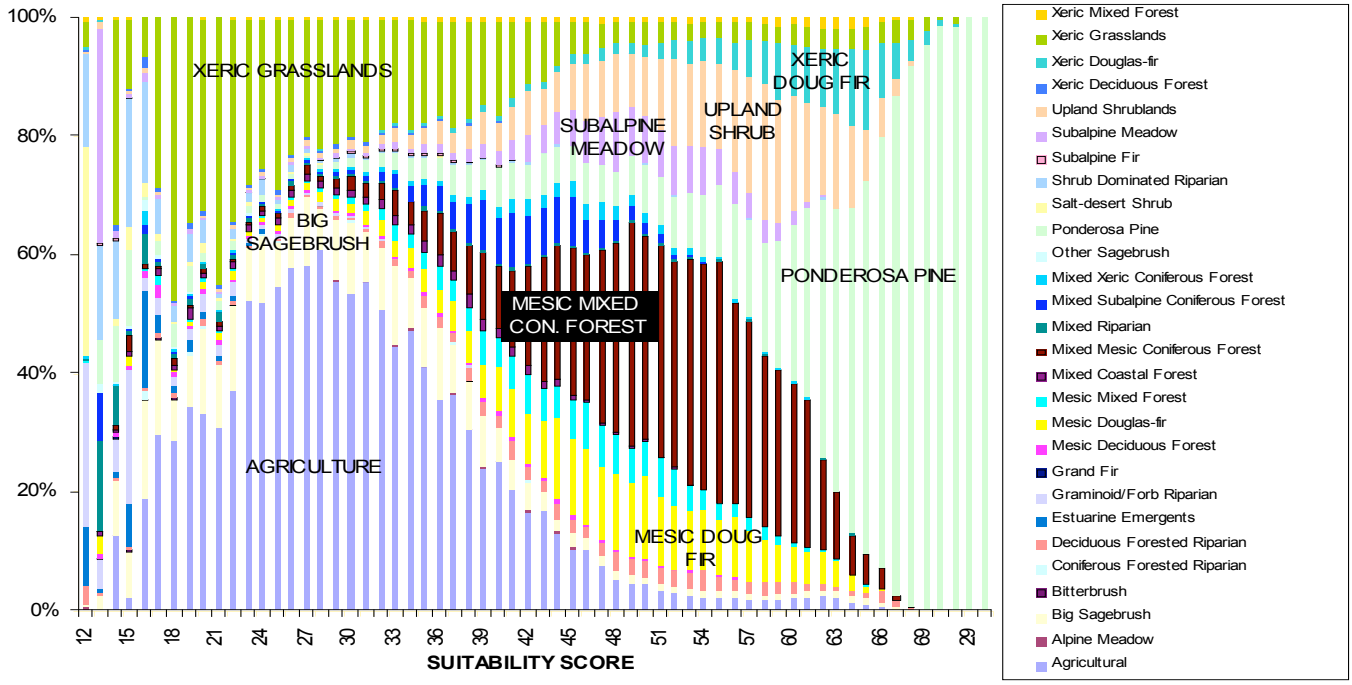


Figure 2-6. Forest suitability scores cross-referenced to land cover classes. The higher the score the more suitable the site is for forests and vice versa.

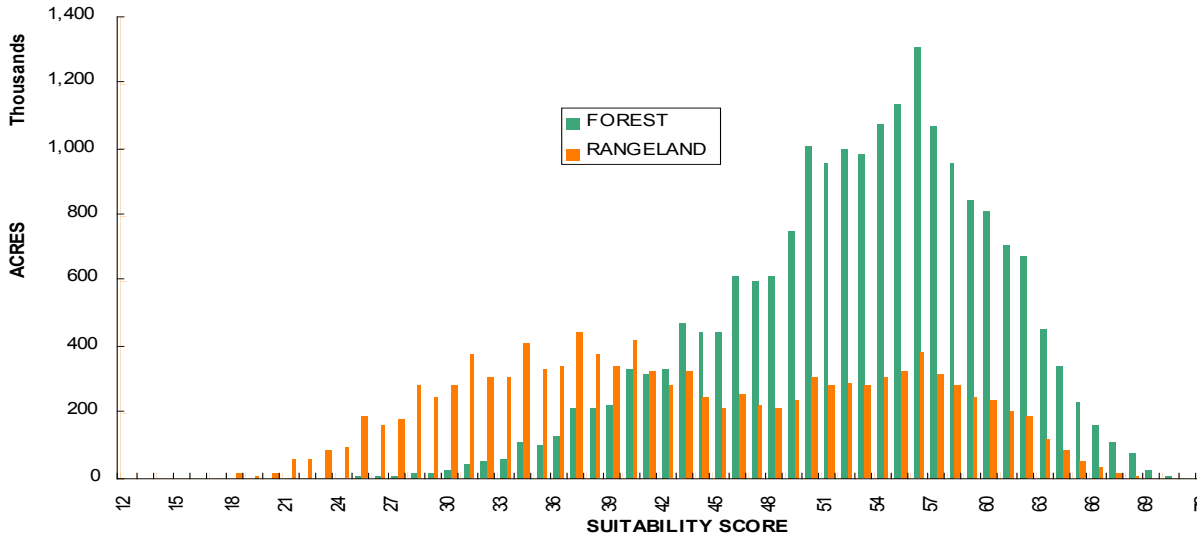


Figure 2-7. Distribution of existing rangelands and all forest classes within the forest suitability classes.

It is clear that a substantial area of existing rangelands have high forest suitability scores and when compared to Figure 2-6, these scores correspond to those for mixed mesic coniferous forest, mixed xeric coniferous forests and ponderosa pine forests. This overlap implies that rangelands could be afforested with species typical of these forest types. Of the total area of existing rangelands, about 9.3 million acres (about 79% with a suitability score >32; Figure 2-7) could be afforested with mesic mixed conifer species and ponderosa pine. In most cases, when overlaps occur for a forest type in a wide range of suitability scores (from low to high), this is reflected in the modeling of the biomass productivity of an afforestation project and is described below. As explained above, in factor map classes where forests do not currently exist in Washington, these classes were flagged and excluded from suitability analysis. Due to the fact that this constraint was introduced, no minimum threshold cut-off in the suitability scores for afforestation candidacy was applied as in the California report (Brown et al 2004).

2.2.4. Species selection analysis

The carbon sequestration potential for any given grid cell was developed by first identifying the dominant forest vegetation types that exist in those suitability classes in other areas of the state. This is the way to select the kinds of tree species that would most successfully be planted on candidate sites. This analysis needed to be constrained because if sites in the northeastern part of the state are in the same suitability class as ones in the southwestern part, they could be assigned the same dominant forest vegetation type, even if this would not be the case in reality. To prevent this, we constrained the species selection step with a map of Holdridge Life Zone classes of the state (Lugo et al. 1999 –Figure 2-8). In this way, the dominant forest vegetation type was mapped for all suitability classes in each Holdridge Life Zone.

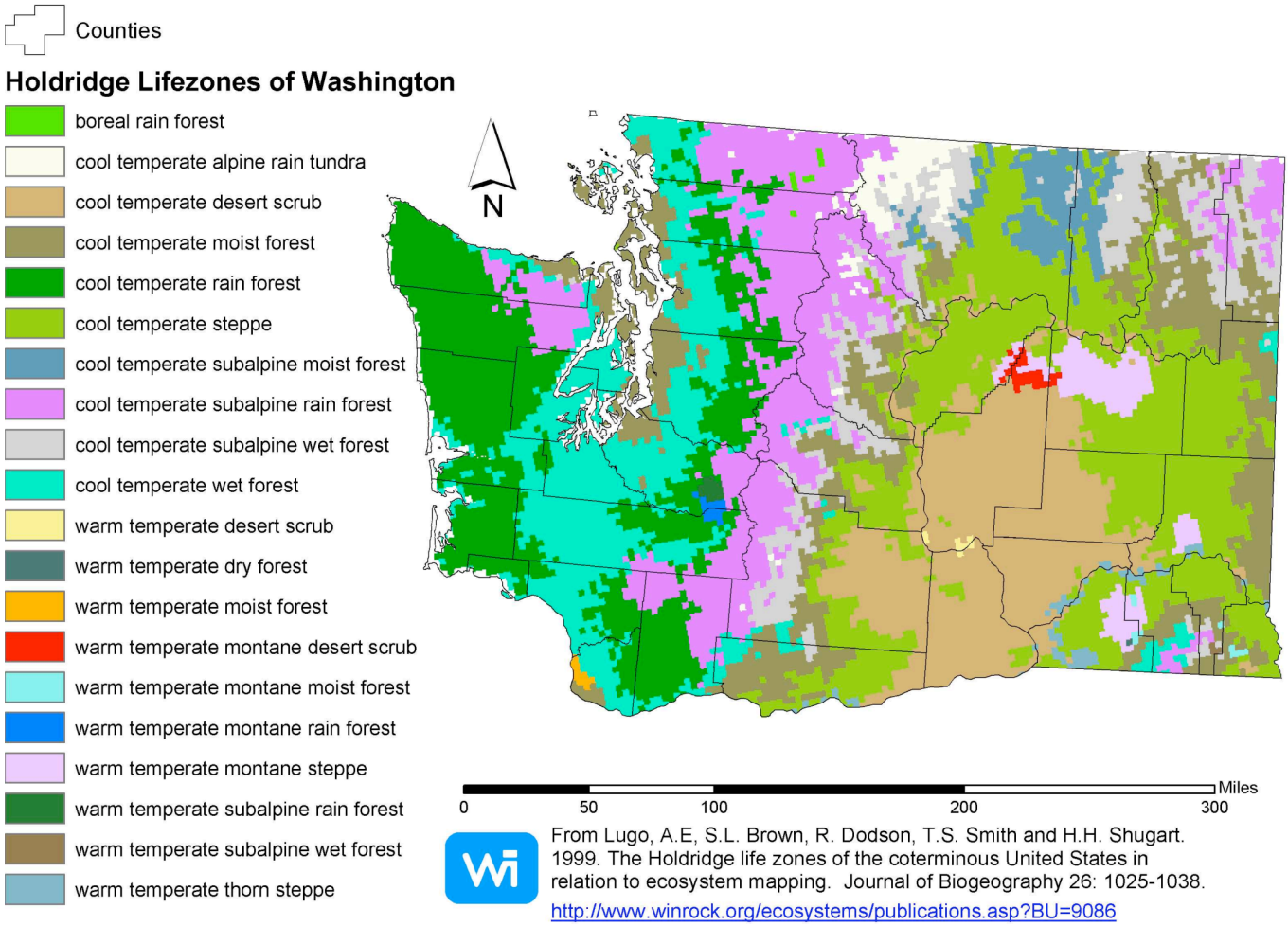


Figure 2-8 Map of Holdridge Life Zones of Washington.

Using the Holdridge Life Zone map to stratify the land also allows for another constraint to be applied in the estimation of the suitability of sites as described in 2.2.3. If a suitability class in a Holdridge Life Zone had no dominant forest species when dominant forest species were extracted, (meaning that it actually has no forest species) even though the suitability class might have forests in other Life Zones, all of these areas were eliminated from candidacy.

2.2.5. Modeling forest carbon sequestration potential

Existing models of forest growth were considered, including CRYPTOS and CACTOS models (Wensel et al., 1986) and Forest Vegetation Simulator developed by the U.S. Forest Service. Given the data requirements for these models, they were deemed to be less useful for application to the large scale of this effort (both in Washington *and* in the California study). Therefore, models were developed to estimate directly rates of forest carbon accumulation on a per unit area basis, and that would require a manageable suite of inputs: forest type and forest suitability class. To simplify, other factors influencing forest growth (e.g. site preparation, planting density, management) were held constant.

The carbon accumulation numbers applied to this analysis were prepared to be conservative yet fully transparent and supported. Where possible the numbers are taken from the US Department of Energy's 1605b greenhouse gas reporting program's look-up tables (http://www.pi.energy.gov/pdf/library/AppendixPartIForestry0321.pdf).

Where look-up table values were not applicable, carbon accumulation data was taken from the published literature. For the analysis, carbon stock densities are required for years 20, 40 and 80, so literature values were used in a growth model to derive values for these years.

The Chapman-Richards function (Richards 1959; Pienaar and Turnbull 1973), a popular sigmoid-shaped biological growth model, has been used in related reports and found to be appropriate as it is simple to use, transparent, and data are available for parameterization. The Chapman-Richards function of the following form was chosen to model biomass carbon accumulation over time:

$$yield = a \times (1 - e^{(-k \times age)})^{1/(1-m)}$$

Parameters for Chapman-Richards models were estimated to tailor carbon yield curves for each vegetation class, and passing through the previously determined age:biomass/ha points.

- "yield" is expressed in metric tons of biomass
- "age" is expressed in years
- "a" (asymptote) determined from literature
- "m" parameter set iteratively at 0.7 (fraction of asymptote (final yield) at which growth rate peaks),
- back calculation for "k" (rate at which the asymptote is approached)

The age at which mean annual increment (MAI) peaks, roughly the age at which stand volume begins to level off (here assumed to be the age at which yield = 80% of the asymptote) was determined in consultation with Josephson (1962), referencing empirically-derived yield tables, and the USFS Silvics of North America for species growing in Washington (Burns and Honkala 1990).

All values reported here include the carbon in above- and belowground live biomass.

Where a single forest class had significant coverage across a wide range of forest suitability classes (>10 classes) in a Holdridge Life Zone, the forest class was further broken down into productivity classes (high, medium, and low productivity). The cumulative distribution of the areas across the life zone's suitability classes was then divided into equal area low, medium and high productivity classes. The carbon sequestration estimates are shown in Table 2-2.

Table 2-2. Estimated rates of carbon sequestration of selected forest vegetation types.

Forest type	Dominant NW Regional Gap Analysis Categories	Example Species	Prod. Class	Biomass carbon (t C/ha) at age:			Source
				20	40	80	
Subalpine forest	Subalpine fir Engelmann spruce Mixed subalpine coniferous forest	Engelmann spruce, Subalpine fir	High	50.65	85.7	159.5	1605b
			Mid	40.85	62.75	114.65	
Mixed coastal forest	Coastal coniferous forest Coastal lodgepole pine Mixed coastal forest Grand fir	Grand fir, Douglas fir, Sitka spruce, lodgepole pine		116	285	501	Smithwick et al.2002, Chapman-Richards
Jeffrey Pine	Jeffrey pine	Jeffrey Pine		38.42	134.87	254.09	Burns and Honkala 1990, Smith et al. 2003, Cairns et al.1997
Lodgepole Pine	Lodgepole pine	Lodgepole Pine		25.2	53.3	95	1605b
Ponderosa Pine	Ponderosa pine	Ponderosa Pine		28.8	46	76.1	1605b
Douglas fir	Mesic Douglas fir	Douglas fir	High	49.6	180.7	391.4	1605b
			Mid	39.5	132.5	315.5	
			Low	29.3	84.2	239.5	
Western Hemlock	Western Hemlock	Western hemlock	High	65.5	231	467.7	1605b
			Mid	51.6	173	399	
			Low	37.7	115	329	

Forest type	Dominant NW Regional Gap Analysis Categories	Example Species	Prod class	Biomass carbon (t C/ha) at age: 20	40	80	Source
Mixed mesic forest	Mountain Hemlock Western Redcedar Mixed mesic coniferous forest Coniferous forested riparian Deciduous forested riparian Whitebark pine Mesic mixed forest Miixed riparian	Douglas fir, Moutain hemlock, Western redcedar		57	161	350	Smithwick et al. 2002, Chapman - Richards
Mixed xeric forest	Mixed xeric coniferous forest Western Larch Xeric Deciduous Forest Xeric Douglas Fir Xeric Mixed Forest	Ponderosa pine, western larch, Douglas fir		22	55	96	Smithwick et al.2002, Chapman - Richards
Mesic deciduous forest	Mesic deciduous forest Deciduous forested riparian	Bigleaf maple, cottonwood, aspen		50.2	84.5	161.5	1605b

2.2.6. Carbon stock baselines in non-tree vegetation

The rangeland vegetation classes from the Northwest regional gap analysis were combined into categories based on biomass. Biomass values for each of the categories were obtained from Forest Inventory and Analysis data (USFS) and from the literature.

The biomass carbon values and the sources of the data are given in Table 2-3.

Table 2-3. Biomass carbon stocks in rangeland vegetation classes.

Vegetation type	Northwest Regional Gap Analysis Categories	Biomass carbon (t C/ha)	Source
Wet Grasslands	Alpine meadow Wet meadow	5.9	Prichard et al., 2000
Mesic Grasslands	Subalpine meadow Gramminoid/Forb Riparina	2.4	Brown and Archer, 1999
Xeric Grasslands	Xeric grasslands	0.6	Winrock unpublished data
Shrub/Tree	Pinyon pine Moutain mahogany Utah juniper Western juniper	25.5	FIA analysis
Shrub	Big sagebrush Shrub-dominated riparian Bitterbrush Other sagebrush Rabbitbrush salt-desert shrub Upland shrubland	5.1	Martin et al., 1981

These carbon stocks on existing rangelands represent the baseline that is not considered attributable to afforestation activities on those lands.

2.2.7. Economic analyses

All economic decisions involve trade-offs. If activity X is forgone in order to undertake activity Y, then the value of undertaking activity X must be considered as the opportunity cost of undertaking activity Y. Simply put, the opportunity cost is the most highly valued alternative to the activity being considered. In this case, the activity being considered is afforestation of range and crop land in Washington. Therefore, the profitability per hectare in Washington represents the opportunity cost of producing carbon on that land (i.e. afforestation). The ultimate cost of producing carbon through afforestation on crop or range land is going to differ from site to site and county to county, primarily based on the quality of the soil and growing conditions, which directly influences both crop and range yields (i.e. opportunity forgone) and carbon yields (i.e. afforestation).

In the economic analysis, the "price" a farmer/rancher would need to receive to take a parcel of land out of agriculture/rangeland and put it in forestland use for increased carbon sequestration needs to be estimated. That "price" must be equal to or greater than the return the farmer/rancher is currently receiving from the agricultural or range use of that land. For a

landowner to consider taking an acre of agricultural or range land out of that use for the purpose of afforestation, the "price" will have to be equal to the marginal return to the farmer from that parcel of land under consideration. That marginal return is the estimated revenue less the input costs for the agricultural enterprise in question for putting that last acre into agricultural or range production. Only the variable costs of agricultural or range production are used in this analysis because it is unlikely that a farmer will enroll all land in a carbon sequestration program, but only a smaller proportion thereof. As a result, the allocation of fixed costs over the amount of unit area remaining in agricultural or range land use remains about the same and can be ignored.

The economic analysis methodology for estimating the opportunity costs of afforestation projects on range and crop land is based on widely available data on prices, costs, and yields of the major crops produced in the state. We have intentionally designed this methodology to be easily replicable across states. In doing so we have foregone some degree of local specificity regarding costs and prices of crop production, but we feel that the simplicity and replicability of this approach outweighs the small margins of error caused by using regional cost and price data.

To calculate the total cost of afforesting rangeland and cropland, the variables considered were opportunity costs, one-time conversion costs, management, costs and measurement and monitoring costs. The economic analysis for rangelands is practically identical to that used for California (Brown et al. 2004) and that for croplands the same as that for the Southern States regional partnership (Brown and Kadyszewski, 2005a). Here we briefly describe the approaches for estimating total costs and the local values used in the analyses.

Rangelands

The most highly valued alternative to afforestation is cattle ranching. (An alternative to afforestation of rangelands could be conversion to urban development, and depending upon the price of real estate, the opportunity cost for this alternative could be high. We did not consider this alternative in our analysis.) Therefore, the profitability per acre of cattle ranching in Washington represents the opportunity cost of producing carbon (i.e. afforestation).

The profitability of cattle ranching varies greatly from year to year and from ranch to ranch. This is due primarily to weather conditions and cyclical fluctuations in the price of beef. Unfortunately annual enterprise budgets for cattle ranching, which indicate profitability, are not officially kept in Washington. Because of this, we used input from recent Cattle-Fax publications and from personal communication with rangeland extension specialists[1] to calculate an average annual profitability value for Washington cattle ranching (Table 2-4). The revenue estimates that reported in Table 2-4 reflect long-term average prices received for cattle. After subtracting total costs of production from revenue, an average annual profit per cow is estimated to be $94.75.

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1 From personal communication with Don Nelson 2005. Washington State University, Extension Beef Specialist for Pacific Northwest; and Tip Hudson 2005. Washington State University Rangeland Extension Specialist.

Table 2-4. Revenue and costs associated with cattle ranching in Washington (data from Cattle-Fax and T. Hudson and D. Nelson, Washington State University, 2005, pers. comm.).

Economics of Ranching in Washington			
Revenue			
	Total	$/animal	Assumption
Calf	$600.00	$510.00	85% wean rate
Cull cows	$425.00	$63.75	15% cull rate
Total Revenue		**$573.75**	
Costs in $/animal			
Pasture		$130.00	
Supplemental feed		$151.00	
Other operating and fixed costs		$198.00	
Total Costs		**$479.00**	
Mean annual profit/animal (Revenue – Costs)		**$94.75**	

Other than the wide swings in the price received for cattle, the most critical variable in determining ranching profitability is the forage production potential of the rangeland. Forage production determines the carrying capacity of the land. Higher forage production can support more cows per acre and therefore results in higher profits per acre. Moisture and soil conditions are the primary predictors of rangeland productivity and are the drivers of the methodology described below.

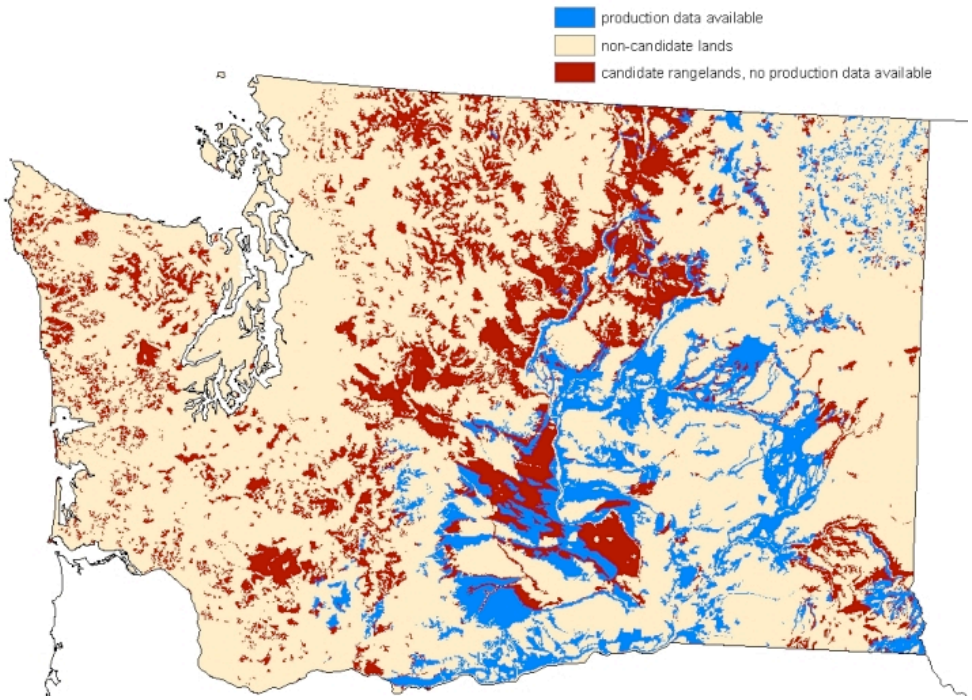
Western rangeland specialists use an average of 791 lbs. of forage dry matter (DM) to represent the monthly requirements for cattle being fed on rangeland forages (L. Metz 2003, USDA-NRCS, Davis, CA, pers. comm.). This monthly requirement is termed an animal unit month (AUM) and it is used as a measure of the carrying capacity of a parcel of rangeland. Therefore, if one acre of rangeland produces 791 lbs. of forage DM over the course of one month, that acre is said to produce one AUM of forage. This translates into an annual per cow forage requirement of 9,492 lbs. DM (12 times the AUM). This forage requirement estimate (i.e. AUM of 791 lbs.) and the average annual per cow profitability of $94.75 was used to estimate the profitability potential (i.e. opportunity cost) for all Washington rangelands, as explained next.

For rangeland that produces only 100 lbs. of forage DM per acre, almost 95 acres will be required to support one head of cattle for a year. The annual per acre profitability of this low-producing rangeland is estimated to be only $1.00 (i.e. $94.75/95). High producing rangeland of 2,000 lbs. DM per acre per year will require only 4.75 acres to support one head. In this case the annual per acre profitability is $19.96 (i.e. $94.75/4.75). The relationship between annual

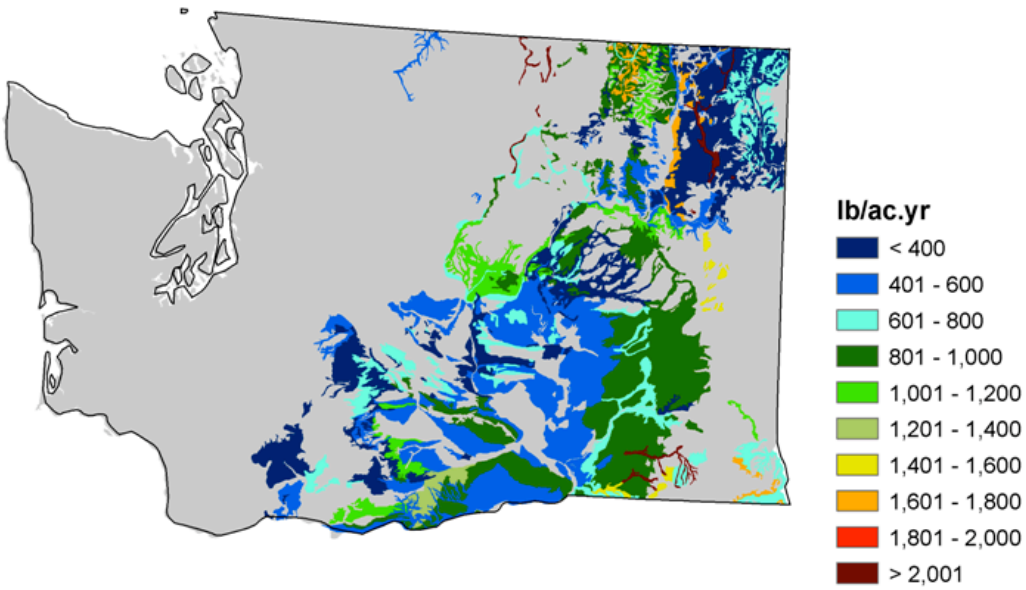
average per cow profitability and annual average per cow forage DM requirements yields a constant relationship indicating that each lb of forage DM is equal to $ 0.009982 in ranch profits. This average profitability figure per lb of forage production is used to project the profitability of all Washington rangelands. The model used to estimate the forage DM production for each pixel of Washington rangeland is described in the following section.

The modeling methodology that was developed to estimate forage production for all Washington rangelands used forage production estimates from the State Soil Geographic Database (STATSGO). The forage production estimates were then translated into a livestock carrying capacity for the land and combined with the average per cow profitability (Table 2-4) to estimate the average annual opportunity cost of afforestation for each pixel of rangelands on the map.

Because forage production from STATSGO was not available for the full extent of a state's rangelands, a multivariate regression was run using the variables of aspect, slope, elevation, mean annual precipitation, mean annual temperature and soil available water content (based on the approach developed for California). These data were extracted from 5180sample locations in both Washington and Oregon where STATSGO data were available for the dominant soil components, and a highly significant relationship as reflected in low P values was derived. Figure 2-9a shows areas where forage production data were unavailable from STATSGO and where the regression analysis was used to fill in the gaps. And Figure 2-9b shows the range of forage production in areas where STATSGO data were available. Most of the mapped rangelands have low productivity (less than 600 lb/ac.yr) and would require about 16 acres to support one animal.



(a)



(b)

Figure 2-9. (a) Dominant soils components with available STATSGO 'rsprod' (range productivity) data (maroon areas were filled with regression results); and (b) estimates of forage production for areas with 'rsprod' data.

Conversion and maintenance costs are those associated with establishing tree plantings on rangelands in Oregon; it was assumed given similarities between the two states that the cost for Washington would be the same. Based on information from a range of timber companies, the cost of establishing forests varies from $300 to $600 per acre, with the variability stemming mostly from soil moisture and texture, and slope of the site. The Oregon Department of Forestry gave an estimate at $550 per acre ($1,360/ha) (J. Cathcart pers. comm.) that was used for this analysis. The maintenance cost is projected to be incurred for a period of 5 years from the beginning of the activities to ensure that enough tree seedlings survive to generate a well-stocked, free-to-grow stand. Activities expected (depending upon local conditions) include replanting seedlings that died, weeding (or herbicide application), possibly fertilizing and adequate fencing to control livestock incursion until the trees get established. Annual maintenance costs are estimated to be approximately $70/ac.yr during the first 5 years of activities ($173/ha.yr) (Table 2-5).

Table 2-5 Assumptions in per-acre cost breakdown for afforestation projects [NOTE: for croplands, 'Site prep' was reduced by 50%]

one-time conversion costs		maintenance costs	
Site Prep	$250	Vegetation Management	$130
Seedling Costs (436 trees/acre @ 10' by 10' spacing)	$150	Interplantiing/Contingencies (seedlings and labor)	$120
Planting Labor Costs	$120	Final Release	$90
Administration	$30	Additional administration costs	$10
	$550		$350
		per year of first 5 years	*$70*

The final cost category is the costs of measuring and monitoring the carbon production over the life of the activity. The average annual M&M costs associated with carbon production contracts is estimated to equal $1.60/ac for 20-year projects, $1.08/ac for 40-year projects, and $0.80/ac for 80-year projects, based on Winrock's experience with measuring and monitoring many afforestation activities throughout the US. Several factors affect the magnitude of the cost including which pools are measured and monitored (in this case we assume only aboveground biomass), frequency of monitoring (once every five years over duration of project), area, and whether the lands are contiguous or dispersed (assumed here to be contiguous). The area of the activity is an important factor and economies of scale exist for M&M costs; therefore, per-acre M&M costs may be significantly higher for smaller activities.

Because the economic analysis is considering afforestation activities that are 20, 40, and 80 years in duration, the annual opportunity cost estimates were projected into the future (20, 40, and 80 years) and then discounted to obtain a present value (PV) estimate of the annual stream of profits from farming that would be foregone to allow for afforestation. The real discount rate used in this analysis is 4 percent (6% discount rate minus 2% inflation rate). The costs that are incurred only at the beginning of the project are not discounted. These include the conversion cost and the contract cost (currently assumed to be zero because data are not available) and are added to the total present value costs. The resulting numbers represent the present value of all of the current and future (for the life of the carbon project) costs associated with sequestering carbon on rangelands through afforestation (Table 2-5).

Table 2-6. Present value of current and future costs associated with sequestering carbon on Washington rangelands through afforestation.

Forage production Lbs/acre.yr	20 year	40 year	80 year
100	$2,310	$2,325	$2,329
500	$2,444	$2,520	$2,565
1000	$2,612	$2,764	$2,860
1500	$2,779	$3,008	$3,155
2000	$2,947	$3,252	$3,450

Crop lands

The economic analysis for croplands involves estimating the profitability of crop production for the major relevant crops of Washington using USDA county-level area and yield data. The crops that are selected to be included in the analysis are the crops that meet both of the following criteria: (1) represent a significantly large area in the state, and (2) have an average profitability that is low enough to allow carbon projects to be a possible alternative (i.e. commodity as opposed to high-value crops). The two crops that meet these criteria for Washington are wheat and hay. Another reason that the higher-value crops were not included in this analysis is that they tend to cover smaller areas and are not distinguished clearly on any land-use or land-cover maps and thus are difficult to identify.

The area and the average yield for each county within Washington were collected from the USDA National Agricultural Statistics Service (NASS) for the years 2000-2004. NASS's annual program focuses on agricultural production for mainstream crops, livestock and associated inventories. The program is based on a series of sample surveys to collect farm level data to produce the State and U.S. crop forecasts and estimates published in the NASS Agricultural Statistics Board reports.

In a given year, net returns (NR) to the land, per area of land can be calculated with the expression,

$NR = PY - CY + G;$

where P is the price per unit for each commodity received by the farmer, Y is the expected yield of that crop, C is the variable cost of production per unit, and G is the amount of money received as government payments or subsidies for producing that crop. Estimates of the total price (P) received by the farmer are based on estimates of future market prices for the year 2005 through 2014. Estimates of future prices for the major U.S. crops are published by the Food and Agriculture Policy Research Institute (FAPRI). The mean of the actual and projected prices for the years 2005-2014 are used as the price in the opportunity cost calculations for this analysis. The costs of production for each of the major crops in each county were calculated by multiplying the reported average yield for the crop by the variable costs of production. Fixed costs of production were ignored.

The variable costs of production for each of the major crops were taken from the enterprise budgets prepared by the extension specialists for each crop. The yield used for each crop in each county is the average of the reported county yields for the years 2000 through 2004. As mentioned above, these data come from the USDA-NASS database. The county-specific yields for each crop generate the variability in estimated profitability associated with crop production across the state.

For most of the major Washington crops included in this analysis, wheat and hay, government payments (G) are applicable only to wheat. For wheat, like other subsidized crops, G consists of up to three components. These are loan deficiency payments received per unit of production, counter-cyclical payments per unit of production, and direct payments per area of production. The loan deficiency payment and counter-cyclical payment are conditional based on the price received for the crop. The direct payment is received regardless of price or yield. The standard formulae for calculating each of the government payments and the total G are applied in this analysis.

Any given area of cropland is likely to have a rotation of crops produced on it over a number of years for agronomic and economic reasons. This analysis has used USDA-NASS data on planted area for each crop in each county to calculate the average percentage of hectares planted to both wheat and hay from 2000-2004. This average for each county is used to estimate a weighted average profitability for crop production in each county. By using county-specific yield and area data, combined with prices and per unit costs that are constant across the region, this analysis is able to produce relatively specific estimates of opportunity costs with a simplified and replicable analytical framework.

The profitability (i.e. opportunity cost) estimates for each crop in each county are then weighted by the average percentage of cropland planted to each crop in each county from 2000 through 2004. This averaging process is necessary to account for the frequency of crop rotations on agricultural land. Each county then ends up with a unique opportunity cost for foregoing crop production for afforestation. This estimated opportunity cost could be viewed as the minimum amount of return necessary to induce landowners to afforest agricultural land.

Added to the opportunity cost are the costs of converting the land to trees, managing the land for afforestation, and measuring and monitoring carbon production on that land as was done for rangelands and described above. Finally, a present value analysis is performed using the same time intervals and discount rates as for rangelands described above. The results of this analysis, in terms of present value of the total costs for afforesting crop lands in Washington, are shown in Table 2-7.

Table 2-7. Present value of the total costs for afforesting crop lands in Washington after different time intervals.

	20 years	40 years	80 years
Mean	$3,316	$3,930	$4,334
Median	$3,143	$3,678	$4,028
Minimum	$2,665	$2,982	$3,188
Maximum	$4,190	$5,203	$5,871

2.3 Results: carbon supply for rangelands and croplands

2.3.1 Carbon sequestration potential

Based on the analyses of carbon sequestration potential and productivity across suitability and Holdridge Life Zone classes, carbon sequestration grids were derived for all rangelands and croplands. On candidate areas, new grids of additional carbon that could be sequestered were obtained by subtracting the current carbon stocks (Table 2-3) from the potential carbon stocks after different time intervals (Table 2-2). The amount of carbon sequestered at any of the time intervals is always lower in the drier east side of the state than in the moister west side (Figures 2-10 and 2-11). Even after 80 years, the maximum carbon stocks that can be attained by afforestation of rangelands and croplands in the eastern part of the state range between 50 to 100 t C/ha. In contrast, this value is attained within 20 years on lands in the western, more humid part of the state.

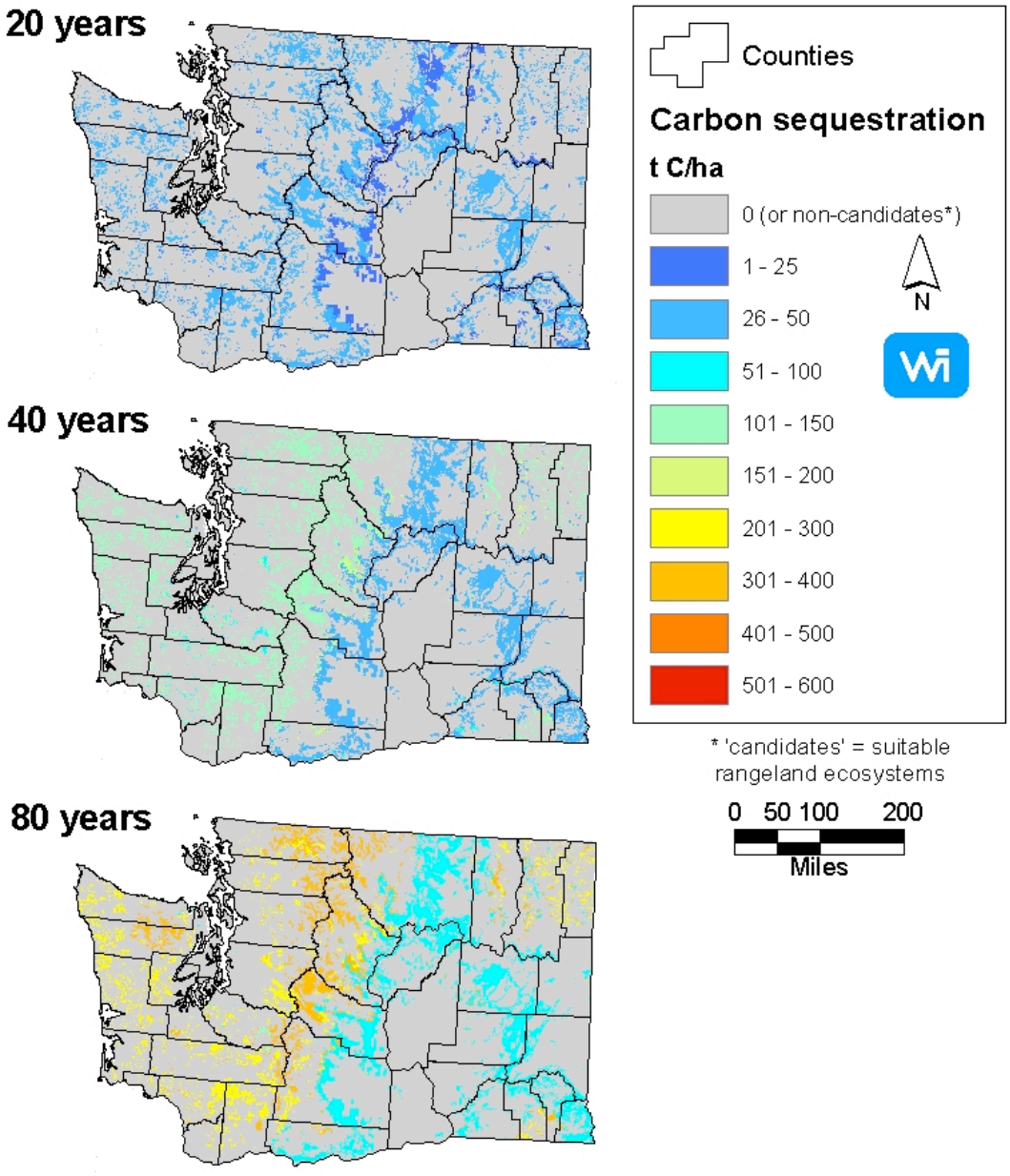


Figure 2-10. Carbon sequestration potential from afforestation with native species on suitable rangelands in Washington.

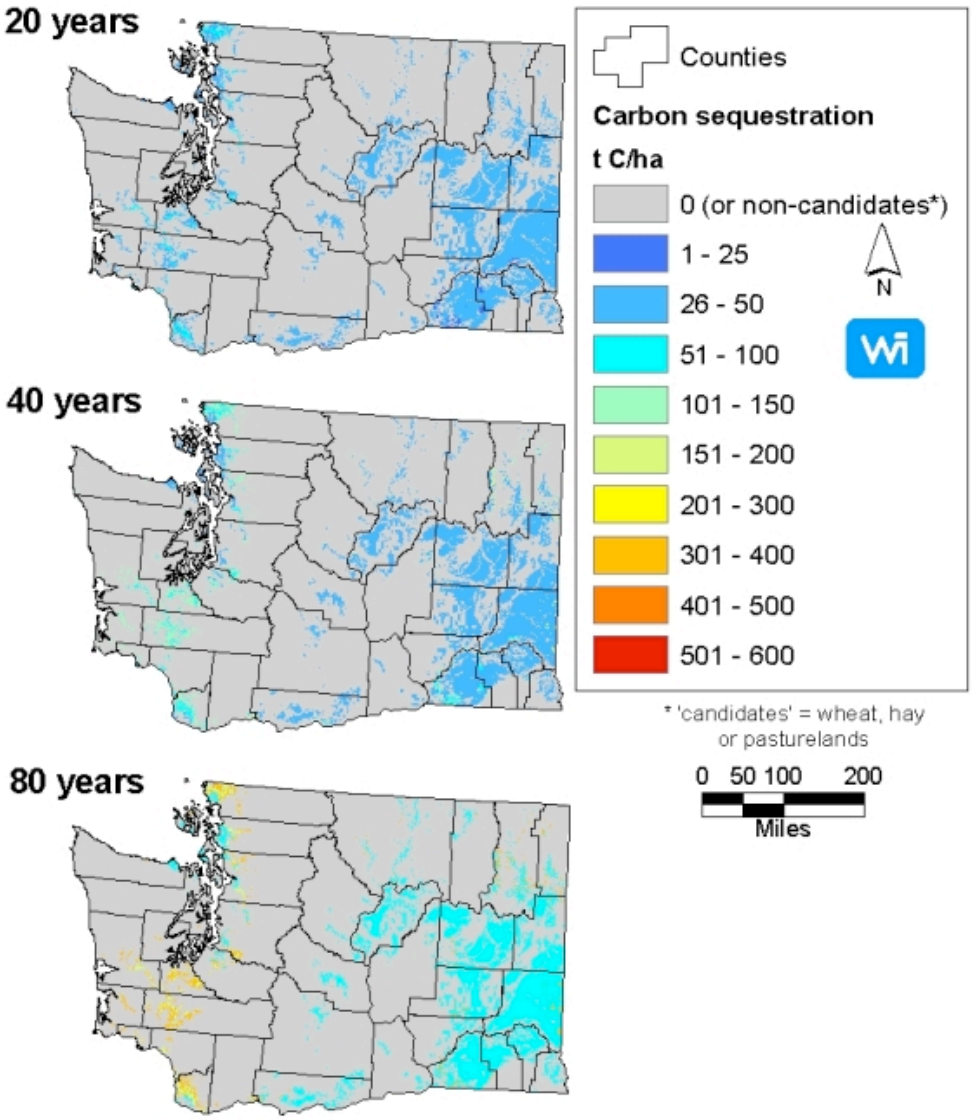


Figure 2-11. Carbon sequestration potential from afforestation with native species on suitable crop lands in Washington.

2.3.2 Total present value of costs

The total costs in $/ha, for afforesting rangelands and croplands are mapped in Figures 2-12 and 2-13. The present value of the costs is higher for the longer duration scenarios because there is a longer period of time where the rangeland opportunity has been forgone. The present value of the cost hurdle on rangelands tend to be less than $3,000/ha for the 40-year duration period. For a project lasting 80 years duration, the present value of the cost hurdle is generally below $3,250/ha, except for a few areas where costs reach up to and above $3,500 /ha (Figure 2-12)

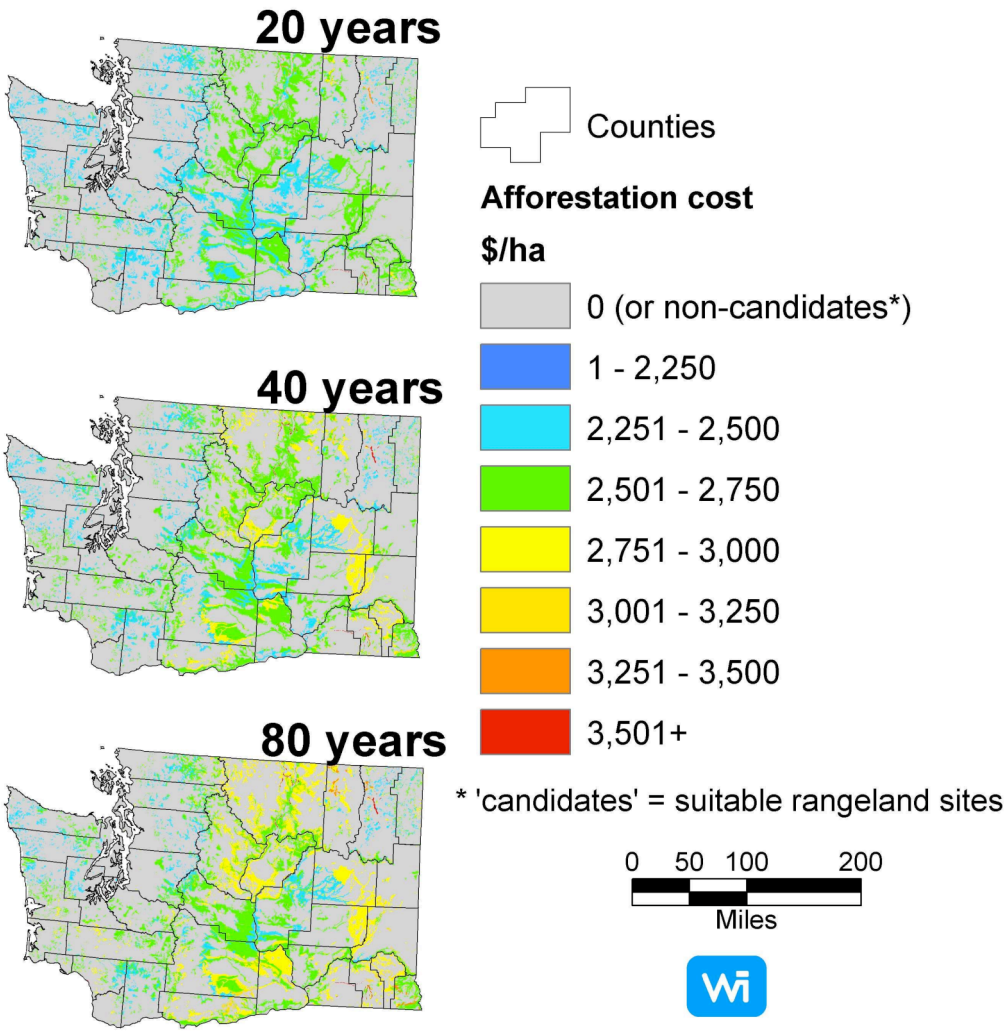


Figure 2-12. The present value of the total cost ($/ha) to afforest candidate rangelands.

The present value for costs of sequestration for croplands are considerably higher than for rangelands as expected (Figure 2-13). Half of the cropland has cost less than $4,000/ha up to 40 years. After 80 years, costs go as high as $5,000/ha.

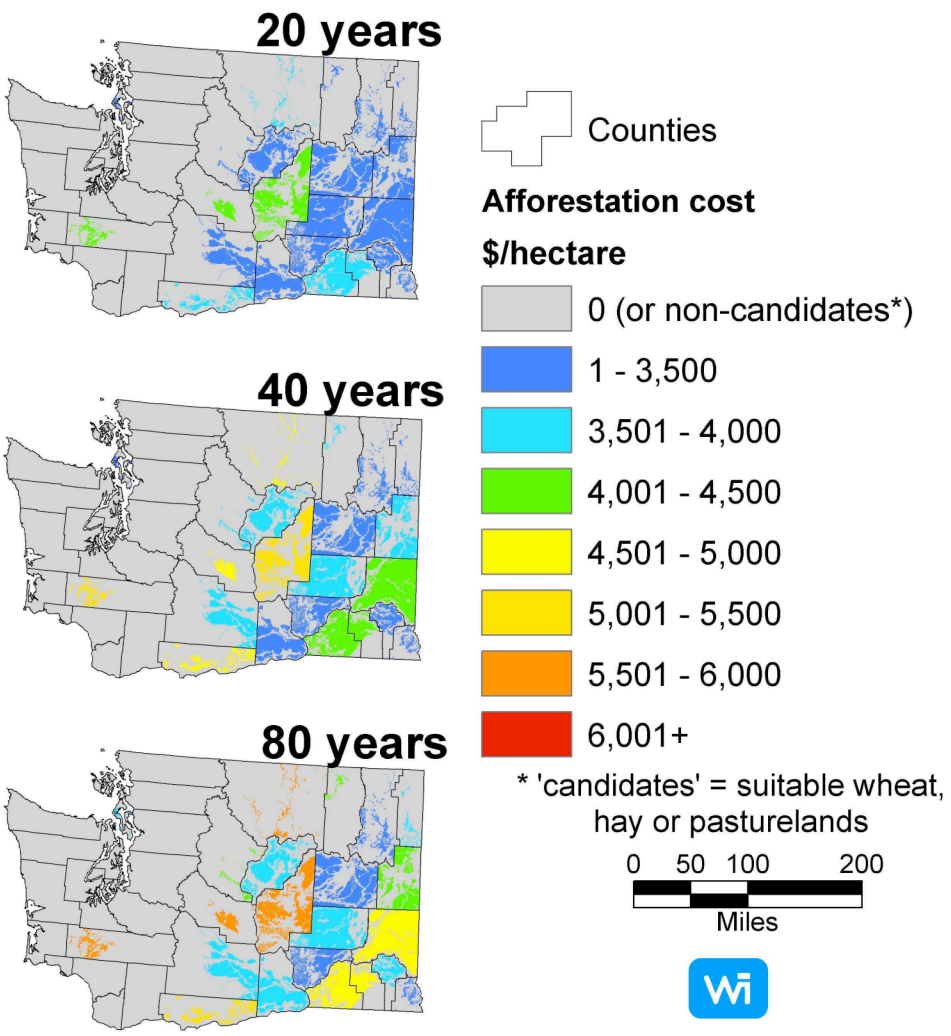


Figure 2-13. The present value of the total cost ($/ha) to afforest candidate croplands.

2.3.3 Carbon supply for afforestation of range and crop lands

Figures 2-14 and 2-15 show the spatial distribution (at 30 m resolution) of the cost per t C for afforesting rangelands and croplands for activities lasting 20, 40, and 80 years, respectively. After 40 years, much of the rangeland available for afforestation supplies carbon at costs of between $16 and $75/t C. However, for longer projects, the costs per t C decrease because the initial afforestation costs are now spread over more years of sequestration so that the amount of carbon storage is increased due to tree growth. The costs per t C decrease through time, so that after 80 years much of the rangeland, especially located towards the western part of the state, could be afforested and supply carbon at costs of less than $10/t C (or <$2.70/t CO_2).

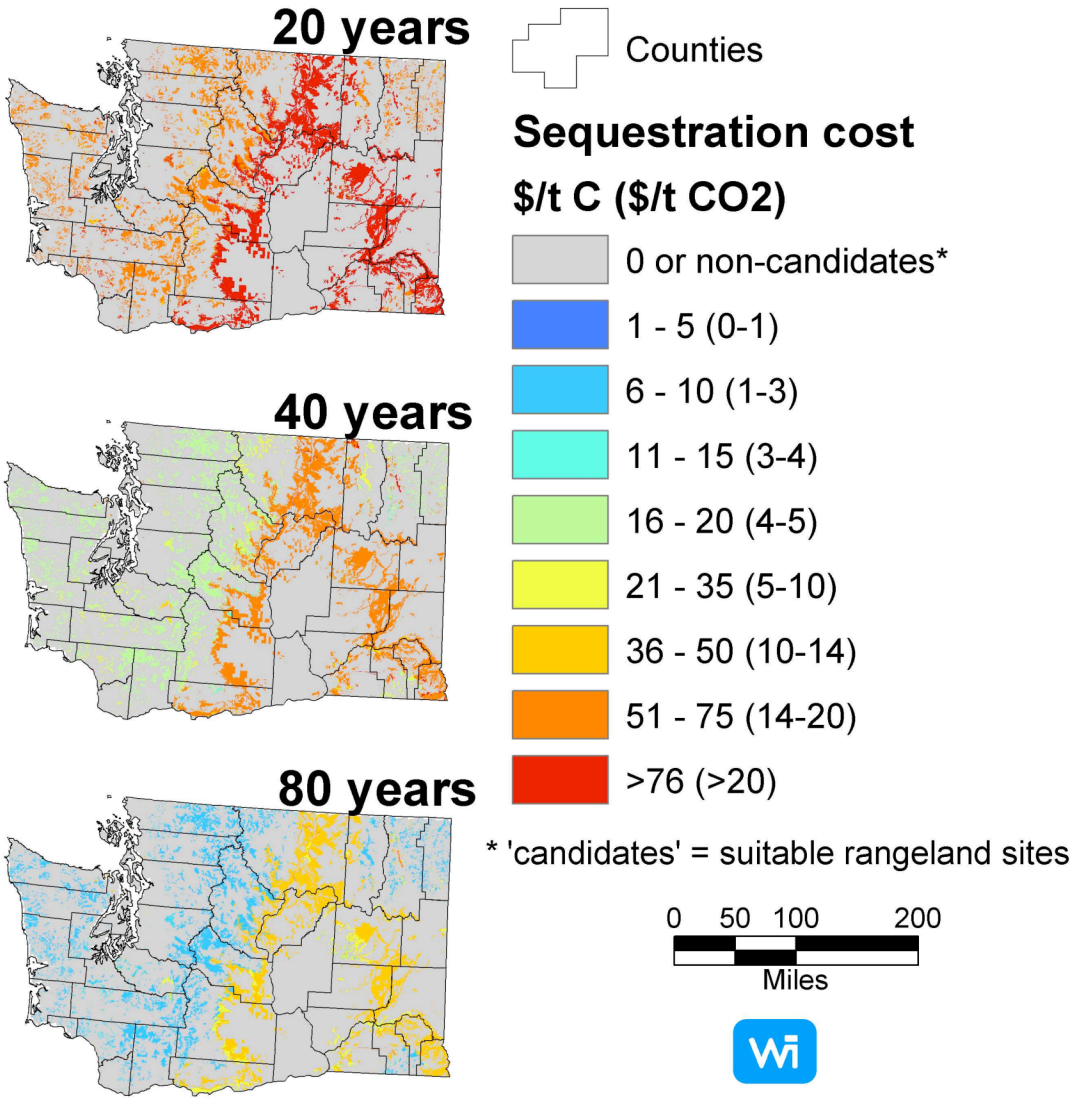


Figure 2-14. Costs of carbon sequestration through afforestation of suitable rangelands of Washington..

Similar to the case for rangelands, for activities lasting only 40 years, much of the cropland available for afforestation supplies carbon at costs of more than $50/t C (Figure 2-15). The costs per t C decrease somewhat for longer lasting projects, but still much of the cropland in the eastern part of the state has the potential to supply carbon mostly in the $36-75/t C range.

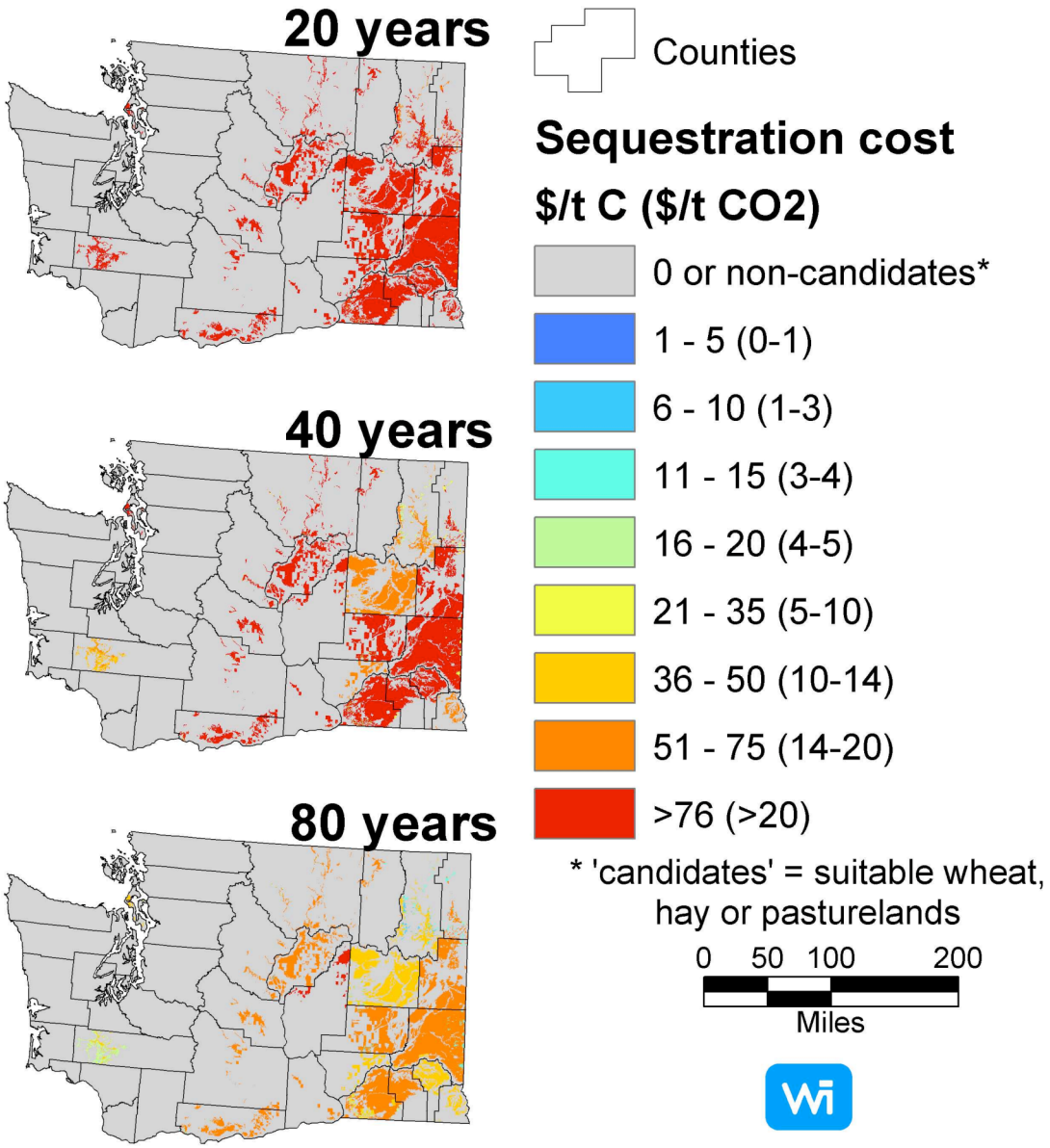


Figure 2-15. Costs of carbon sequestration through afforestation of suitable croplands of Washington.

The area of rangeland available for afforestation increases up to about 3.6 million ha at gradually increasing costs for all project durations (Figure 2-16, top). The quantity of carbon available from afforestation of rangelands at different price points below $100/t C and time period is shown in Figure 2-16 (bottom). At a common carbon price of $36/t C ($10/t CO_2), afforestation of rangelands produces no carbon after 20 years, about 240 million t C after 40 years, and 550 million t C after 80 years.

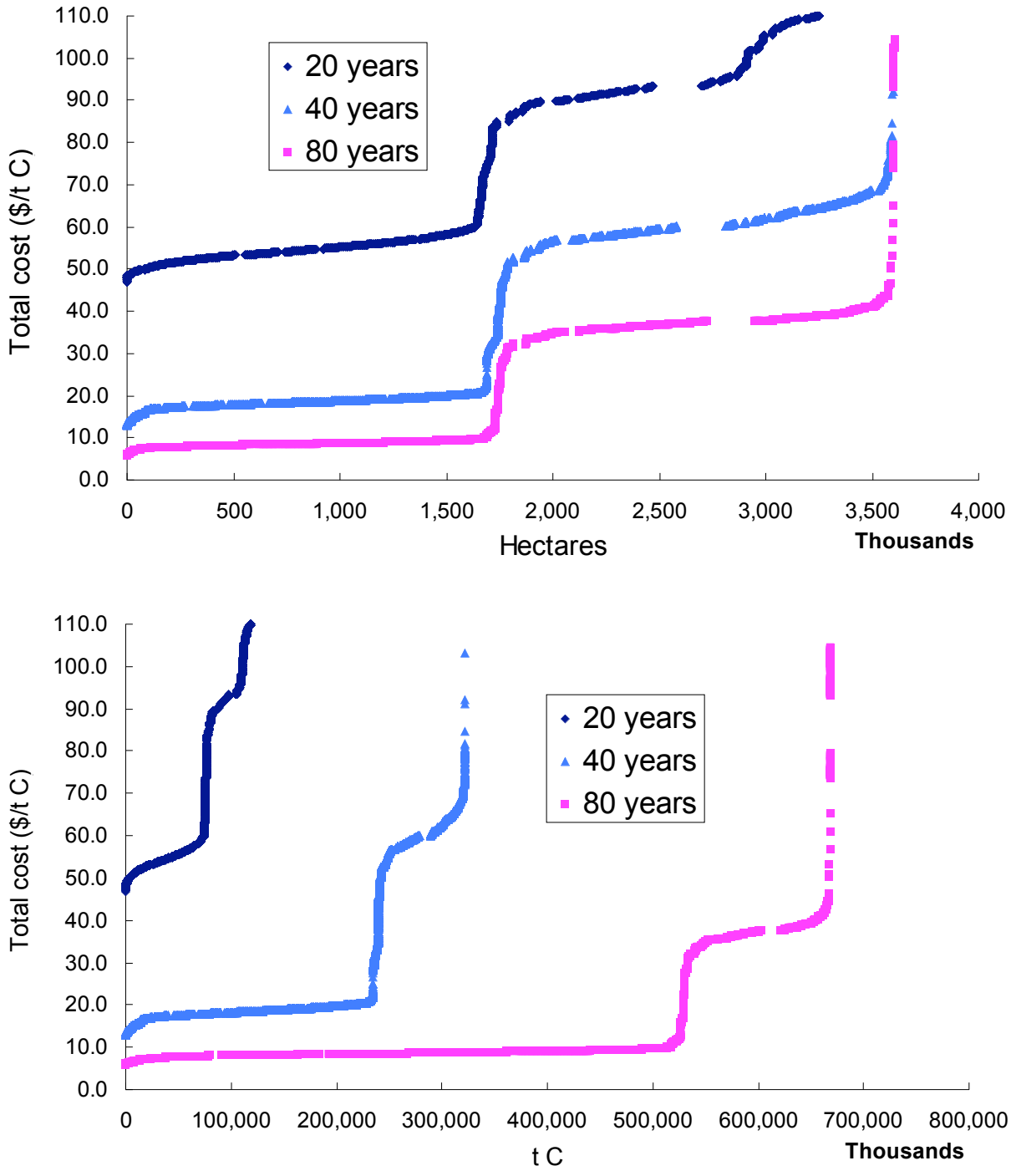


Figure 2-16. Carbon supply curves for afforestation of suitable rangelands in Washington: (top) areas available and (bottom) quantity available at different costs per ton carbon.

The total amount of carbon that could be sequestered by afforestation of rangelands is highest at all three time periods in the counties in the central part of the state, on the eastern side of the Cascades (Figure 2-17). The westernmost counties also have the potential to sequester considerable quantities of carbon at all three time periods. Counties in the southeast part of the

state have the lowest potential and do not exceed 8 million t C even after 80 years, whereas most of the central and many of the western counties have the potential to sequester more than 30 million t C after 80 years.

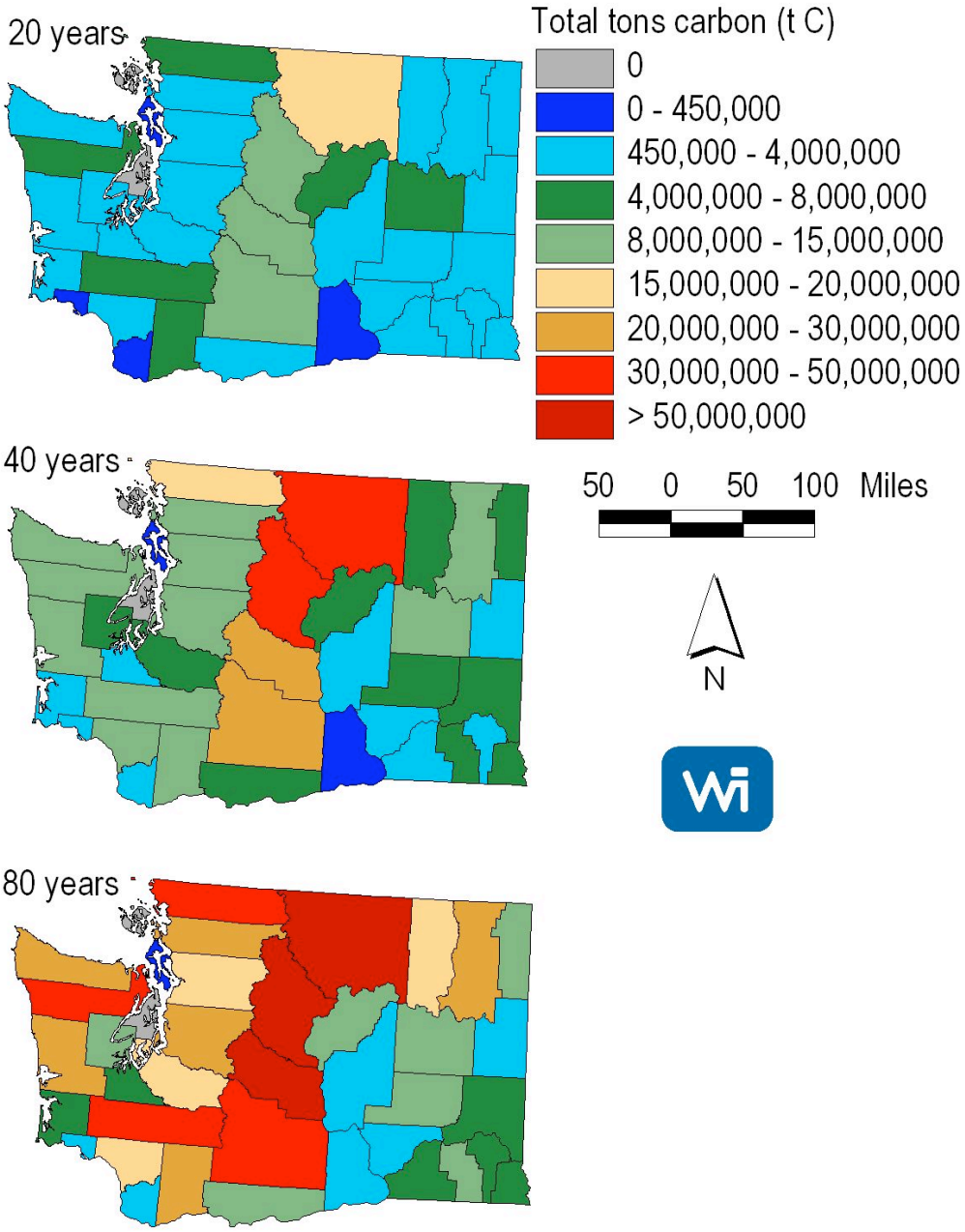


Figure 2-17. Spatial distribution, at the county scale of resolution, of the total amount of carbon that could be sequestered by afforestation of rangelands after 20, 40, and 80 years.

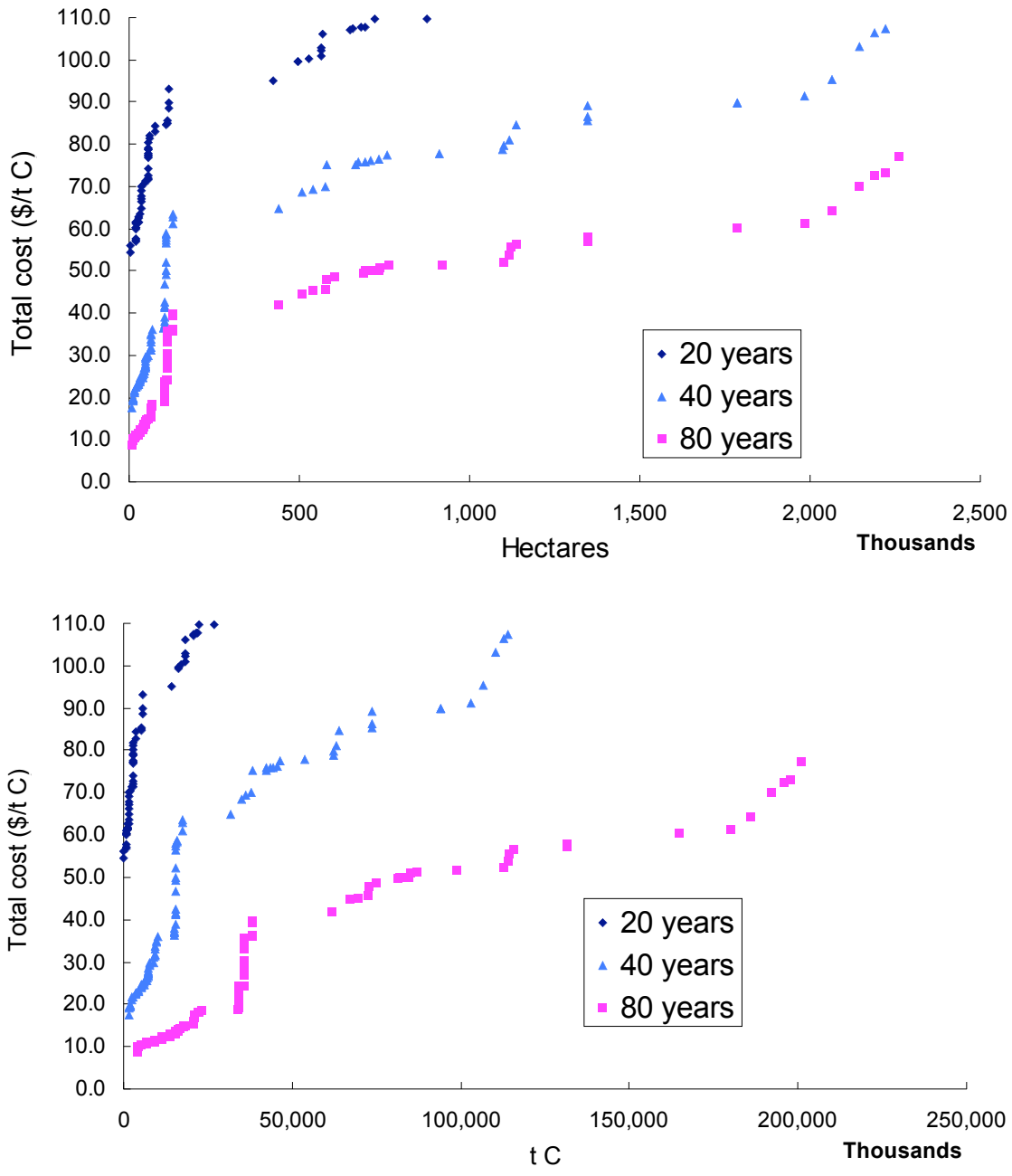


Figure 2-18. Carbon supply curves for afforestation of suitable crop lands in Washington: (top) areas available and (bottom) quantity available at different costs per ton carbon.

The area of cropland available for afforestation increases up to about 2.3 million ha at gradually increasing costs for all time periods (Figure 2-17, top). The quantity of carbon available from afforestation of croplands at different price points below \$100/t C and time period is shown in Figure 2-18 (bottom). At a common carbon price of \$36/t C (\$10/t CO_2), there potentially would none after 20 years, 15 million t C after 40 years, and 38 million t C after 80 years.

The total amount of carbon that could be sequestered by afforestation of croplands is highest at all three time periods in the counties in the eastern part of the state (Figure 2-19). Many of

these eastern counties have the potential to sequester between 15 and 30 million t C after 80 years. Counties in the central and south central part of the state have the lowest potential and do not exceed 4 million t C even after 80 years.

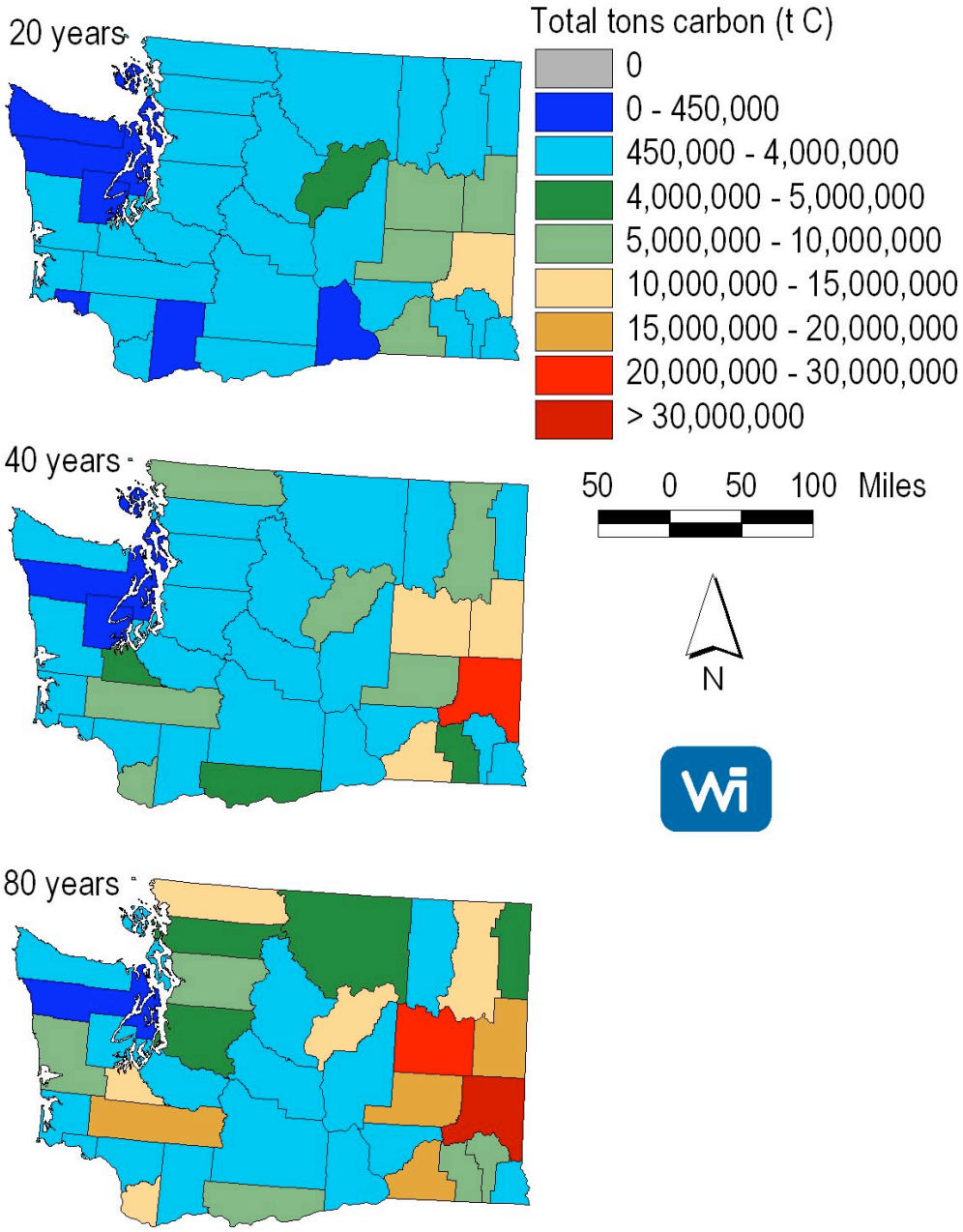


Figure 2-19. Spatial distribution, at the county scale of resolution, of the total amount of carbon that could be sequestered by afforestation of croplands after 20, 40, and 80 years.

3. Changes in forest management

3.1 Background

This paper presents the potential for, and costs of, carbon sequestration through two potential changes in forest management: increasing rotation ages and increasing the area of riparian zones along streams in Washington. A model is presented describing how optimal rotation ages are affected by changes in the value of sequestered carbon. The model is used to estimate the marginal costs of increasing rotation ages 5, 10, and 15 years beyond currently optimal rotation ages. The model is also used to estimate the costs of holding land indefinitely in riparian zones. Estimates of marginal costs are developed for a range of species, site classes, and timber pricing regions in Washington. These costs are then applied to US Department of Agriculture Forest Service Forest Inventory and Analysis (FIA) data to estimate the spatial distribution of carbon sequestration.

The results indicate that there are around 444,000 hectares of private timberland nearing the optimal rotation age in Washington. Up to 12.0 million t C could be stored in 15-year rotation extensions on this land. The average cost per ton is around $136 per t C, or about $2,862 per hectare. For expanding riparian zone management, there appear to be around 14,100 hectares of land nearing the optimal rotation age, with the potential to store 0.6 million t C for an average cost of $122 per t C.

This section is organized as follows: Section 3.2 describes the methodology used to estimate carbon sequestration costs through aging timberland, and presents estimates of the 5, 10, and 15 year extension periods for Washington forests. Section 3.3 describes the approach, data used and results for setting aside timberland in extended riparian zones.

3.2 Extending forest rotations

3.2.1 Approach

Previous estimates of carbon sequestration costs through aging timberland have been developed for Winrock International for several Southern states (Brown & Kadyszewski 2004, 2005) and for California (Brown et al 2004). The methods used to estimate the costs of carbon sequestration through aging in this paper are updated and revised relative to these earlier reports. This paper estimates marginal costs for permanent sequestration of carbon through aging timber, and for permanently setting aside riparian zones along streams.

Several important assumptions underlie this analysis. First, prices for all products and carbon are assumed to be constant over time. Second, for financial analysis, the value of carbon sequestration is discounted, and when calculating potential carbon storage, additional tons gained over time are also discounted. The issue of carbon discounting is discussed in more detail below.

To estimate the marginal costs of carbon sequestration in forests through aging, the optimal rotation period with and without value assigned to carbon storage is calculated. Optimal rotation periods for a range of carbon prices, and the additional (permanent) carbon stored for the alternative rotation periods are calculated. The carbon prices that achieve 5, 10, or 15 year aging periods are thus the marginal costs of sequestering carbon, assuming that carbon and timber prices are constant.

To calculate optimal rotation periods under alternative carbon and timber prices, the following function is maximized:

(1) Stand Value =

$$W(a) = \frac{(P_S\phi_S + P_P\phi_P)V(a)e^{-ra} + P_C\alpha V(a)e^{-ra} + rP_C\int_0^a \beta(n)V(n)e^{-rn}dn - C}{(1-e^{-ra})}$$

Where:

P_S = price of sawtimber products (stumpage, $/ft3)

P_p = price of pulpwood products is (stumpage, $/ft3)

P_C = price of sequestering a ton of carbon forever

$V(a)$ = biomass yield, or growing stock volume (ft3 per hectare)

ϕ_S = proportion of biomass used for sawtimber

ϕ_P = proportion of biomass used for pulpwood

α = conversion factor converting harvested biomass into "permanently" stored carbon.

$\beta(t)$ = conversion factor converting biomass yield into carbon.

C = harvesting costs

r = interest rate

a = rotation period.

The first part of equation (1) represents the value of harvesting the stand and selling products in markets, $(P_S\phi_S + P_P\phi_P)*V(a)e^{-ra}$. The second part of Eq.1 is the value of storing carbon permanently in markets [$P_C\alpha V(a)e^{-ra}$]. The term α is calculated as the present value of initial storage in market products less the present value of decay (or replacement rate of products):

$$\gamma\phi_S(0) - \int_0^\infty \delta_S\gamma\phi_S(n)e^{-rn}dn + \gamma\phi_P(0) - \int_0^\infty \delta_P\gamma\phi_P(n)e^{-rn}dn$$

The term γ accounts for wood density and converts wood biomass into carbon. The term α therefore accounts for the proportion of the harvested volume that is carbon as well as the proportion stored permanently in marketed products. Permanent storage is valued at the market price for carbon sequestration, PC. The term [$rP_C\int_0^a \beta V(n)e^{-rn}dn$] accounts for the value of carbon sequestered on the stump. Carbon on the stump is rented annually at the rate of rPC. Because the volume of carbon on the stump grows over time, the annual value of rental

payments for carbon sequestration will increase over time. Consequently, within each rotation, the present value of rental payments must be calculated with the integral in (1). The term □*(n)* converts timber volume into carbon. As noted in Smith et al. (2003), carbon per unit of timber volume changes over time, so the carbon conversion factor for timber on the stump is a function of time.

For this analysis, Eq.1 is solved numerically for each timber type and pricing region in the state over a set of constant carbon prices (ranging from $0 - $750 per t C). This allows us to determine the optimal rotation age, given timber prices and carbon prices. The carbon price, as shown in Eq.1, represents the marginal cost of carbon storage in forests. For each carbon price (or marginal cost), the optimal additional aging period is calculated.

The additional carbon stored when forests are aged is calculated separately for each aging period. For this analysis, a 300 year period is used to assess carbon gains. Carbon stocks are calculated across this 300 year period for the baseline, and for each increment in rotation ages. The carbon benefit calculated for aging timber is estimated as the net present value of the annual change in the difference in carbon stocks (both in products and stored on the stump) during this period. The annual difference in carbon stocks is given as:

(2a) $CSD_t = CS_t^{ER} - CS_t^{B}$

(2b) $S_t = CSD_t - CSD_{t-1}$

(2c) $NPV(Carbon) = \sum_{0}^{300} S_t (1+r)^{-t}$

where CS^{ER} is the carbon stock in each time period under the extended rotation, and CS^{B} is the carbon stock in each time period under the baseline. Stands are assumed initially to be at the optimal rotation period (the baseline rotation period, "*B*"). In the baseline scenario, stands are assumed to be continuously harvested at the economically optimal rotation age. In the scenario of extended rotations with carbon prices, stands are also assumed to be harvested continuously at optimal rotations, but the optimal rotations will be longer due to carbon prices.

Throughout this study, present value techniques are used to discount carbon flows. While most economists recognize the importance of discounting monetary flows over time, equations (2a – 2c) above discount a non-monetized flow of carbon, rather than carbon values. Discounting carbon flows like this is appropriate for benefit cost analysis under the following conditions.

Suppose a company considers investing in a project that has a stream of costs, C_t, a stream of annual carbon sequestration, S_t, and a stream of the benefits of sequestering a ton of carbon in each year, P^c_t. P^c_t is the price of carbon that would evolve in a carbon market, thus it represents the marginal costs of abating carbon in the next best alternative for the company, i.e. it is the opportunity cost for sequestering carbon. A company would choose to invest in projects where the following condition holds (where *r* is the discount rate):

(3) $\sum_{0}^{X} C_t (1+r)^{-t} < \sum_{0}^{X} P_t^c S_t (1+r)^{-t}$

Assuming that the price of carbon rises at a rate of "g" over time, this equation becomes:

$$\text{(3a)}\quad \sum_{0}^{X} C_t(1+r)^{-t} < \sum_{0}^{X} P_0^c(1+g)^t S_t(1+r)^{-t}$$

$$\text{(3b)}\quad \sum_{0}^{X} C_t(1+r)^{-t} < P_0^c \sum_{0}^{X} S_t\left(\frac{(1+g)}{(1+r)}\right)^t$$

Under this assumption, one would invest in the project if the discounted costs divided by the net discounted carbon gains are less than the current price of carbon.

$$\text{(4)}\quad \frac{\sum_{0}^{X} C_t(1+r)^{-t}}{\sum_{0}^{X} S_t\left(\frac{(1+g)}{(1+r)}\right)^t} < P_0^c$$

Note that for this analysis, no salvage value is assumed, thus the landowner retains the rights to the carbon. Further, the company that purchased the sequestration over the period of time in question must continue to hold sequestered tons beyond the project period, X, equal to the undiscounted stream of S_t. Companies may choose to renegotiate their contracts with existing landowners, purchase new contracts, or abate carbon on their own, depending on the relative costs of other alternatives, at the end of the term of the contract.

As can be seen in equation (4), if g is 0, carbon flows can be discounted at financial discount rates and the costs per ton can be compared to the current opportunity costs of carbon sequestration. Alternatively, one could assume that carbon is discounted with social discount rates to determine the present value of carbon. Social discount rates for carbon could be appropriate for long term problems like climate change where damages occur in the very far distant future. The carbon analysis uses a social discount rate of 3% for carbon. Costs are discounted at 6%.

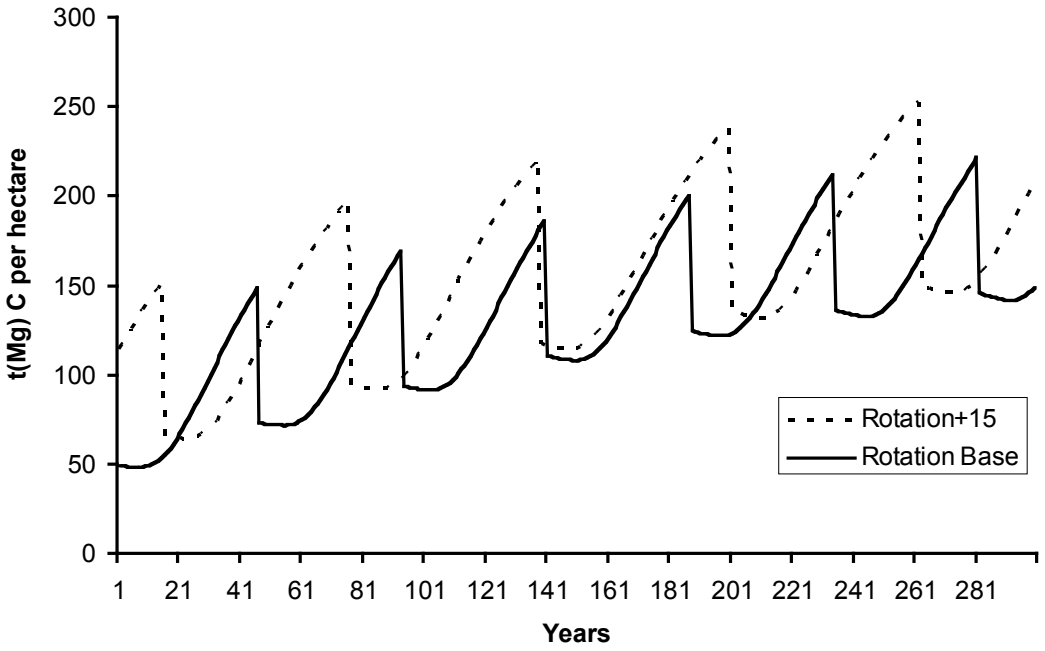


Figure 3-1. Comparison of total carbon storage on the landscape and in forest products over a 300 year period for a high site Douglas Fir stand in western Washington.

To get a sense for the potential carbon flows associated with projects that might arise in Washington, Figure 3-1 compares the baseline rotation with the 15-year extended rotation for a high site Douglas Fir stand in western Washington. Carbon gains are calculated by comparing the differences in the stocks with these two rotations, and then calculating the annual change in this difference. This credits the lengthened rotation for maintaining the stock initially and avoiding an emission, and it credits future storage of timber products. It also debits the lengthened rotation for delaying the faster earlier growing period, and for emitting some carbon at harvest time. The stream of incremental carbon gains or losses are discounted to determine the net present value of the gain in carbon associated with aging a forest additional years.

3.2.2 Data used in the analysis

3.2.2.1 Inventory and yield function parameters

These data are obtained from the USDA Forest Service Forest Inventory and Analysis database (USDA Forest Service, FIA), FIA Mapmaker version 1.7. The most recent complete periodic inventory for Washington is used, namely, data from cycle 3 collected in 1991. The data are unfortunately somewhat dated, however, the 1991 periodic inventory is the most recent complete inventory for the state. Data were downloaded on the age class distribution of forest types, and the proportion in different site classes.

Individual yield functions for RPA timber types in the region were estimated based on information on growing stock and acres in different age classes. RPA timber types are aggregates based on dominant species. Many stands will contain additional species. The values of these additional species can have important effects on site value, thus corrections for

the mix of species present in each RPA timber type were carried out when the marginal value of stands (i.e. the price) is calculated. All yield information is originally estimated in m^3 per hectare. The functional form of the yield function is assumed to be as follows:

(5) Yield (m^3/hectare) = exp(a – b/age)

Yield function parameters for Washington used in this analysis are shown in Table 3-1.

Table 3-1. Estimated yield function parameters or Washington. Yield at 120 years using the parameters and the maximum yield observed in FIA data is shown.

Forest type	Parameter a	Parameter b	Yield at 120 yr from parameter	Maximum Yield in FIA data
			m^3/ha	
Douglas Fir High	7.20	70	747.4	662.4
Douglas Fir Medium	6.85	60	572.5	626.3
Douglas Fir Low	6.35	80	293.9	280.5
Ponderosa Pine Med	5.90	60	221.4	240.5
Ponderosa Pine Low	5.45	50	153.4	184.9
Fir/Spruce Med	5.70	50	197.0	304.0
Fir/Spruce Low	6.00	50	266.0	385.7
Hemlock/Spruce High	6.95	40	747.4	978.0
Hemlock/Spruce Med.	6.80	55	567.7	518.9
Hemlock/Spruce Low	6.30	58	335.9	466.8
Lodgepole Avg	5.85	75	185.9	306.5
Hardwood Average	6.15	35	468.7	429.2

Table 3-2. Parameters used to calculate sawtimber proportion of stands for Washington.

	Parameters		
Forest type	**A**	**B**	**C**
Douglas fir	3	0.05	20
Pond. Pine	3	0.03	20
Fir/Spruce	2.5	0.03	20
Hemlock/Spruce	3	0.03	20
Lodgepole	2.5	0.02	20
Hardwood	1	0.02	20

In addition to determining the growing stock volume, it is important also to estimate the proportion of growing stock used for sawtimber and pulpwood. For this, we utilize USDA Forest Service FIA data that defines the proportion of growing stock that is sawtimber quality to develop the relationship between stand age and sawtimber proportion. The relationship used in this analysis is:

(6) Sawtimber % = 0 if Age < C

= A*(1-EXP(-B*(Age-C)))^4 if Age > C

In addition to the information presented in equation (6), we impose an additional constraint that the sawtimber proportion cannot exceed 85%. Parameters used to estimate the sawtimber proportion for this analysis are given in Table 3-2.

3.2.2.2 Price data

Prices were obtained from the Washington Department of Natural Resources (Tony Ifie, *personal communication*) for the year 2005. Prices are available for a number of different species, and for a range of grades. For this analysis, we assume that an average price for each species is approximated by grade "3S." To determine stumpage prices, we assume that logging and hauling costs are $200 per thousand board feet (MBF; approximately $34 per m^3). As noted above, the analysis is based on RPA timber types, which are often composed of multiple species. That is, stands likely have multiple species within them, although they may be classified into a "dominant type." Because we have prices for individual species, we estimate weighted average prices for RPA timber types by using information on the proportion of each species within each RPA timber type. The resulting weighted average prices for Washington RPA timber types are shown in Table 3-3.

Table 3-3. Timber prices for RPA timber types in Washington (2005)

	R1 (West-side)	R2 (Columbia)	R4 (East-side)
		$ per m^3	
Douglas fir & Larch	$52.63	$59.21	$44.57
Ponderosa Pine	$30.14	$31.46	$40.30
Fir - Spruce	$33.75	$36.19	$33.53
Hemlock-Sitka	$36.56	$46.89	$36.68
Lodgepole	$31.75	$42.49	$33.40
Red Alder	$55.06	$57.51	$53.57
Other HWDS	$54.97	$57.42	$53.48
Pulp and Miscell.	$1.83	$1.83	$1.83

3.2.2.3 Cost data

Costs for regeneration and timberland management in Washington are estimated to be approximately $1,396 per hectare on average for industrial and non-industrial private land. These data were obtained from sources in Oregon (Jim Cathcart, *personal communication*), and were approved for use in this Washington analysis by Tony Ifie (Washington Department of Natural Resources). Specific cost categories are shown in Table 3-4.

Table 3-4. Regeneration cost estimates for Washington

	$$/acre	$$/ha
Private Industrial		
Site Prep	$90	$222
Seedlings	$110	$272
Planting Labor	$110	$272
Veg. Mgmt	$130	$321
Interplanting/Contingencies	$10	$25
Administration	$20	$49
TOTAL	$470	$1,161
Private non-industrial	$660	$1,630
Average	$565	$1,396

3.2.2.4 Taxes

There are three "taxes" on forestland in Washington, according to the Washington Department of Revenue. First, the state levies an excise tax on forests when they are harvested. The excise tax is 5% of the value of the stumpage harvested. Second, the value of bare forestland is taxed at the local millage rate. Bare land values for forestland, as well as county level average land tax rates ($ per $1000 value) were obtained from the Washington Department of Revenue to estimate annual average taxes on each hectare of forestland in different regions. Third, there is a special fire assessment, amounting to approximately $0.72 per hectare on the west-side of the Cascades, and $0.67 per hectare on the east-side of the Cascades. Based on the last two categories of taxes, the annual per hectare tax rate is shown in Table 3-5. The excise tax is incorporated into the spreadsheet used to calculate opportunity costs and is not shown in the table.

Table 3-5. Tax rates used in Washington ($ per hectare per year)

Site Class	West-side WA	Columbia	East-side WA
High	$5.84	$6.04	$5.97
Med	$4.04	$4.17	$4.13
Low	$1.89	$1.94	$1.92

3.2.2.5 Biomass/carbon data

Biomass conversion factors from Smith et al. (2003) are used in this analysis. Only aboveground carbon in live biomass is counted in the analysis. The functional form used to estimate biomass is (parameters for different species are given in Table 3-6):

$$\text{Carbon (tons/hectare)} = 0.5*(E*(F+(1-EXP(-\text{Yield}/G))))$$

Table 3-6. Carbon biomass parameters (from Smith et al., 2003). All parameters are specific to the RPA type for all of Washington, although specific site classes are used to calculate growing stock volume (GSV) and carbon at 70 years.

	Parameters			GSV at	Carbon at
Forest type	E	F	G	70 years	70 years
				m^3/ha	t/hectare
Douglas fir (Med)	984.2	0.0185	1251.5	362.4	132.8
Pond. Pine (Med)	312.80	0.02	331.20	109.9	46.9
Fir/Spruce (Med)	658.80	0.02	757.60	146.3	63.2
Hemlock/Spruce (Med)	658.80	0.02	757.60	462.1	155.7
Lodgepole (Med)	303.40	0.02	390.50	134.3	47.1
Hardwood (Med)	2318.00	0.01	4085.20	284.3	90.8

Carbon stocks in products are tracked using rates suggested by Row and Phelps (1996) and Winjum et al. (1998). First, we assume that when a softwood stand is harvested, 43% enters products and 57% is emitted immediately, either on-site through decomposition of deadwood or through use in the energy sector. Second, solidwood products are assumed to turn over at a rate of 0.5% per year and release carbon, while pulpwood turns over at a rate of 1% per year.

3.2.3 Results: estimated marginal costs of carbon sequestration through extending rotations

Table 3-7 presents the marginal costs, and the carbon gains associated with holding carbon for 5, 10 or 15 years longer than the optimal rotation period for permanent changes in rotations. The results are shown for all site classes and a single pricing region in Washington. Differences in marginal costs arise from differences in initial rotation ages, prices, and yield functions for different site classes and species. The total amount of carbon available for sequestration on private timberland in Washington is shown in Table 3-8. The total is derived by summing the marginal costs and t C/ha for each site class and timber type in each county. Only softwood timberland that is 40 – 60 years old according to the USDA Forest Service FIA database is included in the analysis. Future contracts could be established on younger stands, but currently merchantable age classes are deemed to be the most appropriate for aging at the current time. Only private and non-Forest Service lands are analyzed here as Forest Service lands are excluded from the forest inventories.

Table 3-7. Net carbon sequestered and $ per ton for increasing rotation ages 5 – 10 - 15 years above economically optimal rotation ages in Washington (west-side of Cascades)

	t C per hectare			$ per t C		
	5 years	10 years	15 years	5 years	10 years	15 years
Doug. Fir Hi	18.0	32.1	43.2	$95	$110	$125
Doug. Fir Med	15.0	26.6	35.6	$100	$115	$120
Doug. Fir Low	7.8	14.2	19.2	$60	$70	$80
P. Pine Hi	7.3	12.9	17.2	$65	$70	$70
P. Pine Med.	5.5	9.6	12.8	$70	$70	$75
Fir/Spruce Hi	7.5	13.0	17.2	$60	$85	$85
Fir/Spruce Low	9.7	16.7	22.0	$60	$80	$80
Hem/Spr. Hi	18.7	32.0	42.2	$150	$155	$160
Hem/Spr. Med	16.6	29.0	38.6	$115	$120	$125
Hem/Spr. Low	11.3	19.8	26.4	$95	$100	$102
Lodgepole	6.3	11.0	14.6	$10	$60	$65
Red Alder	7.6	13.2	17.4	$15	$15	$15

*P. pine=ponderosa pine; Hem/Spr. = Hemlock/Spruce

Briefly, the results indicate that 443,665 hectares of private land in Washington are nearing the economically optimal rotation period. If all of this land were contracted to increase rotation ages by 15 years, 12.0 million t C could be sequestered for average costs of $136 per t C (Table 3-

8). The calculation for public land in Washington does not include USDA Forest Service land, but indicates that 147,625 hectares of public land are nearing economically optimal rotation ages and could be contracted for extending rotations. Contracts for 15-year extensions on these lands could provide up to 4.8 million additional tons of carbon for similar average costs (Table 3-8).

Table 3-8. Aggregate estimated carbon potential with holding timber past economically optimal rotation periods for Washington.

	Extension of rotation		
	5 yr.	**10 yr.**	**15 yr.**
Private Land Potential Hectares	443,665		
Million Tons	5.1	9.0	12.0
Million $$	$460	$894	$1,270
Average $$ per ton	$111	$125	$136
Average $$ per hectare	$1,036	$2,014	$2,862
Average Tons per hectare	11.5	20.3	27.0
Public Land Potential Hectares[1]	147,625		
Million Tons	2.0	3.6	4.8
Million $$	$203	$394	$564
Average $$ per ton	$111	$125	$136
Average $$ per hectare	$1,378	$2,672	$3,820
Average Tons per hectare	13.8	24.2	32.3

[1] Note that public land omits Federal USDA Forest Service lands.

A marginal cost curve for carbon sequestration through forest aging is presented for private lands in Figure 3-2. There are relatively few opportunities for less than $50 per t C. The least cost options overall tend to be red alder stands that are nearing economically optimal rotation ages. Figure 3-3 presents the distribution of carbon sequestration costs for 15 year rotation extensions in Washington. Lower cost opportunities tend to occur on the east side of the Cascades due to relatively lower site values for forests overall.

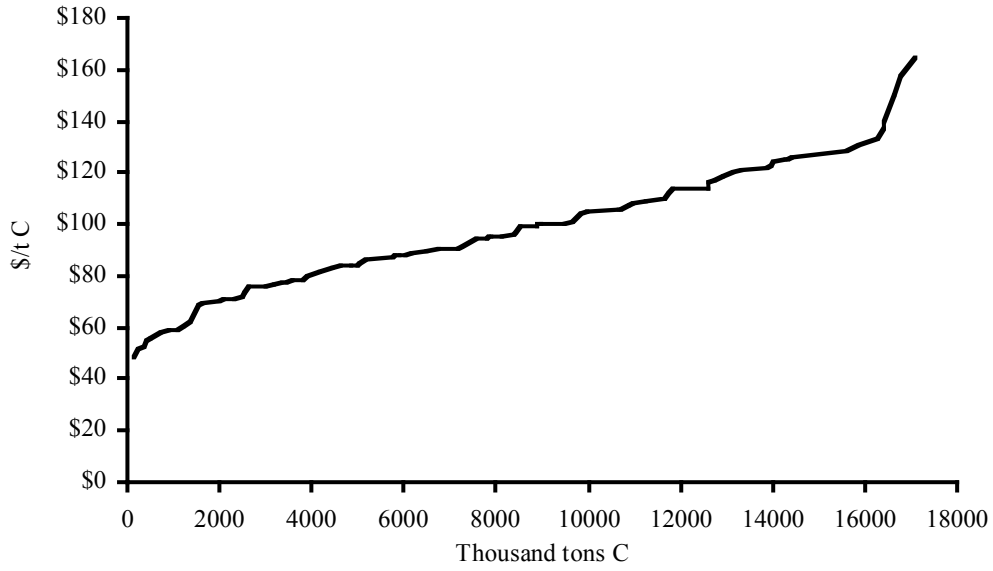


Figure 3-2. Marginal cost curves for carbon sequestration through aging, including 5, 10, and 15 year rotation extension periods in Washington..

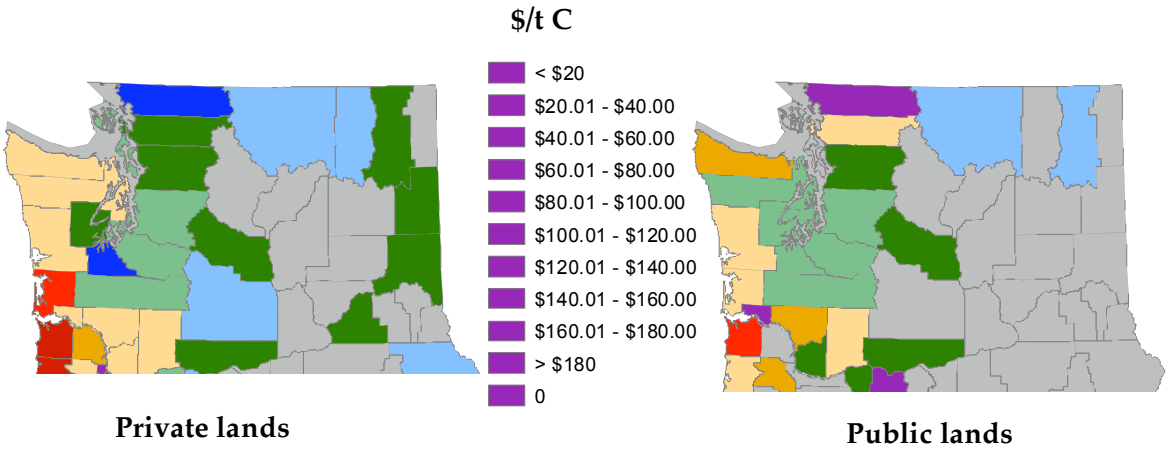


Figure 3-3. Distribution of the costs of carbon sequestration for extending rotations 15 years in Washington.

3.3 Conservation of timber land in extended riparian buffers

3.3.1 Methods and analyses

This section examines the potential for riparian zone management to increase carbon sequestration. For this analysis, it is assumed that 200' riparian buffers are required on all timberland in Washington. The costs of excluding currently mature timber from harvesting for the indefinite future are estimated. This means that the new riparian zones are treated as set-asides, and only economically mature timber at the current time are considered.

The potential carbon sequestration associated with setting aside timberland can be seen through Figure 3-4 below. The figure presents the carbon situation for a riparian zone set-aside (red line) versus harvesting that stand in the same rotation period indefinitely (blue line). For a stand that is initially near the rotation age of 47 years, if the stand is set aside, carbon accumulates along the red line from the year of the set-aside forward. If the stand is harvested, some carbon is stored in wood products and some is emitted initially. Over the entire time period analyzed , the set-aside stand holds more carbon than is held by the harvested stand. Although storage occurs in wood products, holding stands in set-asides appears to sequester more carbon in the long-run than harvesting forests – at least for these relatively productive Douglas Fir stands in Washington.

In this analysis, the carbon is discounted, such that early carbon gains are more valuable than future carbon gains. Thus, the set-aside stand holds more "present value" carbon than the harvested stand, even though these stands have similar average carbon storage in the longer run (i.e., > 400 years). The set-aside stand shown in Figure 3-4 is estimated to hold approximately 89 t of "present value" carbon.

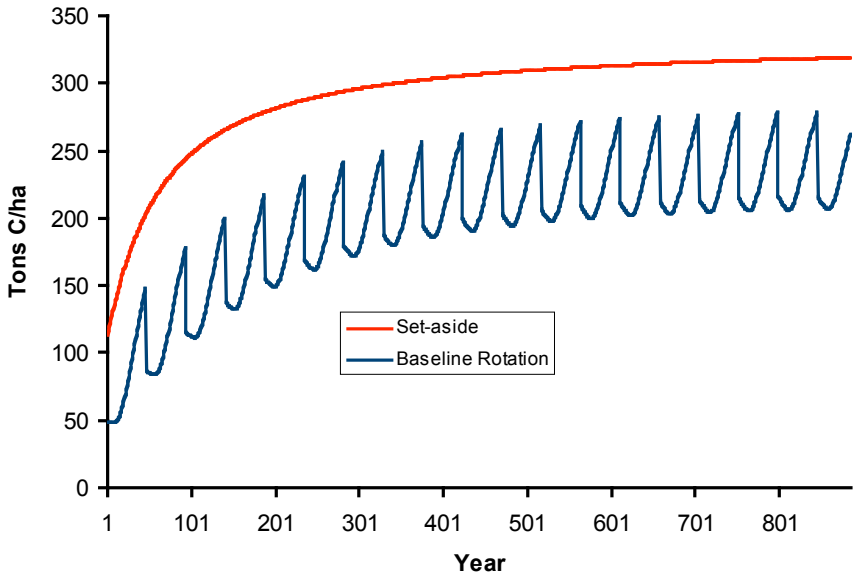


Figure 3-4. Tons carbon per hectare stored in above-ground biomass and products for the baseline (blue) and set-aside (red) for high site Douglas fir stands in Washington region 1.

Table 3-9 presents estimates of the tons of carbon gained and the costs for riparian zone protection in Washington. These estimates assume that the land would otherwise be harvested at economically optional rotation ages, and they assume that the harvests would occur in the relatively near future (i.e. the next 5 – 10 years). Carbon gains depend only on the site class, and thus are the same for each region (assuming the same site classes). The estimates of costs, however, differ due to differences in stumpage prices estimated for the different regions.

Table 3-9. Net carbon sequestered and costs in $ per ton for setting aside mature forests in riparian zones in Washington.

	T C per hectare All Regions	$ per t C		
		Region 1	Region 2	Region 4
Douglas Fir Hi	89.2	$130	$148	$115
Douglas Fir Med	69.6	$154	$175	$129
Douglas Fir Low	44.0	$99	$113	$83
Pond. Pine Hi	28.7	$114	$119	$156
Pond. Pine Med	20.5	$111	$116	$153
Fir/Spruce Hi/Med	28.1	$99	$100	$98
Fir/Spruce Low	35.7	$102	$110	$101
Hem/Sp Med	57.0	$238	$306	$239
Hem/Sp Med	62.0	$164	$211	$165
Hem/Sp Low	45.3	$127	$164	$127
Lodgepole	26.0	$59	$77	$62
Red Alder	25.3	$64	$66	$62

The total costs per hectare of setting aside timberland are estimated as the current stumpage value of mature timber on each hectare, assuming the timber is near the optimal rotation age, plus the present value of bare land. These estimates provide a lower bound estimate of what it would cost individuals interested in purchasing set-asides to negotiate with landowners for the rights to hold the timber on the land indefinitely, for example through a conservation easement. The costs per ton are estimated by dividing total tons gained into the total costs.

It is also useful to estimate how much land is available in riparian areas for protection. To accomplish this, stream lengths through different types of land uses in each county in the two states were estimated. The stream lengths through forested areas were extracted from these data, and used to estimate the total area of land in a set-aside encompassing an additional 100 feet of land on each side of the stream. The data included information on the types of forests, allowing us to attach the economic value and carbon sequestration estimates from the tables above directly to specific stream segments.

The estimates of costs and carbon sequestration assume that land is currently of merchantable age, however, the riparian area data did not distinguish age classes. It was therefore assumed that the riparian zones have the same distribution of age classes as the rest of forests in each county. Thus, the total stream length within in each county was adjusted to reflect the proportion in the county that is merchantable, according to the USDA Forest Service FIA data.

3.3.2 Results: marginal costs of carbon conservation in riparian buffers

The results of the analysis of potential costs of sequestering carbon through riparian zone set-asides are shown in Table 3-10. Currently, it is estimated that there are 14,119 hectares of mature forests in riparian zones within Washington. If these areas were set-aside, the estimated

costs would be approximately $5,268 per hectare, or $74.4 million in total. Approximately 610,000 t C could be sequestered with this action, for an average cost of $122 per t C. The distribution of costs by county is shown in Figure 3-5. As with holding timber longer than optimal rotation periods, costs tend to be lower in counties on the east-side of the Cascades due to lower overall site values, lower productivity and thus lower opportunity costs of not harvesting the timber.

Table 3-10. Estimated total area of riparian zones and total cost of protecting currently mature areas in Washington.

	Washington
Riparian Stream lengths (million meters)	23.2
Total Potential Area (hectares)	141,469
Mature Potential Area (hectares)	14,119
Total Carbon (million tons)	0.61
Total Cost (million $)	$74.4
Average Cost per ton ($/t C)	$122.33
Average Cost per hectare ($/ hectare)	$5,268

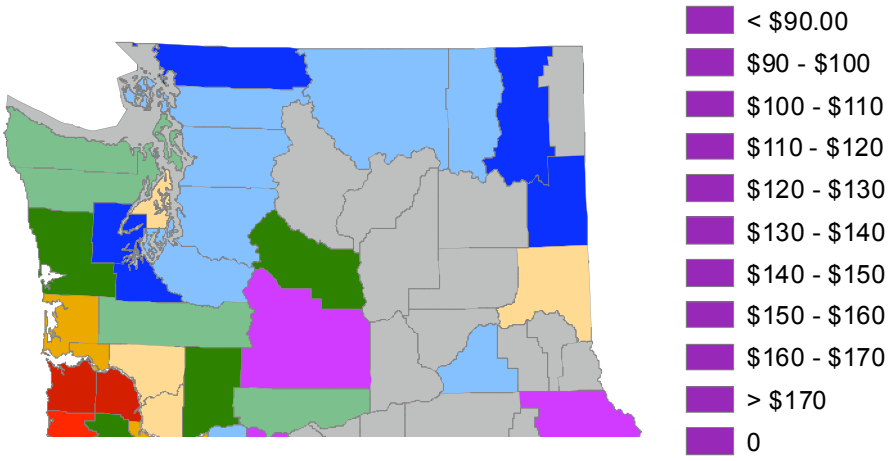


Figure 3-5. Costs of sequestering carbon in $/t C through expanding riparian zones in Washington.

4 Fuel load reduction on wildfire-prone areas

4.1 Introduction

Fires have a significant effect on carbon stocks in forests. Fire management techniques that reduce carbon emissions by reducing the risk of wildfire through removal of biomass fuels potentially offer an opportunity to reduce emissions and thus provide carbon dioxide emission reduction credits (henceforth, carbon credits). Not only would reductions in catastrophic forest

fires reduce carbon and non-CO_2 GHG emissions from burning, but the use of the biomass to generate electricity would offset emissions from fossil fuel-generated energy. The objective of this section is to produce a first-order approximation of the areas and carbon stocks of forests suitable for fuel reduction to reduce their fire risk, and their location relative to existing power plants.

4.1.1 Magnitude of the problem

The last century has seen the transformation of many western forest ecosystems from relatively open, healthy forests in which periodic low-intensity ground fire played an important ecosystem function, to densely stocked, fire-prone forests in which catastrophic crown fires burn hundreds of thousands of acres each fire season. This has resulted in escalating fire suppression budgets, loss of timber, wildlife, recreational and ecosystem values, lost property values, skyrocketing insurance costs, and loss of life. Fires appear to be increasing in size and intensity, resulting in greater losses of forest area and billions of tax dollars spent each year for fire control. As reported by the National Interagency Fire Center, 103,387 fires consumed 4.5 million acres in 1960; by the year 2000, 122,827 fires burned almost twice as much—8.4 million acres—while federal expenditures rose from $845 million in 1994 to $1.7 billion in 2002 (Figure 4-1).

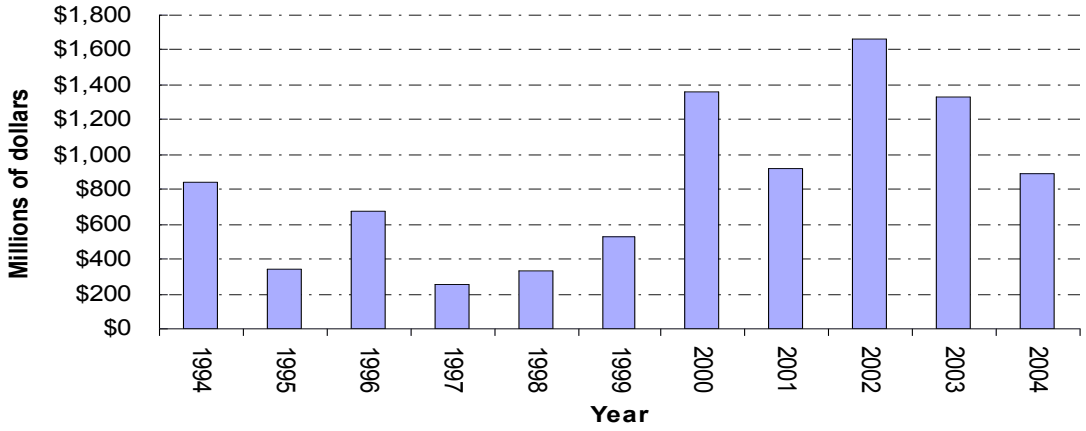


Figure 4-1. National Interagency Fire Center statistics showing federal expenditures in millions of dollars from 1994 to 2004.

The USDA Forest Service (USFS) in 1937 adopted policy of "fast, energetic and thorough suppression of all fires in all locations" (Chase 1989). A more recent scientific consensus suggests that low-intensity ground fire played a natural and important role in many Western forest ecosystems (e.g. Schoennagel et al 2004). Instead of having a healthy fire return interval of 15 or 20 years depending on forest type, a combination of logging, fire suppression and other factors have altered fire regimes and resulted in a fundamentally different forest landscape in which accumulated woody fuels create conditions for infrequent but intense and large-scale fires that can permanently alter ecosystems (Pyne et al 1996). This has led to a debate among landowners and public land managers about how to manage fire across boundaries, and how to

return natural low-intensity fire to these forest ecosystems – starting from a present condition of accumulated fuels that makes it impossible simply to forego fire suppression, let fires burn, or introduce prescribed fire without first undertaking treatments to reduce fuel loads. A national consensus is beginning to develop among government, industry, community and environmental stakeholders that something must be done to reduce fuel loads and return forests to more natural fire regimes; nonetheless, the problem is complex and the barriers to a large-scale solution are political, administrative, environmental, and perhaps most significantly economic. The necessary fuel reduction treatments tend to be labor-intensive and very costly, the value of the material removed relatively low, and agency budgets to pay for treatment increasingly constrained. Creative utilization strategies for understory biomass and small-diameter timber are needed, together with a broad portfolio of approaches and sources of revenue to offset the costs of fuel treatment.

A recent assessment of forests across 15 Western states, conducted under the auspices of the National Fire Plan, found that approximately 67 million acres are at moderate to high risk of wildfire (Fire Regime Condition Class 2 and 3) and 28 million acres at the highest risk level (FRCC 3) [2]. These figures include only those acres considered accessible for some type of treatment to reduce hazardous fuels. The 28 million acres in FRCC 3 could yield 345 million bone dry tons (BDT) in removals, with the greater proportion (70%) of the volume in larger diameter classes (over 7" considered merchantable sawtimber), but the greater number of stems in the < 7" submerchantable biomass category (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003). This hints at both the scale of the wildfire risk/hazardous fuels problem in the West, and one of the key economic barriers: a huge quantity of submerchantable material requiring treatment and/or removal to reduce fire risk, but constituting relatively little volume or value to pay the high cost of handling such a large number of stems.

In Washington alone, 8.5 million acres in FRCC 2 and 3 require hazardous fuel reduction and would yield an estimated 242 million BDT, of which 2.5 million acres are in FRCC 3 and would yield an estimated 63 million BDT (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003).

4.1.2 Approach and analysis of hazardous fuel reduction treatments

Decades of fire suppression practices, resulting in unnatural fuel accumulation and severe wildfire in western forests, are particularly associated with the dry ponderosa pine forest type (Schoennagel et al 2004). According to Schoennagel et al, dry ponderosa pine forests are in

[2] Fire Regime Condition Class (FRCC) is a measure of how much a forest has departed from natural wildland fire conditions (Schmidt et al 2002). The fire regime in Class 2 areas is moderately altered from the historical range; moderate levels of restoration treatments such as fire or mechanical treatments would be required to begin managing a more natural fire cycle. In Class 3 areas, fire regimes have been significantly altered and there is a high risk of losing key ecosystem components in a wildfire. Due to high fuel loadings, mechanical treatments are expected to be needed before the reintroduction of fire (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003).

urgent need of ecological restoration and fire mitigation. Historically, frequent and low-severity fire maintained open stands in low-elevation ponderosa pine; the surface fuel layer, dominated by grasses and needles, usually dries easily, resulting in frequent low-intensity surface fires. Disturbing this historical fire regime in these forests through fire suppression has resulted in build-up of ladder fuels at intermediate heights that carry ground fires into the crown, where they can lead to large, catastrophic fires. Mixed-severity fire regimes occur mostly at mid elevation, in forest stands with variable tree species and densities defined as mixed conifer forests. For these forests, accumulated fuel and climate affect the frequency, severity and size of fires. The impact of suppression practices on fuel loads in these forests varies depending on the tree composition of the forest stand. To restore historical stand structure of ponderosa pine and mixed conifer forests, mechanical HFR treatments are recommended.

A broad range of hazardous fuel reduction (HFR) treatments and technologies is available to address the fire risk problem. Prescribed fire is a relatively low-cost way to reduce fuel loading and ultimately perhaps the preferred treatment if the goal is to reintroduce fire into forest ecosystems. Prescribed fire is fairly constrained in its use today because of the potential for fire escape (especially at the wildland-urban interface), relatively short windows of appropriate conditions, and air quality and sediment yield concerns. Indeed, to treat FRCC 3 forest lands, prescribed fire is probably an option only following some mechanical treatment to reduce fuel loads (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003). One could envision a range of available HFR treatments, each with different constraints, costs, yield of merchantable and submerchantable material and thus revenues, air quality impacts, ground impacts, and greenhouse gas emission impacts (Figure 4-2, Table 4-1).

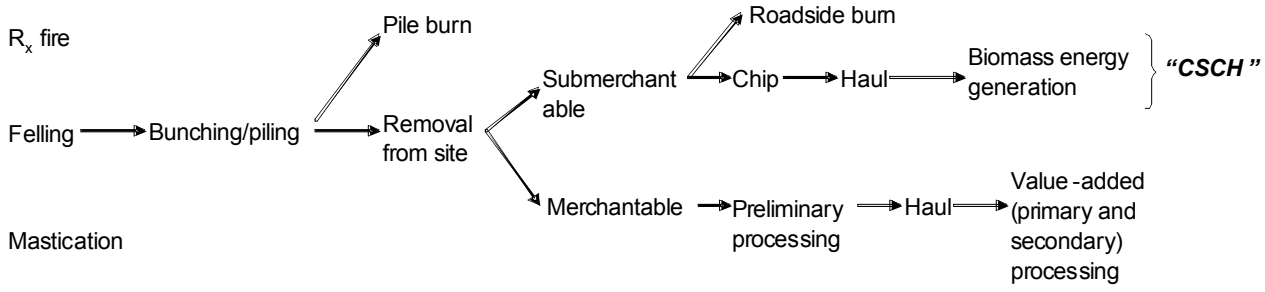


Figure 4-2. Schematic of potential HFR treatments (adapted from USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003).

Table 4-1. Benefits, constraints and representative costs for HFR treatments.

Hazardous fuels reduction treatment	Product yield	Benefits	Constraints	Representative costs
R_x fire	No	Less expensive, re-introduces fire	Air quality, ground impacts, fire escape (WUI), seasonal restrictions, immediate CO_2 emissions to atmosphere	\$35-300/acre, average \$92/acre[3] \$23-223/acre[4]
Masticate – leave on site	No	Efficient, useful for less accessible sites where fuel removal not a goal	Leaves fuel on site, gradual CO_2 emissions to atmosphere	\$100-1,000/acre[2]
Cut-pile-burn	No	Less expensive, can be used on inaccessible or steep sites	Leaves fuel on site, air quality, immediate CO_2 emissions to atmosphere	\$100-750/acre[2]
Cut-lop-scatter	No	Less expensive, can be used on inaccessible or steep sites	Leaves fuel on site, gradual CO_2 emissions to atmosphere	\$105-280/acre[5]
Cable yarding for biomass removal	Yes	Makes less accessible or steeper sites treatable	Expensive, ground impacts	\$80-130/CCF[4]
Cut-skid-chip-haul (for submerchantable biomass) *"CSCH"*	Yes	Removes fuel from site; some product value to offset costs; allows renewable energy generation; greatest CO_2	More expensive; limited to gentler slopes, areas closer to roads for removal, limited haul distance to biomass plant	\$34-48/BDT + haul cost \$0.35/BDT.mile[1] \$560-1,634/acre[6]

[3] USDA Forest Service Research & Development/Western Forestry Leadership Coalition, 2003.
[4] Chalmers and Hartsough, no date.
[5] Fight et al. 2004, Barbour et al 2004.

		benefit		
Cut-skid-process-load-haul (for merchantable)	Yes	Greatest product value to offset costs; removal of merchantable material may be necessary to reduce fire risk (Crowning Index) and meet spacing or forest health goals	More expensive; limited to gentler slopes, areas closer to roads for removal, limited haul distance to processing facility; environmental controversy / frequent litigation	Variable

The present analysis is confined to a single HFR treatment – cut-skid-chip-haul, or "CSCH" because this appears to be the practical way to remove fuel from the forest while at the same time being available for transportation to a biomass energy power plant. We attempt to estimate the total area of Washington forest lands with historically low-severity and mixed-severity (HLS-HMS) fire regimes, how much of this area meets a series of constraints making it feasible to treat using CSCH, how much biomass could be removed from this area using CSCH and be available to existing biomass power plants, and what might be the economics of using CSCH on those forested acres. Thus the focus is primarily on submerchantable biomass, and the use of forest fuels for generating heat and power in biomass energy facilities.

The approach chosen here is necessarily a simplification of the reality of HFR as practiced today, in which a variety of treatments can be applied for different locations, terrain, slope or other conditions. Perhaps most importantly, most HFR prescriptions call for a mix of submerchantable and merchantable material removal, both for economic reasons and to target a desired future forest condition that is defined in terms of residual spacing or basal area, residual fuel loading, reduced ladder fuels to prevent ground fires from moving into the crown, and reduced crown density or crown-touching to prevent crown fires from being sustained or spreading over long distances (Fried et al 2003). While diameter limits are sometimes applied, it is rarely appropriate to exclude all merchantable material to meet these desired future conditions. Accordingly, different treatment types, technologies, and product yield mean different economics of HFR and different types of sites that become treatable either in technical terms (e.g. treatments available for steep slopes) or in economic terms (e.g. treatments that yield more merchantable material, offsetting costs and allowing the contractor to remove more submerchantable biomass to reduce ladder fuels or treat lands on the margin of the maximum haul distance from a biomass energy facility). There is a large literature focused on the economics of different treatments, models to estimate costs of treatment (STHARVEST and others), and models to estimate quantities of biomass available from a given area or the best locations to site biomass energy facilities (FIA Biosum, Coordinated Resource Offering Protocol,

[6] Fried et al 2003.

and others) (Fight et al 2003, 2004; Fried, Barbour and Fight 2003; Fried et al 2002, 2003; Barbour et al 2001, 2004; Christensen et al 2002; Chalmers and Hartsough, no date; Mater 2005).

4.1.3 Objectives

The four primary objectives of this study are:

1) Identify areas of forestland in the state with HLS-HMS fire regimes.
2) Conduct a multi-criteria evaluation to identify forestlands with HLS-HMS fire regimes suitable for fuel removal. This analysis assigns a Suitability for Potential Fuel Reduction (SPFR) score to all forested areas, based on criteria affecting the feasibility of treating these lands, removing and transporting fuels for biomass energy generation.
3) Identify forested areas at risk for catastrophic wildfire that could be treated with "Cut-Skid-Chip-Haul" HFR treatment to mitigate potential extreme fire behavior and to restore these forests to their historical fire regime.
4) Assess how much biomass fuel this "Cut-Skid-Chip-Haul" HFR treatment might generate for use in power plants, and at what cost.

4.2 Results: forested land with historically low-severity and mixed-severity fire regimes

The first step in this analysis was to identify forest areas with HLS-HMS fire regimes that were suitable for fuel removal to restore their historical fire regimes. Forested areas were extracted from the Washington GAP analysis layer (USGS, GAP Analysis Program 2005). There were fifteen forest types recognized in the GAP dataset, dominated by mixed mesic coniferous forest, mesic Douglas-fir and ponderosa pine forests (Table 4-2; Figure 4-3).

Table 4-2. Distribution of forest area (ha) by forest type.

Forest type	Northwest Regional GAP Analysis category	Area (ha) statewide
Mixed Mesic	Mixed Mesic Coniferous Forest	3,088,400
	Mesic Mixed Forest	652,500
	Mesic Mixed Forest	652,500
	Deciduous Forested Riparian	321,500
	Mixed Riparian	68,600
	Coniferous Forested Riparian	4,800
Douglas fir	Mesic Douglas-fir	1,301,500
Ponderosa Pine	Ponderosa Pine	1,108,900
Subalpine	Mixed Subalpine Coniferous	620,600
	Subalpine Fir	20,400
Mixed Xeric	Xeric Douglas-fir	283,900

	Mixed Xeric Coniferous	236,400
	Xeric Mixed	106,400
	Xeric Deciduous	32,300
Mixed Coastal	Mixed Coastal	172,300
Mesic Deciduous	Mesic Deciduous	66,700

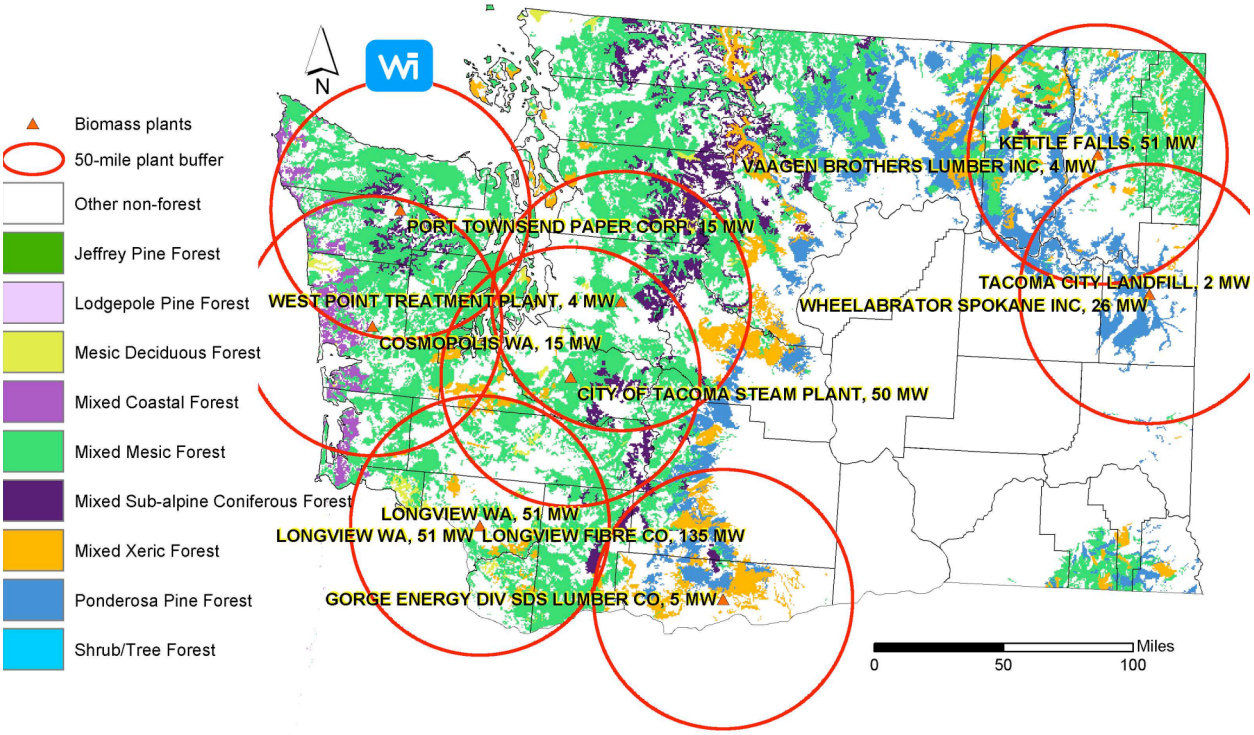


Figure 4-3. Map showing the forest classes for this analysis and names of Washington's biomass power plants and their electric power outputs (in MW).

For this analysis, forest areas with HLS-HMS regimes were identified based on a re-classification of the NW Regional GAP's classification used above. Two forest categories were recognized from the GAP analysis data: ponderosa pine forest and mixed xeric coniferous forest. The total area of ponderosa pine and mixed xeric coniferous forests in Washington was estimated at approximately 1.3 million hectares (Figure 4-4).

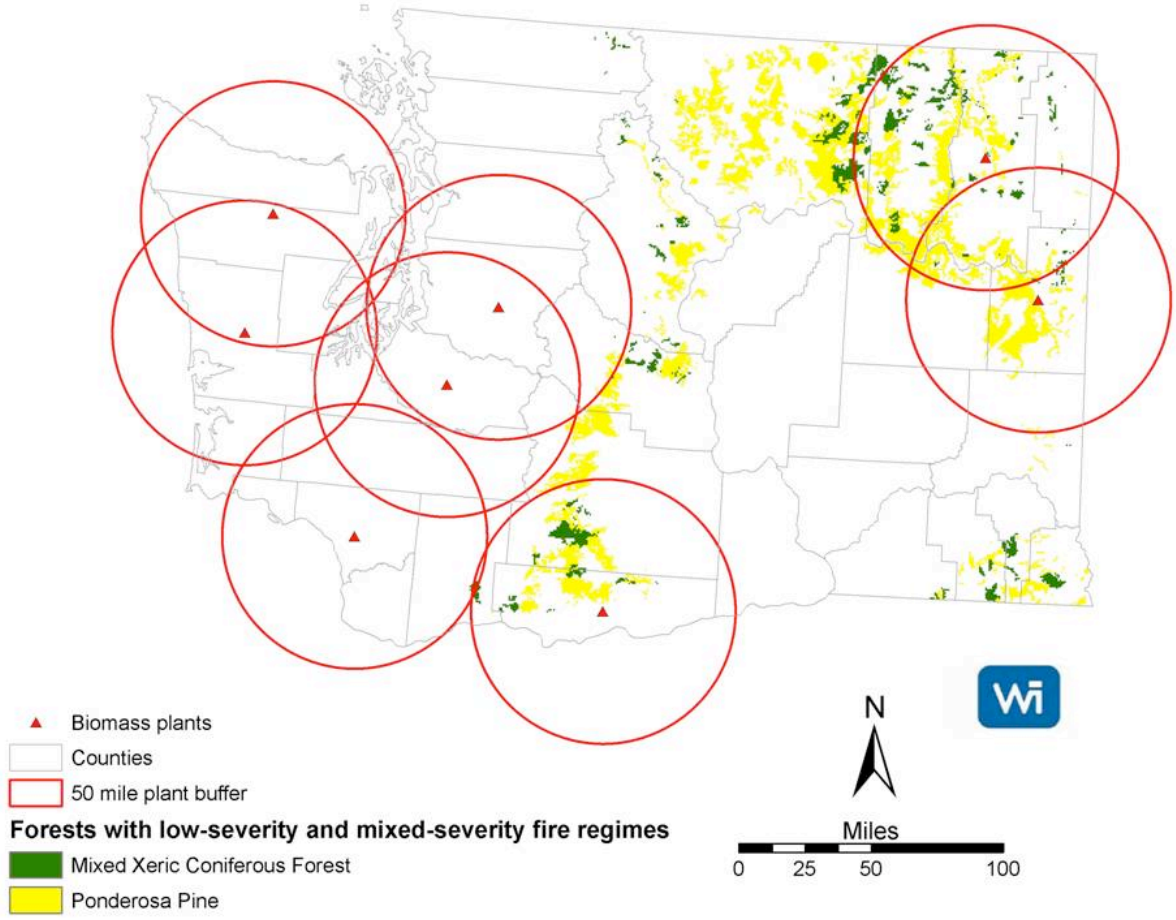


Figure 4-4. Map showing forestlands with low-severity and mixed severity fire regimes and locations of the biomass power plants in Washington State.

4.3 Results: suitability for potential fuel reduction

A multi-criteria evaluation was conducted to identify forestlands suitable for fuel removal. Three factor maps were used in the decision support tool for a Multi-Criteria Evaluation module (MCE): distance from roads, distance from power plants, and slope. The analysis was constrained to a radius of 50 miles from existing power plants, representing a general rule-of-thumb for maximum hauling distance for low-value biomass fuel. These factor maps were combined to create a single raster map showing Suitability for Potential Fuel Removal (SPFR) scores.

The first factor analyzed was distance from roads. A road layer for the Census 2000 TIGER Line was downloaded from the ESRI Data Disclaimer web site, including all major state, interstate highways and local roads statewide. Also, a railroad layer at scale 1:24,000 was downloaded from Washington State Department of Transportation (WSDOT 2005). Both transportation layers were combined to create a layer representing all roads. The Euclidean distance module in ArcView was used to create a distance map from the linear features of all roads. This map was standardized into a range from 0 to 255 using the "FUZZY" module in GIS software Idrisi Kilimanjaro (Eastman 2003), so that the starting point for most suitable areas was 100 meters

away from the roads to avoid a risk of fire close to roads. The greatest travel distance to reach a road was assigned the lowest suitability score (0), and the least travel distance the highest suitability score (255), indicating that as yarding distance increases, cost of removal increases and suitability for fuel removal thus decreases (Figure 4-5).

The second factor analyzed was slope. A slope map in degrees at 1,000 m resolution (same resolution as the FCCS layer) for the state of Washington was derived from a 30m DEM. Slope ranges between 0.0and 32.30 degrees for the state of Washington, and was standardized with a fuzzy classifier to range of 0 to 255, with 255 representing the gentlest slope (easiest access and least ground impact from fuel removal, thus most suitable) and 0 the steepest slope (least suitable) (Figure 4-5).

The third factor analyzed was distance from existing power plants. Locations of electricity generating facilities within the state of Washington with greater than 0 MWh annual biomass/wood net generation in 2000 were obtained from the Emissions & Generation Resource Integrated Database ("eGrid" -U.S. Environmental Protection Agency, 2003). A point file was created using the latitude and longitude information for each plant, then the Euclidean distance module in ArcView was used to create a distance map from the point locations of electricity generating plants. The distance map was standardized to a scale of 0 to 255, with the greatest travel distance to reach a power plant assigned the lowest suitability score (0) and the least travel distance the highest suitability score (255), indicating that as the distance to the nearest power plant increases, cost of hauling fuel increases and suitability for fuel removal thus decreases (Figure 4-5).

All three factor maps were used as inputs for the MCE module, a GIS decision making tool in Idrisi Kilimanjaro software. The output of this module was a SPFR score map on a standard scale from 0 to 255, where 0 represents the least suitable areas and 255 the most suitable areas for potential fuel reduction accounting for distance to roads, slope and distance to power plants (Figure 4-5).

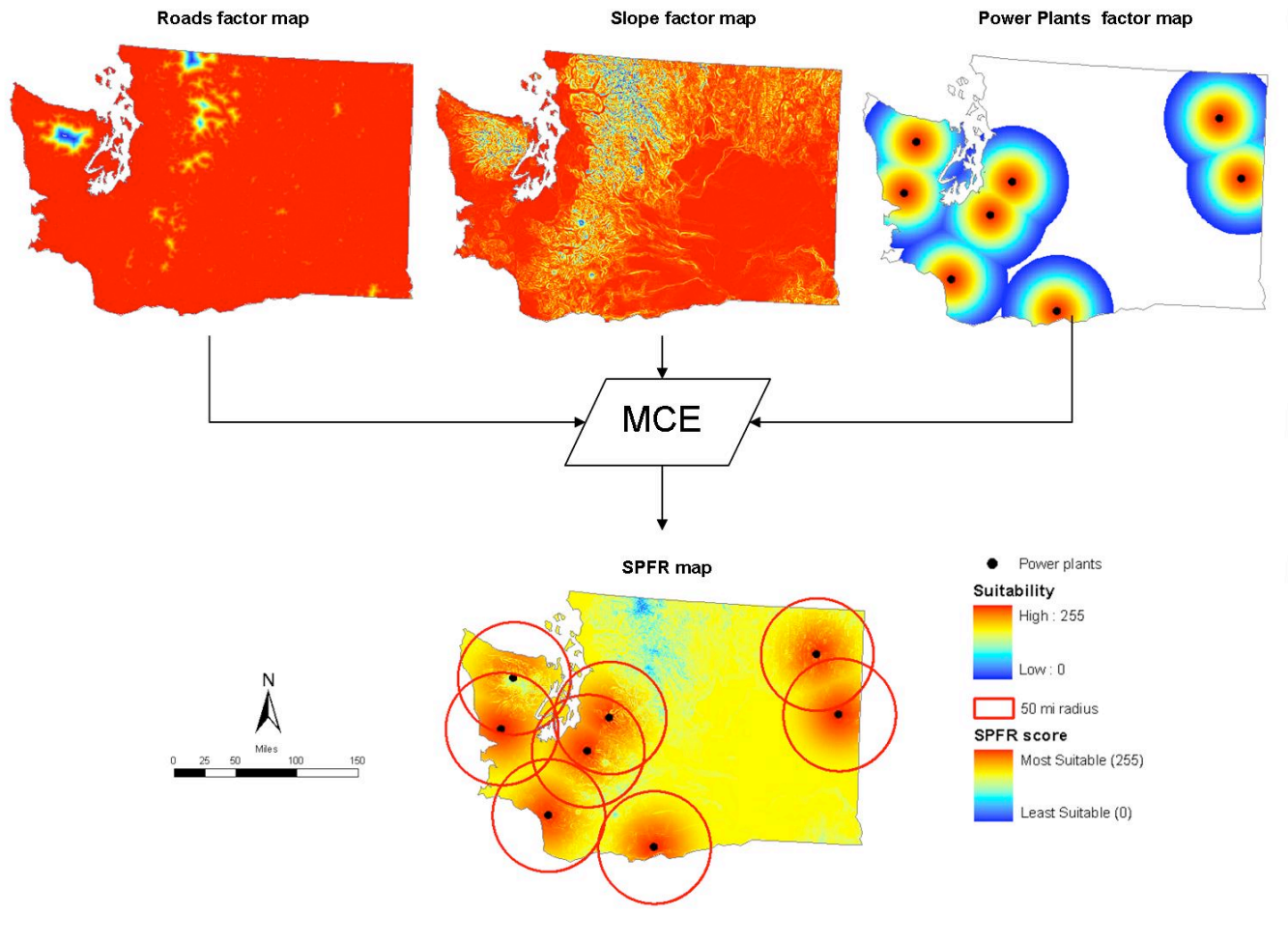


Figure 4-5. Suitability for Potential Fuel Removal (SPFR) scores for Washington, with highest suitability assigned to areas close to roads, on gentle slopes, and close to existing power plants.

The ranges of the SPFR scores for the forests with HLS-HMS fire regimes, and locations of the existing eight power plants in Washington and the buffer zone of 50 miles around them, are shown in Figure 4-6. The SPFR scores for Washington forests with HLS-HMS fire regimes indicated the suitability for treating these forestlands, removing and transporting the fuels to biomass energy generation facility, based on three factors: slope, distance from roads, and maximum distance of 50 miles from power plants. The highest suitability is assigned to forest close to roads and power plants, and on gentle slopes.

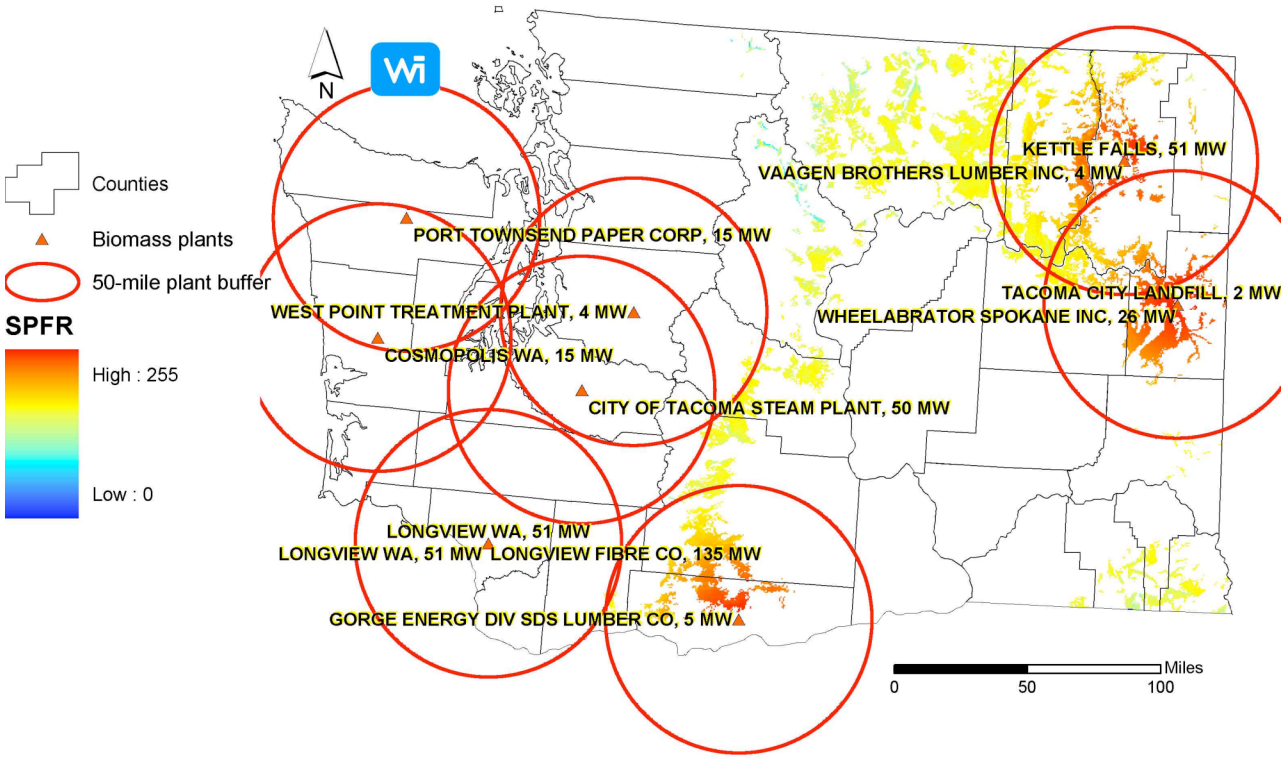


Figure 4-6. Suitability for Potential Fuel Reduction (SPFR) scores for Washington's forests with low-severity and mixed-severity fire regimes [NOTE: 50–mile radii and power outputs of existing biomass power plants].

4.4 Results: historically low-severity and mixed-severity fire regimes forests treatable with "CSCH"

4.4.1 Estimated biomass yield

In the third component of this analysis, we looked in more detail at one potential hazardous fuels treatment, "Cut-Skid-Chip-Haul" (CSCH), a treatment in which hazardous fuel is harvested in the woods, bunched and skidded to a landing, chipped into a chip van, and hauled to a biomass energy facility for electricity and/or heat generation. The objective was to assess the area of HLS-HMS fire regimes forestlands in the state to which this treatment could be applied, how much biomass fuel this might generate for use in power plants, and at what cost.

In this analysis, the following crucial constraints for CSCH treatment were considered for CSCH:

- Maximum slope constraint. Assumes only lands of < 40% slope may be treated with CSCH (Fight et al 2003; Fried et al 2002; Fried et al 2003; Fried, Barbour and Fight 2003). Steeper slopes may be treated in other ways (e.g. cut-pile-burn), but do not allow CSCH due to machinery and equipment access, ease of removal, and ground impacts from harvest and skidding.
- Maximum yarding distance constraint. Assumes only lands within 0.25 miles (400 meters) of existing roads may be treated with CSCH. This is used as a general rule of

thumb for the maximum distance low-value material would be skidded to a landing where a chipper and chip van is parked (Bob Rynearson, WM Beaty & Associates, pers comm. September 2005).

- Maximum haul distance constraint. Assumes only lands within 50 miles of existing power plants may be treated with CSCH due to transport cost. This maximum haul distance may be considerably affected by the volume/value of merchantable material in the prescription, but for a simplified CSCH treatment targeting only low-value submerchantable material, it is assumed that haul distance cannot exceed 50 miles.
- Minimum block size to justify move-in costs of equipment and personnel. A general rule of thumb is that a treatment block must be at least 80-100 acres to justify move-in costs, although this number may be slightly less if equipment is already sited nearby for another project (Bob Rynearson, WM Beaty & Associates, pers comm. September 2005).

Constraints were applied sequentially so that only lands meeting all constraints were available for CSCH treatment. Forests with HLS-HMS fire regimes were superimposed on a slope map and all forestlands of > 40 % slope were excluded (Figure 4-7 A). To meet the requirement of maximum 0.25 miles yarding distance, a buffer layer was created, rasterized and overlain with the HLS-HMS fire regime forests on gentle slopes to exclude any lands further than 0.25 miles from roads (Figure 4-7 B). Finally, the constraint map of 50 mile radii from existing power plants was overlaid on the earlier maps to exclude forests beyond this haul distance (Figure 4-7 C).

The fourth constraint of minimum block size proved difficult to apply when the analysis was conducted. In theory it would be possible to exclude as uneconomic all lands, meeting the three above constraints, but without sufficient contiguous area to meet a minimum 80- or 100-acre minimum treatment block constraint. However, the 1,000-meter level of resolution that the analysis was originally conducted at meant that a single pixel represented 100 hectares or 247 acres, so it was not possible to exclude blocks of only 80-100 acres. Only at a later date would the 1,000-meter pixel data be eliminated from the analysis[7] allowing 30-meter resolution analysis. The WESTCARB Phase II project anticipates application of this constraint in further characterization of opportunities at the finer-scale analyses of the pilot project sites.

Applying sequential factors of slope, yarding distance and 50-mile radius from existing power plants to forestlands with HLS-HMS fire regimes resulted in an estimate of approximately **500 thousand hectares** of dry ponderosa pine and mixed xeric coniferous forests that would be available for CSCH treatment (Figure 4-7.

[7] A 1,000-meter grid cell 'fuel characteristic class system' (FCCS) GIS layer, developed by the Fire and Environmental Research Applications team (FERA) of the USDA Forest Service - Pacific Northwest Research Station - Pacific Wildland Fire Sciences Laboratory, was originally used to identify fuel beds that had moderate and high fire behavior potential and were at high wildfire risk. Subsequent and later reviews indicated that assumptions about forest species compositions as supported by Schoennagel et al (2004) were sufficient for mapping fire risk.

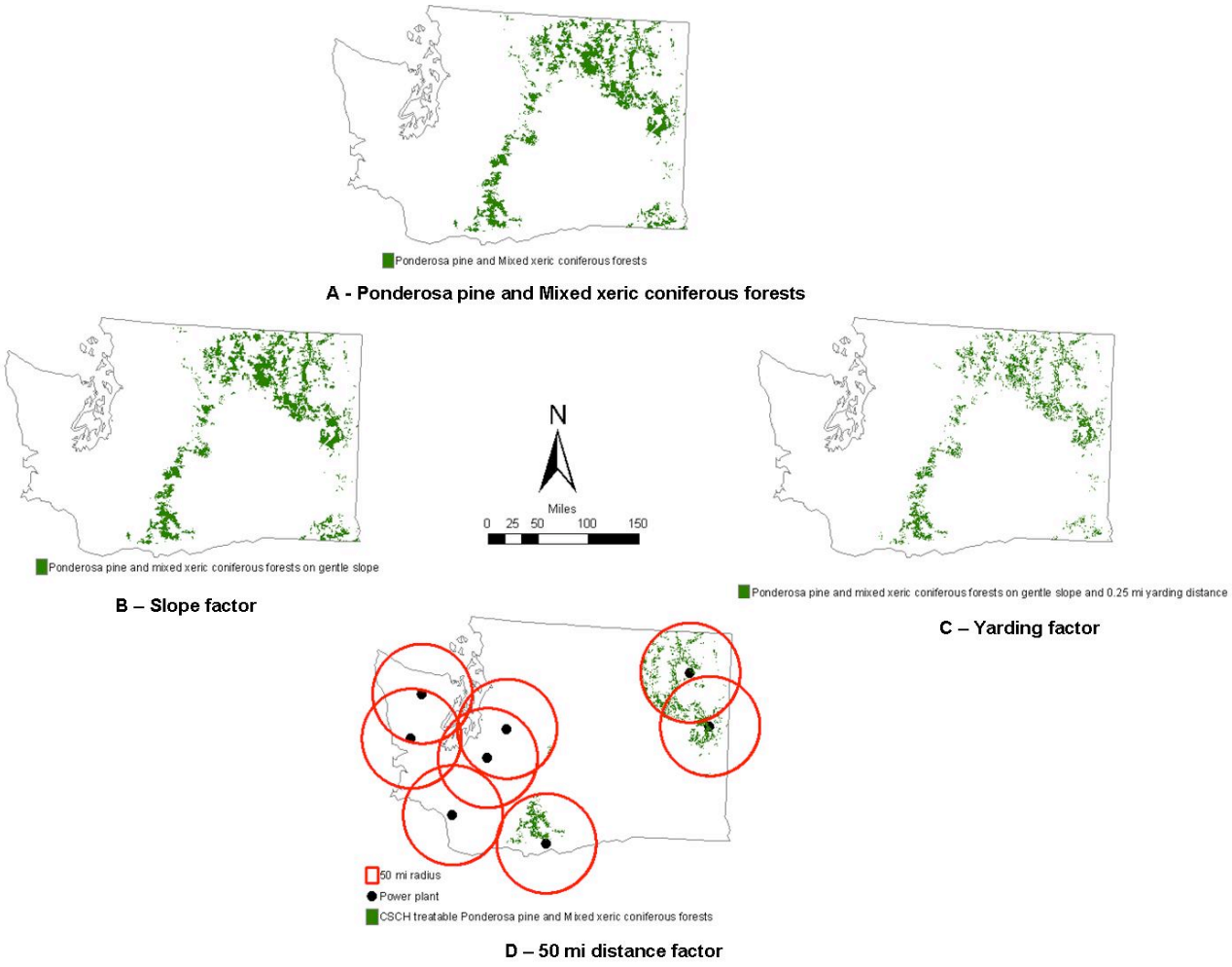


Figure 4-7. Critical factors to determine forest lands with low-severity and mixed-severity fire regimes, suitable for CSCH fuel treatment: A – Ponderosa pine and mixed xeric coniferous forest in Washington; B – Slope less than 40%; C- Yarding distance less than 0.25mi; D- Distance from existing biomass power plants less than 50 miles.

Considering only lands meeting all these constraints, the total area accessible for CSCH across Washington's forestlands with HLS-HMS fire regimes would be approximately **500 thousand hectares**. Available biomass (short tons/acre) for each fuelbed was calculated from the FCCS data set using the available fuel potential index (dimension/scaled) multiplied by 10 (David Sandberg, USDA Forest Service - Pacific Northwest Research Station, pers. comm. August 2005). The available biomass (short tons/ac re) was multiplied by 1.016 to convert to metric tons, and then divided by 0.4 to convert to available biomass (BDT/ha) [8] The total biomass stocking, including trees, accessible for CSCH treatment, would be approximately 39 million BDT.

[8] All numbers are reported in hectares. To convert ha to acres, multiply by 2.47. To convert BDT/ha into BDT/acre, multiply by 0.4.

The total fuel available for removal would be much less than this quantity, as not all biomass on the land will be removed through treatment. Actual percent removal will be highly variable by stand, pre-treatment condition and desired future condition (D. Goehring and D. McCall, PG&E Natural Resources, pers comm. September 2005), making it difficult to assign a percent removal across a broad scale such as a state or region. Over the landscape as a whole, more than 50% removal of the pre-treatment fuel loading may be needed to significantly reduce fire risk (Torching Index and/or Crowning Index; Fried et al. 2002, 2003). Furthermore, more than 50% removal, as a landscape average, is likely to be needed to reach a stand-level residual basal area of 80-125 ft^2/acre, often used in HFR prescription scenarios (Fried et al. 2002). A 15-state strategic assessment of fuels reduction assumed a removal prescription of reducing stand density to 30% of maximum Stand Density Index (SDI) for a given stand, or averaged across the landscape, 70% reduction in SDI (USDA Forest Service Research & Development/ Western Forestry Leadership Coalition 2003).

Given the uncertainty in fuel available for removal, two scenarios were considered to help understand the relationship between potential fuel removal and the subsequent carbon benefits associated with that removal. The first scenario assumed that regardless of pre-treatment condition and desired future condition of the forest stand, the CSCH will remove 10 BDT biomass per hectare (4 BDT/ac). The second scenario assumed that 20 BDT biomass per hectare (8 BDT/ac) will be removed.

In the first scenario, biomass of **approximately 5 million BDT** would be available to biomass energy facilities in Washington from CSCH treatments to reduce fire risk on approximately 500 thousand ha forest lands. This implies an initial loss of forest carbon due to HFR treatment of approximately 2.5 million t C [9] -- although this initial loss is obviously offset by potentially great savings in CO_2 and non-CO_2 greenhouse gas emissions due to reduction in the probability, severity and extent of wildfire attributable to the HFR treatment. The second scenario results in **approximately 10 million BDT** available biomass associated with approximately 5 million t C initial removals. The total carbon stocks for the Washington forest with HLS-HMS fire regimes is approximately 18.5 million t C for the forest area with information from the FCCS dataset on the Available Fuel Potential index.

4.4.2 Economic analysis and potential role of carbon emission reduction credits

Costs for CSCH range widely depending on the treatment prescription, presence or absence of merchantable material in the prescription, region of the country, and the factors identified above (slope, yarding distance, haul distance, etc.). Here the values quoted in a recent broad-scale strategic assessment covering 15 states and a wide range of experience with HFR were use as a guide: the treatment analogous to CSCH had a cost range of $34-48/BDT (USDA Forest Service Research & Development/Western Forestry Leadership Coalition 2003). Assuming from above that biomass of approximately 5 million BDT would be removed from the forest lands in scenario 1, treating all these forest lands would have a total cost of approximately $168 million (low) to approximately $238 million (high). Treating these forest lands in scenario 2 would have a cost of approximately $337 million (low) to approximately $475 million (high).

[9] Carbon stocks are calculated as 50% of biomass.

The value of this biomass for purchase by biomass facilities may be estimated at $36/BDT (Fried et al. 2003), although market prices for fuel will vary somewhat by region depending on the number of biomass plants in operation and thus competition for fuel. For both scenarios, we estimate the amount of revenue that CSCH on the forest lands in question would generate, and/or subsidy required, to remove the available biomass to biomass energy facilities.

In the first scenario, with removal of approximately 5 million BDT biomass from Washington forest lands with HLS-HMS fire regimes, the fuel would have a value of approximately $178 million, and thus range from generating a net revenue of approximately $10 million (if value = $36/BDT and cost = $34/BDT), to requiring a total subsidy of approximately $59 million to treat all these lands (if value = $36/BDT and cost = $48/BDT). In the second scenario, with removal of approximately 10 million BDT biomass, the fuel would have a value of approximately $357 million, and thus range from generating a net revenue of approximately $20 million (if value = $36/BDT and cost = $34/BDT), to requiring a total subsidy of approximately $119 million to treat all these lands (if value = $36/BDT and cost = $48/BDT).

To attempt to investigate whether removal of hazardous fuel that results in reduced fire intensity and reduced carbon emissions (i.e. conservation of forest carbon stocks) makes economic sense, the following first-order calculations are presented. Assuming the higher costs for biomass removal as described above, to treat the 500 thousand ha estimated to be treatable using CSCH would require a per-hectare subsidy of $120 ($59 million total subsidy divided by 500 thousand ha) for removal of 10 BDT/ha, or $240 ($119 million divided by 500 thousand ha) for removal of 20 BDT/ha. Assuming commonly used prices of CO_2, would emissions reductions attributable to HFR activities be sufficient so that the sale of carbon credits from these projects could cover the per-hectare subsidy required?

Depending upon the price of carbon assumed (two commonly used values are $2.40/t CO_2 and $10/t CO_2), the quantity of carbon emissions that would need to be reduced through HFR to cover the per-hectare subsidies needed – essentially, to make high-cost CSCH a break-even activity – varies from as little as about 3 t C/ha to as much as 27 t C/ha (Table 4-3). Whether HFR could produce this order of magnitude of emissions reductions depends on baseline emissions from fires of varying intensities, and whether HFR prior to fire reduces the intensity of fires. In an analysis conducted for this project, the differences between net carbon emissions from medium-intensity fires and low-intensity fires across all forest types in Washington ranged from 8 to 30 t C/ha; the difference in emissions between high-intensity and low-intensity fires ranged from 16 to 80 t C/ha (Brown and Kadyszewski, 2005b). In other words, if HFR resulted in low-intensity forest fires rather than medium-intensity fires, there would be a reduction in carbon emissions attributable to HFR of 8-30 t C/ha; if the reduction was from high-intensity to low-intensity fires, the reduction in emissions would be 16-80 t C/ha. The reduction in emissions attributable to HFR in order to cover the per-hectare subsidies required, 3-27 t C/ha, is well within this range for a change from medium- to low-intensity fires, and much lower for a change from high- to low-intensity fires. Thus it appears, in a preliminary analysis, that the order of magnitude in emissions reductions attributable to HFR, assuming commonly used prices for carbon offsets, is within the realm of practicality to cover subsidies needed for HFR – adding support to the argument for qualifying fuel reduction activities as carbon offset projects. It should be emphasized that this preliminary analysis needs further research and discussion, including collection of additional data on emissions from wildfires of

varying severity, and what reductions in fire severity and/or emissions should be attributable to pre-fire HFR treatment.

Table 4-3. Quantity of CO_2 emissions reductions (t CO_2/ha and t C/ha) that would need to be produced by HFR activities in order to cover estimated per-hectare subsidies needed for CSCH.

Subsidy	$2.4/t CO_2		$10/t CO_2	
	t CO_2/ha	t C/ha	t CO_2/ha	t C/ha
$120/ha	50	14	12	3
$240/ha	100	27	24	7

5. Next steps

This paper has presented the results of carbon supply analyses for several potential activities in Washington: afforestation of rangelands, afforestation of crop lands, changes in forest management including extending rotations and widening riparian buffers, and hazardous fuel reduction to reduce emissions from wildfire in fire-prone forest ecosystems. The final section outlines further characterization work that is needed, both to refine these analyses and to evaluate additional carbon sequestration opportunities for the state and region. The focus is on refinements to the analysis of fuel load reduction, and on afforestation using fast-growing species such as hybrid poplar as a means to sequester carbon and/or provide fuel for biomass energy generation.

5.1 Refinements to the analysis of carbon supply from fuel load reduction

The preliminary analysis presented in Section 4 highlights needs for further research, policy discussion, and consensus-building among the diverse stakeholders with an interest in forests and fire. Further research and analysis is needed, particularly in the following two areas.

5.1.1 Refinement #1: Analysis of other HFR treatment types

In reality a much greater range of treatment types than only CSCH (as used in this paper) is available for fuel reduction and/or removal. Each treatment type has its own ideal conditions for use, constraints on use, costs, product yield and thus revenue to offset costs, and environmental (air quality, sedimentary, and greenhouse gas emission) implications. Some treatments leave the fuel on site or simply change its form, but may be applied on sites that are relatively more inaccessible either from a technical (terrain, slope, distance to roads) or economic (hauling distance) point of view. Thus a more comprehensive model is needed to answer the questions:

- What factors in addition to slope, yarding distance, distance to biomass plants determine the choice of treatment type and technology—minimum size of treatment block to justify move-in costs, mix of diameter classes to be removed, volume and number of stems in the submerchantable and merchantable categories, distance to processing facilities for merchantable material, other factors?

- What is an appropriate decision rule for each factor? In treating the slope factor, this analysis assumed CSCH could be applied on slopes < 40%. An analysis based on meeting constraints ignores the other side of each decision rule: excluding lands of > 40% slope or > 0.25 miles yarding distance only means these lands are not available for CSCH, not that they are excluded from all HFR treatment. On slopes > 40% or at greater distance from roads, other treatments might be available that leave fuel on site but still reduce fire hazard (cut-pile-burn, cut-lop-scatter, prescribed fire etc.).
- What are commonly accepted cost ranges for each treatment type and technology, in $/acre or $/bone dry ton (BDT) for submerchantable material and $/MBF or $/CCF for merchantable?
- What revenues are available from utilization of submerchantable and merchantable material from these projects, and what effects do revenues have on the factors and decision rules used to select treatments? For example, by how much will a greater volume of merchantable material in the prescription increase the yarding distance or distance to a processing facility that is economically feasible?

Most HFR treatments in fact involve a mix of submerchantable and merchantable material, with the value of merchantable material sometimes "subsidizing" the high cost of removing a large number of submerchantable stems, and both submerchantable and merchantable being part of the prescription to achieve a desired condition of spacing, residual basal area per acre, improved forest health, improvement in Torching Index and Crowning Index, etc. Including merchantable material would make more acres accessible for treatment. Thus the estimates here, focusing only on one objective and a single treatment targeting the submerchantable biomass fuel, can be taken as conservative.

5.1.2 Refinement #2: GHG emissions from wildfire, and eligibility of HFR as a carbon offset activity

The suggestion that HFR might produce sufficient emissions reductions to pay for currently uneconomic CSCH treatments, if these emissions reductions were marketable at commonly used prices for CO_2 credits, is a starting point for further study. This suggestion was based on first-order estimates of the difference in CO_2 emissions between low-, medium- and high-intensity fires, and the assumption that HFR treatment might be credited with turning what would have been a high- or medium-intensity (perhaps crown) fire into a low-intensity (perhaps ground) fire. If so, the emission reductions could be credited to the HFR treatment and potentially marketed as a carbon-offset project.

To substantiate this hypothesis, several areas of study are needed. First, work is needed to develop baselines for various wildfire-prone forest types. These baselines will serve as the reference case against which activities to reduce fires would be compared to estimate the potential carbon credits. Such baselines need to include field data and models to quantify the likelihood of fires occurring (e.g. fire-return interval) as well as the effects of fire on greenhouse gas emissions for the forests under different intensities of fire (how much of carbon stock is burned by fire intensity and stand structure). Field data might include measurements of post-fire forest carbon stocks for comparison to unburned areas; measurements in past fires of varying intensities; measurements of areas where fuel loads were reduced prior to fire to quantify how much treatment reduced the loss of carbon stocks; and evaluation of non-CO_2

greenhouse gas emissions such as CH_4 and N_2O, also likely to be released in wildfires though to varying extents depending on the type and intensity of fires.

Second, further scientific research as well as policy discussion and consensus-building are needed around the question of what reductions in fire intensity and/or greenhouse gas emissions should be attributable to pre-fire HFR treatment. Intuitively reducing ladder fuels or crown density should reduce the probability, intensity, and extent of wildfires and thus the loss of forest carbon stocks and other greenhouse gas emissions; but by how much? With a probabilistic phenomenon such as fire, it is not possible to demonstrate that an area treated with HFR would have burned in the absence of treatment, and released X tons of CO_2 equivalent to the atmosphere; nor in the with-treatment scenario is the goal necessarily to avoid fire and its associated emissions, only to reduce the intensity of fire or its extent. Many fire models are currently in use to evaluate probability and impacts of fire under different assumptions, but these models produce highly variable outputs and consensus among models is lacking, and most do not address greenhouse gas emissions from fire. Therefore the process of deciding what types of HFR treatments should be eligible to qualify as carbon offset projects, and assigning values to the greenhouse gas emission reductions attributable to HFR, will involve considerable scientific as well as political consensus-building – even among stakeholders who more or less agree it would be desirable to reduce fuel loads and treat more acres by improving the overall economics of HFR through qualifying these projects for CO_2 credit markets.

Bringing this refinement together with the last, different HFR treatments and technologies could be evaluated in terms of their greenhouse gas emission impacts: for example, "CSCH" would be assigned a triple emission reduction benefit through reduced emissions from wildfire, reduced emissions from fossil fuel-generated electricity due to electricity generation in biomass facilities, and enhanced carbon sequestration in the residual forest stand. Prescribed fire or cut-pile-burn could be assigned a quantifiable benefit for reducing the incidence or intensity of wildfires, but would still put a greater portion of the forest carbon removed in the treatment into the atmosphere.

When potential utilization of both submerchantable biomass and merchantable material from HFR treatments is considered, emissions reduction credits become one of a set of values – along with merchantable material, biomass fuel value, green power incentives, and even other marketed ecosystem services enhanced by these treatments -- that would improve the overall economics of HFR and help federal, state and private landowners to mount a more effective response to the wildfire problem.

Finally, further work would then be needed to develop carbon accounting methods and field protocols for actually quantifying the potential carbon credits for a variety of fuel treatments by forest types. This calculation would include the reduction in greenhouse gas emissions from displacing some quantity (MWh) of electricity that would otherwise be generated using fossil fuels. Such methods and protocols would need to be cost effective, transparent, and reproducible.

These refinements will be addressed through additional field data collection, modeling, analysis, and stakeholder discussions in the second phase of the West Coast Regional Carbon Sequestration Partnership.

5.2 Evaluation of carbon sequestration potential through afforestation using fast-growing species and other forest management methods.

In the first phase of this work, the analysis of afforestation potential on rangelands and croplands looked only at the use of planting native species for forest restoration (see Section 2 above). Two other possibilities exist that will be investigated in Phase 2 of the West Coast Regional Carbon Sequestration Partnership.

5.2.1 Use of fast-growing species

Instead of considering only native species for afforestation activities, fast growing tree species such as hybrid poplar will be investigated. Land suitable for planting such species will be assessed based on existing data, other publications in the region, and partners. Hybrid poplar is already being grown in parts of Oregon and Washington and its extent could be increased. Plantations of hybrid poplar grow fast with up to about 100 t C/ha after 10 years. The potential carbon supply for planting fast growing species on rangelands and crop lands will be investigated including estimating the opportunity costs (as described above), the costs for planting and managing the plantations, and the revenues from the products (pulp, timber, or biomass fuel) plantations. The analysis will be done in a GIS as done for native species and a comparison of the carbon supply from native versus fast-growing species will be preformed.

5.2.2 Other forest management methods

In phase 1 of this work, afforestation of rangelands and croplands considered only the planting of native species for forest restoration. However, it is possible that forest could be grown for timber products. Simulating the growing of trees for timber production affects two components of the carbon supply analysis: the quantity of carbon sequestered and the costs. The effects on the quantity of carbon and the costs will be investigated across the region in phase 2.

The quantity of carbon sequestered in the living component of forests grown for timber production will be less than that for forest grown for restoration. However this decrease in the long term average in living trees can be made up in part by the carbon in the harvested wood that is converted to long term wood products. The balance between these two main pools of live and wood products will vary by forest type and will be investigated in detail in phase 2. Cost will also be different between forests grown for timber and for restoration. When grown for timber, there will be revenues from the sale of timber as well as for the carbon. The analysis of the potential carbon sequestration for the region by afforestation for timber species will incorporate all these factors to arrive at new estimates of the carbon supply and the results compared to those generated in this paper.

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Appendix XXII, Final Report

Action Plan for Phase II Pilot Projects

Deliverable associated with Task 4.0, Item 4

West Coast Regional Carbon Sequestration Partnership
(WESTCARB)
Contract Period: October 1, 2003–September 30, 2005

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March 14, 2005
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Deliverable Mapping

This action plan constitutes the required WESTCARB Phase I deliverable associated with Task 4.0, Identify Options and Opportunities, Item 4 (“an action plan for implementing Phase II pilot projects”). Note that there are companion action plans for Phase II public outreach and identification and resolution of Phase II technology deployment issues.

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Introduction

The West Coast Regional Carbon Sequestration Partnership (known as WESTCARB) is one of seven partnerships established by the U.S. Department of Energy (DOE) to evaluate carbon capture and sequestration (CCS) technologies best suited for different regions of North America.



Accordingly, WESTCARB is exploring the opportunities in six Western states and one Canadian province for removing CO_2 from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted, both of which will help slow the atmospheric buildup of this greenhouse gas.

WESTCARB is identifying the major sources of man-made CO_2 in its territory; assessing the status and cost of technologies for separating CO_2 from process and exhaust gases at large industrial plants; determining the potential for storing captured CO_2 in leak-proof geologic formations; establishing the extent to which changes in the management of forests, rangelands, and agricultural lands could increase carbon storage by plants and soil; assessing the logistics and costs of building pipelines to move CO_2 from the points of capture to the points of storage; and summing the results of cost estimates for capture, transportation, and storage to create carbon storage "supply curves."

Led by the California Energy Commission, WESTCARB's Phase I partners include about 50 organizations from state and provincial resource management and environmental protection agencies; national laboratories and research institutions; colleges and universities; conservation non-profits; oil and gas companies; power companies; pipeline companies; trade associations; vendors and service firms; and consultants.

One of the primary goals of WESTCARB's 2-year "Phase I" project was to develop plans for pilot field tests to validate the feasibility, safety, and efficacy of promising geologic and terrestrial carbon sequestration solutions.

The specific WESTCARB pilot projects, developed in Phase I, to be conducted during Phase II include:

- Conducting two CO_2 storage pilot tests at a gas reservoir leased by Calpine and the underlying saline formation. [Editor's Note: Rosetta Resources became our industrial match partner for this project with the acquisition of Calpine Rio Vista area gas rights in mid-2005. The target

reservoir was subsequently identified as Thornton.] In addition to information on the safety and viability of these sequestration options, they will provide valuable data on monitoring and verification technologies, permitting in California, and the efficacy of public outreach efforts.

- Conducting a CO_2 storage pilot test in northern Arizona (at a site TBD, but expected to be near a Salt River Project coal-fired power plant) to demonstrate the safety and feasibility of CO_2 storage in saline formations in Arizona's portion of the vast Colorado Plateau region, obtain data on monitoring and verification technologies, and gain experience with regulatory permitting and public outreach associated with CO_2 storage in a saline formation in Arizona.

- Performing an in-depth assessment of the storage potential for two additional geologic formations with significant storage potential in the WESTCARB region.

- Conducting two pilot projects in Lake County, OR, and Shasta County, CA, that will test the following options for terrestrial sequestration: afforestation of once-forested lands now used for agriculture or grazing, forest fuel load reduction for improved fire management (i.e., reducing the probability of uncharacteristically severe wildfires and accompanying massive CO_2 releases), and improved forest conservation management.

- Providing web-based interactive access to both geologic and terrestrial sequestration pilot project results by updating the electronic regional carbon sequestration atlas begun in Phase I.

This action plan describes WESTCARB's approach to successfully conducting these pilot projects—within schedule and budget.

Pilot Projects Overview and Contribution to DOE Carbon Sequestration Roadmap Goals

Geologic Pilot Projects

WESTCARB plans to test the most promising sequestration technologies identified in Phase I at sites broadly representative of the region's largest sequestration opportunities. WESTCARB's Phase II activities will include three geologic CO_2 storage pilots and preliminary investigations for two additional geologic pilots (which will be held in "ready reserve" should initial findings at a primary pilot not warrant its continuation). Sinks to be tested include saline formations (which have the region's largest storage capacity) and formations where "cost offsets" can improve economics, such as oil and gas reservoirs and methane-bearing coal beds. These geologic storage pilots will demonstrate the safe and secure storage of CO_2, provide experience with the public and regulatory agencies for permitting storage projects, and provide site-specific information for improving capacity estimation, monitoring technology, and risks assessment methodology. Each pilot project site offers upside potential in terms of future additional CO_2 storage, if not at that location, then in the surrounding formation.

WESTCARB's geologic pilot projects complement DOE's ongoing CO_2 sequestration studies in Frio, Texas; the Central Appalachian Basin in Virginia; New Haven, West Virginia; Weyburn, Canada; and West Pearl Queen, New Mexico. They support DOE Carbon Sequestration Roadmap goals of better understanding the factors that affect CO_2 storage permanence and capacity in geologic formations, the development of field practices to optimize CO_2 storage, and the development of monitoring, mitigation, and verification technologies and processes. They are also consistent with Roadmap sequestration priority research pathways, including saline formations, depleting gas reservoirs, and unmineable coal seams. Table 1 summarizes how the WESTCARB geologic storage pilot tests will help to address the goals identified in DOE's Carbon Sequestration Roadmap.

Table 1. Summary of WESTCARB geologic storage pilot projects' contributions to achievement of DOE Carbon Sequestration Roadmap Goals

DOE Roadmap Goals for Geological Storage of CO_2 and WESTCARB Contributions		
Storage Security and Permanence	**Storage Capacity and Optimization**	**Measurement, Mitigation, and Verification**
• Demonstrate safe and secure storage in a depleting gas reservoir • Demonstrate safe and secure injection into 2	• Perform the first-ever test of CO_2-EGR in a natural gas reservoir • Improve understanding and modeling of CO_2	• Develop methods for monitoring CO_2 storage in gas reservoirs • Test methods for monitoring permeability

saline formations • Improve understanding and modeling of multi-phase flow and residual gas trapping in a saline formations • Improve understanding and modeling of solubility trapping • Predict mineral trapping rates and quantities in two different geologic settings	storage capacity in heterogeneous high permeability sandstones • Improve understanding and modeling of storage capacity in lower permeability highly consolidated sandstones • Develop methods for predicting storage capacity in depleting gas reservoirs • Improve capacity estimation methodology by history matching the injection pilots	changes due to CO_2 injection • Enhance and demonstrate the utility of VSP for monitoring CO_2 mitigation from single-well pilot tests • Demonstrate and refine the use of cross-well seismic monitoring to achieve high resolution images of CO_2 migration • Demonstrate and expand the utility of down-hole pressure measurements for monitoring CO_2 injection operations • Demonstrate and improve CO_2 surface flux measurement techniques

Terrestrial Pilot Projects

WESTCARB will conduct two terrestrial CO_2 storage pilots, which will validate the region's largest terrestrial sequestration opportunities: reforestation of once-forested lands now used for agriculture or grazing (either with natural species or fast-growing "plantation" trees), forest treatments to reduce fuel loads for improved fire management (i.e., reducing the probability of uncharacteristically severe wildfires and accompanying massive CO_2 releases), and improved forest management to increase standing timber carbon storage.

These projects offer valuable co-benefits, such as reduced loss of life (people, plants, and animals) and property/habitat due to wildfires, fuels for biomass power plants (providing no-net-CO_2 electricity and helping achieve renewable portfolio standards), conservation of forest lands for ecological health and habitat preservation, and demonstration of forest carbon accounting protocols and carbon market transactions.

WESTCARB's pilot projects will feature participation from managers/owners of federal, state, and private lands. Demonstrating terrestrial sequestration practices on lands of multiple jurisdictions establishes procedures and precedents—and addresses many permitting and public engagement issues—to speed future scale-up of our proposed pilots and/or development of additional pilots.

WESTCARB's terrestrial pilot projects support the DOE Carbon Sequestration Roadmap goals of better understanding the factors that affect CO_2 storage permanence and capacity in terrestrial ecosystems, the development of field practices to optimize CO_2 storage, and the development of MMV technologies

and processes. They provide an opportunity to study a managed terrestrial sequestration installation over 3–4 years (with the possibility for continuation). They are also consistent with Roadmap terrestrial sequestration research priority pathways, including tree planting to offset greenhouse gas emissions and optimizing silvicultural practices for degraded lands, and they complement recent DOE research focused on reforestation on mined lands in the Appalachian region. Table 2 summarizes how the WESTCARB terrestrial storage pilot tests will help to address the goals identified in DOE's Carbon Sequestration Roadmap.

Table 2. Summary of WESTCARB terrestrial storage pilot projects' contributions to achievement of DOE Carbon Sequestration Roadmap Goals

DOE Roadmap Goals for Terrestrial Storage of CO_2 and WESTCARB Contributions		
Validation of Forest Growth	**Fire Management**	**Forest Management**
• Develop methods for afforestation of previously forested lands that have not returned to forest. • Estimate N_2O and methane impacts of different afforestation activities. • Validate estimates of carbon sequestration from afforestation across different site classes. • Determine minimum soil moisture and precipitation required for successful establishment of trees at pilot sites. • Evaluate ecological impacts of afforestation activities in collaboration with other research funded by the CEC. • Determine minimum time required to successfully establish new forests for different species. • Determine conversion and maintenance costs for different forest	• Develop fire management treatment practices that optimize carbon sequestration while reducing fire risk. • Estimate N_2O and methane impacts of different fire management activities. • Use stratified sampling of chronosequenced sites to validate impacts of past fires for various forest types. • Evaluate predicted changes in carbon stocks for various forest types using fire models currently used by different land managers in the region. • Evaluate ecological impacts of fire management activities in collaboration with other research funded by the CEC. • Develop peer-reviewed methodology for determining appropriate baselines for carbon losses due to fire. Develop	• Develop easements that assure protection of carbon stocks. • Estimate N_2O and methane impacts of different forest management activities. • Validate estimates of carbon sequestration from changes in forest management. • Evaluate and estimate co-benefits associated with forest management actions that increase carbon stocks, including habitat and water quality. • Evaluate ecological impacts of forest management activities.

types. • Evaluate and test dry-site species for harsh-site regeneration. Quantify carbon accumulation rates. • Develop methodology to quantify value of carbon stocks retained in forest products produced from fast-growing plantations.	consensus working with different land managers. • Determine costs for collecting and transporting fuel from forests to biomass plants as function of site conditions and location	

Geologic CO_2 Storage Pilot Project Descriptions

Table 3 summarizes WESTCARB's proposed geologic pilot projects, their hosts, and their goals. [Editor's Note: Rosetta Resources became our industrial match partner for the "stacked" pilot project in the California Delta with the acquisition of Calpine's Rio Vista area gas rights in mid-2005. The target reservoir was subsequently identified as Thornton.]

Table 3. Geologic pilot project goals

Pilot Project	Description	Goals
Thornton Saline Formation CO_2 Storage Pilot (Rosetta Resources)	This project will investigate CO_2 storage in saline reservoirs underlying the Thornton depleted natural gas reservoir. Pending possible revisions from more detailed simulations, we plan to drill the injection and observation wells 50 m (160 ft) apart and inject up to 2000 tonnes of CO_2. Modeling suggests CO_2 breakthrough in about 10 days and geophysical monitoring approaches should be sufficiently sensitive.	• Demonstrate the safety and feasibility of CO_2 storage in saline formations in the northern half of California's vast Central Valley • Obtain site specific information to improve capacity estimation, risk assessment, and monitoring technology • Gain experience with regulatory permitting and public outreach associated with CO_2 storage in saline formations in California
Thornton Gas Reservoir CO_2 Storage Pilot (Rosetta Resources)	The project will investigate CO_2 storage and the feasibility of enhanced gas recovery in the Thornton depleted natural gas reservoir. It will use the same injection and observation wells as the companion Thornton saline formation pilot and inject about 1000 tonnes of CO_2. Modeling suggests CO_2 breakthrough within days and geophysical monitoring approaches should be sufficiently	• Test the feasibility and safety of CO_2 storage in a depleted gas field in Northern California • Test the feasibility of Enhanced Gas Recovery associated with the early stages of a CO_2 storage project in a depleting gas field • Demonstrate and test methods for monitoring CO_2 storage/enhanced recovery projects in gas fields • Gain experience with regulatory

	sensitive.	permitting and public outreach associated with CO_2 storage in depleted gas formations and the potential for CO_2 use in gas production operations in California
Northern Arizona Saline Formation CO_2 Storage Pilot (Salt River Project)	The project will involve drilling a single well to evaluate formation properties, test the feasibility of CO_2 injection, and monitor subsurface movement of the CO_2 in a saline formation underlying or nearby a Salt River Project (SRP) coal-fired generating station (candidates include Navajo and Coronado).	• Demonstrate the safety and feasibility of CO_2 storage in saline formations in the vast Colorado Plateau region in Arizona • Demonstrate and test methods for monitoring CO_2 storage projects in consolidated sandstones, shale, and carbonate fields • Obtain site specific information to improve capacity estimation, risk assessment, and monitoring technology • Gain experience with regulatory permitting and public outreach associated with CO_2 storage in a saline formation in Arizona (including potential agreements with the Navajo Nation)
Centralia Coal Bed CO_2 Storage Investigation (TransAlta)	This project will provide an in-depth assessment of the storage potential for coal-bed formations near TransAlta's 1400-MW coal-fired Centralia power plant in Washington. This site offers the potential for revenue generation from enhanced coal-bed methane recovery to offset the cost of CO_2 storage.	• Evaluate the potential CO_2 injectivity and storage potential of deep Puget Sound coal seams near the Centralia plant • Develop a concept and preliminary planning for a pilot test • Scale-up study results to the region to refine our highly preliminary estimate of 2.8 Gt storage potential and to identify engineering techniques needed to achieve large-scale geologic sequestration in Puget Sound coals
Kimberlina Saline Formation and Oil Field CO_2 Storage Investigation (Clean Energy Systems)	This project will provide an in-depth assessment of the storage potential for San Joaquin Valley sediments underlying the Clean Energy Systems prototype 5-MW oxygen-fired "rocket engine" power plant at Kimberlina, California. This site offers the potential for revenue generation from enhanced oil recovery to offset the cost of CO_2 storage.	• Develop a detailed geological model for assessing the storage options in depleting oil and gas fields near the Kimberlina power plant and the underlying saline formations • Develop a plan for a CO2 injection pilot test that could provide the basis for an integrated demonstration that combines a unique power generation and CO2 capture technology with geologic storage

Thornton Saline Formation and Gas Reservoir CO_2 Storage Pilots

The Central Valley of California, composed of the Sacramento River basin in the north and San Joaquin River basin in the south, contains both saline (brine)

formations and oil and gas reservoirs. The saline formations alone are estimated to have a storage capacity of 70 to 500 Gt CO_2 (Myer et al. 2005), representing a CO_2 sink equivalent to about 600 to 3000 years of California's current large-point-source CO_2 emissions.

The formations are representative of dozens of gas-producing fields in California, the cumulative storage capacity of which is estimated at 1.7 Gt.

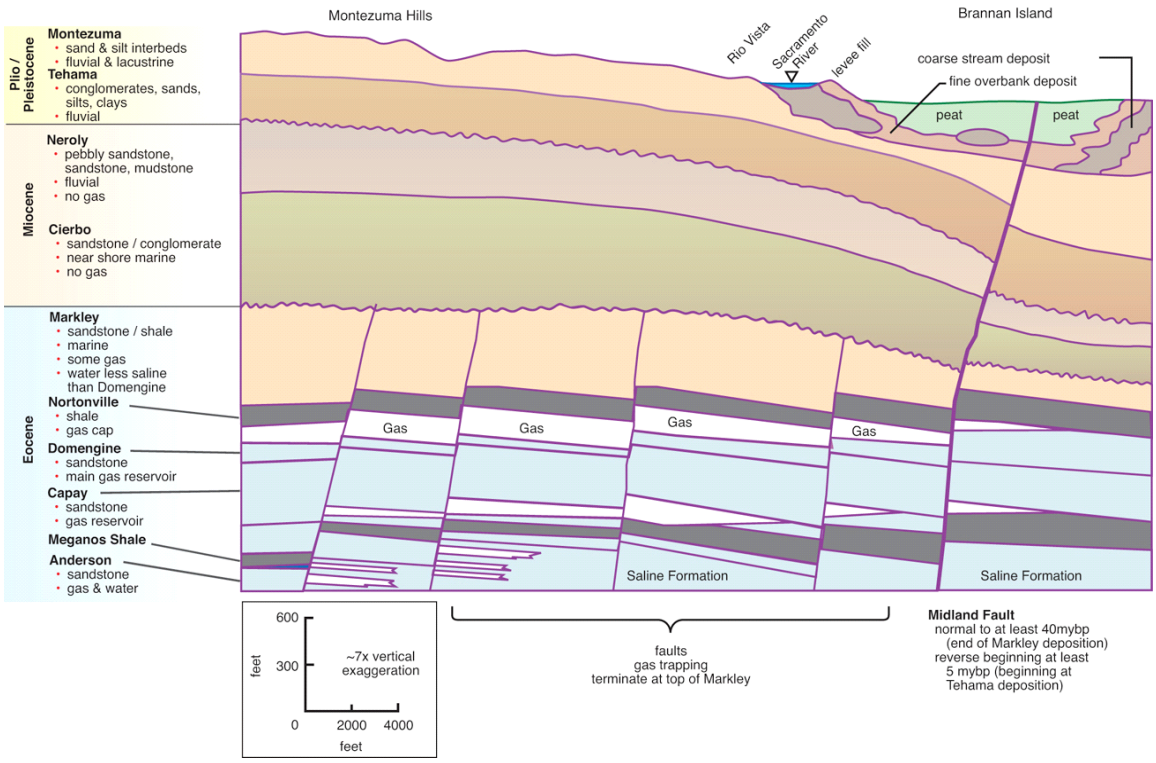


Figure 1. Cross-section of the Rio Vista Gas Field showing thick gas reservoirs (Domengine and Capay) and underlying sandstones (saline formation)

The gas fields near Rio Vista, CA, overlie a thick sequence of brine-filled sandstones. They are representative of a huge sink in California, the Great Central Valley, which is estimated to have from 20 to 120 Gt of CO_2 storage capacity. Due to the high permeability of these saline formations, particularly in the northern portion of the valley, they are also expected to have excellent injectivity. The ability of the intervening shale layers to provide an effective seal is demonstrated by the presence of natural gas accumulations.

This pilot project, hosted by Rosetta Resources at the Thornton depleted gas reservoir near Rio Vista, CA, will be the first test of the feasibility of CO_2 storage in a Central Valley saline formation. Because the gas fields in this area have

been in production for decades and are well understood, we are confident in our ability to model and monitor the subsurface behavior of injected CO_2.

Because the injection well used for the experiment will penetrate numerous brine-filled reservoirs as well as gas-filled zones, we plan to conduct two CO_2 injection pilots using a single pair of wells as illustrated in Figure 2. Because the geologic formations present at Thornton are widespread in the Sacramento Valley, this dual pilot will serve to evaluate CO_2 storage potential throughout the valley, in which many thousands of vertical meters of highly permeable gas- and brine-filled strata are capped by shale formations. In addition to being representative of a very large sink, there are over 11 Mt of CO_2 emissions within about 50 miles of the Thornton pilot site.

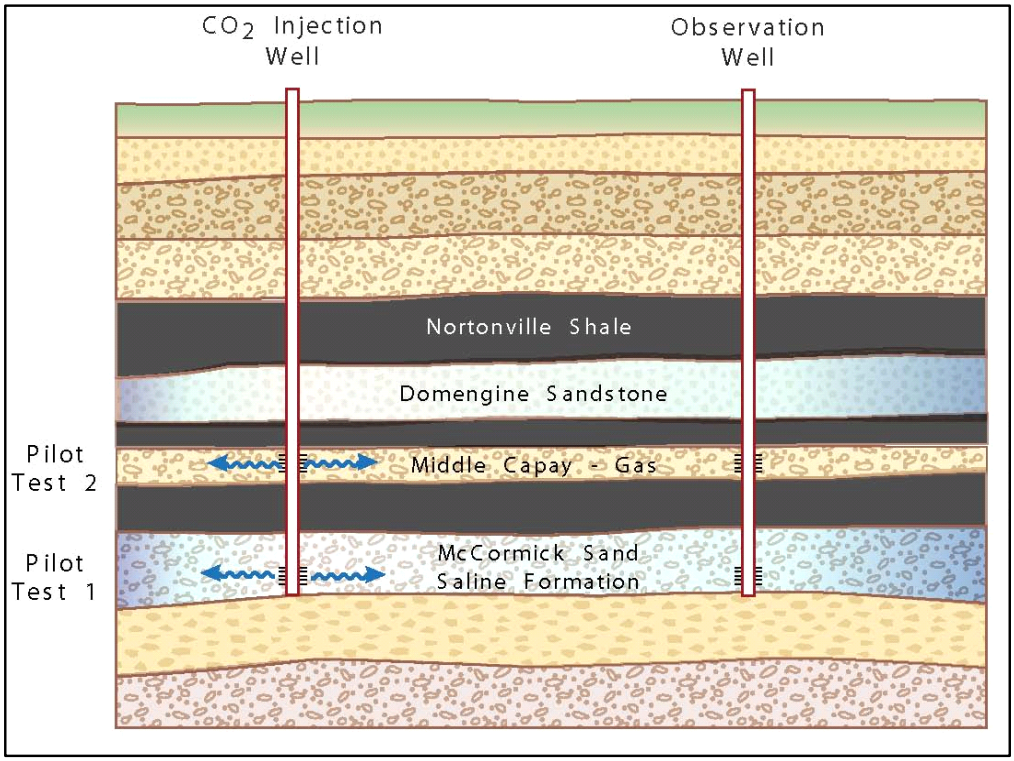


Figure 2. Schematic showing the concept of using a single pair of wells to conduct two pilot tests at Thornton

Northern Arizona Saline Formation CO_2 Storage Pilot

This pilot project also provides an opportunity to assess a large saline formation in the WESTCARB region—the Kaiparowits Basin of the Colorado Plateau. Preliminary volumetric capacity evaluation suggests that 2–6 Gt of CO_2 storage capacity is available in saline formations in the Arizona portion of the basin, but further work is needed to refine and validate these estimates.

The area being evaluated for the pilot site is representative of the southern part of the much larger 360,000 km^2 (140,000 square mi^2) Colorado Plateau region. The occurrence of natural CO_2 accumulations in the Colorado Plateau attests to its potential to store CO_2. Allis et al. (2003) concluded that storage capacity is apt to be large, based on the thickness of the potential storage formations (>100 m or >300 ft) and the presence of good seals. Although less studied than California's Central Valley, initial reconnaissance suggests suitable saline and seal formations lie beneath or near coal-fired plants operated by Salt River Project (however, some are at depths corresponding to subcritical CO_2 pressures). Proximity to this large source of CO_2 could establish much of the infrastructure needed for a future "integrated" pilot project involving both CO_2 capture and sequestration. A phased approach to this pilot allows us to assess the suitability of geologic conditions prior to commencing injection operations.

One of the region's large coal-burning power plants, the Navajo Generating Station lies within the Kaibito plateau physiographic province, which is part of the Kaiparowits Basin. The basin is bounded on the west, south, and east by the Kaibab Uplift, White Mesa, and Navajo Mountain, respectively. The basin covers approximately 3000 square miles (8000 km^2) in Arizona and also extends north into Utah. The youngest to oldest subsurface candidate CO_2 storage formations underlying the Navajo Generating Station site include the Cedar Mesa Sandstone of Permian age, Redwall Limestone of Mississippian age, and Tapeats Sandstone of Cambrian age. Potential reservoir seals include the Muav Limestone, Bright Angel Shale, Organ Rock Shale, and Chinle and Moenkopi Formations. This "layered structure" is generally representative of northeastern Arizona (where another candidate SRP generating station, Coronado, is also located).

Although there are no deep exploratory wells in the immediate vicinity of Navajo Generating Station, estimates of formation depths and thickness underlying the plant are based on projections of the formation tops in the Shell Soda Unit No.1 in Utah and the Sinclair Oil #1 Navajo in Arizona. (The Shell Soda Unit No.1 and Sinclair Oil #1 lie approximately 56 km (35 mi) northwest and 61 km (38 mi) southeast of Navajo Generating Station, respectively.) Figure 3 illustrates the projected formation and seal depths and thicknesses underlying Navajo Generating Station. Allis et al. (2003) and more recently, the Arizona Geological Survey, have characterized the potential storage formations and seals.

Based on the number, thickness, and good porosity of the potential storage formations, and the extremely low permeability of the seals, both have concluded that this region has excellent storage potential. Drilling and testing a borehole will provide the additional information needed to establish injectivity and storage capacity of these widespread saline formations at the southern extent of the vast Colorado Plateau.

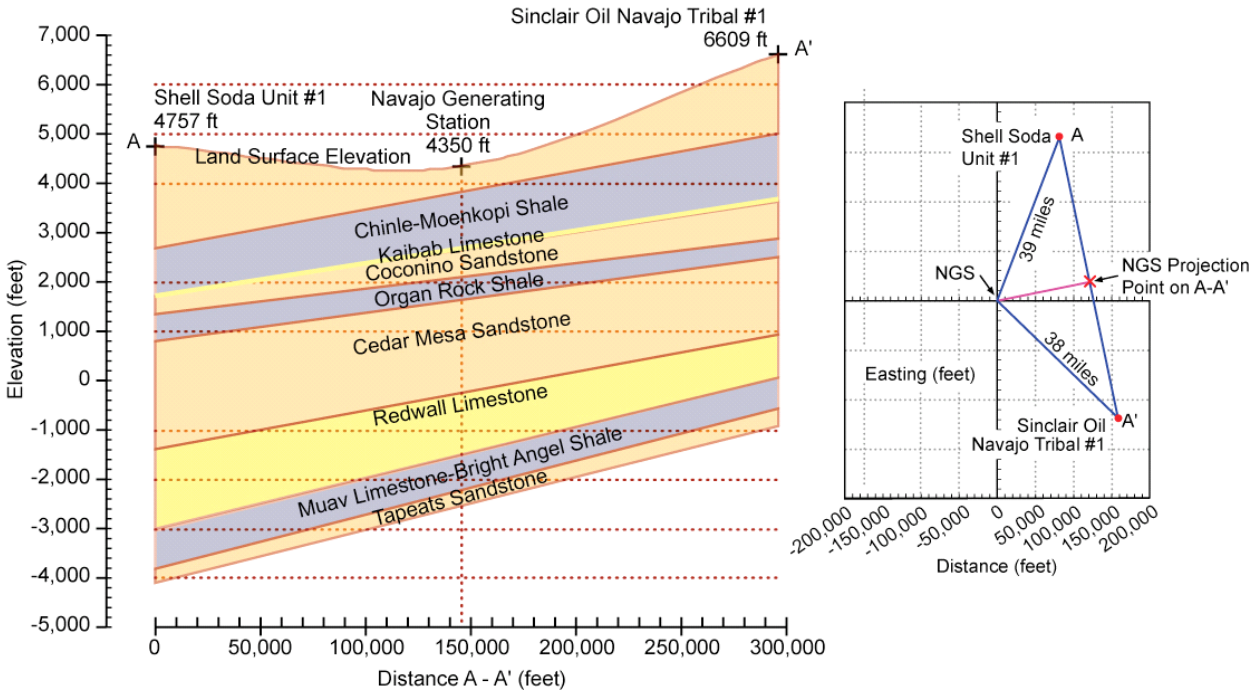


Figure 3. Major Kaibito Plateau seals and storage formation. A map showing the location of wells from which the cross-section is shown to the right.

Additional Pilot Investigations

Centralia Geologic CO_2 Storage and Enhanced Coal-Bed Methane Assessment

The Centralia pilot is located in Washington in the Puget Sound basin, a very deep basin containing up to 6000 m (20,000 ft) of sediments. The Centralia pilot would target deep unmineable coals, which are part of the Puget Group. Data collected during Phase I show that coal rank generally increases from northwest to southeast, coal thickness is on the order of 30 m (100 ft), CO_2 sorption capacity of 700-850 ft^3/t, and permeability on the order of 5 millidarcies. The coals contain methane and coal-bed methane exploration has occurred in the region, but has not yet been commercially successful.

Kimberlina Saline Formation and Oilfield Storage Assessment

The Kimberlina pilot is located north of Bakersfield, California, in the southern San Joaquin basin. Logs from wells southwest of the site were interpreted to identify viable sequestration targets. The data indicate that the site is underlain by the Olcese, Vedder, and Mushrush sandstones, which are porous, permeable sands >100 m (>300 ft) thick. Each is capped by thick, clayey shales. Each of the sand layers contains oil reservoirs within 25 km (15 mi) of the site.

MMV Strategy for Geologic Pilot Projects

WESTCARB's approach to measurement, monitoring, and verification of the geologic pilot tests is based on the experience our researchers gained as a result of our participation in the Frio Brine Pilot Injection Test, the Lost Hills (California) CO_2 EOR pilot test, and the Weyburn Project. To ensure that project goals, permitting requirements, and safety controls are achieved, we will use the process outlined in Figure 4. At the heart of our approach, is a careful requirements definition phase, followed by the repeated use of detailed simulations of flow and transport, coupled to a geophysical imaging code. The repeated use of these tools over the project phases—requirements definition, pre-permitting, permitting and operations—allows us meet project goals, while minimizing costs, by optimizing the injection and observation well spacing, the quantity of CO_2 injected and the suite of monitoring techniques used for the pilot tests.

Simulation of the CO_2 injection and storage will be based on a detailed, site-specific hydrogeological model of the pilot test site. After assembling the hydrogeological model from all of the available data, subsurface flow and transport simulations will be carried out with TOUGH2 and TOUGHREACT (Pruess et al. 1999; Xu et al. 2004). The output of the flow and transport model will then be imported to a geophysical simulator. The geophysical simulator enables calculation of the geophysical response for seismic techniques, electrical and electromagnetic methods, and gravity—and to evaluate whether they have sufficient detection limits to meet the project objectives. These detailed simulations also provide the basis for determining the distance between the injection and observation wells (for the Thornton pilot, where a two-well project design is used) and the amount of CO_2 that needs to be injected to ensure breakthrough at the observation well.

For each pilot test, a comprehensive set of monitoring techniques will be evaluated and deployed as part of the tests, aimed at monitoring CO_2 movement in the storage formation as well as detecting any leakage outside the primary storage formation. Based on our best current understanding, a combination of surface seismic reflection, Vertical Seismic Profiling (VSP), and cross-well seismic imaging will be the primary techniques used to track migration of CO_2 and to detect leakage from the storage formation. Injection rates will be monitored continuously. Wellhead and formation pressures will be monitored to assure that injection pressures remain within the permitted guidelines. Fluid and gas composition will be monitored using samples collected during the CO_2 injection. To ensure the safety of workers on the site, surface CO_2 sensors and an alarm system will be positioned at the wellhead(s), near the injection pump(s), and at any other location where leakage from surface facilities may occur. In addition, all of the subsurface and surface measurements listed in Table 4 will be evaluated on a site-specific basis to determine which will be most effective for

tracking CO_2 movement before deciding which methods and monitoring configurations to deploy.

If seismic methods are not be sufficiently sensitive for tracking CO_2 migration in a natural gas reservoir, the multilevel fluid sampling system will be utilized to track migration and enable evaluation of flow and transport processes.

For the Northern Arizona Saline Formation CO_2 Storage Pilot, the "Frio approach" will be modified to account for the likelihood that the permeability of the formation is much lower than the permeability of the Frio formation (or Thornton saline formation). One of the most significant modifications will be to include passive seismic monitoring, to determine if any micro-seismic events are induced by pressure buildup and temperature changes. In addition, because only one well will be drilled, we will rely on VSP, and possibly only surface seismic, to track migration of the injected CO_2 (see Figure 5). VSP proved to be a very cost-effective technique for monitoring CO_2 migration at the Frio Brine Pilot Test. Not only did it have a high sensitivity for detecting the presence of CO_2, it provided wider area coverage than cross-well imaging methods. For this reason, we are confident that we can obtain a sufficient amount of information to meet the test objectives with a single well test.

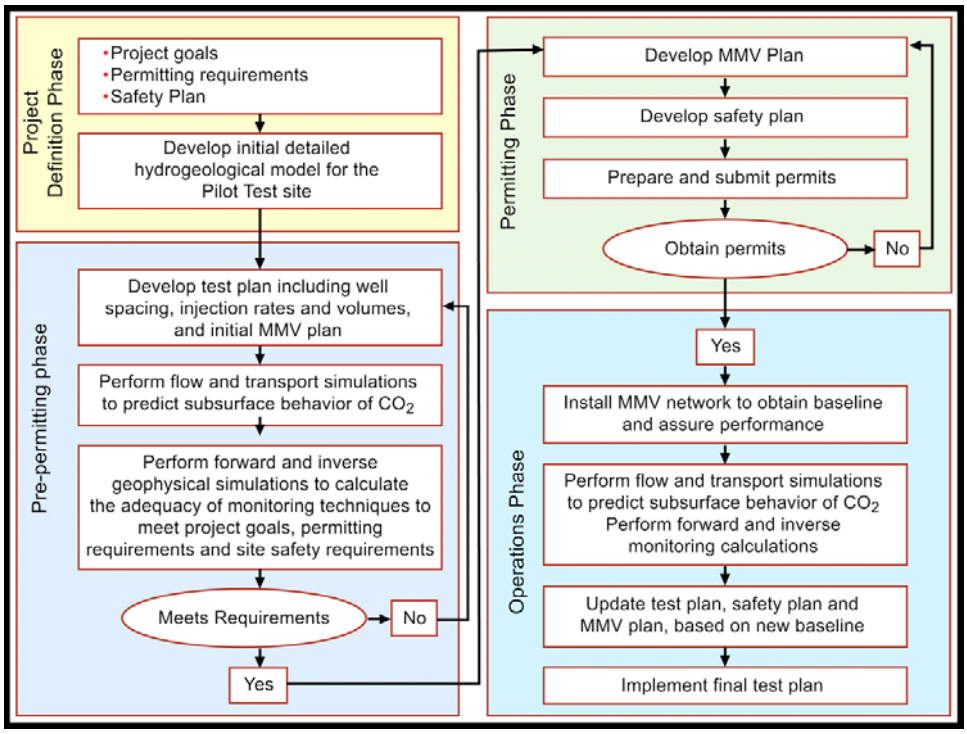
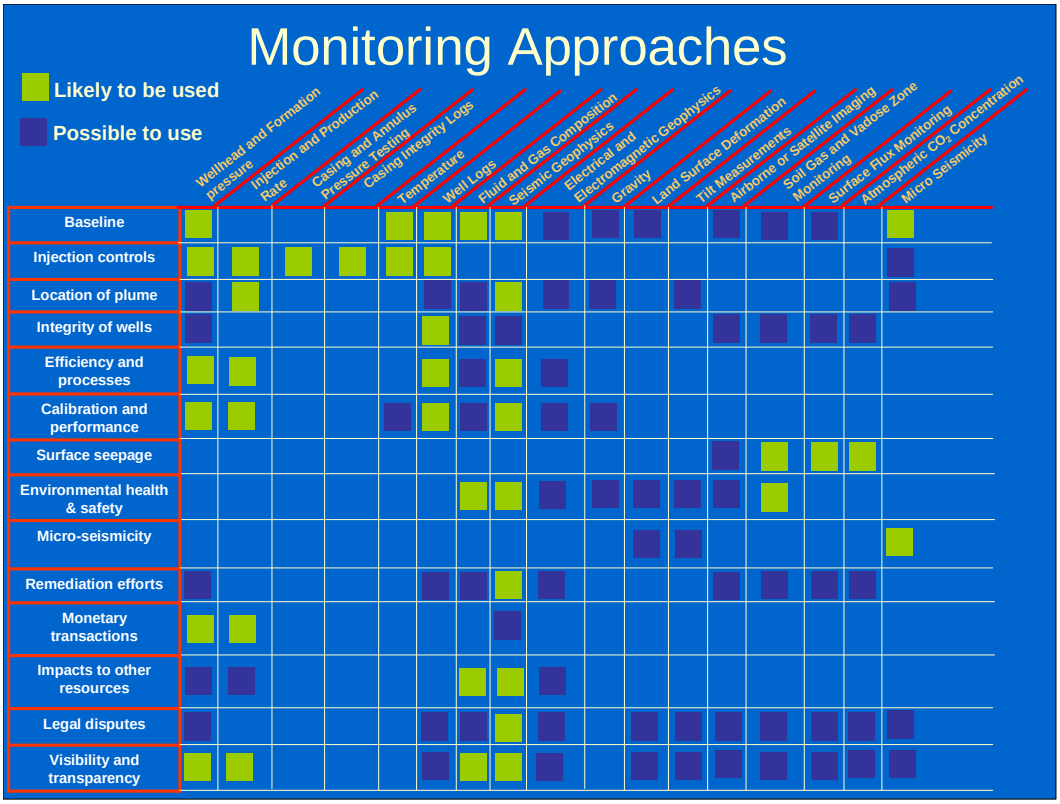


Figure 4. Illustration of the process used to ensure the MMV plan satisfies the goals of the project, permitting requirements, environmental, and safety issues.

Table 4. Potential monitoring methods that could be employed for the monitoring program at the WESTCARB CO_2 Storage Pilot Projects (modified from Benson et al., 2004)



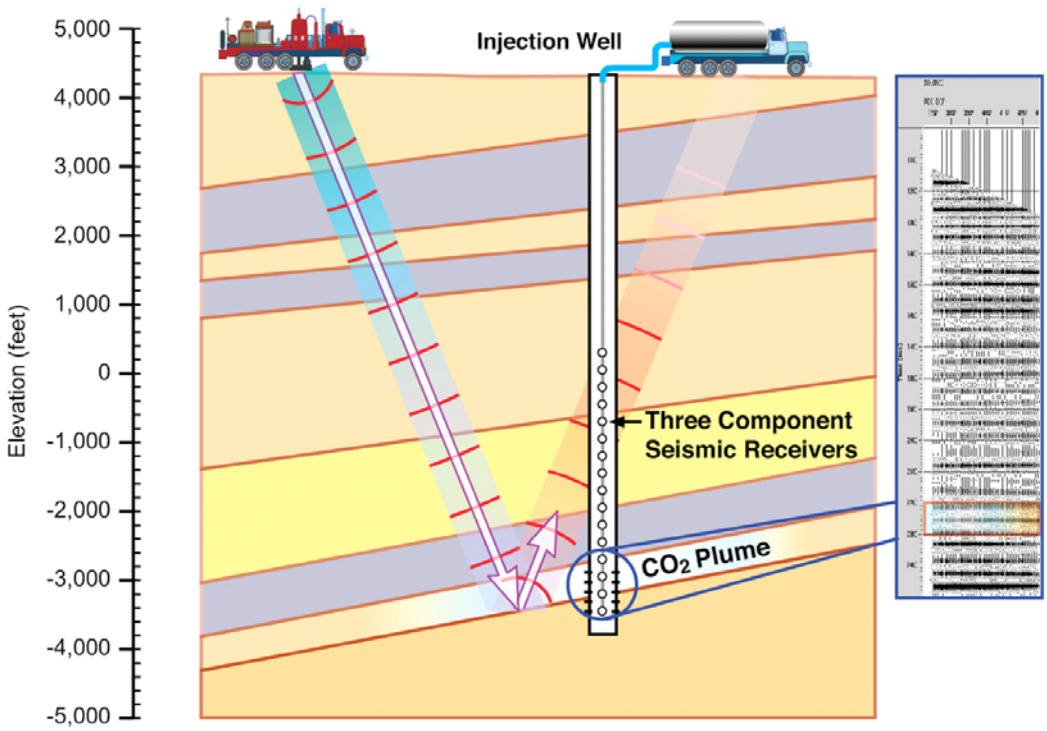


Figure 5. Schematic showing the Northern Arizona Saline Formation CO_2 Storage Pilot and the use of VSP (Vertical Seismic Profiling) to detect CO_2 migration

Risk Mitigation Strategy for Geologic Pilot Projects

WESTCARB will employ risk mitigation approaches to ensure that the geologic pilot tests are carried out safely. Safety will be the first priority as these pilot tests are conducted. Risk mitigation begins with the careful site selection and continues throughout the entire project to plugging and abandoning the wells. Our planned approaches include:

- The WESTCARB Risk Assessment Screening tool developed by WESTCARB during Phase I will be used initially and repeatedly as new information is learned about the sites; based on the best currently available data, the sites selected for the Thornton, Northern Arizona, and Centralia pilot projects all have a low risk profiles.
- An Environment, Health, and Safety (EHS) plan will be developed for each pilot test and implemented based on the best current understanding of the risks associated with CO_2 injection; risks of greatest concern include leakage from the injection and observation wells, releases from the surface facilities associated with pumping CO_2 underground and sampling CO_2 from the observation well; and typical industrial risks associated with well-field operations, transportation to and from the site, and electrical, fall, and trip hazards associated with the kind of work being performed. EHS

related monitoring instruments, including CO_2 sensors with alarm systems, will be installed at all locations where there is a risk of CO_2 release. The goal of the EHS program is to have no recordable or lost day injuries and no significant impact to the environment.

- As part of the permitting process, operating parameters for the CO_2 Storage Pilots will be identified. Issues such as setting maximum injection pressures, determining the injection and observation well completions and constraints on environmental impacts will be established. The location of nearby active or abandoned wells that could provide a leakage pathway to the surface will be identified and monitored for CO_2 releases. If the risk associated with abandoned wells is deemed too great, a nearby site with lower risks will be used. The regulatory permitting process and adherence to it during the pilot tests is an important element of our risk mitigation approach.
- A rigorous monitoring program will implemented during the test and a post-injection confirmatory monitoring period will be used to look for leakage from the storage formation, thus mitigating the potential for damage to groundwater or ecosystems.
- Should at any time, the pilot project not be performing within the safety and environmental parameters set for this project, work will be stopped until a remedy is identified and implemented.

The final and perhaps most important element of our risk mitigation plan is having experienced operators with an excellent safety record in charge of all well-field operations. For the Thornton pilot, Rosetta Resources, the leaseholder for the gas field, will be in charge of drilling operations. A qualified site management contractor will be selected for CO_2 injection and MMV operations. For the Northern Arizona pilot, a contractor with the needed experience will be selected on a competitive basis. This, together with strict adherence to and oversight of our EHS plan, will mitigate the risks associated with these pilots.

Terrestrial CO_2 Storage Pilot Project Descriptions

Three terrestrial sequestration technologies are included in WESTCARB's two Phase II pilot projects: validation of forest growth potential for rangelands, change in forest management, and forest fuel management to reduce the risk of catastrophic fires and prevent emissions. The three technologies will be implemented in Shasta County, California, and Lake County, Oregon (see Table 5). These two counties were chosen because Phase I characterizations found they offer a chance to test each type of the opportunities broadly available throughout the region (see Figures 6 and 7) and also because of the willingness of WESTCARB partners to commit resources to the research.

Table 5. Terrestrial sequestration technologies being demonstrated in WESTCARB pilot projects

Pilot Site	Activity Type	Description
Shasta County, CA	Validation of forest growth type for rangelands	This project will seek to establish native forests on grazing land representative of lands available for afforestation in the region. In Years Three and Four, afforestation tests also will use fast-growing species adapted for drier sites. Partners will select the species, site preparation, and planting techniques to maximize survival on land classes representative of non-forested land available across the region.
Lake County, OR	Validation of forest growth type for rangelands	This project will analyze and seek to establish plantations of fast-growing trees, such as hybrid poplars, on suitable agriculture or grazing land to be harvested on a 10-year rotation. Hybrid poplars offer the potential to sequester >100 t C/ha in 10 years. Sale of carbon credits from the conversion of agriculture or grazing land, and from the displacement of fossil fuels, provides new sources of revenue for landowners considering land conversion. Data from existing stands established on similar lands with similar climate conditions will be used to verify carbon accumulation rates and to determine land conversion and maintenance costs.
Shasta County, CA	Forest management	The Bascom Pacific Forest Management Greenhouse Gas Reduction Project is a public-private effort to achieve forest-based greenhouse gas reductions through the conservation and sustainable management of approximately 10,000 acres of forestland in the headwaters of the Sacramento River, mainly in Shasta county. This project is a partnership between The Pacific Forest Trust (PFT), a non-profit organization, and Bascom Pacific LLC, a timber investment management organization. The project will restore and maintain rare and high-quality early and late seral forest habitats, such as riparian areas, mountain meadows, montane hardwood habitats, and ponderosa mixed conifer forests.
Shasta County, CA, and Lake County, OR	Fuel management	The key objective of work at each pilot project is to develop and test fuel management activities across ownership types and forest types so that available models and results can be evaluated for each management class and be used to build consensus behind methods for setting baselines and conducting measurement and monitoring activities to verify results. The USDA Forest Service will participate in monitoring and verification work and will provide relevant data.

For assessing the forest growth potential for rangelands, each pilot project will draw on the extensive experience of WESTCARB partners to select cost-effective forest establishment practices apt to yield maximum carbon sequestration.

For fuels management activities to reduce fire risk, carbon benefits accrue by (1) decreasing the intensity and extent of wildfires, and consequently their CO_2 emissions, and (2) burning extracted fuels to generate electricity, thereby displacing combustion of fossil fuels. To decrease fire risk, hazardous fuels will be extracted from the forest.

For forest management, our pilot project will focus on emission reductions to be achieved through conservation-based forest management practices. These practices will set higher levels of stewardship than required by the California Forest Practices Act. The new forest management practices will restore and maintain high quality early and late successional forest habitats as noted in Table 5.

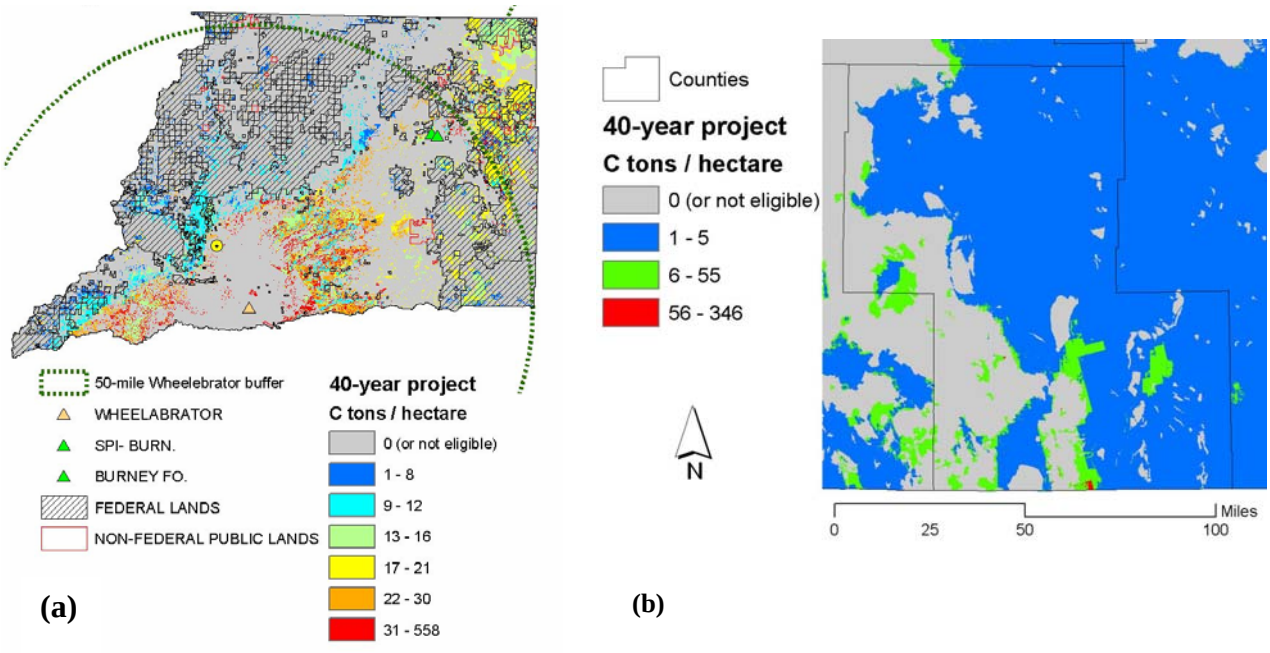


Figure 6. (a) Potential carbon sequestration from afforestation of rangelands after 40 years in Shasta County, CA (triangles represent power plants); (b) Potential carbon sequestration from afforestation of rangelands and agricultural lands with native tree species in Lake County, OR, over 40 years.

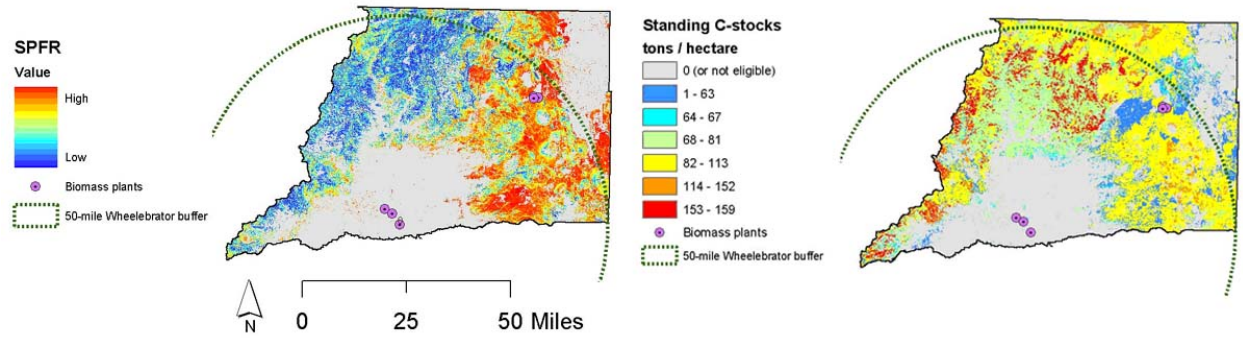


Figure 7. Factor map showing Suitability for Fuels Reduction (SPFR) and standing carbon stocks for forestlands in Shasta County

WESTCARB's first step in determining baselines for the terrestrial sequestration pilots will be to review and reconcile the various methods suggested in existing protocols, such as the California Climate Action Registry (CCAR), DOE's 1605(b) Voluntary Reporting, and the Chicago Climate Exchange. The methods for analyzing baselines should be similar for afforestation activities. However, differences are expected for forest management. In this case, we plan to use the CCAR method, but will assess how baselines would differ using alternative protocols.

No baseline methodology has been developed for fire management; thus, we propose to develop such a methodology. Because reduction in fuels to prevent catastrophic wildfires is an avoided emission activity, the baseline methodology will have similarities to that for forest conservation. Two components are needed for the fire management baseline: the area of forest likely to be burned over time and the carbon stocks exposed to fire and the emissions that would result without fuels treatment. For projecting the area burned, we will develop spatial models based on historical fires (fire products for the region are available for many years; the length of record varying by state). For determining the carbon stocks exposed and amount burned, we will employ established fire models that determine the quantity of fuel and fire intensity. Field work will involve measurements using a chronosequence of sites that include high fire risk forests, mature forests with low fire risk, and sites recently burned. The USFS Pacific Southwest Research Station's experimental sites, at which different fire management treatment types and treatment intensities have been implemented in different forest types, will provide data and proxy sites for measurement.

Regarding leakage and additionality, various protocols include methods for addressing these factors for afforestation and forest management/conservation projects. WESTCARB researchers will select the most appropriate methods and apply them to the proposed pilot projects. Leakage is not an issue for fuels

management, and new methods will be developed to assess additionality linked to the consensus for how to set baselines.

MMV Strategy for Terrestrial Pilot Projects

WESTCARB will base its modeling and MMV of terrestrial carbon sequestration on the peer-reviewed methods summarized by Brown et al. (2004) and MacDicken (1997) and on baselines established for California (Brown et al. 2004) and Oregon. These methods apply to afforestation, change in forest management, and forest conservation project activities—at virtually any scale—and produce accurate, cost-effective measurements of the total change in carbon stocks in dead and live biomass and in soil to a standard of precision of 10% of the mean with 95% confidence.

WESTCARB member Winrock International will work with other partners, including Oregon State University, the USDA Forest Service Pacific Wildland Fire Sciences Laboratory and Pacific Southwest Research Station, and the California and Oregon departments of forestry, to review fire models and collect data to validate models. All carbon sequestration will be reported to CCAR and will meet the standards of the Registry. As noted, established methodologies for measuring the carbon benefits of forest fuel management do not exist. In the course of our pilot projects, we aim to develop and test new methodologies for quantifying these carbon benefits, and to work with CCAR to seek their approval.

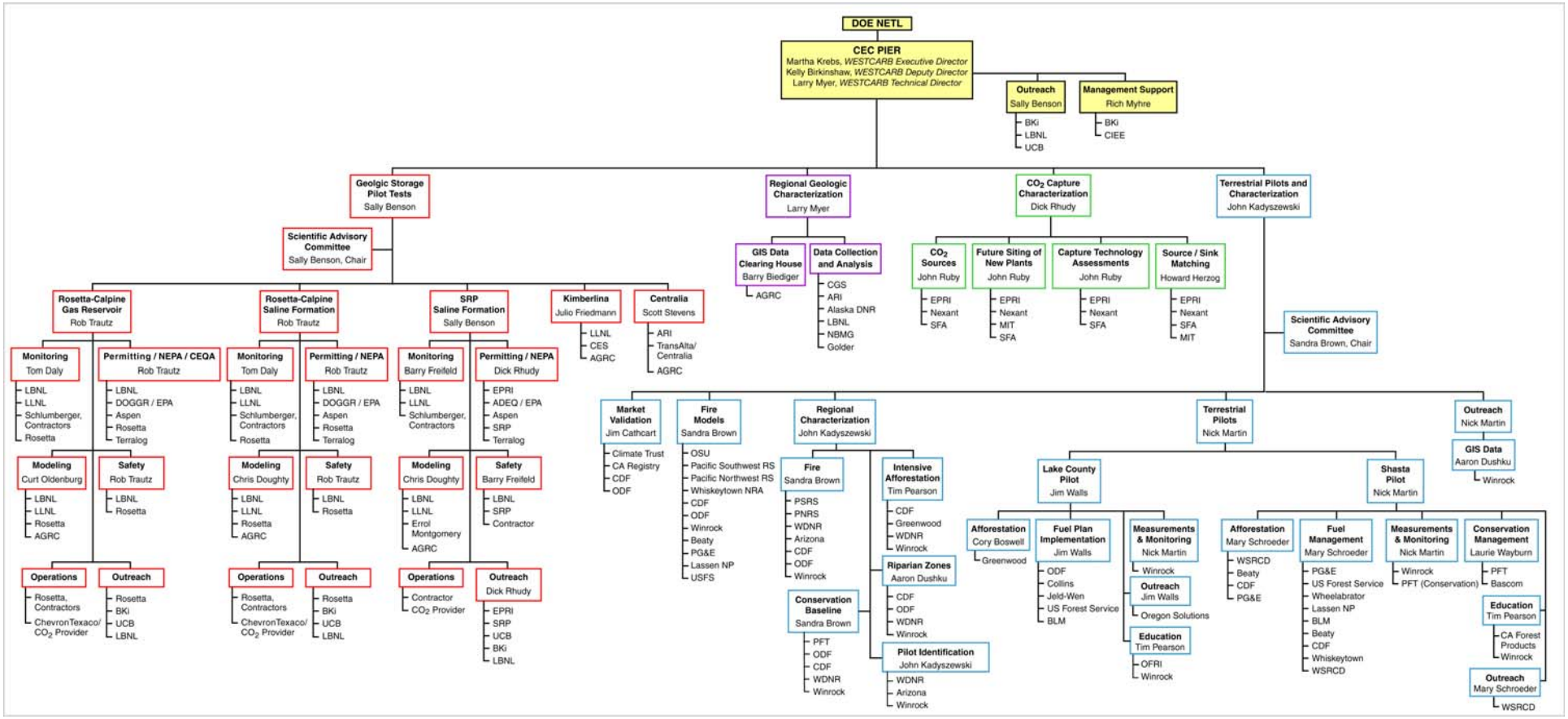
Risk Mitigation Strategy for Terrestrial Pilot Projects

Risks to terrestrial carbon projects in the region are fire, drought, disease/pests, and human disturbance (e.g., arson, animal browsing). These risks affect the pilot projects in different ways with the effect of reducing their carbon sequestration potential:

- Afforestation: Drought, fire, and animal browsing during seedling establishment, pest infestation
- Fuel Management: Fire (either natural ignition source or arson) prior to fuel treatment
- Forest management/conservation: Fire or pest infestation could significantly reduce carbon stocks

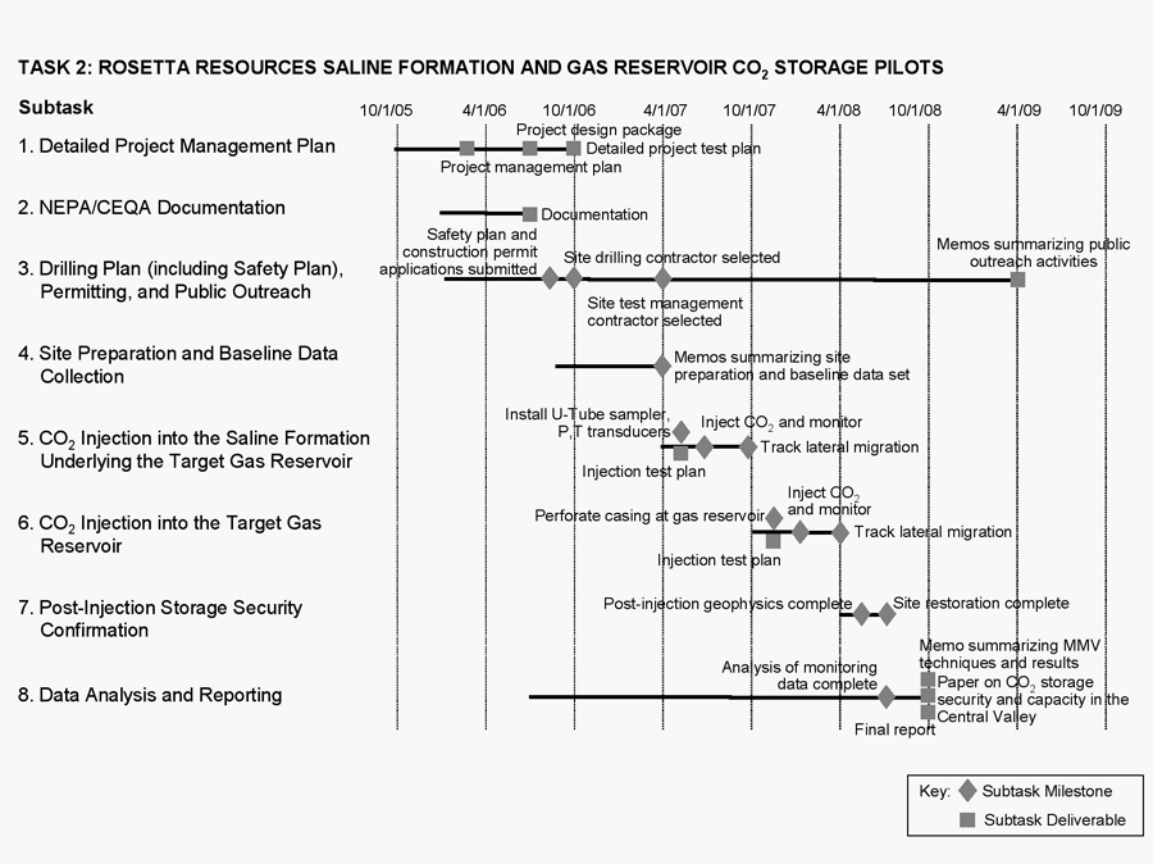
These risks will be addressed in two ways. First, risk criteria were used in the project/site selection (e.g., forest management/conservation in relatively humid stands with low fire risk; afforestation sites selected with low history of fire in the vicinity). Secondly, all projects will be conducted at more than one site and/or over a sufficiently large area to minimize the risk of universal damage.

Project Management: WESTCARB Phase II Management Structure (including pilot project management)

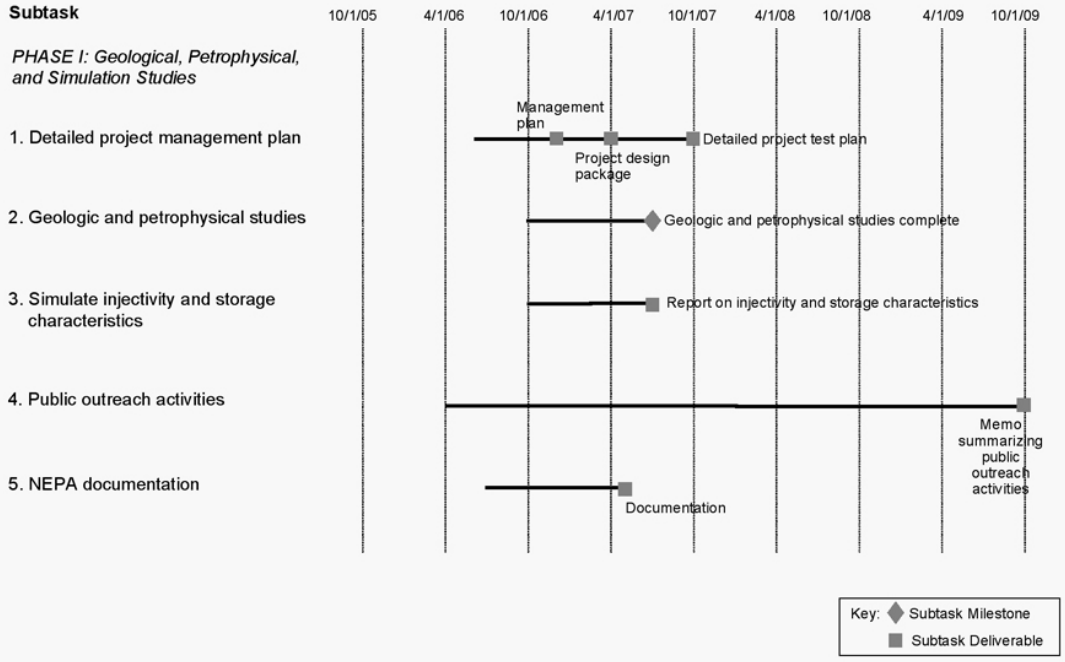


Pilot Projects Schedule

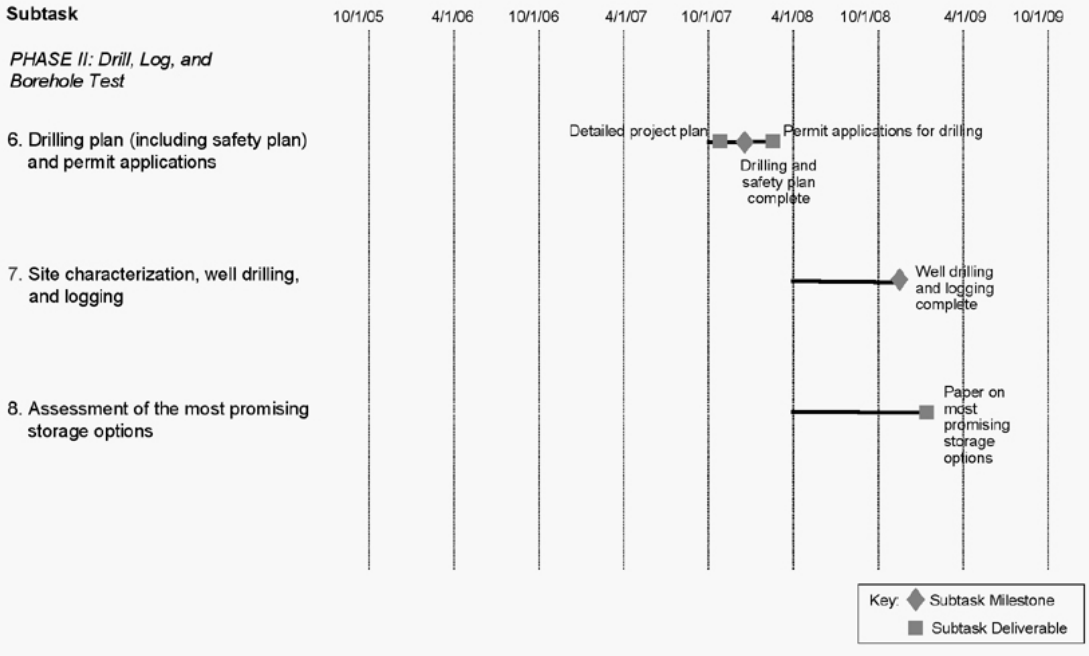
The WESTCARB Phase II schedule, including major milestones and deliverables, for the pilot projects is depicted in the following Gantt charts. Task and subtask numbers correspond to the Phase II Statement of Project Objectives (SOPO) included in Appendix A.



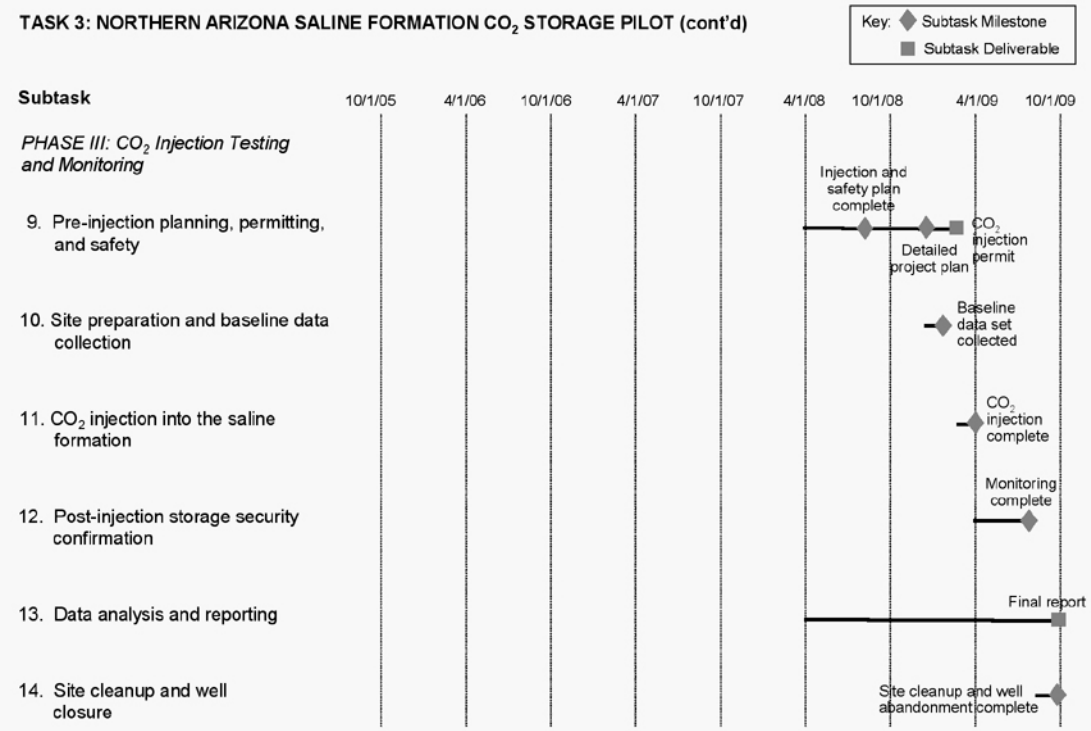
TASK 3: NORTHERN ARIZONA SALINE FORMATION CO_2 STORAGE PILOT



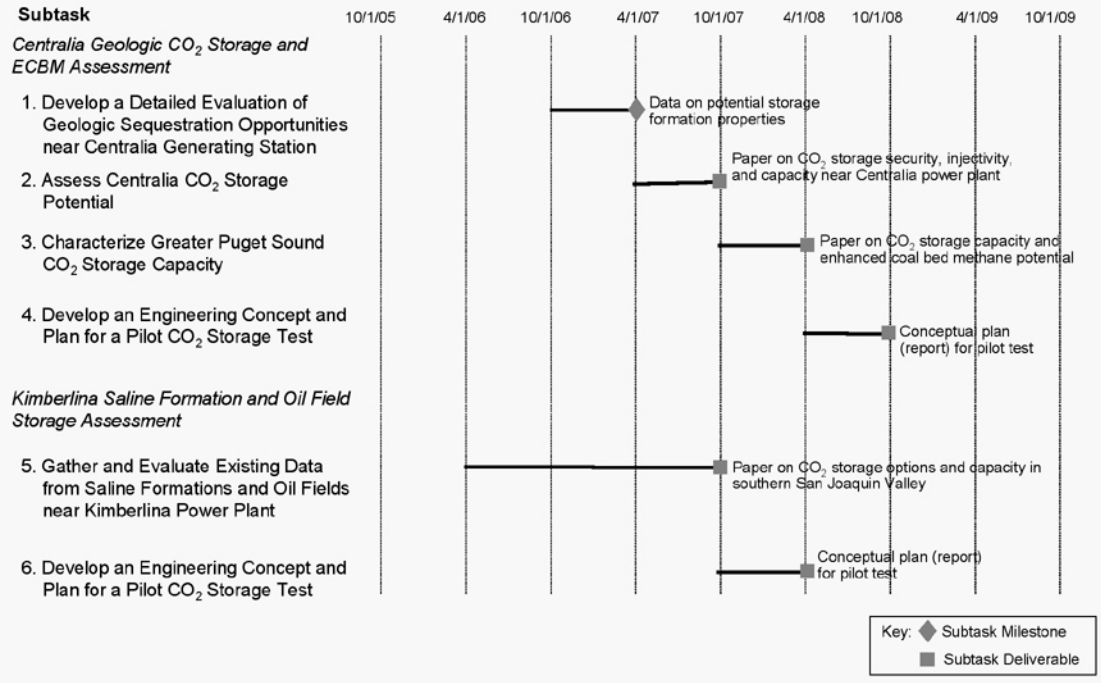
TASK 3: NORTHERN ARIZONA SALINE FORMATION CO_2 STORAGE PILOT (cont'd)

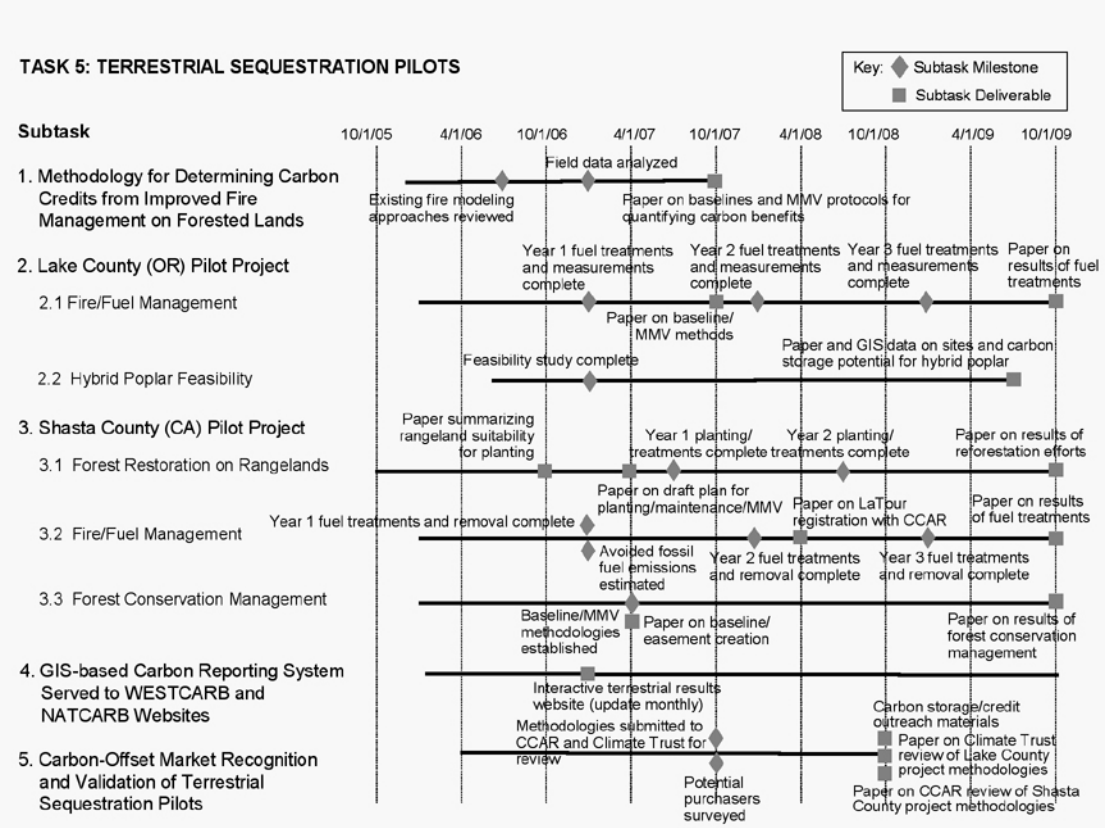


TASK 3: NORTHERN ARIZONA SALINE FORMATION CO_2 STORAGE PILOT (cont'd)



TASK 4: INVESTIGATIONS FOR ADDITIONAL CO_2 STORAGE PILOTS (CENTRALIA AND KIMBERLINA SITE CHARACTERIZATION CO_2 STORAGE PILOTS)




TASK 5: TERRESTRIAL SEQUESTRATION PILOTS
Key: Subtask Milestone
Subtask Deliverable
Subtask
10/1/05
4/1/06
10/1/06
4/1/07
10/1/07
4/1/08
10/1/08
4/1/09
10/1/09
1. Methodology for Determining Carbon Credits from Improved Fire Management on Forested Lands
Field data analyzed
Existing fire modeling approaches reviewed
Paper on baselines and MMV protocols for quantifying carbon benefits
2. Lake County (OR) Pilot Project
2.1 Fire/Fuel Management
Year 1 fuel treatments and measurements complete
Year 2 fuel treatments and measurements complete
Year 3 fuel treatments and measurements complete
Paper on results of fuel treatments
Paper on baseline/ MMV methods
2.2 Hybrid Poplar Feasibility
Feasibility study complete
Paper and GIS data on sites and carbon storage potential for hybrid poplar
3. Shasta County (CA) Pilot Project
3.1 Forest Restoration on Rangelands
Paper summarizing rangeland suitability for planting
Year 1 planting/ treatments complete
Year 2 planting/ treatments complete
Paper on results of reforestation efforts
3.2 Fire/Fuel Management
Paper on draft plan for planting/maintenance/MMV
Year 1 fuel treatments and removal complete
Paper on LaTour registration with CCAR
Paper on results of fuel treatments
Avoided fossil fuel emissions estimated
Year 2 fuel treatments and removal complete
Year 3 fuel treatments and removal complete
3.3 Forest Conservation Management
Baseline/MMV methodologies established
Paper on baseline/ easement creation
Paper on results of forest conservation management
4. GIS-based Carbon Reporting System Served to WESTCARB and NATCARB Websites
Interactive terrestrial results website (update monthly)
5. Carbon-Offset Market Recognition and Validation of Terrestrial Sequestration Pilots
Methodologies submitted to CCAR and Climate Trust for review
Carbon storage/credit outreach materials
Paper on Climate Trust review of Lake County project methodologies
Potential purchasers surveyed
Paper on CCAR review of Shasta County project methodologies

Appendix A: Pilot Project Activities in Phase II SOPO

Appendix A lists the pilot project activities as described in the Phase II Statement of Project Objectives (SOPO).

Task 2. Rosetta Resources Saline Formation and Gas Reservoir CO_2 Storage Pilots

Two pilot tests of CO_2 injection will be performed at Rosetta Resources' Thornton gas reservoir near Rio Vista, California. Obtaining the regulatory permits and public outreach will be included as an essential component of both tests. The first test will inject approximately 2000 tonnes of CO_2 into a saline formation below the Thornton Gas Reservoir. The second test will inject 2000 tonnes of CO_2 into a depleted compartment of the Thornton Gas Reservoir and assess storage potential and any enhanced gas recovery due to reservoir pressurization and displacement of residual methane by CO_2.

CO_2 will be acquired from local supplier and trucked to the pilot test site. Ultimately (beyond Phase II), a nearby power plant in Antioch, California, could supply CO_2 for a larger demonstration (or commercial storage/EGR operations) if a CO_2 separation unit were installed. An observation well completed in the storage formation will be used to directly observe CO_2 migration in the storage formation and for bore and surface-to-borehole geophysical monitoring. Both tests will take place with the same pair of injection and observation wells, thus making the test more cost-effective.

The approach to the pilot test is based on experience gained during the Frio Brine Pilot Injection Test—modified to reflect local opportunities and conditions. In particular, WESTCARB will carry out detailed, site-specific pre-test simulations to predict the behavior of CO_2 in the storage formations. These detailed simulations will provide the basis for determining the distance between the injection and observation wells, the amount of CO_2 that needs to be injected to ensure breakthrough at the observation wells. These simulations, combined with forward and inverse geophysical modeling will be used to ensure that geophysical methods will be sufficiently sensitive to detect and quantify the presence and behavior of CO_2. Pending possible revisions from more detailed simulations, WESTCARB plans to drill the injection and observation wells 50 meters apart and inject 2000 tonnes of CO_2 for each pilot test. With this well spacing and quantity of CO_2, breakthrough is assured and geophysical monitoring approaches should be sufficiently sensitive.

Simulation of the CO_2 injection and storage based on detailed site-specific hydrogeological models will be performed and act as a guide to the final test design. The modeling codes TOUGH2 and TOUGHREACT will be used for this purpose (Pruess et al. 1999; Xu et al. 2004). A comprehensive set of monitoring techniques will be evaluated and deployed as part of the tests, aimed at monitoring CO_2 movement in the storage formation as well as checking for any leakage outside the primary storage formation. The combination of subsurface and surface measurements will be evaluated on

a site-specific basis to determine which will be most effective for tracking CO_2 movement before deciding which methods to deploy. In addition to these techniques, the multilevel fluid sampling system shown in Figure A-1 will be utilized for the gas field pilot test to allow careful evaluation of flow and transport processes that bear on the success of CSEGR.

After testing is completed, detailed analysis of the monitoring data will be performed, including assessing the storage security, estimating storage capacity and extrapolating the capacity over the region. Lesson learned from the pilots will be written and disseminated. Ongoing interaction with regulatory agencies, local community, and the public will keep people informed about progress and help provide confidence in the safety and feasibility of this technology.

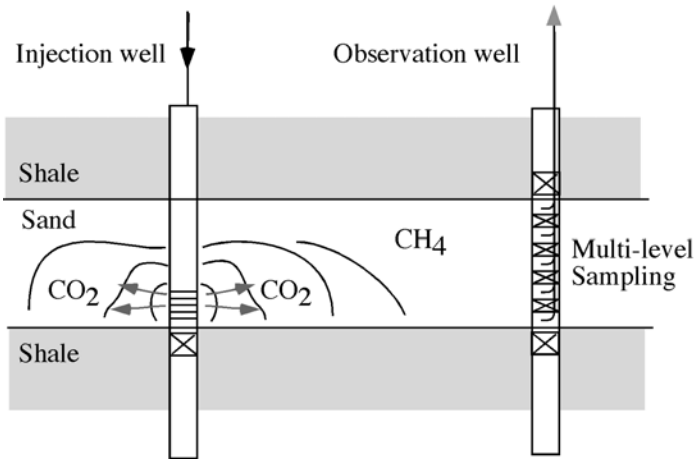


Figure A-1. Detail of CO_2 injection into gas reservoir showing injection in lower part of gas zone and multilevel sampler in observation well

Subtask 2.1: Detailed project management plan for the Rosetta Resources pilot tests

This subtask consists of developing a detailed project management plan for the Rosetta Resources pilot tests. The plan will include a resource-loaded work breakdown structure that lays out all of the tasks and their interrelationships over the course of the project. Project management software will be used to track progress and expenses to ensure that project objectives are satisfied.

Subtask 2.2: NEPA and CEQA documentation

This subtask consists of obtaining NEPA and CEQA documentation for pilot test. The work will be coordinated with the DOE and other Regional Partnerships to develop a consistent approach. WESTCARB expects that this project would be appropriately covered by an Environmental Assessment and it is anticipated that the assessment of the project will yield a Finding-of-No-Significant-Impact. A categorical exclusion, based on

the small-scale, experimental nature of the project, and connection to on-going commercial oil and gas operations, will be explored. WESTCARB expects that the pilot will require California Environmental Quality Act (CEQA) documentation.

Subtask 2.3: Pre-injection planning, permitting, safety, and outreach

This subtask consists of pre-test planning for the injection and monitoring program, permitting of the injection activities, development of a safety plan, and initiation of the outreach program. The 2nd-level subtasks describing this work appear in Table A-1.

Table A-2. 2nd-level subtasks associated with Subtask 2.3

Subtask	Description
Subtask 2.3.1	**Perform detailed analysis of the geology at the pilot test site.** Carry out CO_2 fate and transport simulations. Perform geophysical forward and inverse modeling to select and configure the monitoring program. Select injection and observation well spacing and CO_2 injection rates and quantities.
Subtask 2.3.2	Perform baseline simulations for planning the CO_2 injection pilot in the gas reservoir and saline formation.
Subtask 2.3.3	Develop a preliminary site-safety plan.
Subtask 2.3.4	**Initiate public outreach and educational activities for the community and interested public.** Public meetings will be held in the local community to inform the public before, during, and after the pilot tests. A site visit for interested citizens will be arranged before or after the injection phase of the project. Educational activities will be presented in local schools. Surveys will be conducted to determine how the opinion of the public changes before and after the pilot tests. (Planning will be handled through Subtask 1.4.)
Subtask 2.3.5	Obtain regulatory permits for the gas zone and brine zone pilot injections, entailing working with the California Department of Oil, Gas, and Geothermal Resources and U.S. EPA Region 9. In light of the planned injection into and below a gas reservoir, WESTCARB would initially request a permit for a Class II oil and gas production-related well.

Subtask 2.4: Site preparation and baseline data collection.

This subtask consists of preparing the injection and observation well sites, drilling the injection and recompleting an observation well (well condition may require drilling a new well), and collecting baseline monitoring data. The 2nd-level subtasks describing this work appear in Table A-2.

Table A-2. 2nd-level subtasks associated with Subtask 2.4

Subtask	Description
Subtask 2.4.1	Prepare the site for the injection, including preparing roads, utilities, and temporary shelter.
Subtask 2.4.2	Drill, log, and complete the 5.25-inch diameter injection well for the saline formation injection test.
Subtask 2.4.3	Recomplete an existing well for use as the observation well, or drill a new observation well.

Subtask	Description
Subtask 2.4.4	Obtain baseline geochemical data on the saline formation, including noble gas and isotopic characterization.
Subtask 2.4.5	Obtain baseline surface seismic of the gas and brine zones.
Subtask 2.4.1	Obtain baseline surface CO_2 concentration and CO_2 flux measurements.
Subtask 2.4.2	Perform simulations of test scenarios for test design and to make predictions against which measurements can be made.
Subtask 2.4.3	Update site safety plan in preparation for CO_2 injection.

Subtask 2.5: Perform CO_2 injection into the saline formation

This subtask consists of transporting CO_2 to the injection site, safely injecting CO_2 into a saline formation underneath Rosetta Resources' Thornton Gas Reservoir, monitoring CO_2 migration in the storage formation and at the surface. The 2nd-level subtasks describing this work appear in Table A-3.

Table A-3. 2nd-level subtasks associated with Subtask 2.5

Subtask	Description
Subtask 2.5.1	Install observation well U-Tube sampler in brine zone and related surface infrastructure.
Subtask 2.5.2	Install downhole pressure and temperature transducers in the injection and observation wells.
Subtask 2.5.3	Inject 2000 tonnes of CO_2 into saline formation while monitoring downhole pressure and temperature in injection and observation well, along with periodic U-Tube sampling of fluids from observation well. Monitor wellhead pressure in an array of surrounding wells in overlying gas zones to evaluate leakage.
Subtask 2.5.4	Use 2-D surface seismic to track lateral migration of CO_2 in the saline formation and look for evidence of leakage. Alternatively, or in addition, X-well seismic imaging will be used to determine the distribution of CO_2 in the region between the injection and observation wells.

Subtask 2.6: Perform CO_2 injection into the gas reservoir and evaluate CSEGR potential

This task consists of installing a multi-level sampling in an observation well, transporting CO_2 to the injection site, safely injecting CO_2 into the Thornton Gas Reservoir, collecting gas and CO_2 samples, monitoring CO_2 migration in the storage formation and at the surface. The 2nd -level subtasks describing this work appear in Table A-4.

Table A-4. 2nd-level subtasks associated with Subtask 2.6

Subtask	Description
Subtask 2.6.1	Perforate the injection well in the gas reservoir and install a multilevel packer-sampler in gas reservoir and related surface infrastructure.
Subtask 2.6.2	Inject 2000 tonnes of CO_2 into the gas reservoir while monitoring downhole

	pressure and temperature monitoring in injection and observation well. Monitor gas composition through continuous multilevel sampling. Monitor wellhead pressures in an array of surrounding wells.
Subtask 2.6.3	X-well seismic imaging will be used to determine the distribution of CO_2 in the region between the injection and observation wells.

Subtask 2.7 Post-injection storage security confirmation

This task consists of performing post-injection monitoring to confirm the CO_2 has not leaked from the storage formations or at the land surface. The 2nd-level subtasks describing this work appear in Table A-5.

Table A-5. 2nd-level subtasks associated with Subtask 2.7

Subtask	Description
Subtask 2.7.1	Obtain borehole logging for measuring CO_2 phase saturation around the injection and observation wells.
Subtask 2.7.2	Measure surface CO_2 saturations and fluxes to compare to the baseline data.
Subtask 2.7.3	Carry out a 2-D seismic survey to compare to baseline and detect leakage from the storage formations.

Subtask 2.8 Data analysis and reporting

This task consists of analyzing the monitoring data from the pilot tests, preparing required reports, publishing monitoring data on the WESTCARB website, presenting results at conferences, preparing articles for peer-reviewed journals and developing a lessons-learned report. The 2nd-level subtasks describing this work appear in Table A-6.

Table A-6. 2nd-level subtasks associated with Subtask 2.8

Subtask	Description
Subtask 2.8.1	Analyze the monitoring data from both pilot tests.
Subtask 2.8.2	Prepare comprehensive technical reports on both of the pilots, including assessment of storage security and capacity in the gas reservoir and saline formations in the northern portion of the Central Valley, CA. Disseminate these results through technical conferences, peer reviewed journal articles and participation in outreach meetings or other venues as requested.
Subtask 2.8.3	Disseminate the raw and processed data collected from the pilot tests to other research teams through the WESTCARB web site and the Utah AGRC GIS database. Prepare and make accessible meta-data so that the data can be accurately used by others interested in interpreting the data.
Subtask 2.8.4	Prepare a “lessons learned” report based on experience gained during the pilot test. Topics will include lessons learned from obtaining regulatory permits, public outreach, well site and injection operations, monitoring, simulation, and CSEGR.

Task 3. Northern Arizona Saline Formation CO_2 Storage Pilot

The Northern Arizona storage pilot consists of the three phases. After the completion of each phase, a decision will be made whether or not the results are sufficiently promising to warrant proceeding to the next phase of the pilot. The scope of work for each of the phases is described below.

- **Phase I: Pre-pilot planning, geologic characterization, and outreach**. At the beginning of Phase I a detailed project management plan will be developed for the pilot project. The scope of work for Phase I consists of developing a site-specific hydrogeologic model of sedimentary rocks underlying the Colorado Plateau in Northern Arizona. Rock samples will be gathered from outcrops and nearby boreholes, groundwater water samples will be collected, permeability and porosity will be measured on available samples. All of this data will be compiled to assess the storage potential of the region and identify the most promising storage targets. Concurrently, WESTCARB will meet with community leaders, local businesses, citizens, landowners, and other interested stakeholders to provide information about what the project is and why it being conducted—in an effort to gain support for the project and finalize the pilot location. Detailed plans for Phase II will be developed. NEPA documentation for the project will be developed during Phase I.
- **Phase II**: **Site characterization, detailed pilot project planning, and permitting.** The scope of work for Phase II consists drilling a borehole, nominally to a depth of 7000 feet, to characterize the storage potential of the target sandstones (which may be the Cedar Mesa sandstone, Redwall limestone, and Tapeats sandstone) and the sealing properties of the cap rocks (which may be the Organ and Blue Angel shales). If the storage formations and seals show sufficient promise, detailed plans for the CO_2 injection experiment, including the monitoring program, will be developed and permits for the CO_2 injection will be obtained. Meetings with the community will continue throughout Phase II.
- **Phase III: CO_2 injection, monitoring, and storage assessment.** The scope of work for Phase III consists of injecting approximately 2000 tonnes of CO_2 into the most promising storage formation and using a suite of monitoring tools to track migration and ensure compliance with all environment, health and safety requirements. CO_2 will be purchased and transported to the site for injection. Results from the test will be used to extrapolate the regional storage potential of the Colorado Plateau in Northern Arizona. The capacity of the storage formations will be assessed relative to the size of regional sources of CO_2. Meetings with the community will continue throughout Phase II.

PHASE I. PRE-PILOT PLANNING, GEOLOGIC CHARACTERIZATION, AND OUTREACH

Subtask 3.1: Develop a detailed project management plan for the Northern Arizona pilot test

A project management plan for the Northern Arizona pilot will be developed. The plan will have a resource-loaded work breakdown structure that lays out all of the subtasks and deliverables over the course of the project. Project management software will be used to track progress and expenses to ensure that project objectives are satisfied. The 2nd-level subtasks describing this work appear in Table A-7.

Table A-7. 2nd-level subtasks associated with Subtask 3.1

Subtask	Description
Subtask 3.1.1	Establish work-breakdown structure
Subtask 3.1.2	Set up Earned Value Management System

Subtask 3.2: Perform geological and petrophysical studies

This subtask consists of outcrop investigations, well log analysis, and core analyses to establish the permeability and porosity of the target sandstones. Investigations will be performed with data and representative samples obtained from wells closest to the proposed injection site (expected to be near a Salt River Project coal-fired power plant). The 2nd-level subtasks describing this work appear in Table A-8.

Table A-8. 2nd-level subtasks associated with Subtask 3.2

Subtask	Description
Subtask 3.2.1	Gather and analyze existing geological and well log data from nearby wells and outcrops
Subtask 3.2.2	Obtain a 2-D seismic survey over the pilot test site
Subtask 3.2.3	Evaluate outcrops of the storage formations.
Subtask 3.2.4	Obtain water quality samples from existing wells and analyze them for major elements
Subtask 3.2.5	Obtain core samples of the potential storage formations, if possible, and measure permeability and porosity
Subtask 3.2.6	Develop a detailed site-specific hydrogeological model of the storage formations and caprocks underlying the proposed injection site

Subtask 3.3: Simulate injectivity and storage characteristics

This subtask consists of carrying out simulation studies to establish the feasibility of injecting CO_2 into the target sandstones and evaluating physical and geochemical trapping mechanisms. The 2nd-level subtasks describing this work appear in Table A-9.

Table A-9. 2nd-level subtasks associated with Subtask 3.3

Subtask	Description
Subtask 3.3.1	Perform simulation studies using TOUGH2 to estimate injectivity and migration of CO_2 in the storage formations
Subtask 3.3.2	Perform simulation studies using TOUGH2 and TOUGHREACT and LLNL reactive transport code to estimate regional capacity of the target sandstones
Subtask 3.3.3	Perform detailed planning for well drilling program, including coring, logging, sampling, and testing

Subtask: 3.4 Initiate public outreach activities

This subtask consists of meeting with community leaders, local businesses, citizens, landowners, and other interested stakeholders to provide information about the project and its goals—in an effort to gain support for the project and identify a specific location for the pilot. Special concerns of the community will be identified and monitoring approaches and/or remedies to address these concerns will be identified. The 2nd-level subtasks describing this work appear in Table A-10.

Table A-10. 2nd-level subtasks associated with Subtask 3.4

Subtask	Description
Subtask 3.4.1	Hold discussions with stakeholders to establish a schedule of meetings
Subtask 3.4.2	Hold meetings
Subtask 3.4.3	Disseminate results of meetings and planned resolution of issued identified

Subtask 3.5: NEPA documentation

This subtask consists of obtaining NEPA documentation for pilot test. The work will be coordinated with the DOE and other Regional Partnerships to develop a consistent approach. WESTCARB expects that this project would be appropriately covered by an Environmental Assessment and it is anticipated that the assessment of the project will yield a Finding-of-No-Significant-Impact. A categorical exclusion, based on the small-scale and experimental nature of the project, will be explored.

PHASE II. SITE CHARACTERIZATION, DETAILED PILOT PROJECT PLANNING, AND PERMITTING

Subtask 3.6: Pre-drilling planning, permitting, safety, and outreach

This subtask consists of pre-test planning for drilling the site characterization borehole, permitting the drilling activities, development of a safety plan and continuation of the outreach program. The 2nd-level subtasks describing this work appear in Table A-11.

Table A-11. 2nd-level subtasks associated with Subtask 3.6

Subtask	Description
Subtask 3.6.1	Work with EPA Region 9 and ADEQ to obtain permits for drilling the site characterization well. Obtaining a Temporary Aquifer Protection Permit from the ADEQ will be explored.
Subtask 3.6.2	Develop a drilling site safety plan.
Subtask 3.6.3	Public meetings will be held in the local community to inform the public before, during, and after the pilot tests. A site visit for interested citizens will be arranged before or after the injection phase of the project. Educational activities will be presented in local schools. Surveys will be conducted to determine how the opinion of the public changes before and after the pilot tests.

Subtask 3.7: Site characterization, well drilling, and logging

This subtask consists of preparing the site for drilling the site characterization borehole, drilling and logging the borehole, collecting fluid samples from potential storage intervals, and conducting short-term water injection or pumping tests to measure the permeability of the target sandstones. If possible, core samples of the storage formations and caprocks will be collected. The 2nd-level subtasks describing this work appear in Table A-12.

Table A-12. 2nd-level subtasks associated with Subtask 3.7

Subtask	Description
Subtask 3.7.1	Prepare site for well drilling, including providing access roads, utilities, and temporary shelter
Subtask 3.7.2	Drill initial site characterization borehole, to be converted to injection well: depth 7000 ft
Subtask 3.7.3	Obtain well logs from characterization borehole
Subtask 3.7.4	Develop a 3-D geological model from the available data
Subtask 3.7.5	Obtain baseline pressure and temperature profile from characterization borehole
Subtask 3.7.6	Obtain baseline water quality from potential storage horizons
Subtask 3.7.7	Obtain field-scale permeability measurements of the target sandstones using drill stem tests or short term water injection tests

Subtask 3.8: Assessment of the most promising storage options

This subtask consists of evaluating the feasibility of CO_2 storage in the target sandstones underlying the proposed injection site (expected to be near a Salt River Project coal-fired power plant). The 2nd-level subtasks describing this work appear in Table A-13.

Table A-13. 2nd-level subtasks associated with Subtask 3.8

Subtask	Description
Subtask 3.8.1	Perform simulations to assess the most promising formation for CO_2 storage in the region surrounding a Salt River Project coal-fired power plant
Subtask 3.8.2	Consult with stakeholder such as the Navajo Nation, Arizona Geological Survey, and other organizations to obtain input on the most appropriate storage options.
Subtask 3.8.3	Decide on whether to perform the CO_2 storage test on the target sandstones.

PHASE III. CO_2 INJECTION, MONITORING, AND STORAGE ASSESSMENT

Subtask 3.9: Pre-injection planning, permitting, and safety

This subtask consists of pre-test planning for the injection and monitoring program, permitting of the injection activities, development of a safety plan, and initiation of the outreach program. The 2nd-level subtasks describing this work appear in Table A-14.

Table A-14. 2nd-level subtasks associated with Subtask 3.9

Subtask	Description
Subtask 3.9.1	Perform baseline simulations for planning the CO_2 injection pilot in the selected saline formation. Perform geophysical forward and inverse modeling to select and configure the monitoring program. Select injection rates and quantities.
Subtask 3.9.2	Develop a preliminary site-safety plan for the CO_2 injection experiment.
Subtask 3.9.3	Obtain permits for the CO_2 injection pilot, entailing working with EPA Region 9 , AOGCC, the Arizona Department of Environmental Quality, and possibly the Navajo Nation.

Subtask 3.10: Site preparation and baseline data collection for injection

This subtask consists of preparing the well site for the injection test and collecting baseline-monitoring data. The 2nd-level subtasks describing this work appear in Table A-15.

Table A-15. 2nd-level subtasks associated with Subtask 3.10

Subtask	Description
Subtask 3.10.1	Prepare the site for the injection, including storage tanks, pumps, and safety equipment; recomplete well as necessary.
Subtask 3.10.2	Obtain baseline geochemical data on the saline formation, including noble gas and isotopic characterization.
Subtask 3.10.3	Obtain baseline surface CO_2 concentration and CO_2 flux measurements.
Subtask 3.10.4	Perform simulations of test scenarios for test design and to make predictions against which measurements can be made.
Subtask 3.10.5	Perform baseline high-resolution 2-D or VSP seismic measurements.

Subtask 3.11: Perform CO_2 injection into the saline formation

This subtask consists of transporting CO_2 to the injection site, safely injecting CO_2 into a saline formation, monitoring CO_2 migration in the storage formation and at the surface. The 2nd-level subtasks describing this work appear in Table A-16.

Table A-16. 2nd-level subtasks associated with Subtask 3.11

Subtask	Description
Subtask 3.11.1	Install downhole pressure and temperature transducers in the injection well. Install a passive seismic monitoring system to observe induced seismicity.
Subtask 3.11.2	Inject 2000 tonnes of CO_2 into saline formation while monitoring downhole pressure and temperature in the injection well.

Subtask 3.12: Post-injection storage security confirmation

This Subtask consists of performing post-injection monitoring to confirm the CO_2 has not leaked from the storage formations or at the land surface. The 2nd-level subtasks describing this work appear in Table A-17.

Table A-17. 2nd-level subtasks associated with Subtask 3.12

Subtask	Description
Subtask 3.12.1	Obtain borehole logs for measuring CO_2 phase saturation around the injection well.
Subtask 3.12.2	Measure surface CO_2 saturations and fluxes to compare to the baseline data.
Subtask 3.12.3	Use a combination of geophysical monitoring techniques to track

	movement of CO_2 in the subsurface. Likely techniques include VSP and surface seismic reflection.

Subtask 3.13: Data analysis and reporting

This Subtask consists of analyzing the monitoring data from the pilot tests, preparing required reports, publishing monitoring data on the WESTCARB website, presenting results at conferences, preparing articles for peer-reviewed journals and developing a lessons-learned report. The 2nd-level subtasks describing this work appear in Table A-18.

Table A-18. 2nd-level subtasks associated with Subtask 3.13

Subtask	Description
Subtask 3.13.1	Analyze the monitoring data from the pilot test.
Subtask 3.13.2	Prepare comprehensive technical reports on the pilot, including assessment of storage security and capacity in the target formations in northern Arizona. Disseminate these results through technical conferences, peer reviewed journal articles and participation in outreach meetings or other venues as requested.
Subtask 3.13.3	Disseminate the raw and processed data collected from the pilot tests to other research teams through the WESTCARB web site and the AGRC database. Prepare and make accessible meta-data so that the data can be accurately used by others interested in interpreting the data.

Subtask 3.14: Site cleanup and well closure

After the pilot test is complete the site will be restored to conditions required by Arizona law and the wells will be abandoned in accordance with state regulations. The 2nd-level subtasks describing this work appear in Table A-19.

Table A-19. 2nd-level subtasks associated with Subtask 3.14

Subtask	Description
Subtask 3.14.1	Remove surface facilities and restore site to its initial condition.
Subtask 3.14.2	Plug and abandon the injection well.

Task 4. Investigations for Additional CO_2 Storage Pilots (Centralia Geologic Formation and Kimberlina Saline Formation and Oil Field CO_2 Storage Pilots)

The objective of this task is provide an in-depth assessment of the storage potential for two additional geologic formations with significant storage potential in the West: coal-bed/other formations near TransAlta's 1400-MW coal-fired Centralia power plant in

Washington, and San Joaquin Valley sediments underlying the Clean Energy Systems prototype 5-MW oxygen-fired power plant at Kimberlina, California. Both of these sites offer the potential for revenue generation to offset the costs of storage: from enhanced coal-bed methane recovery near the Centralia site in Washington, and from enhanced oil recovery near the Kimberlina site in California.

Subtask 4.1: Centralia Geologic Formation Storage Assessment

Specific objectives for the Centralia Geologic Formation Storage investigations are: (1) to evaluate the potential CO_2 injectivity and storage potential of deep Puget Sound coal seams and other potential geologic formations near the Centralia plant, (2) to develop a concept and preliminary planning for a pilot test and, (3) scale up study results to the region to refine WESTCARB's highly preliminary estimate of 2.8 Gt storage potential and to identify engineering techniques needed to achieve large-scale geologic sequestration in the greater Puget Sound area.

The scope of the proposed Centralia storage investigation has three principal components:

- ***Geologic/engineering evaluation of Centralia corehole database.*** Use proprietary coal exploration corehole data provided by partner TransAlta to evaluate the detailed geology and reservoir characteristics of deep coals at the Centralia coalfield.
- ***Scope a CO_2 injection pilot.*** Establish the scope for a potential Phase II CO_2 injection pilot, as well as improved engineering approaches and cost reductions that could promote large-scale CO_2 storage in the region.
- ***Scale-up to NW region.*** Refine the estimate of geologic storage capacity and quality of Puget Sound coals, which have reservoir conditions generally similar to those of the Centralia coal field (e.g., depth, thickness, rank, storage capacity, etc.).

The 2nd-level subtasks describing this work appear in Table A-20.

Table A-20. 2nd-level subtasks associated with Subtask 4.1

Subtask	Description
Subtask 4.1.2	**Assess Centralia CO_2 storage potential.** Characterize the CO_2 storage potential of the Centralia coalfield, high-grade CO_2 injection options, and select location for a potential CO_2 injection site.
Subtask 4.1.3	**Characterize regional CO_2 storage capacity.** Integrate study results with regional analysis of Northwest coal deposits to refine estimates of regional CO_2 storage capacity and reservoir quality. Make data and results of analyses available through the WESTCARB web site and the AGRC database.
Subtask 4.1.4	**Develop an engineering concept and plan for a pilot CO_2 storage test.** Evaluate pilot design and operation options. Design factors include number of well(s) and coal seam injection targets; well drilling, completion, and stimulation methods; volume, timing, and physical properties of CO_2 injected; and testing and monitoring procedures.

	Develop cost estimate and design for a potential CO_2 injection pilot.

Subtask 4.2: Kimberlina Saline Formation and Oil Field Storage Assessment

Specific objectives of the Kimberlina site investigations are develop a detailed geological model for assessing the storage options in depleting oil fields near the Kimberlina power plant and/or the saline formations directly underlying it. In addition, a plan for a CO_2 injection pilot test will be developed, which could provide the basis for an integrated demonstration that combines a unique power generation and CO_2 capture technology with geologic storage. This work will complement ongoing regional storage characterization in the San Joaquin Valley performed by the California Geological Survey.

The scope of the Kimberlina investigations has two principal components:

- ***Geologic/engineering evaluation of geological and hydrocarbon database.*** A detailed site assessment will be conducted. This would include a detailed well-log correlation in the subsurface, analysis and interpretation of core and cuttings data, gathering of brine and hydrocarbon composition, and simple numerical modeling.
- ***Scope out CO_2 Injection Pilot.*** Scope out a potential Phase II CO_2 injection pilot, as well as improved engineering approaches and cost savings that could promote large-scale CO_2 storage in the region.

The 2nd-level subtasks describing this work appear in Table A-21.

Table A-21. 2nd-level subtasks associated with Subtask 4.2

Subtask	Description
Subtask 4.2.1	**Gather and evaluate existing data from saline formations and oilfield in the immediate vicinity of the Kimberlina power plan.** Conduct a detailed geologic investigation of storage opportunities in nearby oilfields and saline formations underlying the Kimberlina Power plant. Evaluate the storage capacity of these formations relative to the CO_2 sources in the region and compared to emissions from the 5 MW oxygen-fired power plan. Perform simulations to substantiate volumetric capacity assessments, including the potential for EOR. Make data available through the WESTCARB web site and the AGRC database.
Subtask 4.2.2	**Develop an engineering concept and plan for a pilot CO_2 storage test.** Evaluate pilot design and operation options. Design factors include number of well(s), injection targets; well drilling, completion, and stimulation methods; volume, timing, and physical properties of CO_2 injected; and testing and monitoring procedures. Develop cost estimate and design for a potential CO_2 injection pilot.

Task 5. Terrestrial Sequestration Pilots (Shasta County, CA, and Lake County, OR)

The goal of this task is to implement two terrestrial CO_2 storage pilots (one in Shasta County, CA and one in Lake County, OR), each encompassing—and resolving key uncertainties—for the region's largest sequestration opportunities: reforestation of once-forested lands now used for agriculture or grazing (either with natural species or fast-growing hybrid poplars), forest fuel load reduction for improved fire management (i.e., reducing the probability of uncharacteristically severe wildfires and accompanying massive CO_2 releases), and improved forest conservation management to increase standing timber carbon storage.

Subtask 5.2: Lake County (OR) Pilot Project

This task has two components: a pilot project on fuel treatments and a pilot project investigating the carbon sequestration potential of hybrid poplars. The 2nd-level subtasks describing this work appear in Table A-22.

Table A-22. 2nd-level subtasks associated with Subtask 5.2

Subtask	Description
Subtask 5.2.1	**Review and classify lands where fuel treatments will occur.** Through consultation with local partners and GIS analysis the lands where treatments will occur will be examined and documented.
Subtask 5.2.2	**Design measurement and monitoring plan.** A detailed project design package and management plan will be developed**.** Building from the research in Task 5.1 an MMV plan will be created including the form, timing, and location of activities.
Subtask 5.2.3	**Take field measurements.** Field measurements will be taken to determine the fuel load and the carbon stocks prior to treatment.
Subtask 5.2.4	**Carry out fuel treatments for Year Two.** Treatments will be carried out including cutting and removal of fuels, and the piling and burning of fuels.
Subtask 5.2.5	**Collect data on treatment costs.** Concurrent to treatment activities data will be collected on the costs of treatment so that the future viability of fuel management activities with and without carbon financing can be evaluated.
Subtask 5.2.6	**Take post-treatment measurements.** Measurements will be taken on the forest carbon stocks after fuel removal, plus the biomass of removed fuel. If any fires occur, the relative damage between treated and untreated areas will be examined.
Subtask 5.2.7	**Report results.** Results will be reported to all stakeholders and posted in an interactive ARC-IMS web accessible format
Subtask 5.2.8	**Carry out measurements and fuel treatments for Year Three.**
Subtask 5.2.9	**Carry out measurements and fuel treatments for Year Four.**
Subtask 5.2.10	**Prepare analysis of hybrid poplar.** The carbon sequestration potential of hybrid poplar will be evaluated using data from Greenwood Resources experience including an analysis of the impact terrestrial sequestration benefits could have on the economic attractiveness of hybrid poplar for local landowners.
Subtask 5.2.11	**Identify and rank candidate sites.** Based on the analysis in 5.2.1, a GIS analysis will identify and then rank suitable sites for future hybrid poplar plantations.
Subtask 5.2.12	**Seek voluntary pilot site participants.** Although funds for pilot activities have not been included in the proposal, it may be possible to use methods developed for the Shasta County pilot project to carry out measurements for voluntary participants planning to establish hybrid poplar projects in Lake County.
Subtask 5.2.13	**Collect field data to validate assumptions for analysis**. Field data will be collected to validate the GIS-derived assumption on growth potential of hybrid poplar across growth sites. The sequestration potential will be compared to the biotic and physical characteristics of the growth sites.

Subtask 5.3: Shasta County (CA) Pilot Project

This task has three components: a pilot project validating Phase I determinations of high growth potential for forests planted on rangelands, a pilot project on fuel treatments and a pilot project examining the carbon benefits of conservation management on timberlands. The 2nd-level subtasks describing this work appear in Table A-23.

Table A-23. 2nd-level subtasks associated with Subtask 5.3

Subtask	Description
Rangeland Reforestation (Tree Planting)	
Subtask 5.3.1	**Validation of growth potential for rangelands.** Based on Phase I WESTCARB analyses, large areas of rangelands have both a history of forest cover and the necessary conditions for current forest growth.
Subtask 5.3.2	**Review and classify rangelands that appear suited for forest from Phase I analysis.** Building from research in Phase I, areas that analysis revealed were suited to forest growth in Shasta County will be further studied and classified. Classification will be on the basis of the most suitable species for reforestation and the potential carbon benefit that will arise from reforestation for sites that will be additional.
Subtask 5.3.3	**Prepare plan for planting and maintenance of species selected for largest classes of rangeland with potential for conversion.** A detailed project design package and management plan will be developed. A planting and management plan will be prepared detailing necessary site preparation and subsequent fuel treatments, thinnings, and controlled burns required to maintain forest and maximize carbon sequestration. Plans will be developed through examination of plantings in the region and discussions with local experts.
Subtask 5.3.4	**Convene Technical Panel to review plan.** Experts from CDF, the timber industry, forest research stations, and local landowners will review and, where necessary, amend the plan.
Subtask 5.3.5	**Review site history and take field measurements prior to site preparation to establish baseline.** The baseline should show that forestation would not have occurred in the absence of project intervention, for this purpose the history of the site and surrounding sites with similar conditions will be reviewed. The baseline should also show the carbon stock in the without-project scenario, so the prevalent carbon on the rangelands will be estimated in the field with precision.
Subtask 5.3.6	**Implement plan for Year Two.** Including site preparation, planting, and management treatments.
Subtask 5.3.7	**Implement plan for Year Three.** Including site preparation, planting, and management treatments.
Subtask 5.3.8	**Implement plan for Year Four.** Including site preparation, planting, and management treatments.
Fuel Management	
Subtask 5.3.9	**Review and classify lands where fuel treatments will occur.** Through consultation with local partners and GIS analysis, the lands where treatments will occur will be examined and documented.
Subtask 5.3.10	**Design measurement and monitoring plan.** A detailed project design package and management plan will be developed. Building from the research in Task 5.1 an MMV plan will be created including the form, timing, and location of activities.
Subtask 5.3.11	**Take field measurements.** Field measurements will be taken to determine the fuel load and the carbon stocks prior to treatment.
Subtask 5.3.12	**Carry out fuel treatments for Year One.** Treatments will be carried out including cutting and removal of fuels, and the transport of fuels to roadside.
Subtask 5.3.13	**Transport fuel to Wheelabrator.** Once removed from the forest, fuels will be transported to Wheelabrator biomass energy plant for power generation.
Subtask 5.3.14	**Collect data on treatment and transport costs.** Concurrent to treatment activities data will be collected on the costs of treatment and transport so that

Subtask	Description
	the future viability of fuel management activities with and without carbon financing can be evaluated.
Subtask 5.3.15	**Analyze carbon benefits from biomass energy production.** The degree to which biomass energy from fuel treatments is displacing more carbon intensive fuels (such as coal) and the carbon benefit of fossil fuel displacement will be calculated.
Subtask 5.3.16	**Take post-treatment measurements.** Measurements will be taken on the forest carbon stocks after fuel removal, plus the biomass of removed fuel. If any fires occur the relative damage between treated and untreated areas will be examined.
Subtask 5.3.17	**Report results.** Results will be reported to all stakeholders and posted in an interactive ARC-IMS web accessible format
Subtask 5.3.18	Carry out measurements and fuel treatments for Year Three
Subtask 5.3.19	**Carry out measurements and fuel treatments for Year Four**
Forest Conservation Management	
Subtask 5.3.20	**Develop easement.** A carbon benefit can result from any management practice that exceeds the state-mandated minimum conservation standards. An easement will be put in place to guarantee the maintenance of the conservation management.
Subtask 5.3.21	**Design measurement and monitoring plan.** A detailed design package and management plan will be developed. An MMV plan will be developed that captures the variability in carbon stocks that arises as a result of the forest management. The with-project stocks and, in an adjacent representative area, the without-project stocks will be monitored.
Subtask 5.3.22	**Take baseline measurements.** Baseline measurements will be taken on the project site before the start of the project.
Subtask 5.3.23	**Take Year Four measurements.** In Year Four, measurements will be taken to show the enhancement in carbon stocks as a result of the project.
Subtask 5.3.24	**Coordinate site access and measurements.** The project will be carried out on private lands where landowners want be kept informed of the timing and scope of activities to be carried out on their lands.
Subtask 5.3.25	**Coordinate site access and measurements.** The project will be carried out on private lands where landowners want be kept informed of the timing and scope of activities to be carried out on their lands.
Subtask 5.3.26	**Develop easement.** A carbon benefit can result from any management practice that exceeds the state-mandated minimum conservation standards. An easement will be put in place to guarantee the maintenance of the conservation management.

Subtask 5.4: Develop a GIS-based project carbon reporting system served to WESTCARB and NATCARB web pages

The task consists of creating a reporting system that is Internet-based and is interactive for the user, consistent with the systems being used for WESTCARB and NATCARB geologic characterization. The GIS software ARC IMS will be used. The 2nd-level subtasks describing this work appear in Table A-24.

Table A-24. 2nd-level subtasks associated with Subtask 5.4

Subtask	Description
Subtask 5.4.1	**Design geographic reporting system.** Project activities will be carried out at specific sites in the region. Data and photos from individual sites will be entered into a geographic information system so that project participants and the public can access different levels of information on project activities. Content will be linked to the web using ArcIMS in a format consistent with WESTCARB and NATCARB characterization reporting.
Subtask 5.4.2	**Develop tools and procedures for data integration for fuel load management.** Partners will be trained in the methods and formats for collecting data and photos.
Subtask 5.4.3	**Develop tools and procedures for data integration from validation of forest growth potential for rangelands.** Partners will be trained in the methods and formats for collecting data and photos.
Subtask 5.4.4	**Update monthly.**

Task 5.5: Achieve carbon offset market recognition and validation of terrestrial sequestration pilots

This task has four components: Development of acceptable methods and procedures for reporting carbon benefits from changing fire management, preparation of necessary documentation to register all pilot project activities on the California Climate Action Registry, review and acceptance of carbon benefits by available markets (e.g., DOE 1605(b) voluntary reporting, Climate Trust, Chicago Climate Exchange, etc.), and outreach. The 2nd-level subtasks describing this work appear in Table A-25.

Table A-25. 2nd-level subtasks associated with Subtask 5.5

Subtask	Description
Subtask 5.5.1	**Survey potential purchasers to determine market requirements.** Partners will identify potential markets that could recognize carbon benefits achieved under the pilot project activities and obtain information on market requirements.
Subtask 5.5.2	**Develop protocol for fire and fuel management on forestlands.** See Task 1 for the process that will be used to prepare baselines and measurement and monitoring methods. As one of the partners, CCAR will independently work to develop a protocol for fire management.
Subtask 5.5.3	**CCAR and Climate Trust review.** The partners will submit all activities carried out under pilot projects for review by the California Climate Action Registry and by The Climate Trust. Projects may also be submitted to other potential markets identified by project partners.
Subtask 5.5.4	**Develop materials with industry associations**. Preparing materials that address concerns and questions from the OR and CA forest products industries will improve dissemination of pilot results.
Subtask 5.5.5	**Develop materials with land managers.** Preparing materials that address concerns and questions from land managers will improve dissemination of pilot results. Special attention will be given to reaching public land managers.
Subtask 5.5.6	**Implement public outreach activities.** The partners will identify appropriate industry associations that will use results from the pilot project activities to inform members about how to organize activities with potential carbon benefits.