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FINAL PROJECT REPORT

STUDIES IMPACTING GEOLOGIC CARBON SEQUESTRATION POTENTIAL IN CALIFORNIA:

- Offshore Carbon Sequestration Potential
- Sacramento Basin Salinity Investigation of Select Formations
- Sacramento Basin Hydrocarbon Pool Size Distribution

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PREFACE

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ABSTRACT

This report investigates sequestration potential in California's offshore sedimentary basins to capture and hold carbon dioxide from the state's gas fields; impacts of the U. S. Environmental Protection Agency underground drinking water standard on potential sequestration in parts of California; and impacts of oil and gas pool compartmentalization on carbon sequestration in California's gas fields.

Thirty offshore fields containing conventional sandstone reservoirs are known within the Ventura and Los Angeles basins. The 24 producing or depleted fields have an estimated cumulative CO_2 storage capacity of 236,389,518 metric tons. Six additional undeveloped oil fields may provide an additional 3,194,080 metric tons of potential CO_2 storage capacity.

Statewide evaluation of the impacts of U. S. EPA drinking water standards on geologic sequestration in California is impractical due to a lack of information The study addresses this lack of information. Salinities calculated from geophysical well logs are used to identify low salinity areas within the Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin. These calculations identified only one small low salinity area in the Mokelumne River formation. The estimated storage capacity for the combined formations was decreased by 6 percent to 8 percent to allow for the identified low salinity area.

In many California oil and gas fields, hydrocarbons are not produced from single large reservoirs, but from multiple compartments or "pools" of varying capacities. To investigate the degree of this compartmentalization, pool size distributions for three typical gas fields - the Bunker, Millar, and Conway Ranch fields in the southern Sacramento Basin - are evaluated. Findings suggest that only 14 pools out of the 313 that were identified have potential capacities exceeding 0.5 million tons of CO_2. By field, these 14 pools could provide for 15.2 million tons of storage capacity in Bunker Field (5 pools), 7.0 million tons (7 pools) in Millar Field, and 2.0 million tons (2 pools) in Conway Ranch Field.

Keywords: Carbon dioxide, CO_2, carbon sequestration, geologic sequestration, storage, offshore basins, salinity, reservoir compartmentalization, oil and gas pools

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EXECUTIVE SUMMARY

Background

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is exploring opportunities in seven western states and one Canadian province for removing carbon dioxide (CO_2) from the atmosphere by enhancing natural processes and by capturing it at industrial facilities and storing it securely underground before it is emitted. Such measures will help slow the atmospheric buildup of this greenhouse gas and its associated climatic effects.

Prior WESTCARB Phase I and II studies by the Department of Conservation, California Geological Survey (CGS), provided an initial screening of the geologic sequestration potential of California's onshore sedimentary basins and a regional evaluation of sequestration potential in the southern Sacramento Basin.

The Phase I study involved identifying and characterizing porous and permeable rock formations in 104 onshore sedimentary basins and defining areas within these basins that may be geologically suitable for CO_2 sequestration. This resulted in identifying 27 sedimentary basins (a low area in the earth's crust in which sediments accumulate) possessing varying potentials for CO_2 sequestration. Among the most promising are California's marine sedimentary basins that contain thick sedimentary sections, multiple saline aquifers and oil and gas reservoirs and widespread shale seals, and for which significant geological data is already available from petroleum exploration and production. The larger basins identified are the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins. Estimates of potential storage capacity for the 10 largest onshore basins ranged from 30 to 420 gigatons of CO_2.

The Phase II study evaluated the regional geology of the Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin to better define those areas exhibiting carbon sequestration potential. These formations contain the most aerially extensive sandstone units within the basin meeting minimum depth requirements for CO_2 injection. Sandstone within these formations also accounts for a large part of the natural gas production in the southern Sacramento Basin and comprise the bulk of the saline aquifers within the basin. The estimated storage resource for these three formations was estimated to be 3.5 to 14.1 gigatons of CO_2.

Purpose

The three studies presented in this report expand upon the WESTCARB Phase I and II studies by addressing three separate questions left unanswered by the previous studies:

- What is the potential for geologic sequestration in California's offshore sedimentary basins?
- What are the impacts of the U. S. Environmental Protection Agency's underground drinking water standard of 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) on potential sequestration in selected California basins?

- What impact does compartmentalization within existing oil and gas fields have on carbon sequestration potential within abandoned hydrocarbon reservoirs?

To address these questions, three studies were undertaken by CGS.

Researchers launched an investigation to characterize California's offshore basins in a manner similar to that used in the Phase I onshore evaluation. However, a lack of available information on offshore geology prevented mapping and the subsequent determination of potential CO_2 storage capacity within these offshore saline aquifers. Consequently, storage capacities were calculated only for the known developed and undeveloped offshore oil and gas fields. Consistent with the Phase I evaluation, only conventional sandstone reservoirs in offshore basins were considered. Fractured Monterey shale reservoirs, principally in the Santa Maria and Ventura basins, were omitted from consideration due largely to the difficulty in characterizing fractured reservoirs and the association of known sea floor seeps within many of these reservoirs.

Detailed analytical information on formation water salinity in California basins is generally unavailable. Where it exists, water quality data is typically proprietary and resides in the files of the oil and gas companies that have explored for and/or developed gas and oil reserves in the basin. Because of this, a statewide evaluation of sequestration limitations imposed by the U. S. Environmental Protection Agency's underground drinking water standard of 10,000 mg/l total dissolved solids on potential sequestration within California basins was not practical. However, salinity can often be calculated from geophysical oil and gas well logs. In this study, researchers used salinities calculated from spontaneous potential logs to identify areas of low salinity (less than 10,000 mg/l TDS) and further refine those areas exhibiting the most potential for CO_2 sequestration in the Mokelumne River, Starkey, and Winters formations of the Sacramento Basin.

Geologic sequestration requires identifying suitable storage reservoirs having appropriate characteristics (depth, porosity, seals, and so forth) and capacity to sequester a CO_2 stream from a source, typically a power plant, refinery, or other industrial facility. Such CO_2 producing facilities often have a life of 30 years or more. Because of the large costs involved in the construction and operation of such facilities, it seems likely that operators will want to identify storage reservoirs with enough capacity to sequester the entire projected CO_2 stream over the life of the facility. One proposed means of sequestering this CO_2 is to inject it into abandoned oil or gas fields, filling the space previously occupied by hydrocarbons with CO_2. In many California oil and gas fields, hydrocarbons are not produced from a single large reservoir, but rather from multiple compartments or "pools" of varying capacities representing separate trapped hydrocarbon accumulations. As a result, the total storage capacity calculated from historic oil and gas production from a field may actually be split among a few to many smaller pools. Variation in pool size will potentially affect the economics and practicality of sequestration in depleted oil and gas fields. To evaluate the amount of compartmentalization that might occur, the pool size distribution for three typical gas fields in the southern Sacramento Basin was evaluated.

Conclusions

Geologic Carbon Sequestration Potential in California's Offshore Basins

The lack of publicly available geologic data precluded regional mapping of the saline aquifers which might be available for CO_2 sequestration within California's offshore sedimentary basins. Instead, CO_2 storage capacity estimates were calculated based only on replacement volumetrics for estimated ultimate recoveries of oil and gas in known developed and undeveloped offshore oil and gas fields.

Twenty sedimentary basins lie offshore, or extend offshore, from mainland California, but only three of these basins - the Ventura, Los Angeles, and Santa Maria - contain known oil and gas fields. Many of the known offshore oil reservoirs in the Ventura and Santa Maria basins consist of fractured Monterey Formation shales, which are considered unsuitable for sequestration due to the difficulty in characterizing fractured reservoirs as well as their known association with sea floor seeps.

Thirty offshore oil and gas fields with conventional sandstone reservoirs have been discovered within the Ventura and Los Angeles basins. Of these, 24 fields are producing or have been depleted and are likely the most promising options for potential offshore carbon sequestration based on the reliability of existing production figures and reserve estimates. These fields have a cumulative estimated CO_2 storage capacity of 236,389,518 metric tons. An additional six oilfields have been discovered but remain undeveloped in federal offshore waters. Since these fields have not been produced or delineated by subsurface well control, their reserve estimates remain highly speculative. Based on current reserve estimates, these fields represent additional CO_2 storage capacity of 3,194,080 metric tons.

Salinity in the Mokelumne River, Starkey, and Winters Formations – Southern Sacramento Basin, California

The Mokelumne River, Starkey, and Winters formations of the southern Sacramento Basin all contain significant thicknesses of porous and permeable sandstone that may be suitable for carbon sequestration within existing or abandoned gas and oil fields, or saline aquifers. Previously, the CGS identified areas within these formations exhibiting the most potential based only on minimum depth (1,000 meters) and seal thickness (100 feet [ft]) constraints. Consideration of formation water quality, in respect to eliminating those areas that may one day prove to be potential underground drinking water sources (< 10,000 mg/l TDS), has resulted in a reduction of the area underlain by Mokelumne River Formation sandstone presented previously. Relatively fresh waters were identified in Mokelumne River Formation sandstones within a limited area in the southwest portion of the basin near known Mokelumne River Formation sandstone surface exposures. While no geochemical data are available to verify it, aquifer recharge via these surface sandstone exposures is likely responsible for this area of lower salinity found in this study. No conclusive evidence of water below this threshold was identified within sandstones of the deeper Starkey or Winters formations, which are not exposed at the surface anywhere in the basin. Accordingly, a revised 935 square miles are underlain by Mokelumne River sandstone, while 920 and 1,524 square miles are underlain by

Starkey and Winters formation sandstones, respectively. The revised estimated storage resource for the portions of the three formations meeting depth, seal, and water quality criteria is 3.2 to 13.0 gigatons of CO_2.

Hydrocarbon Pool Size Distribution in the Bunker, Millar, and Conway Ranch Gas Fields – Southern Sacramento Basin, California

The estimated CO_2 storage capacities determined for the known natural gas pools within the Bunker, Millar, and Conway Ranch gas fields suggest that the potential for long term CO_2 storage within singular pools in these and similar fields of the southern Sacramento Basin is limited. Most pools within Mokelumne River, Starkey, and Winters formations have CO_2 storage capacities insufficient to store even a single year's worth of a typical facility's CO_2 emissions. Even the largest pools in each field exhibit limited storage capacities. These range from only 1.7 million metric tons (Mt) (Conway Ranch Field) to 6.6 Mt (Bunker Field), or the equivalent of less than one to slightly more than three years of storage.

Multiple pool strategies are also likely to fall short of meeting the lifetime needs of a typical emissions source. Only 14 out of 313 pools have estimated capacities exceeding 0.5 Mt CO_2. Cumulatively by field, these pools could provide 15.2 Mt of storage capacity in Bunker Field (5 pools), 7.0 Mt (7 pools) in Millar Field, and 2.0 Mt (2 pools) in Conway Ranch Field. With the possible exception of Bunker Field, these pools have estimated capacities much less than the 15 to 30 Mt necessary to meet a single facility's lifetime needs at even 50 percent capture efficiency. The addition of smaller pools to increase capacity in each field does not significantly improve storage capacity. Even if it were economically viable and technically feasible to access the many pools within each field, maximum field storage capacities increase to only 17.9 Mt (Bunker Field), 17.8 Mt (Millar Field), and 6.8 Mt (Conway Ranch Field).

While the Bunker, Millar, and Conway Ranch fields are considered suitable analogs for most gas fields in the Sacramento Basin, larger fields (from a production standpoint) do exist within the basin and may offer better opportunities for CO_2 storage. Although not part of this study, further enhancement of CO_2 storage volume within a specific natural gas field could likely be obtained by considering containment within the saline aquifer portions of reservoir sandstones and within overlying and underlying brine-saturated sandstone bodies.

While this study is limited to fields and formations in the Sacramento Basin, fields in other California basins with similar settings and geologic and tectonic histories could exhibit similar degrees of compartmentalization and limitation of potential reservoir capacity.

Benefits to California

Under Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006) and Executive Order S-3-05, California has established aggressive GHG emissions goals. By 2020, California must reduce its GHG emission to 1990 levels. As part of this effort, WESTCARB in partnership with Department Of Energy is exploring opportunities for removing CO2 from the atmosphere by enhancing natural processes and by capturing it at industrial facilities before it is emitted and storing it securely underground. Determining the potential for long-term underground storage

of CO2 through identification and quantification of resources will help California reduce the carbon intensity of its economy and reduce changes in the climate associated with atmospheric buildup of this GHG.

CHAPTER 1: Introduction

As part of the West Coast Regional Carbon Sequestration Partnership (WESTCARB) Phase II effort, the California Department of Conservation, California Geological Survey (CGS) conducted three separate studies related to different aspects of the potential geologic sequestration of carbon dioxide (CO_2) in California. These three studies build on prior CGS work in Phases I and II of the WESTCARB project.

1.1. Background

During Phase I of WESTCARB, the CGS developed preliminary baseline information concerning geologic options for carbon dioxide (CO_2) sequestration in California. This involved identifying and characterizing porous and permeable rock formations in the numerous onshore sedimentary basins of California and defining areas within these basins that may be geologically suitable for sequestering CO_2.

Screening and follow-up geologic reviews resulted in the identification of as many as 27 onshore sedimentary basins having varying degrees of sequestration potential. The basins ranged from small non-marine basins for which there is little, if any, information, to larger Cenozoic marine basins with abundant subsurface data in the form of geophysical well logs, cores, and other information related to energy industry operations. The marine basins are characterized by several favorable attributes including 1) thick sedimentary fill with multiple porous and permeable sandstone aquifers and hydrocarbon reservoirs; 2) marine shale seals; 3) abundant geological, petrophysical, and fluid data from oil and gas operations; and 4) numerous depleted or mature oil and gas fields, which might be reactivated or benefit from CO_2 enhanced recovery operations (Downey and Clinkenbeard, 2006). The ten largest basins include the San Joaquin, Sacramento, Ventura, Los Angeles, Eel River, Salinas, La Honda, Cuyama, Livermore, and Orinda basins. Estimated storage resources were 30 to 420 gigatons of CO_2 (DOE-NETL 2010a).

During the WESTCARB Phase II study, CGS evaluated the regional geology of the Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin to better define those areas with carbon sequestration potential. Previous Phase I studies identified these formations as potential sequestration targets. These formations contain the most aerially extensive sandstone units within the Sacramento Basin that meet minimum depth requirements for CO_2 injection at required temperature and pressures. Sandstones within these formations also account for a large part of the natural gas production in the southern Sacramento Basin and comprise the bulk of the saline aquifers within this part of the basin.

The Mokelumne River, Starkey, and Winters formations all contain significant thicknesses of porous and permeable sandstone that may be suitable for carbon sequestration. Large areas meeting minimum depth requirements of 1,000 meters (3,280 feet) and seal thickness of more than 100 feet exist for each formation. Approximately 1,045 square miles are underlain by

Mokelumne River sandstone, 920 square miles by Starkey Formation sandstone, and 1,454 square miles by Winters sandstone. Since the formations are vertically stacked, 2,019 net surface square miles meet depth and seal criteria. Stacking provides the potential for much thicker total sandstone sequences than individual formations. The estimated storage resource for the portions of the three formations meeting depth and seal criteria is 3.5 to 14.1 gigatons of CO_2 (Downey and Clinkenbeard, 2010).

1.2 Overview

Findings from the first and second phases of WESTCARB's screening-level characterization of California sedimentary basins indicated significant potential for storage of CO_2 in the depleting oil and gas fields of California and in saline formations outside oil and gas field limits. However, during the course of the first two studies, additional questions were raised regarding the potential CO_2 storage capacity of California basins.

Firstly, what is offshore potential for CO_2 sequestration? Many basins identified as having onshore storage potential extend offshore onto the continental shelf while other basins lie completely offshore. These areas were not included in the Phase I evaluation.

Secondly, what effect does the Environmental Protection Agency's underground drinking water standard of 10,000 mg/l Total Dissolved Solids (TDS) have on the availability of sequestration potential in California basins? In other words, are low salinities present in reservoirs that otherwise meet minimum criteria necessary for sequestration (depth, permeability, and so forth), and how does this impact projected sequestration capacities?

Lastly, the previous studies did not address the potential impact of compartmentalization within existing of oil and gas fields on potential storage capacity and utilization. One proposed method of sequestration involves injecting CO_2 into abandoned oil or gas fields, in effect refilling the space previously occupied by hydrocarbons with CO_2. California's complex geologic history has resulted in many fields producing from multiple compartments or "pools "of varying capacities representing separate trapped hydrocarbon accumulations rather than from a single large reservoir. Consequently, storage capacities estimated from cumulative field production histories may be misleading. Field capacity is typically segregated amongst many smaller pools. The variation in pool size potentially impacts the economics and practicality of sequestration in depleted oil and gas fields.

While conceptually these issues apply to California as a whole, resources and information to evaluate the salinity and compartmentalization issues on a statewide basis were not available. Therefore, studies were focused on the southern Sacramento Basin where previous Phase II geologic characterization provided a starting point for further studies.

To address these issues, further geologic characterization was undertaken to:

- Perform a preliminary assessment of the potential for CO_2 sequestration in California's offshore environment.

- Identify if and where salinities approach or exceed 10,000 mg/l TDS in the Mokelumne River, Starkey, and Winters formations and revise previous carbon storage estimates for these formations, if necessary.
- Identify, delineate, and characterize individual pool capacities within selected gas fields in the Southern Sacramento Basin.

Each of these issues is addressed as a separate task within the contract and the results of each study are presented as separate, stand-alone chapters in this report. A combined glossary of terms and abbreviations and a combined reference list are included at the end of this report. Supporting appendices, where necessary, are also included at the end of the report.

CHAPTER 2:
Geologic Carbon Sequestration Potential in California's Offshore Basins

As part of the WESTCARB Phase I effort in 1996, the CGS developed preliminary baseline information concerning geologic options for carbon dioxide (CO_2) sequestration in onshore California sedimentary basins (Downey and Clinkenbeard, 2006). In 2009, as part of WESTCARB's Phase II continuing evaluation of California's carbon sequestration potential, CGS extended its assessment to include the known offshore California sedimentary basins including both the offshore extensions of onshore basins and those basins lying wholly within both State and Federal offshore jurisdictions.

The Phase I assessment involved mapping depth to basement and sandstone thickness and distribution within each onshore basin for which subsurface well control and/or published geophysical data was available. These maps were used to identify areas within these basins that may be geologically suitable for storage of CO_2 and to determine preliminary estimates of onshore storage capacity within the State's 10 largest onshore basins. To characterize potential saline aquifers and hydrocarbon reservoirs within the basins, oil and gas field historical data as well as specific production, petrophysical, and other physical reservoir data was compiled and attributed to GIS layers. This data was ultimately used by other WESTCARB participants to develop CO_2 storage estimates for the known producing and/or abandoned onshore oil and gas fields within these basins (Golder Associates, 2009; Herzog et al, 2007).

Insufficient well log control and the lack of extensive published geophysical information prevented the preparation of depth to basement and sandstone isopach maps for the offshore basins. Instead, CO_2 storage capacity estimates were calculated only for the known developed and undeveloped offshore oil and gas fields. This approach is also consistent with revised Phase I CO_2 storage capacity estimates for onshore California oil and gas fields prepared by Golder Associates (2009); Herzog, et al. (2007). Additionally, only conventional sandstone reservoirs in offshore basins were considered. Numerous fractured Monterey shale reservoirs were omitted from consideration due to the difficulty in characterizing fractured reservoirs as well as the association of known sea floor seeps with many of these reservoirs.

2.1 Project Approach and Work Methods

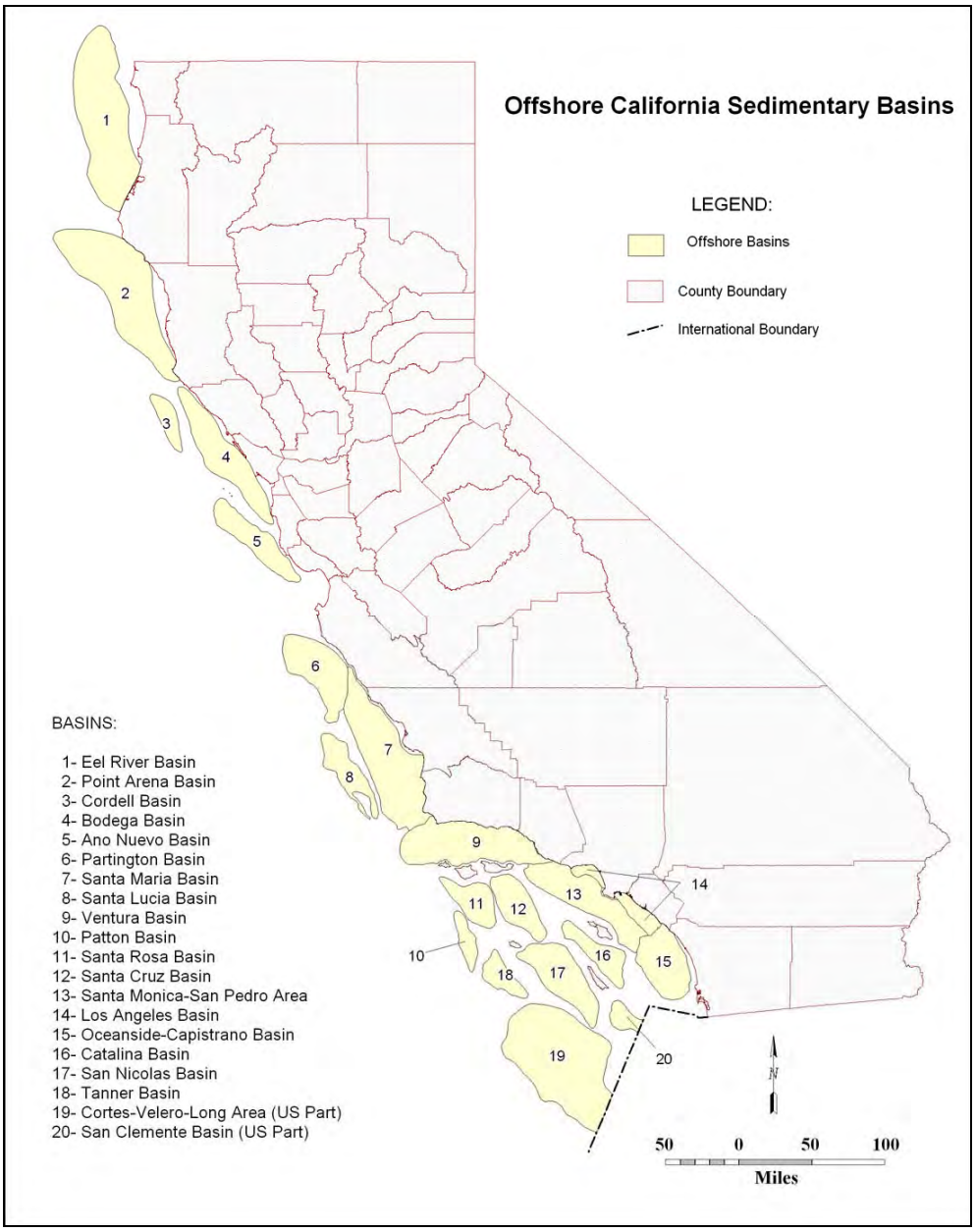
2.1.1 Offshore Basin Inventory

The CGS cataloged twenty offshore California sedimentary basins including the offshore extensions of basins for which the onshore portions were evaluated in Phase I. These basins range in size from the small Patton Basin (approximately 935 sq. km.) off the coast of southern California to the relatively large offshore portion of the Eel River Basin of northern California. The location and geographical extent of these basins were derived from the U.S. Department of

the Interior, Mineral Management Service's *1995 National Assessment of the United States Oil and Gas Resources Assessment of the Pacific Outer Continental Shelf* (Minerals Management Service, 1997).

These included all significant hydrocarbon-producing or potentially producing basins along the California coast underneath State owned lands (to the 3 mile limit) as well as the federally owned lands of the Pacific Outer Continental shelf (Figure 2-1). Basin outlines were digitized to produce an offshore California sedimentary basin GIS layer.

Figure 2-1. California Offshore Sedimentary Basins



Unlike their onshore counterparts, California offshore basins lack sufficient available wellbore control to map basin-wide sandstone thickness and extent, or depth to basement as was accomplished in the CGS Phase I onshore assessment (Downey and Clinkenbeard, 2006). As a result, the carbon sequestration potential of offshore saline aquifers cannot be assessed. Instead, only the CO_2 storage capacity of known producing and depleted, and in some cases discovered but undeveloped, oil and gas reservoirs are assessed in this report.

2.1.2 Offshore Oil and Gas Fields

Coastal California is a tectonically active convergent crustal margin characterized by complex geology. Intermittent periods of Cenozoic sedimentary deposition, volcanism, folding, and faulting within the region have created a number of environments favorable for the generation, accumulation, and entrapment of hydrocarbons, both petroleum and natural gas (MMS, 1997). Numerous geologic basins and areas exist along the continental shelf and slope, some of which are geological extensions of onshore basins and have proven hydrocarbon accumulations either in their onshore and/or offshore portions. To date, all known offshore oil and gas accumulations occur in only three of California's 20 offshore basins off the coast of Southern California, the Santa Maria, Ventura, and Los Angeles basins. Other offshore basins and areas are sparsely explored but are expected to have considerable hydrocarbon potential (MMS, 1997). Basin and reservoir level geology for clastic reservoirs within basins that extend offshore was discussed in the Phase I assessment (Downey and Clinkenbeard, 2006).

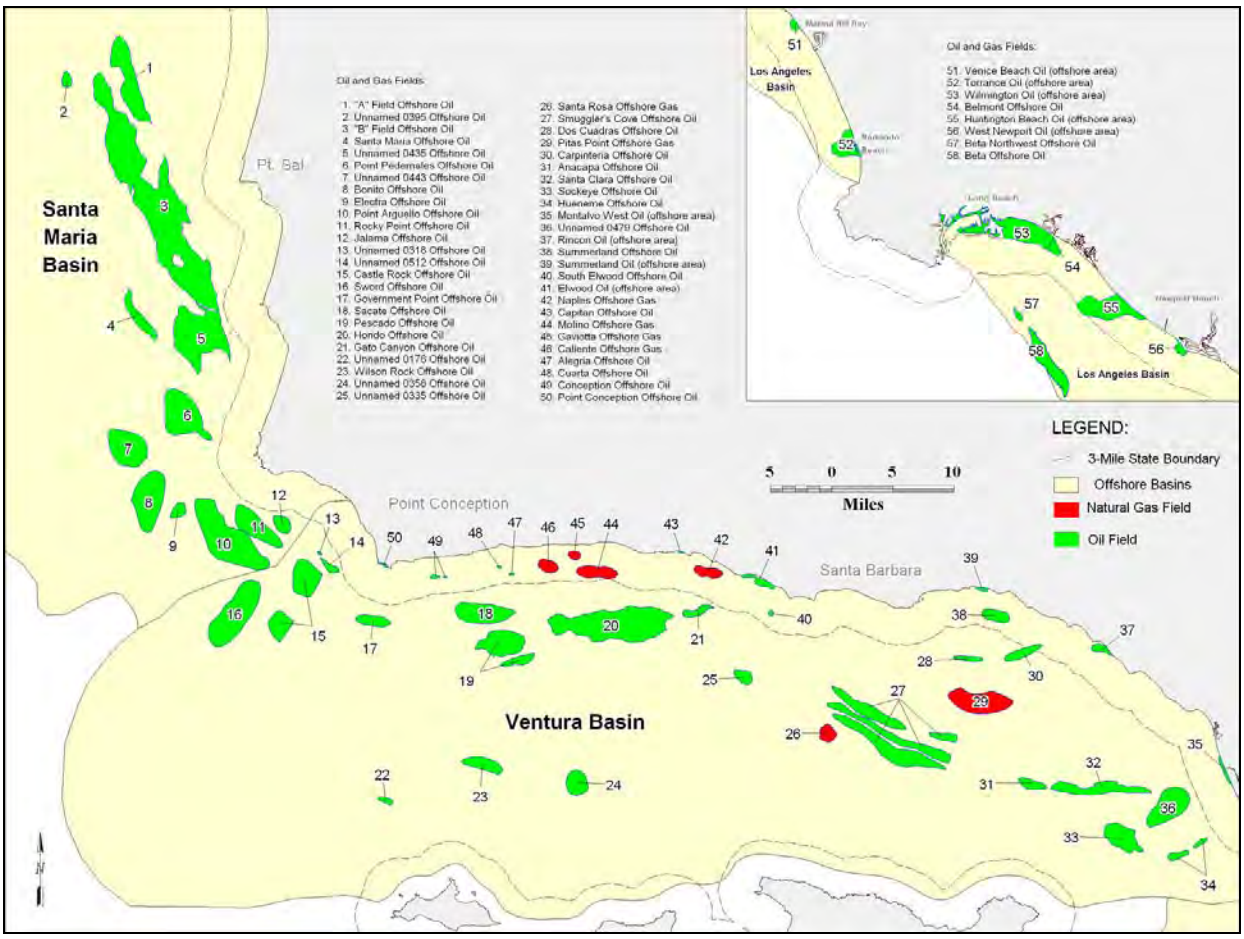
A digital GIS layer of offshore California oil and gas fields was prepared to illustrate the distribution of known oil and gas fields within the California offshore sedimentary basins (Figure 2-2). Oil and gas field location, distribution, size, and shape were derived from publications of the California Division of Oil, Gas, and Geothermal Resources and those of the Mineral Management Service (DOGGR, 1991; MMS, 2007).

Oil and gas fields and individual reservoirs within fields were screened to determine preliminary suitability for potential CO_2 sequestration, with those fields not meeting the screening criteria being excluded from aggregate calculations of potential offshore CO_2 storage potential. Screening included two principal criteria - the presence of significant porous and permeable sandstone reservoirs and sufficient depth to provide critical state pressures for CO_2 injection (> 800 meters, or 2,625 feet). In all cases, the presence of a seal was assumed given the presence of the hydrocarbon accumulations within the reservoirs. However, it must be noted that the absolute effectiveness of any given seal at this level of assessment cannot be assured in California's offshore basins given the numerous occurrences of documented seabed hydrocarbon seeps.

Significant petroleum deposits occur both onshore and offshore within fractured siliceous Monterey Formation shales. Conventional reservoir engineering calculations and models do not work well for anisotropic fractured reservoirs. Further, many California Monterey accumulations (both onshore and offshore) are known or suspected to source surface and submarine oil and gas seeps. For these reasons, Monterey Formation reservoirs were excluded

from consideration as potential CO_2 storage sites. These criteria resulted in the elimination of all known offshore fields in the Santa Maria Basin and are consistent with CGS's Phase I onshore assessment in which the onshore portion of the Santa Maria basin was excluded due to its preponderance of Monterey shale reservoirs. Figure 2-2 depicts the locations of oil and gas fields off selected shores of California.

Figure 2-2. California Offshore Oil and Gas Fields



Exclusion of Monterey hydrocarbon reservoirs has a considerable impact on potential offshore CO_2 sequestration capacity. In many of the offshore basins of south coastal California, Miocene sedimentation is generally characterized by thick sequences of sandstone adjacent to bordering uplifts with a marineward decrease in coarse clastics and a corresponding increase in basinward shales. This is most evident in the Ventura Basin where nearly all producing fields within State waters (up to the 3 mile limit) produce from sandstone reservoirs, while the majority of fields further offshore in Federal waters produce largely from fractured Monterey shale reservoirs. As a result, a higher percentage of offshore fields within Federal waters produce from fractured Monterey shale reservoirs and are considered unsuitable for CO_2 sequestration, as compared to nearer shore fields in State waters.

2.1.3 Oil and Gas Reservoirs and Formation Properties

To characterize the potential hydrocarbon reservoirs, oil and gas field and reservoir data was assembled for depleted and producing fields from publications of the DOGGR and MMS. Data for abandoned or producing fields was also compiled in field-level and reservoir-level databases and attributed to the California offshore 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. For non-producing fields, only basic information such as field name and reservoir zone was available and entered in the database. Field level database parameters are shown in Table 2-1.

Table 2-1. Sample Content of a Field Table Database Record

Field Code:	OSLA07
Field:	Beta Offshore Oil
Discovery Well Operator:	Shell Oil Co.
Discovery Well:	OCS-P-300-1
Section:	NA
Township:	NA
Range:	NA
Meridian:	NA
Discovery Date:	8/1/1976
Deepest Well Operator:	Shell Western Exploration & Production
Deepest Well:	OCS-P-300-A51R
Section:	NA
Township:	NA
Range:	NA
Meridian:	NA
Depth	10,262 ft.
Field Area	1,900 acres
Cum. Oil Prod. (MBO)	88,156
Cum. Gas Prod. (MMCF)	28,911
Base Fresh Water:	None

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. An example of reservoir database parameters is shown in Table 2-2.

Table 2-2. Sample Content of a Zone Table Database Record

Field Code:	OSLA07	Perm.:	
Zone:	Puente Fm.	Perm. Range Min.:	10 md
Age:	Miocene	Perm. Range Max.:	300 md
Oil or Gas:	O	Pressure:	1,600 lb/ft^2
Date of Discovery:	8/1/1976	Press. Range Min.:	
Zone Status (P/A/SI):	P	Press. Range Min.:	
API Gravity:	18	Temperature:	
API Range Min.:		Temp. Range Min.:	140°F
API Range Max.:		Temp. Range Max.:	175°F
GOR:	400	Salinity:	31,500 ppm NaCl
GOR Range Min.:		Sal. Range Min.:	
GOR Range Max.:		Sal. Range Max.:	
Sp. Gravity:	0.66	TDS:	33,000 ppm NaCl
Sp. Gravity Min.:		TDS Range Min.:	
Sp. Gravity Max.:		TDS Range Max.:	
BTU:	1,050	Seal:	Repetto Fm.
BTU Range Min.:		Seal Thickness:	
BTU Range Max.:		Seal Thickness Min.:	5 ft.
Cum. Oil (MBO):	88,145	Seal Thickness Max.:	50 ft.
Cum. Gas (MMCF):	28,911	Trap Type:	Structural
No Pool Breakdown:		Fault Intensity:	H
Depth:	3,800 ft.	ERP 1:	Water Flood
Depth Range Min.:		ERP 1 Start:	1983
Depth Range Max.:		ERP 1 Stop:	Active
Thickness:		ERP 2:	
Thickness Range Min.:	300 ft.	ERP 2 Start:	
Thickness Range Max.:	500 ft.	ERP 2 Stop:	
Producing Area:	400 acres	ERP 3:	
Porosity (%):		ERP 3 Start:	
Porosity Range Min. (%):	16	ERP 3 Stop:	
Porosity Range Max. (%):	26		

2.1.4 Offshore Jurisdictions and Reserve Classification

Offshore oil and gas mineral ownership and regulatory authority is determined by the distance from the shoreline. In California, the State of California owns the minerals rights out to a distance of 3 miles. These lands are administered by the California State Lands Commission and the California Division of Oil, Gas, and Geothermal Resources. Seaward of the 3-mile limit, on the outer continental shelf, mineral rights are owned by the U.S. Government and administered by the Department of the Interior's Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the Minerals Management Service (MMS).

The BOEMRE has categorized known oil and gas deposits upon the outer continental shelf in three categories, based primarily on geological information, production and development infrastructure, and lease status. As a result, significant known deposits of oil and gas for which potential CO_2 storage capacity estimates are included in this assessment may or may not have existing infrastructure such as platforms or pipelines that might be utilized for future sequestration operations. In the case of several fields which have been discovered but never developed, no existing offshore infrastructure of any kind exists. A brief description of these categories follows.

Proved Developed and Producing Reserves (PDP) – After an oil or gas reservoir within an active lease has been discovered, offshore production facilities such as a platform and pipelines have been installed, and production begins, the reservoir is considered to contain *proved developed producing reserves.* While the State of California does not use this specific nomenclature within its jurisdiction, all reserves within producing and depleted oil and gas fields in State waters would fall in this category.

Unproved Possible Reserves (UPOS) – Once a potential reservoir has been discovered with an exploratory well, and that well has been demonstrated to be capable of producing oil and/or gas by means of an accepted test method, reserves are initially considered *unproved possible reserves.* Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves but for which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. More importantly, unproved possible reserves have no history of production and little or no production equipment or infrastructure installed.

Known Resources (KR) - Hydrocarbons associated with reservoirs penetrated by one or more wells that are on leases that are expired or relinquished are identified as *known resources*.

2.1.5 CO_2 Storage Capacity in Oil and Gas Reservoirs

A fundamental assumption in estimating CO_2 storage capacity in oil and gas reservoirs is that the volume of the produced hydrocarbons, at reservoir conditions, becomes available for CO_2 storage and that the storage capacity of the reservoir can be calculated from the reservoir volume of the estimated ultimate recovery (EUR) of oil and gas reserves. Estimated ultimate recoverable (EUR) reserves of oil and gas are the sum of the volume of oil and gas produced

plus the volume of remaining producible oil and gas reserves. An additional assumption is that the reservoir pressure is restored to original reservoir pressure. In real world situations, however, these assumptions may be flawed due to the permanent loss of reservoir pore space available for CO_2 storage due to formation water encroachment, relative fluid permeability, and other physical limitations. Additionally, pressures may or may not be restored to original reservoir pressures as may be dictated by concerns over cap rock integrity.

In the case of oil reservoirs, it's important to note that recorded produced oil volumes are generally less at the surface than at reservoir conditions due to three factors. The most important is the release of gas from the oil as pressure is decreased from reservoir pressure to surface pressure. This causes a rather large decrease in the volume of oil when there is a significant amount of dissolved or "associated" gas as is the case in most California oil fields. The reduction in pressure also causes oil to expand, but only very slightly since petroleum fluids (without dissolved gas) are relatively incompressible with volume reductions of about 0.5 percent for pressures ranging from 1,000 to 4,000 psi (McCain, 1990). The decrease in temperature also causes the oil to contract very slightly, but this is generally offset by the slight expansion due to pressure reduction. This requires that oil production volumes be restored to reservoir conditions by application of a formation volume factor (Bo) which corrects surface volumes to reservoir volumes of oil.

The U.S. Dept. of Energy's *Methodology for Development of Geologic Storage Estimates for Carbon Dioxide* (DOE-NETL, 2010b) provides methods for calculating estimated CO_2 storage capacity in an oil and gas reservoir using standard oil field practices involving the volumetric calculation of oil or gas in place and applying a CO_2 storage efficiency factor. In the absence of specific reservoir parameters such as area, thickness, and so forth, actual production (for depleted fields), and calculated EUR reserves of oil and gas can be substituted resulting the following equations to estimate CO_2 storage capacity.

For oil reservoirs,

$$Q_{CO2} = (V_{prod} + V_{reserves}) \cdot B_o \cdot \rho_{CO2(r)}$$

Where: Q_{CO2} = CO_2 storage capacity in metric tons (Mt)

V_{prod} = volume of oil produced (m^3)

$V_{reserves}$ = volume of remaining producible oil reserves (m^3)

B_o = formation volume factor

$\rho_{CO2(r)}$ = density of CO_2 at reservoir conditions (kg/m^3)

For gas reservoirs,

$$Q_{CO2} = (V_{prod} + V_{reserves}) \frac{Z_{NG(r)} \cdot Z_{CO2(s)}}{Z_{NG(s)} \cdot Z_{CO2(r)}} \cdot \rho_{CO2(s)}$$

Where: Q_{CO2} = CO_2 storage capacity in metric tons (Mt)

V_{prod} = volume of gas produced (m^3)

$V_{reserves}$ = volume of remaining producible gas reserves (m^3)

$Z_{NG(r)}$ = compressibility factor for natural gas at reservoir conditions

$Z_{NG(s)}$ = compressibility factor for natural gas at surface conditions

$Z_{CO2(r)}$ = compressibility factor for CO_2 at reservoir conditions

$Z_{CO2(s)}$ = compressibility factor for CO_2 at surface conditions

$\rho_{CO2(s)}$ = density of CO_2 at surface conditions (kg/m^3)

Based on production and remaining reserve information current through December, 2009, total CO_2 storage capacity for known offshore sandstone reservoirs is estimated at approximately 239,583,598 metric tons. Of this amount, 236,389,518 metric tons (98.7 percent) occurs within 24 depleted or currently producing fields containing reserves classified as proved developed and producing reserves. Only 3,194,080 metric tons occur within sandstone reservoirs classified as unproved possible reserves or known resources for which no actual oil or gas production has occurred.

Table 2-3 summarizes the estimated recoverable oil and gas reserves and potential CO_2 storage capacity for known sandstone reservoirs within California's offshore basins. Recoverable reserves include produced oil and gas (in the case of producing and/or depleted fields) and total estimated reserves of all categories (PDP, UPOS, KR) in unproduced fields. The table reveals that only the Ventura and Los Angeles basins contain discovered oil and gas deposits within sandstones. While 13 oil fields have been discovered in the Santa Maria Basin, all reserves occur within fractured Monterey shale reservoirs. No hydrocarbons have been discovered in the remaining 17 sedimentary basins lying offshore of California; consequently no CO_2 storage capacity has been estimated for these basins. Tables 2- 4a through 2-4d provide more detail and summarize the estimated recoverable reserves by field, jurisdiction, and reserves classification.

Table 2-3: Estimated Ultimate Recoverable Oil and Gas Reserves and CO2 Storage Capacity in Sandstone Reservoirs by Basin – Offshore California

Basin	Number of Fields All Reservoirs	Number of Fields Sandstone Reservoirs	EUR Oil Reserves (MBO) Sandstone Reservoirs	EUR Gas Reserves (MMCF) Sandstone Reservoirs	CO_2 Storage Capacity (metric tons)
Ventura	38	27	807,767	1,651,779	95,576,708
Los Angeles	8	8	2,565,697	1,074,074	144,006,890
Santa Maria	13*	0	0	0	0
Eel River	0	0	0	0	0
Point Arena	0	0	0	0	0
Bodega	0	0	0	0	0
Cordell	0	0	0	0	0
Ano Nuevo	0	0	0	0	0
Partington	0	0	0	0	0
Santa Lucia	0	0	0	0	0
Santa Monica – San Pedro	0	0	0	0	0
Oceanside – Capistrano	0	0	0	0	0
Santa Rosa	0	0	0	0	0
Santa Cruz	0	0	0	0	0
Patton	0	0	0	0	0
Tanner	0	0	0	0	0
San Nicolas	0	0	0	0	0
Catalina	0	0	0	0	0
Cortez – Valero – Long	0	0	0	0	0
San Clemente	0	0	0	0	0
TOTAL	59	35	3,373,464	2,725,853	239,583,598

*All fields in fractured Monterey Formation

Table 2-4a: Estimated Ultimate Recoverable Oil and Gas Reserves and CO2 Storage Capacity in Sandstone Reservoirs by Field – Offshore California – State Lands, Proved Developed and Producing Reserves

Field	Basin	Producing Formations	EUR Oil (MBO)	EUR Gas (MMCF)	CO_2 Storage Capacity (metric tons)	Notes
Alegria Offshore Oil (abd)	Ventura	Vaqueros, Alegria	1,063	4,037	105,526	
Belmont Offshore Oil	Los Angeles	Repetto, Puente	68,573	42,120	4,017,474	
Caliente Offshore Oil (abd)	Ventura	Vaqueros, Sespe, Alegria	0	32,610	2,716,255	
Capitan Offshore Gas (abd)	Ventura	Sespe	71	33	0	All zones too shallow
Carpenteria Offshore Oil (abd)	Ventura	Pico	36,739	40,798	3,875,089	
Conception Offshore Oil (abd)	Ventura	Alegria, Vaqueros, Gaviota	20,933	12,326	1,464,356	
Cuarta Offshore Oil (abd)	Ventura	Alegria, Vaqueros, Gaviota, Sacate,	614	18,767	63,874	
Elwood Oil (Offshore) (abd)	Ventura	Vaqueros, Sespe, Rincon	79,521	67,178	4,070,991	Assume all from zones > 800m
South Elwood Offshore Oil	Ventura	Rincon, Vaqueros, Sespe, Monterey	81,550	71,944	8,497,533	Assume all from zones > 800m
Gaviota Offshore Gas (abd)	Ventura	Vaqueros, Sespe	0	69,955	5,832,487	
Huntington Beach Oil (Offshore)	Los Angeles	Puente, Repetto	615,271	336,306	14,526,312	Half of zones > 800m
Molino Offshore Gas (abd)	Ventura	Vaqueros, Sespe, Matilija	4,593	249,944	21,517,719	
Montalvo W. Oil (Offshore)	Ventura	Sespe	8,967	6,024	627,281	
Naples Offshore Gas (abd)	Ventura	Vaqueros	223	20,815	1,841,015	
West Newport Oil (Offshore)	Los Angeles	Puente	5,773	2,101	383,769	
Point Conception Offshore Oil (abd)	Ventura	Secate	1,130	657	86,417	
Rincon Oil (Offshore)	Ventura	Pico	37,886	37,645	0	All zones too shallow
Summerland Oil (Offshore) (abd)	Ventura	Vaqueros, Casitas	305	0	0	All zones too shallow

Summerland Offshore Oil (abd)	Ventura	Vaqueros	27,558	97,834	2,886,448	
Torrance Oil (Offshore) (abd)	Los Angeles	Puente	7,957	11,519	0	All zones too shallow
Venice Beach Oil (Offshore) (abd)	Los Angeles	Puente	2,717	1,631	181,427	
Wilmington Oil (Offshore)	Los Angeles	Repetto, Puente, Catalina	1,752,906	644,685	119,139,897	Two uppermost zones <
TOTAL			2,754,350	1,768,929	191,833,871	

Table 2-4b: Estimated Ultimate Recoverable Oil and Gas Reserves and CO2 Storage Capacity in Sandstone Reservoirs by Field – Offshore California – Federal Lands, Proved Developed and Producing Reserves

Field	Basin	Producing Formations	EUR Oil (MBO)	EUR Gas (MMCF)	CO_2 Storage Capacity (metric tons)	Notes
Beta Offshore Oil	Los Angeles	Puente	107,700	34,800	5,536,701	
Carpenteria Offshore Oil	Ventura	Repetto	74,100	62,500	6,096,647	
Dos Cuadros Offshore Oil	Ventura	Pico	272,900	164,100	0	All zones too shallow
Hondo Offshore Oil	Ventura	Monterey	358,000	814,020	0	Monterey
Hueneme Offshore Oil	Ventura	Hueneme, Sespe	11,800	7,774	1,216,712	
Pescado Offshore Oil	Ventura	Monterey	175,591	222,321	0	Monterey
Pitas Point Offshore Gas	Ventura	Pico, Repetto	211	239,215	21,057,854	
Point Arguello Offshore Oil	Santa Maria	Monterey	213,900	133,840	0	Monterey
Point Pedernales Offshore Oil	Santa Maria	Monterey	106,000	45,000	0	Monterey
Rocky Point Offshore Oil	Santa Maria	Monterey	88,531	42,270	0	Monterey
Secate Offshore Oil	Ventura	Monterey	123,729	131,097	0	Monterey
Santa Clara Offshore Oil	Ventura	Monterey (36%), Pico & Repetto,	53,414	85,228	4,500,137	36% Monterey
Sockeye Offshore Oil	Ventura	Sespe & Topanga (85%),	58,232	147,198	6,147,596	15% Monterey

TOTAL			1,644,108	2,129,363	44,555,647	

Table 2-4c: Estimated Ultimate Recoverable Oil and Gas Reserves and CO2 Storage Capacity in Sandstone Reservoirs by Field – Offshore California – Federal Lands, Unproved Possible Reserves

Field	Basin	Producing Formations	EUR Oil (MBO)	EUR Gas (MMCF)	CO_2 Storage Capacity (metric tons)	Notes
"A" Field Offshore Oil	Santa Maria	Monterey	98,000	9,800	0	Monterey
"B" Field Offshore Oil	Santa Maria	Monterey	696,000	283,100	0	Monterey
Beta Northwest Offshore Oil	Los Angeles	Puente	4,800	912	221,310	
Bonito Offshore Oil	Santa Maria	Monterey	49,700	56,900	0	Monterey
Electra Offshore Oil	Santa Maria	Monterey	10,900	13,300	0	Monterey
Gato Canyon Offshore Oil	Ventura	Monterey	46,946	46,946	0	Monterey
Jalama Offshore Oil	Santa Maria	Monterey	10,513	7,200	0	Monterey
Santa Maria Offshore Oil	Santa Maria	Monterey	25,400	1,200	0	Monterey
Sword Offshore Oil	Ventura	Monterey	29,500	7,300	0	Monterey
Unnamed 0435 Offshore Oil	Santa Maria	Monterey	91,800	6,900	0	Monterey
Unnamed 0443 Offshore Oil	Santa Maria	Monterey	14,000	14,000	0	Monterey
TOTAL			1,077,559	447,558	221,310	

Table 2-4d: Estimated Ultimate Recoverable Oil and Gas Reserves and CO2 Storage Capacity in Sandstone Reservoirs by Field – Offshore California – Federal Lands, Known Resources

Field	Basin	Producing Formations	EUR Oil (MBO)	EUR Gas (MMCF)	CO_2 Storage Capacity (metric tons)	Notes
Anacapa Offshore Oil	Ventura	Unspecified Sandstones	1,105	884	91,354	
Castle Rock Offshore Oil	Ventura	Monterey	16,039	18,500	0	Monterey
Government Point Offshore Oil	Ventura	Unspecified Sandstones	23,000	182,700	1,901,488	
Smugglers Cove Offshore Oil	Ventura	Monterey	47,600	79,000	0	Monterey
Santa Rosa Offshore Gas	Ventura	Unspecified Sandstones	920	19,000	76,060	
Unnamed 0176 Offshore Oil	Ventura	Unspecified Sandstones	2,533	2,533	209,412	
Unnamed 0318 Offshore Oil	Ventura	Monterey	70	70	0	Monterey
Unnamed 0335 Offshore Oil	Ventura	Monterey	18,900	18,900	0	Monterey
Unnamed 0358 Offshore Oil	Ventura	Monterey	5,091	5,091	0	Monterey
Unnamed 0395 Offshore Oil	Santa Maria	Monterey	12,393	12,393	0	Monterey
Unnamed 0479 Offshore Oil	Ventura	Monterey	11,454	11,454	0	Monterey
Unnamed 0512 Offshore Oil	Ventura	Monterey	1,750	1,900	0	Monterey
Wilson Rock Offshore Oil	Ventura	Unspecified Sandstones	8,400	10,080	694,457	
TOTAL			149,255	362,505	2,972,770	

Summary and Conclusions

Lack of available well log and geophysical data precludes regional mapping of the saline aquifers which might be available for CO_2 sequestration within California's offshore sedimentary basins. Instead, CO_2 storage capacity estimates were calculated only for the known developed and undeveloped offshore oil and gas fields.

While twenty sedimentary basins lie offshore, or extend offshore, from mainland California, oil and gas fields have been discovered in only three of these basins - the Ventura, Los Angeles, and Santa Maria basins. Further, many of the oil reservoirs consist of brittle fractured siliceous shales within the Monterey Formation which are not considered good candidates for CO_2 sequestration. These fractured reservoirs include many of those found within the oilfields of the Ventura Basin, as well as all fields in the offshore Santa Maria Basin.

Excluding the Monterey Shale reservoirs, a total of 30 offshore oil and gas fields with conventional sandstone reservoirs, in whole or in part, have been discovered within the Ventura and Los Angeles basins. Of these, 24 fields are producing or have been depleted and are likely the most promising options for potential offshore carbon sequestration based on the reliability of existing production figures and reserve estimates. These fields have a cumulative estimated CO_2 storage capacity of 236,389,518 metric tons. An additional six oilfields have been discovered, but remain undeveloped in federal offshore waters. Since these fields have not been produced or delineated by subsurface well control, their reserve estimates remain highly speculative. Based on current reserve estimates, these fields represent additional CO_2 storage capacity of approximately 3,194,080 metric tons.

CHAPTER 3:
Salinity in the Mokelumne River, Starkey, and Winters Formations – Southern Sacramento Basin, California

As part of the WESTCARB Phase II program, the CGS conducted a preliminary geologic assessment of the carbon sequestration potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin (Downey & Clinkenbeard, 2010). A goal of phase II was to identify those areas underlain by sandstones within these formations that exhibited the most potential for carbon sequestration within saline aquifers or depleted gas and oil reservoirs.

Since the original Phase II assessment, the issue of formation water quality within the Mokelumne, Starkey, and Winters formations has become a concern. It is the purpose of this supplemental assessment to incorporate water quality data with the previous findings by identifying and excluding areas of sandstone which may contain formation water meeting potential drinking water quality standards. To this end, a salinity of 10,000 mg/l Total Dissolved Solids (TDS) or less was used to define a potential "underground source of drinking water" as defined by the Code of Federal Regulations, Title 40, Chapter 1, part 144.3 (40 CFR Ch.1 part 144.3).

3.1 Project Approach and Work Methods

3.1.1 Objectives

At the outset, it was envisioned that CGS would determine if, and at what depth, formation water salinities reach 10,000 mg/l TDS, then contour salinity data to produce generalized salinity (iso-salinity) maps for the top of each formation. Additionally, in cases where the uppermost sandstone in a formation displayed a salinity of less than 10,000 mg/l, salinities of deeper sandstones would be evaluated to determine at what depth salinities exceed 10,000 mg/l. Since actual laboratory analytical salinity information is not available, salinities were calculated using industry standard practices.

After salinity data for each formation was compiled it was determined that preparing salinity contour maps would not be meaningful or necessary in the context of this assessment. This conclusion was based on the fact that throughout the vast majority of the areas under consideration, salinities at the top of each formation generally met or exceeded the 10,000 mg/l TDS cut-off. Alternatively, areas exhibiting calculated salinities consistently below 10,000 mg/l TDS were simply outlined, and used to reduce or otherwise modify those areas previously identified in Phase II as exhibiting carbon sequestration potential.

Further, in the single case where low salinities were identified in an area of upper Mokelumne River sandstones, salinities never reached 10,000 mg/l at greater depths within the same formation. Consequently, there was no need to prepare any maps relating depth to salinity.

3.1.2 Formation Water Salinities

Actual salinities can only be determined by laboratory analysis of physical fluid samples, which are usually obtained via drill-stem-tests or produced fluid samples. Few analytical data are available for the formations in the Sacramento Basin. What data may exist are typically proprietary and resides in the files of the many oil and gas companies that have explored for and/or developed gas and oil reserves in the basin. Very limited and sporadic salinity data have been published for certain formations on a field wide basis in the California Division of Oil, Gas, and Geothermal Resources Publication TR 10 – Northern California Oil and Gas Fields (DOGGR, 1983). However, no records exist regarding the source or quality of this information (calculated or analytical), or the specific depths or zones to which the salinities correlate.

In the absence of analytical data, estimated water salinities were calculated by indirect methods using spontaneous potential (SP) logs from exploration and development wells. Several methods exist for determining the resistivity/salinity of formation waters from SP logs. Some of these methods are more complex than others, taking into consideration such variables as borehole diameter, borehole invasion, formation shaliness, and so forth. For the purposes of this study, salinity estimates were derived using a simplified petroleum industry method, sometimes referred to as the "Quick look" method in conjunction with Schlumberger's 2009 Log Interpretation Charts (http://www.slb.com/resources/publications/books/log_charts.aspx). A concise and easily understood step-by-step outline of this method is presented by Asquith and Gibson in their basic text on well log analysis (Asquith and Gibson, 1993).

3.1.3 The Spontaneous Potential (SP) Log

The SP log is one of the oldest and most common components of a typical well's electric log suite. Its principle uses are to 1) differentiate between permeable rocks (sandstones, limestones, and so forth) and impermeable rocks (shales, claystone, and so forth), 2) aid in correlation of lithologic units between wells, 3) allow calculation of formation water salinity in water saturated beds, and 4) allow some qualitative determination of the shaliness of a formation or bed.

Pure water is basically non-conductive and non-saline. However, natural waters contain dissolved minerals in the form of electrically charged ions which determine its salinity. These ions also determine the current carrying capacity of natural waters allowing the SP log to be used to estimate formation water resistivities which are then converted to corresponding salinities.

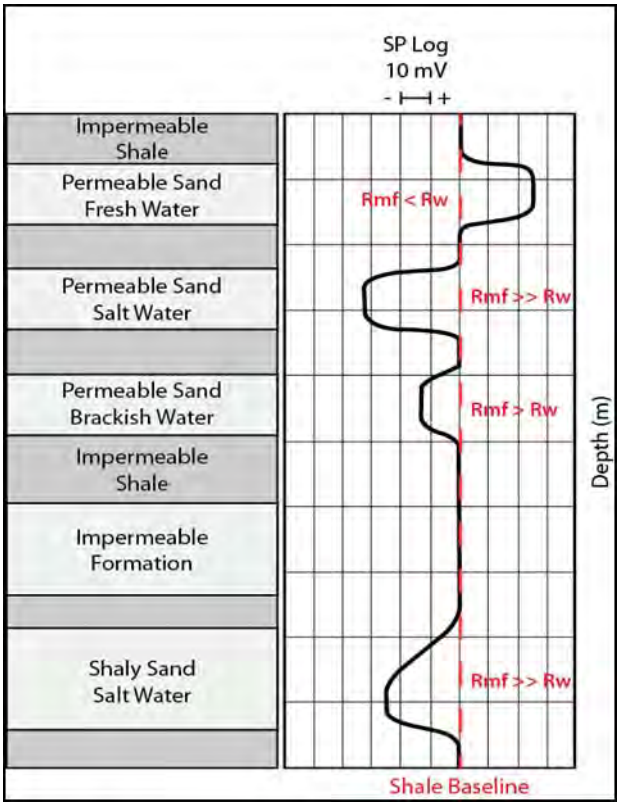
The SP log measures the direct current voltage differences between the naturally occurring electrical potential of a movable electrode in the well logging tool and the potential of a fixed reference electrode located at the surface (Doll, 1948). Electric currents arising in the wellbore create the SP log response generally manifested as deflections adjacent to permeable beds. The SP log response depends primarily on the resistivity contrast between the drilling mud filtrate

(R_{mf}) and the formation water (R_w). Clay content (shaliness) and bed thickness also influence the SP response. The voltage differential between the electrodes is measured in millivolts on the SP log.

Impermeable clays and shales (composed mainly of clays) typically generate one charge while saturated permeable formations such as sandstone will generate an opposite charge. Spontaneous potentials are usually caused by charge separation in the clay minerals, by the presence of a semi-permeable interface impeding the diffusion of ions through the pore space of rocks, or by natural flow of a conducting fluid (salty water) through the rocks.

For the purpose of calculating salinity, a shale section adjacent (above or below) to the permeable sandstone bed in question is taken as a "baseline", from which positive or negative deflections within the permeable bed are measured. The SP log has no absolute scale – only relative changes from the baseline. The direction of deflection (plus or minus millivolts from the baseline) is determined by the relative salinities of the mud filtrate (R_{mf}) and the formation water (R_w). When the salinities are equal ($R_{mf} = R_w$), there is little or no deflection and the SP response in the permeable sandstone equals that of the shale baseline. When the salinity of the formation water is less than that of the mud filtrate ($R_w > R_{mf}$), it results in a positive voltage and deflection (+mv) relative to the shale baseline. Conversely, when the salinity of the formation water is greater than that of the mud filtrate ($R_w < R_{mf}$), it results in a negative voltage and deflection (-mv) relative to the shale baseline. Generally, the greater the difference in the two salinities, the greater the deflection from the baseline (either + or -). A general schematic showing these relationships and their impact on SP response is shown in Figure 3-1.

Figure 3-1: Typical Responses of the SP Log (after P. Grover)



3.1.4 Limitations of the Spontaneous Potential Log in Salinity Calculations

The use of the SP log to calculate salinity has its drawbacks. To use the SP curve quantitatively, the value of the total potential drop around the circuit must be known. This value, the Static Spontaneous Potential (SSP) can be read directly from the well log when the zone is sufficiently thick, clean, shale free, and 100 percent water saturated (oil and gas within the pore spaces reduces the SP response). Deviations from these ideals may result in the SP response being suppressed, which can result in an anomalously low salinity calculation (appearance of fresher water). Various corrective methods can be employed to help offset or negate these effects.

Thin beds (generally less than 20 feet thick) will result in a subdued SP response. While an estimated SSP can be derived for thin beds using correction charts, this additional step was generally not employed in this investigation. Rather, to expedite calculations, salinity was calculated for the uppermost clean sandstone displaying sufficient thickness and water saturation judged to display a direct SSP response. In some cases, however, especially along the thinning margins of the regional sandstone bodies, thin sandstone corrections could not be avoided.

The accuracy of calculations utilizing an SP log response is also highly dependent on the permeability of the bed in question. While most sandstones in the Starkey, Mokelumne River, and Winters formations of the Sacramento Basin are highly porous and permeable, reductions in permeability do occur, and are usually attributable to increased shaliness of the sandstones that can usually be linked directly to depositional environment, or to thin zones of secondary calcification. Declining permeability results in the suppression of SP response and calculated salinity. Unfortunately, the amplitude of the SP curve cannot be used to make a quantitative determination of how permeable the bed is. In conjunction with other geophysical logs (if available) and geologic interpretation, the SP deflection can be used only to qualify the relative permeability of sandstone beds to adjacent sandstones. Hence there is no effective method to quantitatively correct for permeability variations in the salinity calculations.

Calculations using the SP log also require that the objective bed be 100 percent water saturated. The presence of liquid or gaseous hydrocarbons within otherwise thick and porous sandstone also serves to reduce the SP log response and yield an unusually low calculated salinity. For the purpose of this assessment, when hydrocarbons were trapped in the uppermost sandstones of a formation, the first underlying water saturated sandstone was used for the salinity calculation.

Finally, the results of salinity calculations from SP log responses are subject to equipment and human error. All calculations are dependent upon information recorded on the well log's header at the time of logging, specifically the well's bottom hole temperature and the resistivity of the mud filtrate. This information may be erroneous due to logging equipment or mud testing equipment malfunction, miscalibration, or simply data entry errors in the field.

3.1.5 Method of Salinity Calculations

Calculations of water salinity are actually derived from the relative resistivities of the formation water and the drilling mud filtrate in the wellbore at the time the well logs were run. Since resistivity is temperature dependent, calculation of water salinities from SP log responses can be a tedious process. In simplest terms, it involves correcting recorded values of mud filtrate resistivity (R_{mf}) to downhole temperature at the depth of the bed of interest, evaluating the relationship between (R_{mf}) at formation temperature, then determining the "equivalent resistivity" (R_{we}) of the formation water which is then converted to an estimated formation water salinity (R_w). Most modern log headers (post 1960) contain the necessary mud filtrate and temperature information from which to make these determinations. For wells drilled prior to 1960 in the Sacramento basin, this information is not available and salinities cannot be calculated.

The method of calculating salinity from the SP log used in this assessment is a multi-step process that depends largely on published chart data input and interpretation. The method involves:

- Determining formation temperature. The bottom hole temperature recorded on the log header is used to calculate the geothermal gradient, from which the subsurface temperature of the subject sandstone is calculated.
- Calculating resistivity of mud-filtrate (R_{mf}) at formation temperature. The R_{mf} value recorded on the log header is corrected to formation temperature using a resistivity-salinity-temperature correction chart.
- Determining the SSP deflection from the shale base line, in millivolts. Correct the SP for bed thickness to determine SSP, if necessary using thickness correction charts.
- Determining ratio of R_{mf}/R_{we} from charts.
- Determining R_{we} by dividing R_{mf} by R_{mf}/R_{we}.
- Correcting R_{we} To R_w from charts.
- Converting R_w to corresponding salinity

3.1.5 Formation Water Salinities in the Mokelumne River, Starkey, and Winters Formations

As part of the WESTCARB Phase II studies, CGS made a preliminary evaluation of the carbon sequestration potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters Formations (Downey and Clinkenbeard, 2010). The approach involved gross sandstone isopach (thickness) mapping of each formation to determine its maximum extent, followed by a process of elimination in an effort to exclude those areas which did not meet minimum criteria determined to be critical or preferable for subsurface injection and containment of CO_2. For each formation, depth maps were prepared to identify areas considered too shallow for critical state CO_2 injection (<1,000 meters or 3,280 feet), while isopach maps of overlying seals were used to isolate areas overlain by more than 100 feet of continuous shale, a thickness arbitrarily selected to help insure containment within a basin known to be impacted by small scale normal faulting. Further, in the case of the Mokelumne River and Starkey formations, those areas known to be disturbed by post-depositional Paleocene submarine erosion were also excluded due both to the high lateral variability of erosion and the relative paucity of subsurface control within these areas. For each formation, a final sandstone isopach map showing those areas meeting these criteria was produced. This previous study formed the basis for the evaluation of formation water salinities in the current study.

The area involved in this assessment included approximately 4,500 wells. To expedite this assessment, it was planned to evaluate formation water salinities on a density of approximately one well per section for each formation where well density allowed. In areas of lower well density, all wells penetrating the respective formation and for which the well header data were sufficient were used.

Occasionally, a calculated salinity below the 10,000 mg/l threshold was observed within a formation in an area otherwise marked by much higher salinities. In these cases, salinities were calculated for all adjacent wells to help validate the calculation or determine if the value was adversely impacted by incorrect or inaccurate input data taken from the well log header.

To further help validate low salinity calculations in a specific formation, salinities in the other two formations were calculated in the neighboring wells and compared. If the salinities in all three formations within a well appeared to be anomalously low relative to all neighboring wells, the data was considered suspicious and ignored.

Based on calculated salinities within the three formations, only the Mokelumne River Formation appears to contain formation water salinities below the 10,000 mg/l TDS threshold within those areas previously identified as potentially suitable for CO_2 sequestration. While several small areas within the Starkey and Winters formations also exhibited salinities below the threshold, these results are attributed to the effect of reduced permeability on the SP log response and the resulting salinity values.

3.2 Results

3.2.1 Mokelumne River Formation

Analysis of calculated formation water salinities within the Mokelumne River Formation and its equivalents indicates that salinities meet or exceed the 10,000 mg/l baseline throughout most of its distribution in the study area. Generally, calculated salinities ranged from 10,000 mg/l to as much as 95,000 mg/l. An exception to this occurs in an area comprising about 110 square miles marked by low salinity in the southwest corner of the basin.

This area lies down dip of Mokelumne River sandstone outcrops on the north flank of Mount Diablo in Contra Costa County, and extends northward as much as 15 miles into southern Solano County. This localized decrease in salinity is likely attributable to fresh meteoric water infiltration through the exposed outcrops.

Within this area, in their entirety, are the Brentwood Oil Field, and River Break and Oakley gas fields which produce oil and gas largely from Mokelumne Formation equivalent sands, and the southern portions of both Sherman Island and Dutch Slough gas fields, the latter producing in part from Mokelumne River sandstones. Throughout this area, calculated salinities below 10,000 mg/l dominated with many readings of less than 3,000 mg/l (this lower limit based on chart resolution). Low salinity in this area is consistent with salinity information reported in the DOGGR publication TR10 (1983), wherein average salinities for the Mokelumne River and equivalent sandstones in the aforementioned fields ranged from 1,000 mg/l (Brentwood Field) to 7,000 and 3,000 mg/l (Oakley and River Break Fields).

While the vast majority of estimated salinities within this area were low, a few isolated instances of higher salinity were noted. An anomalously high reading of 22,800 mg/l occurred within one well in Brentwood Field, and two localized occurrences of nearly 30,000 mg/l were noted in wells in close proximity to the outcrops and nearby wells exhibiting salinities well below threshold. Since this area of the basin is known to be highly faulted, it is surmised that fault segregation may be responsible for inhibiting recharge in selected fault blocks and allowing sandstones exhibiting higher salinities to coexist in such close proximity to surface exposures.

Figure 3-2 shows the extent of the area in the Mokelumne River Formation with salinities less than 10,000 mg/l TDS. It reflects an additional reduction of about 110 square miles (6 percent) to the area previously considered suitable for carbon sequestration within the Mokelumne River Formation in Downey and Clinkenbeard (2010).

Figure 3-2: Mokelumne River Formation, Potential Sequestration Areas

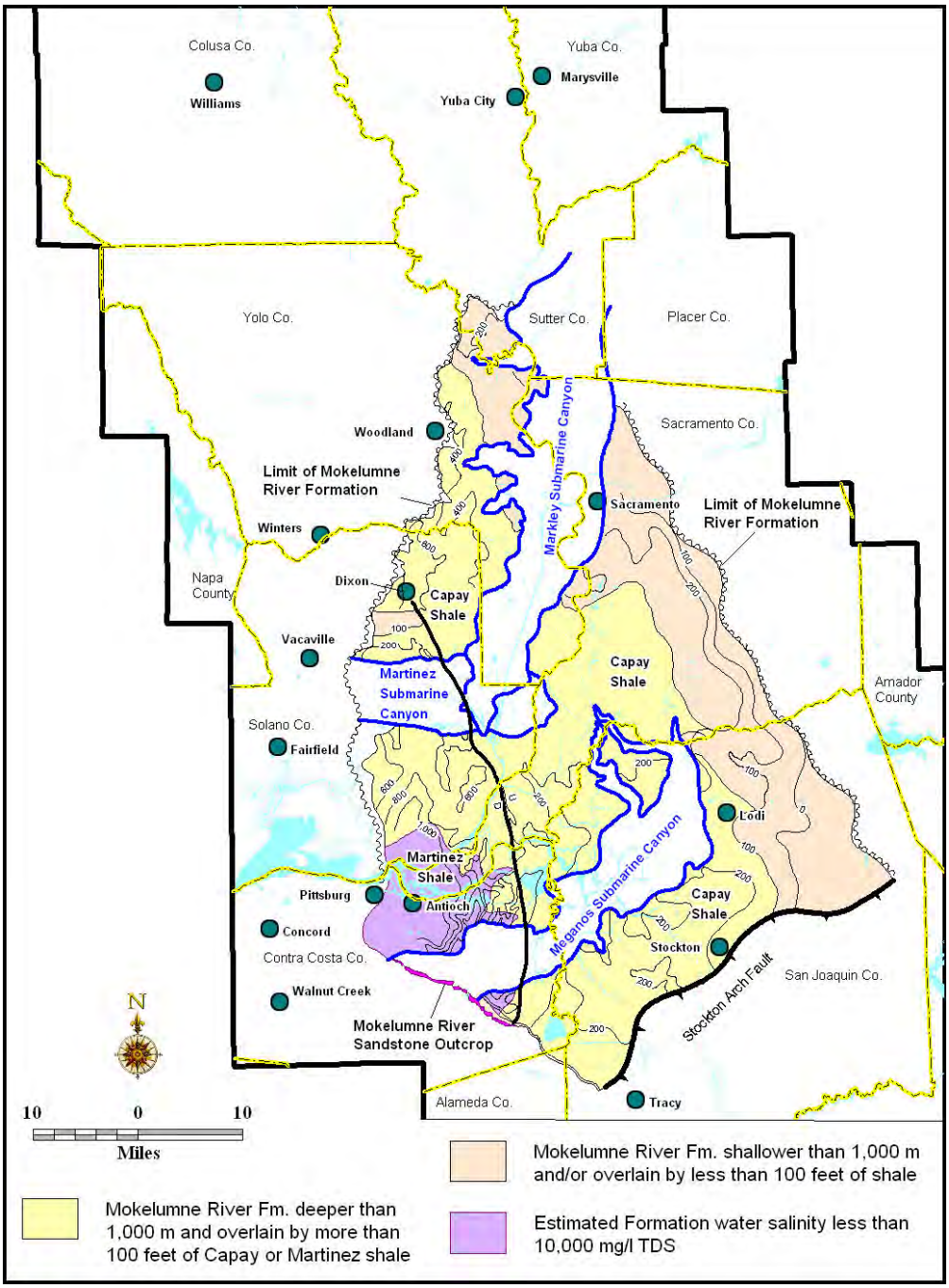


Table 3-1 illustrates the impact of the addition of salinity as a screening criterion (in addition to depth and seal criteria) on the potential availability of Mokelumne River sandstones for subsurface CO_2 sequestration.

Table 3-1: Distribution of Mokelumne River Formation Sandstone

MOKELUMNE RIVER FORMATION		
	Total Net Area	Percentage of Total Area
*Gross Sandstone Distribution	1,908 sq. mi.	100%
*Less Submarine Canyons	1,528 sq. mi.	80%
*Deeper than 1,000 Meters	1,075 sq. mi.	56%
*With 100+ Feet of Seal	1,045 sq. mi.	55%
Salinity > 10,000 mg/l TDS	935 sq. mi.	49%

Source: * From Downey and Clinkenbeard (2010)

3.2.2 Starkey Formation

Estimates of formation water salinity within Starkey Formation sandstones reveal that salinities likely exceed 10,000 mg/l TDS throughout the entire area previously identified as most prospective for carbon sequestration, and that no further reduction is necessary (Table 3-2). In general, calculated salinities ranged from 10,000 to as much as 65,000 mg/l in thicker Starkey sandstones. A notable trend was a general decrease in salinities to the north, west and south corresponding with a thinning and increases in shaliness of the Starkey Formation sandstones. Generally, as would be expected, the highest salinities occurred within the thickest and cleanest sandstone development in southern Sacramento and northern San Joaquin counties.

Notable are several narrow areas along the western and southern pinch-outs of the Starkey sandstones (Figure 3-3). Within these narrow bands, calculated salinities fell below the threshold, but are interpreted to be the result of petrophysical rock conditions rather than formation water chemistry. In each case, the reduced salinities are directly associated with a major deterioration in sand quality (both thinning and shaliness). Salinity calculations are dependent on SP log deflection and increased sandstone shaliness has a similar suppressive effect on SP response as decreasing formation water salinity. This interpretation is consistent with the lateral geological facies changes observed within the Starkey Formation along its southern and western margins. The primary causes of increasing shaliness along these margins is twofold, the result of both primary depositional conditions and post-depositional erosion. To the southwest, the Starkey Formation undergoes a major facies change grading from thick clean deltaic sandstone sequences in northern Sacramento, eastern Solano, and northern San Joaquin counties to shaly prodeltaic deposits containing relatively few dirty sandstone and siltstone stringers in south central Solano and west central San Joaquin counties. This is most apparent in the vicinity of MacDonald Island Field area where salinities below 10,000 mg/l were noted and

south of which Starkey Formation equivalents grade completely to marine shale. Toward the west and northwest, the Starkey Formation is truncated by a regional angular unconformity which resulted in the progressive removal of the thickest and cleanest uppermost deltaic sandstones in the sequence. Accordingly, the top of the Starkey Formation is marked by progressively thinner and shalier more distal sandstones and increasing shale in these directions. This phenomenon results in declining calculated salinities, but only to levels below 10,000 mg/l along the edges where the cleaner sands have been removed and only thin shaly distal facies remain. This is most evident in the vicinities of Winters Gas Field in Solano and Yolo counties, and Buckeye and Sycamore Slough gas fields in Colusa and Yolo Counties.

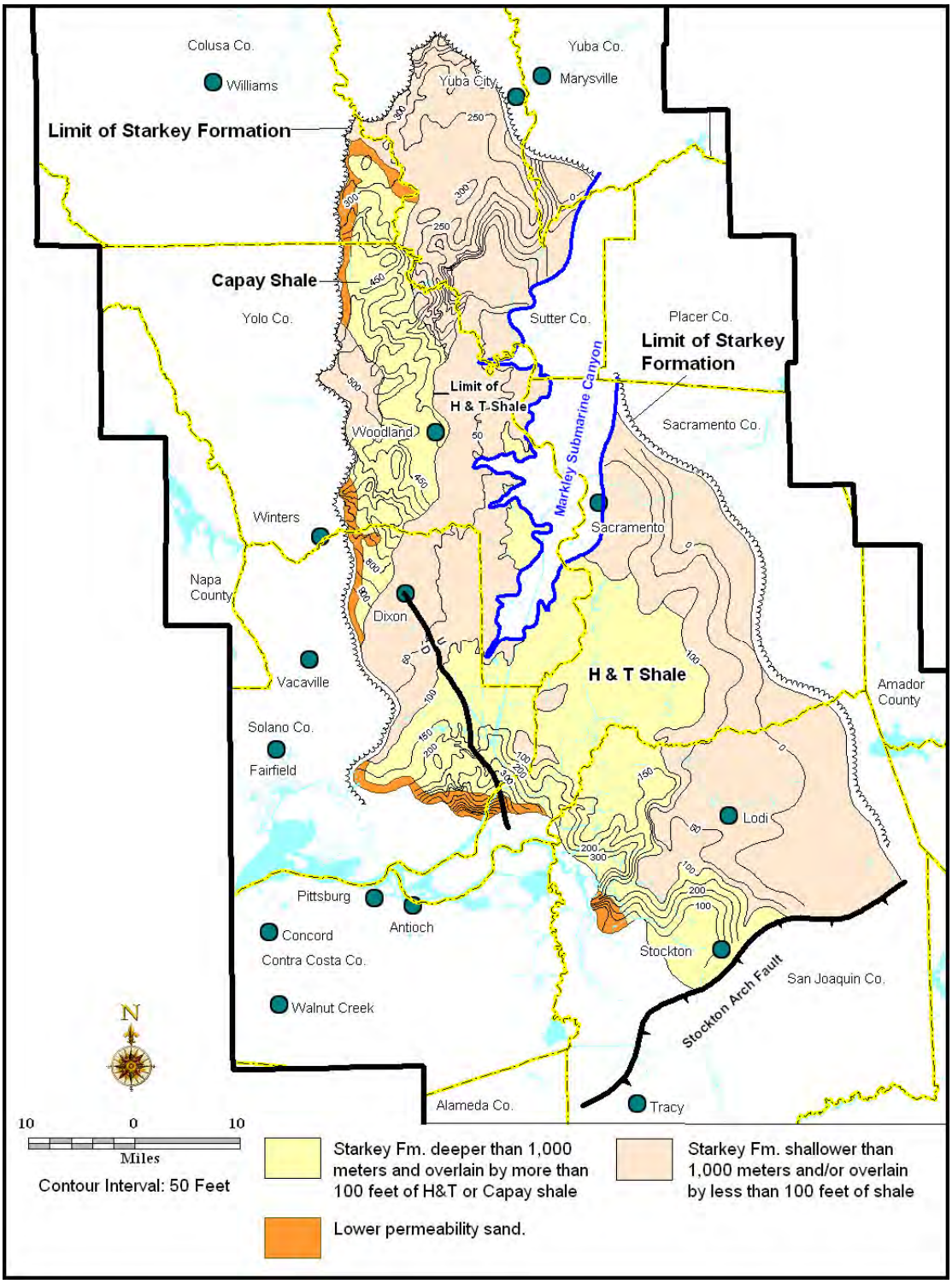
Similar conditions are expected to occur elsewhere along the western and southern margins of the Starkey Formation, but well control is insufficient to identify them. These areas represent only a small fraction of the available Starkey Formation sandstone and should not be ruled out as potential sites for CO_2 sequestration based on estimated water salinity. A decline in sandstone quality and thickness in these areas, however, may have a detrimental effect on potential CO_2 sequestration site selection and capacities.

Table 3-2: Distribution of Starkey Formation Sandstone

STARKEY FORMATION		
	Total Net Area	Percentage of Total Area
*Gross Sandstone Distribution	2,321 sq. mi.	100%
*Less Submarine Canyons	2,214 sq. mi.	95%
*Deeper than 1,000 Meters	1,416 sq. mi.	61%
*With 100+ Feet of Seal	920 sq. mi.	40%
Salinity > 10,000 mg/l	920 sq. mi.	40%

Source: * From Downey and Clinkenbeard (2010)

Figure 3-3: Starkey Formation, Potential Sequestration Areas



3.2.3 Winters Formation

Estimated salinities throughout the 1,524 square miles previously identified for potential sequestration within Winters Formation sandstones also appear to meet or exceed the 10,000 mg/l TDS threshold (Table 3-3). Calculated salinities range from 10,000 – 65,000 mg/l throughout most of its extent, with localized exceptions only occurring along the eastern pinch-out of Winters sandstones where salinities of less than 10,000 mg/l were observed in some wells (Figure 3-4).

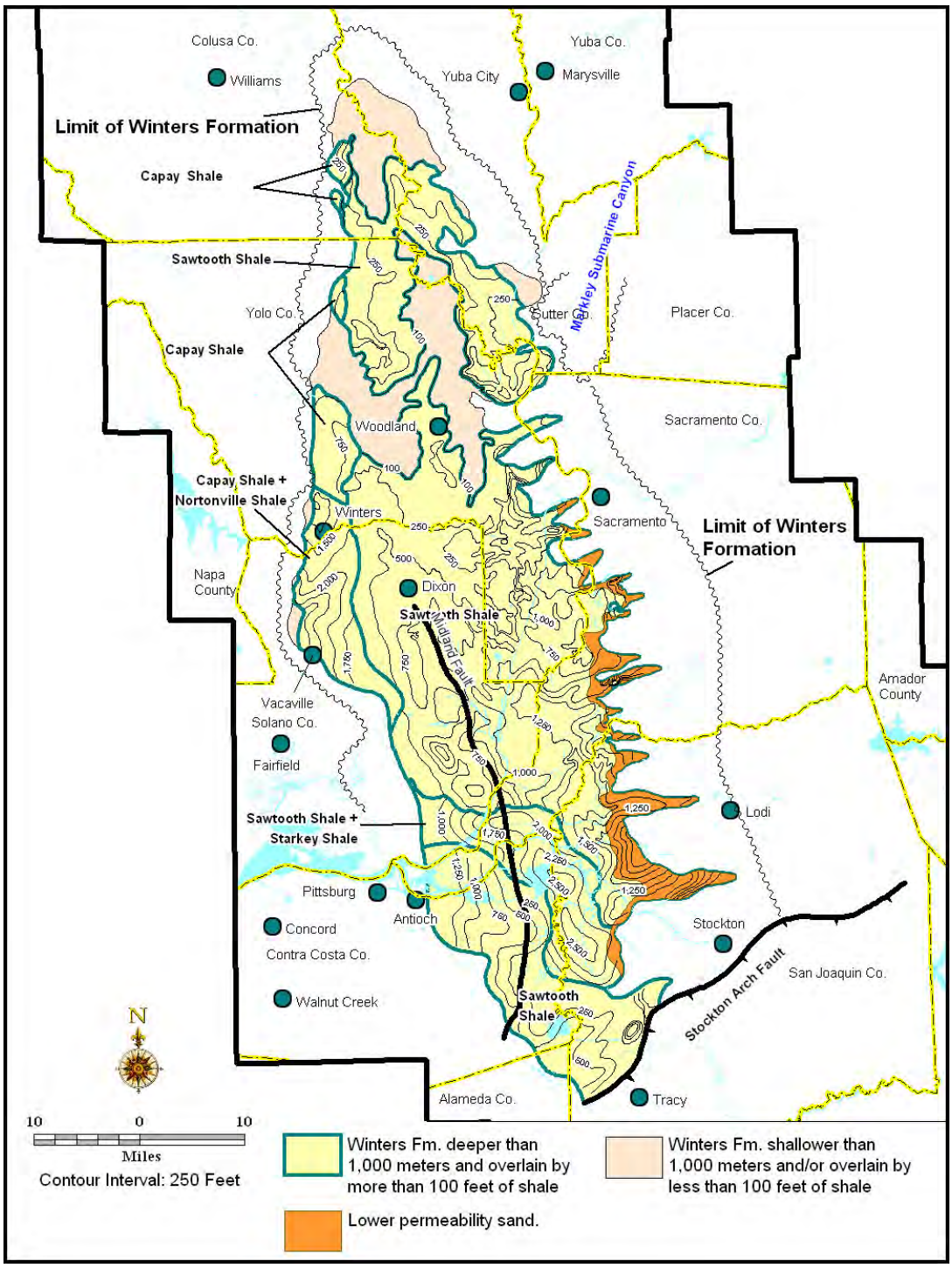
Similar to the marginal areas described in the overlying Starkey Formation, the lower salinities along the Winters pinchout are associated with a pronounced and rapid decline in sandstone quality and thickness and attributable to these lithologic constraints rather than water salinity. Thick Winters sandstone development, reaching over 1,500 feet and representing deeper water fans, thin rapidly eastward terminating in a series of shaly and thin sandstone stringers deposited within narrow marine slope feeder channels. Typically these deposits are laminated sands and shales or thin low permeability sandstones exhibiting suppressed SP responses and correspondingly lower calculated formation water salinities.

Table 3-3: Distribution of Winters Sandstone

WINTERS FORMATION		
	Total Net Area	Percentage of Total Area
*Gross Sandstone Distribution	1,771 sq. mi.	100%
*Less Submarine Canyons	1,771 sq. mi.	100%
*Deeper than 1,000 Meters	1,681 sq. mi.	95%
*With 100+ Feet of Seal	1,524 sq. mi.	86%
Salinity > 10,000 mg/l	1,524 sq. mi.	86%

Source: * From Downey and Clinkenbeard (2010)

Figure 3-4: Winters Formation, Potential Sequestration Areas



3.2.4 Revised CO_2 Storage Resource Estimates

A CO_2 storage *resource* estimate is defined as the volume of porous and permeable sedimentary rocks that is most likely accessible to injected CO_2 via drilled and completed wellbores. CO_2 storage resource assessments do not include economic or regulatory constraints; only physical constraints that define the accessible part of the subsurface are applied (DOE-NETL, 2010b).

CO_2 storage resource estimates were previously presented for the Mokelumne River, Starkey, and Winters formations in the Sacramento Basin (Downey and Clinkenbeard, 2010, Table 4). Those estimates included only those parts of these formations that met minimum depth and seal criteria (depth greater than 1,000 meters and seal thickness greater than 100 feet), but did not take into consideration formation water salinities. Since no areas within the Starkey and Winters formation within these areas were identified as containing formation waters fresher than 10,000 mg/l TDS, the CO_2 storage resource estimates for these formations remain unchanged. However, a portion of the Mokelumne River Formation previously identified as exhibiting potential for CO_2 sequestration has been removed from the estimates due to its potential as a source for underground drinking water. While this reduction amounted to about 6 percent of the area of the Mokelumne River Formation, it has resulted in a reduction of approximately 22 percent in the storage resource estimate for the formation. This disproportionately large reduction in resource estimate relative to area is largely attributable to the presence of some of the thickest Mokelumne River sandstone developments in the basin occurring within this small area. Revised formation and estimated total storage resource estimates are summarized in Table 3-4.

Table 3-4: CO2 Storage Resource Estimates

Formation	**Gigatons CO_2 (1%)**	**Gigatons CO_2 (4%)**
*Mokelumne River	1.0	4.0
*Starkey	1.0	4.1
*Winters	1.2	4.9
Total	3.2	13.0

Note: *For sands greater than 1,000 meters deep, with at least 100 feet of overlying shale seal and estimated formation water salinity greater than 10,000 mg/l TDS.

3.3 Conclusions

The Cretaceous Mokelumne River, Starkey, and Winters formations of the southern Sacramento Basin all contain significant thicknesses of porous and permeable sandstone that may be suitable for carbon sequestration within existing or abandoned gas and oil fields, or saline aquifers. Previously, the CGS identified areas within these formations exhibiting the most potential based only on minimum depth (1,000 m) and seal thickness (100 ft.) constraints. Consideration of formation water quality, in respect to eliminating those areas containing potential underground drinking water sources (< 10,000 mg/l TDS), has resulted in a modification to the area underlain by Mokelumne River Formation sandstone presented previously. Relatively fresh waters were identified in Mokelumne River Formation sandstones within a limited area proximal to known sandstone outcrops. While no geochemical data is available to corroborate it, meteoric aquifer recharge via these exposed outcrops is likely responsible for this phenomenon. No conclusive evidence of fresher water meeting this threshold was identified within sandstones of the deeper Starkey or Winters formations which do not crop out anywhere in the basin.

Accordingly, a revised 935 square miles are underlain by Mokelumne River sandstone, while 920 and 1,524 square miles are underlain by Starkey and Winters formation sandstones respectively. The revised estimated storage resource for the portions of the three formations meeting depth, seal, and water quality criteria is 3.2 to 13.0 Gigatons of CO_2.

This assessment of formation water conditions does not significantly affect the previous conclusions. On a formation level, the Winters Formation sandstones appear to offer the best potential for carbon sequestration. While gross sandstone achieves considerably greater thicknesses in the Mokelumne River Formation, Winters Formation sandstone can exceed 1,500 feet in thickness. Additionally, about 95 percent of these sandstones are below 1,000 meters (3,280 feet). Depth provides additional benefits including a greater number of overlying shale units increasing the likelihood of containment, as well as reducing or eliminating uncertainties associated with downcutting of the Paleocene submarine canyons. Winters sandstones are also appealing from a stratigraphic standpoint. Unlike the Mokelumne River and Starkey formations, which are overlain up-dip to the east by porous sandstone, Winters sandstone pinches out up-dip within marine shale along most of its eastern margin. This configuration creates the potential for large-scale stratigraphic containment.

All calculations used in this assessment were based on standard industry interpretation of geophysical logs with data applied to empirical interpretive charts and are considered the best available information in the absence of actual analytical water analyses. Actual characterization of any formation or zone should include collection and analysis of actual formation fluids before its suitability for carbon sequestration can be conclusively determined.

CHAPTER 4:
Hydrocarbon Pool Size Distribution in the Bunker, Millar, and Conway Ranch Gas Fields – Southern Sacramento Basin, California

As part of the WESTCARB Phase II program, CGS conducted a preliminary geologic assessment of the carbon sequestration potential of the Upper Cretaceous Mokelumne River, Starkey, and Winters formations in the southern Sacramento Basin (Downey & Clinkenbeard, 2010). Other tasks which arose as offshoots from the original assessment included an evaluation of formation water salinities (described elsewhere in this report), and an assessment of typical pool sizes within selected natural gas fields. The latter task was undertaken to evaluate the CO_2 storage capacities of depleted gas pools and provide preliminary information about their potential for commercial scale sequestration options.

Most natural gas reservoirs in the southern Sacramento Basin are marked by extensive normal faulting which results in widespread compartmentalization of independent gas pools. Individual fault blocks may contain one or more distinct gas pools, many of which are small and can be effectively drained by one or two optimally placed wells. Hence, an assessment of pool size within three selected gas fields was undertaken to evaluate pool size distribution and determine the volumetric suitability of depleted gas reservoirs for potential carbon sequestration applications. The selected fields included the Bunker, Millar, and Conway Ranch gas fields.

The sole purpose of this study was to characterize typical volumetric capacities potentially available for CO_2 storage applications based on replacement of produced natural gas volumes only. Potential storage capacities within original saline portions of reservoir sandstones or other brine saturated sandstones within the field's areas were not addressed. No attempt was made to identify and/or recommend specific pools for potential pilot or commercial sequestration applications, and no conclusions were drawn regarding an individual pool's suitability for carbon storage. Such recommendations can only be reached after a thorough site-specific characterization of individual pools under consideration. CO_2 storage capacities for discovered gas pools in the studied fields are based on actual natural gas production volumes and compared to an estimated annual CO_2 emission of 2.0 Mt per year for a typical in-state California point source emitter (power plant, cement plant, or refinery). Data from this study may be used by other workers in future efforts to determine the suitability of specific pools, or combinations thereof, within depleted fields of the southern Sacramento Basin.

The majority of individual pools identified in this study are considered very small and likely unsuitable for even the smallest sequestration project. While some of these pools, either individually or in combination, may provide viable sequestration options, sites for CO_2 sequestration within depleted gas pools may be more limited than one might expect based on casual observation of gas field maps or field production statistics in northern California.

4.1 Project Approach and Work Methods

4.1.1 Objectives

Maps showing natural gas fields in the southern Sacramento Basin reveal a significant number of fields, many encompassing areas of several thousands of acres or more. Closer inspection, however, reveals that most of these fields are highly compartmentalized, consisting of numerous small pools that commonly cover only a few tens of acres at best. Millar Field, for example, while covering an area of about 26,700 acres is comprised of about 178 known pools. Only rarely do individual pools cover more than about 80 acres, with the majority being much smaller. Additionally, multiple pools may be vertically stacked and localized against steeply dipping boundary faults. As a result, as much as 70-80 percent of an indicated field area may not be underlain by productive natural gas pools.

Within these constraints, an attempt was made to determine individual pool sizes within typical gas fields of the southern Sacramento Basin producing from the Mokelumne River, Starkey, and Winters formations. Pool sizes were defined by the estimated CO_2 resource storage capacity of each pool based on actual hydrocarbon production from the depleted reservoirs. Depletion of a reservoir occurs when a well (or wells) is completed (perforated) in the reservoir and its hydrocarbons are extracted. Storage capacity estimates were confined only to reservoir volumes formerly containing, and having produced natural gas. Additional potential CO_2 storage capacity which may exist in brine saturated portions of closures, or within adjacent saline aquifers was not addressed due to data constraints. Capacities were estimated using methods defined in the U.S. Dept. of Energy's Methodology for Development of Geologic Storage Estimates for Carbon Dioxide (DOE-NETL, 2010b).

4.1.2 Field Selection

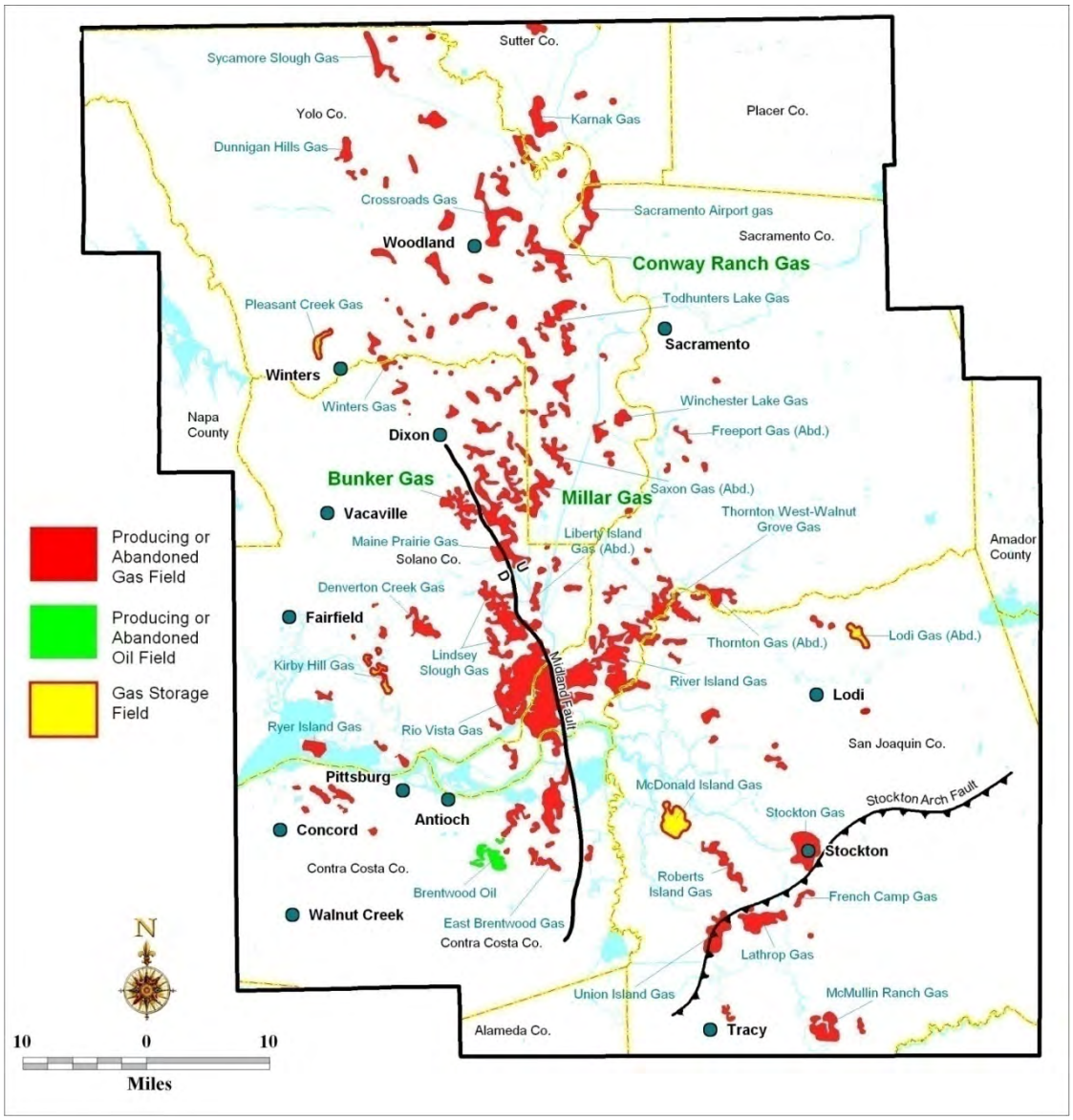
Many fields in the southern Sacramento Basin produce gas from the Mokelumne River, Starkey, and Winters formations. Since the goal of this study was to characterize typical pool sizes, and not to identify specific fields or pools for potential pilot or commercial sequestration applications, no effort was made to identify fields with the largest or most promising pools. Instead, the Bunker, Millar, and Conway Ranch fields (Figure 4-1) were selected as being geologically representative of the many available fields. While some fields produce from all three formations (or more), most have only one or two primary reservoirs. Efforts were made to select fields containing all three formations as primary or secondary reservoirs.

Field selection was also confined to those parts of the basin where the respective formations met previously established minimum requirements for carbon sequestration (Downey & Clinkenbeard, 2010). These requirements include formation depths greater than 1,000 meters, overlying formation level seals of greater than 100 feet, and areas of each respective formation largely undisturbed by younger Paleocene erosion (minor exceptions were made for small areas in southeast corners of Millar and Conway Ranch fields where Paleocene erosion has truncated upper Mokelumne River Formation sandstones). Additionally, areas were avoided that exhibited formation water salinities defined as potential "underground source of drinking water" under 40 CFR Ch.1 part 144.3 (< 10,000 mg/L TDS).

4.1.3 Pool Identification

To determine the potential CO_2 storage capacity for each pool, individual pools and their respective production volumes had to be identified from which its CO_2 storage capacity could be calculated. In most cases monthly production records for each well were examined to allocate production to individual pools. Commercially available well production histories were used for this study. For wells completed in and produced from a single pool, cumulative production data was sufficient. No minimum pool size was determined. Any sandstone in which a completion attempt resulted in recorded gas production (no matter how small) was considered a pool for this study.

Figure 4-1: Location Map Showing the Bunker, Millar, and Conway Ranch Gas Fields



Electric logs from each producing or formerly producing well were first correlated throughout each field with formation tops for the respective producing formations (Mokelumne River, Starkey, and Winters). Correlation establishes the equivalent stratigraphic horizons within each of the many well bores. Locally, individual sandstones within each formation were then correlated as necessary. Logs were then annotated with the original well completion history and all pertinent remedial and/or recompletion information. Historical well data were obtained from the online well record database maintained by the DOGGR. Information included, but was not limited to, completion/recompletion date(s), perforated interval(s), casing/tubing flow

test rate(s), pressure(s), packer depth(s), true vertical depth(s) (TVD), vertical subsea level elevations (VSS), zone and/or well abandonment date(s), and any other information useful for allocating monthly gas production to individual pools.

Each producing well's electric log was correlated with nearby well logs to determine the extent of each producing pool. Pools were identified by formation name, discovery well, date of discovery, and depth. Due to the number of pools, their frequent vertical stacking or juxtaposition, and limited areal extent (often only a few tens of acres), detailed geologic mapping of the pools was beyond the scope and resources of this study. Accurate areal mapping of each pool would require detailed reservoir engineering and geology to translate produced volumes, reservoir thickness, structural dip and so forth, into meaningful representations in map view. A much simpler graphical method was employed to segregate and inventory the individual pools, particularly those producing from equivalent but fault separated sandstones.

The vast majority of pools in these fields consist of localized gas accumulations trapped updip in gently folded or undulating beds against bounding faults. In plan view, they are most often illustrated by an elongate arc (representing the gas-water contact) abutting the bounding fault trace. To represent these geometries, individual pools were identified and represented on a large scale field map by drawing color coded linear ellipses encompassing the surface locations of wells producing from a common pool, and paralleling the prevailing northwest-southeast fault trend. For simplicity, bottom hole locations of directionally drilled wells were not plotted unless the bottom hole departure was sufficient to impart ambiguity in pool identity. Representation of the smallest pools was problematic, especially when pools were vertically stacked. This resulted in numerous small overlapping ellipses, making maps of their spatial relationships impractical at all but the largest scales. Consequently, individual pool maps are not included in this report. However, small scale maps showing very generalized pool distributions are included under the discussion of each respective field.

Subsea level elevations were calculated for the tops of all pools and gas/water contacts (GWCs), if present. Pool and GWC depths in directionally drilled wells were corrected to true vertical depth and true subsea level elevation. Small pools encountered in a single well were common and easy to identify. Well logs exhibiting correlative gas bearing zones were examined to determine if these occurrences represented common pools or fault separated pools. Any observable or inferred faults were noted. Common depths, especially of gas water contacts, were considered indicative of a common pool. Pressure depletion data in more recent completions, where available, was also considered indicative of common pools. Fault separation of correlative producing sandstones was most often identified by significantly dissimilar elevations and/or GWCs, or by the presence of intervening down-dip gas-water contacts. Correlative pools with similar GWCs located perpendicular to bounding faults were examined for potential fault separation, most frequently identified by demonstrable fault separation in overlying or underlying producing pools. Where separation of off-strike correlative pools could not be demonstrated, an assessment of the known or inferred local fault density was used to infer the presence or absence of a separating fault.

4.1.4 Production Allocation and Considerations

For each producing well, monthly production statistics were examined to allocate the appropriate portion of a well's cumulative production to its respective pool. In wells perforated in a single zone, all production was simply allocated to that zone. In wells that were systematically recompleted in new pools after producing pools were depleted, monthly production could also be attributed to each zone with considerable accuracy. However, in some wells, particularly those dually completed through both casing and tubing, separate production records were rarely available. In these cases, a single production volume had to be allocated between two or more pools. Generally this was a subjective process involving a proration based on the pools' initial potentials, flowing pressures (tubing or casing), indicated gas column thicknesses, and lateral extent (if reasonably known). In cases where two pools produced through tubing or casing (commingled) and individual zone potentials or flowing pressures were not known, production was allocated equally between the pools. This usually involved relatively small gas volumes (< 0.5 BCFG), and did not materially alter the conclusions of this study.

Separate spreadsheets were prepared for each producing formation within each field. Production volumes were summed by pool in the spreadsheets. Nearly all pools in the Mokelumne River, Starkey, and Winters formations exhibit active water drives. Wells perforated in the top of the gas column initially produce dry gas with little water. Over time, and sometimes quite abruptly, gas volume declines and water production increases as water replaces gas in the pore spaces and is drawn to the perforations. Ultimately, the produced water in the tubing or casing kills the well, it becomes uneconomical to lift and dispose of the water, and the perforations are abandoned. Since produced water is largely the result of displaced gas in the reservoir, it is not considered in the volumetric calculations for potential CO_2 storage capacity.

For reasons which are beyond the scope of this study, production records for wells in the Bunker Field (on the downthrown west side of the Midland Fault) indicate condensate is associated with the gas production from most pools. Natural gas condensate is a mixture of hydrocarbon liquids produced from many, but not all natural gas reservoirs. Produced condensate is important since it represents hydrocarbon volume previously occupying pore space within the gas pool. Thus, it must be considered with the produced gas volumes, in any calculation of potential CO_2 storage volume. Production records for the many wells in the shallower Millar and Conway Ranch fields (on the upthrown east side of the fault) show an absence of any condensate production.

4.1.4 Data Compilation

Progressing systematically through each well in a field, each productive pool was identified and its relevant information recorded on the spreadsheets. Pools were assigned a unique

identification code based on the field name, pool discovery well operator, well name, location, formation name, and unique depth in the pool's discovery well. Production volumes for common pools produced from separate wells were attributed under the pool discovery well for summation of pool production and determination of average depth. The cumulative pool specific production volumes were used to calculate potential CO_2 resource storage estimates. In total, 313 separate pools were identified.

Additional information necessary to complete the storage calculations was also entered in the spreadsheets. This information included estimated temperature and pressure for each pool based on the average pool depth, as well as constants for methane and CO_2 compressibility at surface and reservoir pressure and temperature conditions. Temperature and pressure information was derived using a geothermal gradient for each field and a standard pressure gradient of 0.46 psi/ft, based on the average depth of the pool. Additional requisite variables necessary to perform the storage calculations including CO_2 and natural gas densities at reservoir conditions were calculated using the WEBGasEOS calculator developed by Lawrence Berkeley Laboratory (http://lnx.lbl.gov/gaseos/gaseos.html).

4.1.5 CO_2 Capacity Calculations

The U.S. Dept. of Energy's Methodology for Development of Geologic Storage Estimates for Carbon Dioxide (DOE-NETL, 2008) provides methods for calculation of estimated CO_2 storage capacity in oil and gas reservoirs using standard oil field practices. These methods typically involve volumetric calculation of oil or gas in place using detailed reservoir parameters and then applying a CO_2 storage efficiency factor. In the absence of specific reservoir parameters, actual cumulative production (for depleted reservoirs) or estimated ultimately recoverable (EUR) reserves of oil and gas (for producing reservoirs) can be substituted, resulting in the following equations to estimate CO_2 storage capacity:

For oil reservoirs,

$$Q_{CO2} = (V_{prod} + V_{reserves}) \cdot B_o \cdot \rho_{CO2(r)}$$

Where: Q_{CO2} = CO_2 storage capacity in metric tons

V_{prod} = volume of oil produced (m^3)

$V_{reserves}$ = volume of remaining producible oil reserves (m^3)

B_o = formation volume factor

$\rho_{CO2(r)}$ = density of CO_2 at reservoir conditions (kg/m^3)

For gas reservoirs,

$$Q_{CO2} = (V_{prod} + V_{reserves}) \frac{Z_{NG(r)} \cdot Z_{CO2(s)}}{Z_{NG(s)} \cdot Z_{CO2(r)}} \cdot \rho_{CO2(s)}$$

Where: Q_{CO2} = CO_2 storage capacity in metric tons

V_{prod} = volume of gas produced (m^3)

$V_{reserves}$ = volume of remaining producible gas reserves (km^3)

$Z_{NG(r)}$ = compressibility factor for natural gas at reservoir conditions

$Z_{NG(s)}$ = compressibility factor for natural gas at surface conditions

$Z_{CO2(r)}$ = compressibility factor for CO_2 at reservoir conditions

$Z_{CO2(s)}$ = compressibility factor for CO_2 at surface conditions

$\rho_{CO2(s)}$ = density of CO_2 at surface conditions (kg/m^3)

In some gas reservoirs of the southern Sacramento Basin where minor subordinate condensate is produced, an adaptation to the equation for oil reservoirs may be used to estimate the approximate storage capacity attributable to the condensate fraction. In a typical oil reservoir, a formation volume factor B_o is applied to account for volumetric shrinkage of produced oil as natural gas expands and is released from solution in the oil at lower surface pressures. This factor is unnecessary when accounting for associated condensate produced from a relatively dry gas pool and the equation relating produced condensate to estimated CO_2 storage capacity may be reduced to:

$$Q_{CO2} = (V_{prod} + V_{reserves}) \cdot \rho_{CO2(r)}$$

Where: Q_{CO2} = CO_2 storage capacity in metric tons

V_{prod} = volume of oil produced in (m^3)

$V_{reserves}$ = volume of remaining producible oil reserves (m^3)

$\rho_{CO2(r)}$ = density of CO_2 at reservoir conditions (kg/m^3)

Further, almost every discovered pool in the Bunker, Millar, and Conway Ranch fields is, or is very nearly, depleted. Hence the variable $V_{reserves}$ in both equations can be considered to be zero.

4.1.6 Exploration Economics and Pool Size

The average or median gas pool size exploited by industry has undergone a downward trend in response to upward pressure on the wellhead price of natural gas. Consequently, many of the small pools identified and considered in this study are of rather recent vintage. Natural gas prices are largely driven by supply and demand fundamentals including weather, demographics, economic growth, fuel competition, available storage, and exports/imports. Until the 1970s, low natural gas prices (typically $0.22/MMBTU) discouraged the development of all but the largest accumulations. Not surprisingly, almost all the larger gas accumulations in the southern Sacramento Basin were discovered and developed by major or large independent producers during this period. In the 1970s and thereafter, sensing the major pools had been discovered, most large operators curtailed their operations in the Sacramento Basin.

Since the 1970s, small independent companies or fledgling forays into the basin by more established companies began exploiting increasingly smaller pools. Starting in the late 1970s, natural gas prices escalated rapidly and became much more volatile. This was most prevalent in California with the deregulation of wholesale natural gas prices in 2000 which at one point allowed prices to briefly spike at over $14/MMBTU due primarily to a shortage of interstate pipeline capacity. Increasing prices and price volatility allowed small producers to develop smaller and smaller pools and recomplete wells in previously sub-economic zones resulting in a steep decline in the median pool size for many Sacramento Basin fields.

No effort has been made in this study to establish a lower limit on pool size based on production or development economics. Clearly, some of the included pools are far too small to ever have been commercial regardless of past gas price. Some of these pools were perforated simply because of the common practice of perforating any prospective zone prior to well abandonment. Whatever the reason, this study includes any pool which was perforated and for which production volumes were recorded.

4.1.7 CO_2 Storage Capacities

To provide a meaningful benchmark for the estimated CO_2 storage capacities identified in this study, some metric of source emissions is needed. Herzog (2005) estimated annual CO_2 emissions for various sources in California (Table 4-1). Four stationary source categories were identified – natural gas fired power plants, cement plants, refineries, and gas processing plants. These estimates were derived from calendar year 2000 power plant emissions or estimates based on production capacities in the case of cement plants and refines. No data was provided for gas processing facilities. Actual current and future emissions will vary depending on many variables, including demand, facility scalability, and actual versus calculated emissions.

Total estimated year 2000 California CO_2 emissions from all identified sources (less the 2 gas processing facilities) were 53.8 million metric tonnes (Mt). Individually, 18 power plants produced a total of 36.5 Mt for an average of 2.0 Mt per plant, 6 cement plants produced 6.0 Mt for an average of 1.0 Mt per plant, and 7 refineries produced 11.3 Mt averaging 1.6 Mt annually. For the purposes of this study, the conservative larger average of 2.0 Mt per year has been employed as indicative of a typical California facility, regardless of type.

Table 4-1: Annual CO_2 Emissions From Stationary Sources by Facility Type

Power Plants			Cement Plants			Refineries			Total		
# of Facilities	CO_2 (Mt)	Avg. (Mt)	# of Facilities	CO_2 (Mt)	Avg. (Mt)	# of Facilities	CO_2 (Mt)	Avg. (Mt)	# of Facilities	CO_2 (Mt)	Avg. (Mt)
18	36.5	2.0	6	6.0	1	7	11.3	1.6	31	53.8	1.7

4.2 Results

4.2.1 Bunker Gas Field

Bunker Gas Field, located in northeastern Solano County, covers approximately eight square miles (5,207 acres) and has produced approximately 191.3 BCFG and 831.4 MBO of associated condensate from fifty-eight (58) wells completed in the Mokelumne River, Starkey, and Winters formations. Sandstones of the Mokelumne River and Winters formations are the primary producing zones, with Starkey sandstones producing less than 6 percent of total production. Presently, all but 26 of these wells have been abandoned, the remainder being near depletion. Total monthly field production for the month of September, 2010 was just 6,775 MCF.

Since its discovery in 1960, approximately 44 pools have been discovered within the field. Figure 4-2 illustrates the approximate cumulative area underlain by the many known natural gas pools within the field, and is provided as a composite view to illustrate the approximate lateral distribution of gas pools in the subsurface. Figure 4-3 diagrammatically illustrates the possible relationship of multiple individual pools in the subsurface to the composite view shown in Figure 4-2.

Approximately 98 completions within these pools have cumulatively produced 87.0 BCFG + 361.2 MBO (Mokelumne), 10.7 BCFG + 52.0 MBO (Starkey), and 93.6 BCFG + 418.2 MBO (Winters). While the majority of wells have been completed in only one or two pools, some wells have been completed in as many as five pools. Similarly, while some pools have only been tapped by a single well, many have been produced through several wells, the field's two largest pools having been produced through 13 and 12 wells respectively.

Total CO_2 storage capacity for all 44 pools identified in Bunker Field is estimated at 17.9 Mt, with 8.9 Mt, 1.0 Mt, and 8.0 Mt attributable to the Mokelumne River, Starkey, and Winters formations, respectively. Pool capacities range in size from a low of 396 tons (<0.1 Mt) to a high of 6.6 Mt. Figure 4-4 is a graph of storage capacity for the 44 individual Bunker Field pools. Clearly, the field is characterized by an abundance of very small pools. Only 5 of the 44 pools exceed 0.5 Mt storage capacities. The five largest pools have individual estimated capacities of 0.65 Mt to 6.6 Mt, with a cumulative capacity of 15.2 Mt. Nearly 63 percent (11.3 Mt) of the entire field's storage capacity occurs within the two largest pools. The largest pool, in the

uppermost Winters Formation at an average depth of 8,756 feet, contains nearly 37 percent (6.6 Mt) of the field's capacity. About 26 percent (4.7 Mt) of the field's capacity occurs in the second largest pool, the "Bunker" sand, a single pool at an average depth of 6,793 feet in the lower Mokelumne River Formation. Of the remaining 39 pools, storage capacities range from a low of <0.1 Mt to a high of 0.35 Mt. Median pool size is 0.05 Mt.

At an assumed emission rate of about 2.0 Mt CO_2 per year for an average California generator, the largest pool (6.6 Mt) would provide only 3.3 years of continuous storage. Adding the second largest pool (4.7 Mt) provides only an additional 2.4 years worth of capacity. The five largest pools (exceeding 0.5 Mt/pool) results in only 7.6 years of potential capacity. If one were to consider adding the remaining 39 pools, the entire ultimate capacity (serviceable life) for the field, in known pools, would only amount to 9 years. The median pool capacity would accommodate only 3 months' worth of emissions.

Figure 4-2: Approximate Areas Underlain by Pools in the Bunker Gas Field.

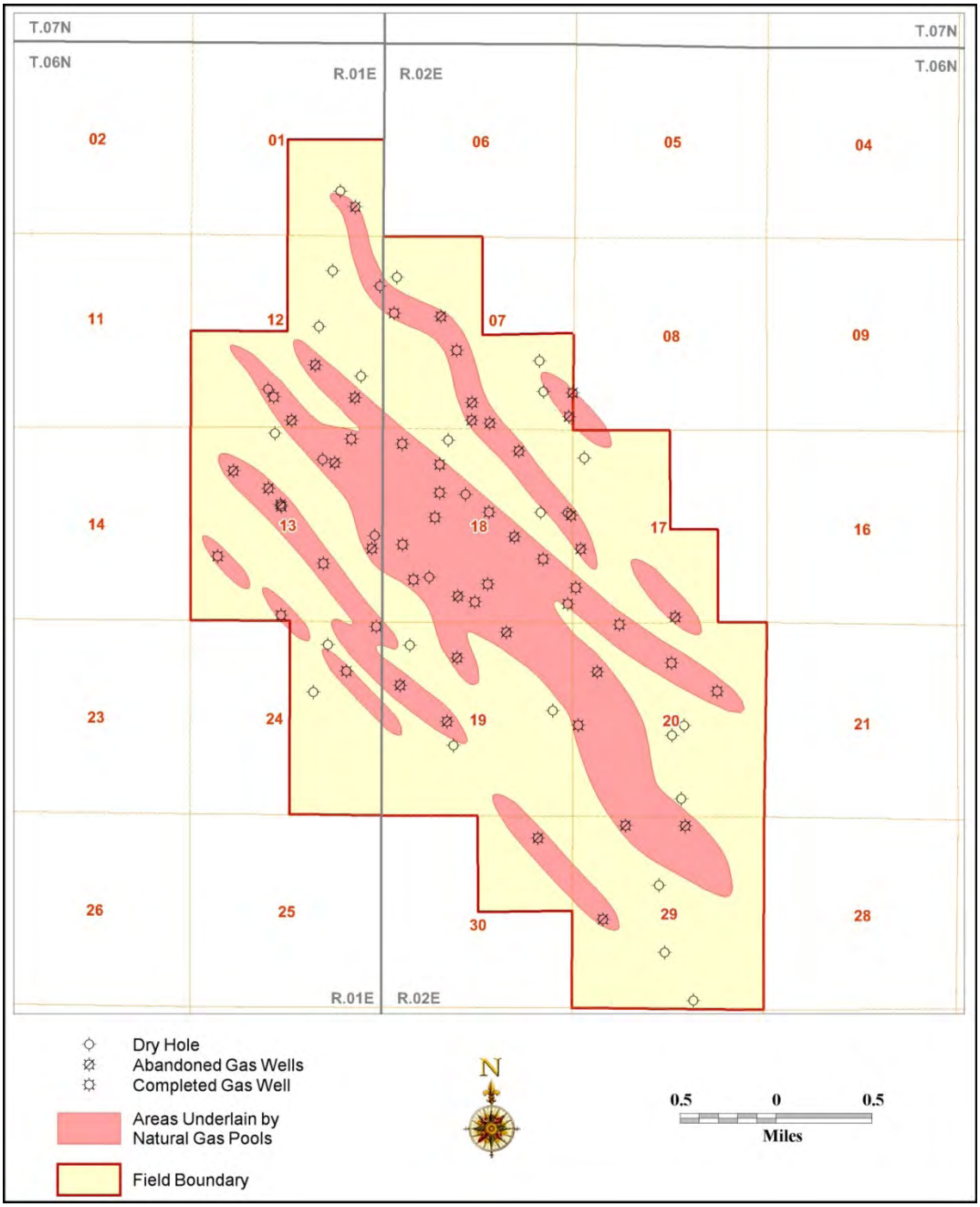


Figure 4-3: Schematic Showing Surface Distribution of Subsurface Gas Pools

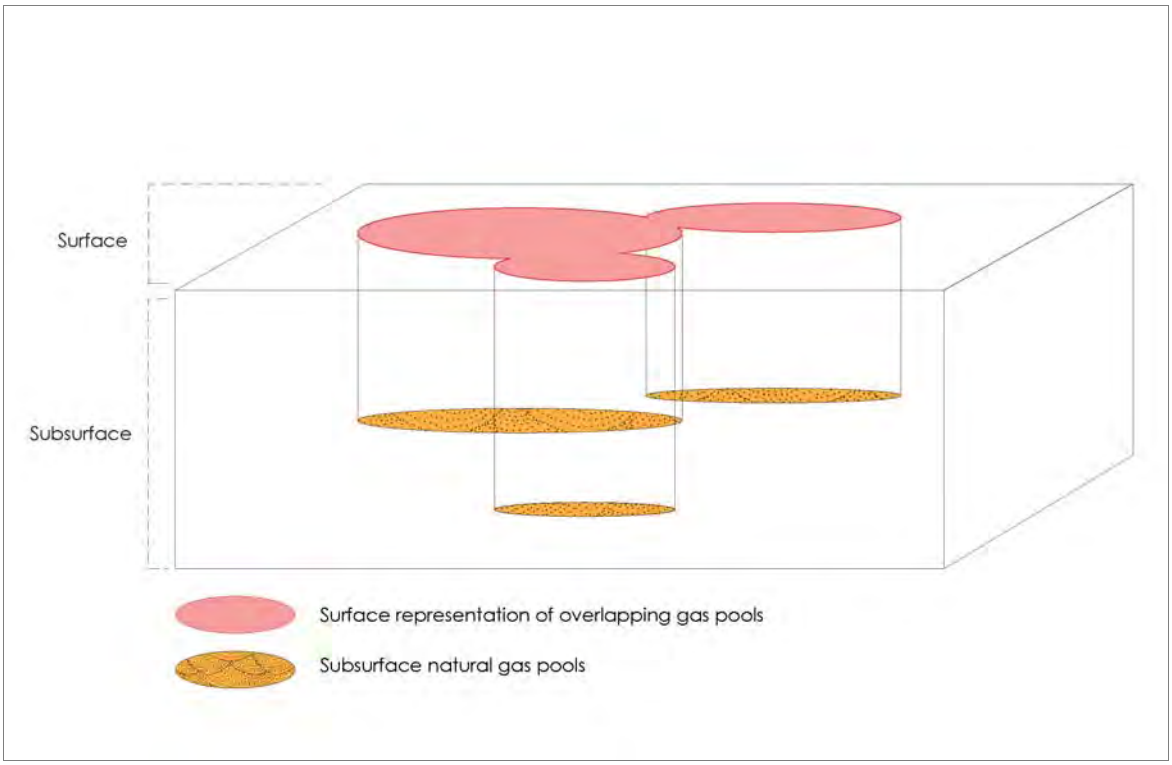
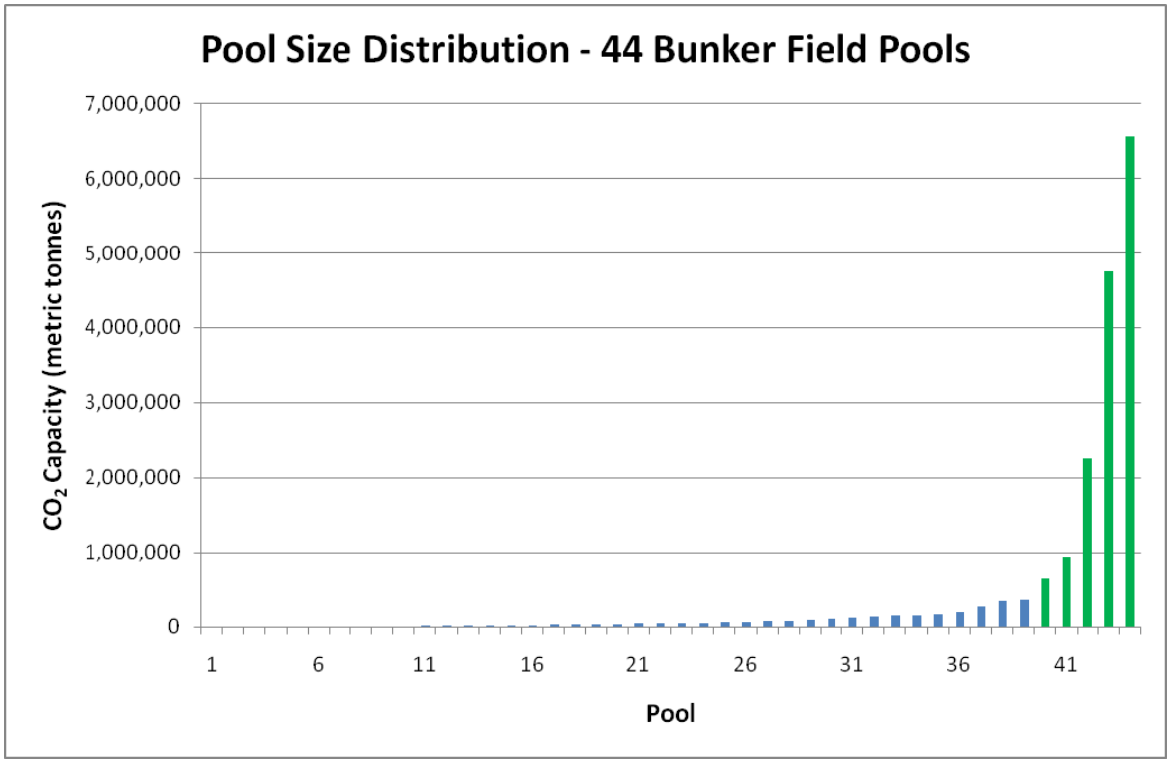


Figure 4-4: Estimated CO2 Storage Capacity by Pool – Bunker Gas Field



4.2.2 Millar Gas Field

Millar Gas Field is located due east of and adjacent to Bunker Gas Field on the upthrown side of the Midland Fault. Consequently, formation depths at Winters level are as much as 600 to 1,600 feet (depending on fault proximity) shallower than wells in the Bunker Field. Millar Field has produced approximately 159.8 BCFG for which monthly production histories are available (DOGGR records indicate a cumulative production of 174 BCF, but no monthly production histories are available corroborating this figure). Production has come from 146 wells, most of which have been abandoned. Only 15 producing or shut-in wells remain, with a production of only 10,409 MCF in September 2010. Unlike Bunker Field, no condensate production is recorded for any well in the field. Also different from the other fields in this study, 11 wells were completed in and produced from the shallower Domengine Formation which was not included in this analysis.

While Millar Field was discovered in 1944, the discovery of a number of new pools in the 1970's and 1980's significantly expanded the field. Occasionally, infill development and new pool exploratory wells are still drilled within the field area which encompasses approximately 42 square miles (26,700 acres).

One hundred seventy eight (178) separate pools were identified within the four formations in Millar Field. The approximate distribution of areas underlain by pools within the field is shown

in Figure 4-5. Cumulative production by formation amounts to 69.3 BCFG (Mokelumne River), 6.8 BCFG (Starkey), and 79.5 BCFG (Winters). The shallow Domengine Formation contributed 4.2 BCFG. Approximately 269 separate completions were required to yield these gas volumes.

Like Bunker Field, most production has been obtained from numerous small pools with only a handful of pools contributing significantly to field production. Total potential CO_2 resource storage capacity for all known pools in Millar Field is estimated to be 17.8 Mt, a number very similar to that of Bunker Field although the cumulative field production is dissimilar. The perceived anomaly between cumulative field production for Bunker (191.3 BCFG and 831.4 MBO) and Millar (159.8 BCFG) fields and their similar storage capacities is attributable to several factors, including: 1) dissimilar formation depths, 2) formation production volumes, and 3) the behavior of supercritical CO_2 at increasing temperature and pressure (depth).

Individual CO_2 capacities range from < 0.01 Mt in the smallest pools to 1.7 Mt in the field's largest pool (Figure 4- 6). The single largest Millar field pool, with a capacity of 1.7 Mt would not fully accommodate one year's average CO_2 emissions from a typical industrial facility. Only seven pools have a capacity exceeding 0.5 Mt. In aggregate, the 7 largest Millar field pools exhibit a capacity for about 7.0 Mt (40 percent of total field capacity), or about 3.5 years' worth of CO_2 emissions. This is about equal to that of the Bunker Field's single largest pool. Fully 76 percent of the pools have a capacity of < 0.1 Mt. Median pool size is just 0.03 Mt. Twenty-two percent of pools lack capacities sufficient to store even a single day's worth of a typical facility's CO_2 emissions.

Figure 4-5: Approximate Areas Underlain by Pools in the Millar Gas Field.

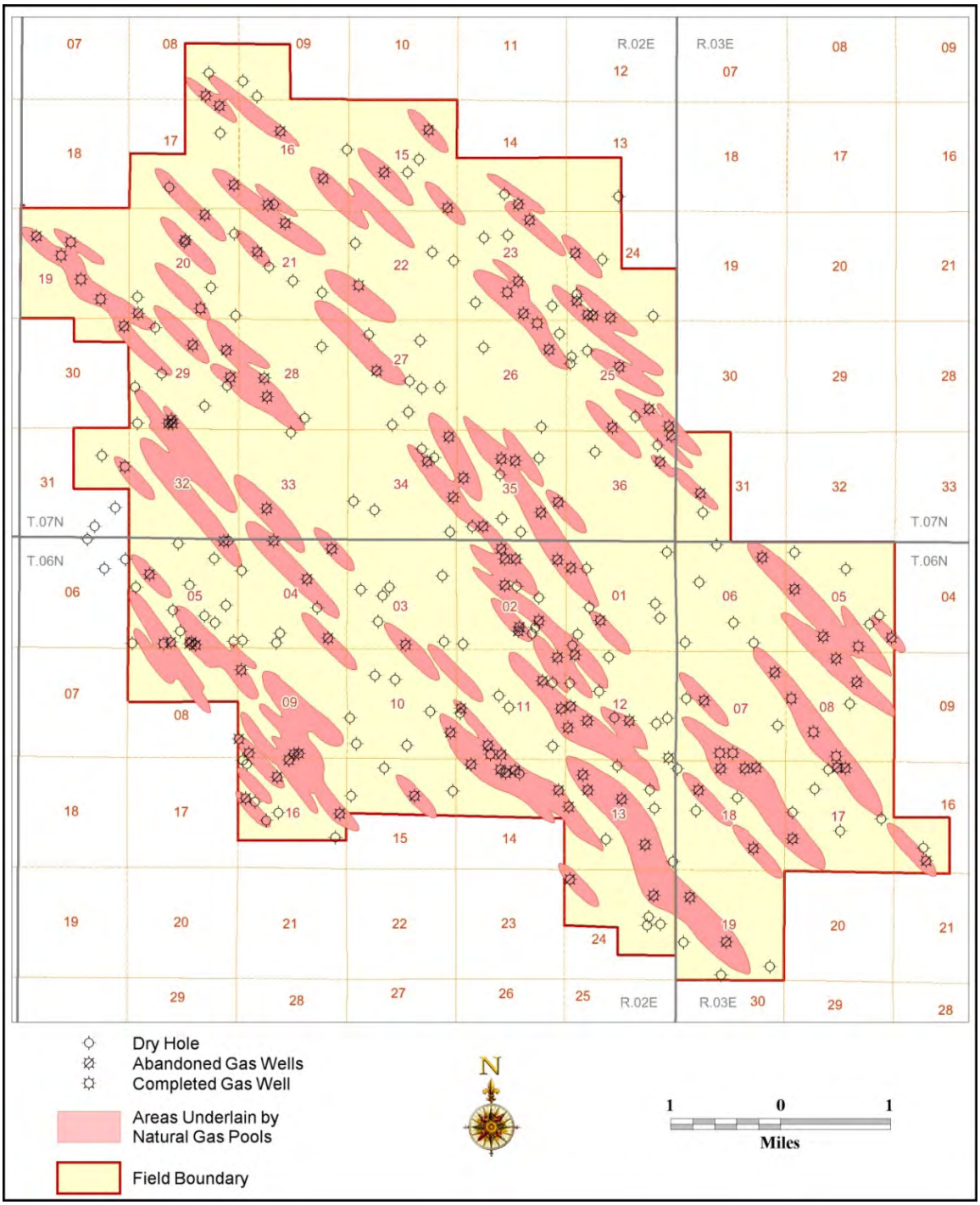
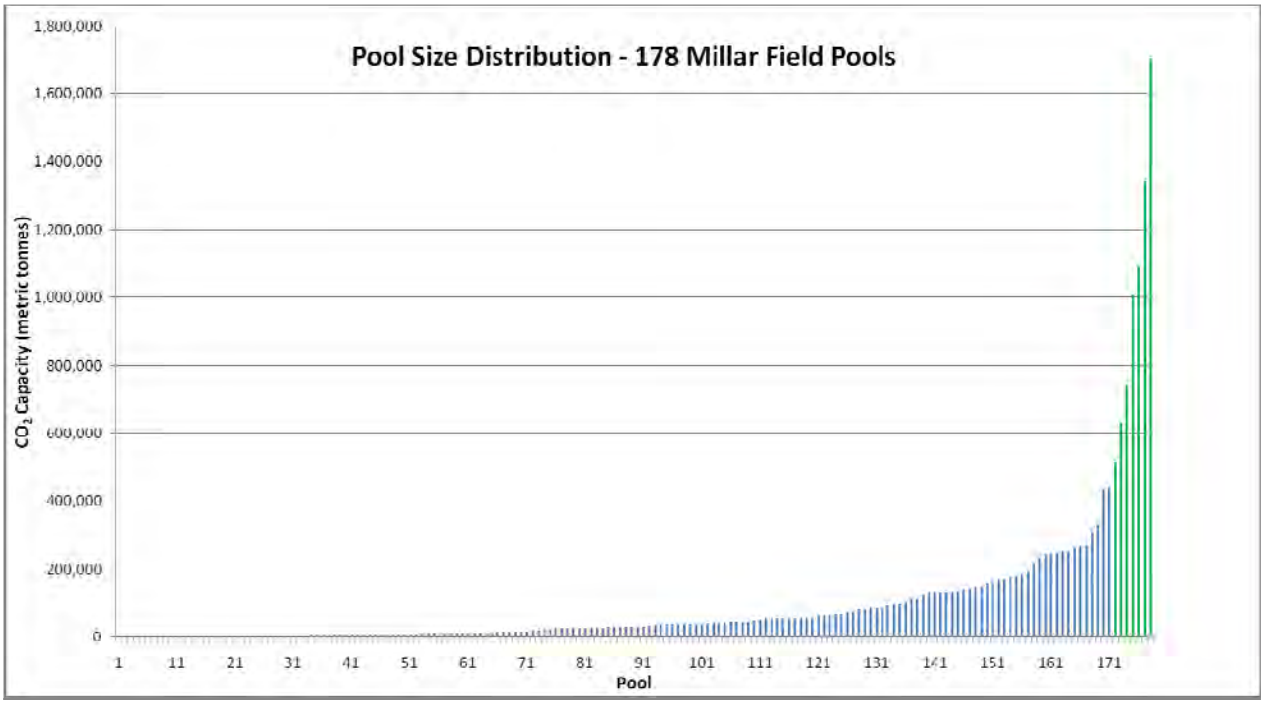


Figure 4-6: Estimated CO2 Storage Capacity by Pool – Millar Gas Field



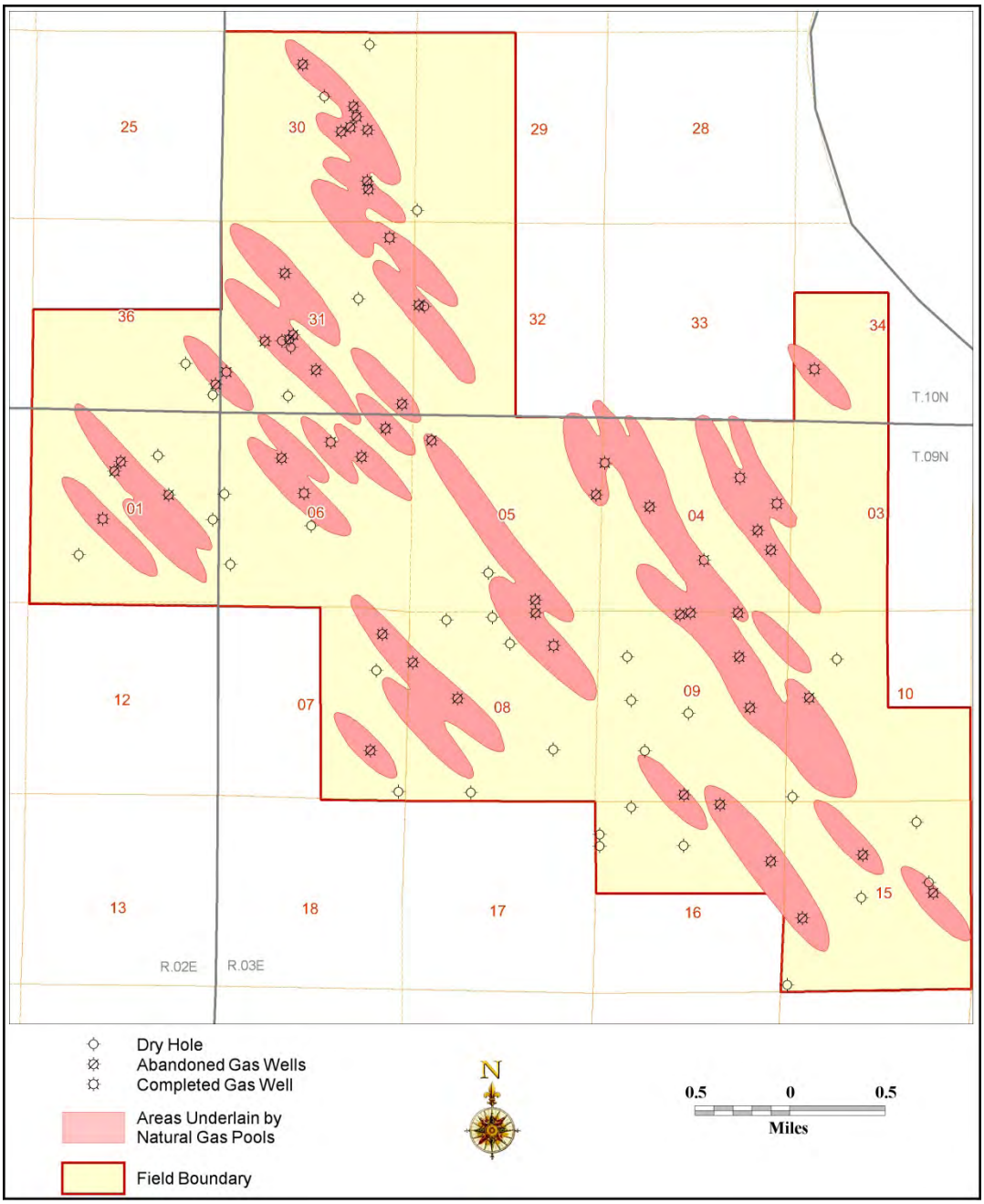
4.2.3 Conway Ranch Gas Field

Conway Ranch Field covers about 13 square miles (8,240 acres) in northeast Yolo County, about six miles northwest of Sacramento. Conway Ranch is the smallest field (in terms of production and CO_2 storage capacity) evaluated in this study. This field was selected to exemplify one of the shallower, principally Starkey Formation, producing fields in the southern Sacramento Basin.

Discovered in 1972, the field has produced approximately 37.8 BCFG with no recorded condensate production from 56 wells completed in approximately 91 separate small pools. Only 10 producing or shut-in wells remain, the last recorded production occurring in August, 2009. The field lies on the shallow eastern basin flank where reservoir depths are as shallow as 2,900 feet in the Mokelumne River Formation. Figure 4-7 illustrates the approximate cumulative area underlain by known natural gas pools within the field boundaries.

The two principal producing horizons are the Starkey and Mokelumne River formations which have produced 26.2 BCFG (69 percent of field production) and 10.8 BCFG (29 percent of field production) respectively. The Winters Formation has contributed only 0.8 BCFG (2 percent of production) from 5 small pools encountered in 5 separate wells. Cumulative pool production ranges from a low of only 436 MCF in a Starkey sandstone to 5.6 BCFG in the largest pool in a Mokelumne River sandstone. Median pool production for all formations is only 0.15 BCFG.

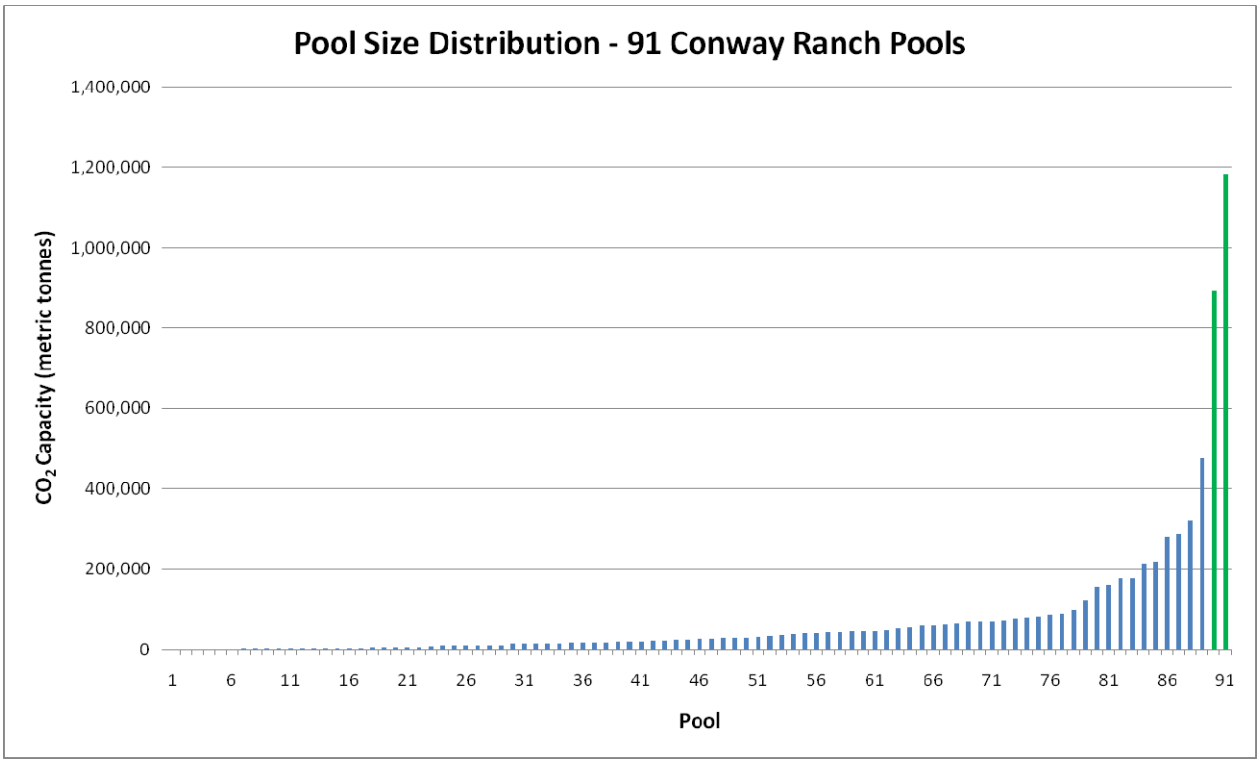
Figure 4-7: Approximate Area Underlain by Pools in the Conway Ranch Gas Field



Total capacity for all 91 pools is estimated at only 6.8 Mt, or about equal to 3.4 years of emissions. The Starkey Formation contains the largest capacity (4.4 Mt), followed by the Mokelumne River Formation (2.3 Mt), and the Winters Formation (0.1 Mt). Individual pool

capacities range from less than 0.01 Mt to a high of only 1.2 Mt in the largest pool (Figure 4-8). Only 2 pools have capacities exceeding 0.5 Mt. Their combined capacity of 2.1 Mt could accommodate an average facility's CO_2 emissions for only a single year. Median pool capacity is less than 0.03 Mt representing less than one week's emission capacity.

Figure 4-8: Estimated CO2 Storage Capacity by Pool – Conway Ranch Gas Field



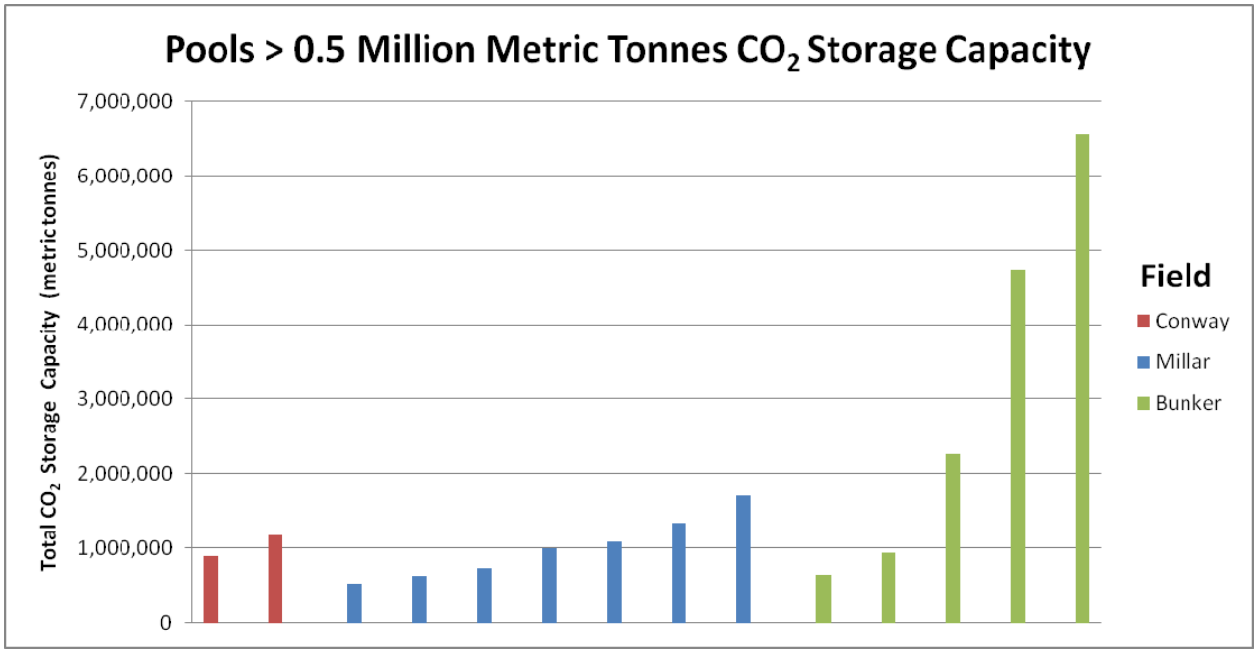
4.3 Conclusions

The implementation of geologic sequestration whether by injection into depleted oil or gas fields or saline aquifers will require identifying suitable storage reservoirs having appropriate characteristics (depth, porosity, seals, and so forth) and capacity to sequester a CO_2 stream from a source, typically a power plant, refinery, or other industrial facility. Such CO_2 producing facilities are often designed with an intended operating life measured in decades, commonly 30 years or more. Due to the potentially large costs associated with such projects, it seems likely that proponents will want to store their CO_2 in reservoirs with enough capacity to sequester the entire projected CO_2 stream over the life of the generating facility. In California, the typical emissions from such facilities range from 1 to 2 million tons of CO_2 annually (Herzog, 2005) producing 30 to 60 Mt of CO_2 over a 30-year operating life. Even if only 50 percent of the CO_2 were captured, this would result in 15 to 30 Mt of CO_2 to be sequestered for a single facility.

The estimated CO_2 storage capacities determined for the known natural gas pools within the Bunker, Millar, and Conway Ranch gas fields suggests that the potential for long term CO_2 storage within singular pools in these and similar fields of the southern Sacramento Basin is limited. Our study of these fields suggest that most pools within Mokelumne River, Starkey, and Winters formations exhibit CO_2 storage capacities well below that necessary to store even a single year's worth of CO_2 emissions. Even the largest individual pools identified in each of these fields exhibit storage capacities ranging from only 1.2 Mt (Conway Ranch Field) to 6.6 Mt (Bunker Field), or the equivalent of less than 1 to slightly more than 3 years' storage when considered individually.

Even when considering multiple pool strategies, these fields fall short of meeting the lifetime needs of a typical emissions source. Only 14 pools out of 313 were identified with capacities exceeding 0.5 Mt CO_2. Cumulatively by field, these pools could provide for 15.2 Mt storage capacity in Bunker Field (5 pools), 7.0 Mt (7 pools) in Millar Field, and 2.0 Mt (2 pools) in Conway Ranch Field (Figure 4-9). With the possible exception of Bunker Field, these pools exhibit capacities much less than the 15 to 30 Mt necessary to met a single facility's lifetime needs even at 50 percent capture efficiency. The addition of smaller pools to increase capacity in each field does not materially improve storage capacity. Even if it were economically viable and technically feasible to access the many pools within each field, maximum field storage capacities increase to only 17.9 Mt (Bunker Field), 17.8 Mt (Millar Field), and 6.8 Mt (Conway Ranch Field).

Figure 4-9: Size Distribution of Pools > 0.5 Mt in the Bunker, Millar, and Conway Ranch Fields



While the Bunker, Millar, and Conway Ranch fields are considered analogs for most fields producing from these formations in the Sacramento Basin, larger fields (from a production

standpoint) do exist within the basin and may offer better opportunities for CO_2 storage. Although not part of this study, further enhancement of CO_2 storage volume within a specific natural gas field could likely be obtained by considering containment within the saline aquifer portions of reservoir sandstones and overlying and underlying brine-saturated sandstone bodies.

Since a field's cumulative production is not indicative of pool size in the Sacramento Basin, a detailed analysis of each field and its respective pools will be essential to determine its actual CO_2 storage potential. Additionally, a detailed cost/benefit analysis would be required to determine what capacity could be made available and at what cost for a specific CO_2 source rate and volume. Although this study makes comparisons between field/pool capacity and potential CO_2 feeds from typical California industrial facilities, no attempt was made to evaluate the lower limit of pool capacity that would be economically realistic for sequestration purposes.

While this study was limited to fields and formations in the Sacramento Basin, fields in other basins with similar settings and geologic and tectonic histories could exhibit similar degrees of compartmentalization of potential reservoir capacity.

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CHAPTER 6: Glossary

BBO	Billion Barrels of Oil
BCFG	Billion Cubic Feet of Gas
BOEMRE	Bureau of Ocean Energy Management, Regulation and Enforcement
CCS	Carbon Capture and Sequestration
CFR	Code of Federal Regulations
CGS	California Geological Survey
Completion	Processes involved in enabling a well to produce oil or gas (casing, perforating, and so forth)
Condensate	Low-density hydrocarbon liquids associated with some natural gasses
Dip	Steepest angle of inclination of an inclined surface relative to horizontal
DOE	U.S. Department of Energy
DOG	California Division of Oil and Gas
DOGGR	California Division of Oil, Gas, and Geothermal Resources
Downdip	Downward direction within a plane, perpendicular to strike
Downthrown	Downwardly displaced side of an inclined to vertical fault plane
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimately Recoverable
GIS	Geographic Information Systems
Gt	Gigaton (One Billion Metric Tons)
Gm^3	Giga (Billion) Cubic Meters
GWC	Gas Water Contact
m^3	Cubic Meters
Mm^3	Mega (Million) Cubic Meters
MBO	Thousand Barrels of Oil
MMBO	Million Barrels of Oil
MMBTU	Million British Thermal Units
MCF	Thousand Cubic Feet

MMCF	Million Cubic Feet
Mt	Million Metric Tons
TCFG	Trillion Cubic Feet of Gas
TVD	True Vertical Depth
Updip	Upward direction within a plane, perpendicular to strike
Upthrown	Upwardly displaced side of an inclined to vertical fault plane
VSS	Vertical Subsea
WESTCARB	West Coast Regional Carbon Sequestration Partnership

APPENDIX A:
Summary Data for Pools in the Bunker, Millar, and Conway Ranch Gas Fields

BUNKER GAS FIELD – POOL SUMMARY							
Pool	FM*	Depth**	Production		CO_2 Storage Capacity (metric tons)		
			Gas (MCF)	Oil (BBLS)	Oil	Gas	Total
Armstrong APC-Rayn 405 Middle Mokelumne Pool	M	6,677	3,887	0	0	396	396
Armstrong APC-Carter 1 Mokelumne Pool	M	6,438	5,351	0	0	562	562
ABA APC-Horigan 4 Winters Pool	W	9,575	12,785	0	0	1,045	1,045
Amerada Norton 1 Mokelumne Pool	M	6,730	10,502	25	3	1,069	1,072
Capitol Robbie 2 Starkey Pool (Petersen)	S	7,286	19,263	225	26	1,835	1,861
Capitol McElwaine 2 RD1 Mokelumne Pool	M	6,163	18,722	692	85	2,034	2,120
Capitol Joslin 1 Winters Pool	W	10,832	27,482	249	28	2,110	2,138
Graham Pardi 2 Mokelumne Pool	M	6,165	31,255	105	13	3,386	3,399
Armstrong Horigan 3 Winters Pool	W	9,935	72,525	400	46	5,816	5,862
Capitol Joslin 1 Winters Pool	W	10,410	78,030	406	47	6,155	6,202
Capitol Robben 1 Pool	W	8,616	117,180	0	0	10,156	10,156
Capitol O'Keefe 1 Mokelumne Sand Pool	M	6,509	81,454	41,011	5,001	8,483	13,484
Armstrong APC-Rayn 404 Mokelumne Pool	M	6,612	133,195	30	4	13,695	13,698
ABA Horigan-Rayn 1 Winters Pool	W	9,321	187,561	398	46	15,525	15,571
TXO Derner 17-1 Starkey Pool	S	6,711	154,896	21	3	15,764	15,767
Capitol McElwaine 2 RD1 Starkey Pool	S	6,660	183,868	0	0	18,797	18,797
Arco Western Luttges 1 Mokelumne Pool	M	6,840	253,000	205	25	25,438	25,463
Arco Western Luttges 1 Mokelumne Pool	M	6,795	253,931	191	23	29,111	29,135
Armstrong APC-Rayn 404 Starkey Pool	S	7,047	349,383	2,024	243	34,285	34,528
Slawson Anderson 1-12 Winters Pool	W	9,400	436,024	2,508	288	35,930	36,219

BUNKER GAS FIELD – POOL SUMMARY							
Pool	FM*	Depth**	Production		CO_2 Storage Capacity (metric tons)		
			Gas (MCF)	Oil (BBLS)	Oil	Gas	Total
Capitol Joslin 1 Winters Pool	W	9,978	514,342	1,620	185	41,117	41,301
Armstrong RDR-Carter Gas Unit 3 Starkey Pool	S	7,515	466,656	0	0	43,924	43,924
ABA Horigan 6 Starkey Pool	S	7,688	519,447	0	0	48,261	48,261
Armstrong APC-Rayn 405 Mokelumne Pool	M	6,543	504,350	356	44	52,276	52,320
Capitol Whitlock 7-1 Mokelumne Pool	M	6,260	541,066	976	120	57,953	58,073
Capitol Joslin 1 Starkey Pool	S	7,480	622,249	3,682	440	58,854	59,293
Graham Pardi 1 RD 1 Mokelumne Pool	M	6,090	649,996	1,503	185	71,015	71,200
Capitol Joslin 1 Starkey Pool (Petersen)	S	8,822	955,944	4,067	471	81,511	81,983
Capitol Whitlock 7-3 Mokelumne Pool	M	6,233	822,007	2,567	316	88,279	88,595
Capitol Whitlock 7-1 Mokelumne Pool	M	6,205	903,986	2,759	339	97,343	97,682
Calpine AHC Horigan 2 Winters Pool	W	10,047	1,579,835	7,033	807	125,987	126,794
Capitol Parker 2 Starkey Pool	S	7,138	1,410,438	9,188	1,100	137,416	138,516
ABA Horigan 5 Winters Pool	W	9,605	1,764,102	10,735	1,241	144,071	145,312
Capitol Pedrick 2 Pool	W	8,731	1,783,262	5,573	651	153,405	154,056
Armstrong RDR-Carter Gas Unit 3 Mokelumne Pool	M	6,620	1,578,595	2,781	339	162,305	162,644
Slawson Anderson 1-12 Starkey Pool	S	8,112	2,094,767	7,503	883	188,021	188,904
Armstrong BGZU 401 Mokelumne Pool	M	6,668	2,634,299	8,254	1,000	269,307	270,307
Armstrong BGZU 502 Mokelumne Pool	M	6,605	3,389,564	10,113	1,233	348,502	349,735
Calpine Rayn-Comber Gas Unit 2 Starkey Pool	S	8,210	3,932,775	25,340	2,981	350,515	353,497
Illini Hanna 1 Mokelumne Pool ("Hanna" Sand')	M	6,301	6,045,468	15,009	1,840	643,601	645,441
Rayn-Comber Gas Unit	W	9,205	11,184,434	47,851	5,554	934,178	939,732

BUNKER GAS FIELD – POOL SUMMARY							
Pool	FM*	Depth**	Production		CO_2 Storage Capacity (metric tons)		
			Gas (MCF)	Oil (BBLS)	Oil	Gas	Total
1 Pool							
Amerada BZGU 901 Mokelumne Pool	M	6,778	22,329,014	82,393	9,969	2,254,837	2,264,805
Amerada BGZU 702 Mokelumne Pool ("Bunker Pool")	M	6,793	46,793,430	192,204	23,255	4,725,311	4,748,566
Capitol BW 1 Pool	W	8,756	75,845,566	341,377	40,000	6,516,993	6,556,993
TOTAL			191,295,886	831,374	98,835	17,826,575	17,925,410
Average			4,347,634	18,895	2,246	405,149	407,396
Median			509,346	1,562	185	46,092	46,092
First Quartile			108,249	170	21	9,738	12,652
Third Quartile			1,625,902	7,691	912	146,405	147,498

* Geologic Formation: M=Mokelumne, S=Starkey, W=Winters
** For directionally drilled holes, depth = true vertical depth

Cumulative Production per DOGGR 2008 Annual Report: 191,260,000 MCF
Cumulative Production per IHS/DOGGR Well Production Records: 191,295,886 MCF
Disparity (%): <1%

Total No of Pools: 44
Largest Pool 6,556,993 metric tons capacity
Smallest Pool 396 metric tons capacity
29 pools less than 100,000 metric tons capacity
5 pools greater than 500,000 metric tons capacity
3 pools greater than 1,000,000 metric tons capacity

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Capitol Currey 5 Winters Pool	W	7,058	1,532	0	150
Source Dawson 1-19 Winters Pool	W	7,533	1,801	0	169
Enerfin Dixon East Unit 1-2 Mokelumne Pool	M	4,892	3,135	0	411
Venada Venada K-1 Mokelumne Pool	M	4,760	3,077	0	414
Enerfin Dixon East Unit 1-2 Mokelumne Pool	M	4,794	3,136	0	419
G.E.C. Rowse-Taylor 1 Winters Pool	W	7,857	6,000	0	550
Stream Belleair 6-9 Mokelumne Pool	M	5,286	5,311	0	651
Hunnicutt & Camp Tri-Valley Millar Unit 3-1 Winters Pool	W	8,247	8,260	0	734
Venada Anderson 1 Mokelumne Pool	M	5,583	6,323	0	742
Venada Timm Unit 3 Mokelumne Pool	M	5,423	6,245	0	751
Stream Belleair 6-9 Mokelumne Pool	M	5,386	7,545	0	911
Stream Belleair 6-9 Mokelumne Pool	M	5,355	7,545	0	914
Hunnicutt & Camp Deffebach 1 Winters Pool	W	7,729	10,461	0	967
Hunnicutt & Camp Deffebach 1 Winters Pool	W	7,578	10,460	0	981
Venada Timm Unit 3 Mokelumne Pool	M	5,361	8,465	0	1,026
Captol English 3 Winters Pool	W	7,322	13,842	0	1,314
Slawson Campbell 1-4 Winters Pool	W	7,822	16,463	0	1,511
Hamilton Belleair 3-9 Starkey Pool	S	5,996	13,705	0	1,516
Venada Venada K-1 Mokelumne Pool	M	4,905	11,614	0	1,517
Hamilton Belleair 3-9 Mokelumne Pool	M	5,737	13,706	0	1,570

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Venada Venada K-1 Mokelumne Pool	M	4,832	12,071	0	1,604
Quintana Giannoni 1 Winters Pool	W	7,388	16,914	0	1,613
Capitol A.W. 1 Winters Pool	W	7,250	18,364	0	1,770
Slawson CP 1-24 Winters Pool	W	8,260	20,726	0	1,842
Slawson Currey 1-24 Winters Pool	W	8,355	21,111	0	1,864
Venada Belleair 3-16 Starkey Pool	S	6,077	20,862	0	2,287
Capitol Currey 4 Winters Pool	W	7,163	24,379	0	2,371
Capitol McCloskey-Southard 2 RD 1 Mokelumne Pool	M	5,604	22,096	0	2,583
Arkoma Arkoma Santana 25-2 Winters Pool	W	7,220	29,215	0	2,830
Slawson Currey 1-24 Winters Pool	W	7,347	31,500	0	3,010
Venada Belleair 1-16 Mokelumne Pool	M	5,254	27,540	0	3,387
TXO Jones 35-1 Winters Pool	W	8,145	38,218	0	3,426
Arding Amerada Rose 1 Mokelumne Pool	M	5,190	28,130	0	3,500
Capitol Elliot 1-24 Mokelumne Pool	M	5,357	31,520	0	3,819
Venada Belleair 3-16 Mokelumne Pool	M	5,700	34,035	0	3,925
Lario Diamondback 1-20 Mokelumne Pool	M	5,094	36,391	0	4,599
G.E.C. Texaco-G.E.C. Unit 1-1 Winters Pool	W	7,192	47,686	0	4,628
Capitol McCloskey-Southard 2 RD 1 Mokelumne Pool	M	5,696	40,387	0	4,658
ABA Hathaway 1 Mokelumne Pool	M	5,664	42,488	0	4,917
Tri-Valley Santana 1 Winters Pool	W	7,483	52,495	0	4,965
ABA Hathaway 1 Mokelumne Pool	M	5,083	49,796	0	6,320

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Venada Belleair 2-9 Mokelumne Pool	M	5,388	52,738	0	6,366
Capitol Amerada Bulkley 1 Winters Pool	W	6,944	67,135	0	6,663
Source Dawson 1-19 Winters Pool	W	7,305	69,532	0	6,677
Capitol GR-1 Mokelumne Pool	M	4,576	49,554	0	6,898
Slawson CP 1-24 Winters Pool	W	8,412	79,285	0	6,962
Capitol Currey Unit 2 Winters Pool	W	7,928	77,132	0	7,025
ABA Hathaway 1 Mokelumne Pool	M	4,976	56,129	0	7,242
Capitol Currey 5 Winters Pool	W	7,209	75,685	0	7,332
Capitol Currey 5 Winters Pool	W	7,556	78,158	0	7,332
Capitol Amerada Bulkley 1 Winters Pool	W	7,202	78,737	0	7,642
ABA Hathaway 1 Mokelumne Pool	M	5,378	59,353	0	7,801
Stream Belleair 6-9 Mokelumne Pool	M	5,450	69,236	0	8,267
Capitol Amerada Fee 1 Domengine Pool	D	3,960	54,723	0	8,728
Injection Systems Dawson Unit 1 Mokelumne Pool	M	5,014	75,184	0	9,658
Castle Dawson Saba 1 Mokelumne Pool	M	4,670	75,859	0	10,364
ABA Hathaway 1 Mokelumne Pool	M	5,126	96,222	0	12,111
Source Dawson 1-19 Winters Pool	W	7,672	133,944	0	12,464
Stream Belleair 6-9 Mokelumne Pool	M	5,329	103,855	0	12,675
Venada VOA 1 RD2 Mokelumne Pool	M	5,582	120,078	0	14,086
Venada VOA 1 RD 1 Starkey Pool	S	5,968	126,591	0	14,091
Venada Timm 5-5 Mokelumne Pool	M	5,344	117,922	0	14,287
Arkoma Arkoma Santana 25-2 Winters Pool	W	7,378	154,593	0	14,745
Castle P.T. Stow Unit 1-3 Winters Pool	W	7,263	155,801	0	15,017

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Castle P.T. Stow Unit 1-3 Winters Pool	W	7,222	155,801	0	15,093
Capitol McCloskey-Southard 2 RD 1 Mokelumne Pool	M	5,667	132,574	0	15,341
Nahama & Weagant East Dixon Unit 1 Winters Pool Winters Pool	W	7,568	164,014	0	15,386
Castle P.T. Stow Unit 1-3 Winters Pool	W	7,195	155,801	0	15,845
Slawson Fletcher 1-20 Starkey Pool	S	8,150	177,232	0	15,876
Venada Timm 5-5 Mokelumne Pool	M	5,589	138,770	0	16,279
Venada D-1 Domengine Pool	D	3,968	107,850	0	17,201
Amerada Campbell Ranch 2 Domengine Pool	D	4,130	119,535	0	18,335
Production Spec. Texaco G.E.C. Unit 1-3 Winters Pool	W	7,246	192,224	0	18,527
Production Spec. Mongoose 15-4 Winters Pool	W	7,470	239,879	0	22,688
Castle Dawson Saba 1 Mokelumne Pool	M	4,744	176,997	0	23,946
Venada Belleair 3-16 Mokelumne Pool	M	5,563	215,943	0	25,420
Capitol Crocker-Emigh 2 Domengine Pool	D	4,000	166,217	0	26,335
Venada Venada K-1 Mokelumne Pool	M	4,956	204,365	0	26,482
Venada Venada K-1 Mokelumne Pool	M	4,802	203,735	0	27,204
Venada Belleair 1-16 Starkey Pool	S	6,014	250,000	0	27,567
Venoco Anderson 2 Mokelumne Pool	M	5,745	249,305	0	28,559
G.E.C. Christensen 1-27 Winters Pool	W	7,490	304,472	0	28,748
McFarland Pope 1 Winters Pool	W	7,110	296,598	0	28,991
Arding Amerada Rose 1 Mokelumne Pool	M	5,165	232,317	0	29,018

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Venada Patricia 1-5 Mokelumne Pool	M	5,619	268,829	0	31,316
Capitol Brigantino 2 Mokelumne Pool	M	5,222	254,491	0	31,535
Venada Belleair 1 RD 1 Mokelumne Pool	M	5,600	276,704	0	32,349
ABA Hathaway 1 Mokelumne Pool	M	4,861	248,573	0	32,765
Capitol Currey 4 Winters Pool	W	7,126	335,294	0	32,774
EOG Campbell Ranch 4-1 Mokelumne Pool	M	4,900	254,287	0	33,367
Arding Smith-Dawson 1 Mokelumne Pool	M	4,950	257,073	0	33,431
Capitol Delhi 1 Mokelumne Pool	M	5,282	281,281	0	34,461
Castle Stow 1 Winters Pool	W	7,460	378,514	0	35,801
Hilliard Yolow Ranch 1-16 Winters Pool	W	7,666	387,479	0	36,058
Aspen Pope Bypass 1-5 Winters Pool	W	7,282	382,103	0	36,760
Castle Yolo Ranch 18-1 Winters Pool	W	7,706	408,783	0	37,863
Capitol Currey 4 Winters Pool	W	7,290	399,000	0	38,386
Venoco Anderson 2 Mokelumne Pool	M	5,601	333,294	0	39,105
Injection Systems Dawson Unit 2 Mokelumne Pool	M	5,283	319,934	0	39,150
Venada Belleair 1 Mokelumne Pool	M	5,290	321,607	0	39,402
Production Spec. Mongoose 15-4 Moklelumne Pool	M	4,484	280,650	0	39,831
Slawson Anderson 1-15 Winters Pool	W	7,130	426,929	0	41,731
Capitol Currey 5 Winters Pool	W	7,045	427,428	0	42,027
Enerfin Dixon East Unit 1-4 Mokelumne Pool	M	4,780	321,609	0	42,943
Castle Stow 1 Winters Pool	W	7,377	455,819	0	43,476
Venada Timm Unit 5-5 Starkey Pool	S	6,085	400,872	0	43,951

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Production Spec. Robben 21-2 Mokelumne Pool	M	4,763	331,971	0	44,536
Capitol Crocker-Emigh 1 Mokelumne Pool	M	5,357	371,486	0	45,007
Venada Timm 5-5 Mokelumne Pool	M	5,429	397,430	0	47,447
Venada VOA 1 RD1 Mokelumne Pool	M	5,601	424,865	0	49,670
EOG Campbell Ranch 4-1 Mokelumne Pool	M	5,085	400,109	0	50,780
Tri-Valley Santana 1 Winters Pool	W	7,269	572,372	0	55,065
G.E.C. Texaco-G.E.C. Unit 1-1 Winters Pool	W	7,281	574,716	0	55,291
Venada Belleair 1 Starkey Pool	S	5,975	504,167	0	55,952
Arding AT&T 4 Winters Pool	W	7,487	595,381	0	56,313
TXO Pitto 15-1 Mokelumne Pool	M	4,762	456,338	0	56,480
Aspen Pope Bypass 1-5 Winters Pool	W	7,205	585,083	0	56,679
Coastal Texaco Operating Unit One 1 Winters Pool	W	7,119	592,383	0	57,904
Capitol C.P. Unit 1 Domengine Pool	D	3,902	358,478	0	58,146
Capitol Currey Unit 1 Winters Pool	W	7,072	595,532	0	58,440
Castle Dawson Saba 1 Mokelumne Pool	M	4,624	448,948	0	61,863
Venada Timm Unit 3 Mokelumne Pool	M	5,452	520,930	0	62,198
Capitol Amerada Bulkley 1 Winters Pool	W	7,330	664,094	0	63,455
Venada Timm 5-5 Mokelumne Pool	M	5,472	557,570	0	66,335
Castle Stow 2 Winters Pool	W	7,236	716,654	0	69,073
Venada Belleair 1 RD 1 Mokelumne Pool	M	5,710	634,555	0	73,186
Reynolds Vista-Christensen 1 Mokelumne Pool	M	4,623	539,141	0	74,291

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Vintage Smith-Gunning 1 Mokelumne Pool	M	4,864	611,390	0	80,584
Capitol Amerada Bulkley 1 Winters Pool	W	7,257	860,243	0	82,913
Arding AT&T 3 Mokelumne Pool	M	5,278	695,809	0	85,577
Rosetta Detar 1 Winters Pool	W	7,807	943,251	0	86,559
Venoco Anderson 1-2 Starkey Pool	S	5,997	792,298	0	87,618
Enerfin Dixon East Unit 1-2 Mokelumne Pool	M	5,030	733,840	0	93,864
Enerfin Dixon East Unit 1-4 Mokelumne Pool	M	4,724	766,570	0	97,631
Capitol McCormick 12-1 Winters Pool	W	7,728	1,059,716	0	98,000
Capitol Atkinson 1 Domengine Pool	D	3,800	595,294	0	98,935
G.E.C. Crocker-Reynolds 1 Winters Pool	W	7,486	1,166,228	0	110,305
Production Spec. Texaco G.E.C. Unit 1-3 Winters Pool	W	7,110	1,138,766	0	111,310
Vintage Smith-Gunning 2 Mokelumne Pool	M	5,043	976,938	0	124,958
Arding Amerada Rose 1 Mokelumne Pool	M	5,291	1,052,657	0	128,967
Hilliard AV Land 1 Winters Pool	W	7,557	1,385,605	0	129,982
Injection Systems Dawson Unit 1 Mokelumne Pool	M	5,241	1,055,070	0	130,267
Castle Tri-Valley Millar Unit 1 Winters Pool	W	7,600	1,400,490	0	131,159
Capitol C. P. Unit 2 Winters Pool	W	6,888	1,315,832	0	131,582
Vintage Smith-Gunning 1 Mokelumne Pool	M	5,209	1,066,186	0	132,643
Arding AT&T 1 Mokelumne Pool	M	5,115	1,074,105	0	135,754

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Amerada Campbell Ranch 1 Mokelumne Pool	M	5,295	1,146,535	0	140,469
Venada Belleair 1 Mokelumne Pool	M	5,481	1,251,057	0	148,839
Hilliard AV Land 1 Winters Pool	W	7,260	1,560,845	0	150,439
Castle Stow 1 Winters Pool	W	7,213	1,594,320	0	154,447
Arding AT&T 3 Mokelumne Pool	M	5,360	1,391,617	0	168,600
Capitol A.W. 1 Winters Pool	W	7,222	1,746,759	0	169,215
Hilliard AV Land 1 Winters Pool	W	7,249	1,788,098	0	172,342
Amerada Campbell Ranch 1 Mokelumne Pool	M	5,107	1,395,155	0	176,331
Castle Stow 1 Winters Pool	W	7,291	1,911,169	0	183,865
Injection Systems Dawson Unit 2 Mokelumne Pool	M	5,150	1,481,099	0	185,749
Phillips Stein-Dauenhauer 1 Mokelumne Pool	M	5,480	1,830,701	0	217,800
Venada Belleair 1-16 Mokelumne Pool	M	5,465	1,965,494	0	234,675
Capitol McCloskey-Southard 1 Mokelumne Pool	M	5,427	2,044,770	0	244,115
Venoco Anderson 2 Mokelumne Pool	M	5,486	2,076,877	0	247,088
Arding Amerada Rose 1 Mokelumne Pool	M	5,249	2,021,351	0	248,605
Vintage Smith-Gunning 1 Mokelumne Pool	M	4,997	1,963,655	0	252,245
Vintage West Levee Unit One - 1 Winters Pool	W	7,694	2,725,433	0	253,216
Capitol English 1 Winters Pool	W	7,220	2,720,887	0	263,582
Vintage Smith-Gunning 1 Mokelumne Pool	M	4,902	2,357,656	0	266,461

MILLAR GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Venada Belleair 1-16 Mokelumne Pool	M	5,315	2,202,937	0	268,862
ABA Atkinson B-1 Winters Pool	W	6,945	3,112,111	0	308,880
Capitol Emigh 1 Mokelumne Pool	M	4,606	2,415,668	0	334,558
Reynolds Amerada-Crocker Unit 1-1 Domengine Pool	D	4,061	2,796,138	0	435,828
Vintage West Levee Unit One - 1 Winters Pool	W	7,439	4,636,905	0	439,328
Arding AT&T 2 Starkey Pool	S	5,664	4,465,438	0	516,722
Hunnicutt & Camp Tri-Valley Millar Unit 2-1 Winters Pool	W	7,614	6,799,360	0	633,768
Arding AT&T 1 Mokelumne Pool	M	5,262	6,000,530	0	738,001
Amerada Millar Com. 1 Mokelumne Pool	M	4,568	7,209,036	0	1,007,093
Phillips Brown-Amerada-Brigantino 1 Winters Pool	W	7,926	11,986,148	0	1,091,661
Hom Hom 1 Mokelumne Pool	M	4,579	9,670,275	0	1,346,134
Phillips Hilliard Farms 1 Winters Pool	W	7,658	18,331,254	0	1,705,886
TOTAL			159,808,150	0	17,772,266
Average			897,799	0	99,844
Median			280,966	0	33,070
First Quartile			56,935	0	6,914
Third Quartile			843,257	0	96,689

* Geologic Formation: M=Mokelumne, S=Starkey, W=Winters, D= Domengine

** For directionally drilled holes, depth = true vertical depth

Cumulative Production per DOGGR 2008 Annual Report: 173,533,000 MCF

Cumulative Production per HIS/DOGGR Well Production Records: 159,808,150 MCF

Disparity (%): 8%

Total No of Pools: 178
Largest Pool 1,705,886 metric tons capacity
Smallest Pool 150 metric tons capacity
136 pools less than 100,000 metric tons capacity
7 pools greater than 500,000 metric tons capacity
4 pools greater than 1,000,000 metric tons capacity

CONWAY RANCH GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Castle WFL 2-1 Starkey Pool	S	4,212	436	0	65
Towne Conway 31-1 Mokelumne Pool	M	3,100	575	0	119
Towne Conway Ranch 4-1 Starkey Pool	S	3,825	1,342	0	222
Towne Conway Ranch 6-1 Starkey Pool	S	3,738	1,547	0	261
Castle WLF 14-30 Starkey Pool	S	3,747	1,795	0	303
Towne Conway Ranch 6-2 Starkey Pool	S	4,120	7,219	0	1,107
Towne Hanks 34-2 Starkey Pool	S	3,452	7,651	0	1,398
Atlantic IOC 15 Starkey Pool	S	3,750	9,329	0	1,573
Atlantic IOC 15 Starkey Pool	S	3,730	9,329	0	1,585
Castle WFL 15-30 Mokelumne Pool	M	3,190	8,297	0	1,657
Santa Fe W.A.D-WFL 4 Starkey Pool	S	3,824	10,126	0	1,677
Towne Conway Ranch 4-4 Starkey Pool	S	3,585	10,437	0	1,840
Towne Conway Ranch 4-2 Starkey Pool	S	3,787	12,987	0	2,174
Castle WFL 2-1 Starkey Pool	S	4,158	14,288	0	2,178
Towne Conway Ranch 4-4 Starkey Pool	S	3,541	14,762	0	2,644
Santa Fe Conway Ranch 9A Starkey Pool	S	4,105	18,860	0	2,911
Santa Fe Conway Ranch 9A Starkey Pool	S	4,009	18,861	0	2,978
Towne Conway 31-1 Starkey Pool	S	3,647	24,177	0	4,183
Towne Conway Ranch 1-1 Starkey Pool	S	3,868	29,886	0	4,881
Atlantic IOC 2 Starkey Pool	S	3,765	31,832	0	5,368
Towne Conray Ranch 6-3 Winters Pool	W	5,223	46,024	0	5,544
Atlantic IOC 17 Starkey Pool	S	3,928	35,400	0	5,684
Santa Fe 11 Winters Pool	W	5,298	48,189	0	5,904

CONWAY RANCH GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Castle WFL 16-30 Starkey Pool	S	3,987	52,475	0	8,369
Towne Conway Ranch 1-1 Starkey Pool	S	4,294	60,080	0	8,880
Castle WFL 2-1 Starkey Pool	S	4,275	61,571	0	9,132
Castle WFL 13-30 Starkey Pool	S	3,910	57,978	0	9,404
Atlantic IOC 33 Starkey Pool	S	4,100	63,892	0	9,861
Castle WFL 2-32 Starkey Pool	S	3,503	57,031	0	10,333
Castle WFL 16-30 Starkey Pool	S	3,964	81,750	0	13,039
Atlantic IOC 33 Starkey Pool	S	3,933	84,695	0	13,599
Towne Conray Ranch 6-3 Winters Pool	W	5,262	114,700	0	14,107
Towne Conway 31-1 Starkey Pool	S	3,628	85,132	0	14,843
Nahama & Weagant Cache Basin 5 Starkey Pool	S	3,851	90,410	0	14,870
Towne Hanks 34-2 Starkey Pool	S	3,478	83,568	0	15,267
Geo Investments IOC 1-4 Starkey Pool	S	3,498	85,241	0	15,444
Castle WFL 3-31 Starkey Pool	S	3,439	89,174	0	16,427
Towne Conway Ranch 1-1 Starkey Pool	S	3,939	106,139	0	17,042
Castle WFL 2-1 Starkey Pool	S	4,087	112,961	0	17,495
Towne Conway 31-1 Starkey Pool	S	3,948	109,846	0	17,638
Castle WFL 3-31 Starkey Pool	S	3,978	123,355	0	19,674
Atlantic IOC 2 Starkey Pool	S	3,875	127,791	0	20,872
Castle WFL 14-30 Mokelumne Pool	M	3,315	114,758	0	22,026
Geo Investments Natomas-IOC 2 Starkey Pool	S	3,564	126,001	0	22,391
Nahama & Weagant Cache Basin 5A Starkey Pool	S	4,166	155,072	0	23,639
Towne Conway Ranch 4-4 Starkey Pool	S	3,788	151,341	0	25,334
Geo Investments IOC 3 Starkey Pool	S	3,625	145,752	0	25,496

CONWAY RANCH GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Atlantic IOC 26 Starkey Pool	S	3,558	150,567	0	26,756
Atlantic IOC 2 Starkey Pool	S	4,200	181,865	0	27,459
Geo Investments IOC 4 Mokelumne Pool	M	3,027	137,434	0	29,002
Castle WFL 1-6 Starkey Pool	S	4,242	210,117	0	31,348
Nahama & Weagant Cache Basin 5 Starkey Pool	S	3,618	187,377	0	32,777
Castle WFL 1-6 Winters Pool	W	5,240	290,161	0	35,825
Geo Investments IOC 1-4 Mokelumne Pool	M	2,988	178,302	0	38,012
Nahama & Weagant Cache Basin 5 Starkey Pool	S	3,490	214,576	0	38,878
Geo Investments Natomas-IOC 2 Starkey Pool	S	3,601	228,716	0	40,323
Castle WFL 8-31 Starkey Pool	S	4,010	265,413	0	41,908
Towne Conway Ranch 6-2 Starkey Pool	S	4,170	277,370	0	42,282
Castle WFL 1-1 Winters Pool	W	5,171	346,916	0	43,333
Atlantic IOC 3 Starkey Pool	S	4,073	283,292	0	44,156
Geo Investments IOC 3 Starkey Pool	S	3,577	251,947	0	44,772
Atlantic IOC 9 RD Starkey Pool	S	3,980	297,560	0	47,459
Nahama & Weagant Cache Basin 5 Starkey Pool	S	3,864	314,238	0	51,325
Atlantic IOC 10 Starkey Pool	S	3,801	314,243	0	52,226
Atlantic IOC 26 Starkey Pool	S	3,816	343,712	0	56,932
APC IOC 1-5 Starkey Pool	S	4,106	382,097	0	58,975
Nahama & Weagant Cache Basin 5A Starkey Pool	S	4,063	385,526	0	60,091
Atlantic IOC 17 Starkey Pool	S	4,171	409,895	0	62,484
Atlantic IOC 12 Starkey Pool	S	4,081	441,685	0	68,845
Nahama & Weagant Cache Basin 5A Starkey Pool	S	3,969	438,171	0	69,885
Nahama & Weagant Cache Basin 5 Starkey Pool	S	3,658	404,646	0	70,013

CONWAY RANCH GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Castle WFL 1-31 Starkey Pool	S	4,060	458,206	0	71,420
Atlantic IOC 26 Starkey Pool	S	4,026	483,488	0	75,847
Castle WFL 1-31 Starkey Pool	S	3,978	492,205	0	78,503
Nahama & Weagant Cache Basin 5A Starkey Pool	S	3,685	471,518	0	80,967
Towne Conway Ranch 4-2 Starkey Pool	S	3,469	464,593	0	84,874
Atlantic IOC 26 Starkey Pool	S	3,862	539,549	0	88,125
Castle WFL 14-30 Starkey Pool	S	3,685	573,867	0	98,541
Castle WFL 12-6 Starkey Pool	S	4,056	776,486	0	121,029
Geo Investments IOC 15-1 Mokelumne Pool	M	3,120	759,723	0	155,147
Geo Investments IOC 3 Starkey Pool	S	3,377	849,620	0	159,525
Geo Investments IOC 1-4 Starkey Pool	S	3,304	917,921	0	176,180
Castle WFL 5-31 Starkey Pool	S	4,002	1,114,938	0	176,646
Towne Conway Ranch 6-1 Starkey Pool	S	3,576	1,195,076	0	212,368
Castle WFL 5-31 Starkey Pool	S	4,074	1,402,470	0	218,600
Atlantic IOC 10 Starkey Pool	S	4,036	1,795,338	0	281,643
Atlantic IOC 10 Starkey Pool	S	3,950	1,795,337	0	288,271
Atlantic IOC 3 Starkey Pool	S	3,512	1,763,707	0	319,554
Geo Investments Natomas-IOC 2 Starkey Pool	S	3,663	2,745,380	0	475,014
Geo Investments Natomas IOC 1 Mokelumne Pool	M	2,910	4,044,333	0	892,487
Geo Investments Natomas IOC 2 Mokelumne Pool	M	2,980	5,553,343	0	1,183,901
TOTAL			37,836,986		6,795,145
Average			415,791		74,672
Median			145,752		25,334
First Quartile			50,332		7,137

CONWAY RANCH GAS FIELD – POOL SUMMARY					
Pool	FM*	Depth**	Production		Total CO_2 Storage Capacity (metric tons)
			Gas (MCF)	Oil (BBLS)	
Third Quartile			407,271		65,664

* Geologic Formation: M=Mokelumne, S=Starkey, W=Winters
** For directionally drilled holes, depth = true vertical depth

Cumulative Production per DOGGR 2008 Annual Report: 40,758,000 MCF
Cumulative Production per HIS/DOGGR Well Production Records: 37,836,986 MCF
Disparity (%): 7%

Total No of Pools: 91
Largest Pool 1,183,901 metric tons capacity
Smallest Pool 65 metric tons capacity
77 pools less than 100,000 metric tons capacity
2 pools greater than 500,000 metric tons capacity
1 pool greater than 1,000,000 metric tons capacity