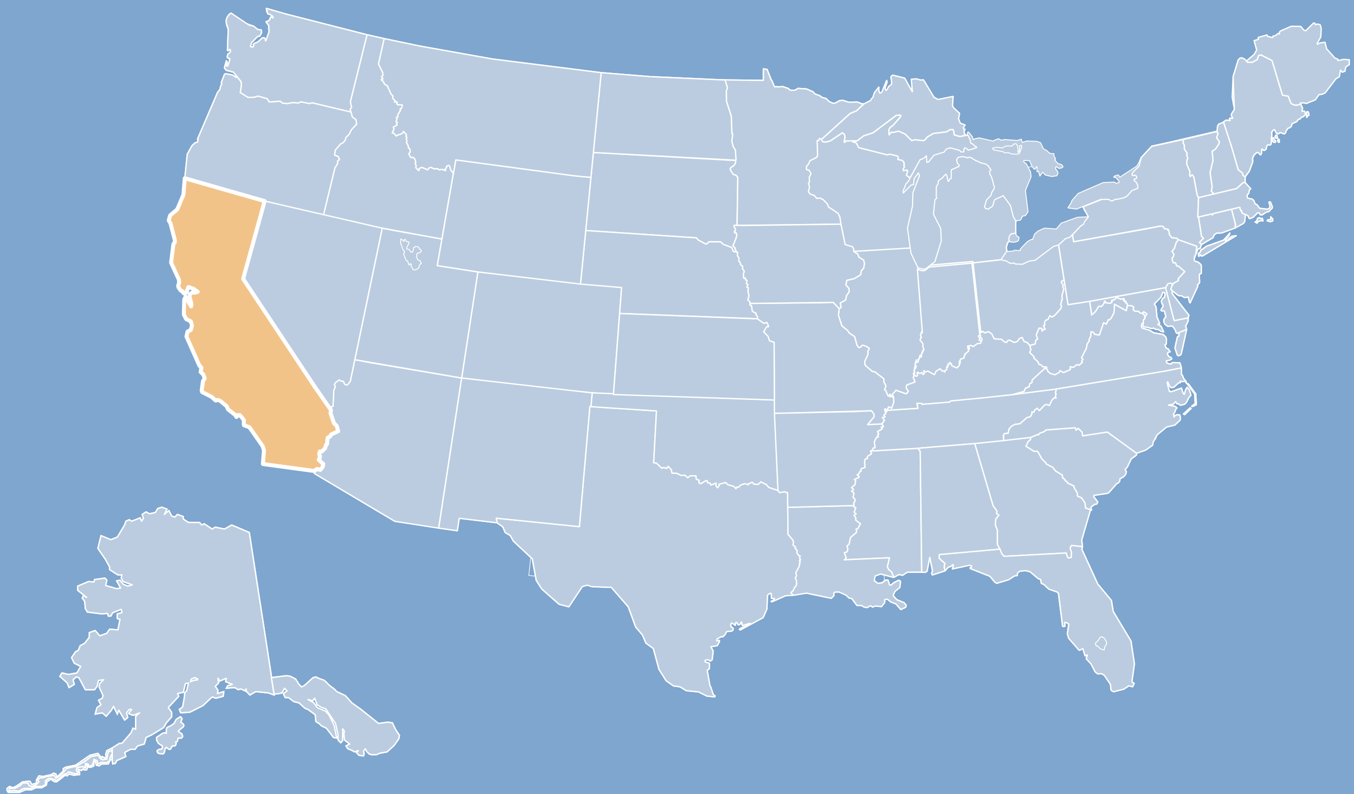
# Basin Oriented Strategies for $CO_2$ Enhanced Oil Recovery:

# *CALIFORNIA*



Prepared for

**U.S. Department of Energy**

***Office of Fossil Energy – Office of Oil and Natural Gas***

Prepared by

**Advanced Resources International**

**April 2005**

# BASIN ORIENTED STRATEGIES FOR $CO_2$ ENHANCED OIL RECOVERY: ONSHORE CALIFORNIA OIL BASINS

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# 1. SUMMARY OF FINDINGS

***1.1 OPPORTUNITIES AND BARRIERS.*** Onshore California holds large volumes of "stranded oil", 57 billion barrels, which will be left in the ground following the use of today's oil recovery practices. A significant portion of this "stranded oil" is in reservoirs technically amenable to enhanced oil recovery (EOR) using carbon dioxide ($CO_2$) injection. Prudent application of $CO_2$-EOR would enable a significant portion of this "stranded oil" to be economically produced.

This report evaluates the future oil recovery potential in the major oil basins and large oil fields of California and the barriers that stand in the way. It then examines how a concerted set of "basin oriented strategies" could help California's oil production industry overcome these barriers.

***1.2 BASIN ORIENTED STRATEGIES FOR OVERCOMING BARRIERS***. A number of actions could be taken to lift the barriers that currently constrain increased recovery of California's "stranded oil". Four of these actions are set forth below:

- First, bringing "State-of-the-art" $CO_2$-EOR technology, being tested and used in other oil basins, to California's oil fields.
- Second, lowering the risks inherent in applying new technology to complex oil reservoirs, by conducting research, pilot tests and field demonstrations of $CO_2$-EOR in California's geologically challenging oil fields.
- Third, providing a package of "risk mitigating" actions such as state production tax reductions, federal investment tax credits and royalty relief to reduce potential oil price and market risks and to improve the economic attractiveness of pursuing this otherwise "stranded oil."
- Fourth, establishing low-cost, reliable "EOR-ready" $CO_2$ supplies from various natural and industrial sources. In the near-term, this would include high-concentration $CO_2$ emissions from refinery hydrogen plants, gas processing facilities and other industrial sources. In the longer-term, this would involve capturing low $CO_2$ concentration emissions from electric power generation plants and other

sources. The capture and productive use of industrial $CO_2$ emissions would help reduce greenhouse gas emissions.

Together, this four part set of "basin oriented strategies" would help revitalize California's economy, increase state tax revenues, and enable additional domestic oil to be recovered and produced.

***1.3 OVERVIEW OF FINDINGS***. Ten major findings emerge from the study of "Basin Oriented Strategies for $CO_2$ Enhanced Oil Recovery: Onshore California Oil Basins."

**1. California has a large "stranded oil" resource base that will be left in the ground following the use of today's oil recovery practices.** The oil resource in California's reservoirs was originally 83 billion barrels. To date, 26 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further oil recovery actions, 57 billion barrels of California's oil resource will become "stranded", much of it in the state's 172 major onshore oil reservoirs, Table 1.

Table 1. Size and Distribution of California's "Stranded Oil" Resource Base

| Basin | No. of Reservoirs | OOIP (Billion Bbls) | Cumulative Recovery/ Reserves (Billion Bbls) | ROIP (Billion Bbls) |
|---|---|---|---|---|
| *A. Major Oil Reservoirs* | | | | |
| San Joaquin | 67 | 39.5 | 14.1 | 25.4 |
| Los Angeles | 64 | 22.9 | 6.3 | 16.6 |
| Coastal | 41 | 12.4 | 3.1 | 9.3 |
| Data Base Total | 172 | 74.8 | 23.5 | 51.3 |
| *B. State Total* | n/a | 83.3 | 26.0 | 57.3 |

**Estimated from State of California onhsore data on cumulative oil recovery and proved reserves, as of the end of 2001.*

**2. Much of California's large "stranded oil" resource base is amenable to $CO_2$ enhanced oil recovery.** To address the "stranded oil" issue, Advanced Resources assembled a data base that contains 172 major onshore California oil reservoirs, accounting for 90% of California's oil production. Of these, 88 reservoirs, with 31.9 billion barrels of OOIP and 22.1 billion barrels of "stranded oil" (remaining oil in-place (ROIP)), were found to be favorable for $CO_2$-EOR, as shown below by basin, Table 2.

Table 2. California's "Stranded Oil" Amenable to $CO_2$-EOR

| Basin | No. of Reservoirs | OOIP (Billion Bbls) | Cumulative Recovery/ Reserves (Billion Bbls) | ROIP (Billion Bbls) |
|---|---|---|---|---|
| San Joaquin | 29 | 11.9 | 3.8 | 8.1 |
| Los Angeles | 36 | 14.1 | 4.2 | 9.9 |
| Coastal | 23 | 5.9 | 1.8 | 4.1 |
| TOTAL | 88 | 31.9 | 9.8 | 22.1 |

**3. Application of miscible and immiscible $CO_2$-EOR would enable a significant portion of California's "stranded oil" to be recovered.** Of the 88 large California oil reservoirs favorable for $CO_2$-EOR, 59 reservoirs (with 21.4 billion barrels OOIP) screen as being favorable for miscible $CO_2$-EOR. The remaining 29 oil reservoirs (with 10.5 billion barrels OOIP) screen as being favorable for immiscible $CO_2$-EOR. The technically recoverable resource from applying $CO_2$-EOR in these 88 large oil reservoirs, ranges from 1,780 million barrels to 4,620 million barrels, depending on the type of $CO_2$-EOR technology that is applied — "Traditional Practices" or "State-of-the-art", Table 3.

Table 3. Technically Recoverable Resource Using Miscible and Immiscible $CO_2$-EOR

| | Miscible | | Immiscible | |
|---|---|---|---|---|
| Basin | No. of Reservoirs | Technically Recoverable* (MMBbls) | No. of Reservoirs | Technically Recoverable* (MMBbls) |
| San Joaquin | 24 | 860-1,800 | 5 | 0-240 |
| Los Angeles | 15 | 470-970 | 21 | 0-520 |
| Coastal | 20 | 450-1,010 | 3 | 0-80 |
| TOTAL | 59 | 1,780-3,780 | 29 | 0-840 |

**Range in technically recoverable oil reflects the performance of "Traditional Practices" and "State-of-the-art" $CO_2$-EOR technology.*

**4. With "Traditional Practices" $CO_2$ flooding technology, high $CO_2$ costs and high risks, very little of California's "stranded oil" will be economically recoverable**. "Traditional" application of $CO_2$-EOR technology to the 88 large reservoirs would enable 1,780 million barrels of this "stranded oil" to become technically recoverable. However, with the current high costs for $CO_2$ and uncertainties about future oil prices, only a very modest portion, 50 million barrels, of this "stranded oil" would become economically recoverable, all of it from the San Joaquin Basin, Table 4.

Table 4. Economically Recoverable Resources with "Traditional Practices" Miscible $CO_2$-EOR

| Basin | No. of Reservoirs | OOIP (MMBbls) | Technically Recoverable (MMBbls) | Economically* Recoverable (MMBbls) |
|---|---|---|---|---|
| San Joaquin | 24 | 8,900 | 860 | 50 |
| Los Angeles | 15 | 7,830 | 470 | - |
| Coastal | 20 | 4,690 | 450 | - |
| TOTAL | 59 | 21,420 | 1,780 | 50 |

**This case assumes an oil price of $25 per barrel, a $CO_2$ cost of 5% of the oil price, and a ROR hurdle rate of 25% (before tax).*

**5. Successful implementation of "basin oriented strategies", including "State-of-the-art" $CO_2$-EOR technology, "risk mitigation" actions and lower $CO_2$ costs would enable 1.8 to 4.0 billion barrels of additional oil to be economically recovered from California's large oil reservoirs.** Using "State-of-the-art" $CO_2$-EOR technology and a $25 per barrel oil price, Scenario #2 below, 1.8 billion barrels of the oil remaining in California's reservoirs to become economically recoverable.

A series of "risk mitigation" actions, involving an increased EOR investment tax credit, reduced state production taxes and federal and state royalty relief (for projects on federal and state lands) that together provide an equivalent of a $10 per barrel increase in the oil price, would enable a much larger portion of California's "stranded oil" to be produced. Under Scenario #3, called "Risk Mitigation", 3.5 billion barrels would become economically recoverable.

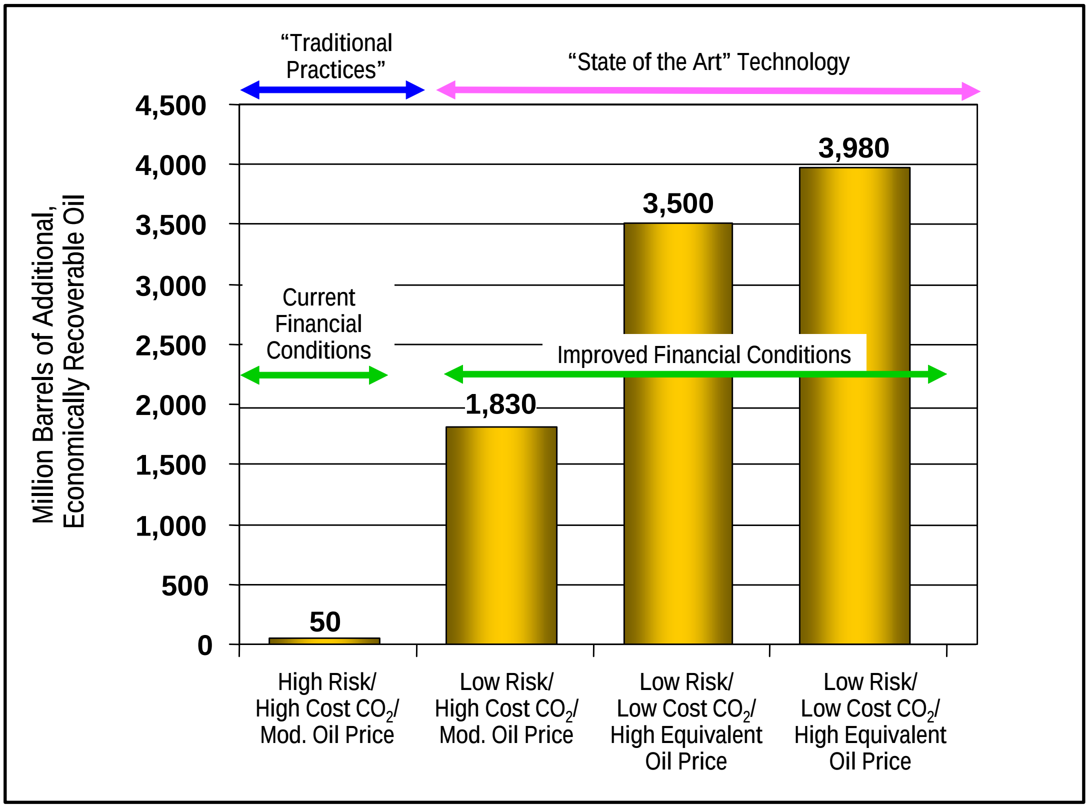
With ample supplies of lower cost $CO_2$, Scenario #4, the economic potential increases to 4.0 billion barrels from California's large onshore oil reservoirs, shown in Figure 1 and Table 5.

Table 5. Economically Recoverable Resources Under Alternative Scenarios

| | Scenario #2: "State-of-the-art" | Scenario #3: "Risk Mitigation" | Scenario #4: "Ample Supplies of $CO_2$" |
|---|---|---|---|
| Basin | Moderate Oil Price/ High $CO_2$ Cost* (MMBbls) | High Equivalent Oil Price/ High $CO_2$ Cost** (MMBbls) | High Equivalent Oil Price/ Low $CO_2$ Cost*** (MMBbls) |
| San Joaquin | 1,060 | 1,380 | 1,780 |
| Los Angeles | 700 | 1,290 | 1,370 |
| Coastal | 70 | 830 | 830 |
| TOTAL | 1,830 | 3,500 | 3,980 |

**This case assumes an oil price of $25 per barrel, a $CO_2$ cost of 5% of the oil price and a ROR hurdle rate of 15% (before tax).*
***This case assumes an equivalent oil price of $35 per barrel, a $CO_2$ cost of 5% of the oil price and a ROR hurdle rate of 15% (before tax).*
****This case assumes an equivalent oil price of $35 per barrel, a $CO_2$ cost of 2% of the oil price and a ROR hurdle rate of 15% (before tax).*

Figure 1. Impact of Technology and Financial Conditions on Economically Recoverable Oil from California's Major Reservoirs Using $CO_2$-EOR (Million Barrels)

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**6. Once the results from the study's large oil reservoirs data base are extrapolated to the state as a whole, the technically recoverable $CO_2$-EOR potential for onshore California is over 5 billion barrels**. The large California oil reservoirs examined by the study account for 90% of the state's oil resource. Extrapolating the 4,620 million barrels of technically recoverable EOR potential in these 88 oil reservoirs to total California oil resources provides an estimate of 5.2 billion barrels of technical $CO_2$-EOR potential. (However, no extrapolation of total economic potential has been estimated, as the development costs of the smaller California oil fields may not reflect the development costs for the 88 large oil reservoirs in the data set.)

7. The ultimate additional oil recovery potential from applying $CO_2$-EOR in California will, most likely, prove to be higher than defined by this study. Introduction of

more "advanced" $CO_2$-EOR technologies still in the research or field demonstration stage, such as gravity stable $CO_2$ injection, extensive use of horizontal well technologies, $CO_2$ miscibility control agents and next-generation immiscible $CO_2$-EOR, could significantly increase recoverable oil volumes while greatly expanding the state's geologic storage capacity for $CO_2$ emissions.  The benefits and impacts of using "advanced" $CO_2$-EOR technology on California's oil reservoir need to be examined in a subsequent study.

**8.  Large volumes of new $CO_2$ supplies will be required in California to achieve the $CO_2$-EOR potential defined by this study.**  The overall market for purchased $CO_2$ could be up to 18 Tcf, plus another 40+ Tcf of recycled $CO_2$.  Assuming that the volume of $CO_2$ stored equals the volume of $CO_2$ purchased and that the bulk of purchased $CO_2$ is from industrial sources, applying $CO_2$-EOR to California's oil reservoirs would enable over 1 billion tons of $CO_2$ emissions to be stored, greatly reducing greenhouse gas emissions.  Advanced $CO_2$-EOR flooding and $CO_2$ storage concepts (plus incentives for storing $CO_2$) could double this amount.

**9.  A public-private partnership will be required to overcome the many barriers facing large scale use of $CO_2$-EOR in California's oil fields.**  The challenging nature of the current barriers — lack of sufficient, reliable, low-cost $CO_2$ supplies, uncertainties as to how the technology will perform in California's complex oil fields, the considerable market and oil price risks, and the public perception of oil extraction — all argue that a partnership involving the oil production industry, potential $CO_2$ suppliers and transporters, the State of California and the federal government will be needed to address the barriers.

**10.  Many entities will share in the benefits of increased $CO_2$-EOR based oil production in California.**  Successful introduction and wide-scale use of $CO_2$-EOR in California will stimulate increased economic activity, provide new higher paying jobs, and lead to higher tax revenues for the state.  It will help revive a declining domestic oil production and service industry.  And, it will provide energy security for the nation and lower greenhouse gas emissions for all.

# 2. INTRODUCTION

***2.1 CURRENT SITUATION.*** California's oil basins are mature and in decline. Stemming the decline in oil production will be a major challenge, requiring a coordinated set of actions by numerous parties who have a stake in this problem — state of California revenue and economic development officials; private, state and federal royalty owners; the California oil production and refining industry; the public, and the federal government.

The main purpose of this report is to provide information to these "stakeholders" on the potential for pursuing $CO_2$ enhanced oil recovery ($CO_2$-EOR) as one option for stopping and potentially reversing the decline in California's oil production.

This report, "Basin Oriented Strategies for $CO_2$ Enhanced Oil Recovery: California Oil Basins," provides information on the size of the technical and economic potential for $CO_2$-EOR in California. It also identifies the many barriers — insufficient and costly $CO_2$ supplies, high market and economic risks, and concerns over technology performance — that currently impede the cost-effective application of $CO_2$-EOR in California's large oil basins.

***2.2 BACKGROUND***. California is the fourth largest domestic oil producing state, behind Louisiana, Texas and Alaska, providing 760 thousands barrels of oil per day, at the end of 2003. California's oil is produced from three main basins, San Joaquin, Los Angeles and Coastal (that combines the Santa Maria and Ventura basins). While known for its heavy oil resources and successful application of steam-based enhanced oil recovery (Steam-EOR), California also has a considerable number of light oil reservoirs that are amenable to miscible carbon-dioxide based enhanced oil recovery ($CO_2$-EOR). In addition, the state has a large number of deep, moderately heavy oil reservoirs, particularly in the Los Angeles Basin that could benefit from the application of immiscible $CO_2$-EOR. The oil basins and selected major oil fields of California are shown in Figure 2.

Figure 2. Major California Oil Basins


***2.3 PURPOSE***. This report, "Basin Oriented Strategies for $CO_2$ Enhanced Oil Recovery: Onshore California Oil Basins" is part of a larger effort to examine the enhanced oil recovery and $CO_2$ storage potential in key U.S. oil basins. Subsequent reports will address the oil fields along the Gulf Coast, the Mid-Continent and Alaska. The work involves examining the geological characteristics of major oil fields; examining the available $CO_2$ sources, volumes and costs; calculating oil recovery and $CO_2$ storage capacity; and, estimating economic feasibility.

Future studies will also examine alternative public-private partnership strategies for developing lower-cost $CO_2$ capture technology; for launching R&D/pilot projects of advanced $CO_2$ flooding technology; and, for structuring royalty/tax incentives and policies that would help accelerate the application of $CO_2$-EOR and $CO_2$ storage in the major oil basins of the U.S.

An important purpose of the larger study is to develop a desktop modeling and analytical capability for "basin oriented strategies" that enable DOE/FE to formulate policies and research programs that would support increased recovery of domestic oil resources. As such, this desktop model complements, but does not duplicate, the more extensive TORIS modeling system maintained by DOE/FE's National Energy Technology Laboratory.

***2.4 KEY ASSUMPTIONS***. For purposes of the study, it is assumed that sufficient supplies of $CO_2$ will become available, either by pipeline from natural sources such as St. John's or McElmo Dome, from industrial sources such as the hydrogen plants at the oil refinery complex at Wilmington, or from power plants in the San Joaquin or Coastal basins.

Figure 3 provides a conceptual illustration of a $CO_2$ pipeline system that would transport captured $CO_2$ emissions from California's refinery complex at Wilmington to the oil basins of California. Figure 4 illustrates one option for bringing $CO_2$ supply from the natural $CO_2$ reservoirs in New Mexico to the oil basins of California.

Figure 3. Major Pipeline System Connecting $CO_2$ Sources With Oil Fields of California

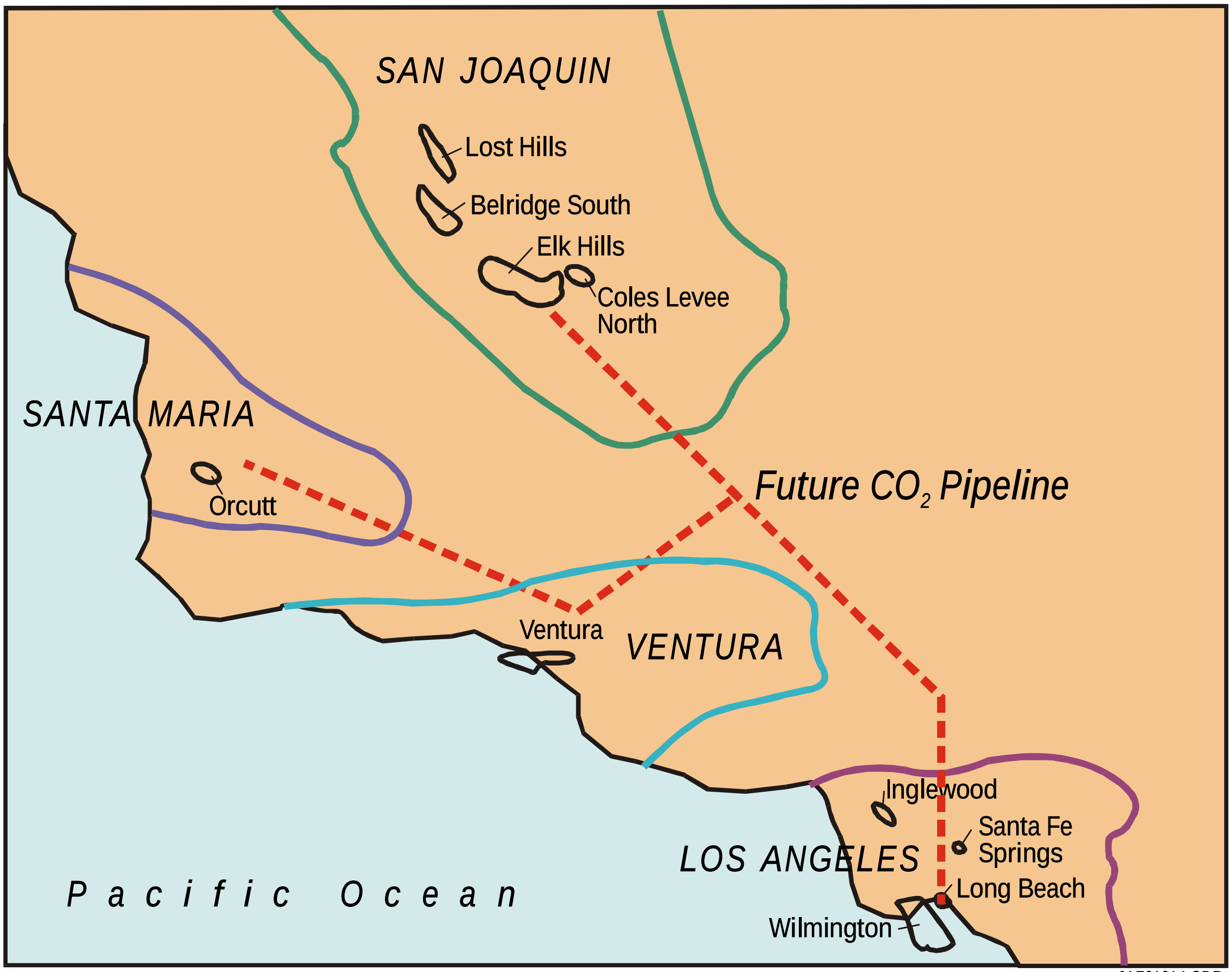


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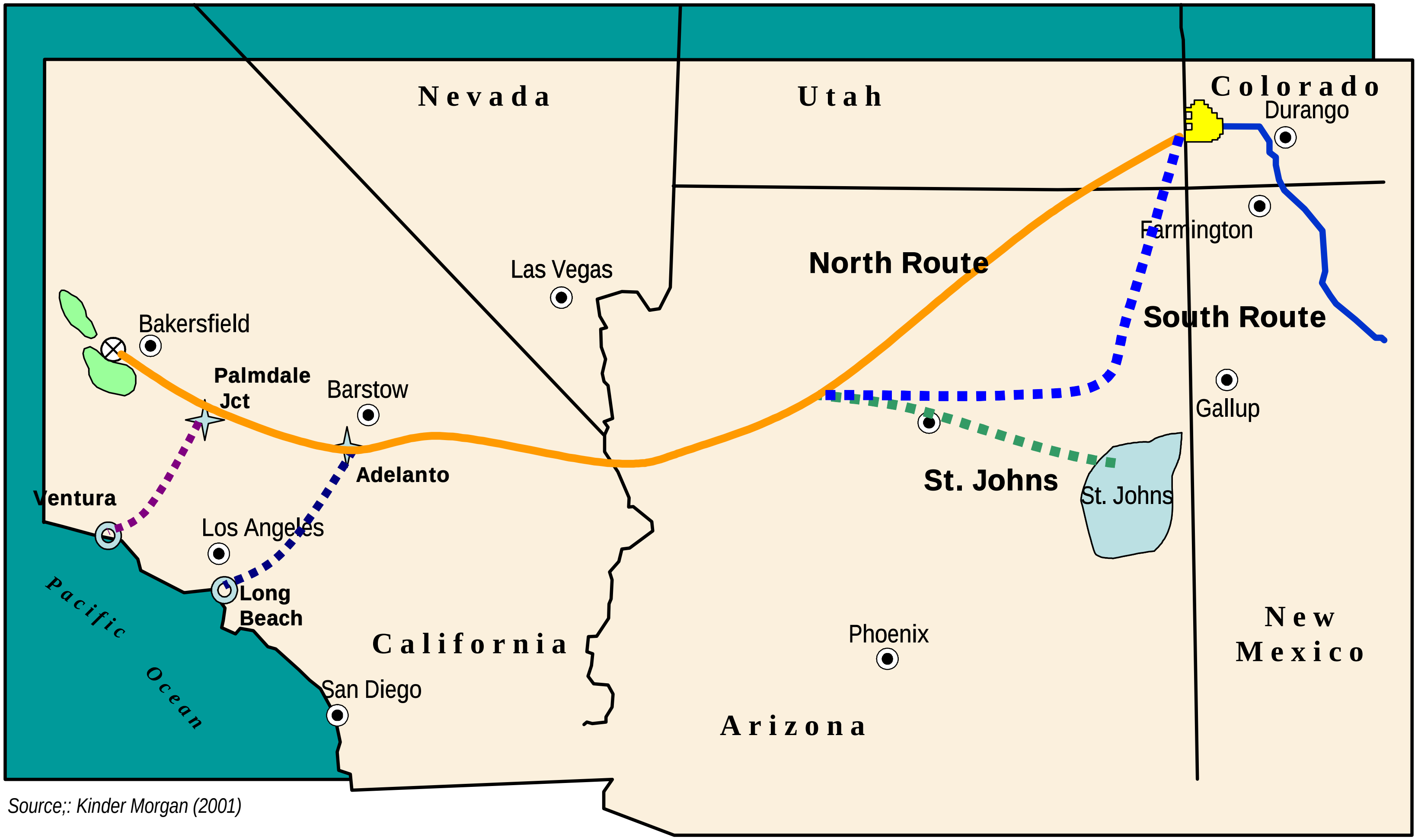
Figure 4. One Option for Transporting $CO_2$ Supplies to California's Oil Fields




*Source;: Kinder Morgan (2001)*

***2.5 TECHNICAL OBJECTIVES.*** The detailed objectives of this study are to examine the technical and economic potential of applying $CO_2$-EOR in California's oil basins, under two technology options:

1. *"Traditional Practices" Technology*. This involves the continued use of past $CO_2$ flooding and reservoir selection practices. It is distinguished by using miscible $CO_2$-EOR technology in light oil reservoirs attempting to minimize injection volumes of $CO_2$ per recovered oil barrel. Typical volumes are 0.4 to 0.5 HCPV.

2. *"State-of-the-art" Technology*. This involves bringing to California the benefits of recent gains in understanding of the $CO_2$-EOR process and how best to custom its application to the many different types of oil reservoirs in the state. Light oil reservoirs are selected for miscible $CO_2$-EOR and the challenging heavier oil reservoirs (that are too deep for steam-based enhanced oil recovery) are targeted for immiscible $CO_2$-EOR. "State-of-the-art" technology also entails injecting much larger volumes of $CO_2$, on the order of 1 HCPV, with considerably higher $CO_2$ recycling. Under "State-of-the-art" technology, with $CO_2$ injection volumes more than twice as large, oil recovery will also be higher than reported for past field projects using "Traditional Practices". The $CO_2$ injection/oil recovery ratio may also be higher under this technology option, calling for increased, lower cost $CO_2$ supplies.

The set of oil reservoirs to which $CO_2$-EOR would be applied fall into two groups, (after excluding certain of California's oil reservoirs, such as the shallow, heavy oil reservoir being produced with thermal oil recovery methods), as set forth below:

1. *Favorable Light Oil Reservoirs Meeting Stringent $CO_2$ Miscible Flooding Criteria*. These are the deeper, higher gravity oil reservoirs where $CO_2$ becomes miscible (after extraction of light hydrocarbon components into the $CO_2$ phase) with the oil remaining in the reservoir. Typically, reservoirs at depths greater than 3,000 feet and with oil gravities greater than 25 °API would be selected for miscible $CO_2$-EOR. Major California light oil fields such

as Elk Hills, Santa Fe Springs and Ventura fit into this category. The great bulk of past $CO_2$-EOR floods have been conducted in these "favorable reservoirs".

2. *Challenging Reservoirs Involving Immiscible Application of $CO_2$-EOR*. These are the deeper, moderately heavy oil reservoirs (as well as shallower light oil reservoirs) that do not meet the stringent requirements for miscibility. This reservoir set includes the large California oil fields, such as Torrance, South Mountain and Wilmington that still hold a significant portion of their original oil. California reservoirs at depths greater than 3,000 feet with oil gravities between 17.5º and 25 °API (or higher) would generally be included in this category. The reliability of projecting oil recovery from these "challenging reservoirs" is subject to considerable uncertainty, although pilot projects of this technology show promise. Therefore, these reservoirs will be considered only in the "State-of-the-art" technology.

Combining the technology and oil reservoir options, the following oil reservoir and $CO_2$ flooding technology matching is applied to California's reservoirs amenable to $CO_2$-EOR, Table 6.

Table 6. Matching of $CO_2$-EOR Technology With California's Oil Reservoirs

| $CO_2$-EOR Technology Selection | Oil Reservoir Selection |
|---|---|
| "Traditional Practices"; Miscible $CO_2$-EOR | ▪ Deep, Light Oil Reservoirs |
| "State-of-the-art"; Miscible and Immiscible $CO_2$-EOR | ▪ Deep, Light Oil Reservoirs<br>▪ Deep, Moderately Heavy Oil Reservoirs |

***2.6 OTHER ISSUES***. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of $CO_2$-EOR in California's major oil reservoirs. Because of confidentiality and proprietary issues, the results of the study have been aggregated at the basin level for the three major California oil basins. As such, reservoir-level data and results are not provided and are not available for general distribution. However, selected non-confidential and non-proprietary information at the field and reservoir level is provided in the report and would be made available for review, on a case by case basis, to provide an improved context for the basin level reporting of results.

# 3. OVERVIEW OF CALIFORNIA OIL PRODUCTION

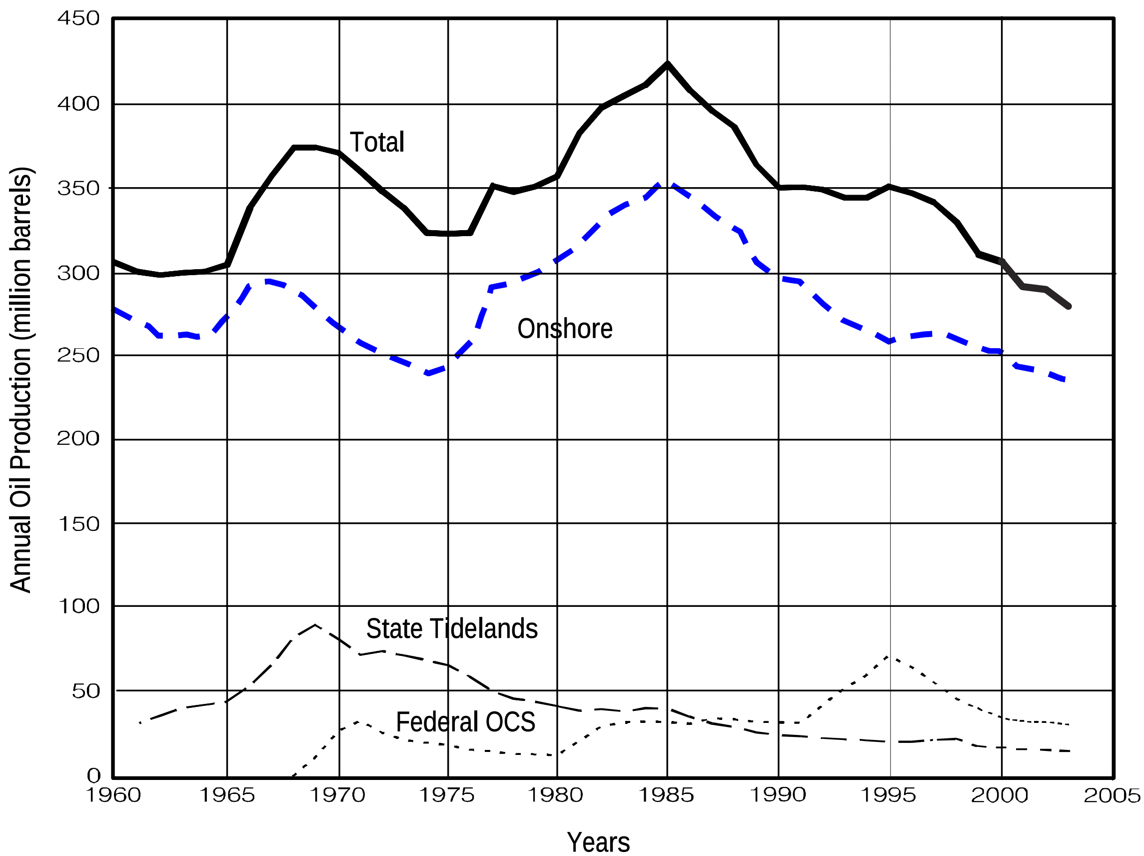
***3.1 HISTORY OF OIL PRODUCTION***. Oil production in California has steadily declined for the past twenty years, since reaching a peak of 420 million barrels per year (1.15 million barrels per day) in 1985, Figure 5. The steep production decline between 1985 and 1990 was arrested in 1990 and remained flat for five years. Aggressive application of steam-based enhanced oil recovery and development of oil fields in the federal offshore waters stemmed the decline. In 1995, oil production resumed its decline reaching a recent low of 280 million barrels (770,000 barrels per day) in 2003.

- The prolific San Joaquin Basin (Districts 4 and 5) remains the state's largest oil producing basin, providing 200 million barrels in 2003.
- The Los Angeles Basin (District 1) is a distant second with 31 million barrels of oil produced in 2003.
- The Coastal Basin, which contains the Ventura (District 2) and Santa Maria (District 3) basins, provided 19 million barrels of oil in 2003.
- The remaining 30 million barrels of California oil production is from the federal offshore and northern California (District 6), which has not been considered in this report.

However, onshore California still holds a rich resource base of oil in the ground. With 83 billion barrels of original oil in-place (OOIP) and 26 billion barrels expected to be recovered, 57 billion barrels is "stranded" due to lack of technology, lack of sufficient, affordable $CO_2$ supplies and high economic risk. A major portion of this "stranded oil" is in world-class size fields that offer potential for enhanced oil recovery.

Table 7 presents the status and annual oil production for the ten largest California oil fields. The table shows that seven of the ten largest fields are in steep production decline. Arresting this decline in California's oil production could be attained by applying enhanced oil recovery technology, particularly $CO_2$-EOR.

Figure 5. History of California Oil Production




*California Department of Conservation, Division of Oil, Gas and Geothermal Resources (2003).*

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Table 7. Annual Production (MMBbl) from the Ten Largest California Oil Fields, 2000-2003

| Oil Fields | 2000 | 2001 | 2002 | 2003 | Production Status |
|---|---|---|---|---|---|
| Midway-Sunset | 58.0 | 51.7 | 50.2 | 48.4 | Declining |
| Belridge, South | 41.6 | 38.8 | 40.1 | 41.0 | Stable |
| Kern River | 45.0 | 41.3 | 38.7 | 37.3 | Declining |
| Cymric | 20.4 | 21.1 | 20.0 | 18.6 | Declining |
| Elk Hills | 17.5 | 18.6 | 19.7 | 18.6 | Stable |
| Wilmington | 16.8 | 15.9 | 15.1 | 14.9 | Declining |
| Lost Hills | 11.1 | 10.9 | 11.3 | 11.1 | Stable |
| Hondo Offshore | 11.0 | 9.9 | 8.9 | 7.7 | Declining |
| Coalinga | 7.9 | 7.2 | 6.9 | 6.5 | Declining |
| Pescado Offshore | 7.1 | 5.8 | 6.7 | 6.3 | Declining |

***3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY***. California's oil producers are familiar with using technology for improving oil recovery. For example, more than half of California's oil production is from application of secondary and enhanced oil recovery. In 2002:

- Use of thermal EOR, primarily steam drive, provided 108 million barrels,
- Waterflooding accounted for 46 million barrels, and
- Gas injection provided 4 million barrels.

Notable is the absence of oil production from $CO_2$-EOR, even though numerous small $CO_2$-EOR pilots have been conducted in the past. The lack of secure, low-cost $CO_2$ supplies is one of the primary reasons for the noted absence of $CO_2$-EOR in California's oil fields.

Table 8 presents data on incremental oil production in California from current waterflooding and gas injection improved oil recovery projects. The successful applications of these "secondary" types of improved oil recovery methods (particularly in the moderately heavy oil reservoirs) help give confidence that the "tertiary" application of $CO_2$-EOR would be successful.

***3.3 THE "STRANDED OIL" PRIZE.*** Even though California's oil production is declining, this does not mean that the resource base is exhausted. California is blessed with a large number of giant oil fields with large remaining oil in-place (ROIP). Table 9 provides information (as of year 2002) on the maturity and oil production history of 14 giant California oil fields, each with estimated ultimate recovery of 500 million barrels or more. Of particular note are the giant light oil fields that may be attractive for miscible $CO_2$-EOR including: Elk Hills (San Joaquin Basin) with 2,780 million barrels of ROIP, Ventura (Ventura Basin) with 2,310 million barrels of ROIP, and Santa Fe Springs (Los Angeles Basin) with 1,980 million barrels of ROIP. Equally notable are the large moderately deep, moderately heavy oil reservoirs that are candidates for immiscible $CO_2$-EOR, such as: Huntington Beach onshore and Wilmington onshore, both in the Los Angeles Basin.

***3.4 REVIEW OF PRIOR STUDIES.*** Past studies of the potential for $CO_2$ enhanced oil recovery in California's oil reservoirs provide a mixed outlook.

A recent study, "Coal-Based Power Generation for California with $CO_2$ Removed for Use in Enhanced Oil Recovery" (Parsons, December 2002), identified only two small California oil fields that were economically favorable for miscible $CO_2$-EOR. Eight additional reservoirs, with 470 million barrels of $CO_2$-EOR potential, screened technically acceptable for $CO_2$-EOR but were judged to be uneconomic. The study did not consider EOR from oil reservoirs with API gravities less than 22º, and did not examine the applicability of immiscible $CO_2$ flooding.

Table 8. Incremental Oil Production from Improved Oil Recovery Projects (2002)

| Field | Waterflooding (Bbls) | Gas Injection (Bbls) |
|---|---|---|
| **Los Angeles Basin** | | |
| Belmont Offshore | 36,000 | - |
| Beverly Hills | 776,000 | - |
| Brea-Olinda | 104,000 | - |
| Coyote, East | 123,000 | - |
| Huntington Beach Offshore | 2,056,000 | - |
| Huntington Beach Onshore | 362,000 | - |
| Inglewood | 2,201,000 | - |
| Las Cienegas | 307,000 | - |
| Long Beach | 919,000 | - |
| Los Angeles Downtown | 89,000 | - |
| Montebello | 540,000 | - |
| Newport West, Onshore | 8,000 | - |
| Richfield | 157,000 | - |
| Rosecrans | 26,000 | - |
| San Vincente | 711,000 | - |
| Sansinena | 105,000 | - |
| Santa Fe Springs | 510,000 | - |
| Sawtelle | 195,000 | - |
| Seal Beach | 35,000 | - |
| Torrance Onshore | 227,000 | - |
| Wilmington Offshore | 11,787,000 | - |
| Wilmington Onshore | 3,256,000 | - |
| Total | 24,530,000 | - |
| **Ventura Basin** | | |
| Oak Ridge | 45,000 | - |
| Rincon | 135,000 | - |
| San Miguelito | 645,000 | - |
| Ventura | 4,400,000 | - |
| Total | 5,225,000 | - |
| **Santa Maria Basin** | | |
| Cat Canyon | 131,000 | - |
| Cuyama, South | 283,000 | - |
| Orcutt | 488,000 | - |
| Russell Ranch | 10,000 | - |
| Santa Maria Valley | 40,000 | - |
| Total | 952,000 | - |
| **San Joaquin Basin** | | |
| Belridge, North | 1,181,000 | - |
| Belridge, South | 9,505,000 | - |
| Coles Levee, North | 176,000 | - |
| Coles Levee, South | 25,000 | - |
| Elk Hills | 2,040,000 | 4,178,000 |
| Lost Hills | 2,254,000 | - |
| Tejon Hills | 4,000 | - |
| Tejon, North | 6,000 | - |
| Wheeler Ridge | 14,000 | - |
| Yowlumme | 580,000 | - |
| Total | 15,785,000 | 4,178,000 |
| State Total | 46,492,000 | 4,178,000 |

Table 9. California's Giant Oil Fields
(Fields with cumulative recovery of 500 million barrels or more, 2002)

| | Field | Year Discovered | Cumulative Production (Mbbl) | Estimated Reserves (Mbbl) | Remaining Oil In-Place (Mbbl) |
|---|---|---|---|---|---|
| 1 | Midway-Sunset | 1894 | 2,697,814 | 759,060 | 4,030 |
| 2 | Wilmington | 1932 | 2,598,498 | 385,895 | 6,464 |
| 3 | Kern River | 1899 | 1,839,893 | 611,407 | 1,824 |
| 4 | Belridge, South | 1911 | 1,315,700 | 585,240 | 4,694 |
| 5 | Elk Hills | 1911 | 1,212,578 | 132,780 | 2,776 |
| 6 | Huntington Beach | 1920 | 1,116,621 | 47,787 | 2,334 |
| 7 | Ventura | 1919 | 968,597 | 43,449 | 2,414 |
| 8 | Long Beach | 1921 | 933,769 | 11,872 | 2,004 |
| 9 | Coalinga | 1890 | 888,089 | 81,801 | 2,240 |
| 10 | Buena Vista | 1909 | 663,795 | 8,012 | 1,348 |
| 11 | Santa Fe Springs | 1919 | 624,317 | 9,437 | 1,976 |
| 12 | Coalinga, E. Extension | 1938 | 504,038 | 4,354 | 464 |

An even more pessimistic outlook was provided in an earlier study of California $CO_2$-EOR potential, reported in Volume II, "An Evaluation of Known Remaining Oil Resources in the State of California", (1994), prepared by the Interstate Oil Compact Commission for the Bartlesville Project Office of DOE. This study stated:

- "While there may be some limited potential for $CO_2$-miscible flooding in California, it is not apparent from this analysis."
- "Immiscible carbon dioxide injection as an alternative to cyclic steam injection in California reservoirs appears to hold some promise according to recent reports. . . The potential for this type of carbon dioxide stimulation was not modeled in this analysis."

A distinctly different outlook was provided in the Society of Petroleum Engineering paper SPE 63305 “$CO_2$ Flood Potential of California Oil Reservoirs and Possible $CO_2$ Sources” by Jeschke, Schoeling and Hemmings (June, 2000). The authors examined the “oil recoverable under both miscible and immiscible $CO_2$ floods from nine representative California oil reservoirs.” The incremental oil recoverable under $CO_2$-EOR from this nine field data base (that included the giant light oil fields of Elk Hills, Santa Fe Springs and Ventura, as well as the large, heavier oil fields of Huntington Beach and Inglewood) was estimated at 1,424 to 2,848 million barrels.

The first two studies are consistent with the rather pessimistic “Traditional Practices” outlook for the $CO_2$-EOR potential in California. The third study supports the application of “State-of-the-art” technology, for both miscible and immiscible $CO_2$ flooding, and gives a much more optimistic outlook for using $CO_2$-EOR in California’s oil reservoirs. The availability of low cost $CO_2$ supplies and a lower risk premium would further improve the outlook, as is set forth in this study.

# 4. MECHANISMS OF $CO_2$-EOR

***4.1 MECHANISMS OF MISCIBLE $CO_2$-EOR.*** Miscible $CO_2$-EOR is a multiple contact process, involving the injected $CO_2$ and the reservoir's oil. During this multiple contact process, $CO_2$ will vaporize the lighter oil fractions into the injected $CO_2$ phase and $CO_2$ will condense into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, a mobile fluid and low interfacial tension.

The primary objective of miscible $CO_2$-EOR is to remobilize and dramatically reduce the after waterflooding residual oil saturation in the reservoir's pore space. Figure 6 provides an one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the $CO_2$ miscible process.

***4.2 MECHANISMS OF IMMISCIBLE $CO_2$-EOR***. When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected $CO_2$ is immiscible with the reservoir's oil. As such, another oil displacement mechanism, immiscible $CO_2$ flooding, occurs. The main mechanisms involved in immiscible $CO_2$ flooding are: (1) oil phase swelling, as the oil becomes saturated with $CO_2$; (2) viscosity reduction of the swollen oil and $CO_2$ mixture; (3) extraction of lighter hydrocarbon into the $CO_2$ phase; and, (4) fluid drive plus pressure. This combination of mechanisms enable a portion of the reservoir's remaining oil to be mobilized and produced. In general, immiscible $CO_2$-EOR is less efficient than miscible $CO_2$-EOR in recovering the oil remaining in the reservoir.

***4.3 INTERACTIONS BETWEEN INJECTED $CO_2$ AND RESERVOIR OIL.*** The properties of $CO_2$ (as is the case for most gases) change with the application of pressure and temperature. Figures 7A and 7B provide basic information on the change in $CO_2$ density and viscosity, two important oil recovery mechanisms, as a function of pressure.

Figure 6. One-Dimensional Schematic Showing the $CO_2$ Miscible Process.

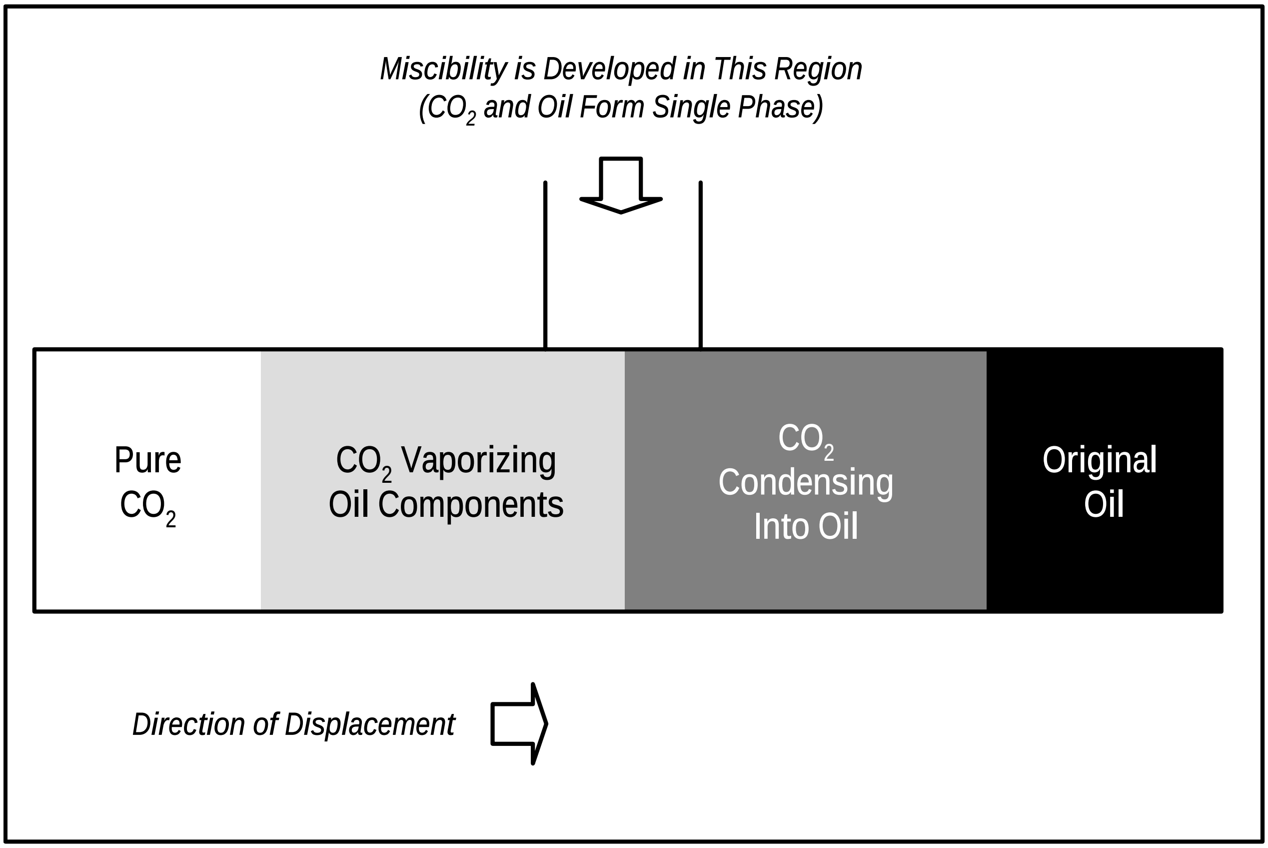


Figure 7A. Carbon Dioxide, $CH_4$ and $N_2$ densities at $105^0$F. At high pressures, $CO_2$ has a density close to that of a liquid and much greater than that of either methane or nitrogen. Densities were calculated with an equation of state (EOS).

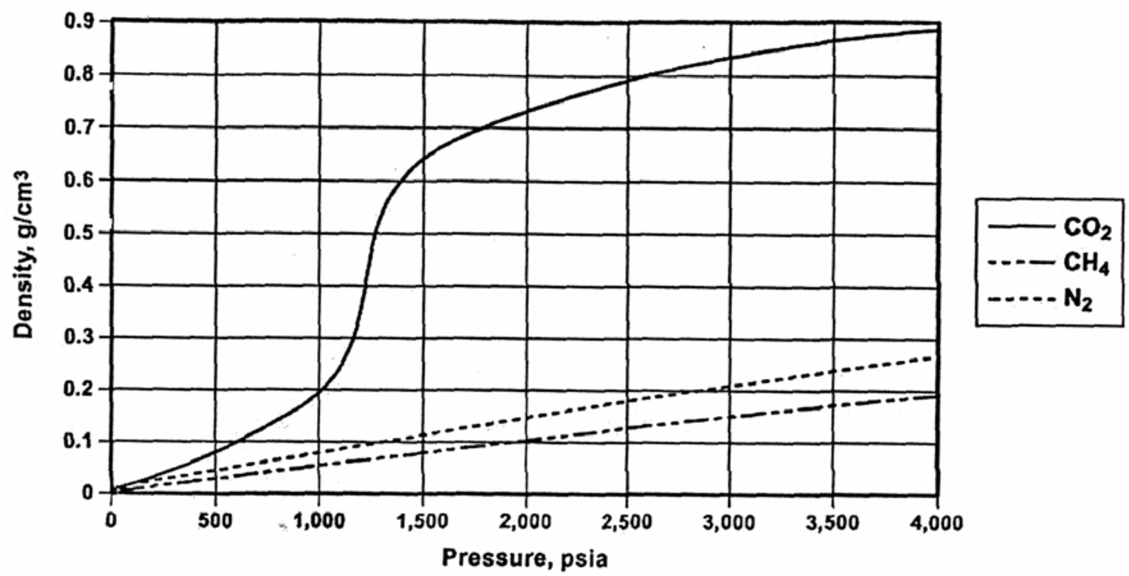
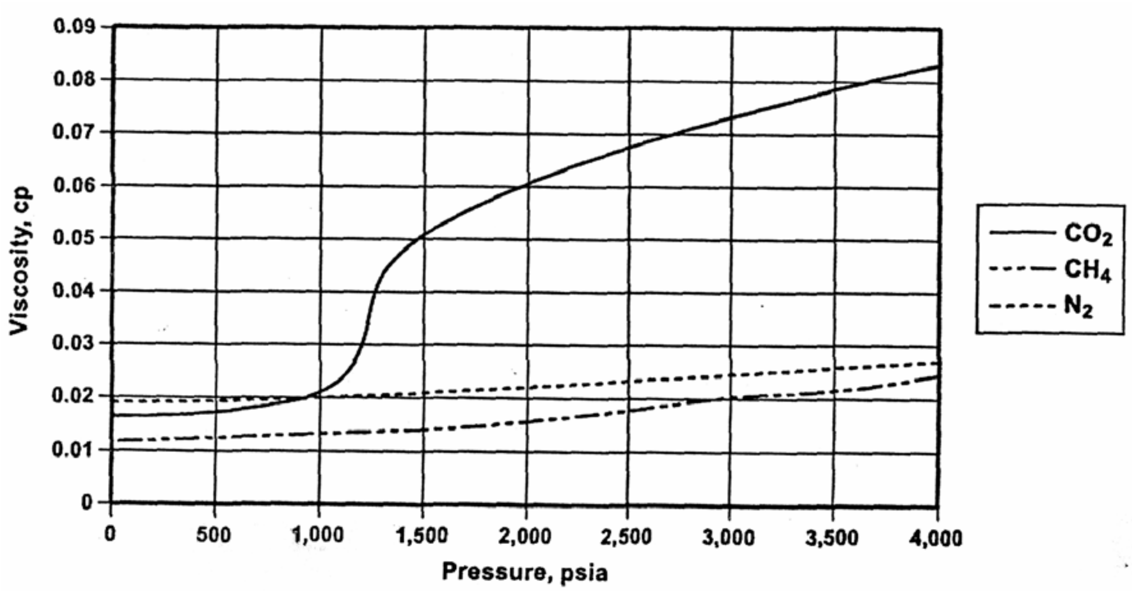



Figure 7B. Carbon Dioxide, $CH_4$ and $N_2$ viscosities at $105^0$F. At high pressures, the viscosity of $CO_2$ is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.



Swelling is an important oil recovery mechanism, for both miscible and immiscible $CO_2$-EOR. Figures 8A and 8B show the oil swelling (and implied residue oil mobilization) that occurs from: (1) $CO_2$ injection into a West Texas light reservoir oil; and, (2) $CO_2$ injection into a very heavy (12 °API) oil reservoir in Turkey. Laboratory work on the Bradford Field (Pennsylvania) oil reservoir showed that the injection of $CO_2$, at 800 psig, increased the volume of the reservoir's oil by 50%. Similar laboratory work on Mannville "D" Pool (Canada) reservoir oil showed that the injection of 872 scf of $CO_2$ per barrel of oil (at 1,450 psig) increased the oil volume by 28%, for crude oil already saturated with methane.

Viscosity reduction is a second important oil recovery mechanism, particularly for immiscible $CO_2$-EOR. Figure 9 shows the dramatic viscosity reduction of one to two orders of magnitude (10 to 100 fold) that occur for a reservoir's oil with the injection of $CO_2$ at high pressure.

Figure 8A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid. (Holm and Josendal)

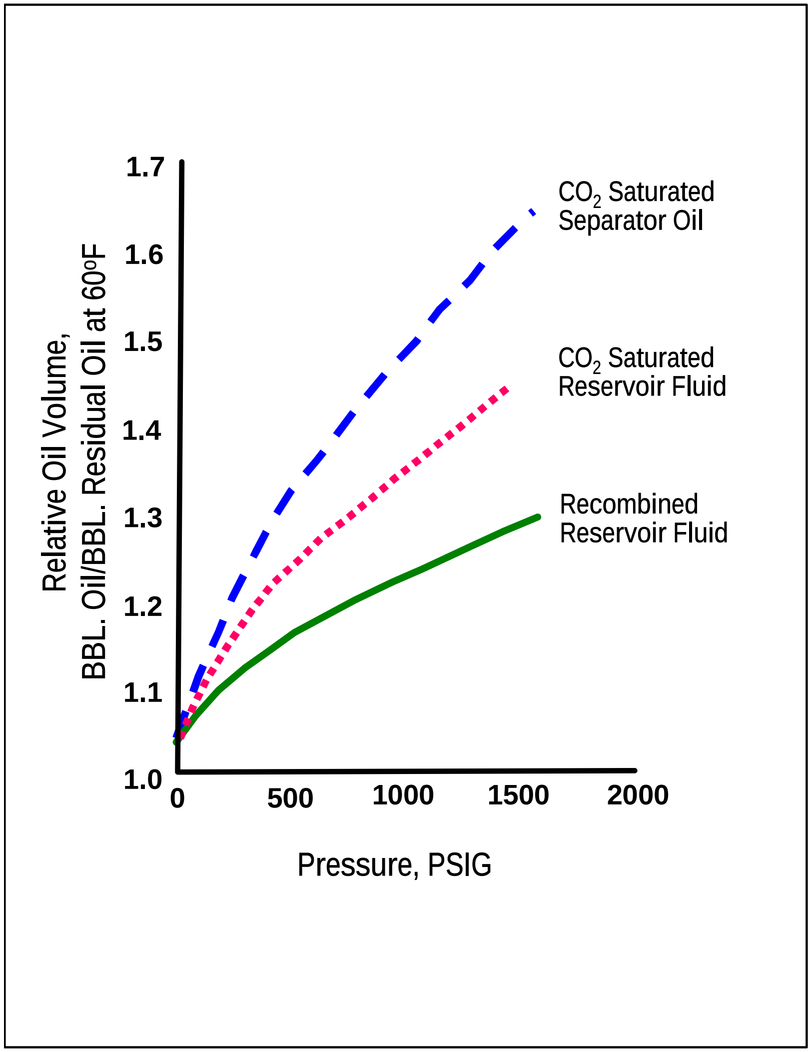



Figure 8B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

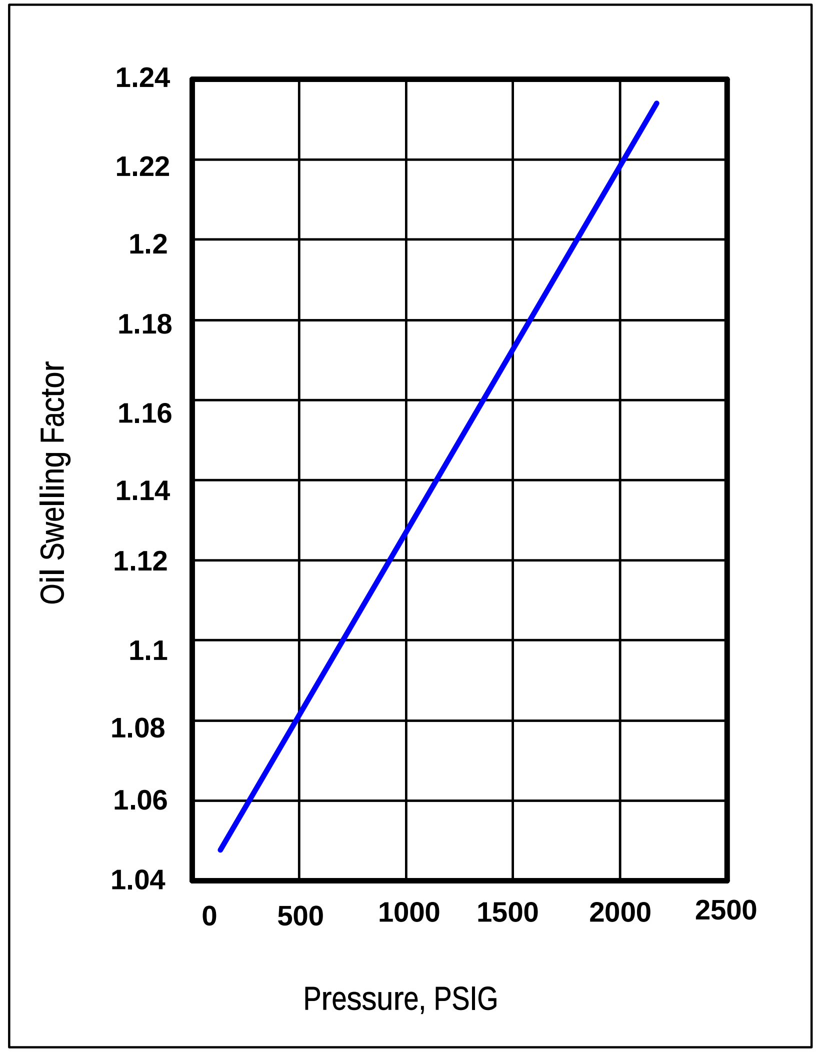
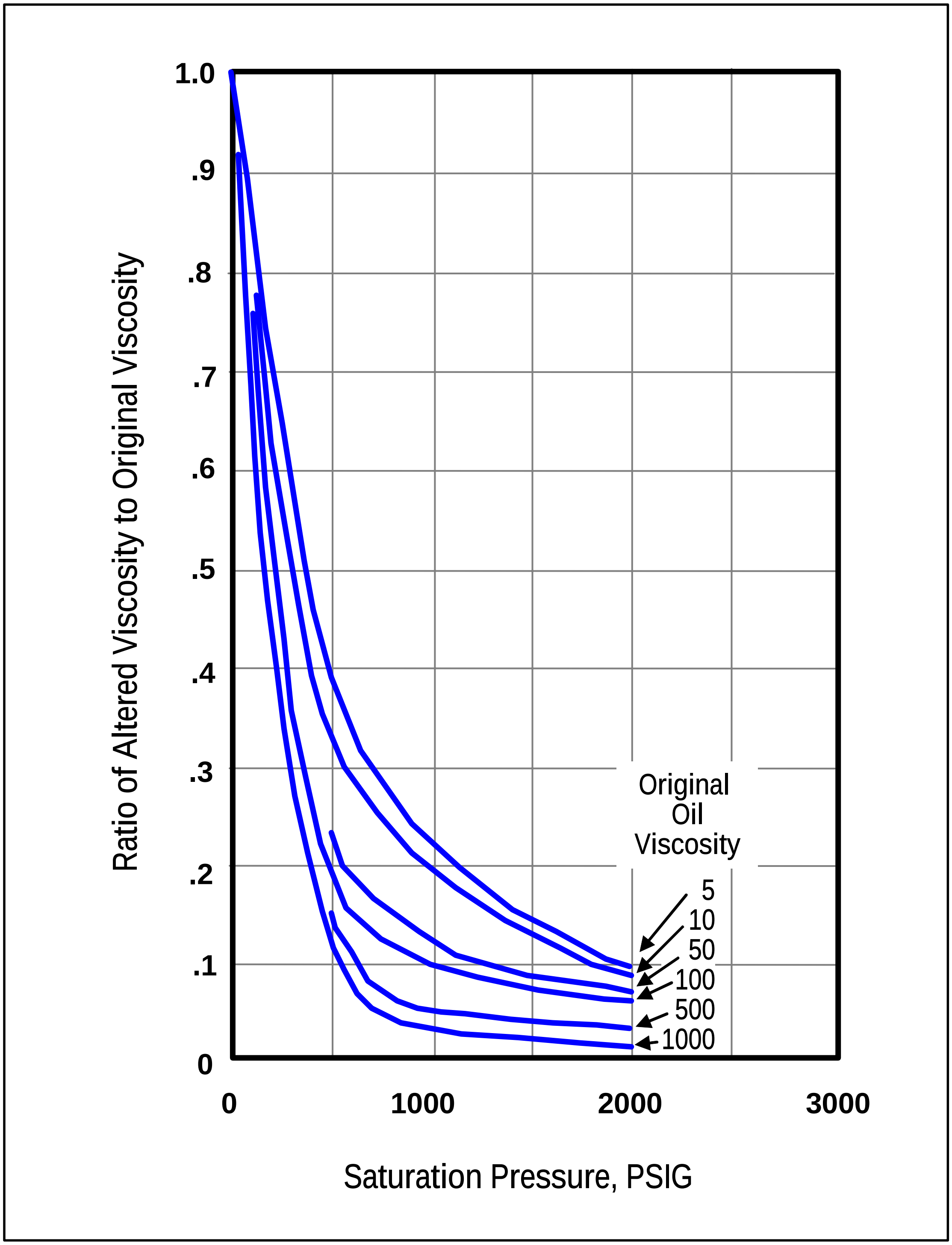


Figure 9. Viscosity Reduction Versus Saturation Pressure. (Simon and Graue)

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# 5. STUDY METHODOLOGY

***5.1 OVERVIEW.*** A seven part methodology was used to assess the $CO_2$-EOR potential of California's oil reservoirs. The seven steps were: (1) assembling the California Major Oil Reservoirs Data Base; (2) screening reservoirs for $CO_2$-EOR; (3) calculating the minimum miscibility pressure; (4) calculating oil recovery; (5) assembling the cost model; (6) constructing an economics model; and, (7) performing sensitivity analyses.

An important objective of the study was the development of a desktop model with analytic capability for "basin oriented strategies" that would enable DOE/FE to develop policies and research programs leading to increased recovery and production of domestic oil resources. As such, this desktop model complements, but does not duplicate, the more extensive TORIS modeling system maintained by DOE/FE's National Energy Technology Laboratory.

***5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE.*** The study started with the National Petroleum Council (NPC) Public Data Base, maintained by DOE Fossil Energy. The study updated and modified this publicly accessible data base to develop the California Major Oil Reservoirs Data Base for the San Joaquin, Los Angeles, and Ventura and Santa Maria oil basins. The latter two basins were combined into the Coastal Basin.

Table 10 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the $CO_2$-EOR screening and oil recovery models, discussed below. Overall, the California Major Oil Reservoirs Data Base contains 172 reservoirs, accounting for 90% of the oil expected to be ultimately produced in California by primary, secondary and thermal injection processes. Considerable work was required to develop an up-to-date, volumetrically consistent Major Oil Reservoirs Data Base, as further discussed below.

Table 10. Reservoir Data Format: Major Oil Reservoirs Data Base.

| | |
|---|---|
| **Basin Name** | |
| **Field Name** | |
| **Reservoir** | |

## Reservoir Parameters:

| | |
|---|---|
| Area (A) | |
| Net Pay (ft) | |
| Depth (ft) | |
| Porosity | |
| Reservoir Temp (deg F) | |
| Initial Pressure (psi) | |
| Pressure (psi) | |
| $B_{oi}$ | |
| $B_o$ @ $S_o$, swept | |
| $S_{oi}$ | |
| $S_{or}$ | |
| Swept Zone $S_o$ | |
| $S_{wi}$ | |
| $S_w$ | |
| API Gravity | |
| Viscosity (cp) | |
| Dykstra-Parsons | |

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## Oil Production

| | |
|---|---|
| Producing Wells (active) | |
| Producing Wells (shut-in) | |
| 2001 Production (Mbbl) | |
| Daily Prod - Field (Bbl/d) | |
| Cum Oil Production (MMbbl) | |
| EOY 2001 Oil Reserves (MMbbl) | |
| Water Cut | |

## Water Production

| | |
|---|---|
| 2001 Water Production (Mbbl) | |
| Daily Water (Mbbl/d) | |

## Injection

| | |
|---|---|
| Injection Wells (active) | |
| Injection Wells (shut-in) | |
| 2001 Water Injection (MMbbl) | |
| Daily Injection - Field (Mbbl/d) | |
| Cum Injection (MMbbl) | |
| Daily Inj per Well (Bbl/d) | |

## Volumes

| | |
|---|---|
| OOIP (MMbl) | |
| Cum Oil (MMbl) | |
| EOY 2001 Reserves (MMbl) | |
| Ultimate Recovery (MMbl) | |
| Remaining (MMbbl) | |
| Ultimate Recovered (%) | |

## OOIP Volume Check

| | |
|---|---|
| Reservoir Volume (AF) | |
| Bbl/AF | |
| OOIP Check (MMbl) | |

## SROIP Volume Check

| | |
|---|---|
| Reservoir Volume (AF) | |
| Swept Zone Bbl/AF | |
| SROIP Check (MMbbl) | |

## ROIP Volume Check

| | |
|---|---|
| ROIP Check (MMbl) | |

A “test bed” data set was assembled for San Joaquin Basin oil reservoirs from the National Petroleum Council (NPC) Public Data Base maintained by DOE/FE. This “test bed” data set, incorporating a representative sample of 20 oil reservoirs in the San Joaquin Basin, was used to seek answers to four questions:

1. How much effort would be required to provide an up-to-date, quality reservoir data base? The reservoir properties, oil production and reserves data for California, in the above cited publicly available data base, has not been updated since 1982. As such, considerable work was required to develop an up-to-date and quality controlled data base for this study.

2. Are all of the data items essential for calculating $CO_2$-EOR using *$CO_2$-PROPHET* in the data base? Considerable effort was placed on developing updated values for key reservoir properties, such as the Dykstra-Parsons coefficient, residual oil in the water swept zone, latest formation volume factor, relative permeability curves and other variables that significantly control oil recovery in *$CO_2$-PROPHET*.

3. How readily do the reservoir data formats integrate with the data input format of *$CO_2$-PROPHET*? The data interface between the publicly available data base and *$CO_2$-PROPHET* was inadequate. To correct this problem, a new data format and user interface was developed to enable *$CO_2$-PROPHET* to efficiently link the reservoir data set with the model’s input requirements.

4. How rigorously do existing screening tools enable the reservoirs in the San Joaquin Basin to be assessed as candidates for miscible or immiscible flooding? An updated methodology was developed by the study for establishing minimum miscibility pressure, for selecting reservoirs eligible for miscible $CO_2$ flooding, and for screening reservoirs eligible for immiscible $CO_2$ flooding.

In summary, considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place in California; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible $CO_2$-EOR; and, (3) provide the *$CO_2$-*

*PROPHET* Model (developed by Texaco for the DOE Class I cost-share program) the essential input data for calculating $CO_2$ injection requirements and oil recovery.

***5.3 SCREENING RESERVOIRS FOR $CO_2$-EOR.*** The data base was screened for reservoirs that would be applicable for $CO_2$-EOR. Five prominent screening criteria were used to identify favorable reservoirs. These were: reservoir depth, oil gravity, reservoir pressure, and reservoir temperature and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible $CO_2$-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard were considered for immiscible $CO_2$-EOR.

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure $CO_2$ injection. A minimum oil gravity of 17.5 °API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 11 tabulates the oil reservoirs that passed the preliminary screening step.

Table 11. California Oil Reservoirs Screened Acceptable for $CO_2$-EOR

| Basin | Field | Formation |
|---|---|---|
| A. Los Angeles | | |
| Los Angeles | Beverly Hills | Miocene, East Area |
| Los Angeles | Beverly Hills | Pliocene, East Area |
| Los Angeles | Beverly Hills | Miocene, West Area |
| Los Angeles | Brea Olinda | Pliocene-Miocene |
| Los Angeles | Dominguez | Pliocene-Miocene |
| Los Angeles | Coyote East | Anaheim |
| Los Angeles | Coyote East | Stern |
| Los Angeles | Coyote West | Main 99W |
| Los Angeles | Coyote West | Main 99E |
| Los Angeles | Coyote West | Emery West |
| Los Angeles | Coyote West | Emery East |
| Los Angeles | Huntington Beach | Jones |
| Los Angeles | Huntington Beach | Onshore |
| Los Angeles | Huntington Beach | S. Ashton-Jones |
| Los Angeles | Inglewood | Moynier |
| Los Angeles | Inglewood | Rubel |
| Los Angeles | Inglewood | Sentous |
| Los Angeles | Las Cienegas | Jefferson |
| Los Angeles | Long Beach | Upper |
| Los Angeles | Los Angeles | Miocene |
| Los Angeles | Montebello | Baldwin |
| Los Angeles | Playa Del Ray | Del Ray Hills |
| Los Angeles | Playa Del Ray | Venice Area |
| Los Angeles | Richfield East Area | Kraemer |
| Los Angeles | Richfield East Area | Chapman |
| Los Angeles | Richfield West Area | W. Chapman |
| Los Angeles | Santa Fe Springs | Main |
| Los Angeles | Seal Beach | McGrath North |
| Los Angeles | Seal Beach | Wasem/McGrath |
| Los Angeles | Seal Beach | McGrath South |
| Los Angeles | Seal Beach | Bixby-Selover |
| Los Angeles | Seal Beach | Wasem |
| Los Angeles | Torrance | Del Amo |
| Los Angeles | Torrance | Main |
| Los Angeles | Wilmington | Fault Block I Terminal |
| B. San Joaquin | | |
| San Joaquin | Asphalto | Stevens |
| San Joaquin | Belridge North | 64 Zone |
| San Joaquin | Buena Vista | B27 |
| San Joaquin | Buena Vista | Stevens |
| San Joaquin | Buena Vista | Antelope |
| San Joaquin | Coalinga | Nose Area |
| San Joaquin | Coles Levee North | Richfield |
| San Joaquin | Coles Levee South | Stevens |

Table 11. California Oil Reservoirs Screened Acceptable for $CO_2$-EOR

| Basin | Field | Formation |
|---|---|---|
| San Joaquin | Cuyama South | Homan |
| San Joaquin | Cymric | Oceanic |
| San Joaquin | Cymric | Phacoides |
| San Joaquin | Edison | Vedder-Freeman |
| San Joaquin | Edison | West Area Chanac |
| San Joaquin | Elk Hills | Upper |
| San Joaquin | Elk Hills | Stevens |
| San Joaquin | Fruitvale | Etchegoin-Chanac |
| San Joaquin | Russell Ranch | Dibblee Sands |
| San Joaquin | Greeley | Stevens |
| San Joaquin | Greeley | Vedder |
| San Joaquin | Guijarral Hills | Main Area |
| San Joaquin | Kettleman Dome North | Temblor |
| San Joaquin | McKittrick | Phacoides & Point of Rocks |
| San Joaquin | Paloma | Paloma Sands |
| San Joaquin | Raisin City | Zilch Sand |
| San Joaquin | Tejon Grapevine | Central Area |
| San Joaquin | Ten Section | Stevens |
| San Joaquin | Wheeler Ridge | L-36 Reserve |
| San Joaquin | Yowlumne | Yowlumne Sand |
| San Joaquin | Kettleman Hills (N. Dome) | Vaqueros |
| C. Coastal | | |
| Coastal | Aliso Canyon | Porter |
| Coastal | Montalvo West | McGrath |
| Coastal | Newhall-Potrero | 7th Zone |
| Coastal | Newhall-Potrero | 3rd Zone |
| Coastal | Newhall-Potrero | 6th Zone |
| Coastal | Newhall-Potrero | 5th Zone |
| Coastal | Oxnard | McInnes |
| Coastal | Ramona | Kern-Del Valley |
| Coastal | Rincon | Rincon, Oak Grove |
| Coastal | Rincon | Oak Grove, Others |
| Coastal | San Miguelito | First Grubb |
| Coastal | San Miguelito | Second Grubb |
| Coastal | San Miguelito | Third Grubb |
| Coastal | Santa Susana | Sespe Second & Third |
| Coastal | Saticoy | Pico |
| Coastal | Shiells Canyon | Eocene |
| Coastal | South Mountain | Bridge-Pliocene |
| Coastal | South Mountain | Sespe |
| Coastal | Ventura | C Block |
| Coastal | Ventura | D 3,4, 5, 6 Blocks |
| Coastal | Ventura | D 7, 8 Blocks |
| Coastal | Ventura | B Sands |
| Coastal | Orcutt | Monterey, Pt Sal |

***5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE.*** The miscibility of a reservoir's oil with injected $CO_2$ is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with $CO_2$, given fixed temperature and oil composition, was to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the reservoir's oil gravity to oil composition.

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure 10. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most California oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below:

$$MMP = 15.988*T^{(0.744206+0.0011038*MW\ C5+)}$$

Where: T is Temperature in ºF, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 11.

The next step was calculating the minimum miscibility pressure (MMP) for a given reservoir and comparing it to the maximum allowable pressure. The maximum pressure was determined using a pressure gradient of 0.6 psi/foot. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible $CO_2$-EOR were selected for immiscible $CO_2$-EOR.

Figure 10. Estimating $CO_2$ Minimum Miscibility Pressure

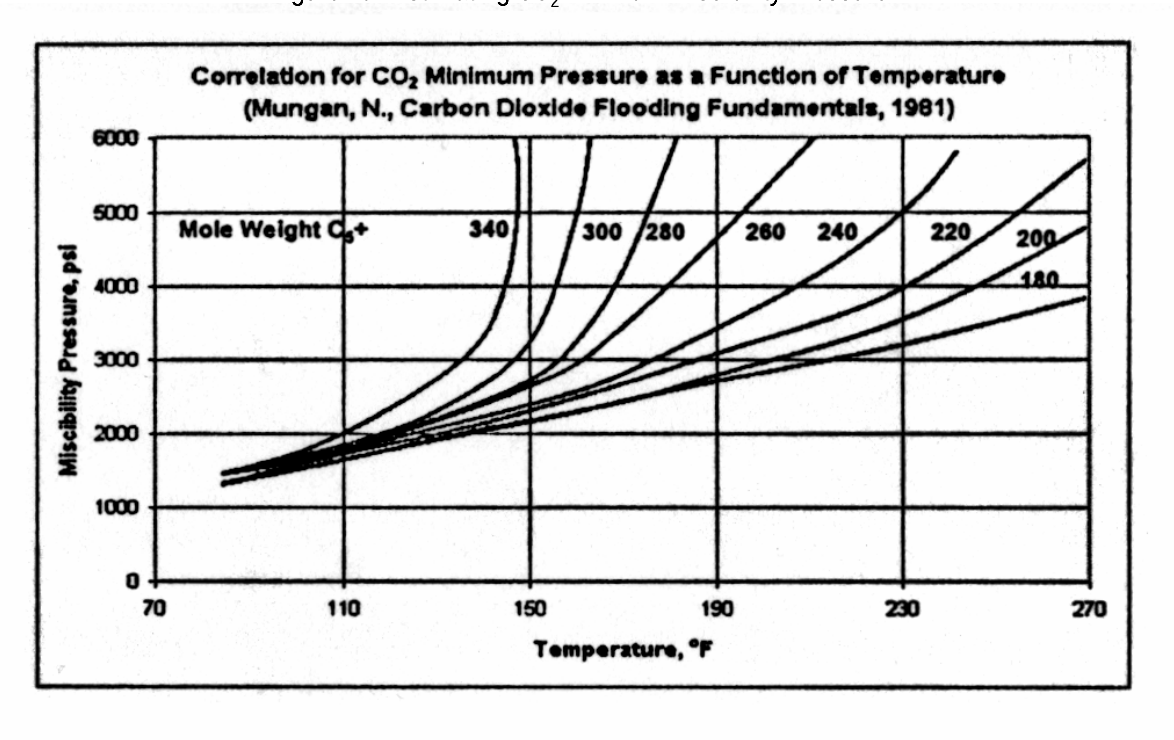
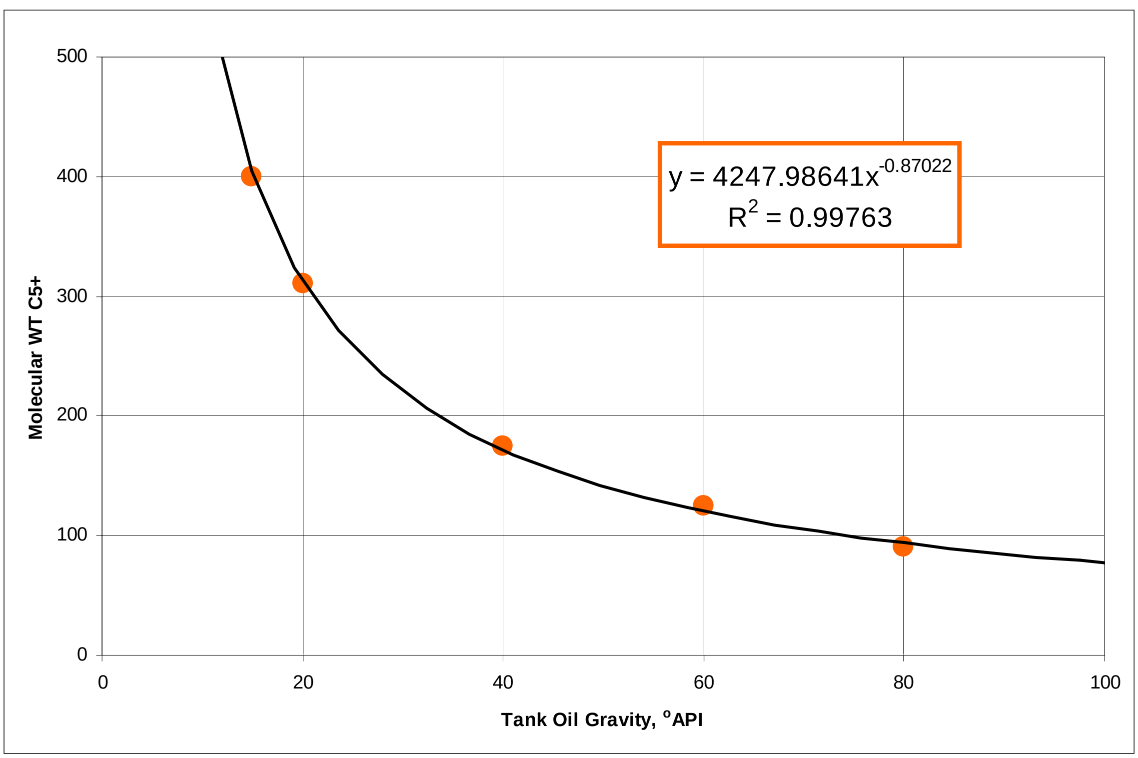



Figure 11. Correlation of MW C5+ to Tank Oil Gravity



***5.5 CALCULATING OIL RECOVERY.*** The study utilized *$CO_2$-PROPHET* to calculate incremental oil produced using $CO_2$-EOR. *$CO_2$-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) as part of the DOE Class I cost share program. The specific project was "Post Waterflood $CO_2$ Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (DOE Contract No. DE-FC22-93BC14960). *$CO_2$-PROPHET* was developed as an alternative to the DOE's $CO_2$ miscible flood predictive model, *$CO_2$PM*. According to the developers of the model, *$CO_2$-PROPHET* has more capabilities and fewer limitations than *$CO_2$PM*. For example, according to the above cited report, *$CO_2$-PROPHET* performs two main operations that provide a more robust calculation of oil recovery than available from *$CO_2$PM*:

- *$CO_2$-PROPHET* generates streamlines for fluid flow between injection and production wells, and
- The model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.)

Appendix A discusses, in more detail, the *$CO_2$-PROPHET* model and the calibration of this model with an industry standard reservoir simulator.

*Even with these improvements, it is important to note the $CO_2$-PROPHET is still primarily a "screening-type" model, and lacks some of the key features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators.*

***5.6 ASSEMBLING THE COST MODEL.*** A detailed, up-to-date $CO_2$-EOR Cost Model was developed by the study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the $CO_2$ recycle plant; (4) constructing a $CO_2$ spur-line from the main $CO_2$ trunkline to the oil field; and, (5) various miscellaneous costs.

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced $CO_2$. A variety of $CO_2$ purchase and reinjection costs options are available to the model user. (Appendix B provides additional details on the Cost Model for $CO_2$-EOR prepared by this study.)

***5.7 CONSTRUCTING AN ECONOMICS MODEL.*** The economic model used by the study is an industry standard cash flow model that can be run on a either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price. A variety of oil prices are available to the model user. Table 12 provides an example of the Economic Model for $CO_2$-EOR used by the study.

***5.8 PERFORMING SENSITIVITY ANALYSES.*** A series of sensitivity analyses were prepared to better understand how differences in oil prices, $CO_2$ supply costs and financial risk hurdles could impact the volumes of oil that would be economically produced by $CO_2$-EOR from California's oil basins and major oil reservoirs.

- Two technology cases were examined. As discussed in more detail in Chapter 2, the study examined the application of two $CO_2$-EOR options — "Traditional Practices" and "State-of-the-art" Technology.
- Two oil prices were considered. A \$25 per barrel oil price was used to represent the moderate oil price case; a \$35 per barrel oil price was used to represent the availability of a variety of economic incentives and/or the continuation of the current high oil price situation.
- Two $CO_2$ supply costs were considered. The high $CO_2$ cost was set at \$1.25 per Mcf (5% of the oil price) to represent the costs of a new transportation system bringing natural $CO_2$ to California's oil basins. A lower $CO_2$ supply cost equal to \$0.50 per Mcf (2% of the oil price) was included to represent the potential future availability of low-cost $CO_2$ from industrial and power plants as part of $CO_2$ storage.

# Table 12. Economic Model Established by the Study

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pattern-Level Cashflow Model | | **Advanced Technology** | | | | | | | | | | | |
| **State** | | | | | | | | | | | | | |
| **Field** | | | | New Injectors | 0.51 | | | 21 | | | | | |
| **Formation** | | | | Existing Injectors | 0.00 | | | | | | | | |
| **Depth** | | | | Convertable Producers | 0.49 | | | | | | | | |
| **Distance from Trunkline (mi)** | | | | New Producers | 0.0 | | | | | | | | |
| **# of Patterns** | | | | Existing Producers | 1.09 | | | | | | | | |
| **Miscibility:** | **Miscible** | | | | | | | | | | | | |
| | **Year** | **0** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
| CO2 Injection (MMcf) | | | 731 | 731 | 731 | 731 | 731 | 731 | 731 | 682 | 656 | 656 | 656 |
| H2O Injection (Mbw) | | | 183 | 183 | 183 | 183 | 183 | 183 | 183 | 207 | 220 | 220 | 220 |
| | | | | | | | | | | | | | |
| Oil Production (Mbbl) | | | - | 11 | 136 | 88 | 62 | 76 | 62 | 53 | 38 | 39 | 38 |
| H2O Production (MBw) | | | 579 | 568 | 339 | 275 | 275 | 249 | 236 | 222 | 246 | 250 | 253 |
| CO2 Production (MMcf) | | | - | 0 | 187 | 394 | 444 | 466 | 515 | 556 | 537 | 528 | 524 |
| | | | | | | | | | | | | | |
| CO2 Purchased (MMcf) | | | 731 | 730 | 543 | 337 | 286 | 265 | 215 | 127 | 119 | 128 | 132 |
| CO2 Recycled (MMcf) | | | - | 0 | 187 | 394 | 444 | 466 | 515 | 556 | 537 | 528 | 524 |
| | | | | | | | | | | | | | |
| Oil Price ($/Bbl) | **$ 25.00** | | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 |
| Gravity Adjustment | **35** | Deg | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 |
| Gross Revenues ($M) | | | $ - | $ 305 | $ 3,714 | $ 2,409 | $ 1,695 | $ 2,066 | $ 1,692 | $ 1,433 | $ 1,033 | $ 1,049 | $ 1,041 |
| Royalty ($M) | **-12.5%** | | $ - | $ (38) | $ (464) | $ (301) | $ (212) | $ (258) | $ (212) | $ (179) | $ (129) | $ (131) | $ (130) |
| Severance Taxes ($M) | **-5.0%** | | $ - | $ (13) | $ (162) | $ (105) | $ (74) | $ (90) | $ (74) | $ (63) | $ (45) | $ (46) | $ (46) |
| Ad Valorum ($M) | **-2.5%** | | $ - | $ (7) | $ (81) | $ (53) | $ (37) | $ (45) | $ (37) | $ (31) | $ (23) | $ (23) | $ (23) |
| Net Revenue($M) | | | $ - | $ 247 | $ 3,006 | $ 1,950 | $ 1,372 | $ 1,672 | $ 1,370 | $ 1,160 | $ 836 | $ 849 | $ 843 |
| **Capital Costs ($M)** | | | | | | | | | | | | | |
| New Well - D&C | | $ (274) | | | | | | | | | | | |
| Reworks - Producers to Producers | | $ (54) | | | | | | | | | | | |
| Reworks - Producers to Injectors | | $ (23) | | | | | | | | | | | |
| Reworks - Injectors to Injectors | | $ - | | | | | | | | | | | |
| Surface Equipment (new wells only) | | $ (81) | | | | | | | | | | | |
| Recycling Plant | | $ - | $ (1,147) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Trunkline Construction | | $ (4) | | | | | | | | | | | |
| Total Capital Costs | | $ (436) | $ (1,147) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **CO2 Costs ($M)** | | | | | | | | | | | | | |
| Total CO2 Cost ($M) | | | $ (913.1) | $ (913) | $ (726) | $ (519) | $ (469) | $ (447) | $ (398) | $ (298) | $ (283) | $ (292) | $ (296) |
| **O&M Costs** | | | | | | | | | | | | | |
| Operating & Maintenance ($M) | | | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) |
| Lifting Costs ($/bbl) | **$ 0.25** | | $ (145) | $ (145) | $ (119) | $ (91) | $ (84) | $ (81) | $ (75) | $ (69) | $ (71) | $ (72) | $ (73) |
| G&A | **20%** | | (50) | (50) | (44) | (39) | (38) | (37) | (36) | (34) | (35) | (35) | (35) |
| Total O&M Costs | | | $ (298) | $ (298) | $ (267) | $ (233) | $ (225) | $ (221) | $ (213) | $ (206) | $ (209) | $ (211) | $ (211) |
| | | | | | | | | | | | | | |
| Net Cash Flow ($M) | | $ (436) | $ (2,357) | $ (964) | $ 2,014 | $ 1,197 | $ 678 | $ 1,003 | $ 758 | $ 656 | $ 343 | $ 347 | $ 335 |
| Cum. Cash Flow | | $ (436) | $ (2,794) | $ (3,757) | $ (1,744) | $ (546) | $ 132 | $ 1,135 | $ 1,893 | $ 2,549 | $ 2,893 | $ 3,240 | $ 3,575 |
| Discount Factor | **15%** | 1.00 | 0.87 | 0.76 | 0.66 | 0.57 | 0.50 | 0.43 | 0.38 | 0.33 | 0.28 | 0.25 | 0.21 |
| Disc. Net Cash Flow | | $ (436) | $ (2,050) | $ (729) | $ 1,324 | $ 685 | $ 337 | $ 434 | $ 285 | $ 215 | $ 98 | $ 86 | $ 72 |
| Disc. Cum Cash Flow | | $ (436) | $ (2,486) | $ (3,215) | $ (1,891) | $ (1,206) | $ (869) | $ (435) | $ (150) | $ 64 | $ 162 | $ 248 | $ 320 |
| | | | | | | | | | | | | | |
| **NPV (BTx)** | 25% | ($401) | | | | | | | | | | | |
| **NPV (BTx)** | 20% | $79 | | | | | | | | | | | |
| **NPV (BTx)** | 15% | $805 | | | | | | | | | | | |
| **NPV (BTx)** | 10% | $1,954 | | | | | | | | | | | JAF2004054.XLS |
| **IRR (BTx)** | | 20.69% | | | | | | | | | | | |

## Table 12. Economic Model Established by the Study (Cont'd)

| | Pattern-Level Cashflow Model | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **State** | | | | | | | | | | | | | | | |
| | **Field** | | | | | | | | | | | | | | | |
| | **Formation** | | | | | | | | | | | | | | | |
| | **Depth** | | | | | | | | | | | | | | | |
| | **Distance from Trunkline (mi)** | | | | | | | | | | | | | | | |
| | **# of Patterns** | | | | | | | | | | | | | | | |
| | **Miscibility:** | **Miscible** | | | | | | | | | | | | | | |
| | | **Year** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** | **25** |
| 1 | CO2 Injection (MMcf) | | 656 | 656 | 656 | 656 | 656 | 656 | 656 | 656 | 416 | - | - | - | - | - |
| 2 | H2O Injection (Mbw) | | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 340 | 548 | 548 | 161 | - | - |
| | | | | | | | | | | | | | | | | |
| 3 | Oil Production (Mbbl) | | 41 | 58 | 57 | 52 | 38 | 26 | 23 | 21 | 19 | 19 | 17 | 4 | - | - |
| 4 | H2O Production (MBw) | | 245 | 229 | 224 | 216 | 223 | 224 | 222 | 222 | 226 | 289 | 411 | 131 | - | - |
| 5 | CO2 Production (MMcf) | | 533 | 530 | 543 | 565 | 579 | 600 | 608 | 613 | 590 | 442 | 221 | 47 | - | - |
| | | | | | | | | | | | | | | | | |
| 6 | CO2 Purchased (MMcf) | | 123 | 126 | 113 | 91 | 78 | 56 | 48 | 43 | - | - | - | - | - | - |
| 7 | CO2 Recycled (MMcf) | | 533 | 530 | 543 | 565 | 579 | 600 | 608 | 613 | 416 | - | - | - | - | - |
| | | | | | | | | | | | | | | | | |
| 8 | Oil Price ($/Bbl) | **$ 25.00** | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ 25.00 | $ - | $ - |
| | Gravity Adjustment | **35** | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ 27.25 | $ - | $ - |
| 9 | Gross Revenues ($M) | | $ 1,109 | $ 1,583 | $ 1,551 | $ 1,420 | $ 1,038 | $ 695 | $ 638 | $ 575 | $ 523 | $ 526 | $ 463 | $ 120 | $ - | $ - |
| 10 | Royalty ($M) | **-12.5%** | $ (139) | $ (198) | $ (194) | $ (177) | $ (130) | $ (87) | $ (80) | $ (72) | $ (65) | $ (66) | $ (58) | $ (15) | $ - | $ - |
| 12 | Severance Taxes ($M) | **-5.0%** | $ (49) | $ (69) | $ (68) | $ (62) | $ (45) | $ (30) | $ (28) | $ (25) | $ (23) | $ (23) | $ (20) | $ (5) | $ - | $ - |
| 13 | Ad Valorum ($M) | **-2.5%** | $ (24) | $ (35) | $ (34) | $ (31) | $ (23) | $ (15) | $ (14) | $ (13) | $ (11) | $ (12) | $ (10) | $ (3) | $ - | $ - |
| 11 | Net Revenue($M) | | $ 898 | $ 1,281 | $ 1,255 | $ 1,149 | $ 840 | $ 562 | $ 516 | $ 465 | $ 423 | $ 426 | $ 375 | $ 97 | $ - | $ - |
| | **Capital Costs ($M)** | | | | | | | | | | | | | | | |
| | New Well - D&C | | | | | | | | | | | | | | | |
| | Reworks - Producers to Producers | | | | | | | | | | | | | | | |
| | Reworks - Producers to Injectors | | | | | | | | | | | | | | | |
| | Reworks - Injectors to Injectors | | | | | | | | | | | | | | | |
| | Surface Equipment (new wells only) | | | | | | | | | | | | | | | |
| | Recycling Plant | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Trunkline Construction | | | | | | | | | | | | | | | |
| | Total Capital Costs | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | **CO2 Costs ($M)** | | | | | | | | | | | | | | | |
| | Total CO2 Cost ($M) | | $ (287) | $ (291) | $ (277) | $ (255) | $ (242) | $ (220) | $ (212) | $ (207) | $ (104) | $ - | $ - | $ - | $ - | $ - |
| | **O&M Costs** | | | | | | | | | | | | | | | |
| | Operating & Maintenance ($M) | | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ (103) | $ - | $ - |
| | Lifting Costs ($/bbl) | **$ 0.25** | $ (71) | $ (72) | $ (70) | $ (67) | $ (65) | $ (62) | $ (61) | $ (61) | $ (61) | $ (77) | $ (107) | $ (34) | $ - | $ - |
| | G&A | **20%** | (35) | (35) | (35) | (34) | (34) | (33) | (33) | (33) | (33) | (36) | (42) | (27) | - | - |
| | Total O&M Costs | | $ (210) | $ (210) | $ (208) | $ (205) | $ (202) | $ (199) | $ (198) | $ (197) | $ (198) | $ (216) | $ (252) | $ (165) | $ - | $ - |
| | | | | | | | | | | | | | | | | |
| | Net Cash Flow ($M) | | $ 401 | $ 781 | $ 769 | $ 689 | $ 396 | $ 143 | $ 106 | $ 61 | $ 122 | $ 209 | $ 123 | $ (68) | $ - | $ - |
| | Cum. Cash Flow | | $ 3,976 | $ 4,757 | $ 5,526 | $ 6,216 | $ 6,612 | $ 6,755 | $ 6,862 | $ 6,923 | $ 7,045 | $ 7,254 | $ 7,377 | $ 7,309 | $ 7,309 | $ 7,309 |
| | Discount Factor | **15%** | 0.19 | 0.16 | 0.14 | 0.12 | 0.11 | 0.09 | 0.08 | 0.07 | 0.06 | 0.05 | 0.05 | 0.04 | 0.03 | 0.03 |
| | Disc. Net Cash Flow | | $ 75 | $ 127 | $ 109 | $ 85 | $ 42 | $ 13 | $ 9 | $ 4 | $ 7 | $ 11 | $ 6 | $ (3) | $ - | $ - |
| | Disc. Cum Cash Flow | | $ 395 | $ 521 | $ 630 | $ 715 | $ 757 | $ 771 | $ 779 | $ 783 | $ 791 | $ 802 | $ 808 | $ 805 | $ 805 | $ 805 |

## Table 12. Economic Model Established by the Study (Cont'd)

| | Pattern-Level Cashflow Model | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **State** | | | | | | | | | | | | | |
| | **Field** | | | | | | | | | | | | | |
| | **Formation** | | | | | | | | | | | | | |
| | **Depth** | | | | | | | | | | | | | |
| | **Distance from Trunkline (mi)** | | | | | | | | | | | | | |
| | **# of Patterns** | | | | | | | | | | | | | |
| | **Miscibility:** | **Miscible** | | | | | | | | | | | | |
| | | **Year** | **26** | **27** | **28** | **29** | **30** | **31** | **32** | **33** | **34** | **35** | **36** | |
| 1 | CO2 Injection (MMcf) | | - | - | - | - | - | - | - | - | - | - | - | 13,429 |
| 2 | H2O Injection (Mbw) | | - | - | - | - | - | - | - | - | - | - | - | 5,500 |
| | | | | | | | | | | | | | | |
| 3 | Oil Production (Mbbl) | | - | - | - | - | - | - | - | - | - | - | - | 979 |
| 4 | H2O Production (MBw) | | - | - | - | - | - | - | - | - | - | - | - | 6,354 |
| 5 | CO2 Production (MMcf) | | - | - | - | - | - | - | - | - | - | - | - | 10,022 |
| | | | | | | | | | | | | | | |
| 6 | CO2 Purchased (MMcf) | | - | - | - | - | - | - | - | - | - | - | - | 4,291 |
| 7 | CO2 Recycled (MMcf) | | - | - | - | - | - | - | - | - | - | - | - | 9,138 |
| | | | | | | | | | | | | | | |
| 8 | Oil Price ($/Bbl) | **$ 25.00** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| | Gravity Adjustment | **35** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 9 | Gross Revenues ($M) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 26,678 |
| 10 | Royalty ($M) | **-12.5%** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (3,335) |
| 12 | Severance Taxes ($M) | **-5.0%** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,167) |
| 13 | Ad Valorum ($M) | **-2.5%** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (584) |
| 11 | Net Revenue($M) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 21,592 |
| | **Capital Costs ($M)** | | | | | | | | | | | | | |
| | New Well - D&C | | | | | | | | | | | | | $ (274) |
| | Reworks - Producers to Producers | | | | | | | | | | | | | $ (54) |
| | Reworks - Producers to Injectors | | | | | | | | | | | | | $ (23) |
| | Reworks - Injectors to Injectors | | | | | | | | | | | | | $ - |
| | Surface Equipment (new wells only) | | | | | | | | | | | | | $ (81) |
| | Recycling Plant | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,147) |
| | Trunkline Construction | | | | | | | | | | | | | $ (4) |
| | Total Capital Costs | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,583) |
| | **CO2 Costs ($M)** | | | | | | | | | | | | | |
| | Total CO2 Cost ($M) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (7,649) |
| | **O&M Costs** | | | | | | | | | | | | | |
| | Operating & Maintenance ($M) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (2,377) |
| | Lifting Costs ($/bbl) | **$ 0.25** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (1,833) |
| | G&A | **20%** | - | - | - | - | - | - | - | - | - | - | - | $ (842) |
| | Total O&M Costs | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ (5,052) |
| | | | | | | | | | | | | | | |
| | Net Cash Flow ($M) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 7,309 |
| | Cum. Cash Flow | | $ 7,309 | $ 7,309 | $ 7,309 | $ 7,309 | $ 7,309 | $7,309 | $7,309 | $7,309 | $7,309 | $7,309 | $7,309 | |
| | Discount Factor | **15%** | 0.03 | 0.02 | 0.02 | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | |
| | Disc. Net Cash Flow | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 805 |
| | Disc. Cum Cash Flow | | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | $ 805 | |

- <u>Two minimum rate of return (ROR) hurdles were considered</u>, a high ROR of 25%, before tax, and a lower 15% ROR, before tax. The high ROR hurdle incorporates a premium for the market, reservoir and technology risks inherent in using $CO_2$-EOR in a new reservoir setting. The lower ROR hurdle represents application of $CO_2$-EOR after the geologic and technical risks have been mitigated with a robust program of field pilots and demonstrations.

These various technology, oil price, $CO_2$ supply cost and rate of return hurdles were combined into four scenarios, as set forth below:

- The first scenario captures how $CO_2$-EOR technology has been applied and has performed in the past. In this low technology, high risk scenario, called "Traditional Practices", there is little economically feasible potential in this oil producing region for using $CO_2$-EOR.

- The second scenario, entitled "State-of-the-art", assumes that the technology progress in $CO_2$-EOR, achieved in other areas, is successfully applied to the geologically complex oil reservoirs of California. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to these complex oil reservoirs. However, because of limited sources of $CO_2$, these supply costs are high, equal to a per Mcf cost of 5% of the oil price) and significantly hamper economic feasibility of using $CO_2$-EOR.

- The third scenario, entitled "Risk Mitigation," examines how the economic potential of $CO_2$-EOR could be increased through a combination of state production tax reductions, improved federal investment tax credits and federal/state royalty relief that together would provide an equivalent of a $10 per barrel increase in the marker price (WTI) of crude oil.

- In the fourth scenario, entitled "Ample Supplies of $CO_2$," low-cost "EOR-ready" $CO_2$ supplies (equal to a per Mcf cost of 2% of the oil price) are aggregated from various high concentration $CO_2$ vents and sources. These would be augmented, in the longer-term, from low $CO_2$ concentration industrial sources including combustion and electric generation plants. Capture of industrial $CO_2$ emissions would be part of national efforts for reducing greenhouse gas emissions.

# 6. RESULTS BY BASIN

***6.1 SAN JOAQUIN BASIN***. The San Joaquin Basin within Districts 4 and 5 is located in central California, Figure 12. It is the dominant oil producing basin in California, having produced or proven nearly 16 billion barrels of crude oil. Oil production from this basin has steadily declined in recent years, Table 13.

Table 13. San Joaquin Basin Oil Production

| | Annual Oil Production | |
|---|---|---|
| | (MMBbls/Yr) | (MBbls/D) |
| 2000 | 217 | 596 |
| 2001 | 209 | 572 |
| 2002 | 206 | 564 |
| 2003(e) | 200 | 548 |

Improved recovery projects provided the great bulk (123 million barrels) of the basin's oil production in 2002. Of this, 20 million barrels was from waterflooding and gas injection. Two expansion waterflood projects (at Lost Hills and Elk Hills) were approved in 2002.

**San Joaquin Basin Oil Fields**. While best known for its massive heavy oil fields, such as Kern River and Midway-Sunset, the San Joaquin Basin also contains large light oil fields that may be amenable to miscible $CO_2$-EOR, such as:

- Elk Hills, Stevens
- Coalinga, E. Extension, Nose Area
- Kettleman, N. Dome, Temblor
- Cuyama South, Homan

Figure 12. California Oil Districts Containing the San Joaquin Basin


*California Department of Conservation, Division of Oil, Gas and Geothermal Resources (2002).*

JAF02318.PPT

Assuming adequate oil prices and availability of low-cost $CO_2$ supplies, these four fields could serve as "anchors" for the initial $CO_2$–EOR activity in the basin that then could extend to other fields. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) in these four major "anchor" light oil reservoirs are provided in Table 14.

Table 14. Status of San Joaquin Basin "Anchor" Fields/Reservoirs, 2001

| Anchor Fields/Reservoirs | | Cumulative Production (MMBbls) | Proved Reserves (MMBbls) | Remaining Oil In-Place (MMBbls) |
|---|---|---|---|---|
| 1 | Elk Hills (Stevens) | 691 | 117 | 1,557 |
| 2 | Coalinga, E. Extension (Nose Area) | 468 | 4 | 464 |
| 3 | Kettleman Dome, N. (Temblor) | 407 | 2 | 891 |
| 4 | Cuyama S. (Homan) | 223 | 2 | 605 |

These four large "anchor" reservoirs, each with about 500 million (or more) barrels of ROIP, are technically amenable for miscible $CO_2$-EOR. Table 15 provides the reservoir and oil properties for these reservoirs and their current secondary oil recovery activities.

Table 15. Reservoir Properties and Improved Oil Recovery Activity, "Anchor" Oil Fields/Reservoirs

| Anchor Fields | | Depth (ft) | Oil Gravity (°API) | Active Waterflood or Gas Injection |
|---|---|---|---|---|
| 1 | Elk Hills (Stevens) | 5,500 | 35 | Injecting 44 MMB water annually; new project in Stevens (NW) reservoir. |
| 2 | Coalinga, E. Extension (Nose Area) | 7,800 | 30 | No current activity reported. |
| 3 | Kettleman, N. Dome (Temblor) | 8,000 | 36 | No current activity reported. |
| 4 | Cuyama S. (Homan) | 4,000 | 32 | Injecting 11 MMB water annually. |

In addition to the four "anchor" light oil reservoirs, the San Joaquin Basin contains several large and moderately deep heavy oil reservoirs. These reservoirs tend to have lower oil recoveries (10% to 30% OOIP), are not well suited to thermal EOR, and respond only moderately to waterflooding. These fields could become "secondary target" oil reservoirs and candidates for immiscible $CO_2$–EOR. They include:

- Elk Hills, Main Area, Upper
- Fruitvale, Etchegoin-Chanac
- Cymric, Phacoides/Carneros

These "secondary target" oil reservoirs, each with 400 million barrels (or more) of OOIP have been screened as immiscible $CO_2$–EOR candidates for the San Joaquin Basin. The reservoir and oil properties for these fields and their latest secondary oil recovery activity are shown on Table 16.

Table 16. Reservoir Properties and Improved Oil Recovery Activity
"Secondary Target" Oil Fields/Reservoirs

| Secondary Fields/Reservoirs | | Depth (ft) | Oil Gravity (°API) | Waterflood or Gas Injection |
|---|---|---|---|---|
| 1 | Elk Hills (Main Area/Upper) | 3,000 | 22.5 | Injecting 16 MMcf/d of gas annually |
| 2 | Fruitvale (Etchegoin-Chanac) | 3,730 | 19 | Injecting 12 MM barrels of water annually |
| 3 | Cymric (Phacoides/Carneros) | 3,800 | 23 | No appreciable activity |

***Past $CO_2$-EOR Projects***. Two $CO_2$-EOR projects have been conducted in the San Joaquin Basin, at North Coles Levee and at Lost Hills.

*North Coles Levee*. ARCO (now BP) initiated $CO_2$ injection in the Stevens Sand of the North Coles Levee field in 1981 through 1984. $CO_2$ injection involved two adjacent 10 acre patterns and one 10 acre line drive pattern:

- The $CO_2$ was from a hydrogen plant at ARCO's refinery. A total of 1.7 Bcf of $CO_2$ was injected before loss of $CO_2$ supply due to refinery closure.
- The pilot was reported to have successfully mobilized oil in the $CO_2$ swept area, in the range of 15% to 20% HCPV.
- However, problems with pattern balance and $CO_2$ injection design led to high $CO_2$ to oil ratios, of 7 to 32 Mcf/barrel of oil produced.

Reservoir simulation indicated that a larger, more balanced $CO_2$ slug of 62% to 82% HCPV would have provided a considerably higher oil recovery, as shown in Table 17.

Table 17. Reservoir Simulation of Oil Recovery vs. $CO_2$ Injection, N. Coles Levee

| $CO_2$ Injection (% HCPV) | Oil Recovery (% OOIP) | Oil Recovery Efficiency (Mcf $CO_2$/Bbl) |
|---|---|---|
| 41% | 13.2-15.4% | 5.5-6.4 |
| 62% | 16.7-18.5% | 6.9-7.5 |
| 82% | 19.9-20.7% | 7.6-8.6 |

*<u>Lost Hills</u>*. In 2000, ChevronTexaco initiated a pilot water alternating gas (WAG) $CO_2$ injection project in the Lost Hills field. During its life, 1.9 Bcf of $CO_2$ was injected into the Etchegoin oil reservoir. The project was suspended in 2002, after a two year assessment period.

***Future $CO_2$-EOR Potential***. The San Joaquin Basin contains 24 large deep light oil reservoirs that are candidates for miscible $CO_2$-EOR technology. In addition, the basin has 5 large moderately deep, moderately heavy oil reservoirs that could benefit from immiscible $CO_2$–EOR. The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $25 per barrel, $CO_2$ supply costs of 5% of oil price ($1.25/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under "Traditional Practices", involving miscible EOR with a modest volume $CO_2$ injection, the technical and economic potential for $CO_2$-EOR in the San Joaquin Basin is low. With Base Case financial conditions, only 3 of the 24 light oil reservoirs are economic, providing 50 million barrels of additional oil recovery from the San Joaquin Basin.

Applying "State-of-the-art" technology, involving miscible EOR, with high volume $CO_2$ injection and immiscible $CO_2$-EOR, the technically recoverable potential for $CO_2$-EOR increases to over 2 billion barrels. The use of "State-of-the-art" $CO_2$ miscible EOR technology and immiscible $CO_2$ in heavy oil fields (with a lower investment rate of return hurdle of 15% before tax), enables over 1 billion barrels to become economically recoverable. The number of economically favorable oil reservoirs increase to 15 (out of 29), Table 18.

Table 18. Economic Oil Recovery Potential Under Base Case Financial Conditions, San Joaquin Basin.

| $CO_2$-EOR Technology | No. of Reservoirs Studied | Original Oil In-Place (MMBbls) | Technical Potential (MMBbls) | Economic Potential (No. of Reservoirs) | Economic Potential (MMBbls) |
|---|---|---|---|---|---|
| "Traditional Practices" | 24 | 8,906 | 860 | 3 | 50 |
| "State of Art Technology" | 29 | 11,909 | 2,040 | 15 | 1,060 |

Improved financial conditions consisting of "risk mitigation" and lower-cost $CO_2$ supplies would significantly increase the economically recoverable oil volumes from the San Joaquin Basin, particularly when applied with "State-of-the-art" $CO_2$-EOR Technology. With the benefit of these more favorable financial conditions, up to 1,780 million barrels of additional oil (in 24 major oil reservoirs) would become economically recoverable from the San Joaquin Basin, Table 19.

Table 19. Economic Oil Recovery Potential with
More Favorable Financial Conditions, San Joaquin Basin

| More Favorable Conditions | No. of Economic Reservoirs | Economic Potential (MMBbls) |
|---|---|---|
| Plus: “Risk Mitigation”* | 21 | 1,380 |
| Plus: Low Cost $CO_2$** | 24 | 1,780 |

**Assumes an equivalent of $10 per barrel is added to the oil price, adjusted for market factors*

***Assumes reduced $CO_2$ supply costs of 2% of oil price or $0.70 per Mcf*

***6.2 LOS ANGELES BASIN***. The Los Angeles Basin within District 1 encompasses the southern portion of California, Figure 13. Oil production in this basin has remained steady due to waterflooding, Table 20.

Table 20. Los Angels Basin Oil Production

| | Annual Oil Production | |
|---|---|---|
| | (MMBbls/Yr) | (MBbls/D) |
| 2000 | 16.9 | 46 |
| 2001 | 16.8 | 46 |
| 2002 | 16.9 | 46 |
| 2003(e) | 16.7 | 46 |

The great bulk of the oil currently produced in the Los Angeles Basin is incremental oil from the application of improved recovery. For example, of the 16.9 million barrels of total oil produced in 2002, about 13 million barrels was due to waterflooding. The two largest waterfloods are in the Wilmington Field with 372 million barrels of annual water injection and in the Inglewood Field with 90 million barrels of annual water injection. Two new waterflooding expansions were approved in year 2002, both for the Inglewood Field.

Figure 13. California Oil District Containing the Los Angeles Basin


*California Department of Conservation, Division of Oil, Gas and Geothermal Resources (2002).*

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**Los Angeles Basin Oil Fields**. The Los Angeles Basin contains a number of world scale light oil fields that may be amenable to miscible $CO_2$- EOR, such as:

- Santa Fe Springs
- Dominguez

These two major oil fields could serve as the "anchor" sites for the initial $CO_2$ projects that could later extend to other fields in the basin. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for these two major "anchor" light oil reservoirs are set forth in Table 21.

Table 21. Status of Los Angeles Basin "Anchor" Fields/Reservoirs, 2001

| Anchor Fields/Reservoirs | | Cumulative Production (MMBbls) | Proved Reserves (MMBbls) | Remaining Oil In-Place (MMBbls) |
|---|---|---|---|---|
| 1 | Santa Fe Springs (Main Area) | 624 | 10 | 1,976 |
| 2 | Dominquez (Plio-Miocene) | 274 | 5 | 403 |

These two large "anchor" reservoirs, one with nearly 2,000 million barrels of ROIP, are amenable to $CO_2$-EOR. Table 22 provides the reservoir and oil properties for these two reservoirs and their current secondary oil recovery activities.

Table 22. Reservoir Properties and Improved Oil Recovery Activity,
"Anchor" Oil Fields/Reservoirs

| | Anchor Fields/Reservoirs | Depth (ft) | Oil Gravity (°API) | Active Waterflood or Gas Injection |
|---|---|---|---|---|
| 1 | Santa Fe Springs (Main Area) | 5,400 | 33 | Injecting 27 MM barrels of water annually. |
| 2 | Dominquez (Pliocene-Miocene) | 4,000 | 30 | No appreciable activity |

In addition to the two "anchor" light oil reservoirs, numerous relatively deep and moderately heavy oil fields exist in the Los Angeles Basin. Prior experience with $CO_2$ injection in certain of these fields, using immiscible $CO_2$-EOR, indicates that these fields could become "secondary target" fields for immiscible $CO_2$-EOR.

Two such "secondary target" fields, each with 500 million barrels or more of OOIP, are shown on Table 23. These two fields may be amenable to immiscible $CO_2$-EOR based on their reservoir properties and their positive response to waterflooding.

Table 23. Reservoir Properties and Improved Oil Recovery Activity, Los Angeles Basin "Secondary Target" Oil Fields/Reservoirs

| | Secondary Fields/Reservoirs | Depth (ft) | Oil Gravity (°API) | Active Waterflood or Gas Injection |
|---|---|---|---|---|
| 1 | Brea Olinda (Pliocene-Miocene) | 3,240 | 18.4 | Injecting 3.0 MM barrels of water annually |
| 2 | Torrance (Main) | 3,740 | 19 | Injecting 0.4 MM barrels of water annually |

Access and environmental issues would need to be fully examined to establish how much of the potential in the "anchor" or "secondary target" oil fields could be developed with $CO_2$-EOR in the Los Angeles Basin.

***Past $CO_2$-EOR Projects***. The Los Angeles Basin has also seen an active history of $CO_2$ based enhanced oil recovery.

Wilmington. The Long Beach Oil Development company initiated an immiscible $CO_2$ project in the Fault Block Tar Zone (14 °API reservoir oil at 2,300 feet) of the Wilmington field, in 1982 through 1987. The $CO_2$ flood was a 330 acre project involving 42 producing wells and 8 injection wells in a line drive pattern.

- The $CO_2$ was from the stack gas of the hydrogen units at Texaco's Wilmington refinery.
- The injected gas contained 85% $CO_2$ and 15% $N_2$.

- A total of 8.2 Bcf of gas (7 Bcf of $CO_2$) was injected in 4 years; recycling of produced gas continued through 1987.
- The project recovered an estimated 488,000 barrels of oil through August 1987.

According to the technical report, this immiscible $CO_2$-EOR project injected only about one third of the "ideal" volume of $CO_2$. Reservoir analysis by the company indicated that a larger volume of $CO_2$, additional injection wells, and a modified WAG ratio would have significantly improved results, Table 24.

Table 24. Oil Recovery vs. Volume of $CO_2$ Injection

| $CO_2$ Injection (Bcf) | Oil Recovery (MBbls) | Oil Recovery Efficiency (Mcf $CO_2$/Bbl) |
|---|---|---|
| Actual: 7 | 488 | 14.3 |
| Ideal: 23 | 6,660* | 3.5 |

**Equal to 9.8% 00IP*

Other $CO_2$ Injection Projects. Four additional $CO_2$ injection projects are reported by the State of California and briefly discussed in the technical literature:

- East Coyote, Huadle Dome Unit: this $CO_2$ WAG project started in 1982 and stopped in 1984, with 183 MMcf $CO_2$ injected.
- Huntington Beach, Onshore Area A-37: this cyclic $CO_2$ project started in 1981 and stopped in 1982, with 183 MMcf $CO_2$ injected.
- Wilmington, Fault Block I Ranger: this $CO_2$ WAG project started in 1983 and stopped in 1986, with 2,330 MMcf $CO_2$ injected.
- Wilmington, Fault Block III Tar: this $CO_2$ WAG project started in 1981 and stopped in 1996, with 3,490 MMcf $CO_2$ injected.

***Future $CO_2$-EOR Potential.*** The Los Angeles Basin contains 15 large light oil reservoirs, such as Dominquez (Pliocene) and Santa Fe Springs (Main Area) that are candidates for miscible $CO_2$-EOR. In addition, the basin has 21 large moderately deep, moderately heavy oil fields, such as Huntington Beach and Torrance that have low oil recoveries and could benefit from enhanced oil recovery.

Under "Traditional Practices" (and Base Case financial conditions, defined above), there are no economically attractive oil reservoirs for miscible $CO_2$ flooding in the Los Angeles Basin. Applying "State-of-the-art Technology" (involving higher volume $CO_2$ injection and immiscible EOR) (and a lower investment rate of return hurdle of 15%, before tax), the number of economically favorable oil reservoirs the Los Angeles Basin increases to 14, providing 700 million barrels of additional oil recovery, Table 25.

Table 25. Economic Oil Recovery Potential Under
Base Case Financial Conditions, Los Angeles Basin.

| $CO_2$-EOR Technology | No. of Reservoirs Studied | Original Oil In-Place (MMBbls) | Technical Potential (MMBbls) | Economic Potential | |
|---|---|---|---|---|---|
| | | | | (No. of Reservoirs) | (MMBbls) |
| "Traditional Practices" | 15 | 7,828 | 470 | - | - |
| "State of Art Technology" | 36 | 14,072 | 1,490 | 14 | 700 |

Improved financial conditions, consisting of "risk mitigation" and of lower-cost $CO_2$ supplies, would significantly increase the economical volumes of oil that could be produced by $CO_2$-EOR from the Los Angeles Basin (when combined with "State-of-the-art" $CO_2$-EOR technology). With the benefit of more favorable financial conditions, up to 1,370 million barrels of additional economic oil recovery (from 28 major oil reservoirs) would be possible in the Los Angeles Basin, Table 26.

Table 26. Economic Oil Recovery Potential with
More Favorable Financial Conditions, Los Angeles Basin

| More Favorable Financial Conditions | No. of Reservoirs | (Million Bbls) |
|---|---|---|
| Plus: “Risk Mitigation”* | 22 | 1,290 |
| Plus: Low Cost $CO_2$** | 28 | 1,370 |

**Assumes an equivalent of $10 per barrel is added to the oil price, adjusted for market factors*
***Assumes reduced $CO_2$ supply costs of 2% of oil price or $0.70 per Mcf*

***6.3 COASTAL BASIN***. The Coastal Basin within Districts 2 and 3 is on the western coastline of California, stretching from the northern border of Los Angeles to the southern border of the San Francisco Bay area, Figure 14. Oil and gas production in this basin has steadily declined during recent years, Table 27.

Table 27. Coastal Basin Oil Production

| | Annual Oil Production | |
|---|---|---|
| | (MMBls/Yr) | (MBbls/D) |
| 2000 | 14.1 | 39 |
| 2001 | 13.5 | 37 |
| 2002 | 13.3 | 36 |
| 2003(e) | 13.0 | 36 |

The Coastal Basin has seen a moderately active program of secondary oil recovery. Of the 13.3 million barrels of oil produced in 2002, about 4 million barrels was due to waterflooding. The largest current waterflood project in the basin is in the Ventura oil field, with 45.6 million barrels of water injected in 2002. No new improved oil recovery projects were approved in year 2002.

Figure 14. California Oil Districts Containing the Coastal Basin


*California Department of Conservation, Division of Oil, Gas and Geothermal Resources (2002).*

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***Coastal Basin Oil Fields***. The Coastal Basin contains two large mature light oil fields that are being produced by waterflooding, and thus may be amenable to miscible $CO_2$-EOR:

- Ventura
- San Miguelito

These two fields could serve as the "anchor" sites for the initial $CO_2$–EOR projects in the basin that could later be extended to other fields. The cumulative oil production, proved reserves and remaining oil in place (ROIP) for these two "anchor" light oil fields are set forth in Table 28.

Table 28. Status of Coastal Basin "Anchor" Fields/Reservoirs, 2001

| Anchor Fields/Reservoirs | | Cumulative Production (MMBbls) | Proved Reserves (MMBbls) | Remaining Oil In Place (MMBbls) |
|---|---|---|---|---|
| 1 | Ventura (All reservoirs) | 964 | 48 | 2,310 |
| 2 | San Miguelito (All reservoirs) | 113 | 25 | 169 |

These two large "anchor" fields, one with over 2,000 million barrels of ROIP, may be favorable for miscible $CO_2$ -EOR, based on their reservoir properties, Table 29.

Table. 29 Reservoir Properties and Improved Oil Recovery Activity, "Anchor" Oil Fields/Reservoirs

| | Anchor Fields | Depth (ft) | Oil Gravity (°API) | Active Waterflood or Gas Injection |
|---|---|---|---|---|
| 1 | Ventura (All) | 6,500-11,000 | 29-33 | Injecting 46 MMB annually |
| 2 | San Miguelito (all) | 5,000-8,410 | 30-31 | Injecting 5 MMB annually |

***Past $CO_2$-EOR Projects***. A pilot $CO_2$ injection project was initiated in the Ventura field, D-6 (c) reservoir in 1988, with 215 MMcf of $CO_2$ injected. No further results are publicly reported.

***Future $CO_2$-EOR Potential***. The Coastal Basin (Santa Maria and Ventura basins) contains 20 large deep light oil reservoirs that are candidates for miscible $CO_2$-EOR. In addition, the basin has 3 large moderately deep, moderately heavy oil reservoirs that are candidates for immiscible $CO_2$-EOR.

Using "Traditional Practices" would not enable the "stranded oil" in the Coastal Basin to become economic. Using "State-of-the-art" technology (and a lower investment rate of return hurdle of 15%, before tax) would enable 3 reservoirs in the Coastal Basin to become economically favorable for $CO_2$ flooding, Table 30.

Table 30. Economic Oil Recovery Potential Under Current Conditions, Coastal Basin.

| $CO_2$-EOR Technology | No. of Reservoirs Studied | Original Oil In-Place (MMBbls) | Technical Potential (MMBbls) | Economic Potential | |
|---|---|---|---|---|---|
| | | | | (No. of Reservoirs) | (MMBbls) |
| "Traditional Practices" | 20 | 4,692 | 450 | - | - |
| "State of Art Technology" | 23 | 5,883 | 1,090 | 3 | 70 |

Improved financial conditions of "risk mitigation" and lower cost $CO_2$ supplies would enable $CO_2$-EOR in the Coastal Basin to recover up to 830 million barrels of oil (from 16 major reservoirs), Table 31.

Table 31. Economic Oil Recovery Potential with
More Favorable Financial Conditions, Coastal Basin

| More Favorable Financial Conditions | No. of Economic Reservoirs | Economic Potential (MMBbls) |
|---|---|---|
| Plus: "Risk Mitigation"* | 16 | 830 |
| Plus: Low Cost $CO_2$** | 16 | 830 |

**Assumes an equivalent of $10 per barrel is added to the oil price, adjusted for market factors*

***Assumes reduced $CO_2$ supply costs of 2% of oil price or $0.70 per Mcf*

# Appendix A

# Using *$CO_2$-PROPHET* for Estimating Oil Recovery

## Model Development

The study utilized the *$CO_2$-PROPHET* model to calculate the incremental oil produced by $CO_2$-EOR from the large California oil reservoirs. *$CO_2$-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) as part of the DOE Class I cost share program. The specific project was “Post Waterflood $CO_2$ Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir” (DOE Contract No. DE-FC22-93BC14960). *$CO_2$-PROPHET* was developed as an alternative to the DOE’s $CO_2$ miscible flood predictive model, *$CO_2$PM*.

## Input Data Requirements

The input reservoir data for operating *$CO_2$-PROPHET* are from the Major Oil Reservoirs Data Base. Default values exist for input fields lacking data. Key reservoir properties that directly influence oil recovery are:

- Residual oil saturation,
- Dykstra-Parsons coefficient,
- Oil and water viscosity,
- Reservoir pressure and temperature, and
- Minimum miscibility pressure.

A set of three relative permeability curves for water, $CO_2$ and oil are provided (or can be modified) to ensure proper operation of the model.

## Calibrating $CO_2$-PROPHET

The *$CO_2$-PROPHET* model was calibrated by Advanced Resources with an industry standard reservoir simulator, *GEM*. The primary reason for the calibration was to determine the impact on oil recovery of alternative permeability distributions within a multi-layer reservoir. A second reason was to better understand how the absence of a gravity override function in *$CO_2$-PROPHET* might influence the calculation of oil recovery. *$CO_2$-PROPHET* assumes a fining upward permeability structure.

The San Joaquin Basin's Elk Hills (Stevens) reservoir data set was used for the calibration. The model was run in the miscible $CO_2$-EOR model using one hydrocarbon pore volume of $CO_2$ injection.

The initial comparison of *$CO_2$-PROPHET* with *GEM* was with fining upward and coarsening upward (opposite of fining upward) permeability cases in *GEM*. All other reservoir, fluid and operational specifications were kept the same. As Figure A-1 depicts, the *$CO_2$-PROPHET* output is bounded by the two *GEM* reservoir simulation cases of alternative reservoir permeability structures in an oil reservoir.

A second comparison of *$CO_2$-PROPHET* and *GEM* was for randomized permeability (within the reservoir modeled with multiple layers). The two *GEM* cases are High Random, where the highest permeability value is at the top of the reservoir, and Low Random, where the lowest permeability is at the top of the reservoir. The permeability values for the other reservoir layers are randomly distributed among the remaining layers. As Figure A-2 shows, the *$CO_2$-PROPHET* results are within the envelope of the two *GEM* reservoir simulation cases of random reservoir permeability structures in an oil reservoir.

Based on the calibration, the *$CO_2$-PROPHET* model seems to internally compensate for the lack of a gravity override feature and appears to provide an average calculation of oil recovery, neither overly pessimistic nor overly optimistic. As such, *$CO_2$-PROPHET* seems well suited for what it was designed — providing project scoping and preliminary results to be verified with more advanced evaluation and simulation models.

## Comparison of *$CO_2$-PROPHET* and *$CO_2$PM*

According to the *$CO_2$-PROPHET* developers, the model performs two main operations that provide a more robust calculation of oil recovery than available from *$CO_2$PM*:

Figure A-1. *CO2-PROPHET* and *GEM*: Comparison to Upward Fining and Coarsening Permeability Cases of *GEM*

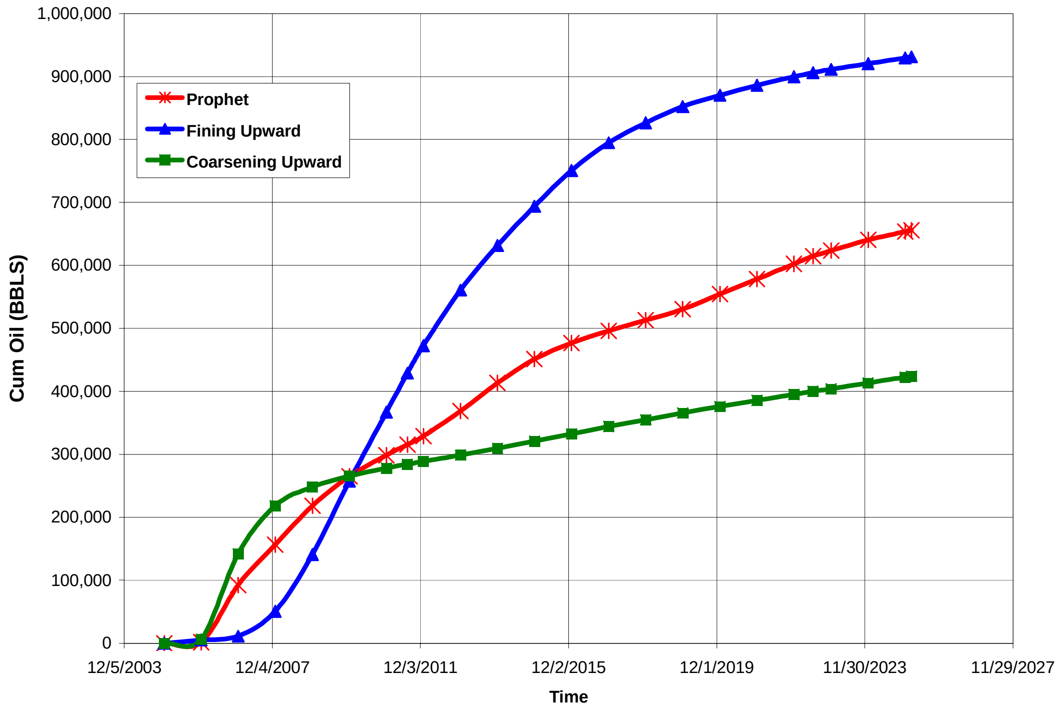
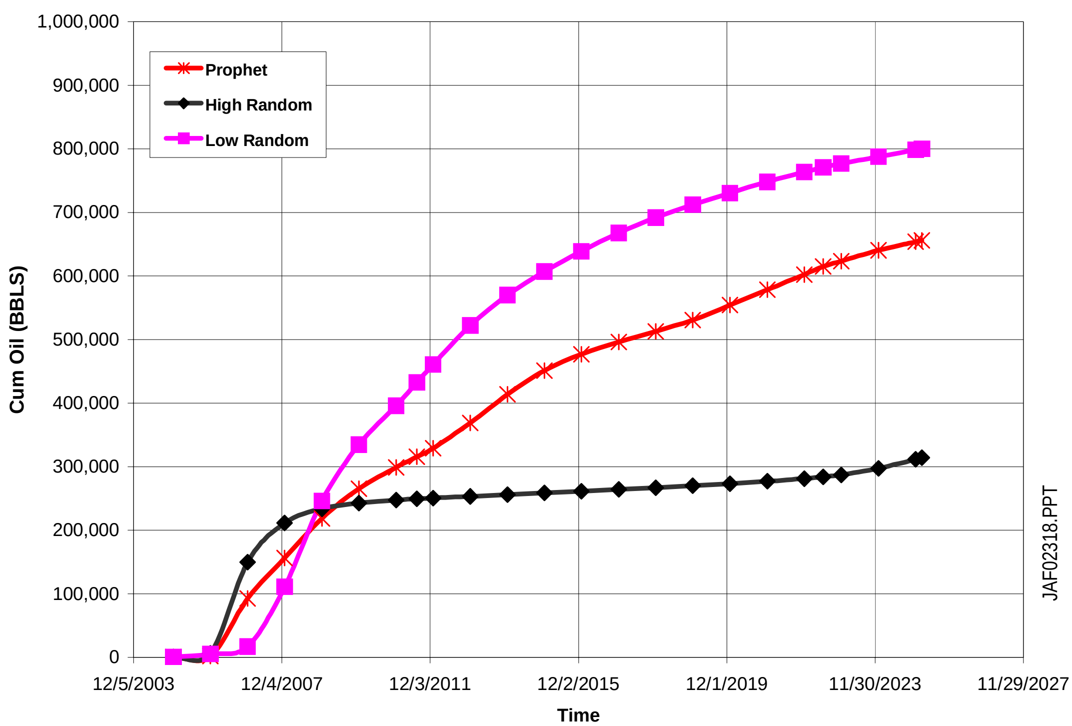



Figure A-2. $CO_2$-*PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*

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*$CO_2$-PROPHET* generates streamlines for fluid flow between injection and production wells, and

- The model then performs oil displacement and recovery calculations along the streamlines. (A finite difference routine is used for the oil displacement calculations.)

Other key features of *$CO_2$-PROPHET* and its comparison with the technical capability of *$CO_2$PM* are also set forth below:

- Areal sweep efficiency in *$CO_2$-PROPHET* is handled by incorporating streamlines that are a function of well spacing, mobility ratio and reservoir heterogeneity, thus eliminating the need for using empirical correlations, as incorporated into *$CO_2$PM*.
- Mixing parameters, as defined by Todd and Longstaff, are used in *$CO_2$-PROPHET* for simulation of the miscible $CO_2$ process, particularly $CO_2$/oil mixing and the viscous fingering of $CO_2$.
- A series of reservoir patterns, including 5 spot, line drive, and inverted 9 spot, among others, are available in *$CO_2$-PROPHET*, expanding on the 5 spot only reservoir pattern option available in *$CO_2$PM*.
- *$CO_2$-PROPHET* can simulate a variety of recovery processes, including continuous miscible $CO_2$, WAG miscible $CO_2$ and immiscible $CO_2$, as well as waterflooding. *$CO_2$PM* is limited to miscible $CO_2$.

# Appendix B

# California $CO_2$-EOR Cost Model

## Cost Model for $CO_2$-Based Enhanced Oil Recovery ($CO_2$-EOR)

This appendix provides documentation for the cost module of the desktop $CO_2$-EOR policy and analytical model (COTWO) developed by Advanced Resources for DOE/FE-HQ. The sections of this cost documentation report are organized according to the normal sequence of estimating the capital and operating expenditures for a $CO_2$-EOR project:

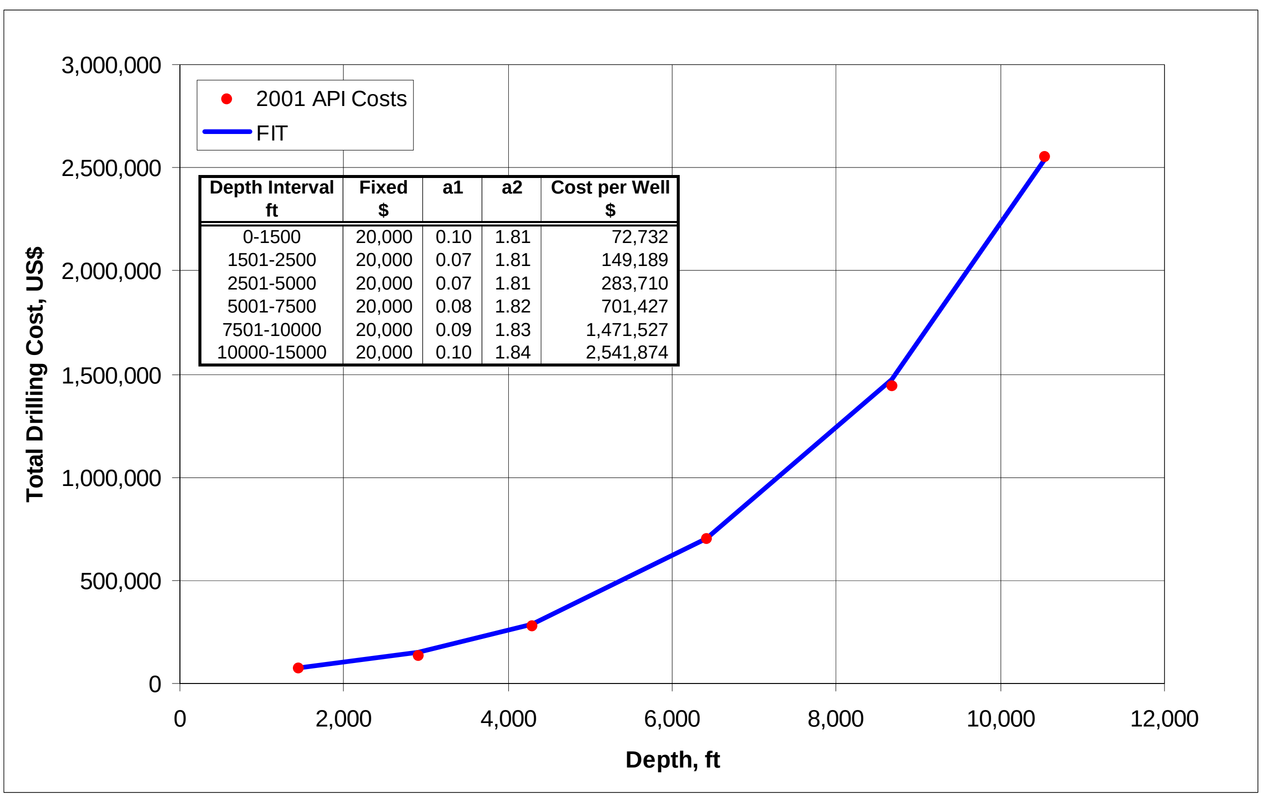
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for California.

The well D&C cost equation has a fixed cost constant for site preparation and other fixed cost items and a variable cost equation that increases exponentially with depth. The total equation is:

Well D&C Costs = $a_0 + a_1 D^{a2}$
Where: $a_0$ = \$20,000 (fixed)
$a_1$ ranges from 0.07 to 0.10, depending on depth
$a_2$ ranges from 1.81 to 1.84, depending on depth
D is well depth

Figure B-1 provides the details for the cost equation and illustrates the “goodness of fit” for the well D&C cost equation for California.

Figure B-1 – Oil Well D&C Costs for California




| Depth Interval ft | Fixed $ | a1 | a2 | Cost per Well $ |
|---|---|---|---|---|
| 0-1500 | 20,000 | 0.10 | 1.81 | 72,732 |
| 1501-2500 | 20,000 | 0.07 | 1.81 | 149,189 |
| 2501-5000 | 20,000 | 0.07 | 1.81 | 283,710 |
| 5001-7500 | 20,000 | 0.08 | 1.82 | 701,427 |
| 7501-10000 | 20,000 | 0.09 | 1.83 | 1,471,527 |
| 10000-15000 | 20,000 | 0.10 | 1.84 | 2,541,874 |

2. <u>Lease Equipment Costs for New Producing Wells.</u> The costs for equipping a new oil production well are based on data reported by the EIA in their 2002 EIA “Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations” report. This survey provides estimated lease equipment costs for 10 wells producing with artificial lift, from depths ranging from 2,000 to 12,000 feet, into a central tank battery.

The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$

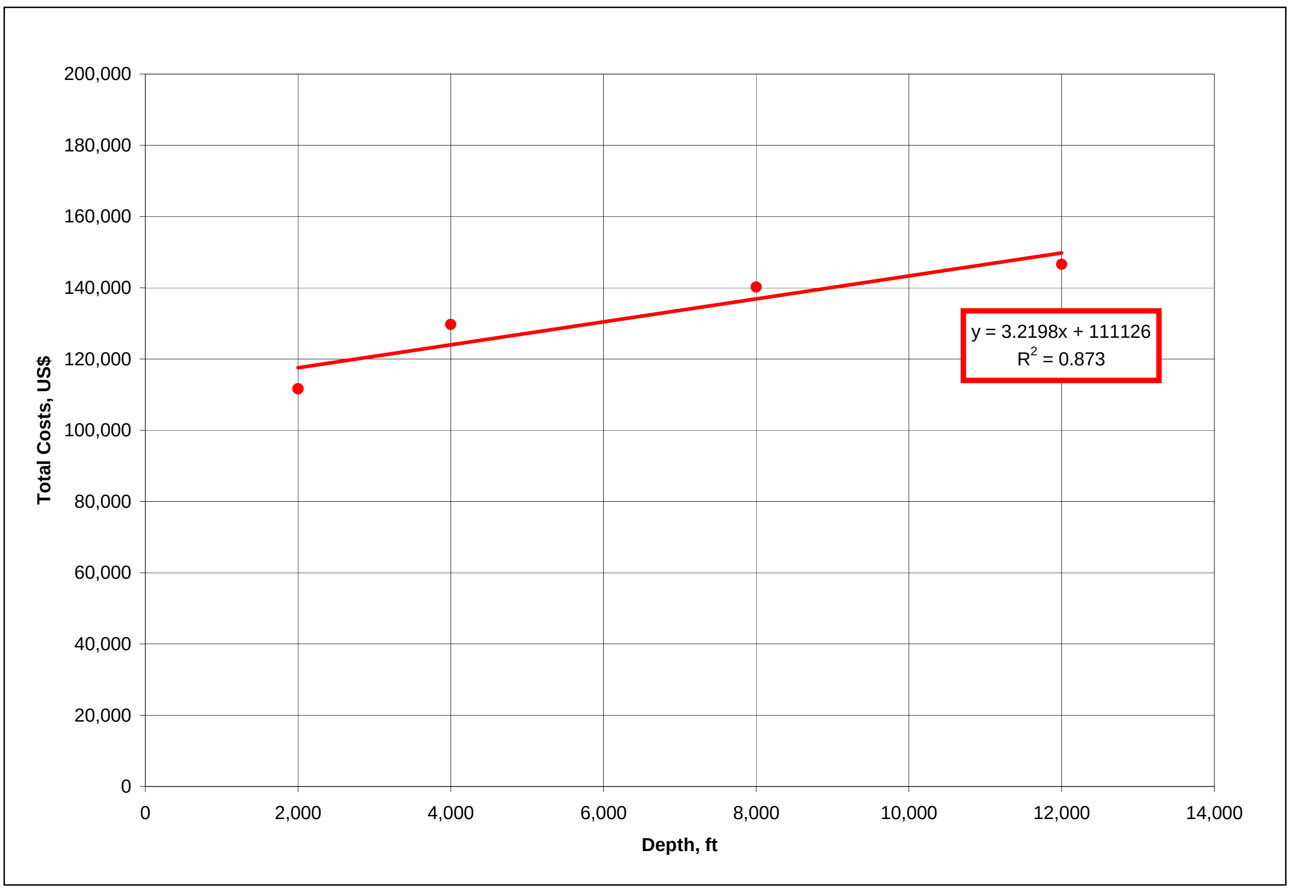
Where: $c_o$ = \$111,126 (fixed)

$c_1$ = \$3.22 per foot

D is well depth

Figure B-2 illustrates the application of the lease equipping cost equation for a new oil production well as a function of depth.

Figure B-2 – Lease Equipping Cost for a New Oil Production Well in California vs. Depth



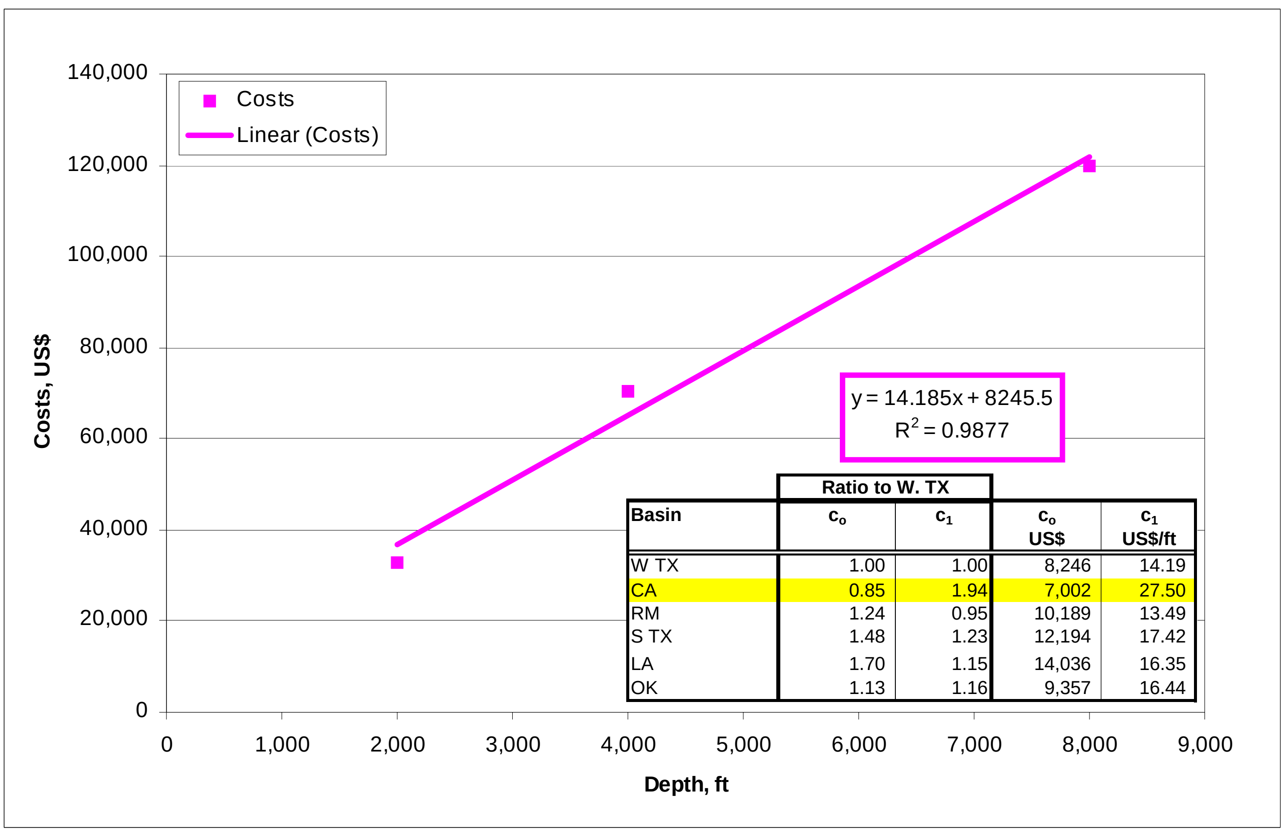
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in California include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation for California is:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: $c_o$ = \$7,002 (fixed)
$c_1$ = \$27.50 per foot
D is well depth

Figure B-3 illustrates the application of the lease equipping cost equation for a new injection well as a function of depth for West Texas. The West Texas cost data for lease equipment provides the foundation for the California cost equation.

Figure B-3 – Lease Equipping Costs for a New Injection Well in West Texas vs. Depth




| Basin | Ratio to W. TX $c_o$ | Ratio to W. TX $c_1$ | $c_o$ US\$ | $c_1$ US\$/ft |
|---|---|---|---|---|
| W TX | 1.00 | 1.00 | 8,246 | 14.19 |
| CA | 0.85 | 1.94 | 7,002 | 27.50 |
| RM | 1.24 | 0.95 | 10,189 | 13.49 |
| S TX | 1.48 | 1.23 | 12,194 | 17.42 |
| LA | 1.70 | 1.15 | 14,036 | 16.35 |
| OK | 1.13 | 1.16 | 9,357 | 16.44 |

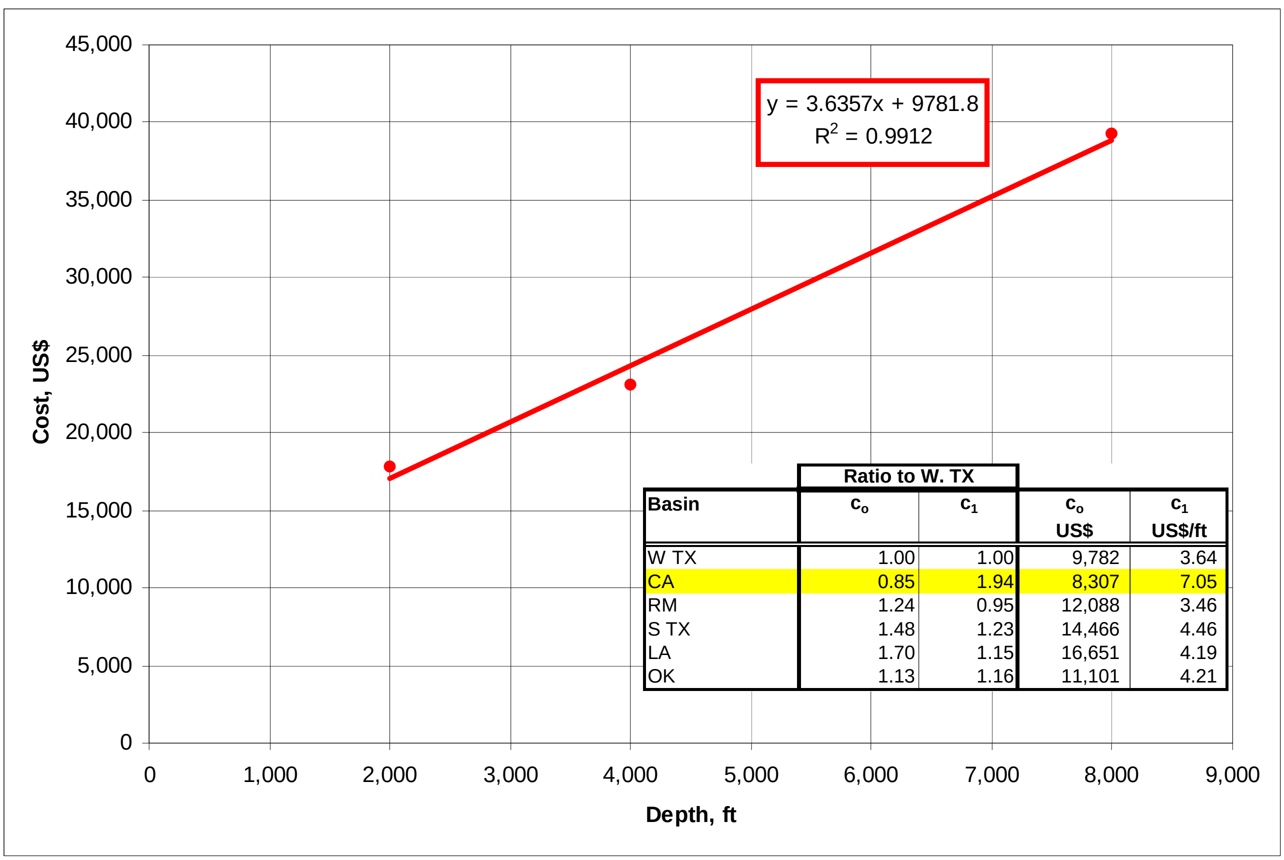
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into $CO_2$ and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are already in place on the lease.

The existing well conversion costs include a fixed cost component and a depth-related cost component, which varies based on the required surface pressure and tubing length. The equation for California is:

Well Conversion Costs = $c_0 + c_1D$
Where: $c_o$ = \$8,307 (fixed)
$c_1$ = \$7.05 per foot
D is well depth

Figure B-4 illustrates the average cost of converting an existing producer into an injection well for West Texas. The West Texas cost data for converting wells provide the foundation for the California cost equation.

Figure B-4 – Cost of Converting Existing Production Wells into Injection Wells in West Texas vs. Depth




| | Ratio to W. TX | | | |
|---|---|---|---|---|
| Basin | $c_o$ | $c_1$ | $c_o$ US$ | $c_1$ US$/ft |
| W TX | 1.00 | 1.00 | 9,782 | 3.64 |
| CA | 0.85 | 1.94 | 8,307 | 7.05 |
| RM | 1.24 | 0.95 | 12,088 | 3.46 |
| S TX | 1.48 | 1.23 | 14,466 | 4.46 |
| LA | 1.70 | 1.15 | 16,651 | 4.19 |
| OK | 1.13 | 1.16 | 11,101 | 4.21 |

5. <u>Costs of Reworking an Existing Waterflood Production or Injection Well for $CO_2$-EOR (First Rework).</u> The reworking of existing oil production or $CO_2$-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation for California is:

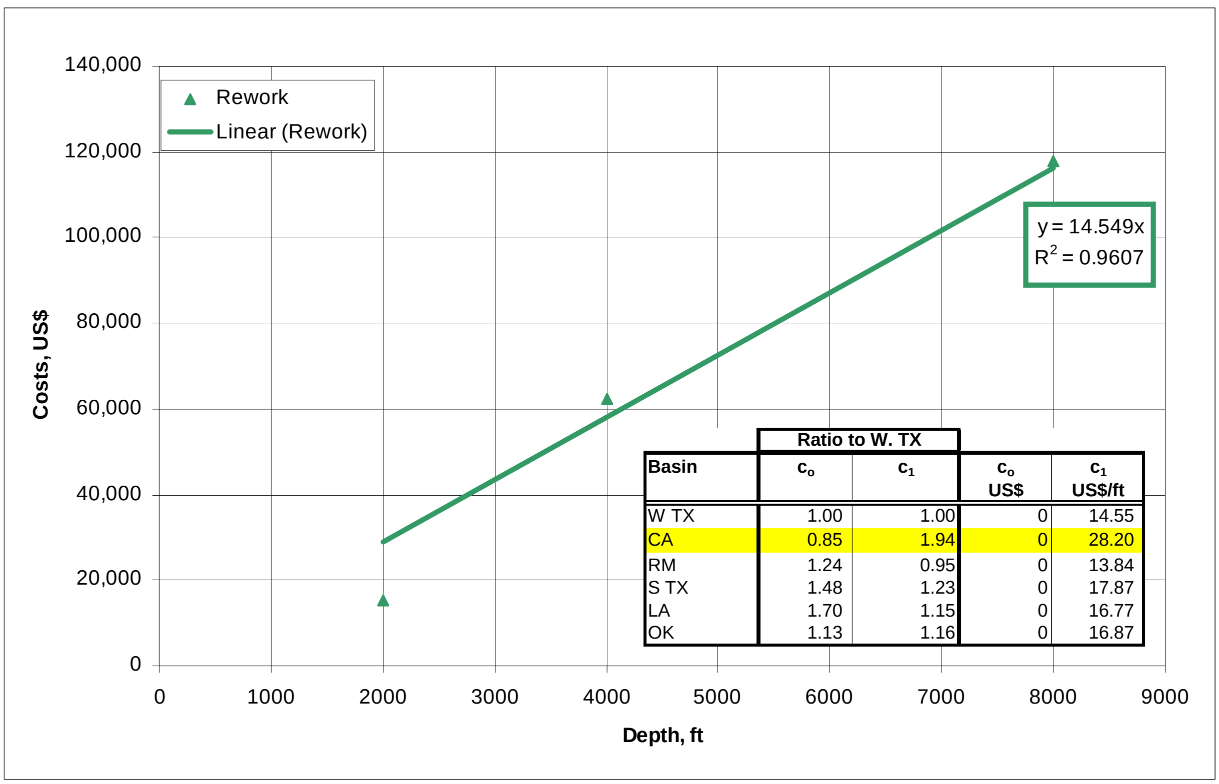
Well Rework Costs = $c_1D$

Where: $c_1$ = \$28.20 per foot)

D is well depth

Figure B-5 illustrates the average cost of well conversion as a function of depth for West Texas. The West Texas cost data for reworking wells provides the foundation for the California cost equation.

Figure B-5 – Cost of Reworking an Existing Waterflood Production or Injection Well for $CO_2$-EOR in West Texas vs. Depth




| Basin | Ratio to W. TX $c_o$ | Ratio to W. TX $c_1$ | $c_o$ US$ | $c_1$ US$/ft |
|---|---|---|---|---|
| W TX | 1.00 | 1.00 | 0 | 14.55 |
| CA | 0.85 | 1.94 | 0 | 28.20 |
| RM | 1.24 | 0.95 | 0 | 13.84 |
| S TX | 1.48 | 1.23 | 0 | 17.87 |
| LA | 1.70 | 1.15 | 0 | 16.77 |
| OK | 1.13 | 1.16 | 0 | 16.87 |

6. <u>Annual O&M Costs, Including Periodic Well Workovers.</u> The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and California primary oil production O&M costs (Figure B-6) are used to estimate California secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table B-1.

Figure B-6 – Annual Lease O&M Costs for Primary Oil Production by Area

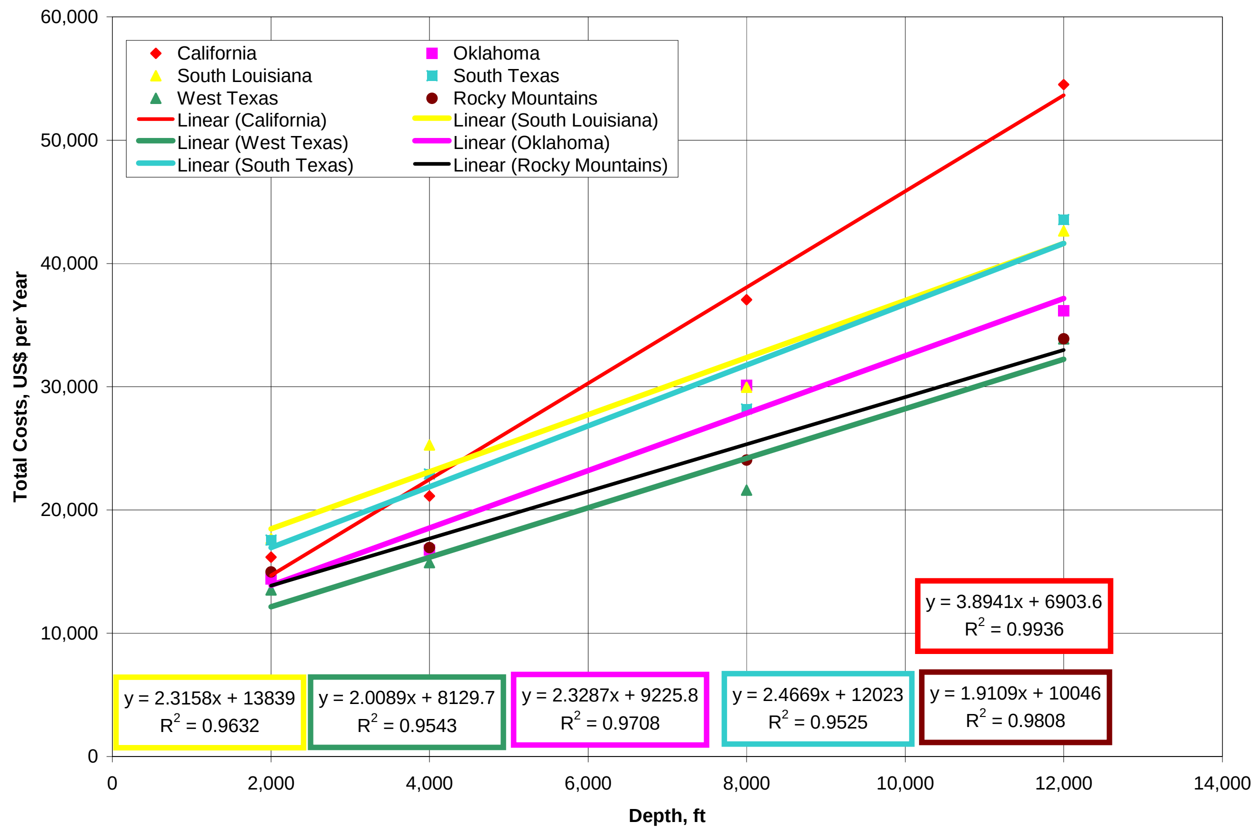



Table B-1 – Regional Lease O&M Costs and Their Relationship to West Texas

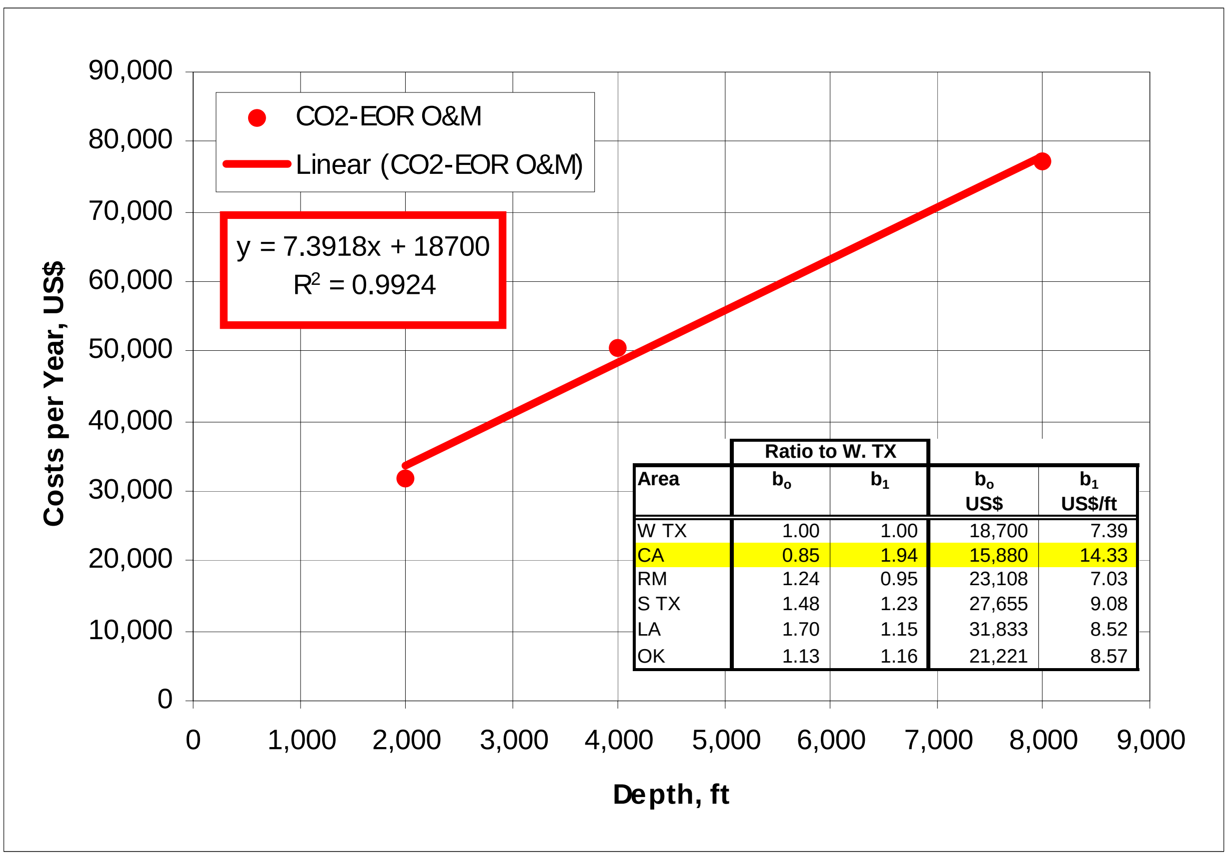
| Basin | $c_o$ US$ | $c_1$ US$/ft | Ratio to W. TX $c_o$ | Ratio to W. TX $c_1$ |
|---|---|---|---|---|
| West Texas | 8,130 | 2.01 | 1.00 | 1.00 |
| California | 6,904 | 3.89 | 0.85 | 1.94 |
| Rocky Mountain | 10,046 | 1.91 | 1.24 | 0.95 |
| South Texas | 12,023 | 2.47 | 1.48 | 1.23 |
| Louisiana | 13,839 | 2.32 | 1.70 | 1.15 |
| Oklahoma | 9,226 | 2.33 | 1.13 | 1.16 |

To account for the O&M cost differences between waterflooding and $CO_2$-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in $CO_2$-EOR projects. Liquid lifting are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for $CO_2$-EOR. (Liquid lifting costs for $CO_2$-EOR are discussed in a later section of this appendix.)

Figure B-7 shows the depth-relationship for $CO_2$-EOR O&M costs in West Texas. These costs were adjusted to develop O&M for California, shown in the inset of Figure B-7. The equation for California is:

Well O&M Costs = $b_0 + b_1D$
Where: $b_0$ = \$15,880 (fixed)
$b_1$ = \$14.33 per foot
D is well depth

Figure B-7 – Annual $CO_2$-EOR O&M Costs for West Texas




| Area | Ratio to W. TX $b_o$ | Ratio to W. TX $b_1$ | $b_o$ US\$ | $b_1$ US\$/ft |
|---|---|---|---|---|
| W TX | 1.00 | 1.00 | 18,700 | 7.39 |
| CA | 0.85 | 1.94 | 15,880 | 14.33 |
| RM | 1.24 | 0.95 | 23,108 | 7.03 |
| S TX | 1.48 | 1.23 | 27,655 | 9.08 |
| LA | 1.70 | 1.15 | 31,833 | 8.52 |
| OK | 1.13 | 1.16 | 21,221 | 8.57 |

7. <u>$CO_2$ Recycle Plant Investment Cost.</u> Operation of $CO_2$-EOR requires a recycling plant to capture and reinject the produced $CO_2$. The size of the recycle plant is based on peak $CO_2$ production and recycles requirements.

The cost of the recycling plant is set at $700,000 per MMcf/d of $CO_2$ capacity. As such, small $CO_2$-EOR project in the Stevens formation of the Asphalto field, with 20 MMcf/d of $CO_2$ reinjection, will require a recycling plant costing $14.3 million. A large project in the Stevens formation of the Elk Hills field, with 810 MMcf/d of $CO_2$ reinjection and 502 injectors, requires a recycling plant costing $567 million.

The model has three options for installing a $CO_2$ recycling plant. The default setting costs the entire plant one year prior to $CO_2$ breakthrough. The second option places the full $CO_2$ recycle plant cost at the beginning of the project (Year 0). The third option installs the $CO_2$ recycle plant in stages. In this case, half the plant is built (and half the cost is incurred) in the year of $CO_2$ breakthrough. The second half of the plant is built when maximum recycle capacity requirements are reached.

8. <u>Other COTWO Model Costs.</u>

a. <u>$CO_2$ Recycle O&M Costs.</u> The O&M costs of $CO_2$ recycling are indexed to energy costs and set at 1% of the oil price ($0.25 per Mcf @ $25 Bbl oil).

b. <u>Lifting Costs.</u> Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.25 per barrel. This cost includes liquid lifting, transportation and re-injection.

c. <u>$CO_2$ Distribution Costs.</u> The $CO_2$ distribution system is similar to the gathering systems used for natural gas. A distribution "hub" is constructed with smaller pipelines delivering purchased $CO_2$ to the project site.

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing $CO_2$ injection requirements. These range from $80,000 per mile for 4" pipe ($CO_2$ rate less than 15MMcf/d), $120,000 per mile for 6" pipe ($CO_2$ rate of 15 to 35 MMcf/d), $160,000 per mile for 8" pipe ($CO_2$ rate of 35 to 60 MMcf/d), and $200,000 per mile for pipe greater than 8" diameter ($CO_2$ rate greater than 60 MMcf/d). Aside from the injection volume, cost also depends on the distance from the $CO_2$ "hub" (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The $CO_2$ distribution cost equation for California is:

Pipeline Construction Costs = $150,000 + $C_D$*Distance
Where: $C_D$ is the cost per mile of the necessary pipe diameter (from the $CO_2$ injection rate)
Distance = 10.0 miles

d. G&A Costs. General and administrative (G&A) costs of 20% are added to well O&M and lifting costs.

e. Royalties. Royalty payments are assumed to be 12.5%.

f. Production Taxes. Severance and ad valorum taxes are set at 5.0% and 2.5%, respectively, for a total production tax of 7.5% on the oil production stream. Production taxes are taken following royalty payments.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for California ($1 per barrel) and the current gravity differential (-$0.25 per °API, from a basis of 30 °API) into the average wellhead oil price realized by each oil reservoir. The equation for California is:

Wellhead Oil Price = Oil Price + $1.00 – [$0.25*(30 -°API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 30 °API, the wellhead oil price is reduced; if the oil gravity is greater than 30 °API, the wellhead oil price is increased.