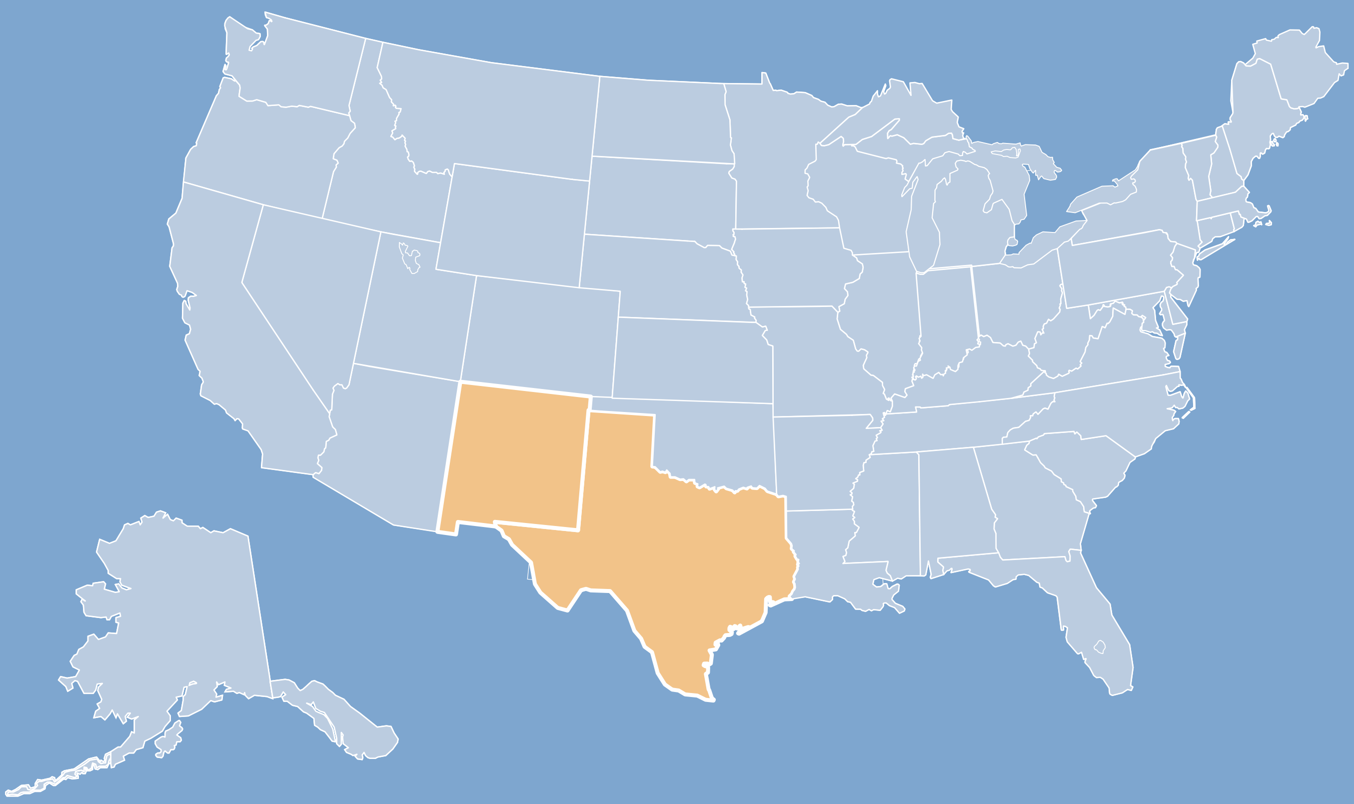
Basin Oriented Strategies for CO_2 Enhanced Oil Recovery:

PERMIAN BASIN



Prepared for

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Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by

Advanced Resources International

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1. SUMMARY OF FINDINGS

1.1 INTRODUCTION*.* The oil and gas producing regions of the Permian Basin, in New Mexico and West Texas (RR Districts 8 and 8A) have an original oil endowment of 95.4 billion barrels. Of this, 33.7 billion barrels or 35% will be recovered. As such, nearly 61.7 billion barrels of oil will be left in the ground, or “stranded”, following the use of today’s oil recovery practices. A major portion of this “stranded oil” is in reservoirs that appear to be technically and economically amenable to enhanced oil recovery (EOR) using carbon dioxide (CO_2) injection.

This report evaluates the future oil recovery potential in the large oil fields of the Permian Basin and the barriers that stand in the way of realizing this potential. The report then discusses how a concerted set of “basin oriented strategies” could help the Permian Basin’s oil production industry overcome these barriers and capture the large “stranded oil” prize.

1.2 ALTERNATIVE OIL RECOVERY STRATEGIES AND SCENARIOS. The report sets forth four scenarios for using CO_2-EOR to recover “stranded oil” in the Permian Basin producing region.

- The first scenario captures how CO_2-EOR technology has been applied and has performed in the past. This low technology, high-risk scenario is called “Traditional Practices”.
- The second scenario, entitled “State-of-the-art”, assumes that the technology progress in CO_2-EOR, achieved in recent years, is successfully applied in the Permian Basin. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations will help lower the risks inherent in applying new technology to these complex Permian Basin oil reservoirs.

- The third scenario, entitled “Risk Mitigation” examines how the economic potential of CO_2-EOR could be increased through a strategy involving state production tax reductions, federal investment tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to the price that the producer uses for making capital investment decisions for CO_2-EOR.
- The final scenario, entitled “Ample Supplies of CO_2,” examines a setting where low-cost, “EOR-ready” CO_2 supplies are aggregated from various industrial and natural sources. These CO_2 supply sources include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These supplies would be augmented, in the longer-term, from capture of low concentration CO_2 emissions from refineries and electric power plants. Capture of industrial CO_2 emissions could also be part of a national effort for reducing greenhouse gas emissions.

The CO_2-EOR potential of the Permian Basin is examined using these four bounding scenarios.

1.3 OVERVIEW OF FINDINGS. Twelve major findings emerge from the study of “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Permian Basin.”

1. Today’s oil recovery practices will leave behind a large resource of “stranded oil” in the Permian Basin. The original oil resource in the Permian Basin reservoirs is estimated at 95.4 billion barrels. To date, 33.7 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further oil recovery methods, 61.7 billion barrels of the Permian Basin’s oil resource will become “stranded”, Table 1.

Table 1. Permian Basin's Oil Resource and Reservoirs

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
New Mexico	62	13.1	3.9	9.2
West Texas	145	57.1	21.0	36.1
Data base Total	207	70.2	24.9	45.3
*B. Regional Total**	n/a	95.4	33.7	61.7

**Estimated from Permian Basin data on cumulative oil recovery and proved reserves, as of the end of 2002.*

2. A major portion of the "stranded oil" resource in the large oil reservoirs of the Permian Basin is amenable to CO_2 enhanced oil recovery. To address the "stranded oil" issue, Advanced Resources assembled a data base that contains 207 major Permian Basin oil reservoirs, accounting for 70% of the region's estimated ultimate oil production. Of these, 182 reservoirs, with 59.3 billion barrels of OOIP and 39.3 billion barrels of "stranded oil" (ROIP), were found to be favorable for CO_2-EOR, Table 2.

Table 2. Permian Basin's "Stranded Oil" Resources Amenable to CO_2-EOR

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
New Mexico	55	11.9	3.5	8.4
West Texas	127	47.4	16.5	30.9
TOTAL	182	59.3	20.0	39.3

3. Application of miscible CO_2-EOR would enable a significant portion of the Permian Basin's "stranded oil" to be recovered. The 182 large Permian Basin oil reservoirs (with 59.3 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The technically recoverable resource from applying miscible CO_2-EOR in these 182 large oil reservoirs ranges from 6,872 million barrels to 15,290 million barrels Table 3.

Table 3. Technically Recoverable Resource Using Miscible CO_2-EOR

	Miscible		Immiscible	
State	No. of Reservoirs	Technically Recoverable* (MMBbls)	No. of Reservoirs	Technically Recoverable* (MMBbls)
New Mexico	55	1,276-2,846	-	-
West Texas	127	5,596-12,444	-	-
TOTAL	182	6,872-15,290**	-	-

**Range in technically recoverable oil reflects the performance of "Traditional Practices" and "State-of-the-art" CO_2-EOR technology.*
***1 BBbls of tertiary incremental oil has already been recovered.*

4. A portion of Permian Basin's "stranded oil" is economically recoverable using "Traditional Practices" of CO_2 flooding technology. As shown above, "traditional" application of miscible CO_2-EOR technology (involving a relatively modest volume of CO_2 injection) to the 182 large reservoirs in the data base would enable nearly 6.9 billion barrels of "stranded oil" to become technically recoverable in the Permian Basin. With current costs for CO_2 in the Permian Basin (equal to $1.20 per Mcf) and a substantial risk premium (arising from uncertainties about future oil prices and the performance of CO_2-EOR technology) about 680 million barrels of this "stranded oil" could become economically recoverable at oil prices of $30 per barrel, as adjusted for gravity and location, Table 4. Some portion of the 680 million barrels is mobile oil that could have been recovered with more intense infill drilling and secondary (waterflooding) oil recovery practices.

Table 4. Economically Recoverable Resources Under Scenario #1:
"Traditional Practices" CO_2-EOR

State	No. of Reservoirs	OOIP (MMBbls)	Technically Recoverable (MMBbls)	Economically* Recoverable (MMBbls)
New Mexico	55	11,873	1,280	20
West Texas	127	47,395	5,600	660
TOTAL	182	59,268	6,880	680

**This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.20 per Mcf, and a ROR hurdle rate of 25% (before tax).*

5. Introduction of "State-of-the-art" CO_2-EOR technology, plus risk mitigation incentives and lower CO_2 costs, would enable 11.1 billion barrels of additional oil to become economically recoverable from the Permian Basin. With "State-of-the-art" CO_2-EOR technology, and its higher oil recovery efficiency (at oil prices of $30/Bbl and high cost CO_2), 7.7 billion barrels of the oil remaining in the Permian Basin's large oil reservoirs becomes economically recoverable, Scenario #2.

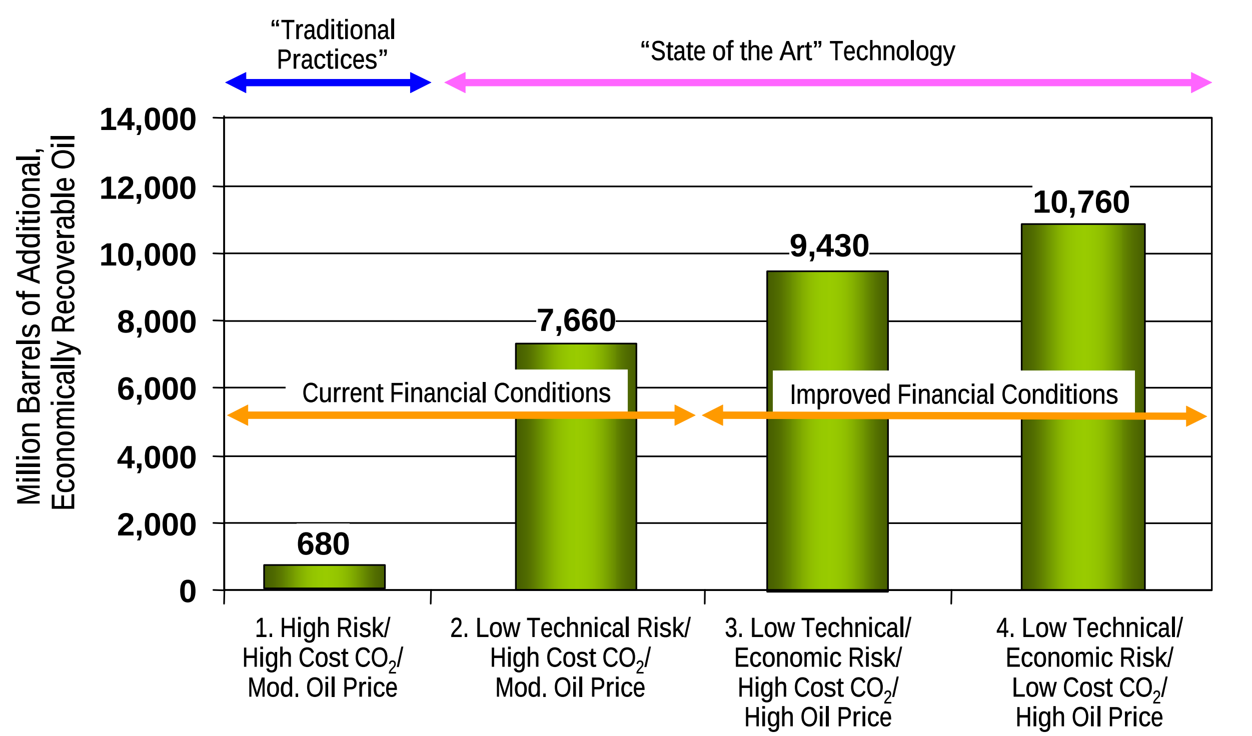
Risk mitigation incentives and/or higher oil prices, providing an oil price equal to $40 per barrel, would enable 9.4 billion barrels of oil to become economically recoverable from the Permian Basin's large oil reservoirs, Scenario #3.

Lower cost CO_2 supplies, equal to $0.80 per Mcf at $40/Bbl and assuming a large-scale CO_2 transportation system and incentives for CO_2 capture of emissions, would enable the economic potential to increase to 10.8 billion barrels, Scenario #4, Table 5 and Figure 1.

Table 5. Economically Recoverable Resources - Alternative Scenarios

Basin	Scenario #2: "State-of-the-art" (Moderate Oil Price/ High CO_2 Cost)		Scenario #3: "Risk Mitigation" (High Oil Price/ High CO_2 Cost)		Scenario #4: "Ample Supplies of CO_2" (High Oil Price/ Low CO_2 Cost)	
	(# Reservoirs)	(MMBbls)	(# Reservoirs)	(MMBbls)	(# Reservoirs)	(MMBbls)
New Mexico	15	830	16	840	19	1,040
West Texas	52	6,830	60	8,590	75	9,720
TOTAL	67	7,660	76	9,430	94	10,760

Figure 1. Impact of Advanced Technology and Improved Financial Conditions on Economically Recoverable Oil from the Permian Basin's Major Reservoirs Using CO_2-EOR (Million Barrels)



1. This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.20/Mcf and a ROR hurdle rate of 25% (before tax).
2. This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.20/Mcf and a ROR hurdle rate of 15% (before tax).
3. This case assumes an oil price of $40 per barrel, a CO_2 cost of $1.60/Mcf and a ROR hurdle rate of 15% (before tax).
4. This case assumes an oil price of $40 per barrel, a CO_2 cost of $0.80/Mcf and a ROR hurdle rate of 15% (before tax).

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 the Permian Basin is estimated at 21 billion barrels. The large Permian Basin oil reservoirs examined by the study, account for 74% of the region's oil resource. Extrapolating the 15.3 billion barrels of technically recoverable EOR potential in these 182 oil reservoirs to the total Permian Basin oil resource provides an estimate of 20.8 billion barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the 182 large Permian Basin oil fields may not reflect the development costs for the smaller oil reservoirs in the region.)

7. The ultimate additional oil recovery potential from applying CO2-EOR in the Permian Basin will, most likely, prove to be higher than defined by this study. Introduction of more advanced "next generation" CO2-EOR technologies still in the research or field demonstration stage, such as gravity stable CO2 injection, extensive use of horizontal or multi-lateral wells and CO2 miscibility and mobility control agents, could significantly increase recoverable oil volumes. These "next generation" technologies would also expand the state's geologic capacity for storing CO2 emissions. The benefits and impacts of using "advanced" CO2-EOR technology on Permian Basin oil reservoirs have been examined in a separate study.

8. A portion of this CO2-EOR potential is already being pursued by operators in the Permian Basin. Approximately 49 CO2-EOR projects are currently underway in the Permian Basin, three in New Mexico (e.g. Vacuum field) and 46 in Texas (e.g. Salt Creek field). Together, the CO2-EOR projects are producing 170 MBbls of oil per day, accounting for 20% of the Permian Basin oil production. To date, CO2-EOR in the Permian Basin has recovered about one billion barrels of incremental oil.

9. Large volumes of CO_2 supplies will be required in the Permian Basin to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be up to 49.0 Tcf, plus another 104.6 Tcf of recycled CO_2, Table

6. 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 the Permian Basin's oil reservoirs would enable 2.5 billion tonnes 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.

Table 6. Potential CO_2 Supply Requirements in the Permian Basin
Scenario #4 ("Ample Supplies of CO_2")

Region	No. of Reservoirs	Economically Recoverable* (MMBbls)	Purchased CO_2 (Bcf)	Recycled CO_2 (Bcf)
New Mexico	19	1,042	4,623	10,439
West Texas	75	9,720	44,356	94,197
TOTAL	94	10,762	48,979	104,636

**Under Scenario #4: "Ample Supplies of CO_2"*

10. Significant supplies of both natural and industrial CO_2 emissions exist in the Permian Basin, sufficient to meet the CO_2 needs for EOR. The natural CO_2 deposits at McElmo Dome, Bravo Dome, and Sheep Mountain Dome are estimated to hold upwards of 20 Tcf of recoverable CO_2. CO_2 emissions, from gas processing plants and hydrogen plants, could provide additional high concentration (relatively low cost) CO_2. Finally, large supplies of low concentration CO_2 emissions would be available from the large power plants and refineries in the region, assuming affordable cost CO_2 capture technology is developed.

11. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in the Permian Basin's oil fields. The challenging nature of the current barriers — lack of sufficient, low-cost CO_2 supplies, uncertainties as to how the technology will perform in many of the smaller Permian Basin's oil fields, and the considerable market and oil price risk — all argue that a partnership involving the oil production industry, potential CO_2 suppliers and transporters, the states of New Mexico and Texas and the federal government will be needed to overcome these barriers.

12. Many entities will share in the benefits of increased CO_2-EOR based oil production in the Permian Basin. Successful introduction and wide-scale use of CO_2-EOR in the Permian Basin 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.

1.4 ACKNOWLEDGEMENTS. Advanced Resources would like to acknowledge the most valuable assistance provided to the study by a series of individuals and organizations in New Mexico and Texas. In New Mexico, we would like to acknowledge the New Mexico Oil and Gas Engineering Committee for production data. In Texas, we would like to thank Steve Melzer for his invaluable assistance in compiling this report. In addition we would like to acknowledge the prior work by the Texas Bureau of Economic Geology on the potential for CO_2-EOR in Texas which serves as a basis for comparison with our results.

2. INTRODUCTION

2.1 CURRENT SITUATION. The Permian Basin contains a large number of maturing oil fields. Oil production in the Permian Basin peaked in the mid 1970's and has seen a steady decline since that time. Implementation of tertiary oil recovery projects has helped stem this decline.

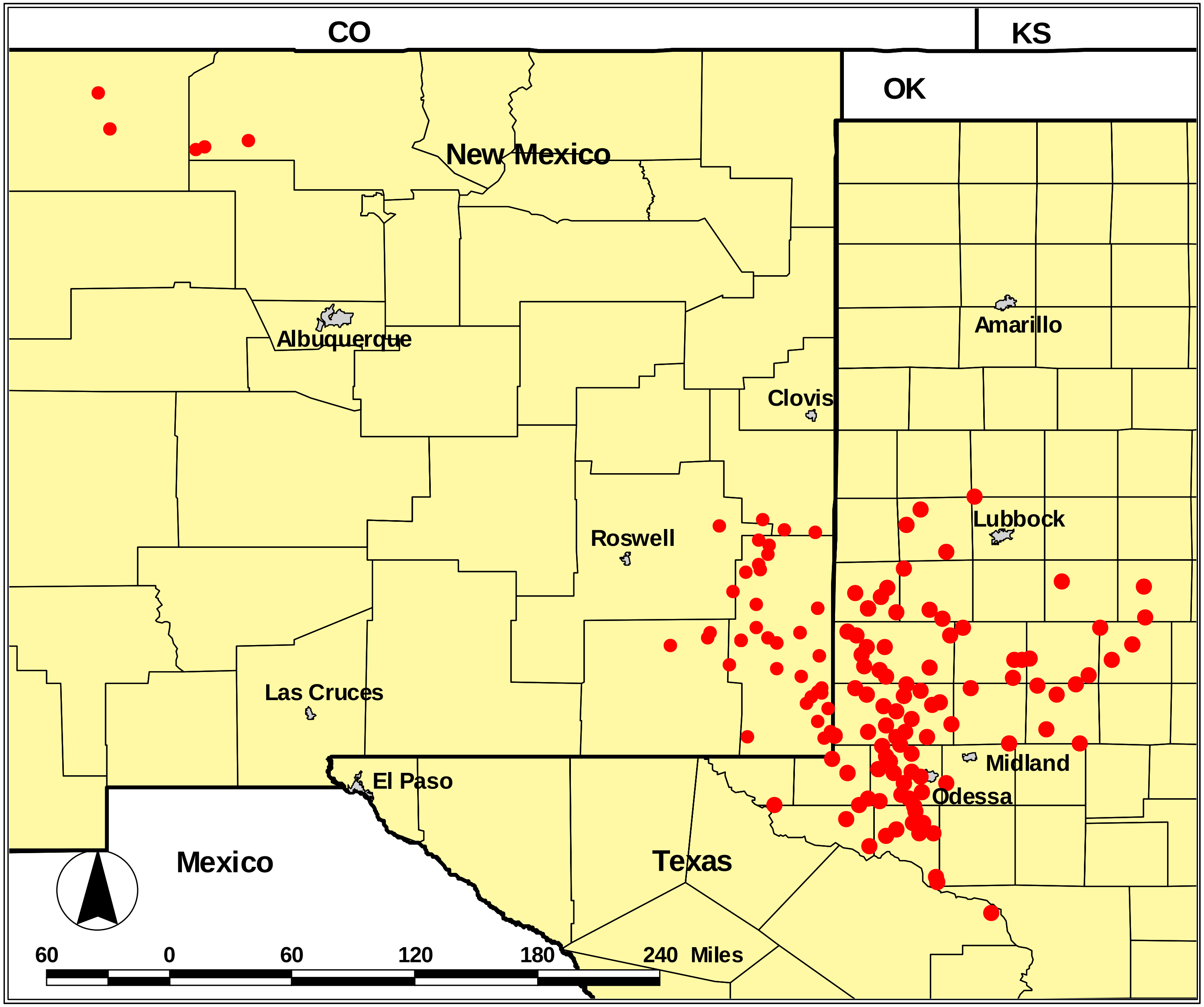
As of early 2005, there were approximately 49 active CO_2-EOR projects (in 35 oil fields) in the Permian Basin, producing 170 thousand barrels per day, almost 20% of the basin's total oil production. Appendix A provides the present, cumulative, and estimated ulimate production for EOR projects in the Permian Basin. As further discussed later in this report, CO_2-EOR has been successfully utilized in many of the major Permian Basin fields, such as the Wasson, Seminole, and Vacuum oil fields.

The main purpose of this report is to provide information on the potential of increased CO_2 enhanced oil recovery (CO_2-EOR) activity for slowing or potentially reversing the decline of oil production in the Permian Basin.

This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Permian Basin," provides information on the size of the technical and economic potential for CO_2-EOR in the Permian Basin's oil producing regions. 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 more advanced methods of CO_2-EOR in the Permian Basin.

2.2 BACKGROUND. The Permian Basin of New Mexico and West Texas currently produces 841 thousand barrels of oil per day (in 2004). It also contains deep, light oil reservoirs that are ideal candidates for miscible carbon dioxide based enhanced oil recovery (CO_2-EOR). The Permian Basin oil producing region and the concentration of its major oil fields are shown in Figure 2.

Figure 2. Location of Major Permian Basin and NW New Mexico Oil Fields Amenable to CO_2-EOR



Tertiary oil recovery efforts, utilizing CO_2 flooding, were initiated in the Permian Basin of New Mexico and West Texas in the 1970's. Between 1970 and 1973, Shell and Chevron pioneered tertiary oil recovery in the area using anthropogenic CO_2. Chevron built the first super-critical CO_2 pipeline, known as the CRC pipeline, carrying CO_2 from the gas plants in the Val Verde Basin to the Kelly-Snyder (SACROC) Field, the first large-scale CO_2-EOR project in the Permian Basin. Following CO_2 injection, production in the Canyon Reef reservoir of the SACROC Field increased significantly. However, early breakthrough of CO_2 limited the performance and recovery efficiency of this CO_2 miscible flood (Coleman, 2005).

By the 1980's, natural CO_2 sources had been discovered near the Permian Basin at Bravo Dome, McElmo Dome, and Sheep Mountain. Large scale pipelines were constructed to bring CO_2 to oil fields in the northern Permian Basin. Tertiary recovery incentives were also established during this time, including the DOE-sponsored tertiary oil price incentives. This was followed by the passage of EOR investment tax credits by the federal government (1982), and reduced severance taxes by the state (1982). Major oil companies, including Shell, Exxon, Chevron, Mobil and Amoco used the CO_2 delivered by this major pipeline infrastructure to undertake CO_2–EOR in many of the Permian Basin's numerous oil fields. The drastic drop in oil prices, starting in the mid-1980's stalled further expansion of CO_2-EOR in the basin.

In the late 1990's, a number of new companies entered the CO_2-EOR industry in the Permian Basin, including Oxy Permian and Kinder Morgan. To date, CO_2-EOR in the Permian Basin has produced 1 billion barrels of incremental oil. Approximately 7.3 Tcf of CO_2 has been sequestered in the Permian Basin and over 1,500 miles of major CO_2 pipelines have been built (Coleman, 2005).

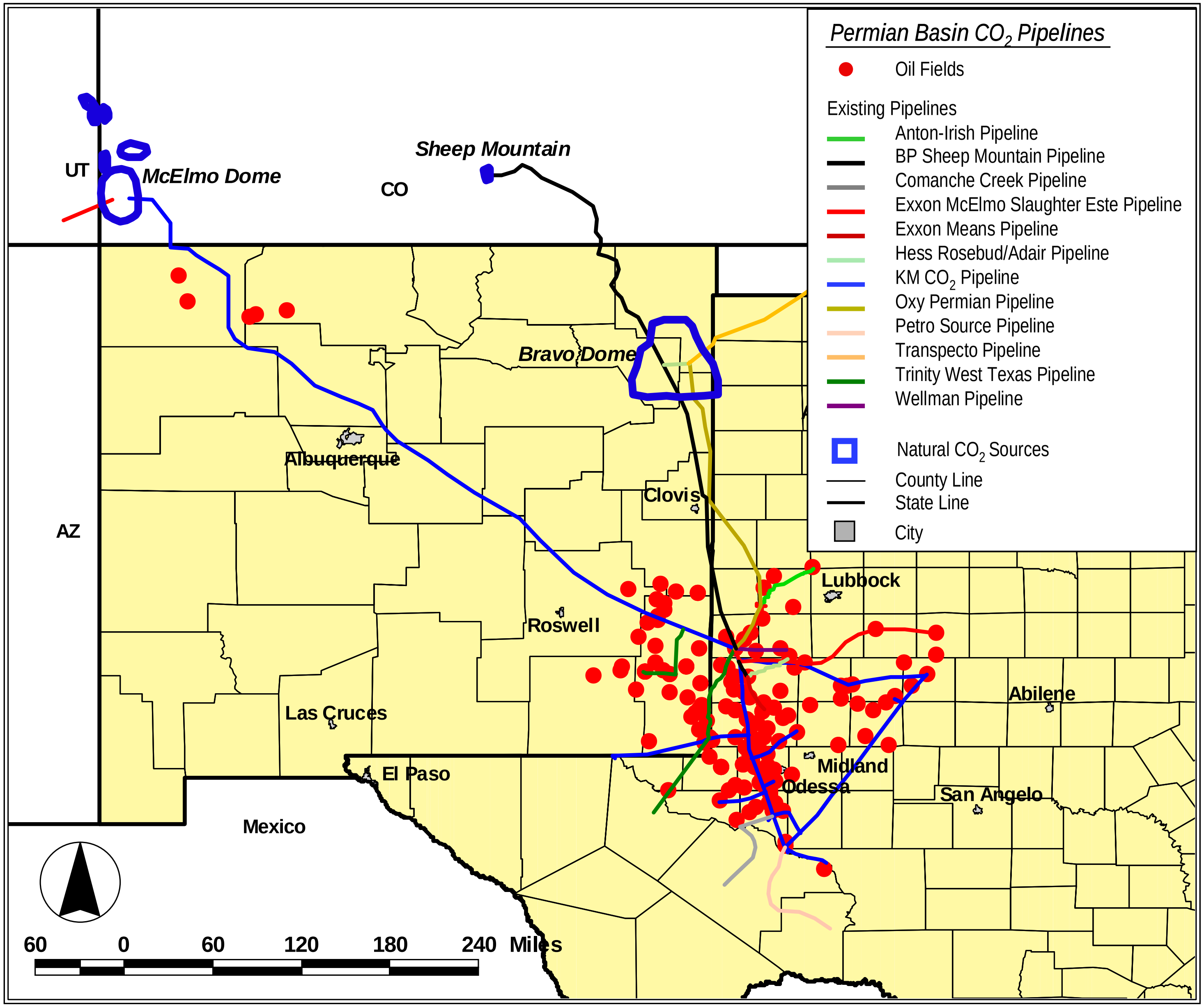
Although CO_2-EOR has been utilized in the Permian Basin since the early 1970's, both the mature giant oil fields (some of which are already under CO_2 flooding) and the numerous smaller oil fields that have yet to be flooded with CO_2, stand to benefit from added incentives and increased CO_2-EOR technology. Importantly, many of these active CO_2 floods are not yet field-wide in scope and there are numerous smaller Permian Basin fields that could benefit from lower cost CO_2 for undertaking miscible EOR.

2.3 PURPOSE. This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Permian Basin" is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. The work involves establishing the geological and reservoir characteristics of the major oil fields in the region; examining the available CO_2 sources, volumes and costs; calculating oil recovery and CO_2 storage capacity; and, estimating economic feasibility of applying CO_2-EOR. The aim of this report is to provide information that could assist in: (1) formulating alternative public-private partnership strategies for developing lower-cost CO_2 capture technology; (2) launching R&D/pilot projects of advanced CO_2 flooding technology; and, (3) structuring royalty/tax incentives and policies that would help accelerate the application of CO_2-EOR and CO_2 storage.

An additional important purpose of the study is to develop a desktop modeling and analytical capability for "basin oriented strategies" that would enable the Department of Energy/Fossil Energy (DOE/FE) itself 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 this study, it is assumed that sufficient supplies of CO_2 are available, either by pipeline from natural sources such as the Bravo Dome, McElmo Dome, and Sheep Mountain, or from anthropogenic sources such as the natural gas processing plants in West Texas. Figure 3 shows the locations of some of the major CO_2 pipelines in the Permian Basin.

Figure 3. Existing CO_2 Pipelines and Sources in the Permian Basin



2.5 TECHNICAL OBJECTIVES. The objectives of this study are to examine the technical and the economic potential of applying CO_2-EOR in the Permian Basin oil reservoirs, 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 and by injecting moderate volumes of CO_2, on the order of 0.4 hydrocarbon pore volumes (HCPV), into these reservoirs. (Immiscible CO_2 is not included in the "Traditional Practices" technology option).

2. *"State-of-the-art" Technology*. This involves bringing to the Permian Basin the benefits of recent gains in understanding of the CO_2-EOR process and how best to customize its application to the many different types of oil reservoirs in the region. As further discussed below, moderately deep, light oil reservoirs are selected for miscible CO_2-EOR and the shallower light oil and the heavier oil reservoirs are targeted for immiscible CO_2-EOR. "State-of-the-art" technology entails injecting much larger volumes of CO_2, on the order of 1 HCPV, with considerable CO_2 recycling. It also involves managing the CO_2 flood to achieve improved vertical conformance and efficiently using this larger volume of CO_2.

   Under "State-of-the-art" technology, with CO_2 injection volumes more than twice as large, oil recovery is projected to be higher than reported for past field projects using "Traditional Practices", although this concept required further testing. The CO_2 injection/oil recovery ratio may also be higher under this technology option, further spotlighting the importance of lower cost CO_2 supplies. With the benefits of field pilots and pre-commercial field demonstrations, the risk premium for this technology option and scenario would be reduced to conventional levels.

The set of oil reservoirs to which CO_2-EOR would be applied fall into two groups, as set forth below:

1. *Favorable Light Oil Reservoirs Meeting Stringent CO_2 Miscible Flooding Criteria*. These are the moderately deep, 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 Permian Basin light oil fields such as Wasson, Seminole and Salt Creek fit into this category. The great bulk of past CO_2-EOR floods have been conducted in these types of "favorable reservoirs".
2. *Challenging Reservoirs Involving Immiscible Application of CO_2-EOR*. These are the moderately heavy oil reservoirs (as well as shallower light oil reservoirs) that do not meet the stringent requirements for miscibility (shallower than 3,000 ft or having oil gravities between 17.5° and 25 °API). In this study, there were no Permian Basin oil reservoirs that were considered for immiscible flooding.

Combining the technology and oil reservoir options, the following oil reservoir and CO_2 flooding technology matching is applied to the Permian Basin's reservoirs amenable to CO_2-EOR, Table 7.

Table 7. Matching of CO_2-EOR Technology with the Permian Basin's Oil Reservoirs

CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices" Miscible CO_2-EOR	▪ 182 Deep, Light Oil Reservoirs
"State-of-the-art" Miscible and Immiscible CO_2-EOR	▪ 182 Deep, Light Oil Reservoirs ▪ No Deep, Moderately Heavy Oil Reservoirs

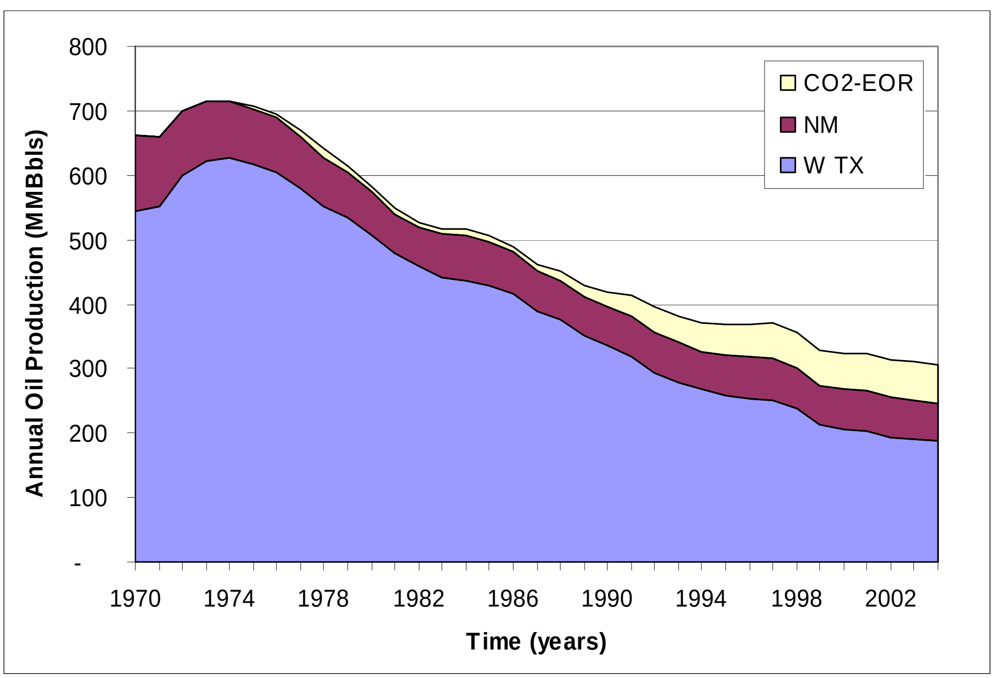
2.6 OTHER ISSUES. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Permian Basin's major oil reservoirs. Because of confidentiality and proprietary issues, reservoir-level data and results are not 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 additional information could be made available for review, on a case by case basis, to provide an improved context for the results reported in this study.

3. OVERVIEW OF PERMIAN BASIN OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production for the Permian Basin of United States — encompassing New Mexico and West Texas — has declined in the past 30 years as exploration and new field discoveries slowed in the 1980s and 1990s, Figure 4. Since reaching a peak in 1974, at approximately 715 MMBbls, oil production in the Permian Basin has declined sharply. However, the progressive increase in the success of CO_2-EOR has helped to significantly slow this decline in oil production. In spite of this, oil production reached a low of 307 million barrels (841 MBbls per day) in 2004.

- New Mexico, with 59 MMBbls (162 MBbls per day) of oil produced in 2004, has seen its slide in production halted by tertiary recovery projects in the late 1980's.
- West Texas, with 188 MMBbls (515 MBbls per day) of oil produced in 2004, has seen a continued decline in production despite many CO_2-EOR projects.
- CO_2-EOR production in the Permian Basin has grown since the implementation of CO_2 floods in the 1970's, reaching 62 MMBbls (170 MBbls per day) in 2004.

Figure 4. Permian Basin Historical Crude Oil Production since 1970



The Permian Basin still holds a rich resource of oil in the ground that is amenable to CO_2-EOR. With 95.4 billion barrels of original oil in-place (OOIP) and approximately 33.7 billion barrels expected to be recovered, 61.7 billion barrels of oil will be "stranded" due to lack of technology, lack of sufficient, affordable CO_2 supplies and high economic and technical risks.

Table 8 presents the status and annual oil production for the ten largest Permian Basin oil fields that account for about one fourth of the oil production in this region. The table shows that eight of the largest oil fields are in production decline. Arresting this decline in the Permian Basin's oil production could be attained by further applying additional enhanced oil recovery technology, particularly CO_2-EOR.

Table 8. Crude Oil Annual Production, Ten Largest Permian Basin Oil Fields, 2001-2003
(Million Barrels per Year)

Major Oil Fields	2001	2002	2003	Production Status
1. Slaughter*	14.9	14.5	14.2	Declining
2. Denver Wasson Unit*	13.4	13.1	12.8	Declining
3. Levelland Unit	10.7	10.3	9.9	Declining
4. Seminole*	10.0	9.4	8.9	Declining
5. Yates	8.5	7.3	7.5	Stable
6. Cowden North*	7.3	6.8	6.5	Declining
7. McElroy	6.0	5.6	5.5	Declining
8. Salt Creek*	6.0	5.7	5.3	Declining
9. SACROC (Kelly Snyder)*	3.7	5.3	8.1	Increasing
10. Howard Glasscock	2.9	2.7	2.6	Declining

** Fields currently under EOR operations*

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Permian Basin oil producers are familiar with using technology for improving oil recovery. One of the first successful CO_2 floods and, at the time, the world's largest, began in the early 1970's in the SACROC (Kelly Snyder Field) in West Texas. The early success observed at SACROC resulted in 49 additional CO_2-EOR projects being started throughout the Permian Basin of New Mexico and West Texas.

One of the favorable conditions for the area is that the Permian Basin is located near natural sources of CO_2. These natural sources of CO_2 enabled the conduction of several CO_2-EOR pilots in the 1980s and continue to be sources of CO_2 for the 49 active CO_2 floods underway in the Permian Basin. Additional discussion of the experience with CO_2-EOR in the Permian Basin is provided in Chapter 6, a detailed tabulation of ongoing and past CO_2-EOR projects in Appendix A, and two cost studies of CO_2-EOR performance are provided in Appendices E and F.

3.3 THE "STRANDED OIL" PRIZE. Even though the Permian Basin's oil production is declining, this does not mean that the resource base is depleted. The Permian Basin reservoirs analyzed in this study still contain 65% of their OOIP (62 BBbls) after primary and secondary oil recovery. This large volume of remaining oil in-place (ROIP) is the "prize" for CO_2-EOR.

Table 9 provides information on the maturity and oil production history of 9 large Permian Basin oil fields, each with primary/secondary estimated ultimate recovery of 500 million barrels or more.

Table 9. Selected Major Oil Fields of the Permian Basin Favorable for CO_2-EOR

	Field/State	Year Discovered	Cumulative Production (MBbl)	Estimated Reserves (MBbl)	Remaining Oil In-Place (MMBbl)
1	Wasson – TX 8A*	1937	1,734	394	3,676
2	Yates – TX 8	1926	1,388	91	3,521
3	Slaughter – TX 8A*	1937	1,150	204	2,351
4	SACROC(Kelly Snyder) – TX 8A*	1948	1,102	147	1,681
5	Cowden – TX 8*	1930	828	114	1,384
6	Levelland Unit – TX 8A	1945	657	144	980
7	McElroy – TX 8	1926	561	80	1,912
8	Vacuum – NM*	1929	498	34	975
9	Ward – TX 8	1927	501	16	1,381

** Fields with active CO_2 flooding*

3.4 REVIEW OF PRIOR STUDIES. Several studies have been conducted on the potential of using CO_2-EOR in the Permian Basin.

- *"Ranking of Texas Reservoirs for Application of Carbon Dioxide Miscible Displacement" prepared by Science Applications Inc. in 1996.* The study used a data base of 431 large Texas oil reservoirs (179 reservoirs in the Permian Basin) and assumed an average CO_2-EOR oil recovery efficiency of 10%, an oil price of $17 per barrel, and CO_2 costs of $0.60 per Mcf. Based on these assumptions, the study estimated that 4 billion barrels of additional oil resources could be recovered by applying CO_2-EOR to the large Texas oil reservoirs. (No further detail, by basin or Railroad District, was provided.)

- *"Reduction of Greenhouse Gas Emissions through Underground CO_2 Sequestration in Texas Oil and Gas Reservoirs" prepared by the Texas Bureau of Economic Geology in 1999.* The study used a data base of 3,000 Texas oil reservoirs containing 197 billion barrels (BBbls) of OOIP. Of these, 1,730 reservoirs were screened as being favorable for CO_2-EOR. These reservoirs were estimated to hold 80 BBbls of OOIP, and 31 BBbls of mobile ROIP, plus an unspecified amount of immobile ROIP and are located within 90 miles of CO_2 producing power plants. The study estimated that an additional 8 BBbls could be recovered using CO_2-EOR, assuming a recovery factor of 10% of OOIP. The authors noted that most of this production would come from the open-carbonate platform reservoirs in the Permian Basin.

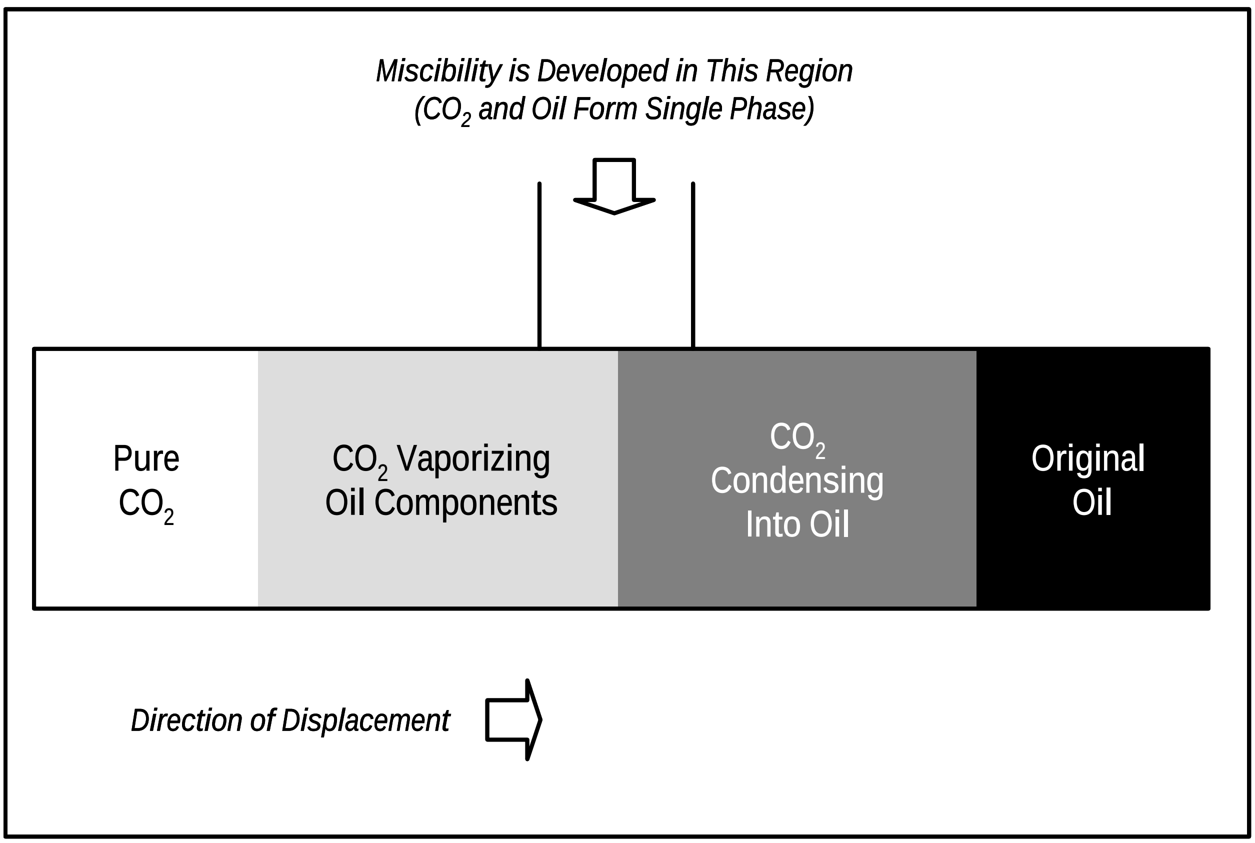
- *"The Financial Prospects for a Coal-Based IGCC Plant with Carbon Capture Serving California" prepared by NETL and Parsons Corporation in 2002.* The study used the TORIS data base to identify 43 large West Texas and 20 large New Mexico oil reservoirs with 12.8 BBbls of OOIP that screened technically and economically favorable for CO_2-EOR. The study used an oil price of $25 per barrel with CO_2 costs of $1.00 per Mcf. The study estimated that an additional 1.4 billion barrels could be recovered using CO_2-EOR, equal to 11% of OOIP.

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 5 provides a one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO_2 miscible process.

Figure 5. One-Dimensional Schematic Showing the CO_2 Miscible Process



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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 enables 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 6A and 6B provide basic information on the change in CO_2 density and viscosity, two important oil recovery mechanisms, as a function of pressure.

Oil swelling is an important oil recovery mechanism, for both miscible and immiscible CO_2-EOR. Figures 7A and 7B show the oil swelling (and implied residual 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 8 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 6A. Carbon Dioxide, CH_4 and N_2 densities at 105^0F. 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).

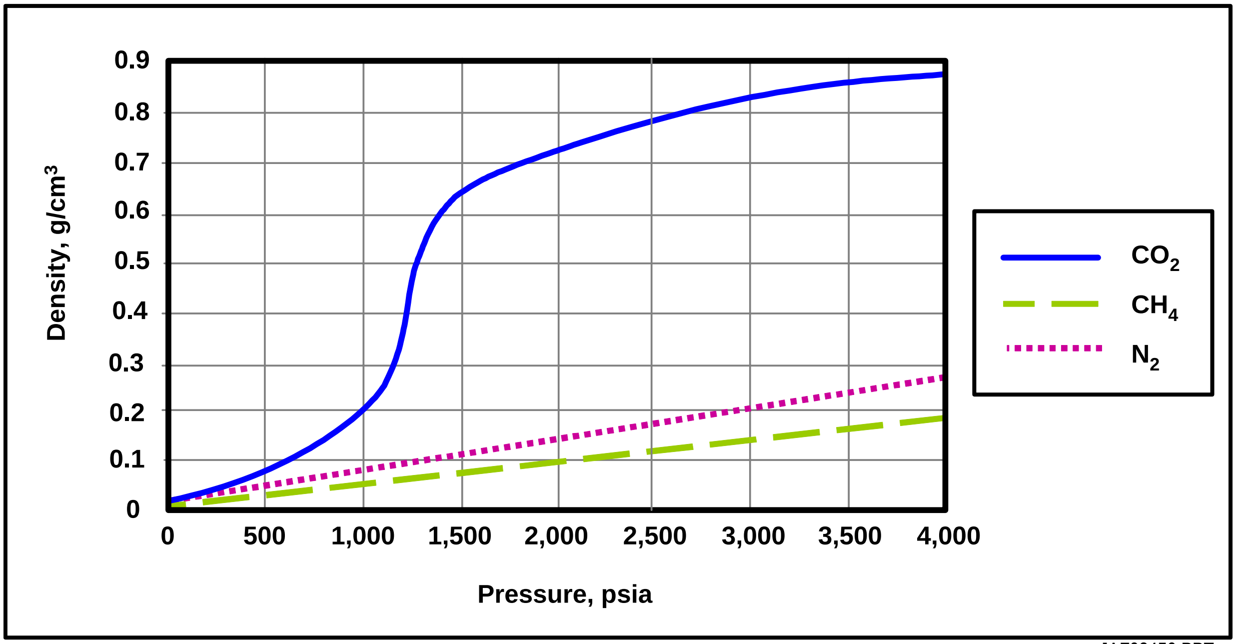

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Figure 6B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

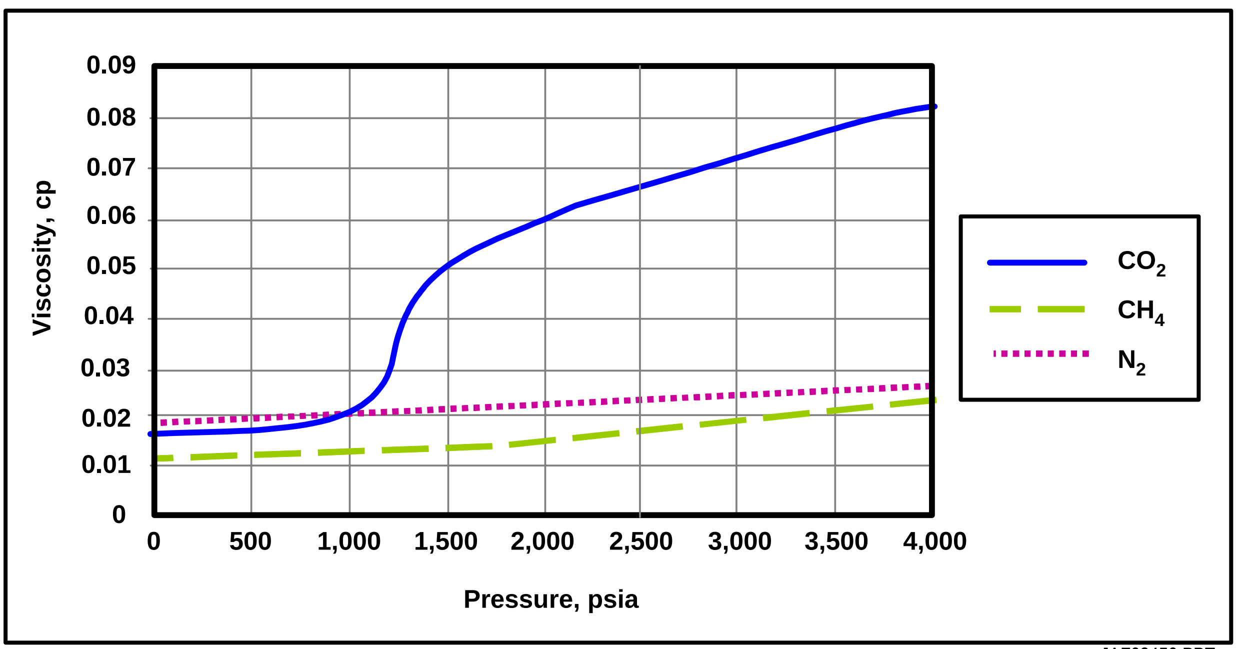

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Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

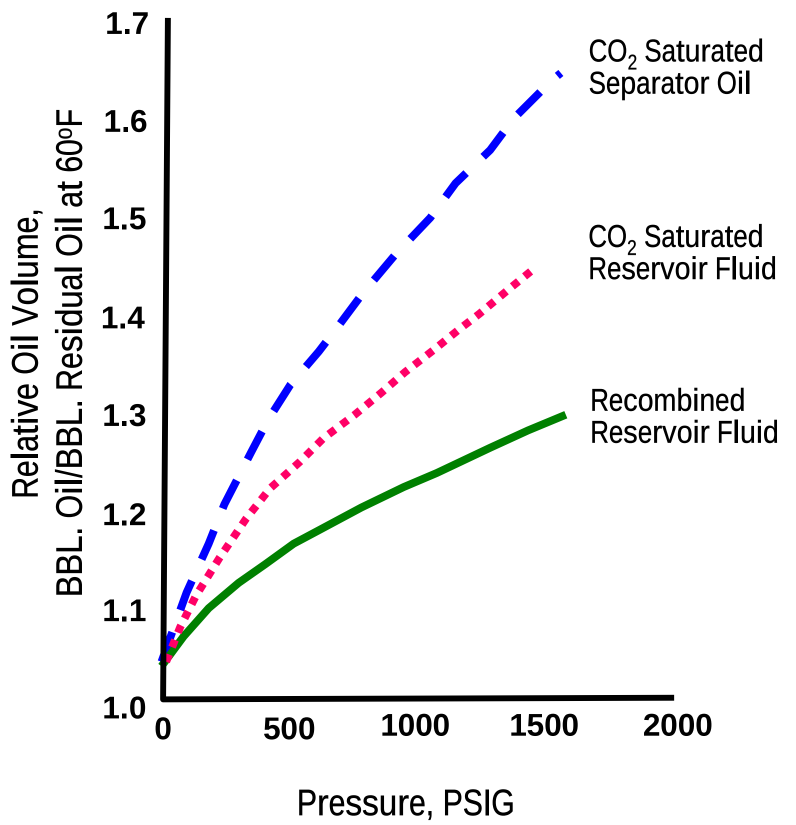


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

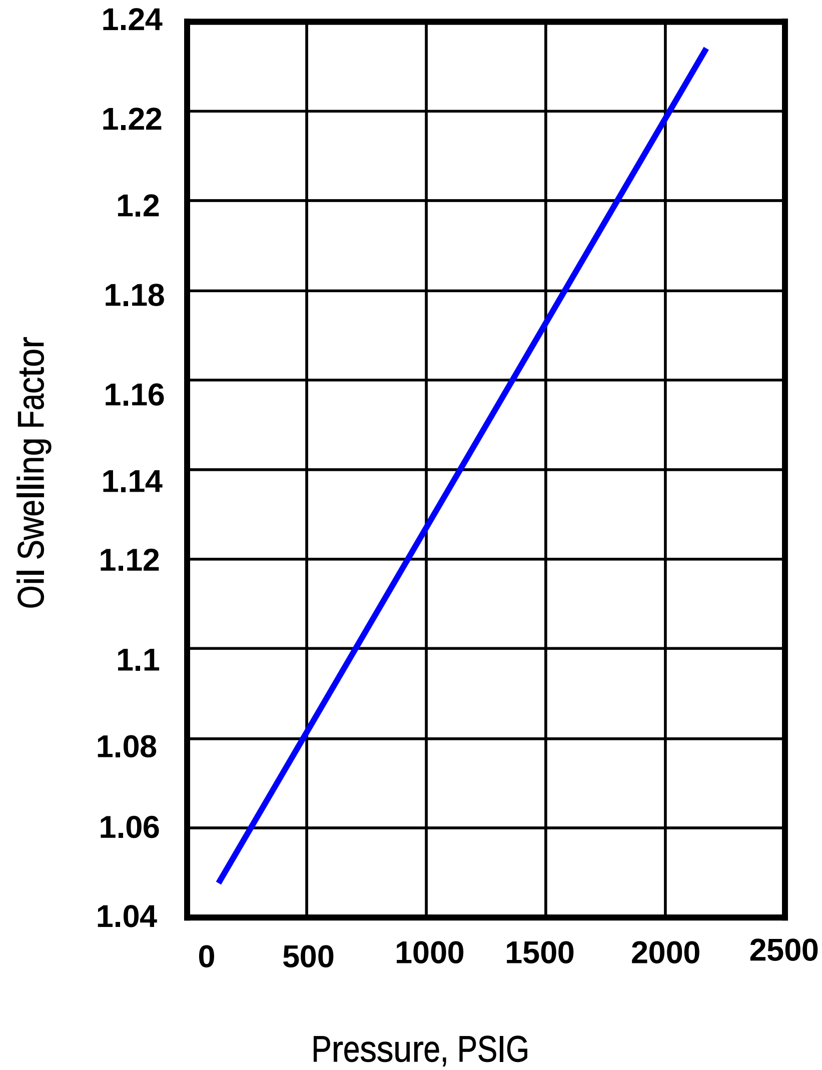
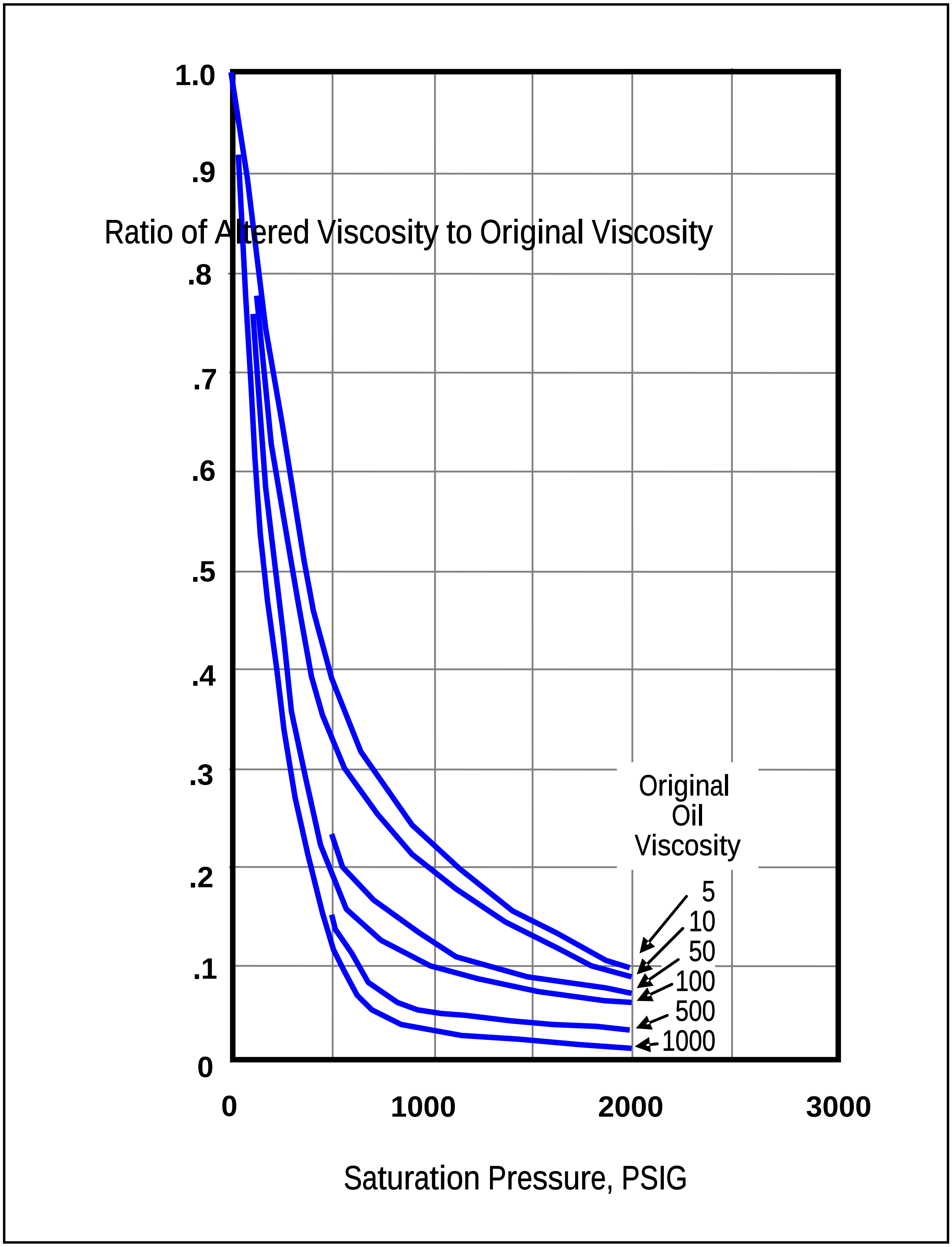


Figure 8. Viscosity Reduction Versus Saturation Pressure (Simon and Graue)



5. STUDY METHODOLOGY

5.1 OVERVIEW. A seven part methodology was used to assess the CO_2-EOR potential of the Permian Basin's oil reservoirs. The seven steps were: (1) assembling the Permian Basin 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 scenario 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 Permian Basin Oil Reservoirs Data Base for New Mexico and West Texas (RR Districts 8 and 8A).

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 Permian Basin Major Oil Reservoirs Data Base contains 207 reservoirs, accounting for 70% of the oil expected to be ultimately produced in the Permian Basin by primary and secondary oil recovery processes.

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

Basin Name	
Field Name	
Reservoir	

Reservoir Parameters:	TORIS	ARI
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		

Oil Production	TORIS	ARI
Producing Wells (active)		
Producing Wells (shut-in)		
2002 Production (Mbbl)		
Daily Prod - Field (Bbl/d)		
Cum Oil Production (MMbbl)		
EOY 2002 Oil Reserves (MMbbl)		
Water Cut		

Water Production	TORIS	ARI
2002 Water Production (Mbbl)		
Daily Water (Mbbl/d)		

Injection	TORIS	ARI
Injection Wells (active)		
Injection Wells (shut-in)		
2002 Water Injection (MMbbl)		
Daily Injection - Field (Mbbl/d)		
Cum Injection (MMbbl)		
Daily Inj per Well (Bbl/d)		

EOR	
EOR Type	
2002 EOR Production (MMbbl)	
Cum EOR Production (MMbbl)	
EOR 2002 Reserves (MMbbl)	
Ultimate Recovery (MMbbl)	

Volumes	TORIS	ARI
OOIP (MMbl)		
Cum P/S Oil (MMbl)		
2002 P/S Reserves (MMbl)		
Ult P/S Recovery (MMbl)		
Remaining (MMbbl)		
P/S Recovery Efficiency (%)		

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)		

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 the Permian Basin; (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, 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. Many of these fields contain multiple reservoirs, with each reservoir holding a great number of stacked sands. Because of data limitations, this screening study combined the sands into a single reservoir.

Table 11. Permian Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
A. New Mexico		
Permian	ALLISON	BOUGH C
Permian	ALLISON	PENNSYLVANIAN
Permian	ARROWHEAD	GRAYBURG
Permian	BAGLEY NORTH	PERMO-PENN
Permian	BAGLEY	SILURO-DEVONIAN
Permian	BISTI	LOWER GALLUP
Permian	BLINEBRY	BLINEBRY
Permian	CAPROCK EAST	DEVONIAN
Permian	CAPROCK	QUEEN
Permian	CATO	SAN ANDRES
Permian	CHA-CHA	GALLUP
Permian	CHAVEROO	SAN ANDRES
Permian	DENTON	DEVONIAN
Permian	DENTON (ENTIRE FIELD)	WOLFCAMP
Permian	DEVILS FORK	GALLUP
Permian	DOLLARHIDE	DEVONIAN
Permian	DOLLARHIDE	QUEEN
Permian	DOLLARHIDE	TUBB DRINKARD
Permian	DRINKARD	YESO-VIVIAN
Permian	EMPIRE	ABO
Permian	ESCRITO	GALLUP
Permian	EUNICE MONUMENT	GRAYBURG-SAN ANDRES
Permian	EUNICE SOUTH	SEVEN RIVERS-QUEEN
Permian	FLYING M	SAN ANDRES
Permian	GRAYBURG-JACKSON	GRAYBURG-SAN ANDRES
Permian	HARE	SIMPSON
Permian	HOBBS	BLINEBRY-YESO
Permian	HOBBS	GRAYBURG-SAN ANDRES*
Permian	INBE	PENNSYLVANIAN
Permian	JUSTIS	BLINEBRY
Permian	KEMNITZ	LOWER WOLFCAMP
Permian	LANGLIE-MATTIX	SEVEN RIVERS-QUEEN-GRAYBURG
Permian	LINDRITH WEST	GALLUP-DAKOTA
Permian	LOVINGTON	ABO
Permian	LOVINGTON	PADDOCK
Permian	LOVINGTON	SAN ANDRES
Permian	LUSK	STRAWN
Permian	MALJAMAR	6TH GRAYBURG SAND ZONE
Permian	MALJAMAR	9TH SAN ANDRES MASSIVE

Table 11. Permian Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Permian	MALJAMAR	GRAYBURG-SAN ANDRES*
Permian	MALJAMAR	SAN ANDRES LOWER 7TH
Permian	MALJAMAR	SAN ANDRES UPPER 7TH
Permian	MALJAMAR	SAN ANDRES UPPER 9TH
Permian	MILNESAND	SAN ANDRES
Permian	NORTH VACUUM	ABO
Permian	PADUCA	DELAWARE SAND
Permian	PEARL	QUEEN
Permian	PENROSE-SKELLY	GRAYBURG
Permian	SAUNDERS	PERMO-PENNSYLVANIAN
Permian	SQUARE LAKE	GRAYBURG-SAN ANDRES
Permian	VACUUM	ABO REEF
Permian	VACUUM	GLORIETTA
Permian	VACUUM	GRAYBURG-SAN ANDRES*
Permian	VADA	PENNSYLVANIAN
Permian	WEST SAWYER	SAN ANDRES
B. Texas, RR District 8		
Permian	ANDECTOR	ELLEN BURGER
Permian	ANDREWS	WOLFCAMP-PA
Permian	ARENOSO	STRAWN DETRITUS
Permian	BAKKE	WOLFCAMP
Permian	BLOCK 31	DEVONIAN
Permian	BREEDLOVE	DEVONIAN
Permian	CORDONA LAKE	DEVONIAN*
Permian	COWDEN SOUTH	8790 CANYON
Permian	COWDEN NORTH	DEEP
Permian	COWDEN NORTH	SAN ANDRES*
Permian	COWDEN SOUTH	SAN ANDRES-GRAYBURG*
Permian	CROSSETT	DEVONIAN*
Permian	CROSSETT SOUTH	DEVONIAN
Permian	DOLLARHIDE (CLEAR FORK)	CLEARFORK*
Permian	DOLLARHIDE (DEVONIAN)	DEVONIAN*
Permian	DOLLARHIDE	ELLENBURGER
Permian	DOLLARHIDE	SILURIAN
Permian	DORA ROBERTS	DEVONIAN-ELLENBURGER
Permian	DUNE	PERMIAN-SAN ANDRES
Permian	EDWARDS WEST	CANYON
Permian	EMMA	SAN ANDRES
Permian	FOSTER	SAN ANDRES
Permian	FUHRMAN-MASCHO	GRAYBURG-SAN ANDRES
Permian	FULLERTON	8500

Table 11. Permian Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Permian	FULLERTON	CLEARFORK
Permian	FULLERTON	SAN ANDRES
Permian	GOLDSMITH	CLEARFORK
Permian	GOLDSMITH NORTH	CON SAN ANDRES
Permian	GOLDSMITH	SAN ANDRES*
Permian	HARPER	ELLENBURGER
Permian	HARPER	SAN ANDRES
Permian	HOWARD GLASSCOCK	MAIN
Permian	HUTEX	DEVONIAN
Permian	JOHNSON	GRAYBURG-SAN ANDRES
Permian	JORDAN	SAN ANDRES
Permian	KEYSTONE	COLBY
Permian	KEYSTONE	ELLENBURGER
Permian	KEYSTONE	HOLT
Permian	KEYSTONE	SILURIAN
Permian	LAWSON	SAN ANDRES
Permian	LUTHER S.E.	SILURIAN-DEVONIAN
Permian	MABEE	SAN ANDRES*
Permian	MAGUTEX	DEVONIAN
Permian	MCELROY	GRAYBURG-SAN ANDRES*
Permian	MCFARLAND	QUEEN
Permian	MEANS	QUEEN SAND
Permian	MEANS	SAN ANDRES*
Permian	MIDLAND FARMS	ELLENBURGER
Permian	MIDLAND FARMS	SAN ANDRES
Permian	MONAHANS	CLEARFORK
Permian	MOORE	MAIN
Permian	NOLLEY	WOLFCAMP
Permian	OCEANIC	PENNSYLVANIAN
Permian	PENWELL	GLORIETTA
Permian	PENWELL	SAN ANDRES*
Permian	RUNNING W	WADDELL
Permian	SAND HILLS	MCKNIGHT
Permian	SAND HILLS	TUBB
Permian	SCARBOROUGH	YATES
Permian	SHAFTER LAKE	SAN ANDRES
Permian	SHIPLEY	QUEEN SAND
Permian	SPRABERRY	DEAN WOLFCAMP
Permian	SPRABERRY	TREND AREA CLEARFORK
Permian	SULPHUR DRAW	DEAN 8790
Permian	THREE BAR UNIT	DEVONIAN

Table 11. Permian Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Permian	TWOFREDS	DELAWARE*
Permian	TXL	5600'-GOLDSMITH/TUBB
Permian	TXL	ELLENBURGER
Permian	TXL	SAN ANDRES
Permian	TXL	TUBB
Permian	UNIVERSITY WADDELL	DEVONIAN*
Permian	UNION-WITCHER A	SAN ANDRES
Permian	UNIVERSITY BLOCK 9	WOLFCAMP
Permian	VEALMOOR EAST	CANYON REEF
Permian	WADDELL	SAN ANDRES
Permian	WARD ESTES NORTH	YATES-SEVEN RIVERS*
Permian	YARBROUGH AND ALLEN	ELLENBURGER
C. Texas, RR District 8A		
Permian	72 WASSON	SAN ANDRES
Permian	ACKERLY	DEAN SAND
Permian	ADAIR	SAN ANDRES*
Permian	ADAIR	WOLFCAMP
Permian	ANTON IRISH UNIT	CLEARFORK*
Permian	BENNETT RANCH WASSON SAN ANDRES	SAN ANDRES*
Permian	BRAHANEY	SAN ANDRES*
Permian	CEDAR LAKE	SAN ANDRES*
Permian	COGDELL AREA	CANYON REEF*
Permian	CORNELL UNIT WASSON	SAN ANDRES*
Permian	DENVER WASSON	SAN ANDRES*
Permian	DIAMOND M	CANYON LIME
Permian	FLANAGAN	CLEARFORK
Permian	FLUVANNA	STRAWN
Permian	GMK	SAN ANDRES*
Permian	HARRIS	GLORIETTA-SAN ANGELO
Permian	HUNTLEY	3400
Permian	JO-MILL	SPRABERRY
Permian	KELLY SNYDER (SACROC)	CANYON REEF*
Permian	KELLY SNYDER (SACROC)	CISCO
Permian	KINGDOM	ABO REEF
Permian	LEVELLAND UNIT	SAN ANDRES*
Permian	MAHONEY WASSON	SAN ANDRES
Permian	NE WASSON	CLEARFORK*
Permian	ODC WASSON	SAN ANDRES*
Permian	OWNBY	CLEARFORK
Permian	OWNBY	SAN ANDRES
Permian	PRENTICE	CLEARFORK 6700

Table 11. Permian Basin Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Permian	PRENTICE	MAIN
Permian	REEVES	SAN ANDRES
Permian	REINECKE	CISCO*
Permian	RILEY NORTH	CLEARFORK-NORTH RILEY UNIT
Permian	ROBERTSON	CLEARFORK
Permian	ROBERTSON	GLORIETTA
Permian	ROBERTSON NORTH	CLEARFORK-7100
Permian	ROBERTS WASSON	SAN ANDRES
Permian	ROPES	CANYON REEF
Permian	RUSSELL	CLEARFORK
Permian	RUSSELL NORTH	DEVONIAN
Permian	SALT CREEK	CANYON REEF*
Permian	SEMINOLE	SAN ANDRES*
Permian	SEMINOLE WEST	SAN ANDRES
Permian	SLAUGHTER	SAN ANDRES*
Permian	SPRABERRY WEST	DEEP
Permian	SPRAYBERRY DEEP	MAIN
Permian	VON ROEDER	CANYON REEF
Permian	WELCH	SAN ANDRES*
Permian	WELLMAN	WOLFCAMP REEF*
Permian	WILLIARD UNIT WASSON	SAN ANDRES*
Permian	YELLOWHOUSE	SAN ANDRES

** Reservoirs with significant EOR activity.*

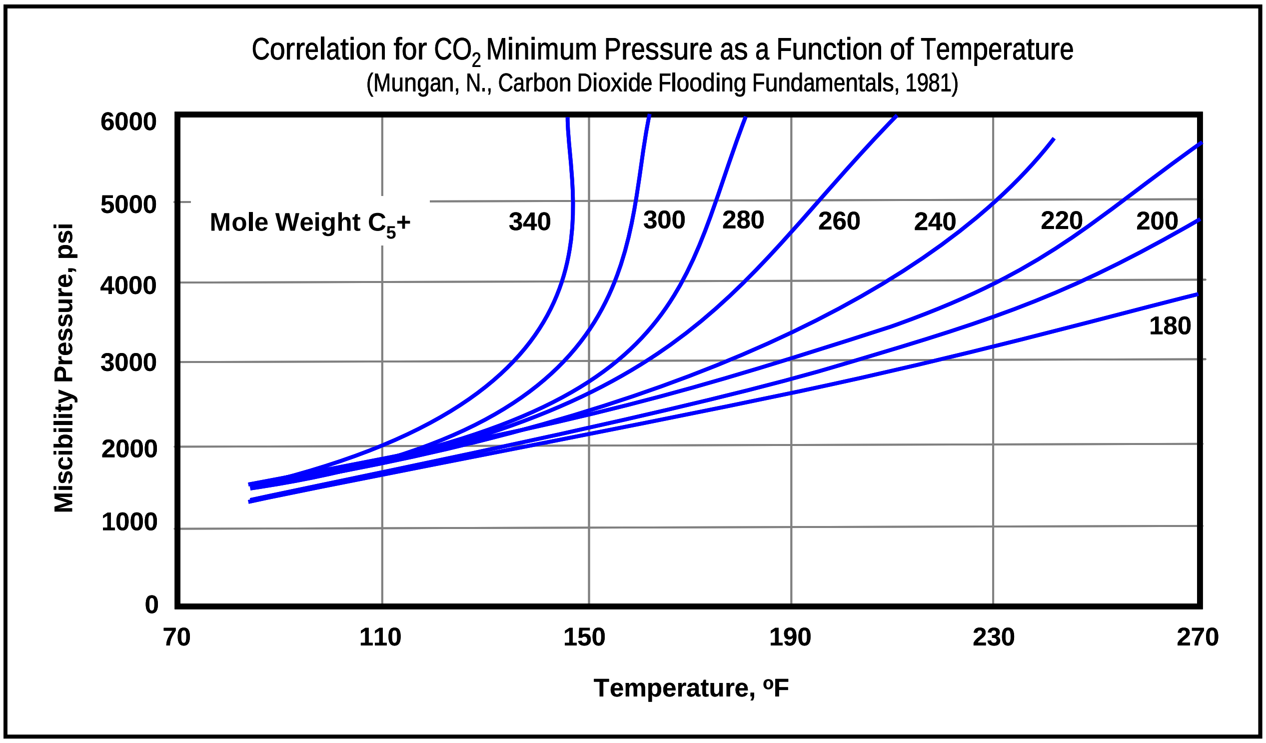
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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 9. 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 Permian Basin 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 °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

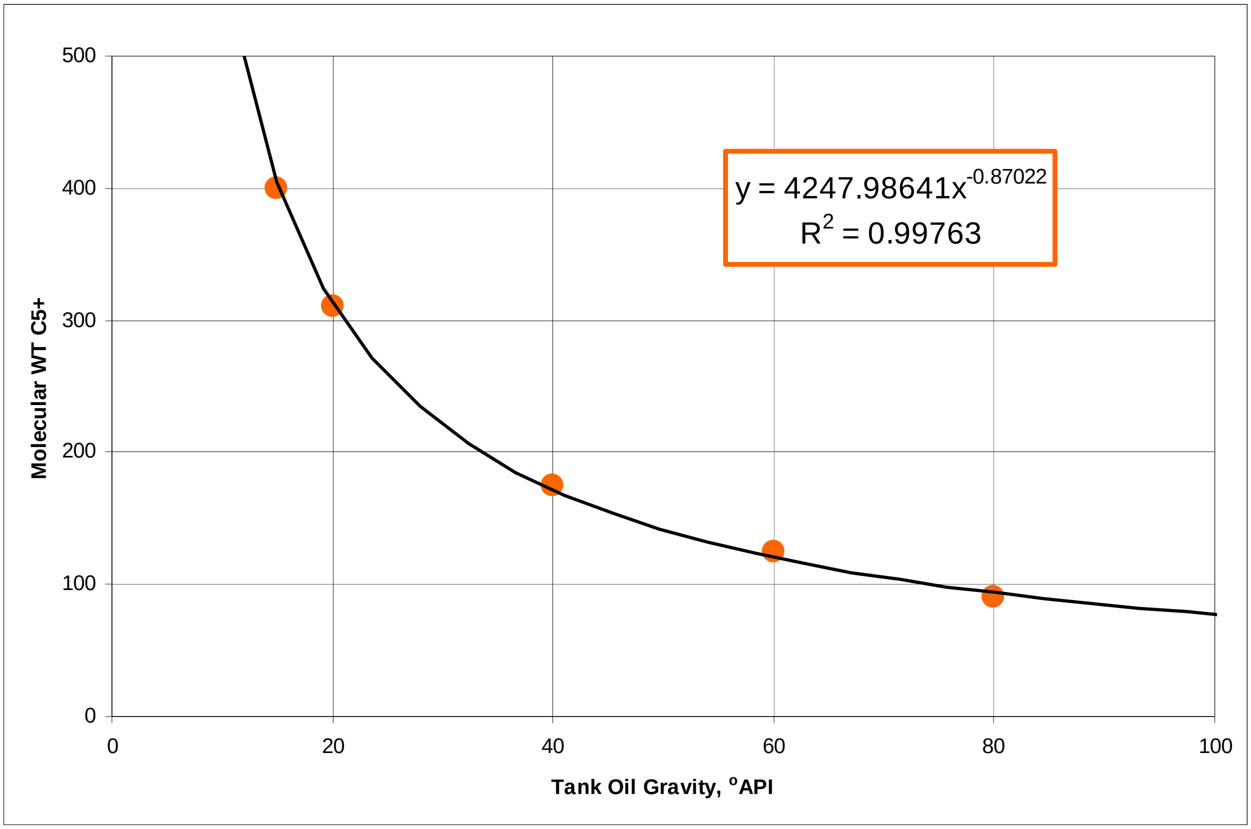
Figure 9. Estimating CO_2 Minimum Miscibility Pressure.



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 10.

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 consideration by immiscible CO_2-EOR.

Figure 10. Correlation of MW C5+ to Tank Oil Gravity.
(modified from: Mungan, N., Carbon Dioxide Flooding Fundamentals, 1981)



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_2PM*. According to the developers of the model, *CO_2-PROPHET* has more capabilities and fewer limitations than *CO_2PM*. 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_2PM*:

- *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 B 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. (Appendices C and D provide state-level 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 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.

Table 12. Economic Model Established by the Study

Field Cashflow Model		Advanced		Pattern			Field						
State				Existing Injectors Used	1.00		Existing Injectors Used	3					
Field				Converted Producers Used	0.00		Converted Producers Used	0		Total Injectors Required			
Formation				New Injectors Needed	0.00		New Injectors Needed	0		3			Existing Injectors
Depth				New Producers Needed	0.00		New Producers Needed	0		Total Producers Required			
Distance from Trunkline				Existing Producers Used	2.49		Existing Producers Used	7		7			Existing Producers
# of Patterns													
Miscibility:	Miscible												
		0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO_2 Injection (MMcf)			1,461	2,922	4,383	5,844	7,305	7,305	7,305	7,305	7,305	7,305	7,275
H_2O Injection (Mbw)			365	731	1,096	1,461	1,826	1,826	1,826	1,826	1,826	1,826	1,841
Oil Production (Mbbl)			-	91	469	781	974	1,113	1,144	869	631	511	456
H_2O Production (MBw)			942	1,789	2,326	2,761	3,217	2,716	2,295	2,177	2,164	2,121	2,086
CO_2 Production (MMcf)			-	-	35	501	1,226	2,129	3,114	4,137	4,793	5,217	5,458
CO_2 Purchased (MMcf)			1,461	2,922	4,348	5,343	6,079	5,177	4,191	3,168	2,512	2,088	1,817
CO_2 Recycled (MMcf)			-	-	35	501	1,226	2,129	3,114	4,137	4,793	5,217	5,458
Oil Price ($/Bbl)	**$ 30.00**		$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	**37**		$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25
Gross Revenues ($M)			$ -	$ 2,669	$ 13,712	$ 22,854	$ 28,487	$ 32,569	$ 33,466	$ 25,411	$ 18,459	$ 14,949	$ 13,331
Royalty ($M)	**-12.5%**		$ -	$ (334)	$ (1,714)	$ (2,857)	$ (3,561)	$ (4,071)	$ (4,183)	$ (3,176)	$ (2,307)	$ (1,869)	$ (1,666)
Severance Taxes ($M)	**-2.3%**		$ -	$ (54)	$ (276)	$ (460)	$ (573)	$ (655)	$ (674)	$ (511)	$ (371)	$ (301)	$ (268)
Ad Valorum ($M)	**-2.1%**		$ -	$ (50)	$ (256)	$ (426)	$ (531)	$ (607)	$ (624)	$ (474)	$ (344)	$ (279)	$ (248)
Net Revenue($M)			$ -	$ 2,232	$ 11,466	$ 19,111	$ 23,822	$ 27,236	$ 27,986	$ 21,249	$ 15,436	$ 12,501	$ 11,148
Capital Costs ($M)													
New Well - D&C		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Reworks - Producers to Producers		$ (88)	$ (88)	$ (88)	$ (88)	$ (88)	$ -	$ -	$ -	$ -	$ -		
Reworks - Producers to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Reworks - Injectors to Injectors		$ (34)	$ (34)	$ (34)	$ (34)	$ (34)	$ -	$ -	$ -	$ -	$ -		
Surface Equipment (new wells only)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
CO_2 Recycling Plant	**2**	$ -	$ -	$ (11,152)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	**1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (1,893)											
Total Capital Costs		$ (2,015)	$ (122)	$ (11,274)	$ (122)	$ (122)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)			$ (1,753)	$ (3,506)	$ (5,228)	$ (6,562)	$ (7,662)	$ (6,851)	$ (5,963)	$ (5,042)	$ (4,452)	$ (4,071)	$ (3,818)
O&M Costs ($M)													
Operating & Maintenance ($M)	**1**		$ (71)	$ (141)	$ (212)	$ (282)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)
Lifting Costs ($M)			$ (235)	$ (470)	$ (699)	$ (885)	$ (1,048)	$ (957)	$ (860)	$ (761)	$ (699)	$ (658)	$ (636)
G&A	**20%**		(61)	(122)	(182)	(234)	(280)	(262)	(243)	(223)	(210)	(202)	(198)
Total O&M Costs			$ (367)	$ (734)	$ (1,093)	$ (1,401)	$ (1,680)	$ (1,572)	$ (1,455)	$ (1,337)	$ (1,262)	$ (1,213)	$ (1,186)
Net Cash Flow ($M)		$ (2,015)	$ (2,243)	$ (13,282)	$ 5,023	$ 11,026	$ 14,479	$ 18,813	$ 20,567	$ 14,870	$ 9,722	$ 7,218	$ 6,144
Cum. Cash Flow		$ (2,015)	$ (4,258)	$ (17,540)	$ (12,517)	$ (1,491)	$ 12,988	$ 31,801	$ 52,368	$ 67,238	$ 76,960	$ 84,177	$ 90,321
Discount Factor	**25%**	1.00	0.80	0.64	0.51	0.41	0.33	0.26	0.21	0.17	0.13	0.11	0.09
Disc. Net Cash Flow		$ (2,015)	$ (1,794)	$ (8,501)	$ 2,572	$ 4,516	$ 4,744	$ 4,932	$ 4,313	$ 2,495	$ 1,305	$ 775	$ 528
Disc. Cum Cash Flow		$ (2,015)	$ (3,809)	$ (12,310)	$ (9,738)	$ (5,222)	$ (477)	$ 4,454	$ 8,768	$ 11,262	$ 12,567	$ 13,342	$ 13,870
NPV (BTx)	25%	$15,795											
NPV (BTx)	20%	$ 23,966											
NPV (BTx)	15%	$ 36,740											
NPV (BTx)	10%	$ 58,340											
IRR (BTx)		50.71%											

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

Field Cashflow Model															
State															
Field															
Formation		47													
Depth															
Distance from Trunkline		109													
# of Patterns															
Miscibility:	Miscible														
		12	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
CO2 Injection (MMcf)		7,126	6,978	6,829	6,680	6,561	6,561	6,561	6,562	6,561	6,561	6,561	6,561	6,561	6,561
H2O Injection (Mbw)		1,916	1,990	2,064	2,139	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198
Oil Production (Mbbl)		426	419	436	451	448	433	410	386	367	350	333	318	308	297
H2O Production (MBw)		2,103	2,142	2,174	2,216	2,261	2,264	2,257	2,252	2,244	2,241	2,242	2,241	2,242	2,240
CO2 Production (MMcf)		5,534	5,494	5,407	5,301	5,226	5,259	5,334	5,411	5,481	5,534	5,577	5,617	5,643	5,676
CO2 Purchased (MMcf)		1,593	1,483	1,422	1,379	1,336	1,303	1,227	1,151	1,080	1,028	985	944	919	886
CO2 Recycled (MMcf)		5,534	5,494	5,407	5,301	5,226	5,259	5,334	5,411	5,481	5,534	5,577	5,617	5,643	5,676
Oil Price ($/Bbl)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	37	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25
Gross Revenues ($M)		$ 12,469	$ 12,248	$ 12,764	$ 13,196	$ 13,112	$ 12,662	$ 12,004	$ 11,293	$ 10,732	$ 10,235	$ 9,749	$ 9,307	$ 8,994	$ 8,685
Royalty ($M)	-12.5%	$ (1,559)	$ (1,531)	$ (1,596)	$ (1,649)	$ (1,639)	$ (1,583)	$ (1,501)	$ (1,412)	$ (1,341)	$ (1,279)	$ (1,219)	$ (1,163)	$ (1,124)	$ (1,086)
Severance Taxes ($M)	-2.3%	$ (251)	$ (246)	$ (257)	$ (266)	$ (264)	$ (255)	$ (242)	$ (227)	$ (216)	$ (206)	$ (196)	$ (187)	$ (181)	$ (175)
Ad Valorum ($M)	-2.1%	$ (232)	$ (228)	$ (238)	$ (246)	$ (244)	$ (236)	$ (224)	$ (210)	$ (200)	$ (191)	$ (182)	$ (173)	$ (168)	$ (162)
Net Revenue($M)		$ 10,427	$ 10,242	$ 10,674	$ 11,035	$ 10,964	$ 10,589	$ 10,038	$ 9,444	$ 8,974	$ 8,559	$ 8,153	$ 7,783	$ 7,521	$ 7,263
Capital Costs ($M)															
New Well - D&C															
Reworks - Producers to Producers															
Reworks - Producers to Injectors															
Reworks - Injectors to Injectors															
Surface Equipment (new wells only)															
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction															
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)															
Total CO2 Cost ($M)		$ (3,571)	$ (3,428)	$ (3,328)	$ (3,245)	$ (3,171)	$ (3,141)	$ (3,073)	$ (3,004)	$ (2,941)	$ (2,894)	$ (2,855)	$ (2,818)	$ (2,795)	$ (2,766)
O&M Costs ($M)															
Operating & Maintenance ($M)	1	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)
Lifting Costs ($M)		$ (632)	$ (640)	$ (652)	$ (667)	$ (677)	$ (674)	$ (667)	$ (660)	$ (653)	$ (648)	$ (644)	$ (640)	$ (637)	$ (634)
G&A	20%	(197)	(199)	(201)	(204)	(206)	(205)	(204)	(202)	(201)	(200)	(199)	(199)	(198)	(197)
Total O&M Costs		$ (1,182)	$ (1,191)	$ (1,206)	$ (1,223)	$ (1,236)	$ (1,232)	$ (1,224)	$ (1,215)	$ (1,207)	$ (1,201)	$ (1,196)	$ (1,191)	$ (1,188)	$ (1,184)
Net Cash Flow ($M)		$ 5,674	$ 5,623	$ 6,139	$ 6,567	$ 6,558	$ 6,215	$ 5,742	$ 5,225	$ 4,827	$ 4,465	$ 4,102	$ 3,773	$ 3,538	$ 3,313
Cum. Cash Flow		$ 95,995	$ 101,618	$ 107,757	$ 114,324	$ 120,882	$ 127,097	$ 132,839	$ 138,064	$ 142,891	$ 147,355	$ 151,457	$ 155,231	$ 158,769	$ 162,082
Discount Factor	25%	0.07	0.05	0.04	0.04	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Disc. Net Cash Flow		$ 390	$ 309	$ 270	$ 231	$ 185	$ 140	$ 103	$ 75	$ 56	$ 41	$ 30	$ 22	$ 17	$ 13
Disc. Cum Cash Flow		$ 14,260	$ 14,569	$ 14,839	$ 15,070	$ 15,255	$ 15,394	$ 15,498	$ 15,573	$ 15,629	$ 15,670	$ 15,700	$ 15,723	$ 15,739	$ 15,752
NPV (BTx)	25%														
NPV (BTx)	20%														
NPV (BTx)	15%														
NPV (BTx)	10%														
IRR (BTx)															

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

Field Cashflow Model		26	27	28	29	30	31	32	33	34	35	36
State												
Field												
Formation												
Depth												
Distance from Trunkline												
# of Patterns												
Miscibility:	Miscible											
CO2 Injection (MMcf)		6,561	6,562	6,561	6,338	5,026	3,714	2,401	1,089	-	-	-
H2O Injection (Mbw)		2,198	2,198	2,198	2,310	2,966	3,622	3,918	3,478	2,927	1,831	736
Oil Production (Mbbl)		289	284	280	275	274	269	247	194	141	85	33
H2O Production (MBw)		2,233	2,232	2,228	2,231	2,475	2,983	3,208	2,762	2,310	1,620	670
CO2 Production (MMcf)		5,714	5,730	5,752	5,815	5,551	4,626	3,550	2,393	1,194	311	78
CO2 Purchased (MMcf)		848	831	809	523	-	-	-	-	-	-	-
CO2 Recycled (MMcf)		5,714	5,730	5,752	5,815	5,026	3,714	2,401	1,089	-	-	-
Oil Price ($/Bbl)	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00
Gravity Adjustment	37	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25	$ 29.25
Gross Revenues ($M)		$ 8,459	$ 8,301	$ 8,178	$ 8,048	$ 8,001	$ 7,868	$ 7,231	$ 5,688	$ 4,135	$ 2,497	$ 974
Royalty ($M)	**-12.5%**	$ (1,057)	$ (1,038)	$ (1,022)	$ (1,006)	$ (1,000)	$ (983)	$ (904)	$ (711)	$ (517)	$ (312)	$ (122)
Severance Taxes ($M)	**-2.3%**	$ (170)	$ (167)	$ (165)	$ (162)	$ (161)	$ (158)	$ (146)	$ (114)	$ (83)	$ (50)	$ (20)
Ad Valorum ($M)	**-2.1%**	$ (158)	$ (155)	$ (152)	$ (150)	$ (149)	$ (147)	$ (135)	$ (106)	$ (77)	$ (47)	$ (18)
Net Revenue($M)		$ 7,074	$ 6,942	$ 6,839	$ 6,730	$ 6,691	$ 6,579	$ 6,046	$ 4,756	$ 3,458	$ 2,088	$ 815
Capital Costs ($M)												
New Well - D&C												
Reworks - Producers to Producers												
Reworks - Producers to Injectors												
Reworks - Injectors to Injectors												
Surface Equipment (new wells only)												
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction												
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
Total CO2 Cost ($M)		$ (2,731)	$ (2,717)	$ (2,697)	$ (2,373)	$ (1,508)	$ (1,114)	$ (720)	$ (327)	$ -	$ -	$ -
O&M Costs ($M)												
Operating & Maintenance ($M)	1	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (353)	$ (282)	$ (212)	$ (141)	$ (71)
Lifting Costs ($M)		$ (631)	$ (629)	$ (627)	$ (627)	$ (687)	$ (813)	$ (864)	$ (739)	$ (613)	$ (426)	$ (176)
G&A	20%	(197)	(196)	(196)	(196)	(208)	(233)	(243)	(204)	(165)	(113)	(49)
Total O&M Costs		$ (1,180)	$ (1,178)	$ (1,176)	$ (1,175)	$ (1,248)	$ (1,399)	$ (1,460)	$ (1,226)	$ (989)	$ (681)	$ (296)
Net Cash Flow ($M)		$ 3,163	$ 3,047	$ 2,966	$ 3,183	$ 3,935	$ 4,066	$ 3,866	$ 3,204	$ 2,468	$ 1,407	$ 519
Cum. Cash Flow		$ 165,244	$ 168,291	$ 171,258	$ 174,440	$ 178,375	$ 182,442	$ 186,308	$ 189,512	$ 191,980	$ 193,388	$ 193,906
Discount Factor	25%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Disc. Net Cash Flow		$ 10	$ 7	$ 6	$ 5	$ 5	$ 4	$ 3	$ 2	$ 1	$ 1	$ 0
Disc. Cum Cash Flow		$ 15,761	$ 15,769	$ 15,774	$ 15,779	$ 15,784	$ 15,788	$ 15,791	$ 15,793	$ 15,795	$ 15,795	$ 15,795
NPV (BTx)	25%											
NPV (BTx)	20%											
NPV (BTx)	15%											
NPV (BTx)	10%											
IRR (BTx)												

5.8 PERFORMING SCENARIO ANALYSES. A series of 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 the Permian Basin'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 $30 per barrel oil price was used to represent the moderate oil price case; a $40 per barrel oil price was used to represent the availability of Federal /state risk sharing 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 4% of the oil price ($1.20 per Mcf at $30 per barrel) to represent the costs of a new transportation system bringing natural CO_2 to the Permian Basin's oil basins. A lower CO_2 supply cost equal to 2% of the oil price ($0.80 per Mcf at $40 per barrel) was included to represent the potential future availability of low-cost CO_2 from industrial and power plants as part of CO_2 storage.

- Two minimum rate of return (ROR) hurdles were considered, 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.

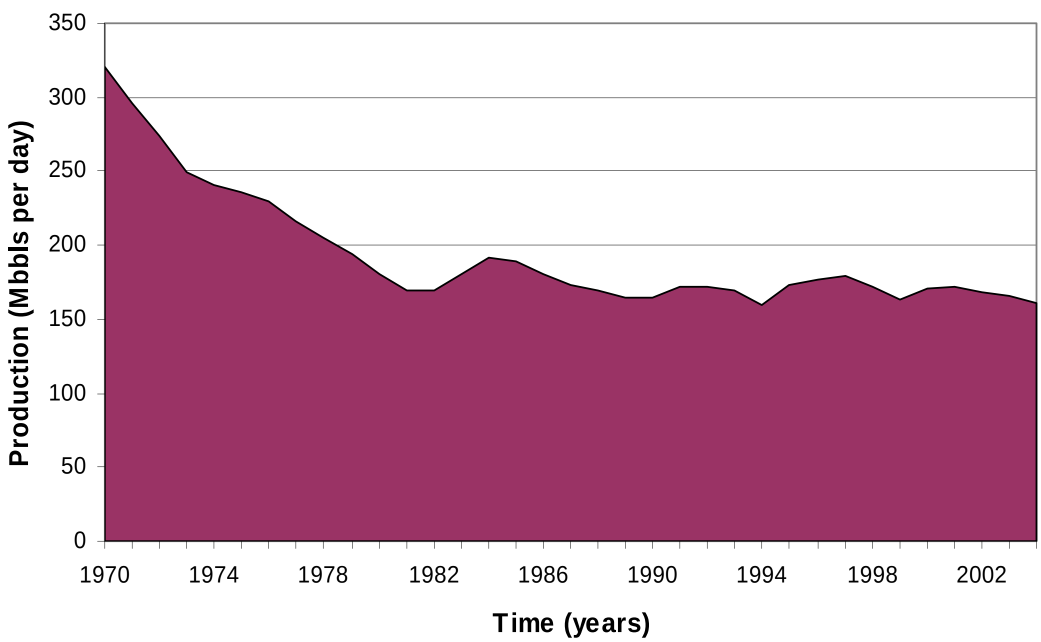
These various technology, oil price, CO_2 supply cost and rate of return hurdles were combined into four scenarios, as set forth below:

- The first scenario captures how CO_2-EOR technology has been applied and has performed in the past. This low technology, high risk scenario, is called "Traditional Practices".
- The second scenario, entitled "State-of-the-art", assumes that the technology progress in CO_2-EOR, achieved in the past ten years in other areas, is successfully applied to the oil reservoirs of the Permian Basin. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations will help lower the risk inherent in applying new technology to these complex Permian Basin oil reservoirs.
- The third scenario, entitled "Risk Mitigation incentives," examines how the economic potential of CO_2-EOR could be increased through a strategy involving state production tax reductions, federal tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to the price that the producer receives for produced crude oil.
- The final scenario, entitled "Ample Supplies of CO_2," low-cost, "EOR-ready" CO_2 supplies are aggregated from various industrial and natural sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants, chemical plants and other sources in the region. These would be augmented, in the longer-term, from concentrated CO_2 emissions from refineries and electric power plants. Capture of industrial CO_2 emissions could be part of a national effort for reducing greenhouse gas emissions.

6. RESULTS BY STATE

6.1 NEW MEXICO. Crude oil production in New Mexico began in 1920's, reaching a cumulative recovery of 5 billion barrels through 2004. In 2004, New Mexico ranked 5th in crude oil production in the onshore U.S., producing approximately 59 MMBbls of oil (161 MBbls per day). It has about 27,389 producing oil wells and oil reserves of 677 MMBbls. Oil production in New Mexico peaked at 353 MBbls per day (129 MMBbls a year) and has declined since then, Figure 11.

Figure 11. New Mexico History of Oil Production Rates



An active program of secondary and tertiary oil recovery has helped maintain oil production in the past five years, Table 13. However, many waterfloods are now mature, with many of the fields near their production limits, requiring greater reliance on tertiary oil recovery, particularly CO_2-EOR for maintaining oil production.

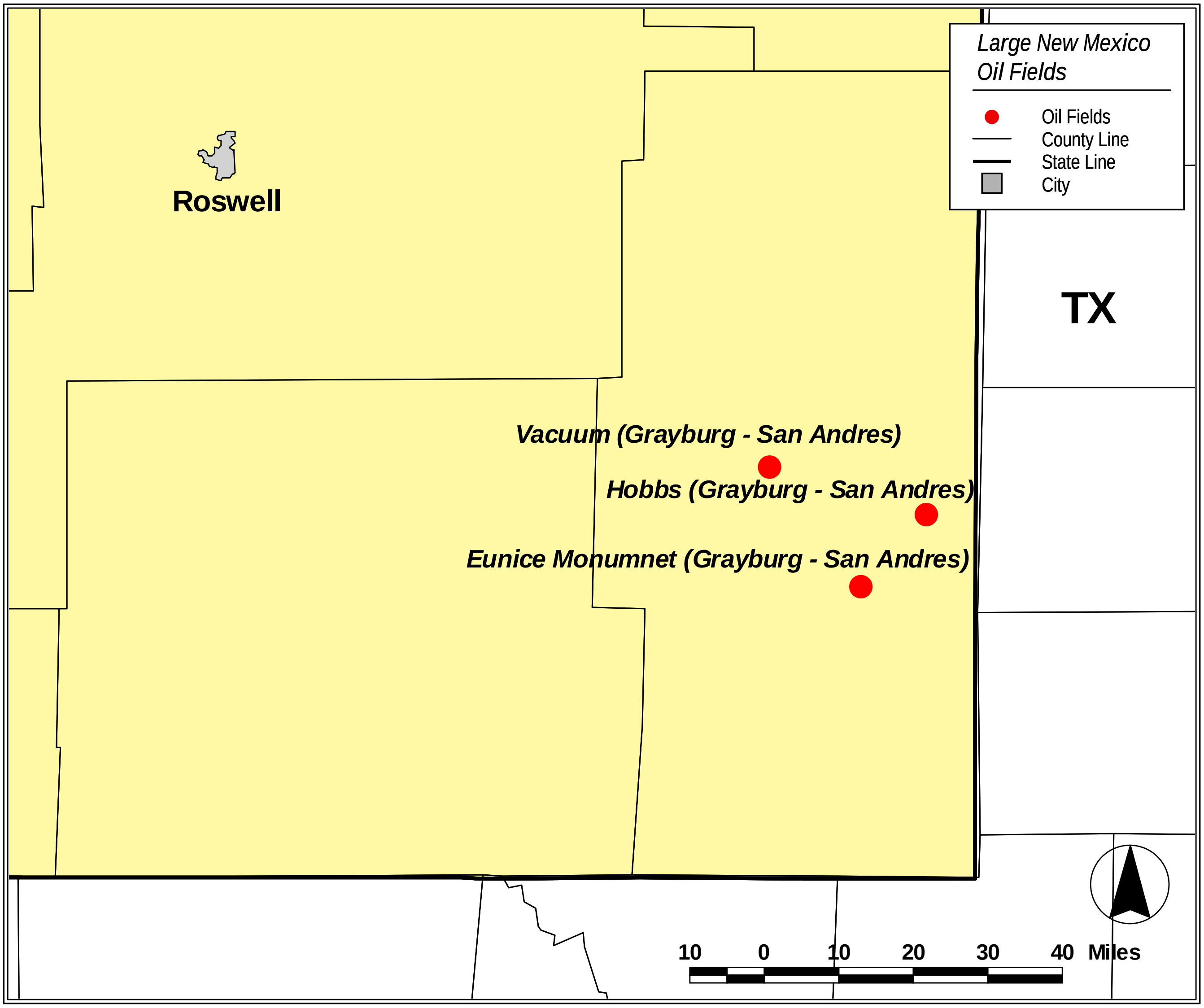
Table 13. Recent History of New Mexico Oil Production

	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
2000	62	171
2001	63	172
2002	62	168
2003	61	166
2004	59	161

New Mexico Oil Fields. To better understand the potential of using CO_2-EOR in New Mexico's light oil fields, this section examines, in more depth, three large oil fields, shown in Figure 12.

- Eunice Monument (Grayburg-San Andres)
- Hobbs (Grayburg-San Andres)
- Vacuum (Grayburg-San Andres)

Figure 12. Large New Mexico Oil Fields



Two of these three fields, the Hobbs and Vacuum Fields, are already under CO_2 flood. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for these three large light oil fields are set forth in Table 14.

Table 14. Status of Large New Mexico Oil Fields/Reservoirs (as of 2002)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Primary/ Secondary Production (MMBbls)	Proved Primary/ Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Eunice Monument (Grayburg-San Andres)	2,000	392	22	1,586
2	Hobbs (Grayburg-San Andres)	873	342	10	521
3	Vacuum (Grayburg-San Andres)	1,001	331	19	651

These three large "anchor" fields, each with 500 or more million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 15.

Table 15. Reservoir Properties and Improved Oil Recovery Activity, Large New Mexico Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Eunice Monument (Grayburg-San Andres)	4,400	32	Undergoing waterflooding
2	Hobbs (Grayburg-San Andres)	4,100	34	Undergoing CO_2 flooding
3	Vacuum (Grayburg-San Andres)	4,500	36	Undergoing CO_2 flooding

Past CO_2-EOR Projects. Table 16 lists the tertiary oil production for past and current CO_2 pilots/projects in the Permian Basin portion of New Mexico. Appendix E provides a more detailed analysis of the successful implementation of the CO_2 flood in the East Vacuum GSA Unit of the Vacuum Field.

Table 16. Past and Current CO_2-EOR Project/Pilot Production, New Mexico

Field	Reservoir	2004 CO_2-EOR (MMBbls)	Total CO_2-EOR (MMBbls)
Maljamar	Grayburg-San Andres	-	0.58
Vacuum	San Andres	2.94	24.80
Hobbs	San Andres	0.31	0.62
TOTAL		3.25	26.00

Future CO_2-EOR Potential. New Mexico contains 55 reservoirs that are candidates for miscible CO_2-EOR. Under "Traditional Practices" (and Base Case financial conditions, defined above), there is one economically attractive oil reservoir for miscible CO_2 flooding in New Mexico. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection) and lower risk financial conditions, the number of economically favorable oil reservoirs in New Mexico increases to 15, providing 640 million barrels of additional oil recovery, Table 17.

Table 17. Economic Oil Recovery Potential Under Two Technologic Conditions, New Mexico

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential*	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"	55	11,873	1,280	1	20
"State-of-the-art" Technology	55	11,873	2,850	15	830

* Oil price of $30 per barrel; CO_2 costs of $1.20/Mcf.

Combining “State-of-the-art” technologies with risk mitigation incentives and/or higher oil prices and lower cost CO_2 supplies would enable CO_2-EOR in New Mexico to recover 1,040 million barrels of CO_2-EOR oil (from 19 major reservoirs), Table 18. A portion of this CO_2-EOR potential has already been developed in New Mexico, as discussed above.

Table 18. Economic Oil Recovery Potential with More Favorable Financial Conditions, New Mexico

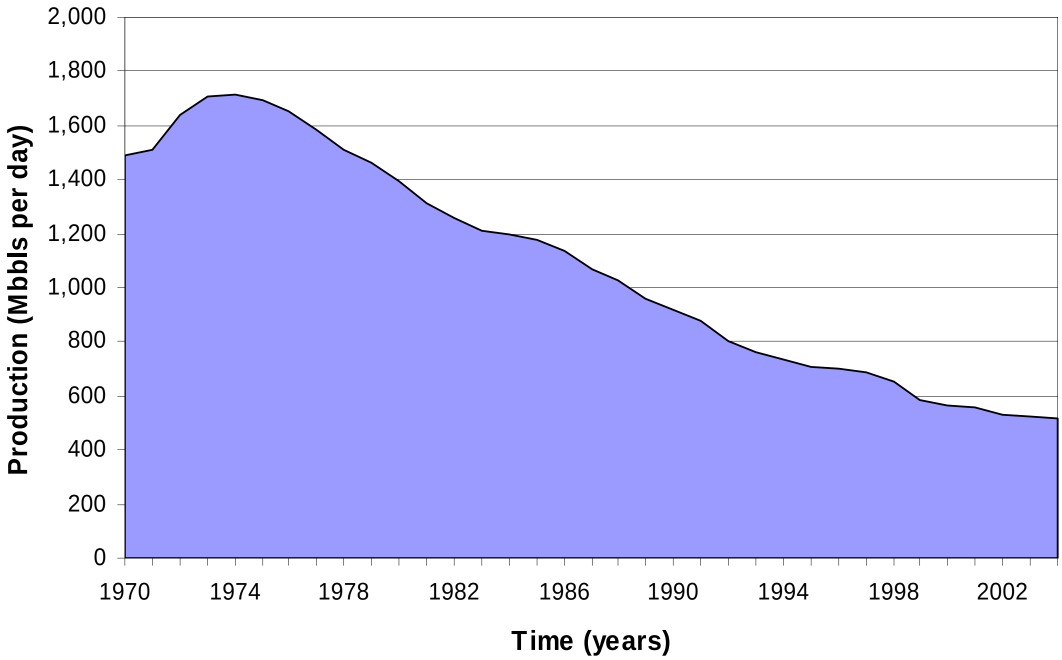
More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation Incentives*	2,846	16	840
Plus: Low Cost CO_2 Supplies**	2,846	19	1,040

** Oil price of $40 per barrel, adjusted for gravity and location differentials; CO_2 supply costs, $1.60/Mcf*

*** CO_2 supply costs, $0.80/Mcf*

6.2 WEST TEXAS. The West Texas portion of the Permian Basin (Railroad Districts 8 and 8A) is one of the largest oil producing regions in the world. In 2004, West Texas ranked only behind the state of Alaska in onshore U.S. oil production, producing approximately 235 MMBbls of oil (644 MBbls per day) 13.5% of the U.S. total. Oil production in West Texas began in 1921 and peaked at 1,715 MBbls per day (626 MMBbls a year) in 1974, Figure 13. Cumulative oil production in West Texas has reached 25 billion barrels with 3.6 billion barrels of oil reserves.

Figure 13. West Texas History of Oil Production Rates



Application of secondary and tertiary recovery methods have significantly slowed the oil production decline in West Texas in recent years, Table 19.

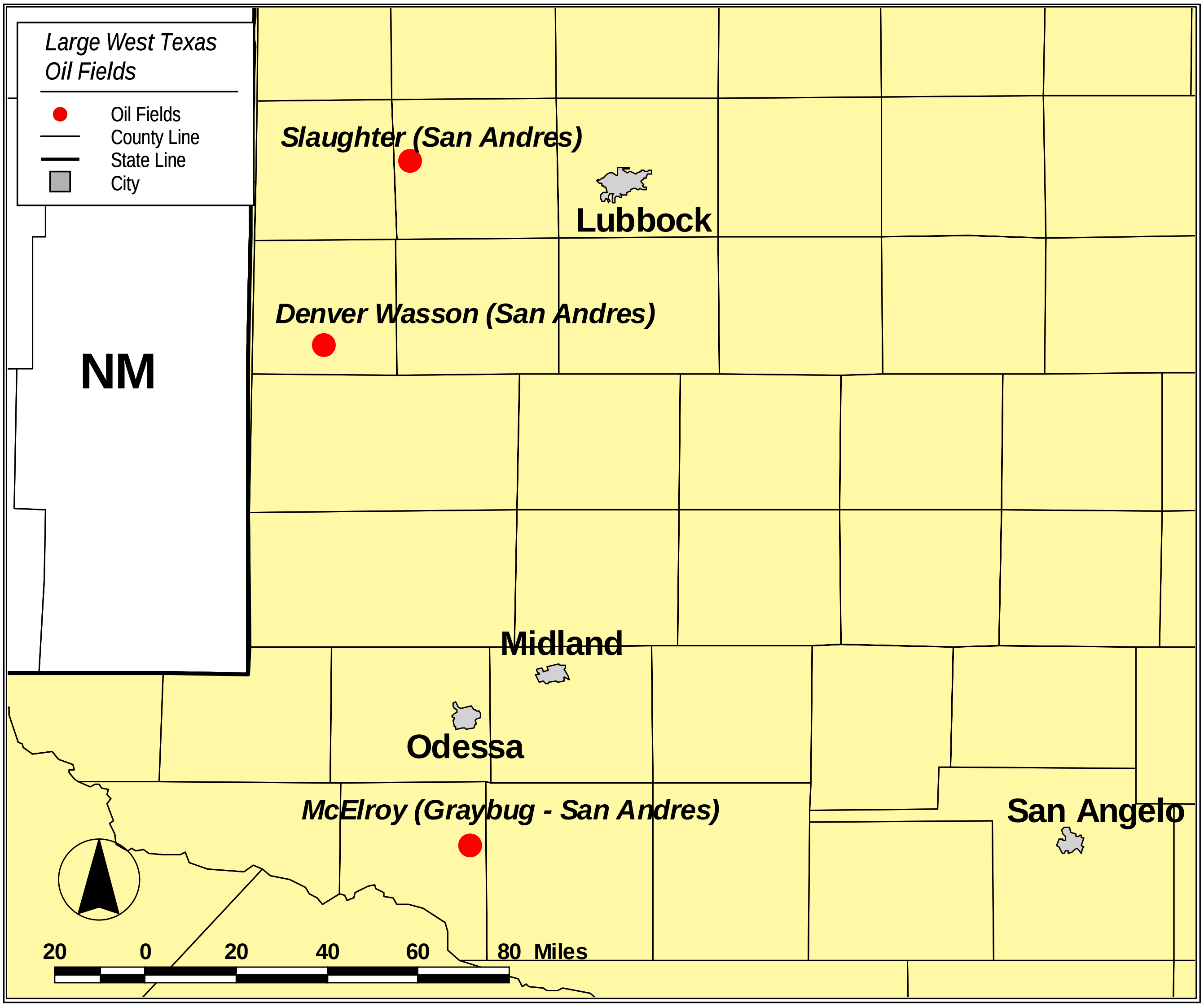
Table 19. Recent History of West Texas Oil Production

	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
2000	259	710
2001	258	705
2002	248	680
2003	248	680
2004	235	644

West Texas Oil Fields. To better understand the potential of using CO_2-EOR in West Texas's light oil fields, this section examines, in more depth, three large oil fields, shown in Figure 14.

- Slaughter (San Andres)
- McElroy (Grayburg-San Andres)
- Denver Wasson (San Andres)

Figure 14. Large West Texas Oil Fields



Two of these three major oil fields already have ongoing CO_2 flooding projects and the third, McElroy (Grayburg-San Andres) had plans to inject CO_2. The cumulative oil production and proved reserves from primary/secondary recovery plus remaining oil in-place (ROIP) for these three major light oil reservoirs are set forth in Table 20.

Table 20. Status of Large West Texas Oil Fields/Reservoirs (as of 2002)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Primary/Secondary Production (MMBbls)	Proved Primary/Secondary Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Slaughter (San Andres)	3,600	1,150*	99*	2,351
2	McElroy (Grayburg-San Andres)	2,544	562	70	1,912
3	Denver Wasson (San Andres)	2,372	1,042*	57*	1,273

Excluding CO_2-EOR

These three large oil reservoirs, with over 1 billion barrels of ROIP, are amenable to CO_2-EOR. Table 21 provides the reservoir and oil properties for these three reservoirs and their current secondary oil recovery activities.

Table 21. Reservoir Properties and Improved Oil Recovery Activity, Large West Texas Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Slaughter (San Andres)	5,000	32	Active CO_2 Flood
2	McElroy (Grayburg-San Andres)	3,000	32	Active Waterflood
3	Denver Wasson (San Andres)	5,200	33	Active CO_2 Flood

Past and Current CO_2-EOR Projects. Table 22 lists the reported tertiary production from past and current CO_2 pilots/projects in the West Texas portion of the Permian Basin. Presented in Appendix F is a more detailed analysis of the successful implementation of the CO_2 flood in the Salt Creek Field.

Table 22. Past and Current CO_2-EOR Project/Pilot Production, West Texas

Field	Reservoir	2004 CO_2-EOR (MMBbls)	Total CO_2-EOR (MMBbls)
ADAIR	SAN ANDRES	0.3	1.8
ALVORD SOUTH	CADDO	-	0.7
ANTON IRISH	CLEARFORK	2.6	13.8
CEDAR LAKE	SAN ANDRES	1.4	9.3
COGDELL	CANYON REEF	0.2	0.4
CORDONA LAKE	DEVONIAN	0.1	4.0
COWDEN NORTH	GRAYBURG-SAN ANDRES	0.1	2.0
COWDEN SOUTH	SAN ANDRES	0.1	0.7
CROSSETT	DEVONIAN	0.3	16.2
CROSSETT SOUTH	DEVONIAN	1.2	8.8
DOLLARHIDE	DEVONIAN/CLEARFORK	0.1	9.9
GMK	SAN ANDRES	0.2	2.5
FORD GERALDINE	DELAWARE	-	5.4
EAST HUNTLEY	SAN ANDRES	-	0.2
SACROC	CANYON REEF	8.1	202.8
LEVELLAND UNIT	SAN ANDRES	-	4.6
MABEE	SAN ANDRES	0.7	13.7
MEANS	SAN ANDRES	3.2	43.4
EAST PENWELL	SAN ANDRES	0.1	0.3
REINECKE	CISCO	0.4	2.8
SABLE	SAN ANDRES	-	1.3
SALT CREEK	CANYON	3.4	42.0
SEMINOLE	SAN ANDRES	8.3	141.0
SHARON RIDGE	CANYON REEF	0.4	1.8
SLAUGHTER	SAN ANDRES	6.9	84.6
SPRAYBERRY	SPRAYBERRY	-	*
TWOFREDS	DELAWARE	0.1	4.6
NORTH WARD ESTES	YATES	-	4.1
WASSON	SAN ANDRES	14.6	254.6
WELCH	SAN ANDRES	-	4.2
WELLMAN	WOLFCAMP	-	8.0

Future CO_2-EOR Potential. West Texas contains 127 large light oil reservoirs that are candidates for miscible CO_2-EOR.

Under "Traditional Practices" (and Base Case financial conditions, defined above), there are 8 economically attractive oil reservoirs for miscible CO_2 flooding in West Texas. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection and lower risk), the number of economically feasible oil reservoirs increases to 52, providing 6,830 million barrels of additional oil recovery, Table 23.

Table 23. Economic Oil Recovery Potential Under Two Technologic Conditions, West Texas

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential*	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"	127	47,395	5,600	8	660
"State-of-the-art" Technology	127	47,395	12,440	52	6,830

** Oil price of $30 per barrel; CO2 costs of $1.20/Mcf.*

Combining "State-of-the-art" technology with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies, would enable CO_2-EOR in West Texas to recover an additional 9,880 million barrels of CO_2-EOR oil (from 81 major oil reservoirs), Table 24. A portion of this CO_2-EOR potential is already being developed in West Texas, as discussed above.

Table 24. Economic Oil Recovery Potential with More Favorable Financial Conditions, West Texas

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation Incentives*	12,444	60	8,590
Plus: Low Cost CO_2 Supplies**	12,444	75	9,720

** Oil price of $40 per barrel, adjusted for gravity and location differentials; CO_2 supply costs, $1.60/Mcfs*

*** CO_2 supply costs, $0.80/Mcf*

Appendix A

Permian Basin CO_2-EOR Projects

Table 1-A. Permian Basin CO_2-EOR Projects/Pilots

Field	Reservoir	Operator	Start Date	Project Area (acres)	Field Area (acres)	Depth (ft)	Prod Wells	Inj. Wells	Cumulative CO_2-EOR (MMBbls)	2004 CO_2-EOR Rate (bopd)	Estimated Ultimate Recovery (MMbbls)
Active Fields											
ADAIR	SAN ANDRES	Amerada Hess	Nov-97	1,100	8,000	4,870	19	18	1.83	900	6.8
ANTON IRISH UNIT	CLEARFORK	Occidental Permian	Apr-97	2,853	7,543	5,900	93	75	13.6	7,089	52.9
CEDAR LAKE	SAN ANDRES	Occidental Permian	Aug-94	2,870	8,600	4,800	143	84	9.1	3,900	30.7
COGDELL AREA	CANYON REEF	Occidental Permian	1-Oct	2,204	25,488	6,700	77	37	3.6	5,400	33.6
CORDONA LAKE	DEVONIAN	ExxonMobil	Dec-85	2,084	2,900	5,400	30	20	4	400	6.0
COWDEN NORTH	SAN ANDRES	Occidental Permian	Feb-95	200	12,933	4,300	10	3	2	200	3.0
COWDEN SOUTH	SAN ANDRES-GRAYBURG	Phillips	Feb-81	4,900	23,795	4,100	43	22	0.7	250	1.9
CROSSETT	DEVONIAN	Occidental Permian	Apr-72	1,155	1,540	5,300	27	14	20.3	943	25.0
CROSSETT SOUTH	DEVONIAN	Occidental Permian	Jun-88	2,090	2,086	5,200	61	19	9.4	4,306	30.8
DOLLARHIDE	DEVONIAN	Pure Resources	May-85	6,183	7,834	8,000	83	66	9.3	2,600	22.2
DOLLARHIDE	CLEARFORK	Pure Resources	Nov-95	160	5,585	6,500	21	4	0.34	190	1.3
GMK	SAN ANDRES	ExxonMobil	1982	1,143	1,504	5,100	31	28	2.2	400	4.4
HOBBS	GRAYBURG-SAN ANDRES	Occidental Permian	3-Mar	800	12,847	4,100	52	20	0.62	1,700	7.8

Table 1-A. Permian Basin CO_2-EOR Projects/Pilots

Field	Reservoir	Operator	Start Date	Project Area (acres)	Field Area (acres)	Depth (ft)	Prod Wells	Inj. Wells	Cumulative CO_2-EOR (MMBbls)	2004 CO_2-EOR Rate (bopd)	Estimated Ultimate Recovery (MMbbls)
KELLY SNYDER	CANYON REEF	Kinder Morgan	Jan-72	49,900	49,900	6,700	300	300	200	23,000	327.6
MABEE	SAN ANDRES	Chevron Texaco	Jan-92	6,000	12,095	4,700	260	85	13.7	2,000	23.6
MEANS	SAN ANDRES	ExxonMobil	Nov-83	8,500	22,452	4,250	484	284	40.2	8,700	83.4
PENWELL	SAN ANDRES	First Permian	May-96	540	5,753	3800	34	13	0.29	100	0.8
REINECKE	CISCO	Pure Resources	Jan-98	700	7,182	6,791	32	8	2.7	1,200	9.4
SALT CREEK	CANYON REEF	ExxonMobil	Oct-93	12,000	12,097	6,300	137	100	36.7	9,300	88.3
SEMINOLE							423	170	131.9	24100	265.6
Main Pay	San Andres	Amerada Hess	Mar-83	15,669	15,669	5,300	408	160	129	22,700	254.9
ROZ Phase 1	San Andres	Amerada Hess	Jul-96	500	15,669	5,500	15	10	2.9	1,400	10.7
SHARON RIDGE	CANYON REEF	ExxonMobil	Feb-99	1,400	18,000	6,600	46	9	1.8	1,000	7.3
SLAUGHTER							898	700	77.1	18,887	181.9
Slaughter	San Andres	Amoco	Nov-72	12	79,097	4,950	0	0	0.5	0	0.5
Frazier	San Andres	Amoco	Dec-84	5,700	79,097	4,950	67	52	10.3	1,331	17.7
Estate	San Andres	Amoco	Dec-84	1,600	79,097	4,950	190	164	22.6	4,246	46.2
Slaughter	San Andres	Exxon	May-85	569	79,097	4,900	24	11	2.4	580	5.6

Table 1-A. Permian Basin CO_2-EOR Projects/Pilots

Field	Reservoir	Operator	Start Date	Project Area (acres)	Field Area (acres)	Depth (ft)	Prod Wells	Inj. Wells	Cumulative CO_2-EOR (MMBbls)	2004 CO_2-EOR Rate (bopd)	Estimated Ultimate Recovery (MMbbls)
Slaughter	San Andres	Mobil	Jun-89	2,495	79,097	5,000	228	154	12.9	4,000	35.1
Central Mallet	San Andres	Amoco	Jan-84	6,412	79,097	4,900	181	137	13.5	3,000	30.1
Sundown	San Andres	Texaco	Jan-94	8,685	79,097	4,950	155	144	14.2	4,978	41.8
HT Boyd	San Andres	Anadarko	1-Aug	1,240	79,097	5,000	32	24	0.2	300	1.9
Alex Estate	San Andres	Occidental Permian	Aug-00	246	79,097	4,950	21	14	0.5	452	3.0
TWOFREDS	DELAWARE	Great Western Drilling	Jan-74	4,392	4,473	4,820	32	9	6.4	170	7.2
VACUUM							3744	1961	24	91,402	58.0
Vacuum	San Andres	Phillips	Feb-81	4,900	19,205	4,500	192	103	17.7	5,200	39.5
Vacuum	Sam Andres	Chevron Texaco	Jul-97	2,240	19,205	4,550	48	24	6.5	2,846	18.4
WASSON							1639	843	226.5	40533	451.4
Denver Unit	SAN ANDRES	Occidental Permian	Apr-83	20,000	27,848	5,200	916	464	149.8	25,560	291.6
Cornell Unit	SAN ANDRES	ExxonMobil	Jul-85	1,923	1,923	5,200	61	50	4.2	700	8.1
Williard Unit	SAN ANDRES	Occidental Permian	Jan-86	8,000	10,787	5,100	312	128	22.3	4,094	45.0
Bennett Ranch Unit	SAN ANDRES	Occidental Permian	Jun-95	830	7,028	5,100	51	38	3.1	1,803	13.1
ODC Unit	SAN ANDRES	Occidental Permian	Nov-84	7,800	7,841	5,100	299	163	47.1	8,376	93.6

Table 1-A. Permian Basin CO_2-EOR Projects/Pilots

Field	Reservoir	Operator	Start Date	Project Area (acres)	Field Area (acres)	Depth (ft)	Prod Wells	Inj. Wells	Cumulative CO_2-EOR (MMBbls)	2004 CO_2-EOR Rate (bopd)	Estimated Ultimate Recovery (MMbbls)
WELCH							113	74	4.1	1145	10.5
Welch	San Andres	Cities Service	Feb-82	2,675	27,959	4,890	0	0	0.4	0	0.4
South Welch	San Andres	Oxy USA	Sep-93	1,160	27,959	4,900	89	68	3.6	1,095	9.7
West Welch	San Andres	Oxy USA	Oct-97	240	27,959	4,900	24	6	0.1	50	0.4
Total Active Fields: 26									843	166,459	1,741
Inactive Fields											
GERALDINE	FORD	Conoco	Feb-81	3,850	7,272	2,600	0	0	5.41	0	5.4
HUNTLEY							0	0	0.41	0	0.4
East	San Andres	Conoco	Jan-94	700	865	3,400	0	0	0.19	0	0.2
South	San Andres	Conoco	Jan-94	560	865	3,100	0	0	0.22	0	0.2
LEVELLAND UNIT							0	0	0.07	0	0.1
Levelland	San Andres	Amoco	Mar-73	13	37,587	4,900	0	0	0.05	0	0.1
Levelland	San Andres	Texaco	Aug-78	15	37,587	4,900	0	0	0.02	0	0.0
MALJAMAR							0	0	0.58	0	0.6
Maljamar MCA Unit	Grayburg-San Andres	Conoco	May-83	5	20,418	3,665	0	0	0.05	0	0.1

Table 1-A. Permian Basin CO_2-EOR Projects/Pilots

Field	Reservoir	Operator	Start Date	Project Area (acres)	Field Area (acres)	Depth (ft)	Prod Wells	Inj. Wells	Cumulative CO_2-EOR (MMBbls)	2004 CO_2-EOR Rate (bopd)	Estimated Ultimate Recovery (MMbbls)
Maljamar	Grayburg-San Andres	Conoco	Jan-89	1,200	20,418	4,200	0	0	0.53	0	0.5
Maljamar	Grayburg-San Andres	Phillips	Nov-89	40	20,418	4,600	0	0	0	0	0.0
SABLE	SAN ANDRES	Arco	Dec-84	7,800	-	5,200	0	0	1.34	0	1.3
UNIVERSITY WADDELL	DEVONIAN	Chevron	May-83	920	7,004	9,040	0	0	0.05	0	0.1
WARD ESTES NORTH	YATES-SEVEN RIVERS	Chevron	Mar-89	3,840	32,302	3,000	0	0	4.09	0	4.1
WELLMAN	WOLFCAMP	Union Texas Petroleum	Jul-83	1,400	1,400	9,712	0	0	7.96	0	8.0
Total Inactive Fields: 8									19.5	0	19.5

Appendix B

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 Permian Basin 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_2PM*.

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 California 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_2PM*

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_2PM*:

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

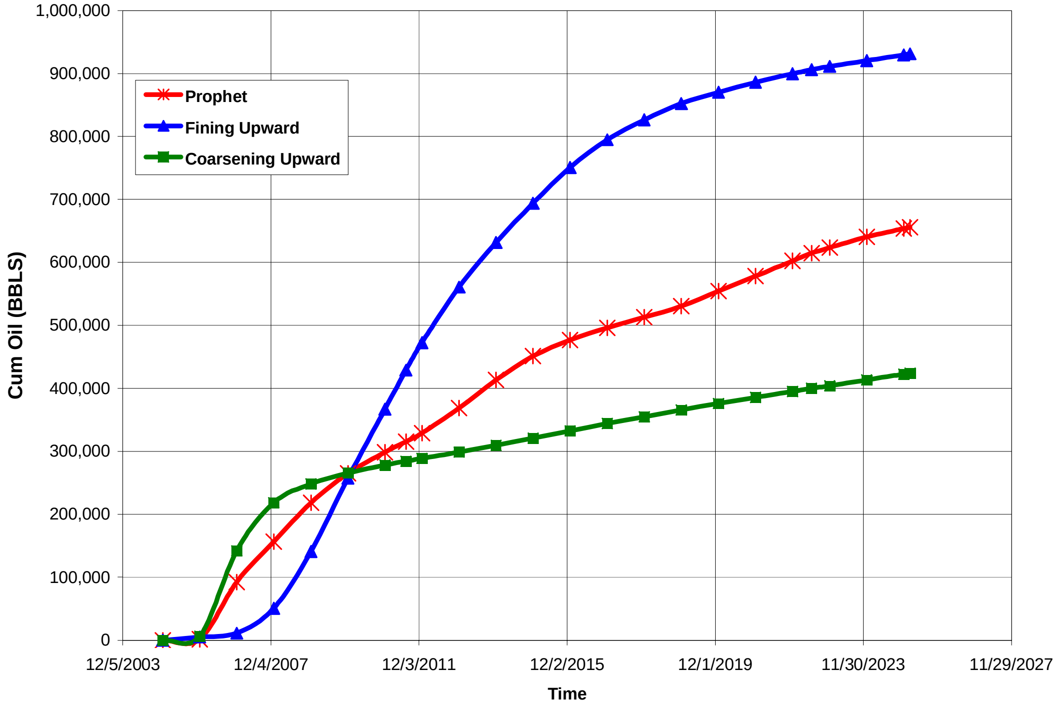
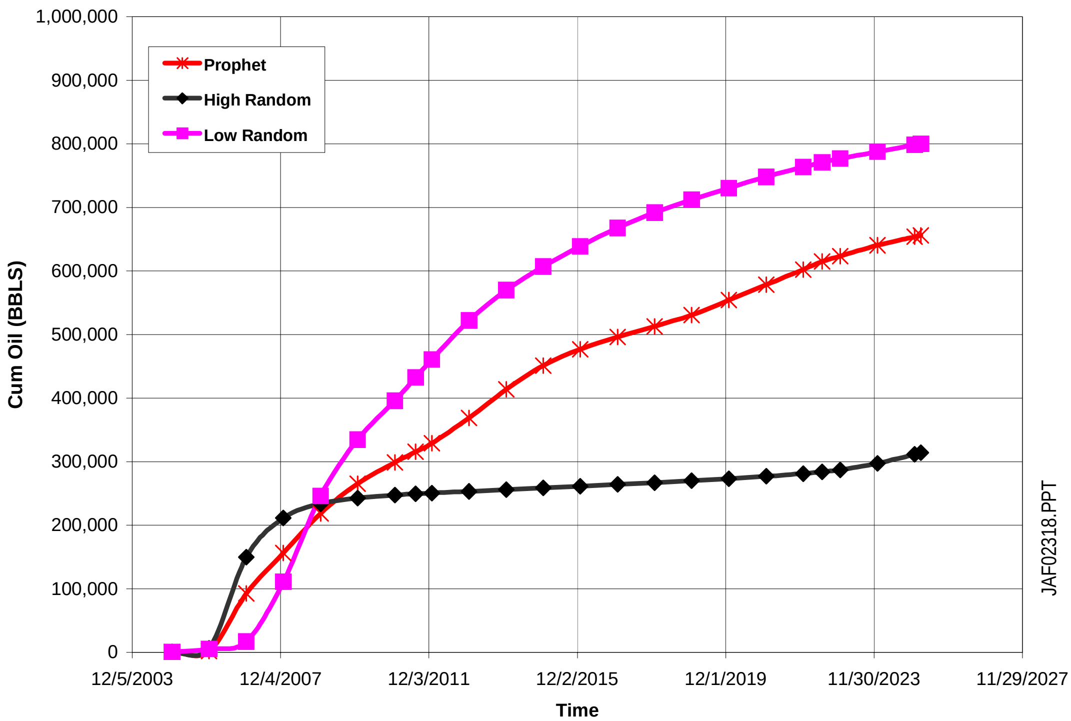


Figure A-2. *CO_2-PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



- *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_2PM* 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_2PM*.
- 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_2PM*.
- *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_2PM* is limited to miscible CO_2.

Appendix C

New Mexico 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 2003 JAS cost study recently published by API for New Mexico.

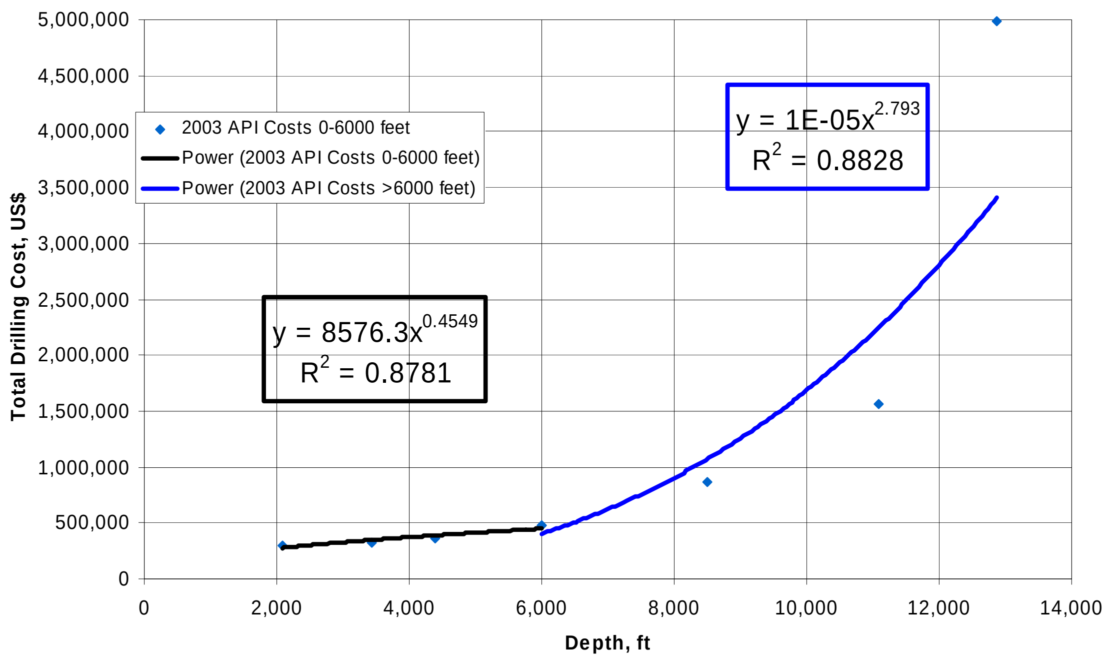
The well D&C cost equation has fixed cost constants for site preparation and other fixed cost items and variable cost equations that increases exponentially with depth for depths 0-6000 feet and greater than 6000 feet. The total equation is:

New Mexico drilling, 0-6000 feet
Well D&C Costs = $a_0D^{a_1}$
Where: a_0 is 8576
a_1 is 10.45
D is well depth

New Mexico drilling, >6000 feet
Well D&C Costs = $a_0D^{a_1}$
Where: a_0 is 1×10^{-5}
a_1 is 2.79
D is well depth

Figure C-1 provides the details for the cost equation and illustrates the "goodness of fit" for the well D&C cost equation for New Mexico.

Figure C-1. Oil Well D&C Costs for New Mexico



In order to bring the 2003 API drilling costs (the most recent available) into 2004 numbers where increased oil prices are expected to result in significantly increased drilling costs, a relationship was established between average drilling costs and average annual oil prices. Drillings costs from the ten year period of 1994-2003 (API data) were plotted versus the three year weighted average annual oil prices for those years (EIA Annual Energy Review, 2004) and the following relationship was established:

Drilling costs (per foot) = \$5.04(annual oil price) – \$3.2116.

Applying the 2004 average oil price of \$36.77 gives a drilling cost of \$182 per foot and an increase of 25.6% over the 2003 cost of \$145 per foot. Therefore, drilling and completion costs were increased by 25% over the New Mexico D&C cost calculations to reflect this increase in 2004 drilling costs.

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 2004 “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.

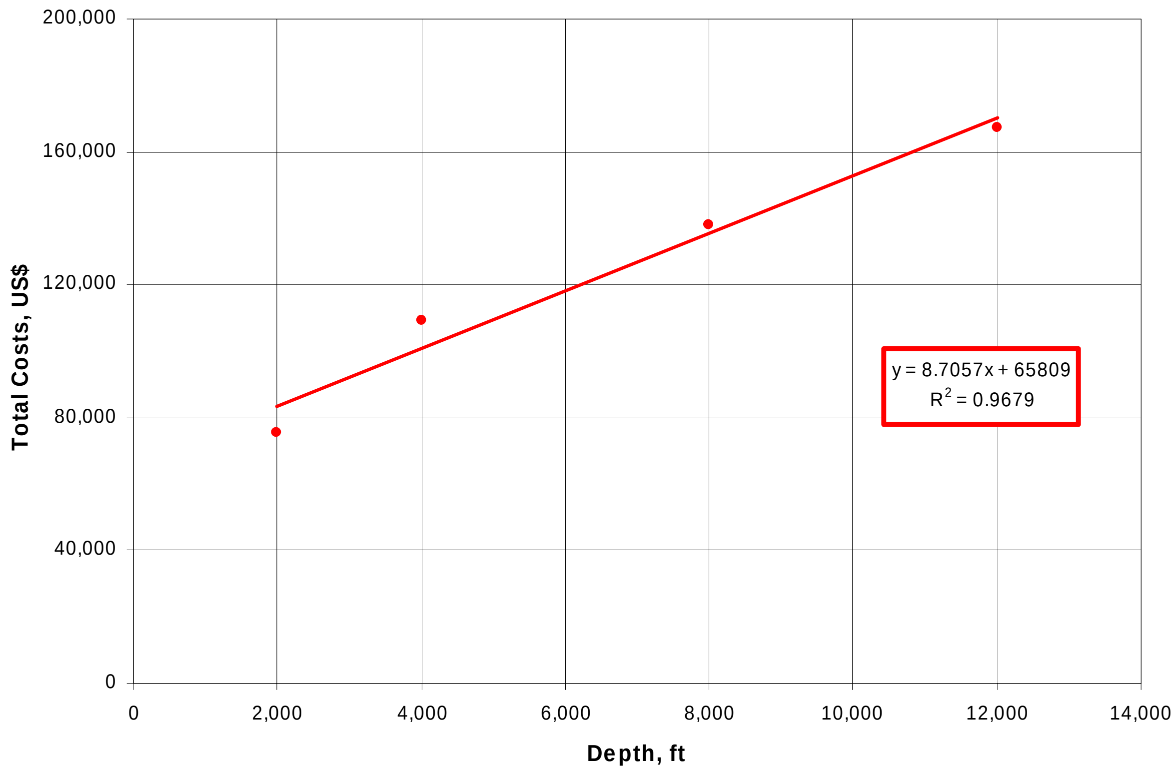
The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$65,809 (fixed)

c_1 = \$8.706 per foot
D is well depth

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

Figure C-2. Lease Equipping Cost for a New Oil Production Well in New Mexico vs. Depth



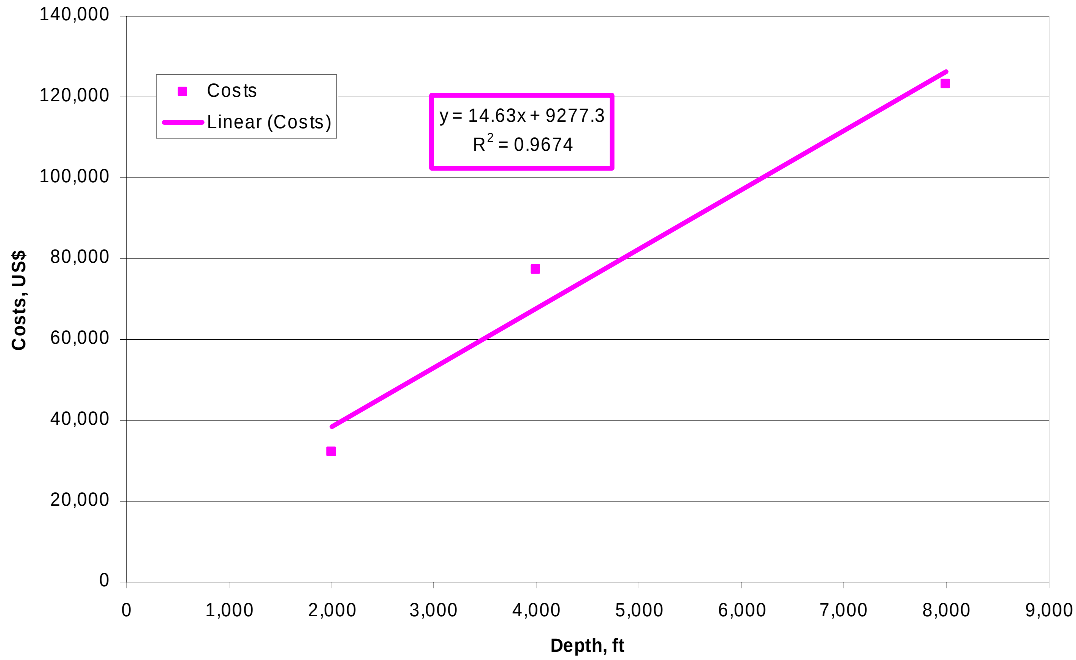
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in New Mexico include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$9,277 (fixed)
c_1 = \$14.63 per foot
D is well depth

Figure C-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 New Mexico cost equation.

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



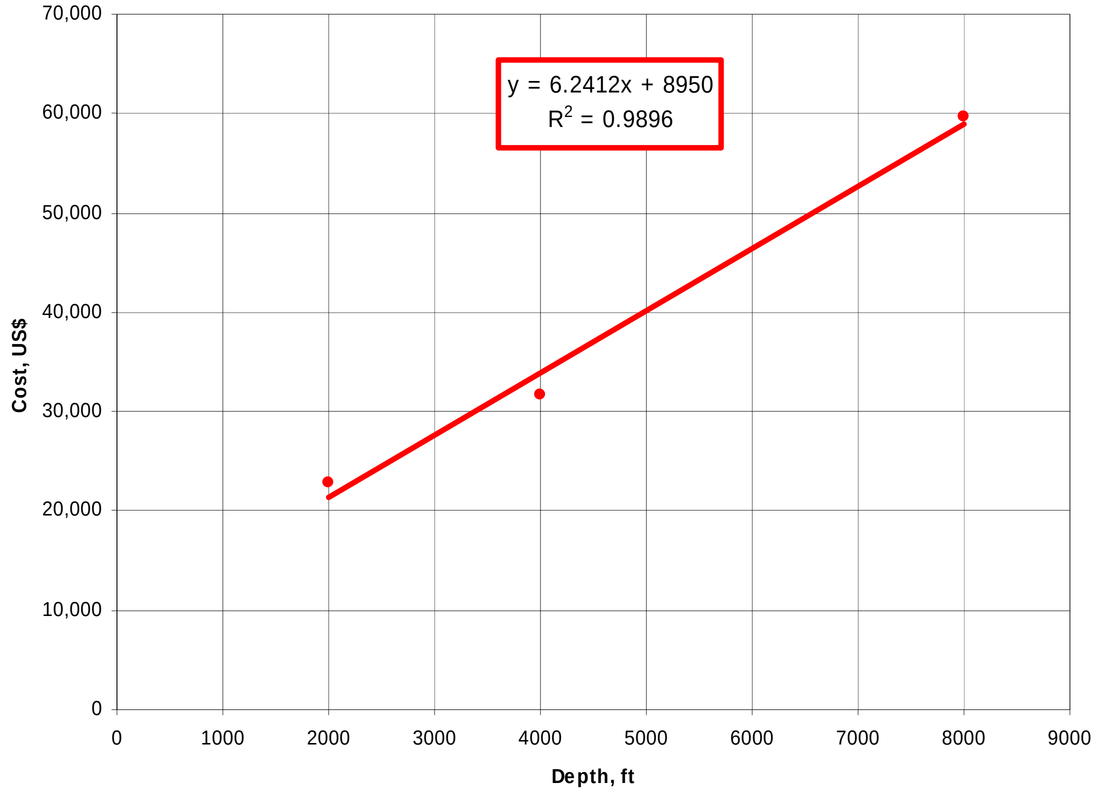
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection 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 New Mexico is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$8,950 (fixed)
c_1 = \$6.24 per foot
D is well depth

Figure C-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 New Mexico cost equation.

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

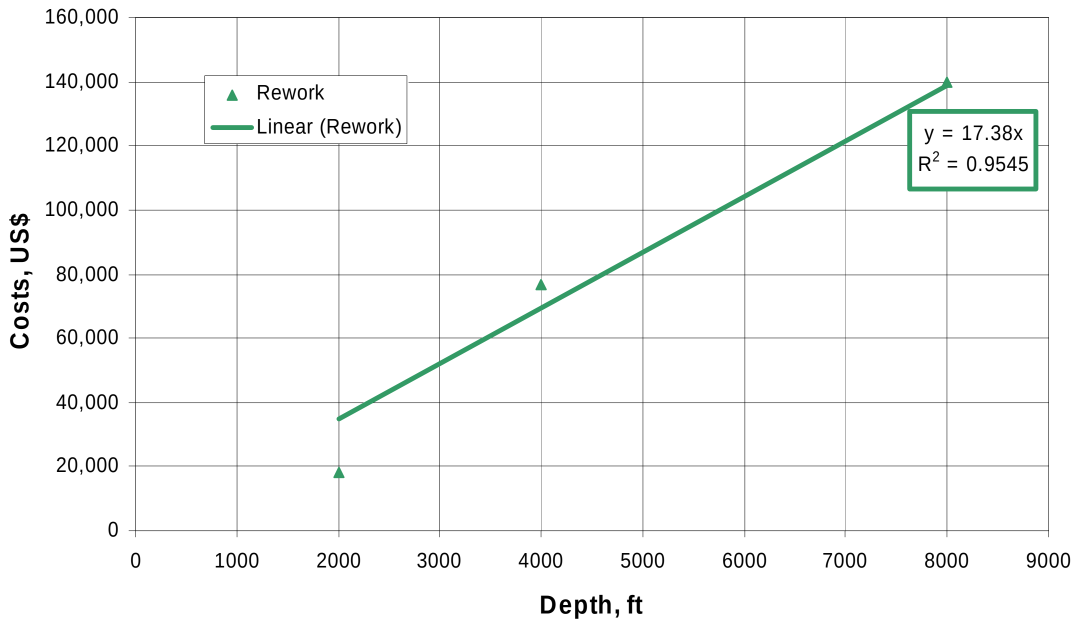


5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation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

Well Rework Costs = c_1D
Where: c_1 = \$17.38 per foot
D is well depth

Figure C-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 New Mexico cost equation.

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



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 New Mexico primary oil production O&M costs (Figure C-6) are used to estimate New Mexico secondary recovery O&M costs. Linear trends are used to identify fixed cost constants and variable cost constants for each region, Table C-1.

Figure C-6. Annual Lease O&M Costs for Primary Oil Production by Area

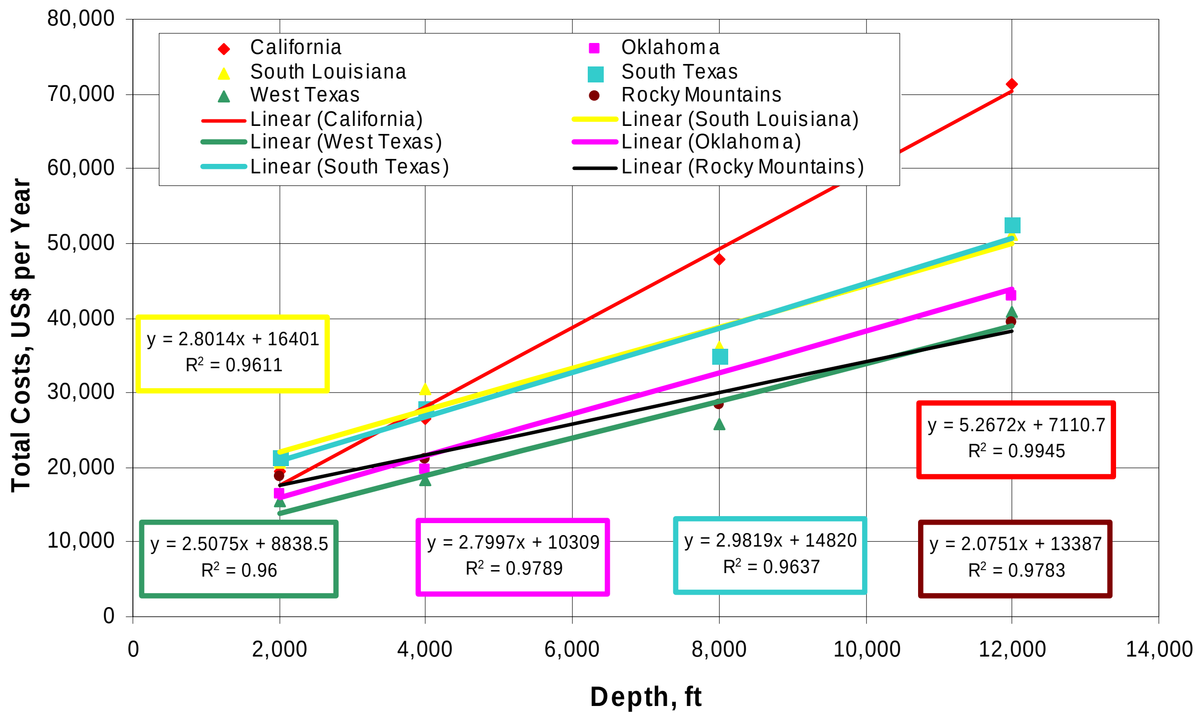


Table C-1. Regional Lease O&M Costs
and Their Relationship to West Texas

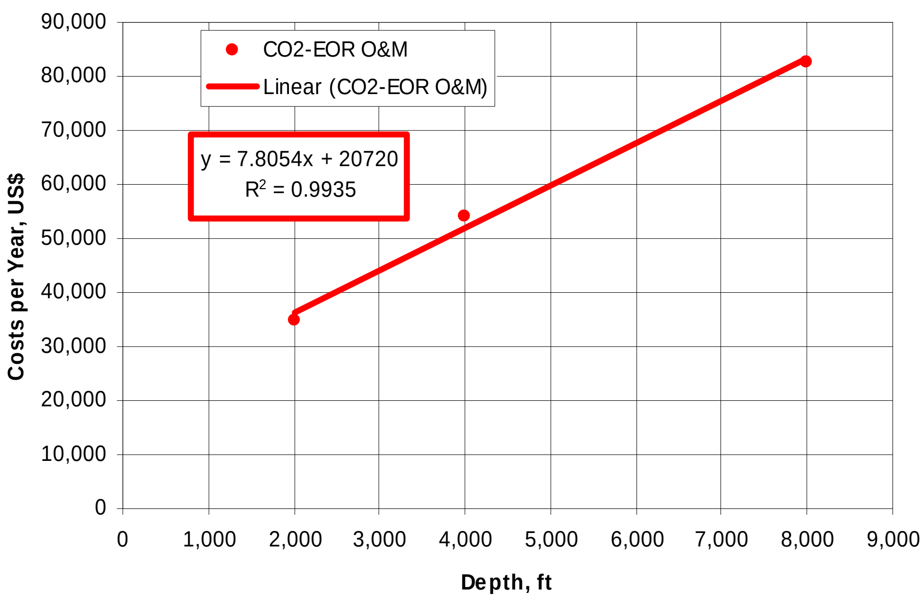
			Ratio to W. TX	
Basin	**c_0 US$**	**c_1 US$**	**c_0**	**c_1**
New Mexico	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Rocky Mountain	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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 C-7 shows the depth-relationship for CO_2-EOR O&M costs in West Texas. These costs were used for O&M for New Mexico, shown in the inset of Figure C-7. The equation for New Mexico is:

Well O&M Costs = $b_0 + b_1 D$
Where: b_0 = \$20,720 (fixed)
b_1 = \$7.805 per foot
D is well depth

Figure C-7. Annual CO_2-EOR O&M Costs for West Texas



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 recycling requirements.

The cost of the recycling plant is set at \$700,000 per MMcf/d of CO_2 capacity. As such, a small CO_2-EOR project in the Delaware Sand formation of the Paduca field, with 24 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$17 million. A large project in the Empire field, with 229 MMcf/d of peak CO_2 reinjection and 84 injectors requires a recycling plant costing \$160 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. Other COTWO Model Costs.

a. CO_2 Recycle O&M Costs. 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. Lifting Costs. 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. CO_2 Distribution Costs. 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, costs also depend 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 New Mexico 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. New Mexico has enacted risk sharing actions for enhanced oil recovery. The New Mexico Tax Code section 7-29-4.1 provides incentives for production tax rate reductions for various projects in New Mexico including qualified enhanced oil recovery projects.

The state normally charges a 3.75% severance tax on all oil production; however the rate is dropped by 50% to 1.875% for qualified EOR projects. This savings of 1.875% equates to 49 cents per barrel of oil produced. The ad valorum tax rate varies by county and an average value of 2.318% was used. In the model, severance and ad valorum taxes are charged after royalties are taken out.

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 ($0.00 differential for New Mexico) and the current gravity differential (-$0.25 per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for New Mexico is:

Wellhead Oil Price = Oil Price + (-$0.60) – [$0.25*(40 - °API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within New Mexico contain very light oil (>45 API). In order to keep the economics of these fields level with the rest of the fields, we imposed a ceiling of 45 °API for all fields with lighter oil when applying the Crude Oil Price Differential.

Appendix D

West Texas 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 2003 JAS cost study recently published by API for West Texas Railroad Districts (RRD) 8 and 8a.

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 for RRD 8, 0-6,300 feet depth is:

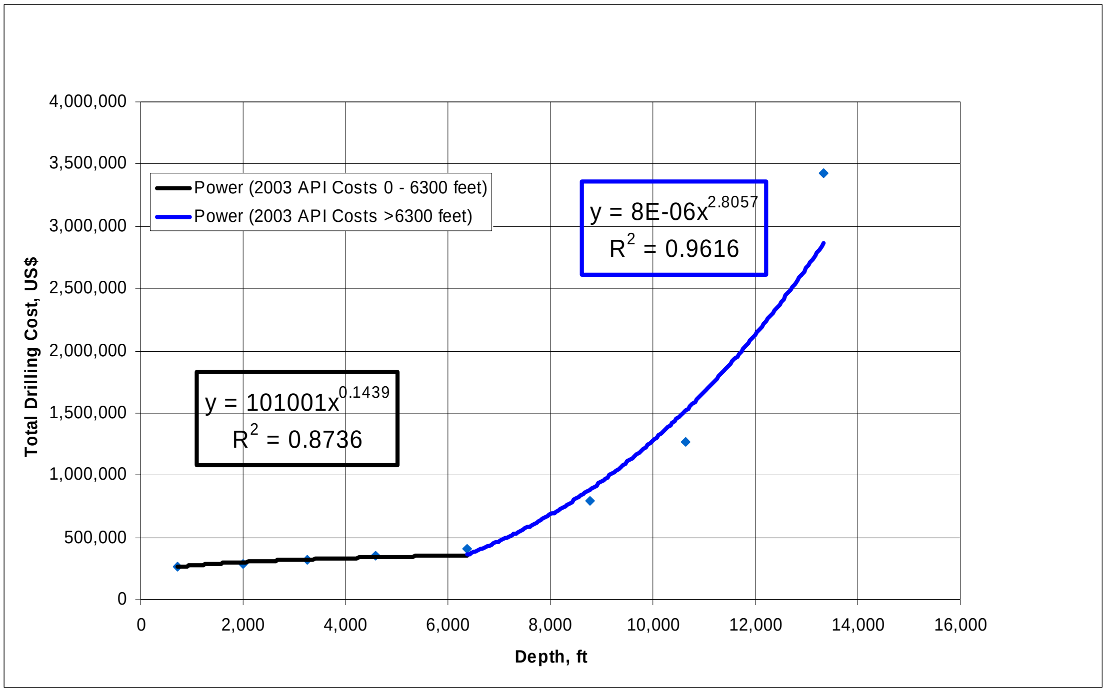
Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 1×10^5
a_1 is 0.1439
D is well depth

The total equation for RRD 8, >6,300 feet depth is:

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 8×10^{-6}
a_1 is 2.806
D is well depth

Figure D-1a and D-1b provide the details for the cost equation and illustrates the "goodness of fit" for the well D&C cost equation for Texas RRD 8 and 8a, respectively.

Figure D-1a. Oil Well D&C Costs for Texas RRD 8



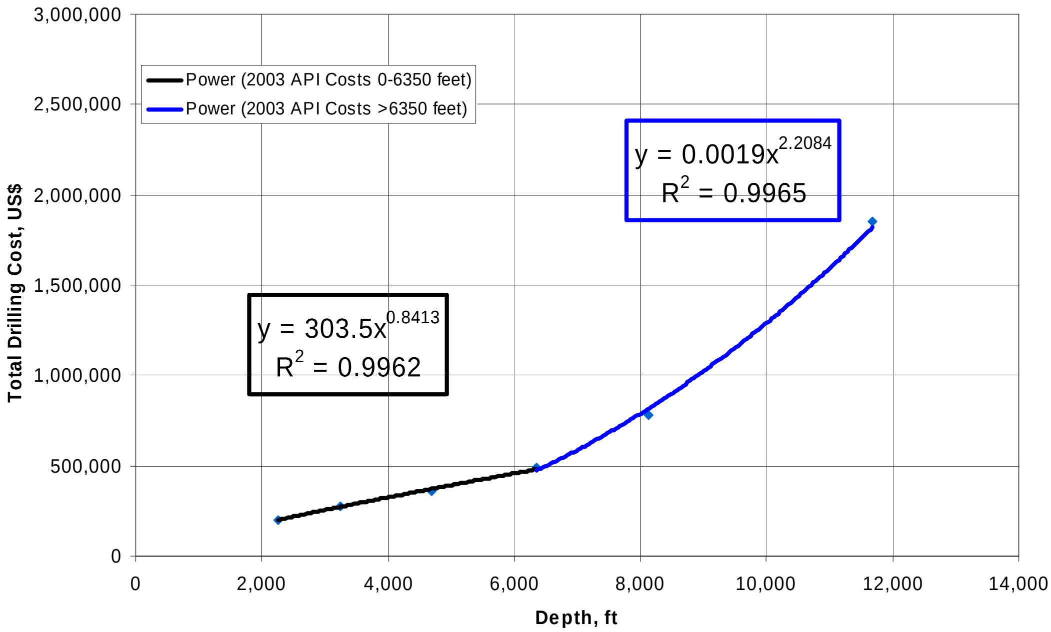
The total equation for RRD 8a, 0-6,350 feet depth is:

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 303.5
a_1 is 0.8413
D is well depth

The total equation for RRD 8a, >6,350 feet depth is:

Well D&C Costs = $a_0 D^{a_1}$
Where: a_0 is 0.0019
a_1 is 2.208
D is well depth

Figure D-1b. Oil Well D&C Costs for Texas RRD 8a



In order to bring the 2003 API drilling costs (the most recent available) into 2004 numbers where increased oil prices are expected to result in significantly increased drilling costs, a relationship was established between average drilling costs and average annual oil prices. Drillings costs from the ten year period of 1994-2003 (API data) were plotted versus the three year weighted average annual oil prices for those years (EIA Annual Energy Review, 2004) and the following relationship was established:

Drilling costs (per foot) = \$5.04(annual oil price) – \$3.2116.

Applying the 2004 average oil price of \$36.77 gives a drilling cost of \$182 per foot and an increase of 25.6% over the 2003 cost of \$145 per foot. Therefore, drilling and completion costs were increased by 25% over the West Texas D&C cost calculations to reflect this increase in 2004 drilling costs.

2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 “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.

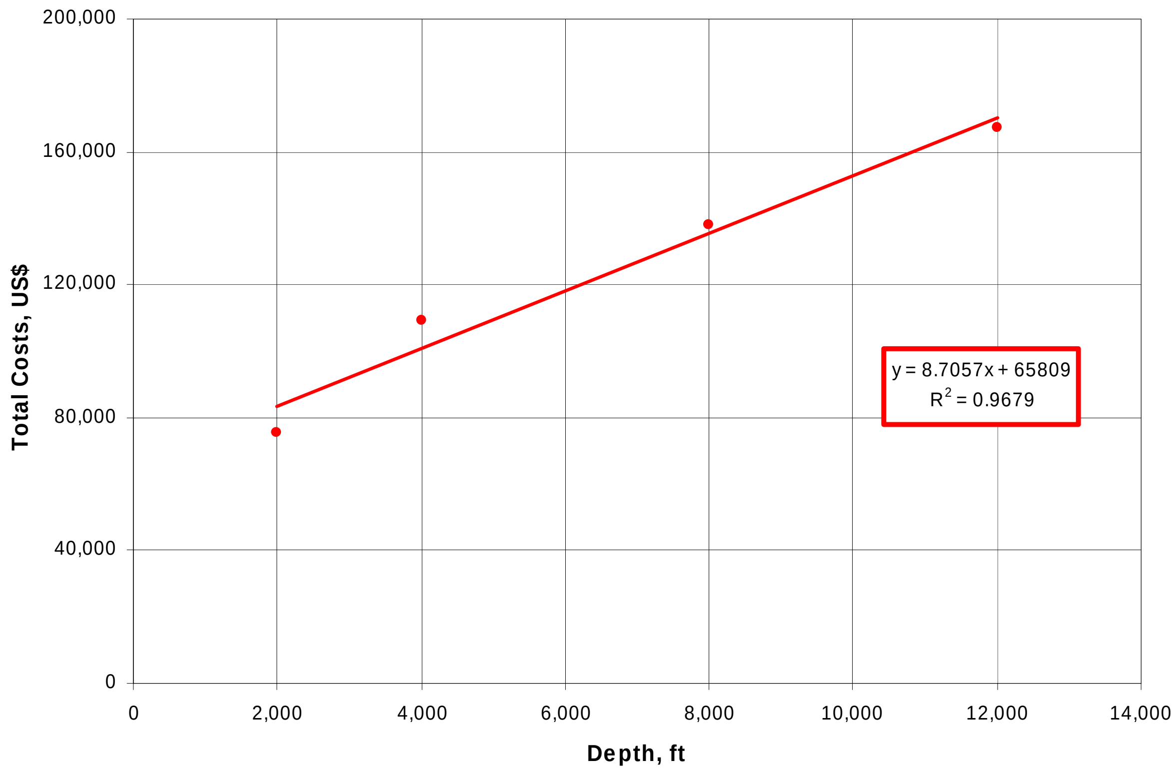
The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$65,809 (fixed)

c_1 = \$8.706 per foot
D is well depth

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

Figure D-2. Lease Equipping Cost for a New Oil Production Well in West Texas vs. Depth



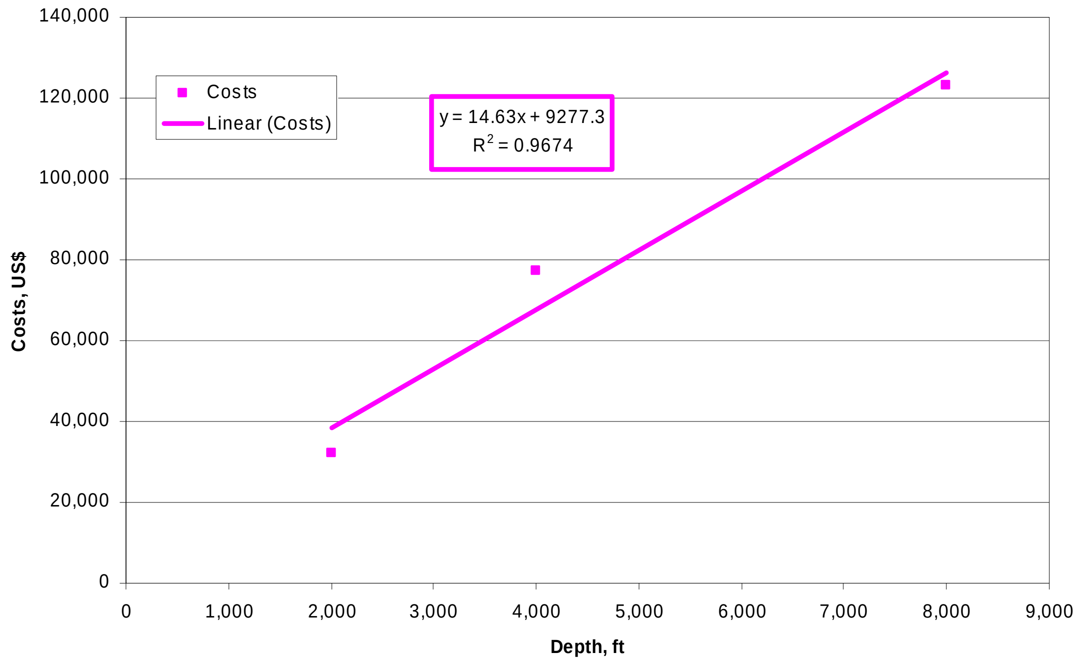
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in West Texas include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$9,277 (fixed)
c_1 = \$14.63 per foot
D is well depth

Figure D-3 illustrates the application of the lease equipping cost equation for a new injection well as a function of depth for West Texas.

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



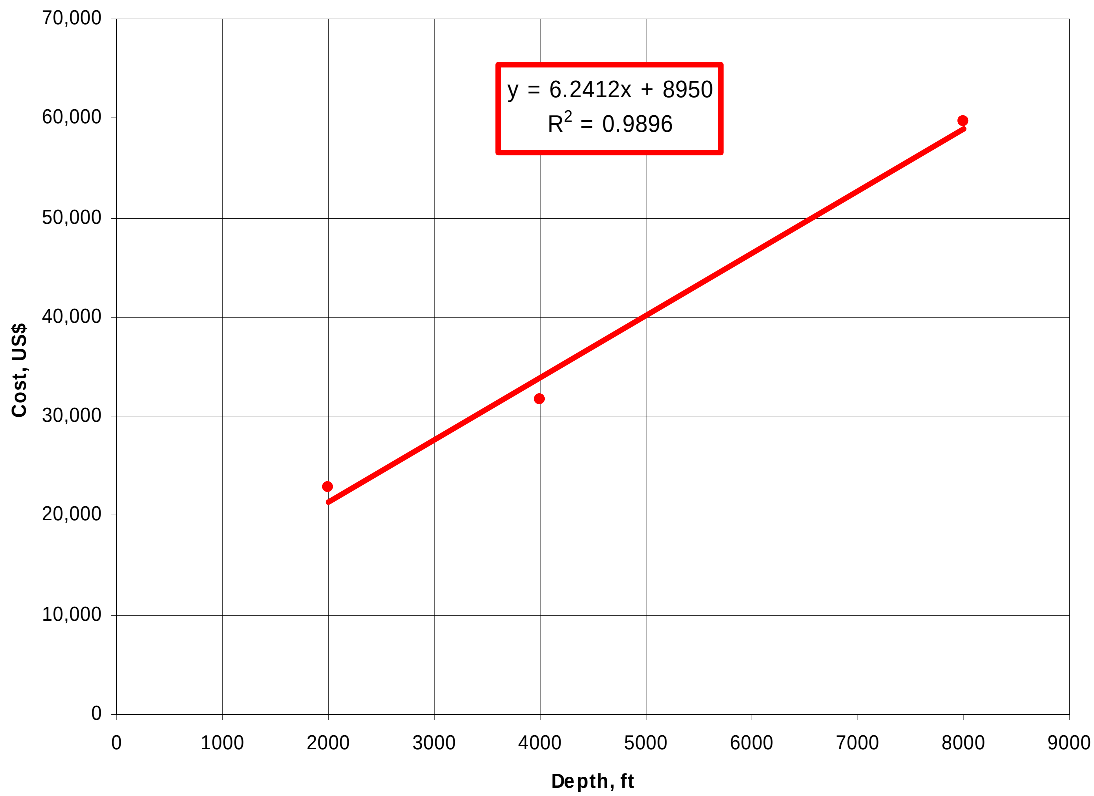
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection 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 West Texas is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$8,950 (fixed)
c_1 = \$6.241 per foot
D is well depth

Figure D-4 illustrates the average cost of converting an existing producer into an injection well for West Texas

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

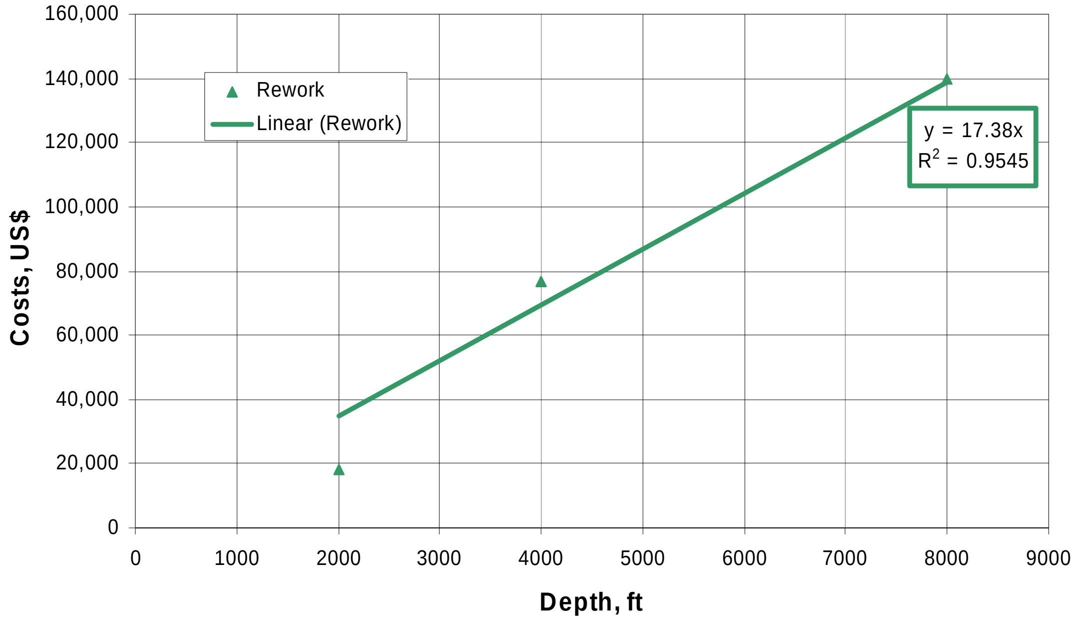


5. <u>Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework).</u> The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The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

Well Rework Costs = c_1D
Where: c_1 = $17.38 per foot
D is well depth

Figure D-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 West Texas cost equation.

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



6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs for West Texas (Figure D-6) linear trends are used to identify fixed cost constants and variable cost constants for each region, Table D-1.

Figure D-6. Annual Lease O&M Costs for Primary Oil Production by Area

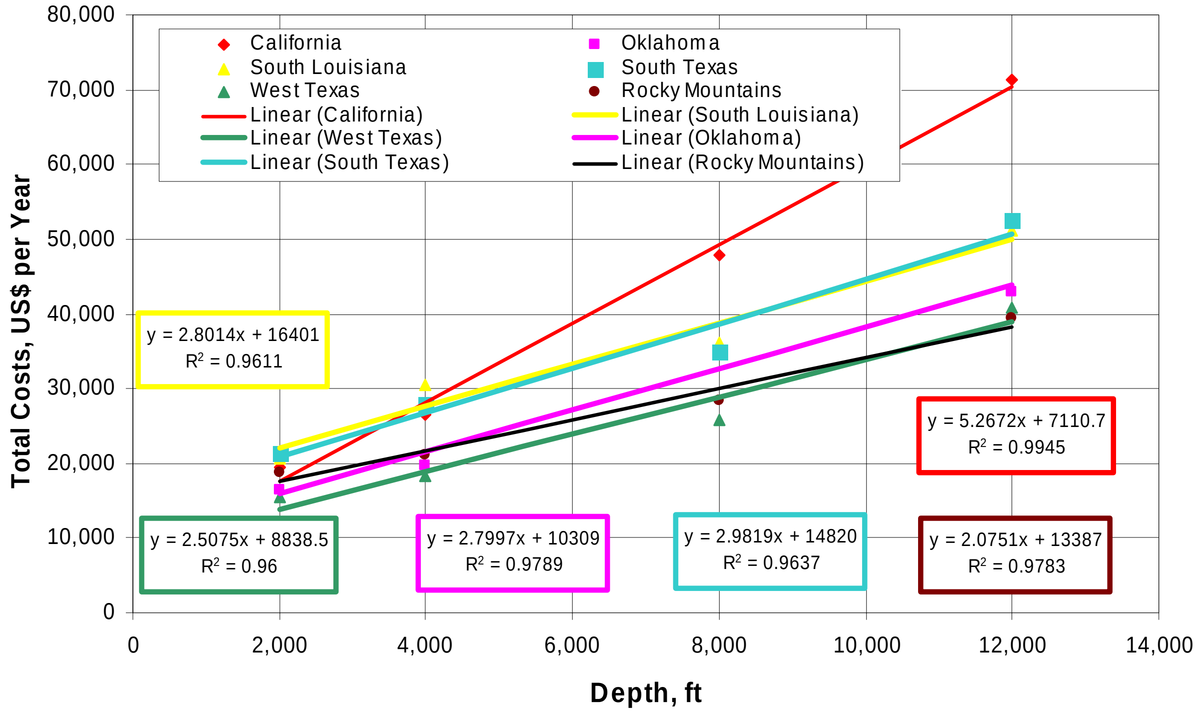


Table D-1. Regional Lease O&M Costs and Their Relationship to West Texas

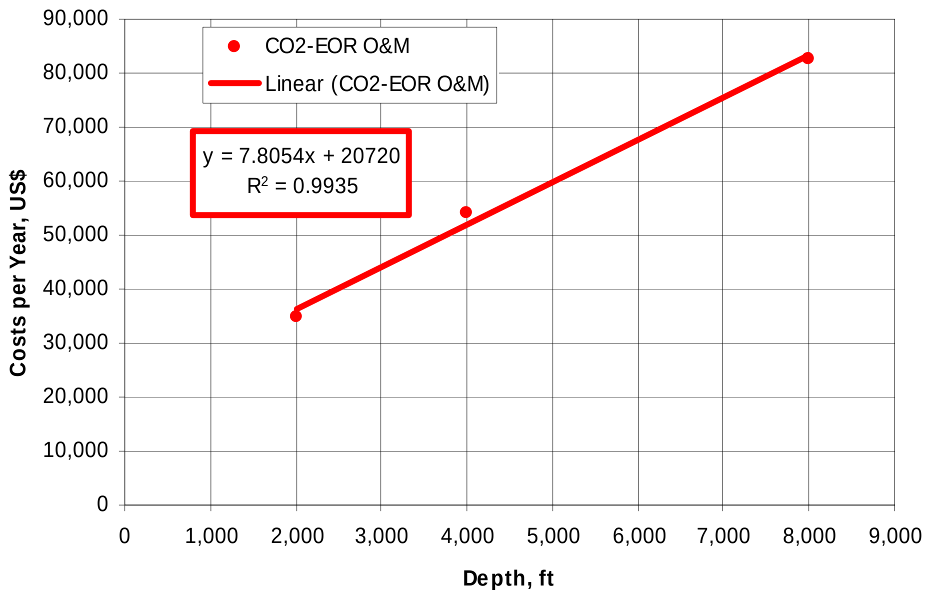
			Ratio to W. TX	
Basin	**c_0 US$**	**c_1 US$**	**c_0**	**c_1**
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Rocky Mountain	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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 D-7 shows the depth-relationship for CO_2-EOR O&M costs in West Texas. The equation for West Texas is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$20,720 (fixed)
b_1 = \$7.805 per foot
D is well depth

Figure D-7. Annual CO_2-EOR O&M Costs for West Texas



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 recycling 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 San Andres formation of the Emma field, with 42 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$29 million. A large project in the Cowden North field, with 547 MMcf/d of peak CO_2 reinjection and 531 injectors requires a recycling plant costing \$382 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. Lifting Costs. 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. CO_2 Distribution Costs. 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, costs also depend 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 West Texas 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. Texas has enacted risk sharing actions for enhanced oil recovery. The West Texas Code MCA 15-36-303(22) and 15-36-304(6) provide incentives for production tax rate reductions for various projects in West Texas including qualified enhanced oil recovery projects. The state charges typically charges an oil production severance tax of 4.6% on all oil production and the discounted rate for EOR projects is 2.3%. However, the provisions of the EOR statute are that if the average price of west Texas intermediate crude oil is above \$30 per barrel, the all projects, including EOR must pay the full severance tax. Therefore, in the model, the full 4.6% is charged. A state average ad valorum tax of 2.13% was used. Severance and ad valorum taxes are charged after royalties are taken out.

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 West Texas (-\$0.00 per barrel) and the current gravity differential (-\$0.25

per °API, from a basis of 40 °API) into the average wellhead oil price realized by each oil reservoir. The equation for West Texas is:

Wellhead Oil Price = Oil Price + (-$0.60) – [$0.25*(40 - °API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
°API is oil gravity

If the oil gravity is less than 40 °API, the wellhead oil price is reduced; if the oil gravity is greater than 40 °API, the wellhead oil price is increased. In addition, some fields within West Texas contain very light oil (>45 API). In order to keep the economics of these fields level with the rest of the fields, we imposed a ceiling of 45 °API for all fields with lighter oil when applying the Crude Oil Price Differential.

Appendix E

EAST VACUUM (GRAYBURG SAN ANDRES UNIT) CO_2-EOR PROJECT

HIGHLIGHT. The East Vacuum CO_2-EOR case study highlights the importance of adopting a flexible, performance-driven CO_2 flood design and strategies, adapted to changes in local geologic and reservoir properties. Implementation of this strategy is enabling the CO_2 flood at East Vacuum to recover 37 MMB (14% of OOIP).

The East Vacuum CO_2-EOR project (operated by ConocoPhillips) also examined the feasibility of using foam injection (surfactant plus CO_2) to obtain improved CO_2 conformance and incremental oil recovery.

Finally, the East Vacuum project stimulated the application of a new CO_2-EOR project in the Central Vacuum Unit (in 1997) that is projected to recover 15% of OOIP on top of a high primary/secondary recovery of about 50% OOIP.

BACKGROUND. The East Vacuum Grayburg San Andres (EVGSA Unit), located in the Permian Basin (near, Hobbs, New Mexico), produces from a rapidly varying Upper and Lower San Andres carbonate, at a depth of 4,400 feet. Initial development of the field began in 1938 with a waterflood initiated in 1958. The EVGSA Unit covering 7,000 acres and holding 300 million barrels of OOIP, is part of the larger Vacuum oil field that covers 19,200 acres and holds about 1,000 million barrels of OOIP, Figure 1.

PRODUCTION HISTORY AND RECOVER EFFICIENCY EXPECTATIONS. The East Vacuum CO_2-EOR case study provides an example of how on-going modifications matching the CO_2 flood design to rapidly changing reservoir properties helped optimize project efficiency. Primary and secondary (P/S) oil recovery (120 million barrels) is expected to provide a 40% oil recovery efficiency of the 300 million barrels of original oil in-place (OOIP) in the Unit.

The CO_2 flood at East Vacuum was initiated in 1985, covering 5,000 acres or about 70% of the total Unit area. (This CO_2 flood area contains 260 million barrels of OOIP.) Initially, the CO_2 flood, consisting of 45 patterns, used the same 80-acre inverted nine spot patterns established in the waterflood.

The original CO_2 flood design was expected to recover 21 million barrels of incremental oil, equal to 8% OOIP, Table E-1. Modifications to the original flood design, as reported in the ten year performance review in 1996, raised the expectations from the CO_2 flood at East Vacuum Unit to 30 million barrels, 11.5% of the 260 million barrels of OOIP in the CO_2 project area. About 4 million barrels (about 1.5% OOIP) would be from infill drilling. Subsequent modifications to the CO_2 flood in the past eight years have increased expected ultimate oil recovery from the CO_2 flood to 37 million barrels or 14% OOIP (discussed further below).

GEOLOGICAL SETTING AND RESERVOIR PROPERTIES. The East Vacuum Grayburg San Andres Unit is located in the northwest shelf of the Central Basin Platform. It produces from two benches (each containing two grain-rich, shoal intensive flow units) in the Upper San Andres, Figure 2. The reservoir consists of grainstones and packstones, deposited as high energy shoals and bars that have been altered by solution-enhanced diagenic processes. This combination of deposition and diagenetic alternation has led to rapid variations in lateral and vertical reservoir quality.

In the larger East Vacuum Unit, the gross interval of the main pay zone averages 300 feet, with 71 feet of net pay and 11.7% porosity and 11 md of permeability. In the CO_2 flood area, the net pay is thicker, averaging 88 feet. Table 2 provides the reservoir properties for the EVGSA Unit and the CO_2 flood area.

OPERATING THE CO_2 FLOOD. While the overall CO_2 flood response at the EVGSA Unit has been excellent (as noted by the field operator), the flood performance was not uniform. The significant variations in reservoir quality made it difficult to manage the flood under the original fixed WAG operating strategy. Pattern specific problems, such as uneven CO_2 front movement, early CO_2 breakthrough, poor conformance and low sweep efficiency were, according to the operator "becoming the rule rather than the exception." To address these problems, the field operator undertook the following steps:

- A field performance data acquisition and analysis system was installed to match field production and operating data with reservoir geology and properties, enabling the CO_2 flood area to be grouped in to three distinct settings, designated as Areas A, B and C, Figure 3.
- A series of 25 infill producing wells (including taking core and zone-by-zone pressure, flow capacity and oil saturation data) were used to update the geologic model and track flood performance.
- The infill wells identified a series of major problems with the CO_2 flood:
  1. Reservoir pressure was below minimum miscibility pressure, particularly in the Upper San Andres interval of Area C.
  2. There was little presence of CO_2 and essentially no oil displacement in the Upper San Andres interval in Area C.
  3. The core analysis identified a series of 5 to 10 foot high permeability thief zones that were taking the majority of the injected CO_2.

The above information enabled the operator to make the following design and operating changes to the CO_2 flood:

- Adding new infill injection wells to Area C, completed in the Upper San Andres to accelerate re-pressurization.
- Tailoring the WAG ratio for each pattern, with high gas production patterns having a WAG ratio of 4:1 and low gas production patterns having a WAG ratio of 0.8 to 1.
- Realignment of patterns with conversion of NE-SW side wells to CO_2 and water injection; with drilling of new infill wells, this converted the flood to a line drive pattern.
- Selective fracture stimulation treatments on wells with wide contrasts in permeability between the Upper and Lower San Andes intervals.

- Conducting a CO_2-foam pilot (in one pattern) to improve vertical CO_2 injection conformance.

ASSESSMENT OF PERFORMANCE. The above CO_2 flood management actions increased the expected incremental oil recovery from the CO_2 flood from the original 21 MMB (8% of OOIP), Figure 4.

Subsequent to the reported actions in the ten year review (in 1996), the operator has further reduced well spacing, increasing the number of patterns and injection wells to 103 and has continued to increase CO_2 injection and optimize the CO_2 flood. Based on the latest reported oil production (O&G Journal, 2004), the CO_2 flood has recovered 18 million barrels and is producing an incremental 5,200 B/D from 192 active producers and 103 injectors. Based on this, the East Vacuum Unit CO_2 flood is estimated to ultimately recover 37 million barrels, or 14% of the OOIP in the CO_2 flood area, Table E-3.

Under the original flood design, the operator planned to inject 230 Bcf of CO_2 (including recycling), equal to 30% HCPV. This would have provided a gross CO_2 to oil ratio of 11 Mcf/B. Based on the changes in flood management and optimization, the volume of CO_2 to be injected has been increased.

SUMMARY. The East Vacuum Grayburg San Andres Unit CO_2-EOR case study provides an excellent example of the transition from the “traditional” CO_2-EOR operating strategies of the 1980s toward the more modern “state-of-the-art” CO_2-EOR practices of today.

A significant mid-course diagnostic program was conducted after CO_2 project initiation, helping diagnose and correct existing problems, particularly limited oil displacement in the Upper San Andres interval.

The mid-course diagnostics helped evolve the CO_2 reservoir management strategy from the original fixed, 2 to 1 WAG design and small (30% HCPV) design to the flexible, performance-driven WAG strategy in use today.

The performance-driven strategy was essential for addressing the many challenges and problems faced by this project, including: (1) vertical conformance; (2) pattern balancing and sweep efficiency; (3) changes in MMP due to changes in injection gas composition (from installation of a liquid recovery facility); and, (4) large changes in gas production rates.

The operational changes implemented to address these problems produced significant improvements in profitability, increased oil production and reduced gas handing problems. Specifically the resulting project design and operating changes have increased the oil recovery efficiency of the CO_2 flood from an initial 8% OOIP to the currently expected 14% OOIP.

To date, the CO_2-EOR project at the East Vacuum Unit has recovered 18 million barrels of incremental oil and is producing 5,200 B/D from 192 active producers and 103 active CO_2/water injectors.

Finally, the successful performance of the East Vacuum Unit CO_2 flood stimulated the initiation of a subsequent CO_2 flood (in 1997) in the Central Vacuum Unit. This CO_2 flood expects to add 15% OOIP to an already high primary/secondary recovery of 50% OOIP.

Table E-1. Original Expected Oil Recovery EVGSAU CO_2 Project (MMB)

	Total	**Primary/ Secondary**	**CO_2-EOR**
OOIP	260		
Cum. Recovery (1985)	80(e)		
EUR	125	104	21
Recovery Efficiency (%OOIP)	48%	40%	8%

Table E-2. East Vacuum Field Unit Reservoir Properties
(CO_2 Flood Area)

Reservoir Depth ft*	4,400
Area, acres	5,000
Net Pay, Ft	
- Unit	71
- Project Area	88
Average Porosity, %	11.7
Average Permeability, md	11
Initial Water Saturation	0.159
Initial Formation Volume Factor	1.288
Initial Reservoir Pressure, psig	1,613
Reservoir Temperature, °F	101
Oil Gravity, °API	38
Oil Viscosity, cp	1.0

Table E-3. Latest Expected Oil Recovery from EVGSA Unit CO_2 Project (MMB)			
	Total	**Primary/ Secondary**	**CO_2-EOR**
OOIP	260		
Cum. Recovery (2003)	130		
EUR	141	104	37
Recovery Efficiency (% OOIP)	54%	40%	14%

Figure E-1. Location of the East Vacuum Grayburg San Andres Unit in the Permian Basin

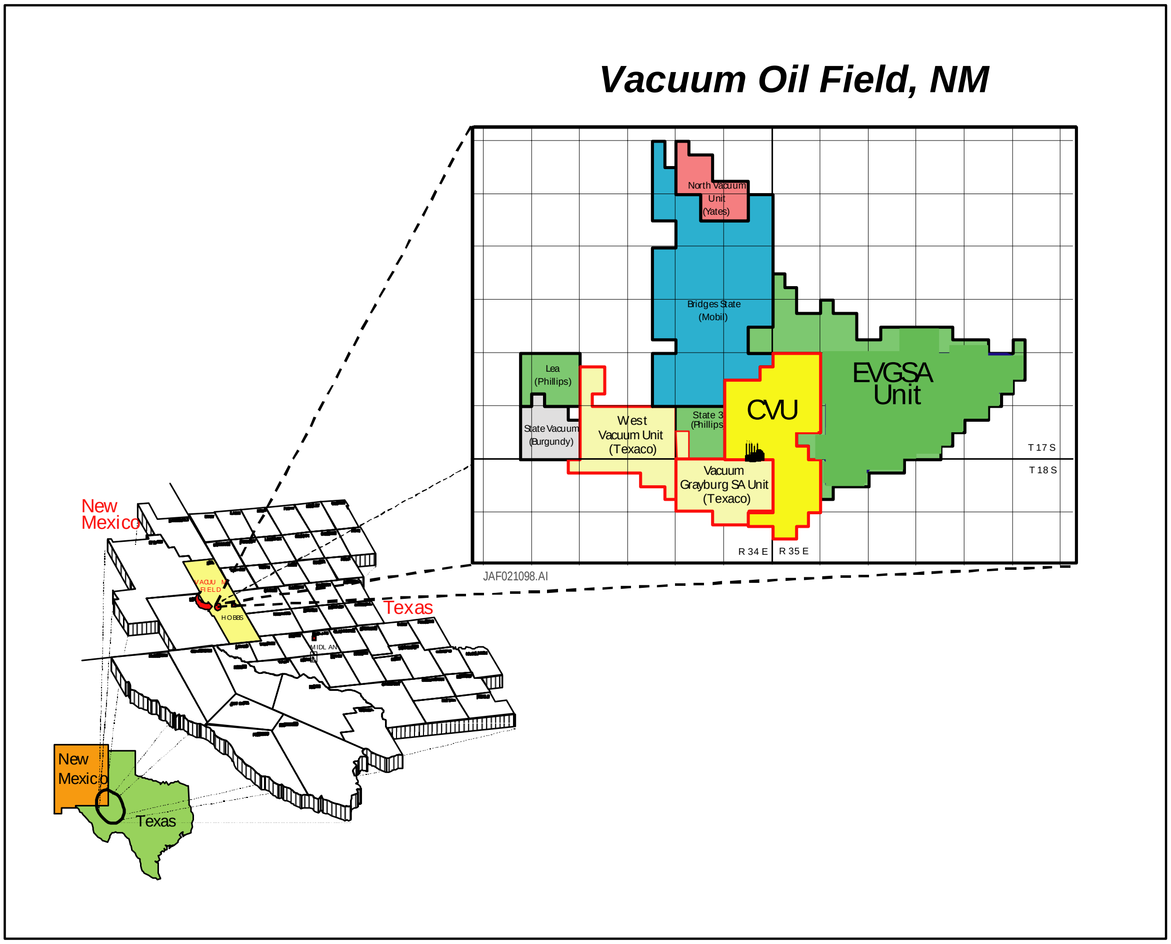


Figure E-2. Type Log for the East Vacuum Grayburg San Andres Unit

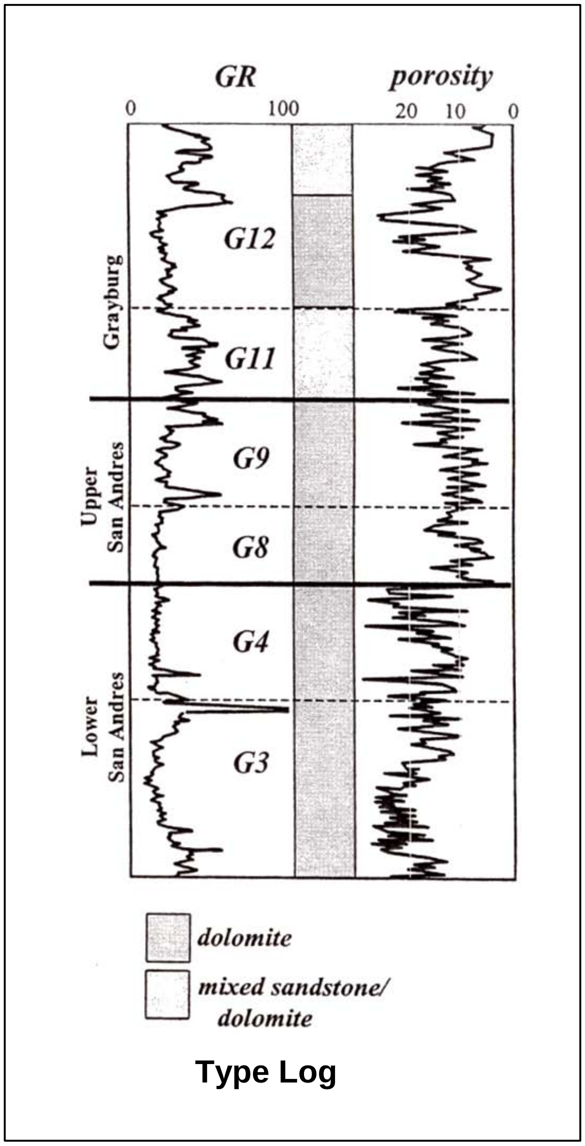


Figure E-3. Sub Divisions of the East Vacuum Grayburg San Andres Unit

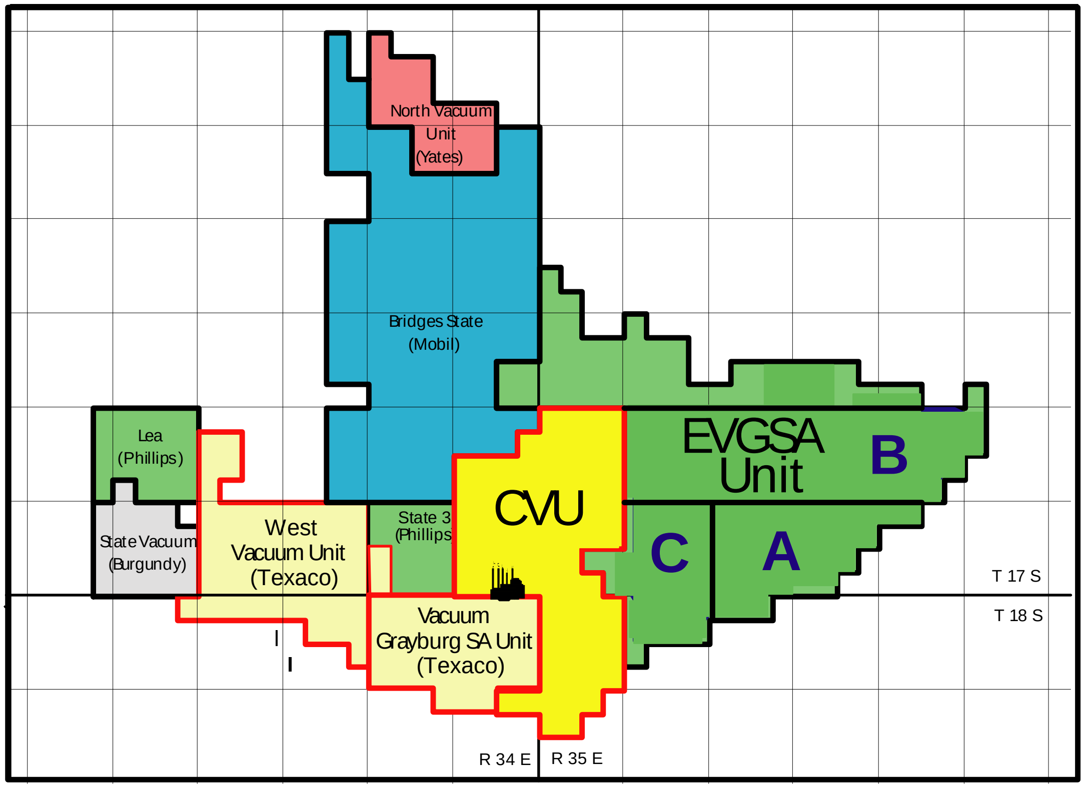


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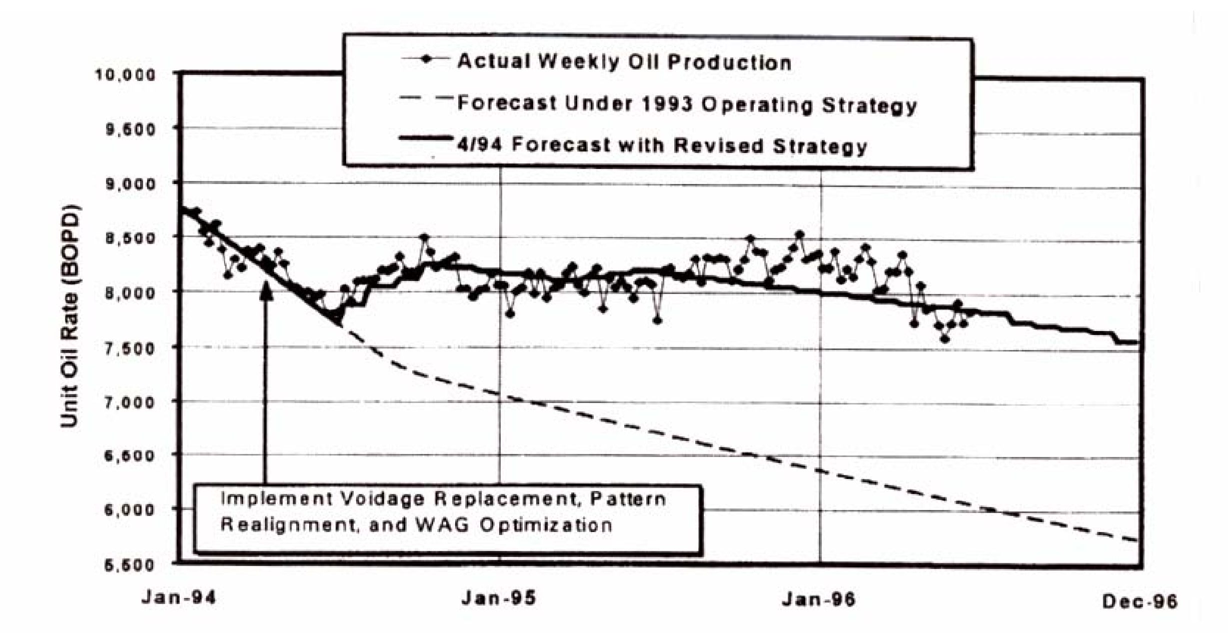
Figure E-4. EVGSA Unit Oil Production Response to Changes in Reservoir Management Strategy



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Appendix F

Salt Creek Field Unit CO_2-EOR Project

HIGHLIGHTS. The Salt Creek CO_2-EOR case study demonstrates that high oil recovery efficiencies, in excess of 60% of OOIP, is achievable from a multi-layer, highly heterogeneous carbonate reservoir using optimized water flooding, infill drilling and CO_2-EOR. A CO_2 flood tracking system (Zonal Allocation Program, ZAP) is being used to monitor performance on a zone by zone basis. This system provides timely information for altering CO_2 injection volumes and for modifying well completions to improve vertical conformance and optimize oil production.

BACKGROUND. The Salt Creek Field Unit (SCFU), located in the Permian Basin (Kent County, Texas), produces from a highly heterogeneous Canyon Reef limestone reservoir, at a depth of 6,300 feet. The Salt Creek Field was discovered in 1950. Water injection in the field was started shortly after field discovery, in 1953. The field has been extensively infill drilled and is currently developed on five-spot, 20-acre spacing per well, patterns.

PRODUCTION HISTORY AND RECOVERY EFFICIENCY EXPECTATIONS. The Salt Creek CO_2-EOR case study provides an example of successfully applying CO_2-EOR to an oil field with a high primary/secondary oil recovery efficiency. Primary and secondary (P/S) oil recovery (336 million barrels) has provided 48% recovery efficiency of the 700 million barrels of original oil in-place (OOIP). This high P/S oil recovery efficiency (as reported by the operator) is due to intensive infill drilling, rigorous optimization of the waterflood and selective use of polymer augmented waterflooding (PAW). The PAW is estimated to have provided about 10 million barrels or 1.5% toward the 48% P/S recovery of the OOIP.

The Phase I CO_2 flood began in the South Main Body (SMB) of the field in 1993. The Phase II CO_2 flood in the smaller, geologically separate Northwest Extension (NWE), began in 1996. In 2000, following a pilot program testing the economic feasibility of CO_2 flooding in the underlying residual oil zone (ROZ), larger scale CO_2 injection was initiated into the ROZ at the SMB, into zones A, B and C (Figure F-3). The ROZ project currently involves 36 wells.

The expectations are that the CO_2 flood in the main pay zone will recover 91 million barrels, or 13% of the OOIP. This oil recovery efficiency assumes an injection of 1,200 Bcf of CO_2, equal to 0.8 HCPV. If the CO_2 flood achieves its expectations, the field will produce 427 million barrels, or 61% of the OOIP. (No estimates of ultimate oil recovery exist for the CO_2 flood in the ROZ, although incremental oil recovery (as of mid-2002) is reported at 1,800 B/D from the 36 well ROZ program.)

Figure F-1 provides the oil production history of the Salt Creek field. Figure F-2 displays the actual and expected oil recovery, by process. Table F-1 provides a tabulation of actual and expected oil recovery, by process.

GEOLOGICAL SETTING AND RESERVOIR PROPERTIES. The Salt Creek Field Unit is a multi-layered, highly heterogeneous carbonate reservoir. The gross interval of the main pay zone averages 250 feet, with 100 feet of net pay and 11% porosity. The gross interval in the northern portion of the SMB thickness appreciates to over 600 feet. The ROZ on the eastern side of the SMB averages 120 feet and has reservoir properties similar to the main pay zones. Table F-2 provides the reservoir properties for the SCFU.

The geological setting of the field is complex, with numerous individual stacked reservoirs forming a series of grainstone shoal complexes. The average permeability of the reservoir is 20 md, with a range of 1 to 2,000 md in individual flow units. Figure F-3 provides a type log of the main pay zone and the ROZ.

OPERATING THE CO_2 FLOOD. Considerable effort was placed on understanding how the reservoir architecture would influence the CO_2 flood and how best to operate the CO_2 flood to optimize performance:

- Sequence stratigraphy was used to identify and organize the flow units (zones) and vertical flow barriers.
- Reservoir rock typing and porosity/permeability algorithms were used to identify: (1) the high porosity grainstone facies prone to early CO_2

breakthrough; and (2) the muddier reservoir facies that are slow to accept CO_2.

- Injection profile logs and a Zonal Allocation Program (ZAP) were used to track CO_2 and water injection by zone, to estimate zonal maturity (as a fraction of hydrocarbon pore volume of CO_2 injected), and track actual performance against type curves relating volume of CO_2 injection to incremental oil production.
- Output from the ZAP, a one-page summary for each CO_2 pattern, tabulates the OOIP, volume of CO_2 injected, (total and % HCPV of CO_2) and fluid (oil, water, CO_2) production for each pattern and its geologic zones. Actual oil recovery versus CO_2 injected is compared to a type curve to analyze pattern performance and to forecast future oil production.
- The information in the ZAP report was used to identify well workover candidates, plan vertical profile modifications and identify mature (CO_2 swept) layers. Well workovers for modifying the CO_2 injection profile included plugs, cement squeezes, straddle packers and placement of liners to “shut-off” mature, CO_2 swept intervals and redistribute the CO_2 to the remaining intervals. Occasionally, CO_2 injection into a particularly tight interval was increased by stimulation.

Overall, the vertical profile modification and well workover program has proven to be successful, with a 6 month or less payout (on average) per workover. However, on an individual well basis, the workover success rate (measured in terms of a significant change in the CO_2 injection profile and increased oil production) was successful only about 50% of the time.

ASSESSMENT OF PERFORMANCE. Based on 36% HCPV of CO_2 injection (as of early 2004), the CO_2-EOR project has recovered 6% of OOIP or 42 million barrels. The current gross CO_2 to oil ratio at 36% HCPV of CO_2 (540 Bcf of CO_2) and 6% OOIP oil recovery (142 MMB) is about 13 Mcf/B. Given that the CO_2 flood is anticipated to provide 13% recovery of OOIP or 91 million barrels with injection of 1,200 Bcf of CO_2 (80% HCPV), the ultimate gross CO_2 to oil ratio would also be 13 Mcf/B.

The SCFU currently produces 12,000 B/D oil, 4,000 B/D of gas plant liquids, 135 MMcf/d of gas (85% CO_2) and 320,000 B/D water from 170 active producers. Current CO_2 injection is 150 MMcf/d of which 30 MMcf/d is purchased for replacement of CO_2 retained in the reservoir.

OBSERVATION. The CO_2 flood at the geologically challenging Salt Creek Field Unit is on track to provide significant additional oil recovery (13% OOIP), in addition to already high (48% OOIP) oil recovery from waterflooding and intense infill development, Figure F-4.

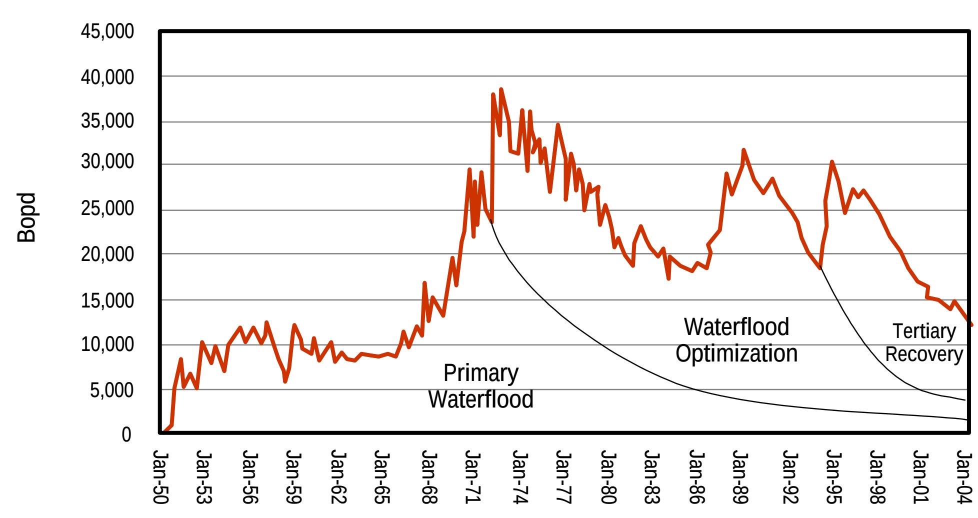
Table F-1. Actual and Expected Oil Recovery at SCFU (MMB)

	Total	**Primary/ Secondary**	**CO2-EOR**
OOIP	700		
Cum. Recovery (2003)	370	328	42
EUR	427	336	91
%OOIP	61%	48%	13%

Table F-2. Salt Creek Field Unit Reservoir Properties

Reservoir Interval, ft*	6,200-6,700
Area, acres	12,100
Net Pay, Ft	100
Average Porosity, %	11
Average Permeability, md	20
Initial Water Saturation	0.19
Initial Formation Volume Factor	1.2
Initial Reservoir Pressure, psig	2,915
Current Reservoir Pressure, psig	3,150
Reservoir Temperature, °F	129
Oil Gravity, °API	39
Oil Viscosity, cp	0.53

*Includes ROZ interval from 6,500’ to 6,700’.



Source: Genetti, D.B., ExxonMobil Production Company; et. al., SPE paper 81458, “Applying Improved Recovery Processes and Effective Reservoir Management to Maximize Oil Recovery at Salt Creek”, presented at the SPE 13th Middle East Oil Shale & Conference, Bahrain, 5-8 April 2003.

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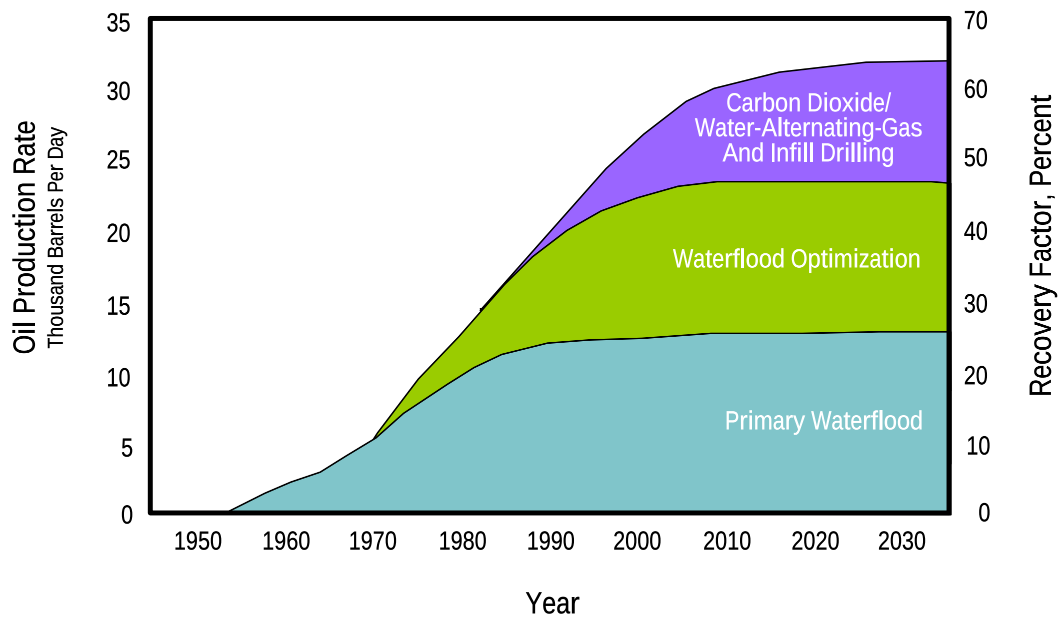
Figure F-1. Salt Creek Oil Production History



Source: Wilkinson, J.R., ExxonMobil Production Company; et. al., SPE paper 88770,"Lessons Learned from Mature Carbonates for Application to Middle East Fields", presented at the SPE 11th Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, 10-13 October 2004.

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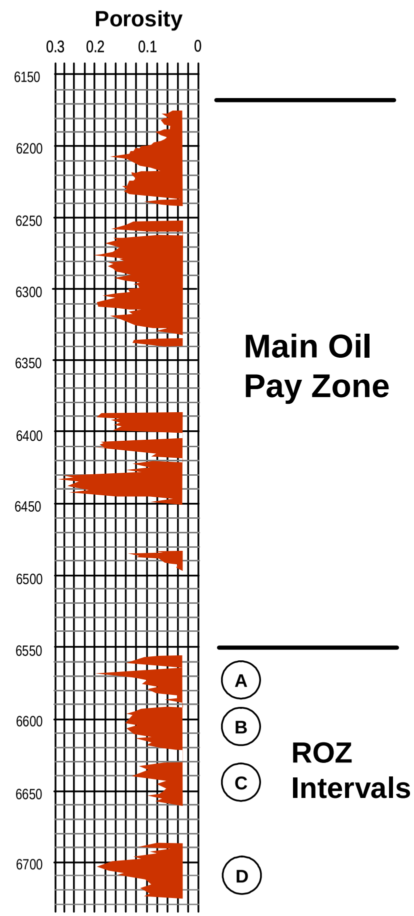
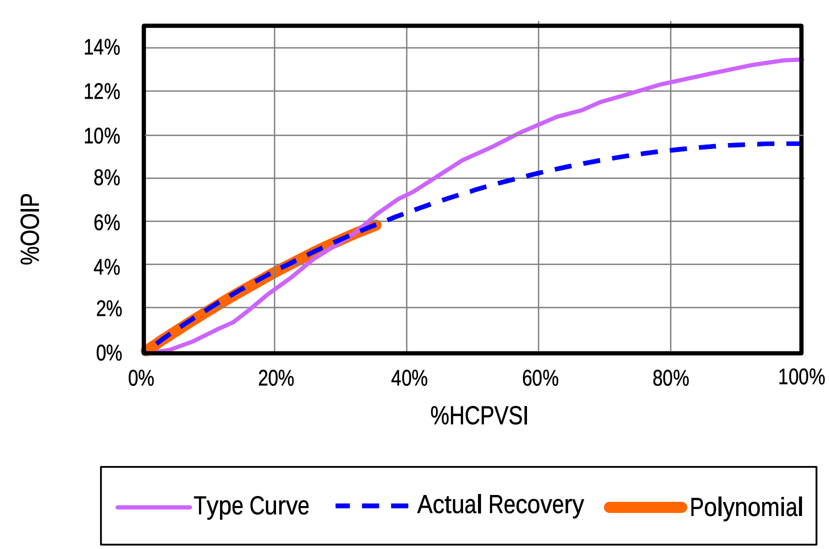
Figure F-2. Salt Creek Field Oil Recovery Factor, by Process



Source: Bishop, D.L., ExxonMobil Production Company; et. al., SPE paper 88720, "Vertical Conformance in a Mature Carbonate CO2 Flood: Salt Creek Field Unit, Texas", presented at the SPE 11th Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, 10-13 October 2004.

Figure F-3. Salt Creek Type Log, Canyon Fm.



Source: Bishop, D.L., ExxonMobil Production Company; et. al., SPE paper 88720, "Vertical Conformance in a Mature Carbonate CO2 Flood: Salt Creek Field Unit, Texas", presented at the SPE 11th Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, 10-13 October 2004.

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Figure F-4. Salt Creek Oil Recovery (Actual Data and Expected) Compared with Type Curve.

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