BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY:

OKLAHOMA

Prepared for:

U.S. Department of Energy

Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by:

Advanced Resources International, Inc.

March 2005

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1. SUMMARY OF FINDINGS

***1.1 INTRODUCTION**.* The oil and gas producing regions of Oklahoma have 45 billion barrels of oil which 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 old 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 Oklahoma 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 Oklahoma'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 Oklahoma.

- The first scenario describes how CO_2-EOR technology has been applied and has performed in the past. Under this low technology, high-risk scenario, called "Traditional Practices" because of low oil recovery efficiency, there is potential for using CO_2-EOR in the oil reservoirs of Oklahoma. This is because many of the older oil fields in this oil producing region may have substantial volumes of secondary (mobile) oil left in the reservoirs. However, because the data reporting is incomplete and often out of date, considerable uncertainty exists on the volumes of secondary oil that could be recovered along with the tertiary oil from using CO_2-EOR.

- The second scenario, entitled "State of the Art", assumes that the technology progress in CO_2-EOR, achieved in other areas, is successfully applied to the oil reservoirs of Oklahoma. A comprehensive set of reservoir characterization, pilot tests and field demonstrations will be essential for helping lower the risk inherent in applying new technology to these extremely mature, complex oil reservoirs. Because of limited sources of CO_2, this scenario assumes that supply costs will be high (equal to $1.25 per Mcf). These high costs for CO_2 significantly hamper the economic feasibility of using CO_2-EOR in Oklahoma.

- The third scenario, entitled "Risk Mitigation," examines how the economic potential of CO_2-EOR in Oklahoma could be increased through a strategy involving state production tax reductions, increased federal investment tax credits, and royalty relief that together would add an equivalent of $10 per barrel to the WTI marker price for crude oil.

- The final scenario, entitled "Ample Supplies of CO_2," assumes that significant volumes of low-cost, "EOR-ready" CO_2 supplies (equal to $0.70 per Mcf) are aggregated from various sources. These sources would include high-concentration CO_2 emissions from hydrogen facilities, gas processing plants and other industrial sources. These supplies would be augmented, in the longer-term, from low CO_2 concentration industrial sources including combustion and electric generation plants. Capture of industrial CO_2 emissions could be part of national efforts for reducing greenhouse gas emissions.

The CO_2-EOR potential of Oklahoma is examined using these four bounding scenarios.

1.3 OVERVIEW OF FINDINGS. Ten major findings emerge from the study of "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Oklahoma."

1. Today's oil recovery practices will leave behind a large resource of "stranded oil" in Oklahoma. The original oil resource in Oklahoma reservoirs is estimated at 60 billion barrels (Because of limitations in data in many of the older fields, the original resource used by this study for Oklahoma may be significantly underestimated. For example, some of the highly knowledgeable oil and gas officials in Oklahoma have stated that the original oil resource may be as large as 75 to 100 billion barrels). To date, 15 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further oil recovery methods, 45 billion barrels of Oklahoma's oil resource will become "stranded", Table 1.

Table 1. Oklahoma's Oil Resource and Reservoirs

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
Data Base Total	96	36.5	9.2	27.3
*B. Regional Total**	n/a	60.3	15.2	45.1

**Estimated from State of Oklahoma 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 Oklahoma is amenable to CO_2 enhanced oil recovery. To address the "stranded oil" issue, Advanced Resources assembled a database that contains 96 major Oklahoma oil reservoirs, accounting for 60.5% of the region's estimated ultimate oil production. Of these, 63 reservoirs, with 23.4 billion barrels of OOIP and 17.5 billion barrels of "stranded oil" (ROIP)), were found to be favorable for CO_2-EOR, Table 2.

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

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
Oklahoma	63	23.4	5.9	17.5

3. Application of miscible CO_2-EOR would enable a significant portion of Oklahoma's "stranded oil" to be recovered. All of the 63 large Oklahoma oil reservoirs (with 23.4 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR, leaving none of the reservoirs for development by the less efficient CO_2 immiscible process. The technically recoverable resource from applying miscible CO_2-EOR in these 63 large oil reservoirs ranges from 2,590 million barrels to 5,440 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)
Oklahoma	63	2,590 - 5,440	0	-

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

4. Because of limited past secondary oil recovery practices, a portion of Oklahoma'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 63 large reservoirs in the data base would enable 2,590 million barrels of "stranded oil" to become technically recoverable in Oklahoma. With current costs for CO_2 in Oklahoma (equal to $1.25 per Mcf) and a substantial risk premium, because of uncertainties about future oil prices and the performance of CO_2-EOR technology, about 940 million barrels of this "stranded oil" could become economically recoverable at oil prices of $25 per barrel, as adjusted for gravity and location, Table 4. A significant portion of the 940 million barrels is mobile oil that could have been recovered with more intense applications of 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)
Oklahoma	63	23,400	2,590	940

**This case assumes an oil price of $25 per barrel, a CO_2 cost of $1.25 per Mcf, and a ROR hurdle rate of 25% (before tax).*
***Less than 5 MMBbls.*

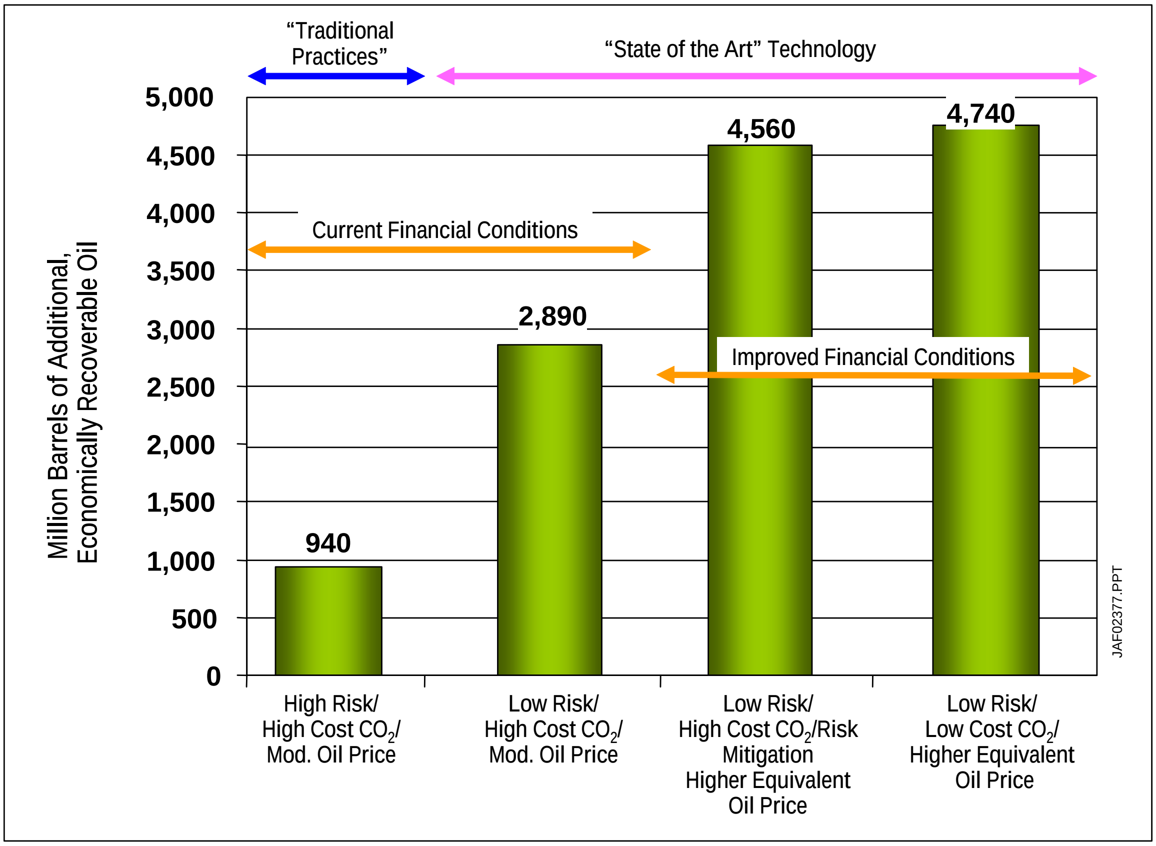
5. Introduction of "State of the Art" CO_2-EOR technology, "risk mitigation" actions and lower CO_2 costs, would enable up to 4.7 billion barrels of Oklahoma's "stranded oil" to become economically recoverable. Use of "State of the Art" CO_2-EOR technology, with higher oil recovery efficiency, allows 2.9 billion barrels of the oil remaining in Oklahoma's reservoirs to become economically recoverable. Introducing "risk mitigation" actions, such as an increased EOR investment tax credit, reduced state production taxes and Federal/state royalty relief (for projects on Federal/state lands) that together provide an equivalent of a $10 per barrel increase in the oil price would enable 4.6 billion barrels of oil to become economically recoverable. Providing lower cost CO_2 supplies (from a large transportation system and incentives for CO_2 capture) would enable the economic potential to increase to 4.7 billion barrels and would enable CO_2-EOR projects to compete more favorably for investment capital, as shown in Figure 1 and Table 5.

Table 5. Economically Recoverable Resources Under Alternative Scenarios

	Scenario #2: "State of the Art"	Scenario #3: "Risk Mitigation"	Scenario #4: "Ample Supplies of CO_2"
State	(Moderate Oil Price/ High CO_2 Cost*) (MMBbls)	(Higher Equivalent Oil Price/ High CO_2 Cost**) (MMBbls)	(Higher Equivalent Oil Price/ Low CO_2 Cost***) (MMBbls)
Oklahoma	2,890	4,560	4,740

**This case assumes an oil price of $25 per barrel, a CO_2 cost of $1.25 per Mcf and a ROR hurdle rate of 15% (before tax).*
***This case assumes an oil price of $35 per barrel, a CO_2 cost of $1.25 per Mcf and a ROR hurdle rate of 15% (before tax).*
****This case assumes an oil price of $35 per barrel, a CO_2 cost of $0.70 per Mcf and a ROR hurdle rate of 15% (before tax).*

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



6. Once the results from the study's large oil reservoirs database are extrapolated to the state as a whole, the technically recoverable CO_2-EOR potential for Oklahoma is estimated at 9 billion barrels. The large Oklahoma oil reservoirs examined by the study account for 60.5% of the region's oil resource. Extrapolating the 5.4 billion barrels of technically recoverable EOR potential in these 64 oil reservoirs to the total Oklahoma oil resource provides an estimate of 9.0 billion barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the 63 large Oklahoma 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 CO_2-EOR in Oklahoma will, most likely, prove to be higher than defined by this study. Introduction of more "advanced" CO_2-EOR technologies still in the research or field demonstration stage, such as gravity stable CO_2 injection, horizontal or multi-lateral wells and CO_2 miscibility control agents, could significantly increase recoverable oil volumes while expanding the state's geologic storage capacity for CO_2 emissions. The benefits and impacts of using "advanced" CO_2-EOR technology on Oklahoma oil reservoirs will be examined in a subsequent study.

8. Large volumes of CO_2 supplies will be required in Oklahoma to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be up to 14 Tcf, plus another 48 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 Oklahoma's oil reservoirs would enable over 0.8 billion tons of CO_2 emissions to be stored, greatly reducing greenhouse gas emissions. Advanced CO_2-EOR flooding and CO_2 storage concepts (plus incentives for storing CO_2) could double this amount.

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

Region	No. of Reservoirs	Economically Recoverable* (MMBbls)	Purchased CO_2 (Bcf)	Recycled CO_2 (Bcf)
Oklahoma	48	4,740	13,850	47,620

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

9. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in Oklahoma'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 Oklahoma's old and complex 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 state of Oklahoma and the Federal Government will be needed to overcome these barriers.

10. Many entities will share in the benefits of increased CO_2-EOR based oil production in Oklahoma. Successful introduction and wide-scale use of CO_2-EOR in Oklahoma 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 Oklahoma. As such, we would like to thank the Oklahoma Geological Survey and particularly Charles Mankin and Dan T. Boyd for providing valuable insights, data on reservoir properties, and historical information on Oklahoma oil and gas fields.

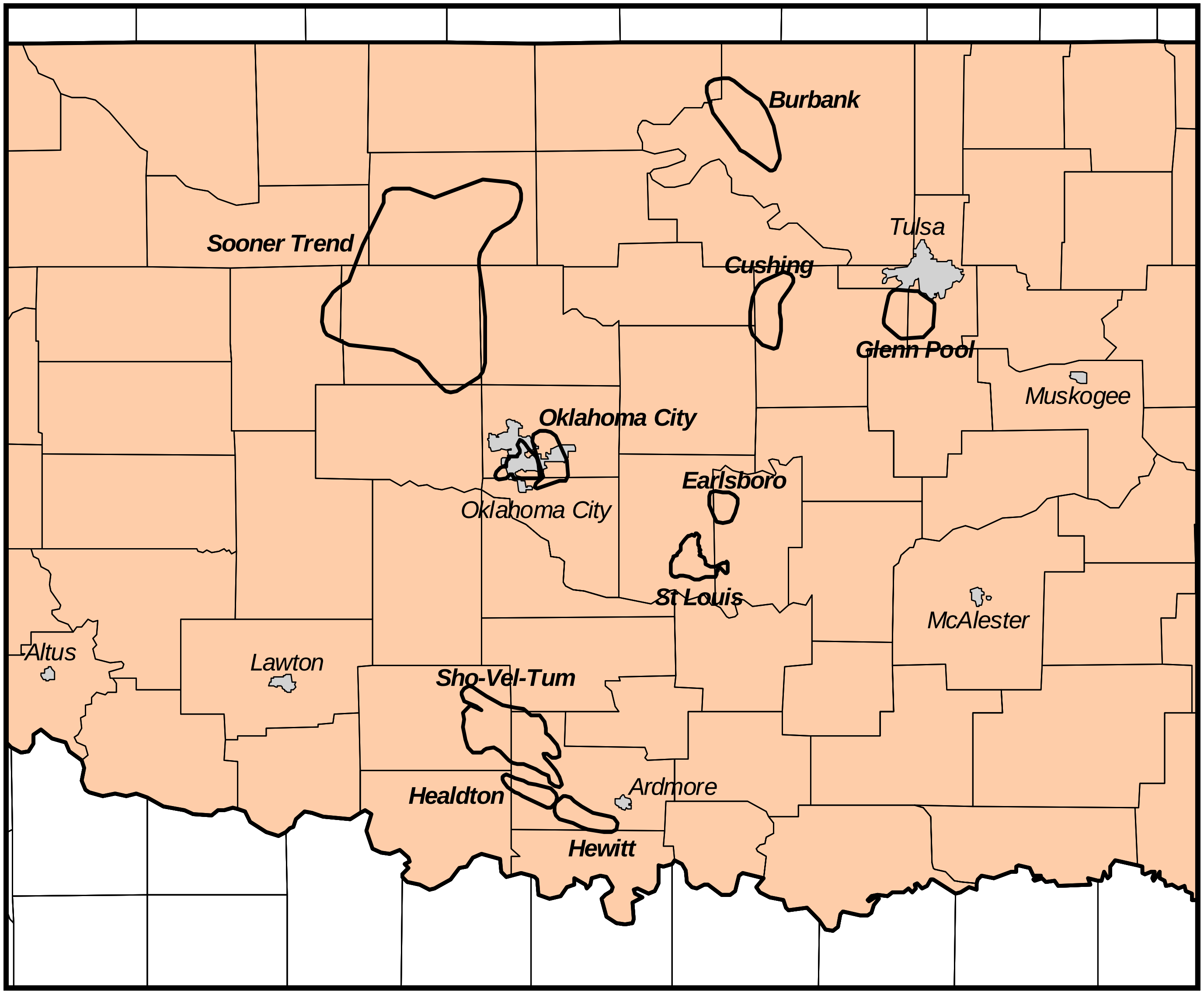
2. INTRODUCTION

2.1 CURRENT SITUATION. Oklahoma contains numerous abandoned oil fields, and those that are still active are considered mature and in decline. Stemming the decline in oil production will be a major challenge, requiring the application of more advanced oil recovery methods and technology, particularly CO_2 enhanced oil recovery. The main purpose of this report is to provide information to these "stakeholders" on the potential for pursuing CO_2 enhanced oil recovery (CO_2-EOR) as one option for slowing or potentially stopping the decline in Oklahoma's oil production.

This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Oklahoma," provides information on the size of the technical and economic potential for CO_2-EOR in Oklahoma 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 CO_2-EOR in Oklahoma.

2.2 BACKGROUND. Although Oklahoma still remains one of the largest oil producing states, it has experienced large declines in oil production over the past 10 years. The state currently produces only 180 thousand barrels of oil per day (in 2002). However, the deep, light oil reservoirs of this region are ideal candidates for miscible carbon-dioxide based enhanced oil recovery (CO_2-EOR). Some of the major oil fields of Oklahoma are shown below in Figure 2.

Figure 2. Large Oklahoma Oil Fields



2.3 PURPOSE. This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Oklahoma" is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. A previous report addressed the oil fields of California and the Gulf Coast regions of Louisiana, Mississippi, and Texas. 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.

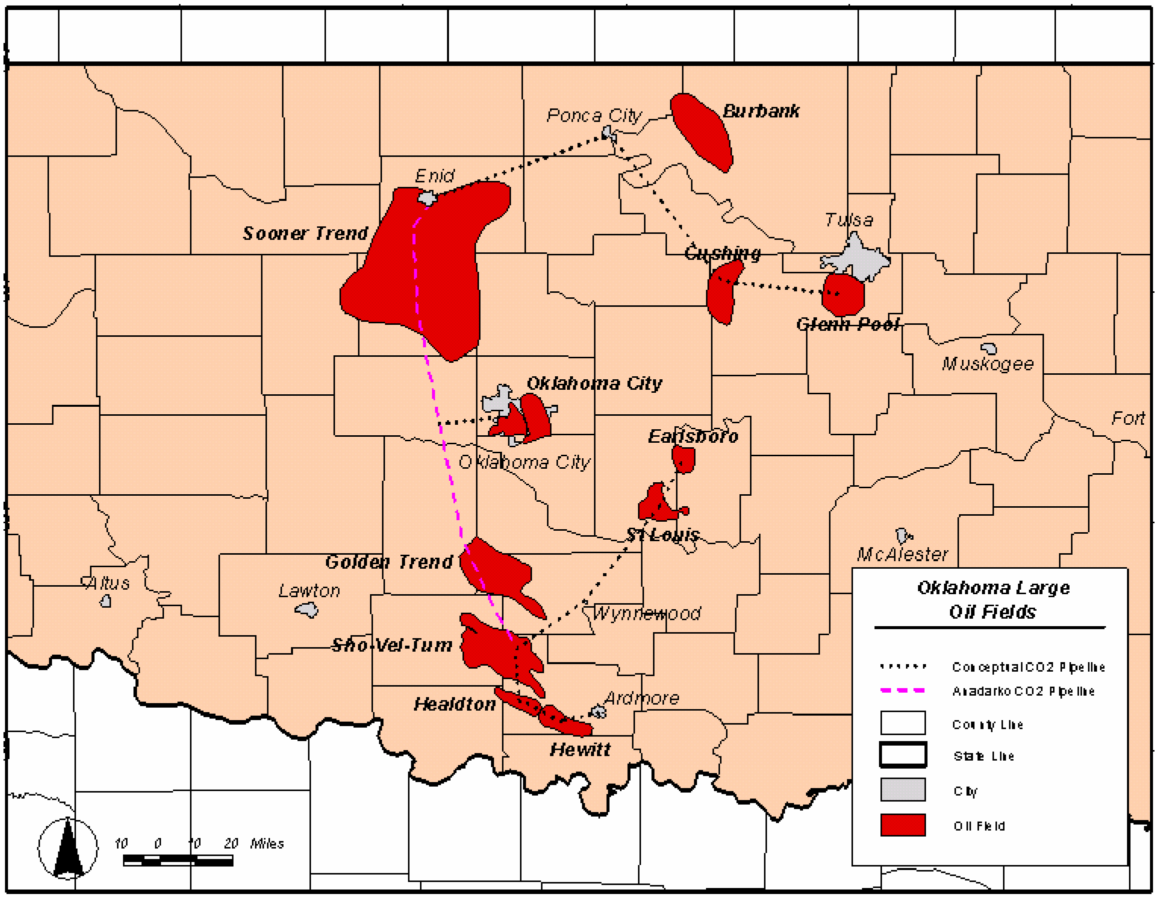
Future studies will also examine: 1) alternative public-private partnership strategies for developing lower-cost CO_2 supply; 2) launching R&D/pilot projects of advanced CO_2 flooding technology; and 3) structuring royalty/tax incentives and policies that would help accelerate the application of CO_2-EOR and CO_2 storage in the major oil basins of the U.S.

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

2.4 KEY ASSUMPTIONS. For purposes of this study, it is assumed that sufficient supplies of CO_2 will become available, either by pipeline from natural sources such as the Bravo Dome of New Mexico, or from the hydrogen plants at the refineries in Ponca City, OK (hydrogen production capacity of 11 MMcfd), Ardmore, OK (hydrogen production capacity of 26 MMcfd), and Wynnewood, OK (hydrogen production capacity of 9 MMcfd). The timing of this availability assumes that this CO_2 will be delivered in the near future, as forecasting field life is not an aspect of this study.

Figure 3 provides a conceptual illustration of a CO_2 pipeline system that would transport captured CO_2 emissions from Ponca City, Ardmore, and Wynnewood refineries to some of the large oil fields of Oklahoma with positive CO_2-EOR potential. It makes no warranties as to the availability of pipeline right-of-ways due to environmental and/or landowner constraints.

Figure 3. Conceptual CO_2 Pipeline System Connecting CO_2 Sources With Oklahoma Oil Fields



Currently, Anadarko operates a 120-mile CO_2 pipeline that transports CO_2 from Enid in northern Oklahoma to the Northeast Purdy and the Bradley Unit of the composite Golden Trend Field and to the Sko-Vel-Tum Field, both south of Oklahoma City (also shown in Figure 3). This pipeline could also provide CO_2 to other CO_2-EOR candidate fields, including Sooner Trend, Oklahoma City, Healdton, and Hewitt. Kinder Morgan provides CO_2 from the Bravo Dome to the Postle and Camrick fields in the Oklahoma Panhandle near Guyman, OK through Transpetco's CO_2 Pipeline.

Constructed in 1996, the 120-mile Transpetco/Bravo Pipeline with 12 ¾-inch line has a capacity of 175 MMCFD, Figure 4.

Figure 4. Transpetco/Bravo CO2 Pipeline to Postle Field

Given the limited oil reservoir data in Oklahoma, many reservoirs within a field were lumped together in our analysis of CO_2-EOR potential. A more detailed breakout of the reservoir properties and oil production of the many reservoirs within each field is beyond the scope of our initial assessment.

It should also be noted that there are thousands of oil and gas wells in Oklahoma without records, API numbers, or locations. These old, abandoned wells, often unplugged, would need to be located and plugged prior to initiation of a CO_2 flood. Finding and plugging these old wells presents one of the biggest challenges to the success of CO_2-EOR in Oklahoma oil reservoirs.

2.5 TECHNICAL OBJECTIVES. The objectives of this study are to examine the technical and the economic potential of applying CO_2-EOR in Oklahoma 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). Given the still limited application of CO_2-EOR in Oklahoma and the inherent technical and geologic risks, economic evaluations typically add 0 risk factor for using this technology option in Oklahoma.

2. *"State of the Art" Technology*. This involves bringing to Oklahoma 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. 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^o API would be selected for miscible CO_2-EOR. Major Oklahoma light oil fields such as Cement, Golden Trend and Sho-Vel-Tum 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^o and 25^o API). However, in this study, there were no Oklahoma 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 Oklahoma's reservoirs amenable to CO_2-EOR, Table 6.

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

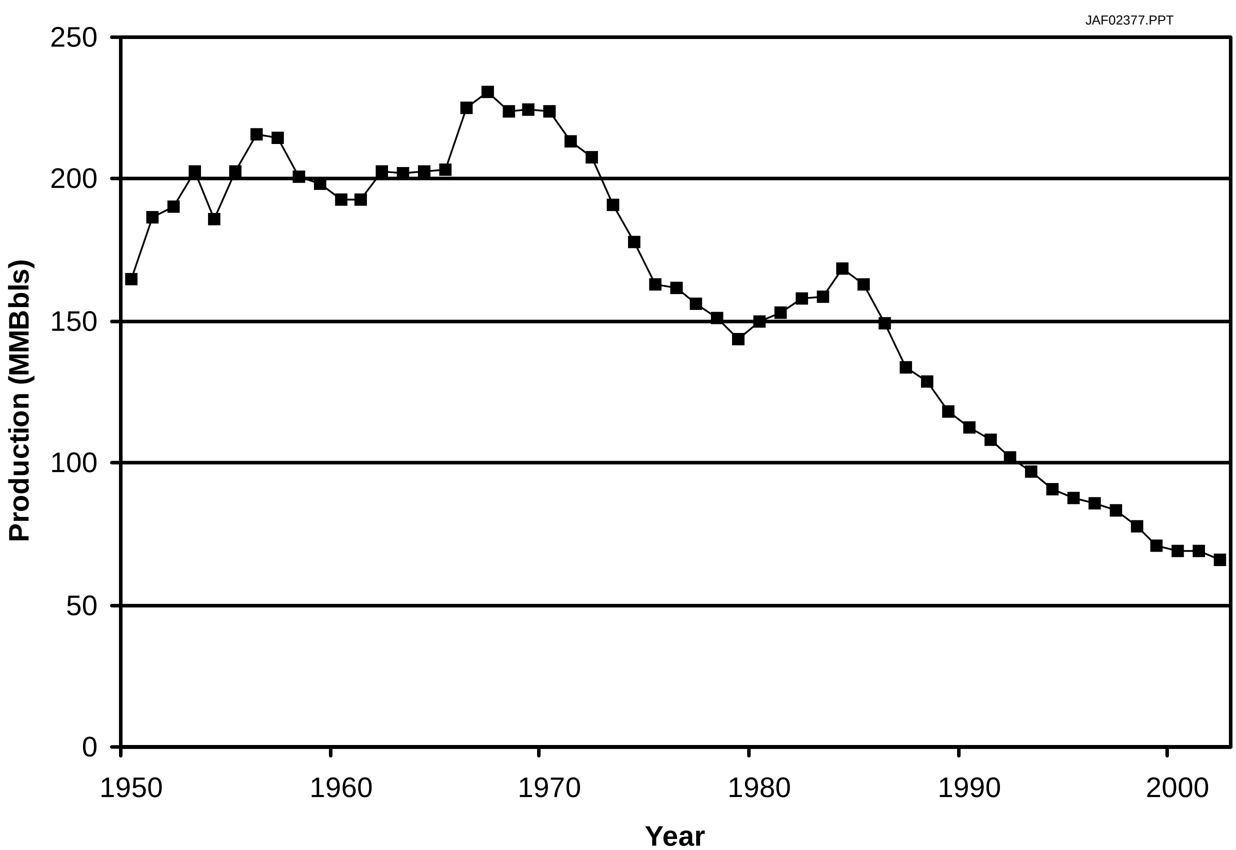
CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices"; Miscible CO_2-EOR	▪ Deep, Light Oil Reservoirs
"State of the Art"; Miscible and Immiscible CO_2-EOR	▪ Deep, Light Oil Reservoirs ▪ Deep, Moderately Heavy Oil Reservoirs

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 Oklahoma'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 OKLAHOMA OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production in Oklahoma began before 1900, reaching an intermediate peak in 1967, Figure 5. Since then oil production has declined, despite secondary recovery attempts and waterflooding applications in many of the large and aging oil fields. Oil production in 2002 dropped to 181,000 barrels per day, down from the state's peak in 1967 of 632,000 barrels per day.

Figure 5. History of Oklahoma Crude Oil Production, 1950 - 2002.



However, Oklahoma still holds a rich resource of oil in the ground. With more than 60 billion barrels of original oil in-place (OOIP) and approximately 15 billion barrels expected to be recovered, 45 billion barrels of oil will be "stranded" due to lack of technology, lack of sufficient, affordable CO_2 supplies and high economic and technical risk.

Table 7 presents the status and latest annual oil production for the ten largest Oklahoma oil fields that account for a quarter of the oil production in this region. The table shows that six of the largest oil fields are experiencing a production decline. Arresting this decline in Oklahoma's oil production could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

Table 7. Crude Oil Annual Production, Ten Largest Oklahoma Oil Fields, 2000-2002
(Million Barrels per Year)

Major Oil Fields	2000	2001	2002	Production Status
Burbank	0.8	0.8	0,8	Stable
Cushing	1.0	1.0	1.1	Stable
Glenn Pool	0.5	0.4	0.4	Declining
Oklahoma City	0.7	0.6	0.6	Declining
Sho-Vel-Tum	8.4	7.8	7.8	Declining
St. Louis	0.5	0.5	0.5	Stable
Sooner Trend	2.3	2.2	1.7	Declining
Healdton	1.1	1.0	1.0	Declining
Hewitt	1.2	1.0	0.6	Declining
Earlsboro	0.1	0.1	0.1	Stable

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Oklahoma's oil producers are familiar with using technology for improving oil recovery. For example, a large number of oil fields have undergone or are currently under waterflood recovery and significant efforts are underway in several Oklahoma oil fields, such as Northeast Purdy, Bradley Unit, Sho-Vel-Tum and Camrick in applying CO_2 for enhanced oil recovery. Additional discussion of the experience with CO_2-EOR in Oklahoma is provided in Chapter 6.

3.3 THE "STRANDED OIL" PRIZE. Even though Oklahoma's oil production is declining, this does not mean that the resource base is depleted. The oil producing regions of Oklahoma still contain 75% of their OOIP after primary and secondary oil recovery. This large volume of remaining oil in-place (ROIP) is the "prize" for CO_2-EOR.

Table 8 provides information (as of year 2002) on the oil production history and remaining oil in place of 10 large Oklahoma oil fields, each with estimated ultimate recovery of 200 million barrels or more. Of particular note are the giant light oil fields that may be attractive for miscible CO_2-EOR, including: Sho-Vel-Tum with 3,232 million barrels of ROIP, Sooner Trend with 1,687 million barrels of ROIP, and Glenn Pool and Oklahoma City both with 1,571 million barrels of ROIP.

Table 8. Selected Major Oil Fields of Oklahoma

	Field	Cumulative Production (MMbbl)	Estimated Reserves (MMbbl)	Remaining Oil In-Place (MMbbl)
1	BURBANK	252	8	610
2	CUSHING	458	7	1,110
3	GLENNPOOL	388	4	1,570
4	OKLAHOMA CITY	754	4	1,570
5	SHO-VEL-TUM	1,417	63	3,230
6	ST. LOUIS	245	6	590
7	SOONER TREND	317	12	1,690
8	HEALDTON	345	7	680
9	HEWITT	293	7	700
10	EARLSBORO	208	1	1,190

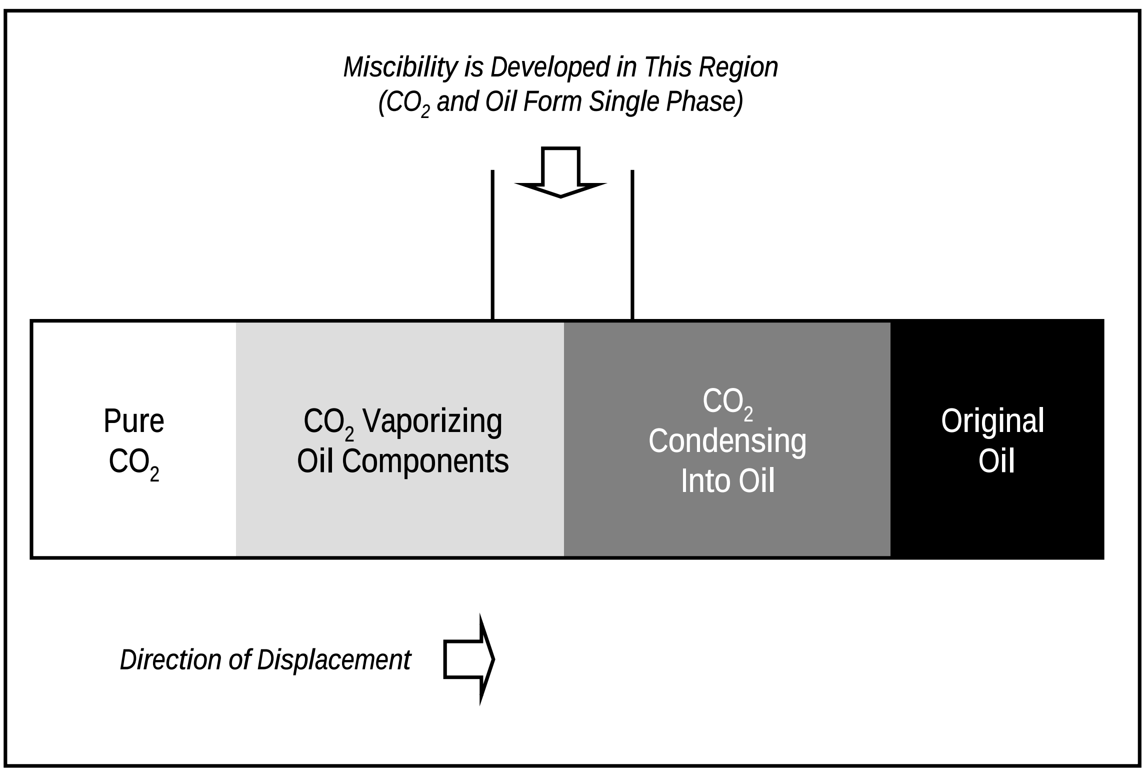
3.4 REVIEW OF PRIOR STUDIES. No recent studies of the potential for CO_2 enhanced oil recovery in Oklahoma oil reservoirs have been conducted since the National Petroleum Council's efforts in 1984 and 1976. These studies were conducted for the United States as a whole and do not contain results by state.

4. MECHANISMS OF CO_2-EOR

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

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

Figure 6. 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 7A and 7B provide basic information on the change in CO_2 density and viscosity, two important oil recovery mechanisms, as a function of pressure.

Oil swelling is an important oil recovery mechanism, for both miscible and immiscible CO_2-EOR. Figures 8A and 8B show the oil swelling (and implied 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^{o}API) oil reservoir in Turkey. Laboratory work on the Bradford Field (Pennsylvania) oil reservoir showed that the injection of CO_2, at 800 psig, increased the volume of the reservoir's oil by 50%. Similar laboratory work on Mannville "D" Pool (Canada) reservoir oil showed that the injection of 872 scf of CO_2 per barrel of oil (at 1,450 psig) increased the oil volume by 28%, for crude oil already saturated with methane.

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

Figure 7A. 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).

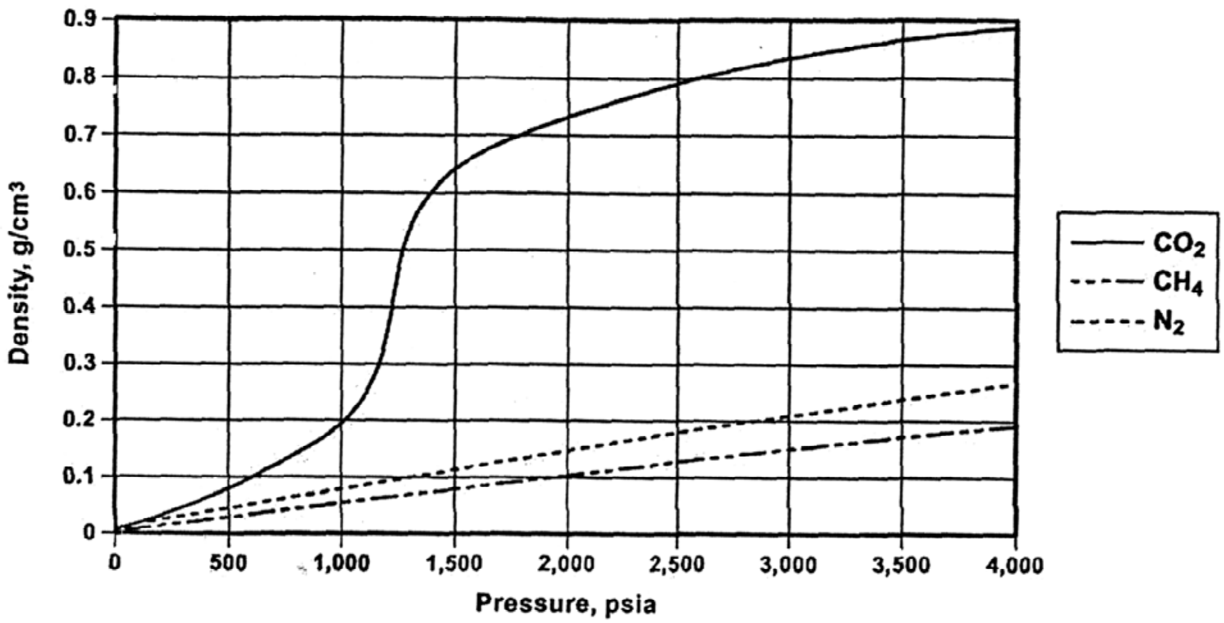


Figure 7B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

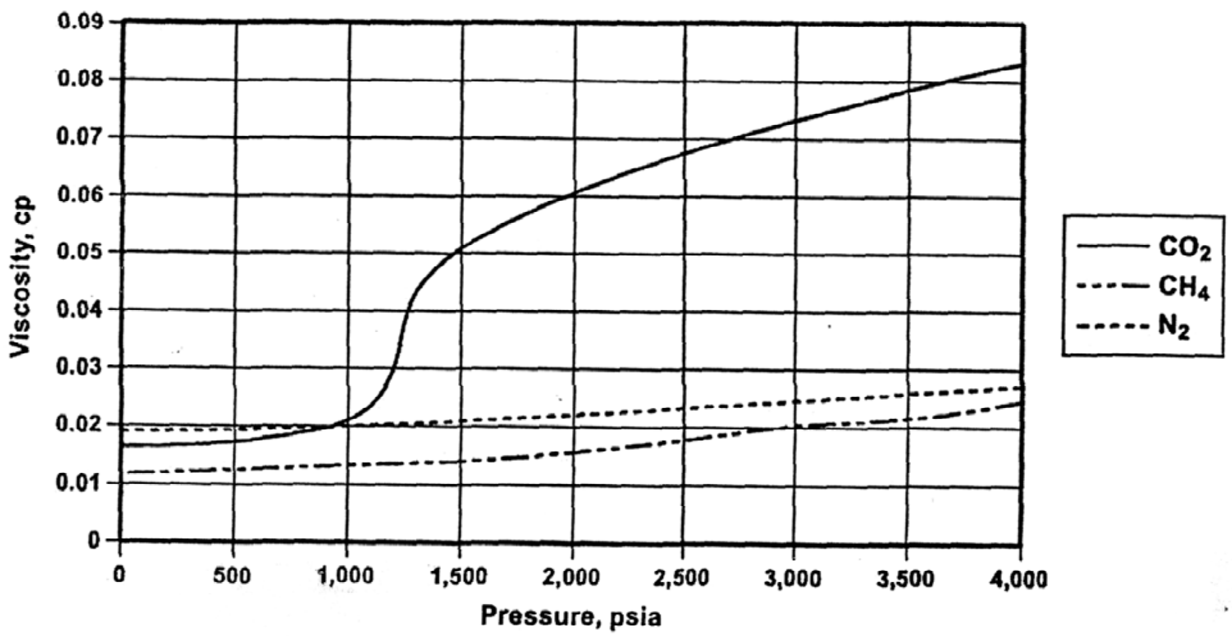


Figure 8A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid. (Holm and Josendal)

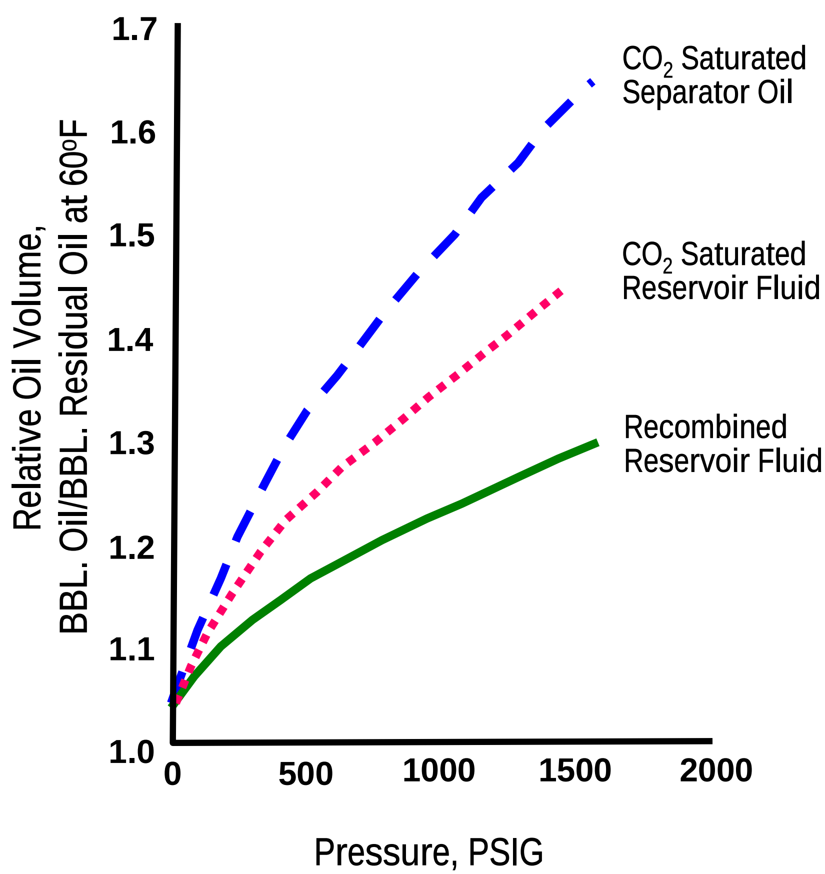


Figure 8B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

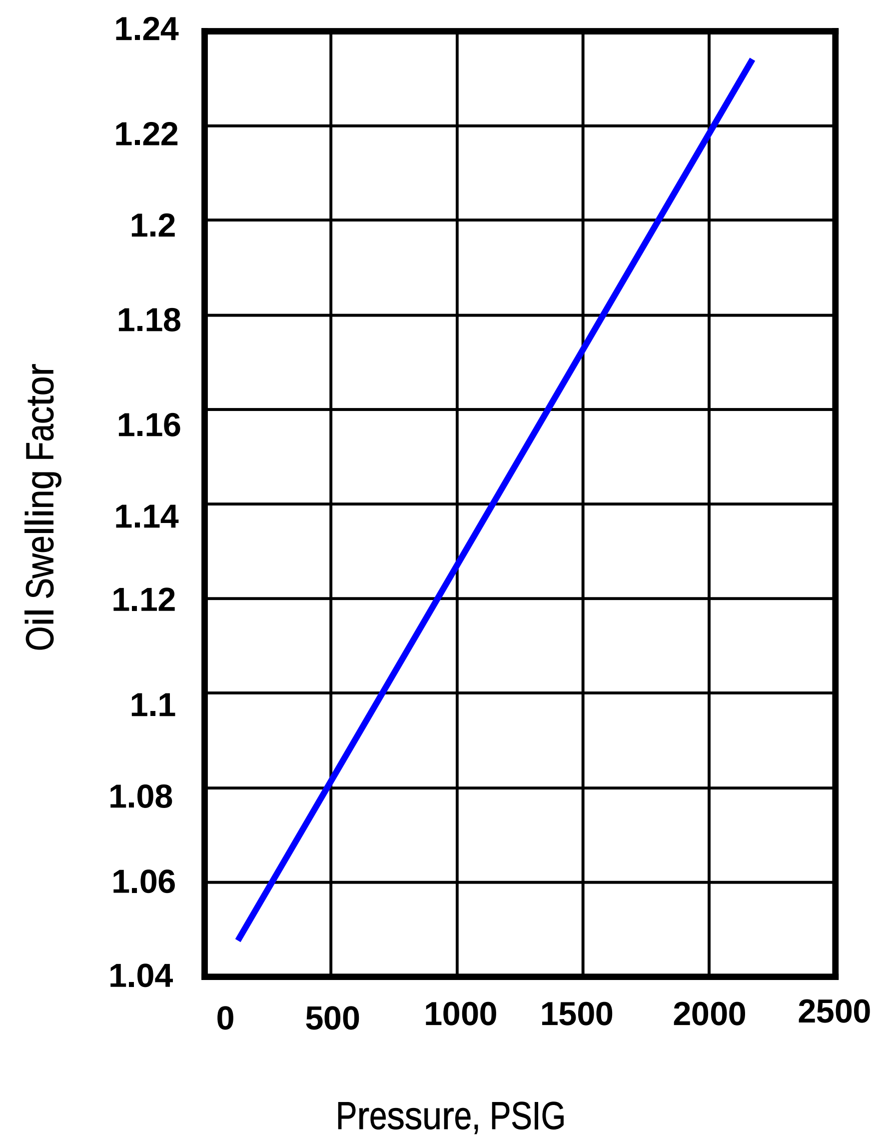
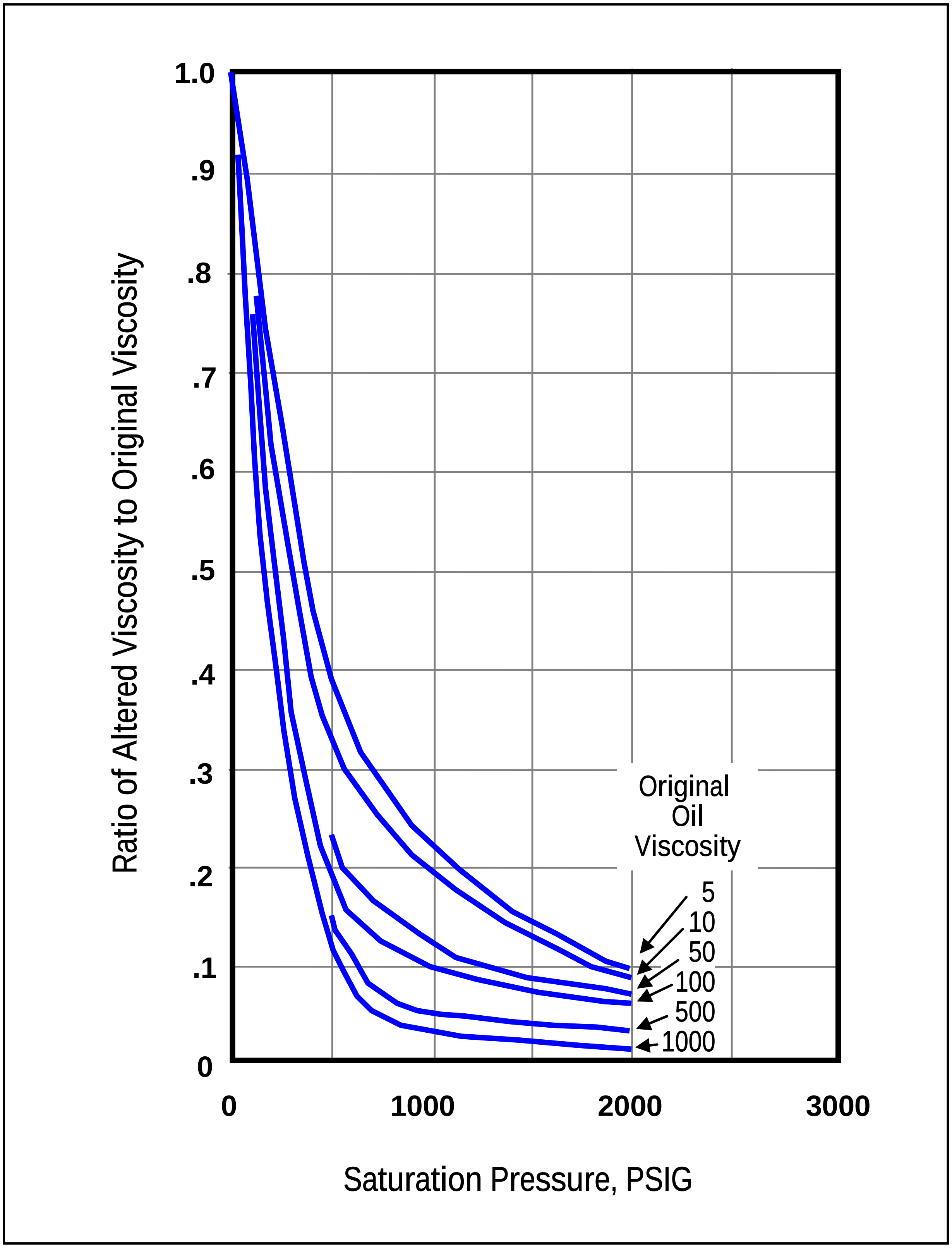


Figure 9. Viscosity Reduction Versus Saturation Pressure. (Simon and Graue)



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5. STUDY METHODOLOGY

5.1 OVERVIEW. A six part methodology was used to assess the CO_2-EOR potential of Oklahoma's oil reservoirs. The seven steps were: (1) assembling the Oklahoma 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; and, (6) performing economic and sensitivity analyses.

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

5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE. The study started with the National Petroleum Council (NPC) Public Data Base, maintained by DOE Fossil Energy. The study updated and modified this publicly accessible data base to develop the Oklahoma Oil Reservoirs Data Base.

Table 9 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 Oklahoma Major Oil Reservoirs Data Base contains 96 reservoirs, accounting for 60.5% of the oil expected to be ultimately produced in Oklahoma by primary and secondary oil recovery processes.

Table 9. Reservoir Data Format: Major Oil Reservoirs Data Base.

Basin Name

Field Name

Reservoir

Reservoir Parameters:

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

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Oil Production

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

Water Production

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

Injection

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

Volumes

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

OOIP Volume Check

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

SROIP Volume Check

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

ROIP Volume Check

ROIP Check (MMbl)	

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 Oklahoma; (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^o API was used to ensure the reservoir's oil had sufficient mobility. Table 10 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 10. Oklahoma Oil Reservoirs Screened Acceptable for CO_2-EOR

State	Field	Formation
A. Louisiana		
Oklahoma	ALLEN DISTRICT	CROMWELL, HUNTON, BROMIDE
Oklahoma	ANTIOCH,SOUTHWEST	DEESE
Oklahoma	APACHE	BROMIDE
Oklahoma	AYLESWORTH	MISENER AND OTHERS
Oklahoma	BINGER	MARCHAND
Oklahoma	BOWLEGS	ALL
Oklahoma	CAMRICK DISTRICT	MORROW
Oklahoma	CARTHAGE DISTRICT	MORROW
Oklahoma	CEMENT	HOXBAR
Oklahoma	CEMENT	PERMIAN & HOXBAR
Oklahoma	CHEROKITA TREND	CHEROKEE
Oklahoma	CHEYENNE VALLEY	CV CHEROKEE
Oklahoma	CHEYENNE VALLEY	RED FORK
Oklahoma	CHICKASHA	MARCHAND
Oklahoma	CHICKASHA	NOBLE-OLSON
Oklahoma	CROMWELL	VARIOUS PENNSYLVANIAN
Oklahoma	CUMBERLAND	MCLISH-BROMIDE
Oklahoma	CUSHING	OTHER SANDS
Oklahoma	EARLSBORO	EARLSBORO
Oklahoma	EDMOND WEST	HUNTON
Oklahoma	EDMOND WEST	PENN SANDS
Oklahoma	EDMOND WEST	SIMPSON AND WILCOX 2
Oklahoma	ELK CITY	HOXBAR
Oklahoma	EOLA ROBBERSON	SIMPSON
Oklahoma	FITTS	HUNTON
Oklahoma	FITTS	SIMPSON & VIOLA
Oklahoma	FITTS WEST	VIOLA
Oklahoma	GOLDEN TREND	BROMIDE AND DEEP SS
Oklahoma	GOLDEN TREND	DEESE AND PENN SS
Oklahoma	GOLDEN TREND	HUNTON-VIOLA
Oklahoma	HEALDTON	ARBUCKLE
Oklahoma	KEOKUK	MISENER-HUNTON
Oklahoma	KNOX	PONTOTOC-HOXBAR-DEESE
Oklahoma	LITTLE RIVER	CROMWELL
Oklahoma	LITTLE RIVER	WILCOX
Oklahoma	MAUD	HUNTON
Oklahoma	MISSION	HUNTON
Oklahoma	MUSTANG NORTH	HUNTON BOIS D'ARC
Oklahoma	OAKDALE	RED FORK

Table 10. Oklahoma Oil Reservoirs Screened Acceptable for CO_2-EOR

State	Field	Formation
Oklahoma	OKLAHOMA CITY	LOWER SIMPSON
Oklahoma	OKLAHOMA CITY	PENNSYLVANIAN
Oklahoma	OKLAHOMA CITY	WILCOX
Oklahoma	PAPOOSE	CROMWELL
Oklahoma	PAULS VALLEY	BASAL PENNSYLVANIAN
Oklahoma	PAULS VALLEY, EAST	BURNS-BRUNDIDGE
Oklahoma	POSTLE	MORROW
Oklahoma	PUTNAM	OSWEGO
Oklahoma	RINGWOOD	MANNING
Oklahoma	SEMINOLE	WILCOX & OTHER SANDS
Oklahoma	SHO-VEL-TUM	DEESE
Oklahoma	SHO-VEL-TUM	DORNICK-SPRINGER
Oklahoma	SHO-VEL-TUM	SYCAMORE
Oklahoma	SOONER TREND	HUNTON
Oklahoma	SOONER TREND	LAYTON AND OTHERS
Oklahoma	SOONER TREND	MANNING AND CHESTER
Oklahoma	SOONER TREND	MERAMEC
Oklahoma	SOUTH LONE ELM	CLEVELAND SAND
Oklahoma	ST LOUIS	ALL
Oklahoma	TONKAWA	WILCOX
Oklahoma	WASHINGTON	OSBORNE
Oklahoma	WATONGA TREND	MORROW
Oklahoma	WEST SEMINOLE	WILCOX
Oklahoma	WEWOKA DISTRICT	CROMWELL

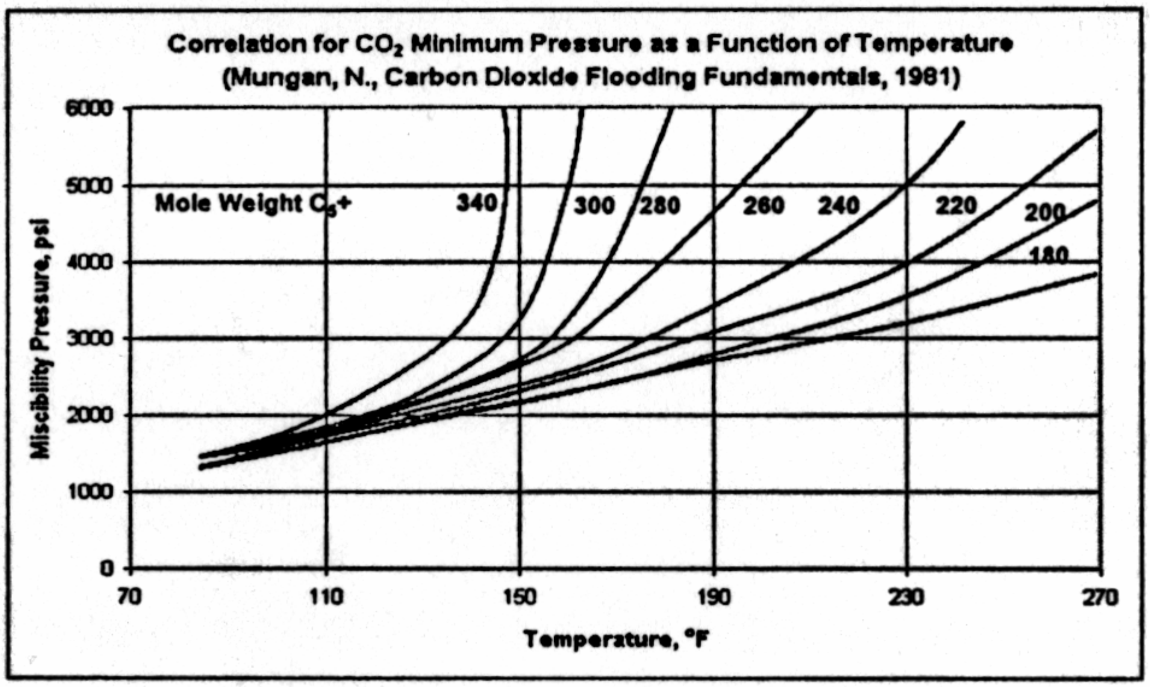
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and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

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure 10. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most Oklahoma 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 ^{o}F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

Figure 10. Estimating CO_2 Minimum Miscibility Pressure



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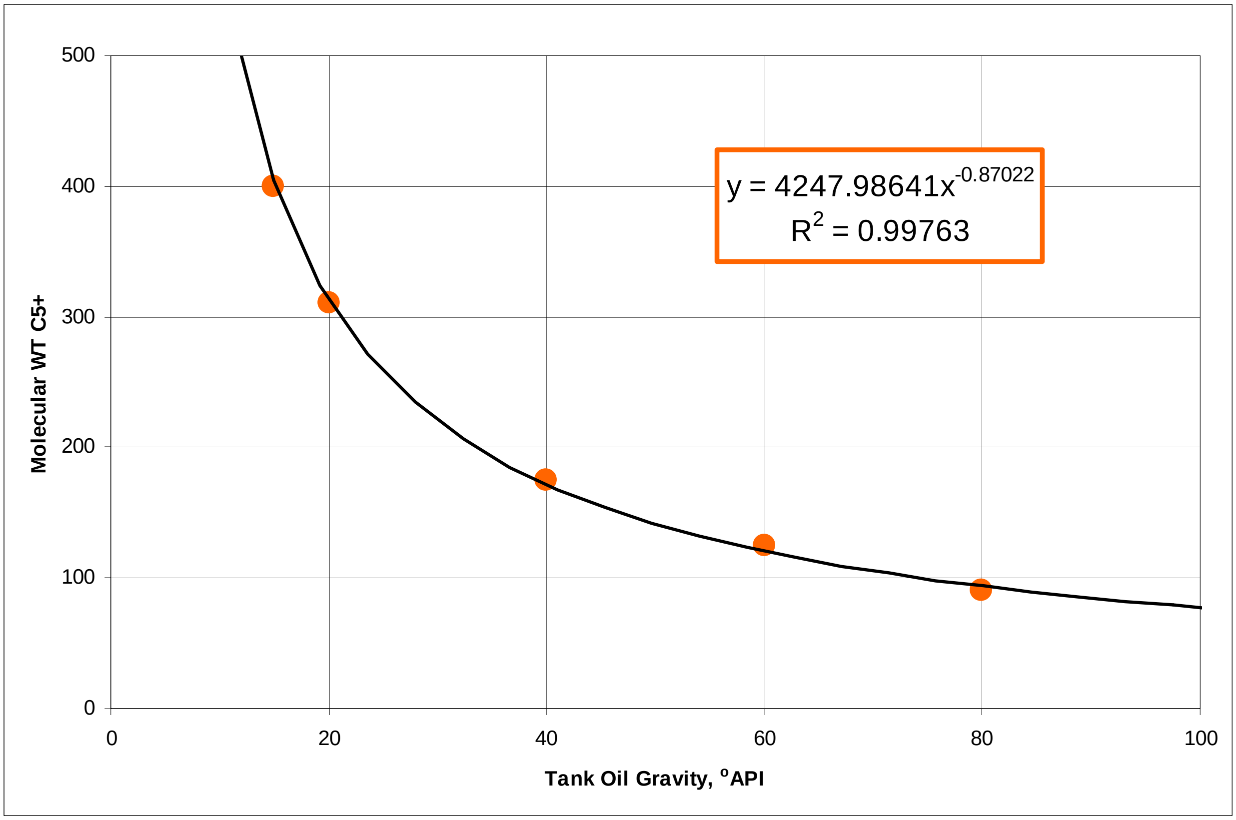
The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 11.

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

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



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

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

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

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2. A variety of CO_2 purchase and reinjection costs options are available to the model user. (Appendices B, 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.

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 could be economically produced by CO_2-EOR from Oklahoma's oil basins and major oil reservoirs.

- <u>Two technology cases were examined</u>. 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.

- <u>Two oil prices were considered</u>. A $25 per barrel oil price was used to represent the moderate oil price case; a $35 per barrel oil price was used to represent the availability of Federal/state risk sharing and/or the continuation of the current high oil price situation.

- <u>Two CO_2 supply costs were considered.</u> The high CO_2 cost was set at $1.25 per Mcf to represent the costs of a new transportation system bringing natural CO_2 to Oklahoma's oil basins. A lower CO_2 supply cost equal to $0.70 per Mcf was included to represent the potential future availability of low-cost CO_2 from industrial and power plants as part of CO_2 storage.

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

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

- The first scenario captures how CO_2-EOR technology has been applied and has performed in the past. 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 other areas, is successfully applied to the oil reservoirs of Oklahoma. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to these complex oil reservoirs. However, because of limited sources of CO_2, these supply costs are high (equal to $1.25 per Mcf) the oil price) and significantly hamper economic feasibility of using CO_2-EOR.
- The third scenario, entitled "Risk Mitigation," examines how the economic potential of CO_2-EOR could be increased through a strategy involving state production tax reductions, increased federal investment tax credits and royalty relief that together would add an equivalent of $10 per barrel to the WTI marker price for crude oil.
- In the final scenario, entitled "Ample Supplies of CO_2," low-cost, "EOR-ready" CO_2 supplies (equal to $0.70 per Mcf) are aggregated from various sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants and other industrial sources. These would be augmented, in the longer-term, from low CO_2 concentration industrial sources including combustion and electric generation plants. Capture of industrial CO_2 emissions would be part of national efforts for reducing greenhouse gas emissions.

Table 11. Economic Model Established by the Study

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

Table 11. Economic Model Established by the Study (Cont'd)

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

Table 11. Economic Model Established by the Study (Cont'd)

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

6. STUDY RESULTS

6.1 OKLAHOMA OIL PRODUCTION. Oklahoma is still one of the largest oil producing states in the country with a rich history of oil recovery. Crude oil production began in 1897, and has reached a cumulative recovery of over 14.5 billion barrels of oil to date. In 2002, Oklahoma ranked 5th in production in the onshore U.S., producing 66 MMBbls of oil (181 MBbls/day) from 83,389 producing wells, and 5th in reserves at 598 MMBbls. The state contains 5 petroleum refineries with a crude oil distillation capacity of over 4.7 MMBbls/day.

Despite being one of the top oil producing states, Oklahoma has seen a continuation of the decline in oil production in recent years, Table 12.

Table 12. Recent History of Oklahoma Oil Production

	Annual Oil Production	
	(MMBls/Yr)	(MBbls/D)
1999	71	195
2000	69	189
2001	69	189
2002	66	181

An active program of secondary oil recovery has helped maintain oil production in the state. As of 2002, over 50% of oil fields in the state of Oklahoma had been or were currently undergoing waterflooding. Most of the major waterflood projects, however, have occurred in the western half of the state in the Anadarko Basin, where thick point-bar sandstone deposits make for a more favorable waterflooding conditions.

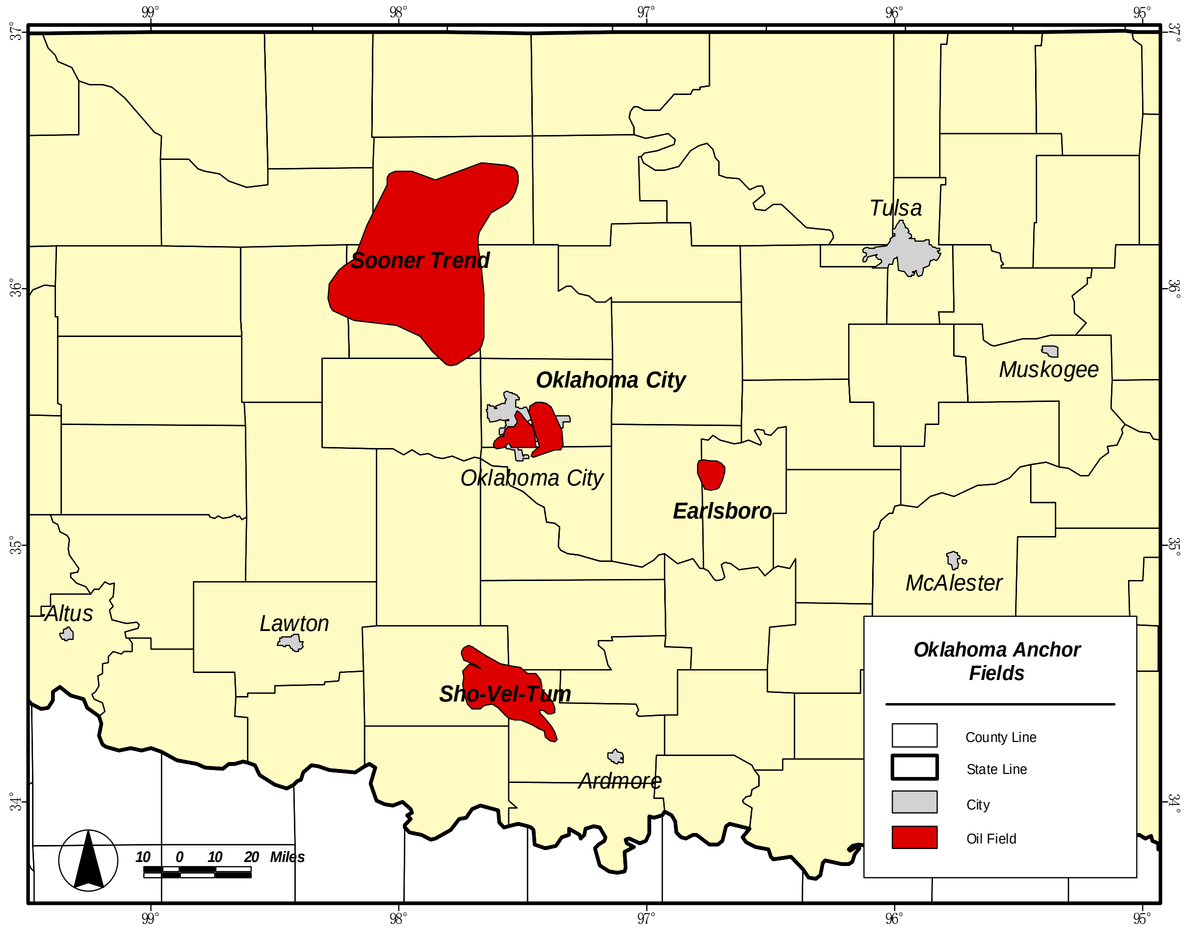
To the east, in the Cherokee Uplift, waterflooding has been unreliable. Currently, a waterflood demonstration project is taking place at the Wolco Field in Osage County, OK. The project is too new to have yielded any substantial waterflood production data, however, the project indicates that optimum performance would occur in thicker sand sections by using horizontal injection and production wells.

Overall the success of waterflooding has been minimal in the eastern portion of the state as a result of lack of detailed reservoir characterization and field-wide simulation. The waterfloods in the larger oil fields of western Oklahoma are mature, with many of the fields near their production limits, calling for alternative methods for maintaining oil production.

6.2 OKLAHOMA OIL FIELDS. To better understand the potential of using CO_2-EOR in Oklahoma's light oil fields, this section examines, in more depth, four large fields, shown in Figure 12. The stack of individual reservoirs in many of these fields has been grouped into:

- Earlsboro (Earlsboro Reservoirs)
- Oklahoma City (Wilcox Reservoirs)
- Sho-Vel-Tum (Deese Reservoirs)
- Sooner Trend (Meramec Reservoirs)

Figure 12. Oklahoma Anchor Fields



These four fields could serve as the "anchor" sites for the initial CO_2-EOR projects in the state that could later be extended to other fields. The cumulative oil production, proved reserves and remaining oil in place (ROIP) for these four "anchor" light oil fields are set forth in Table 13.

Table 13. Status of Oklahoma "Anchor" Fields/Reservoirs, 2002

Anchor Fields/Reservoirs		Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In Place (MMBbls)
1	Earlsboro (Earlsboro)	208	1	1,185
2	Oklahoma City (Wilcox)	520	3	971
3	Sho Vel Tum (Deese)	482	22	935
4	Sooner Trend (Meramec)	152	6	894

These four large "anchor" fields, each with 800 or more million barrels of ROIP, appear to be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 14.

Table 14. Reservoir Properties and Improved Oil Recovery Activity, "Anchor" Oil Fields/Reservoirs

	Anchor Fields	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Earlsboro (Earlsboro)	3,500	39.0	Undergoing waterflooding
2	Oklahoma City (Wilcox)	6,000	38.7	Undergoing waterflooding
3	Sho Vel Tum (Deese)	3,050	29.0	Undergoing waterflooding
4	Sooner Trend (Meramec)	6,900	40.0	Undergoing waterflooding

6.3 PAST AND ON-GOING CO_2-EOR PROJECTS. CO_2-EOR projects in Oklahoma are underway at Northeast Purdy, Bradley Unit, Postle, Sho-Vel-Tum, and Camrick oil fields. The largest CO_2-EOR project has been ExxonMobil's 11,000 acre Postle Field CO_2 flood, started in 1995 involving 140 production wells and 110 injection wells. The most recent CO_2-EOR project is Chaparral Energy's 2,320 acre Camrick Field CO_2 flood strarted in 2001.

Postle Field. Beginning in November of 1995, ExxonMobile began injecting CO_2 into the Postle Field of Oklahoma, applying CO_2-EOR at the end of the waterflood. Located in near the town of Guyman in the Oklahoma Panhandle, the Postle Field began waterflooding in 1967, having produced about 92 MMBbls of oil by 1995. Oil production peaked in 1970 at 22,000 bbls/day, and had dropped to about 2,000 bbls/day when CO_2 injection began.

At the start of the project ExxonMobil, the operator, had plans to increase production to 2,300 bbls/day by 1996, peaking at about 10,000 bbls/day by 2000, and incremental recovery of 10-14% of OOIP.

- CO_2 injection began on November 15, 1995 at a rate of 35 MMscfd, after construction of a $25 million, 120-mile pipleline to carry $CO_2$from Bravo Dome, New Mexico. In 1998, ExxonMobile was injecting 90 MMcfd of CO_2.
- Oil response to CO_2 injection occurred 6 months after CO_2 injection began. Significant response occurred after 10% pore volume of CO_2 had been injected.
- Production has risen to 6,500 bbls/day in late 1999 and 2,000 bbls/day in 2003 with 6,000 bbls/day of enhanced oil production due to the CO_2 flood. Estimated ultimate oil production from CO_2-EOR in the Postle Field is 25 MMBbls. As of 2004, expansion of the project is noted as likely.

Northeast Purdy and Bradley Unit Fields. Currently Anadarko Petroleum has two CO_2 floods underway in the Northeast Purdy and Bradley Unit fields of Oklahoma. The company operates a 120-mile pipeline, transporting CO_2 from a large fertilizer complex in the town of Enid in northern Oklahoma to Lindsay, south of Oklahoma City. Enhanced oil production in the Northeast Purdy Field is 1,800 bbls/day and in the Bradley Unit is 600 bbls/day. The CO_2-EOR project in the Bradley Unit is expected to expand to a field-wide flood, as of 2004.

6.4 OTHER PROJECTS. Chaparrel Energy is operating two CO_2-EOR projects in the Sho-Vel-Tum Field in southern Oklahoma. The miscible CO_2 flood at Sho-Vel-Tum was started in 1982 in the light oil (30^o API) Sims reservoir. This 1,100 acre project, involving 60 production and 40 injections wells is half finished and is producing an incremental 1,250 barrels per day of oil due to CO_2-EOR. The immiscible CO_2 flood at Sho-Vel-Tum was started in late 1998 in a heavier oil (19^o API) Aldridge reservoir. This 98 pilot project involving 6 production and injection wells is producing about 100 barrels of additional oil per day due to CO_2-EOR and is evaluated as being promising and profitable by the operator.

Chaparrel Energy's third CO_2-EOR project, a miscible CO_2 flood in the Camrick Field of western Oklahoma was started in 1991. This 2,320 acre project in the Morrow reservoir has 14 production and 10 injection wells. This recently started project is producing 390 additional (490 total) barrels of oil per day due to the CO_2 flood. The operator rates the project as successful and profitable and indicates plans to expand the flood.

Future CO_2-EOR Potential. Oklahoma contains 64 reservoirs that are candidates for miscible CO_2-EOR.

Under "Traditional Practices" (and current financial conditions, defined above), there are 21 economically attractive oil reservoirs for miscible CO_2 flooding in Oklahoma. 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 Oklahoma increases to 32, providing 2,890 million barrels of additional oil recovery, Table 15.

Table 15. Economic Oil Recovery Potential Under Current Conditions, Oklahoma.

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
"Traditional Practices"*	63	23,500	2,590	21	940
"State of Art Technology"*	63	23,500	5,440	32	2,890

*Assumes an oil price of $25 per barrel, a CO2 cost of $1.25 per Mcf and a ROR hurdle rate of 25% (before tax).
**Assumes an oil price of $25 per barrel, a CO2 cost of $1.25 per Mcf and a ROR hurdle rate of 15% (before tax).

Lower cost CO_2 supplies and risk sharing/higher oil prices would enable CO_2-EOR in Oklahoma to recover up to 4,740 million barrels of oil (from 48 major reservoirs), Table 16.

Table 16. Economic Oil Recovery Potential with More Favorable Financial Conditions, Oklahoma

More Favorable Financial Conditions	No. of Economic Reservoirs	Economic Potential (MMBbls)
Plus: Risk Mitigation*	45	4,560
Plus: Low Cost CO_2**	48	4,740

** Assumes an equivalent of $10 per barrel adjusted for market factors*

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

Appendix A

Using *CO_2-PROPHET* for Estimating Oil Recovery

March 2005

Model Development

The study utilized the *CO_2-PROPHET* model to calculate the incremental oil produced by CO_2-EOR from the large Oklahoma 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 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*

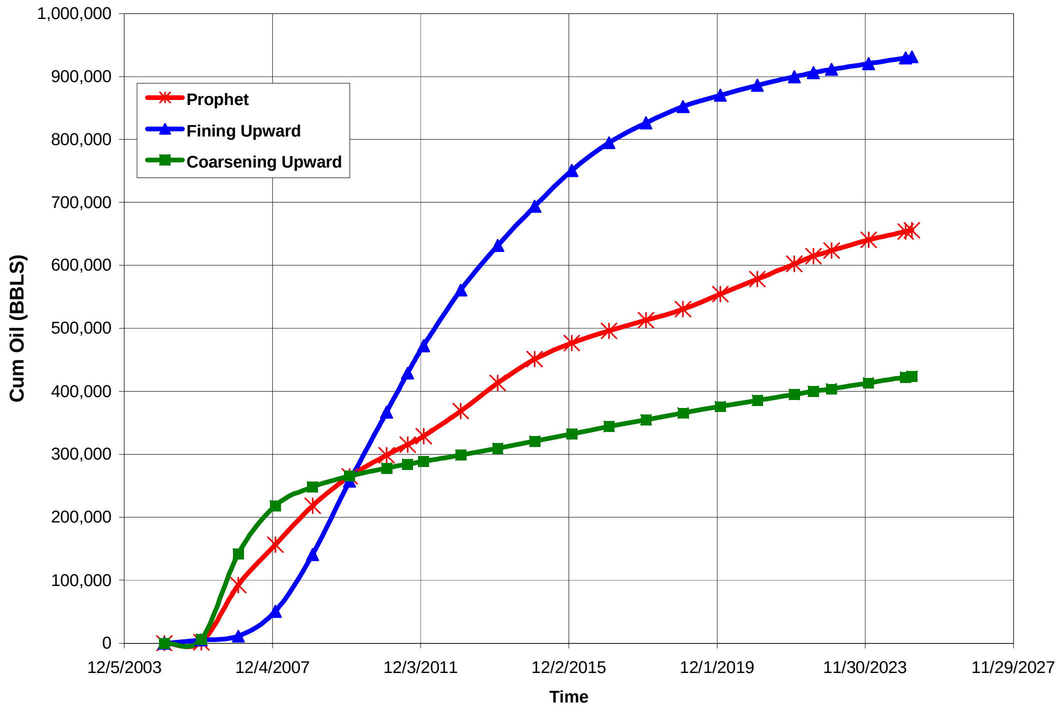
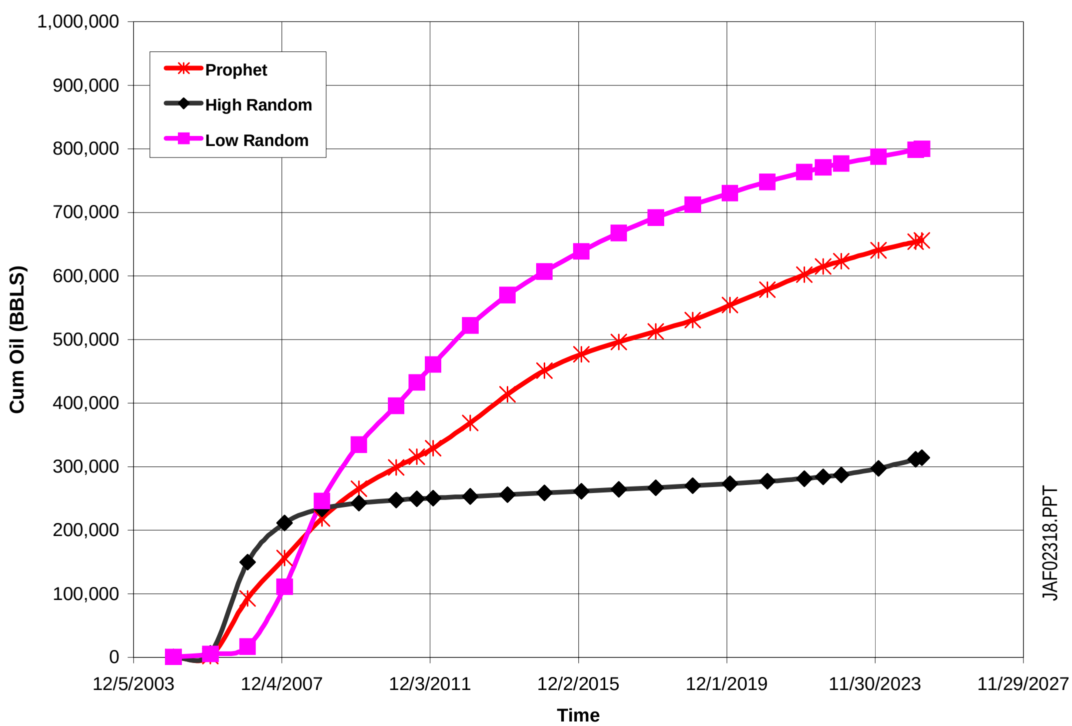


Figure A-2. *CO_2-PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



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

Other key features of *CO_2-PROPHET* and its comparison with the technical capability of *CO_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 B

Oklahoma CO_2-EOR Cost Model

March 2005

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:

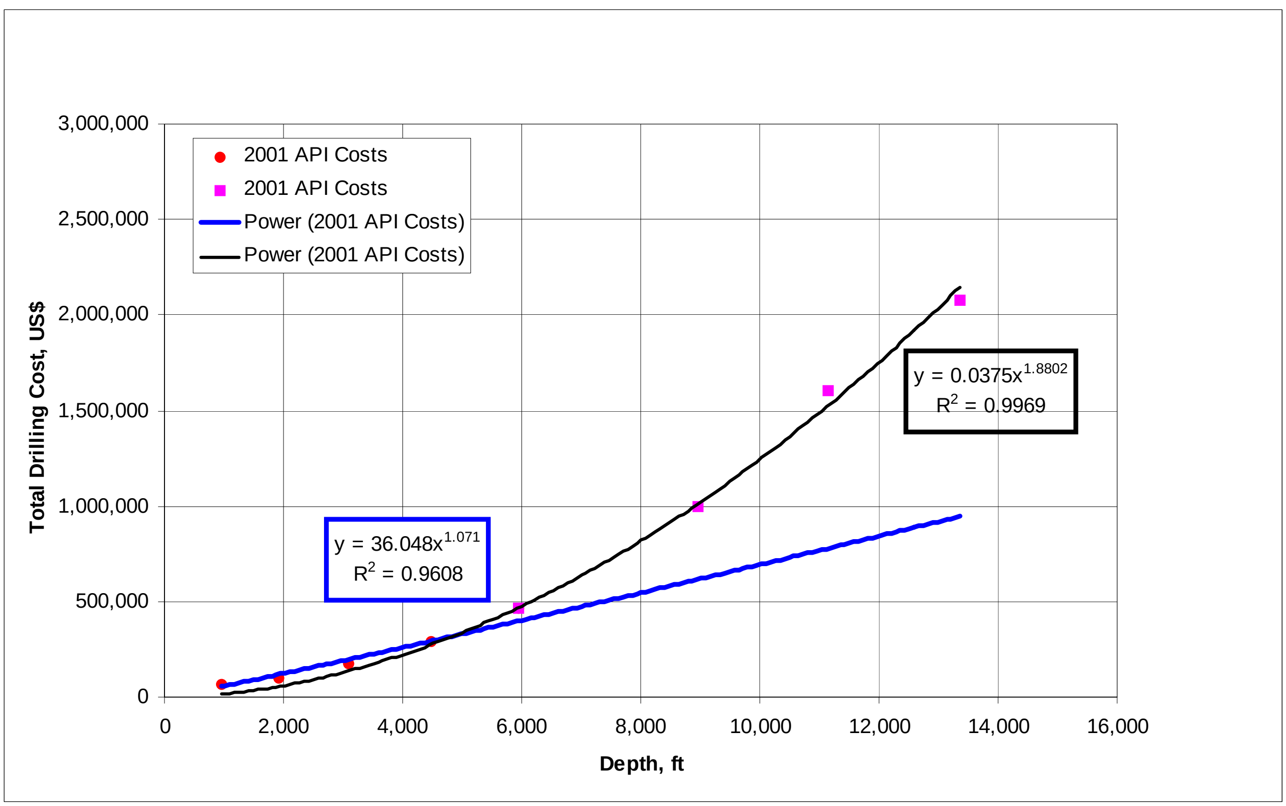
1. <u>Well Drilling and Completion Costs.</u> The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Oklahoma.

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

Well D&C Costs = $a_0 D^{a1}$
Where: a_0= 36.05 for depths less than 5,000 ft. and 0.038 for depths greater than 5,000 ft.
a_1= 1.07 for depths less than 5,000 ft. and1.88 for depths greater than 5,000 ft.
D is well depth

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

Figure B-1. Oil Well D&C Costs for Oklahoma



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

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

Production Well Equipping Costs = $c_0 + c_1D$

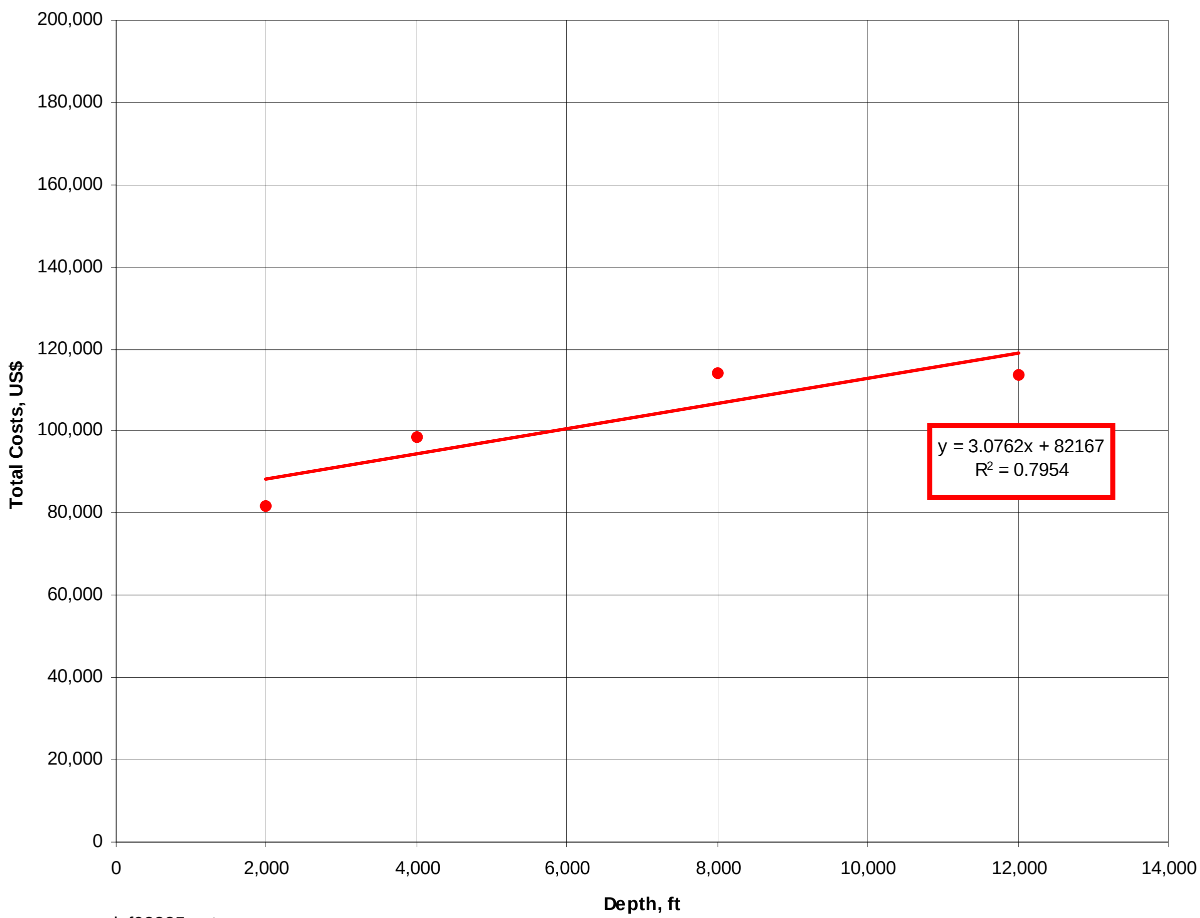
Where: c_o = \$82,167 (fixed)

c_1 = \$3.08 per foot

D is well depth

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

Figure B-2. Lease Equipping Costs for a New Oil Production Well in Oklahoma vs. Depth



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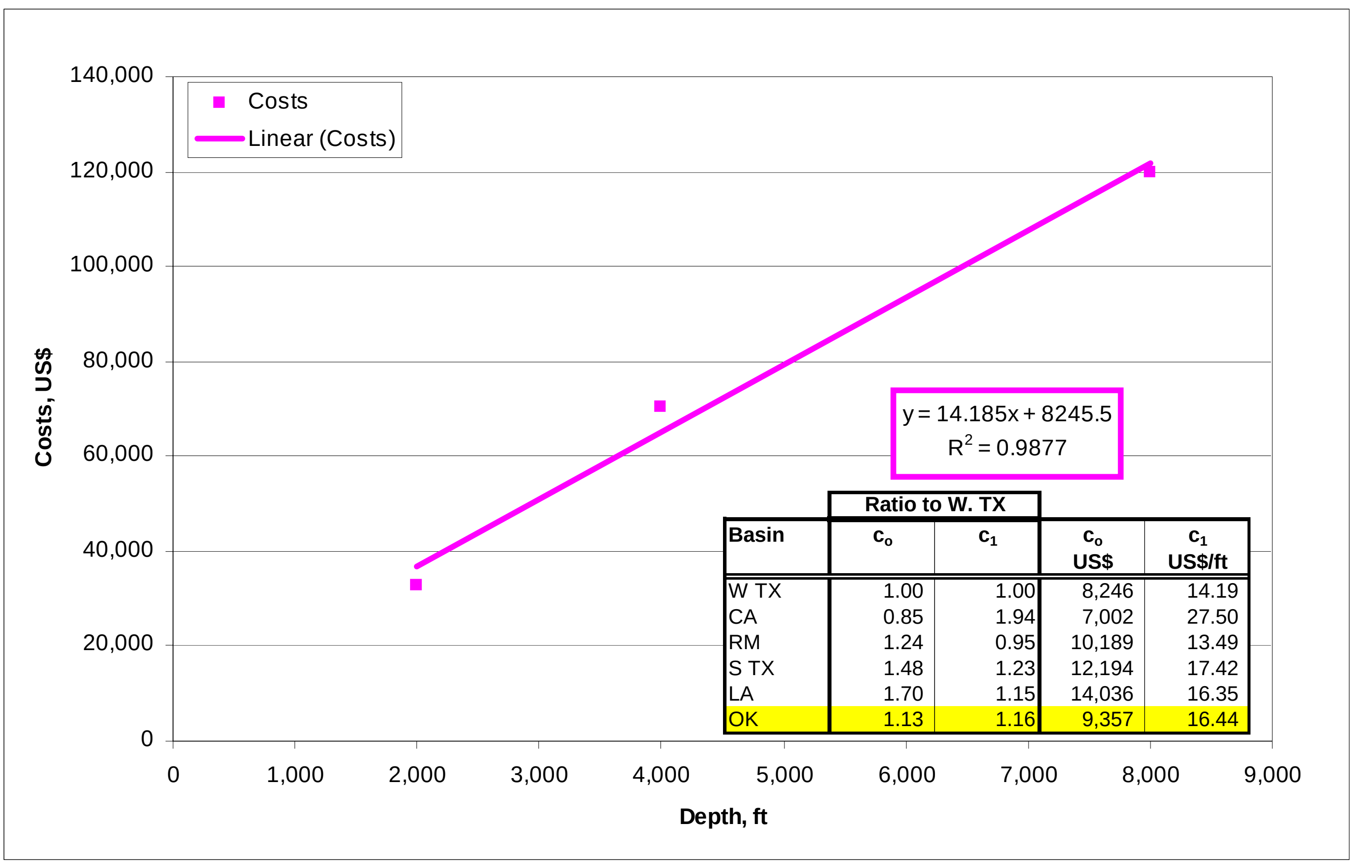
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Oklahoma include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$9,357 (fixed)
c_1 = \$16.44 per foot
D is well depth

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

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



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

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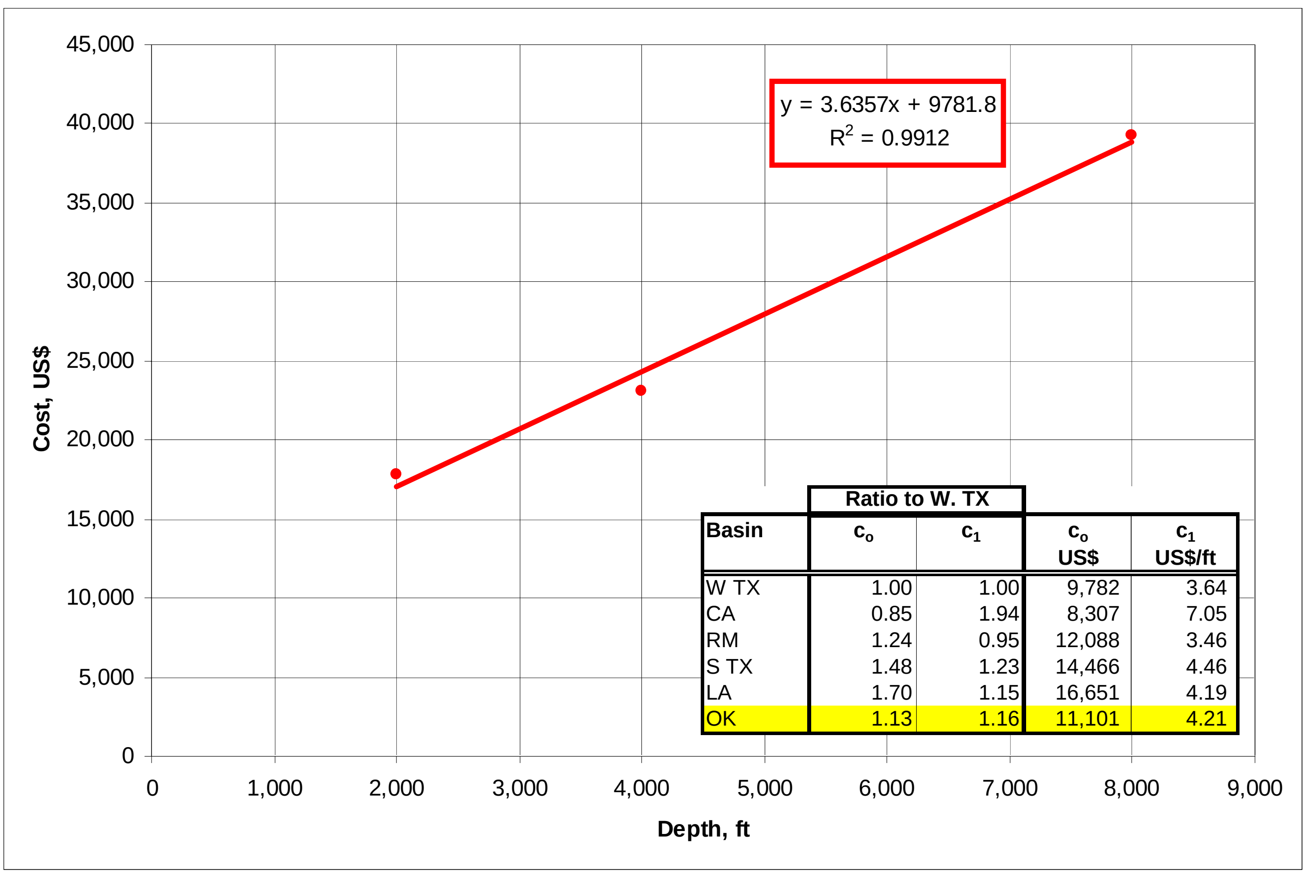
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$11,101 (fixed)
c_1 = \$4.21 per foot
D is well depth

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

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



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

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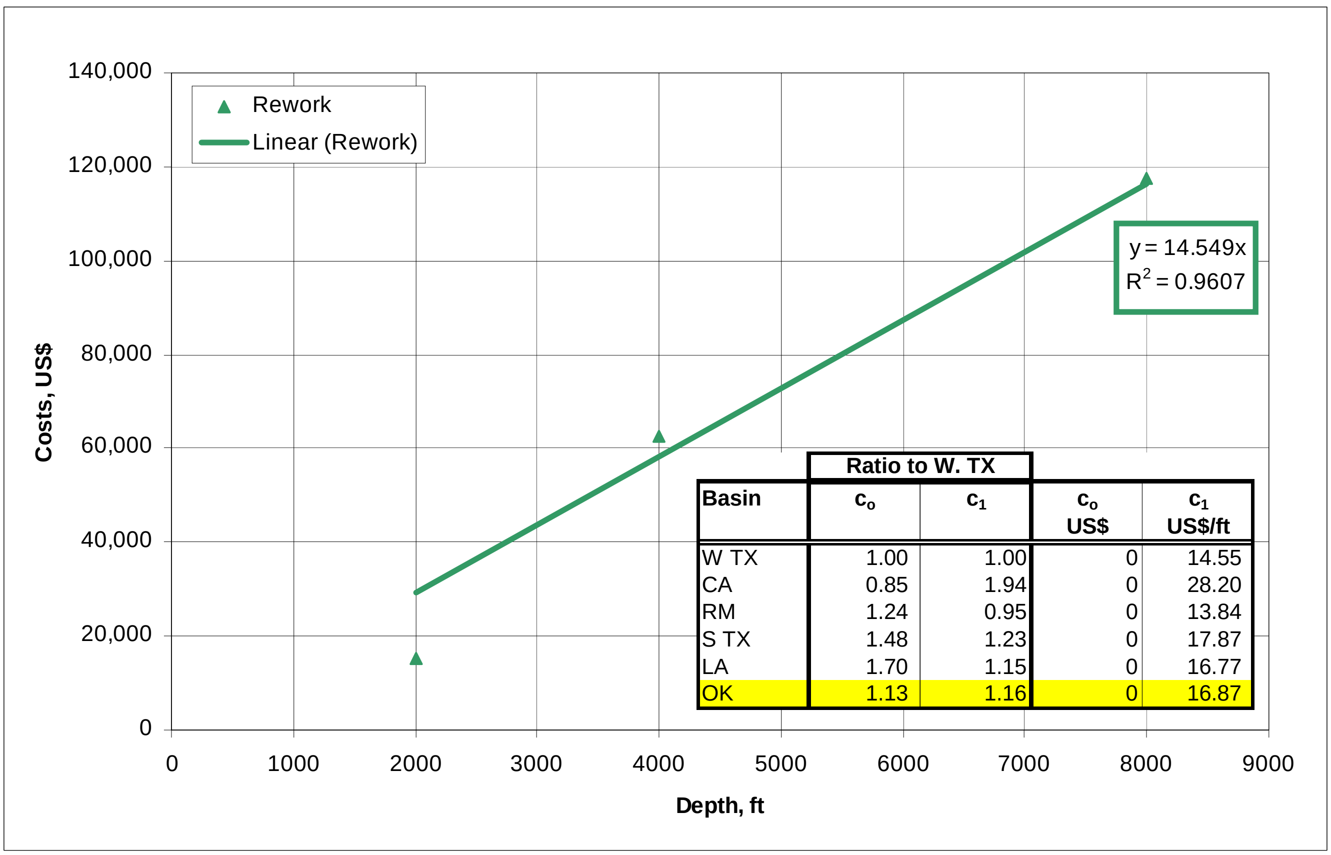
5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing oil production or CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation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

Well Rework Costs = c_1D
Where: c_1 = $28.20 per foot)
D is well depth

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

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



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

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

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

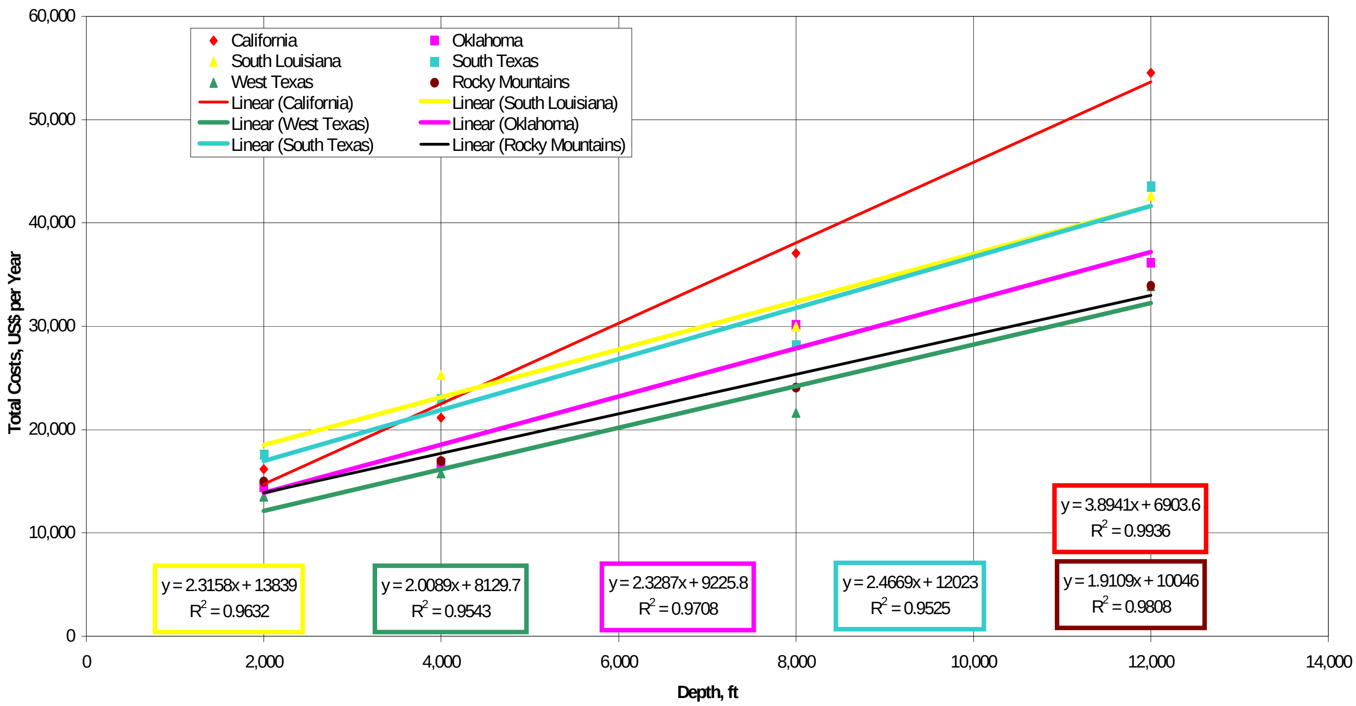

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Table B-1. Regional Lease O&M Costs and Their Relationship to West Texas

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

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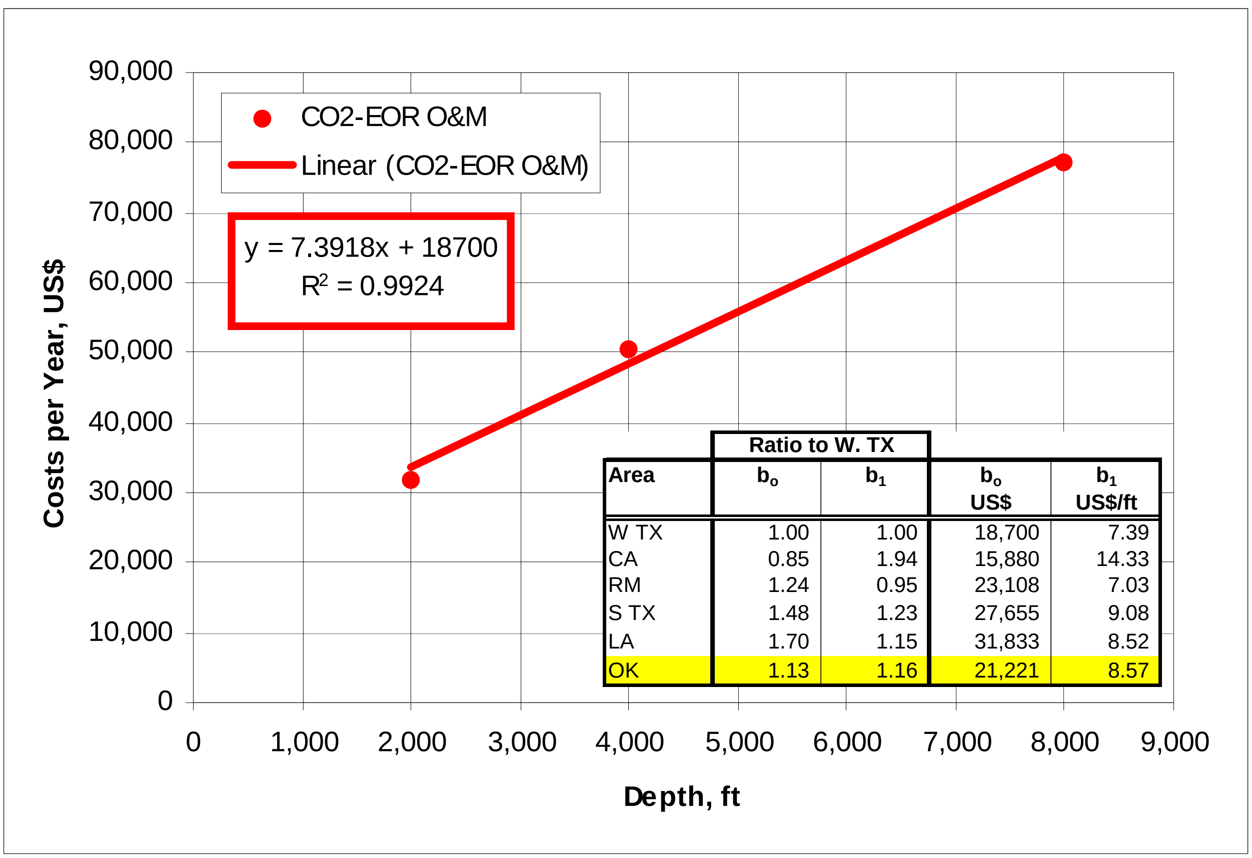
To account for the O&M cost differences between waterflooding and CO_2-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR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

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

Well O&M Costs = $b_0 + b_1 D$
Where: b_0 = \$21,221 (fixed)
b_1 = \$8.57 per foot
D is well depth

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



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

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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 recycling plant is based on peak CO_2 production and recycling requirements.

The cost of the recycling plant is set at $700,000 per MMcfd of CO_2 capacity. As such, a small CO_2-EOR project in the Misener formation of the Aylesworth field, with 18 MMcfd of CO_2 reinjection, will require a recycling plant costing $12.4 million. A large project in the Dornick-Springer formation of the Sho-Vel-Tum field, with 579 MMcfd of CO_2 reinjection and 360 injectors, requires a recycling plant costing $406 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 GOTWO Model Costs.</u>

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

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

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

The distribution pipeline cost is dependent on the injection requirements for the project. The fixed component is $150,000. The variable cost component accounts for increasing piping diameters associated with increasing CO_2 injection requirements. These range from $80,000 per mile for 4” pipe (CO_2 rate less than 15MMcfd), $120,000 per mile for 6” pipe (CO_2 rate of 15 to 35 MMcfd), $160,000 per mile for 8” pipe (CO_2 rate of 35 to 60 MMcfd), and $200,000 per mile for pipe greater than 8” diameter (CO_2 rate greater than 60 MMcfd). 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 Oklahoma 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. <u>G&A Costs.</u> General and administrative (G&A) costs of 20% are added to well O&M and lifting costs.

e. <u>Royalties.</u> Royalty payments are assumed to be 12.5%.

f. <u>Production Taxes.</u> Severance and ad valorum taxes are set at 7.0% and 0.0%, respectively, for a total production tax of 7.0% on the oil production stream. Production taxes are taken following royalty payments. There are no state tax incentives for CO_2-EOR.

g. <u>Crude Oil Price Differential.</u> To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis differential for Oklahoma ($0 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Oklahoma is:

Wellhead Oil Price = Oil Price + $0.00 – [$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas Intermediate)
^{o}API is oil gravity

If the oil gravity is less than 40 ^{o}API, the wellhead oil price is reduced; if the oil gravity is greater than 40 ^{o}API, the wellhead oil price is increased.