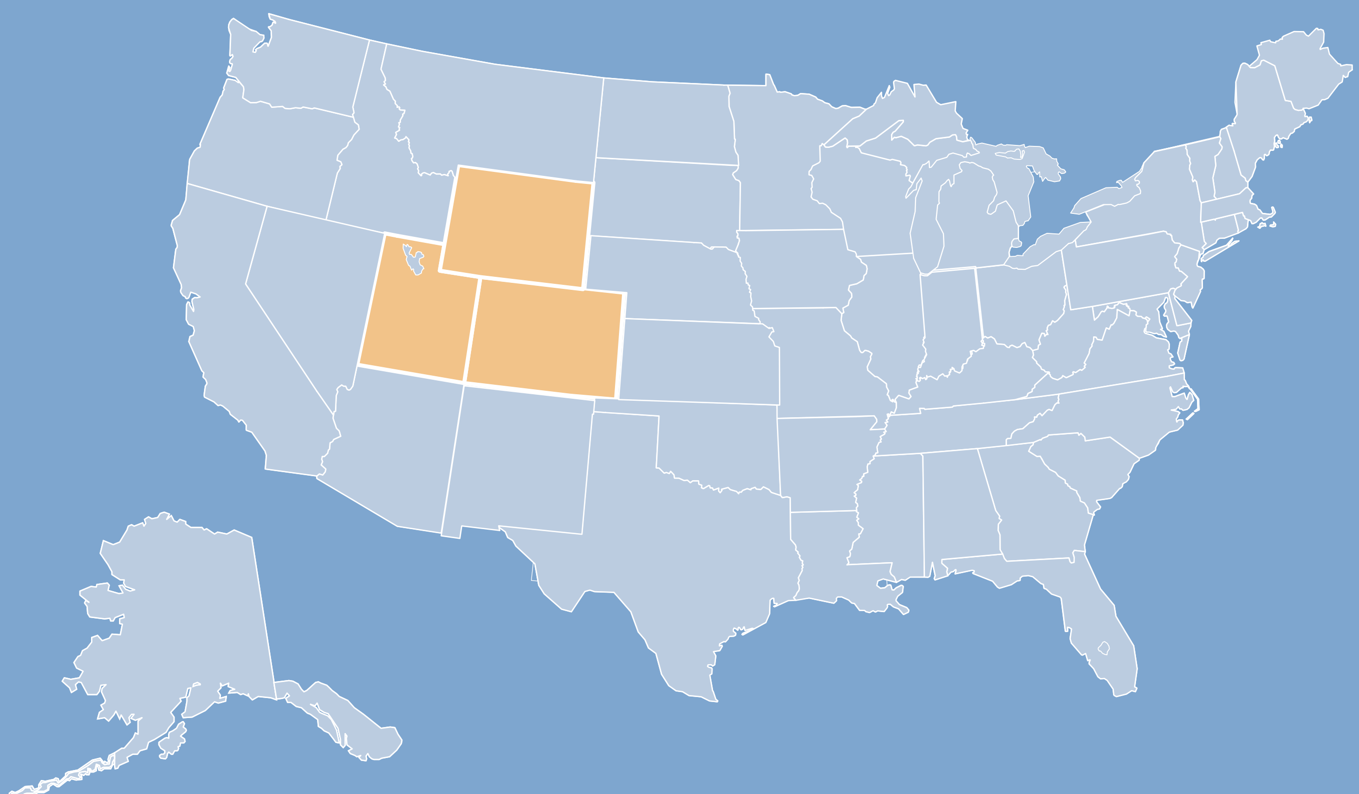
Basin Oriented Strategies for CO_2 Enhanced Oil Recovery:

ROCKY MOUNTAIN REGION



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Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by

Advanced Resources International

February 2006

BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY: ROCKY MOUNTAIN REGION OF COLORADO, UTAH, AND WYOMING

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1. SUMMARY OF FINDINGS

1.1 INTRODUCTION. The Rocky Mountain oil and gas producing region of Colorado, Utah and Wyoming has an original oil endowment of nearly 34 billion barrels. Of this, 11 billion barrels (33%) has been produced or proven. As such, nearly 23 billion barrels of oil will be left in the ground, or "stranded", following the use of traditional oil recovery practices. A major portion of this "stranded oil" is in reservoirs technically and economically amenable to enhanced oil recovery (EOR) using carbon dioxide (CO_2) injection. To date, tertiary recovery projects carried out in 5 fields in the Rocky Mountain region have recovered or proven about 200 MMbbls of this stranded oil.

This report evaluates the future CO_2-EOR oil recovery potential from the large oil fields of the Rocky Mountain region, highlighting the barriers that stand in the way of achieving this potential. The report then discusses how a concerted set of "basin oriented strategies" could help the Rocky Mountain region's oil production industry overcome these barriers helping increase domestic oil production.

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 Rocky Mountain 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 and in other areas, is successfully applied in the Rocky Mountain region. In addition, this scenario assumes that a comprehensive program of research, pilot tests and field demonstrations help lower the risks inherent in applying new technology to these Rocky Mountain region 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 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 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.

1.3 OVERVIEW OF FINDINGS. Twelve major findings emerge from the study of “Basin Oriented Strategies for CO2 Enhanced Oil Recovery: Rocky Mountain Region of Colorado, Utah and Wyoming.”

1. Today’s oil recovery practices will leave behind a large resource of “stranded oil” in the Rocky Mountain region. The original oil resource in the Rocky Mountain region reservoirs is 33.6 billion barrels. To date, 11 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further efforts, 22.6 billion barrels of the Rocky Mountain region’s oil resource will become “stranded”, Table 1.

Table 1. Size and Distribution of the Rocky Mountain Region's Large Oil Reservoirs Data Base

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/Reserves* (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
Colorado	28	3.5	1.4	2.1
Utah	16	4.1	1.2	2.9
Wyoming	118	15.2	4.8	10.4
Data Base Total	162	22.8	7.4	15.4
*B. Regional Total**	n/a	33.6	11.0	22.6

**Estimated from state data on cumulative oil recovery and proved reserves, as of the end of 2004.*

2. The great bulk of the "stranded oil" resource in the large oil reservoirs of the Rocky Mountain region is amenable to CO_2 enhanced oil recovery. To address the "stranded oil" issue, Advanced Resources assembled a data base that contains 162 major Rocky Mountain region oil reservoirs, accounting for 68% of the region's estimated ultimate oil production. Of these, 92 reservoirs, with 18.1 billion barrels of OOIP and 12.4 billion barrels of "stranded oil" (ROIP)), were found to be favorable for CO_2-EOR, as shown below by state, Table 2.

Table 2. The Rocky Mountain Region's "Stranded Oil" Amenable to CO2-EOR

State	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
Colorado	12	3.0	1.2	1.8
Utah	14	4.0	1.2	2.8
Wyoming	66	11.1	3.5	7.6
TOTAL	92	18.1	5.9	12.2

3. Application of miscible CO_2-EOR would enable a significant portion of the Rocky Mountain region's "stranded oil" to be recovered. Of the 92 large Rocky Mountain region oil reservoirs favorable for CO_2-EOR, 81 reservoirs (with 13.8 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The remaining 11 oil reservoirs (with 4.3 billion barrels OOIP) screen as being favorable for immiscible CO_2-EOR. The total technically recoverable resource from applying CO_2-EOR in these 92 large oil reservoirs, ranges from 1,190 million barrels to 2,930 million barrels, depending on the type of CO_2-EOR technology that is applied — "Traditional Practices" or "State-of-the-art", Table 3.

Table 3. Applicability of Miscible and Immiscible CO2-EOR

State	Miscible			Immiscible		
	No. of Reservoirs	Technically Recoverable* (MMBbls)		No. of Reservoirs	Technically Recoverable (MMBbls)	
		Traditional Practices**	State-of -the-art **		Traditional Practices	State-of -the-art
Colorado	12	330	740	0	–	–
Utah	14	380	810	0	–	–
Wyoming	55	480	1,090	11	–	290
TOTAL	81	1,190	2,640	11	–	290

** Range in technically recoverable oil reflects the performance of "Traditional Practices" and "State-of-the-art" CO2-EOR technology.*

*** Nearly 200 MMbbls of this ROIP has already been proven/recovered through tertiary EOR.*

4. With "Traditional Practices" CO_2 flooding technology, high CO_2 costs and high risks, very little of Rocky Mountain region's "stranded oil" will become economically recoverable. Traditional application of miscible CO_2-EOR technology to the 81 large reservoirs in the data base would enable 1,190 million barrels of "stranded oil" to become technically recoverable from the Rocky Mountain region. However, with high costs for CO_2 (equal to $1.50 per Mcf at $30 Bbl), uncertainties about future oil prices and the less than optimum performance of CO_2-EOR technology, only eight reservoirs with 110 million barrels of recoverable resource would become economical at oil prices of $30 per barrel, as adjusted for gravity and location differentials, Table 4.

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

State	No. of Reservoirs	OOIP	Economically* Recoverable	
		(MMBbls)	(# Reservoirs)	(MMBbls)
Colorado	12	2,960	2	30
Utah	14	3,970	1	30
Wyoming	55	6,850	5	50
TOTAL	81	13,780	8	110

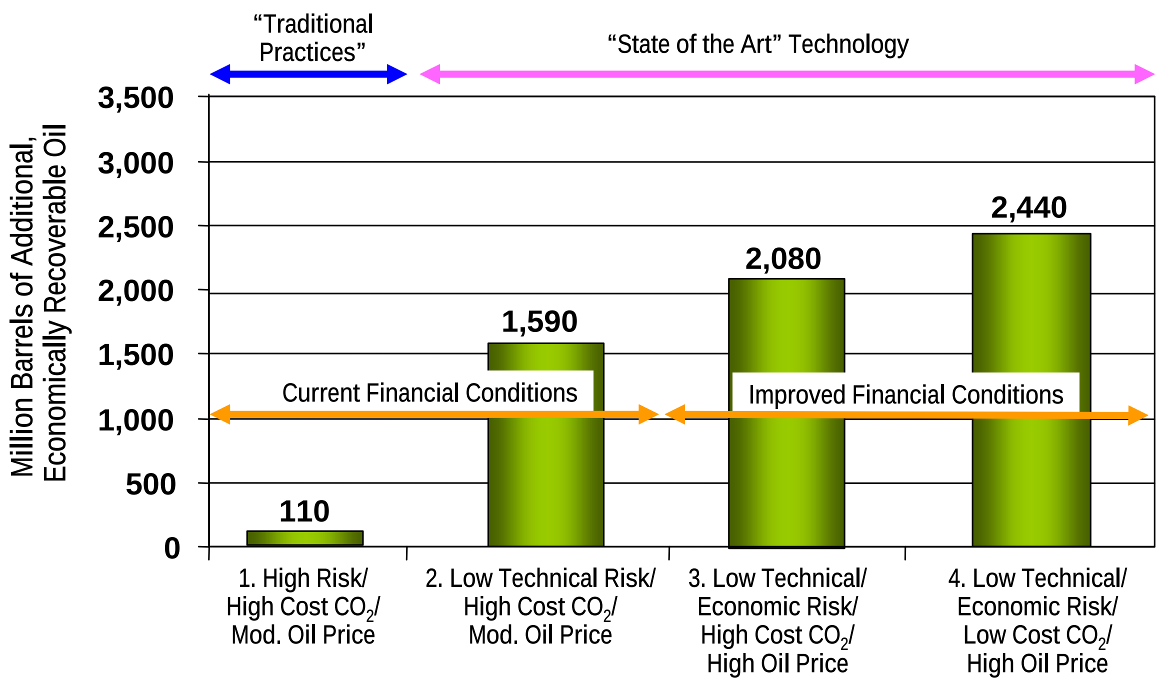
**This case assumes an oil price of $30 per barrel, a CO_2 cost of $1.50 per Mcf, and a ROR hurdle rate of 25% (before tax).*

5. Introduction of "State-of-the-art" CO_2-EOR technology, risk mitigation incentives and lower cost CO_2 costs would enable 2.4 billion barrels of additional oil to become economically recoverable from the Rocky Mountain region. With "State-of-the-art" CO_2-EOR technology and its higher oil recovery efficiency (but at oil prices of $30/B and high cost CO_2) 1,590 million barrels of the oil remaining in Rocky Mountain region's reservoirs becomes economically recoverable.

Risk mitigation incentives and/or higher oil prices, providing an oil price equal to $40 per barrel, would enable 2,080 million barrels of oil to become economically recoverable from Rocky Mountain region's large oil reservoirs.

Lower cost CO_2 supplies, equal to $0.80 per Mcf, assuming a large-scale CO_2 transportation system and incentives for CO_2 emissions capture with oil prices at $40/per barrel, would enable the economic potential to increase to 2,440 million barrels, Figure 1 and Table 5.

Figure 1. Impact of Technology and Financial Conditions on Economically Recoverable Oil from the Rocky Mountain Region'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 $1.50/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 $1.50/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 $2.00/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).

Table 5. Economically Recoverable Resources - Alternative Scenarios

State	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)
Colorado	5	510	6	510	8	580
Utah	6	360	9	730	10	740
Wyoming	32	730	39	840	53	1,120
TOTAL	43	1,590	54	2,080	71	2,440

6. Once the results from the study's large oil reservoirs data base are extrapolated to the region as a whole, the technically recoverable CO_2-EOR potential for the Rocky Mountain region is estimated at nearly 4.2 billion barrels. The large oil reservoirs in the Rocky Mountain region oil reservoirs examined by the study account for 68% of the region's oil resource. Extrapolating the 2,930 million barrels of technically recoverable EOR potential in these oil reservoirs to the total Rocky Mountain region oil resource provides an estimate of 4,200 million barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the large Rocky Mountain region 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 Rocky Mountain region will, most likely, prove to be higher than defined by this study. Introduction of more advanced "next generation" CO_2-EOR technologies still in the research or field demonstration stage, such as gravity stable CO_2 injection, extensive use of horizontal or multi-lateral wells and CO_2 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 CO_2 emissions. The benefits and impacts of using "advanced" CO_2-EOR technology on Rocky Mountain Region oil reservoirs have been examined in a separate study.

8. A portion of this CO_2-EOR potential is already being pursued by operators in the Rocky Mountain region. Five significant EOR Field projects are currently underway, one in Colorado (Rangely Field), two in Utah (ex. Greater Aneth Field) and two in Wyoming (ex. Lost Soldier Field). Together, these five EOR projects have produced or proven about 200 million barrels of the CO_2-EOR potential set forth in this study.

9. Large volumes of CO_2 supplies will be required in the Rocky Mountain region to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be over 10 Tcf, plus another 22 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 Rocky

Mountain region's oil reservoirs would enable over 500 million metric 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) would significantly increase this amount.

Table 6. Potential CO_2 Supply Requirements in the Rocky Mountain Region: Scenario #4 ("Ample Supplies of CO_2")

Region	No. of Reservoirs	Economically Recoverable (MMBbls)	Market for Purchased CO_2 (Bcf)	Market for Recycled CO_2 (Bcf)
Colorado	8	580	2,090	4,290
Utah	10	740	3,440	8,390
Wyoming	53	1,120	4,530	10,000
TOTAL	71	2,440	10,060	22,680

10. Significant supplies of industrial CO_2 emissions exist in the Rocky Mountain region, sufficient to meet the CO_2 needs for EOR. The natural CO_2 deposits at McElmo Dome (CO) and Sheep Mountain (CO) produce about 18 million tonnes of CO_2 per year for CO_2-EOR in the Permian Basin of eastern New Mexico and west Texas. CO_2 emissions, from gas processing 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 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 Rocky Mountain region'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 the Rocky Mountain region's oil fields, and the considerable market and oil price risks — all argue that a partnership involving the oil production industry, potential CO_2 suppliers and transporters, the Rocky Mountain region states 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 Rocky Mountain region. Successful introduction and wide-scale use of CO_2-EOR in the Rocky Mountain region will stimulate increased economic activity, provide new higher paying jobs, and lead to higher tax revenues for the state. It will also 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 Colorado, Utah and Wyoming.

In Utah, we would like to thank Christopher Kierst of the Utah Department of Natural Resources, Division of Oil, Gas, and Mining for assistance in compiling data on Utah's injection wells. In Colorado, we would like to thank Ms. Genevieve Young of the Colorado Geological Survey for the review of this report.

In Wyoming, we would like to thank Nancy Barclay and Dave Hutton of the Wyoming Oil and Gas Commission for state historical oil production data.

2. INTRODUCTION

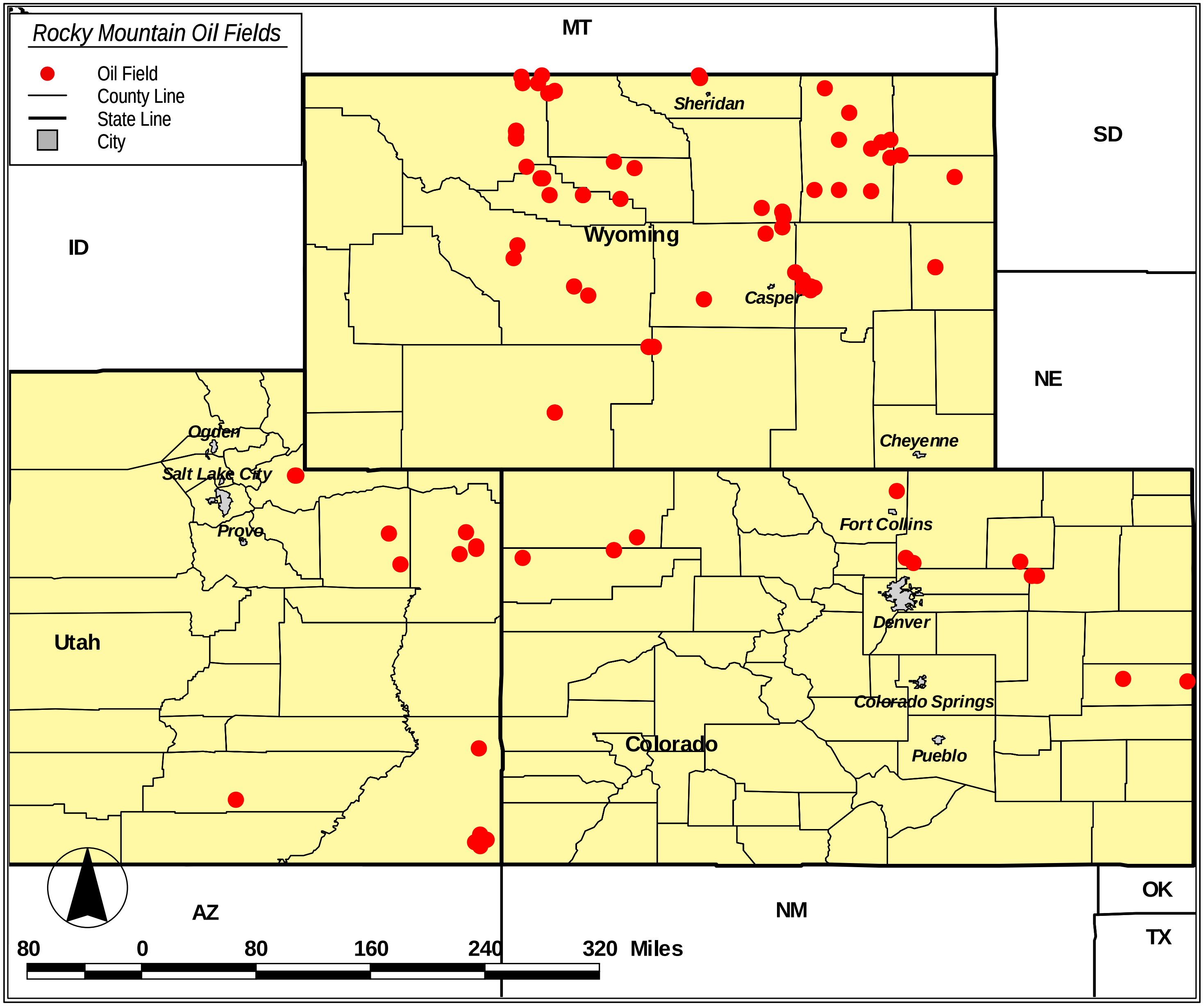
2.1 CURRENT SITUATION. The Rocky Mountain oil producing region addressed in the report is mature and in decline. Stemming the decline in oil production will be a major challenge, requiring a coordinated set of actions by numerous parties who have a stake in this problem — Rocky Mountain region state revenue and economic development officials; private, state and federal royalty owners; the Rocky Mountain region oil production and refining industry; the public, and the federal government.

The main purpose of this report is to provide information to these “stakeholders” on the potential for pursuing CO_2 enhanced oil recovery (CO_2-EOR) as one option for slowing and potentially stopping the decline in the Rocky Mountain region’s oil production.

This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Rocky Mountain region of Colorado, Utah and Wyoming,” provides information on the size of the technical and economic potential for CO_2-EOR in the Rocky Mountain 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 the Rocky Mountain oil producing region.

2.2 BACKGROUND. The Rocky Mountain Region of Colorado, Utah and Wyoming currently produce nearly 35,000 barrels of oil per day (in 2004). However, the deep, light oil reservoirs of this region are ideal candidates for miscible carbon dioxide-based enhanced oil recovery (CO_2-EOR). The Rocky Mountain major oil fields amenable to CO_2-EOR are shown in Figure 2.

Figure 2. Location of Major Rocky Mountain Region Oil Fields Amenable to CO2-EOR



2.3 PURPOSE. This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Rocky Mountain Region of Colorado, Utah and Wyoming" 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, examining the 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.

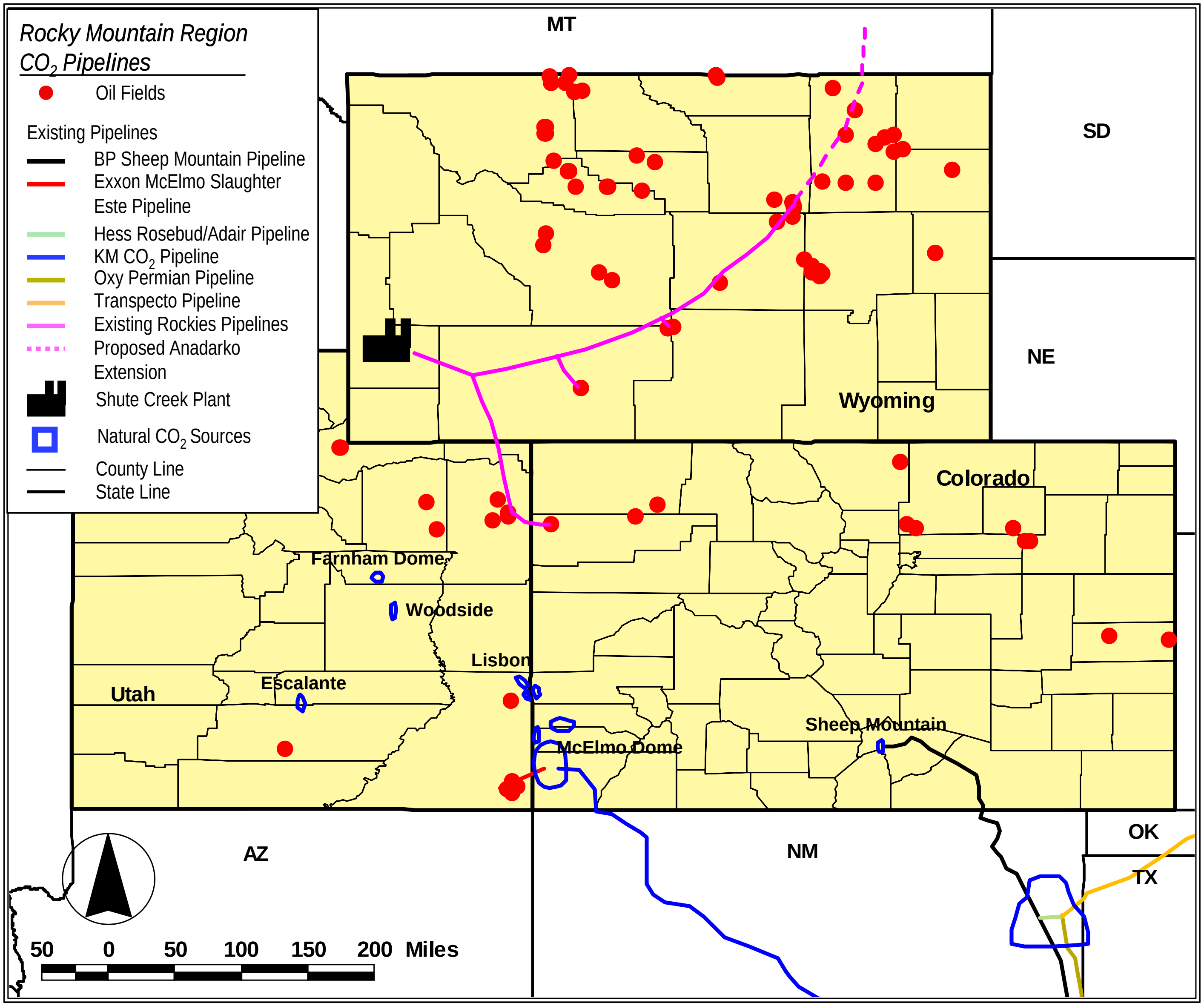
An additional important purpose of the study is to develop a desktop modeling and analytical capability for "basin oriented strategies" that would enable the Department of Energy/Fossil Energy (DOE/FE) itself to formulate policies and research programs that would support increased recovery of domestic 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 will become available, by pipeline from natural sources, such as McElmo and Sheep Mountain Domes, as well as from industrial sources, such as the hydrogen plants and refineries in Woods Cross, Utah, and Sinclair, Wyoming; and from the gas processing and chemical plants in the region such as the Shute Creek Gas Plant where over 2 TCF of CO_2 has been separated from the La Barge Gas Field stream. Finally, the electric power plants in these three states are assumed to be major sources of CO_2 supplies. Importantly, the study assumes that this CO_2 supply will become available in the near future, before the oil fields in the region are abandoned.

Figure 3 shows the existing pipeline system that transports CO_2 from the Shute Creek gas processing plant to the Rangely oil field in Colorado and to the oil fields in

Wyoming that are undergoing CO_2-EOR including, Patrick Draw, Lost Soldier, Wertz, and Salt Creek. Proposals exist to extend this CO_2 pipeline further north into Montana. Additional large capacity CO_2 pipelines exist in southern Colorado (and Utah) linking the McElmo Dome and Sheep Mountain CO_2 reservoirs to the Greater Aneth Field of Utah and to the numerous oil fields in the Permian Basin. Proposals exist to expand the capacity of these already large volume CO_2 pipelines.

Figure 3. Location of Existing and Planned CO_2 Supply Pipelines in the Rocky Mountain Region



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 Rocky Mountain oil region, 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 this region and the inherent technical and geologic risks, operators typically add a risk premium when evaluating this technology option in the Rocky Mountain region.

2. *"State-of-the-art" Technology*. This involves bringing to the Rocky Mountain region the benefits of recent improvements in the performance of CO_2-EOR process and gains in understanding of 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". 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 hydrocarbon components into the CO_2 phase and solution of CO_2 in the oil 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 Rocky Mountain region light oil fields such as Rangeley (CO), Altamont-Bluebell (UT) and Elk Basin (WY) 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. This reservoir set includes the large Rocky Mountain region oil fields, such as Hamilton Dome (WY), which still hold a significant portion of their original oil. Although few, Rocky Mountain region reservoirs at depths greater than 3,000 feet with oil gravities between 17.5° and 25 °API (or higher) would generally be included in this category.

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

Table 7. Matching of CO_2-EOR Technology With the Rocky Mountain Region's Oil Reservoirs

CO_2-EOR Technology Selection	Oil Reservoir Selection
"Traditional Practices" Miscible CO_2-EOR	▪ 81 Deep, Light Oil Reservoirs
"State-of-the-art" Miscible and Immiscible CO_2-EOR	▪ 81 Deep, Light Oil Reservoirs ▪ 11 Deep, Moderately Heavy Oil Reservoirs

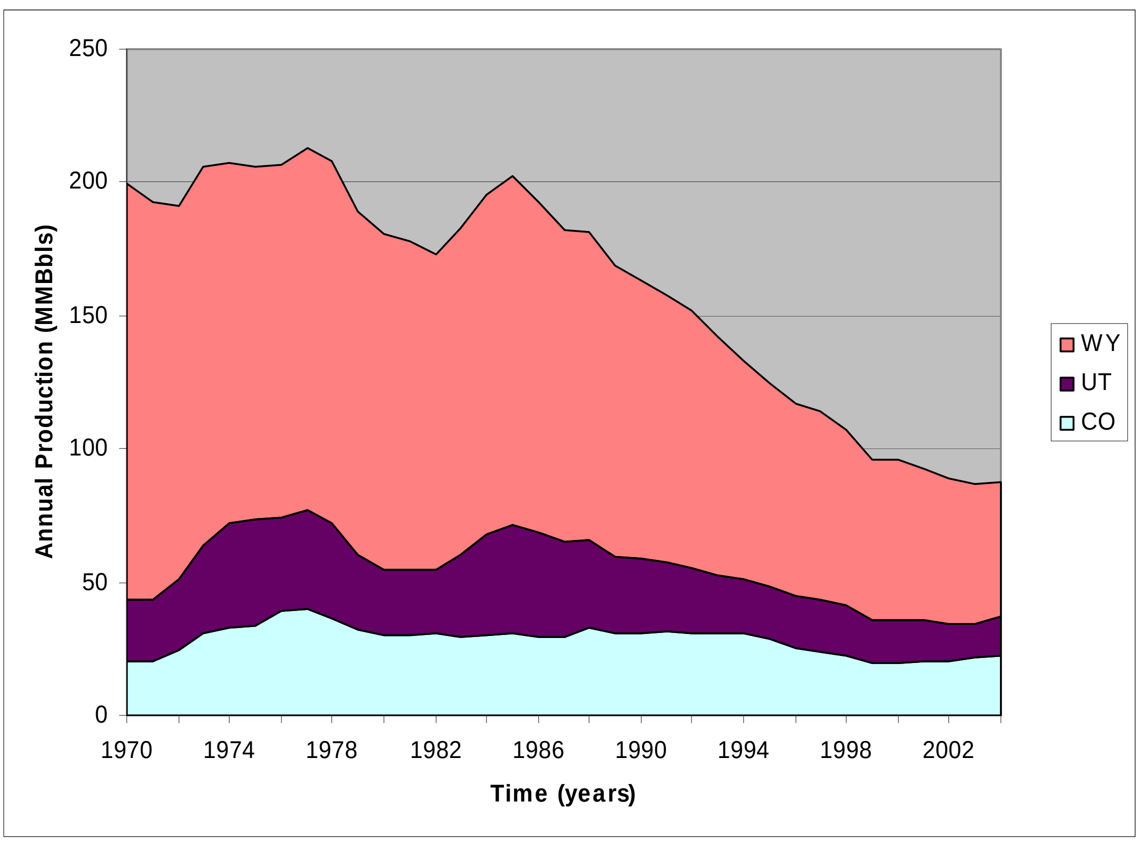
2.6 OTHER ISSUES. This study draws on a series of sources for basic data on the reservoir properties and the expected technical and economic performance of CO_2-EOR in the Rocky Mountain region's major oil reservoirs. Because of confidentiality and proprietary issues, the results of the study have been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

3. OVERVIEW OF ROCKY MOUNTAIN REGION OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Figure 4 tracks oil production for the Rocky Mountain region of the United States — encompassing Colorado, Utah and Wyoming — for the past 30 years. Since reaching a peak in the late 1970's, oil production fluctuated for another ten years before beginning a sharp decline, reaching low of 88 million barrels (241,000 barrels per day) in 2004.

- Colorado, with 22 million barrels of oil produced in 2004, has seen oil production increase slightly (16%) since a low of 19 million barrels in 2000.
- Utah, with 15 million barrels of oil produced in 2004, has seen a recent plateau in oil production.
- Wyoming, with 51 million barrels of oil produced in 2004, has seen a moderation in its declining oil production.

Figure 4. Rocky Mountain Historical Oil Production since 1970



However, the Rocky Mountain region still holds a rich resource of oil in the ground. With 34 billion barrels of original oil in-place (OOIP) and approximately 11 billion barrels expected to be recovered, 23 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 Rocky Mountain region oil fields that account for about one fifth of the oil production in this region. The table shows that five of the largest oil fields are in production decline. Arresting this decline in the Rocky Mountain region's oil production could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

Table 8. Crude Oil Annual Production, Ten Largest Rocky Mountain Region Oil Fields, 2002-2004 (Million Barrels per Year)

Major Oil Fields	2002	2003	2004	Production Status
1. Rangely, CO*	5.4	5.2	5.1	Declining
2. Oregon Basin, WY	2.9	2.7	2.6	Declining
3. Altamont-Bluebell, UT	2.6	2.4	2.5	Stable
4. Lost Soldier, WY*	1.9	1.9	1.9	Stable
5. Salt Creek, WY*	1.9	1.8	1.7	Declining
6. Greater Aneth – McElmo Creek Unit, UT*	1.7	1.5	1.3	Declining
7. Monument Butte, UT	1.6	1.8	2.3	Increasing
8. Elk Basin, WY	1.6	1.6	1.5	Stable
9. Hamilton Dome, WY	1.5	1.4	1.3	Declining
10. Grass Creek, WY	1.1	1.1	1.2	Stable

** Fields under EOR operations.*

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Rocky Mountain region oil producers are familiar with using technology for improving oil recovery. CO_2-EOR projects in Colorado's Rangely Field and Wyoming's Lost Soldier and Wertz fields have been underway since the 1980's. In addition, several new projects have been initiated in the past two years. Additional discussion of the experience with CO_2-EOR in the Rocky Mountain region is provided in Chapter 6.

3.3 THE "STRANDED OIL" PRIZE. Even though the Rocky Mountain region's oil production is declining, this does not mean that the resource base is depleted. The three regions of production in the Rocky Mountain region – Colorado, Utah and Wyoming, still contain 67% 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 9 provides information on the maturity and oil production history of eight large Rocky Mountain region oil fields, each with estimated ultimate recovery of 200 million barrels or more.

Table 9. Selected Major Oil Fields of the Rocky Mountain Region

	Field/State	Year Discovered	Cumulative* Production (MMbbl)	Estimated* Reserves (MMbbl)	Remaining Oil In-Place (MMbbl)
1	RANGELEY, CO	1902	794	12	1,066
2	SALT CREEK, WY	1917	627	27	855
3	OREGON BASIN, WY	1912	558	32	1,807
4	GREATER ANETH, UT	1956	410	61	872
5	ELK BASIN, WY	1915	320	13	533
6	ALTAMONT-BLUEBELL, UT	1949	274	46	1,174
7	HAMILTON DOME, WY	1918	239	10	396
8	GRASS CREEK, WY	1914	203	11	491

**Cumulative oil production and reserves do not include CO_2-EOR.*

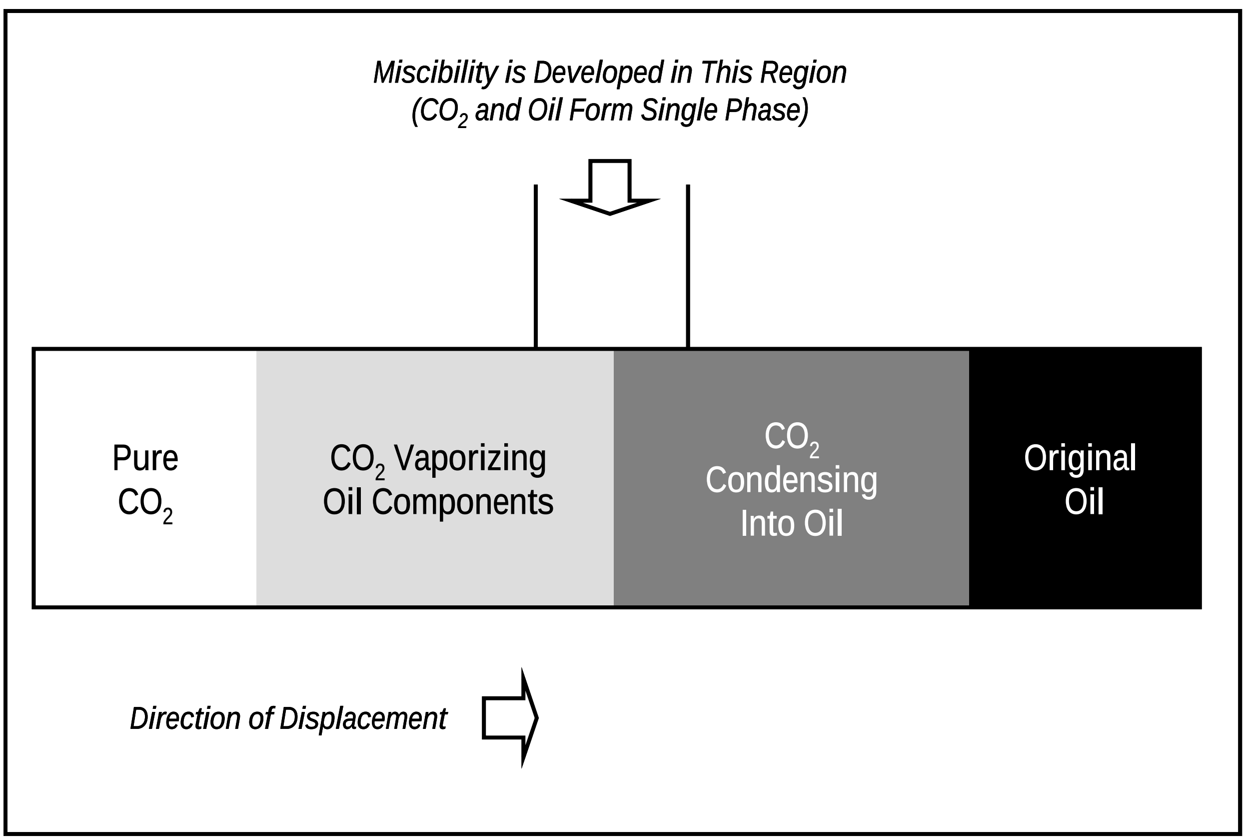
3.4 REVIEW OF PRIOR STUDIES. An assessment of the potential for CO_2-EOR in Wyoming's oil fields was conducted by Petro Source Corp. and the Wyoming Geological Survey in 2001. This study identified 46 large fields that screened as being favorable for CO_2-EOR. The fields contained 8 billion barrels of OOIP. The study concluded that that CO_2-EOR could increase the cumulative oil recovery by 0.4 - 1.2 billion barrels assuming this technology could recover 5-15% of the OOIP. Applications of CO_2-EOR would require 2.4 – 12 TCF of CO_2 (De Bruin, 2001, Wyoming Geological Survey, Information Pamphlet 8).

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.



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).

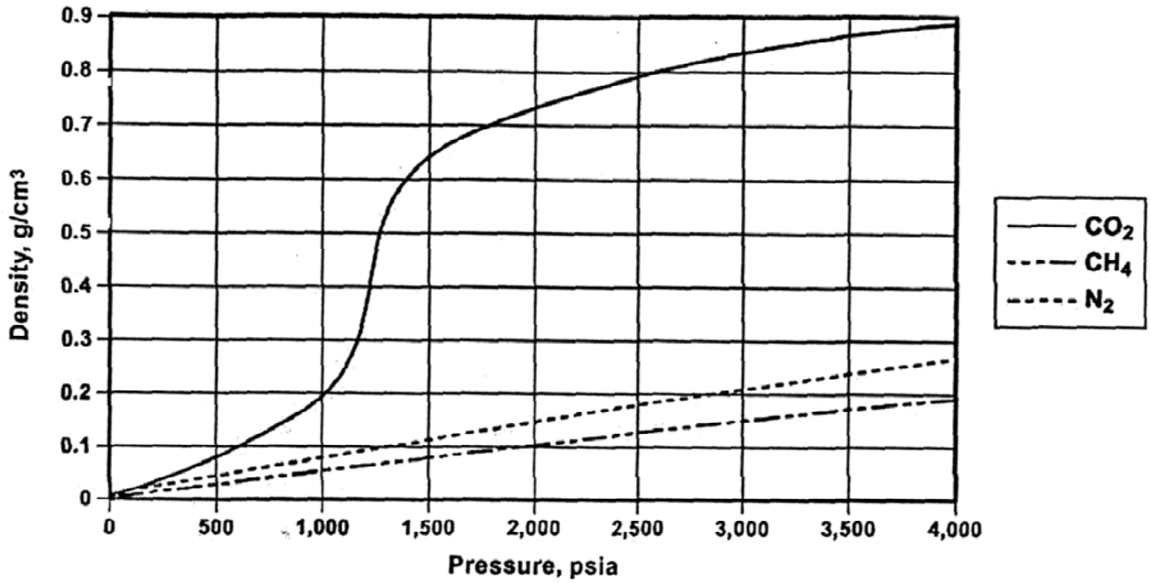


Figure 6B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it remains low in comparison to that of liquids. Viscosities were calculated with an EOS.

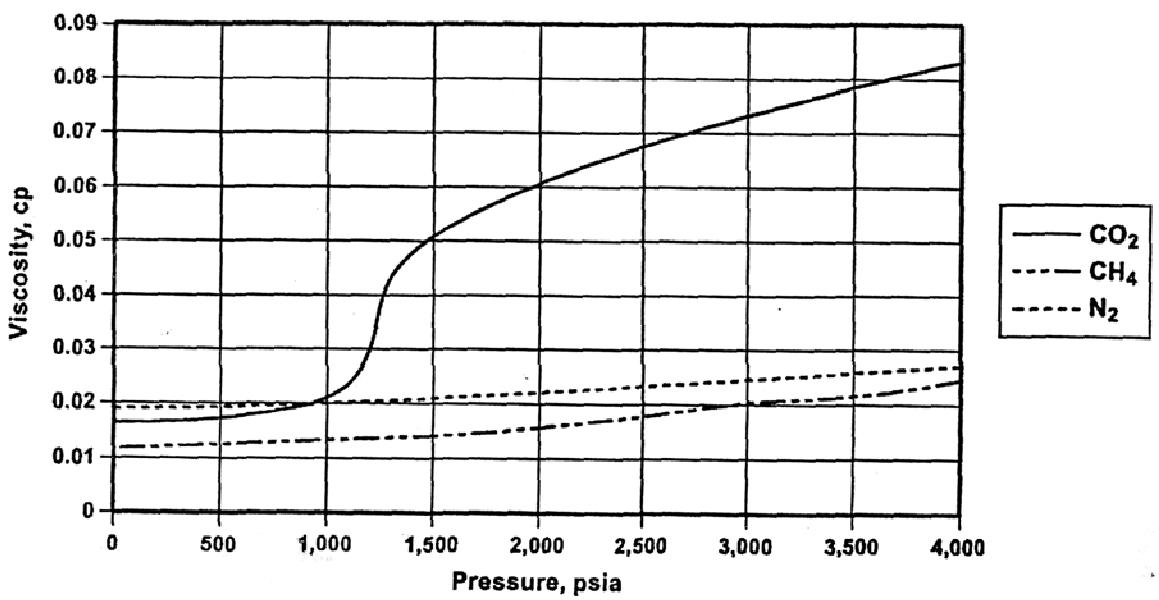


Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid (Holm and Josendal).

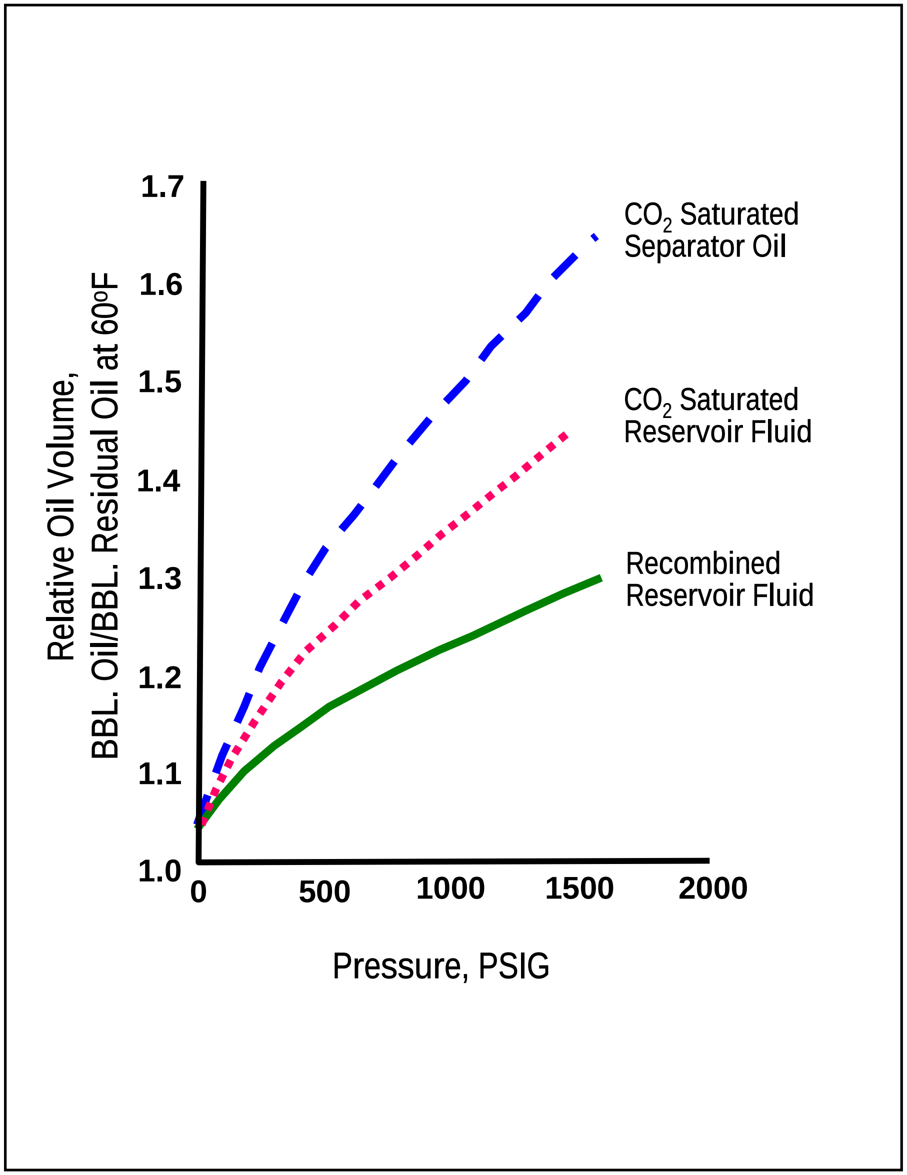


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

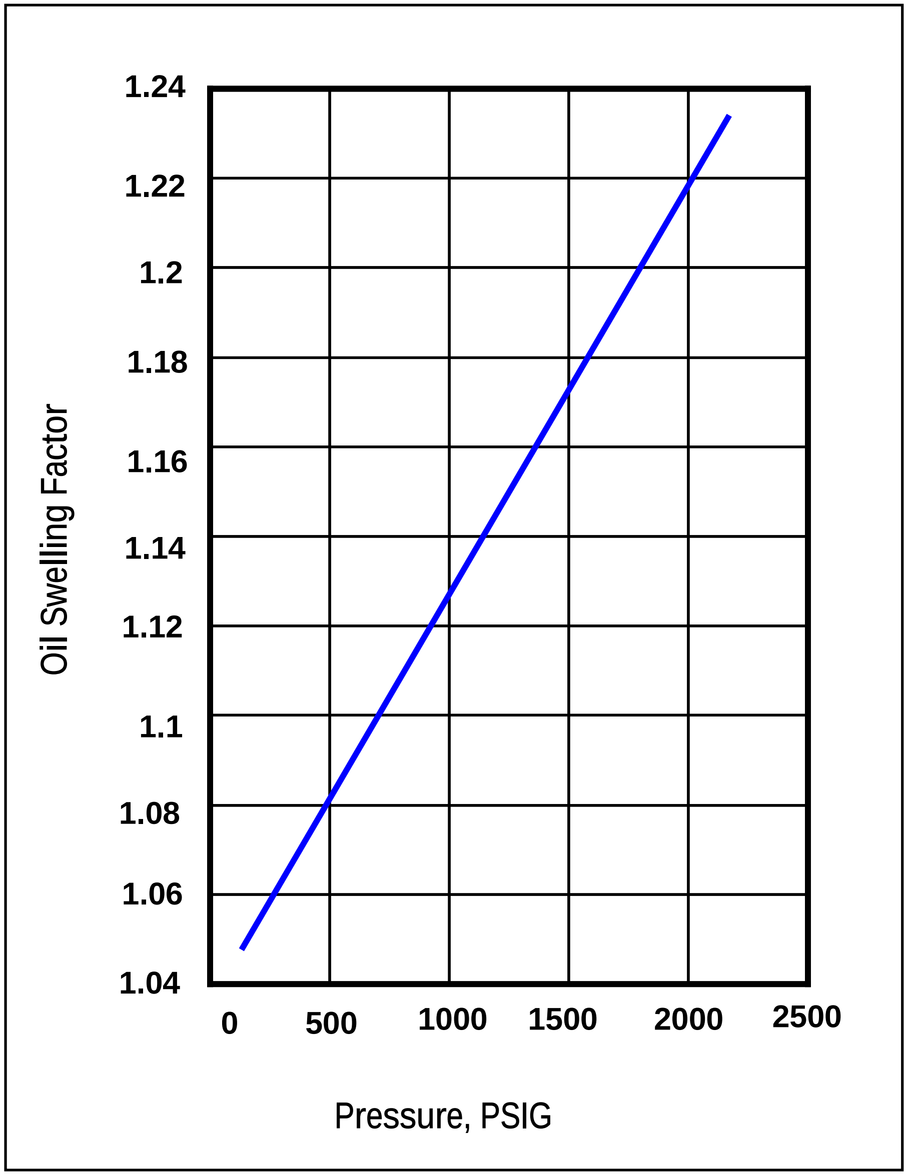
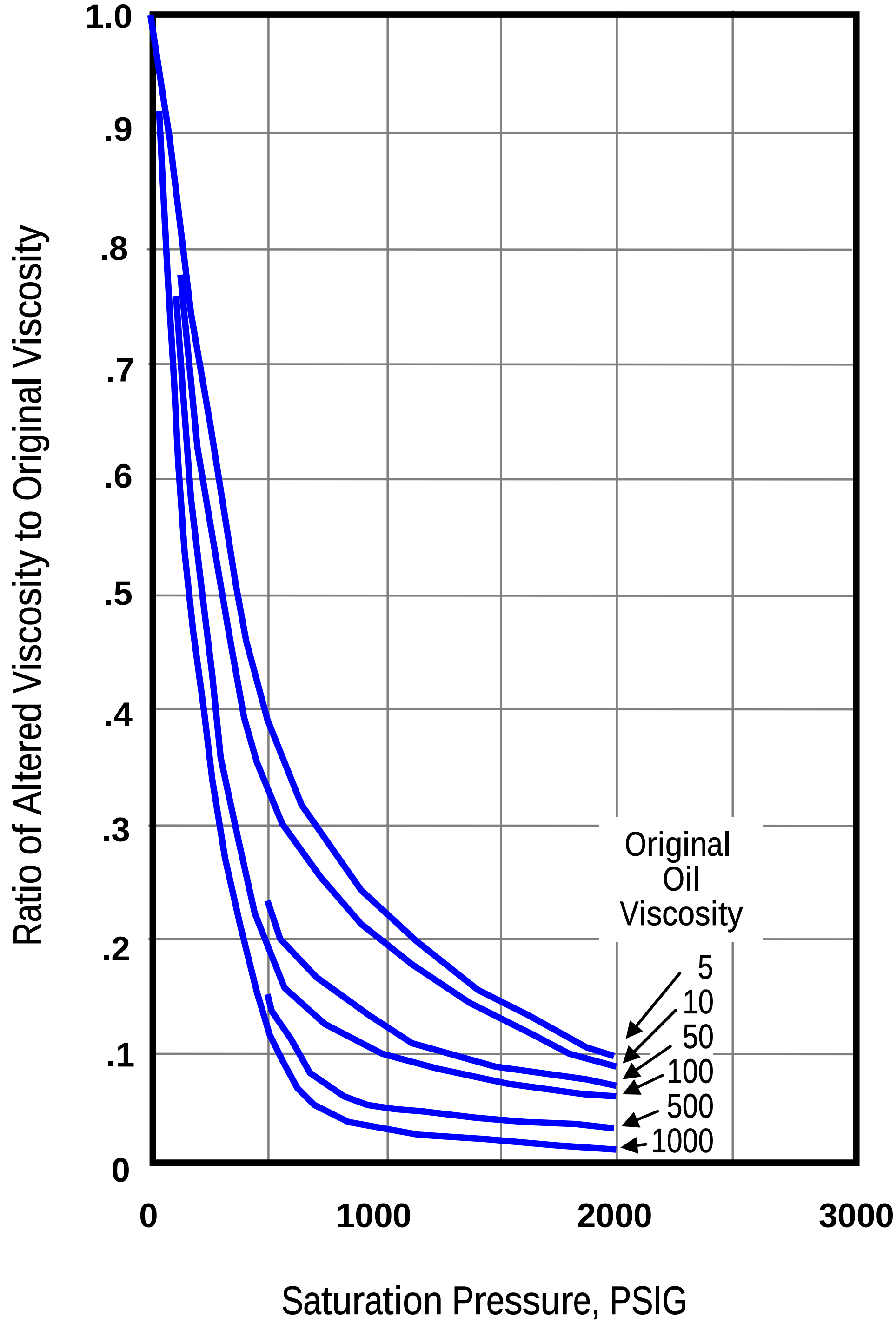


Figure 8. Viscosity Reduction Versus Saturation Pressure (Simon and Graue).



5. STUDY METHODOLOGY

5.1 OVERVIEW. A seven part methodology was used to assess the CO_2-EOR potential of the Rocky Mountain region's oil reservoirs. The seven steps were: (1) assembling the Rocky Mountain Region 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/FE. The study updated and modified this publicly accessible data base to develop the Rocky Mountain Region Major Oil Reservoirs Data Base for Colorado, Utah and Wyoming.

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 Rocky Mountain Region Major Oil Reservoirs Data Base contains 162 reservoirs, accounting for 33% of the oil expected to be ultimately produced in the Rocky Mountain region 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)		
2003 Production (Mbbl)		
Daily Prod - Field (Bbl/d)		
Cum Oil Production (MMbbl)		
EOY 2003 Oil Reserves (MMbbl)		
Water Cut		

Water Production

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

Injection

	TORIS	ARI
Injection Wells (active)		
Injection Wells (shut-in)		
2003 Water Injection (MMbbl)		
Daily Injection - Field (Mbbl/d)		
Cum Injection (MMbbl)		
Daily Inj per Well (Bbl/d)		

EOR

Type	
2003 EOR Production (MMbbls)	
Cum EOR Production (MMbbls)	
Reserves (MMbbls)	
Ultimate Recovery (MMbbls)	

Volumes

	TORIS	ARI
OOIP (MMbl)		
Cum P/S Oil (MMbl)		
2003 P/S Reserves (MMbl)		
Ult P/S Recovery (MMbl)		
Remaining (MMbbl)		
Ultimate Recovered (%)		

OOIP Volume Check

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

SROIP Volume Check

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

ROIP Volume Check

	TORIS	ARI
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 Rocky Mountain region; (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. Because of data limitations, this screening study combined the sands into a single reservoir.

Table 11. Rocky Mountain Region Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
A. Colorado		
Colorado	ADENA	J SAND
Colorado	ARAPAHOE	MORROW
Colorado	ILES	SUNDANCE
Colorado	LITTLE BEAVER	D SAND
Colorado	LITTLE BEAVER EAST	D SAND
Colorado	MOUNT PEARL	MORROW
Colorado	RANGELY	WEBER*
Colorado	SPINDLE	SUSSEX
Colorado	SPINDLE	SHANNON/SUSSEX
Colorado	WELLINGTON	MUDDY
Colorado	WILSON CREEK	MORRISON
Colorado	WILSON CREEK	SUNDANCE
B. Utah		
Utah	ALATAMONT-BLUEBELL	WASATCH AND GREEN RIVER
Utah	ASHLEY VALLEY	PHOSPHORIA-WEBER
Utah	GREATER ANETH-ANETH UNIT	DESERT CREEK/ISMAY*
Utah	GREATER ANETH-MCELMO CREEK UNIT	DESERT CREEK/ISMAY
Utah	GREATER ANETH - RATHERFORD UNIT	DESERT CREEK/ISMAY
Utah	GREATER ANETH - WHITE MESA UNIT	DESERT CREEK/ISMAY
Utah	LISBON	MADISON - REDWALL
Utah	MONUMENT BUTTE	GREEN RIVER
Utah	PINEVIEW	NUGGET SANDSTONE
Utah	PINEVIEW	TWIN CREEK
Utah	RED WASH UNIT	GREEN RIVER
Utah	UPPER VALLEY UNIT	KAIBAB
Utah	WALKER HOLLOW	GREEN RIVER
Utah	WONSITS VALLEY	GREEN RIVER
C. Wyoming		
Wyoming	ASH CREEK	SHANNON
Wyoming	ASH CREEK SOUTH	SHANNON
Wyoming	BEAVER CREEK	MADISON
Wyoming	BIG MUDDY	FRONTIER
Wyoming	BIG MUDDY EAST	DAKOTA
Wyoming	BIG POLECAT	TENSLEEP
Wyoming	BIG SAND DRAW	TENSLEEP
Wyoming	BYRON	EMBAR - TENSLEEP
Wyoming	COLE CREEK	SHANNON
Wyoming	COLE CREEK SOUTH	DAKOTA

Table 11. Rocky Mountain Region Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Wyoming	COTTONWOOD CREEK	PHOSPHORIA
Wyoming	COYOTE CREEK	DAKOTA
Wyoming	ELK BASIN	EMBAR - TENSLEEP
Wyoming	ELK BASIN SOUTH	EMBAR - TENSLEEP
Wyoming	FRANNIE	PHOSPHORIA - TENSLEEP
Wyoming	GARLAND	MADISON
Wyoming	GARLAND	TENSLEEP
Wyoming	GAS DRAW	MUDDY
Wyoming	GEBO	EMBAR
Wyoming	GEBO	TENSLEEP
Wyoming	GLENROCK SOUTH	DAKOTA (CONOCO ONLY)
Wyoming	GLENROCK SOUTH	LOWER MUDDY B CONOCO ONLY
Wyoming	GRASS CREEK	CURTIS
Wyoming	GRASS CREEK	PHOSPHORIA
Wyoming	GRASS CREEK	TENSLEEP
Wyoming	GRIEVE	MUDDY
Wyoming	HAMILTON DOME - ENTIRE FIELD	TENSLEEP
Wyoming	HARTZOG DRAW	SHANNON
Wyoming	HILIGHT	MUDDY, MINNELUSA
Wyoming	HOUSE CREEK	SUSSEX
Wyoming	KITTY	MUDDY
Wyoming	LANCE CREEK	LEO
Wyoming	LANCE CREEK	SUNDANCE
Wyoming	LITTLE BUFFALO BASIN	TENSLEEP
Wyoming	LOST SOLDIER	FLATHEAD*
Wyoming	LOST SOLDIER	MADISON*
Wyoming	LOST SOLDIER	TENSLEEP*
Wyoming	MEADOW CREEK	SHANNON A-B
Wyoming	MEADOW CREEK NORTH	SUSSEX
Wyoming	MURPHY DOME	TENSLEEP
Wyoming	OREGON BASIN	EMBAR NORTH
Wyoming	OREGON BASIN	MADISON NORTH
Wyoming	OREGON BASIN	TENSLEEP NORTH
Wyoming	OREGON BASIN	EMBAR SOUTH
Wyoming	OREGON BASIN	MADISON SOUTH
Wyoming	OREGON BASIN	TENSLEEP SOUTH
Wyoming	OSAGE	NEWCASTLE
Wyoming	PATRICK DRAW (MONELL UNIT)	MONELL ALMOND*
Wyoming	PATRICK DRAW (PECH UNIT)	ALMOND
Wyoming	RAVEN CREEK	MINNELUSA
Wyoming	RECLUSE	MUDDY

Table 11. Rocky Mountain Region Oil Reservoirs Screened Amenable to CO_2-EOR

Basin	Field	Formation
Wyoming	ROZET	MUDDY
Wyoming	SALT CREEK	TENSLEEP
Wyoming	SALT CREEK EAST	FRONTIER
Wyoming	SALT CREEK EAST	TENSLEEP
Wyoming	STEAMBOAT BUTTE	TENSLEEP
Wyoming	STEWART	MINNELUSA
Wyoming	SUSSEX	SHANNON
Wyoming	SUSSEX	SUSSEX
Wyoming	SUSSEX	TENSLEEP AMSDEN B
Wyoming	SUSSEX WEST	A-B SHANNON
Wyoming	TIMBER CREEK	MINNELUSA
Wyoming	WERTZ	MADISON-Darwin*
Wyoming	WERTZ	TENSLEEP*
Wyoming	WINKLEMAN DOME	TENSLEEP
Wyoming	WORLAND UNIT	TENSLEEP

** Reservoirs with significant EOR activity.*

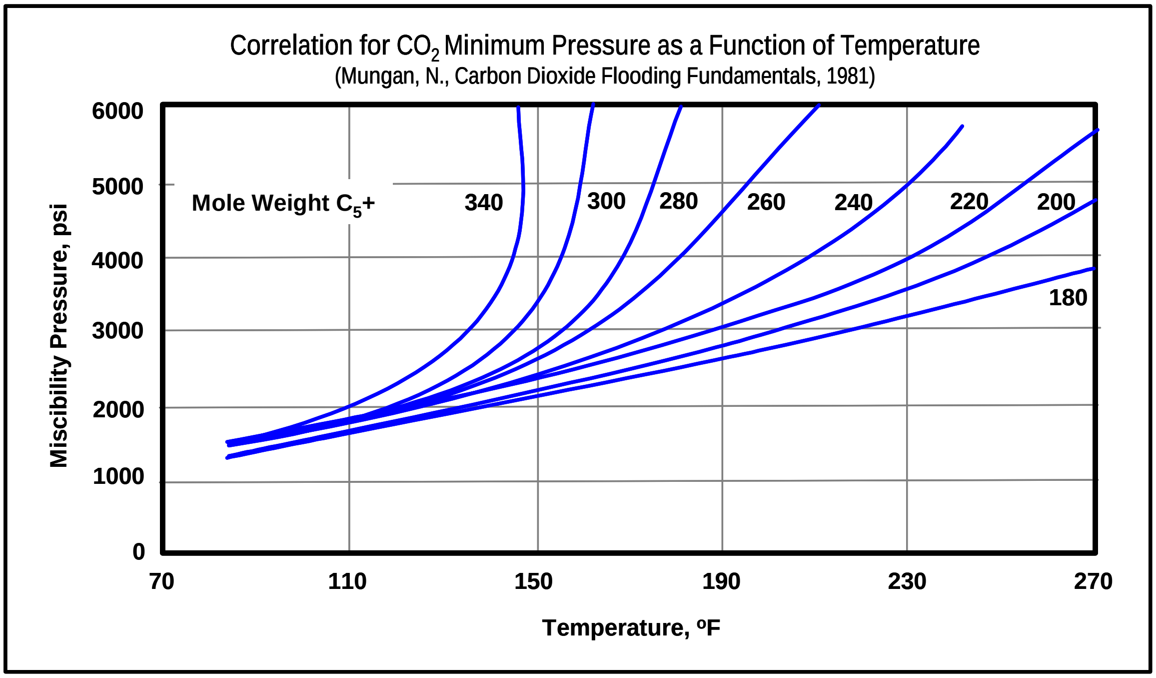
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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 Rocky Mountain region 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.

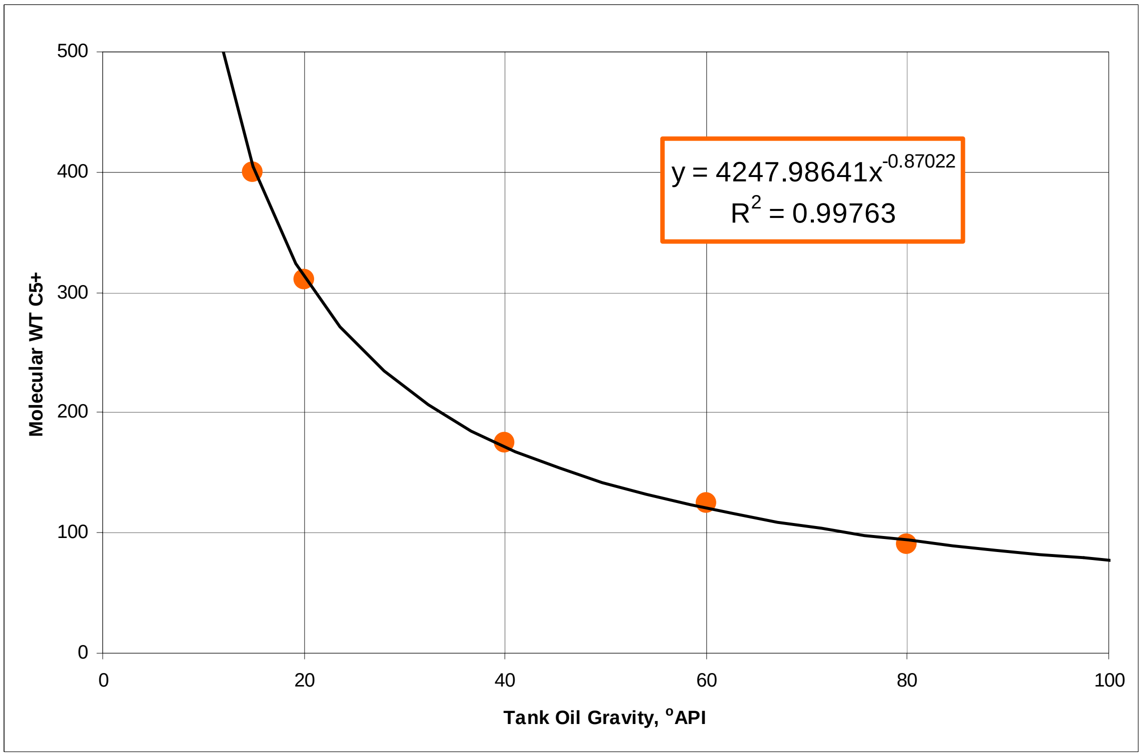
Figure 9. Estimating CO_2 Minimum Miscibility Pressure.



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 with oil gravities >17.5 °API 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 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 provide 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 would be economically produced by CO_2-EOR from the Rocky Mountain region's 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 purchased CO_2 cost was set at 5% of the oil price (e.g. \$1.50 per Mcf at \$30 per barrel) to represent the costs of a new transportation system bringing natural CO_2 to the Rocky Mountain region's oil basins. A lower purchased CO_2 supply cost equal to 2% of the oil price (e.g. \$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 rates 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 Rocky Mountain region. 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 Rocky Mountain region 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 tax credits, royalty relief and/or higher world oil prices that together would add an equivalent $10 per barrel to the oil price that the producer uses for making investment decisions.
- 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.

Table 12. Economic Model Established by the Study.

Pattern-Level Cashflow Model												
State												
Field												
Formation												
Depth												
Distance from Trunkline (mi)												
# of Patterns												
Miscibility:	**Miscible**											
	Year	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
CO_2 Injection (MMcf)		2,187	2,187	1,713	-	-	-	-	-	-	-	-
H_2O Injection (Mbw)		733	733	970	1,826	1,826	1,099	-	-	-	-	-
Oil Production (Mbbl)		91	88	88	94	93	54	-	-	-	-	-
H_2O Production (MBw)		733	730	753	997	1,427	929	-	-	-	-	-
CO_2 Production (MMcf)		1,956	1,970	2,023	1,802	747	282	-	-	-	-	-
CO_2 Purchased (MMcf)		231	217	-	-	-	-	-	-	-	-	-
CO_2 Recycled (MMcf)		1,956	1,970	1,713	-	-	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 30.00**	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ -	$ -	$ -	$ -	$ -
Gravity Adjustment	**29**	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ (2.75)	$ (2.75)	$ (2.75)	$ (2.75)	$ (2.75)
Gross Revenues ($M)		$ 2,469	$ 2,395	$ 2,387	$ 2,559	$ 2,529	$ 1,458	$ -	$ -	$ -	$ -	$ -
Royalty ($M)	**-12.5%**	$ (309)	$ (299)	$ (298)	$ (320)	$ (316)	$ (182)	$ -	$ -	$ -	$ -	$ -
Severance Taxes ($M)	**-6.0%**	$ (130)	$ (126)	$ (125)	$ (134)	$ (133)	$ (77)	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**-6.0%**	$ (130)	$ (126)	$ (125)	$ (134)	$ (133)	$ (77)	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 1,901	$ 1,844	$ 1,838	$ 1,970	$ 1,947	$ 1,123	$ -	$ -	$ -	$ -	$ -
Capital Costs ($M)												
New Well - D&C												
Reworks - Producers to Producers												
Reworks - Producers to Injectors												
Reworks - Injectors to Injectors												
Surface Equipment (new wells only)												
CO_2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction												
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)												
Total CO_2 Cost ($M)		$ (934)	$ (917)	$ (514)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs												
Operating & Maintenance ($M)		$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (274)	$ (270)	$ (276)	$ (343)	$ (449)	$ (286)	$ -	$ -	$ -	$ -	$ -
G&A	**20%**	(81)	(80)	(81)	(95)	(116)	(83)	-	-	-	-	-
Total O&M Costs		$ (485)	$ (481)	$ (488)	$ (568)	$ (696)	$ (499)	$ -	$ -	$ -	$ -	$ -
Net Cash Flow ($M)		$ 482	$ 447	$ 837	$ 1,402	$ 1,251	$ 623	$ -	$ -	$ -	$ -	$ -
Cum. Cash Flow		$ 36,258	$ 36,705	$ 37,542	$ 38,944	$ 40,195	$ 40,818	$ 40,818	$ 40,818	$ 40,818	$ 40,818	$ 40,818
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		$ 1	$ 1	$ 2	$ 2	$ 2	$ 1	$ -	$ -	$ -	$ -	$ -
Disc. Cum Cash Flow		$ (504)	$ (503)	$ (502)	$ (500)	$ (498)	$ (497)	$ (497)	$ (497)	$ (497)	$ (497)	$ (497)
NPV (BTx)	25%											
NPV (BTx)	20%											
NPV (BTx)	15%											
NPV (BTx)	10%											
IRR (BTx)												

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

Pattern-Level Cashflow Model															
State	**WY**														
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**
CO2 Injection (MMcf)		2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187	2,187
H2O Injection (Mbw)		733	733	733	733	733	733	733	733	733	733	733	733	733	733
Oil Production (Mbbl)		154	155	174	173	177	168	159	156	150	130	114	103	88	87
H2O Production (MBw)		774	772	753	748	733	743	742	732	727	742	748	745	751	747
CO2 Production (MMcf)		1,695	1,695	1,693	1,708	1,736	1,733	1,758	1,792	1,819	1,835	1,859	1,894	1,919	1,931
CO2 Purchased (MMcf)		492	492	494	479	451	454	429	395	368	352	328	293	268	257
CO2 Recycled (MMcf)		1,695	1,695	1,693	1,708	1,736	1,733	1,758	1,792	1,819	1,835	1,859	1,894	1,919	1,931
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	**29**	$ 27.25	$ 27.25	$ 27.25	$ 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)		$ 4,183	$ 4,216	$ 4,742	$ 4,712	$ 4,829	$ 4,589	$ 4,341	$ 4,237	$ 4,074	$ 3,532	$ 3,117	$ 2,807	$ 2,387	$ 2,360
Royalty ($M)	**-12.5%**	$ (523)	$ (527)	$ (593)	$ (589)	$ (604)	$ (574)	$ (543)	$ (530)	$ (509)	$ (441)	$ (390)	$ (351)	$ (298)	$ (295)
Severance Taxes ($M)	**-6.0%**	$ (220)	$ (221)	$ (249)	$ (247)	$ (254)	$ (241)	$ (228)	$ (222)	$ (214)	$ (185)	$ (164)	$ (147)	$ (125)	$ (124)
Ad Valorum ($M)	**-6.0%**	$ (220)	$ (221)	$ (249)	$ (247)	$ (254)	$ (241)	$ (228)	$ (222)	$ (214)	$ (185)	$ (164)	$ (147)	$ (125)	$ (124)
Net Revenue($M)		$ 3,221	$ 3,246	$ 3,651	$ 3,628	$ 3,718	$ 3,533	$ 3,343	$ 3,263	$ 3,137	$ 2,719	$ 2,400	$ 2,161	$ 1,838	$ 1,817
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		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction															
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)															
Total CO2 Cost ($M)		$ (1,247)	$ (1,246)	$ (1,249)	$ (1,231)	$ (1,198)	$ (1,201)	$ (1,171)	$ (1,130)	$ (1,098)	$ (1,079)	$ (1,049)	$ (1,008)	$ (978)	$ (964)
O&M Costs															
Operating & Maintenance ($M)		$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)
Lifting Costs ($/bbl)	**$ 0.25**	$ (232)	$ (232)	$ (232)	$ (230)	$ (227)	$ (228)	$ (225)	$ (222)	$ (219)	$ (218)	$ (215)	$ (212)	$ (275)	$ (273)
G&A	**20%**	(72)	(72)	(72)	(72)	(72)	(72)	(71)	(70)	(70)	(70)	(69)	(69)	(81)	(81)
Total O&M Costs		$ (435)	$ (435)	$ (435)	$ (433)	$ (429)	$ (430)	$ (427)	$ (423)	$ (420)	$ (418)	$ (415)	$ (411)	$ (487)	$ (485)
Net Cash Flow ($M)		$ 1,539	$ 1,565	$ 1,968	$ 1,964	$ 2,091	$ 1,902	$ 1,744	$ 1,710	$ 1,620	$ 1,222	$ 936	$ 742	$ 373	$ 368
Cum. Cash Flow		$ 17,571	$ 19,136	$ 21,103	$ 23,068	$ 25,159	$ 27,061	$ 28,805	$ 30,515	$ 32,134	$ 33,357	$ 34,293	$ 35,034	$ 35,408	$ 35,776
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		$ 106	$ 86	$ 87	$ 69	$ 59	$ 43	$ 31	$ 25	$ 19	$ 11	$ 7	$ 4	$ 2	$ 1
Disc. Cum Cash Flow		$ (950)	$ (864)	$ (777)	$ (708)	$ (649)	$ (606)	$ (575)	$ (550)	$ (532)	$ (520)	$ (513)	$ (509)	$ (507)	$ (506)
NPV (BTx)	25%														
NPV (BTx)	20%														
NPV (BTx)	15%														
NPV (BTx)	10%														
IRR (BTx)															

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

Pattern-Level Cashflow Model												
State												
Field												
Formation												
Depth												
Distance from Trunkline (mi)												
# of Patterns												
Miscibility:	**Miscible**											
	Year	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
CO2 Injection (MMcf)		2,187	2,187	1,713	-	-	-	-	-	-	-	-
H2O Injection (Mbw)		733	733	970	1,826	1,826	1,099	-	-	-	-	-
Oil Production (Mbbl)		91	88	88	94	93	54	-	-	-	-	-
H2O Production (MBw)		733	730	753	997	1,427	929	-	-	-	-	-
CO2 Production (MMcf)		1,956	1,970	2,023	1,802	747	282	-	-	-	-	-
CO2 Purchased (MMcf)		231	217	-	-	-	-	-	-	-	-	-
CO2 Recycled (MMcf)		1,956	1,970	1,713	-	-	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 30.00**	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ 30.00	$ -	$ -	$ -	$ -	$ -
Gravity Adjustment	**29**	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ 27.25	$ (2.75)	$ (2.75)	$ (2.75)	$ (2.75)	$ (2.75)
Gross Revenues ($M)		$ 2,469	$ 2,395	$ 2,387	$ 2,559	$ 2,529	$ 1,458	$ -	$ -	$ -	$ -	$ -
Royalty ($M)	**-12.5%**	$ (309)	$ (299)	$ (298)	$ (320)	$ (316)	$ (182)	$ -	$ -	$ -	$ -	$ -
Severance Taxes ($M)	**-6.0%**	$ (130)	$ (126)	$ (125)	$ (134)	$ (133)	$ (77)	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**-6.0%**	$ (130)	$ (126)	$ (125)	$ (134)	$ (133)	$ (77)	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 1,901	$ 1,844	$ 1,838	$ 1,970	$ 1,947	$ 1,123	$ -	$ -	$ -	$ -	$ -
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		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction												
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cap Ex G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
Total CO2 Cost ($M)		$ (934)	$ (917)	$ (514)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs												
Operating & Maintenance ($M)		$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ (130)	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (274)	$ (270)	$ (276)	$ (343)	$ (449)	$ (286)	$ -	$ -	$ -	$ -	$ -
G&A	**20%**	(81)	(80)	(81)	(95)	(116)	(83)	-	-	-	-	-
Total O&M Costs		$ (485)	$ (481)	$ (488)	$ (568)	$ (696)	$ (499)	$ -	$ -	$ -	$ -	$ -
Net Cash Flow ($M)		$ 482	$ 447	$ 837	$ 1,402	$ 1,251	$ 623	$ -	$ -	$ -	$ -	$ -
Cum. Cash Flow		$ 36,258	$ 36,705	$ 37,542	$ 38,944	$ 40,195	$ 40,818	$ 40,818	$ 40,818	$ 40,818	$ 40,818	$ 40,818
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		$ 1	$ 1	$ 2	$ 2	$ 2	$ 1	$ -	$ -	$ -	$ -	$ -
Disc. Cum Cash Flow		$ (504)	$ (503)	$ (502)	$ (500)	$ (498)	$ (497)	$ (497)	$ (497)	$ (497)	$ (497)	$ (497)
NPV (BTx)	25%											
NPV (BTx)	20%											
NPV (BTx)	15%											
NPV (BTx)	10%											
IRR (BTx)												

6. RESULTS BY STATE

6.1 COLORADO. Colorado is a major oil producing state with a rich history of oil and gas development. Crude oil production began in 1887, and has reached a cumulative recovery of 1.9 billion barrels through 2004. In 2004, Colorado ranked 11th in oil production in the onshore U.S., providing 22 MMBbls of oil (61 MBbls/day). It has about 13,379 producing oil wells and oil reserves of 225 MMBbls. Colorado has seen a slow increase in production in recent years, Table 13.

Table 13. Recent History of Colorado Oil Production

	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
1999	19	53
2000	19	52
2001	20	54
2002	20	56
2003	21	58
2004	22	61

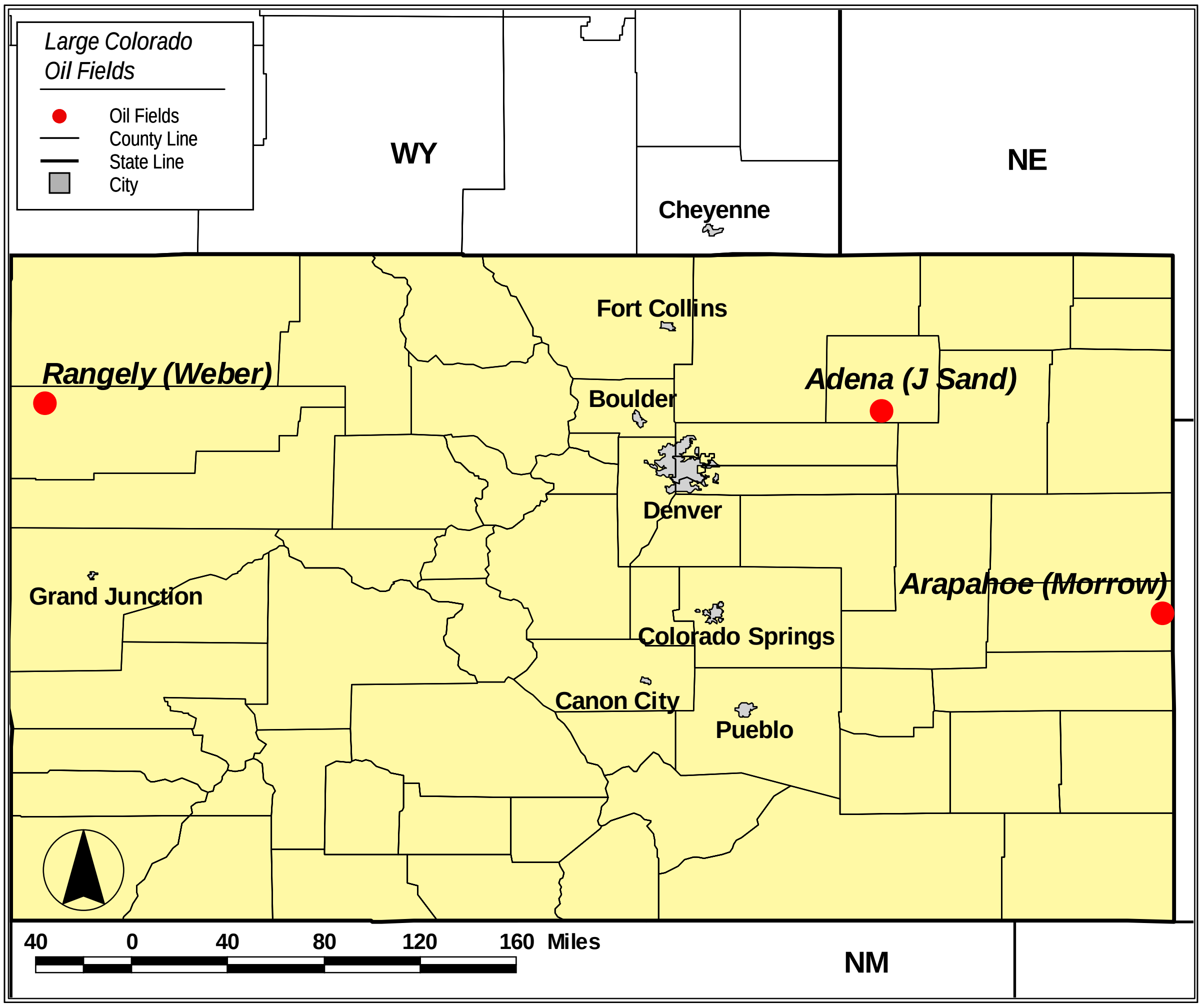
An active program of secondary oil recovery as well as CO_2-EOR in Rangely Field continues to contribute to oil production. However, the bulk of the increase in Colorado's oil production in recent years has been from liquids extraction at the Wattenberg Gas Field, where 10.8 million barrels of high gravity oil (50 °API) was produced in 2004.

Colorado Oil Fields. To better understand the potential of using CO_2-EOR in Colorado's light oil fields, this section examines, in more depth, three large oil fields, shown in Figure 11.

- Adena (J Sand Reservoir)

- Arapahoe (Morrow Reservoir)
- Rangely (Weber Reservoirs)

Figure 11. Large Colorado Oil Fields



These three fields, distributed across Colorado, could serve as the “anchor” sites for 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 three large light oil fields are set forth in Table 14.

Table 14. Status of Large Oil Colorado Fields/Reservoirs (as of 2004)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Adena (J Sand)	135	59	0.4	75
2	Arapahoe (Morrow)	120	24	9	87
3	Rangely (Weber)	1,900	783	12	1,105

These three large "anchor" fields, each with over 1,170 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 Colorado Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (˚API)	Active Waterflood or Gas Injection
1	Adena (J Sand)	5,600	43	Active Waterflood
2	Arapahoe (Morrow)	5,130	40	Active Waterflood
3	Rangely (Weber)	6,000	34	CO_2 WAG flood

Past CO_2-EOR Projects. CO_2-EOR was initiated in the Rangely Oil Field of Colorado in the 1980s.

Rangely Oil Field. The Rangely oil field is located atop the Rangely Anticline of the Piceance-Uinta Basin in northwestern Colorado. The field is currently owned and operated by Chevron. The Rangely field is one of the oldest and largest in Colorado and has been producing oil from the Weber Sandstone, its principal reservoir, since the 1940's. The Weber Sandstone reservoir is at a depth of 5,500 to 6,500 feet and has a net thickness of 50 to 400 feet. The field was unitized in 1957 and was under waterflood until 1986 when tertiary recovery using CO_2 injection was initiated.

- CO_2 is transported to the field from Exxon's Shute Creek gas processing plant near LaBarge, Wyoming.
- 1,124 BCF of CO_2 has been injected into the Weber reservoir since start of CO_2-EOR in 1986.
- Currently CO_2 is being injected via 247 injection wells at a rate of 166 MMcf/d. Oil, water and CO_2 are produced from 373 active wells in the field.
- Chevron is expecting to recover an additional 114 million barrels of oil from using CO_2-EOR, 6% of OOIP (Chevron Texaco, 2005).

The CO_2-EOR project at Chevron's Rangely Field provides valuable information for conducting future CO_2-EOR projects in Colorado.

***Future CO_2-EOR Potential*.** Colorado contains 12 reservoirs that are candidates for miscible CO_2-EOR. Under "Traditional Practices" (and Base Case financial conditions, defined above), only two of these are economically attractive for miscible CO_2 flooding. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection) and establishing lower risk financial conditions, the number of economically favorable for CO_2-EOR oil reservoirs in Colorado increases to 5, providing 510 million barrels of additional oil recovery, Table 16.

Table 16. Economic Oil Recovery Potential Under Two Technologic Conditions, Colorado

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"	12	2,956	330	2	30
"State-of-the-art" Technology	12	2,956	740	5	510

* Oil price of $30 per barrel; CO_2 costs of $1.50/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 Colorado to recover 580 million barrels of CO_2-EOR oil (from 8 major reservoirs), Table 17.

Table 17. Economic Oil Recovery Potential with More Favorable Financial Conditions, Colorado

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
Plus: Risk Mitigation Incentives*	740	6	510
Plus: Low Cost CO_2 Supplies**	740	8	580

* Oil price of $40 per barrel, adjusted for gravity and location differentials; CO_2 supply costs, $2/Mcf

** CO_2 supply costs, $0.80/Mcf

6.2 UTAH. Utah is the 13th largest domestic oil producing state, providing 15 MMBbls (40 MBbls/day) of oil (in 2004), from about 6,300 producing wells. Oil production in Utah began in 1891. Since then, the state has produced almost 1.3 billion barrels of oil and it still holds 0.2 billion barrels of oil reserves.

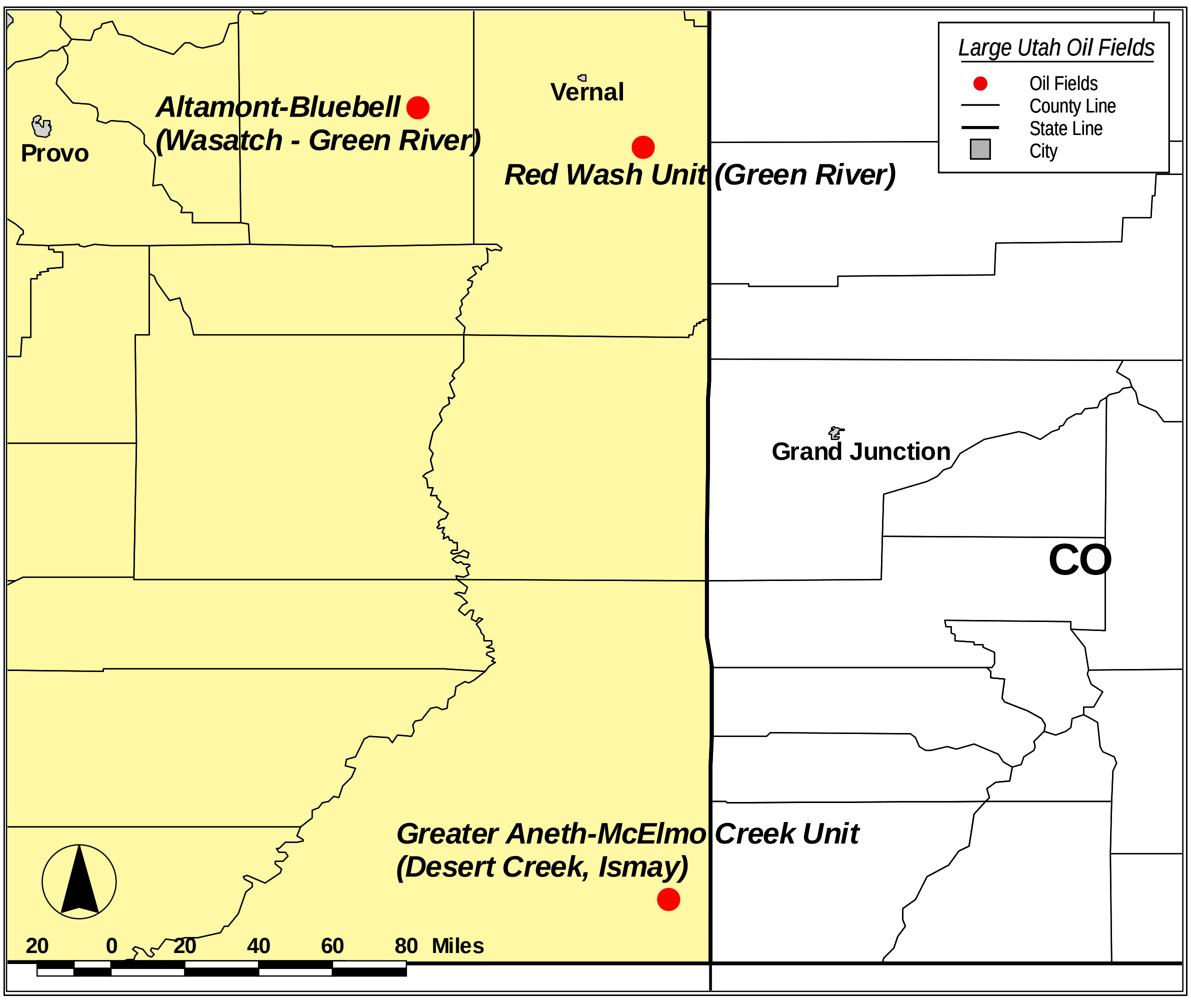
Table 18. Recent History of Utah Oil Production

	Annual Oil Production (MMBbls/Yr)	Annual Oil Production (MBbls/D)
1999	16	45
2000	16	43
2001	15	42
2002	14	39
2003	13	36
2004	15	40

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

- Altamont-Bluebell (Wasatch - Green River)
- Greater Aneth-McElmo Creek Unit (Desert Creek, Ismay)
- Red Wash Unit (Green River)

Figure 12. Large Utah Oil Field



The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for these three major light oil reservoirs are set forth in Table 19.

Table 19. Status of Large Utah Oil Fields/Reservoirs (as of 2004)

	Large Fields/Reservoirs	Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Altamont-Bluebell (Wasatch – Green River)	1,490	274	46	1,170
2	Greater Aneth-McElmo Creek Unit (Green River)	527	160	24	343
3	Red Wash Unit (Desert Creek, Ismay)	309	85	8	216

These three large oil reservoirs are amenable to CO_2-EOR. Table 20 provides the reservoir and oil properties for these reservoirs and their current secondary oil recovery activities.

Table 20. Reservoir Properties and Improved Oil Recovery Activity, Large Utah Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Altamont-Bluebell (Wasatch – Green River)	11,400	37	none
2	Greater Aneth-McElmo Creek Unit (Green River)	5,500	41	waterflood, CO_2 flood
3	Red Wash Unit (Desert Creek, Ismay)	5,400	28	none

Past and Current CO2-EOR Projects. One CO_2-EOR project is underway in Utah at the Greater Aneth Field.

<u>Greater Aneth Field.</u> The greater Aneth Field is located in the Paradox Basin of southeastern Utah. It was discovered in the late 1950's and has been under waterflood since the 1960's when it was also divided into four units. Production is predominantly from the low permeability (0.2-5 md) Desert Creek Formation. A CO_2 flood was initiated in the McElmo Creek Unit of this field in 1985 using a five spot pattern on 40-acre spacing. By the early 1990's, the flood was considered a technical success but

marginal economically due in large part to low CO_2 injectivity into the low permeability formation. In the mid 1990's a horizontal drilling program was started. Analysis showed that a horizontal well, 5-spot, line-drive pattern outperformed the vertical pattern by 2.2 to 2.5 times in terms of oil production. Recently, CO_2 floods were begun in the Ratherford and Aneth Units of this field using horizontal wells. In general, the horizontal multi-lateral completions are expected to recover 15% of OOIP, with CO_2-EOR expected to add 10% of OOIP. The field was acquired by Resolute and NNOG (Navajo Nation Oil and Gas Co.) from Chevron in 2004.

Future CO_2-EOR Potential. Utah contains 14 large light oil reservoirs that are candidates for miscible CO_2-EOR.

Under "Traditional Practices" (involving a small volume of high cost CO_2 injection and high risk financial conditions), miscible CO_2 flooding would be economically attractive in one Utah oil field. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection, immiscible EOR, and lower risk), the number of economically feasible oil reservoirs in Utah increases to 6, providing 360 million barrels of additional oil recovery, Table 21.

Table 21. Economic Oil Recovery Potential Under Two Technologic Conditions, Utah

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential*	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"	14	3,974	380	1	30
"State-of-the-art" Technology	14	3,974	810	6	360

* Oil price of $30 per barrel; CO_2 costs of $1.50/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 Utah to recover an additional 740 million barrels of CO_2-EOR oil (from 10 major oil reservoirs), Table 22.

Table 22. Economic Oil Recovery Potential with More Favorable Financial Conditions, Utah

More Favorable Financial Conditions	Technical Potential (MMBbls)	Economic Potential	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation Incentives*	810	9	730
Plus: Low Cost CO_2 Supplies**	810	10	740

* Oil price of $40 per barrel, adjusted for gravity and location differentials; CO_2 supply costs, $2/Mcfs

** CO_2 supply costs, $0.80/Mcf

6.3 WYOMING. Wyoming is the 7th largest domestic oil producing state, providing 51 MMbbls (139 Mbbls/day) of oil in 2004, from almost 33,000 producing wells. Oil production in the state of Wyoming began in 1894. Cumulative oil recovery in the state has reached 6.8 billion barrels with 0.6 billion barrels of reserves. In recent years, the oil production decline in Wyoming has moderated, supported by several new CO_2-EOR projects in the state, Table 23.

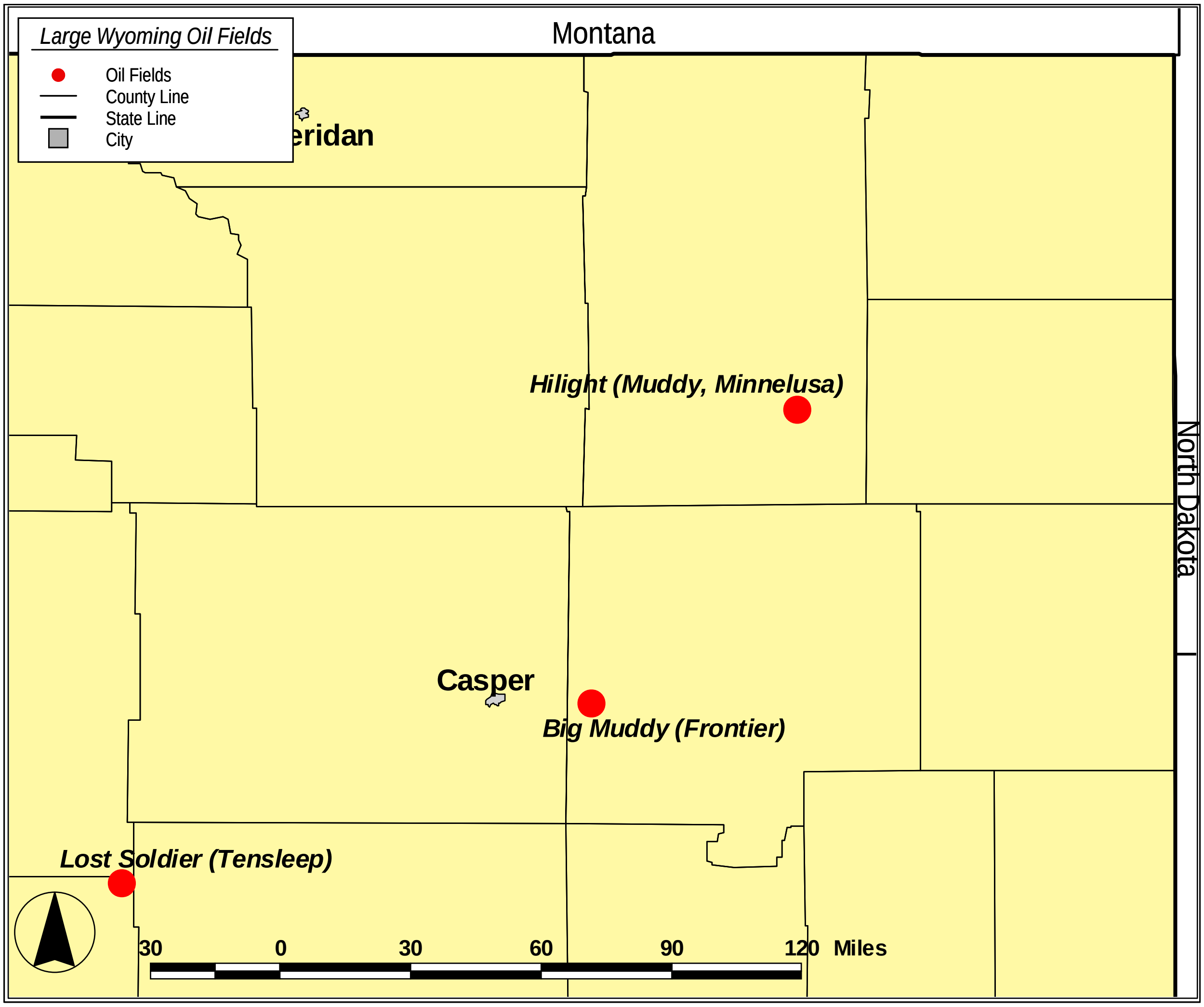
Table 23. Recent History of Wyoming Oil Production

	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
1999	61	166
2000	61	166
2001	58	156
2002	55	150
2003	52	143
2004	51	139

Wyoming Fields. Wyoming contains several large oil fields that may be amenable to miscible CO_2-EOR, Figure 13. These include:

- Big Muddy (Frontier)
- Hilight (Muddy, Minnelusa)
- Lost Soldier (Tensleep)

Figure 13. Large Wyoming Oil Fields



The cumulative oil production, proved reserves and remaining oil in-place (ROIP) in these three large oil reservoirs are provided in Table 24.

Table 24. Status of Large Wyoming Oil Fields/Reservoirs (as of 2004).

Large Fields/Reservoirs		Original Oil In-Place (MMBbls)	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In-Place (MMBbls)
1	Big Muddy (Frontier)	223	55	0	168
2	Hilight (Muddy, Minnelusa)	192	76	1	115
3	Lost Soldier (Tensleep)	250	100	12	138

These three large oil reservoirs, with over 420 million barrels of ROIP, are technically amenable for miscible CO_2-EOR. Table 25 provides the reservoir and oil properties for these reservoirs and their current oil recovery activities.

Table 25. Reservoir Properties and Improved Oil Recovery Activity, Large Wyoming Oil Fields/Reservoirs

	Large Fields/Reservoirs	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Big Muddy (Frontier)	3,200	35	undergoing waterflooding
2	Hilight (Muddy, Minnelusa)	10,300	41	none
3	Lost Soldier (Tensleep)	5,000	35	waterflood/CO_2 flood

In addition to the three major light oil reservoirs, several fields in Wyoming have reservoirs containing heavier oils, such as Oregon Basin, South and Salt Creek. These fields could become candidate fields for immiscible CO_2-EOR, Table 26.

Table 26. Reservoir Properties and Improved Oil Recovery Activity Potential, Utah "Immiscible-CO_2" Oil Fields/Reservoirs

	Candidate Fields/Reservoirs	Depth (ft)	Oil Gravity (°°API)	Active Waterflood or Gas Injection
1	Oregon Basin, South (Tensleep)	3,800	21	undergoing waterflooding
2	Salt Creek (Tensleep)	3,900	25	undergoing waterflooding

Past and Current CO_2-EOR Projects. Several CO_2-EOR projects are currently underway in Wyoming. Two CO_2-EOR projects, in the Lost Soldier and Wertz fields, have been underway since the 1980's. Two additional projects, at Salt Creek and Patrick Draw fields, have been started by Anadarko in the past few years.

Lost Soldier and Wertz Fields. The CO_2 floods in the Lost Soldier and Wertz (1986) fields are reported as being successful. The Lost Soldier flood began in 1989 in the Tensleep formation and has since been expanded to the Darwin-Madison and

Cambrian formations. The three floods combined produce at a rate of over 3,000 barrels per day. The Wertz flood began in 1986 in the Tensleep formation and has since been expanded to the Darwin-Madison formation. The two floods currently produce at a rate of 1,300 barrels per day. The Lost Soldier flood has recovered over 44 million barrels of oil (through year 2000) which is 11% OOIP and the Wertz field has recovered over 17 million barrels of oil (through year 2000) which is 8% OOIP.

Salt Creek Field. The Salt Creek oil field (Wall Creek reservoir) of northeastern Wyoming was discovered in 1917 and is operated by Anadarko Petroleum. Full scale waterflooding in the field began in 1961. Following a successful CO_2-EOR pilot, a full scale CO_2-EOR project was started in 2004.

Injection of CO_2 into the Salt Creek oil field began in January of 2004. It is expected to raise field production to 25,000 - 30,000 BPD, compared to 6,000 BPD in 2004. This CO_2-EOR project could reverse the state's oil production decline.

Approximately 130 MMcf/d of CO_2 is being injected into the formation.

Early results are meeting expectations and are promising.

Future CO_2-EOR Potential. Wyoming contains 66 oil reservoirs that are candidates for miscible or immiscible CO_2-EOR technology.

The potential for economically developing these oil reservoirs is examined first under Base Case financial criteria that combine an oil price of $30 per barrel, CO_2 supply costs ($1.50/Mcf), and a high risk rate of return (ROR) hurdle (25% before tax).

Under "Traditional Practices" (involving a small volume of high cost CO_2 injection and high risk financial conditions), miscible CO_2 flooding would be economically attractive in 5 Wyoming oil fields. Applying "State-of-the-art Technology" (involving higher volume CO_2 injection, immiscible EOR, and lower risk), the number of economically feasible oil reservoirs in Utah increases to 32, providing 730 million barrels of additional oil recovery, Table 27.

Table 27. Economic Oil Recovery Potential Under Two Technologic Conditions, Wyoming

CO_2-EOR Technology	No. of Reservoirs	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential*	
				(No. of Reservoirs)	(MMBbls)
"Traditional Practices"	55	6,849	490	5	50
"State-of-the-art" Technology	66	11,098	1,380	32	730

** Oil price of $30 per barrel.*

Combining "State-of-the-art" technologies with risk mitigation incentives and/or higher oil prices plus lower cost CO_2 supplies would enable CO_2-EOR Wyoming to recover an additional 1,120 million barrels of CO_2-EOR oil (from 53 major oil reservoirs), Table 28.

Table 28. Economic Oil Recovery Potential with More Favorable Financial Conditions, Wyoming

More Favorable Conditions	Technical Potential (MMBbls)	Economic Potential*	
		(No. of Reservoirs)	(MMBbls)
Plus: Risk Mitigation*	1,380	39	840
Plus: Low Cost CO_2**	1,380	53	1,120

*Oil price of $40 per barrel, adjusted for gravity differential; CO_2 supply costs, $2/Mcf

** CO_2 supply costs, to $0.80/Mcf

Appendix A

Using *CO_2-PROPHET* for Estimating Oil Recovery

Model Development

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

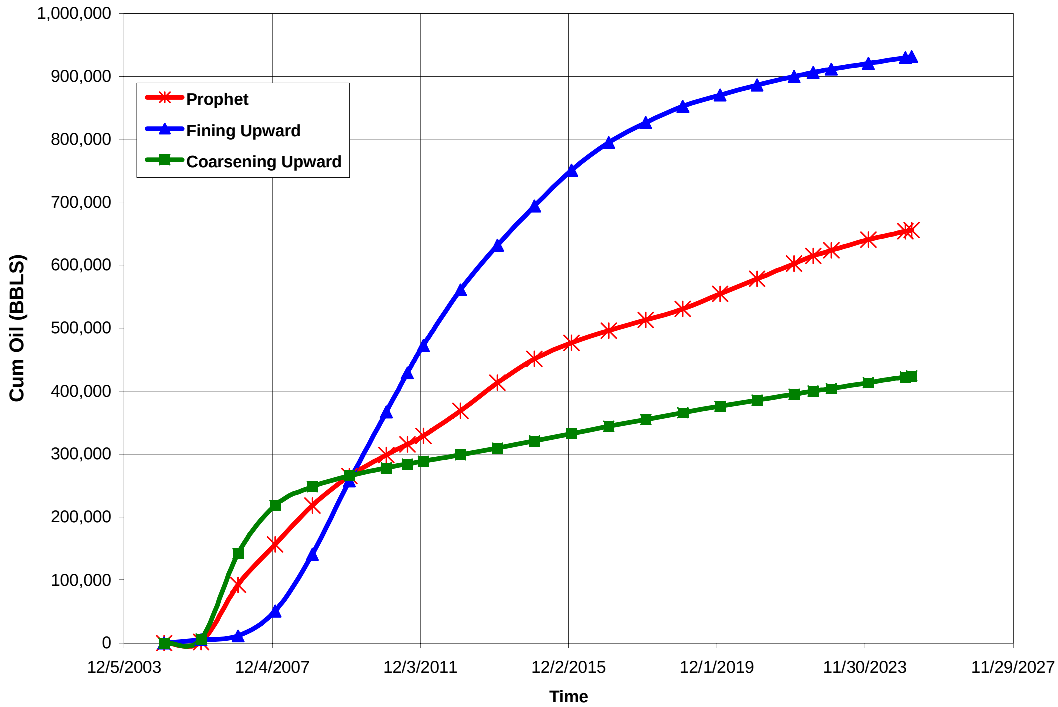
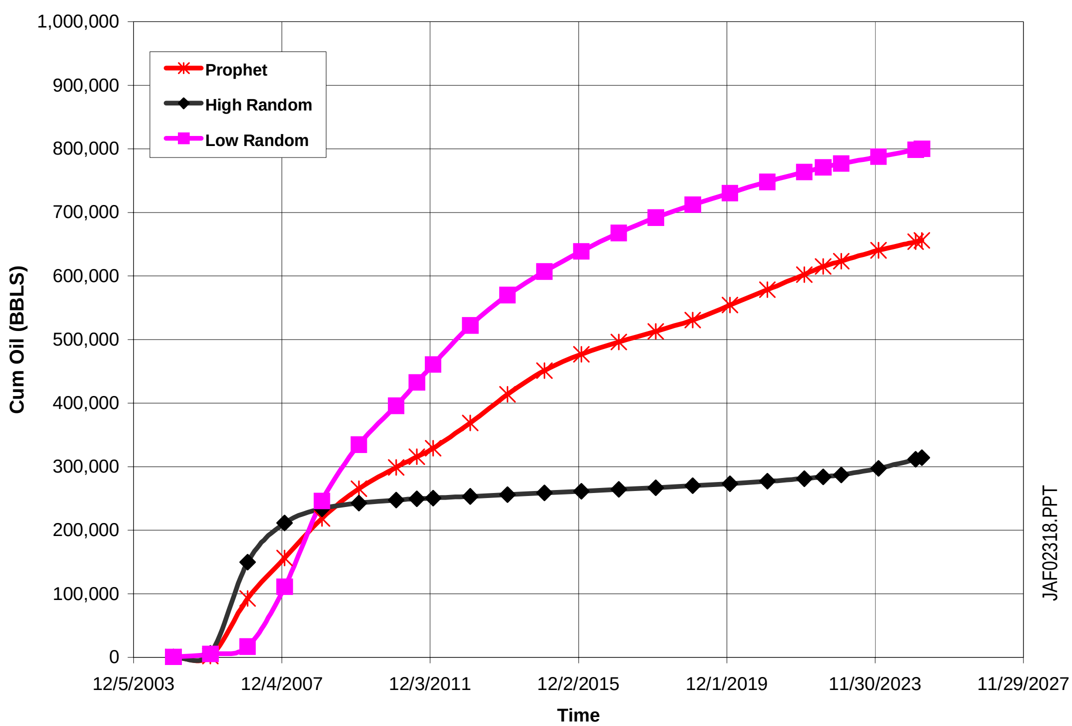


Figure A-2. CO_2-*PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



- *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 B

Colorado 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:

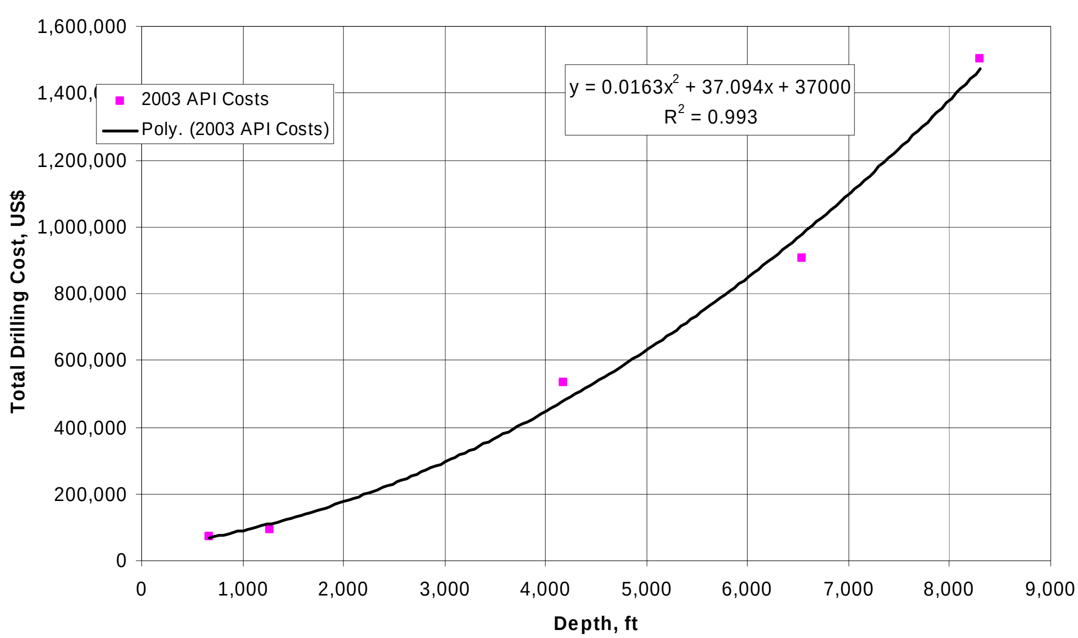
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Colorado.

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 with depth. The total equation is:

Well D&C Costs = $a_0D^2 + a_1D + a_2$
Where: a_0 is 0.0163
a_1 is 37.09
a_2 is 37000
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 Colorado.

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



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 Colorado D&C cost calculations to reflect this increase in 2004 drilling costs.

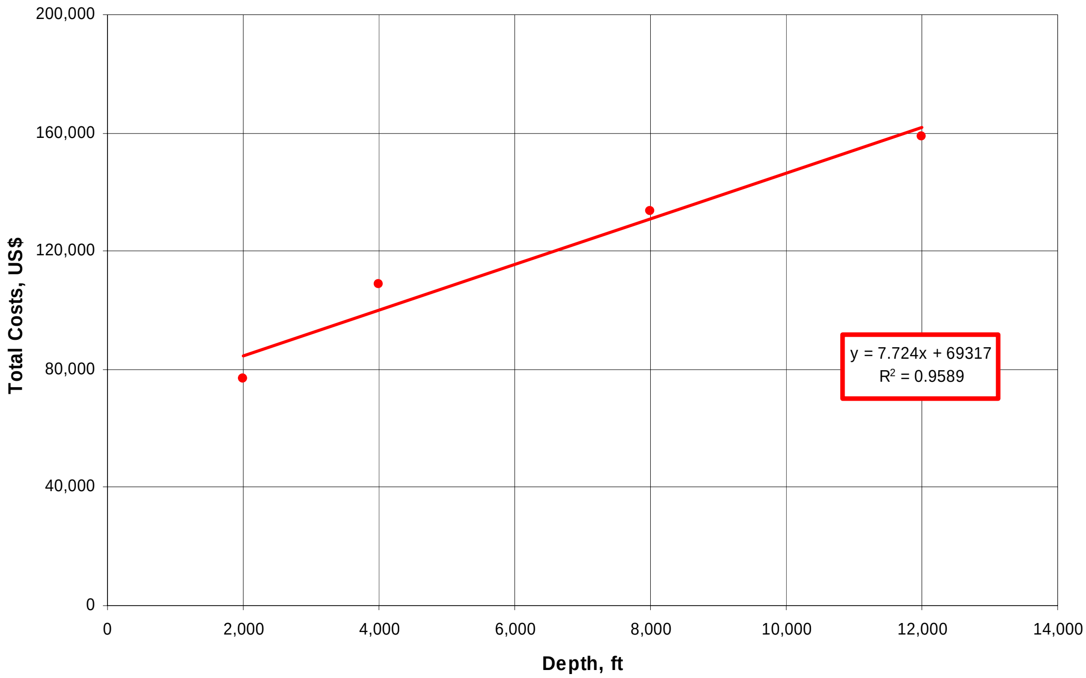
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs for 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 = $c_0 + c_1 D$
Where: c_o = $69,317 (fixed)
c_1 = $7.724 per foot
D is well depth

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

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



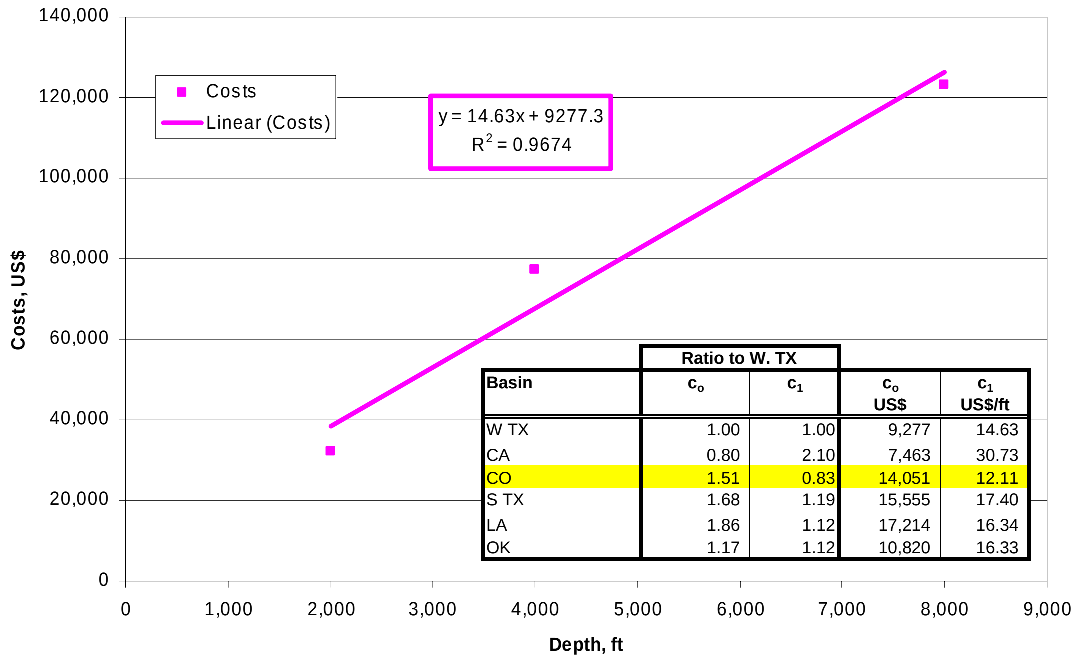
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Colorado include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$14,051 (fixed)
c_1 = \$12.11 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 Colorado 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	9,277	14.63
CA	0.80	2.10	7,463	30.73
CO	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

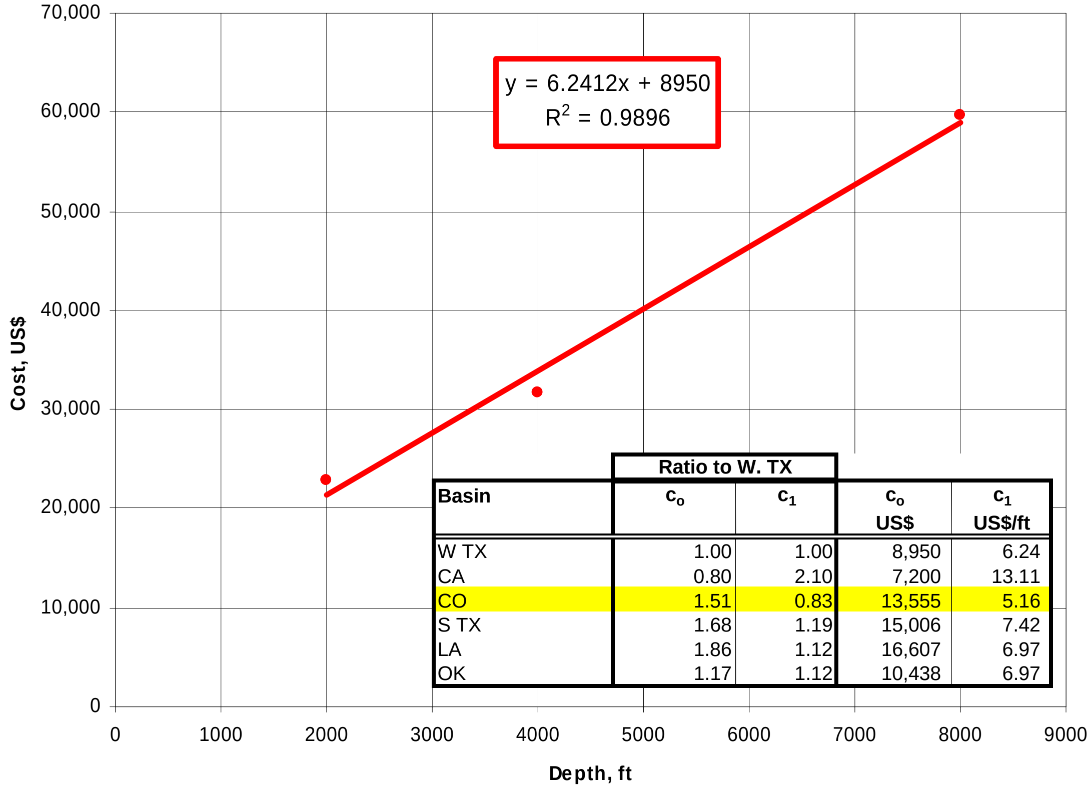
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are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

Well Conversion Costs = $c_0 + c_1D$
Where: c_0 = $13,555 (fixed)
c_1 = $5.16 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 Colorado cost equation.

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



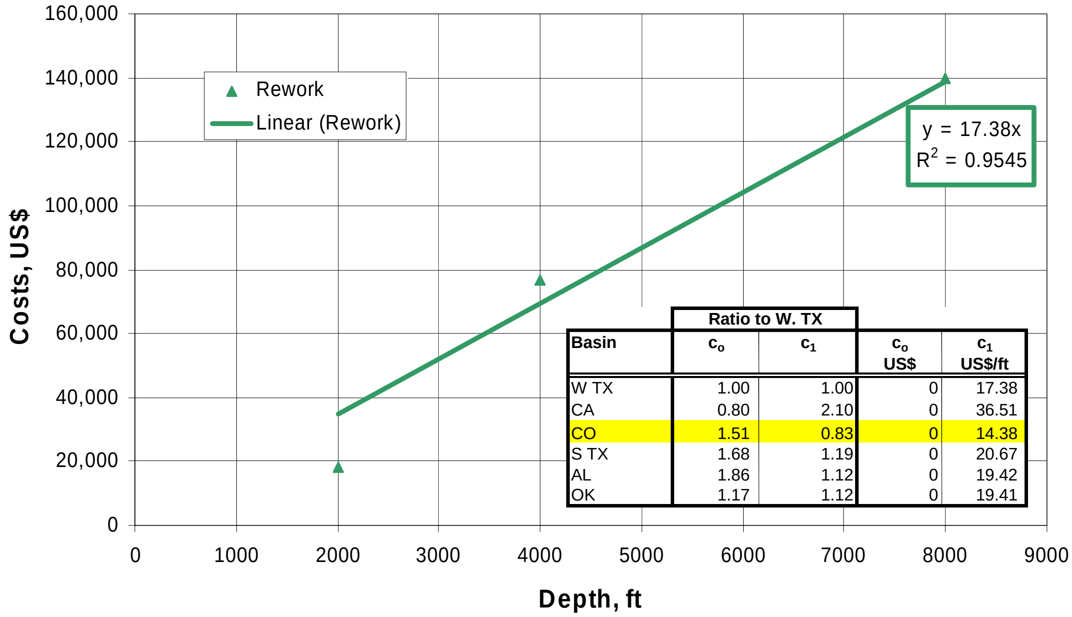
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
CO	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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 Colorado is:

Well Rework Costs = c_1D
Where: c_1 = $14.38 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 Colorado cost equation.

Figure B-5. Cost of 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	17.38
CA	0.80	2.10	0	36.51
CO	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

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

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

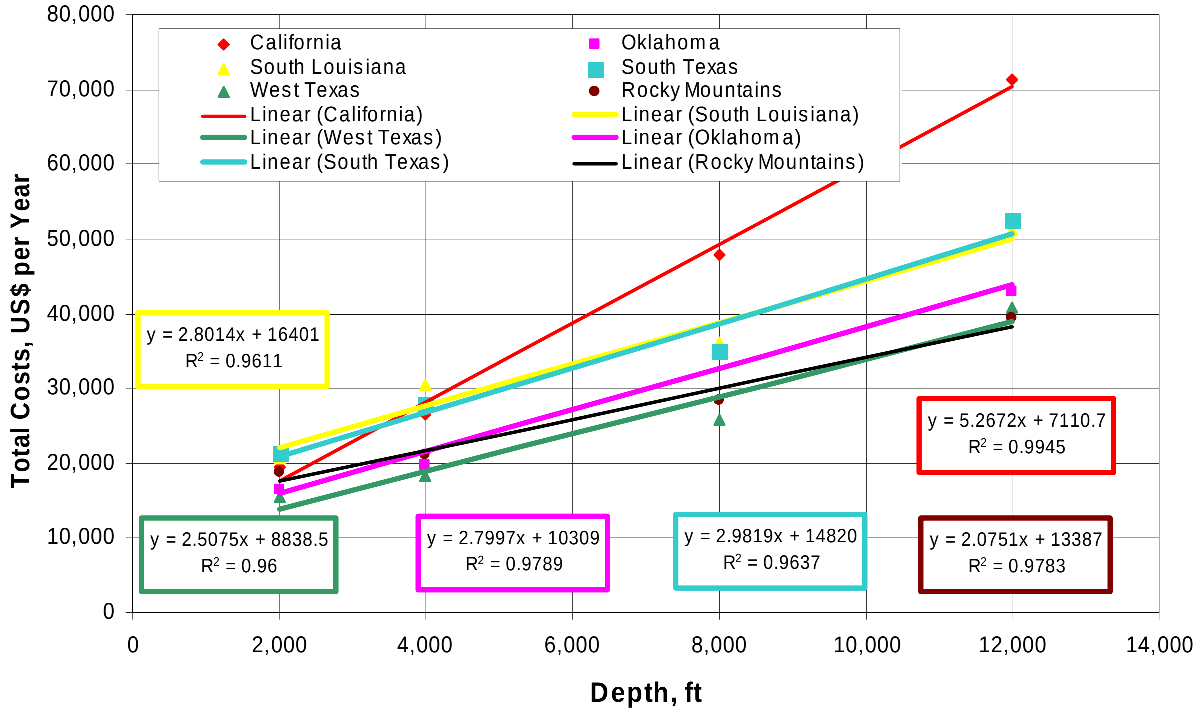


Table B-1. Regional Lease O&M Costs and Their Relationship to West Texas

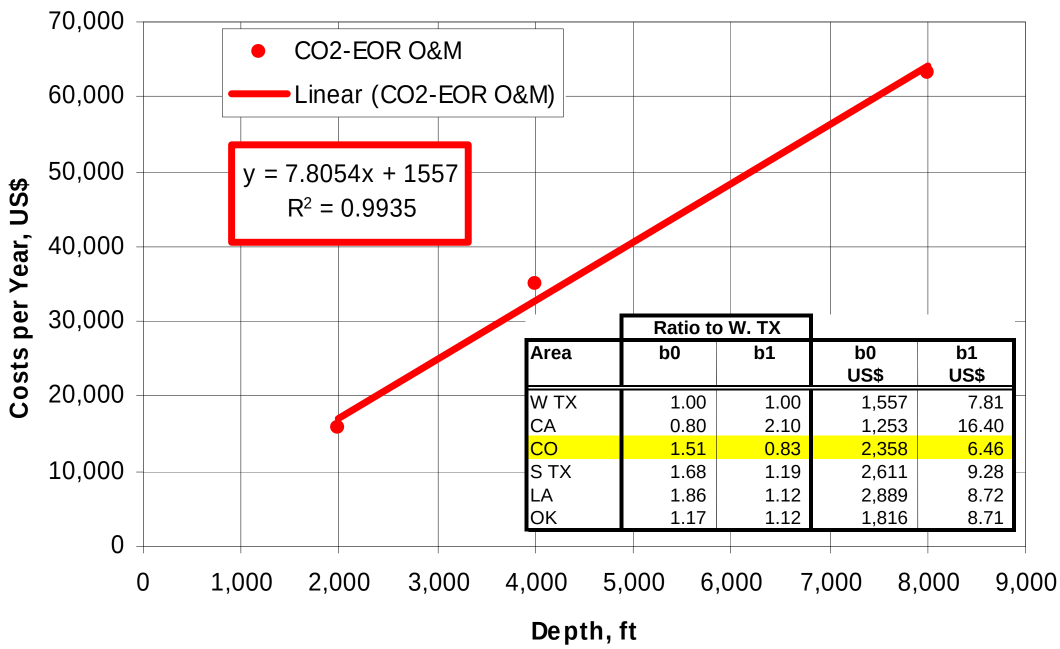
			Ratio to W. TX	
Basin	**c_0 US$**	**c_1 US$**	**c_0**	**c_1**
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Colorado	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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 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 Colorado, shown in the inset of Figure B-7. The equation for Colorado is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$31,381 (fixed)
b_1 = \$6.46 per foot
D is well depth

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



	Ratio to W. TX			
Area	**b0**	**b1**	**b0 US$**	**b1 US$**
W TX	1.00	1.00	1,557	7.81
CA	0.80	2.10	1,253	16.40
CO	1.51	0.83	2,358	6.46
S TX	1.68	1.19	2,611	9.28
LA	1.86	1.12	2,889	8.72
OK	1.17	1.12	1,816	8.71

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 D-Sand formation of the Little Beaver field, with 9 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$6 million. A large project in the Spindle Unit field, with 76 MMcf/d of peak CO_2 reinjection, requires a recycling plant costing \$53 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 Colorado 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. Colorado charges a 5% severance tax on all oil production after $299,000 income. Ad valorum taxes vary from 4% to 10 % and an average value of 7% was used in the study. However, severance taxes may be deducted from the ad valorum, so a net ad valorum of 2% was input into the model. Severance and ad valorum taxes are charged after royalty payments are made.

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 Colorado (-$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 Colorado is:

Wellhead Oil Price = Oil Price + (-$0.00) – [$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 Colorado 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 C

Utah 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:

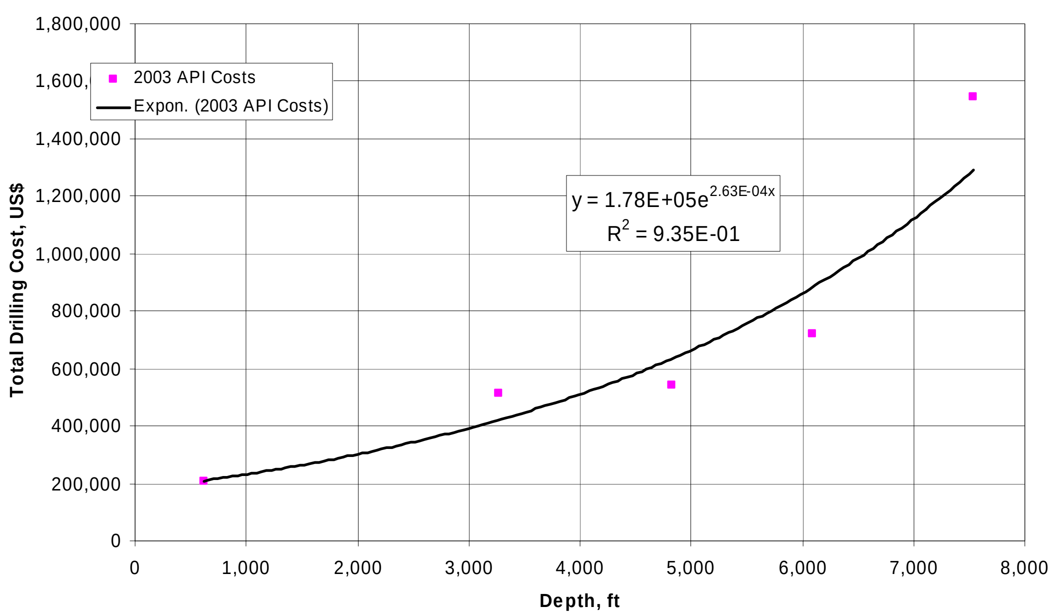
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2003 JAS cost study recently published by API for Utah.

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 with depth. The total equation is:

Well D&C Costs = $a_0 + D^{a_1}$
Where: a_0 is 1.78×10^5
a_1 is 2.36×10^{-5}
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 Utah.

Figure C-1. Oil Well D&C Costs for Utah



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 Utah D&C cost calculations to reflect this increase in 2004 drilling costs.

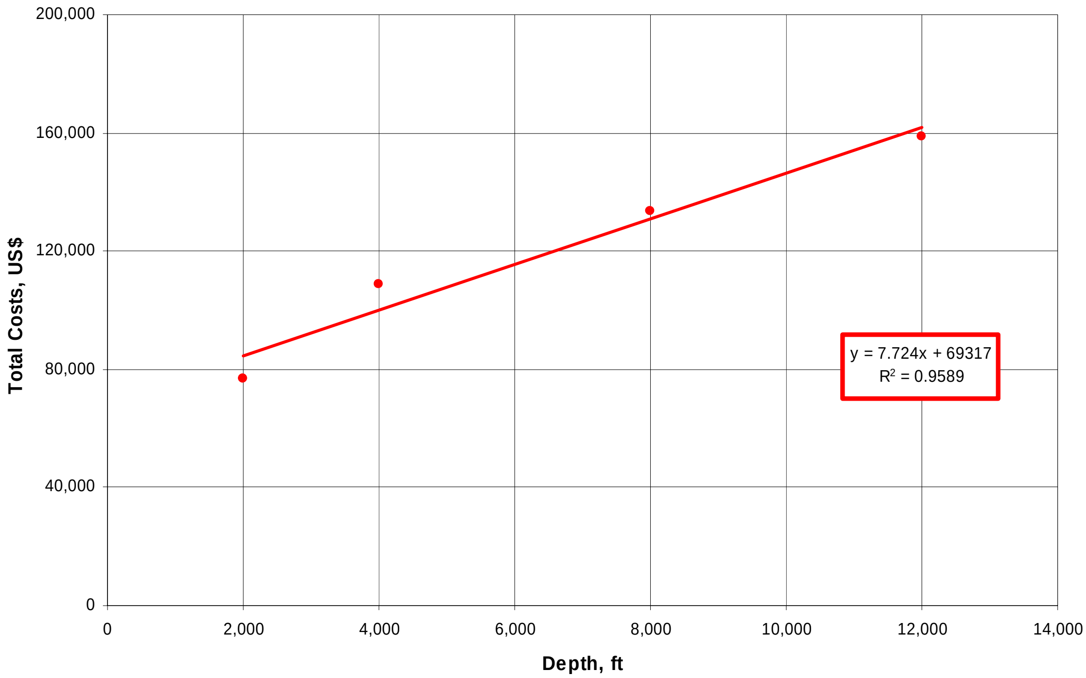
2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well are based on data reported by the EIA in their 2004 "Cost and Indices for Domestic Oil and Gas Field Equipment and Production Operations" report. This survey provides estimated lease equipment costs for 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 = $69,317 (fixed)
c_1 = $7.724 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 Utah vs. Depth



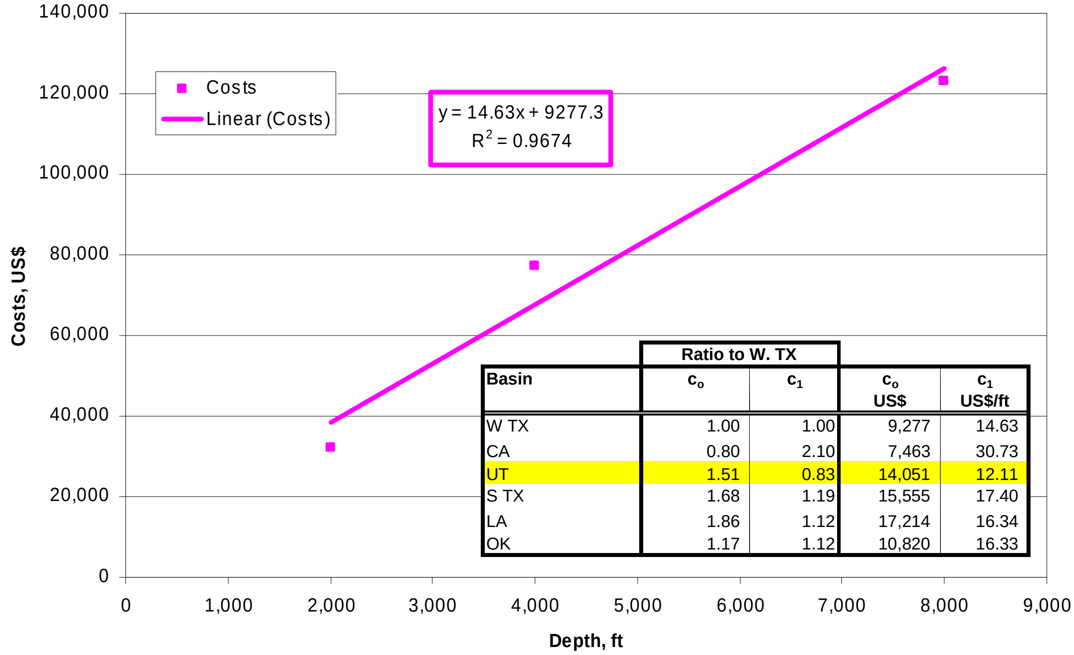
3. <u>Lease Equipment Costs for New Injection Wells.</u> The costs for equipping a new injection well in Utah include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$14,051 (fixed)
c_1 = \$12.11 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 Utah cost equation.

Figure C-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	9,277	14.63
CA	0.80	2.10	7,463	30.73
UT	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

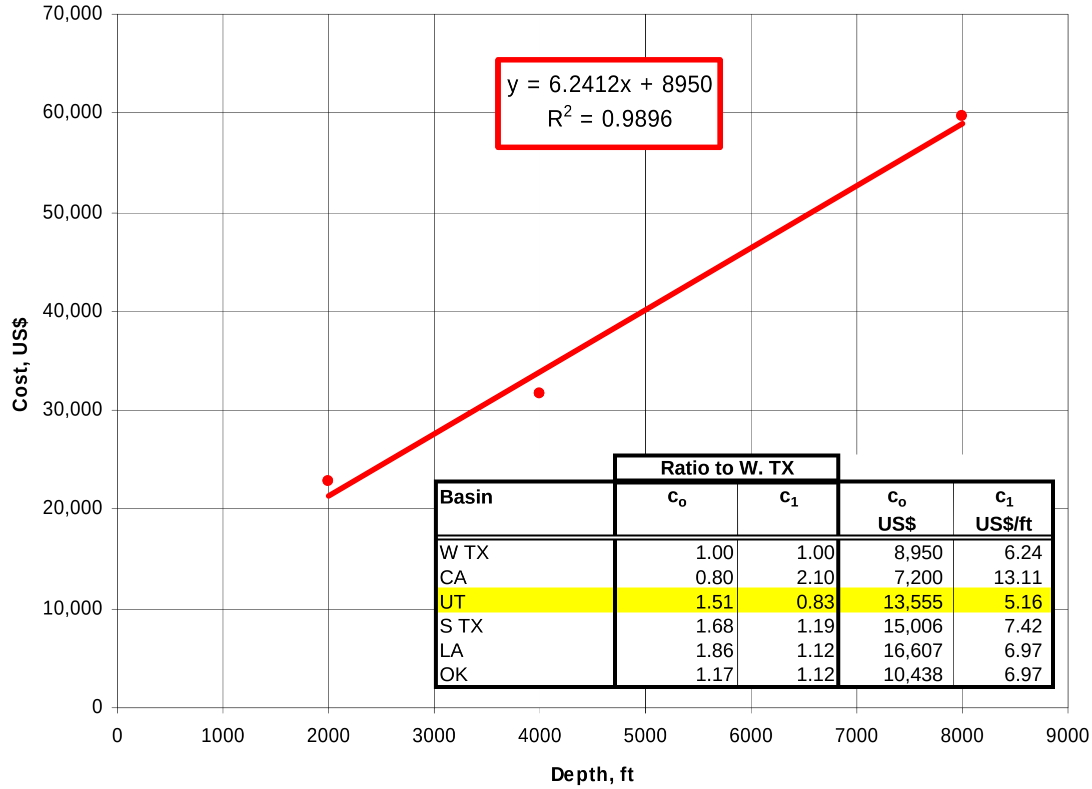
4. <u>Converting Existing Production Wells into Injection Wells.</u> The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = $13,555 (fixed)
c_1 = $5.16 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 Utah cost equation.

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



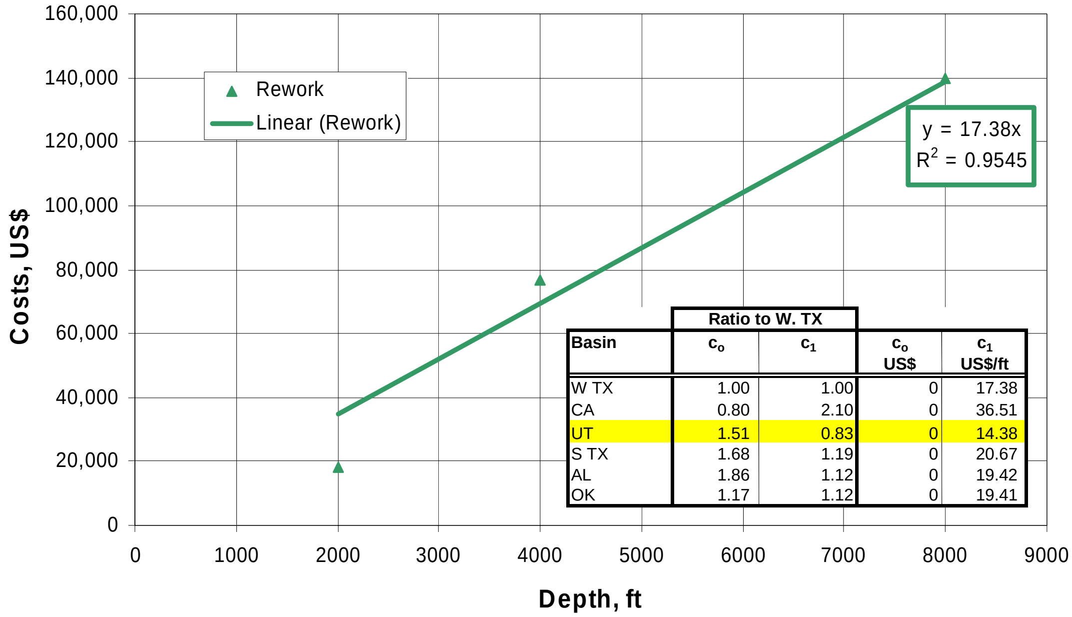
Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
UT	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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 Utah is:

Well Rework Costs = c_1D
Where: c_1 = \$14.38 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 Utah cost equation.

Figure C-5. Cost of 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	17.38
CA	0.80	2.10	0	36.51
UT	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides secondary operating and maintenance (O&M) costs only for West Texas. As such, West Texas and Utah primary oil production O&M costs (Figure C-6) are used to estimate Utah 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

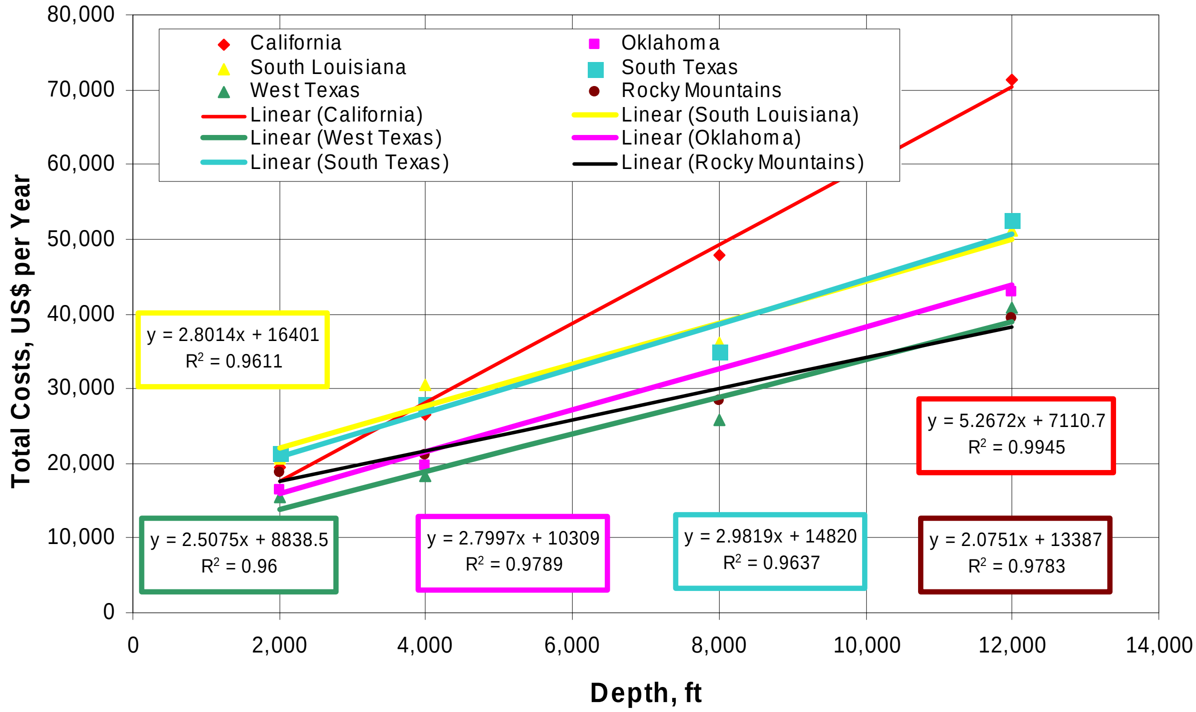


Table C-1. Regional Lease O&M Costs and Their Relationship to West Texas

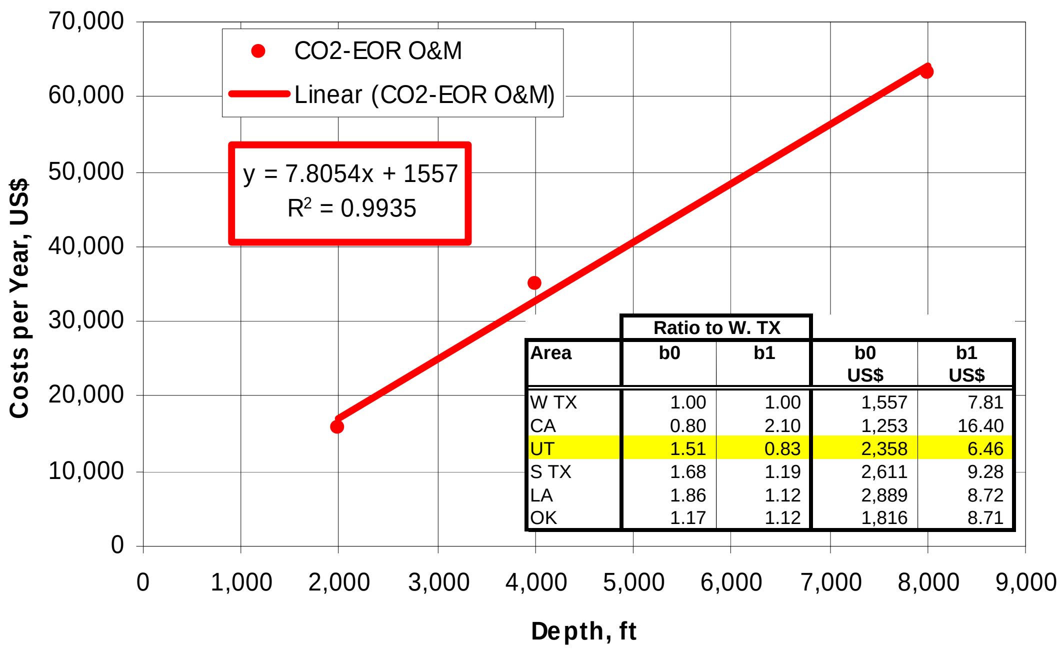
Basin	c_0 US$	c_1 US$	Ratio to W. TX c_0	Ratio to W. TX c_1
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Utah	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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 adjusted to develop O&M for Utah, shown in the inset of Figure C-7. The equation for Utah is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$31,381 (fixed)
b_1 = \$6.46 per foot
D is well depth

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



Area	Ratio to W. TX b0	Ratio to W. TX b1	b0 US$	b1 US$
W TX	1.00	1.00	1,557	7.81
CA	0.80	2.10	1,253	16.40
UT	1.51	0.83	2,358	6.46
S TX	1.68	1.19	2,611	9.28
LA	1.86	1.12	2,889	8.72
OK	1.17	1.12	1,816	8.71

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 Phosphoria-Weber formation of the Ashley Valley field, with 10 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$7 million. A large project in the Red Wash Unit field, with 131 MMcf/d of peak CO_2 reinjection, requires a recycling plant costing \$92 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. CO₂ 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 Utah 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. Utah charges a 5% severance tax on all oil production over $13 per barrel. However, the state has enacted a 50% reduction in the severance tax rate for qualified enhanced recovery projects (2.5%). This reduction equates to a savings of 65 cents per barrel (for the $30 per barrel case). Ad valorum taxes vary by county and an average rate of 1% is used in the model. Severance and ad valorum taxes are charged after royalty payments are made.

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 Utah (-$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 Utah is:

Wellhead Oil Price = Oil Price + (-$0.00) – [$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 Utah 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

Wyoming 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 Wyoming.

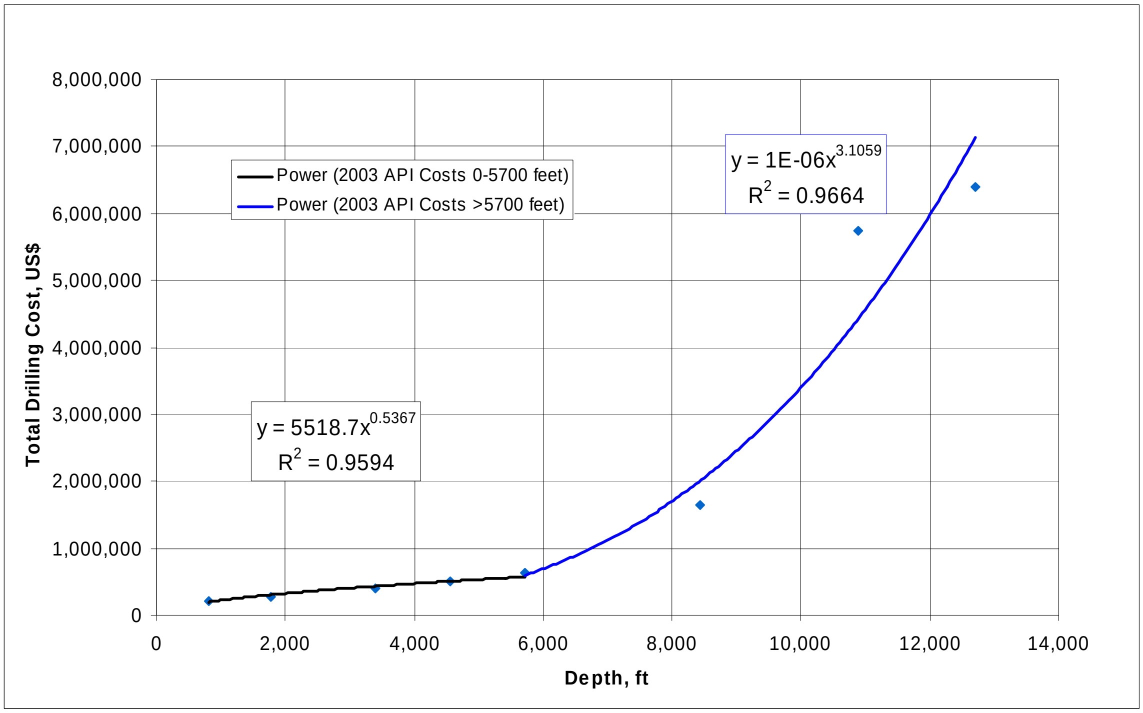
The well D&C cost equation has a fixed cost constant for site preparation and other fixed cost items and a variable cost equation that increases with depth. The total equation is:

Wyoming drilling 0-5700 feet
Well D&C Costs = $a_0 + D^{a_1}$
Where: a_0 is 5518
a_1 is 0.0537
D is well depth

Wyoming drilling >5700 feet
Well D&C Costs = $a_0 + D^{a_1}$
Where: a_0 is 1×10^{-6}
a_1 is 3.106
D is well depth

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

Figure D-1. Oil Well D&C Costs for Wyoming



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 Wyoming 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.

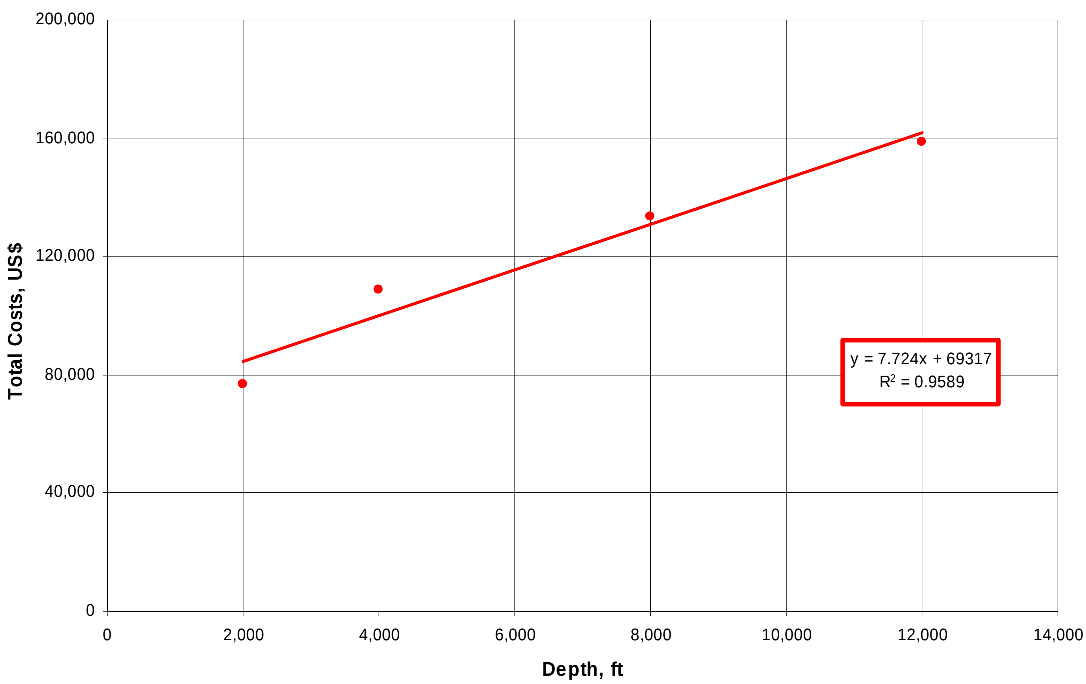
The equation contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs such as for pumping equipment. The total equation is:

Production Well Equipping Costs = $c_0 + c_1D$

Where: c_o = \$69,317 (fixed)
c_1 = \$7.724 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 Wyoming vs. Depth



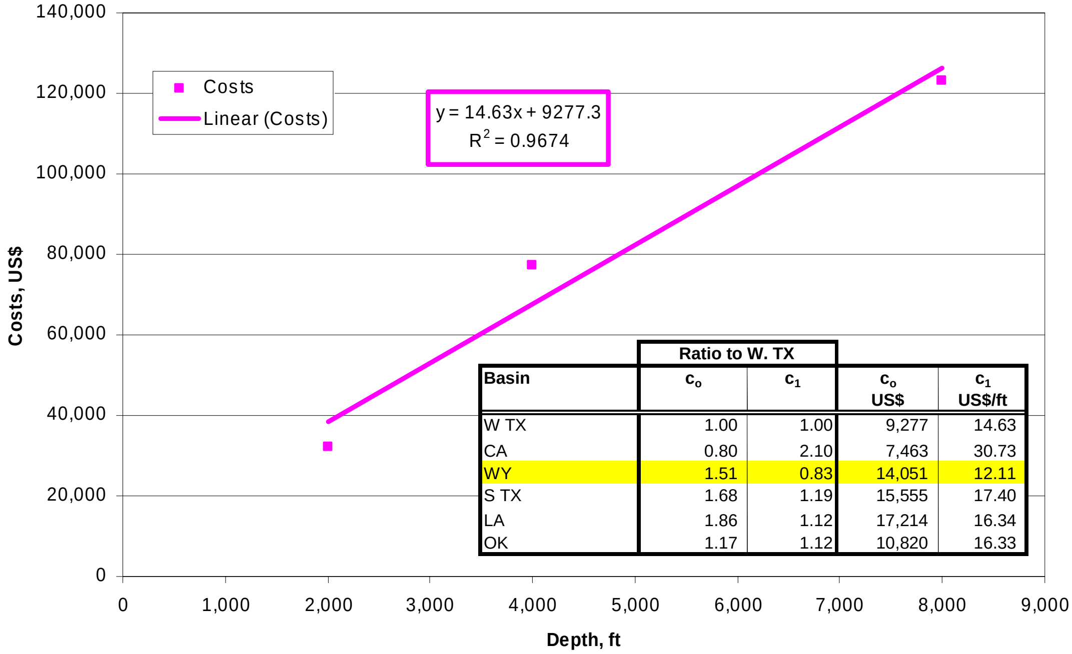
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in Wyoming include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

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

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$14,051 (fixed)
c_1 = \$12.11 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. The West Texas cost data for lease equipment provides the foundation for the Wyoming cost equation.

Figure D-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	9,277	14.63
CA	0.80	2.10	7,463	30.73
WY	1.51	0.83	14,051	12.11
S TX	1.68	1.19	15,555	17.40
LA	1.86	1.12	17,214	16.34
OK	1.17	1.12	10,820	16.33

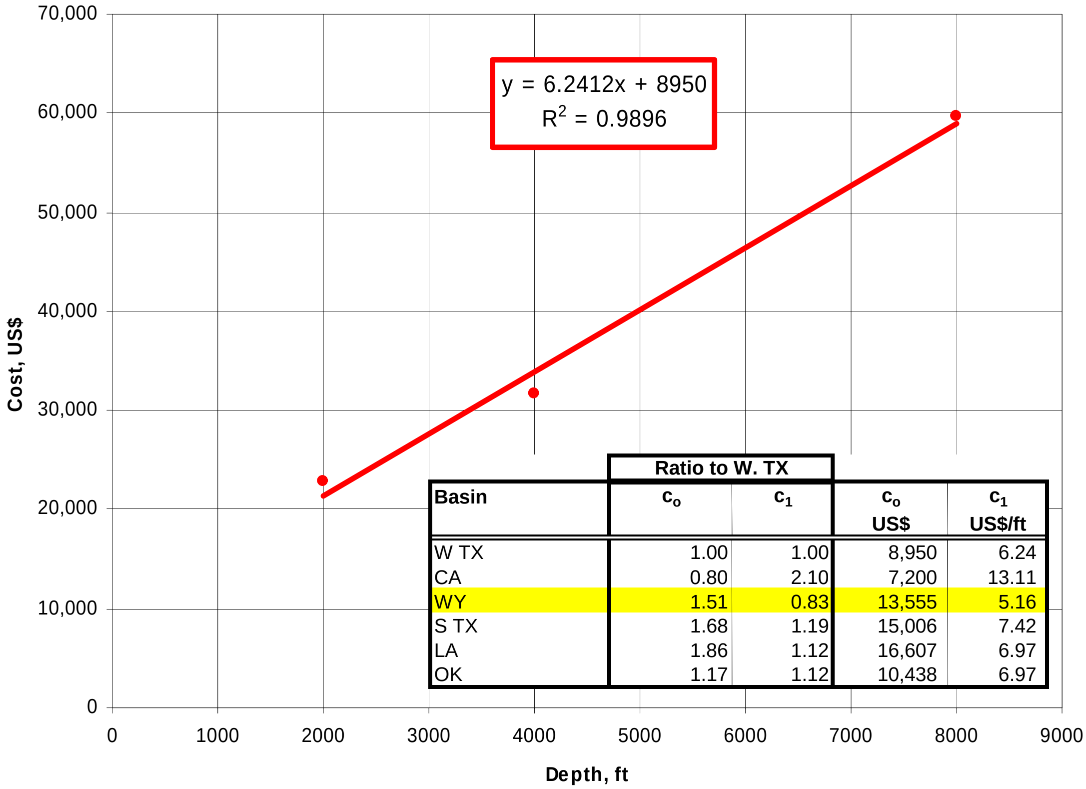
4. Converting Existing Production Wells into Injection Wells. The conversion of existing oil production wells into CO_2 and water injection wells requires replacing the tubing string and adding distribution lines and headers. The costs assume that all surface equipment necessary for water injection are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

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$13,555 (fixed)
c_1 = \$5.16 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. The West Texas cost data for converting wells provide the foundation for the Wyoming cost equation.

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



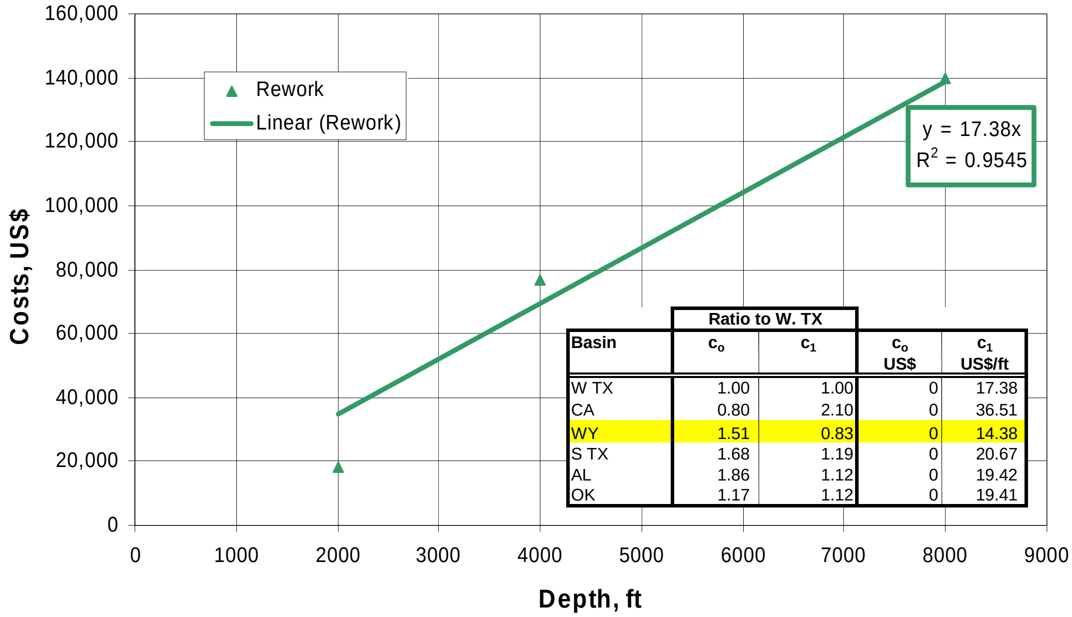
	Ratio to W. TX			
Basin	**c_o**	**c_1**	**c_o US$**	**c_1 US$/ft**
W TX	1.00	1.00	8,950	6.24
CA	0.80	2.10	7,200	13.11
WY	1.51	0.83	13,555	5.16
S TX	1.68	1.19	15,006	7.42
LA	1.86	1.12	16,607	6.97
OK	1.17	1.12	10,438	6.97

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 Wyoming is:

Well Rework Costs = c_1D
Where: c_1 = \$14.38 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 Wyoming cost equation.

Figure D-5. Cost of 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	17.38
CA	0.80	2.10	0	36.51
WY	1.51	0.83	0	14.38
S TX	1.68	1.19	0	20.67
AL	1.86	1.12	0	19.42
OK	1.17	1.12	0	19.41

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 Wyoming primary oil production O&M costs (Figure D-6) are used to estimate Wyoming secondary recovery O&M costs. 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

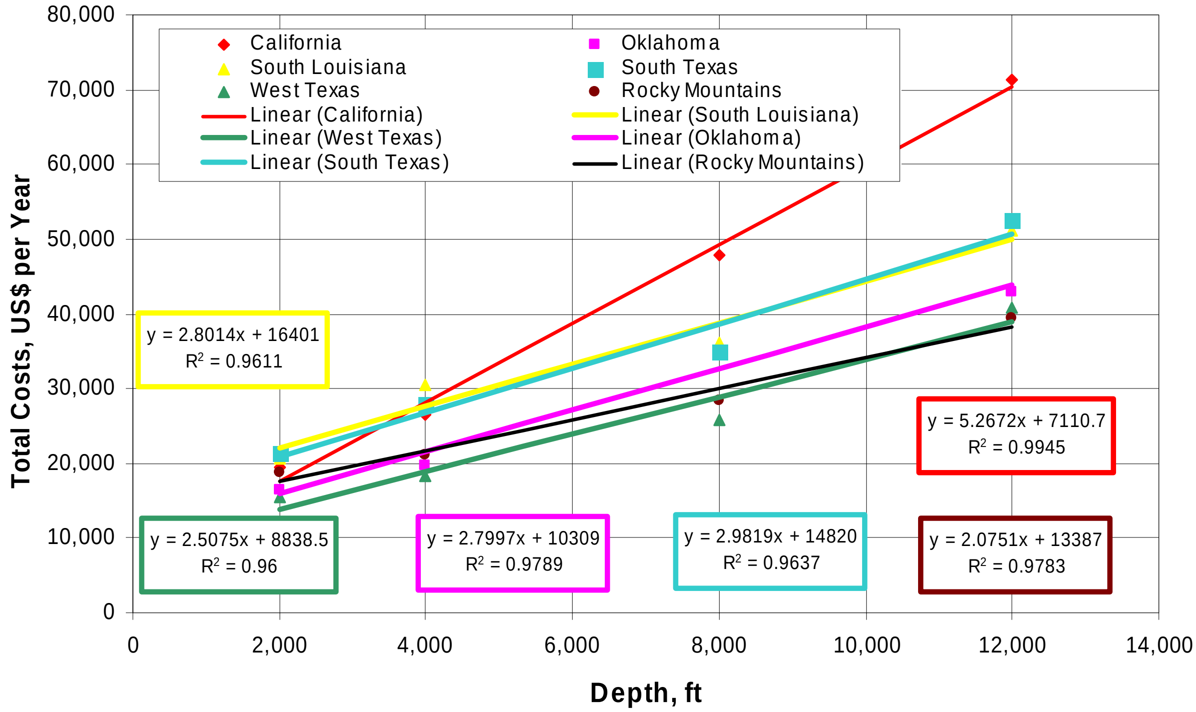


Table D-1. Regional Lease O&M Costs and Their Relationship to West Texas

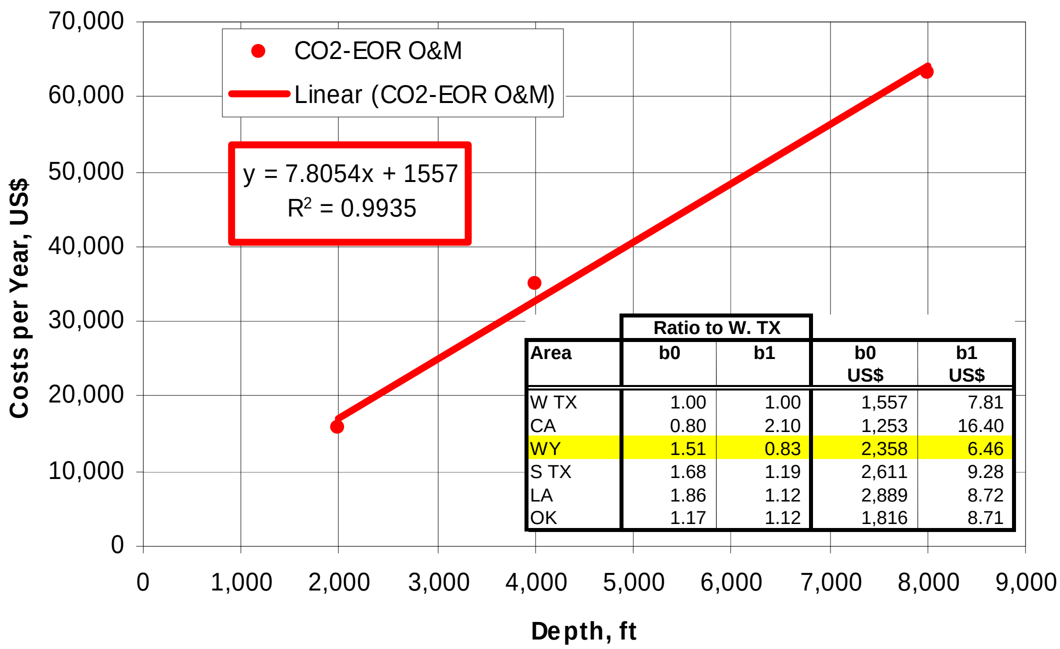
			Ratio to W. TX	
Basin	**c_0 US$**	**c_1 US$**	**c_0**	**c_1**
West Texas	8,839	2.51	1.00	1.00
California	7,111	5.27	0.80	2.10
Wyoming	13,387	2.08	1.51	0.83
South Texas	14,820	2.98	1.68	1.19
Louisiana	16,401	2.80	1.86	1.12
Oklahoma	10,309	2.80	1.17	1.12

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. These costs were adjusted to develop O&M for Wyoming, shown in the inset of Figure D-7. The equation for Wyoming is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$31,381 (fixed)
b_1 = \$6.46 per foot
D is well depth

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



Area	Ratio to W. TX b0	Ratio to W. TX b1	b0 US$	b1 US$
W TX	1.00	1.00	1,557	7.81
CA	0.80	2.10	1,253	16.40
WY	1.51	0.83	2,358	6.46
S TX	1.68	1.19	2,611	9.28
LA	1.86	1.12	2,889	8.72
OK	1.17	1.12	1,816	8.71

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 Sussex field, with 6 MMcf/d of CO_2 reinjection, will require a recycling plant costing \$4 million. A large project in the Steamboat Butte field, with 54 MMcf/d of peak CO_2 reinjection, requires a recycling plant costing \$38 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 Wyoming 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. Wyoming charges a 6% severance tax on all oil production. Ad valorum taxes vary by county and an average rate of 6% is used in the model. Severance and ad valorum taxes are charged after royalty payments are made.

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 Wyoming (-$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 Wyoming is:

Wellhead Oil Price = Oil Price + (-$0.00) – [$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 Wyoming 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.