BASIN ORIENTED STRATEGIES FOR CO_2 ENHANCED OIL RECOVERY:

ALASKA

Prepared for:

U.S. Department of Energy

Office of Fossil Energy – Office of Oil and Natural Gas

Prepared by:

Advanced Resources International, Inc.

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1. SUMMARY OF FINDINGS

1.1 INTRODUCTION. The oil and gas producing regions of Alaska have nearly 45 billion barrels of oil which will be left in the ground, or "stranded", following the use of today's oil recovery practices. A major portion of this "stranded oil" is in reservoirs technically and economically amenable to enhanced oil recovery (EOR) using carbon dioxide (CO_2) injection.

This report evaluates the future oil recovery potential in the large oil fields of the North Slope and Cook Inlet regions of Alaska and the barriers that stand in the way of this potential. The report then discusses how a concerted set of "basin-oriented strategies" could help Alaska's oil production industry overcome these barriers.

1.2 ALTERNATIVE OIL RECOVERY STRATEGIES AND SCENARIOS. The report sets forth three scenarios for using CO_2-EOR to recover "stranded oil" in Alaska.

- The first scenario, entitled "State of the Art", assumes that the technology progress in CO_2-EOR, achieved in other areas, is successfully applied to the oil reservoirs of Alaska. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to Alaska's oil reservoirs. Because of limited sources of CO_2, the supply costs are high (equal to $1.25 per Mcf) and significantly hamper economic feasibility of using CO_2-EOR.

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

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

The CO_2-EOR potential of Alaska is examined using these three bounding scenarios. (A fourth scenario, called “Traditional Practices”, involving the injection of a smaller volume of CO_2, as was practiced in the 1980s, was found to be ineffective for Alaska’s oil reservoirs and thus was not further examined in this report.)

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

1. Today’s oil recovery practices will leave behind a large resource of “stranded oil” in Alaska. The original resource in Alaska’s oil reservoirs was 67 billion barrels. To date, 22 billion barrels of this original oil in-place (OOIP) has been recovered or proved. Thus, without further oil recovery methods, 45 billion barrels of Alaska’s oil resource will become “stranded”, Table 1.

Table 1. Alaska's Oil Resources and Reservoirs

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
A. Major Oil Reservoirs				
North Slope	21	62.2	20.3	41.9
Cook Inlet	13	3.1	1.3	1.8
Data Base Total	34	65.3	21.6	43.7
*B. Regional Total**	n/a	67.3	22.2	45.0

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

2. The great bulk of the "stranded oil" resource in the large oil reservoirs of Alaska is amenable to CO_2 enhanced oil recovery. To address the "stranded oil" issue, Advanced Resources assembled a database that contains 34 major Alaskan oil reservoirs, accounting for 97% of the state's estimated ultimate oil production. Of these, 32 large oil reservoirs, with 65 billion barrels of OOIP and 43 billion barrels of "stranded oil" (ROIP), were found to be favorable for CO_2-EOR, Table 2.

Table 2. Alaska's "Stranded Oil" Resource Amenable to CO_2-EOR

Region	No. of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
North Slope	19	61.4	19.9	41.5
Cook Inlet	13	3.1	1.3	1.8
TOTAL	32	64.5	21.2	43.3

3. Application of "State of the Art" miscible and immiscible CO_2-EOR would enable a significant portion of Alaska's "stranded oil" to be recovered. Of the 32 Alaskan oil reservoirs favorable for CO_2-EOR, 31 reservoirs (with 64 billion barrels OOIP) screen as being favorable for miscible CO_2-EOR. The one remaining oil reservoir (with 0.04 billion barrels OOIP) screens as being favorable for immiscible CO_2-EOR. The total technically recoverable resources from applying CO_2-EOR in these 32 oil reservoirs is 12 billion barrels, Table 3.

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

	Miscible		Immiscible	
Region	No. of Reservoirs	Technically Recoverable (MMBbls)	No. of Reservoirs	Technically Recoverable (MMBbls)
North Slope	19	11,370	0	-
Cook Inlet	12	670	1	4
TOTAL	31	12,040	1	4

4. "State of the Art" CO_2 flooding technology, by itself, is insufficient to enable Alaska's "stranded oil" to become economically recoverable. Even though advanced application of miscible CO_2-EOR technology would enable 12 billion barrels of "stranded oil" to become technically recoverable from the North Slope and Cook Inlet regions, numerous barriers constrain economic feasibility at world oil prices of $25 per barrel, as adjusted for gravity and location, and the current high costs for CO_2 (established as a percentage of oil price at $1.25 per Mcf). These constraints include the high transportation and gravity differential penalties incurred by Alaska's crude oil.

5. However, combining "State of the Art" CO_2-EOR technology with "risk mitigation" actions and lower CO_2 costs would enable nearly 8 billion barrels of Alaska's "stranded oil" to become economically recoverable. With "State of the Art" CO_2-EOR technology (higher oil recovery efficiency) and "risk mitigation" action (an equivalent of adding $10 per barrel to the marker WTI oil price), 7.3 billion barrels of "stranded oil" would become economically recoverable from Alaska's large oil reservoirs. Providing lower cost CO_2 supplies (from a large transportation system and incentives for CO_2 capture), estimated at $0.70 per Mcf, would enable the economic potential to increase to 7.7 billion barrels, shown in Figure 1 and Table 5.

Table 5. Economically Recoverable Resources Under Alternative Scenarios

Basin	Scenario #2: "State of the Art" (Moderate Oil Price/ High CO_2 Cost*) (MMBbls)	Scenario #3: "Risk Mitigation" (High Oil Price/ High CO_2 Cost**) (MMBbls)	Scenario #4: "Ample Supplies of CO_2" High Oil Price/ Low CO_2 Cost*** (MMBbls)
North Slope	-	7,280	7,600
Cook Inlet	-	-	140
TOTAL	-	7,280	7,740

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

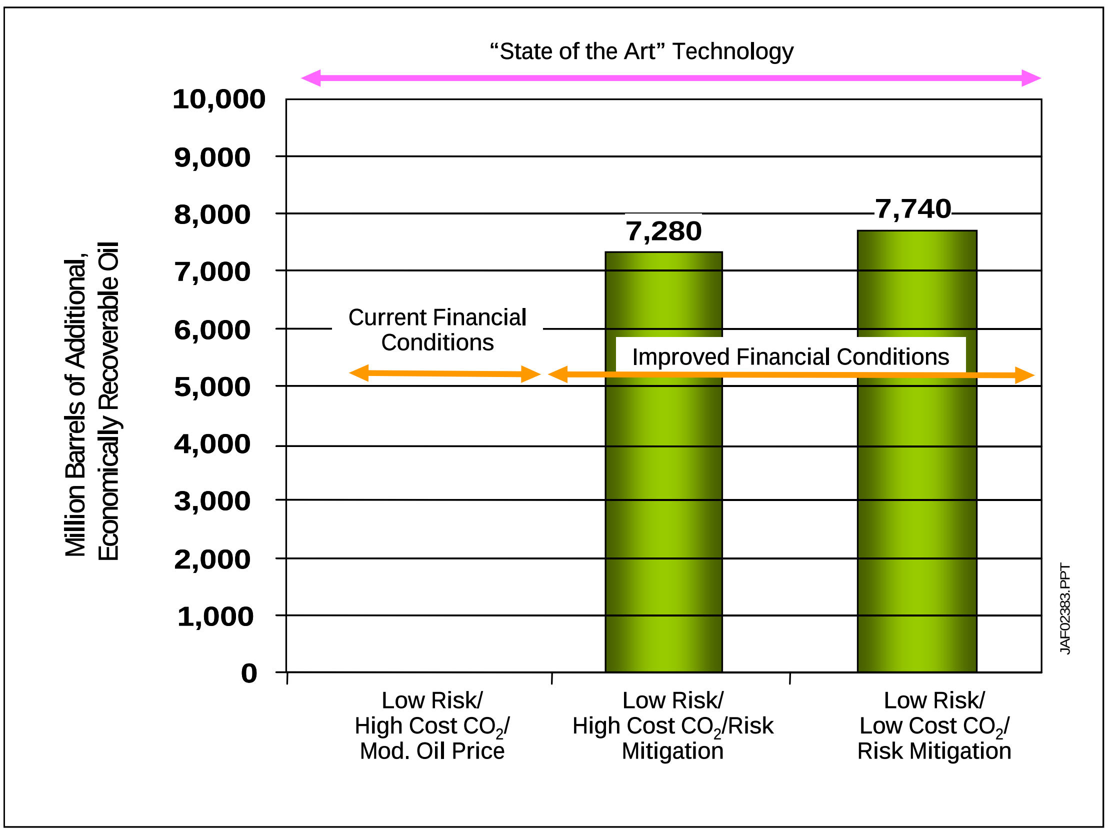

Figure 1. Impact of Improved Technology and Financial Conditions on Economically Recoverable Oil from the Alaska's Major Reservoirs Using CO_2-EOR (Million Barrels).

6. Once the results from the study's large oil reservoirs database are extrapolated to the state as a whole, the technically recoverable CO_2-EOR potential for Alaska is estimated at 12 billion barrels. The large Alaskan oil reservoirs examined by the study account for 97% of the region's oil resource. Extrapolating the 12.1 billion barrels of technically recoverable EOR potential in these 34 oil reservoirs to the total Alaskan oil resource provides an estimate of 12.4 billion barrels of technical CO_2-EOR potential. (However, no extrapolation of economic potential has been estimated, as the development costs of the 34 large Alaskan oil fields may not reflect the development costs for the smaller oil reservoirs in the region.)

7. The ultimate additional oil recovery potential from applying CO_2-EOR in Alaska will, most likely, prove to be higher than defined by this study. Introduction of more "advanced" CO_2-EOR technologies still in the research or field demonstration stage, such as gravity stable CO_2 injection, horizontal or multi-lateral wells and CO_2 miscibility control agents, could significantly increase recoverable oil volumes while expanding the state's geologic storage capacity for CO_2 emissions. The benefits and impacts of using "advanced" CO_2-EOR technology on Alaskan oil reservoirs will be examined in a subsequent study.

8. Large volumes of CO_2 supplies will be required in Alaska to achieve the CO_2-EOR potential defined by this study. The overall market for purchased CO_2 could be nearly 26 Tcf, plus another 82 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 (for example, fuel usage is estimated to liberate approximately 250 Bcf/year of CO_2 on the North Slope) applying CO_2-EOR to Alaska's oil reservoirs would enable over a billion tons of CO_2 emissions to be stored, greatly reducing greenhouse gas emissions. Advanced CO_2-EOR flooding and CO_2 storage concepts (plus incentives for storing CO_2) could double this amount.

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

Region	No. of Reservoirs	Economically Recoverable* (MMBbls)	Purchased CO_2 (Bcf)	Recycled CO_2 (Bcf)
North Slope	6	7,600	25,100	80,100
Cook Inlet	2	140	600	1,700
TOTAL	8	7,740	25,700	81,800

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

9. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in Alaska'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 Alaska's complex oil fields, and the considerable market and oil price risk - - all argue that a partnership involving the oil production industry, potential CO_2 suppliers and transporters, the Alaska state government and the Federal Government will be needed to overcome these barriers.

10. Many entities will share in the benefits of increased CO_2-EOR based oil production in Alaska. Successful introduction and wide-scale use of CO_2-EOR in Alaska will stimulate increased economic activity, provide new higher paying jobs, and lead to higher tax revenues for the state. It will help revive a declining domestic oil production and service industry.

1.4 ACKNOWLEDGEMENTS. Advanced Resources would like to acknowledge the most valuable assistance provided to the study by a series of individuals and organizations in Alaska. As such, we would like to acknowledge the Division of Oil and Gas, Alaska Department of Natural Resources and the State of Alaska Oil and Gas Conservation Commission for providing to the public much of the data necessary to complete this study. Reservoir specific characteristics as well as production and reserves data were readily available from their easy to use internet portals. It is our

hope that other states develop their data dissemination system using Alaska as a model.

Additionally, we would like to recognize the efforts of Mr. Brent Sheets of the Arctic Energy Office of DOE/FE and Dr. Charles Thomas and Mr. David Faulder of Science Applications International Corporation for their insightful advice and for providing the data to “fill in” our input data files.

2. INTRODUCTION

2.1 CURRENT SITUATION. Oil production from the North Slope is mature and in decline. Recently developed fields, such as Northstar, have somewhat lessened this rate of decline. Future oil production from fields at Pt. Thompson and the National Petroleum Reserve could also help stabilize oil production from this area in the near-term. However, the peak of oil production from the North Slope appears to be in the past.

A similar story applies to oil field development in the Cook Inlet, south of Anchorage, AK. Oil-producing fields here have been on decline since the mid-1970s, although the decline has slowed during the past 15 years. However, for the longer term, the Alaska DNR expects Cook Inlet production to again decline once their fields become mature.

Primary and secondary recovery operations are nearing completion in many Alaskan oil fields. In several fields, tertiary oil recovery operations using hydrocarbon miscible flooding are currently being planned or are in operation. Thus, stemming the decline in oil production will be a major challenge, will require a coordinated set of actions by numerous parties who have a stake in this problem - - Alaskan state revenue and economic development officials; private, state and Federal royalty owners; the Alaskan 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 or potentially stopping the decline in Alaska’s oil production.

This report, “Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska,” provides information on the size of the technical and economic potential for CO_2-EOR in the North Slope and Cook Inlet oil producing regions of Alaska. 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 these regions of Alaska.

2.2 BACKGROUND. Alaska, particularly the North Slope, has been one of single most important oil-producing provinces in the United States for the past 30 years. Cook Inlet oil production has been small but non-trivial since the late 1950s. On the North Slope, Prudhoe was responsible for reducing the decline of U.S. oil production in the early 1980s.

In 1988, North Slope oil production began to decline from its peak of approximately 2.1 million barrels per day. Although development in nearby areas, such as the Kuparuk River and Colville River units, have helped to slow the production decline of North Slope oil, Alaskan reserves and production have dipped to 7,520 million barrels and production has declined to below one million barrels per day. However, many light oil reservoirs on the North Slope and in the Cook Inlet are ideal candidates for miscible carbon-dioxide based enhanced oil recovery (CO_2-EOR).

Alaskan oil producing regions and the concentration of its major oil fields are shown in Figures 2A and 2B.

Figure 2A. Oil and Gas Fields of the Cook Inlet Region, Alaska

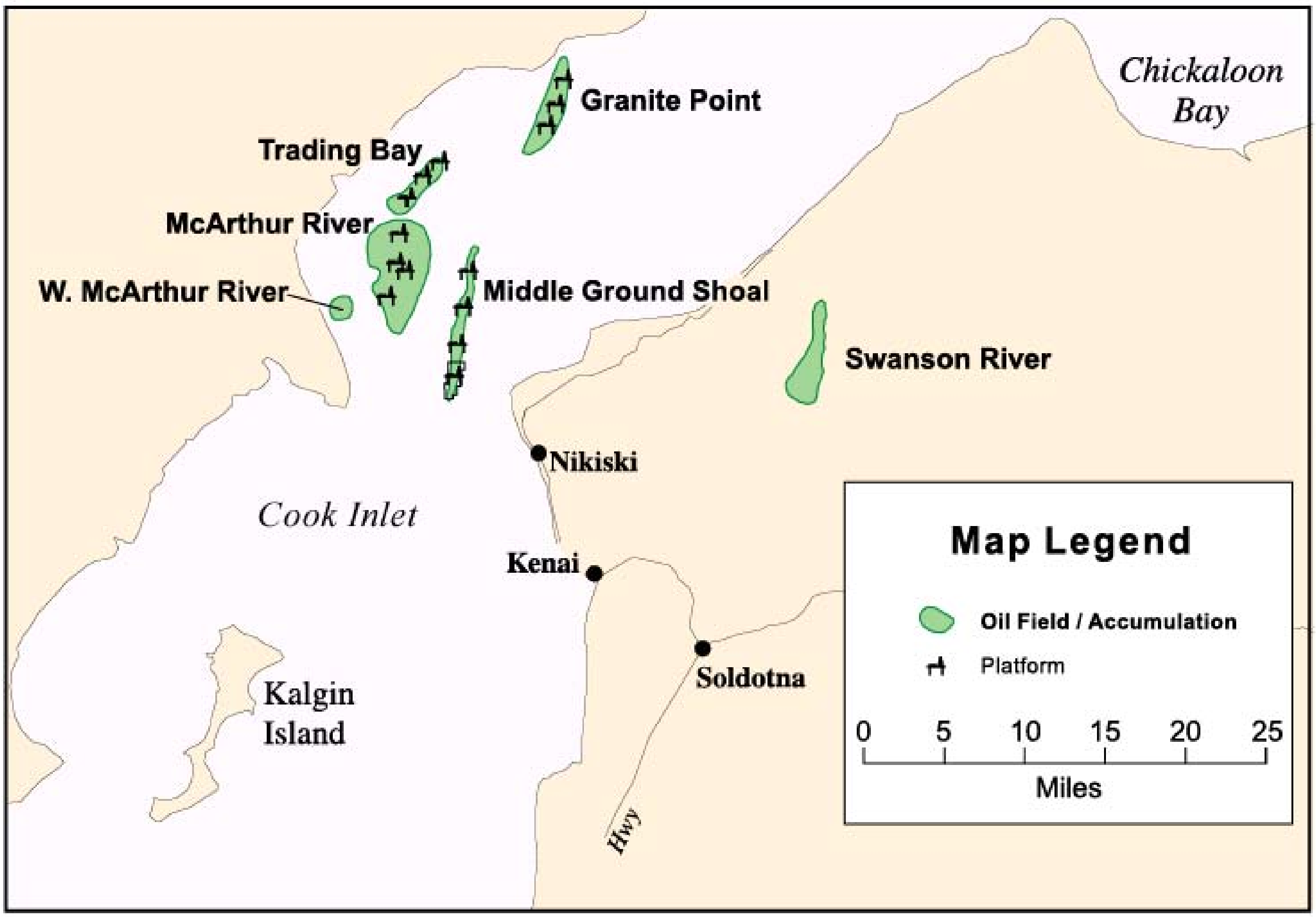

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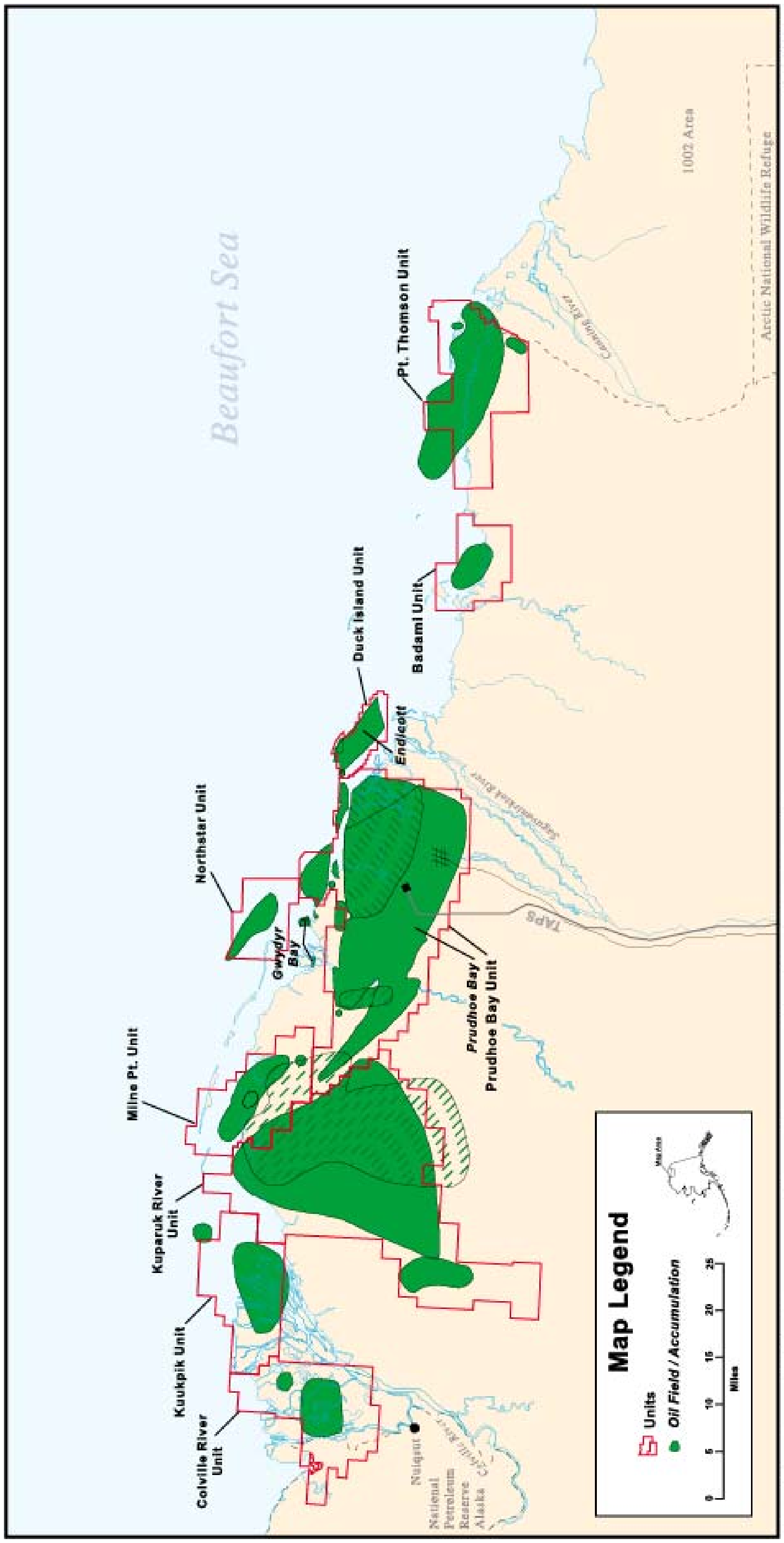
Figure 2B. Oil and Gas Fields of the North Slope, Alaska



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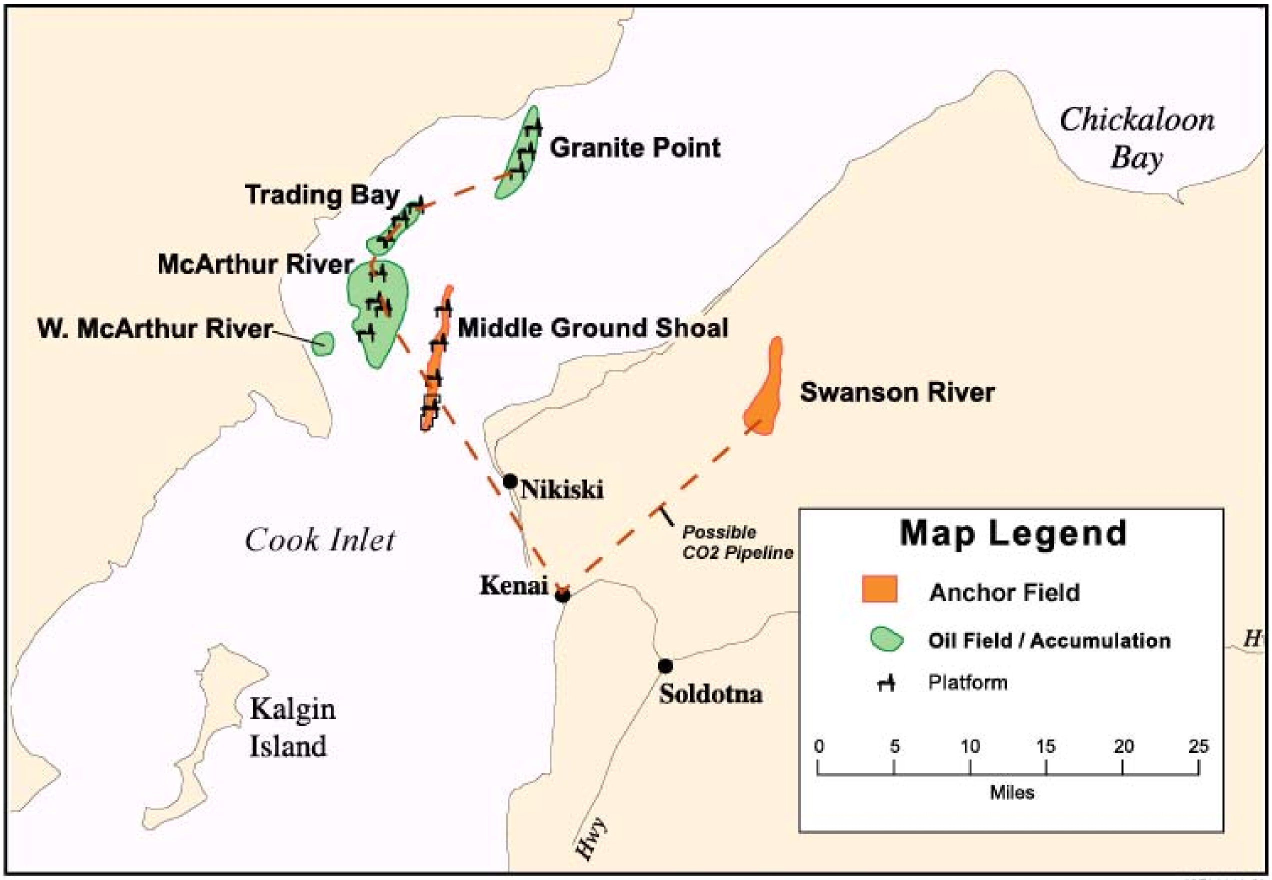
2.3 PURPOSE. This report, "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska" is part of a larger effort to examine the enhanced oil recovery and CO_2 storage potential in key U.S. oil basins. Previous reports addressed the oil fields of California and the Gulf Coast. Subsequent reports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

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

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

2.4 KEY ASSUMPTIONS. For purposes of this study, it is assumed that sufficient supplies of CO_2 will be available from natural deposits (although there are no known natural Alaskan CO_2 deposits), from industrial sources, or from power plants. For North Slope projects, the sources will include the natural CO_2 currently being injected, and for the Cook Inlet projects, CO_2 could be derived from power plants in the Anchorage area or from Tesoro's Kenai refinery (with CO_2 production estimated at 5 MMcfd), Figure 3 (No warranties have been made as to the availability of pipeline right-of-ways due to environmental and/or landowner constraints). The timing of this availability assumes that this CO_2 will be delivered in the near future, as forecasting field life is not an aspect of this study.

Figure 3. Alaska Oil Refineries and Large Oil Fields



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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 North Slope and Cook Inlet oil regions, using advanced oil recovery technology practices:

"State of the Art" Technology. This involves bringing to Alaska the benefits of recent gains in understanding of the CO_2-EOR process and how best to customize its application to the many different types of oil reservoirs in the region. As further discussed below, moderately deep, light oil reservoirs are selected for miscible CO_2-EOR and the shallower light oil and the heavier oil reservoirs are targeted for immiscible CO_2-EOR. "State of the Art" technology entails injecting much larger volumes of CO_2, on the order of 1 HCPV, with considerable CO_2 recycling.

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

1. *Favorable Light Oil Reservoirs Meeting Stringent CO_2 Miscible Flooding Criteria*. These are the moderately deep, higher gravity oil reservoirs where CO_2 becomes miscible (after extraction of light hydrocarbon components into the CO_2 phase) with the oil remaining in the reservoir. Typically, reservoirs at depths greater than 3,000 feet and with oil gravities greater than 25^o API would be selected for miscible CO_2-EOR. Major Alaska light oil fields such as the North Slope's Prudhoe and Kuparuk and the Cook Inlet's McArthur River fields 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 heavy oil Tyonek pool in the Cook Inlet's Trading Bay field. Portions of the supergiant Schrader Bluff pools in the West Sak and Milne Point fields may also be amenable to immiscible CO_2.

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

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

CO_2-EOR Technology Selection	Oil Reservoir Selection
"State of the Art"; Miscible CO_2-EOR	▪ Deep, Light Oil Reservoirs
"State of the Art"; Immiscible CO_2-EOR	▪ 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 CO2-EOR in Alaska's major oil reservoirs. Because of confidentiality and proprietary issues, the results of the study have been aggregated for the two producing areas within Alaska. 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 results reported in this study..

3. OVERVIEW OF ALASKAN OIL PRODUCTION

3.1 HISTORY OF OIL PRODUCTION. Oil production from Alaska began in 1958 with the Swanson River Field in the Cook Inlet, south of Anchorage, and production in this area peaked in 1970 at 220,000 barrels per day. Subsequently, Alaskan oil production entered a new peak with the discoveries at Prudhoe Bay (1969) and the completion of the Trans Alaska Pipeline in 1977. In 1978, the first full year of production after pipeline completion, the North Slope produced 1.1 million barrels per day. North Slope production increased through 1988, peaking at 2.1 million per day, Figure 4. Production has declined since, although, with the recent development of fields at Colville River and at Northstar, production has leveled off, averaging about 1 million barrels per day in the period 2000-2002.

In 2002, Alaska ranked second in oil production in the U.S., producing 361 MMBbls of oil (989 MBbls/day) from over 1,800 producing wells, and was second in reserves at 7,520 MMBbls.

- Production from Alaska's Prudhoe Bay and Kuparuk River fields, the 1st and 3rd largest fields in the U.S., respectively, has been declining for over 12 years.
- North Slope oil reserves have been declining steadily since 1987 (at an average of 3% per year)
- New developments in the National Petroleum Reserve-Alaska and at Point Thompson are expected to help hold North Slope production steady through 2008. Production is expected to drop thereafter by 5% per year.

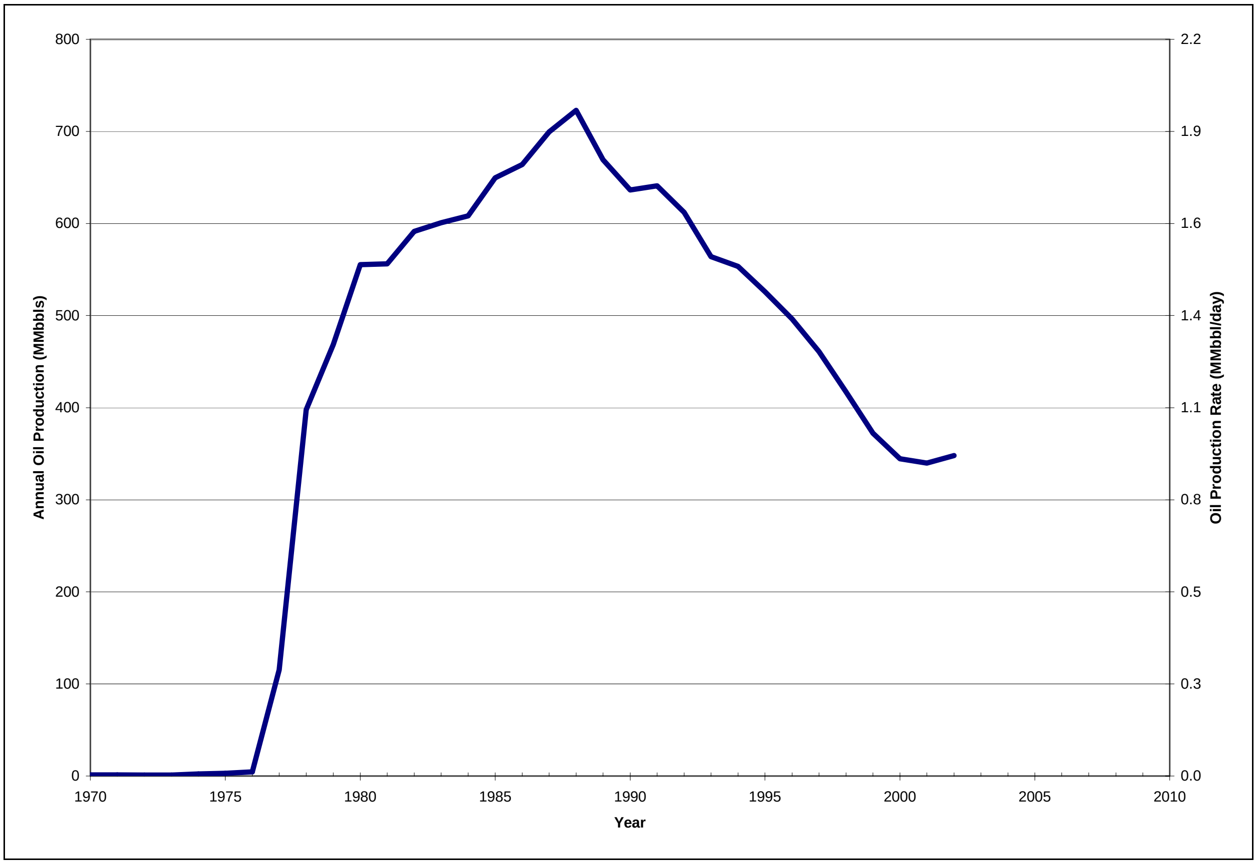


Figure 4. History of North Slope Alaska Oil Production, 1977-2002.

However, Alaska's developed fields still hold a rich resource of oil in the ground. With more than 67 billion barrels of original oil in-place (OOIP) and approximately 22 billion barrels expected to be recovered, about 45 billion barrels of oil will be "stranded" due to lack of technology, lack of sufficient, affordable CO_2 supplies and high economic and technical risk.

Table 7 presents the status and latest annual oil production for the major North Slope fields. The table shows that four fields, accounting for over 72% of 2002 oil production, are in steep production decline. Arresting this decline in the North Slope's oil production could be attained by applying enhanced oil recovery technology, particularly CO_2-EOR.

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

Major Oil Fields	2000	2001	2002	Production Status
Prudhoe Bay	187.1	166.7	151.0	Declining
Kuparuk River	74.1	68.3	58.9	Declining
Colville River	2.2	28.7	35.0	Increasing
Pt. McIntyre	23.7	18.1	14.7	Declining
Milne Point	19.1	19.3	18.7	Stable
Kuparuk River Satellites	12.2	11.5	18.5	Increasing
Northstar	0	1.3	17.9	Increasing
Prudhoe Bay Satellites	13.1	15.0	23.8	Increasing
Duck Island Unit	12.0	10.4	9.1	Declining

3.2 EXPERIENCE WITH IMPROVED OIL RECOVERY. Alaska's oil producers are familiar with using technology for improving oil recovery. For example, a large number of North Slope oil fields are currently undergoing some form of enhanced recovery project, including hydrocarbon miscible and immiscible flooding. They are Prudhoe Bay, Kuparak River, Tarn and Alpine. Planned projects are slated for Aurora, Borealis, Orion and Polaris oil fields.

3.3 THE "STRANDED OIL" PRIZE. Even though Alaska's (and in particular, the North Slope's) oil production is declining, this does not mean that the resource base is depleted. The North Slope fields still contain over 60% of their OOIP after primary and secondary oil recovery (Cook Inlet fields contain ~54% OOIP after primary and secondary recovery). This large volume of remaining oil in-place (ROIP) is the "prize" for CO_2-EOR.

Table 8 provides information (as of year 2002) on the oil production history and remaining oil in place for 13 Alaskan oil fields, each with estimated ultimate recovery of 150 million barrels or more. Of particular note are the giant light oil fields that may be attractive for miscible CO_2-EOR, including: Prudhoe Bay with 16,443 million barrels of ROIP, Kuparuk River with 3,533 million barrels of ROIP and McArthur River with 842 million barrels of ROIP.

Table 8. Selected Major Oil Fields of Alaska

	Field/State	Year Discovered	Cumulative Production (MMbbl)	Estimated Reserves** (MMbbl)	Remaining Oil In-Place (MMbbl)
1	Prudhoe Bay	1967	10,699	3,024	16,443
2	Kuparuk River	1969	1,859	1,031	3,533
3	Colville River	1966	66	431	503
4	Pt. McIntyre	1988	349	154	755
5	Milne Point	1969	182	503	892
6	Kuparuk River Satellites*	---	60	470	17,496
7	Northstar	1984	19	191	257
8	Prudhoe Bay Satellites	---	234	562	1,281
9	Duck Island Unit	1978	421	162	718
10	McArthur River	1965	611	46	842
11	Granite Point	1965	139	12	264
12	Middle Ground Shoal	1962	189	15	243
13	Swanson River	1957	228	4	207

***includes the 17.5 billion barrel West Sak Oil Field**

****Alaska Oil and Gas Conservation Commission Annual Report 2003**

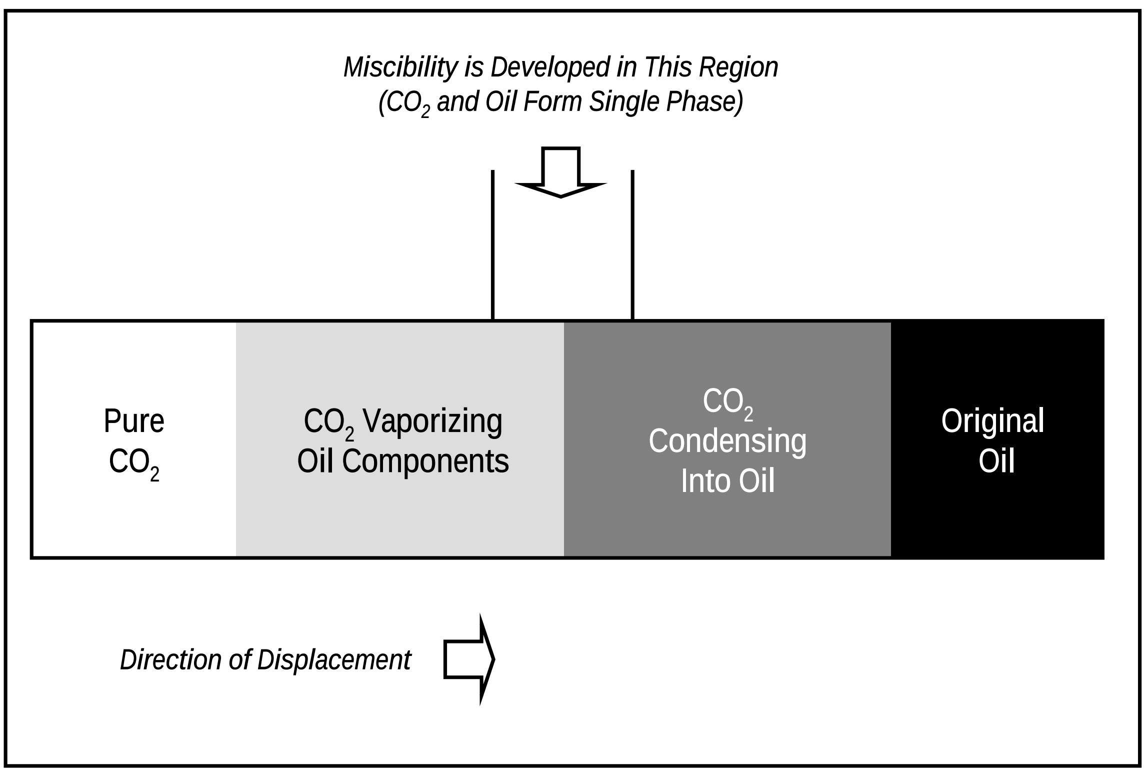
3.4 REVIEW OF PRIOR STUDIES. No recent studies of the potential for CO_2 enhanced oil recovery in Alaskan oil reservoirs have been conducted since the National Petroleum Council's efforts in 1984 and 1976. The results of the studies were reported for the United States as a whole and do not contain results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

4. MECHANISMS OF CO_2-EOR

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

The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the after waterflooding residual oil saturation in the reservoir's pore space. Figure 5 provides a one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO_2 miscible process.

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



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4.2 MECHANISMS OF IMMISCIBLE CO_2-EOR. When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected CO_2 will not become miscible 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^oAPI) 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 t hat of either methane or nitrogen. Densities were calculated with an equation of state (EOS).

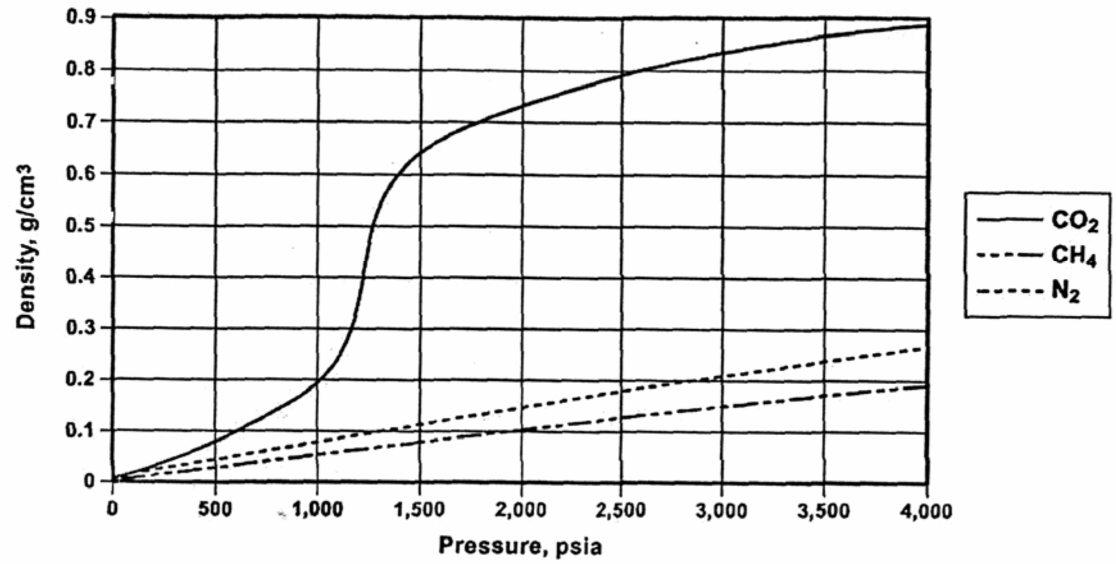

Figure 6B. Carbon Dioxide, CH_4 and N_2 viscosities at 105^0F. At high pressures, the viscosity of CO_2 is also greater then that of methane or nitrogen, although it r emains low in comparison to that of liquids. Viscosities were calculat ed with an EOS.

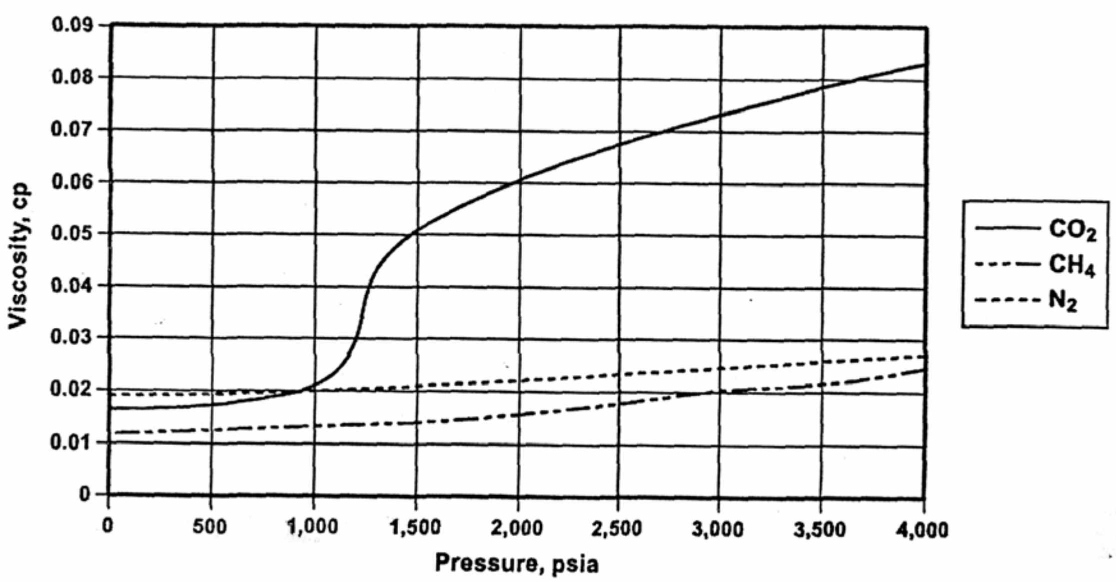

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Figure 7A. Relative Oil Volume vs. Pressure for a Light West Texas Reservoir Fluid. (Holm and Josendal)

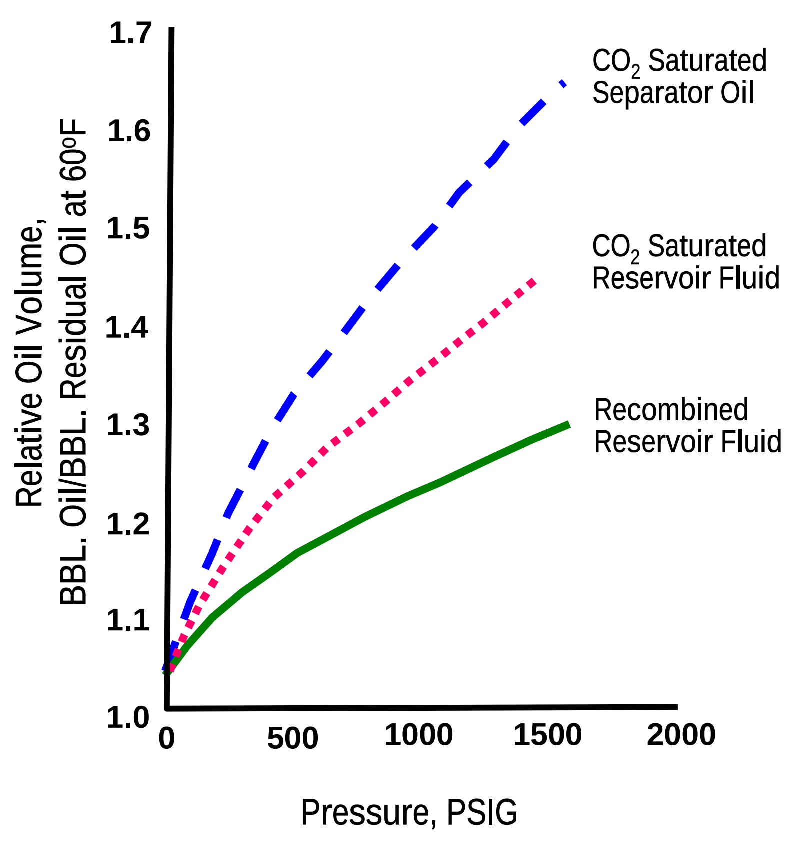


Figure 7B. Oil Swelling Factor vs. Pressure for a Heavy Oil in Turkey (Issever and Topkoya).

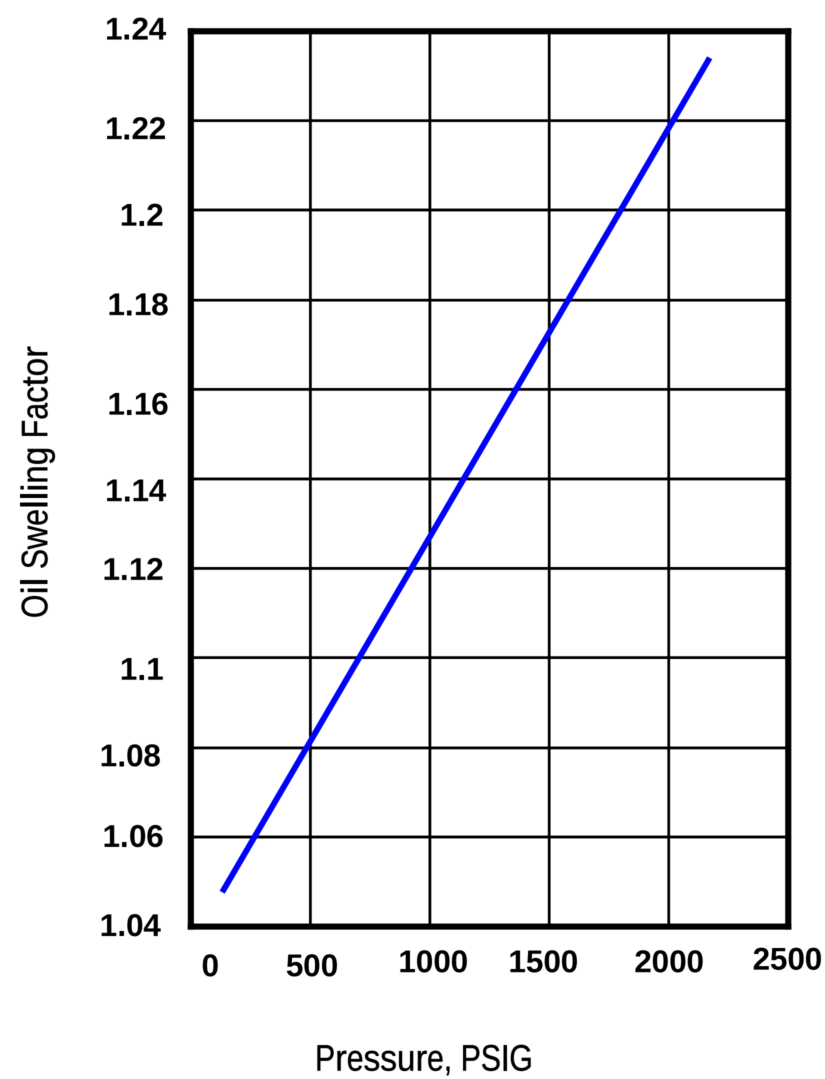
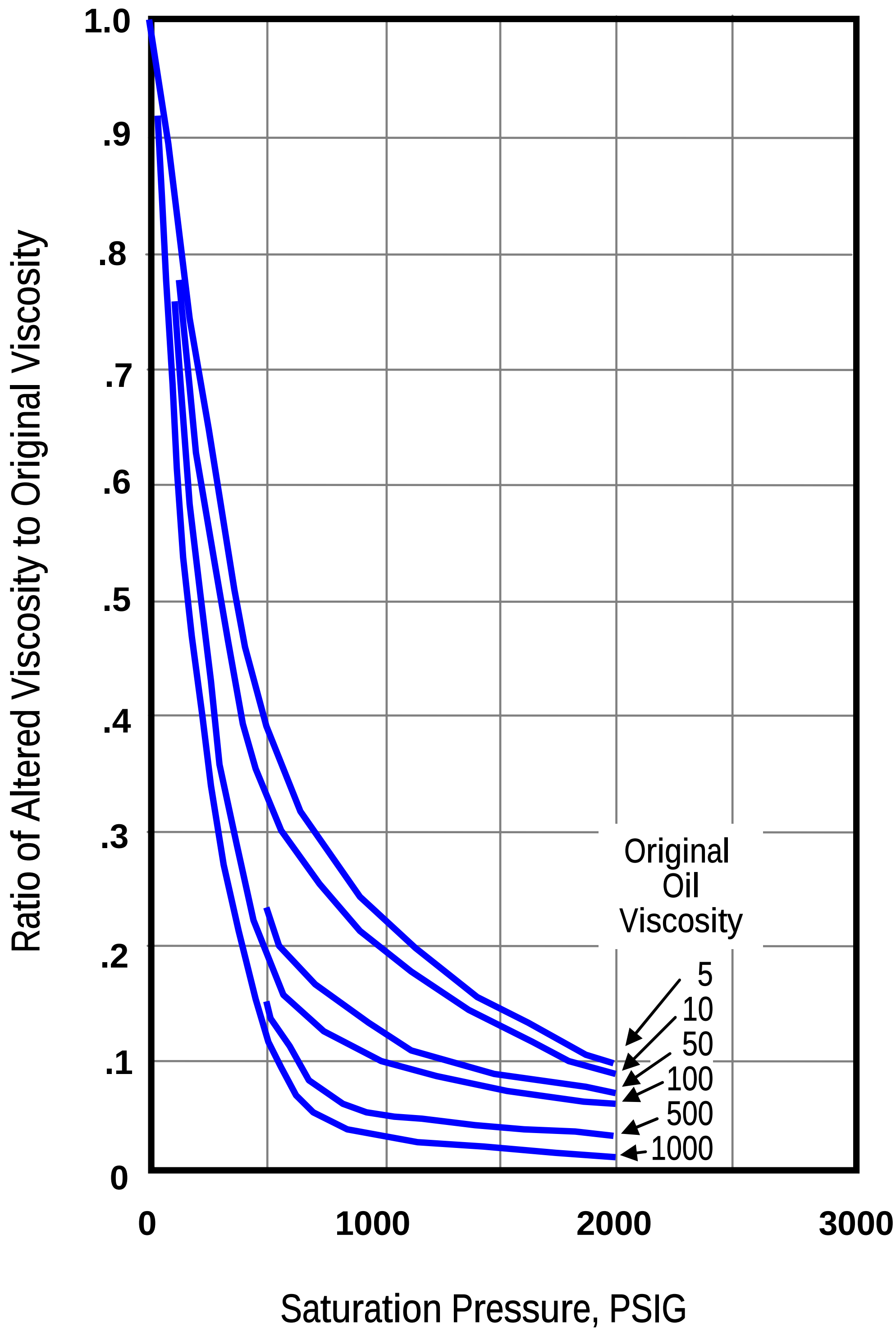


Figure 8. Viscosity Reduction Versus Saturation Pressure. (Simon and Graue)



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5. STUDY METHODOLOGY

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

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

5.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE. The study started with the National Petroleum Council (NPC) Public Data Base, maintained by DOE Fossil Energy. This study updated and modified this publicly accessible data base to develop the Alaskan Major Oil Reservoirs Data Base for North Slope and Cook Inlet oil fields.

Table 9 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the CO_2-EOR screening and oil recovery models, discussed below. Overall, the Alaska Major Oil Reservoirs Data Base contains 34 reservoirs, accounting for 97% of the oil expected to be ultimately produced in current Alaskan fields by primary and secondary oil recovery processes.

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

Basin Name

Field Name

Reservoir

Reservoir Parameters:

- Area (A)
- Net Pay (ft)
- Depth (ft)
- Porosity
- Reservoir Temp (deg F)
- Initial Pressure (psi)
- Pressure (psi)

- B_{oi}
- B_o @ S_o, swept
- S_{oi}
- S_{or}
- Swept Zone S_o
- S_{wi}
- S_w

- API Gravity
- Viscosity (cp)

- Dykstra-Parsons

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Oil Production

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

Water Production

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

Injection

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

Volumes

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

OOIP Volume Check

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

SROIP Volume Check

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

ROIP Volume Check

- ROIP Check (MMbl)

Considerable effort was required to construct an up-to-date, volumetrically consistent data base that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place in Alaskan fields; (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 EOR program) the essential input data for calculating CO_2 injection requirements and oil recovery.

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

The preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet, at the mid-point of the reservoir, was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5^o API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection. Table 10 tabulates the oil reservoirs that passed the preliminary screening step. Many of these fields contain multiple reservoirs, with each reservoir holding a great number of stacked sands. Because of data limitations, this screening study combined the sands into a single reservoir.

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

Basin	Field	Formation
A. North Slope		
	PRUDHOE - PBU	SAG RIVER SHUBLIK IVISHAK
	POINT MCINTYRE-PBU	KUPARUK RIVER
	NIAKUK-PBU	KUPARUK RIVER
	WEST BEACH TERTIARY-PBU	KUPARUK RIVER
	LISBURNE-PBU	WAHOO ALAPAH
	MIDNIGHT SUN-PBU	KUPARUK RIVER
	AURORA-PBU	KUPARUK RIVER
	BOREALIS-PBU	KUPARUK RIVER
	POLARIS-PBU	SCHRADER BLUFF
	WEST SAK - KUPARUK RIVER UNIT	SCHRADER BLUFF
	KUPARUK - KUPARUK RIVER UNIT	KUPARUK RIVER
	TARN - KUPARUK RIVER UNIT	SEABEE
	MELTWATER - KUPARUK RIVER UNIT	SEABEE
	MILNE POINT - MILNE POINT UNIT	KUPARUK RIVER
	SCHRADER BLUFF - MILNE POINT UNIT	SCHRADER BLUFF
	BADAMI UNIT	BADAMI SANDS
	COLVILLE RIVER UNIT	ALPINE
	NORTHSTAR UNIT	IVISHAK
	ENDICOTT - DUCK ISLAND UNIT	KEKIKTUK
	ENDICOTT - DUCK ISLAND UNIT	EIDER
B. Cook Inlet		
	GRANITE POINT	MIDDLE KENAI
	MCARTHUR RIVER	HEMLOCK
	MCARTHUR RIVER	TYONEK MIDDLE KENAI G ZONE
	MCARTHUR RIVER	WEST FORELAND
	MIDDLE GROUND SHOAL	TVONEK-HEMLOCK E,F,& G
	SWANSON RIVER	HEMLOCK
	MIDDLE GROUND SHOAL	A TYONEK
	MIDDLE GROUND SHOAL	BCD TYONEK
	BEAVER CREEK	TYONEK HEMLOCK CONGLOMERATE
	KATALLA	KATALLA-BURLS CREEK MBR
	REDOUBT SHOALS	HEMLOCK CONGLOMERATE
	TRADING BAY	B TYONEK MIDDLE KENAI
	TRADING BAY	C TYONEK MIDDLE KENAI
	TRADING BAY	D TYONEK MIDDLE KENAI
	TRADING BAY	E TYONEK MIDDLE KENAI
	TRADING BAY	HEMLOCK

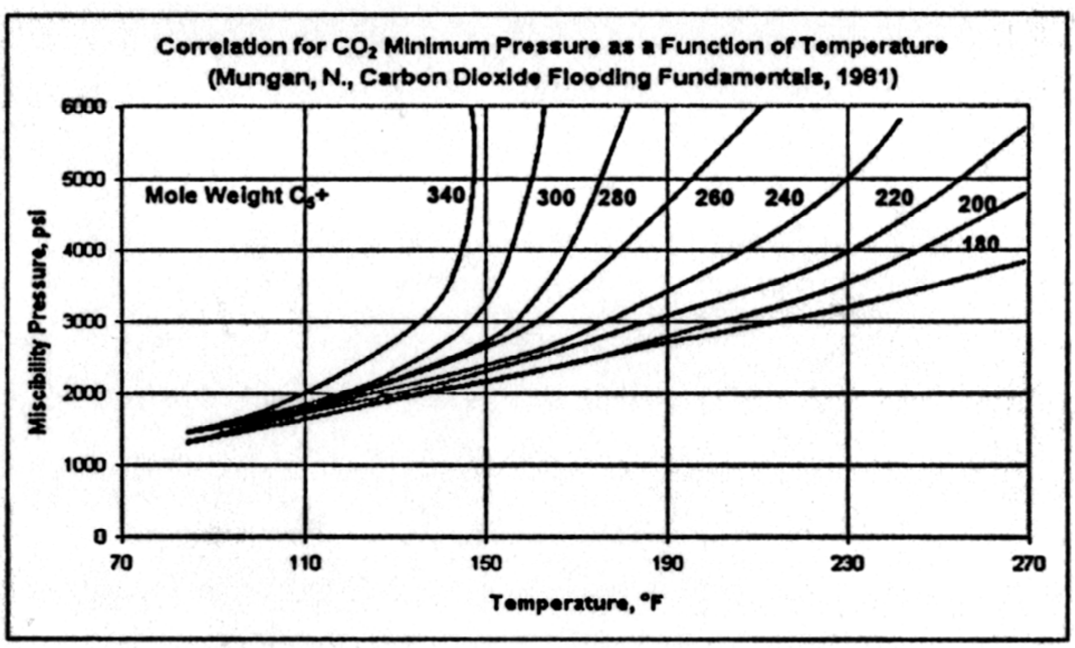
5.4 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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. The Cronquist correlation is set forth below:

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

Where: T is Temperature in ^oF, MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil, and MPC1 is the mole percent of methane and nitrogen in the reservoir.

Figure 9. Estimating CO_2 Minimum Miscibility Pressure



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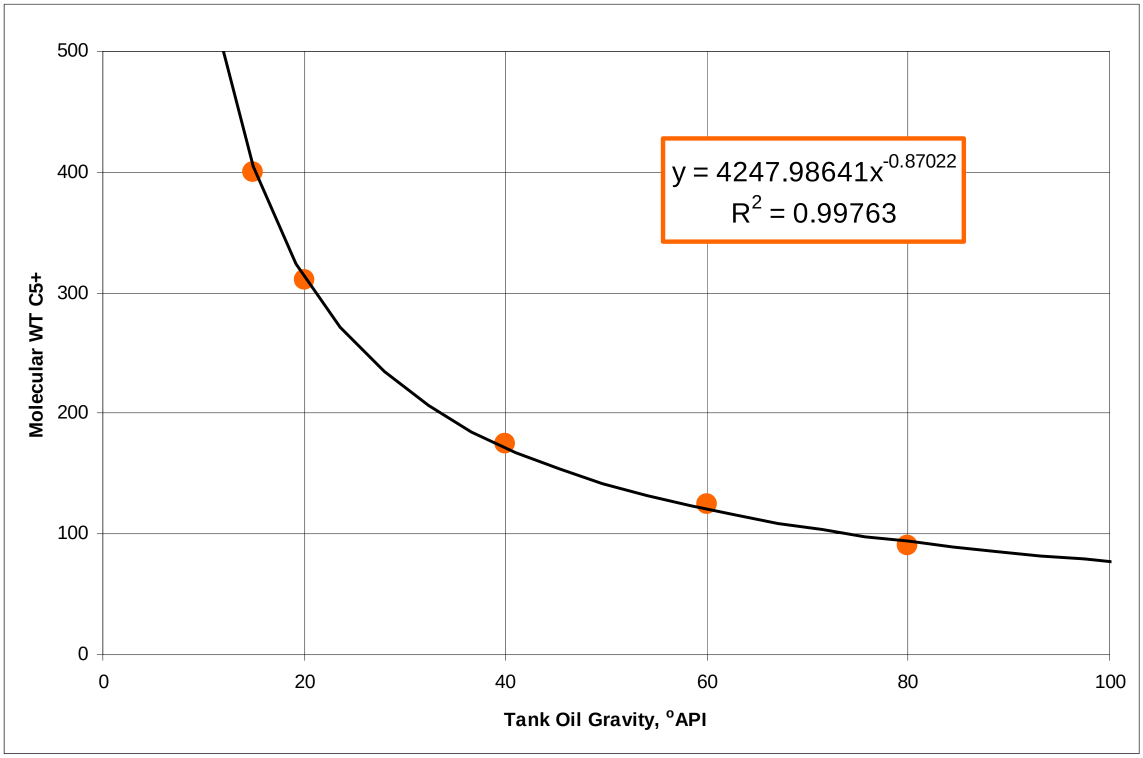
The temperature of the reservoir was taken from the data base or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was obtained from the data base or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 10.

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

Figure 10. Correlation of MW C5+ to Tank Oil Gravity



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5.5 CALCULATING OIL RECOVERY. The study utilized *CO_2-PROPHET* to calculate incremental oil produced using CO_2-EOR. *CO_2-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) as part of the DOE Class I EOR 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 cost options are available to the model user. (Appendices B, C and D provide state-level details on the Cost Model for CO_2-EOR prepared by this study.)

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

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

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

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

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

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

- The first scenario, entitled "State of the Art", assumes that the technology progress in CO_2-EOR, achieved in other areas, is successfully applied to the oil reservoirs of Alaska. In addition, a comprehensive set of research, pilot tests and field demonstrations help lower the risk inherent in applying new technology to these complex oil reservoirs. However, because of limited sources of CO_2, these supply costs are high (equal to $1.25 per Mcf) the oil price) and significantly hamper economic feasibility of using CO_2-EOR.

- The second scenario, entitled "Risk Mitigation," examines how the economic potential of CO_2-EOR could be increased through a strategy involving state production tax reductions, increased federal investment tax credits, and Federal/state royalty relief (on Federal/state lands) that together would add an equivalent of $10 per barrel to the marker (WTI) price for crude oil.
- In the final scenario, entitled "Ample Supplies of CO_2," low-cost, "EOR-ready" CO_2 supplies (equal to $0.70 per Mcf) are aggregated from various sources. These include industrial high-concentration CO_2 emissions from hydrogen facilities, gas processing plants and other industrial sources. These would be augmented, in the longer-term, from low CO_2 concentration sources including combustion and electric generation plants. Capture of industrial CO_2 emissions would be part of national efforts for reducing greenhouse gas emissions.

Table 11. Economic Model Established by the Study

Pattern-Level Cashflow Model		Advanced											
State	**AK**												
Field				New Injectors	0.72			9					
Formation				Existing Injectors	0.28								
Depth				Convertable Producers	0.00								
Distance from Trunkline (mi)				New Producers	0.7								
# of Patterns				Existing Producers	0.52								
Miscibility:	**Miscible**												
	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
CO2 Injection (MMcf)			1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,642	1,640	1,640
H2O Injection (Mbw)			457	457	457	457	457	457	457	457	549	550	550
Oil Production (Mbbl)			-	25	316	219	178	181	151	116	104	94	114
H2O Production (MBw)			1,191	1,164	764	654	603	568	545	546	561	595	579
CO2 Production (MMcf)			-	0	215	747	985	1,062	1,203	1,291	1,333	1,276	1,261
CO2 Purchased (MMcf)			1,826	1,826	1,611	1,079	841	765	623	535	310	365	380
CO2 Recycled (MMcf)			-	0	215	747	985	1,062	1,203	1,291	1,333	1,276	1,261
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	35	Deg	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65
Gross Revenues ($M)			$ -	$ 669	$ 8,416	$ 5,836	$ 4,746	$ 4,834	$ 4,011	$ 3,094	$ 2,764	$ 2,510	$ 3,046
Royalty ($M)	-12.5%		$ -	$ (84)	$ (1,052)	$ (730)	$ (593)	$ (604)	$ (501)	$ (387)	$ (345)	$ (314)	$ (381)
Severance Taxes ($M)	-7.5%		$ -	$ (44)	$ (552)	$ (383)	$ (311)	$ (317)	$ (263)	$ (203)	$ (181)	$ (165)	$ (200)
Ad Valorum ($M)	-2.0%		$ -	$ (12)	$ (147)	$ (102)	$ (83)	$ (85)	$ (70)	$ (54)	$ (48)	$ (44)	$ (53)
Net Revenue($M)			$ -	$ 530	$ 6,664	$ 4,622	$ 3,759	$ 3,828	$ 3,176	$ 2,450	$ 2,188	$ 1,988	$ 2,412
Capital Costs ($M)													
New Well - D&C		$ (7,121)											
Reworks - Producers to Producers		$ (136)											
Reworks - Producers to Injectors		$ -											
Reworks - Injectors to Injectors		$ (24)											
Surface Equipment (new wells only)		$ (286)											
Recycling Plant		$ -	$ (5,707)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (22)											
Total Capital Costs		$ (7,590)	$ (5,707)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)													
Total CO2 Cost ($M)			$(2,282.9)	$ (2,283)	$ (2,068)	$ (1,536)	$ (1,298)	$ (1,221)	$ (1,080)	$ (991)	$ (720)	$ (775)	$ (790)
O&M Costs ($M)													
Operating & Maintenance ($M)	1		$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)
Lifting Costs ($/bbl)	$ 0.25		$ (298)	$ (297)	$ (270)	$ (218)	$ (195)	$ (187)	$ (174)	$ (166)	$ (166)	$ (172)	$ (173)
G&A	20%		(95)	(95)	(90)	(80)	(75)	(73)	(71)	(69)	(69)	(70)	(71)
Total O&M Costs			$ (572)	$ (572)	$ (539)	$ (477)	$ (449)	$ (440)	$ (424)	$ (414)	$ (415)	$ (422)	$ (423)
Cashflow													
Net Cash Flow ($M)		$ (7,590)	$ (8,562)	$ (2,325)	$ 4,058	$ 2,609	$ 2,011	$ 2,167	$ 1,672	$ 1,045	$ 1,054	$ 791	$ 1,199
Cum. Cash Flow		$ (7,590)	$ (16,152)	$ (18,477)	$(14,419)	$(11,810)	$ (9,799)	$ (7,632)	$ (5,959)	$(4,914)	$(3,861)	$(3,070)	$(1,871)
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21
Disc. Net Cash Flow		$ (7,590)	$ (7,445)	$ (1,758)	$ 2,668	$ 1,492	$ 1,000	$ 937	$ 629	$ 342	$ 299	$ 196	$ 258
Disc. Cum Cash Flow		$ (7,590)	$ (15,035)	$ (16,793)	$(14,125)	$(12,633)	$(11,633)	$(10,696)	$(10,068)	$(9,726)	$(9,427)	$(9,231)	$(8,973)
NPV (BTx)	25%	($10,386)											
NPV (BTx)	20%	($9,440)											
NPV (BTx)	15%	($7,948)											
NPV (BTx)	10%	($5,498)											
IRR (BTx)		3.99%											

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

Pattern-Level Cashflow Model																
State																
Field																
Formation																
Depth																
Distance from Trunkline (mi)																
# of Patterns																
Miscibility:	**Miscible**															
	Year		**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
CO2 Injection (MMcf)			1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	1,640	635	-	-	-
H2O Injection (Mbw)			550	550	550	550	550	549	550	550	550	550	1,052	1,370	734	-
Oil Production (Mbbl)			121	122	114	99	90	65	56	49	50	62	66	63	34	-
H2O Production (MBw)			560	554	551	555	548	568	568	570	566	551	593	953	597	-
CO2 Production (MMcf)			1,290	1,302	1,330	1,363	1,402	1,420	1,445	1,460	1,466	1,471	1,598	866	250	-
CO2 Purchased (MMcf)			350	339	310	277	238	221	196	180	175	169	-	-	-	-
CO2 Recycled (MMcf)			1,290	1,302	1,330	1,363	1,402	1,420	1,445	1,460	1,466	1,471	635	-	-	-
Oil Price ($/Bbl)	$	**25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ -
Gravity Adjustment		**35**	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ 26.65	$ -
Gross Revenues ($M)			$ 3,214	$ 3,257	$ 3,035	$ 2,636	$ 2,393	$ 1,740	$ 1,487	$ 1,295	$ 1,335	$ 1,639	$ 1,764	$ 1,687	$ 895	$ -
Royalty ($M)	**-12.5%**		$ (402)	$ (407)	$ (379)	$ (329)	$ (299)	$ (218)	$ (186)	$ (162)	$ (167)	$ (205)	$ (221)	$ (211)	$ (112)	$ -
Severance Taxes ($M)	**-7.5%**		$ (211)	$ (214)	$ (199)	$ (173)	$ (157)	$ (114)	$ (98)	$ (85)	$ (88)	$ (108)	$ (116)	$ (111)	$ (59)	$ -
Ad Valorum ($M)	**-2.0%**		$ (56)	$ (57)	$ (53)	$ (46)	$ (42)	$ (30)	$ (26)	$ (23)	$ (23)	$ (29)	$ (31)	$ (30)	$ (16)	$ -
Net Revenue($M)			$ 2,545	$ 2,579	$ 2,404	$ 2,087	$ 1,895	$ 1,378	$ 1,178	$ 1,026	$ 1,057	$ 1,298	$ 1,397	$ 1,336	$ 709	$ -
Capital Costs ($M)																
New Well - D&C																
Reworks - Producers to Producers																
Reworks - Producers to Injectors																
Reworks - Injectors to Injectors																
Surface Equipment (new wells only)																
Recycling Plant			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction																
Total Capital Costs			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)																
Total CO2 Cost ($M)			$ (760)	$ (749)	$ (720)	$ (687)	$ (648)	$ (631)	$ (606)	$ (590)	$ (585)	$ (579)	$ (159)	$ -	$ -	$ -
O&M Costs ($M)																
Operating & Maintenance ($M)		1	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ (179)	$ -
Lifting Costs ($/bbl)	$	**0.25**	$ (170)	$ (169)	$ (166)	$ (163)	$ (160)	$ (158)	$ (156)	$ (155)	$ (154)	$ (153)	$ (165)	$ (254)	$ (183)	$ -
G&A		**20%**	(70)	(70)	(69)	(69)	(68)	(68)	(67)	(67)	(67)	(66)	(69)	(87)	(72)	-
Total O&M Costs			$ (419)	$ (418)	$ (415)	$ (411)	$ (407)	$ (405)	$ (402)	$ (401)	$ (400)	$ (399)	$ (413)	$ (520)	$ (434)	$ -
Cashflow																
Net Cash Flow ($M)			$ 1,365	$ 1,412	$ 1,269	$ 989	$ 840	$ 342	$ 169	$ 35	$ 73	$ 320	$ 825	$ 816	$ 275	$ -
Cum. Cash Flow			$ (505)	$ 907	$ 2,176	$ 3,165	$ 4,005	$ 4,347	$ 4,517	$ 4,551	$ 4,624	$ 4,944	$ 5,769	$ 6,585	$ 6,860	$ 6,860
Discount Factor	**15%**		0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.03
Disc. Net Cash Flow			$ 255	$ 230	$ 179	$ 121	$ 90	$ 32	$ 14	$ 2	$ 4	$ 17	$ 38	$ 33	$ 10	$ -
Disc. Cum Cash Flow			$ (8,718)	$ (8,489)	$ (8,309)	$ (8,188)	$ (8,098)	$ (8,066)	$ (8,052)	$ (8,050)	$ (8,046)	$ (8,029)	$ (7,990)	$ (7,958)	$ (7,948)	$ (7,948)
NPV (BTx)	25%															
NPV (BTx)	20%															
NPV (BTx)	15%															
NPV (BTx)	10%															
IRR (BTx)																

Table 11. 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)		-	-	-	-	-	-	-	-	-	-	-	36,572
H2O Injection (Mbw)		-	-	-	-	-	-	-	-	-	-	-	13,951
Oil Production (Mbbl)		-	-	-	-	-	-	-	-	-	-	-	2,488
H2O Production (MBw)		-	-	-	-	-	-	-	-	-	-	-	15,505
CO2 Production (MMcf)		-	-	-	-	-	-	-	-	-	-	-	26,034
CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-	12,616
CO2 Recycled (MMcf)		-	-	-	-	-	-	-	-	-	-	-	23,956
Oil Price ($/Bbl)	$ 25.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gravity Adjustment	35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gross Revenues ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,305
Royalty ($M)	-12.5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,288)
Severance Taxes ($M)	-7.5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,351)
Ad Valorum ($M)	-2.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,160)
Net Revenue($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,505
Capital Costs ($M)													
New Well - D&C													$ (7,121)
Reworks - Producers to Producers													$ (136)
Reworks - Producers to Injectors													$ -
Reworks - Injectors to Injectors													$ (24)
Surface Equipment (new wells only)													$ (286)
Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,707)
Trunkline Construction													$ (22)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,297)
CO2 Costs ($M)													
Total CO2 Cost ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (21,759)
O&M Costs ($M)													
Operating & Maintenance ($M)	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,302)
Lifting Costs ($/bbl)	$ 0.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,523)
G&A	20%	-	-	-	-	-	-	-	-	-	-	-	$ (1,765)
Total O&M Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,590)
Cashflow													
Net Cash Flow ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,860
Cum. Cash Flow		$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	$ 6,860	
Discount Factor	15%	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	
Disc. Net Cash Flow		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,948)
Disc. Cum Cash Flow		$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	$ (7,948)	
NPV (BTx)	25%												
NPV (BTx)	20%												
NPV (BTx)	15%												
NPV (BTx)	10%												
IRR (BTx)													

6. RESULTS BY REGION

6.1 North Slope. The North Slope is the premier oil producing province in the United States, with a rich history of oil recovery. Crude oil production began in earnest in 1977, and has reached a cumulative recovery of more than 13.6 billion barrels of oil to date. In 2002, the region produced 348 MMBbls of oil (953 MBbls/day) from nearly 1,600 producing wells. The region still has proved oil reserves of 7,353 million barrels.

Despite being the premier oil-producing province in the United States, the North Slope has seen a modest decline in production in recent years, Table 12.

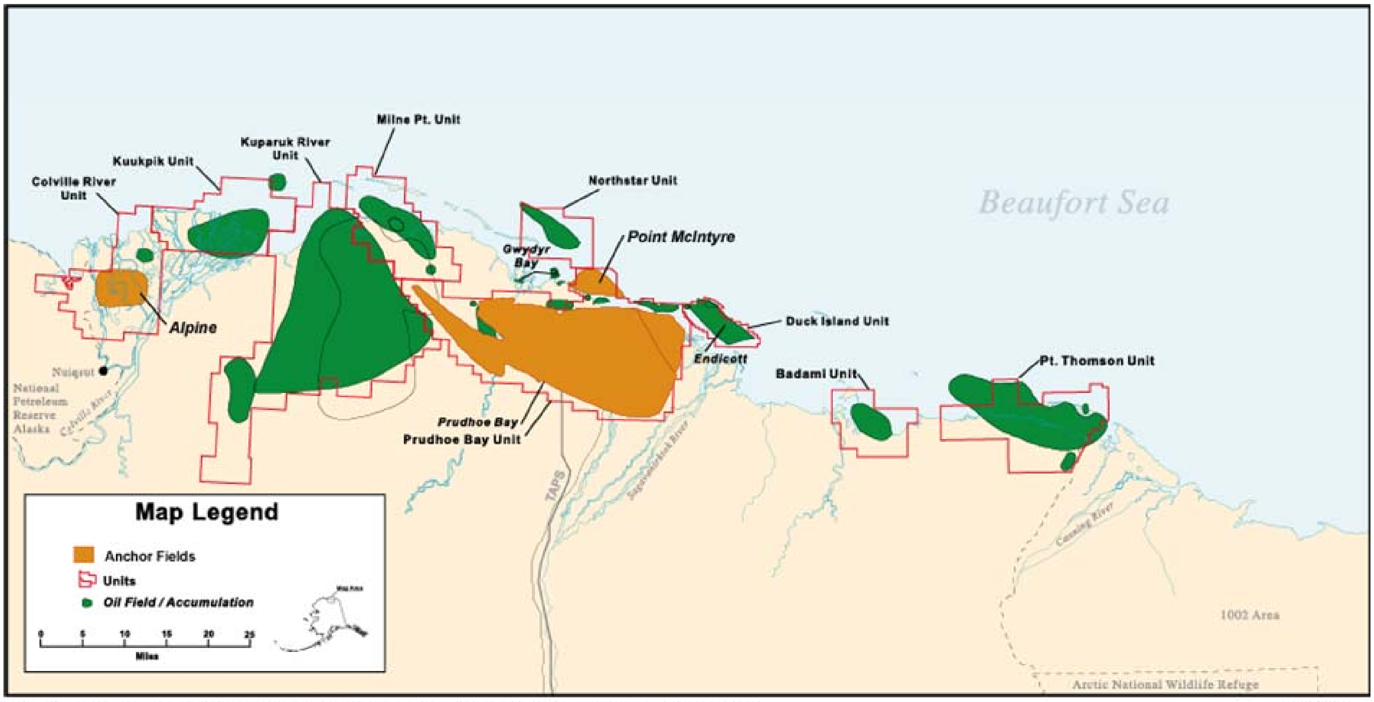
Table 12. Recent History of North Slope Oil Production

	Annual Oil Production	
	(MMBls/Yr)	(MBbls/D)
1999	372	1,019
2000	344	942
2001	339	929
2002	348	953

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

- Colville River (Alpine)
- Pt. McIntyre (Kuparuk River)
- Prudhoe Bay (Sag River Shublik Ivislak)

Figure 11. North Slope Anchor Fields



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

Table 13. Status of North Slope “Anchor” Fields/Reservoirs, 2002

	Anchor Fields/Reservoirs	Cumulative Production (MMBbls)	Proved Reserves (MMBbls)	Remaining Oil In Place (MMBbls)
1	Colville River (Alpine)	66	431	503
2	Pt McIntyre (Kuparuk River)	350	154	755
3	Prudhoe Bay (Sag River Shiblik Ivishak)	10,430	3,024	16,443

These three large “anchor” fields, each with 500 or more million barrels of ROIP, may be favorable for miscible CO_2 -EOR, based on their reservoir properties, Table 14.

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

	Anchor Fields	Depth (ft)	Oil Gravity (°API)	Active Waterflood or Gas Injection
1	Colville River (Alpine)	7,000	40.0	Currently injecting 0.1 Bcf/day and 0.1 MMbbl/day from 12 gas injection wells and 18 water injection wells
2	Pt McIntyre (Kuparuk River)	8,800	27.0	Currently injecting 0.2 Bcf/day and 0.2 MMbbl/day from 2 gas injection wells and 13 water injection wells
3	Prudhoe Bay (Sag River Shiblik Ivishak)	8,800	28.0	Currently injecting ~8 Bcf/day and ~1.4 MMbbl/day from ~60 gas injection wells and ~155 water injection wells

Ongoing and Planned CO_2-EOR Projects. Although there are no all CO_2-miscible EOR projects on the North Slope, there are six ongoing hydrocarbon miscible projects, where the injected gas contains significant concentrations of CO_2. Four of these projects are located within the larger Prudhoe Bay Unit's (including its satellite fields) Prudhoe Bay, Aurora, Eileen Ward and Pt. McIntyre fields and the remaining two projects are in the Tarn (Kuparak River Unit) and Alpine (Colville River Unit) fields.

The hydrocarbon miscible injectant (primarily from the processing of Prudhoe Bay and Kuparuk gas production) contains 22% CO_2, 25% methane, 22% ethane, 26% propane, and 5% butane and heavier hydrocarbons. Variability in the injectant mixture occurs with a decreasing reservoir pressure (depth), typically resulting in a reduction in the methane mole fraction to maintain miscibility.

The Oil and Gas Journal (April 12, 2004) provided quantitative results for the hydrocarbon miscible floods. While four of the six floods are new projects, Prudhoe Bay and Kuparak River are far enough along to gauge the results.

Prudhoe Bay. The Prudhoe Bay enhanced recovery project began in late 1982, following waterflooding operations, and progressed in stages to a field-wide flood by 1987. This field-wide CO_2 rich hydrocarbon miscible flood utilizes 318 production wells and 93 injection wells covering 55,000 acres. The project has been termed a success and is currently producing about 60 Mbbl/day of incremental oil.

Kuparak River. In mid-1988, a CO_2 rich hydrocarbon miscible flooding operation began at Kuparak River and responded in stages through the end of 1996. This field-wide flood utilizes 350 production wells and 260 injection wells covering 70,000 acres. This project has also been termed a success and is currently producing about 33 Mbbl/day of incremental oil.

Future CO_2-EOR Potential. The North Slope contains 19 reservoirs that are candidates for miscible CO_2-EOR.

Under "State-of-the-Art Practices", current financial investment standards, defined above, and either a high or low risk financial hurdle rate, there are no economically favorable oil reservoirs for CO_2-EOR on the North Slope, Table 15. However, should the financial risk hurdle remain high for using CO_2-EOR in Alaska, the oil reservoir is no longer economically feasible.

Table 15. Economic Oil Recovery Potential Under Current Conditions, North Slope, AK.

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place (MMBbls)	Technical Potential (MMBbls)	Economic Potential (No. of Reservoirs)	Economic Potential (MMBbls)
"High Risk State of the Art"	19	61,430	11,370	0	0
"Low Risk State of the Art"	19	61,430	11,370	0	0

"Risk mitigation" actions and lower cost CO_2 supplies would enable CO_2-EOR on Alaska's North Slope to recover up to 7,600 million barrels of oil from 8 field-reservoir combinations, Table 16.

Table 16. Economic Oil Recovery Potential with
More Favorable Financial Conditions, North Slope, AK

More Favorable Financial Conditions	No. of Economic Reservoirs	Economic Potential (MMBbls)
Plus: "Risk Mitigation"*	3	7,280
Plus: Low Cost CO_2**	8	7,600

** Assumes "risk mitigation" action that add on an equivalent of $10 per barrel to the oil price, adjusted for market factors*
*** Assumes reduced CO_2 supply costs, $0.70 per Mcf*

6.2 Cook Inlet. The Cook Inlet is the second important oil-producing region in Alaska. Production is relatively small though not insignificant. This region produced 11.3 MMBbls (31 MBls/day) in 2002, from 223 wells. Oil production in the Cook Inlet region began in 1959, and cumulative oil recovery has reached almost 1.3 billion barrels. The region has 167 MMBbls of crude oil reserves.

With many old and mature fields, oil production in the Cook Inlet continues to decline, Table 17. (The Cook Inlet region has 1 oil refinery in the immediate area, Tesoro's Nikiski, with CO_2 production estimated at 5 MMcfd).

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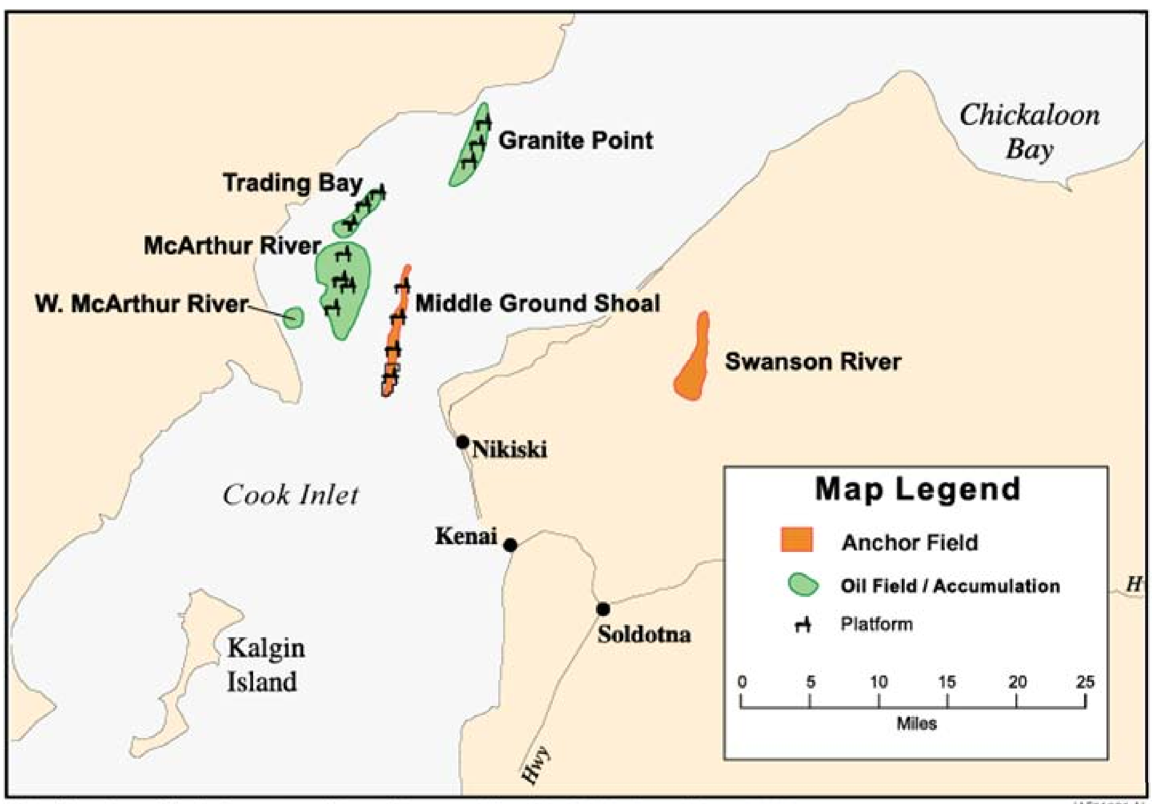
Table 17. Recent History of Cook Inlet Oil Production

	Annual Oil Production	
	(MMBbls/Yr)	(MBbls/D)
1999	10.9	30
2000	10.7	29
2001	11.5	32
2002	11.3	31

Cook Inlet Oil Fields. The Cook Inlet contains a number of oil fields that may be amenable to miscible CO_2- EOR, Figure 12. These include:

- Middle Ground Shoal (Tyonek-Hemlock E,F,G sands)
- Swanson River (Hemlock Sands)

Figure 12. Cook Inlet Anchor Fields



Edited from State of Alaska, Department of Natural Resources, Oil and Gas Division Annual Report, 2000

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These two oil fields could serve as the "anchor" sites for the initial CO_2 projects that could later extend to other fields in the basin. The cumulative oil production, proved reserves and remaining oil in-place (ROIP) for these two major "anchor" light oil reservoirs are set forth in Table 18.

Table 18. Status of Cook Inlet "Anchor" Fields/Reservoirs, 2001

	Anchor Fields/Reservoirs	Cumulative Production	Proved Reserves	Remaining Oil In-Place
		(MMBbls)	(MMBbls)	(MMBbls)
1	Middle Ground Shoal, Tyonek-Hemlock E,F,G sands	163	13	215
2	Swanson River, Hemlock	228	4	284

These two "anchor" reservoirs, ranging from just over 200 to nearly 300 million barrels of ROIP, are amenable to CO_2-EOR. Table 19 provides the reservoir and oil properties for these two reservoirs and their current secondary oil recovery activities.

Table 19. Reservoir Properties and Improved Oil Recovery Activity, "Anchor" Oil Fields/Reservoirs

	Anchor Fields/Reservoirs	Depth (ft)	Oil Gravity (^oAPI)	Active Waterflood or Gas Injection
1	Middle Ground Shoal, Tyonek-Hemlock E,F,G sands	7,100	35	Currently injecting 6.3 Mbbl/day from 10 water injection wells
2	Swanson River, Hemlock	10,800	39	Currently injecting more 1 MMcf/day from 1gas injection well

Past, Ongoing and Planned CO_2-EOR Projects. Currently, the only oil field within Cook Inlet implementing gas injection operations is the Swanson River Field, which is done for pressure maintenance purposes. No other field has undertaken any form of EOR other than waterflooding.

Future CO_2-EOR Potential. The Cook Inlet contains 12 large light oil reservoirs that are candidates for miscible CO_2-EOR. In addition, the region has 1 oil field, Trading Bay Tyonek B, that could benefit from immiscible CO_2-EOR.

Under "State-of-the-Art" and current high risk financial hurdles, defined above, miscible CO_2 flooding would not be economic in Cook Inlet. Even with a lower risk financial hurdle, the reservoirs remain uneconomic.

Table 20. Economic Oil Recovery Potential Under
Base Case Financial Conditions, Cook Inlet, AK

CO_2-EOR Technology	No. of Reservoirs Studied	Original Oil In-Place	Technical Potential	Economic Potential	
		(MMBbls)	(MMBbls)	(No. of Reservoirs)	(MMBbls)
"High Risk State of the Art"	13	3,070	670	0	0
"Low Risk State of the Art"	13	3,070	670	0	0

Improved financial conditions, including and "risk mitigation" actions and lower-cost CO_2 supplies, combined with "State of the Art" CO_2-EOR Technology, would increase economically-produced oil volumes in the Cook Inlet. These actions would allow up to 140 million barrels of additional oil recovery (from 2 major oil reservoirs), Table 22.

Table 21. Economic Oil Recovery Potential with
More Favorable Financial Conditions, Cook Inlet, AK

More Favorable Financial Conditions	No. of Reservoirs	(Million Bbls)
Plus: "Risk Mitigation"*	-	0
Plus: Low Cost CO_2**	2	140
Assumes "risk mitigation" action that add on an equivalent of $10 per barrel to the oil price, adjusted for market factors* * Assumes reduced CO_2 supply costs, $0.70 per Mcf*		

Appendix A

Using CO_2-*PROPHET* for Estimating Oil Recovery

March 2005

Model Development

The study utilized the *CO_2-PROPHET* model to calculate the incremental oil produced by CO_2-EOR from the large Alaska oil reservoirs. *CO_2-PROPHET* was developed by the Texaco Exploration and Production Technology Department (EPTD) as part of the DOE Class I cost share program. The specific project was "Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir" (DOE Contract No. DE-FC22-93BC14960). *CO_2-PROPHET* was developed as an alternative to the DOE's CO_2 miscible flood predictive model, *CO_2PM*.

Input Data Requirements

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

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

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

Calibrating CO_2-PROPHET

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

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

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

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

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

Comparison of *CO_2-PROPHET* and *CO_2PM*

According to the *CO_2-PROPHET* developers, the model performs two main operations that provide a more robust calculation of oil recovery than available from *CO_2PM*:

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

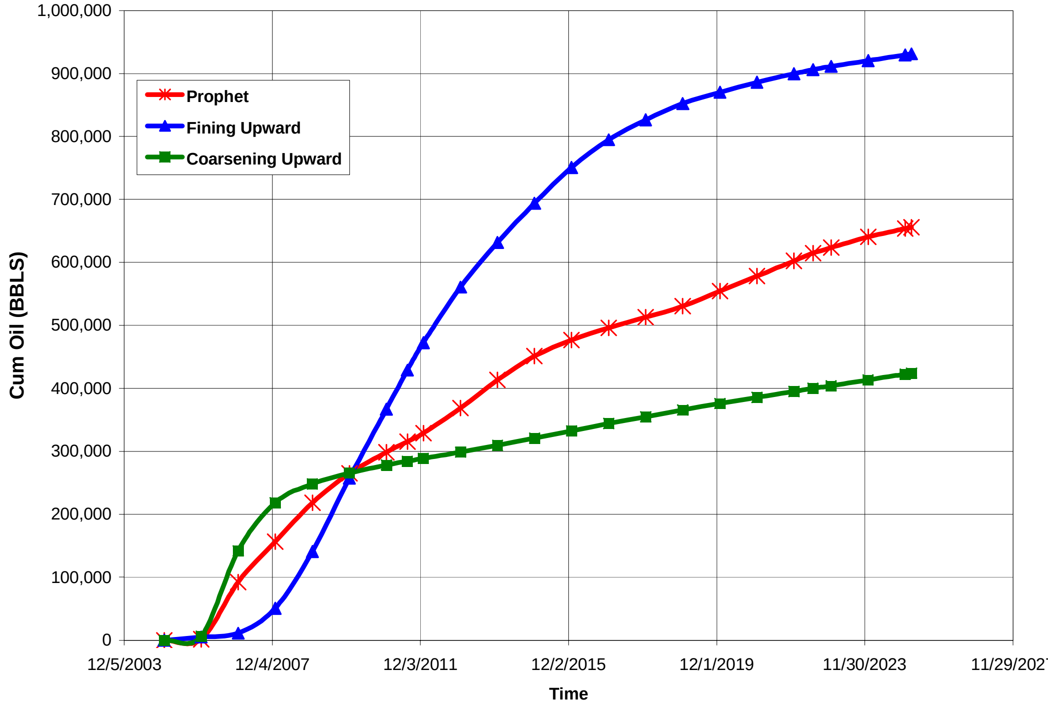
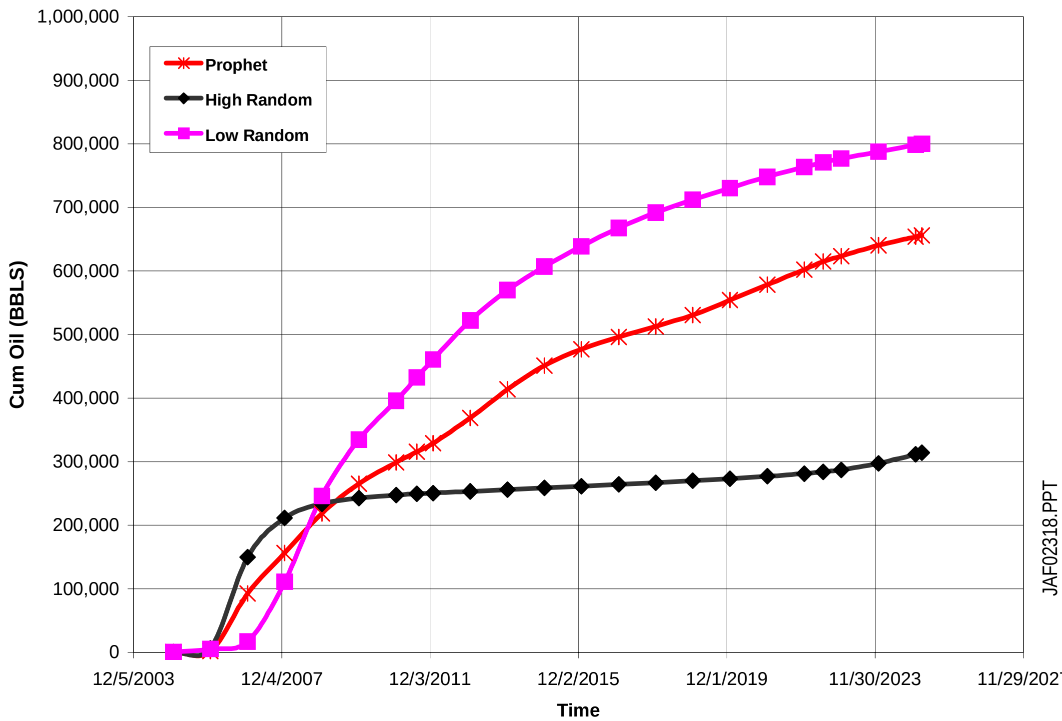


Figure A-2. CO_2-*PROPHET* and *GEM*: Comparison to Random Permeability Cases of *GEM*



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

Other key features of *CO_2-PROPHET* and its comparison with the technical capability of *CO_2PM* are also set forth below:

- Areal sweep efficiency in *CO_2-PROPHET* is handled by incorporating streamlines that are a function of well spacing, mobility ratio and reservoir heterogeneity, thus eliminating the need for using empirical correlations, as incorporated into *CO_2PM*.
- Mixing parameters, as defined by Todd and Longstaff, are used in *CO_2-PROPHET* for simulation of the miscible CO_2 process, particularly CO_2/oil mixing and the viscous fingering of CO_2.
- A series of reservoir patterns, including 5 spot, line drive, and inverted 9 spot, among others, are available in *CO_2-PROPHET*, expanding on the 5 spot only reservoir pattern option available in *CO_2PM*.
- *CO_2-PROPHET* can simulate a variety of recovery processes, including continuous miscible CO_2, WAG miscible CO_2 and immiscible CO_2, as well as waterflooding. *CO_2PM* is limited to miscible CO_2.

Appendix B

Cook Inlet Offshore CO_2-EOR Cost Model

March 2005

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

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

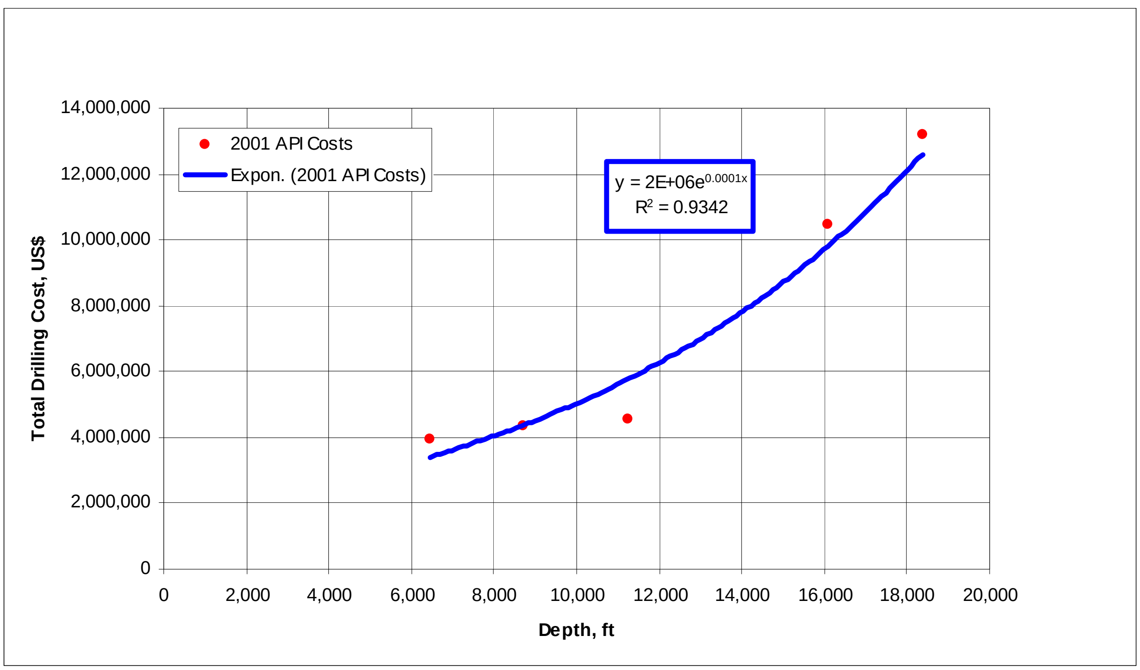
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Alaska.

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

Well D&C Costs = $a_0 e^{(0.0001D)}$
Where: a_0 = \$2,000,000 (fixed)
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 Alaska.

Figure B-1. Oil well D&C costs for Alaska



2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well in the Cook Inlet Offshore, Alaska are based on sparsely available industry data. These costs are expected to include all subsurface and surface production equipment necessary to produce oil in a CO_2-EOR project, excluding tubing costs, which are included in drilling costs. These costs are estimated from the EIA Cost and Indices Report.

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 for Cook Inlet Offshore is based on Offshore Gulf Coast costs and multiplied by a factor of 1.5:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$180,000 (fixed)
c_1 = \$7.53 per foot
D is well depth

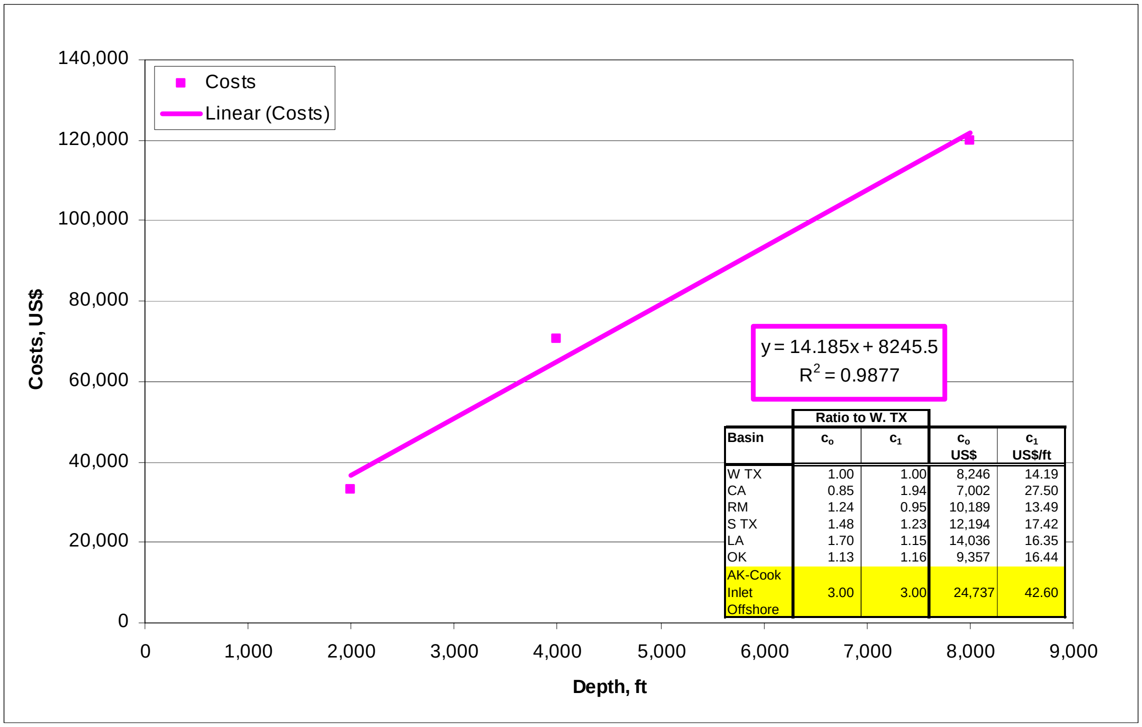
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in the Offshore Cook Inlet, Alaska include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. In the absence of data specific to the Offshore Cook Inlet region, information for the Offshore Gulf Coast lease equipment costs was used, which was originally based on West Texas cost data. The equation was multiplied by a factor of 1.5 for Offshore Cook Inlet:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$24,737 (fixed)
c_1 = \$42.60 per foot
D is well depth

Figure B-2 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 Alaska cost equations.

Figure B-2 - Lease Equipping Costs for a New Injection Well 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	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
LA	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44
AK-Cook Inlet Offshore	3.00	3.00	24,737	42.60

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. Costs are based on those for the Offshore Gulf Coast multiplied by a factor of 1.5. The equation for Offshore Cook Inlet is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$307,500 (fixed)
c_1 = \$34.50 per foot
D is well depth

5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing water injection wells to CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation, based on Offshore Gulf Coast reworking costs multiplied by 1.5, for Offshore Cook Inlet is:

Well Rework Costs = $c_0 + c_1D$
Where: c_0 = \$60,000 (fixed)
c_1 = \$7.50 (per foot)
D is well depth

Existing oil production wells must also be reworked to be acceptable for production using CO_2-EOR. This requires pulling and replacing the tubing string and pumping equipment. Like above, the rework costs are depth-dependent.

Well Rework Costs = $c_0 + c_1D$
Where: c_0 = \$157,500 (fixed)
c_0 = \$34.50 (per foot)
D is well depth

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides operating and maintenance (O&M) costs for only Gulf of Mexico platforms in water depths from 100 to 600 feet. Using the 300 foot water depth platform as an average platform type, platform O&M costs were estimated for Offshore Cook Inlet, Alaska.

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. First, workover costs, reported as surface and subsurface maintenance, were doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Second, liquid lifting costs are subtracted from the total O&M costs to allow for more rigorous handling of lifting costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR area discussed in a later section of this appendix.) These total costs were then broken down to a per well value and multiplied by a factor of 1.5 for Offshore Cook Inlet. The equation for the average per well O&M cost for CO_2-EOR in Alaska is:

Well O&M Costs = b_0
Where: b_0 = \$318,000 (fixed)

7. CO_2 Recycle Plant Investment Cost. 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 recycle requirements.

The cost of the recycling plant is set at $1,400,000 per MMcfd of CO_2 capacity. As such, a large CO_2-EOR project in the Middle Kenai formation in the Granite Point field, with 236 MMcfd of CO_2 reinjection, will require a recycling plant costing $330 million. A smaller project in the B Tyonek Middle Kenai formation in the Trading Bay field, with 5 MMcfd of CO_2 reinjection, requires a recycling plant costing $7 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 $0.38 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 15MMcfd), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcfd), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcfd), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, cost also depends on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO_2 distribution cost equation for Offshore Cook Inlet 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 5% are added to well O&M and lifting costs, because a number of the nominal G&A costs, such as insurance and accounting, are already in the well O&M costs set forth above..

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

f. Production Taxes. Severance and ad valorum taxes are set at 7.5% and 2.0%, respectively, for a total production tax of 9.5% on the oil production stream. Production taxes are taken following royalty payments.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis (transportation costs) differential for Offshore Cook Inlet (-$1.50 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Alaska is:

Wellhead Oil Price = Oil Price + (-$1.50) – [$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

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

Appendix C

North Slope CO_2-EOR Cost Model

March 2005

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

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

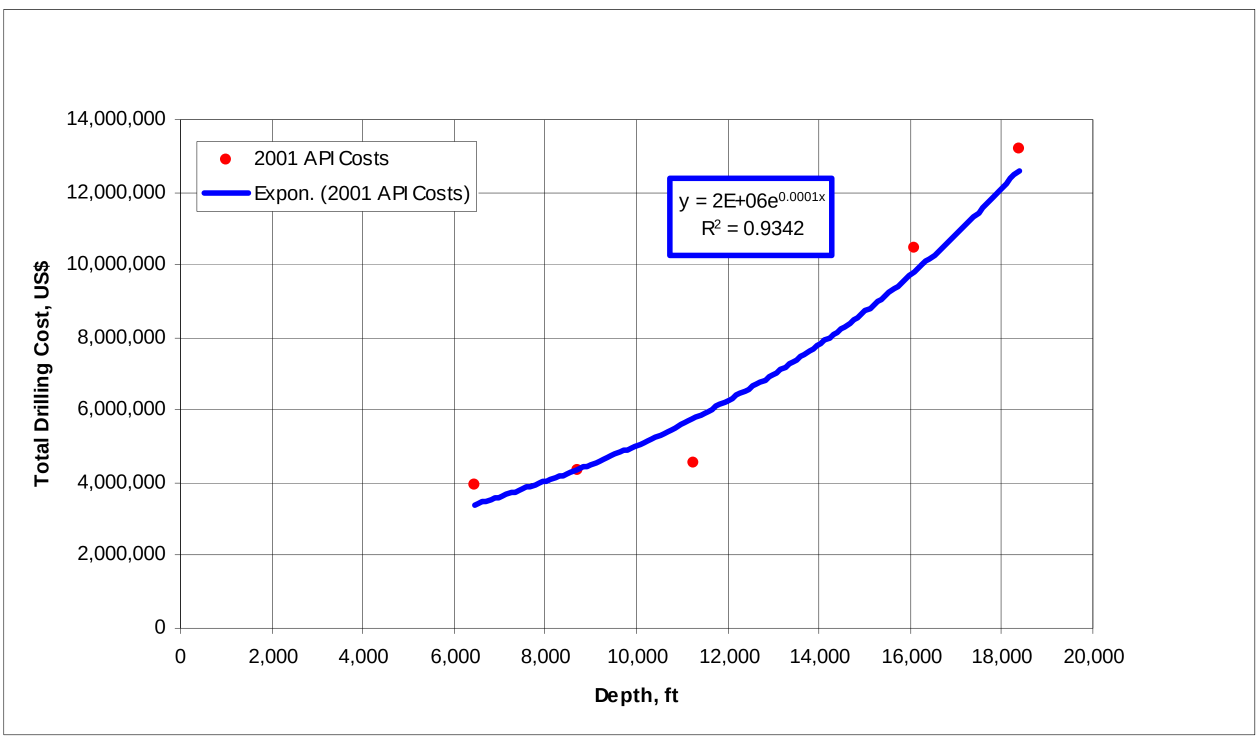
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Alaska.

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

Well D&C Costs = $a_0e^{(0.0001D)}$
Where: a_0 = \$2,000,000 (fixed)
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 Alaska.

Figure B-1. Oil well D&C costs for Alaska



2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well on the North Slope, Alaska are based on sparsely available industry data. These costs are expected to include all subsurface and surface production equipment necessary to produce oil in a CO_2-EOR project, excluding tubing costs, which are included in drilling costs. These costs are estimated from the EIA Cost and Indices Report.

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 for Cook Inlet Onshore is based on South Louisiana costs and multiplied by a factor of 2.0:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$163,422 (fixed)
c_1 = \$10.04 per foot
D is well depth

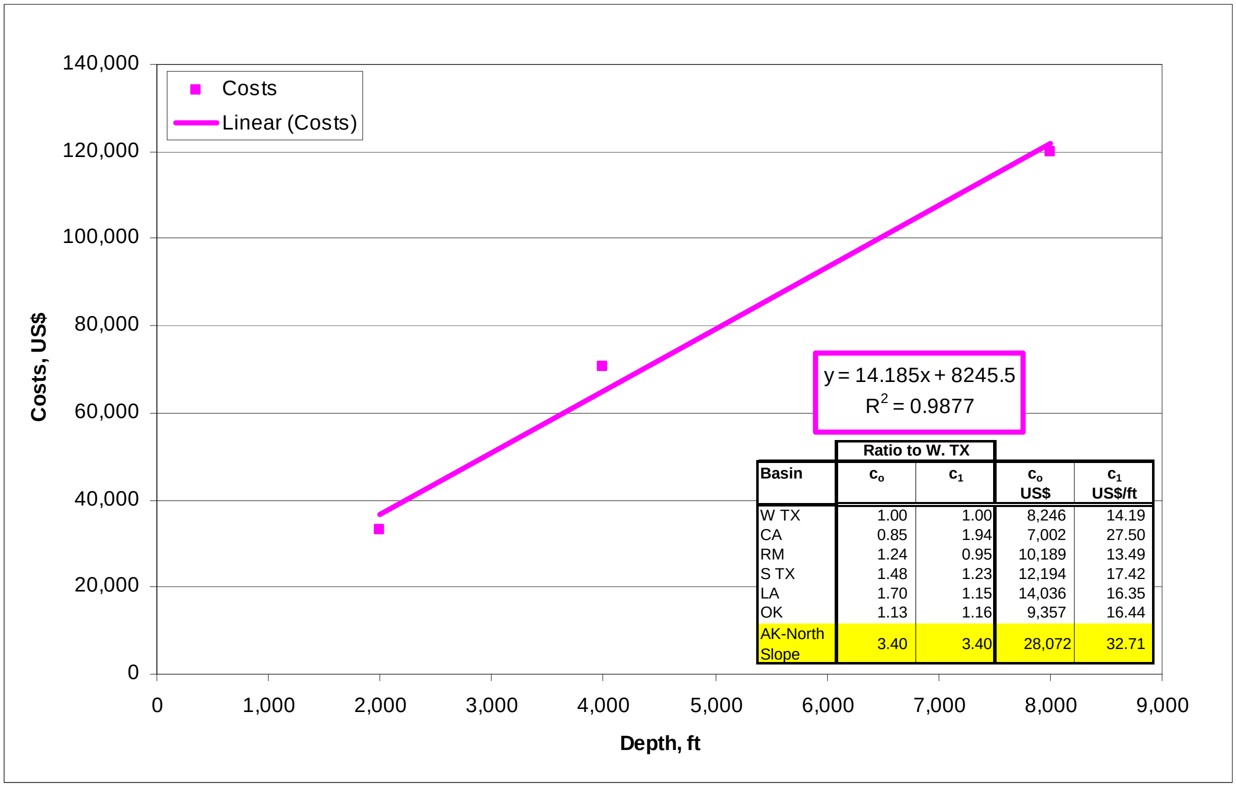
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in the Onshore Cook Inlet, Alaska include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. In the absence of data specific to the North Slope, information for South Louisiana lease equipment costs was used, which was originally based on West Texas cost data. The equation was multiplied by a factor of 2.0 for the North Slope:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$28,072 (fixed)
c_1 = \$32.70 per foot
D is well depth

Figure B-2 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 North Slope cost equations.

Figure B-2 - Lease Equipping Costs for a New Injection Well in West Texas vs. depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
LA	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44
AK-North Slope	3.40	3.40	28,072	32.71

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. Costs are based on those for South Louisiana multiplied by a factor of 2.0. The equation for Onshore Cook Inlet is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = \$33,303 (fixed)
c_1 = \$8.38 per foot
D is well depth

5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing water injection wells to CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation, based on South Louisiana reworking costs multiplied by 2.0, for the North Slope is:

Well Rework Costs = c_0D
Where: c_0 = \$80,000 (fixed)
c_1 = \$10.00 (per foot)
D is well depth

Existing oil production wells must also be reworked to be acceptable for production using CO_2-EOR. This requires pulling and replacing the tubing string and pumping equipment. Like above, the rework costs are depth-dependent.

Well Rework Costs = c_0D
Where: c_0 = \$33.54 (per foot)
D is well depth

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides operating and maintenance (O&M) costs for South Louisiana, which provides the basis for O&M costs in the Onshore Cook Inlet region.

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. First, workover costs, reported as surface and subsurface maintenance, were doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Second, liquid lifting costs are subtracted from the total O&M costs to allow for more rigorous handling of lifting costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR area discussed in a later section of this appendix.) These total costs were then broken down to a per well value and multiplied by a factor of 2.0 for the North Slope. The equation for the average per well O&M cost for CO_2-EOR is:

Well O&M Costs = $b_0 + b_1D$
Where: b_0 = \$63,666 (fixed)
b_1 = \$17.04 per foot
D is well depth

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 recycle requirements.

The cost of the recycling plant is set at $1,400,000 per MMcfd of CO_2 capacity. As such, a large CO_2-EOR project in the Kuparuk River formation in the Kuparuk River field, with 1,707 MMcfd of CO_2 reinjection, will require a recycling plant costing $2.4 billion. A smaller project in the Seabee unit of the Tarn development field, with 147 MMcfd of CO_2 reinjection, requires a recycling plant costing $206 million.

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

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

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

b. <u>Lifting Costs.</u> Liquid (oil and water) lifting costs are calculated on total liquid production and costed at $0.50 per barrel. This cost includes liquid lifting, transportation and re-injection.

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

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

The CO_2 distribution cost equation for Onshore Cook Inlet 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, because a number of the nominal G&A costs, such as insurance and accounting, are already in the well O&M costs set forth above..

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

f. Production Taxes. Severance and ad valorum taxes are set at 7.5% and 2.0%, respectively, for a total production tax of 9.5% on the oil production stream. Production taxes are taken following royalty payments.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis (transportation costs) differential for the North Slope (-$4.00 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Alaska is:

Wellhead Oil Price = Oil Price + (-\$4.00) – [\$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

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

Appendix D

Cook Inlet Onshore CO_2-EOR Cost Model

March 2005

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

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

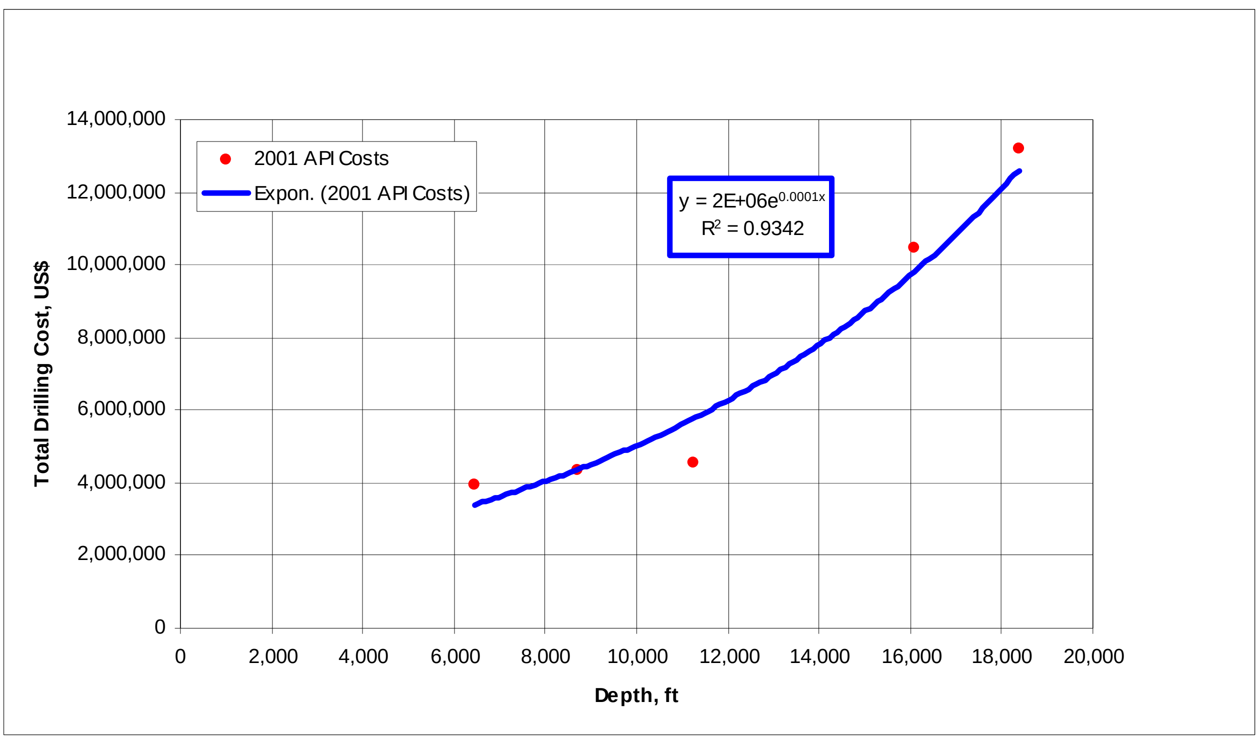
1. Well Drilling and Completion Costs. The costs for well drilling and completion (D&C) are based on the 2001 JAS cost study recently published by API for Alaska.

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

Well D&C Costs = $a_0e^{(0.0001D)}$
Where: a_0 = $2,000,000 (fixed)
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 Alaska.

Figure B-1. Oil well D&C costs for Alaska



2. Lease Equipment Costs for New Producing Wells. The costs for equipping a new oil production well in the Cook Inlet Onshore, Alaska are based on sparsely available industry data. These costs are expected to include all subsurface and surface production equipment necessary to produce oil in a CO_2-EOR project, excluding tubing costs, which are included in drilling costs. These costs are estimated from the EIA Cost and Indices Report.

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 for Cook Inlet Onshore is based on South Louisiana costs and multiplied by a factor of 1.5:

Production Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$122,567 (fixed)
c_1 = \$7.53 per foot
D is well depth

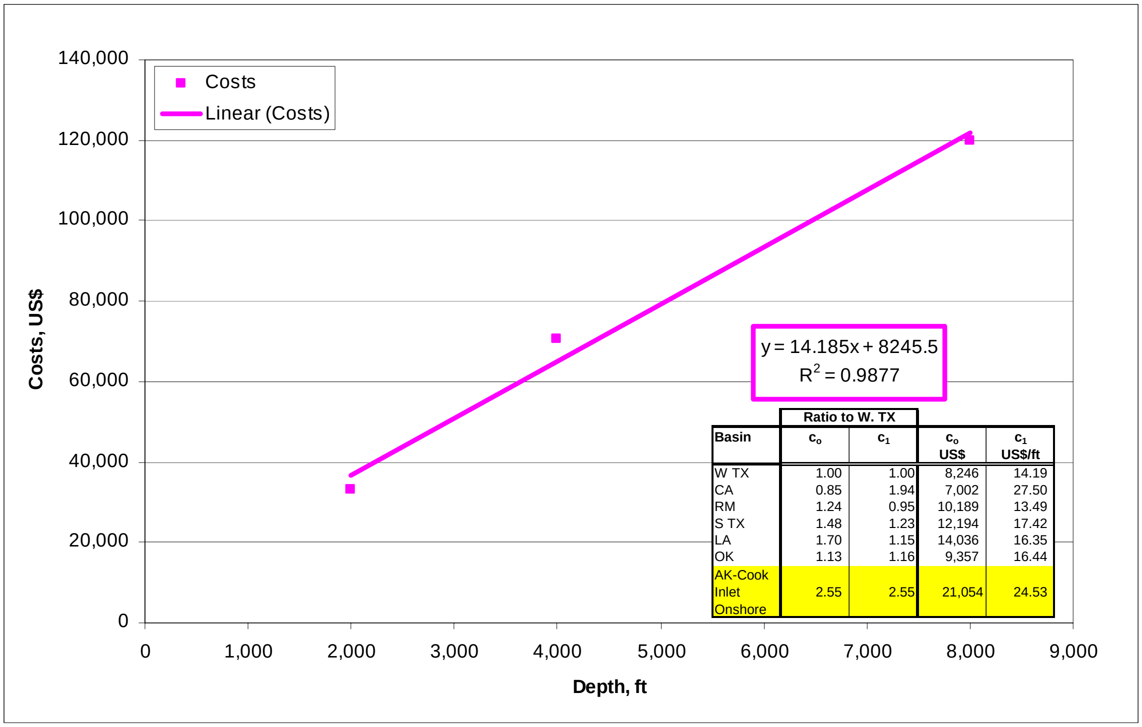
3. Lease Equipment Costs for New Injection Wells. The costs for equipping a new injection well in the Onshore Cook Inlet, Alaska include gathering lines, a header, electrical service as well as a water pumping system. The costs are estimated from the EIA Cost and Indices Report.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. In the absence of data specific to the Onshore Cook Inlet region, information for South Louisiana lease equipment costs was used, which was originally based on West Texas cost data. The equation was multiplied by a factor of 1.5 for Onshore Cook Inlet:

Injection Well Equipping Costs = $c_0 + c_1D$
Where: c_o = \$21,054 (fixed)
c_1 = \$24.53 per foot
D is well depth

Figure B-2 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 Alaska cost equations.

Figure B-2 - Lease Equipping Costs for a New Injection Well in West Texas vs. depth



Basin	Ratio to W. TX c_o	Ratio to W. TX c_1	c_o US$	c_1 US$/ft
W TX	1.00	1.00	8,246	14.19
CA	0.85	1.94	7,002	27.50
RM	1.24	0.95	10,189	13.49
S TX	1.48	1.23	12,194	17.42
LA	1.70	1.15	14,036	16.35
OK	1.13	1.16	9,357	16.44
AK-Cook Inlet Onshore	2.55	2.55	21,054	24.53

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. Costs are based on those for South Louisiana multiplied by a factor of 1.5. The equation for Onshore Cook Inlet is:

Well Conversion Costs = $c_0 + c_1D$
Where: c_o = $24,977 (fixed)
c_1 = $6.29 per foot
D is well depth

5. Costs of Reworking an Existing Waterflood Production or Injection Well for CO_2-EOR (First Rework). The reworking of existing water injection wells to CO_2-EOR injection wells requires pulling and replacing the tubing string and pumping equipment. The well reworking costs are depth-dependent. The equation, based on South Louisiana reworking costs multiplied by 1.5, for Onshore Cook Inlet is:

Well Rework Costs = $c_0 + c_1 D$
Where: c_0 = \$60,000 (fixed)
c_1 = \$7.50 (per foot)
D is well depth

Existing oil production wells must also be reworked to be acceptable for production using CO_2-EOR. This requires pulling and replacing the tubing string and pumping equipment. Like above, the rework costs are depth-dependent.

Well Rework Costs = $c_0 D$
Where: c_0 = \$25.16 (per foot)
D is well depth

6. Annual O&M Costs, Including Periodic Well Workovers. The EIA Cost and Indices report provides operating and maintenance (O&M) costs for South Louisiana, which provides the basis for O&M costs in the Onshore Cook Inlet region.

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. First, workover costs, reported as surface and subsurface maintenance, were doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Second, liquid lifting costs are subtracted from the total O&M costs to allow for more rigorous handling of lifting costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR area discussed in a later section of this appendix.) These total costs were then broken down to a per well value and multiplied by a factor of 1.5 for Onshore Cook Inlet. The equation for the average per well O&M cost for CO_2-EOR is:

Well O&M Costs = $b_0 + b_1 D$
Where: b_0 = \$47,750 (fixed)
b_1 = \$12.78 per foot
D is well depth

7. CO2 Recycle Plant Investment Cost. 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 recycle requirements.

The cost of the recycling plant is set at $1,400,000 per MMcfd of CO_2 capacity. As such, a large CO_2-EOR project in the Hemlock formation in the McArthur River field, with 465 MMcfd of CO_2 reinjection, will require a recycling plant costing $651 million. A smaller project in the Tyonek Middle Kenai G formation in the McArthur River field, with 41 MMcfd of CO_2 reinjection, requires a recycling plant costing $57 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 $0.38 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 15MMcfd), $120,000 per mile for 6" pipe (CO_2 rate of 15 to 35 MMcfd), $160,000 per mile for 8" pipe (CO_2 rate of 35 to 60 MMcfd), and $200,000 per mile for pipe greater than 8" diameter (CO_2 rate greater than 60 MMcfd). Aside from the injection volume, cost also depends on the distance from the CO_2 "hub" (transfer point) to the oil field. Currently, the distance is set at 10 miles.

The CO_2 distribution cost equation for Onshore Cook Inlet 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 5% are added to well O&M and lifting costs, because a number of the nominal G&A costs, such as insurance and accounting, are already in the well O&M costs set forth above..

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

f. Production Taxes. Severance and ad valorum taxes are set at 7.5% and 2.0%, respectively, for a total production tax of 9.5% on the oil production stream. Production taxes are taken following royalty payments.

g. Crude Oil Price Differential. To account for market and oil quality (gravity) differences on the realized oil price, the cost model incorporated the current basis (transportation costs) differential for Onshore Cook Inlet (-$2.00 per barrel) and the current gravity differential (-$0.25 per ^{o}API, from a basis of 40 ^{o}API) into the average wellhead oil price realized by each oil reservoir. The equation for Alaska is:

Wellhead Oil Price = Oil Price + (-$2.00) – [$0.25*(40 - ^{o}API)]
Where: Oil Price is the marker oil price (West Texas intermediate)
^{o}API is oil gravity

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