Enhanced Oil Recovery

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An Analysis of the Potential
for Enhanced Oil Recovery from Known Fields
in the United States--1976 to 2000

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National Petroleum Council

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NATIONAL PETROLEUM COUNCIL

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Introduction

The October 1973 Arab oil embargo was not the first warning of impending energy shortages—nor was it the first embargo. Even without the embargo, farsighted individuals had previously called attention to the inevitability of an "energy crunch." The October 1973 embargo did, however, bring the problem "front and center."

Since then, the Administration, Congress, labor, industry, and consumers have increasingly realized that new sources of energy, new attitudes and discipline must be developed and adopted. Clearly, a comprehensive energy program is complex—a unified and complete national program must encompass the consideration of all options. The potential of each needs to be explored.

One such option is to produce more oil—*to enhance the recovery*—from domestic oil fields. When considered by itself, enhanced oil recovery (EOR) is but one of the "building blocks" in an overall national energy structure. Increased production from existing fields may well be a good source of future domestic energy supply.

In recognition of the potential of enhanced recovery, on March 18, 1975, Assistant Secretary of the Interior, Jack W. Carlson stated in a letter to National Petroleum Council Chairman, John E. Swearingen (see Appendix A for the complete text of the request letter):

> While we pursue unknown and unevaluated conventional and unconventional energy sources, we must continue to improve our ability to recover larger proportions of known oil and gas deposits on land and on the Outer Continental Shelf.

He, therefore, requested the National Petroleum Council to:

> . . . assess the state of the art of enhanced recovery for oil and gas from known oil and gas reserves . . . (appraise) the probable ranges of volumetric outcomes based on alternative economic conditions . . . (and recommend) how public policy can improve the outlook.

The Council agreed to undertake the study and, with approval of the Department of the Interior, established a Committee on Enhanced Recovery Techniques for Oil and Gas in the United States. A Coordinating Subcommittee and two Task Groups assisted the Committee in preparing the report (see Appendix B for rosters). In selecting the membership of the Committee and the working groups, an attempt was made to appoint individuals who represented the various divergent views on enhanced recovery. Some individuals and organizations are optimistic about the future of enhanced recovery in the United States, while others are pessimistic. Although individual members of the National Petroleum Council may disagree with specific parts, this study represents a consensus of the Council's views.

The Council agreed to examine known enhanced recovery methods and the recovery potential from known oil fields in the United States from the present to the year 2000. This report does not consider the impact on future supply of oil fields discovered after December 31, 1975, nor does it consider the possible application of EOR processes to those fields.

The Council did not estimate potential enhanced recovery from producing gas fields, since the opportunity for improving total gas recovery through non-conventional or enhanced recovery processes in these fields is limited. The major potential for non-conventional gas recovery is from low-permeability, presently uneconomic reservoirs. The magnitude of this potential is unknown, but may represent a substantial contribution to the Nation's future energy supply. However, very little information is available specifying reservoir volume, location, reservoir geologic characteristics, or other data required to analyze potential recovery and producing rates. Therefore, estimates of possible enhanced gas recovery were not made.

This report presents estimates of what could happen under certain technical and economic circumstances and is not intended to represent a forecast of what will occur. Other recent studies on enhanced recovery were used as references when appropriate and their results are compared with the results of this study in Chapter Three.

The possible environmental impacts of enhanced oil recovery operations have been considered by the Council. Chapter Four includes a general discussion on environmental protection, and specific details on the possible effects of each process are contained in the appendices.

This report does not address the broader issues of energy policy such as energy conservation, import dependency, alternate energy forms, etc. It focuses on only one of the several possibilities to increase the supply of domestically produced petroleum. The Council feels that, despite its technical uncertainties and expected high costs, the pursuit of enhanced recovery is in the Nation's best interest. However, the degree to which enhanced recovery should be pursued as an instrument of U.S. energy policy must be addressed in the broader context of an overall policy.*

*The Council is currently conducting a study on Future Energy Prospects, which will address these broader issues. This report is expected to be completed in the Spring of 1977.

Summary

Background

The term "enhanced oil recovery" refers, in the broadest sense, to any method used to recover more oil from a petroleum reservoir than would be obtained by primary recovery. In primary recovery, naturally occurring forces, such as those associated with gas and liquid expansion or influx of water from aquifers, are utilized to produce the oil. Conventional secondary recovery methods, such as waterfloods, are considered to be "enhanced recovery" methods under this broader definition. Waterflooding of reservoirs, in which water is injected to supplement original reservoir forces and drive more oil to producing wells, currently accounts for about half of U.S. oil production. For this study, however, "enhanced oil recovery," or "EOR," is considered in a more narrow sense, and it is defined as: the additional recovery of oil from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods.

The petroleum industry has conducted extensive research on enhanced oil recovery since the 1930's. As a result, several potential processes have been developed and field tested. Some of these processes are designed to recover the oil left in a reservoir after waterflooding or following other conventional secondary recovery processes. These EOR processes—usually the third type of recovery method employed in the reservoir—have been called "tertiary" recovery methods. Because some of the enhanced recovery processes may be used as an alternative to waterflooding or other conventional secondary recovery processes, the term "enhanced oil recovery" as used in this report is considered to have a broader meaning than "tertiary" oil recovery.

The potential of enhanced oil recovery is of significant interest because of the number of U.S. fields to which it might be applied. While recovery in individual reservoirs is highly variable, the average recovery from conventional primary and secondary recovery methods in all U.S. reservoirs is expected to be only about one-third of the original oil in place, leaving nearly 300 billion barrels in currently known reservoirs. A portion of this remaining oil will constitute a target for enhanced oil recovery. The rest exists in unfavorable geologic or geographic regions or is so diffusely spread out in the reservoir rock that it very likely will not be recoverable by any process.

Three general classifications of EOR have shown significant promise and are considered in this study. These classifications are: (1) chemical flooding; (2) carbon dioxide miscible flooding; and (3) thermal methods. Of these, only one of the thermal methods (steamflooding) has been proven by several large-scale commercial applications. The other processes are receiving limited field testing at this time, but most of them have not been put into large-scale, commercial use because of their high cost. For projecting the potential for enhanced recovery, this study assumes that EOR technology will continue to improve. It does not, however, consider the effects of future major technological breakthroughs.

Analysis Procedures

This study is based primarily on a review of the applicability of EOR processes to a data base of 245 known reservoirs in California, Texas, and Louisiana. From this data base, extrapolations were made for all reservoirs in the three states and for the United States as a whole. Potential producing rates during the 1976-2000 time frame and incremental ultimate recovery achievable from EOR processes started during the period 1976-2000 were calculated for 30 sets of economic assumptions. The potential producing rate and incremental ultimate recovery results shown in this study are only for application of EOR processes to reservoirs discovered as of December 31, 1975. Discoveries after that date are not considered in this report.

Before this economic review was begun, the technical feasibility of process application to the data base reservoirs was established. A screening procedure, based on process characteristics, reservoir geologic conditions, and fluid properties, was used to make this determination. When a reservoir passed the screening procedures for more than one process, dominance criteria were applied to select the process which would be expected to be most suitable, considering chances of success, potential recovery and economics.

Calculations were made of incremental ultimate recovery and potential producing rate. The calculations used simplified equations and were based upon the limited information contained in the original data base for the 245 reservoirs.

The next step was to determine the detailed costs associated with implementing each enhanced oil recovery process. These included process-independent cost data, such as costs of drilling and completing wells, and process-dependent costs, or those costs peculiar to each EOR process evaluated. Costs associated with environmental protection have been included in the detailed cost analyses of each process.

Finally, the economics of each project (the application of the assigned process to its respective reservoir) were evaluated for five possible oil prices, three minimum rate of return cases, and two tax cases. The economic criteria were chosen arbitrarily to represent a range of conditions for calculation purposes only. Constant 1976 dollars were used in all analyses. The term "constant 1976 dollars" refers to the purchasing power of the U.S. dollar in 1976 without consideration of possible future fluctuations in currency value. This was used to provide a measure of comparability to projections of costs, revenues, rates of return and capital requirements, which might otherwise have been distorted by varying estimates of the unpredictable factors of inflation or deflation.

For the five oil price cases ($5, $10, $15, $20, and $25 per barrel) prices were assumed to be effective immediately and to remain constant throughout the 1976-2000 period. For example, results shown for a $20 per barrel oil price in 1990 do not mean that oil will reach a price of $20 per barrel in that year; they illustrate the potential producing rates and incremental ultimate recovery that could be achieved by EOR if oil were to be valued at $20 per barrel from 1976 on.

Three minimum discounted cash flow rates of return (DCFROR) were assumed as criteria for evaluating each reservoir. These rates (10, 15, and 20 percent) were used in the analysis only as minimum requirements and not as expectations for average results. These rates of return, as were the oil prices, were on an inflation-free basis. They correspond approximately to nominal rates of return minus the rate of inflation.

Calculations were also made for two tax cases, which represent two possible interpretations of current (July 1976) tax law. These analyses were deemed necessary because most of the EOR processes are virtually untried in commercial application, and it is not known how current tax law would be interpreted as it would apply to these projects. In essence, the "moderate" case assumed expensing of certain costs while the "restrictive" case assumed the items would be amortized over a number of years.

The incremental ultimate recovery for the United States for each economic condition was calculated by adding the projected ultimate recoveries from data base reservoirs and then extrapolating to the United States as a whole. Potential producing rates in the period 1976 through 2000 were obtained in a similar manner, with some added assumptions on rates of development.

The estimates of incremental ultimate recovery from EOR are subject to major uncertainty because of unknown reservoir characteristics and the experimental status of several of the EOR methods considered. The estimates of potential producing rate include these uncertainties, together with those implicit in the additional assumptions on rates of development. To gain perspective on the uncertainty in the results for each process, sensitivity studies were made on several critical process variables. The possible ranges of incremental ultimate recovery and potential producing rate—as a function of some of the major uncertainties—are important segments of this report. To re-emphasize, results in this study are estimates of what *could* happen and are not forecasts of what *will* occur.

Results

There are two types of results from this study. The first is a series of estimates of incremental ultimate recovery and potential producing rates that could be expected from EOR under the various economic conditions considered. These results were calculated from "base cases" for each process. *The term "base case" refers solely to best estimates of process performance and associated process costs, and implies no judgments regarding future oil prices, tax cases, or* *rate of return requirements.* Estimates of process performance in the base case represent roughly the mean of expected results. The base case represents neither a minimum assured result nor, conversely, an upper bound on the potential of enhanced oil recovery processes.

The second type of results from the study is the analysis of the uncertainty in the base case estimates, and is of equal importance in describing the potential of EOR processes. At any specified economic condition, uncertainties in process performance, process cost, and reservoir characterization may affect both the total number of reservoirs to which EOR processes may be applied economically and the estimates of incremental ultimate recovery from EOR. Potential producing rate estimates involve all these elements, plus additional uncertainty in the rates of development and application of EOR processes.

The aggregate results for all U.S. fields for incremental ultimate recovery and potential producing rates are shown in Figures 1 and 2, respectively. A minimum 10 percent DCFROR requirement and the moderate tax case have been used in these figures. Since the major thrust of this study is to examine the technical outlook for enhanced oil recovery in the United States, these figures are plotted using those of the economic criteria studied which would display the greatest EOR potential. This decision is not to imply that the NPC recommends any of the price levels shown; further, the Council does not intend to imply which one, if any, of the DCFROR requirements would be acceptable or sufficient for any individual operator or for the industry as a whole.* Results under different economic conditions are shown in Chapter Three, together with more detail on the contribution of individual processes to the cumulative results for all EOR processes.

Incremental ultimate recovery from EOR processes increases with oil price, from less than 3 billion barrels at $5 per barrel to about 24 billion barrels at $25 per barrel, in constant 1976 dollars. At $5 per barrel, all EOR production is from thermal methods. At $10 per barrel, the contribution of carbon dioxide miscible flooding is about equal to that of the thermal methods. Chemical flooding has a low potential at $10 per barrel, but increases substan-

*The relationship between risk and rate of return is discussed in greater detail in Chapter Three. See especially Figure 48 for the sensitivity of incremental ultimate recovery to minimum rate of return requirements.

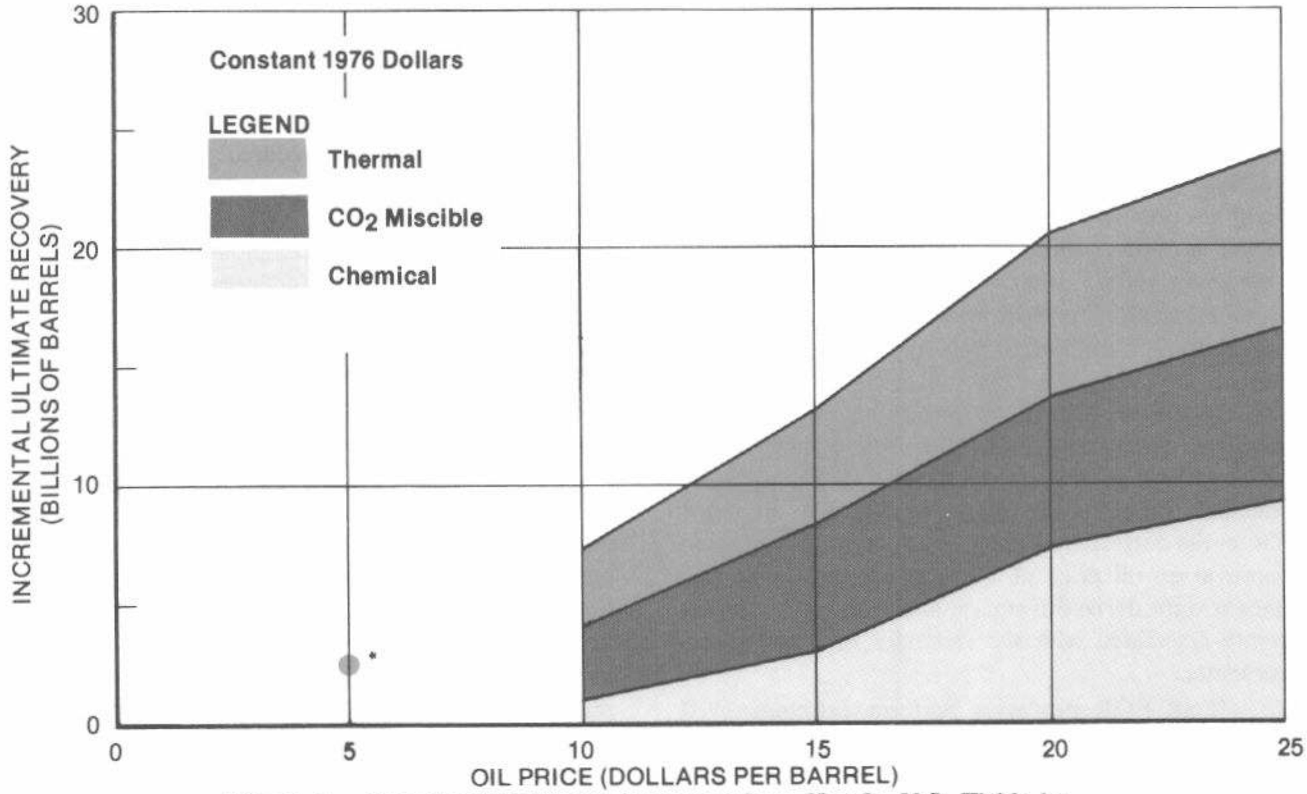

Figure 1. **Incremental Ultimate Recovery from Known U.S. Fields by Enhanced Recovery Process.**

*Recovery for Thermal at $5. Recovery for Chemical and CO_2 miscible flooding are zero at $5 per barrel and as shown at $10 per barrel. Recovery for intermediate prices between $5 and $10 per barrel has not been determined.

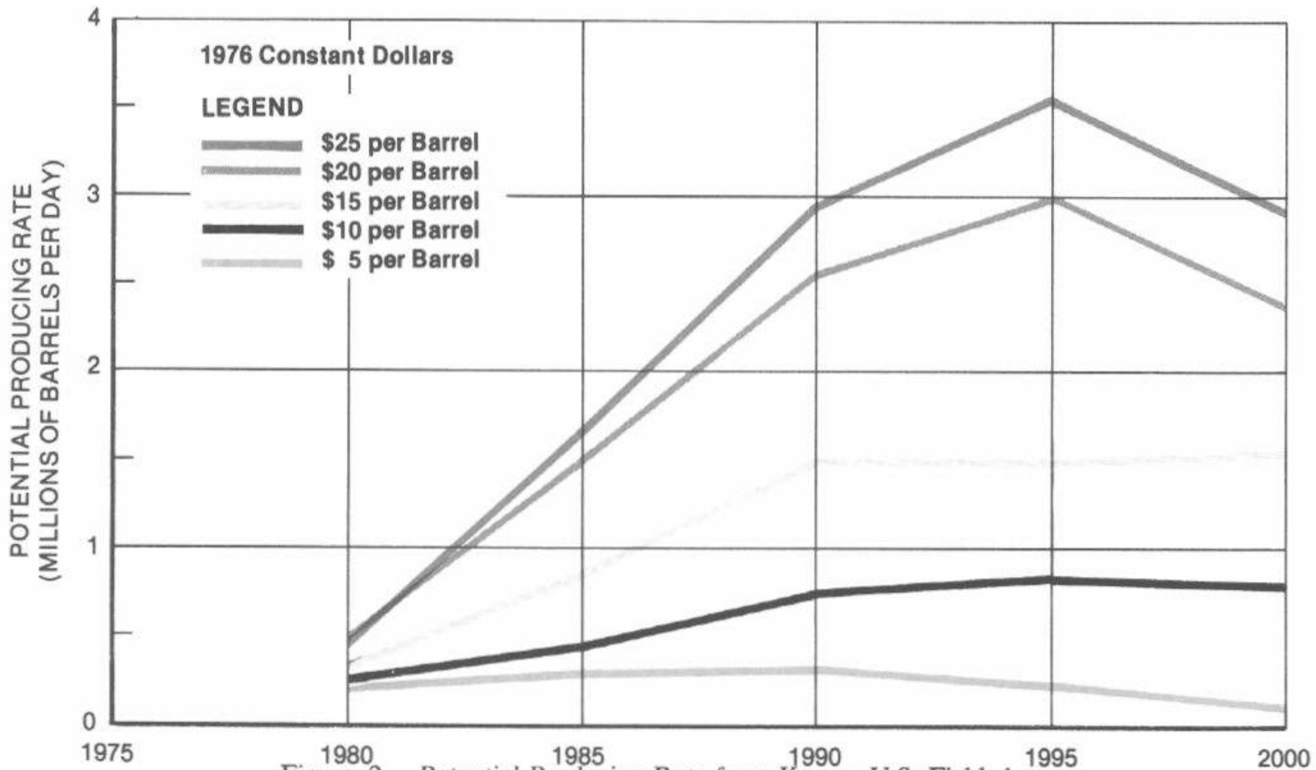

Figure 2. Potential Producing Rate from Known U.S. Fields by Enhanced Recovery Processes.

tially with price, accounting for 9 billion of the 24 billion barrel total EOR at $25 per barrel.

The potential producing rate is also sensitive to oil price. The potential rate in 1985 varies from 0.3 million barrels per day at $5 per barrel to about 1.7 million barrels per day at $25 per barrel. Peak production (for most oil prices) from application of EOR processes to currently known reservoirs is projected in 1995 (with the assumptions on rates of development and application in this study), and ranges from about 0.25 million barrels per day at $5 per barrel to 3.5 million barrels per day at $25 per barrel.

The large amount of uncertainty in the above estimates is depicted in Figures 3 and 4. Figure 3 shows the range of incremental ultimate recovery for the same economic conditions as Figure 1. Figure 4 shows the corresponding range of potential producing rates, at an oil price of $15 per barrel. The ranges shown were derived from examination of the uncertainty associated with the estimates of process performance.

If all EOR processes perform extremely well (substantially better than expected in the base case) incremental ultimate recovery might range from about 4 billion barrels at $5 per barrel to about 33 billion barrels at $25 per barrel. If all processes perform substantially poorer than assumed in the base case, ultimate recovery could range from 2 billion barrels at $5 per barrel to about 12 billion barrels at $25 per barrel. The range of incremental ultimate recovery at $15 per barrel is from 7 billion to 27 billion barrels, compared to a base case estimate of 13 billion barrels.

The uncertainty in potential producing rate at any point in time is larger than the uncertainty in ultimate recovery. With the assumptions made in this study regarding rates of development and process application, the potential producing rate in 1985 at $15 per barrel ranges from less than 0.5 million barrels per day (poorer than expected performance) to more than 1.5 million barrels per day (better than expected performance), with a base case estimate of about 0.9 million barrels per day. At peak production, expected in about 1995 with the assumptions used, the uncertainty is largest. At $15 per barrel, the potential producing rate ranges from about 0.75 million barrels per day to about 3.3 million barrels per day, with a base case of 1.5 million barrels per day.

There is an equal probability for either the high or low estimates of process performance to occur. As this broad range reflects only an estimate of the uncertainty, actual results could be even better or worse than calculated. It appears unlikely, however, that the uncertainty would be resolved in a uniformly positive or negative direction for all processes. It is more probable that some processes will perform better than expected, and some more poorly, so that the aggre-

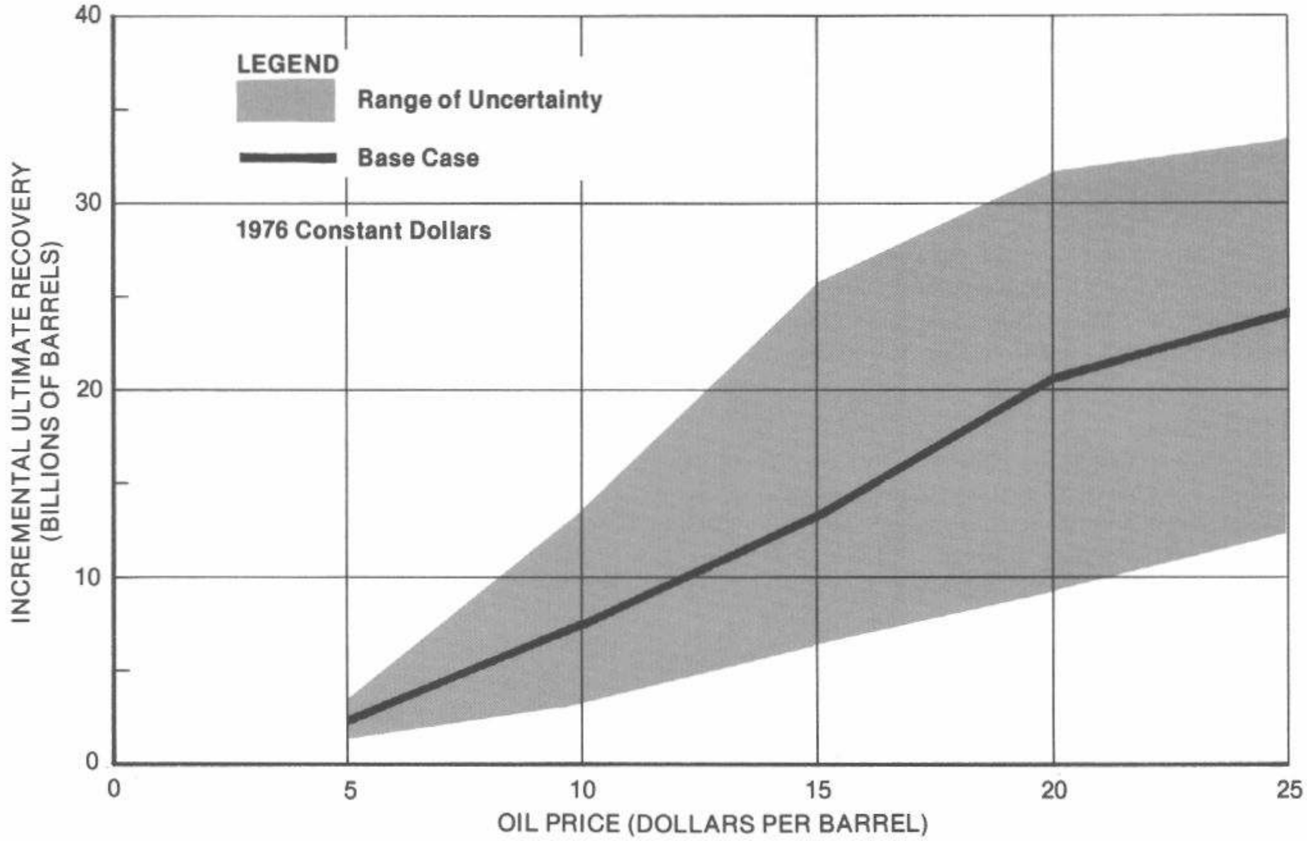

Figure 3. Uncertainty in Incremental Ultimate Recovery.

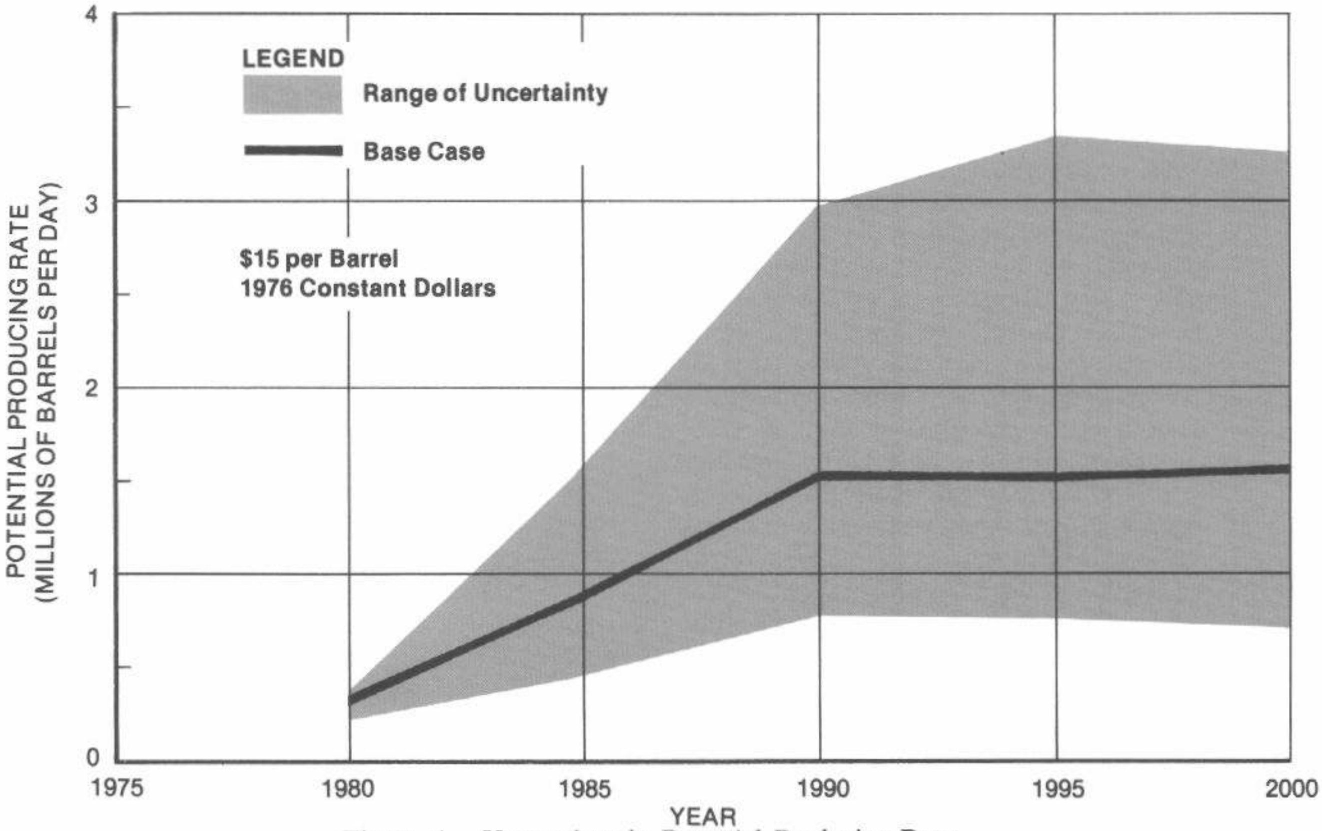

Figure 4. Uncertainty in Potential Producing Rate.

gate results are expected to be within the range shown.

Other data obtained in the course of this study and more complete treatment of the type of results shown in Figures 1 through 4 are presented in the chapters and appendices of the report. These include: discussion of possible enviromental impacts of EOR operations; examination of the sensitivity of the results to several parameters other than process performance; and an analysis of logistical requirements associated with the projected EOR activity.

Conclusions

The potential for enhanced recovery involves complex relationships among technology, economics, and government policy; valid generalizations are difficult. From this study, however, the National Petroleum Council draws the following three interrelated conclusions:

- *Enhanced recovery processes, if technically successful and broadly applied, could have a significant impact on oil production from known U.S. reservoirs during the years 1985-2000.* Assuming historical depletion trends, production of current API proved reserves (excluding North Slope) will decline to about 3 million barrels per day by 1985 and to less than 1 million barrels per day in 1995-2000. Successful application of enhanced recovery technology could slow this decline during the period 1985-2000, if the rate of technology development and field testing from 1976 to 1985 is accelerated from current levels. In fact, the rate of enhanced recovery production from known reservoirs could exceed that of primary and secondary production by the late 1980's. Figure 5 shows potential enhanced oil recovery producing rates, superimposed on the calculated decline curve of remaining primary and secondary production of current U.S. proved reserves.
- *The potential of enhanced recovery processes is uncertain at this time.* The technical uncertainties in most enhanced recovery processes are so great that estimates of ultimate recovery and producing rate for any specified economic condition may be substantially in error. Further process research, reservoir characterization studies, and field testings will be required to improve prediction capabilities.
- *Incremental ultimate recovery and the potential producing rate for enhanced recovery are highly dependent on oil price and other economic factors.* Enhanced recovery processes are inherently high-cost methods designed to recover oil which is left in the reservoir by lower-cost, conventional recovery methods. These high-cost processes are not widely used at present because current domestic oil prices and other economic factors do not permit profitable application, even when they are technically successful.

Government Policy Comments

Government policy may affect both the ultimate recovery from EOR processes, and the timing of the application of EOR technology. The principal effect will result from policies which influence the economics of EOR processes. Oil price relative to process cost will be the primary factor influencing the level of EOR application. Policies which artificially depress oil price will diminish the number of reservoirs to which EOR can be economically applied.

Other factors that have substantial effects on project economics will be sensitive to related policy. For example, tax treatment may be significant, particularly regarding the degree to which cash outlays must be capitalized rather than expensed. Policy which requires amortization of large front-end investments, such as injected chemicals, would have a severe, detrimental effect on surfactant flooding, a significant negative impact on carbon dioxide miscible flooding, and a lesser effect on thermal EOR processes. Other tax policies might have important effects.

Several policy areas, which indirectly affect project economics, may have large aggregate impacts. Since environmental protection costs are included in project costs, more stringent requirements would increase costs. Of the EOR processes studied, thermal recovery operations appear to be the most sensitive to the cost of environmental protection. Regulations which offer differential benefits to some leases or producers, such as multiple-tier price controls or regulations giving special treatment to certain classes of producers, may make unitization impossible, with resulting higher application costs, or even elimination of reservoirs from consideration.

With limited total world oil resources, all oil recoverable at real price levels as high or higher than those considered in this report, eventually may be produced. The cost of enhanced recovery might be substantially increased by delay, because of plugging of wells and abandonment of surface facilities. Moreover, the present value of the oil to the Nation is directly affected by delay. The major effect of the future direction of government policy will be to estab-

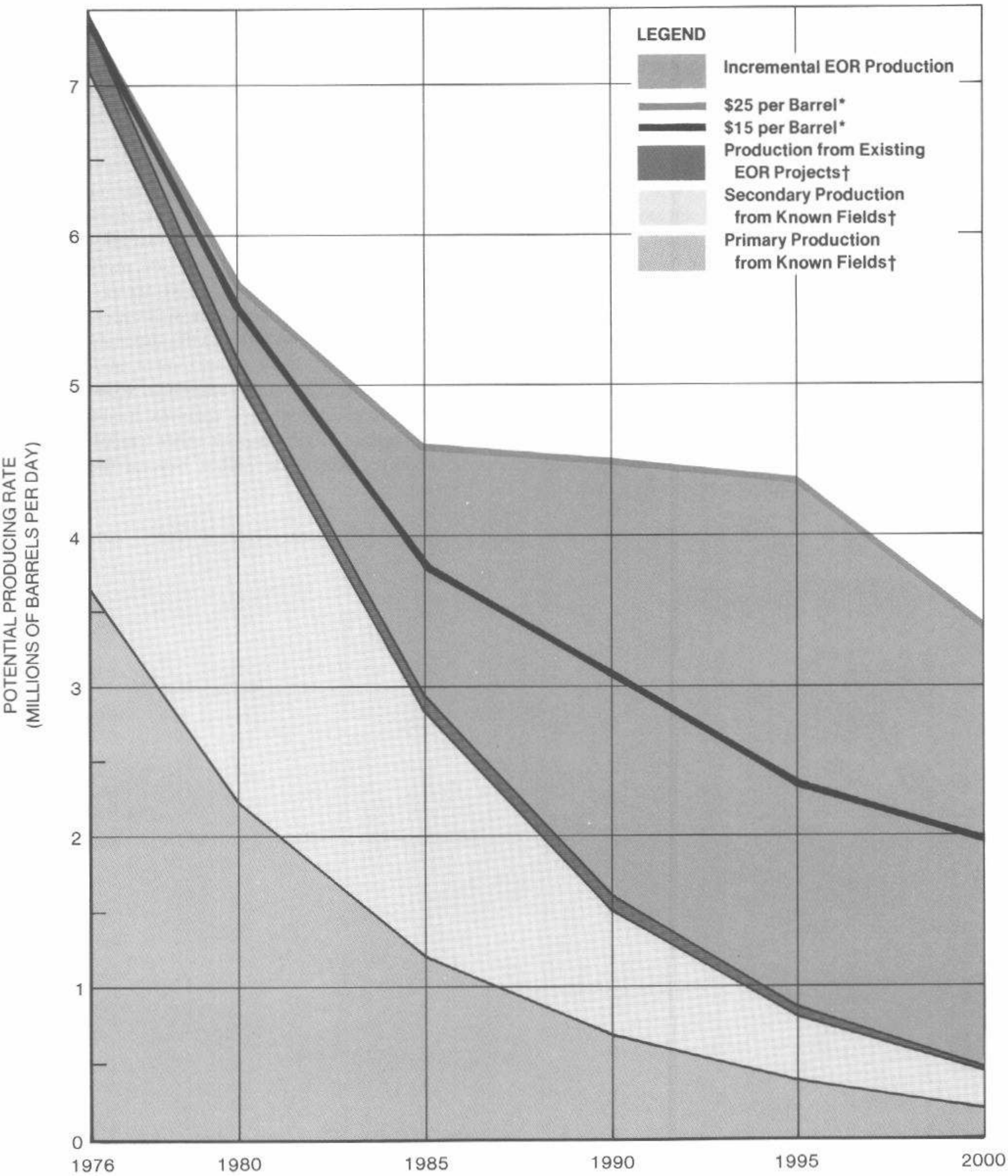

Figure 5. Potential U.S. Crude Oil Production Rate from Known Fields.

*Constant 1976 Dollars and Minimum DCFROR Requirement — 10%

†Estimated Producing Rates Based on December 31, 1975 API Reserves (See Appendix H).

Note: Production from the following sources is not considered and will be additive to the rates shown:

- Revisions except as included in API "Indicated Additional Reserves" as of December 31, 1975
- Extensions from realized enlargement of known fields
- New reservoir discoveries in known fields
- New field discoveries after December 31, 1975
- EOR from extensions, new reservoir discoveries, and new field discoveries
- North Slope, Alaska

lish *when* oil is recovered by EOR processes.

Investment in EOR processes will have to compete for available funds with other activities, such as oil exploration, which also have the potential to increase domestic petroleum resources. Higher real oil prices would provide increased incentives for all such activities, including EOR. As already stated, this study has not considered the relative value of EOR compared to other means of increasing domestic energy supply; however, one result of this study, which bears on such questions, merits emphasis: With the exception of a few thermal applications in unusually favorable reservoirs, the upside potential of EOR project economics is limited, even when the project is technically successful. There are no bonanzas in EOR. To the degree that exploration, or other alternatives, offer higher upside potential (with comparable risk and profitability expectations), they may continue to receive the majority of available funding, even if general economic conditions improve.

Enhanced oil recovery projects require long lead times and are high-risk investments. The degree of risk will decrease as the results from more large-scale projects are obtained, providing a basis for improved process engineering. The U.S. Energy Research and Development Administration (ERDA) program in support of field pilot experiments is designed to provide added field test data, and it should have some positive effects on risk considerations. Demonstration of the technical feasibility of EOR, however, will not result in increased production unless economic conditions for EOR are favorable.

There are many ways in which differential benefits could be extended to EOR applications in order to accelerate EOR development and use. The question of whether such differential treatment is in the Nation's best interest requires analysis of the proper role of EOR *vis-a-vis* other available domestic energy alternatives, and is beyond the scope of this study.

Chapter One
Background of Oil Recovery Operations

Overview of Elements of Oil Recovery

General

In the United States, 418 billion barrels of crude oil had been discovered as of December 31, 1975. Total ultimate recovery with existing economic conditions is estimated to be 137 billion barrels, of which 109 billion barrels have already been produced. Thus, the remaining proved reserves recoverable by conventional production methods are 28 billion barrels, leaving nearly 300 billion barrels of oil in currently known reservoirs.* Most of this oil is not recoverable with foreseeable technology, because of unfavorable reservoir geology, adverse fluid properties, or because it is so diffusely spread out in the reservoir rock. However, a portion of this oil volume should be producible by enhanced oil recovery methods. This report addresses the amount and rate of recovery that may be economically recoverable by EOR methods.

Domestic producing rates in 1975 totalled about 8 million barrels per day of crude oil and 2 million barrels per day of lease condensate and gas plant liquids. An approximate equivalent amount of natural gas (on a BTU basis) was also produced in 1975. Domestic oil and gas production accounted for about 55 percent of the Nation's energy needs, with another 20 percent of the Nation's needs being filled by imported oil. The remaining 25 percent was from other energy sources such as coal, nuclear and hydroelectric power.

*API, *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1975*, Vol. 30, May 1976. All data exclude the North Slope of Alaska.

The Reservoir

Crude oil is found in underground rock formations called reservoirs. The oil resides together with water, and sometimes gas, in very small holes (pore spaces) and fractures. The size, shape, and degree of interconnection of the pores vary considerably from place to place in an individual reservoir. Thus, the anatomy of a reservoir is complex, both micro- and macroscopically. A complete, detailed, quantitative description of a reservoir is never possible. The detailed data which can be obtained from wells represents only an infinitesimal fraction of the reservoir volume, even under the best of circumstances.

Properties of crude oil and formation water in different parts of an individual reservoir generally vary only slightly, although there are notable exceptions. For different reservoirs, crude properties cover a wide spectrum of differences. Some are thinner than water, while others are thicker than cold molasses. Generally, crude oils are lighter than water. The water in different reservoirs also varies, in salinity and other mineral content.

Because of the existence of a wide range of properties of both rock and fluids, reservoirs act differently and must be treated individually.

Primary Oil Recovery

Primary oil recovery uses natural reservoir energy to drive the oil through the complex pore network to producing wells. The driving energy may be derived from one or more of the following: gas that evolves from solution out of the oil; expansion of free gas; influx of natural water; or gravity force. The primary recovery efficiency is generally low when gas is the drive agent; much higher recoveries are associated with water drives. Reservoirs with effective gravity drainage can also have higher recoveries. Eventually, the natural drive energy is dissipated. When this occurs, energy must be added to the reservoir to produce any additional oil.

Secondary Oil Recovery

Secondary oil recovery involves the introduction of energy into a reservoir by injecting gas or water under pressure. Separate wells are usually used for injection and production. The added energy stimulates the movement of oil, providing additional recovery at increased rates.

Today, limited use is being made of gas injection because of its low oil displacement effectiveness and the need for gas supplies in the market. When gravity drainage is effective, pressure maintenance by gas injection is effective. Waterflooding is the principal secondary recovery method and accounts for about half the current U.S. daily oil production.

Efficiency of Conventional Recovery Methods

Ultimately, conventional primary and secondary recovery are expected to produce about one-third of the original oil discovered. The recovery from individual reservoirs can range from as low as 5 percent to as high as 80 percent of original oil in place (OOIP). This broad range of recovery efficiency is a result of the variations in the properties of the specific rock and fluids involved from reservoir to reservoir, as well as the kind and level of energy that drives the oil to producing wells, where it is captured.

The Remaining Oil

Oil left after conventional recovery applications is retained in the pore space of reservoir rock at a lower concentration than originally existed; the produced oil is replaced by gas and/or water in the pores. The remaining oil exists in portions of the reservoir as droplets trapped by water either in individual pores or clusters of pores; as a film lining the pore walls; or in the pores of these segments of reservoir rock which by geological conditions or well positioning were not contacted by driving fluids.

The forces that contribute to the retention of the oil are capillarity (blotter effect), gravity (buoyancy effect), and viscous forces (drag effect). These forces act simultaneously in the reservoir and the resultant effect depends on conditions at individual locations. Releasing the remaining oil so that it can be produced is the intent of enhanced oil recovery operations. Through chemical or thermal means, the objective is to increase the effectiveness of oil removal from pores of the rock (displacement efficiency) by eliminating or minimizing the oil-imprisoning capillary forces; by overcoming or utilizing the effects of gravity which cause vertical segregation of the fluids in the reservoir; by thinning the oil so that it will flow more readily; and by improving sweep efficiency, causing the injected or driving fluids to contact more of the oil-containing reservoir rock.

The degree of technical success achieved by enhanced oil recovery will depend on the development of process technology, on the behavior of the new drive fluids, and the accuracy of reservoir engineering in characterizing the physical nature of individual reservoirs.

Overview of Enhanced Recovery Methods

Enhanced Oil Recovery

For the economic parameters studied in this report, the incremental ultimate recovery is defined as the additional recovery of oil from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods. Enhanced recovery methods capable of recovering additional oil are broadly categorized as (1) thermal, (2) carbon dioxide (CO_2) miscible, and (3) chemical flooding.

After nearly half a century of industrial research, a number of enhanced recovery methods have evolved. Some of these appear to be more promising than others. The three major categories—thermal, carbon dioxide miscible, and chemical flooding—differ in degree of complexity and in the amount of experience that has been derived from field application:

- *Thermal* is the most advanced on the learning curve in terms of field experience, and so has the least uncertainty in estimating performance if good reservoir description is available. Commercial application of some of the thermal processes has been underway for the last decade and currently contributes about 200 thousand barrels per day of enhanced oil recovery to the Nation's oil supply.
- *Carbon dioxide miscible* is lower on the learning curve than thermal, but in the middle range of complexity of the three categories used in this study. At least two CO_2 miscible programs are underway at the commercial level and several pilot tests are either under-

way or planned to evaluate this recovery method in different types of reservoirs.

- *Chemical flooding* is the most complex, is lowest on the learning curve, and has the highest degree of uncertainty. Yet, where its application can be properly designed and controlled, it may have the greatest chance to achieve maximum recovery. Over the past decade, several field pilot tests have been conducted. While some tests have been successful, most of these resulted in operators returning to the research laboratories to improve upon their chemical formulations. Currently, chemical flooding is being carefully and thoroughly field piloted, with the objectives of developing better applications technology, understanding the limitations of this method, and informing the industry at large as to field test results.

Thermal Processes

Thermal processes add heat to the reservoir to reduce oil viscosity or to vaporize the oil. In both instances, the oil is made more mobile so that it can be more effectively driven to producing wells. In addition to adding heat, these processes provide a driving force (pressure) to move oil to producing wells. There are two principal thermal enhanced recovery methods: steam injection and in-situ combustion.

Steam Injection

Steam injection has been commercially applied in California for the last decade. It occurs in two steps:

- Steam stimulation of the producing well (Figure 6), and
- Steam drive from steam injected into wells to increase production from nearby producing wells (Figure 7).

In practice, a mixture of steam and hot water is normally injected into the formation. The ratio of steam to water injected may vary from mostly steam (high quality) to mostly water (low quality).

At different times and in various sequences, different phases of steam injection may be applied to any one project. Normally, steam stimulation precedes steam drive. It is the steam stimulation phase of steam injection that began in California ten years ago. In steam stimulation, heat is applied to the reservoir by the injection of high quality steam into the producing well. The cyclic, so-called "huff and puff" or "steam soak," process uses the same well for injection and production.

This period of steam injection is followed by production of reduced-viscosity oil and condensed steam (water). The driving energy for production is the flashing of hot water (originally condensed from steam injected under high pressure) back to steam as pressure is lowered when a well is put on production. After several steam stimulation cycles, some wells are converted to continuous steam injection and others to continuous production. At this point the operation becomes a steam drive.

In-Situ Combustion

In-situ combustion has also been extensively field-tested. Heat is generated in the reservoir by injecting air and burning part of the crude oil. This reduces the viscosity, partially vaporizes the oil in place, and drives it forward by a combination of steam, hot water, and gas drive. Production is obtained at wells offsetting injection locations. In some applications, the efficiency of the total in-situ combustion operation can be improved by alternating water and air injection (see Figure 8). The injected water tends to improve the utilization of heat by transferring it from the hot rock behind the combustion zone to the rock immediately ahead of the combustion zone. Due to density contrasts, injected air tends to override in-place oil. Where gravity effects cause extensive overriding problems, steamflooding may prove to be a more efficient process. In-situ combustion is normally applied to reservoirs containing low gravity oil, but it can be applied to higher gravity oil reservoirs also. In some high-gravity oil reservoirs, in-situ combustion would compete with other EOR methods. For the reservoirs considered in this study, other EOR methods normally took precedence due to economic dominance considerations used in this study. Other alternative dominance criteria might result in greater potential use of in-situ combustion.

Carbon Dioxide Miscible Flooding

Carbon dioxide (Figure 9) is capable of miscibly displacing some oils, thus permitting recovery of most of the oil from the reservoir rock that is contacted. Miscible displacement overcomes the capillary forces which otherwise retain oil in pores of the rock. The CO_2 is not miscible with the oil initially. However, as CO_2 contacts in-situ crude oil, some of the hydrocarbon constituents of the crude oil are vaporized. At the displacement front, the

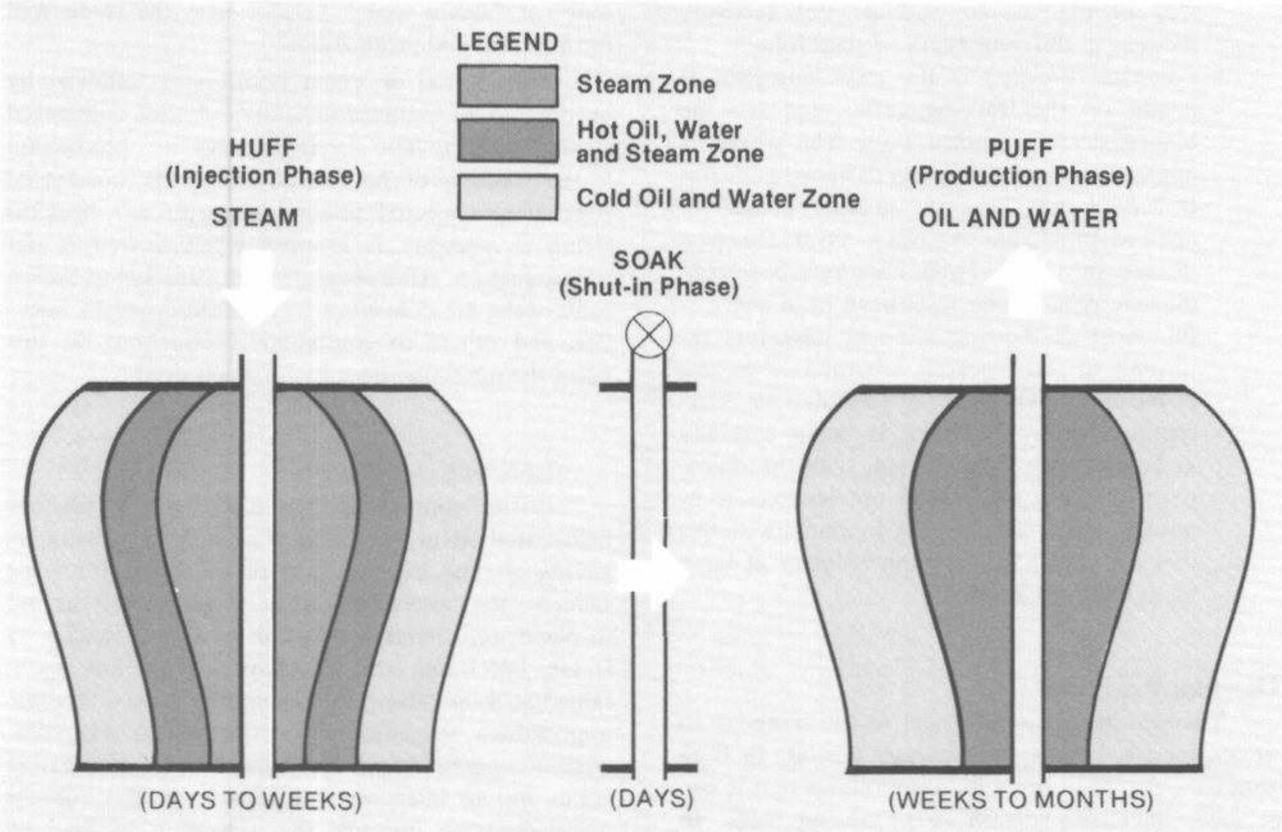

Figure 6. Cyclic Steam Stimulation Process.

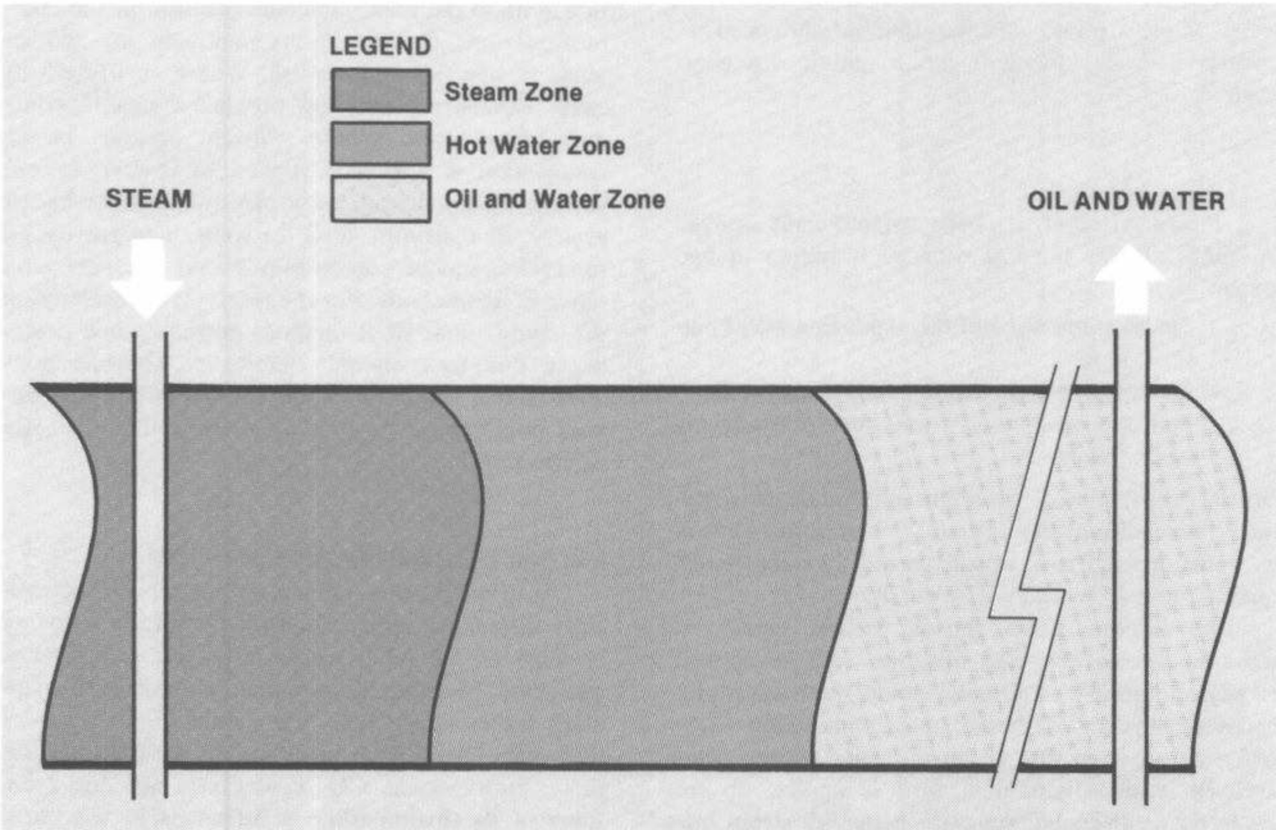

Figure 7. Steam Drive Process (Steam Flood).

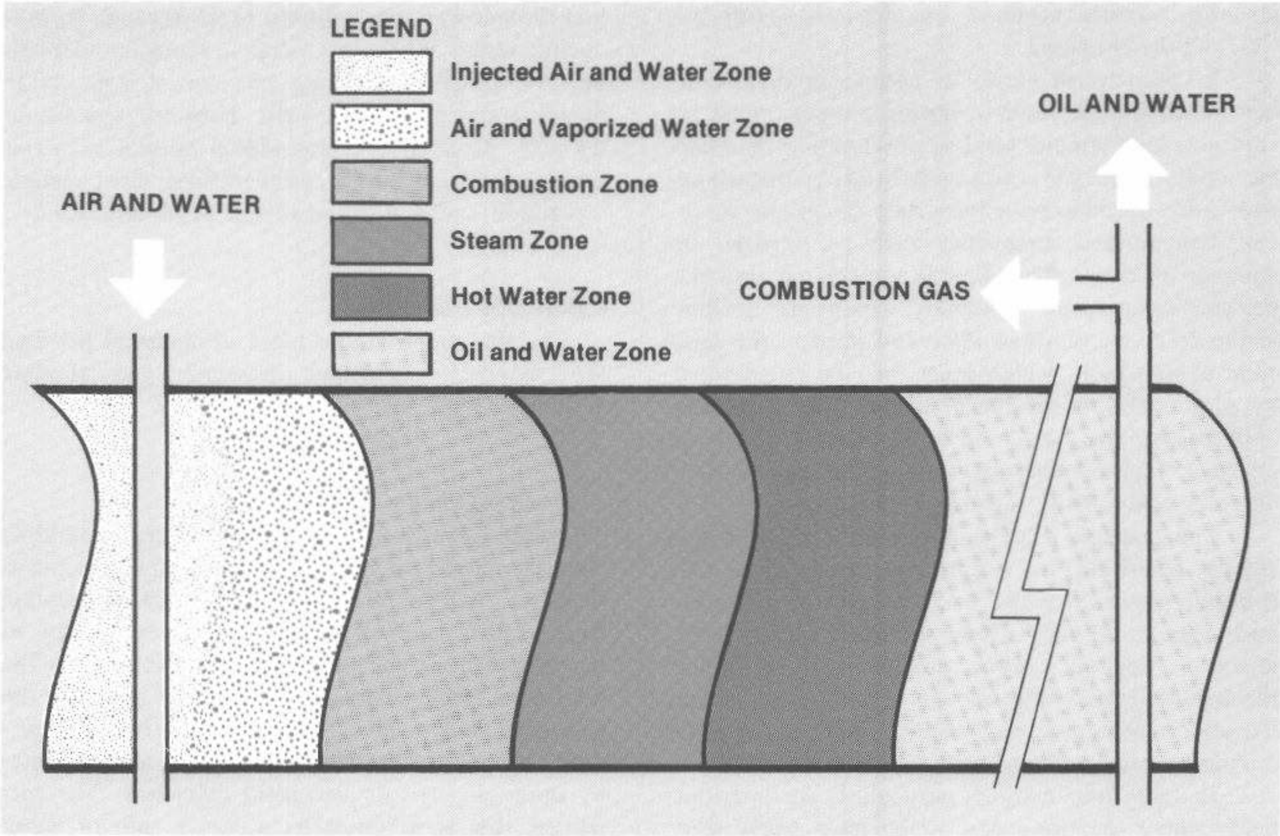

Figure 8. In-Situ Combustion Process—Wet Combustion.

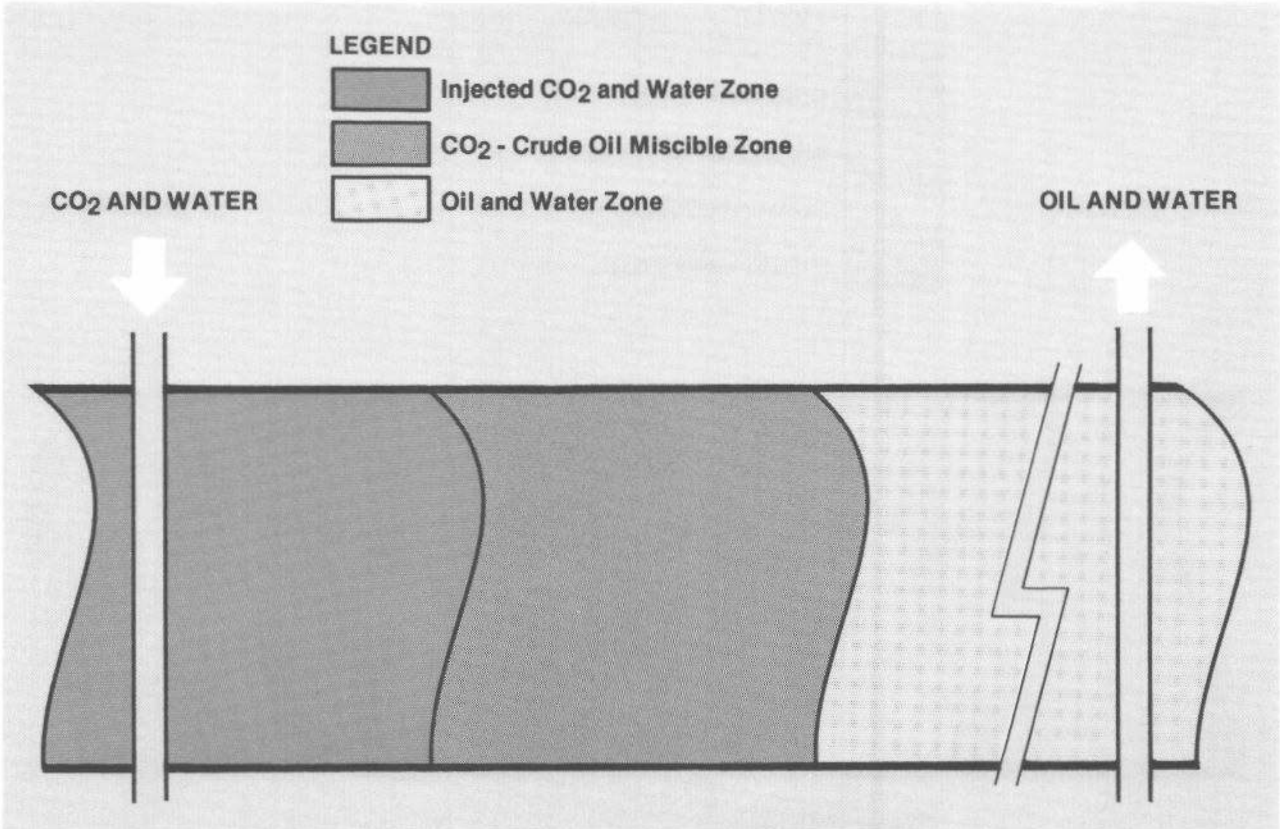

Figure 9. Carbon Dioxide Miscible Flooding Process.

resulting mixture becomes miscible with both the CO_2 and the in-situ oil.

To accomplish successful carbon dioxide miscible floods, the reservoir operating pressure must be kept at a high enough level to develop and maintain the mixture of CO_2 and vaporized hydrocarbons which are miscible with the crude oil at the reservoir temperature. Impurities such as nitrogen or methane in the carbon dioxide stream increase the pressure required for miscibility. Mixing due to flow in the reservoir tends to alter and destroy the miscible composition, which must then be regenerated by additional vaporization of hydrocarbons. In field applications, there may be both miscible and near miscible displacements proceeding simultaneously in different parts of the reservoir.

The injected volume of carbon dioxide is designed specifically for a particular application, and it usually ranges from 25 to 50 percent of the reservoir space to be swept. Near the latter stages of the injection program, carbon dioxide may be driven through the reservoir by a low-cost inert gas or water. To achieve higher sweep efficiency, water and carbon dioxide gas may be injected in alternate cycles.

In some applications, particularly in limestone fields where the use seems to be most likely, carbon dioxide may prematurely break through to producing wells. When this occurs, remedial methods may be possible by using mechanical controls in injection and production wells. However, a substantial CO_2 production is considered normal with this process, and economic considerations must include separation and reinjection of this produced CO_2.

Chemical Flooding

In this report, three types of chemical flooding are analyzed: surfactant, polymer, and alkaline flooding.

Surfactant Flooding

Surfactant flooding (Figure 10) is a multiple slug type process involving the addition of chemicals to water. A slug of surfactant material, amounting to a small fraction of the reservoir pore volume to be processed, is injected. The surfactant lowers the interfacial tension between the injected fluid and the reservoir oil and water to almost zero. This low interfacial tension minimizes the capillary forces, thereby improving the displacement efficiency. The surfactant slug is followed by a larger slug of water

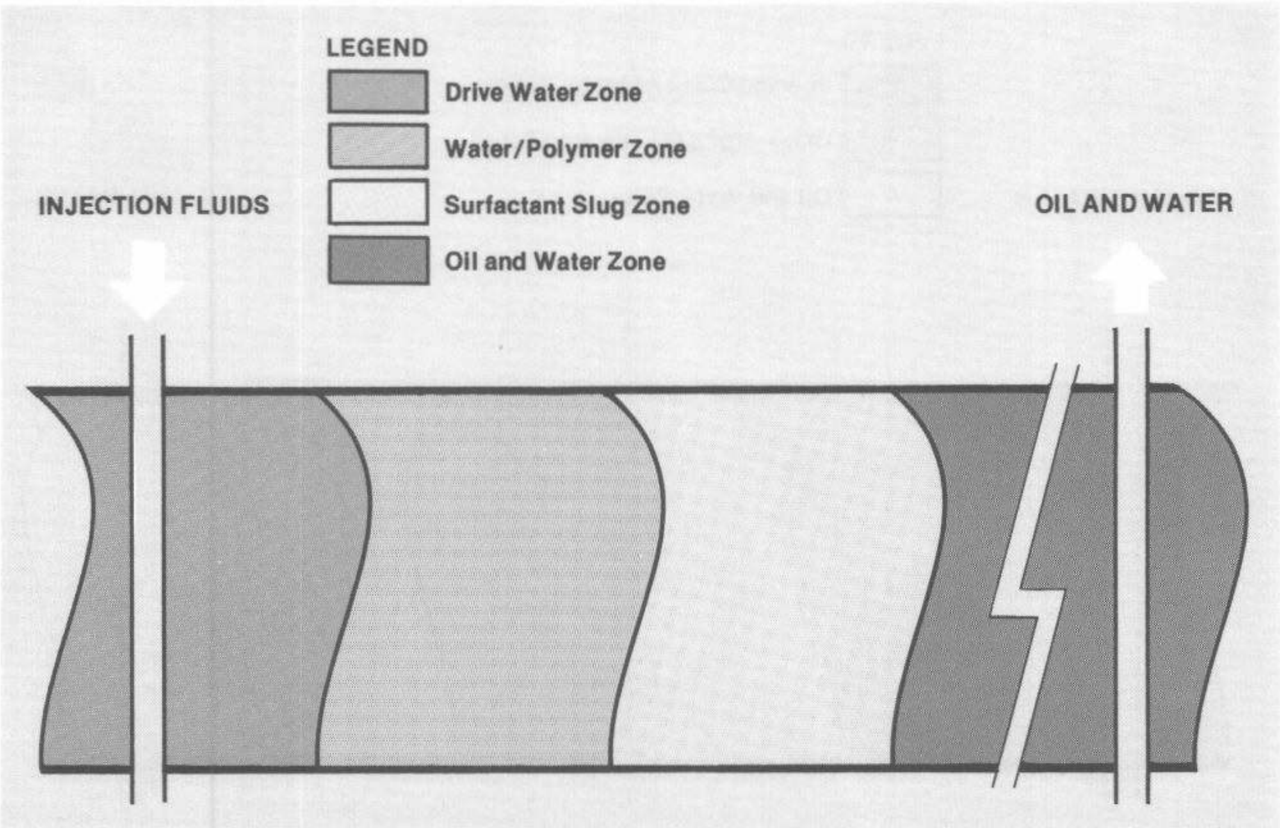

Figure 10. Surfactant Flooding Process.

containing a high molecular weight polymer. This slug usually ranges in size from 25 to 100 percent of the total pore volume of the reservoir to be processed. The water/polymer slug is used to develop a favorable mobility ratio displacement, to improve the sweep efficiency, and to preserve the integrity of the costly slug of surfactant chemicals.

Each reservoir has unique properties, and specific chemical systems must be designed for each individual application. The concentration and volume of chemicals used will depend upon specific properties of the fluids and the rocks involved.

Surfactant flooding is receiving widespread attention, both in laboratory and field tests. Pilot tests are necessary to evaluate the effectiveness of a specially designed process in each specific reservoir. Successful pilot tests are prerequisite to oil producers and chemical manufacturers making financial commitments for commercial attempts on entire reservoirs.

Polymer Flooding

Polymer flooding is an augmented waterflood. Polymers in use currently are synthetic (polyacrylamide) and biologically produced (polysaccharide). These high molecular weight polymers are added to the injection water to improve (decrease) the mobility contrast between the in-place and injected fluids. This can increase the sweep efficiency and thereby improve oil recovery. Unlike the use of polymer as a drive fluid in surfactant flooding, where it is necessary to achieve a favorable mobility ratio (less than unity) to protect the integrity of the surfactant slug, the polymer augmented waterflood is not always designed to achieve a favorable ratio. By requiring only an improved mobility ratio, the process may be used with higher viscosity oil than those for which a surfactant flood might be considered.

In operation, the polymer reduces the ability of the injected water to flow in the reservoir, which results in improved sweep efficiency. The polymer-water enters otherwise bypassed pore spaces, thus contacting more of the oil and moving it to wells. It has its greatest utility with waterfloods in reservoirs that contain viscous oils (up to about 200 cp), that are moderately heterogeneous, and that possess a permeability variation up to a ten-fold range. Increased recovery over waterflood will be modest, and the increased cost of production moderate. Currently, polymer flooding is being used commercially on a limited scale, both in the United States and elsewhere.

Alkaline Flooding

Alkaline flooding uses chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate added to flood water to enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction, spontaneous emulsification, or wettability alteration. These mechanisms are related to the in-situ formation of surfactants from the neutralization of petroleum acids by alkaline chemicals in the displacing fluids. Since the content of such natural petroleum acids is normally higher in the lower API gravity crude oils, this process seems to be applicable primarily, or exclusively, to the recovery of moderately viscous, low API gravity, naphthenic type crudes.

Although emulsification in alkaline flooding processes provides mobility control to a certain degree, emulsification alone may not be sufficient in sweeping highly viscous crudes; other chemicals may be required to improve mobility contrast.

Only a few field tests have been reported, a few of which were technologically encouraging (see Appendix D).

Enhanced Gas Recovery

Enhanced gas recovery represents an entirely different problem from enhanced oil recovery. Gas flows to producing wells entirely by natural expansion due to pressure reduction, and normally recovery cannot be improved economically by displacement with another fluid.

The possibility of recovering significant volumes of gas from very low permeability (tight) gas bearing formations has received much attention during the last decade. Although these deposits may contain large volumes of gas, the gas cannot normally be produced at rates sufficient to merit the costs of drilling and development. Most current research and field testing is concentrated on hydraulic fracturing of the reservoir to improve producing rates, including massive fracturing treatments which may propagate fractures in the reservoir several thousand feet. Success in field testing has been variable, apparently depending on the geologic nature of the reservoir tested.

To project the potential recovery in the time frame 1976-2000 would require both an ability to project the results of a variety of hydraulic fracture treatments in a variety of reservoirs, and definition of the target to which the process might be applied. The gas volume, reservoir location, geologic characteristic of reservoirs and other data on this potential resource are essentially undefined at this time because these factors have not been explored. Thus, it was not possible to make meaningful projections of enhanced gas recovery in this study.

Chapter Two

Analysis Considerations and Procedures

This chapter reviews general economic considerations for enhanced recovery processes, and the specific economic and technical analysis procedures used in this study. The technical and economic considerations are closely interrelated. Calculation of the potential of EOR is dependent both on technical viability of specific EOR processes in specific reservoirs, and on the number of such reservoirs where application would meet or exceed a minimum discounted cash flow rate of return (DCFROR) requirement for the economic conditions considered. The calculation procedure in this study is based on reservoir-by-reservoir examination of 245 sample reservoirs in the states of California, Texas, and Louisiana and supplemented by information from other sources. The data base was provided to the Council for this study by the Department of the Interior and was developed by Lewin & Associates in conjunction with a study for the Federal Energy Administration. Results for the United States as a whole were extrapolated from this data base.

Project Economic Considerations

General Economic Considerations

As opposed to exploration for new fields, EOR approaches are applied to known reservoirs and, thus, are not susceptible to finding risks. However, the physical and financial outcomes of most present EOR attempts may well be at least as uncertain as conventional exploration. Although reservoir locations are certain, the expenditure requirements, oil recovery effectiveness, and net unit revenues from EOR operations will vary widely from project to project. Moreover, these projects generally will require very large front-end capital commitments and long lead times before any future benefits begin to accrue.

The uncertainty associated with relatively risky ventures, such as EOR projects, requires commensurately higher than average target returns to offset attempts that fail. This would be especially true for first generation EOR efforts during the early years of development.

Estimates of project economics, as measured by discounted cash flow rate of return, differ from historic, overall book returns; project evaluations recognize expenditures in the time period in which they occur, while accounting books time-spread some expenditures through use of depreciation, depletion, and other non-cash accounts. Also, accounting books measure the aggregate performance of all foregoing investments that are still active, and these would encompass a wide spectrum of quality, ranging from highly successful to very poor.

The aggregation of successes and failures, the time-spreading of capital expenditures via depreciation and depletion charges, and the inclusion of other costs not specifically associated with individual projects will almost always result in actual booked return on investment being significantly lower than acceptable target DCFROR's for individual projects. Therefore, in order to achieve aggregate results adequate to maintain historic book return levels, target DCFROR's for individual projects must be set well above historic book rates, even for low-risk project investments.

At this time, most key determinants of prospective EOR project returns are highly uncertain. Some of these factors are:

- **Investment Cost**—Since most EOR processes are as yet untried on a large commercial scale, the initial investment requirements are subject to substantial and unknown variance.

- **Operating Cost**—Additional uncertainties arise since large-scale operating experience is lacking at this time. Also, future escalation rates for the various operating cost items will differ from one another, and are now indeterminate.
- **Process Effectiveness**—Again, lack of experience, coupled with the physical and technological unknowns regarding reservoir configurations and process behavior, cause expected production performance to be extremely uncertain.
- **Crude Oil Prices**—The unit revenues to be derived is a key determinant of expected financial results. At this time, the future market value (world price) of oil is unknown; moreover, the regulatory policies of the U.S. Government introduce another order of oil price risk. At this time, there is no assurance that all EOR oil would be allowed to be sold at market prices. Also, it is not known at what levels future domestic oil prices may be established.
- **Taxation**—The application of existing tax laws to EOR projects (e.g., expensing versus capitalizing of injected fluids) has not yet been firmly resolved. Furthermore, ongoing determinations of tax law changes may significantly affect EOR economics.
- **Environmental Factors**—The future costs and restraints associated with environmental protection in EOR operations is uncertain at this time.

The combined impact of uncertainties associated with each of these key factors is to effect a wide variance of possible DCFROR outcomes for EOR projects, at least initially. As experience is gained, this variance should narrow to some extent, but may remain significant for some years. In the meantime, relatively high target DCFROR's will be required to compensate for the high risk of loss.

Other EOR Investment Considerations

EOR projects must compete with alternative opportunities for investment dollars, manpower, and other resources. Companies must carefully allocate their limited capital and other resources to the most productive projects; thus, EOR projects must compete with a full slate of more conventional exploration and production (E&P) and other petroleum-related activities within each company.

If the petroleum industry as a whole is to increase capital outlays beyond existing cash flow restraints, external capital must be attracted by opportunities equal or superior to non-petroleum investment alternatives of equivalent risk.

It is emphasized that high DCFROR's for prospective EOR projects are necessary, but not always sufficient to promptly effect the investments required. Industry and company cash flows must be adequate to support the additional investments. Thus, current cash generation from all petroleum industry activities is a critical determinant of total EOR progress, as is the prospective DCFROR for a specific EOR project.

Project Evaluation Case Parameters

General

In the interest of simplifying comparative case analysis, project evaluations were computed in terms of constant 1976 dollars.

Oil Price Cases

In order to assure consideration of a wide range of possible prices, crude oil prices of $5, $10, $15, $20, and $25 per barrel (constant 1976 dollars) were selected for case analysis. Simplifying assumptions made for purposes of this analysis are: (a) the prices specified represent wellhead prices for all domestic production regardless of quality, location and recovery mechanism; and (b) that these prices are immediately attained and would prevail throughout the period analyzed.

The second assumption is not unique to petroleum supply economics. Conventional supply/price analysis generally assumes that all prices considered are received in the same time of reference. The assumption that price specifications apply to all domestic oil is important in this study because petroleum prices affect some of the project costs (see process appendices) as well as the revenues.

Income Tax Cases

Tax treatment of prospective EOR projects could be a key determinant in accept/reject decisions. Although the application of existing tax law to EOR projects is not yet certain, the moderate and restrictive cases described in Table 1 are believed to be consistent with probable interpretations of existing tax law, and were selected to assess tax treatment sensitivity.

It is assumed for both cases that federal and state income tax rates would total 50 percent, and

TABLE 1

ASSESSMENT OF TAX TREATMENT SENSITIVITY

Item	Tax Treatment Cases: Moderate	Restrictive
Intangible Drilling and Development Costs		
— Producing Wells	Expense	Expense
— Injection Wells	Expense	Expense
— Water Source Wells	Expense	Capitalize
Hardware		
— Depreciation Method	5-year (SL)*	11-year (SYD)†
— Investment Tax Credit	10% of 2/3 of Total	7% of Total
Cost of Injected Material		
— Capitalize or Expense	Expense	Capitalize
— Depreciation Term	Not Applicable	Reservoir Life
— Depreciation Method	Not Applicable	SL*
— Tax Credit	Not Applicable	None

* Straight-line method of depreciation.
† Sum-of-the-year's digits method of depreciation.

that no depletion allowances would be applicable. A more complete discussion of EOR sensitivity to tax treatment is included in Appendix C.

Rate of Return Cases

To include a range of capital cost possibilities, minimum constant dollar DCFROR requirement cases of 10, 15, and 20 percent were selected. Most projects in the aggregation for each of these DCFROR requirement cases would exceed the specified rate, i.e., these rates are used in the analysis only as minimum requirements and not as expectations for average results.

DCFROR's derived from estimated constant dollar cash flows will be lower than those derived from estimated current (or inflated) dollar cash flows by an amount approximately equal to the inflation rate. Thus, in a 5 percent annual inflation environment, the 10, 15, and 20 percent constant dollar DCFROR's would be about equivalent to 15, 20, and 25 percent *current* dollar DCFROR's, respectively. This distinction is noted since both bases are commonly used.

While the higher portion of the DCFROR range selected probably will be most applicable during the early stages of technology development, as experience is gained and results become more predictable, required DCFROR's should decline somewhat. In any event, the results for the higher DCFROR cases also are shown in the report.

Overhead and Non-Income Taxes

Surveys of available industry data and the consensus of expert opinion indicate the following generalized estimates for project screening purposes:

Item	Estimated Cost
• Capital Investment Overhead	10 Percent of Investment
• Operating Overhead	20 Percent of Direct Operating Cost
• Production and Property Taxes	8 Percent of Producer Revenue

Overhead estimates refer to general corporate costs not directly identifiable with specific projects, but which contribute to the firm's continuing capital investment and operating activities. Examples of such costs include general management, administration, research and development (R&D), etc. While the costs of these functions are not directly tied to specific projects, they tend to fluctuate with investment and operations activity levels. Thus, estimated incremental overhead costs are appropriate items to be included in project economics.

Pilot Testing Economic Considerations

While pilot testing costs may be significant for an individual company and/or an individual reservoir, in an industry context, pilot testing will not be a large component of average EOR unit costs. For example, surfactant flooding research and development (R&D) costs, including pilot testing, may total less than $.10 per barrel of additional oil, if surfactant flooding is widely adopted. R&D costs for other processes probably will be even less.

Owing to the small unit costs for R&D, they are assumed to be covered by the overhead estimate and/or well within the precision afforded by other estimates and assumptions.

Cost Data Summary

Cost estimates were developed in two broad categories: (1) process-independent, and (2) process-dependent. Process-independent costs include widely applied items, such as well drilling and completion costs, workover costs, well equipment costs, lease equipment costs, lease operating costs, etc. Process-dependent costs are those more specifically associated with the individual processes studied. For example, for thermal methods the cost of steam generators, air compressors, and steam feedwater treatment equipment would be applicable only to that specific process. Likewise, CO_2 transmission and compression costs would be unique to CO_2 miscible operation, and surfactant costs would apply only to chemical flooding.

Process-independent cost estimates are detailed in Appendix C, and process-dependent costs are discussed within the respective process text and appendix sections of this report.

With the inflation-free economics used in this report, most costs—both process-dependent and -independent—were assumed constant, varying neither with time nor economic conditions specified. In a few cases, however, oil price and process cost were so closely related that ignoring this effect in the analysis would have caused serious distortion. For this reason, a few important cost factors, such as chemicals for chemical flooding, electric power costs for electrically driven air compressors in thermal recovery, and carbon dioxide compression costs, were assumed to vary with oil price using approximations shown in the appendices.

Economic Calculation Procedure

The approach to economic analysis employed in this study is based on the estimated economic viability of specific enhanced recovery methods as applied to sample reservoirs under each set of economic conditions specified. Details are discussed in the following section and the appendices. The steps involved in this procedure may be summarized as follows:

- The 245 sample reservoirs in California, Texas, and Louisiana were each categorized as being best suited to one or more of the enhanced oil recovery processes considered, or to none. (The screening process for determination of technical viability is discussed in the "Technical Analysis Procedures" section of this chapter.)
- The physical outcomes, i.e., the ultimate and time-rated additional oil recovery, of applying the selected EOR process(es) to these reservoirs were established.
- Using the price, cost, and tax cases specified, DCFROR's for each sample project were calculated for each set of economic parameters.
- Comparison of these results with each minimum rate of return criterion indicated whether or not requisite economic conditions were satisfied. Aggregation of results for each economic condition established total estimates for the sample reservoirs. Thus, both incremental ultimate recovery and producing rate projections for each economic condition vary primarily as a function of the number and size of the reservoirs to which application of the specified EOR process is economic at that condition.
- Results from the sample reservoirs were extrapolated twice: first, to totals for all reservoirs in the three sample states, and then to the United States as a whole. Extrapolation procedures are discussed briefly under "Technical Analysis Procedures," and are reviewed in more detail in the individual process appendices.

Technical Analysis Procedures

Estimates of the potential of enhanced recovery ultimately depend on engineering judgment. In this study, the analysis is based on consideration of the applicability of each process to each of 245 sample reservoirs in the data base. Judgment is applied first in the screening process to match reservoirs with specific EOR processes. The development of equations to calculate recovery is based on a large body of technical literature and tempered by practical operating experience. Geologic review of reservoirs was used as an additional screening criterion, both to determine applicability and to rate the quality of the reservoir for EOR applications. This second screen was based almost entirely on qualitative judgment.

The Technology Task Group served as a forum for collective review and discussion of judgments made during the course of the study. Experts in the companies represented on the Task Groups and Coordinating Subcommittee, other companies, and universities were consulted extensively.

Detailed descriptions of the analysis procedure used for each enhanced recovery process in this study are provided in the appendices. Although minor differences exist in the detailed procedures, the basic approach used in evaluating the potential of each method was similar to the seven-step procedure outlined below.

1. State-of-the-Art Assessments
2. Data Base Review
3. Selection Procedure—Screening and ranking of data base reservoirs as potential EOR candidates
4. Dominance Determination—Designation of preferred process for each EOR candidate
5. Process Performance Predictions—Estimation of ultimate oil recovery and typical production rates for various reservoir parameters, field development, etc.
6. Process Economics—Calculations made for various economic conditions including studies of the effect of uncertainties such as process costs, recoverable oil, and timing
7. Extrapolation—EOR potential recovery and production rates obtained for reservoirs in primary data base, extrapolated to three-state totals for California, Texas, and Louisiana and to the entire United States.

State-of-the-Art Assessments

The state-of-the-art assessment for each EOR process includes a brief description of the process, including background information and a discussion of factors (reservoir parameters and crude properties) affecting its use. In addition, a brief review of field results and current applications is included. As a part of these assessments, screening criteria were developed for use in identifying potential enhanced oil recovery candidates from a list of 245 crude oil reservoirs (175 fields) contained in the primary data base described below.

Data Base Review

For this study, the data base developed by Lewin & Associates in conjunction with their study for the Federal Energy Administration* was supplemented with information from other sources. The basic data base consists of information developed from a variety of public sources for 245 crude oil reservoirs in 175 oil fields in the states of Louisiana, Texas, and California. These 175 fields contain approximately 60 percent of the oil remaining after primary recovery and conventional secondary recovery from known fields in these three states; they contain between 35 and 40 percent of the oil remaining after primary and secondary recovery in known fields in the United States, excluding the North Slope of Alaska.

In addition to the above data base, use was made of the Petroleum Data System (PDS)† data base at the University of Oklahoma, of information developed by the Gulf Universities Research Consortium for ERDA, and of American Petroleum Institute (API) statistics. Data compiled by the Interstate Oil Compact Commission were utilized in making estimates of recoverable oil saturations. Estimates of reservoir temperatures and water salinities were obtained from a number of public sources, including surveys, etc. Additions to the primary data base were transmitted to the Department of the Interior as they were made.

One of the principal sources of uncertainty in the estimates in this study of enhanced oil recovery potential arises from the lack of the detailed reservoir information that would normally be required to evaluate the applicability of enhanced recovery processes. Typically, such an evaluation will involve an extensive study of the reservoir, requiring several man-years of effort and much more detailed geologic and reservoir engineering data than is normally obtained or required in designing a conventional recovery process, such as a waterflood. This limitation was alleviated insofar as possible by combining information contained in several data bases with estimates of the variability of factors that could influence enhanced oil recovery performance. For example, the economic analyses of surfactant flooding candidates included high-, low-, and mid-range estimates of the recoverable oil saturation. In other cases, factors such as reservoir geology, the presence of extensive faulting or fractures, etc., were judged to limit the recovery potential of enhanced recovery methods.

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*The Lewin data base was obtained by the Department of the Interior from the Federal Energy Administration for use in this study.

†PDS was developed by the University of Oklahoma under contract to the U.S. Geological Survey.

Selection Procedure

The screening criteria used in this study to select and rank potential EOR candidates are summarized in Table 2. A list of potential EOR candidates was obtained by applying these basic screening criteria to all reservoirs in the data base.

A typical example of the application of the screening criteria is that for CO_2 miscible flooding. The basic screening criteria for CO_2 flooding include the reservoir temperature, oil composition and viscosity at reservoir conditions, and a procedure (using the oil gravity--°API) that predicts the minimum pressure required for a miscible-CO_2 displacement. In addition, consideration is given to geologic criteria such as the absence of extensive natural fracture systems or high-permeability, stratigraphic, thief zones. When the CO_2 screens are applied to the primary data base of 245 reservoirs, the initial screening step reduces the number of possible CO_2 candidates to 165 reservoirs.

Reservoirs passing the first screening step were then subjected to a second, more detailed review. On this second review, information concerning additional factors that would influence oil recovery performance of each reservoir was included whenever such information was available. Both geological and reservoir engineering data were sought, including the gross depositional environment, general lithology, estimated degree of heterogeneity of the reservoir, success of past waterflooding, and the likely influence of gas caps or underlying aquifers. This review served as a second screening process. Some reservoirs were

TABLE 2

SCREENING CRITERIA FOR SELECTION OF EOR CANDIDATES

		Chemical Flooding Processes			Miscible Processes	Thermal Processes	
Screening Parameters	Units	Surfactant	Polymer	Alkaline	Carbon Dioxide	Steam	In-Situ Combustion
Oil Gravity	°API	≥25	--	≤ 35*	≥27*	≤25	≤25
Oil Viscosity, (μ)	cp	≤30*†	≤200	≤200	≤10	≥20	≥20
Depth (D)	Feet	--†	--	--	>2,300*	>200<5000*	>5,000*
Zone Thickness (h)	Feet	--	--	--	--	>20	>10
Temperature	°F	≤250	≤200	≤200	< 250*	--	--
Permeability, Average ($\bar{K}$)	md	≥20†	≥ 20	≥20	--	--	--
Transmissibility (Kh/μ)	md-ft/cp	--	--	--	--	100	20
Salinity of formation brine (TDS)	ppm	≤200,000	--*	--*	--	--	--
Minimum oil saturation at start of process							
In water-swept zones (S_{orw})	fraction	≥.20*	--	--	--	--	--
Mobile (S_{or}-S_{orw})	fraction	--	≥.10				
Minimum Oil Content at start of process (S_{or})	B/AF	--	--	--	--	>500	>500
Rock type	--	sandstone	--	sandstone	sandstone or carbonate	sandstone or carbonate	sandstone
Other	--	‡	‡	‡	‡	‡	‡

* See text of appropriate appendix.

† Used to estimate required well spacing for given project life.

‡ Other criteria including geological data were also considered. The specific criteria used depended upon the process. In general, reservoirs with continuous and uniform strata were ranked higher than were heterogeneous reservoirs with extensive faulting, discontinuous lens-type deposits, fractures, etc. Similarly, reservoirs with extensive underlying aquifers or overlying gas caps were ranked lower or excluded as EOR candidates in view of the decreased likelihood of a successful EOR project.

rejected because of their unfavorable properties.

Reservoirs that passed the second screen for any EOR process were ranked good, fair, or poor candidates for that process. In some reservoirs, subdivisions were made with each receiving its own rank. In general, the geological and reservoir engineering data were not adequate to provide a precise technological ranking for any given reservoir. In order to rank the reservoirs, it was frequently necessary to rely upon the experience and judgment of the geologists and reservoir engineers reviewing the available information. Although the ranking of any individual reservoir may be higher or lower than it actually deserves, the average ranking of all potential EOR candidates should offset these errors to an acceptable degree.

Again using the miscible-CO_2 process as an example, 109 CO_2 candidates remained at the end of this second screening, of which 37 were also candidates for other EOR processes. The next step in the analysis procedure was to determine which EOR process would be the dominant method.

Dominance Determination

As indicated above, some reservoirs satisfied the screening criteria for more than one recovery process. The method used for determining which EOR process would be the preferred (or dominant) process is described below.

The rankings given to the reservoir for each competing process during the second screening review were compared. In general, the process that ranked the highest was selected as the preferred method. However, if a reservoir received the same ranking for two EOR processes, economic calculations were made for both processes, and the process having the highest present value profit calculated for a rate of return of 10 percent and a crude price of \$25 per barrel was selected as the dominant (or preferred) process. The effect of this procedure was to favor the selection of the process with the higher prospective oil recovery.

Of the 37 CO_2 candidates which were also candidates for other processes, CO_2 flooding was selected as the preferred process for 11; the remaining 26 reservoirs were assigned to other EOR processes, primarily to surfactant flooding.

Process Performance Predictions

Evaluations of EOR processes require that estimates be made of both the incremental ultimate oil recovery that can be achieved and typical production rates as a function of time for each candidate reservoir. As noted in Chapter Three, results were calculated both for the best estimate of parameters (the base case) and for several additional cases, to study the influence of key parameters on results. For each of the EOR processes included in this study, the critical reservoir parameters affecting process performance were identified and the impact of each of these key parameters on process economics was determined for reasonable ranges of the parameter. For all processes, the impact of various projections of recovery performance and process costs was evaluated. For surfactant flooding specifically, the profitability of surfactant flood application in each of the reservoirs assigned to that process was determined for two well spacings and for high-, low-, and mid-range estimates of (a) the recoverable oil saturations, (b) chemical costs, and (c) the size of the surfactant slug. The mid-range estimates were selected as the "most likely" values of the various reservoir parameters and, as such, were used to develop the "best estimates" of the performance of individual reservoirs. The base case results for any specified set of economic assumptions were obtained by aggregating the total potential ultimate recovery and the corresponding production rates of reservoirs satisfying the specified economic criteria.

Process Economics

General economic considerations and procedures are described in the preceding section of this chapter. A standard economic model, described in more detail in Appendix C, was used for the economic evaluations. This model utilizes the technical forecasts of oil production rates, together with cost data specifying capital requirements, operating expenses, and other costs as a function of time and provides the discounted cash flow rate of return for each economic condition. Calculations were made for each projection of reservoir performance described above for each assumed crude price (\$5, \$10, \$15, \$20 or \$25 per barrel) and each of two tax treatments. The minimum crude price from those considered which would be required for the EOR process to satisfy each different rate of return criterion was then determined for each projection of process performance.

Extrapolation

The objective of this study has been to estimate the overall enhanced oil recovery potential, for the three states, California, Texas, and Louisiana, and for the entire United States, from a representative sample of U.S. reservoirs. As indicated above, the reservoirs in the original data base contained about 60 percent of the original oil-in-place in those three states and 35 to 40 percent of the U.S. total, excluding the North Slope.

Although extrapolation of the results will introduce additional uncertainty to the projected results from the data base reservoirs, the extrapolation factors are not large and should be reasonable, since a large fraction of the total original oil-in-place in the United States was contained in the reservoirs in the data base.

The extrapolation procedures used for the different EOR processes are described in detail in the individual process appendices. However, the general approach was to develop extrapolation factors for each district (Texas), area (California), or state (Louisiana) based on estimates on the original oil in place in the data base fields and the corresponding totals for other reservoirs in each subdivision which were judged to have similar reservoir and crude properties (lithology, oil viscosity, remaining oil saturation, etc.). The rationale for using specified geographic locations for the scale-up base is that the geologic setting, and hence, the reserve and economic model, is similar over a narrow geographic base.

Since the data base reservoirs were restricted to California, Texas, and Louisiana, other sources of data were utilized for extrapolation to the remainder of the United States. The API and PDS data bases were the primary sources of information used for extrapolations although the Bureau of Mines study of *Heavy Oil Resources in the U.S.* was used in addition to the above as a guideline in extrapolating the potential of thermal methods.

Typical factors used for extrapolation from the three-state totals to those for the entire United States were 1.39 for surfactant flooding, 1.35 for polymer flooding, 1.25 for alkaline flooding, about 1.25 for CO_2 miscible, and 1.15 for thermal processes. Further discussion of these factors and their application appears in individual process appendices.

Chapter Three

Potential for Enhanced Oil Recovery

Results

The state-of-the-art assessments of EOR technology indicated considerable uncertainty in the probable performance of most EOR processes. From the outset of the study, it was apparent that a range of potential results would be more meaningful as a representation of recovery potential than any single estimate. As noted in the preceding chapter, the approach taken in this study was to obtain best estimate, base case performance and cost for each process, followed by study of the variability of results as a function of the possible range of individual critical parameters. While the base case results represent the single best estimate at this time, the range of potential results is equally important in establishing perspective on the potential of EOR processes.

Base Case Definition

The best estimate or base case performance estimates were made by developing best estimates of individual parameters, such as unit displacement efficiency, sweep efficiency, etc., which determine the calculated performance for each process. These base case performance estimates were considered to be roughly the mean of expected results. The consensus best estimate judgments were reviewed by a number of persons considered expert in enhanced recovery technology, and should represent a reasonable approximation to the overall judgment of industry at this time. *The base case represents neither a minimum assured result nor, conversely, an upper bound on the potential of enhanced recovery processes.*

The best estimate of costs for each process was developed in a manner similar to the performance estimates, with individual estimates of several key cost elements. Results shown for a "base case" thus represent best estimates of both performance and cost. *The term "base case" has no implications regarding oil price, tax case, or rate of return requirement.*

Each set of base case calculations consisted of 10 separate analyses, with computed economic results for five different oil prices ($5, $10, $15, $20, and $25 per barrel) at each of two tax cases (moderate and restrictive), with results from each analysis tested to establish reservoirs satisfying the 10, 15, or 20 percent DCFROR requirements in constant 1976 dollars.

The assumptions made in establishing the base case estimates are discussed further in the "Discussion of Results" section of this chapter.

Total of Base Case Estimates of All Processes

Since the potential of all enhanced recovery processes is so strongly dependent on economic incentive and involves uncertainties which cannot yet be fully evaluated, there is no single graph which can be used to depict the best estimate of the potential of enhanced recovery processes. The base case results can be summed to present a figure showing total for all processes, but must be determined and plotted for specified rate of return requirement and tax case (and, in the case of potential producing rate, specified values of oil price). Moreover, these estimates must be viewed in the light of the uncertainties in process performance and process cost. All results are incremental to existing production and current API proved reserves.

The sum of the base case results for incremental ultimate recovery from all enhanced recovery processes at a 10 percent rate of return requirement is shown in Figure 11. Potential ultimate recovery from enhanced recovery processes is heavily dependent on oil price. At $5 per barrel, total potential ultimate recovery is only about 2 billion barrels and is essentially all due to thermal processes. At an oil price of $10 per barrel, potential ultimate recovery increases to about 7 billion barrels, with carbon dioxide miscible flooding contributing an amount about equal to thermal, and with a very small amount of chemical flooding oil potential. At $15 per barrel, the potential ultimate recovery of 13 billion barrels is approximately equally distributed between thermal, carbon dioxide miscible, and chemical processes.

At oil prices of $20 and $25 per barrel (and at the assumed 10 percent rate of return), chemical flooding becomes the process with highest potential. The maximum potential calculated from the sum of base case results is approximately 24 billion barrels, at an oil price of $25 per barrel.

Figure 12 shows a somewhat different picture of potential ultimate recovery for a 20 percent rate of return requirement. At this higher DCFROR requirement, incremental ultimate recovery at $25 per barrel drops from about 24 billion barrels to 15 billion barrels, with chemical flooding having a relatively small impact. The influence of rate of return requirement is discussed in the "Discussion of Results" section of this chapter.

The total base case potential producing rate for all processes, for oil at $15 per barrel and a minimum DCFROR requirement of 10 percent is shown in Figure 13. Under these economic conditions, the incremental producing rate in 1980 is projected to be approximately 300 thousand barrels per day, and is essentially all from thermal processes. Incremental production in 1985 could be approximately 900 thousand barrels per day, with chemical flooding beginning to play a significant role. By 1990, thermal processes applied to existing reservoirs would be peaking out, and carbon dioxide miscible processes would become more important with a total potential producing rate of about 1.5 million barrels per day. This further increase in CO_2 miscible flooding would tend to offset decreases in the chemical and thermal

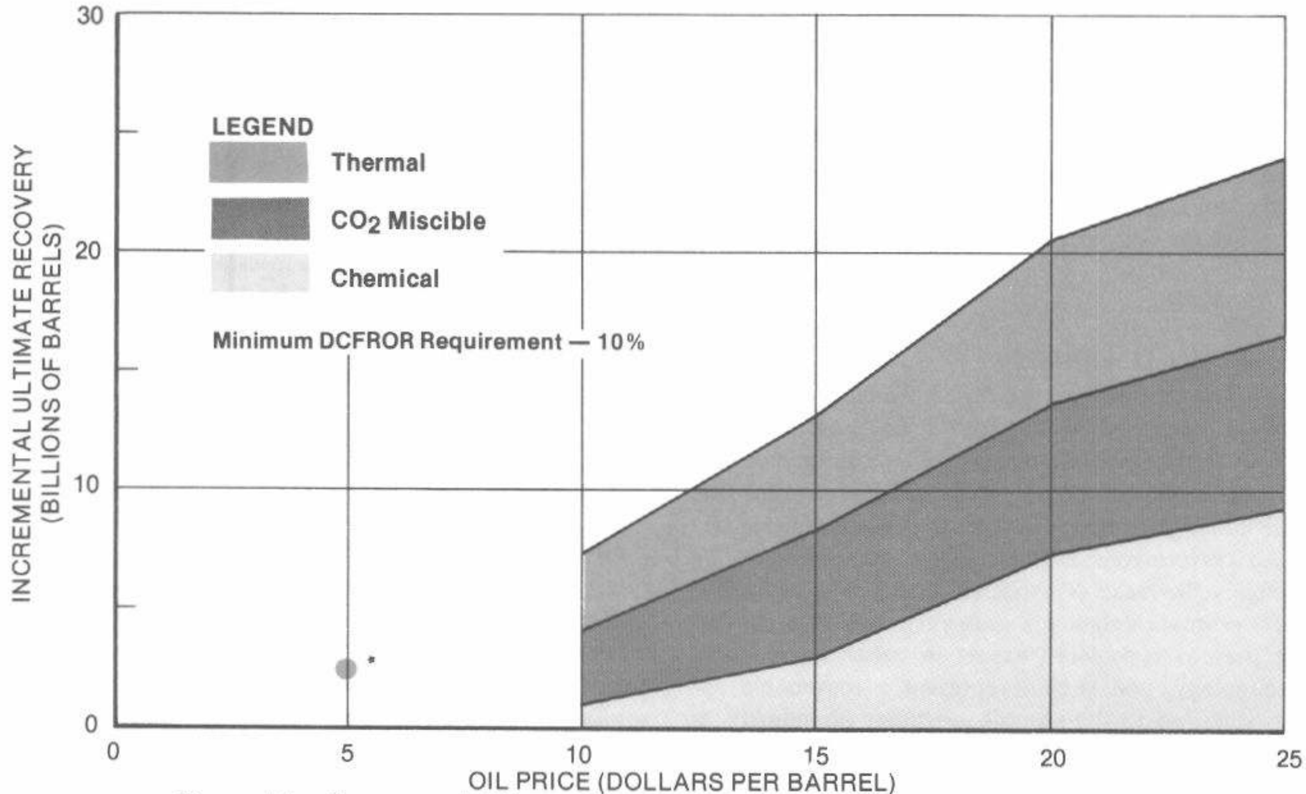

Figure 11. Incremental Ultimate Recovery—Base Case Performance and Costs.

*Recovery for Thermal at $5. Recovery for Chemical and CO_2 miscible flooding are zero at $5 per barrel and as shown at $10 per barrel. Recovery for intermediate prices between $5 and $10 per barrel has not been determined.

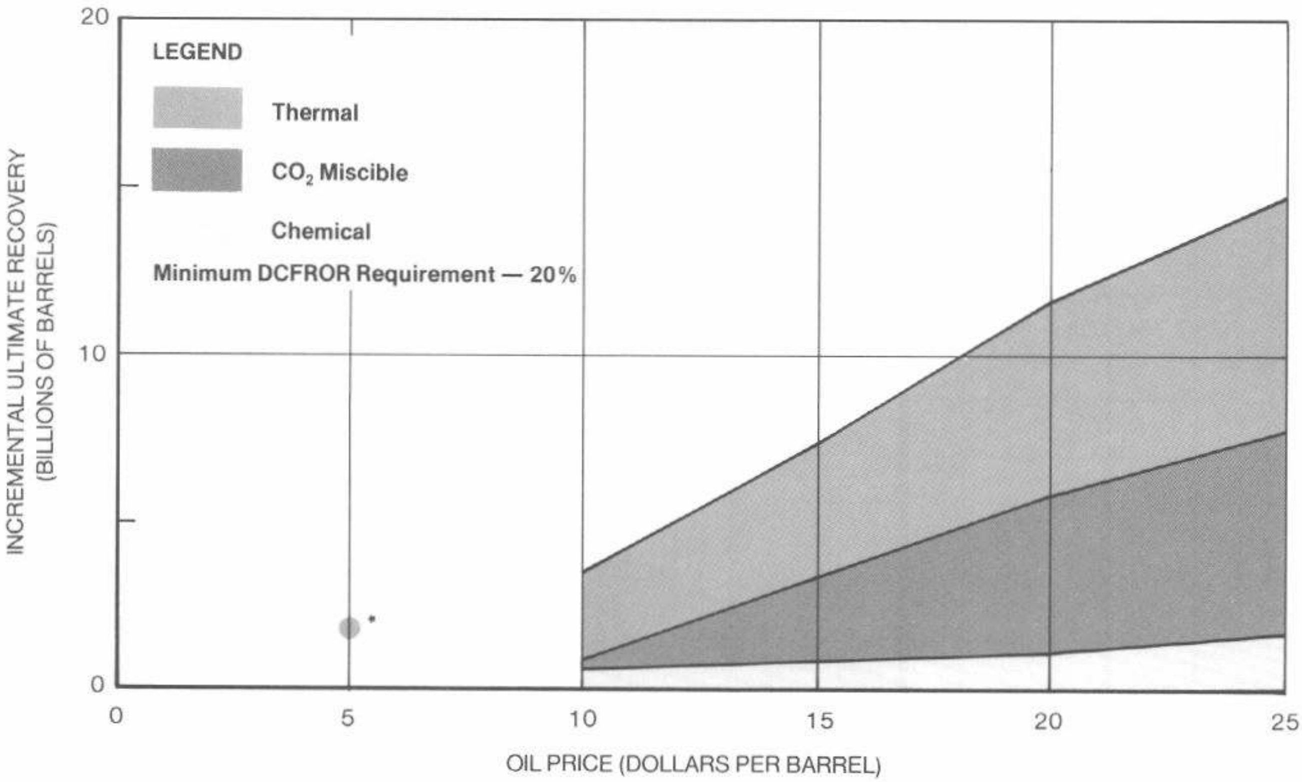

Figure 12. Incremental Ultimate Recovery—Base Case Performance and Costs.

* Recovery for Thermal at \$5. Recovery for Chemical and CO_2 miscible flooding are zero at \$5 per barrel and as shown at \$10 per barrel. Recovery for intermediate prices between \$5 and \$10 per barrel has not been determined.

producing rates between 1990 and 2000, so that the total producing rate from all processes would continue to climb slightly, to approximately 1.6 million barrels per day by the year 2000.

As shown in Figure 14, potential producing rates, for an oil price of \$25 per barrel, and a minimum DCFROR requirement of 10 percent are nearly double those for \$15 per barrel in the time frame 1985-2000. The potential producing rate in 1980 is affected only slightly and would be approximately 500 thousand barrels per day. By 1985, however, the producing rate with a \$25 per barrel oil price is expected to be potentially as high as 1.7 million barrels per day, which is more than the peak rate in the year 2000 for an oil price of \$15 per barrel. The potential producing rate at \$25 per barrel would continue to climb through the year 1995, and would peak at approximately 3.6 million barrels per day, dropping to approximately 3 million barrels per day by the year 2000.

Results by Recovery Process

All estimates of the total potential of enhanced recovery in the United States represent the sum of the calculated potential of individual enhanced recovery processes. The results in this study for each individual process do not indicate the absolute potential of that process if it were to be considered independently, because of the effect of dominance criteria on the results. For example, surfactant flooding, if considered by itself, would be applicable to several of the sandstone reservoirs that are considered to be candidates for carbon dioxide miscible flooding. In the event carbon dioxide miscible flooding proves to be significantly less efficient or more costly than indicated by the analysis in this study, it is entirely possible that chemical flooding would achieve a greater potential than is shown. The same type of interaction is present in several other instances.

In analyzing each process, the best estimate results were calculated first to establish a base case. The uncertainty or variability in results was then determined by calculating the sensitivity to key parameters, such as recovery performance or important process cost elements. All parameters other than the key parameter being studied were held constant at base case values during the variability analysis.

In the following presentation of results for individual process analyses, all results shown are the extrapolated values for the total United States unless

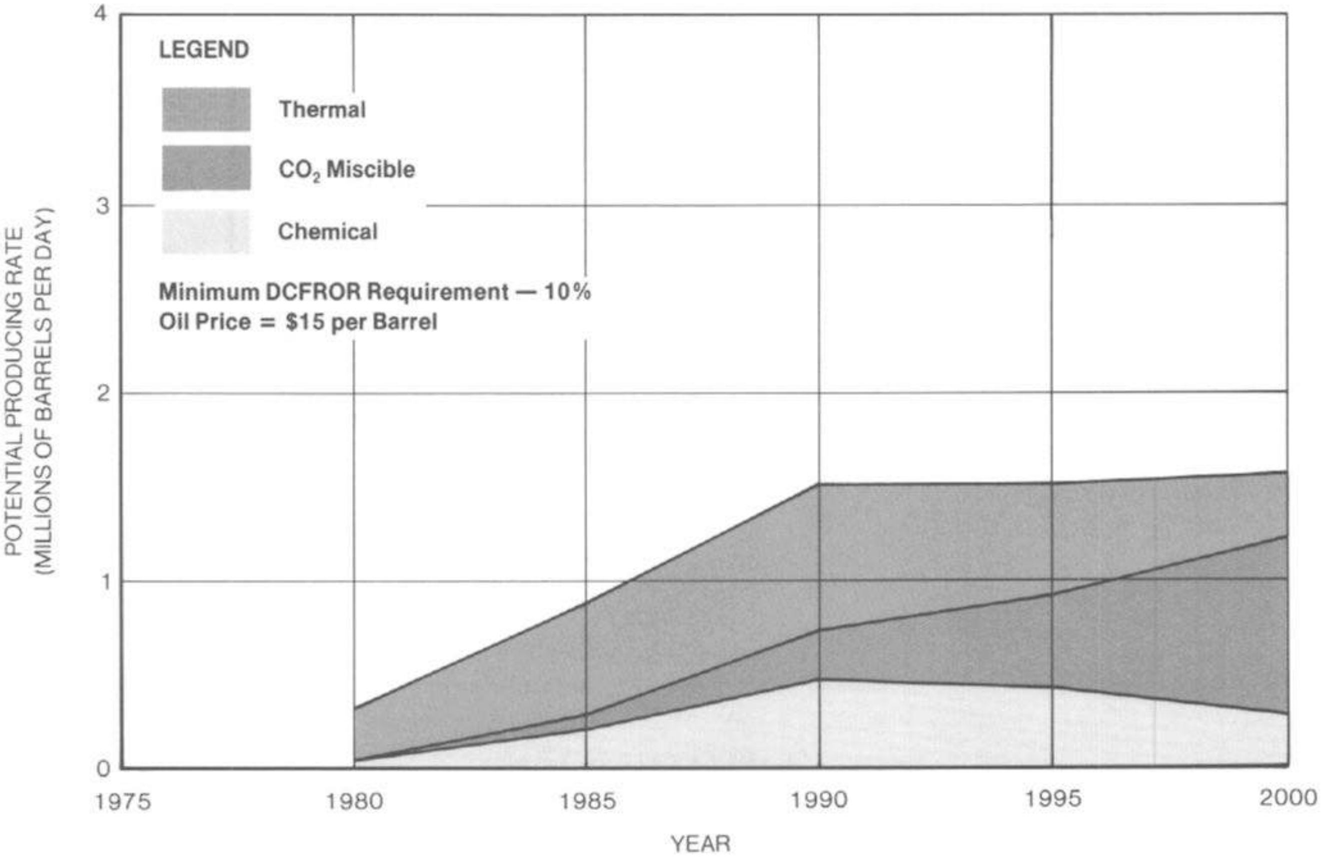

Figure 13. Potential Producing Rate—Base Case Performance and Costs.

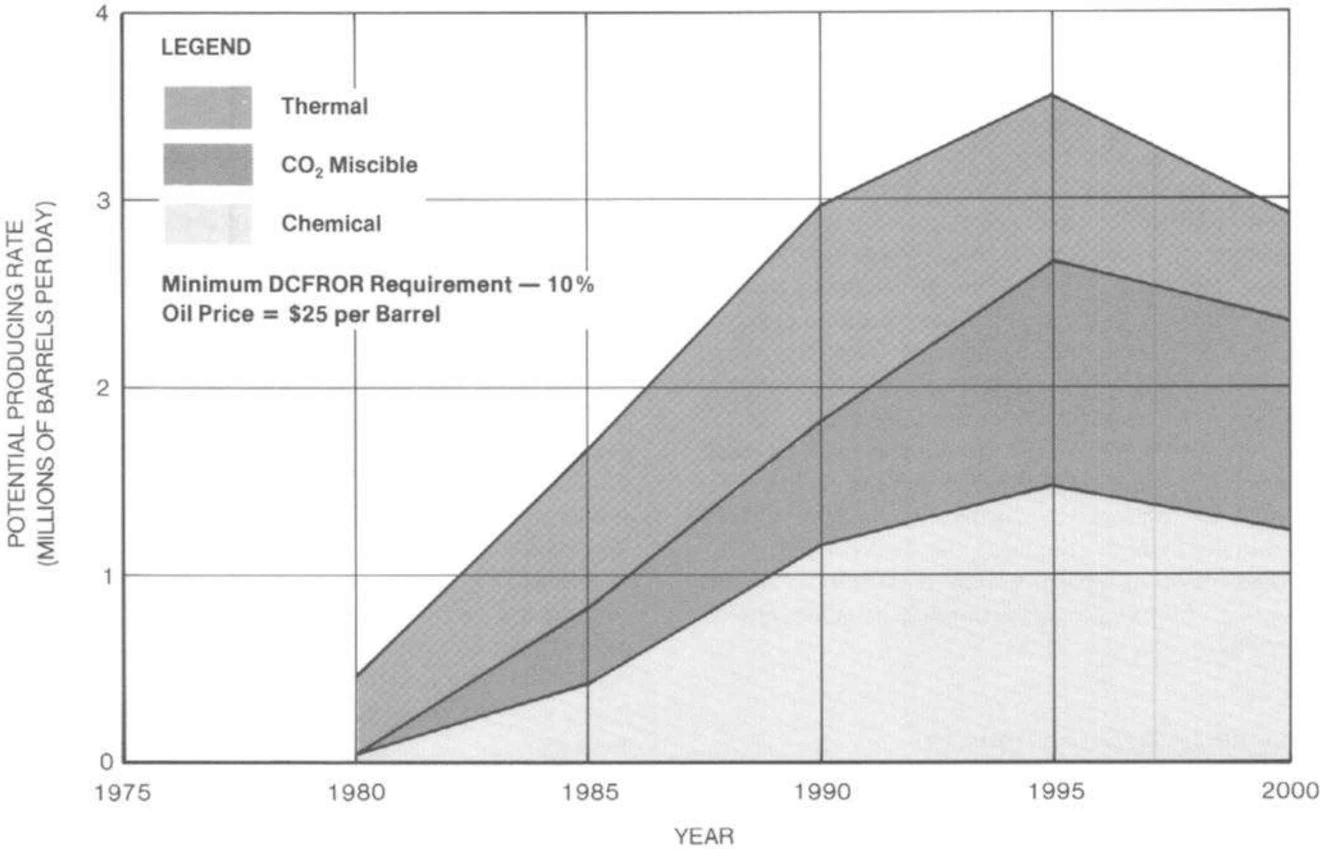

Figure 14. Potential Producing Rate—Base Case Performance and Costs.

specifically noted. All results except those specifically comparing tax cases are for the "moderate" tax case. When comparing results for different oil prices, the discounted cash flow rate of return requirement is 10 percent unless otherwise noted. Additional results for each process are presented in the process appendices.

Chemical Flooding

The base case results for ultimate recovery and potential producing rate of chemical flooding are shown in Figures 15 and 16. These results represent the sum of individually calculated results from surfactant, polymer, and alkaline flooding processes. In this analysis it was apparent that surfactant flooding, with a maximum incremental ultimate recovery of over 8 billion barrels, constituted the bulk of chemical flooding potential. The base case ultimate recovery of polymer flooding was calculated to be a maximum of approximately 470 million barrels, and of alkaline waterflooding to be a maximum of less than 400 million barrels. More detailed results for polymer and alkaline waterflooding, together with analyses of the effect of key variables, are presented in Appendix D.

The base case results for surfactant flooding are shown in Figures 17 and 18. They indicate essentially no economic production from surfactant flooding at an oil price less than $10 per barrel. This is consistent with the fact that essentially no oil has been produced economically by surfactant flooding to date. At a rate of return requirement of 10 percent, the incremental ultimate recovery from surfactant flooding is strongly affected by oil price, showing a potential of slightly over 2 billion barrels at $15 per barrel, about 6.5 billion barrels at $20 per barrel, and nearly 8.4 billion barrels at $25 per barrel. At higher required rates of return, however, the potential drops off rapidly, with few projects able to achieve as much as a 20 percent DCFROR.

Essentially no economic production from surfactant flooding is expected prior to the early 1980's under any economic condition. By 1985 potential producing rate could range from about 120 thousand barrels per day at $15 per barrel to over 300 thousand barrels per day at $25 per barrel. The peak rate from surfactant flooding on existing reservoirs, with the development schedule used in this analysis, would occur around 1995, and would range from around 350 thousand barrels per day at $15 per barrel to more than 1.4 million barrels per day at $25 per barrel.

The degree to which a single "best estimate" projection presents an incomplete picture of the potential of surfactant flooding is shown vividly in examining the variability of results as a function of oil recovery performance. Results of this analysis are shown in Figures 19 and 20. The "high" and "low" estimates of performance on these figures are defined and discussed in detail in Appendix D. Fundamentally, they represent the range of potential outcomes associated with uncertainties in reservoir oil saturation before and after a surfactant flood. Incremental ultimate recovery at $15 per barrel ranges from about 140 million barrels to over 11 billion barrels, with a base case result of slightly over 2 billion barrels. At $25 per barrel, with a base case estimate of nearly 8.4 billion barrels of ultimate recovery, results show a range of potential outcomes from about 2 billion barrels to nearly 13 billion barrels.

The corresponding range of potential producing rates for $15 per barrel in 1985 is from near zero to about 450 thousand barrels per day. At the peak producing rate in about 1995, potential producing rate ranges from near zero to about 1.8 million barrels per day.

While the high and low curves in Figures 19 and 20 are considered to be substantially less probable than the best estimates characterized by the base case, there is a significant probability that surfactant flooding results could be even higher or lower than results shown, since the range of potential results in these two figures is based on variability in only one key parameter associated with the process.

Variability in results for surfactant flooding, as a function of chemical cost, is shown in Figures 21 and 22. Since the potential recovery from surfactant flooding in any given reservoir is assumed to be independent of chemical costs in the analysis procedures, uncertainty in this parameter has an influence on the oil price required to achieve a given level of incremental ultimate recovery or production, but not on the maximum recovery attainable from that reservoir. The number of reservoirs to which surfactant flooding may be economically applied is smaller with higher chemical costs, and larger with lower chemical costs, with resulting variability in total recovery and producing rate. At an oil price of $15 per barrel, incremental ultimate recovery may vary from approximately 2 billion barrels to nearly 8 billion barrels, depending on chemical costs. Peak producing rate in 1995 would also vary from 350 thousand barrels per day to about 1.3 million barrels per day. Higher chemical costs would tend to reduce the incremental ultimate recovery at $25

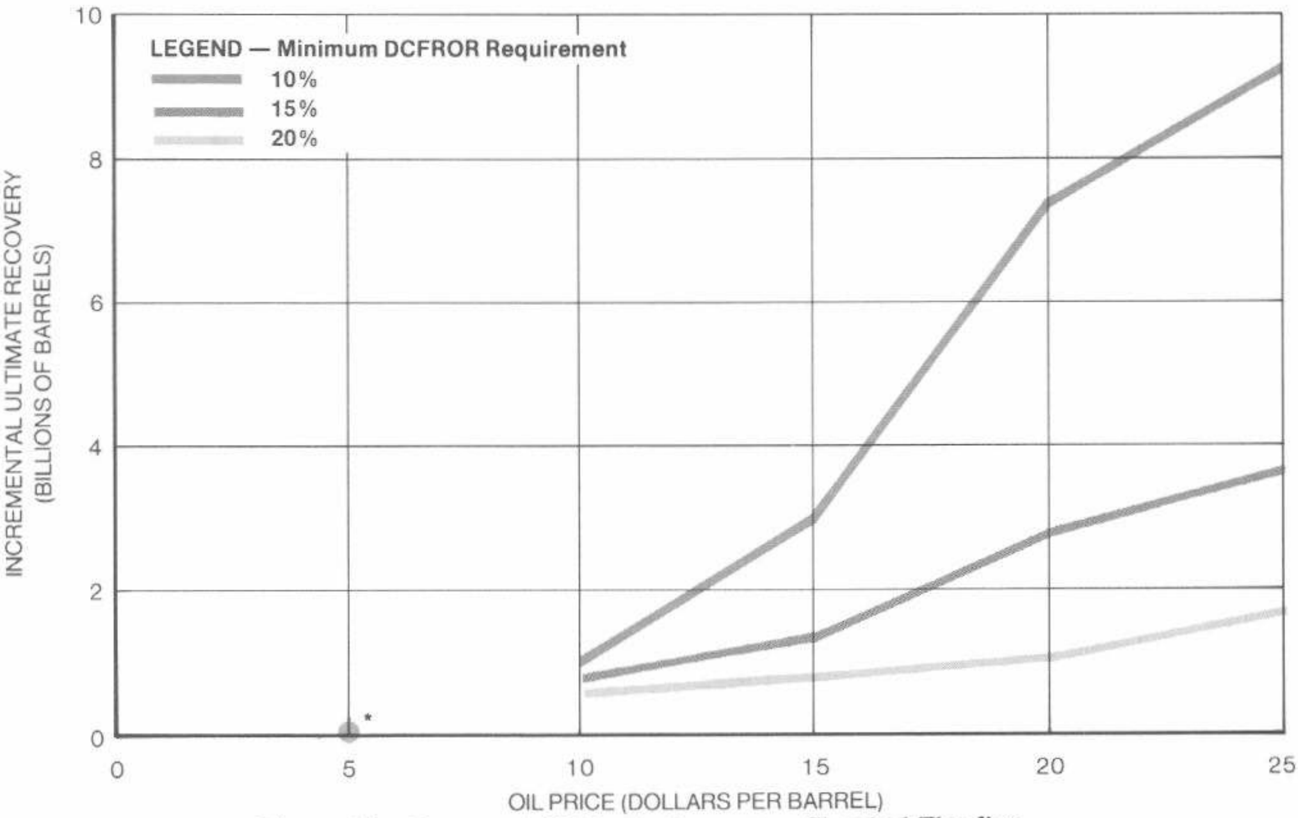

Figure 15. Incremental Ultimate Recovery—Chemical Flooding—Base Case Performance and Costs.

* Recovery for chemical flooding is zero at $5 per barrel and as shown at $10 per barrel.

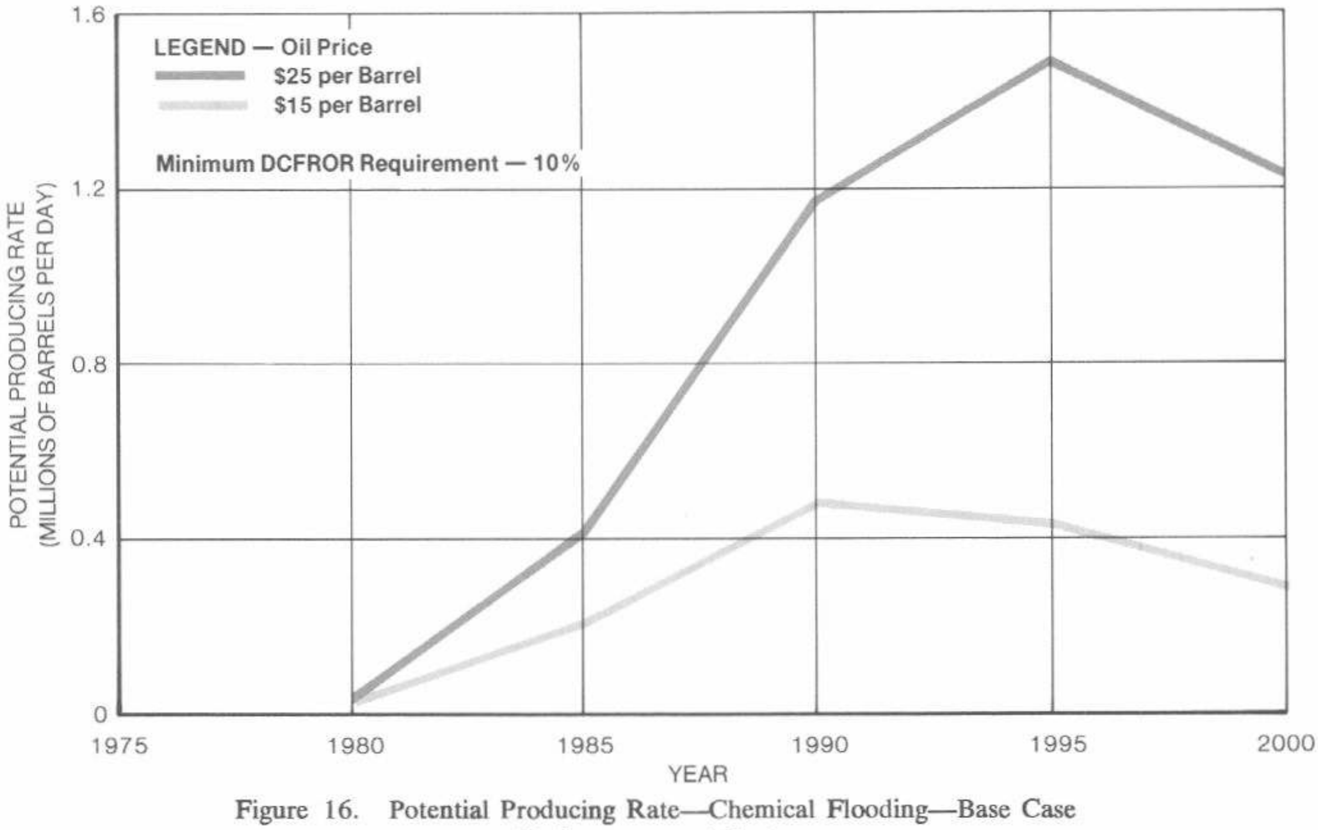

Figure 16. Potential Producing Rate—Chemical Flooding—Base Case Performance and Costs.

per barrel from a base case value of nearly 8.4 billion barrels to approximately 3 billion barrels.

The assumption that recovery in a given reservoir is independent of chemical cost was necessary to develop workable analysis procedures, but is not fully realistic. Lower chemical costs might permit larger chemical slugs, with some resulting increase in recovery. This second order effect was considered to be beyond the scope of this analysis.

Chemical costs represent a large fraction of the total cost of surfactant flooding. Since surfactant costs are directly associated with the cost of petroleum feedstocks, it was necessary to derive an escalation factor for surfactant costs based on the fraction of chemical production costs attributable to feedstock costs. This escalation factor could not be determined accurately. The range of chemical costs shown represents approximately a ±25 percent variation in surfactant costs at any given oil price. Since both the type and quantity of chemicals required for surfactant flooding are uncertain at this time, the ±25 percent variation used in this study is well within the bounds of the uncertainty in this key process parameter.

The variability in results for surfactant flooding as a function of other key parameters, such as the well spacing or chemical slug size used in the reservoir for this process, is shown in Appendix D.

Carbon Dioxide Miscible Flood

The base case results for incremental ultimate recovery and potential producing rate of carbon dioxide miscible flooding are shown in Figures 23 and 24.* The potential of this process is heavily dependent on oil price and reasonably sensitive to the rate of return requirement. No economic production from the process is expected at an oil price of $5 per barrel. The threshold level to begin production is between $5 and $10 per barrel with projected incremental ultimate recovery of 3 billion barrels at $10 per barrel and a 10 percent DCFROR requirement. Incremental ultimate recovery is projected at 5.3 billion barrels of oil at $15 per barrel, and as much as 7.2 billion barrels at $25 per barrel.

Even under favorable circumstances, little incremental production (over that from the few projects in existence today) would be expected before the mid-1980's. Peak production would not be expected to occur until around the year 2000, and would range from about 500 thousand barrels per day with oil at $10 per barrel to about 1.1 million barrels per day with oil at $25 per barrel. The delay in reaching peak production is due in part to time factors associated with development of CO_2 sources, transmission systems, and oilfield facilities, and in part to the relatively low injectivity and productivity of several of the reservoirs to which this process is applicable. Production by the year 1990 would be expected to be less than half of the ultimate peak producing rate for any oil price.

The several factors influencing and tending to delay production with the carbon dioxide miscible flooding process are reviewed in detail in Appendix E. The most significant factor is the time required to find and develop CO_2 reserves and to justify and build appropriate pipeline networks to bring CO_2 from where it is found to where it is needed. The analysis procedures are based on the assumption that sufficient CO_2 can be found to satisfy process requirements for each oil price assumed. The procedures include consideration of the time required for pilot testing in developing economic justification for a pipeline. The pipeline timing is assumed to be dependent on these and other economic parameters.

The potential variability in process performance makes the projections of both recovery and production rate in the base case uncertain at this time. The "best estimate" results in the base case are based on analysis procedures in which the process is assumed to perform relatively poorly in reservoirs that pass the screen but are considered "poor" candidates, and to perform well in reservoirs that are considered "good" candidates. The sensitivity of incremental ultimate recovery and potential producing rate to process performance is shown in Figures 25 and 26. In each case the upper curve is based on the assumption that all reservoirs perform at the level of a "good" reservoir and the lower curve is representative of all reservoirs performing at the level of a "poor" reservoir.

At $10 per barrel, the range of incremental ultimate recovery is from 1 to 5 billion barrels, with a base case of 3 billion barrels. At an oil price of $25 per barrel, the range of ultimate recovery is from 4.4 to 10 billion barrels, with a base case result of 7.2 billion barrels.

Potential producing rate for an oil price of $15 per barrel continues to peak around the year 2000 in all cases, but ranges from approximately 400 thousand barrels per day to 1.2 million barrels per day with a base case result of approximately 900 thousand barrels per day.

*Potential producing rates for CO_2 miscible flooding (see Figures 24, 26, and 28) are shown past the year 2000 because of the late peak in production for this process.

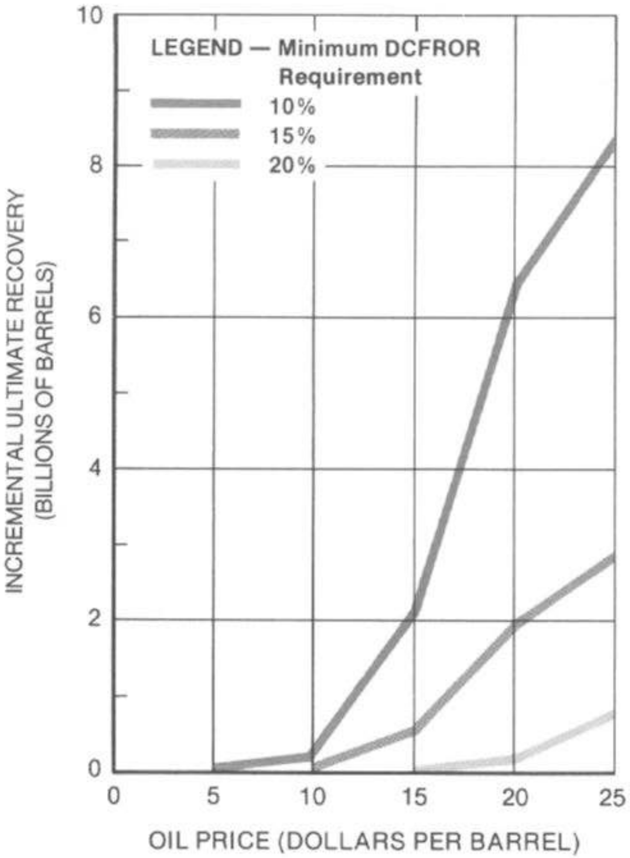

Figure 17. Incremental Ultimate Recovery—
Surfactant Flooding—
Base Case Performance and Costs.

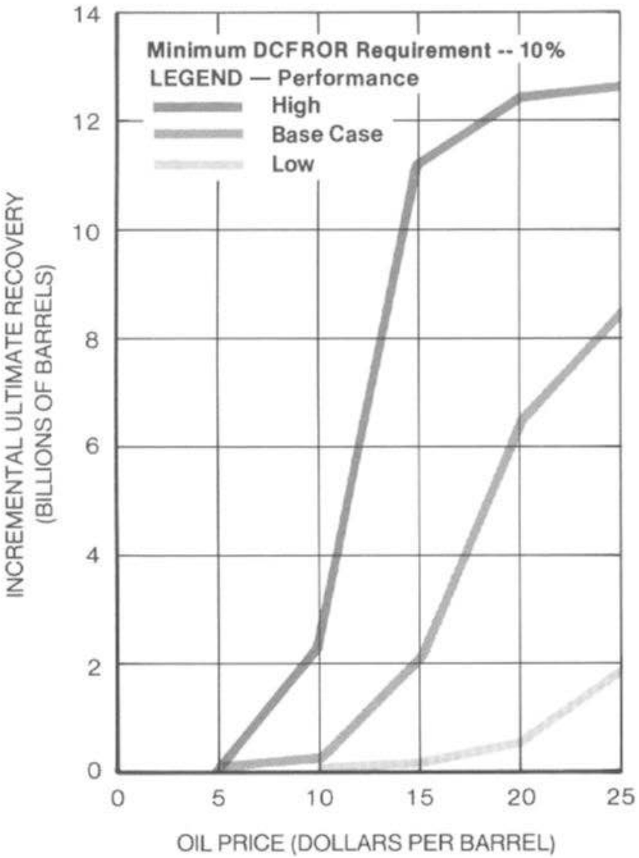

Figure 19. Surfactant Flooding—
Variability of Incremental Ultimate
Recovery with Recovery Performance.

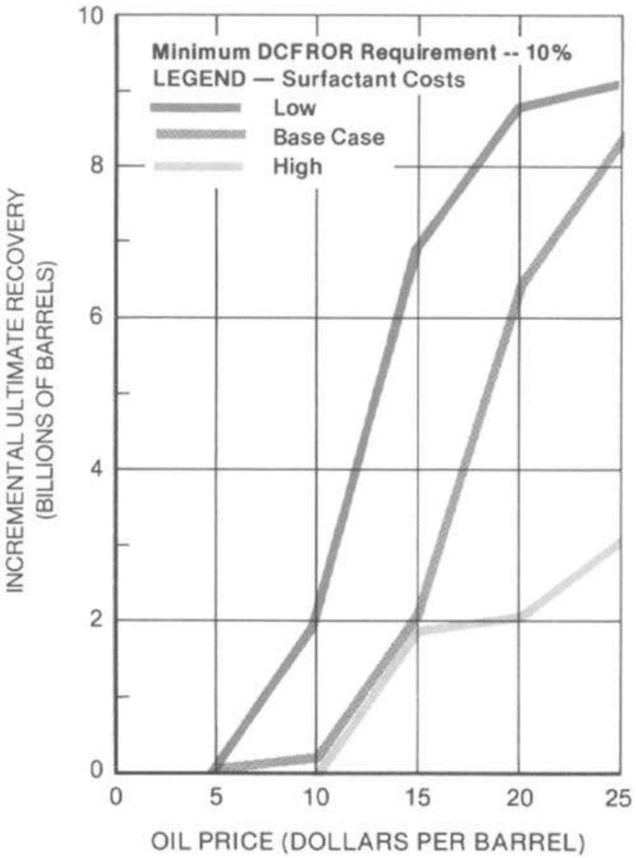

Figure 21. Surfactant Flooding—
Variability of Incremental Ultimate Recovery
with Surfactant Cost.

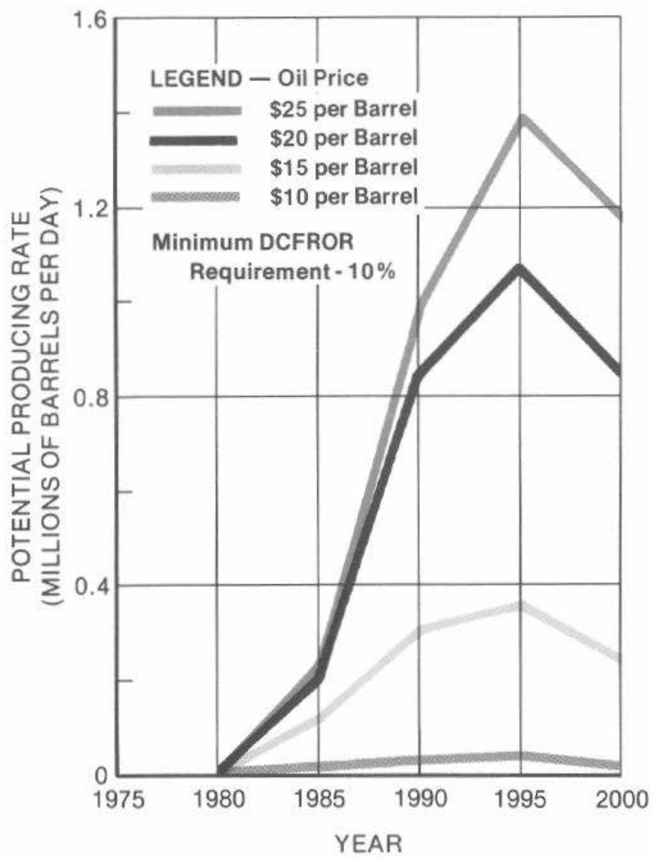

Figure 18. Potential Producing Rate—
Surfactant Flooding—
Base Case Performance and Costs.

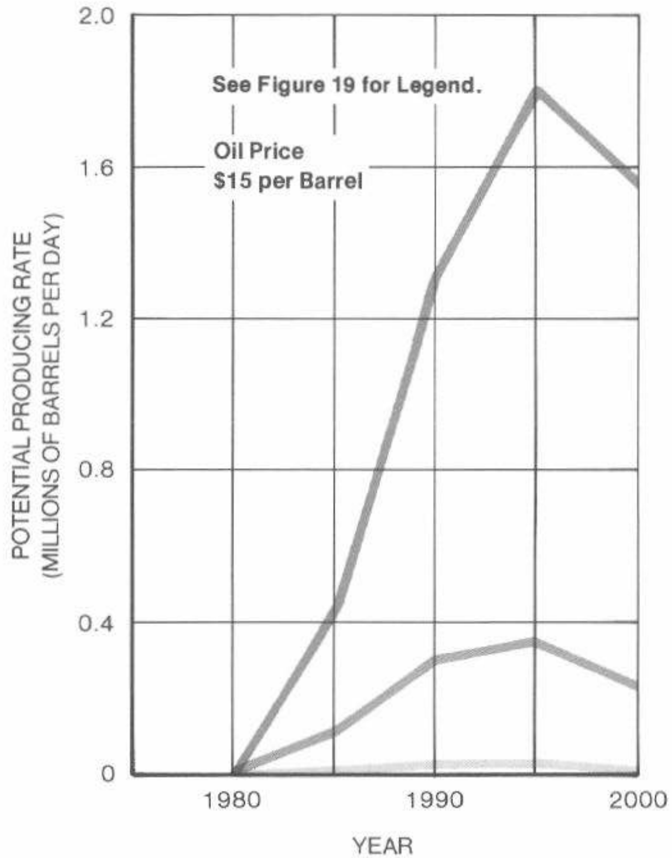

Figure 20. Surfactant Flooding—
Variability of Potential Producing Rate
with Recovery Performance.

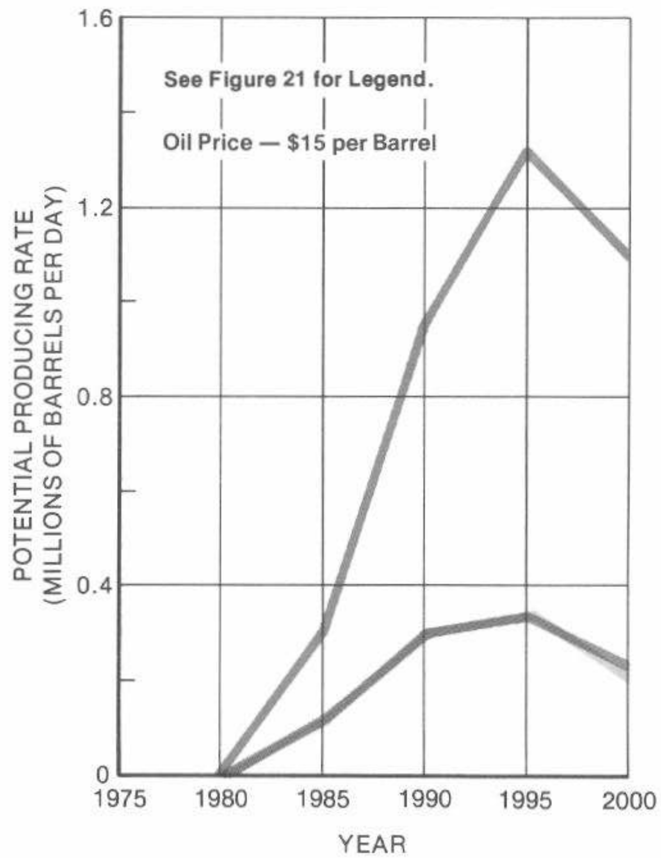

Figure 22. Surfactant Flooding—
Variability of Potential Producing Rate
with Surfactant Cost.

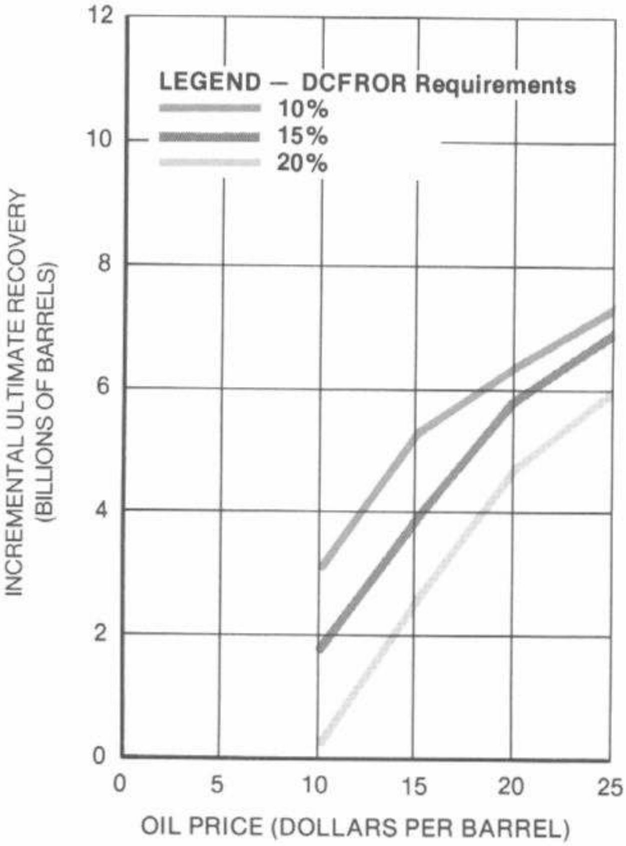

Figure 23. Incremental Ultimate Recovery—Carbon Dioxide Miscible Flooding—Base Case Performance and Costs.

Since CO_2 slug size was assumed to be a function of the economic parameters in this analysis, the recovery from any given reservoir was calculated to depend on economics. The range of estimates of incremental ultimate recovery shown in Figures 25 and 26 reflects both the impact of the performance of the carbon dioxide miscible flooding process in a single reservoir and the number of reservoirs to which the process could be applied economically.

A second major uncertainty in estimating the potential of the carbon dioxide miscible flooding process is the cost of carbon dioxide as delivered to the reservoir. This factor will be influenced strongly by the location and quality of CO_2 reserves yet to be found. Even with the assumption that sufficient volumetric reserves can be found, the development cost of such reserves and the cost to construct and operate pipelines from such reserves to the reservoirs where CO_2 is needed are speculative at this time.

Figures 27 and 28 show the sensitivity of incremental ultimate recovery and potential producing rate for the carbon dioxide miscible flooding process to the cost of carbon dioxide delivered to the reservoir.

In the base case calculations, carbon dioxide

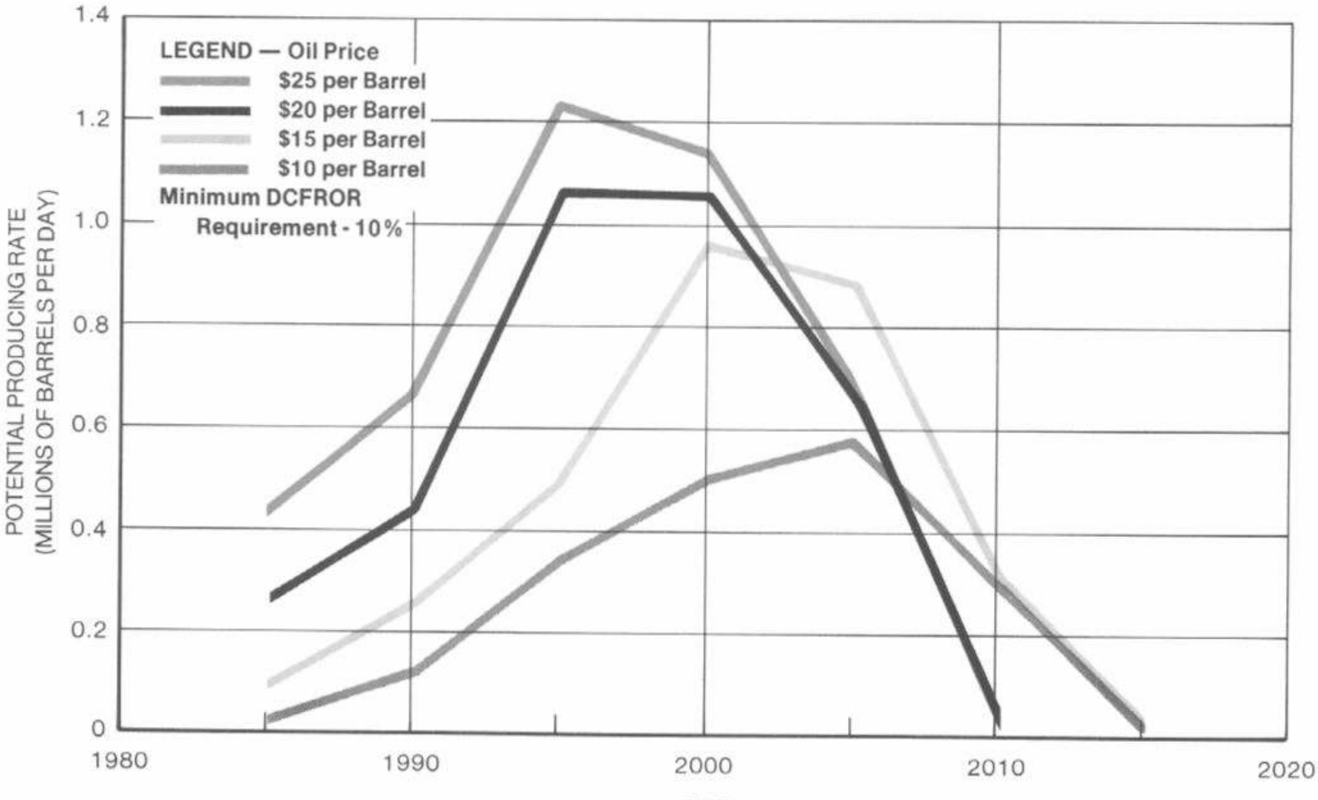

Figure 24. Potential Producing Rate—Carbon Dioxide Miscible Flooding—Base Case Performance and Costs.

cost was calculated for each reservoir based on the location of the reservoir in respect to both the assumed location of CO_2 reserves, and other reservoirs requiring CO_2 which would influence justification for a pipeline. The upper curve in Figures 27 and 28 represents potential production with lower cost CO_2 wherein the cost of CO_2 in each reservoir was assumed to be 50 percent of the cost calculated for the base case; the lower curve in both figures corresponds to production at twice the base case CO_2 cost. For higher cost CO_2, ultimate recovery at $10 per barrel drops to zero. Lower cost CO_2 shows a projected ultimate recovery of 4.6 billion barrels, with a base case of 3 billion barrels. The relative influence of carbon dioxide cost tends to decrease at higher oil prices. At $25 per barrel, the range of projected incremental ultimate recovery is from 5.8 billion barrels to approximately 8 billion barrels, with a base case of 7.2 billion barrels.

The peak potential producing rate around the year 2000, with low cost CO_2 is only marginally higher than in the base case. The primary influence of lower CO_2 costs is a higher rate of production in the time frame 1985-1995. Lower cost CO_2 would permit the start of projects with trucked CO_2 that otherwise would be uneconomic, or that would be-

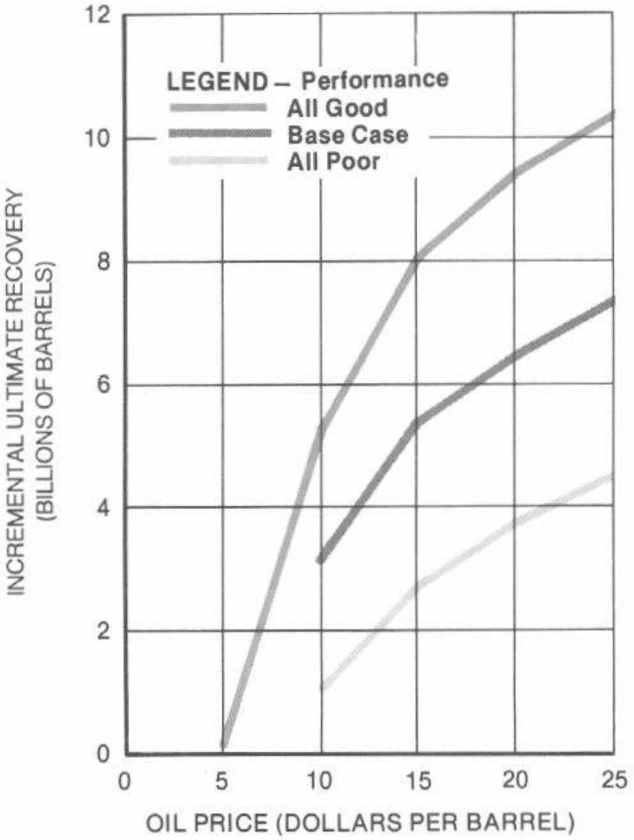

Figure 25. Carbon Dioxide Miscible Flooding—Variability of Incremental Ultimate Recovery with Reservoir Recovery Performance.

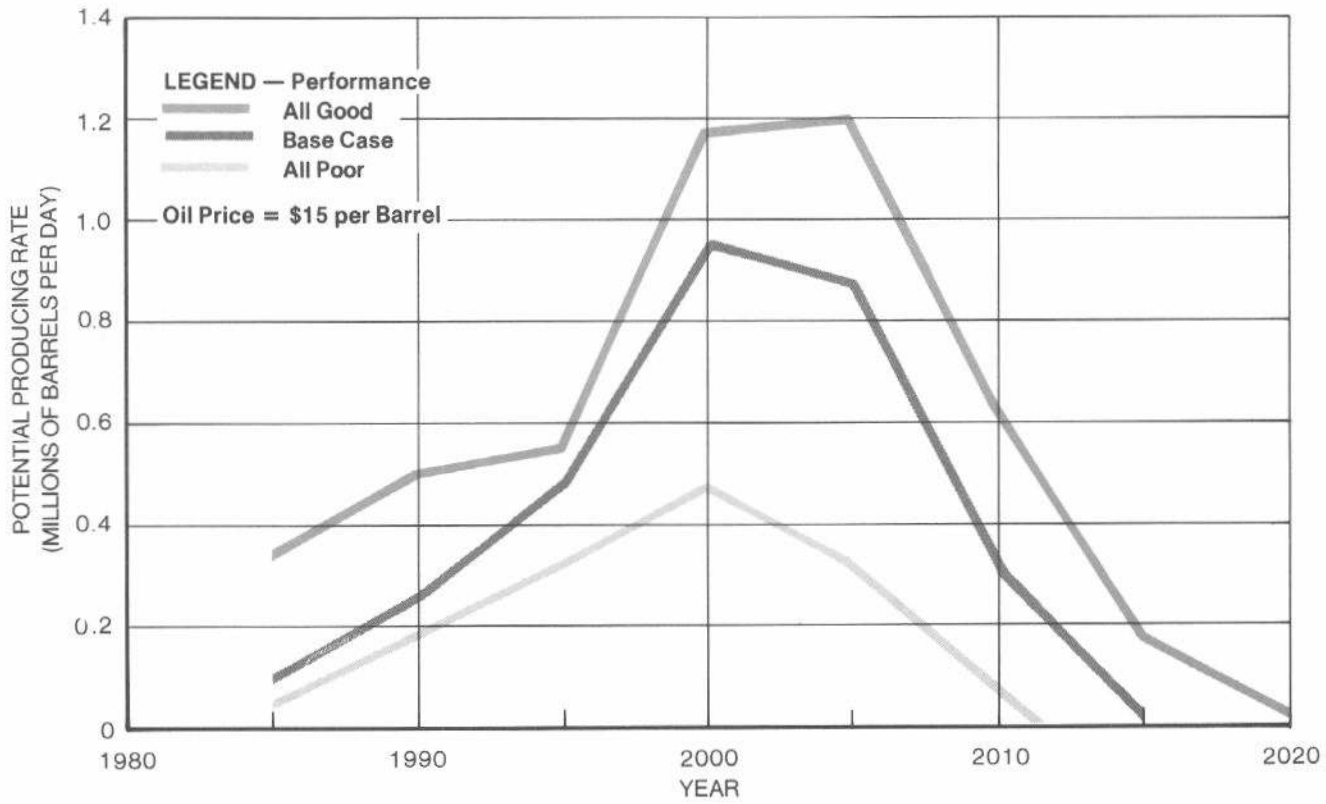

Figure 26. Carbon Dioxide Miscible Flooding—Variability of Potential Producing Rate with Reservoir Recovery Performance.

come economic only after a pipeline was justified and built. With higher CO_2 costs, however, peak producing rate of approximately 500 thousand barrels per day is only about half of that attainable with base case costs or lower CO_2 costs.

Further discussion of the variability of the potential of carbon dioxide miscible flooding with key parameters is presented in Appendix E.

Thermal Recovery

Thermal recovery encompasses the process of steam drive with associated steam stimulation, hot water flooding, and in-situ combustion. Results in this section are shown as the sum of all processes. More detailed results showing the distribution between steam processes and in-situ combustion are given in Appendix F.

The base case incremental ultimate recovery and potential producing rates for thermal recovery are shown in Figures 29 and 30. Results are sensitive to oil price but relatively insensitive to minimum rate of return requirements. The effect of rate of return is discussed in more detail in the section on "Discussion of Results." The maximum potential ultimate recovery of about 7.5 billion barrels at $25

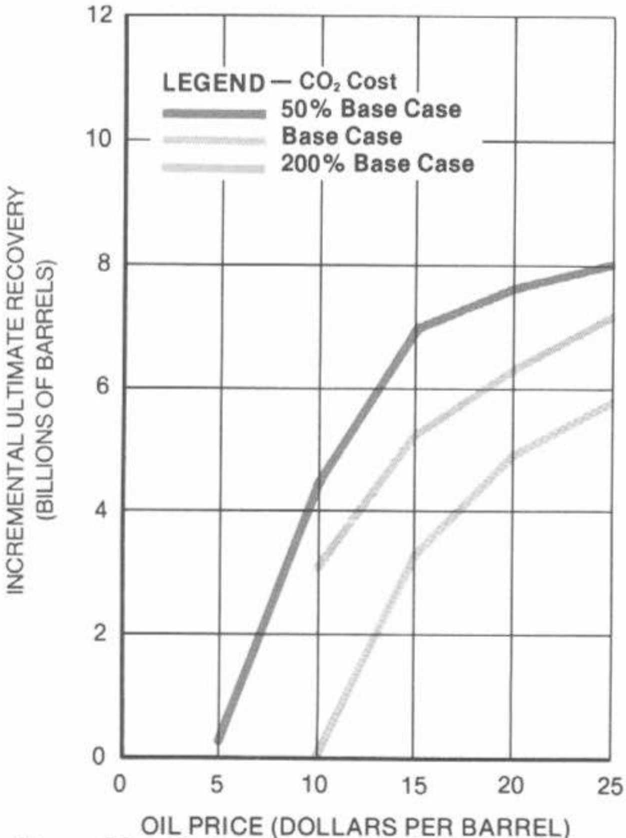

Figure 27. Carbon Dioxide Miscible Flooding—Variability of Incremental Ultimate Recovery with Carbon Dioxide Cost.

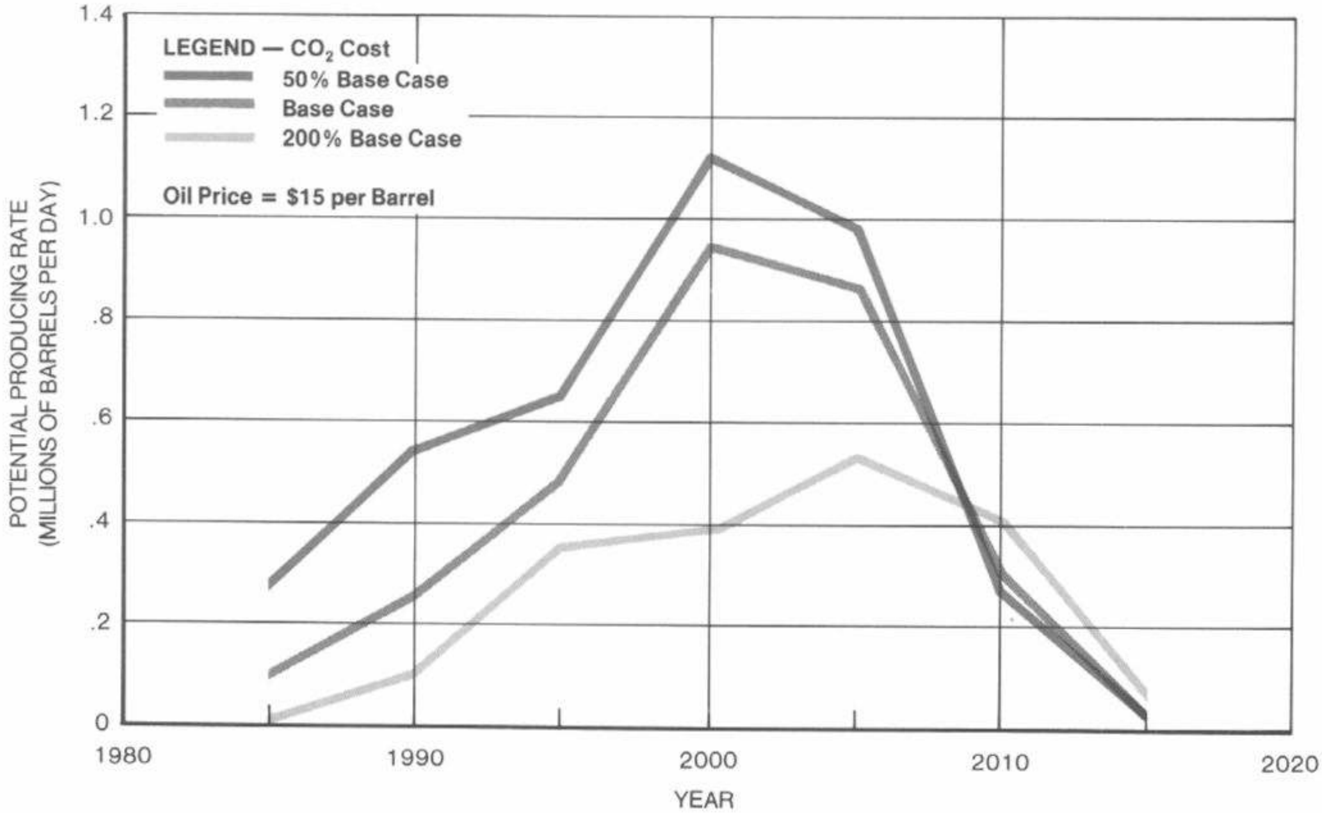

Figure 28. Carbon Dioxide Miscible Flooding—Variability of Potential Producing Rate with Carbon Dioxide Cost.

per barrel of oil is of the same order as that for surfactant or carbon dioxide miscible flooding. However, unlike the other two processes, approximately two-thirds of this potential is available at an oil price of $15 per barrel. The threshold value for accomplishing some incremental thermal recovery is about $5 per barrel, where an incremental recovery of approximately 2 billion barrels is indicated. Much of the current production from thermal methods in California is under price control which results in a price of less than $4 per barrel. Reservoirs that can be produced profitably at this price were the original "best prospects" in regard to reservoir characteristics for steam stimulation. Moreover, most are operated with relatively low cost equipment purchased before inflation had a major effect on process costs. Few, if any, new steamfloods could be started today with new equipment and operated profitably at oil prices of less than $4 per barrel.

Thermal recovery processes are the only area of enhanced recovery in which significant incremental rates of production are possible by the early 1980's. Depending on the level of economic incentive, incremental producing rates could range from about 200 thousand barrels per day to over 400 thousand barrels per day. This rate would be expected to continue to climb until about the year 1990. The producing rate at the peak in about 1990 is highly dependent on oil price, ranging from approximately 300 thousand barrels per day at $5 per barrel of oil to nearly 1.2 million barrels per day with oil at $25 per barrel. Production from the application of thermal methods to existing reservoirs would then be expected to decline fairly rapidly to a level of about 100 thousand barrels per day at $5 per barrel, or to 500 thousand barrels per day at $25 per barrel, in the year 2000.

Figure 31 shows the effect of a ±25 percent variation in recovery performance for the process applied to each reservoir. For oil at $15 per barrel, the range of potential ultimate recovery associated with uncertainty in process performance actually varies from 3 billion barrels to nearly 7 billion barrels, with a base case of about 5 billion barrels. Corresponding potential producing rates peak in about 1990 and range from 450 thousand barrels per day to about 1 million barrels per day, with a base case of 780 thousand barrels per day, as shown in Figure 32.

Figures 33 and 34 show the influence of an assumed variation in process cost from 90 percent to 125 percent of base case costs. The process cost which was varied does not include the cost of oil burned for process energy, except as this is reflected

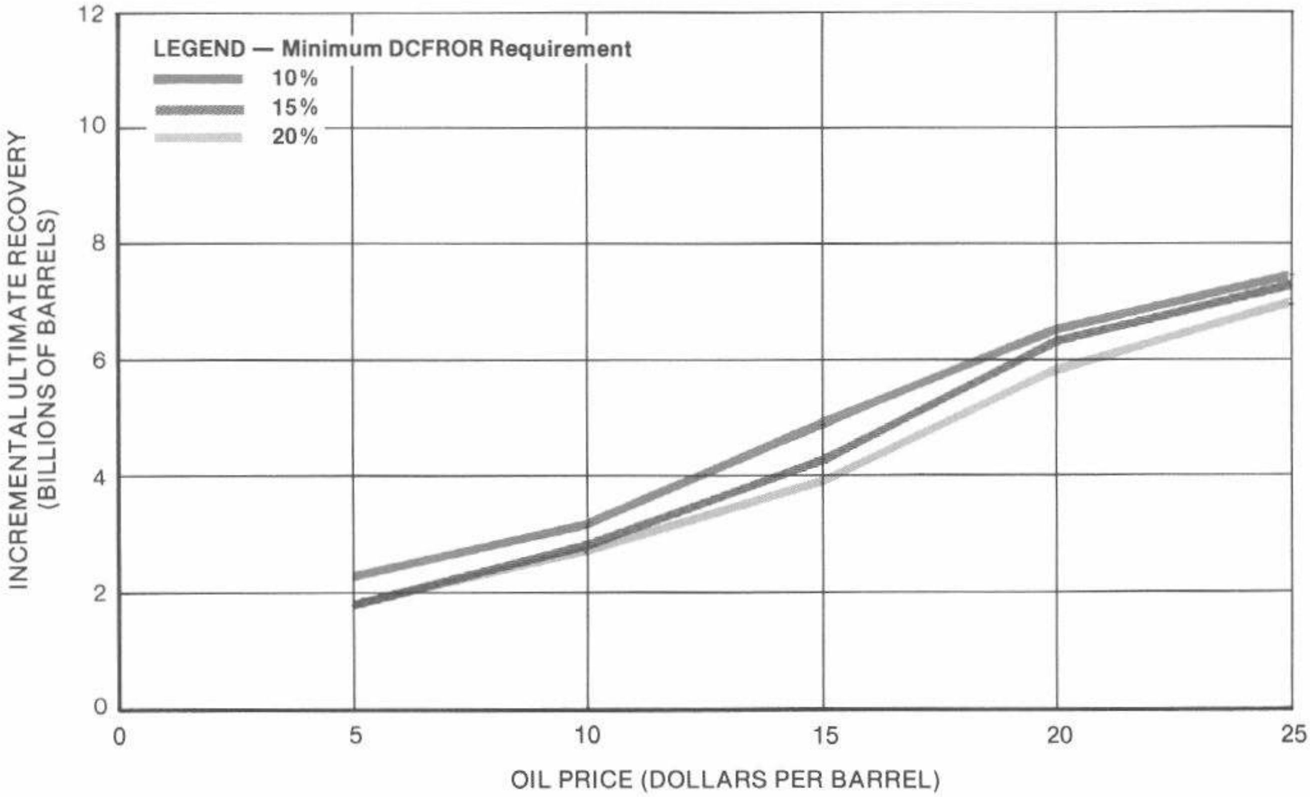

Figure 29. Incremental Ultimate Recovery—Thermal Recovery—Base Case Performance and Costs.

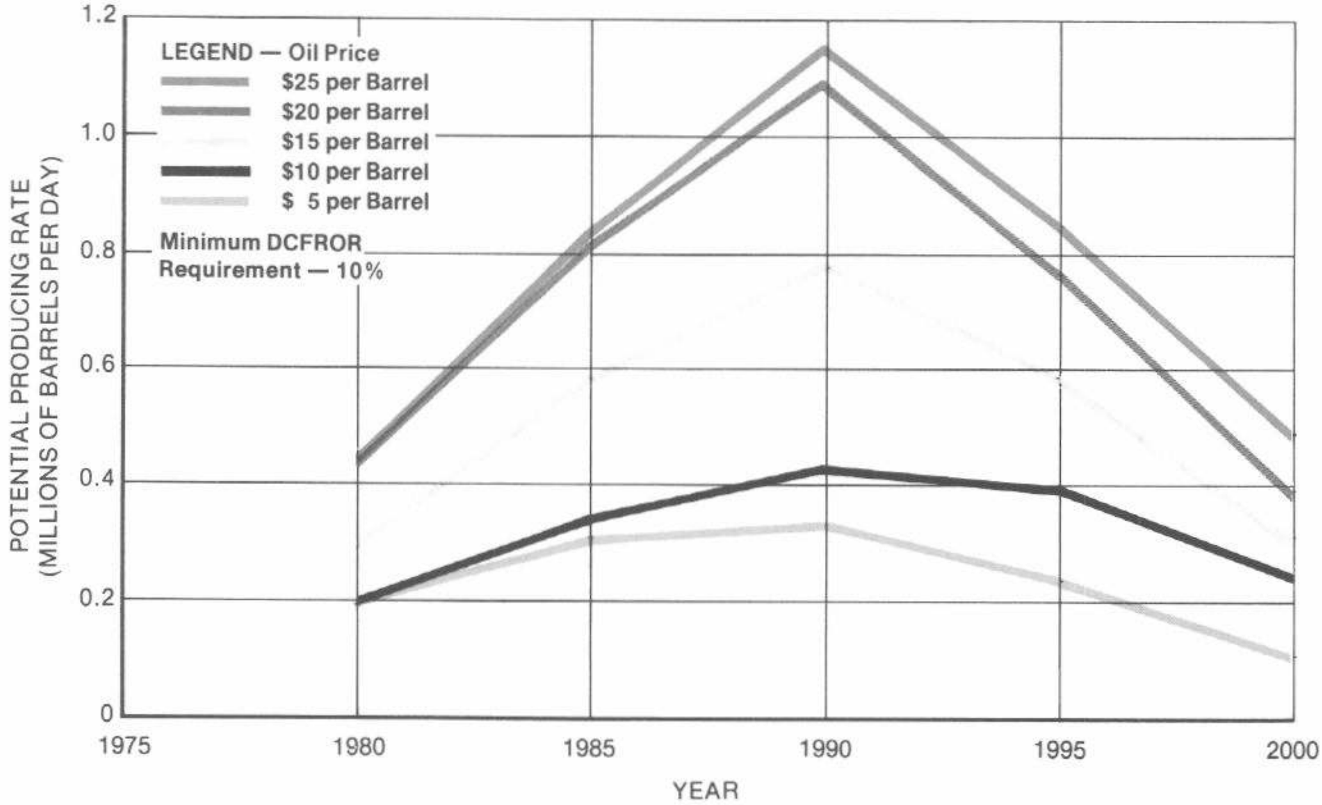

Figure 30. Potential Producing Rate—Thermal Recovery—Base Case Performance and Costs.

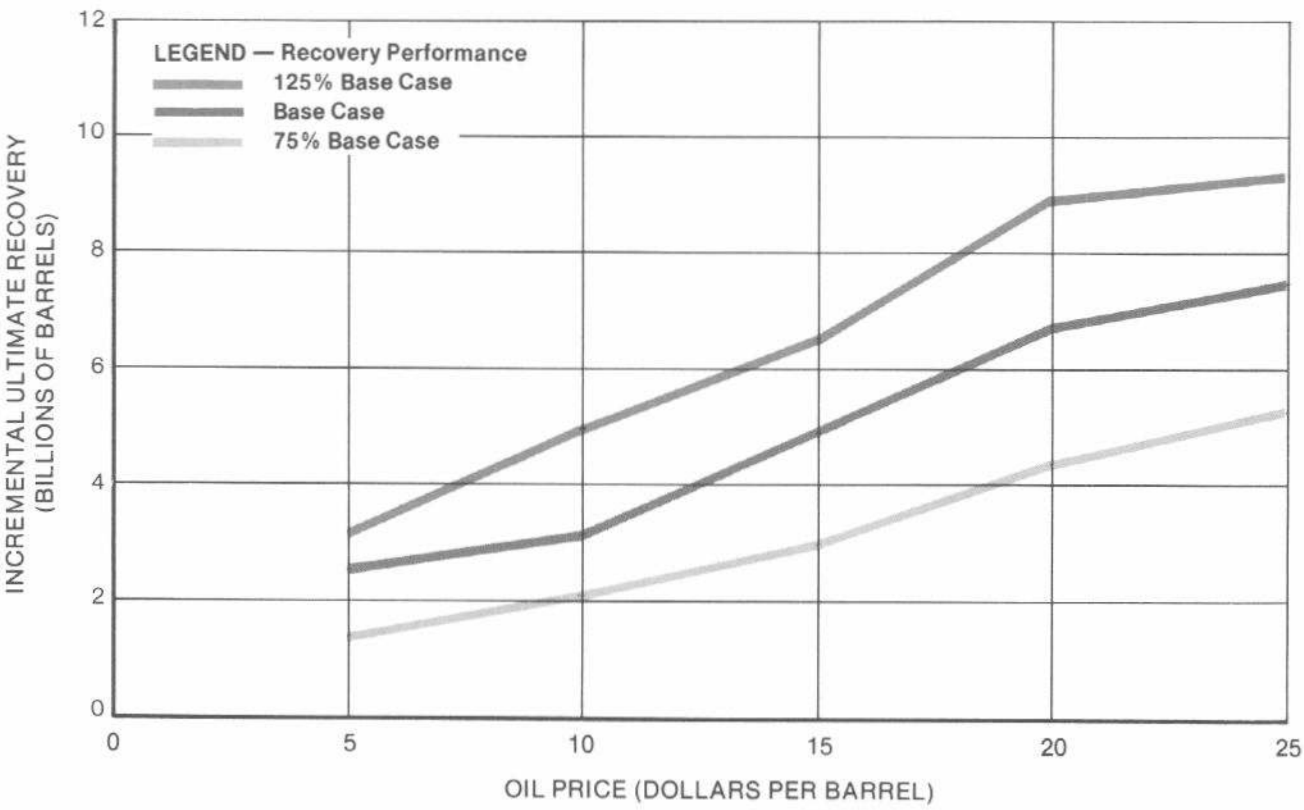

Figure 31. Thermal Recovery—Variability of Incremental Ultimate Recovery with Reservoir Performance.

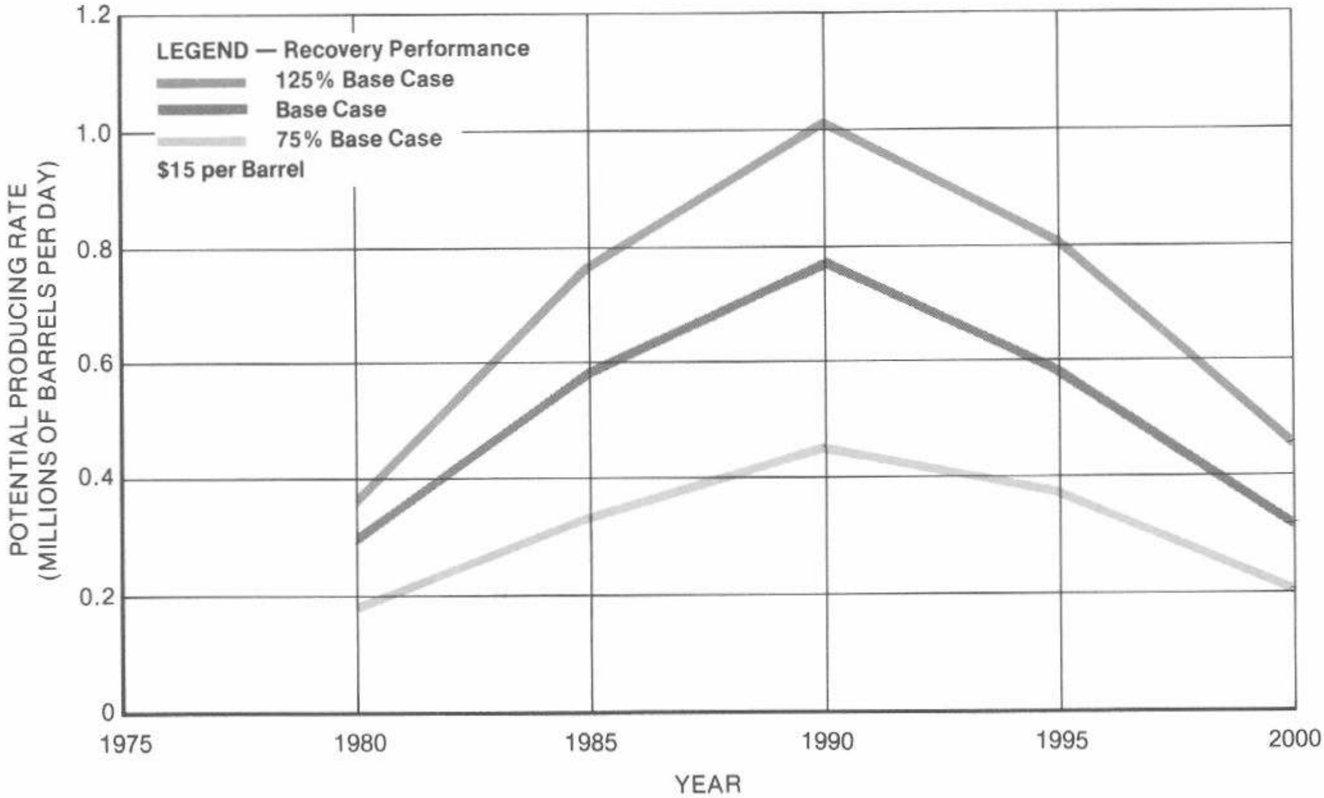

Figure 32. Thermal Recovery—Variability of Potential Producing Rate with Reservoir Recovery Performance.

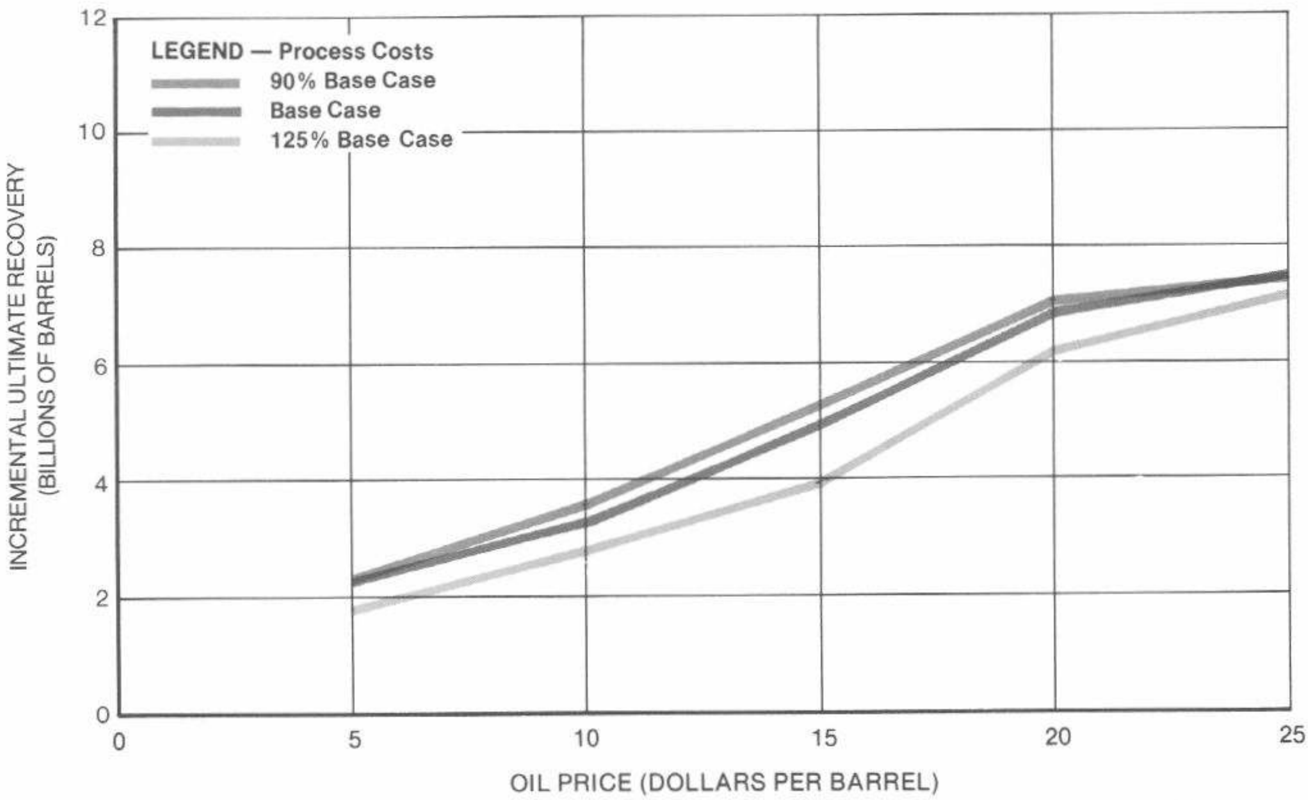

Figure 33. Thermal Recovery—Variability of Incremental Ultimate Recovery with Process Costs.

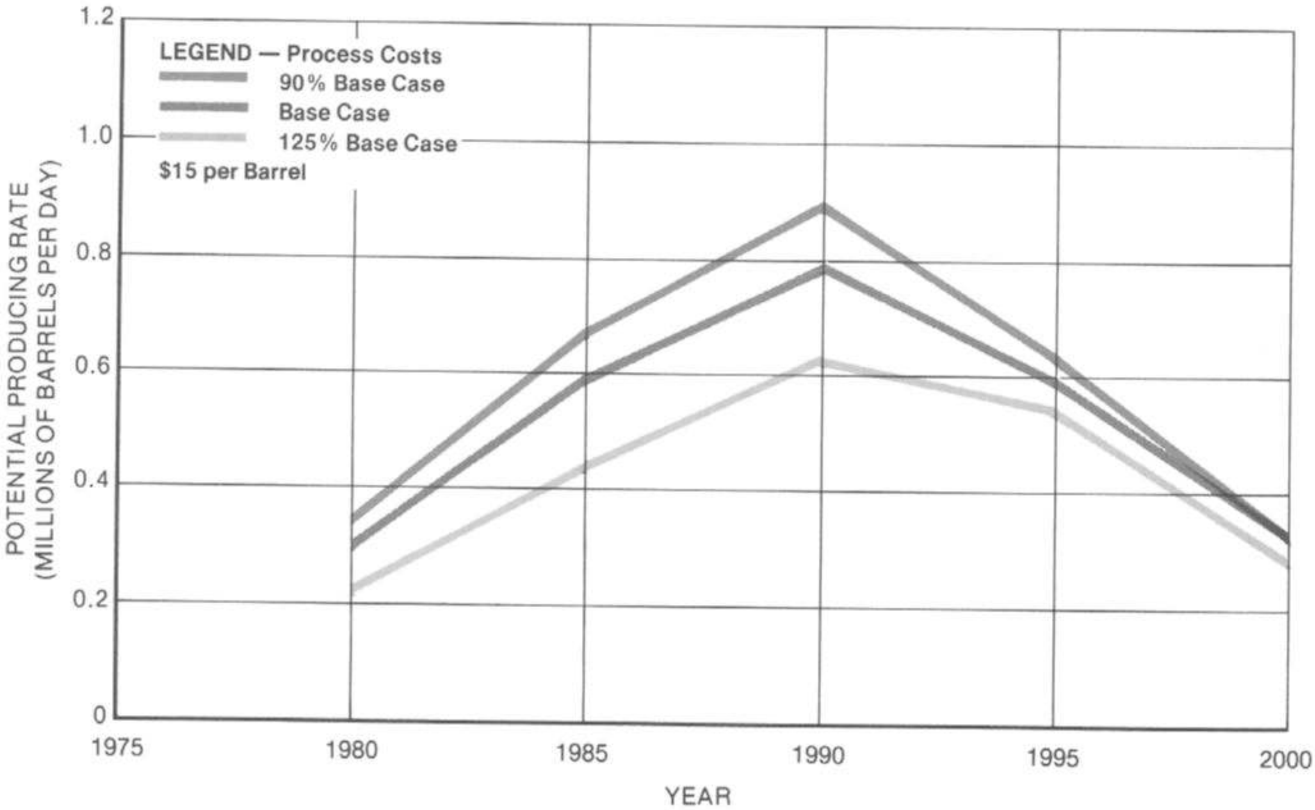

Figure 34. Thermal Recovery—Variability of Potential Producing Rate with Process Costs.

in a change in the production tax for the oil used as process fuel. As a result, only a small variation in ultimate recovery and potential producing rate is projected due to this parameter. While this probably understates the variability, it emphasizes the fact that thermal processes are far more sensitive to recovery performance than to non-fuel process costs.

Income Tax Sensitivity

Analysis of the two income tax cases specified for evaluation in this study shows that tax treatment strongly impacts on the potential magnitude and timing of enhanced oil recovery. All previous results in this chapter are based on the "moderate" tax specifications as described in Table 1, Chapter Two. To examine the effects of less favorable interpretations of existing tax laws, recovery and producing rate estimates were made for the base case estimates of performance and costs using the "restrictive" tax treatment, also described in Table 1. Longer depreciation terms and capitalization of injected fluids are key items in the "restrictive" tax treatment.

Figure 35 shows the potential incremental ultimate recovery at 10 percent DCFROR requirement for all processes for the two tax cases considered. The restrictive tax treatment would decrease the number of reservoirs satisfying specified economic criteria; it would reduce ultimate recovery by about 4 billion barrels at an oil price of $15 per barrel, and by 8 billion barrels for $25 per barrel oil. Corresponding results for a 20 percent DCFROR requirement are shown in Figure 36. The impact of the restrictive tax treatment on ultimate recovery from all processes is less at 20 percent DCFROR requirement primarily because the high rate of return requirement greatly diminishes the applicability of surfactant flooding, which is the process most sensitive to tax treatment.

Figure 37 shows the effect of the restrictive tax case on potential producing rate. Restrictive taxes would reduce potential enhanced oil recovery producing rates by about a third, or about 250 thousand barrels per day in 1985 and by 500 thousand barrels per day in the 1990-2000 period in the $15 per barrel oil price case. Figure 38 shows that the adverse effects of the restrictive case are even greater in the $25 per barrel price case, with resulting reductions in production rate of about 300 thousand barrels per day in 1985, 950 thousand barrels per day in 1990, and 1.25 billion barrels per day for 1995 through 2000.

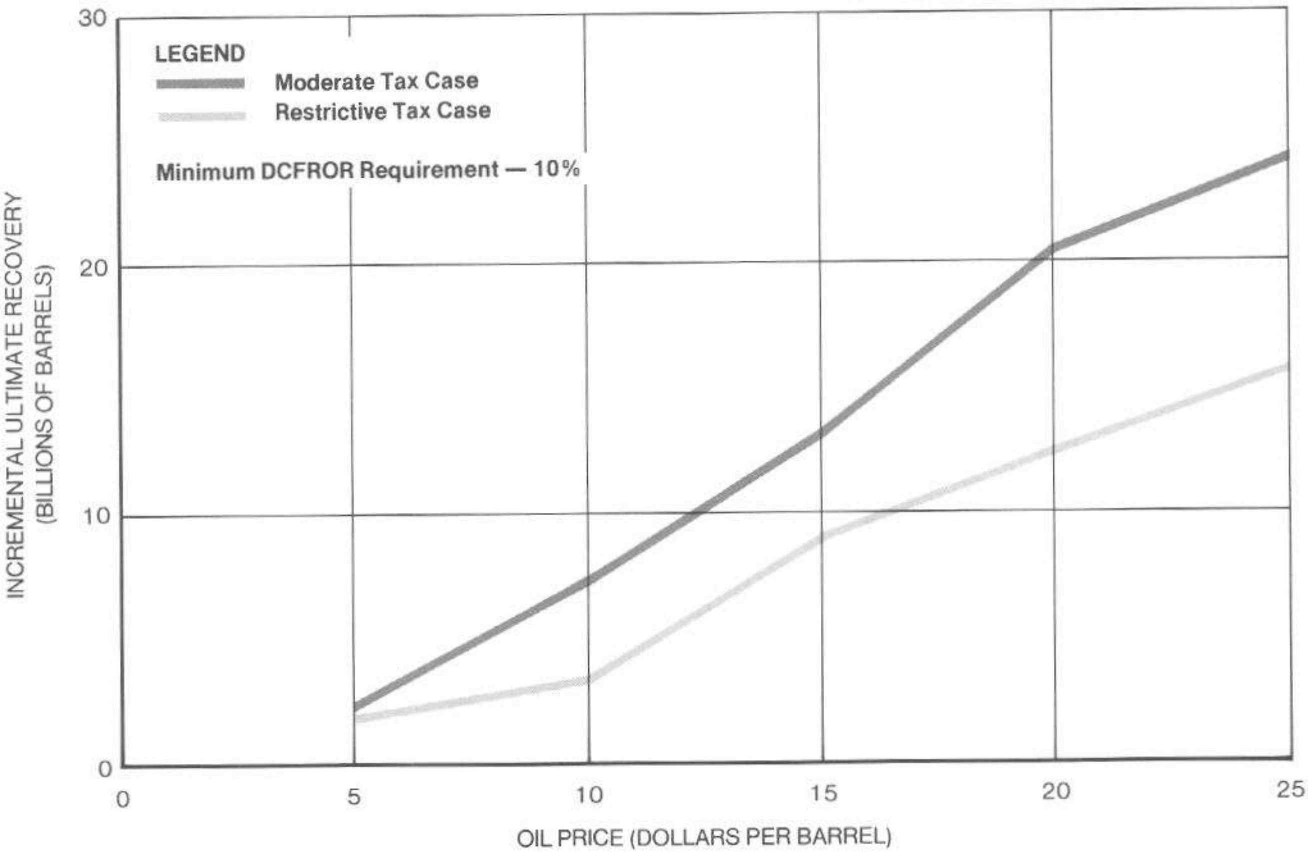

Figure 35. Effect of Tax Treatment on Incremental Ultimate Recovery—Total for All Processes.

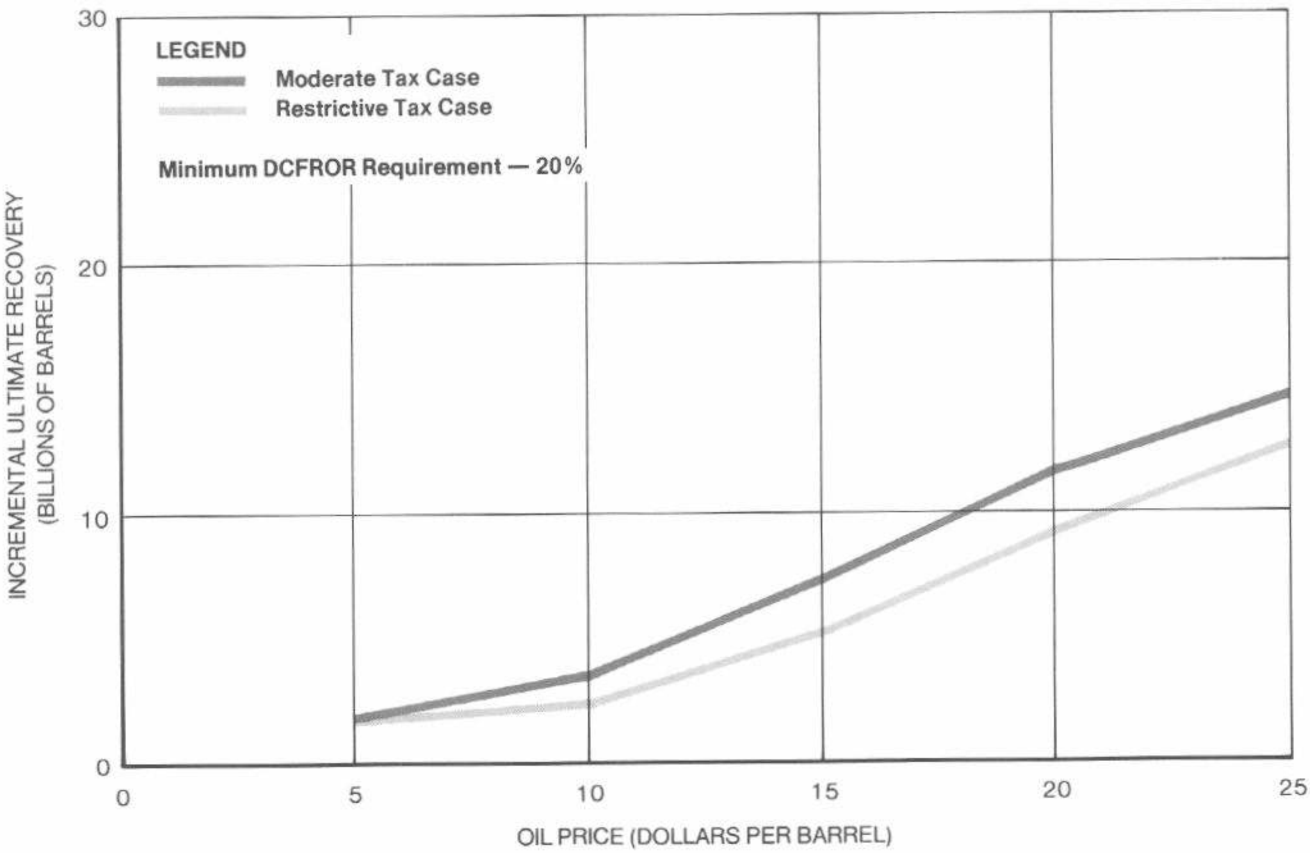

Figure 36. Effect of Tax Treatment on Incremental Ultimate Recovery—Total for All Processes.

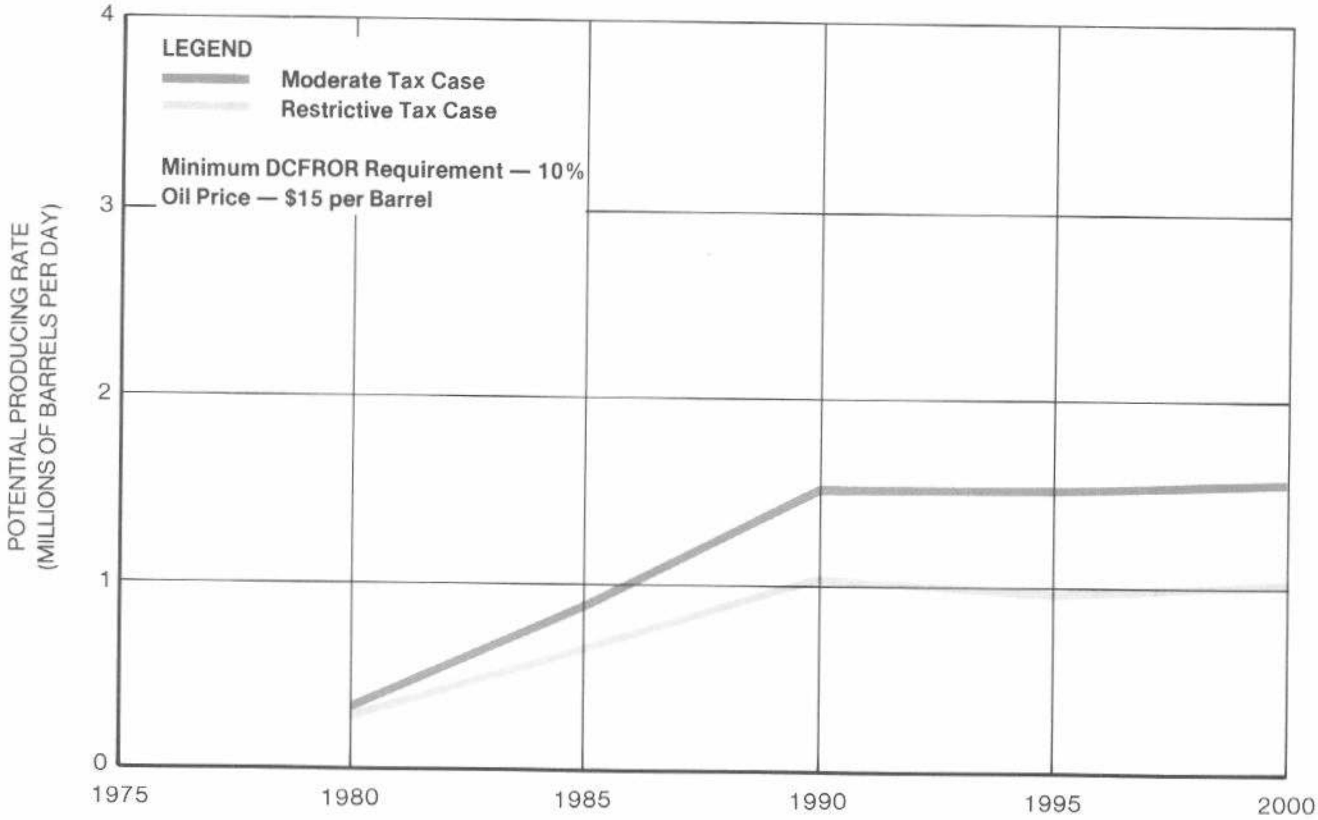

Figure 37. Effect of Tax Treatment on Potential Producing Rate—Total for All Processes.

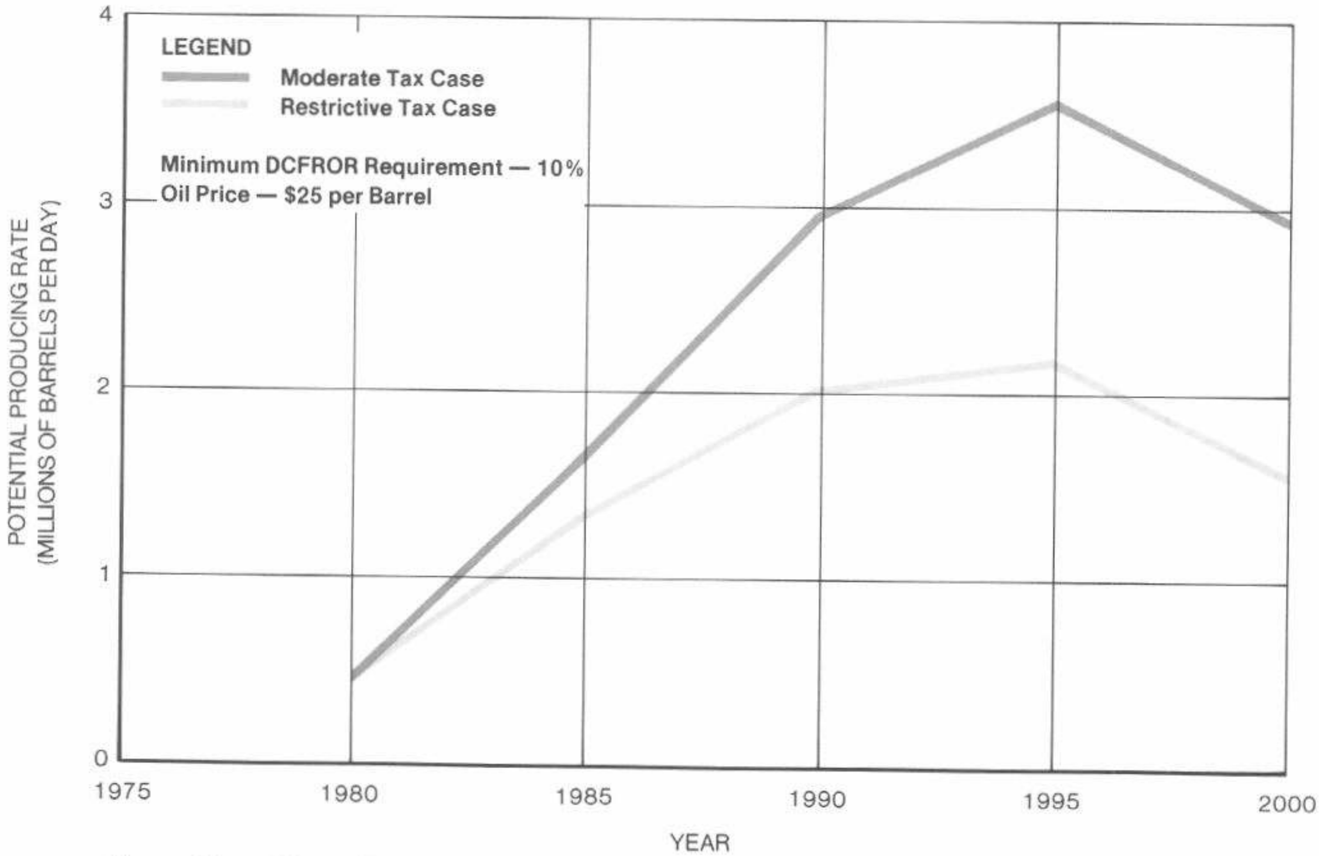

Figure 38. Effect of Tax Treatment on Potential Producing Rate—Total for All Processes.

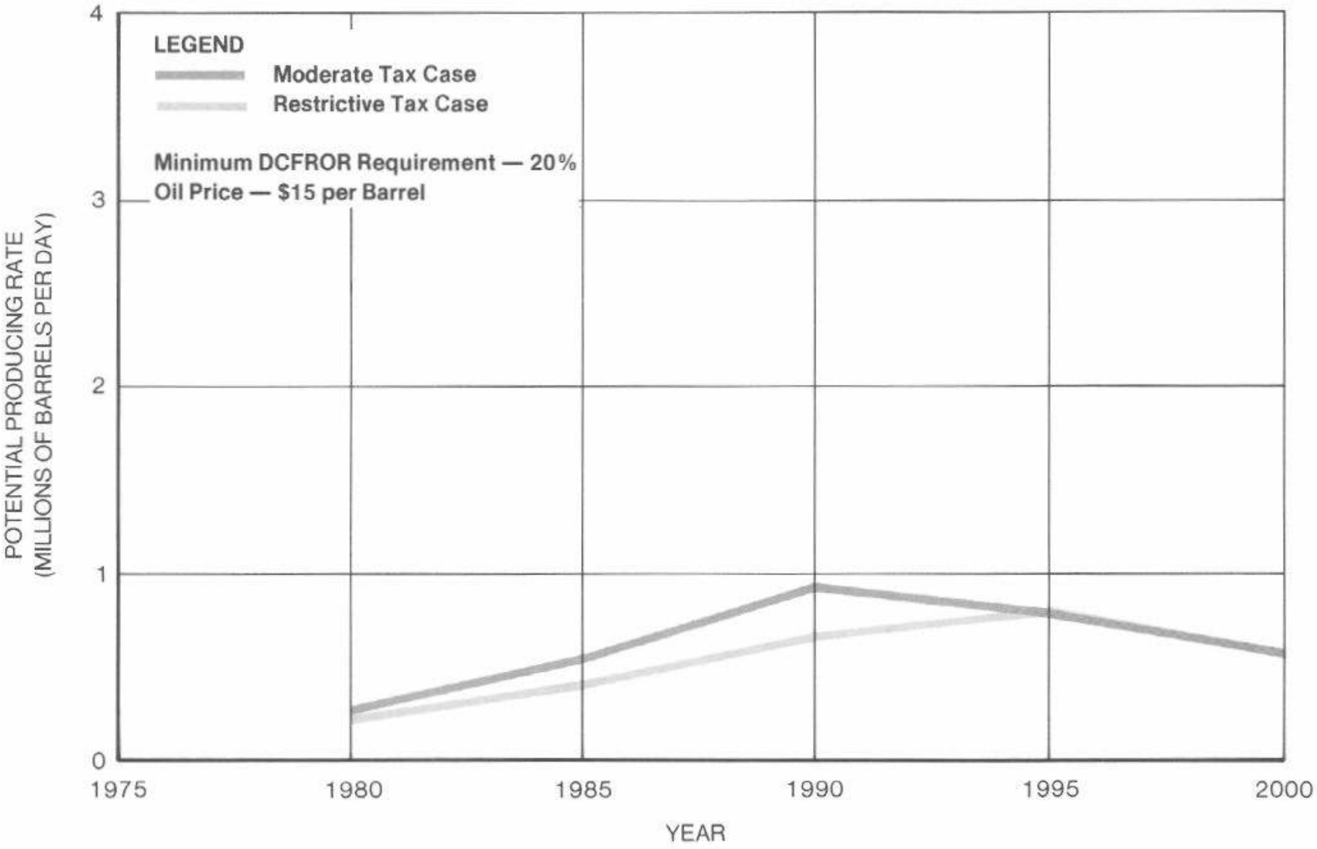

Figure 39. Effect of Tax Treatment on Potential Producing Rate—Total for All Processes.

The tax effects on potential producing rate diminish as DCFROR requirement increases, as shown in Figure 39. This is due to a corresponding decrease in the significance of surfactant flooding at high DCFROR requirement.

These comparisons demonstrate the importance of tax policy as a determinant of enhanced oil recovery potential.

Additional Cash Outlays and Field Activity Requirements

Total domestic industry cash outlays required for all enhanced oil recovery projects are estimated for key years as shown in Table 3.

These estimates show that expenditures required for EOR are extremely sensitive to oil price. The $25 per barrel case indicates annual expenditure rates of about 3 to 4 times greater than the $15 per barrel case in the 1985-1995 decade.

In the interest of providing some perspective, these annual outlay requirements for enhanced recovery compare with 1974 expenditures of $19.1 billion for all domestic exploration, development and production of oil and gas.

TABLE 3

ANNUAL CASH OUTLAY FOR ALL PROCESSES*
(Billions of Constant 1976 Dollars)

Year	$15 per Barrel Case	$25 per Barrel Case
1980	1.1	1.6
1985	3.3	8.7
1990	3.5	14.6
1995	4.0	12.8
2000	2.7	8.1
Cumulative Total Through Year 2000	69	208

* Based on a minimum 10 percent DCFROR requirement and moderate tax case.

Table 4 summarizes some key indicators of physical activity and material requirements. Additional drilling requirements of over 2,000 wells per year in the $15 per barrel case and over 4,000 wells per year in the \$25 per barrel case during the 1980-1990 decade are shown. This increment of drilling activity would represent a 5 percent to 10 percent gain over current levels of nearly 40,000 wells per year.

Although workover activities are only loosely definable at best, the additional 1,000 to 4,000 workovers per year noted in Table 4 probably would reflect a less than 10 percent gain over existing activity levels.

Of the chemicals considered, surfactants very probably will present the greatest problem in terms of new chemical plant construction requirements. With the exception of alcohols, total U.S. manufacture of surfactants of the type used in EOR processes probably totals considerably less than 0.5 billion pounds per year. This compares with the additional requirements of up to 5 billion pounds per year shown in Table 4.

Additional alkaline requirements reach about 0.3 billion pounds per year or roughly 10 percent of current total domestic production of the most commonly used materials.

Definitional problems hinder similar comparisons for polymers.

Naturally occurring CO_2 will likely be the prime source of CO_2 for EOR application on the large scale examined in this report; however, other sources such as by-product gas from ammonia plants may supply individual projects (see Appendix E for discussion of CO_2 sources).

Greater manpower requirements will be associated with increased levels of EOR activity but were not evaluated for this study. (See SPE-AIME President, Donald G. Russell's remarks at FEA Hearings, September 16-20, 1974, for quantification of manpower needs.)

Distribution of Base Case Results by State

Figures 40, 41, and 42 exhibit the distribution of total incremental ultimate recovery and potential producing rate from all processes over the 1976-2000 time frame. The results are shown for the

TABLE 4

ADDITIONAL ANNUAL ACTIVITY AND MATERIALS REQUIREMENTS FOR ENHANCED RECOVERY WORK *

	Wells Drilled Per Year	Well Workovers Per Year	Surfactant Used (Millions of Pounds per Year)
\$15 per Barrel Oil Price			
1976-1980	1,100	700	0
1981-1985	2,300	1,500	700
1986-1990	2,100	1,700	1,100
\$25 per Barrel Oil Price			
1976-1980	1,400	1,200	0
1981-1985	3,900	3,100	2,500
1986-1990	4,600	4,300	5,000
	Alkaline Chemicals Used (Millions of Pounds per Year)	**Polymer Used (Millions of Pounds per Year)**	**CO_2 Used (Billion Cubic Feet per Year)**
\$15 per Barrel Oil Price			
1976-1980	150	20	0
1981-1985	300	100	200
1986-1990	200	150	400
\$25 per Barrel Oil Price			
1976-1980	150	20	0
1981-1985	300	150	700
1986-1990	200	300	2,000

*Constant 1976 dollars; minimum DCFROR requirement of 10 percent; and moderate tax case. Data shown are in addition to the requirements of existing EOR projects.

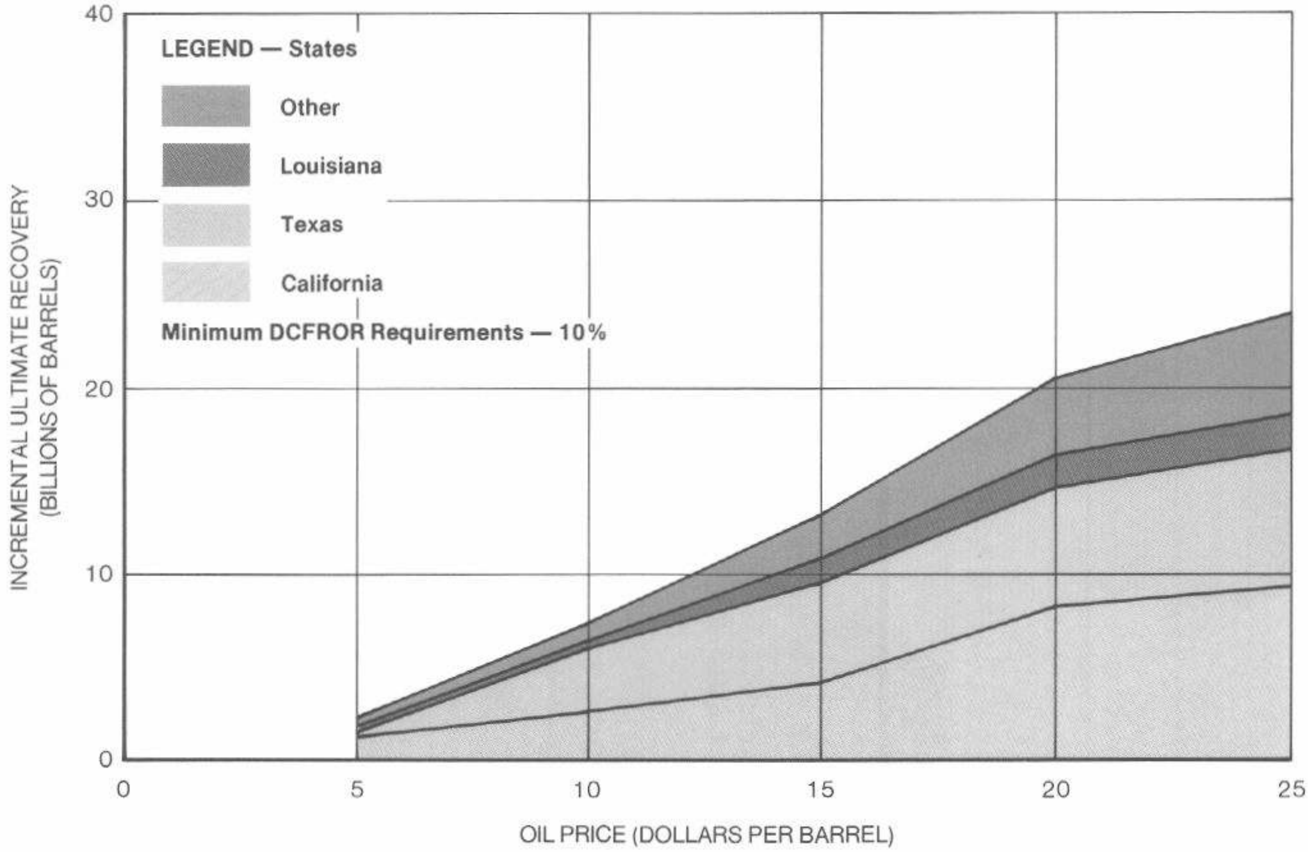

Figure 40. Incremental Ultimate Recovery by State.

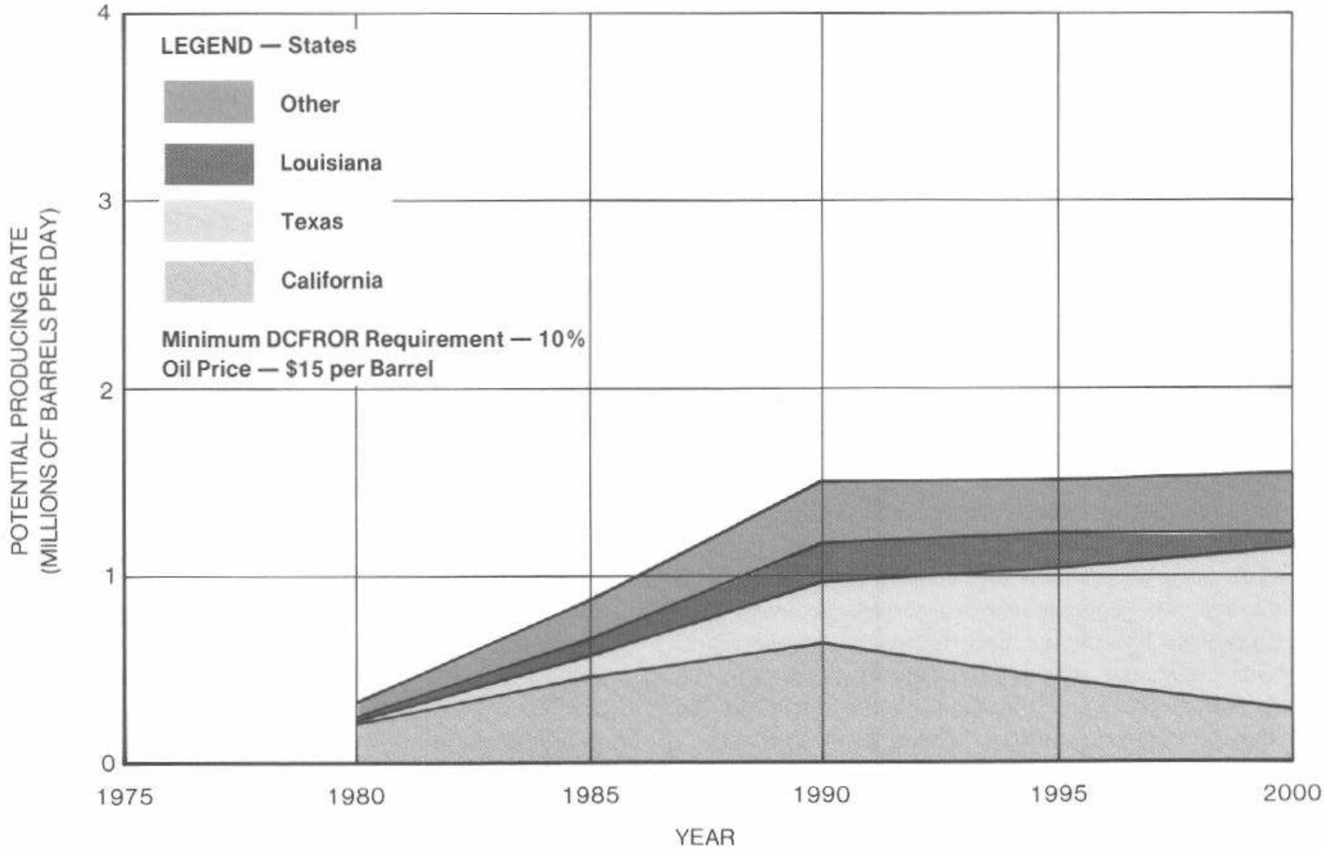

Figure 41. Potential Producing Rate by State.

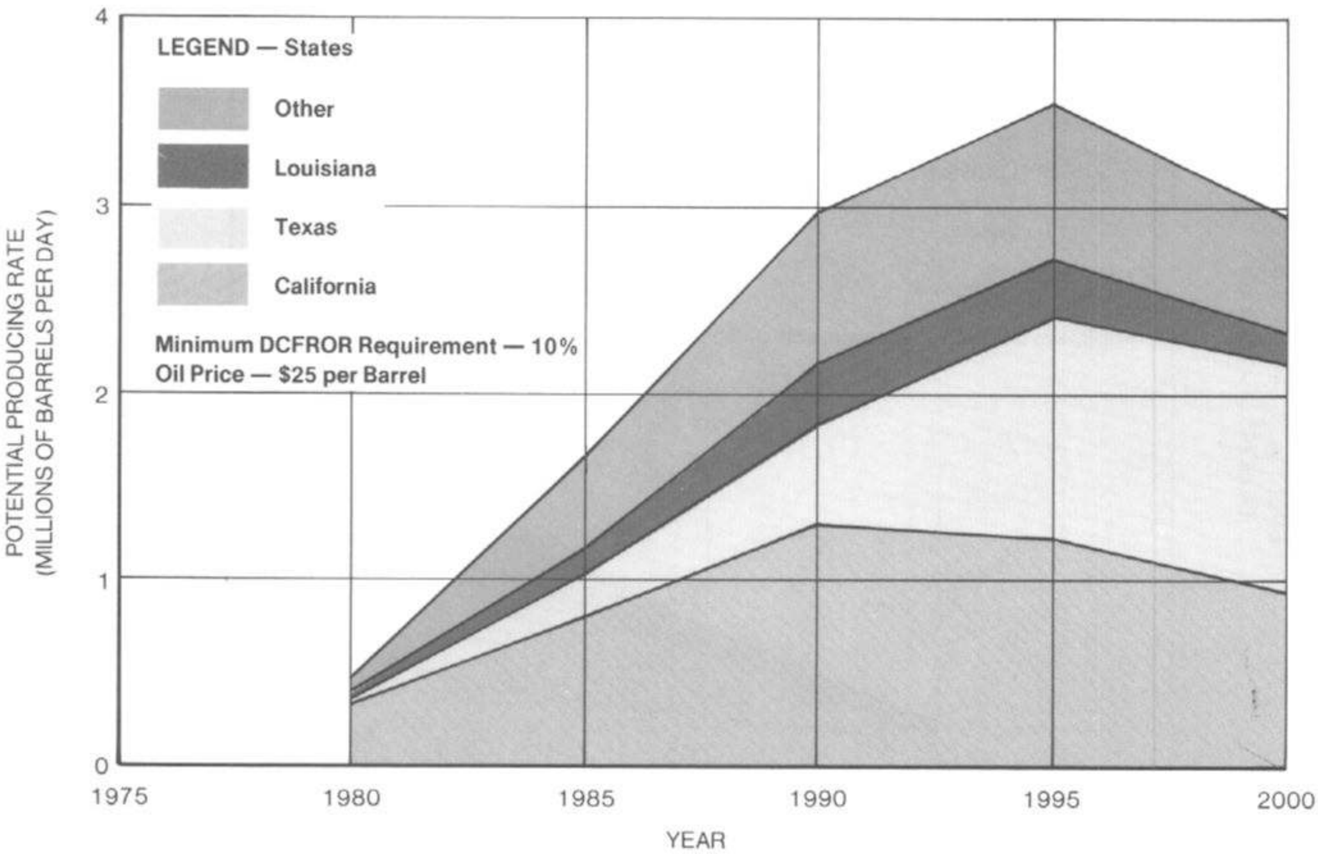

Figure 42. Potential Producing Rate by State.

three states, Texas, California, and Louisiana, as well as for other states to which results were extrapolated in this study. As indicated in the appendices, the California contribution would be predominantly from thermal methods, and carbon dioxide miscible flooding would have a major potential impact in Texas. Louisiana has a somewhat smaller potential, due in part to more efficient primary and secondary characteristics of its reservoirs.

Cumulative Variability in Results

Since different key parameters were used in analyzing the variability of possible results for each enhanced recovery process, it is impossible to show the variation in cumulative results for all processes as a function of a single key parameter. In each case, however, at least one critical variable for each process was representative of process recovery performance. The overall uncertainty in cumulative results associated with recovery performance was ascertained, therefore, by summing the results of the high performance and low performance analysis.

Figure 43 shows the uncertainty in ultimate recovery at a 10 percent DCFROR requirement based on the sum of high- and low-range performance estimates for individual processes. Results at \$15 per barrel range from about 6 to about 27 billion barrels incremental ultimate recovery for all processes, with a base case of approximately 13 billion barrels. Corresponding results at a 20 percent DCFROR requirement are shown in Figure 44. The range of potential with this DCFROR requirement with oil at \$15 per barrel is from 4 to 12 billion barrels.

The uncertainty in potential producing rates at 10 percent rate of return requirement is demonstrated in Figure 45, for oil at \$15 per barrel, and Figure 46, for oil at \$25 per barrel.

The potential producing rate in 1985 varies from about 450 thousand barrels per day to 1.6 million barrels per day at \$15 per barrel, and from 1.1 to 2.4 million barrels per day at \$25 per barrel. Peak rate in about 1995 varies from as little as 800 thousand barrels per day to 3.4 million barrels per day at \$15 per barrel, and from about 2 million to as high as 4.7 million barrels per day at \$25 per barrel.

The apparent flattening of the high-range performance curve in Figure 43 at oil prices above \$15 per barrel may be in error due to the screening parameters used in this study being too severe for

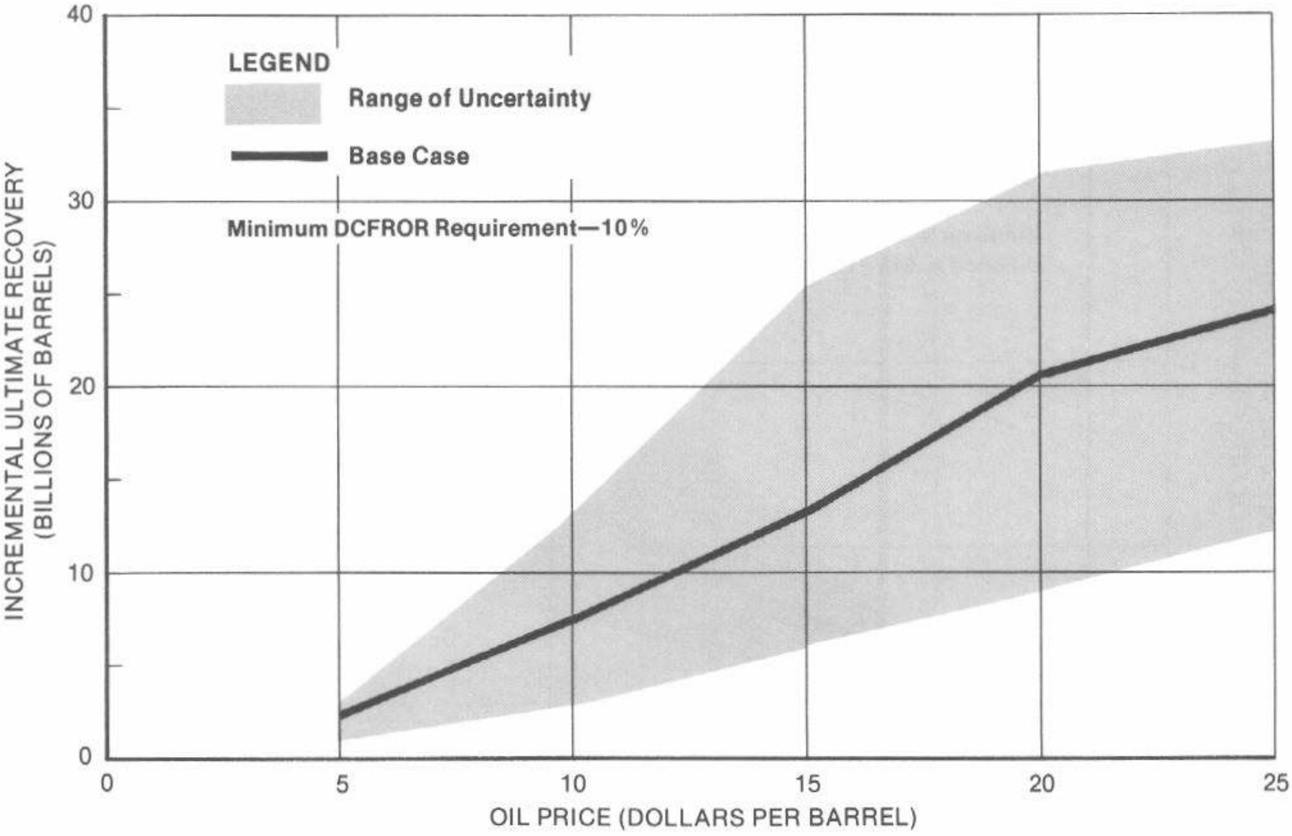

Figure 43. Uncertainty in Incremental Ultimate Recovery.

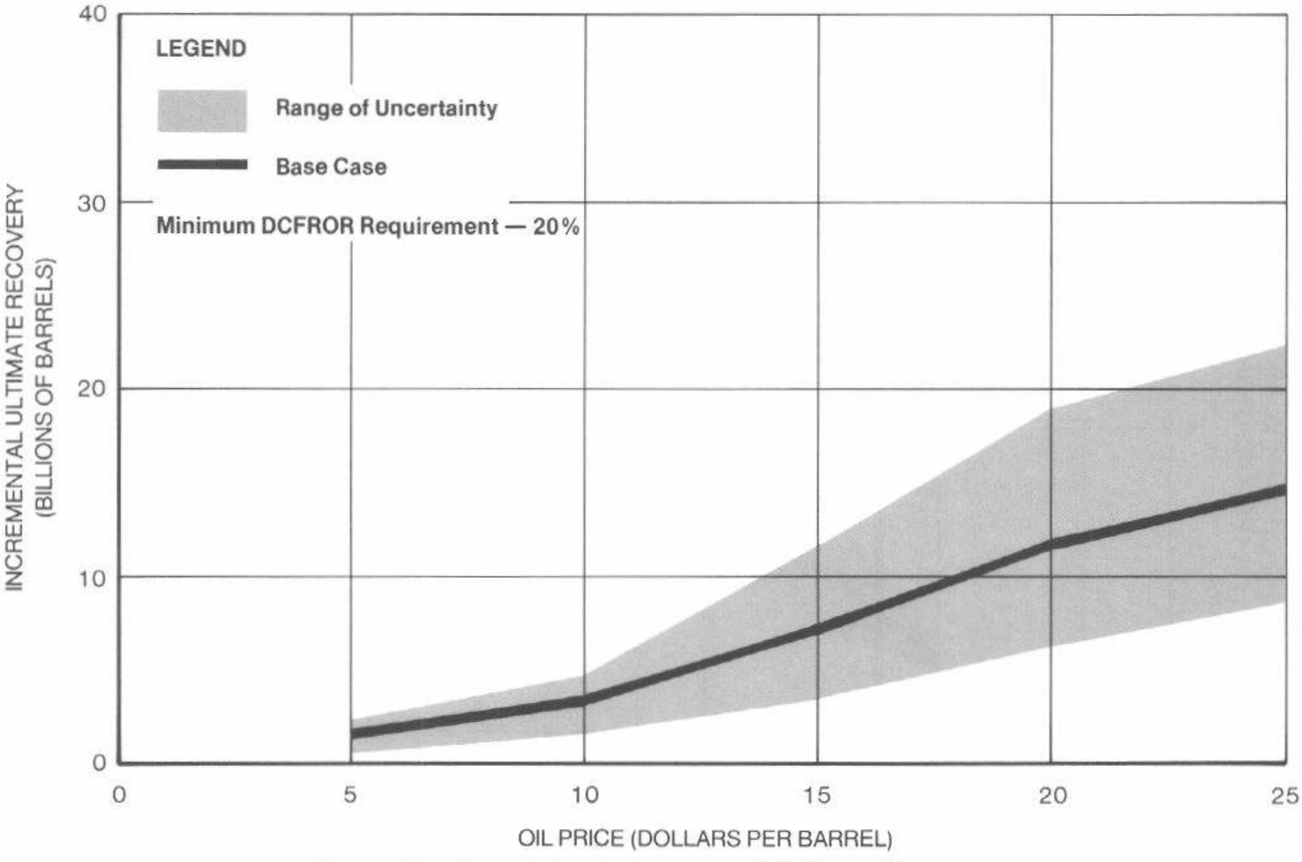

Figure 44. Uncertainty in Incremental Ultimate Recovery.

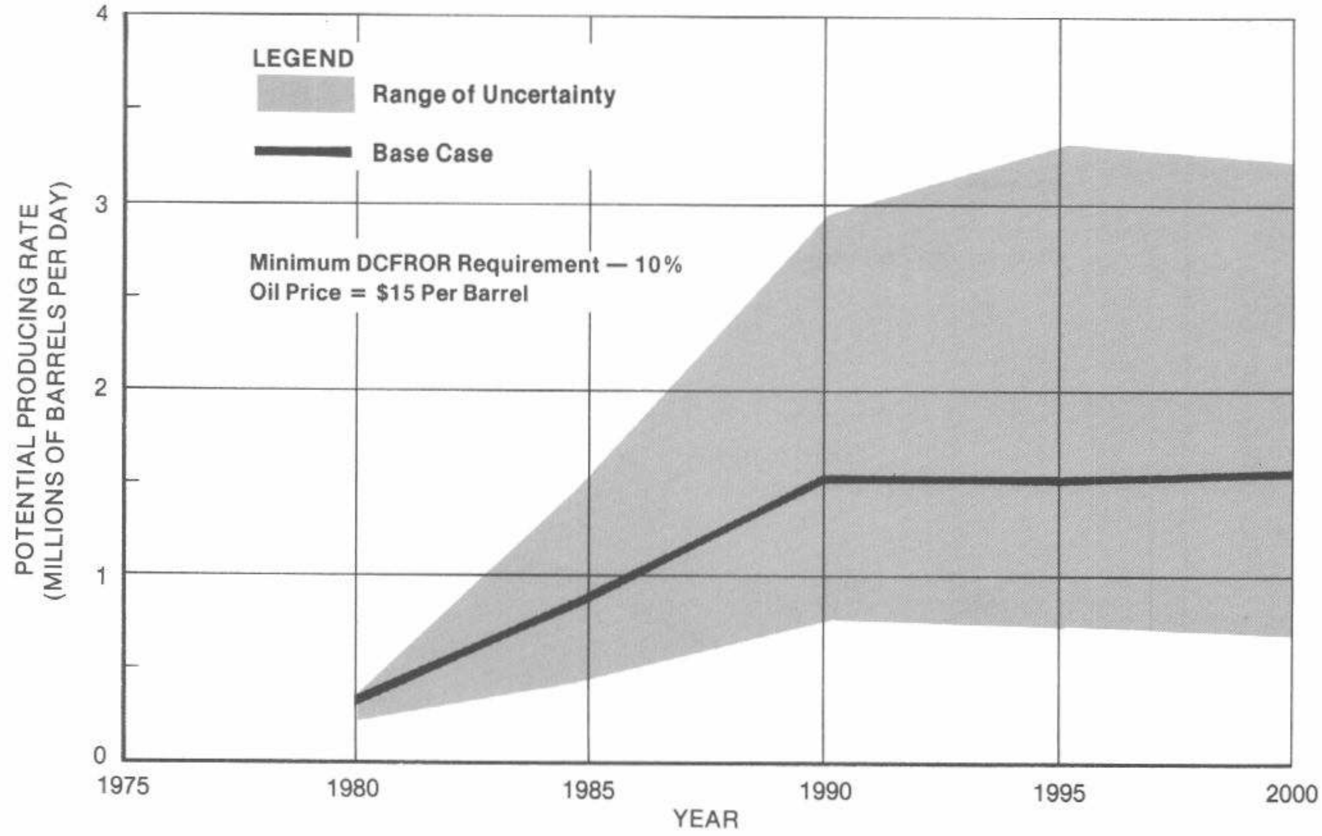

Figure 45. Uncertainty in Potential Producing Rate.

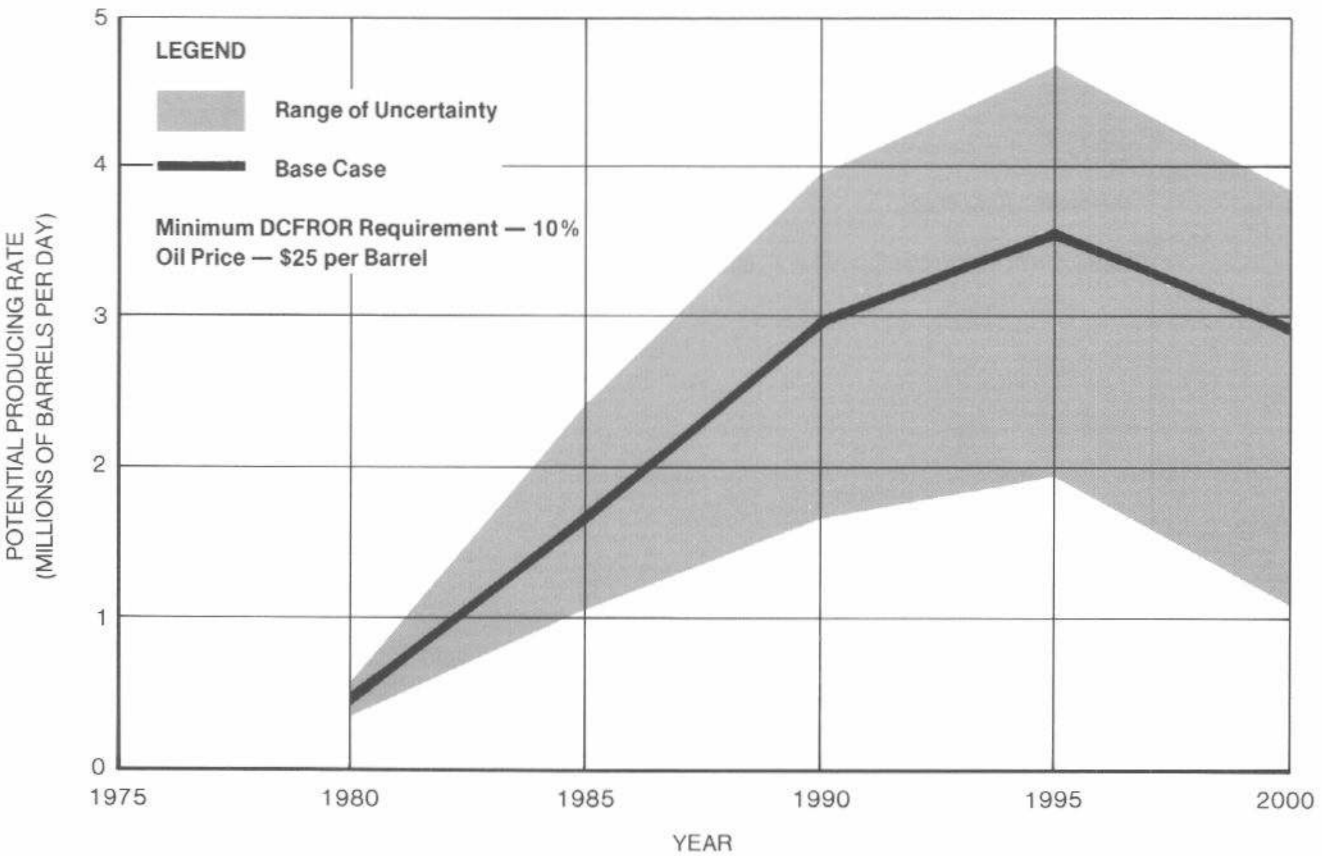

Figure 46. Uncertainty in Potential Producing Rate.

this highly favorable combination of performance and economic conditions. The screening parameters were established primarily to select candidate reservoirs assuming performance levels similar to those in the base case results. Some reservoirs excluded in the screening process might actually be economic at oil prices of $20 and $25 if performance were as favorable as that shown in the high-range curve.

Since the values shown represent the uncertainty associated only with process recovery performance, and not the several other parameters (such as process cost) that also influence the range of results, they tend to represent only the *minimum* total uncertainty in results. The variability due to other parameters is offset, in part, by the probability that all processes will not simultaneously prove to show either very good or very poor performance. Therefore, these variability analyses may be assumed to be reasonably representative of the overall uncertainty in results at a specified economic condition. Similar results may be generated for other economic conditions to obtain the full perspective on possible results.

The potential importance of enhanced recovery processes to domestic oil supply, if sucessfully applied at base case levels, is shown in Figure 47. This figure shows the potential enhanced oil recovery production rates, superimposed on the calculated decline curve of remaining primary and secondary production of current U.S. proved reserves. Production from future discoveries is not included. Derivation of this decline curve is discussed in Appendix H. At these economic conditions, EOR represents a substantial addition to potential producing rates during the time frame 1990-2000.

Discussion of Results

Enhanced recovery technology, with few exceptions, is unproven in the field. In spite of extensive industry research and hundreds of millions of dollars spent on development and field testing of enhanced recovery processes, current production from enhanced recovery processes in the U.S. today is only about 350 thousand barrels per day, with the majority of this production coming from steam stimulation and steam drive in California.

Results from this study indicate that the major reason for lack of further application of enhanced recovery processes in the U.S. today is lack of sufficient economic incentive. However, calculations showing the variability of potential results with uncertainty in the key parameters indicate that even with additional economic incentives, the potential of enhanced recovery remains highly uncertain. The history of enhanced recovery includes few pilot tests with processes, other than steam, that have been successful from both a technical and an economic standpoint. It is only through detailed engineering analysis of the many failures in attempts to apply enhanced recovery processes in the field that the industry has reached the state of the art today which permits at least some estimate of future potential. The base case results in this study represent the best estimate that could be made at this time of such future potential. It is imperative, however, that the uncertainties associated with the base case estimates be recognized.

Uncertainty

Results of this study pertaining to ultimate recovery are probably less uncertain than the results projecting potential producing rates. The question of potential producing rate involves judgments of what could happen regarding both industry and government activity which add additional potential variability to the rate at which enhanced recovery reserves available at any oil price would actually be developed.

There are four major areas of uncertainty associated with projections in this study. These are:

- Process performance
- Associated process costs
- Characterization of the reservoirs to which enhanced recovery processes may be applied
- The economic climate in which enhanced recovery is developed.

Uncertainty in results of the study is due primarily to fundamental uncertainty, with the current state of the art, regarding both EOR processes and industry ability to characterize reservoirs. It is compounded, however, by the fact that the information available to the study group was insufficient to apply detailed engineering analysis to each reservoir, even for the limited number of reservoirs in the data base used. This introduced an additional potential variability in results associated with reservoir characterization, since only the limited information in the data base, together with qualitative judgments made during the geologic review of reservoirs for the study, was applied in this analysis.

Uncertainties in process performance and cost are greatest for chemical flooding. In surfactant flooding, which makes up the bulk of chemical flooding potential, essentially *no* oil has been produced *economically* to date, although about 400,000 barrels have been produced in field tests. The results in this study, therefore, constitute an extrapolation from near zero. While the use of surfactants for enhanced

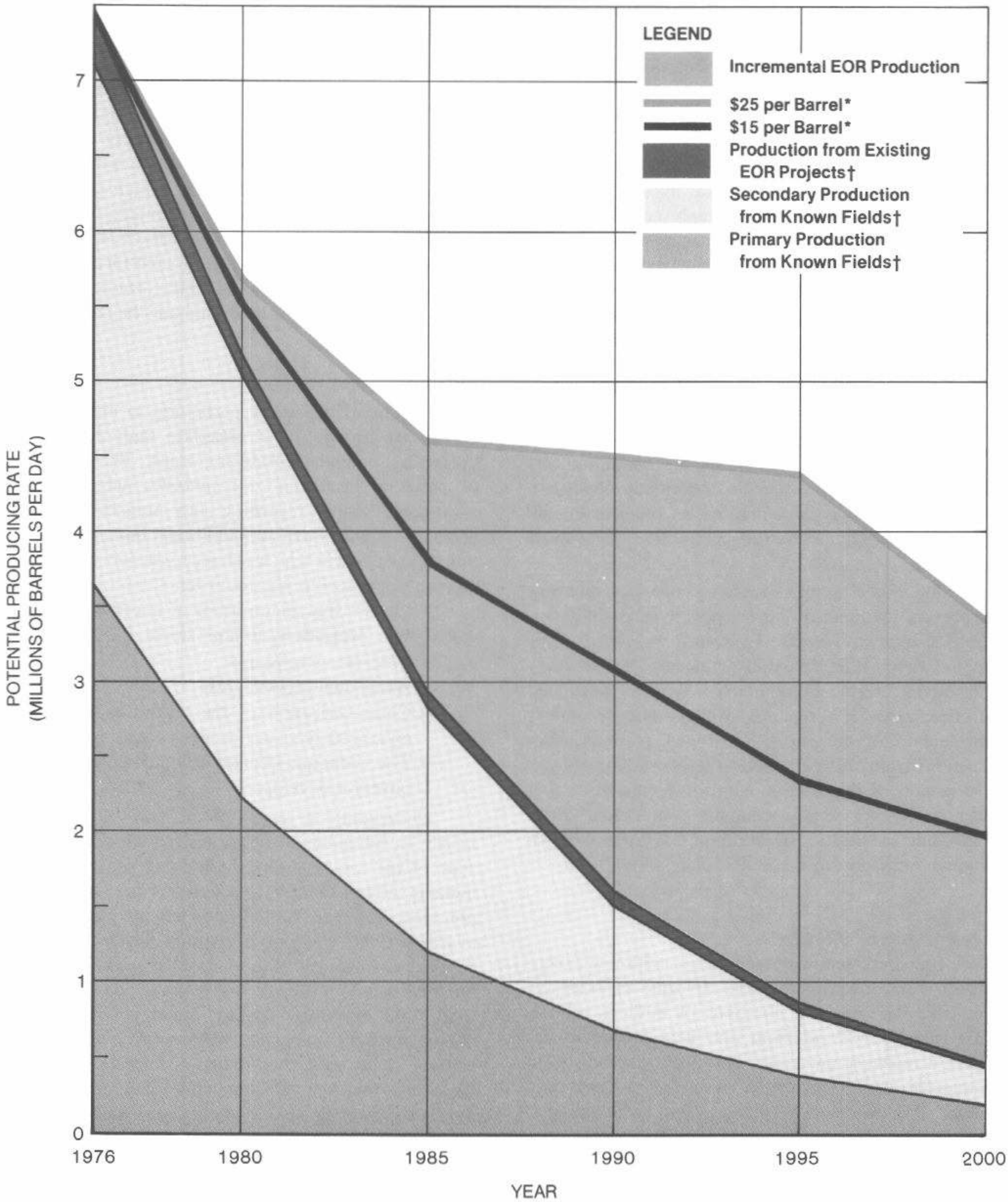

Figure 47. Potential U.S. Crude Oil Production Rate from Known Fields.

*Constant 1976 Dollars and Minimum DCFROR Requirement — 10%

†Estimated Producing Rates Based on December 31, 1975 API Reserves (See Appendix H).

Note: Production from the following sources is not considered and will be additive to the rates shown:

- Revisions except as included in API "Indicated Additional Reserves" as of December 31, 1975
- Extensions from realized enlargement of known fields
- New reservoir discoveries in known fields
- New field discoveries after December 31, 1975
- EOR from extensions, new reservoir discoveries, and new field discoveries
- North Slope, Alaska

oil recovery has been studied in the laboratory for at least 25 years, pilot testing has been somewhat limited compared to other processes, both with regard to the total number of tests and to the availability of test data in reservoirs of differing characteristics. Moreover, the process is inherently a "slug" type process; that is, a small fraction of the reservoir pore volume of chemicals is used because of their relatively high cost. This type of process has historically been the most difficult to implement economically because of the tendency of heterogeneity and other effects in the reservoir to destroy the integrity of the small slug.

On the positive side, however, the extensive industry research has brought technical knowledge of the process to a point where profitable application can be foreseen (given additional economic incentives), with substantial promise of future process improvement. There is a high current level of activity in research laboratories on chemical flooding from which continuing improvements may be expected. The time-varying screening process used in this study reflects a consensus judgment as to the probable rate of continuing improvement in process characteristics. Surfactant flooding is potentially the most flexible process of those studied in this report from the standpoint of tailoring the process to a given reservoir.

The carbon dioxide miscible flooding process is a simpler process than surfactant flooding, but has been field tested in even a smaller number of reservoirs. No oil has been produced economically in a tertiary mode to date, although the process is receiving some large-scale use in secondary recovery applications. Average residual oil saturation left by the process, sweep efficiency obtainable by the process, and resulting ratios of oil produced to carbon dioxide injected for the process are all uncertain at this time. On the positive side, the process uses a much larger slug of material, volumetrically, than chemical flooding, and has the property of regeneration of miscibility as long as pressure is maintained above miscibility pressure. This tends to make the process less sensitive to reservoir heterogeneity than surfactant flooding. It is primarily for this reason that carbon dioxide miscible flooding is the only process in this study envisioned for use in carbonate reservoirs, which tend to be highly heterogeneous.

The process appears promising and should be economic in some reservoirs today at current "upper tier" oil price. The total potential for this process in adding to U.S. reserves and production, however, is dependent not only on uncertain process characteristics, but also heavily dependent on the availability of very large quantities of sufficiently low-cost carbon dioxide where needed. Assumptions in this study regarding availability, location, and resulting cost of carbon dioxide may constitute the greatest uncertainty regarding the potential of this process.

In thermal recovery, the technology of steam stimulation is well known; this process is being applied extensively today. The recovery potential of steam drive in a given reservoir appears to be reasonably predictable, at least in those reservoirs for which there is an adequate reservoir description. The major uncertainty for steam stimulation and steam drive is in extension of this technology to new reservoirs and undeveloped parts of existing reservoirs. The degree to which process costs escalate as poorer quality reservoirs are treated is speculative, at best.

In-situ combustion involves an intermediate degree of uncertainty regarding both process performance and process cost. The in-situ combustion process has been tested extensively in the field, but has been applied economically in only a few instances. It appears to have promise, however, for some heavy oil reservoirs which cannot be treated economically with steam.

For all enhanced recovery methods the degree of reservoir characterization and engineering required for successful application may be an order of magnitude greater than for waterflooding. This has significant implications not only for the timing of development, but also for engineering and production manpower requirements to achieve the potential of this technology.

In projecting potential producing rates to achieve the ultimate potential cumulative recovery for each process, there are several additional uncertainties. The intent of this study was to project what *could* happen and not to forecast what *will* happen. The only economic variables considered explicitly in the analysis were oil price, process cost, and tax treatment. These factors do not fully describe the economic climate. The economic climate tacitly assumed in estimating potential producing rates might be characterized as "middle-of-the-road" for economic factors not explicitly studied. That is, it represents neither a minimum rate of development nor the maximum potential rate, given conditions of maximum stimulation and incentives.

It was also necessary to make tacit assumptions regarding general government policy, other than oil price, since such policy considerations may affect the rate of development of enhanced recovery processes. In projecting potential producing rates in this study, it was tacitly assumed that no major changes from current policy would occur in areas such as ERDA funding of field pilot testing. Industry willingness to conduct pilot tests and resulting attempts at commercialization were assumed to be consistent with the oil price specified, with no major impact of factors other than oil price and tax or equivalent economic incentives on the rate of field pilot testing.

This study probably does not take into account adequately the effect of oil price on rate of development. In most cases, the calculated rate of development probably corresponds to an intermediate oil price among those studied. At lower oil prices (i.e., with a lower economic incentive), the rate of pilot testing would probably be slower than that projected, with a resulting decrease in rate of development from the rate projected in this report. At higher oil prices, the rate of development might be greater than indicated in this report.

In considering the results of this study, it is important to recognize the impact of the constant dollar, inflation-free economic conditions assumed for the analyses. For example, production shown in 1990 for an oil price of \$20 is not based on the price level reaching \$20 by 1990—it is based on the somewhat artificial condition of oil price immediately jumping to \$20 in 1976 and remaining constant thereafter in terms of 1976 dollars.

Assumptions regarding the rate of technology evolution were developed by consensus judgments, and probably represent an intermediate rate of development corresponding to the assumed rate of field application. There is potential for more rapid evolution and for the solving of some problems which were assumed in this report to be formidable. Conversely, however, there is a possibility that the new technical developments which have been assumed in areas such as chemical flooding will not in fact be made on schedule.

Risk and Rate of Return

Two key factors in determining whether a particular enhanced recovery process will be applied to a particular reservoir, after it has been determined to be technically viable, are the anticipated DCFROR and the discounted net present value of the project. In this report, the influence of oil price on both incremental ultimate recovery and potential producing rate is primarily in affecting the number of reservoirs in which a given process can be expected to meet a specified minimum DCFROR criterion. This is equivalent to specifying a positive discounted net present value at the specified discount rate. As reviewed in more detail in Chapter Two, the rate of return used in this report is a "real" rate of return, without consideration of inflation. It is approximately equivalent to the more familiar nominal rate of return minus inflation rate. For example, the 10 percent rate of return in this report would correspond to a nominal 15 percent rate of return, if inflation were 5 percent.

One of the more significant findings in this study was that very few surfactant flooding projects are expected to show greater than a 20 percent constant dollar rate of return even with a \$25 per barrel oil price. A relatively small fraction of carbon dioxide miscible flooding projects are expected to show higher rates of return. Results for surfactant flooding were shown in Figure 17, from which it is apparent that a minimum DCFROR criterion of 20 percent decreases incremental ultimate recovery to near zero. Results for carbon dioxide miscible flooding were shown in Figure 23, which indicates the detrimental effect of higher specified rate of return requirements on incremental ultimate recovery.

In any economic endeavor containing a risk element, the profitability of successful operations must be sufficient to cover losses in unsuccessful operations if the enterprise is to continue. High potential rates of return are particularly important in the early stages of implementation of new technology, when the risk of failure is highest. The history of application of major technological innovations in the petroleum business indicates that nearly all such innovations had the potential for high profits in at least a few instances, which provided the incentive to attempt application even when the technology was in its uncertain, early states. For example, in waterflooding, the high profitability of successful applications offset the early failures, leading both to further attempts under uncertain conditions and to the development of the technology required to diminish the risk. Other examples include the introduction of hydraulic fracturing, the move into offshore operations, and the exploration of high-cost frontier areas.

When the profitability of fully *successful* operations is relatively low, the risk of failure must be comparably low, or the cost of failures will more than offset the profit from succesful operations. *The state of the art in surfactant flooding and carbon dioxide miscible flooding has not yet reached this point.* Further improvements in the industry's ability to predict the results of application of this technology will be required before widespread application can be expected. This will require substantial expenditures and time for laboratory research and field pilot testing. For this reason, the projections in this report showing little production from surfactant flooding and carbon dioxide miscible flooding until the mid-1980's appear realistic, if not optimistic. The rate of field pilot testing must increase substantially from the current rate if these results are to be achieved.

Surfactant flooding involves the highest risk of failure and shows the greatest effect of rate of return requirement on incremental ultimate recovery. Surfactant flooding is not only a high-cost process, but is also heavily "front end loaded" from an investment standpoint, because of the large fraction of overall costs associated with the injection of an expensive chemical slug. Risk and uncertainty of results, given the current state of the art, are high.

The risk associated with carbon dioxide miscible flooding ventures depends on both the nature of the application and the geographical location of the project in respect to sources of CO_2. Pilot testing of this process can be very time-consuming, since the reservoirs in which it may be applied are frequently low-permeability carbonates. In these reservoirs, the rate of movement of carbon dioxide is very low because of injectivity limits. Pilot testing can also be very costly if it is necessary to truck CO_2 to the pilot.

Alkaline waterflooding is a high-risk method because of its very limited applicability, but involves relatively low-cost injection materials. The cost of pilot testing would normally be relatively low. Polymer augmented waterflooding is also a relatively low-cost, but low-potential, process. Pilot test costs can be low. However, pilot tests are ambiguous because of the difficulty in establishing the true amount of incremental oil obtained by using the polymer. This is normally estimated by the difference between what is actually produced and what would have been obtained by waterflooding without the polymer.

The risk in applying in-situ combustion is at an intermediate level and depends on the nature of the reservoir to which it is to be applied. This process has been extensively field tested, although most of the early tests of this process utilized the "dry combustion" process, without injection of water. Pilot testing time and costs are also at an intermediate level.

Steam stimulation and steam drive are the most predictable processes considered in this report. Risks associated with process applications are relatively low, although still higher than waterflooding. When successful, relatively high rates of return may be generated. The primary risks normally are concerned with the reservoir characterization of new areas to which the process is to be applied, rather than with process characteristics themselves. Pilot testing costs

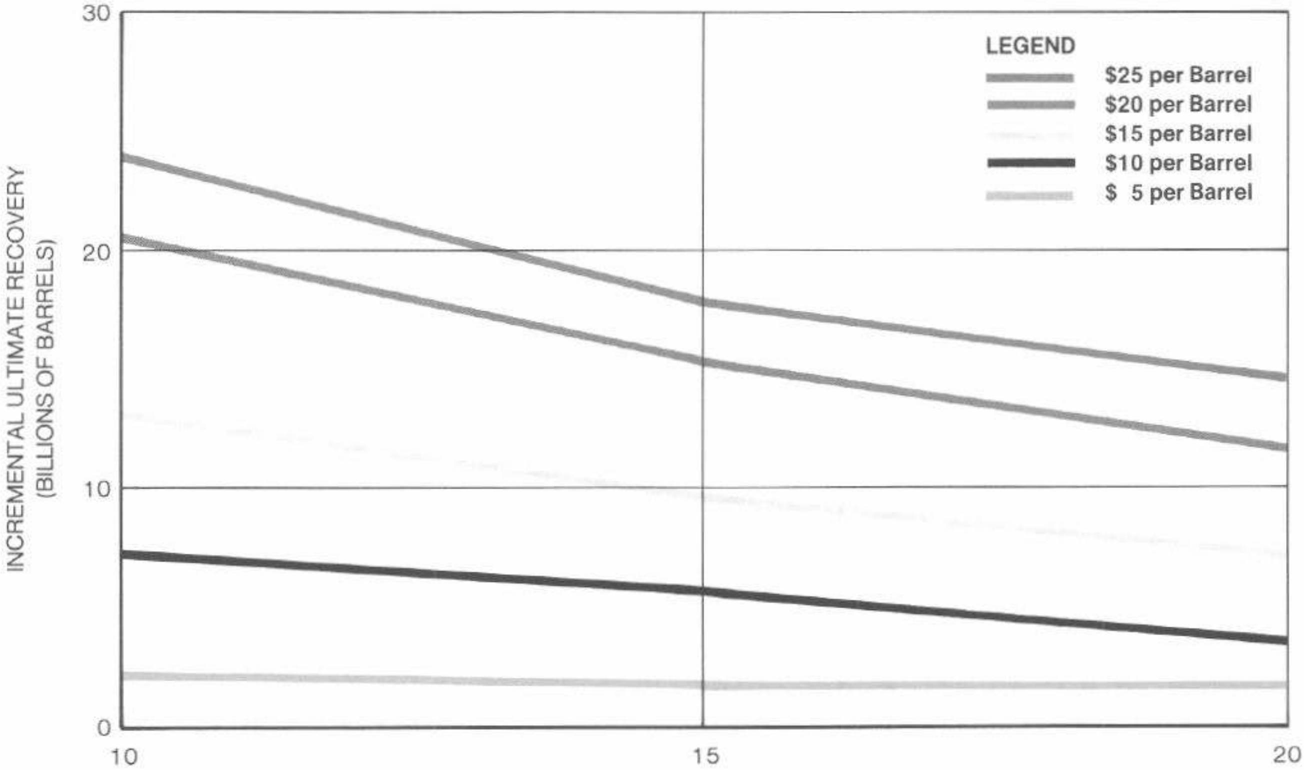

Figure 48. Incremental Ultimate Recovery—Base Case Performance and Costs.

are moderate, and pilots can normally be run on sufficiently close well spacing that results can be obtained rapidly.

The overall influence of DCFROR requirement on incremental ultimate recovery is shown in Figure 48. The need for research and pilot testing to decrease risk and minimize required rate of return is apparent.

Internal Consistency of Analysis Procedures

The treatment of sweep efficiency, residual oil saturation after waterflooding, and original oil in place as three separate, independent variables, together with the assumption that API statistics on reserves and original oil in place may be accepted for the reservoirs in question, results in mathematical over-specification of the problem. Apparent remaining waterflood reserves for the reservoirs in this study may be calculated by analyzing the oil production implied by waterflood sweep efficiency and waterflood residual as a fraction of original oil in place and then subtracting cumulative production to date. Since API does not, in general, publish reserves by reservoir, it is not possible to compare results with API statistics on each reservoir. In the aggregate, however, it appears that results based on sweep efficiency and waterflood residual from this study indicate higher apparent remaining reserves than those shown in API statistics. This raises some question as to the internal consistency of the analysis procedures, and indicates the differences which may occur in comparing independent assessments developed with different procedures, methodology, and judgment.

Some of this apparent difference is due to the method used by API in establishing reserve figures. Potential waterflood oil in parts of reservoirs which are not yet fully developed for waterflooding is not included in proved reserves by API, but is listed as "indicated additional reserves from known reservoirs." API reserves also do not include potential waterfloods which are not economic at current prices, but which would be economic at the higher oil prices considered in this study. Several California reservoirs appear to fit into one or both of these categories. API reserves also do not include additional stripper production at the higher oil prices considered in this study (see Appendix H). However, these factors, though important, do not fully explain the difference in apparent remaining reserves.

The primary question of consistency arises in examining the independent specification of waterflood sweep efficiency and residual oil to waterflooding (in the swept region). In general, the sweep efficiency for chemical flooding was assumed to be the same as waterflood sweep efficiency. The apparent difference with API reserve statistics indicates either that waterflood sweep efficiency, on the average, is not as high as assumed in this study, or that residual oil to waterflood, on the average, is not as low as used in this study. Since both parameters were selected based on engineering judgment to represent a broad range of reservoir characteristics, some degree of error would be expected in both parameters. Experience has shown that original oil in place estimates are also frequently in error.

If sweep efficiency were lower than that used in this study for both waterflooding and EOR processes, the potential for EOR would be reduced. The effect is largest for surfactant flooding. However, since the volume of surfactant injected is determined as a fraction of swept pore volume, rather than total reservoir pore volume, the economics of this process are not highly sensitive to the sweep efficiency assumed. The total potential volume of recovery is directly affected by sweep efficiency since this parameter establishes the "target oil" for the process.

If average residual oil saturation after waterflooding were higher than that used in this report, the potential for EOR processes would increase from that shown by results from this study. Calculations of the uncertainty in results as a function of waterflood residual oil shows that chemical flooding, in particular, is highly sensitive to this parameter. Since an increase in waterflood residual oil provides larger potential recovery with no substantial increase in process cost, the economics of processes such as surfactant flooding may be improved considerably by larger waterflood residual oil saturations.

The consensus judgment of the study participants is that the average waterflood residual oil used in this study is known more accurately than the average sweep efficiency. The sweep efficiencies assumed for some reservoirs in this study are probably too high. Because small errors in underestimating waterflood residual oil may counterbalance larger errors in overestimating sweep efficiency, however, there appears to be no reason to expect that this should cause either a uniformly positive or uniformly negative bias in results obtained. Further measurement of these two key parameters to establish the target oil for EOR with greater accuracy in reservoirs being considered for EOR would constitute a substantial improvement in industry ability to project the potential of EOR processes.

Incremental Cost

Examination of the recovery response to price estimates presented in this study indicates that the incremental cost of successive additional volumes of oil recovered generally increases at an accelerating rate. Indeed, this relationship is typical of any product produced under increasing cost conditions. Whether or not an increment of oil recovery justifies the indicated added cost depends primarily upon the full incremental cost of alternative energy supplies. Currently, the most readily available alternative supply is imported oil, the cost of which is its delivered price plus any implicit costs associated with supply insecurity, balance of payments burden, and other social and political disadvantages of foreign supply.

Long-range supply alternatives include several high-cost sources of domestic energy. Some U.S. energy consumers are already paying $3 and $4 per MMBTU for LNG and SNG and planned Arctic gas would cost $3 to $4 or more per MMBTU. More exotic forms of energy such as solar, geothermal, fusion, etc. may well be twice as costly depending upon locations and end-use applications. Though this study has made no attempt to compare enhanced oil recovery with these other energy sources, the development of very costly forms of energy will involve payments of a substantial premium over the present price of domestic conventional or imported energy supplies.

There is a large potential for additional EOR oil costing $20 to $25 per barrel ($3.40 to $4.25/MMBTU). This oil would cost less than the probable threshold cost of several alternative energy forms now being developed. In the event that acceptable substitutes for incremental volumes of EOR oil were not available, the value of these foregone supplies would depend upon what buyers would be willing to pay in an unconstrained market environment. If demand elasticity were low, it is entirely possible that high values would be assigned to oil supplies in a condition of restricted availability.

Another problem involved in making comparisons of the marginal value and cost comparisons of incremental oil supplies is the imprecise nature of cost estimates, particularly at price levels not yet attained.

Even if it were determined that the average cost of EOR oil were acceptable but the incremental costs were higher than desired, it would be extremely difficult to impose a segregated multi-level price system that would minimize the difference between individual producer's cost and revenues. An example would be wheat production.

Without a regimen of extremely rigid price controls, it would not be possible to pay farmers prices for their crops based upon costs of individual units of acreage rather than on overall average costs. As a practical matter, lower prices could not be paid for wheat grown on the most productive and lowest unit cost acreage with higher prices reserved for marginal lands.

It is equally illogical to tie EOR prices to specific fields and/or specific processes in relation to estimated unit cost conditions. In this sense, the economics of oil supply are not materially different than for other goods or services.

General Outlook

The indeterminate nature of the ultimate value of recoverable oil deserves emphasis. In the foregoing sections, the principal elements of uncertainty were discussed as they related to individual technologies. In addition, there is a wide range of more general unknowns relating to government resource development policies, taxes, manpower and logistics, and other considerations that may be more or less favorable than assumed in this study. The following is a list of some factors or events which could result in ultimate oil recovery greater than the range estimated in this study:

- Major breakthroughs in the efficiency of enhanced recovery techniques or methods
- The development of economic methods of applying EOR techniques other than CO_2 injection, in carbonate rocks which represent about 30 percent of the U.S. petroleum resource base
- An extension of the depth of potential economic thermal recovery of oil below the limits assumed
- Reservoir porosity and saturation levels substantially exceeding the assumed range of conditions
- The discovery of large new onshore and offshore petroleum reserves suitable for EOR application (results in this study are limited to currently existing fields)
- Lower than projected development and operating costs, resulting from favorable experience factors, or less severe than anticipated environmental related costs
- More favorable than assumed general economic conditions, including tax burdens, or access to external capital that would expand industry cash available for EOR investment.

A comparable list of negative factors could be developed which could cause results to be even poorer than foreseen in this study.

There is no meaningful *technical* upper bound to the potential recovery of remaining oil in place except, possibly, net energy considerations. This net energy limit has not been determined, but is certainly much higher than levels considered in this report (possibly over 100 billion barrels). Constraints on recovery are ultimately established by *economic* factors. Even with the level of technology assumed to be available during the time frame 1976-2000, the slopes of the curves obtained in this study indicate a continuously increasing potential recovery level as economic incentives increase. As technology continues to advance, the economic balance will tend to shift. At any given level of technology, however, oil recovery will always be strongly affected by oil price.

Oil price and perception of future price or equivalent economic incentives are far and away the most important factors in establishing the potential of enhanced recovery processes. Industry has demonstrated a willingness to support high levels of laboratory research on enhanced recovery, together with a willingness to invest risk capital in field pilot testing in circumstances where there appears to be justification for anticipating future profitability. Moreover, in the last few years industry has shown an increasing willingness to share information on enhanced recovery technology in an attempt to accelerate the industry-wide development and application of this technology by decreasing the risk. Dissemination of technology throughout the industry can be expected to occur soon after new techniques are proven and should not represent a substantial timing factor.

The greatest potential impact of government policy is in the area of oil pricing and equivalent economic incentives. The potential effects of other government and public policy issues are discussed in Chapter Four.

Comparisons With Results of Other Studies

There have been a number of previous estimates of enhanced oil recovery potential. The results from several of these studies are summarized in Table 5.

Caution should be exercised in comparing results from the various studies since the results are not comparable directly on a one-for-one basis. Greatly differing degrees of detail went into the various projections, and different scenarios were assumed for developing reserves. Different criteria for economic parameters, such as discounted cash flow rate of return, probably were employed. The same improved recovery methods were not considered in all of the studies, and even somewhat different definitions of enhanced oil recovery appear to have been used.

With the exception of the recent Lewin & Associates study, none of the previous estimates was based on a reservoir-by-reservoir approach. In the Environmental Protection Agency (EPA) study conducted by Mathematica, Inc., a limited data base was compiled on over 350 major domestic oil fields.* However, rather than making specific reservoir estimates, oil in this data base was classified into several categories, determined by ranges of oil and reservoir properties that were believed to serve as criteria for the various enhanced recovery processes. Potential incremental recovery was estimated from the oil in the various categories. A modified Delphi survey approach was used by the Gulf Universities Research Consortium (GURC).† A series of conferences, sequential questionnaires, interim report reviews, and individual discussions was used to develop an industry consensus. In the Project Independence projection, a fraction of the previously discovered oil in place was added to proved reserves each year as a tertiary reserve component.‡ This fraction was subjectively estimated.

The Lewin & Associates projection, however, followed a methodology similar to that used in this report. The same data base on 245 reservoirs in California, Texas, and Louisiana was used as the starting point for both analyses. Individual reservoirs were screened for process suitability by applying screening criteria for reservoir and oil properties. When two or more processes appeared to be candidates in the same reservoir, dominance criteria were applied that determined the one process to be considered for each reservoir that passed the screening tests. The amount of oil recoverable by the enhanced process and the rate at which this oil would be produced were estimated for each reservoir by simple process models. Each reservoir was then subjected to an economic analysis. Finally, the results for the reservoirs in the data base were scaled up

*Mathematica, Inc., for EPA, *The Estimated Recovery Potential of Conventional Source Domestic Crude Oils*, May 1975.

†*Planning Criteria Relative to a National RDT & D Program Directed to the Enhanced Recovery of Crude Oil and Natural Gas*, Gulf Universities Research Consortium Report No. 148, February 28, 1976.

‡Federal Energy Administration, *Project Independence Report*, November 1974.

to reflect totals for each process for each of the three states.

A comparison of the three-state estimate made by Lewin & Associates for ultimate recovery potential with the three-state estimate resulting from this study is given in Figure 49. The comparison was made for a minimum DCFROR requirement of 8 percent. For the range of oil prices investigated, roughly one-third as much oil was estimated to be recoverable ultimately in this study as was estimated by Lewin & Associates. Both studies projected that steamflooding, carbon dioxide flooding, and surfactant flooding would be the processes with greatest potential.

A comparison of estimated oil production rates up to the year 2000 is shown in Figure 50. An oil price of $11.28 (1975 dollars) was assumed for the Lewin & Associates projection. Their "lower bound" case assumed that enhanced oil recovery remained a high-risk technology throughout this time period. Their "upper bound" case assumed that through a massive effort in research development, and field

TABLE 5

ESTIMATES OF ENHANCED OIL RECOVERY POTENTIAL

		Potential EOR Recovery (Billions of Barrels)	Production in 1985 (Millions of Barrels/Day)
NPC Study*			
-----$ 5	(1976 dollars)	2.2	0.3
-----$10	(1976 dollars)	7.2	0.4
-----$15	(1976 dollars)	13.2	0.9
-----$20	(1976 dollars)	20.5	1.5
-----$25	(1976 dollars)	24.0	1.7
GURC†‡			
-----$10	(1974 dollars)	18-36	1.1
-----$15	(1974 dollars)	51-76	—
FEA/PIR§			
-----business as usual, $11		—	1.8
-----accelerated development, $11		—	2.3
EPA¶			
-----$ 8-12	(1975 dollars)	7	—
-----$12-16	(1975 dollars)	16	—
FEA/Energy Outlook**			
-----$12		—	0.9
FEA†† (3 states)			
-----upper bound, $11.28	(1975 dollars)	30.5‡‡	2
-----lower bound, $11.28	(1975 dollars)	15.6§§	1

* Total U.S.; base case performance and costs; minimum DCFROR requirement of 10 percent; moderate tax case.

† *Planning Criteria Relative to a National RDT & D Program to the Enhanced Recovery of Crude Oil and Natural Gas*, Gulf Universities Research Consortium Report Number 130, November 1973.

‡ *Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Testing*, Gulf Universities Research Consortium Report Number 148, February 28, 1976.

§ *Project Independence Report*, Federal Energy Administration, November 1974.

¶ *The Estimated Recovery Potential of Conventional Source Domestic Crude Oil*, Mathematica, Incorporated for the U.S. Environmental Protection Agency, May 1975.

** *1976 National Energy Outlook*, Federal Energy Administration.

†† *The Potential and Economics of Enhanced Oil Recovery*, Lewin & Associates, Incorporated for the Federal Energy Administration, April 1976.

‡‡ Reserves added by the year 2000 if projects return DCFROR of 8 percent or greater.

§§ Reserves added by the year 2000 if projects return DCFROR of 20 percent or greater.

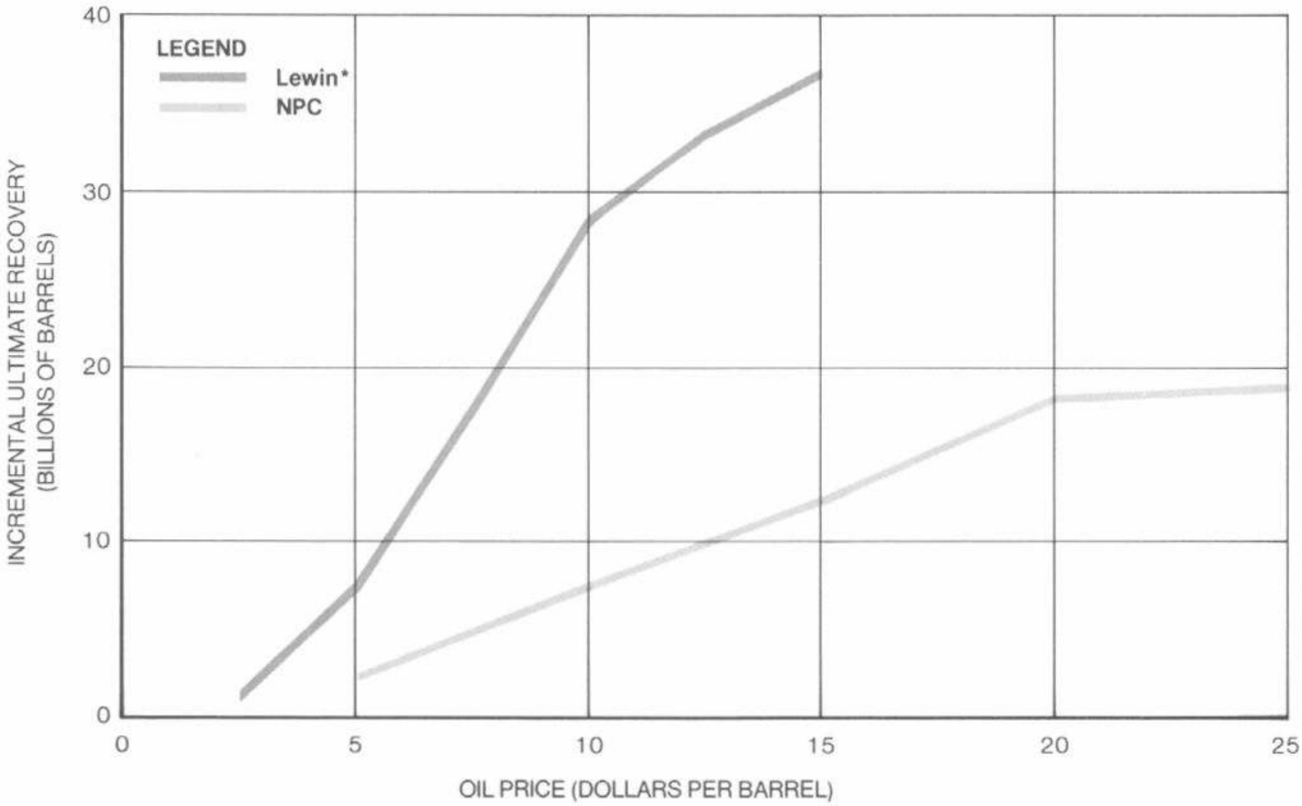

Figure 49. Incremental Ultimate Recovery—All Processes—Texas, California, Louisiana—Minimum DCFROR Requirement—8%.

* *The Potential and Economics of Enhanced Oil Recovery*, Lewin and Associates, Incorporated for Federal Energy Administration, April 1976.

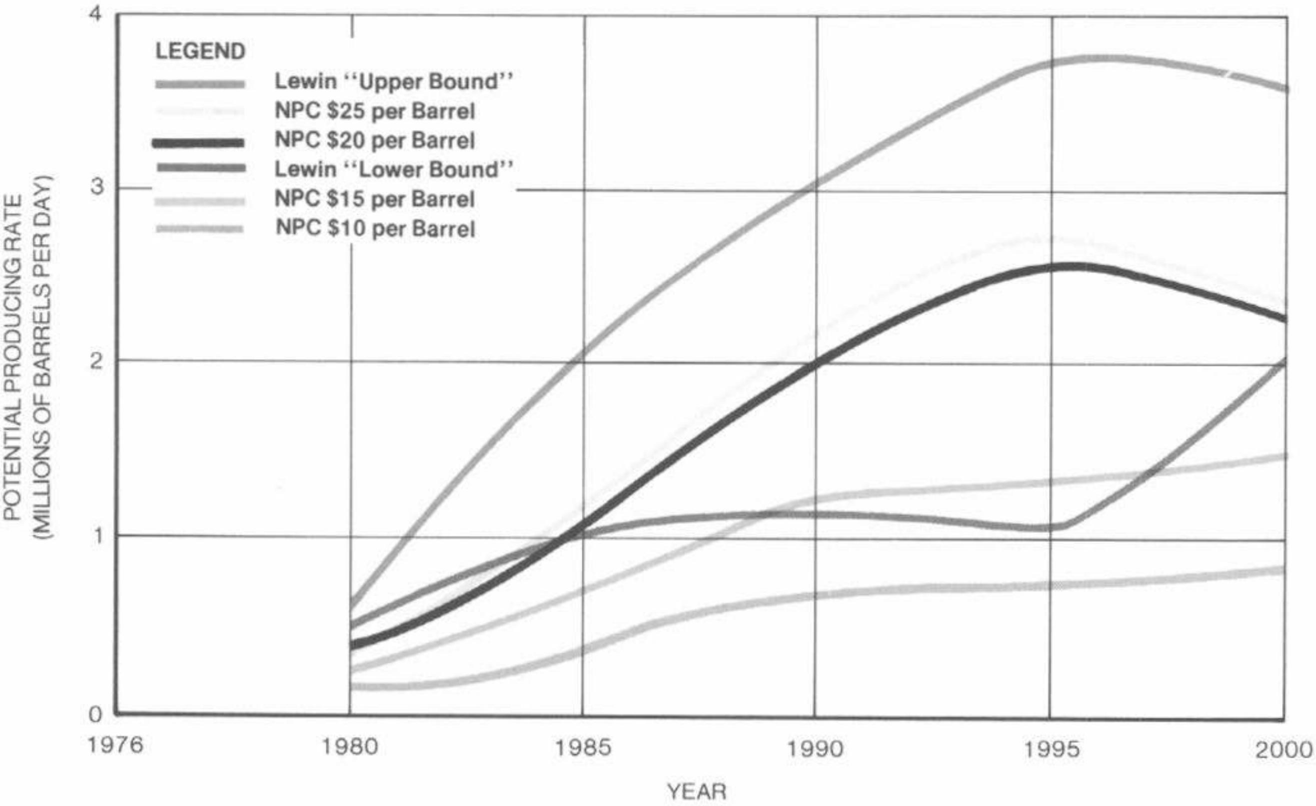

Figure 50. Projected Oil Producing Rate from Enhanced Recovery Total for Three States.

Note: All curves are based on a minimum DCFROR requirement of 8 percent except Lewin "Lower Bound" which is based on a minimum DCFROR requirement of 20 percent.

testing as a result of a concerted federal initiative, enhanced oil recovery would become a proven, conventional technology by 1990 to the degree that only an 8 percent real DCFROR is demanded for projects. The producing rates shown in Figure 50 for the NPC study were projected, assuming that at least an 8 percent DCFROR was required for project initiation. Even at the $25 oil price, the oil producing rates projected by this study do not reach the levels projected for the Lewin & Associates "upper bound" case. At this high oil price the incremental ultimate recovery projected in this study for all the reservoirs with EOR projects returning an 8 percent real DCFROR or better was still less than the incremental ultimate recovery projected by Lewin & Associates for the $11.28 oil price (19 versus 30.5 billion barrels).

Both the Lewin & Associates and NPC studies started with the same reservoir data base and used a similar reservoir-by-reservoir analysis approach, but the conclusions arrived at differ substantially. Although a direct, reservoir-by-reservoir comparison was not made and although there are numerous differences in detail between the two studies, the factors listed below appear to have contributed to a substantial part of the disagreement.

- Those reservoirs passing the process criteria in the NPC study were subjected to further review by geologists and engineers. This screening for geological factors and past performance eliminated many reservoirs from further consideration.
- The average oil saturation that the enhanced recovery fluids contact in a tertiary recovery flood was estimated differently in the two studies. For many fields this led to substantially lower oil recovery being projected by the NPC study for carbon dioxide flooding and for surfactant flooding. Lewin & Associates assumed this contactable saturation would be the material balance residual oil saturation (i.e., the saturation calculated by assuming all the oil left in a reservoir at the start of improved recovery flooding to be *uniformly* distributed throughout the reservoir). In the NPC study the view was held that carbon dioxide and surfactant solutions would flow preferentially in the previously water-invaded regions and only contact the lower waterflood residual oil saturation.
- Different methods were used to account for volumetric sweepout in the steamflood process. The method used in the NPC study should estimate less oil recovery for the thicker oil zones as a result of the gravity segregation of fluids. In addition, recovery adjustment factors were applied to the base estimates in this study (homogeneous reservoir) to account for reservoir heterogeneity and for reservoir quality.
- The unit cost to produce a barrel of enhanced recovery oil probably was different in the two studies for many of the fields examined. At any given oil price, fewer projects would be considered economically viable by the NPC study.

Additional details of comparisons with other studies are given in Appendix G.

Chapter Four
Policy Considerations

Introduction

This chapter discusses several aspects of EOR activities which go beyond the strictly technical and economic aspects discussed in the earlier chapters. Areas included are the possible social costs and benefits of EOR projects, regulations and federal policy considerations, economic incentives, and environmental considerations. These topics are more general than the earlier discussions and apply to all EOR processes and levels of activity. In fact, many of the considerations could apply to any industrial activity.

The net social effects of EOR activities appear to be beneficial and should encourage supportive regulations and government policies. EOR project feasibility and economics are sensitive to a wide range of government regulations and environmental considerations. These interactions are reviewed.

Social Costs and Benefits

The principal focus of this study is on the technological, economic and environmental factors which impact on specific EOR project results. These projects may, however, have additional significant impacts on society in general. The following sections identify and discuss various social benefits and costs associated with EOR projects and are not necessarily considered in project economic analyses.

Social Benefits

The social benefits of enhanced recovery programs are primarily political and technological. The political benefits hinge on reducing oil import requirements as a result of increased domestic production. The technological benefits relate to potential future expansion of enhanced recovery technology applications and to the resulting increased recovery of oil in place associated with both past and future discoveries. Since neither of these effects is reflected in routine project evaluations, they represent an additional social benefit of EOR activities.

Other benefits relate to economies of scale and to the flow of tax revenues. Briefly, the areas in which society might benefit from enhanced recovery programs can be outlined as follows:

- **Domestic Energy Policy**—Increases in domestic oil production could reduce foreign import requirements and permit a scaling back of emergency oil storage programs. The existence of higher domestic production levels would also reduce the Nation's ultimate vulnerability in the event that an embargo might outlast strategic storage volumes.
- **Foreign Policy and National Security**—Reduced dependence on oil imports would afford greater independence and flexibility in conducting U.S. foreign policy. Limiting oil imports from politically sensitive areas of the world would make the U.S. society and economy more secure from the disruptive effects of another embargo.
- **Expanded Use of Enhanced Recovery Technology**—Development of enhanced recovery technology for the larger, most promising U.S. fields probably will demonstrate the applicability of EOR processes, both to other domestic and foreign fields. Also some in-situ processes aimed at conventional oil may be

modified and adapted to heavy oil, shale, and/or coal recovery.

- **Expected Recovery of Reserves**—With enhanced recovery technology, producers could expect ultimately to recover an increased percentage of oil in place in newly discovered fields. Thus, fields that otherwise might be considered marginally unattractive could become economically viable. The resulting oil recovery increase would contribute to the Nation's natural resources inventory.
- **Economies of Scale**—Expansion of enhanced recovery technology and application would also cause expansion and economies of scale both in those industries supplying materials for the individual projects and in all ancillary and downstream activities. Society would benefit since these economies of scale would tend to result in lower oil costs than would otherwise occur.
- **Flow of Tax Revenues**—Severance, royalty and property taxes imposed on enhanced recovery projects would contribute to the funding of government services.

The minimum social benefit of increased domestic oil production should be measured against the price of the most prominent alternative energy supply, i.e., imported oil. Moreover, other energy alternatives, which are even more costly than imports, are being seriously and actively considered. This fact could generate other social benefits associated with increased U.S. oil production resulting from successful application of enhanced recovery techniques.

Social Costs

The potential social costs of enhanced recovery programs would primarily relate to air and water quality, health and safety, and land use. However, federal, state and local regulations will require firms involved in enhanced recovery to pay the costs of reducing environmental hazards. Moreover, enhanced recovery programs will take place within existing oil fields, and thus, will not generally require additional land use. These projects usually will employ existing lease equipment, tankage, and transportation facilities. Enhanced recovery programs will involve few, if any, major new land use requirements or industrialization commitments, which would substantially increase the social and financial burdens of the surrounding communities. In most cases, EOR projects will have little community impact since they will occur in presently producing fields.

Summary

On balance, the social benefits clearly appear to outweigh the social costs. Essentially all of the potential social costs now perceived very likely will be paid for by the operator through existing and/or future environmental protection regulations.

Regulations and Federal Policy Considerations

This section considers the impact of government regulations and controls on enhanced oil recovery potential.

The Impact of Government Controls and Regulations Upon the Cost and Availability of Capital

The major consideration affecting the petroleum industry's ability to commit additional funds to enhanced recovery projects is the attractiveness of these investments relative to alternative opportunities. Uncertainties about future price controls and taxes affect investor decisions and tend to boost minimum acceptable target rates of return. Of course, investors are not only concerned with existing rules, but with future and unpredictable shifts from the established regulatory environment.

As demonstrated in this study, the potential for the successful application of enhanced recovery methods is highly dependent upon economic factors. Public policies which reduce capital costs by increasing the potential scale of operations, lowering the required minimum rates of return for investors, and increasing the efficiency of investments, will substantially contribute to increasing ultimate oil recovery rates.

Price Effects

In an unregulated environment, market supply and demand forces determine the equilibrium prices to which both consumers and producers respond. When market price determination is unimpaired by regulatory restraints, a decentralized benefit/cost analysis is continuously being made by both consumers and producers whose responses tend toward an optimized supply/demand condition. In an activity such as enhanced oil recovery, where there are not important adverse economic or social considerations, the free market result tends toward efficient allocation of resources.

Crude oil price controls as presently administered generally discourage EOR projects because of the difficulty of qualifying enhanced recovery from reservoirs subject to steep production decline as "new oil." Regulatory changes now being considered may help relieve this problem.

Non-Price Incentives

The U.S. Energy Research and Development Administration has authority to fund research efforts to increase U.S. energy production. Such funding has been directed in various ways to support EOR technology development and commercialization. Although most technical problems involved in enhanced recovery should be manageable within the private sector given adequate price and tax incentives, accelerated field testing of EOR technology may benefit from selective government initiatives.

Tax incentives could effectively assist in the recovery of research, development, and commercialization investments. The cases analyzed herein show that alternative tax treatment would have substantial impact on enhanced recovery.

High royalties discourage EOR investment since they are claims on gross revenues rather than net earnings and, thus, represent a burden which would preclude development of otherwise economic reserves.

Plugging and Abandonment

Many oil fields in which waterfloods were started in the 1950's have now reached advanced stages of depletion. Some are approaching their economic limit and gradually wells are being plugged and abandoned. For these fields, it would be advantageous if steps were taken to initiate enhanced recovery projects, where feasible, while the existing wells and surface equipment are still intact and usable. Otherwise, the added costs incurred in redrilling of wells and replacement of production facilities will make enhanced recovery projects more costly. In offshore operations, the potential added costs of redrilling may be compounded by the need to install new drilling platforms.

All producing states have statutes or regulations requiring oil and gas wells to be plugged upon final abandonment or within a specified time after production ceases. Such plugging requirements are designed to avert waste and pollution by preventing oil, gas and salt water from escaping at the surface or into subsurface water-bearing formations.

Ordinarily, when the field or unit operator desires to retain a well for evaluation and future reentry or injection, an exception to the plugging rule may be obtained upon application to a state regulatory agency. However, the risk exists that numerous individual operators having wells nearing the economic limits of current operations will plug and abandon such wells because they fail to see any economic incentive for future enhanced oil recovery projects in the area.

Unitization

Nearly all producing reservoirs are characterized by multiple ownership and will require unitization to implement enhanced recovery projects. Unitized enhanced recovery operations involve some cooperation among production firms. One producer usually is designated as the operator, but all parties with ownership interest share in the investment costs, operating costs and output on the basis of prearranged terms.

Under present regulatory policies, a high degree of uncertainty now exists in that unitization agreements may be precluded due to differing regulated prices and taxation provisions applicable to the different owners.

Any present or future laws or regulations establishing differential price ceilings, tax treatment or other regulatory controls for different classes of oil and gas producers substantially reduces the prospect of reaching mutual agreement on unitization required for implementation of enhanced recovery projects.

Economic Incentives

The results of this study indicate that public policies that provide increased economic incentives for the production of enhanced recovery oil will result in increased volumes. Conversely, those policies which decrease economic incentives will result in a diminished production of enhanced recovery oil. This is illustrated in Figure 1, which charts estimated EOR ultimate recovery versus oil price. An almost directly linear relationship between incremental ultimate recovery volume and crude oil prices can be observed. Likewise, Figure 2, which charts potential EOR producing rate versus time for the five assumed oil prices, clearly indicates the effect of increased economic incentives on volume.

Government actions can influence economics of enhanced recovery by price policies, tax policies, or other regulations. A serious question may be raised regarding the propriety of extending special advantages favoring EOR investment that would not be similarly provided to conventionally produced petroleum, or, indeed, any equivalent or substitutable form of domestically produced energy. It is hazardous to suggest conclusions regarding the impact or desirability of policy actions specifically affecting EOR without considering their effect upon other energy supply options. Energy policy decisions must be based upon a thorough consideration of the full range of sectoral impacts and interactions, which goes well beyond the scope of this study.

The possibilities of improving economic incentives for EOR production through changes in tax policies are many. A treatment of the subject of U.S. tax policy for the petroleum industry is being prepared as part of the National Petroleum Council's study on Future Energy Prospects. This study is expected to be completed in the Spring of 1977.

Research and Development

Enhanced recovery processes are in a development stage. The rate at which development by the industry takes place depends upon the economic outlook perceived by the industry for these methods. If management were assured that oil prices indeed will rise to substantially higher levels in the future or that other developments would improve profitability, larger investments would be made in very long lead time field tests and other steps leading to commercialization of emerging EOR technology. Government policy with respect to oil price and other factors influencing EOR profitability is thus the dominant factor in establishing the level of R&D funding and the rate of evolution of technology.

From industry's point of view, economic considerations of pilot testing are not overriding; that is, industry is prepared to carry out whatever pilot tests are needed, as they have for decades. What is significant is the economics of full field-scale applications. Progress in developing enhanced recovery processes requires many field tests. As discussed elsewhere, the only way to determine if a process works is to try it out in the field. Although continuing laboratory research is desirable and necessary, laboratory-based research and development is far ahead of field trial research and development.

A major problem in pursuing field development and application of enhanced recovery processes is the lack of detailed knowledge of the properties and characteristics of reservoirs and their susceptibility to the process being applied. Funding by industry of field pilot tests is usually concentrated on testing the applicability of a specific process to a specific reservoir, with the goal of optimizing information gathered per dollar spent. Opportunities exist for obtaining additional information in such tests through supplemental funding, particularly with regard to more general considerations which may be important in relating test results to opportunities in other reservoirs. Funding of field work such as special cores and logs, single well tests, and other techniques used to establish the level and distribution of residual oil in reservoirs after waterflooding would be of broad general benefit in better defining this critical parameter.

Other less obvious incentives, which government can supply, include a patent policy which would protect the rights of those who have funded research on EOR processes. The government can also provide additional incentive for research and development by minimizing the administrative burden on joint projects between industry and the government. The negotiations, record keeping, and report requirements by the government for joint government-industry field testing projects provide a formidable disincentive.

Environmental Considerations

Scope

This section outlines possible impacts on the environment that may result from enhanced oil and gas recovery. It is a general overview rather than a comprehensive assessment of the environmental impacts associated with any specific method at a particular site. The environmental considerations for the individual processes are discussed in more detail in Appendices D, E, and F.

Environmental discussions in this report are derived from a general knowledge of the subject by the study team members. No new technological study of environmental effects was undertaken.

Background

Although some of the suggested enhanced recovery techniques are relatively new, all have been field tested, and many of the methods and chemicals suggested for enhanced recovery have been used to some degree for many years in primary or secondary production. The data collected to date and the continuing, further evolution of these techniques will aid in avoiding or mitigating detrimental environmental effects in the future. Long-range monitoring of a specific technique may be necessary to fully assess its environmental effects.

Each site being considered for enhanced recovery techniques will require evaluation from both a technical and environmental viewpoint in order to determine the best enhanced recovery method and to define the measures necessary to protect the environment.

Throughout this study, environmental costs resulting from present or anticipated needs have been included for each EOR method in establishing total process cost; thus, the cost of protecting the environment is included in project costs by the producer.

A number of laws bear upon environmental aspects of enhanced recovery, and of these, the Clean Air Act, the Federal Water Pollution Control Act, and the Safe Drinking Water Act would have the most significance.

Areas of Concern

Water Supply

Published estimates indicate that the United States needs nearly 400 billion gallons of water a day and that these requirements may reach nearly 500 billion gallons by 1980. Since the supply of fresh, high-quality water is scarce in some areas, the amount of water used and the disposal thereof are of major concern in enhanced oil and gas recovery methods.

EOR processes that use large amounts of water are anticipated to make major use of recycling of formation water as a conservation measure. Thus, net requirements would be much less than would appear from considering only the total volume injected.

Water Quality

Problems in water quality relate to the handling and disposal of produced water. Water for enhanced recovery processes may be either fresh or saline, depending on process requirements. In the past, waterflooding commonly used saline water, in many cases with salt concentrations higher than sea water; however, some EOR methods require relatively fresh water.

The two most significant points with which danger to water quality is identified are: (1) spills of chemicals as a result of transportation, on-site manufacturing, and handling; and (2) improperly controlled disposal of chemically loaded produced water. Both of these areas can be dealt with through proper operating procedures. Further research and review of the types of chemicals planned for use and the methods for handling them appear to be the best ways for establishing adequate safeguards from potential toxic and carcinogenic effects.

The 1972 amendments to the Federal Water Pollution Control Act provide a useful framework for evaluating the potential impact for EOR techniques on water quality. A National Pollutant Discharge Elimination System Permit is required under this Act before commencing a waste-water discharge to surface waters from a point source. The intent of the Act and the discharge permits is to require use of the best available technology economically achievable by 1983 and to attain and maintain receiving water quality adequate to assure protection of public water supplies, agricultural and industrial uses, and the protection and propagation of a healthy population of shellfish, fish, and wildlife, and to allow recreational activities in and on the water. Under the Safe Drinking Water Act of 1974, the EPA is required to regulate subsurface injection and waste discharges in order to protect groundwater quality. EPA is also severely limiting discharge of produced water to surface waters.

Process water that is not recycled can be disposed of in two ways: injection into separate salt water aquifers or discharge to surface waters. Injection into separate salt water aquifers is an established operating procedure. For surface disposal, also an established procedure, process water for disposal is and will continue to be treated to meet standards of purity required by law. As new chemicals are applied to EOR, new treatment methods for disposal will have to be developed.

Groundwater aquifers, when accidentally infiltrated by chemical pollutants, are contaminated for varying lengths of time, depending on the chemicals and rock type. The concentration of the chemicals may be decreased with time and distance traveled in the reservoir. This decrease may be attributed to dilution, entrapment, absorption and degradation within the reservoir.

Groundwater aquifers when used for disposal, however, have distinct characteristics: they normally are saltwater aquifiers; they are not hydraulically connected to freshwater aquifiers; and they are commonly associated with and connected to oil reservoirs.

Leaks may occur from broken lines, improperly plugged wells, or improperly cased and cemented wells. However, existing technology, mandatory use of surface casing to protect freshwater aquifiers, and existing state monitored safety and inspection procedures used in drilling a well minimize the probability of an undetected leak. In spite of the possible accidents and potential hazards of drilling and completing wells that intersect brine and freshwater aquifers, little groundwater pollution has occurred in the past. It is felt that this record can remain intact for enhanced recovery methods by use of the same safe non-polluting work procedures.

Automatic shutdown and fail-safe devices are available. The use of such protecting devices should be given high priority.

Air Quality

Enhanced recovery can influence air quality in several ways. For example, steamflooding uses steam generators which emit combustion products; in-situ combustion uses air compressors; and in-situ combustion produces combustion products along with produced oil.

Thermal applications will have to deal with three primary constraints contained in the Federal Clean Air Act and state laws and regulations pursuant to the Act: (1) ambient air quality standards; (2) significant deterioration regulations; and in some cases, new source performance standards. Under present laws and EPA regulations, usual sized steam generators are too small to be subject to new source performance standards. The major constraints will be ambient air quality standards and significant deterioration regulations.

The EPA has set national ambient air quality standards to protect human health, allowing an adequate margin of safety (primary standards), and to protect property, vegetation, and other known or anticipated effects on public welfare (secondary standards). The primary and secondary standards are defined by permissible concentrations of carbon monoxide, photo-chemical oxidants, nitrogen dioxide, non-methane hydrocarbons, sulfur oxides and particulates. In addition, some states (for example, California) have established state ambient air quality standards which are more stringent than the federal standards. EPA regulations allow major new air pollutant sources only if they do not prevent or interfere with the attainment or maintenance of these ambient standards.

In addition, EPA regulations have been promulgated to prevent significant deterioration of air quality by sulfur oxides and particulates in regions where air quality is superior to the ambient air quality standards. These regulations allow states to classify their "clear air" regions into three zones. In the more restrictive zone (Class I), only extremely small emission sources would be permitted. In the Class II zone, new sources with moderate emissions would be permitted as long as they, in combination with all other new sources, do not exceed the allowable increment of air quality deterioration. In Class III zones, air quality would be required to meet the national or more stringent state ambient air quality standards, and emissions would be allowed to these standards.

The largest potential for thermal recovery on an extensive scale exists in California's Central Valley. Much of this region exceeds the photo-chemical oxidant and particulate air quality standards and a few locations are at or near the standard for sulfur oxides. At present, most of the oilfield areas in the Central Valley have air quality good enough to be subject to significant deterioration regulations with respect to sulfur oxides. At the present time, these areas are Class II zones which allow installations that do not exceed the allowable increment of air quality deterioration. These Class II classifications are initial ones established by the EPA, pending specific further classification by the State Air Resource Boards. If these thermal opportunity areas should be classified Zone III in the future, installations would be limited by the national or more stringent state ambient air quality standards.

Air quality maintenance plans, which each state must develop to attain and maintain national ambient air quality standards, are likely to be the mechanism for determining how the air pollution from thermal EOR applications will be controlled in California and other states in the future. Among the possible means of meeting these potential standards are (1) use of low-sulphur oil; (2) flue-gas desulfurization; and (3) the consolidation of facilities to increase the feasibility of emission control technology.

Other

Because enhanced recovery will take place in existing oil and gas fields, only minor changes should occur in present land use practices. In some cases, additional surface equipment will be needed, storage areas may be required, and additional wells may be drilled, but the overall appearances of the field will remain about the same.

Sources of noise may increase due to truck and other traffic, steam venting, well drilling, and other production activities. Noise control practices and devices will be needed to control noise levels to comply with regulations.

Manufacturers of toxic and hazardous chemicals for EOR will be required to follow laws and regulations governing the manner of transport and end-use, including evaluation in pilot tests.

CO_2 is non-toxic, but it is heavier than air so that its discharge to the atmosphere needs to be done in accordance with safe practices. H_2S, a toxic gas, will be produced from some projects. Both CO_2 and H_2S production are common in conventional oil and gas production, and regulations governing their safe handling are established under current procedures.

Other aspects for the use of chemicals which are of concern are combinations of toxicity and low degradability and synergistic effects which can convert two or more substances into one which becomes more dangerous than either one alone. A report on the Environmental Consequences of Tertiary Oil Recovery, submitted February 9, 1976, to the EPA, and prepared by Energy Resources Co., Inc., in which some of these questions are raised, indicates that the chemicals being used in combination now do not exhibit toxic or hazardous properties sufficient to raise serious environmental concern over present EOR operations. This aspect of the potential hazard from new chemical combinations in future operations should be subject to additional research.

Summary

It is natural that some concern exists as to what new environmental elements will be introduced by experimental enhanced oil and gas recovery techniques. Proper planning and research will be needed to assure that EOR operations can be carried out in the manner consistent with environmental protection needs and programs.

Most of the new enhanced recovery techniques will have considerable lead time before being put into operation. Except for thermal methods, which have had considerable use already, most of the enhanced recovery projects will not begin on a major scale until 1980 or later. Areas of potential concern should be identified and resolved in the interim.

In responding to applicable environmental laws, compliance with ambient air quality standards and significant deterioration regulations for thermal operations would appear to require considerable effort. Compliance with injection of waste water disposal regulations will also require considerable effort for all EOR applications.

Appendix A

Request Letter

UNITED STATES
DEPARTMENT OF THE INTERIOR
Office of the Secretary
Washington, D.C. 20240

C O P Y

March 18, 1975

Dear Mr. Swearingen:

The President and the Congress are considering changes in energy policies to reduce the Nation's vulnerability to interruptible and high-cost energy from abroad. However, any pathway to energy independence will depend upon our ability to apply existing and new technology.

The National Petroleum Council has provided the Department of the Interior with useful advice on the extent and recovery of the Nation's oil and gas resources through such studies as Impact of New Technology, Future Petroleum Provinces, U.S. Energy Outlook, and Ocean Petroleum Resources.

While we pursue unknown and unevaluated conventional and unconventional energy sources, we must continue to improve our ability to recover larger proportions of known oil and gas deposits on land and on the Outer Continental Shelf. New and anticipated technology and major changes in domestic and world market conditions require new estimates of ultimate resource recovery. While the U.S. could expect to recover an average of about one-third of the oil and four-fifths of the gas from known reserves in the past, new conditions will undoubtedly improve the recovery rates in the future. We need to obtain the best estimates of likely new recovery rates because of the changes experienced during the past few years.

We therefore request the National Petroleum Council to assess the state of the art of enhanced recovery for oil and gas from known oil and gas reserves. Your assessment should draw from and revise such relevant data from previous advisory committee reports and reports of others as you deem appropriate and should include, to the extent possible, an appraisal of the probable ranges of volumetric outcomes based on alternative economic conditions. Additionally, your report should contain recommendations as to how public policy can improve the outlook.

We would appreciate discussing a study outline this spring for a study to be completed within a year.

Sincerely,

/s/ JACK W. CARLSON

Jack W. Carlson
Assistant Secretary of the Interior

Mr. John Swearingen
Chairman, National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Appendix B
Committee Rosters

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For Oil and Gas in the United States

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Ex Officio
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The Chase Manhattan Bank

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Appendix C

Additional Economic Considerations

Additional Discussion— Project Economics

This appendix contains additional discussion on various key areas bearing on the project evaluation bases employed in this study. Topics included are:

- Process-independent costs
- Discussion of income tax cases
- Crude quality price differentials, and
- Project economics calculation.

Process–Independent Costs

Introduction

For the purposes of this study, the development cost and annual operating expenses for enhanced oil recovery operations are categorized according to: (1) non-process-oriented costs and (2) process-oriented costs. Because all of the EOR processes considered in this study utilize the injection of water into the reservoir, the generic non-process cost associated with EOR was determined by estimating the costs of installing and operating waterflood projects.

In the oil producing industry, the cost of developing and operating an oil field is dependent upon numerous factors that vary from field to field, and no well, lease, or field represents the average of all the factors involved. However, guidelines were developed, under certain criteria and assumptions considered to be consistent with current (1976) practices, by which reasonable cost estimates could be made. Presented in this report are the estimated costs at mid-year 1976 for the following classifications:

- Direct annual operating expenses for waterflooding
- Cost of drilling and completing production and injection wells
- Cost of equipment for:
  - Producing well equipment
  - Lease equipment
  - Water injection equipment
- Cost of utilizing existing wells as:
  - Producing wells
  - Injection wells.

Direct Annual Operating Expenses

The major factor that influences the non-process-oriented costs associated with enhanced oil recovery is depth. Depth not only affects the cost of drilling, completing and equipping the wells, but it has a profound effect upon the annual operating expenditures. For the purpose of this study, non-process costs were estimated for depths of 2,000, 4,000, 8,000, and 12,000 feet.

The direct annual operating expenses are those that are essential to the production of oil and gas, such as cost of labor, power, surface and subsurface equipment repair and maintenance, fluid injection, treatment of oil and gas for sale, etc. These operating expenses were estimated by formulating a set of assumptions and conditions whereby total annual cost was computed by summing the cost of small component items considered to be representative of oil production, in the geographic area considered, and from each of the assumed depths. Although these annual expense estimates will not be identical to those incurred in a particular field, during a particular year, or for a particular oil producer, they are considered to be representative of the expenses that may be incurred over the life of an enhanced oil recovery project. These costs were estimated on an annual basis for each item and then proportioned as if for individual wells.

The fuel or power expenses for producing oil from a well will vary considerably, depending primarily upon the type of, and depth at which, production equipment is installed. It was assumed that all power requirement was electricity; this cost was estimated from prevailing area electrical rates and the estimated horsepower required for each project. Costs were allocated on a per-well basis, where many wells were served by the same facility, such as the water injection plant for a project. Scale and corrosion inhibitors and deemulsifier costs were determined on a monthly per-well basis.

Costs for surface and subsurface equipment repair, maintenance, and service were determined by assigning frequencies of occurrences for each problem and estimating the cost of correcting the problem. The cost of correcting the problem was multiplied by the frequency of occurrence to obtain an annual per-well cost. Some of the most common types of production problems considered were broken rods, tubing leaks, and pump failures. Less frequent problems were casing leaks, sanding, packer failure, and poor cement jobs.

Summation of annual costs for all items resulted in the non-process, direct annual operating expenses shown in Table 6.

TABLE 6

1976 DIRECT ANNUAL OPERATING EXPENSE FOR WATER FLOODING*
(Dollars per Producing Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	14,900	19,300	24,100	25,400
California	19,300	22,600	29,100	33,000

* Estimated at mid-year 1976.

Cost of Drilling and Completing Production and Injection Wells

Geological and stratigraphic variations between areas can cause large differences in the costs of drilling and completing wells. Drilling time required for the same depth well, completion techniques, and formation evaluation will differ, not only for each area, but also for individual operators within that area.

In view of the variations that occur in drilling and completing wells, cost data developed by the *Joint Association Survey* (JAS) were considered to be the most representative for use in this study.*

For each of the five onshore areas studied, 1974 average costs of oil wells per foot drilled were compared to average depths, for each of the JAS depth intervals. Regression analysis was used to fit a curve that describes these intervals and the functional relationship between average 1974 drilling cost per foot and depth. In some areas, the average cost per foot either remained relatively constant or decreased with depth to about the 8,000-foot level due to the depth-independent costs such as roads, moving in, rigging up, pits, surface casing, etc.

The Independent Petroleum Association of America (IPAA) index of cost of drilling and equipping new wells in the United States for year-end 1975 was 120.3 (1974 = 100); it was estimated that the mid-year 1976 index would be 126.3. Therefore, the 1976 trend of drilling cost per foot was developed by increasing the 1974 index by 26.3 percent, as shown in Figures 51 through 55. These costs include drilling and completing the wells through the wellhead, including tubing.

Cost of Equipment

The costs of producing and injecting equipment were based on mid-1976 manufacturer's or supplier's list prices of new equipment, for a design considered to be the most commonly used in the areas under consideration.

Producing Well Equipment

Table 7 shows the cost of all well equipment, except tubing and wellhead, required to lift the fluid to the surface by artificial lift. For this study, it was assumed that the wells would be equipped either with rod pump or hydraulic lift, depending upon the depth.

Lease Equipment

Table 8 shows the cost of all lease equipment required to process the produced fluids prior

**Joint Association Survey*, sponsored by the American Petroleum Institute, the Independent Petroleum Association of America, and the Mid-Continent Oil and Gas Association, published March 1976 with cost data for 1974.

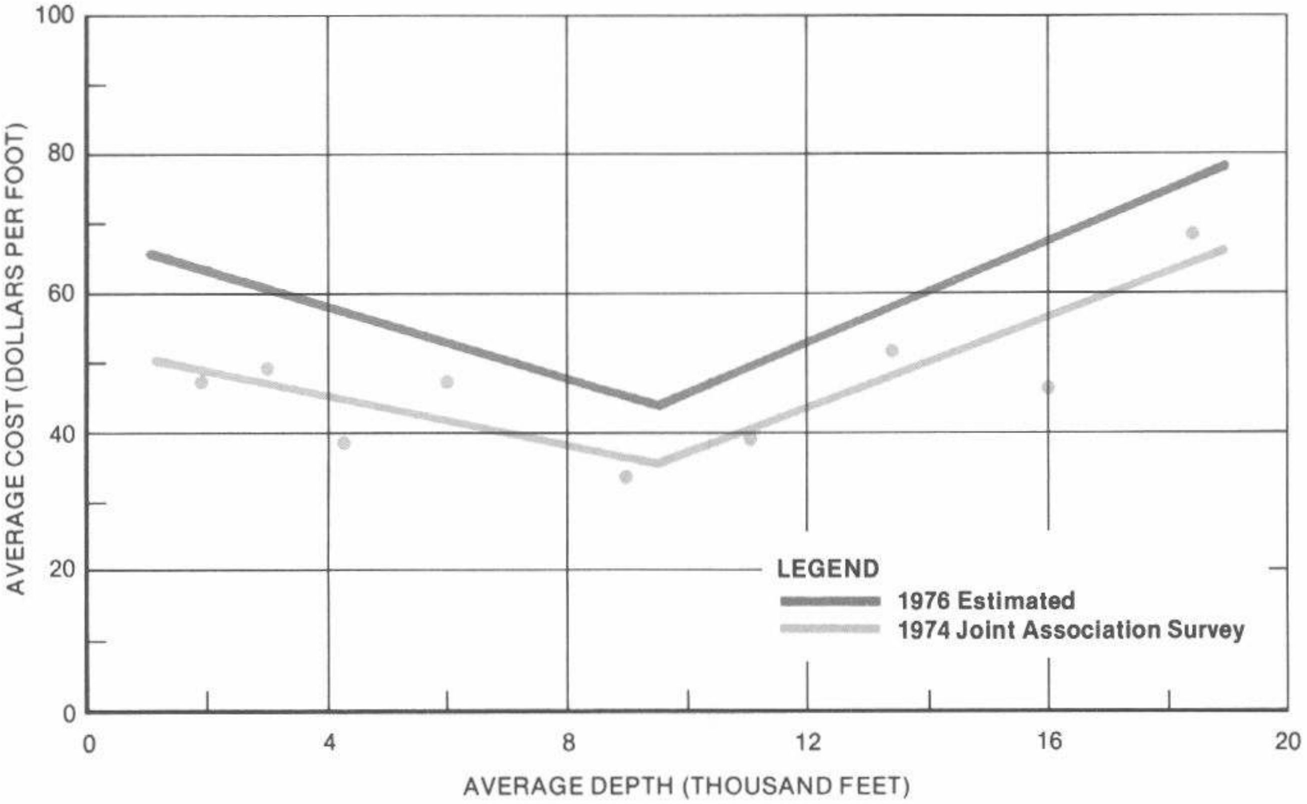

Figure 51. Cost of Drilling and Completing Production and Injection Wells—South Louisiana.

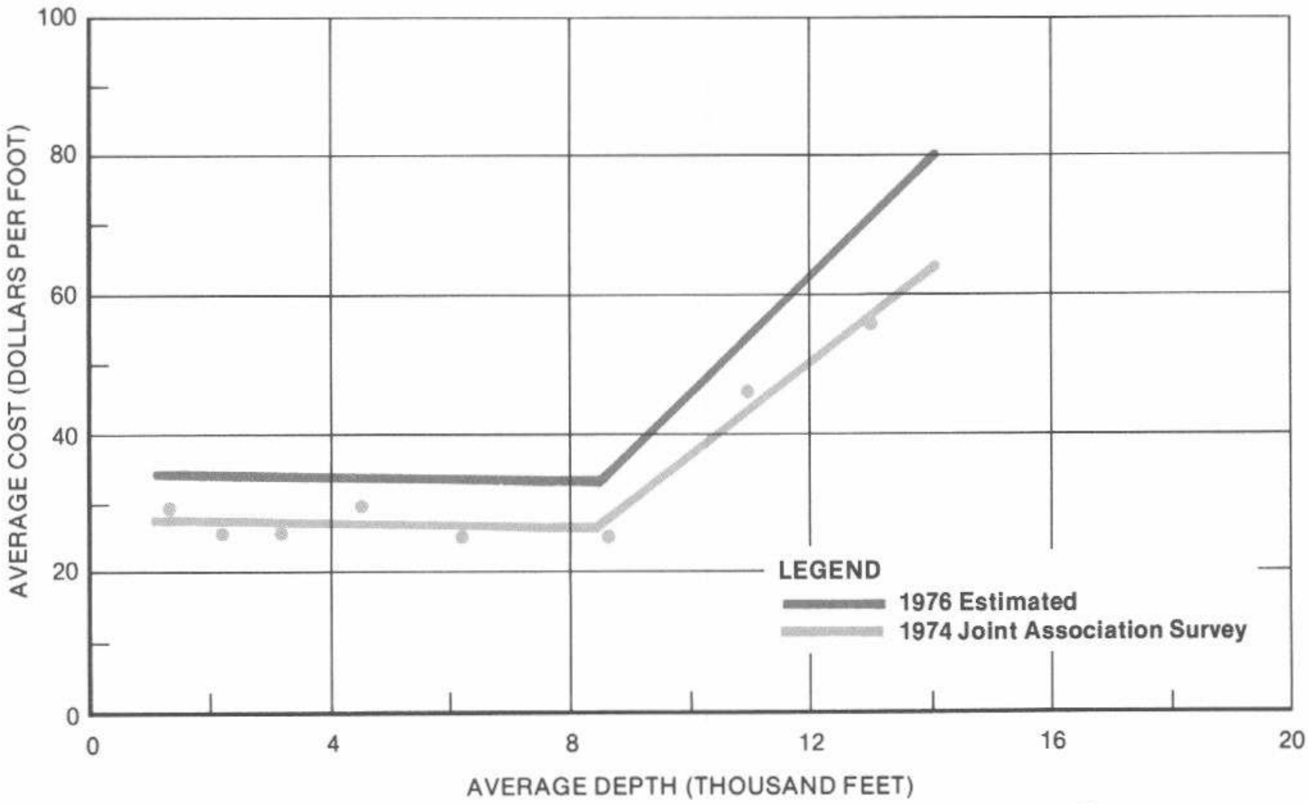

Figure 52. Cost of Drilling and Completing Production and Injection Wells Texas Districts 2 and 3 Combined.

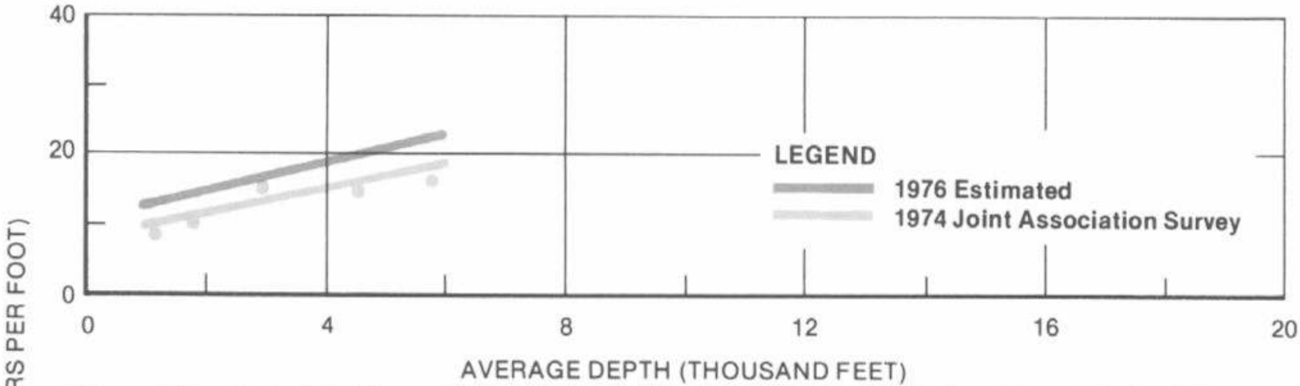

Figure 53. Cost of Drilling and Completing Production and Injection Wells—Texas District 7B.

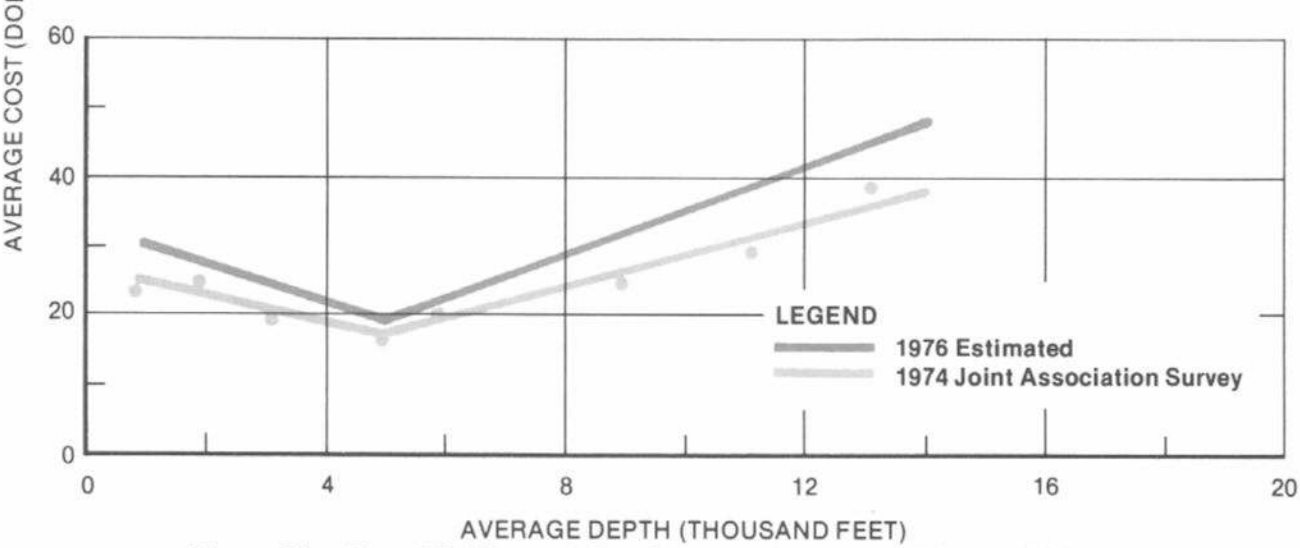

Figure 54. Cost of Drilling and Completing Production and Injection Wells Texas Districts 8 and 8A Combined.

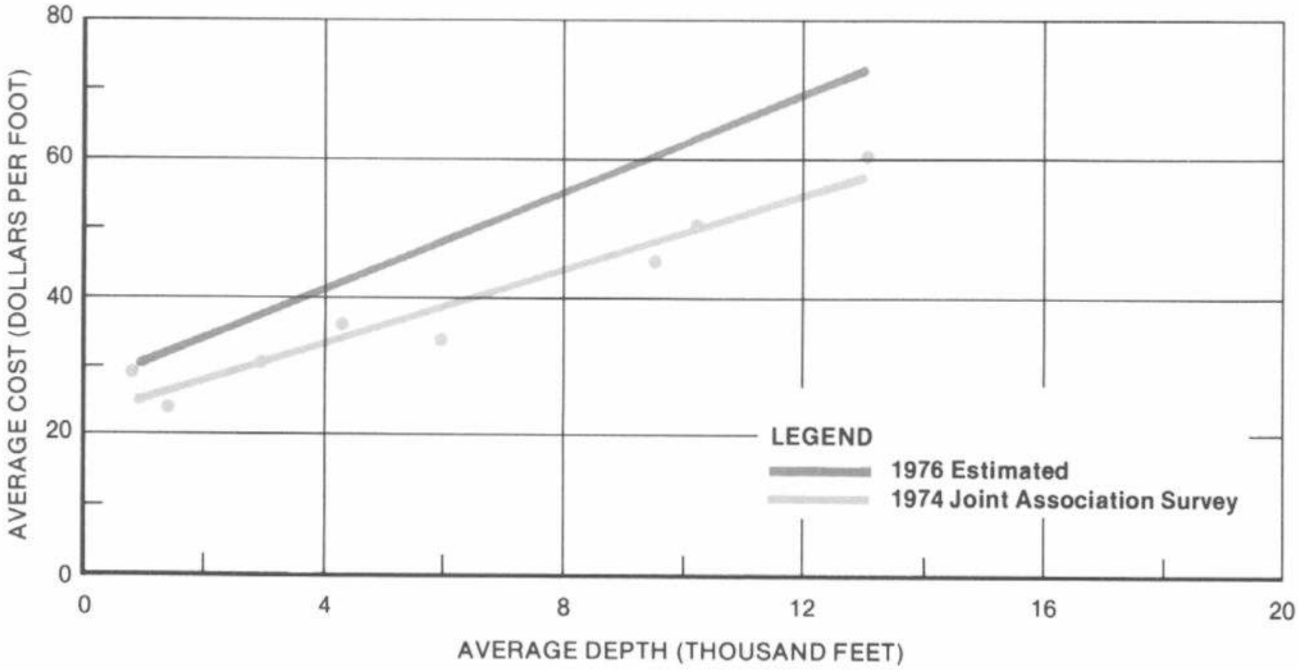

Figure 55. Cost of Drilling and Completing Production and Injection Wells—Onshore California.

TABLE 7

1976 COST OF PRODUCING WELL EQUIPMENT FOR WATERFLOOD*
(Dollars per Producing Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	9,900 (Rod)	18,500 (Rod)	25,500 (Hydraulic)	25,500 (Hydraulic)
California	17,600 (Rod)	34,500 (Rod)	28,400 (Hydraulic)	32,400 (Hydraulic)

* Estimated at mid-year 1976.

TABLE 8

1976 LEASE EQUIPMENT COST*
(Dollars per Producing Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	13,200	14,400	15,000	15,000
California	15,700	17,400	18,800	18,800

* Estimated at mid-year 1976.

to custody transfer. The major items include heater treaters, separators, well test systems, tanks, flowlines and water disposal systems.

Water Injection Equipment

Table 9 shows the cost of water injection equipment. These costs include all equipment necessary to install a waterflood in a depleted primary producing field. The major items included are: water supply wells, water tankage, injection plant and accessories, injection header, water injection lines, and electrification.

Cost of Utilizing Existing Wells

When installing an enhanced oil recovery project in a field, many already existing wells may be utilized as producing or injection wells. However, some wells will need workover and new equipment. Table 10 shows the assumed percentage of wells in a field that will require workover and equipment

TABLE 9

1976 COST OF WATER INJECTION EQUIPMENT FOR WATERFLOOD PROJECT*
(Dollars per Injection Well)

Area	Depth (Feet) 2,000	4,000	8,000	12,000
Texas and Louisiana	27,700	27,700	44,100	44,100
California	30,500	30,500	48,500	48,500

* Estimated at mid-year 1976.

replacement.

When existing wells are to be reconditioned for further use in the EOR process, the cost of conversion depends on the age of existing equipment. Shown in Table 11 is the estimated cost of converting an existing well to an EOR producing well; Table 12 shows the cost of converting to an injection well.

Discussion of Income Tax Cases

The incentive to proceed with EOR projects and the potential volume of enhanced recovery oil is sensitive to the income tax treatment applied to these projects. In evaluating this sensitivity, each project was analyzed for two tax treatment cases: (1) a moderate case and (2) a restrictive case. Tax legislation and interpretation are ever-changing, and it is uncertain how future tax law will be applied to

TABLE 10

PROPORTION OF WELLS REQUIRING CONVERSION FOR ENHANCED RECOVERY

Number of Years Field Has Been in Operation	Percentage of Wells
26 or more	100
16 to 25	50
6 to 15	25
1 to 5	0

Source: Information obtained from discussion with company employees involved in production and conversion for secondary oil recovery projects. This data confirmed percentages previously published.

TABLE 11

COST OF CONVERTING EXISTING PRODUCING WELL TO AN EOR PRODUCING WELL
(1976 Dollars)

State	Depth	Equipment Installed Before 1950	Equipment Installed 1951-1960	Equipment Installed 1961-1970
West Texas	2,000	18,000	14,400	10,300
	4,000	30,800	23,800	16,800
	8,000	64,100	50,700	37,400
	12,000	129,100	104,300	79,400
South Louisiana	2,000	38,900	30,200	21,500
	4,000	70,400	59,800	42,200
	8,000	104,700	82,900	61,000
	12,000	130,200	105,100	80,100
California	2,000	22,500	17,500	12,400
	4,000	56,300	43,500	30,700
	8,000	115,200	91,100	67,100
	12,000	212,700	171,800	130,800

Note: Costs to workover old producing wells and install new production equipment for enhanced oil recovery were calculated based on percentages of applicable items of new well drilling costs, and equipment replacement costs as required for conversion. These costs were estimated at mid-year 1976.

TABLE 12

COST OF CONVERTING EXISTING PRODUCING WELL TO INJECTION WELL
(1976 Dollars)

State	Depth	Equipment Installed Before 1950	Equipment Installed 1951-1960	Equipment Installed 1961-1970
West Texas	2,000	13,600	11,400	9,100
	4,000	21,500	18,000	14,500
	8,000	45,400	39,000	32,500
	12,000	124,900	103,500	82,100
South Louisiana	2,000	28,600	23,800	19,100
	4,000	54,000	63,700	36,300
	8,000	74,200	63,700	53,100
	12,000	135,900	112,700	89,400
California	2,000	16,500	13,800	11,100
	4,000	39,300	32,800	26,400
	8,000	81,600	70,100	58,400
	12,000	205,800	170,500	135,300

Note: Costs to workover old producing wells and install equipment for enhanced oil recovery were calculated based on percentages of applicable items of new well drilling costs, and equipment replacement costs as required for conversion. These costs were estimated at mid-year 1976.

EOR projects. However, these cases are considered to be within reasonable interpretation of present tax laws. The moderate case assumes that, considering the energy-related nature of such projects, tax law interpretations will tend to encourage substantial expenditures of additional capital to increase domestic energy production. The restrictive interpretation is also described for purposes of testing tax policy effects. The assumptions and interpretations regarding the general tax parameters, used as the basis in evaluating these two cases, are shown in Table 13.

Intangible Development Costs

For all practical purposes, the option to expense intangible development costs (IDC) has existed since the first income tax statute. However, the first administrative ruling authorizing the taxpayer to deduct intangible expenditures incurred in drilling oil and gas wells was issued in connection with the Revenue Act of 1916. (Specific statutory authority did not exist until the Internal Revenue Code of 1954 was enacted.) Only the owner of the operating rights in a property (i.e., the working interest owner) is entitled to deduct IDC under this election. Deductible items falling within this option include any cost which in itself has no salvage value (i.e., wages, fuel, repairs, hauling, supplies, etc.) and which is "incident to and necessary for the drilling of wells and the preparation of wells for production of oil and gas." The cost of tangible equipment is not subject to this election, and it must be capitalized and depreciated. The cost to install equipment "incident to and necessary for" the drilling and preparing of wells for production is considered intangible and subject to the option; however, such costs related to the installation of production facilities (equipment installed after the casing and Christmas tree are in place) must be capitalized as equipment cost. The taxpayer's basis in capitalized installation and tangible equipment cost must then be recovered through depreciation in the manner outlined in the discussion of "Hardware."

In both tax treatment cases it was assumed that IDC is 70 percent of total new well cost. Following is a discussion of the tax treatment of IDC under the two tax cases.

Moderate Case

It is assumed that all wells included in EOR projects (injection, production, and water source)

TABLE 13

INCOME TAX PARAMETERS FOR TWO CASES

	Moderate Case	Restrictive Case
Intangible Drilling and Development Costs (IDC)*	Expense costs of all wells	Expense costs of injection and production wells
		Capitalize costs of water source wells
Hardware	Capitalize and depreciate over five years by Straight-line Method	Capitalize and depreciate over eleven years using Sum-of-the-Year's Digits Method
	Take investment tax credit based on 10 percent of two-thirds of total investment	Take investment tax credit based on 7 percent of total investment
Cost of Injected Material	Expense	Capitalize
		No investment tax credit
		Depreciate over life of reservoir by SL Method
Depletion	None	None
Federal and State Income Tax	50 percent	50 percent

* New well costs assumed to be 70 percent intangibles.

will come within the election and that all IDC incurred is deductible for tax purposes.

Restrictive Case

Costs of both production and injection wells are considered to have been incurred "incident to and necessary for" the drilling and preparation of oil and gas wells for production and, accordingly, come within the intangibles option. On the other hand, costs of water source wells incurred in connection with EOR projects would generally be considered to be incident to the maintenance of production; hence, the intangibles would not fall within the option. Therefore, all such costs must be capitalized and are depreciated under the methods established for "Hardware."

Hardware

The physical facilities that are required in an EOR project include storage tanks, pipelines and valves, water and gas separation equipment, wastewater treatment facilities, and other hardware. These items have a useful life of more than one year and may not be deducted as an expense in the year of their purchase and installation. Instead, a proportional amount of depreciation for the exhaustion, wear-and-tear, and obsolescence of this property is allowed as a deduction.

The incentive to proceed with an EOR program depends upon the type of the depreciation method, the expected life of the facilities, and the investment tax credit that are applied to the hardware. The following discussion describes the assumptions that were made for the two tax treatment cases considered here.

Moderate Case

In this case, the physical hardware is capitalized and depreciated over a five-year period, using the straight-line (SL) method of depreciation. A 20 percent depreciation credit is taken for each year. Under this quick write-off, the total cost of hardware is recovered in the first five years of its useful life. Only 68 percent of its cost would be recovered over this period using the eleven-year sum-of-the-year's digits (SYD) depreciation method assumed for the restrictive tax case. Although the total depreciation allowed is the same as under the SYD method, the earlier deduction improves the economic incentive of the EOR program.

In the moderate tax case, due to the shorter depreciation period, the investment tax credit is based on two-thirds of 10 percent of the total investment; thus, it is assumed that the present 10 percent credit would be extended beyond the current expiration date.

Restrictive Case

It was assumed that all hardware would be capitalized and depreciated under the Asset Depreciation Range (ADR) System, using the lower limit of the appropriate asset depreciation range. It was also assumed that the sum-of-the-year's digits method would be adopted to depreciate such facilities over this eleven-year period. Under the SYD method, a different fraction is applied each year to the cost of the hardware to determine the allowable depreciation. The denominator (bottom number) of the fraction, which remains constant each year, is the total of the digits representing each year of estimated useful life of the property (i.e., $1 + 2 + 3 + \ldots + 11$). The numerator of the fraction changes each year to represent the years of useful life remaining at the beginning of the year for which the computation is made. With the SYD method, a larger fraction, and hence a larger portion, of the depreciation is allowed in the early years; however, while the depreciation periods for the SL and SYD methods differ, the total depreciation allowed for equipment used in a project is the same for any depreciation method.

The investment tax credit is assumed to be 7 percent of the total qualified investment. This 7 percent was the investment tax credit allowed prior to an increase to 10 percent, effective with the Income Tax Reduction Act of 1975. This higher tax credit was due to expire at the end of 1976 at the time these cases were specified; thus, restrictive tax case analyses reflect reversion to a 7 percent tax credit in 1977.

Cost of Injected Material

In many of the enhanced oil recovery processes it is necessary to inject high-cost materials into the oil formation. In all such projects, some of the injected material remains in the production formation and is never recovered. The varying tax treatment assumptions applied to the unrecoverable portion of this material are described in the following discussion.

Moderate Case

The total cost of purchased material injected and lost in the reservoir is treated as an expense item and is deducted in the year in which it was injected.

Restrictive Case

The costs of the unrecoverable material, which has been purchased and injected into the reservoir, is capitalized and depreciated over the life of the reservoir, using the straight-line method. However, if it can be demonstrated, in any year, that a particular injection project is a failure (i.e., the injection of this material did not benefit production), a loss may be claimed for the undepreciated cost of the injected material. These expenditures would not constitute qualified investment for purposes of claiming investment tax credit.

Depletion

Federal income tax law takes into account the distinctive nature of the mineral producing industries, including production of oil and natural gas, and, therefore, provides a percentage depletion allowance. The percentage depletion deduction recognizes that the producer's capital—the value of his oil, gas, or other mineral in the ground—has no necessary relationship to the cost of its discovery. This procedure was adopted as a method of avoiding taxation of capital (the value of the oil or other mineral in the ground) as if it were part of the producer's income.

Generally, the percentage depletion provision for oil and gas production was disallowed for major oil companies by the 1975 Income Tax Reduction Act; but it remains for the production of other minerals. For this study, it was assumed that no percentage depletion would be allowed, either in the restrictive or the moderate tax case.

Federal and State Income Tax Rate

The federal income tax rate on corporate profits presently is 48 percent. The state income tax rate varies, but is, on the average, approximately 2 percent (after federal offset). An assumed total federal and state income tax rate of 50 percent was applied in both the restrictive and moderate tax cases.

Crude Quality Price Differentials

This study provides estimates of enhanced recovery production that would be economically attractive at oil equivalent prices of $5, $10, $15, $20, and $25 per barrel (constant 1976 dollars). Each price case selected for analysis in this study represents a single average price for a mixture of potential enhanced recovery crude oils. It is recognized, however, that in some cases individual crude oil prices currently vary significantly from the average. Following is a discussion of the reasons for these variations and their likely impact on the study results.

The most important factor currently contributing to variance of crude price from an average is the three-tier pricing structure, imposed by government price control regulations. Other contributing factors to price differences are field location, resultant transportation costs to point of consumption, and crude quality characteristics, including gravity, sulfur content, asphalt level, etc.

The current spectrum of prices paid for crude oil in the United States is illustrated in Table 14. Current price differentials are particularly burdensome to thermal projects already underway, because thermal production is primarily low-gravity oil. As illustrated in Table 14, the combination of government price control and quality price differentials results in some low-gravity crudes (especially in California) currently being priced considerably below the lower end of the price-case spectrum assumed for this study. Continuation of this pricing environment would have a significant impact on future EOR project economics, since a large proportion of enhanced recovery production is expected to be heavy oil, especially in the near term.

Distortions in quality price differentials caused by price controls would be eliminated before most EOR projects are expected to come on stream, if the control legislation expires on schedule. Also, these distortions may be corrected to some extent within existing law.

The API gravity of a crude provides some indication of a crude's initial product yield. Generally, a relatively light 35° API crude will yield a greater proportion of lighter, more valuable products, such as gasoline, per dollar of processing than a heavier 20° API crude; and, therefore, it is more valuable to refiners. This greater value is reflected in gravity differential adjustments in the crude price paid to the producer. Current adjustments in the United States can range from $.02 per degree API for higher gravity crudes to $.06 per degree for lower gravity crudes.

The foregoing discussion does not imply that quality price differentials are generally distorted. In a free market, these differentials are rationally determined and reflect the cost of converting crude to a desired mix of products of acceptable quality. This conversion, or processing, cost is different for each crude type. For example, it is more costly to make

TABLE 14

CRUDE OIL PRICES AS OF JUNE 1, 1976

Crude Type	Gravity (°API)	Lower Tier ($/Bbl.)	Upper Tier ($/Bbl.)	Imports* ($/Bbl.)
California				
— San Ardo	11	3.85	9.81	
— Long Beach	25	4.78	10.50	
— Kettleman Hills	34	5.24	10.86	
Mid Continent				
— West Texas Sour	16	4.85	11.07	
— West Texas Sour	40	5.33	11.55	
— Wyoming Heavy	29	4.92	11.82	
— Wyoming Sweet	40	5.31	12.45	
Nigerian	37			14.00
Arabian Light	34			12.50

* Estimated laid down cost at the Gulf Coast

lighter products, such as gasoline, from relatively heavy crudes and to convert high-sulfur crudes to low-sulfur products.

Ignoring gravity differentials in this study introduces a margin for error of about $1.00 per barrel for some crudes. This difference is not regarded as critical, considering the number and magnitude of other uncertainties that are associated with enhanced recovery.

Project Economics Calculation

Economic evaluations of all processes, except CO_2 miscible flooding, were calculated through a computer system named PLANS.* The system includes a standard discounted cash flow rate of return (DCFROR) analysis and has the additional capability of saving selected operational data, such as oil production, amount of injected material by process, well drilling and workover activity by years. The PLANS system was modified to incorporate the economic criteria discussed earlier in this appendix and to facilitate ready access and usage by the Technology Task Group.

The basic unit of evaluation was the individual reservoir; considerations included projected production, operating expense, investments, and injection material quantities for the applicable recovery process. Figure 56 is a flow diagram, which shows the sequence of calculations in the analysis. Each reservoir was evaluated by computing the present worth of the net cash value of its production at specified DCFROR's of 10 percent, 15 percent, and 20 percent for each of the five oil prices and two income tax cases.

To facilitate aggregating individual reservoir results for each process, as well as for extrapolating the results to a U.S. total, base case and sensitivity case computer files were developed for storage of selected vector and scalar quantities for each reservoir evaluation (see Table 15).

An additional computer program, named RESSUM, was developed for the specific purpose of interrogating, aggregating and extrapolating data from the files. Figure 57 shows a flow diagram of the RESSUM computer program.

*The PLANS system was provided and supported by Cities Service Company. The system was resident on the General Electric Time-Sharing Service.

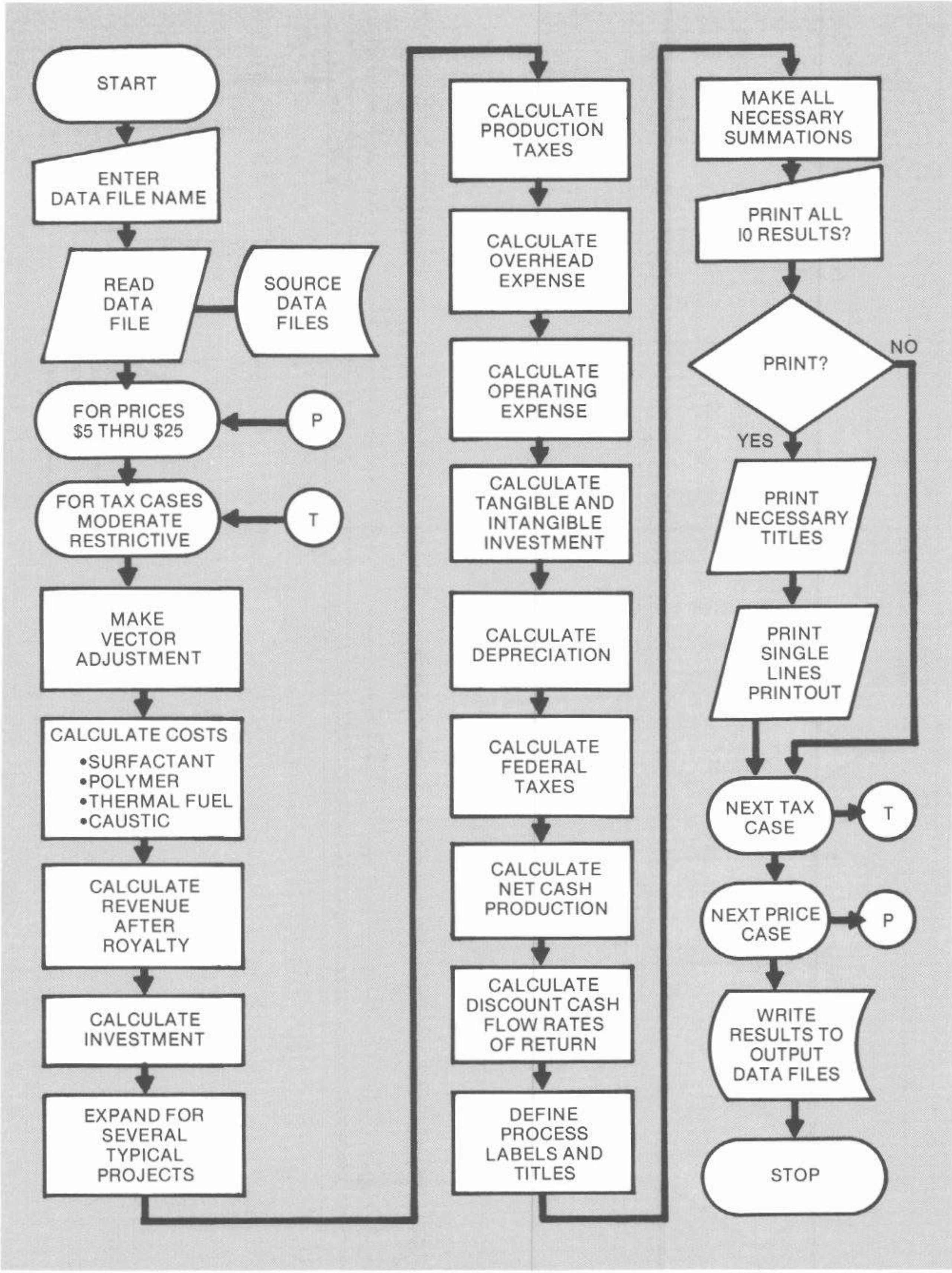

Figure 56. Economic Analysis Flow Diagram.

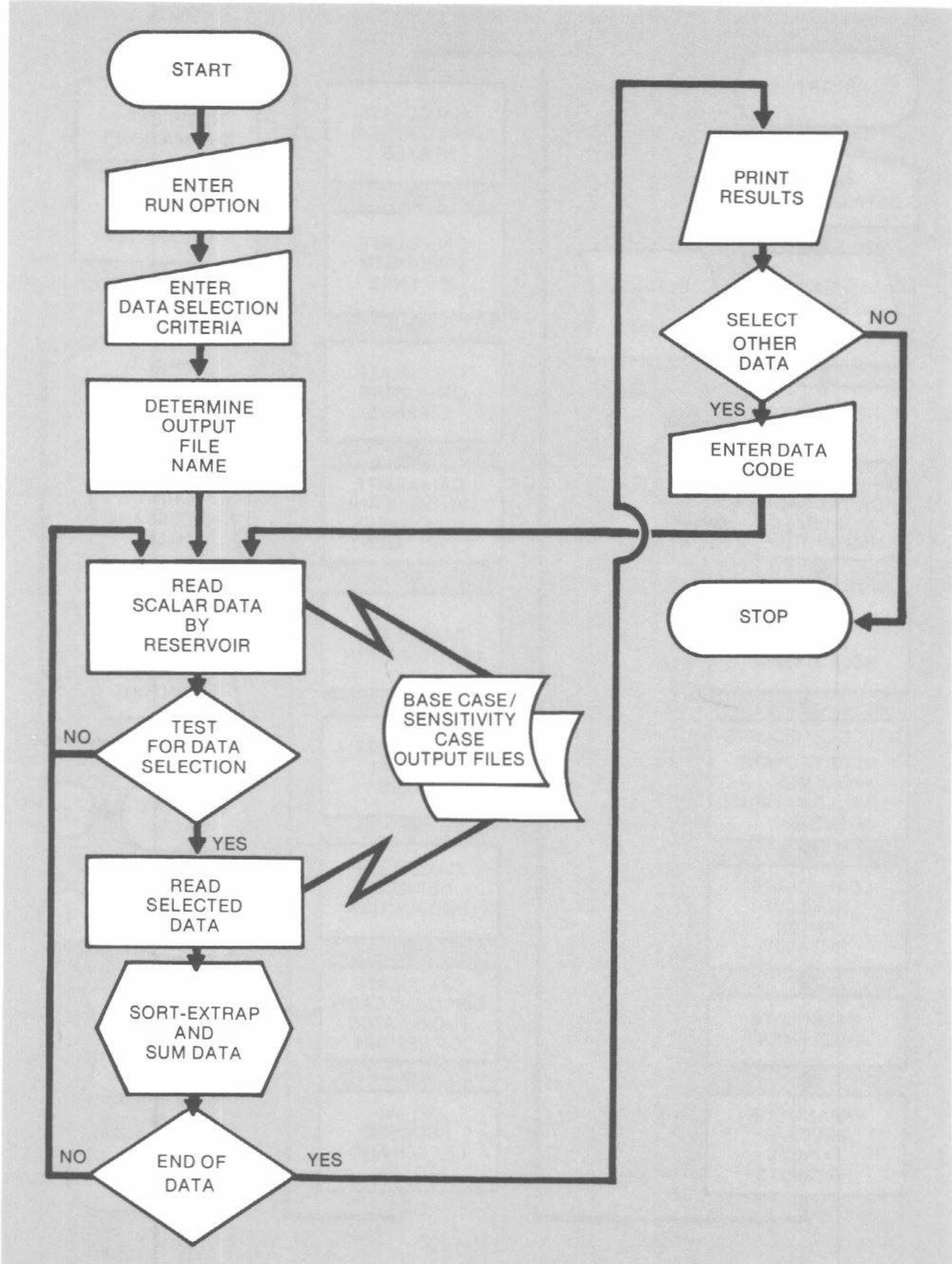

Figure 57. RESSUM Flow Diagram.

TABLE 15

BASE CASE AND SENSITIVITY CASES OUTPUT DATA FILE STORED VALUES

Scalar Quantities:

1. NPC Reservoir Data Base Page Number
2. Input Data File Name
3. Process Code
4. Starting Year
5. Starting Month
6. Life of Project
7. Rate of Return for Each Price and Tax Case
8. Ultimate Oil Production
9. Total Investment
10. Total Undiscounted Net Cash Production for Each Tax and Price Case
11. Total Oil Reserve Additions
12. NPC Screen and Performance Case Code
13. Project Description
14. Total Net Cash Production Discounted at 8, 10, 15, 20 Percent for Each Price and Tax Case

Yearly Data:

1. Undiscounted Net Cash Production for Each Price and Tax Case
2. Oil Production
3. Oil Reserve Additions
4. Annual Cash Outlay

Yearly Data: (Base Case Files Only)

1. Wells Drilled Less Than 4,000 Feet
2. Wells Drilled Greater Than 4,000 Feet
3. Injection Wells Drilled Less Than 4,000 Feet
4. Injection Wells Drilled Greater Than 4,000 Feet
5. Wells Worked Over
6. Surfactant (Thousand Barrels)
7. Polymer (Thousand Pounds)
8. Alkaline (Thousand Pounds)
9. CO_2 Purchased (Million Cubic Feet)

Appendix D

Chemical Flooding Processes

Introduction

The purpose of this appendix is to define the potential additions to crude oil ultimate recovery and producing rate from application of chemical flooding to known reservoirs in the United States. The chemical flooding processes studied were surfactant flooding, polymer flooding, and alkaline waterflooding. The results provide the best available measure of level of impact, but they should not be considered a precise measure or value for two reasons:

- The engineering data needed to describe the reservoir geology, reservoir fluids, and producing characteristics of target fields were not available; thus, it was necessary to draw broad analogies between fields with similar characteristics in making the performance assessments.
- These methods (particularly surfactant and alkaline flooding) have not demonstrated success on the field scale adequately to permit projection of process performance on a broad basis.

Given these limitations, the study can be expected to provide only an assessment of the "level of impact" of chemical flooding, together with a study of the sensitivity of results to selected variables. For example, a projection of the ultimate recovery from surfactant flooding for the United States was made for the following assumptions: (1) a crude price of $15 per barrel; (2) a discounted cash flow rate of return (DCFROR) requirement of at least 10 percent; and (3) moderate tax treatment. The projected recovery is about 2 billion barrels of oil; the projected producing rate under these assumptions is approximately 0.35 million barrels per day by 1990. This projection constitutes what may be a reasonable measure of the possible level of impact of surfactant flooding, given these economic premises. Yet, the currently unresolvable uncertainty is so great that the producing rate projected for these conditions could be negligible or, *although unlikely,* more than *double these* projections. Nevertheless, with proper focus on the uncertainties, the projections of the study should be of value in assessing the possible size and probable cost levels of this energy source.

In this appendix surfactant flooding is treated in one section, while polymer flooding and alkaline waterflooding are treated together in a separate section. Each section contains a state-of-the-art summary, a description of analysis procedures, cost data, and analysis results. A combined summary of environmental considerations for chemical flooding processes is also included.

The contribution of each of the three chemical flooding processes to projected enhanced oil recovery are put in perspective by comparing recoveries assuming base case performance and costs, a 10 percent minimum DCFROR requirement, $15 per barrel oil prices and the moderate tax case. Ultimate recovery by surfactant was estimated at 2.1 billion barrels, polymer about 500 million barrels and alkaline 400 million barrels for a total of 3 billion. Projected producing rate by the year 1990 by surfactant flooding is 310 thousand barrels per day, polymer is 60 thousand barrels per day and alkaline 10 thousand barrels per day for a total of 380 thousand barrels per day. Production was projected to peak about the year 1995 with 350 thousand barrels per day by surfactant, 50 thousand barrels per day by polymer and 30 thousand barrels per day by alkaline for a total maximum chemical flooding production rate of 430 thousand barrels per day.

Surfactant Flooding

State-of-the-Art Assessment

For this study, surfactant flooding is defined as any of several processes that utilize injection of surfactant solutions or dispersions into underground oil reservoirs to enhance crude oil recovery. The composition of the injected mixture (chemical slug) normally includes some or all of the following components: water; hydrocarbons; alcohols; polymers; and inorganic salts. Mechanisms for this method of oil removal include reduction of oil-water interfacial tension, oil solubilization, emulsification, and mobility enhancement.

Efficient displacement generally requires that the mobility of the displacing fluid be less than that of the fluids being displaced. The chemical slug must therefore have a higher effective viscosity than that of the oil-water bank it is pushing through the reservoir. Since this slug contains expensive chemicals, the volume injected must be a small fraction of the total pore volume of the oil reservoir. This small surfactant slug in turn is displaced by a drive water. In order to achieve an efficient displacement, water-soluble polymers are normally added to the drive water so that its effective viscosity, or resistance to flow, is at least equal to that of a surfactant slug; otherwise the drive water tends to overrun the surfactant slug as it traverses the reservoir. In addition to water-soluble polymers, various combinations of other components (alcohol, hydrocarbons, etc.) may also be used to produce the required viscosity of the surfactant slug and drive water.

As summarized in Table 16, field experiments with surfactant flooding have been conducted in reservoirs with temperatures ranging from 55°to 169°F. Some tests shown in Table 16 have not been technically successful, and many have not been underway long enough for evaluation. Tests planned but not initiated have not been included in Table 16. Laboratory studies indicate that surfactant flooding should be applicable at temperatures of at least 170°F. For this study, it was assumed that this limit will be extended by future improvements in the process to about 250°F by 1995.

The salinity range of field tests have been from 2,400 to 160,000 parts per million (ppm) total dissolved solids (TDS). Most field expansions to date appear to have been limited to reservoirs of lower salinity levels (or to reservoirs that can be preflushed to lower salinity levels). Although it may be possible to preflush some reservoirs to decrease the original salinity level and thereby reduce process costs and increase recovery efficiency, this may be feasible only in a limited number of reservoirs. Thus, the trend in research is toward development of systems applicable at higher salinities without requiring a preflush. Application at salinity levels of 150,000 ppm (15 percent) may be possible within a few years, and at salinities of 200,000 ppm (20 percent) or more by 1995.

Surfactant flooding should be feasible over a fairly wide range of reservoir permeabilities. The average permeability of the reservoirs given in Table 16 ranges from 52 to 2,500 millidarcies (md). However, surfactant flooding could be applicable for a wider range of permeability. Surfactant flooding becomes less attractive at lower permeabilities, because individual injection and production well rates are reduced and because larger amounts of chemicals are frequently required to compensate for increased surfactant retention on clays, etc. A lower limit of 20 md was considered reasonable for general screening purposes; however, in exceptional cases where high oil saturations are present and clay content is not excessive, reservoirs having a permeability lower than 20 md might be suitable candidates.

The crude oil viscosity range of field tests has been 0.36 to 17.0 centipoise (cp), as shown in Table 16. The higher the reservoir oil viscosity, the less attractive the reservoir is for surfactant flooding. The most important criterion is the effective viscosity of the oil-water bank, which depends on both the relative permeabilities and the viscosities of the oil and water.

Reservoir geological and rock characteristics desirable for surfactant flooding candidates include vertical and lateral uniformity of rock properties, high levels of porosity and permeability, and low clay content. Undesirable factors are fractures, large gas-cap or bottom water drive, unusually low residual oil saturations, and pay zones that are vertically stratified or laterally discontinuous. A successful waterflood is a good indication of a reservoir's suitability for surfactant flooding. However, if the residual oil saturation in the water-swept zone is low, the potential for chemical flooding may also be low.

In practice, the most successful surfactant flood tests have been conducted in low-temperature, low-salinity, sandstone reservoirs, having a moderate-to-high permeability and containing relatively low-viscosity crude oils. This assessment was made from

TABLE 16

SUMMARY OF SURFACTANT FIELD TESTS

Field	State	County	Operator	Process Type*	Area (Acres)	Start	Pay	Porosity (%)	Perm. (Md)	Depth (ft)	Reservoir Oil (°API)	(cp)	Temp. (°F)	Salinity (ppm)	Comment
Robinson	Ill.	Crawford	Marathon	MSF	0.75-40	11/62	Robinson	20	200	1,000	35-36	7	72	HPW 18,150 ppm TDS (119-R)	6 tests
	Ill.		Marathon	MSF	4.3	5/70	Aux Vases			3,000					
Bingham	Penn.	McKean	Pennzoil	MSF	0.75-45	12/68	Bradford	18	82	1,860		5	68	2,800 C1⁻	2 tests
Goodwill Hill	Penn.	Waxyen	Quaker St.	MSF	10	5/71	First Venongo			600	40	4.5	55		
Benton	Ill.	Franklin	Shell	Aqueous	1-160	11/67	Tar Springs	19	69	2,100		4	86	77,000 ppm TDS	2 tests
Loudon	Ill.		Exxon	Aqueous Solution	0.65	9/70	Chester Cypress	21	103	1,460		4	Est. 95	64,000 C1⁻ 104,000 TDS	
Higgs Unit	Tx.	Jones	Union	SOF	8.23	8/69	Bluff Creek	22.9	500	1,870	37	4.3	95	54,000 C1⁻	
Big Muddy	Wyo.	Converse	Conoco	SF	1	8/73	Second Wall Creek	19.2	52	3,100	34	5.6	114	7,700 TDS, 20 ppm fractured. Ca + Mg	
Griffin Consol.	Ind.	Gibson	Conoco	SF	0.8	11/73	Upper Cypress	20	75	2,400	37				
Wichita Co. Regular	Tx.	Wichita	Mobil	LTWF	209	7/73	Gunsight	22	53	1,750	42	2.2	89	160,000 TDS	
Borregos	Tx.	Kleberg	Exxon	Aqueous Solution	1.25	mid 60's	Frio	21	±400	5,000	42	0.36	165	33,000 TDS	
Guerra	Tx.	Star	Sun	SF	2.0		Jackson	33	2,500	2,270	36	1.6	122	20,000 TDS	
Bridgeport	Ill.	Lawrence	Marathon	MSF	2.5	9/69	Kirkwood	18	90	1,500	38-39	5.5	72		
Sayles	Tx.	Jones	Conoco	SF	2.5	/63	Flappen	21.7	457	1,900	38				
Montague	Tx.	Montague	Conoco	SF	2.5	/63	Cisco	24.2	394	1,200	27			150,000 TDS	
Loma Novia	Tx.	Duval	Mobil	SF	5.0	mid 60's									4% kaolinite 5.5% Na Montor
Salem	Ill.	Marion	Texaco	LTWF	5.8	4/74	U. Benoist	14.8	87	1,750	38.0	3.6	0.85	40,000Cl⁻	
Sloss	Neb.	Kimball	Amoco	SF	10.0	1/75	Muddy J.	17.1	93	6,250	34.0	0.8	165	2,457 TDS	
West Ranch	Tx.	Jackson	Mobil	LTWF	2.5	6/74	41A	31.0	950	5,700	31.8	0.7	169	60,000Cl⁻	
La Barge	Wyo.	Sublette	Texaco	SF	1.7	1/75	Almy	26.0	450	700	26.0	17.0	60	1,017 Ca^{++} and Mg^{++}	

* Process Type normally refers to specific surfactant floods used, but is not intended to characterize actual differences: Aqueous -- dispersion of sulfonate in water with very little oil in slug; MSF -- micellar surfactant flood; SOF -- normally considered "oil external" chemical slug; SF and LTWF -- surfactant flood and low tension water flood normally similar to aqueous systems.

reported field tests summarized in Table 16.

Field experimentation results have also shown that surfactant flooding will require more chemicals, more careful chemical formulation and handling, and perhaps more wells, than were anticipated 10 to 15 years ago, when significant field experimentation began.

As field tests have shown, it is difficult to prevent a small chemical slug from losing its oil recovery capability as it traverses the reservoir and encounters reservoir heterogeneities and other unknown geologic conditions. Although over 400 thousand barrels of incremental oil have been produced in various tests of this process, field development on a successful commercial scale has not been demonstrated thus far. Current attempts at field expansion are limited to low-temperature and low-salinity reservoirs.

Screening Criteria

The process and reservoir geology parameters listed on Table 17 were developed as screening criteria for use in assessing the potential suitability of oil reservoirs for surfactant flooding. Future developments that will extend the applicability of the surfactant flooding process will largely affect the range of conditions under which the chemical slug may be effective. To account for these improvements, the screening criteria incorporate changes with time. The current (1976) screening criteria limits represent surfactant flooding technology that has undergone some field testing and might be ready for field development. The limits defined for the future are a projection of the time that each technological advance might be ready for field development.

This screen was applied to 175 fields (245 reservoirs) in the states of Texas, Louisiana, and California. (This data base is described in Chapter Two.) The descriptors contained in this data base were quite limited, so the full value of the screening criteria was not realized. However, by supplementing the original data base, a reasonable application of the screening criteria could be made. For example, reservoir temperatures and oil viscosities were frequently unknown;

TABLE 17

SCREENING CRITERIA — SURFACTANT FLOODING

Process Parameters	Limit by Year 1976	1980	1985	1990	1995
Temperature (°F) Max.	120	170	200	225	250
Salinity (wt. % TDS) Max.	2	15	15	15	20
Viscosity (cp) Max.	10	20	20	20	30
Permeability (md) Min.	50	20	20	20	20

General Reservoir Parameters	1976-1985	1985-2000
Geologic Criteria	Only sandstone reservoirs	Only sandstone reservoirs
	Uniform and continuous sands	Minor variations in uniformity, if good well-to-well correlations exist
	Exclude reservoirs with extensive faulting, conglomerate rock, or lense-type deposits interbedded with shale	Exclude reservoirs with extensive faulting, conglomerate rock, or lense-type deposits interbedded with shale
	Carbonate reservoirs excluded	Carbonate reservoirs excluded
Other Considerations	No bottom water-drive reservoirs	No bottom water-drive reservoirs
	No reservoirs with gas caps, unless waterflooding has been successful	No thin oil column overlain with gas
	No reservoirs where fluid movement is primarily through fractures	No reservoirs where fluid movement is primarily through fractures

those parameters were assigned to the data base fields, using published correlations. Reservoir salinity data were rarely available and had to be estimated to the degree possible. Although a well-defined geologic model is crucial to the appropriate design of a surfactant flood, no such individual field studies were possible for this analysis. Consequently, screening for geology and reservoir performance was applied by drawing on the study group's knowledge of the geology and reservoir characteristics of the data base reservoirs, or other fields in similar geologic settings. This type of assessment was an important consideration in the ranking of fields as "good," "fair," or "poor" candidates for surfactant flooding. This good, fair, or poor ranking was employed to determine chemical requirements for flooding the respective reservoirs and to aid in assigning individual reservoirs to either surfactant flooding or to a competing EOR process (see the discussion under "Dominance Determination," Chapter Two).

As a result of applying the screening criteria (Table 17) and the good, fair, and poor reservoir rankings to the data base fields, 67 reservoirs were selected as candidates for further study. After applying the economic and dominance criteria discussed in Chapter Two, 9 of these reservoirs were considered more likely candidates for another recovery process.

Process-Dependent Economic Parameters

Process-related costs for surfactant flooding were developed, in addition to the process-independent cost data described in Appendix C. These include the costs of surfactants (typically, petroleum sulfonates), alcohols, polymers, crude oil and inorganic chemicals used in the process slug, and viscosity buffers. Costs of these materials were determined for each crude price used in this study.

1976 cost levels for the specific chemicals of interest were obtained from Gulf Universities Research Consortium (GURC) studies and from chemical suppliers. The chemical costs used are shown in Tables 18 and 19. Factors to adjust chemical cost with oil price are also shown in these tables. An average cost for a 50-50 polymer blend of polysaccharides and polyacrylamides was used for the polymer slug. Costs for the surfactant slug are given in Table 20.

As another cost aspect of surfactant flooding, the cost level of pilot testing in the field was broadly estimated. This cost, although a major hurdle to the start of a project, will be small on the basis of cost per barrel of enhanced oil produced, if the recovery process proves generally successful. The number of chemical flood pilots required between now and the year 2000 to enable commercial-scale application, consistent with the NPC screening criteria, is highly speculative. However, the small relative costs of this activity compared to value of potential production can be shown, using the following assumptions:

- Ten pilots will be required to define and extend the range of process parameters, primarily temperature and salinity.
- Ten pilots will be required to evaluate commercial potential in different reservoir types.
- Twenty additional pilots might be required to develop the approximately 2 billion barrels of incremental ultimate recovery projected for the $15 per barrel crude oil price.

TABLE 18

PRICE ESTIMATES OF PETROLEUM BASED CHEMICALS FOR DIFFERENT CRUDE PRICES

Crude Oil Price (Dollars per Barrel)	Price Adjustment Factor for Converting to Different Crude Prices	Polyacrylamides (Dollars per Pound)	Isopropyl Alcohol (Cents per Pound)	100% Active Sulfonates (Cents per Pound)
5.00	.82	1.14	13	29
Base Case: 10.00	1.00	1.40*	16†	35‡
15.00	1.23	1.72	20	43
20.00	1.45	2.04	23	51
25.00	1.68	2.35	27	59

* Base Case price of $1.30 per pound (GURC report of March 1976) plus 10¢ per pound for freight and state sales tax.

† Base Case price of 14¢ per pound (GURC report of March 1976) plus 2¢ per pound for freight and state sales tax.

‡ Base Case price of 32¢ per pound (GURC report of March 1976) plus 3¢ per pound for freight and state sales tax.

TABLE 19

PRICE ESTIMATES OF POLYSACCHARIDES FOR DIFFERENT CRUDE PRICES

	Crude Oil Price (Dollars per Barrel)	Price Adjustment Factor for Converting to Different Crude Prices	Polysaccharides (Dollars per Pound)
	5.00	0.96	2.30
Base Case:	10.00	1.00	2.40*
	15.00	1.04	2.49
	20.00	1.08	2.58
	25.00	1.13	2.70

* Base Case price of $2.25 per pound (GURC report of March 1976) plus 15¢ per pound for freight and state sales tax.

TABLE 20

ESTIMATED COST OF SURFACTANT SLUG FOR VARIOUS CRUDE OIL PRICES AND SURFACTANT COSTS (Dollars per Barrel)

Crude Price	Sulfonate Costs			Alcohol Cost	Oil Cost	Total Surfactant Slug Costs		
	Low	Central Value	High			Low	Central Value	High
5	3.81	5.08	6.34	.68	0.50	4.99	6.26	7.52
10	4.59	6.12	7.65	.84	1.00	6.43	7.96	9.49
15	5.64	7.52	9.41	1.05	1.50	8.19	10.07	11.96
20	6.69	8.92	11.16	1.21	2.00	9.90	12.13	14.37
25	7.74	10.32	12.91	1.42	2.50	11.66	14.24	16.83

Note: Low and High values of chemical costs were used to define study sensitivity to these costs. ±25% variance in cost of surfactants was used to develop the high and low value.

- The average cost of each pilot will be $3 million. Thus about 40 pilots, costing $120 million, might be required at a cost of about $.06 per barrel of oil recovered.

The costs of pilot testing appear small, but only sandstone reservoirs without complicating features of geology or reservoir character, as indicated by the NPC screen, were considered. In reality, other, less desirable candidates for surfactant flooding will also be tested. However, even if the number of pilots were doubled, the cost would still be much less than the uncertainty in the cost of each barrel of surfactant flood oil recovered. For the purpose of this study, it was assumed that pilot costs were included in the overhead cost, along with the cost of laboratory research.

Description of Process Analysis Procedures

As a result of applying the screening and process dominance criteria to the 245 reservoirs in the data base, 58 were selected as candidates for surfactant flooding.* This section describes: (1) the method used to calculate the swept zone water and chemical

*Reservoirs included in the data base developed by Lewin & Associates, Inc. in connection with their study for the Federal Energy Administration.

flood residual oil saturations; (2) the estimation of the ultimate incremental recovery that might be achieved; (3) the hypothetical chemical system selected as being representative of those used in many surfactant floods; and (4) the model developed to project oil production rate versus time for economic calculations.

Calculation of Surfactant Flood Recovery from Water-Flushed Zone

Since the economics of surfactant flooding are extremely sensitive to the volume of oil that can be recovered by a surfactant system, special emphasis was placed on estimating the oil saturation (S_{orw}) in the water-flushed zone that would likely be contacted during surfactant flood and the oil saturation (S_{orc}) remaining in the same region after the flood.

Reservoir characteristics (rock type, etc.) and production method are generally recognized as the principal factors affecting S_{orw}, and were used as the basis for assigning S_{orw} values to the candidate reservoirs. These characteristics were established by drawing upon the study group's general knowledge of the data base reservoirs or fields in similar geologic settings. Only reservoirs having residual oil saturations in the water-swept porton of the reservoir (S_{orw}), of 20 percent pore volume or more were accepted as surfactant flood candidates. Candidate reservoirs in California, Texas, and Louisiana were then individually assigned S_{orw} values of either 20, 25, or 30 percent pore volume.

The method used for assigning S_{orw} relied upon drawing an analogy through rock and fluid type to better known examples and was chosen for the following reasons:

- Estimates of original oil in place, particularly those made with sparse data, are uncertain and may be overstated for any specific field due to inability to quantify net pay, areal extent, reservoir irregularities and original oil saturation. As producing historical data is accumulated and injection projects begun, the value of OOIP must frequently be revised.
- The primary target for surfactant flooding is the final waterflood swept residual. Values for ultimate primary plus waterflooding recovery are not known for specific fields to the degree needed to confidently determine waterflood residuals, particularly considering the uncertainty in value of OOIP.
- Extensive studies to determine waterflood residuals for a few selected fields have been conducted and results published. This information, plus knowledge of laboratory determinations of water flood residuals for various reservoir rock and fluid types, was used to assign residuals to the data base fields based on analogy to the rock and crude oil characteristics of those fields. This procedure was judged to provide the best estimate of the amount of oil that can be recovered (unit oil recovery) from the water-flushed zone by surfactant flooding. However, in recognition of the magnitude of the uncertainty associated with this or any other method of assigning a target residual oil saturation, a saturation interval of 5 percent pore volume was used when assigning the value of S_{orw} to each surfactant flood candidate. For example, a reservoir believed to have an S_{orw} of between 22.5 and 27.5 percent would be given an assigned value of 25 percent.

Another method that could be used to estimate the target residual oil saturation is the "material balance" approach. This method was judged to be inadequate to define the unit oil recovery used for the economic calculations because of the uncertainties in the data and the following considerations:

- The material balance value represents all the oil estimated to be left in the reservoir after waterflooding; some of this oil is left in the unswept or poorly swept portions of the reservoir at high saturation, while the rest is left in the water-swept portion at saturations much lower than the material balance average saturation.
- If the OOIP estimate is too high, the estimate of material balance oil saturation will be correspondingly high. In general, the higher the waterflood sweep efficiency, the closer the agreement between the assigned S_{orw} values and material balance saturations will be.

In a few cases, comparisons of the assigned S_{orw} values used in this study with the total average reservoir oil saturation after waterflood, or "material balance" oil saturation, were possible. In some instances the assigned values were only slightly smaller, but in other cases, they were significantly less than material balance estimates.

The amount of oil that can be recovered by a surfactant flood is proportional to the difference between the S_{orw} and the residual oil saturation (S_{orc}) remaining in the swept zone after the surfactant flood.

The surfactant flood residual oil saturations (S_{orc}) in laboratory tests using large slugs (25 to 50 percent of pore volume at typical chemical concentrations of 4-5 percent) are typically less than 5 percent. For very small slugs (5 to 15 percent of pore volume) the injected slug frequently loses its effectiveness, even in laboratory tests using long (16- to 32-foot) cores, because of dispersive mixing between the various slugs and adsorption of the surfactants. In these tests, the residual oil saturation is frequently between 5 and 10 percent pore volume.

When a surfactant slug is injected into a reservoir, it will encounter large-scale heterogeneities, which tend to destroy its integrity, and thereby its displacement efficiency. This tendency may be unimportant in fairly homogeneous reservoirs, if displacing fluids have sufficiently favorable mobility ratios; but it could be significant in many reservoirs. It is anticipated that the average residual saturation left behind the surfactant slug in field applications will normally be more than that typically observed in laboratory floods. Lower residuals will remain in better quality rock (high permeability, high porosity, and low clay content) and higher values in the poorer quality rock. Therefore, for a typical surfactant flood target reservoir and for economically sized chemical slugs and polymer drives, a value of 10 percent pore volume was used for the average residual oil saturation left in the swept portion of the reservoir.

Calculation of Incremental Ultimate Recovery

An estimate of the incremental ultimate recovery was made for each candidate reservoir. The assumptions required before this estimate could be made included estimation of the original oil in place, the average initial water saturation in the reservoir, and an overall sweep efficiency.

In accord with the sparsity of reservoir descriptors in the data base, the following simple equation was employed to calculate the incremental ultimate oil recovery from each candidate reservoir.

incremental ultimate recovery =

$$\left[\frac{OOIP \times B_{oi}}{(1 - S_{wi})}\right] (S_{orw} - S_{orc}) \frac{E}{B_o}$$

where:

OOIP = original oil in place (stock tank barrels)

B_{oi} = original oil formation volume factor (reservoir barrels per stock tank barrel)

B_o = current oil formation volume factor (reservoir barrels per stock tank barrel)

S_{wi} = original water saturation

S_{orw} = residual oil saturation by waterflood in swept zone

S_{orc} = residual oil saturation by surfactant flood in swept zone

E = waterflood and chemical flood volumetric sweep efficiency

This equation provides an estimate of the incremental volume of oil that might be recovered by surfactant flooding over that which could ultimately be achieved by conventional waterflooding.

In addition to the uncertainties in the values to be used in the above equation for S_{orw} and S_{orc}, there are uncertainties in the values for each of the remaining terms for OOIP, S_{wi}, and the value used for E.

Reservoir thickness and areal extent information available from the reservoir data base were frequently in conflict with the estimates given for the OOIP volumes. Although the data base values for OOIP and S_{wi} data judged best were used for estimating the reservoir pore volume (the bracketed quantity), there can be considerable uncertainty in the reservoir pore volume for any given reservoir. A surfactant flooding sweep efficiency was likewise assigned to each surfactant flood candidate based on broad analogy of reservoir rock and fluid type. When the assigned sweep efficiencies for a number of reservoirs were compared with material balance estimates for the same group of reservoirs, it appeared that the assigned values were possibly too high—by about 15-20 percent in Texas and Louisiana, and possibly as much as 33 percent in California. If so, the estimates of the incremental ultimate recovery will be correspondingly high. *However, since the volume of chemicals injected was determined as a fraction of swept pore volume, rather than total reservoir pore volume, the economics are not highly sensitive to the sweep efficiency used.*

This difference in the estimates for Texas and Louisiana is generally within the range of uncertainty in the calculations of incremental ultimate recovery. Additional factors which may contribute to the apparent discrepancy, especially in California, are as follows. API reserves statistics do not include potential waterflood reserves from a given field until the waterflood has been implemented and an economic production response at existing economic conditions demonstrated. At higher crude prices, additional waterflooding projects may become economically attractive. Hence, additional waterflood reserves from some reservoirs, particularly in California, could increase the overall waterflood sweep efficiencies experienced in such reservoirs. To the extent that such increased waterflood sweep efficiencies may not be possible, the projections of the incremental ultimate oil recovery may be high.

The reservoir description and performance data needed to resolve the uncertainties in enhanced recovery projections will undoubtedly be collected by the individual field operators when the sizable costs of data collection can be justified. Such data are not now available on numerous fields, including those in the data base used in this study.

Surfactant System Design

The volumes of the surfactant slug and polymer drive water required for a surfactant flood depend upon the reservoir volume that can be contacted by the surfactant system and, hence, on reservoir type and quality. Thus, the amount of chemical required to process the swept pore volume of each surfactant flood candidate was adjusted according to the ranking given that reservoir for surfactant flooding.

An idealized, or base case, chemical system design was used in this study to represent a mid-range estimate of industry experience, as described in published field test data. A summary of the system design follows:

- **Chemical Slug**
  - Size: 8 percent of swept pore volume for good reservoirs
    10 percent of swept pore volume for fair reservoirs
    14 percent of swept pore volume for poor reservoirs
  - Surfactant Concentration: 5 percent by weight of active ingredients
  - Alcohol and Other Components: 1.5 percent by weight
  - Oil Content: 10 percent by volume
- **Mobility Drive (Water-Polymer Slug)**
  - Bank Size: 50 percent of swept pore volume
  - Polymer Average Concentration: 600 ppm.

The amount of chemical used in the economic calculations for each barrel of oil produced is given in Table 21 for reservoirs rated as good, fair, or poor candidates for surfactant flooding. The dependence of the assumed chemical requirements for different residual oil saturations (20, 25, and 30 percent pore volume, corresponding to reservoir types A, B, and C), is also given. Table 22 presents an example of chemical costs for fair surfactant flood candidates, for the same values of residual oil saturation and for crude prices of $5, $10, $15, $20, and $25 per barrel.

TABLE 21

CHEMICAL REQUIREMENT PER BARREL OF OIL PRODUCED
(Pounds per Barrel)

EOR Code	S_{orw} (% PV)	Polymer	Surfactant Reservoir Quality Rank: Good	Fair	Poor
A	20	1.05	14.00	17.50	24.50
B	25	.70	9.33	11.67	16.33
C	30	.52	7.00	8.75	12.25

TABLE 22

EXAMPLE TOTAL CHEMICAL COST FOR "FAIR" SURFACTANT FLOODING CANDIDATES
(Dollars per Barrel of Oil Produced)

Crude Price	Reservoir Type: A	B	C
5	8.07	5.38	4.03
10	9.96	6.64	4.98
15	12.28	8.19	6.14
20	14.56	9.71	7.28
25	16.89	11.26	8.44

Economic Model

Projected oil producing rates, development capital requirements, operating expense and chemical costs as a function of time were developed for use in a simplified economic model. (The component costs were discussed in Appendix C.)

The basic assumptions used in preparing development and production projections for a single pattern area and then for the overall project development, as illustrated in Figure 58, were:

- Individual chemical flooding projects would require two years to drill new wells, work over old wells, and install new field facilities prior to starting surfactant injection.
- The flood life of each pattern area would be 10 years, during which 1.5 swept pore volumes would be injected.
- All projects in a technologic advancement segment (see "Screening Criteria") would be developed uniformly over the following 15-year period.
- Oil production and cash flow projections from

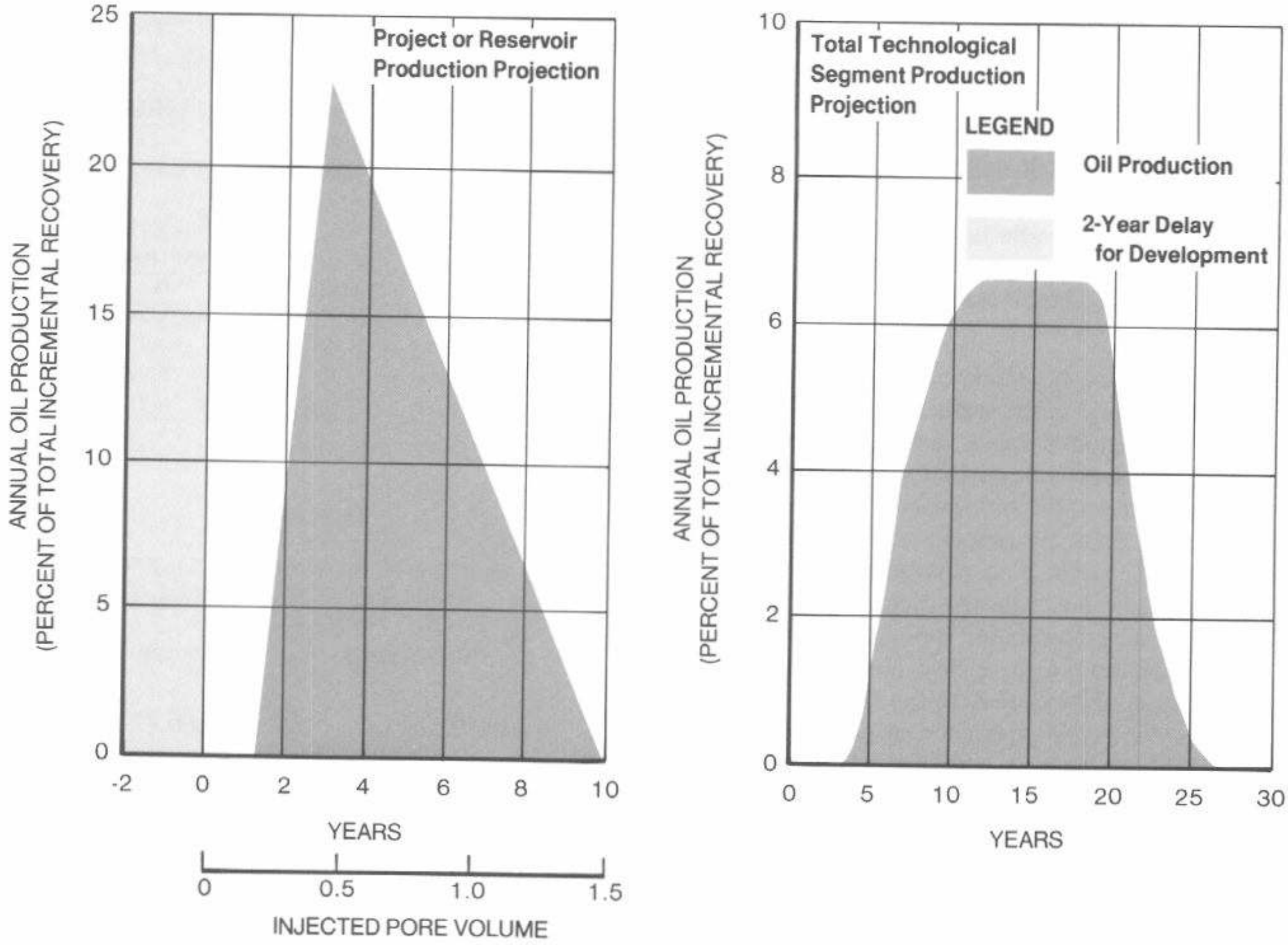

Figure 58. Production Development Schedule.

reservoirs with positive profitabilities under any assumed economic criteria are additive.

This development and production program was used to project oil production rate, capital expenditures, and operating costs. It was assumed that development drilling and facility costs would be expended during the two years before injection starts. Direct operating costs were spread uniformly over the 10-year injection life of the project. Injection costs, including chemical costs, relate directly to the time each type of injection (chemical slug, polymer drive, etc.) is scheduled.

It is anticipated that, in practice, a large reservoir or group of reservoirs can be developed sequentially; this sequential development should permit improvements in flood system design as the flood progresses, thereby saving material and resources. This type of sequential development concept was utilized in this study by assuming that 1/15 of each reservoir (or group of similar reservoirs) would be developed each year for 15 years. This 15-year development scheme is arbitrary and could vary, depending on the economic climate. However, a revision in the development program would not alter ultimate recovery, even though it could affect the rate of production, development expenditure and other variables.

The number of wells required in any specific field development is also essential to an economic analysis of surfactant flooding. This number is a function of assumed project flood life, production and injection well capacities, reservoir permeability, oil viscosity, swept pore volumes (which directly affects total quantity of injection), pattern of injectors and producers, and pressure drop from injector to producer. Assumptions used in the study are summarized as follows:

- New wells were drilled for all injectors.
- Five-spot patterns were used (for purposes of establishing well requirements).*
- Well spacing was selected consistent with the assumption that a total of 1.5 pore volumes

*See Glossary, "flood pattern."

of the swept zone could be injected in a 10-year project life. The well spacing estimate was subject to the following constraints:

- Maximum production and injection rates would be less than or equal to 2 thousand, 1.5 thousand, and 1 thousand barrels per day per well in South Louisiana, California, and Texas and North Louisiana, respectively.
- The well rates will be less than or equal to that calculated using the steady-state pressure-rate equation for five-spot flooding, assuming an effective viscosity of 20 times the viscosity of water and a pressure differential from injector to producer of one-half pound per square inch per foot of reservoir subsurface depth.
- Well spacing will not exceed 80 acres per production well, or 40 acres per well.

These assumptions, the desired project life, plus information in the reservoir data base, were used as the basis for determining number of wells drilled and operated for the surfactant flooding economic model.

Extrapolation Process

Incremental ultimate recovery and potential producing rates for surfactant flooding were extrapolated from the candidate reservoirs to a larger geographic base. This extrapolation was based on ratios of OOIP (from API data) in sandstone reservoirs in the geographic areas considered; the sequence was first to obtain a total for the three data-base states, and then for the total United States. This simplistic method was used because insufficient reservoir data were available for a rigorous appraisal of the total potential from surfactant flooding over a wide geographic base, and some subjective judgments were necessary to establish extrapolation factors. The following discussion describes the sequence of assumptions used to estimate the total surfactant flood response for the three states and the entire United States.

Three-State Totals

An extrapolation factor, based on the ratio of the OOIP in each district (Texas), area (California), or state (Louisiana) to the OOIP of the data base reservoirs in the same region, was used as a multiplier of incremental ultimate recovery, production rate, net cash flow, etc. The extrapolation factor, which is unique to any given region, was used for each reservoir in the specified region. The rationale for using specified geographic areas for the scale-up base is that the geologic setting, and therefore, the character of the reservoirs, is similar over a narrow geographic base. For California and Texas, the subdivision by area and district for extrapolation was justified by the adequate representation of reservoirs and original oil in place in the data base. It should be particularly noted that offshore California is adequately represented by the data base reservoir file; the data base includes five Wilmington field reservoirs, three Rincon reservoirs, and the Dos Cuadras field.

Louisiana, however, was rather poorly represented for scale-up by geographic area. Offshore Louisiana was not represented in the data base, although significant surfactant flooding candidate reservoirs are known to exist, particularly in the more prolific, less geologically complex reservoirs not far from an operating base. The scale-up factor selected for Louisiana data base fields includes the North and South onshore plus 70 percent of the offshore OOIP. The 70 percent factor was judged to include that portion of the total offshore oil volume which is near enough to an onshore operating base to be a target for surfactant flooding. Table 23 lists offshore fields that are in about 100 feet or less of water and shows that much of the offshore oil volume is near shore. These nine fields contain about 60 percent of the offshore OOIP used in the Louisiana extrapolation, and about 42 percent of the total offshore. As a whole, the quality ranking of these offshore reservoirs was judged to be more favorable than many of the Louisiana reservoirs included in the original data base.

TABLE 23

QUALITY RANKING OF LOUISIANA OFFSHORE RESERVOIRS

Field	API Estimated Original Oil in Place (Millions of Barrels)	Approximate Water Depth (Feet)
South Pass Block 27	818	100
South Pass Block 24	975	30
Main Pass Block 41	453	100
Bay Marchand Block 2	1,558	40
West Delta Block 30	640	50
Grand Isle Block 43	575	100
Ship Shoal Block 207	288	100
Ship Shoal Block 208	261	100
Cote Blanche Bay, West	451	20
Total 9 Fields	**6,019**	

Total United States

The extrapolation of three-state EOR results to the total U.S. potential is, at best, only a reasonable estimation of the probable level of EOR volumes. Changes in the following key assumptions may significantly affect the results of the extrapolations: (1) the data base reservoirs were assumed to provide a representative sample of the reservoir characteristics and crude oil properties of reservoirs in the remaining states; (2) the average drilling and operating costs used in the standard economic model were assumed to be representative of those in other locations and reservoirs; and (3) production rate versus time was assumed to be consistent with that represented by the data base reservoirs, despite varying geologic settings in other states.

The mechanics of the scale-up employs a ratio of sandstone original oil in place volumes. The extrapolated U.S. total oil volume is comprised of: (1) the three-state data base OOIP; (2) the total OOIP from five midcontinent states (Illinois, Kansas, New Mexico, Oklahoma, and Wyoming) with broad-ranged surfactant flooding potential; and (3) 50 percent of the OOIP from the remaining states in the United States, excluding North Slope, Alaska. The 50-percent factor was obtained simply as an estimate of the relative number of reservoirs that might be amenable to surfactant flooding, compared to reservoirs in the three data base and the five midcontinent states.

The volumes used in the scale-up factor are shown in Table 24. The extrapolation factor is used as a multiplier for each reservoir, along with the district, area or state factor previously described. Table 25 illustrates the method selected for going from the data base to a national total for one set of base case reservoir and economic parameter assumptions.

TABLE 25

EXAMPLE EXTRAPOLATION OF INCREMENTAL ULTIMATE RECOVERY
(Millions of Barrels)

	Data Base Only	Extrapolated to State Total	Extrapolated to Nation Total	Ratio of Nation Total to Data Base
California	433	558	777	1.79
Texas	107	122	170	1.59
Louisiana	354	819*	1,139	4.19
Total	**812**	**1,499**	**2,086**	**2.57**

* For the described method of extrapolation, the portion of this volume from offshore fields is 261 million barrels. The same evaluation at $25 per barrel includes 394 million barrels from offshore Louisiana.

Note: Assumptions are a 10 percent rate of return requirement, $15 per barrel crude oil price, and moderate tax case.

Results for Louisiana, Texas and California, and for Total United States*

The results of the profitability calculations outlined above are presented for the data base results

*All values extrapolated to state or U.S. totals on all figures in this appendix were calculated from base case performance and costs, a minimum DCFROR requirement of 10 percent, moderate tax case, constant 1976 dollars, and oil price of $15 per barrel unless otherwise noted.

TABLE 24

EXTRAPOLATION OF SURFACTANT FLOODING RESERVES
THREE-STATE TO TOTAL UNITED STATES

Volume Component	Original Oil in Place (Millions of Barrels)	Brief Description
3-States	191,021	Cal. + Tx. + La. (with 70% offshore)
Midcontinent (5 states)	58,598	Ill. + Kan. + N.M. + Okla. + Wym.
42-States	16,329	One-half of remaining OOIP in U.S.
Total	**265,948**	

Extrapolation Factor =

$$\frac{265{,}948}{191{,}020} = 1.392$$

(3-State to Total U.S.)

extrapolated to the totals for individual states of California, Texas, and Louisiana, and to the three-state total in Figures 59 and 60.

As shown in Figure 59, the incremental ultimate oil recovery for the three-state total increases from about 1.5 billion barrels for a crude price of $15 per barrel to about 6 billion barrels at $25 per barrel (assuming the moderate tax case and a DCFROR of 10 percent). California contributes the major portion (about ⅔) of this potential recovery. The corresponding potential producing rate versus time (Figure 60) peaks in 1995 at about 0.25 million barrels of oil per day at a crude price of $15 per barrel, and at about 1.0 million barrels per day at $25 per barrel.

The projections at $15 and $25 per barrel oil prices for the entire United States are 2.1 and 8.4 billion barrels of incremental ultimate recovery and peak production rates of 0.35 and 1.4 million barrels of oil per day in 1995 (see Figure 61).

The incremental ultimate recovery projected for the United States decreases from 2.1 billion barrels for a minimum DCFROR requirement of 10 percent at $15 per barrel crude price, to essentially zero at a minimum DCFROR requirement of 20 percent (see Figure 62).

The sensitivity of the base case projections to uncertainty in chemical costs and process performance is illustrated in Figures 63 and 64. The base case chemical costs were varied by ± 25 percent in the calculations for Figure 63. This range for chemical costs realistically reflects the uncertainty in projecting future costs, which are influenced by type of surfactant used, scale of production, availability of raw materials, etc. Uncertainty in process performance was characterized by the uncertainty in the reduction in waterflood residual oil saturation achieved by the surfactant slug. This saturation reduction ($S_{orw}-S_{orc}$) depends both on the waterflood residual oil saturation in the swept region and upon the average oil saturation left in the region swept by the surfactant slug. An uncertainty of ± 5 percent pore volume (PV) in the base case values for ($S_{orw}-S_{orc}$) was examined in the calculations for Figure 64. The ± 5 percent PV variation is well within the current ability to characterize waterflood and chemical flood residual saturations.

Another variable studied was the effect of reduced pattern life. For this study a 10-year production model was used to represent surfactant flood pattern life. This flood pattern life was judged to best represent the limited field experience available. However, since chemicals required at project start are the most significant cost factor, alternative development models merit consideration for an actual project. To explore the impact of pattern acceleration by infill drilling, a project life of 5 years was evaluated. It showed that for those reservoirs that were economically attractive candidates (using the 10-year pattern life assumption) infill drilling could be beneficial (providing a 5-year pattern life). Although the simple production model used in this study cannot be considered to be best for representing any particular field, it indicates that infill drilling can improve project economics, and undoubtedly will be considered in actual field implementation of the surfactant flooding process.

Various of these sensitivity studies are shown in Table 26.

Estimated well workover and drilling requirements for surfactant flooding projects in the United States are shown in Figure 65 as related to oil price and in Figure 66 as related to time for a $15 per barrel oil price. Cumulative and yearly cash outlays are illustrated in Figures 67 and 68.

Polymer and Alkaline Flooding

State-of-the-Art Assessment

Polymer Flooding

Polymer flooding is essentially an improved waterflooding method, in which high molecular-weight, water-soluble polymers are added to the injection water to improve the mobility ratio of the water-flood. The polymers are added at low concentrations (250 ppm to 1,500 ppm); increased sweep efficiency may result from the improved mobility ratio. This method has its greatest potential in reservoirs containing viscous oils, and where the mobility ratio of ordinary waterflooding is adverse.

Currently, two types of polymers are commercially available: (1) a synthetic polymer (polyacrylamide); and (2) a biologically produced polymer (polysaccharide). In addition to increasing the water viscosity, polyacrylamides may also decrease the permeability of the formation to water. When this occurs, the polymer concentration necessary to achieve a given mobility ratio improvement is reduced.

The magnitude of mobility ratio improvement achievable with polyacrylamides decreases with water salinity and divalent ion concentration. Thus, a source of relatively fresh water (total dissolved solids less than approximately 10,000 ppm) is desirable for the most effective use of polyacrylamides.

The ability of polyacrylamides to decrease permeability of the formation to water may be severely reduced by shearing as the polymer is injected. Very high injection rates, especially through perfora-

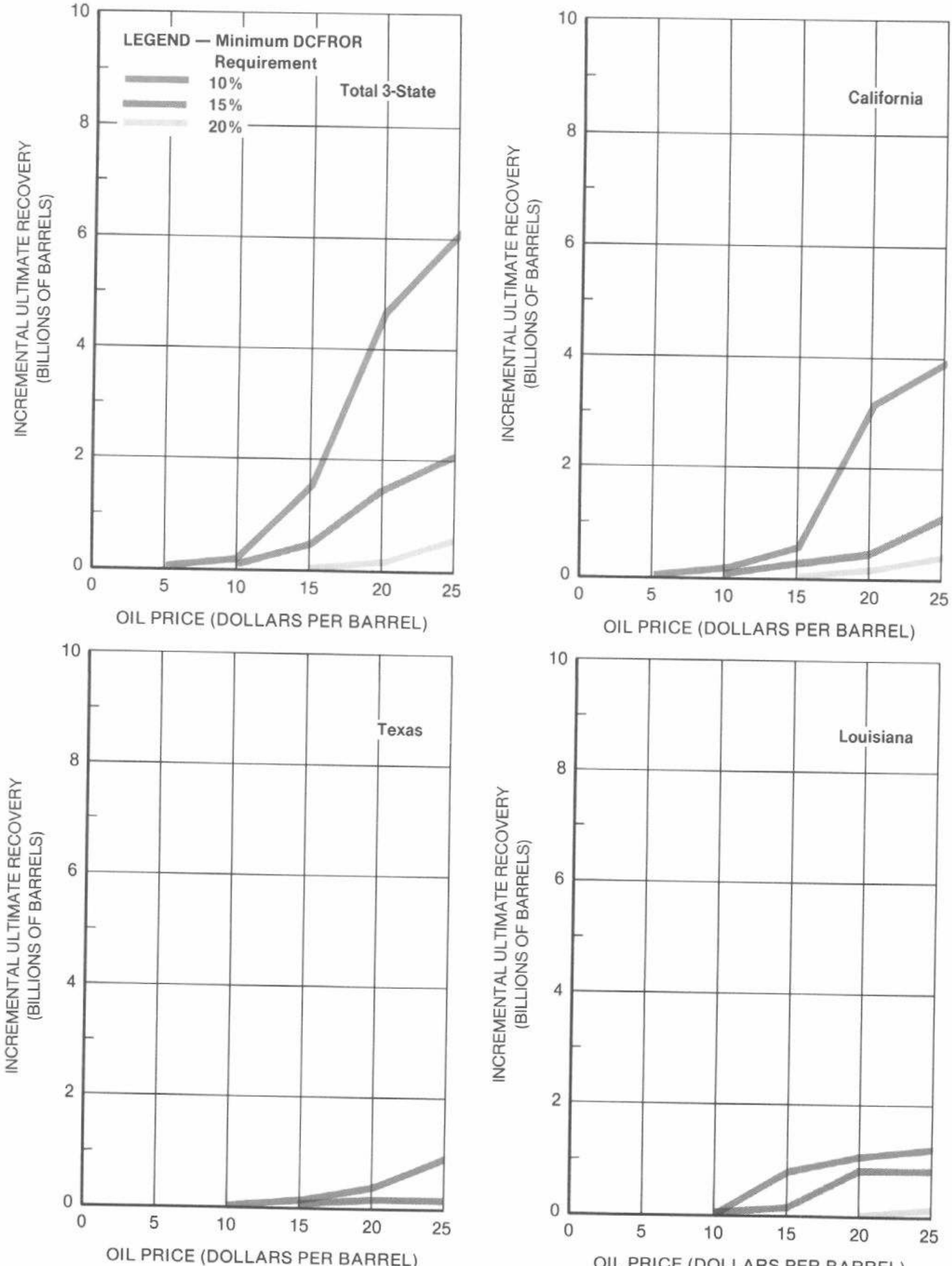

Figure 59. Incremental Ultimate Recovery—Surfactant Flooding—
Base Case Performance and Costs.

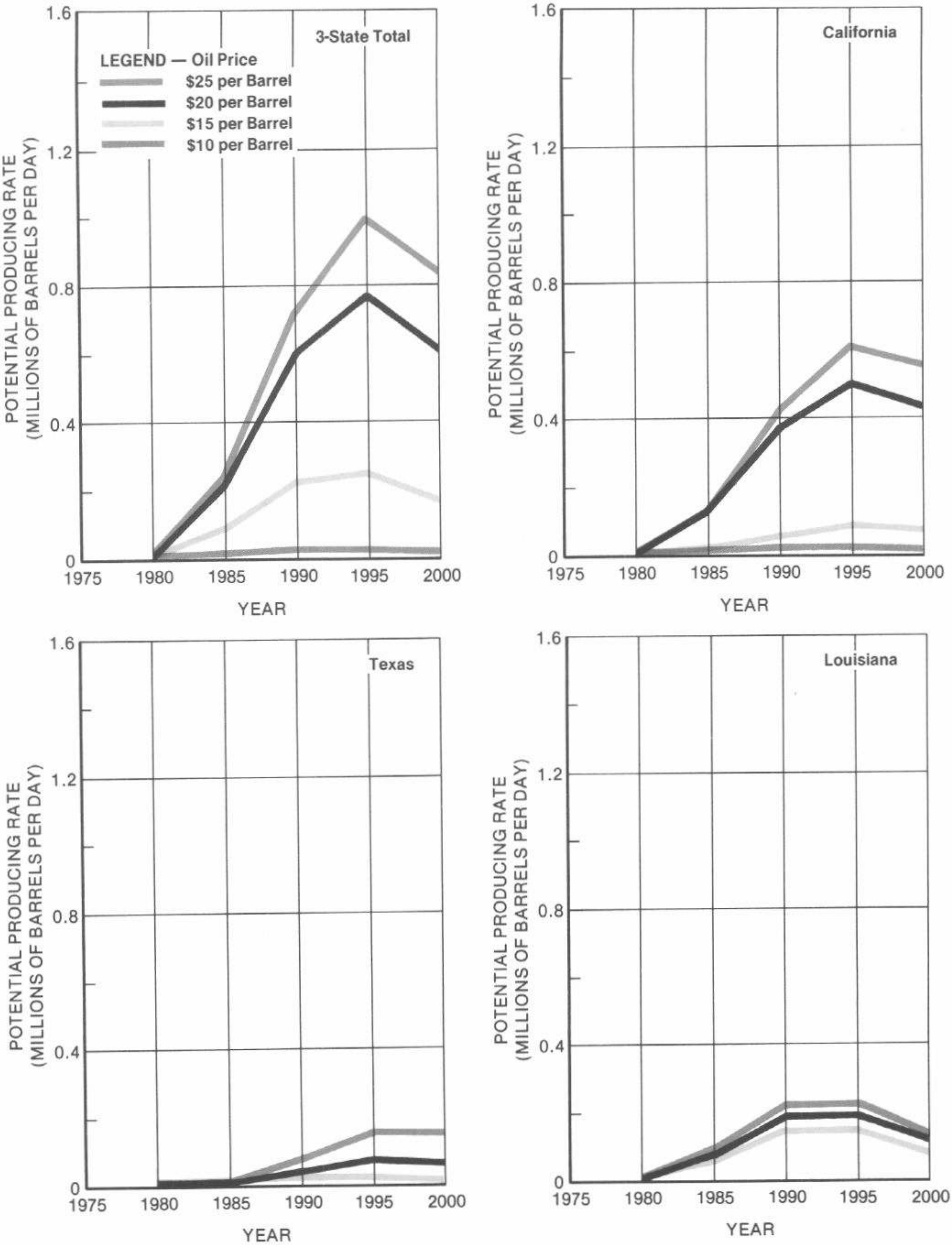

Figure 60. Potential Producing Rate—Surfactant Flooding—
Base Case Performance and Costs.

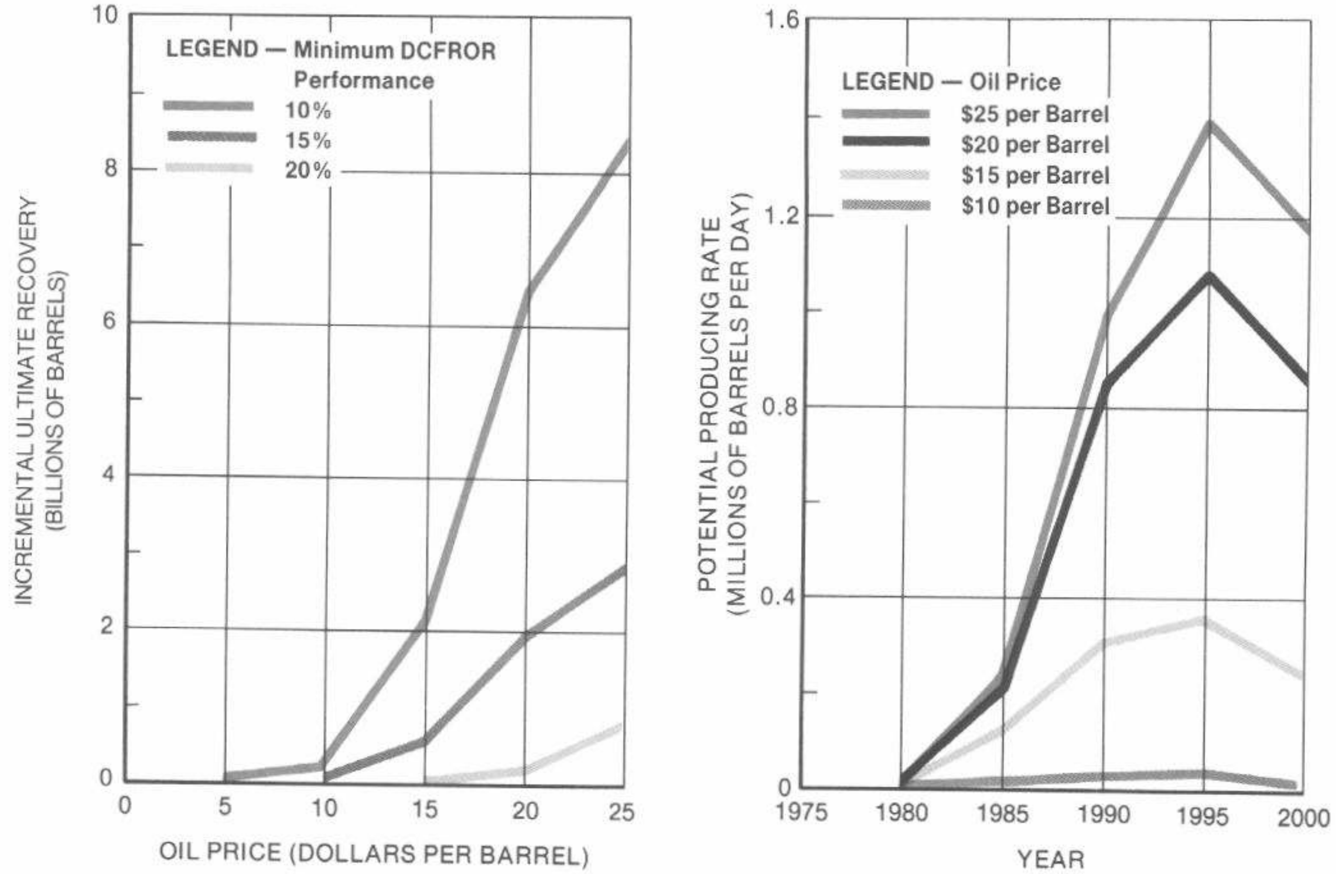

Figure 61. Incremental Ulitmate Recovery and Potential Producing Rate Surfactant Flooding - Base Case Performance and Costs - Total U.S.

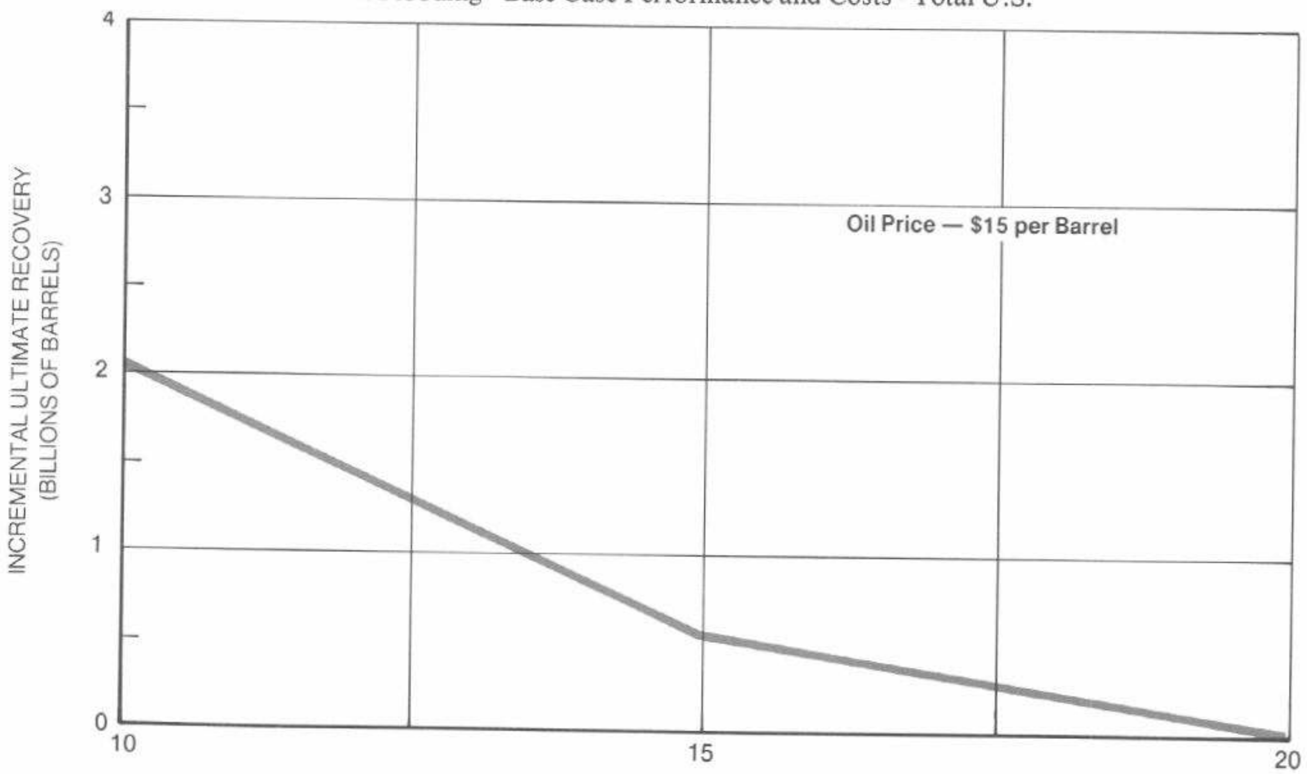

Figure 62. Surfactant Flooding—Variability of Incremental Ultimate Recovery with Minimum DCFROR Requirement—Total U.S.

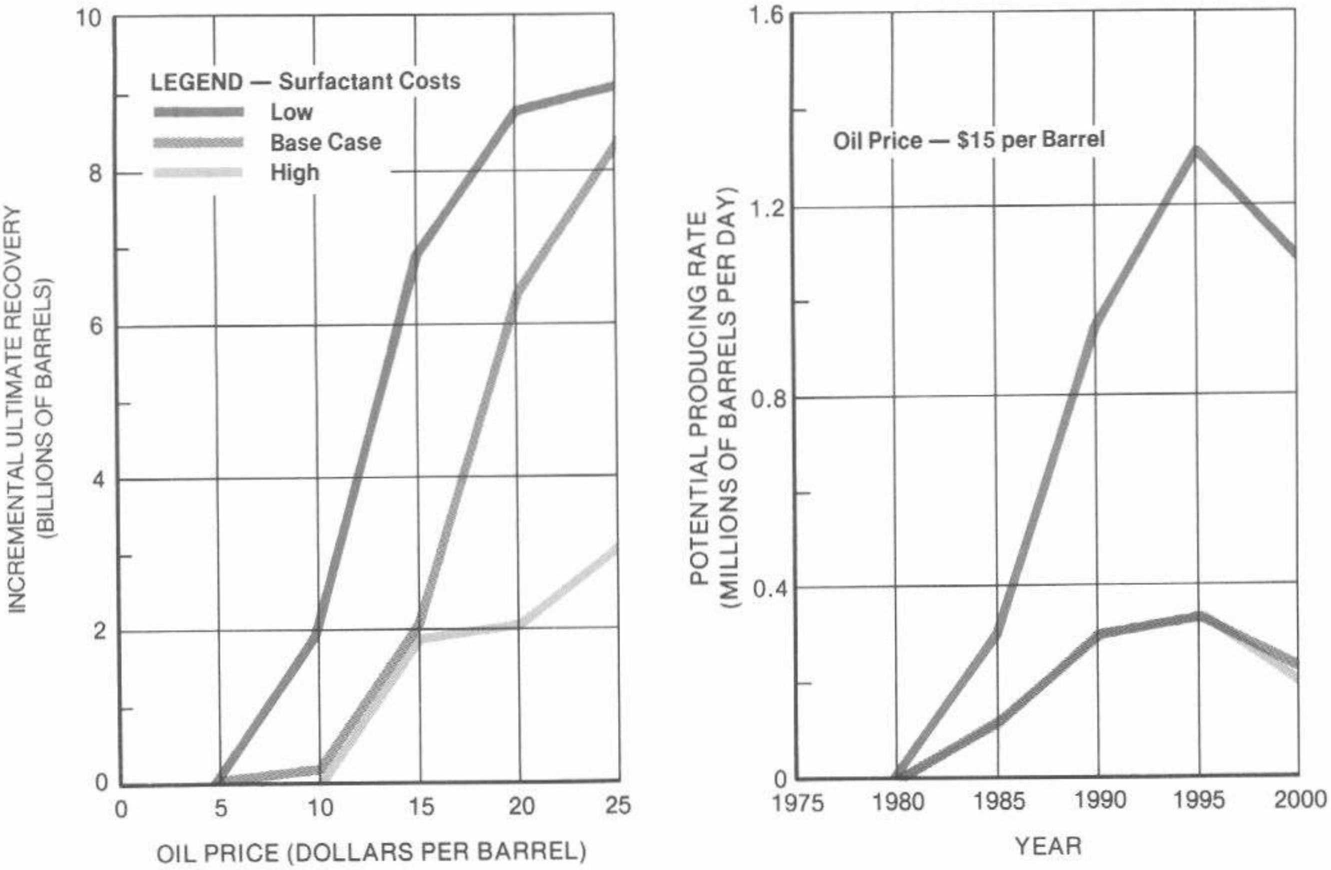

Figure 63. Surfactant Flooding—Variability of Incremental Ultimate Recovery and Potential Producing Rate with Surfactant Costs—Total U.S.

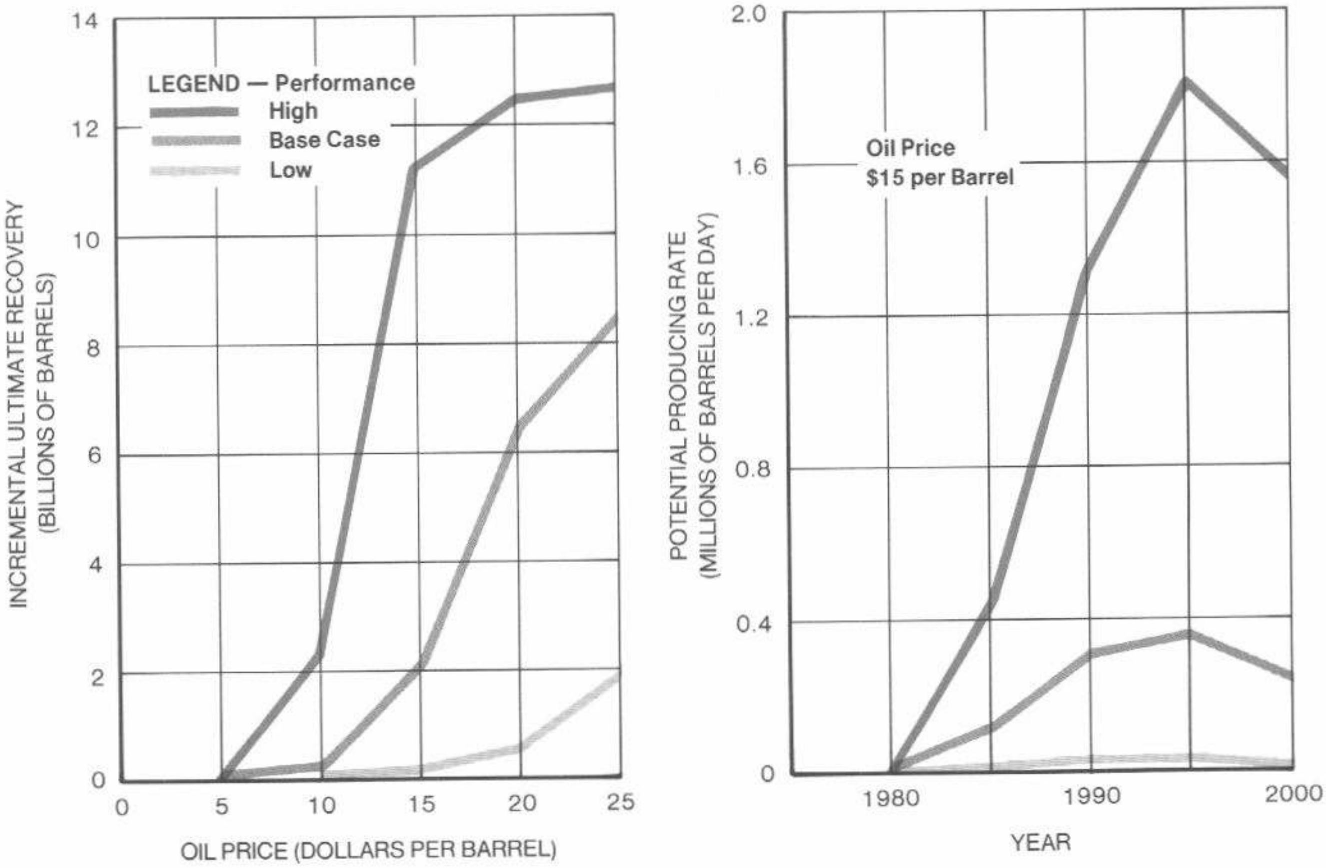

Figure 64. Surfactant Flooding—Variability of Incremental Ultimate Recovery and Potential Producing Rate with Recovery Performance—Total U.S.

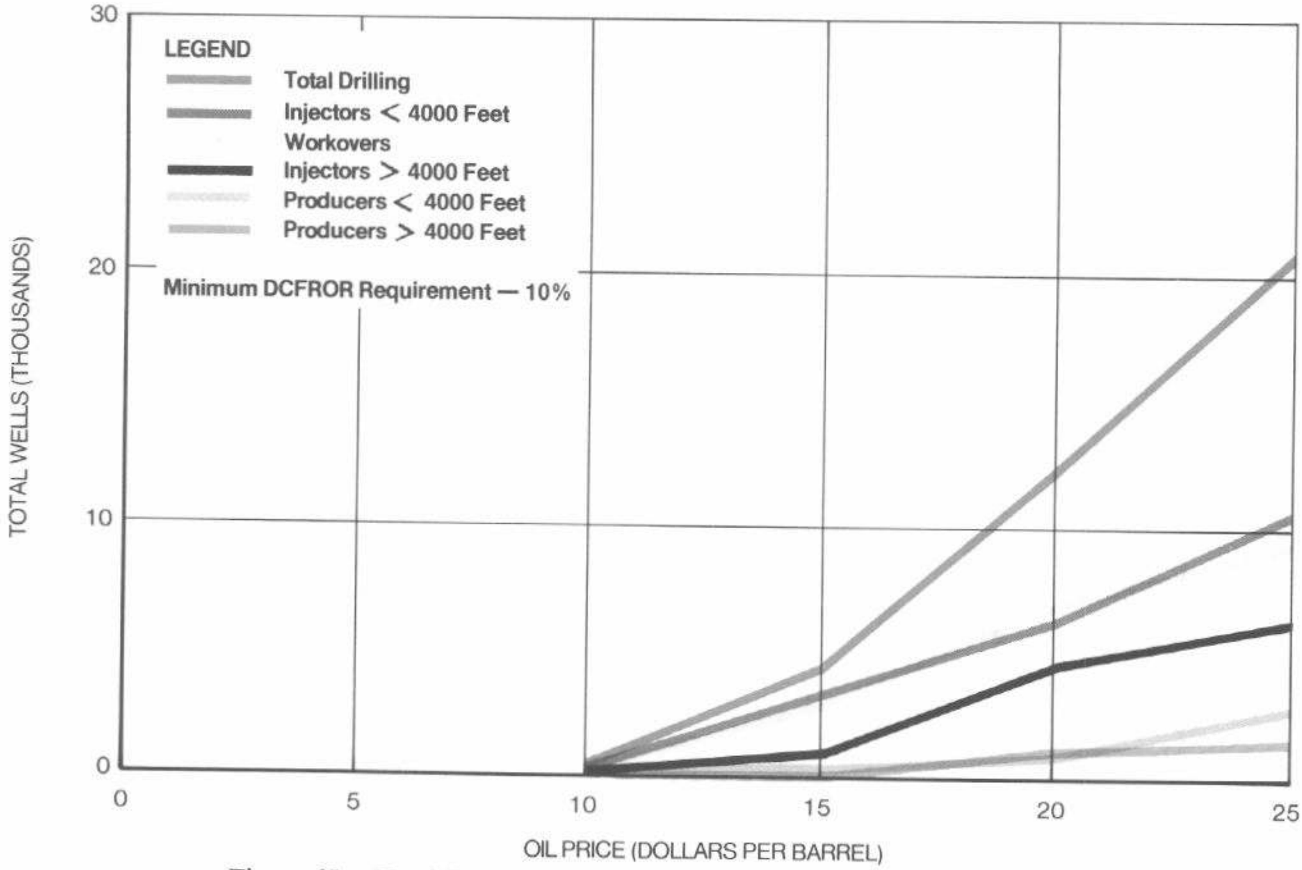

Figure 65. Total Drilling and Workover Activity—Surfactant Flooding.

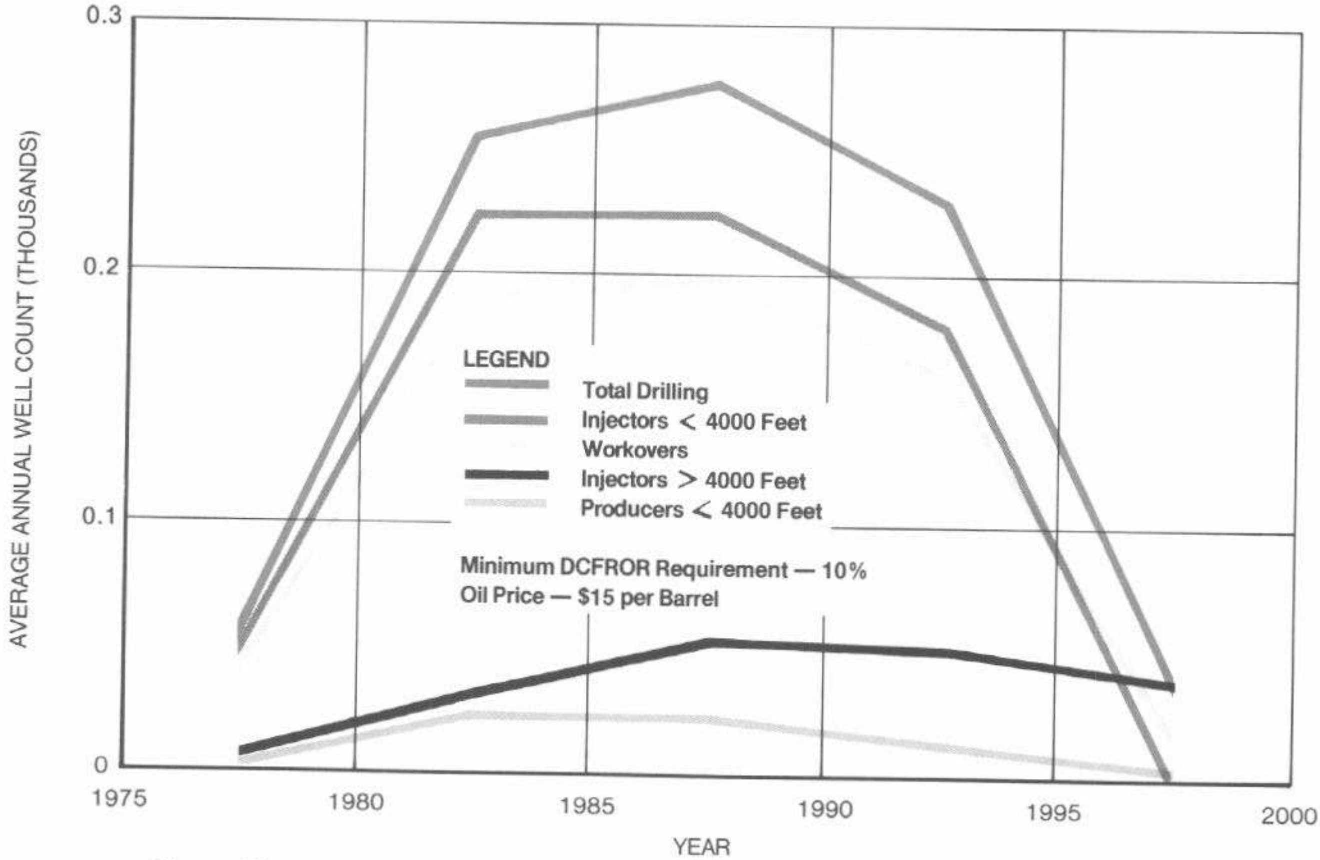

Figure 66. Average Annual Drilling and Workover Activity—Surfactant Flooding.

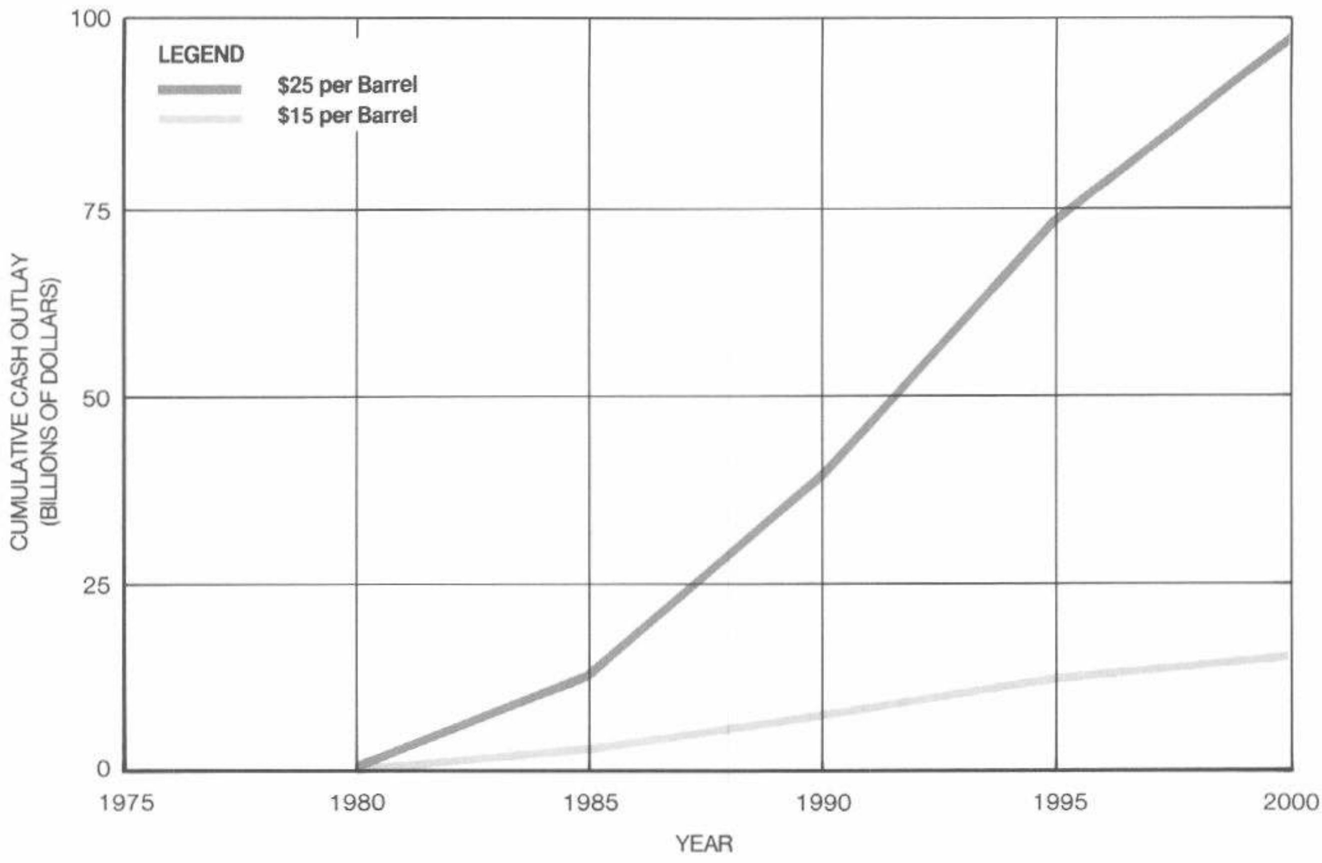

Figure 67. Cumulative Cash Outlay—Surfactant Flooding.

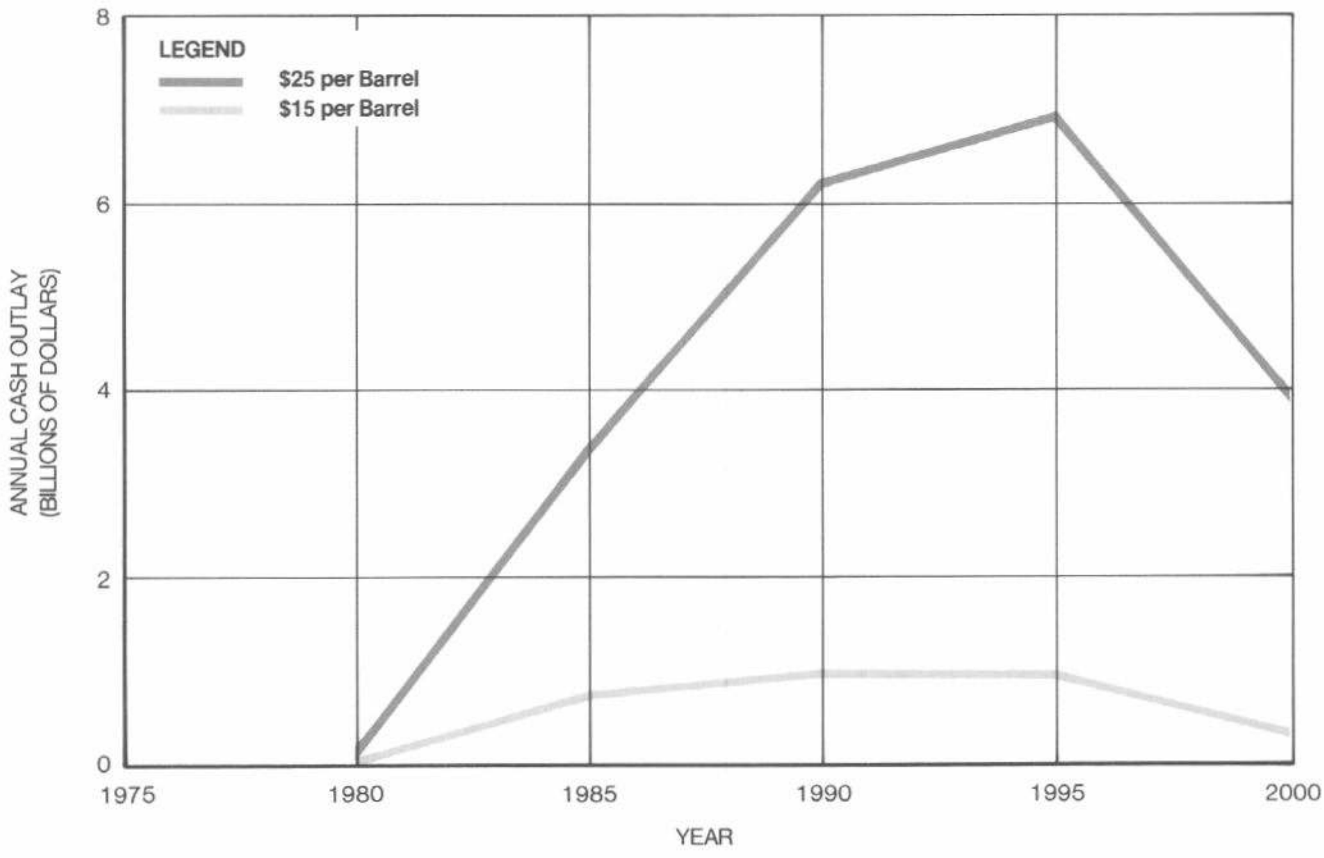

Figure 68. Annual Cash Outlay—Surfactant Flooding.

TABLE 26

SURFACTANT FLOODING SENSITIVITY STUDY RESULTS (Billion Barrels)

Case*		Incremental Ultimate Recovery	
Crude Price	$15	$20	$25
Base	2.09	6.480	8.380
Base, restrictive taxes	0.00	0.186	0.816
5-year project life	5.60	9.040	9.220
Low surfactant cost	7.86	8.780	9.220
High surfactant cost	1.93	2.090	3.150
Low recoverable oil saturation change	0.14	0.520	1.890
High recoverable oil saturation change	11.20	12.500	12.700
Small chemical slug	8.78	9.490	9.940
Large chemical slug	0.19	2.270	2.430

* Moderate taxes, minimum DCFROR requirement of 10 percent, and 10-year project life unless noted. All volumes are extrapolated to U.S. totals.

tions, may be harmful; hence, moderate injection rates as well as care in surface handling are required to minimize shearing.

Polysaccharides are less sensitive to salinity and divalent ion (calcium and magnesium) concentration and are less likely to shear during injection. However, these polymers, as currently manufactured, may need to be filtered through micron-sized filters to prevent well plugging. Bactericides are normally required to prevent bacterial attack and oxygen scavengers are required to maintain effectiveness. Their long-term stability in higher temperature ($\geqq 160°F$) reservoir environments has not yet been demonstrated. Polysaccharides currently are more expensive per pound than polyacrylamides.

High clay content in reservoirs is undesirable because the consumption (loss) of polymer is increased.

Polymer flooding with polyacrylamides has been extensively field tested, while testing of polysaccharides has been limited. Several field tests are in operation which should contribute significantly to the state of the art. The incremental ultimate oil recovery achievable by polymer flooding is expected to be modest.

Alkaline Flooding

The first patent on alkaline flooding to improve oil recovery was issued in the United States in 1927. Numerous publications of laboratory and field tests of alkaline flooding have appeared since that time. Alkaline chemicals, such as sodium hydroxide, sodium silicate, and sodium carbonate, when added to flood water, are reported to enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction; emulsification of oil; and formation wettability alteration. These mechanisms result from the in-situ formation of surfactants as the alkaline flood neutralizes petroleum acids. Interfacial tension reduction and wettability reversal can reduce oil saturation below the S_{orw} saturation. Oil emulsification appears to reduce the mobility of the injected water.

The effectiveness of alkaline flooding usually improves as the acid content of the crude increases. The potential for alkaline flooding will normally be highest for recovery of viscous, naphthenic, low API-gravity crudes, since the acid content of crude oils generally increases as the API gravity decreases. Reported laboratory experiments and field test results have indicated that the primary mechanisms responsible for increased oil recovery in this process may differ from one application to another, depending on the particular oil-water-rock system investigated. Therefore, the screening criteria in several categories (such as lithology, salinity and hardness of formation water, and temperature limitations) are ambiguous. However, reservoirs with low-salinity water, a low divalent cation content, and a low clay content are preferred for the process.

Field experience has been limited; information from seven alkaline flooding field tests reported to date are summarized in Table 27. One of the tests reportedly has been successful enough to be considered for commercial expansion. A few of the other tests were considered to be technologically encouraging.

Several unreported field tests are known to be in progress, but results are not available either for technical or economical assessment. Because the potential for this process appears to be greatest for recovering higher viscosity crude oils, polymer flooding and some thermal methods might be alternative EOR methods. However, the alkaline flooding process, unlike polymer flooding, has an advantage in that it can reduce the oil saturation below the S_{orw}; in some laboratory experiments, it has reduced the oil saturation to near zero in the swept region.

Although oil emulsification in alkaline flooding has improved the mobility ratio measured in some laboratory experiments, the emulsification mechanism alone may not be sufficient to achieve significant incremental recovery of highly viscous crude oil. One method proposed for improving sweepout of the

TABLE 27

ALKALINE WATERFLOODING FIELD TRIALS

Field	State	Operator	Acres	Start	Pay Sand-Lith.	Depth (Ft.)	ø,%/k,md*	Res. Oil °API/cp/Acid†	T,°F‡	Salinity (TDS-ppm)§	Chemical Used	Comments
Harrisburg	NEB	Pan Am	40	1960	Muddy J Sandstone	5,900	15/119	— — —	200	8,500	2%NaOH, 40,000 lb	Wet. Rev. (O/W)¶
Midway-Sunset	CA	Chevron	100	1962	Top Oil & Kinney Sandstone	1,500-2,000	34/450	16/180/1.5	87	15,062	1%NaOH, Crude oil-water (70/30)	Emulsification
Singleton	NEB	Sinclair	40	1966	J-1 Sandstone	—	—	—/1.5/—	160	—	2%NaOH, 8% PV	Wet. Rev. (O/W)¶
Whittier	CA	Chevron	63	1966	2nd and 3rd Sandstone	1,500-2,100	—/410	20/40/—	120	—	0.2%NaOH in softened water	Emulsification
South East Texas	TX	Exxon	2 wells	—	Miocene Sandstone	1,250	—	low/70/1.0	—	—	0.3 M Na_2CO_3	Wet. Rev.(W/O)**
North Ward Estates	TX	Gulf	5	1974	Queen Sand	3,140	21/20	34/2.4/0.22	—	—	5% NaOH, 15% PV	Wet. Rev. (O/W)¶
Orcutt Hill	CA	Union	420	1974	Frac. Shale Sand	2,950	23/71	22/11/—	168	14,300	NaOH, Na-Silicate, $CaCl_2$	Mobility Control

* Porosity in percent; permeability in millidarcies.
† Residual oil: Gravity in degrees API; viscosity in centipoises; acid number.
‡ Reservoir temperature, degrees Fahrenheit.
§ Salinity -- total dissolved solids, parts per million.
¶ Wettability reversal -- oil to water wet.
** Wettability reversal -- water to oil wet.

alkaline injection fluids is the combination of alkaline chemicals and polymers. Another method is the alternate injection of small slugs of sodium silicate and calcium chloride. As they mix in the reservoir, the two materials react to precipitate calcium silicate particles, which partially plug the various strata as they are flooded out. This method has had limited field testing.

Screening Criteria

The development of quantitative screening mechanisms for polymer and alkaline flooding proceeded in three phases: (1) analysis of published polymer and alkaline field test data; (2) review of the literature on the applicability of polymer and alkaline flooding; and (3) consultation with authorities from industry, government agencies, and universities. The screening criteria for polymer and alkaline flooding shown in Table 28 are compilations of the technical factors that approximate the decision parameters currently used by the oil industry in selecting reservoirs for further consideration as polymer or alkaline recovery projects. These screening criteria were used as the first screening for reservoirs in the data base. API gravity, crude viscosity and reservoir temperature data were supplemented or corrected as necessary.

TABLE 28

SCREENING CRITERIA FOR POLYMER AND ALKALINE FLOODING

Polymer Flooding

1. Natural Water Drive: None to Weak
2. Gas Cap: None to Minor
3. Fracture: None to Minor
4. Reservoir Temperature (°F): $\leqslant 200$
5. Crude Viscosity (cp): $\leqslant 200$
6. Average Reservoir Permeability (md): $\geqslant 20$
7. Mobile Oil Saturation* (%PV): $\geqslant 10$
8. Lithology: Not Critical in this screen

Alkaline Flooding

1. Natural Water Drive: None to Weak
2. Gas Cap: None to Minor
3. Fractures: None to Minor
4. Reservoir Temperature (°F): $\leqslant 200$
5. Crude Oil Acid Number (mg KOH/g of oil): $\geqslant 0.2$
6. °API Gravity: $\leqslant 35$
7. Crude Oil Viscosity (cp): $\leqslant 200$
8. Average Reservoir Permeability (md): $\geqslant 20$
9. Lithology: Sandstone

* Mobile oil saturation calculation: $S_o = S_{oip} - S_{orw}$

where:

S_o = Mobile oil saturation (%PV)

S_{oip} = Current oil saturation (%PV)

S_{orw} = Waterflood residual oil saturation (%PV)

Thirty-three reservoirs passed the first screening for polymer flooding, and 18 reservoirs passed for alkaline flooding processes. Additional screening of these reservoirs was performed by geologists and reservoir engineers from the participating companies. Factors such as depositional environment, general lithology, degree of heterogeneity, past waterflooding performance, and the likely influence of gas caps, natural water drives, and fractures were considered whenever possible. The geological and engineering review was used to reject some reservoirs on the basis of unfavorable properties. The remaining reservoirs were ranked as good, fair, or poor candidates for polymer and alkaline flooding. Factors such as the magnitude of mobile oil saturation, viscosity, permeability, and reservoir temperature were also considered in making the rankings. Only 13 reservoirs remained as candidates for polymer flooding and 5 as candidates for alkaline flooding processes after the second screening.

Crude oil acid numbers were used only in the second screening. Acid numbers were obtained from the correlation shown in Figure 69 and from other public sources, when available.

Since polymer and alkaline flooding processes can be applied to reservoirs having crude oil viscosities ranging from 5 cp to 200 cp, many candidates were also selected for other enhanced recovery processes. Therefore, the dominance rules discussed in Chapter Two were applied to those reservoirs suitable for more than one process. There was one exception to the dominance rules; some large fields were divided into several areas, with different processes applied in each area. After the application of dominance rules, only 7 reservoirs remained as final polymer candidates, and 4 reservoirs remained as alkaline flooding candidates.

Process-Dependent Cost Data

There are two categories of cost data in polymer and alkaline flooding processes: process-independent costs, described in Appendix C; and chemical costs and some special treatments related to alkaline flooding. Only this second cost category is discussed here.

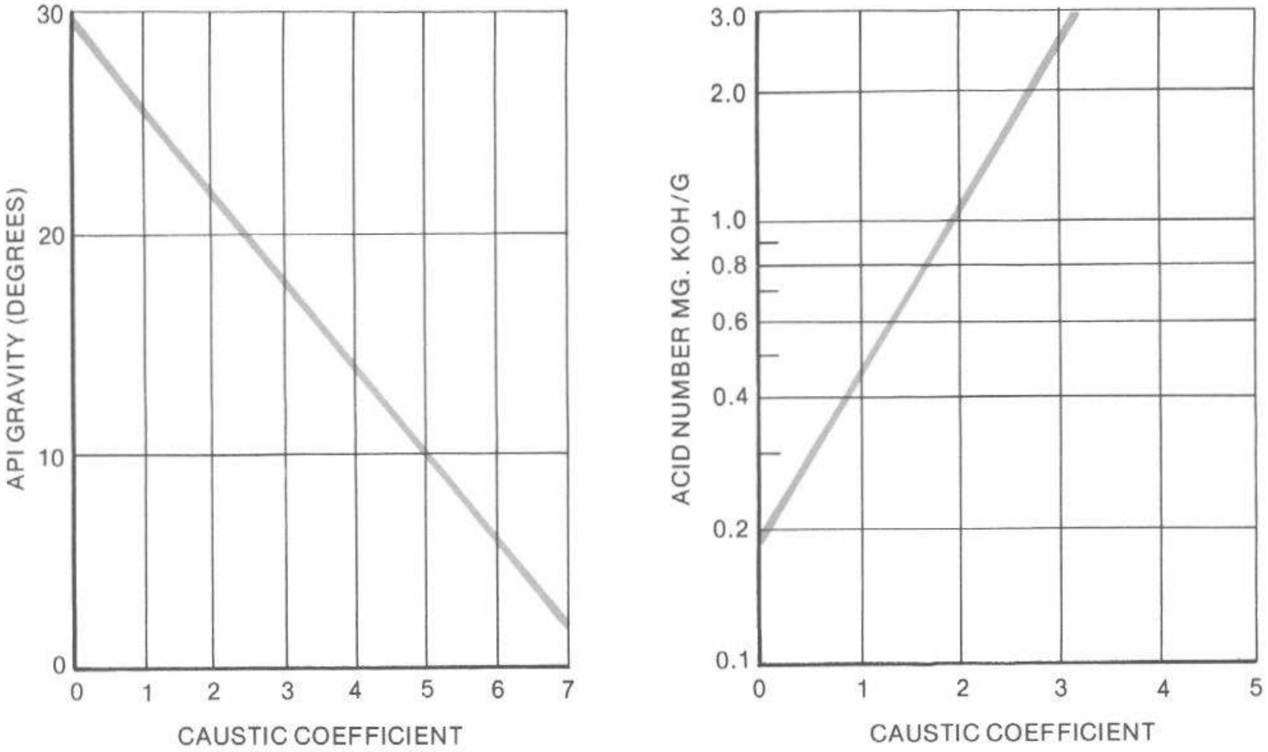

Figure 69. Determination of Crude Oil Acid Number from API Gravity Data.

Note: Reference 16 -- Alkaline Water Flooding.

Polymer

Average prices of polysaccharide and polyacrylamide polymers were used in economic computations. These prices, versus crude oil price, are shown in Table 29.

Sodium Hydroxide

Although several chemicals, such as sodium carbonate, sodium silicate, and sodium hydroxide, have been tried in field tests, sodium hydroxide (NaOH) appears to have the greatest potential in the alkaline flooding process. Therefore, the chemical costs used in this analysis are based on the cost of sodium hydroxide. Because of the high energy consumption in the production of NaOH by electrolysis, its cost was assumed to be sensitive to crude oil price, as illustrated in Table 30.

TABLE 29

AVERAGE PRICE OF POLYMER MIXTURE AT DIFFERENT CRUDE PRICES
(50% Polysaccharides: 50% Polyacrylamides)

Crude Oil Price (Dollars per Barrel)	Poly-saccha-rides (Dollars per Pound)	Poly-acryla-mides (Dollars per Pound)	Average Price (Dollars per Pound)
5.00	2.30	1.14	1.72
Base Case: 10.00	2.40 *	1.40 *	1.90
15.00	2.49	1.72	2.10
20.00	2.58	2.04	2.31
25.00	2.70	2.35	2.52

* See Notes - Tables 18 and 19.

TABLE 30

COST OF SODIUM HYDROXIDE VERSUS CRUDE OIL PRICE

Crude Oil Price (Dollars per Barrel)	Cost of NaOH* (Dollars per Pound)
5	0.103
10	0.117
15	0.127
20	0.143
25	0.165

* These costs include the cost of transportation and a sales tax of $.03 per pound.

Acidizing of Injection Wells

Injectivity reduction has been experienced in the alkaline flooding process. Acidizing of injection wells once a year appeared to be frequent enough. The average cost of acidizing was estimated to be $10,000 per well. Therefore, total acidizing cost per pattern was assumed to be $20,000 (two treatments per injection well).

Demulsification

In alkaline flooding, the production of oil-water emulsions may be expected. Therefore an emulsion treatment cost of $.10 per barrel of crude oil produced was used in the economic calculations.

Pilot Tests

Pilot testing costs were not treated explicitly in the economic evaluation of individual reservoirs and were assumed to be included in overhead costs, along with the cost of laboratory research.

Description of Process Analysis Procedures

Process analysis procedures included the calculation of ultimate recovery, the estimation of chemical slug size and concentration, the determination of pattern size, flood life and field-wide expansion schedules, and the application of cost data to candidate reservoirs.

Calculation of Incremental Ultimate Recovery—Polymer Flooding

The addition of polymers to water increases the effective viscosity of water and thus results in a more favorable mobility (decreased) ratio than is present in an ordinary waterflood. The principal benefits of the improved mobility ratio are an improved areal sweep, improved vertical sweepout in permeability-stratified reservoirs, and, possibly, some crossflow of oil from low-permeability to higher-permeability strata. Although polymer flooding of reservoirs containing high viscosity oils will not reduce the oil saturation in the swept regions below the waterflood irreducible residual oil saturation, the oil saturation in the polymer-swept regions can approach irreducible values with less cumulative volume injected than is possible in ordinary waterfloods.

Although, in principle, the same ultimate recovery can be achieved by prolonged waterflooding as can be achieved by polymer flooding, in practice, an uneconomic water-oil ratio may be reached by ordinary waterflood before this recovery level is achieved. Thus, the incremental oil recovery attributable to polymer flooding in any individual reservoir depends strongly upon the economic conditions affecting the performance of an ordinary waterflood, as well as upon the properties of the reservoir oil and the nature of reservoir heterogeneities. Detailed evaluations require information not available in the data base.

Incremental oil recovery was estimated by an approximate method. The total oil that remains to be recovered by polymer flooding in each candidate reservoir was estimated by determining the current oil saturation in the reservoir and by assuming an average of 50-percent volumetric sweepout. This estimation of remaining oil recovery included both oil that could have been recovered by continued waterflooding and the incremental recovery attributable to polymer flooding.

Published field experience suggests that the incremental recovery attributable to polymer flooding is approximately 25 percent of the remaining oil recovery; therefore, this percentage was used to separate the incremental recovery from the total remaining recovery for all candidate reservoirs. When this procedure was applied to the candidate reservoirs, the average incremental oil recovery was calculated to be about 3 percent OOIP.

These calculations were used to develop base case estimates of incremental recovery for the candidate reservoirs, regardless of the good, fair, or poor rankings of the reservoirs. There is a degree of uncertainty associated with the reservoir rankings and the individual reservoir recovery estimates. To approximate the impact of this uncertainty on the total incremental ultimate recovery projected for polymer flooding, calculations were made for two more cases: (1) assuming that all reservoirs were good flooding candidates; and (2) assuming that all reservoirs were poor flooding candidates. For the first assumption, base case recovery estimates for reservoirs rated "poor" were adjusted upward by 50 percent to estimate improved recovery if the reservoir should perform better than expected. Similarly, base case recovery for reservoirs rated "good" was decreased by 50 percent to reflect decreased recovery if these reservoirs should perform more poorly than expected. Base case recoveries for reservoirs rated "fair" were increased or decreased by 25 percent for the range of uncertainty calculations.

Calculation of Incremental Ultimate Recovery—Alkaline Flooding

The method used for estimating incremental oil recovery assumes that a reduction in the waterflood residual oil saturation will be the dominant mechanism responsible for increased oil recovery in future applications of this method. The correlation presented in Figure 70 was used to estimate the final oil saturation left in the regions of a reservoir flushed with alkaline flood water. This correlation provides the ratio of the oil saturation remaining after an alkaline waterflood to the oil saturation remaining after a conventional waterflood. Since this correlation is based on experiments in laboratory cores with various acidic crude oils, its use for field applications required that adjustments be made for each alkaline flooding candidate. This adjustment is necessary to account for the higher average oil saturations that will result in the swept zones of a reservoir due to heterogeneities, unexpected harmful minerals, dilution and reduced effectiveness of the alkaline slug, and other factors. Because of the lack of definitive field tests of alkaline waterflooding, these adjustments were largely made by analogy with other processes.

Incremental recovery was estimated by using the following equation:

$$\text{incremental ultimate recovery} = \frac{OOIP \times B_{oi}}{(1 - S_{wi})B_o}(S_{orw} - S_{ora})\,E$$

where:

- $OOIP$ = original oil in place (stock tank barrels)
- B_{oi} = original oil formation volume factor (reservoir barrels per stock tank barrel)
- B_o = current oil formation volume factor (reservoir barrels per stock tank barrel)
- S_{wi} = original water saturation
- S_{orw} = residual oil saturation by waterflood in swept zone

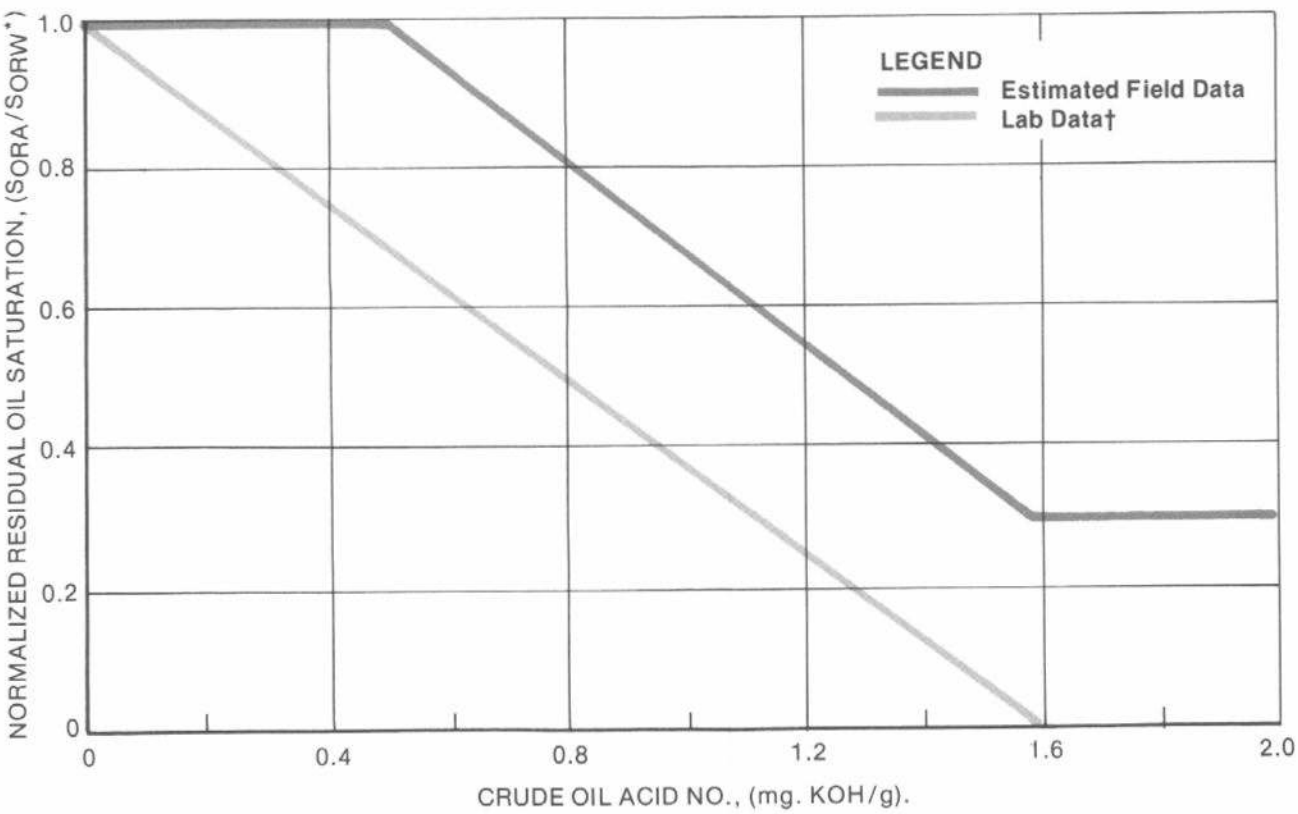

Figure 70. Correlation of Crude Oil Acid No. vs. Normalized Alkaline Flooding Residual Oil Saturation.

*S_{ora} -- Oil Saturation After Alkaline Flooding - Percent
S_{orw} -- Oil Saturation After Conventional Waterflooding - Percent.
†Laboratory Data References 38, Alkaline Flooding.

S_{ora} = residual oil saturation by alkaline flood in swept zone

E = waterflood and chemical flood volumetric sweep efficiency

The alkaline flooding candidates generally contained moderately viscous oils. For this reason the waterflood residual oil saturation values taken from the Bureau of Mines correlations shown in Figure 71 were used in the alkaline flooding projections rather than the residual oil values assumed for the surfactant projections. Formation volume factors were assumed to be 1.0 and a volumetric sweep efficiency of 50 percent was used.

Uncertainty in the recovery projections was treated in a manner similar to that described for polymer flooding.

Chemical System Design and Development Schedules—Polymer and Alkaline Flooding

Estimation of Chemical Slug Size and Concentration

Polymer slug size and concentration in the design of a polymer flood depend upon the water-oil mobility ratio, reservoir permeability, degree of stratification and other heterogeneities, type of polymer, reservoir fluid properties, polymer consumption, and economics. In this study an average of 125 ppm-PV* was assumed to be required for effective flooding with current polymers. For example, a 0.5-PV polymer slug size was assumed to contain polymer at 250-ppm concentration.

Two chemicals, sodium hydroxide and polymer were assumed to be required for the alkaline flooding process. The quantity of NaOH required for alkaline flooding was estimated to be 3,000 ppm-PV (or 1.5 weight percent and 0.2 pore volume); this figure was based on results of field tests to date (see Table 27). Although polymer requirements for alkaline flooding vary from reservoir to reservoir depending on the crude oil viscosity, an average of 600 ppm-PV was used.

*This unit is a combination of concentration (in parts per million) and slug size (in fraction of a pore volume).

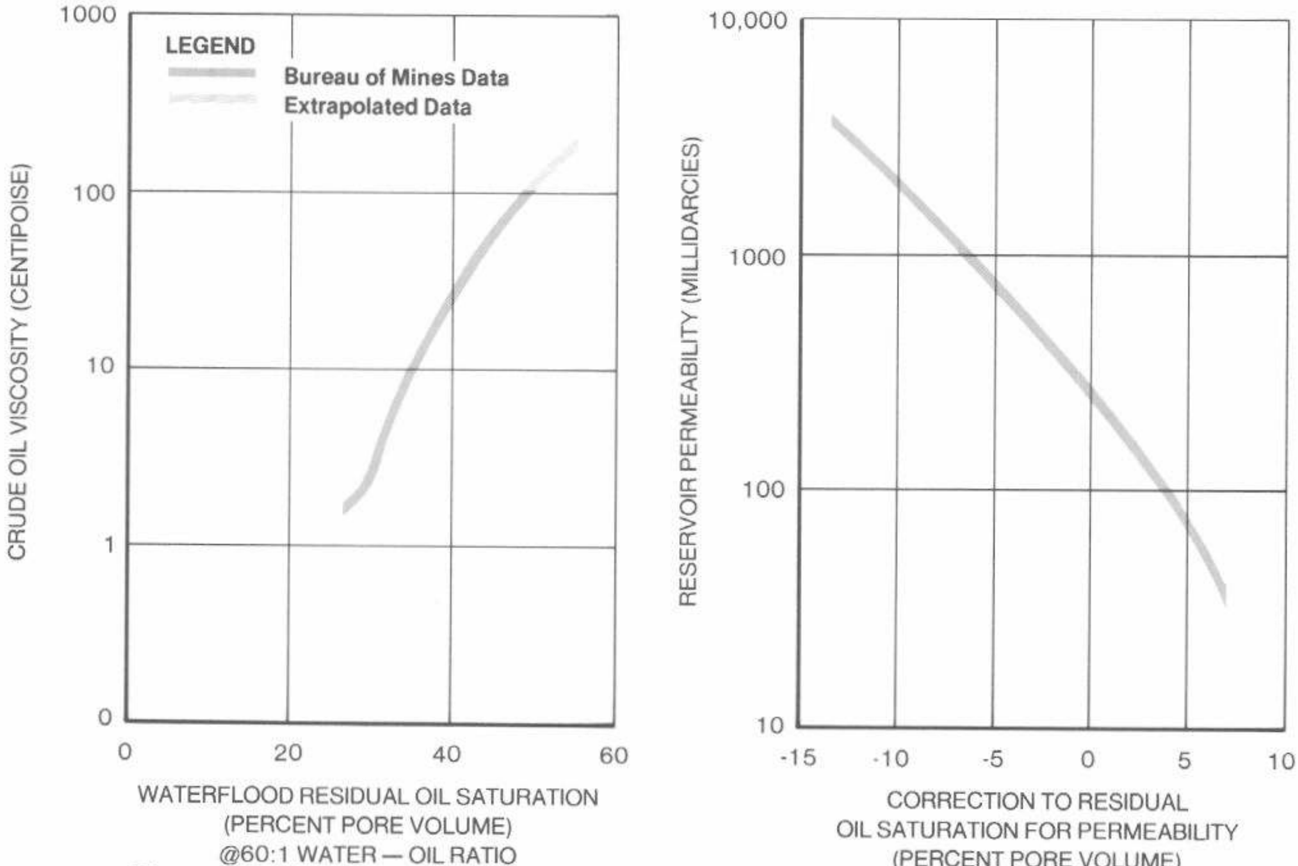

Figure 71. Oil Saturation and Viscosity Trends Developed by the Bureau of Mines.*

*Sloat, Ben. Petroleum Engineer, (May, 1971), 84.
EXAMPLE: For 10 Centipoise Viscosity and 1000 Millidarcies, S_{ORW} = 36 + (-6) = 30%

Pattern Size, Flood Life, and Field Expansion Schedules

In practice, the desired pattern size and flood life are determined from economic optimization studies. Calculations were not made in detail for this study; instead, both for polymer flooding and for alkaline flooding, a 20-acre, five-spot pattern was assumed to be approximately the pattern size that would allow a 10-year flood life, which was in turn assumed to roughly approximate the optimum flood life. For candidate reservoirs that had larger well spacings, infill drilling costs were included in the economic calculations.

Production rate schedules assumed for the incremental oil production attributable to polymer flooding and alkaline flooding are illustrated in Figures 72 and 73. In these figures, production rate is expressed as a percentage of total incremental recovery that is produced each year. Injection of the polymer and alkaline water slug was assumed to take place in the first two years.

The assumed program for staging project starts was the same for both processes. The initial stage consisted of 10 patterns. After three years for process evaluation, another 20 patterns were added. Thereafter, project expansion was scheduled at the rate of 20 patterns every two years.

The calendar year in which projects were started was determined by the current depletion status of the candidate reservoirs. Except for those reservoirs that are currently under field test or for which there are plans for tests in the near future, the project starting time was scheduled after 1980. For reservoirs currently in the early stages of waterflooding, the total estimated incremental oil recovery by polymer flooding was used. This estimated recovery was reduced by 25 percent for polymer flood projects initiated after 1980, to account for depletion up to the start of polymer flooding. It was assumed that projects in reservoirs with temperatures greater than 175° F would not be initiated until after 1985.

Extrapolation Process

Polymer Flooding

The only polymer flooding prospects identified from the data base reservoirs were located in California; they consisted of sandstone reservoirs that contained crude oils, with API gravities in the range of 20° to 30°. Therefore, results were extrapolated only for sandstone reservoirs containing crude oils in this gravity range. To reflect the influence of the screening criterion for temperature on the estimated ultimate recovery, separate extrapolations were made for reservoirs with depths less than 4,000 feet and for reservoirs with depths equal to or greater than 4,000 feet. The extrapolations were based on the OOIP contained in these depth and API-gravity categories; these were estimated for California, Texas, Louisiana, Oklahoma, Kansas, Wyoming, and New Mexico from API data and from information contained in the Petroleum Data System (PDS).

The extrapolation was made in the following steps:

- **California**—Total OOIP in the depth and API-gravity categories described above was divided by the OOIP in the data base reservoirs in these categories. The resulting ratio was multiplied by the ultimate recovery calculated for the data base polymer flood candidate reservoirs.
- **Texas and Louisiana**—No prospects were found in the data base reservoirs of these states. Potential polymer flood recovery from reservoirs not included in the data base was projected by subtracting OOIP in the data base reservoirs in these states from the total OOIP in the API-gravity and depth categories. This difference was then divided by the OOIP in the California data base reservoirs in the specified depth and API-gravity categories; the result was then multiplied by the ultimate recovery projected for the California data base reservoirs.
- **Oklahoma, Wyoming, Kansas, and New Mexico**—Recovery for each state was estimated for the separate categories by dividing the OOIP in the state by the total OOIP in the three states; this ratio was then multiplied by the extrapolated value of total ultimate recovery for the three states.
- **Total United States**—Since the seven-state total API OOIP amounted to 85.5 percent of the total U.S. OOIP, the ultimate recovery for the United States was estimated by dividing the ultimate recovery estimated for the seven states by 0.855.

Alkaline Flooding

All alkaline flooding candidates were found to be in California. The API gravity of the oil in the majority of candidate reservoirs was below 20°. Oil in the remaining candidate reservoirs had API gravities between 20° and 30°. Separate extrapolations were made for reservoirs that contained crude oils with API gravities less than 20° and for reser-