Enhanced Oil Recovery

National Petroleum Council

NATIONAL PETROLEUM COUNCIL
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June 21, 1984

The Honorable
Donald Paul Hodel
Secretary of Energy
Washington, D.C. 20585

My dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you the report Enhanced Oil Recovery, as approved by the Council at its meeting on June 21, 1984. This report was prepared in response to a March 10, 1982 request from the Secretary of Energy. It is gratifying to advise you that we have reached the broad conclusion that enhanced oil recovery (EOR) from known reservoirs in the United States could contribute significantly to the nation's future domestic crude oil supply. However, this potential is highly dependent on a broad spectrum of economic, technological, and policy considerations and constraints, which will require the concerted attention of both industry and government in order for the nation to realize the benefits of this resource.

Conventional primary and secondary recovery methods will produce only about one-third of the oil discovered in the United States to date. Of the remaining two-thirds, a portion is producible through EOR technology. The report concludes that as much as 14.5 billion barrels of additional oil could ultimately be recovered with the successful application of existing EOR technology, under current economic conditions. The rate at which this additional resource could be produced is equally significant, potentially exceeding 1 million barrels per day by the early 1990s and sustaining this rate for nearly twenty years. The Council believes that this report presents the most realistic estimate made to date on the timing of enhanced oil production.

Technology and economics will both have a major impact on enhanced recovery potential. Technical uncertainties still exist with regard to the various EOR processes examined in the report; the level of technical maturity varies among the processes. The report demonstrates the significant impact that technological advances can have on the recovery potential. However, only through continued process research and field testing, with both industry and government support, can the large volume of hydrocarbons discussed in the report be produced. Additionally, the high costs and risks associated with EOR development present potential economic constraints that must be met with reasonable and consistent economic and regulatory policies.

While the report demonstrates the significant potential recovery from EOR methods, this potential represents only a fraction of the production that will be required to meet the nation's future demand for liquid petroleum. If successfully applied, EOR methods can constitute an important contribution to the future domestic petroleum supply and must be vigorously pursued by both industry and government. However, the potential recovery from EOR methods will not by itself be a solution to the nation's long-term energy needs. It must be emphasized that this potential should be considered as but one component of the supply mix necessary to meet these needs. All other sources must also be considered.

The National Petroleum Council is pleased to be able to serve you and our nation. We sincerely hope that this study benefits you and the government in your efforts to facilitate the expansion of the U.S. liquid fuels supply through the development of all potential resources.

Respectfully submitted,

Robert A. Mosbacher
Chairman

RAM/pkd
Enclosure

Enhanced Oil Recovery

National Petroleum Council

Ralph E. Bailey, Chairman, Committee on Enhanced Oil Recovery
L. B. Curtis, Chairman, Coordinating Subcommittee

June 1984

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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Introduction

During the 1970s, declining domestic production and increasing demand for oil forced the United States into a greater reliance on foreign supplies. While much has been accomplished since then in arresting the decline in domestic production and reducing consumption, the nation's oil supply problem has not been solved on a long-term basis. Future demand for liquid fuels will have to be met from a number of competing sources, including the production of more oil—"enhanced recovery"—from known domestic oil fields.

In 1976, the National Petroleum Council (NPC) issued its report entitled *Enhanced Oil Recovery: An Analysis of the Potential for Enhanced Oil Recovery from Known Fields—1976-2000.* That report was a comprehensive, far-reaching analysis of enhanced oil recovery (EOR) potential in the United States that focused on the processes by which recovery from existing reservoirs might be improved.

Since that time, there have been significant changes in technologies, economics, government policy, and the U.S. energy outlook in general that will have an effect on the potential for enhanced oil recovery, as presented in the 1976 NPC report. Extensions in process technologies have had an impact on the amount of incremental oil that can be produced and the rate at which it is produced. Also, the general environment in which the petroleum industry operates, including the regulatory climate, has changed dramatically such that the projected costs and economic assumptions of the 1976 report are outdated.

In recognition of these changes, on March 10, 1982, the Secretary of Energy requested the NPC to undertake a new study of enhanced oil recovery, updating it where appropriate and expanding on it where necessary. (The complete text of the Secretary's request letter, a description of the National Petroleum Council, and a roster of the Council membership are provided in Appendix A.)

The NPC agreed to a complete restudy, rather than a literal update, of the 1976 report. Since 1976, a number of studies, both in industry and government, have been conducted to assess the potential for enhanced oil recovery. However, this study represents the first significant industry-wide effort since 1978.

To assist it in response to the Secretary's request, the Council established the Committee on Enhanced Oil Recovery, under the Chairmanship of Ralph E. Bailey, Chairman and Chief Executive Officer, Conoco Inc. Hon. William A. Vaughan, Assistant Secretary for Fossil Energy, U.S. Department of Energy, served as Government Cochairman of the Committee.[1] The Committee established a Coordinating Subcommittee to aid it in directing the overall study effort, and four task groups to assist in defining consistent, reasonable estimates of EOR potential. The broad membership of these groups includes representatives of both major and independent petroleum companies and the academic, consulting, and environmental communities. Rosters of these study groups are included in Appendix B. In selecting the study participants, an attempt was made to appoint individuals who represented the various divergent views on

[1]Hon. Jan W. Mares served as Government Cochairman until January 1984.

enhanced recovery. As might be expected, there are varying degrees of optimism regarding the potential of enhanced recovery. Although all study participants do not necessarily endorse every part, the report represents a consensus of the participants' views.

This study presents estimates of the amount and timing of incremental oil that might be recovered through the application of EOR techniques to known reservoirs in the United States over the next 30 years. *The results presented in the study are not intended to be a forecast of what will occur. Rather they represent projections of what could happen under certain technical and economic assumptions and constraints.* The study results do not reflect the impact of new oil discoveries or the possible application of EOR methods to those fields.

The study results are based on a detailed analysis of the resource base thought to be most amenable to EOR methods. A thorough review was made of state-of-the-art technologies of the processes considered, the costs associated with enhanced recovery, and the economic and physical factors, both internal and external to the processes, that may affect the EOR potential. In addition to the presentation of recovery and rate estimates, the study outlines the significant changes affecting enhanced recovery since the 1976 NPC report was issued. The potential environmental impacts associated with EOR operations are assessed, as is the relative importance of enhanced oil recovery to the nation's energy supply. The study also addresses recent research efforts and the future implications for research and development programs.

Executive Summary

Background

Enhanced oil recovery, for the purposes of this study, is defined as the incremental ultimate oil that can be economically produced from a petroleum reservoir over that which can be economically recovered by conventional primary and secondary methods. Primary methods rely on the natural reservoir energy to drive the oil through reservoir rock to the production wells. Over time, this natural energy drive dissipates, and energy must be added to the reservoir to produce significant amounts of additional oil. Conventional secondary recovery methods introduce additional energy through the injection of water or gas, under pressure, into the formation. Waterflooding has been and continues to be very successful at improving the recovery of oil from known reservoirs.

Although secondary methods such as waterflooding are, in the broadest sense, methods for enhancing oil recovery, this study focuses on the potential recovery from other processes that have been developed and field tested and have achieved some level of technical and/or commercial success in the field. These EOR processes have often been referred to as tertiary recovery methods. However, the term "enhanced oil recovery," as used in this report, is considered to have a broader meaning than "tertiary oil recovery," in that the potential from reservoirs that are not suitable for the application of conventional primary and secondary techniques is included.

The three general classifications of EOR methods that have shown significant promise are: (1) chemical flooding; (2) miscible flooding; and (3) thermal recovery. Although other methods have been studied and tested, these three methods are thought to have the greatest potential for recovering additional oil from known reservoirs in the 30-year time frame of this study. The various processes that fall within these three classifications differ considerably in the physical mechanisms for oil recovery, the level of maturity gained through field application, and the potential for technical and economic success.

Recovery from EOR methods currently accounts for 6 percent of U.S. daily oil production. The resource to which enhanced oil recovery may be applied in the future is significant because conventional primary and secondary methods are expected to recover only about one-third of the oil originally discovered. Much of the remaining two-thirds of the oil originally in place (OOIP) is not producible, due to adverse fluid properties and unfavorable reservoir geology. However, a portion of this remaining resource will constitute the target for enhanced oil recovery.

Analysis Procedures

This study analyzes the potential for enhanced oil recovery from known reservoirs in the United States. Potential producing rates during the 30-year time frame of the study, and incremental ultimate recovery achievable from EOR processes, were calculated for a wide range of technical and economic assumptions. Within the three general EOR methods, six distinct processes are considered: chemical methods, including polymer flooding, surfactant flooding, and alkaline flooding; miscible displacement methods, including carbon dioxide (CO_2) miscible flooding; and thermal recovery methods, including steamflooding and in situ combustion.

The analysis is based on a resource data base consisting of over 2,500 reservoirs with approximately 325 billion barrels of OOIP. This data base was developed from a variety of sources, and was extensively reviewed and upgraded by the study participants. It represents over two-thirds of all the oil that has been discovered in the United States to date.

In order to reflect potential technological improvements in EOR processes, two technology cases were studied. The Implemented Technology Case refers to technology that is currently proven in the field, at least in the field test stage. The Advanced Technology Case refers to technology advancements that might conceivably come about within the 30-year time frame of the study.

Initially, the technical feasibility of process application was determined for the reservoirs in the data base. Screening criteria, based on process characteristics, reservoir geologic conditions, and fluid properties, were developed to make this determination. In many cases, a given reservoir was found to be amenable to more than one EOR process. Such reservoirs were eventually assigned to the process that recovered the most oil, provided that a specified rate of return was achieved.

Recovery performance was estimated for each reservoir according to the process or processes found to be applicable from the screens. Simplified predictive models were extensively calibrated against actual field performance data and against predictions of more complex reservoir simulators, and then were used to estimate incremental ultimate recovery and potential producing rates for each reservoir/process combination.

Detailed costs associated with the implementation of each EOR process were also defined. These include process-independent cost data, such as well drilling and completion costs, and process-dependent costs encompassing those costs specific to the individual EOR processes.

A standard economics program, appropriately modified for each process, was used to provide a measure of project profitability. Economic evaluation criteria were chosen to represent a broad range of conditions. Evaluations were made for each project on the basis of four oil price cases and three minimum rates of return.

Crude oil prices considered in the report are \$20, \$30, \$40, and \$50 per barrel. These prices are assumed to be effective at the start of the study period and remain constant throughout the 30-year time frame of the study. All crude oil prices are expressed in nominal terms and relate to 40°API mid-continent crude oil; reductions were made to reflect crude oil quality differentials and transportation costs. A constant dollar analysis procedure was used in all evaluations, with all costs and prices being expressed in constant 1983 dollars. The constant crude oil price and constant dollar analysis procedures were used to provide a measure of comparability for the various study projections, which might otherwise be distorted by varying estimates of the unpredictable factors of inflation and the timing of crude oil price changes.

Three minimum discounted cash flow rates of return were assumed as criteria for evaluating each reservoir. These rates of 0, 10, and 20 percent were used in the analysis only as economic screens and are not expectations for results. They are assumed to represent after-tax rates, and are independent of the effect of inflation. The use of these minimum rates of return is not meant to imply that any one particular rate is acceptable to the petroleum industry as a whole. Individual companies will employ different evaluation criteria in investment and project selection on the basis of the cost of capital, the perception of technical risk associated with the investment or project, and the availability of other investment opportunities.

To facilitate the study analysis, a financial structure approximating that of a major company was assumed in defining corporate income taxes, state and local taxes, severance taxes, and royalty rates. The effects of applying the Windfall Profit Tax were not included in the economic analyses primarily because the majority of the production estimated in this study is produced after the legislated phaseout date of the current law. A discussion of the impact of the Windfall Profit Tax and its consideration in this study is contained in Chapter Three.

Calculations of incremental ultimate recovery and potential producing rates were made on the basis of procedures designed to screen the reservoirs based on economics, assign economic reservoirs by process, and rank and schedule the individual projects, in accordance with the best judgments of the study participants. It should be emphasized that the results presented in this study are estimates of what could happen under the various stated technical and economic assumptions, and should not in any way be interpreted as forecasts of what will occur.

Results

This study estimates the incremental ultimate recovery and potential producing rates for the major EOR methods. Projections were made for two technology scenarios. A base economic case was defined as one using a nominal $30 per barrel oil price and a 10 percent minimum discounted cash flow rate of return. A number of economic sensitivities to this base economic case, including price sensitivities and rate of return sensitivities, were also examined. More detailed study results, including those of the various sensitivity analyses, are presented in Chapter Four and Appendices D, E, and F.

The distribution of ultimate recovery by major EOR method for the Implemented Technology Case is shown in Figure 1. These results assume the base economic case. Incremental ultimate recovery is projected as 14.5 billion barrels, of which 3.5 billion barrels will be produced through currently implemented EOR projects. Chemical flooding is projected to contribute 17 percent of the total, miscible flooding 38 percent, and thermal recovery 45 percent. It should be noted that these results, and others presented in this report that include thermal recovery estimates, are gross results in that they include the amount of crude oil that would be used as fuel for steam generators. Actual net sales to market would be somewhat less than the projected volumes.[1]

Figure 2 shows the estimated production rate for this ultimate recovery potential, and the contribution of each major EOR method to the rate. Thermal recovery methods are projected to contribute significantly to the total producing rate through the rest of this decade, peaking in the early 1990s. Miscible flooding production will continue to increase through the rest of the century, and peak shortly after the year 2000. Production from chemical flooding methods will contribute to the total rate much later in the study period, and its producing rate is projected to be rising as the study period ends. The combined effects of these three producing rates is the projected peak rate of over 1 million barrels per day, sustained from the early 1990s to beyond 2005.

[1]A variety of fuel sources are used for steam generation, including produced oil and natural gas. The choice of fuel is highly dependent upon the relative economics at the time of project implementation, as well as on availability and environmental considerations. In addition, many projects maintain dual-firing capabilities in order to adjust to shifting economic conditions. Thus, no accurate estimate can be made of the total amount of produced oil burned in steam generators. The presentation of gross production values in this study is consistent with industry and government practice.

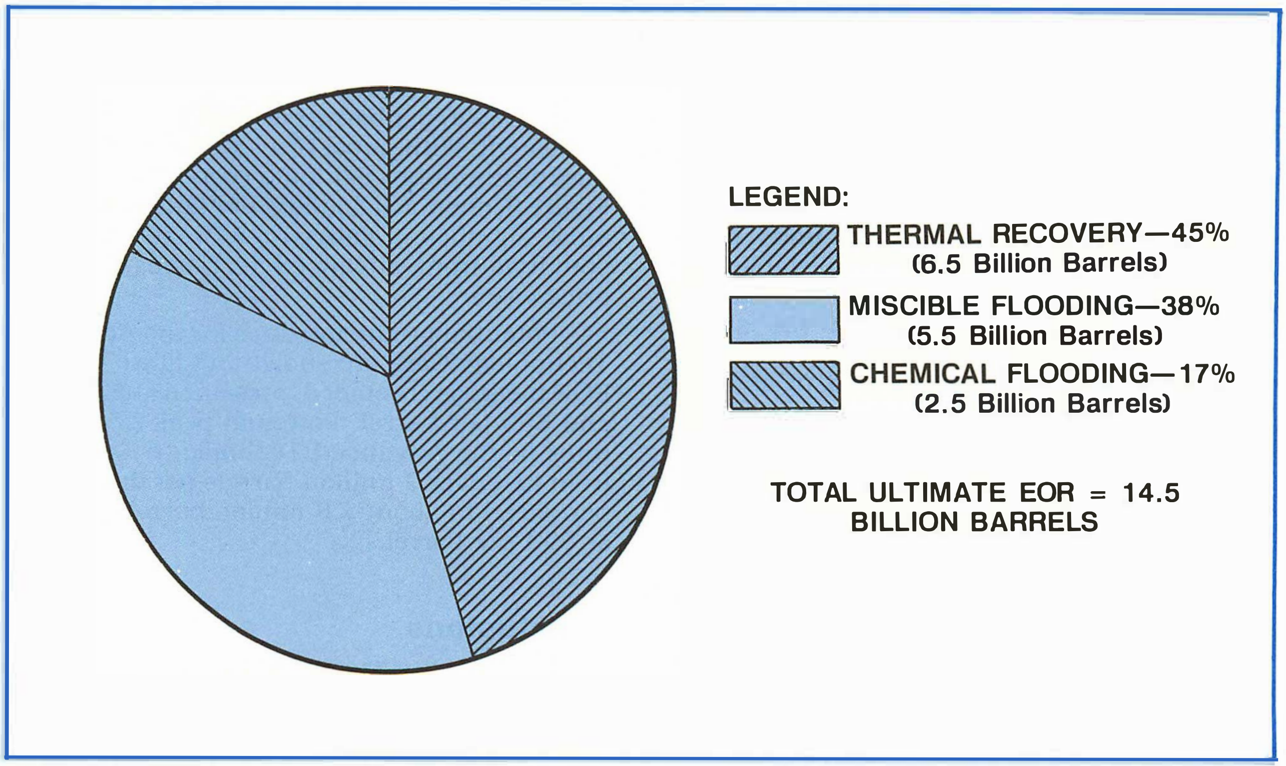


Figure 1. Ultimate Recovery—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

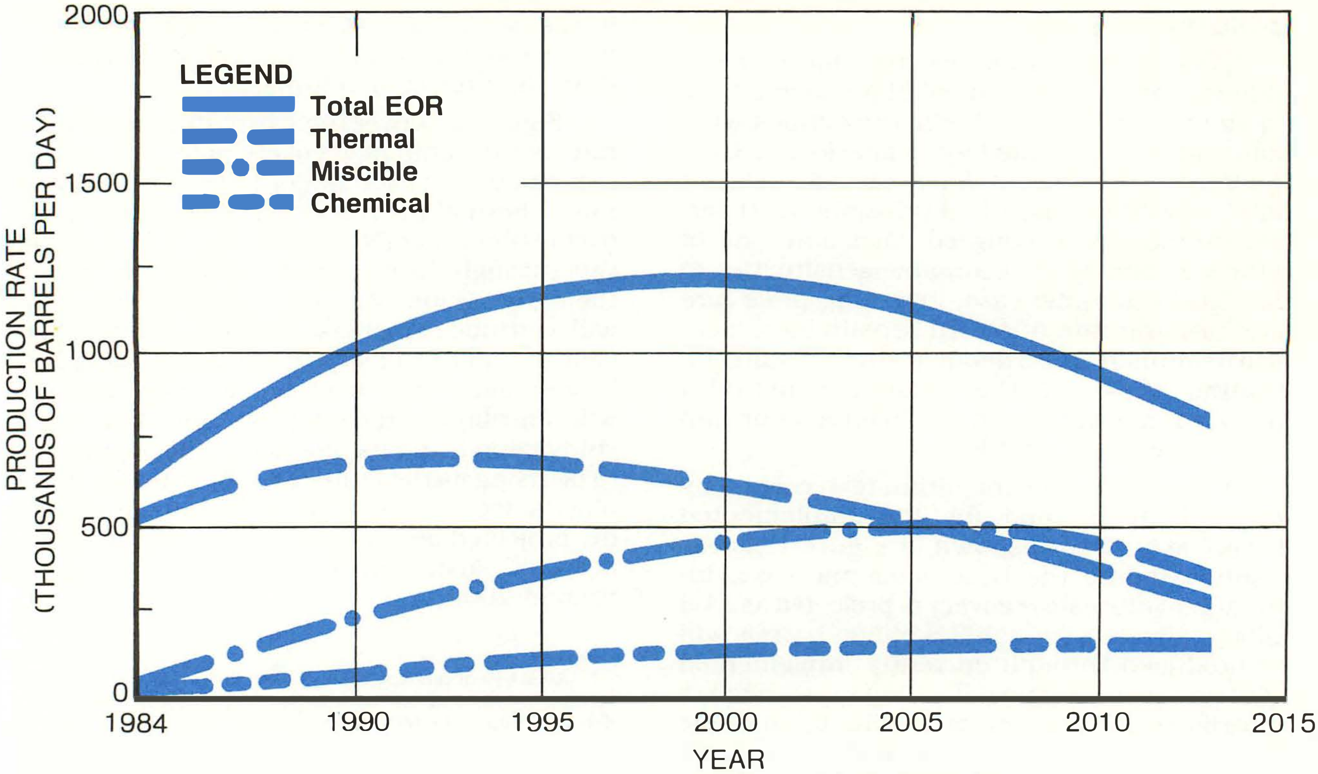


Figure 2. Production Rate—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

Advanced Technology Case results demonstrate a sensitivity to technology advancements. They represent estimates of the impact of specified technological advancements on the Implemented Technology Case results. Detailed descriptions of the Advanced Technology Case assumptions are contained in Chapter Three and Appendices D, E, and F. Although it was recognized that technological advances will occur on a continuous basis throughout the study period, an achievable date for advanced technology of 1995 was assumed for most processes, to facilitate the study analysis. Advanced technology for ongoing steamflood projects was assumed to start in 1988, rather than 1995, due to the mature status of current technology.

It should be noted that *the results of the Advanced Technology Case and the Implemented Technology Case are not additive.* The Advanced Technology Case results include the Implemented Technology Case results as well as the additional recovery resulting from technology advancements, where they apply.

Figure 3 presents a comparison of the Advanced Technology Case recovery potential with the Implemented Technology Case recovery potential. The sensitivity of ultimate recovery to price and technology is demonstrated for all processes. The Advanced Technology Case results vary from 27 billion barrels of ultimate recovery at $30 per barrel to 34 billion barrels of ultimate recovery at $50 per barrel. (No price sensitivity was examined at $20 per barrel for the Advanced Technology Case; the $20 per barrel case was considered inconsistent with most Advanced Technology Case assumptions of higher costs.) As shown in Figure 3, chemical flooding methods realize the most significant gains in ultimate recovery potential from advanced technology, for all price cases.

Potential producing rates for the Advanced Technology Case are shown in Figure 4 for all EOR methods combined, presented at $30, $40, and $50 per barrel. Potential peak producing rates in the Advanced Technology Case vary from just over 2 million barrels per day at $30 per barrel to about 2.8 million barrels per day at $50 per barrel.

Conclusions

EOR activity has increased since 1976. The primary stimulus for this activity was a significant rise in real oil price. A number of decisions to develop EOR resources through the implementation of EOR methods were made in light of higher oil prices and the expectations of future price growth. Although oil prices peaked in 1981 and have since declined, commitments have been made that will greatly affect the EOR potential. Additionally, progress in research and field applications over this time period has resulted in a better understanding of the fundamentals of each process.

For the most part, these factors have been considered in the analysis and are reflected in the study results. Still, the potential for enhanced oil recovery is subject to a broad spectrum of technological, economic, and policy considerations. Although generalizations are difficult, the following conclusions can be drawn from this study:

- *The potential exists for significantly increasing the domestic crude oil supply through the successful application of EOR processes to known reservoirs.* Recoverable oil reserves from currently producing fields in the United States are approximately 28 billion barrels of oil. Of this amount, about 3.5 billion barrels, or 13 percent, will be produced through currently implemented EOR projects. This study estimates that an additional 11 billion barrels could be added to the domestic crude oil supply from currently producing fields with the successful application of existing EOR technology, for a potential ultimate recovery of 14.5 billion barrels from EOR methods. The net addition to the domestic crude oil supply is equivalent to approximately 40 percent of the current recoverable U.S. reserves.

- *Technical uncertainties vary among EOR processes, depending in large part on the amount of experience derived from field applications.* The extent to which technical uncertainties influence EOR estimates is related to the relative maturity of any given process. The greatest level of confidence lies with steam processes, which have been extensively applied in the field and contribute the majority of current EOR production. Process research and field testing are needed to reduce the technical uncertainties that currently delay commercial development of some processes. Continued research by both industry and government will be required to develop the large volume of hydrocarbons discussed in this report.

- *The potential ultimate recovery from EOR methods, and the rate at which*

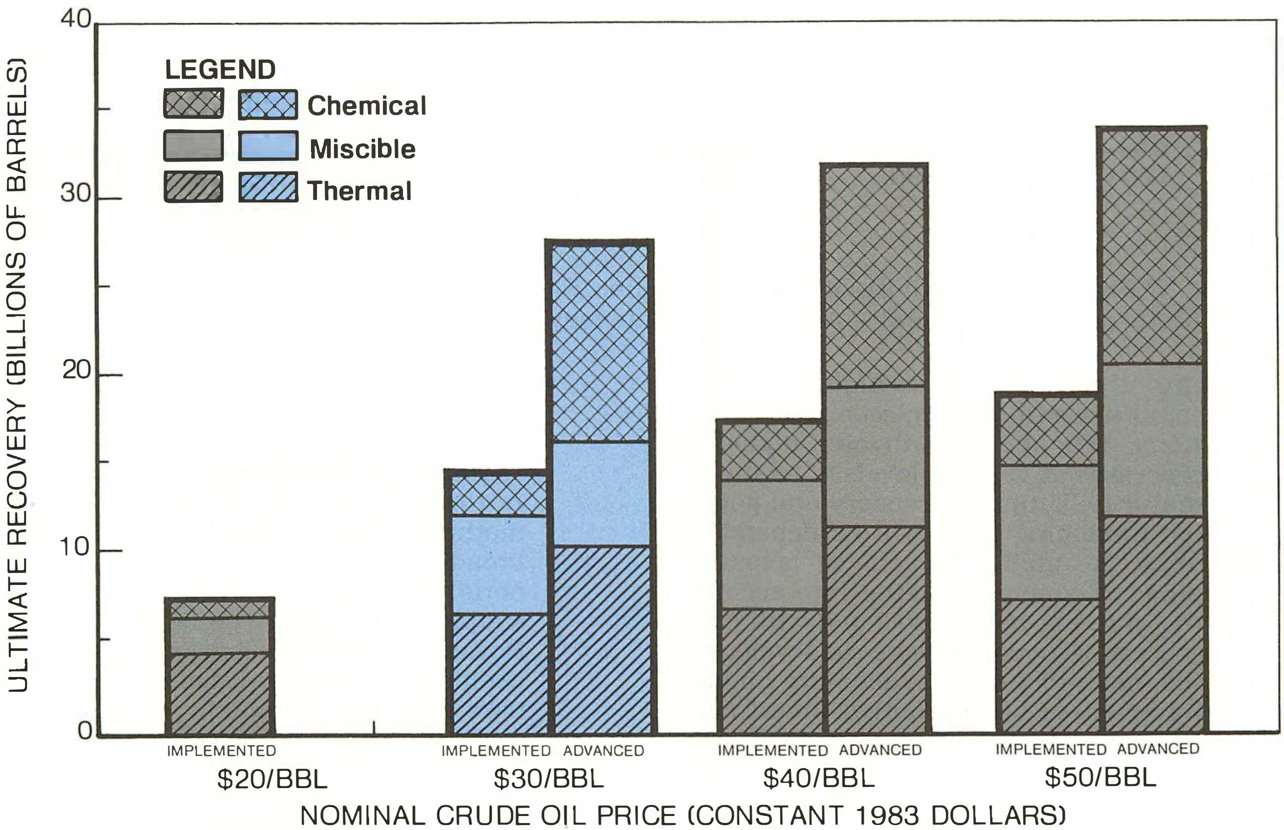


Figure 3. Ultimate Recovery by Process—Advanced and Implemented Technology Cases (10 Percent Minimum ROR).

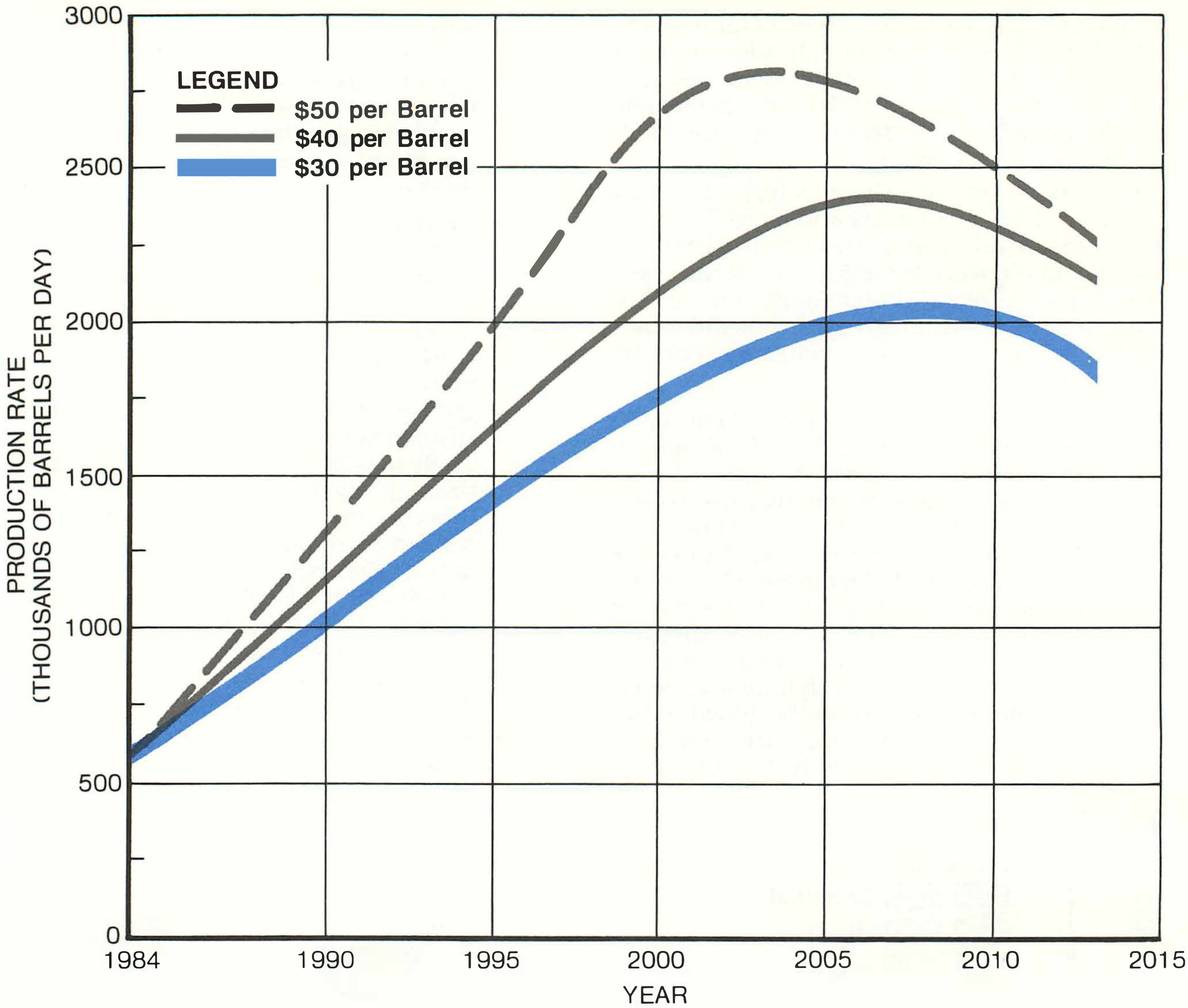


Figure 4. Sensitivity of Total Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)— Advanced Technology Case (10 Percent Minimum ROR).

this oil is produced, are highly sensitive to oil price and other economic conditions. EOR methods involve high-cost processes at varying levels of technical maturity. Ultimate recovery and potential producing rates will be dependent upon the ability to achieve favorable project economics taking into account the inherent risks associated with each process. Of equal influence in developing this potential is the availability and attractiveness of alternative investment opportunities. Investment in EOR projects will compete for available capital with other activities that have the potential to increase domestic oil supplies, such as conventional exploration and development programs.

- *Although the potential recovery from EOR methods is significant, it will contribute only a fraction of the production required to meet the nation's future demand for liquid petroleum.* EOR methods, if technically successful and broadly applied, may constitute an important component of the petroleum supply picture over the next 30 years. However, enhanced oil recovery is not by itself the complete solution to the country's long-term oil supply problem. All other sources must be considered. The extent to which all sources, including EOR, will contribute to long-term domestic petroleum supply will depend in large part on market conditions and advances in technology.

Chapter One

Background of Oil Recovery Operations

Overview of Elements of Oil Recovery

In the United States, 481 billion barrels of crude oil had been discovered as of December 31, 1982. Total ultimate recovery with existing technology and economic conditions is estimated to be 158 billion barrels, of which 130 billion barrels have already been produced. Thus, the remaining proved recoverable reserves are 28 billion barrels. About 323 billion barrels, or two-thirds of the discovered oil, will be left in currently known reservoirs.[1] Most of this oil is not recoverable with foreseeable technology because of unfavorable reservoir geology, adverse fluid properties, or low oil content in the reservoir rock. However, a portion of this oil volume is producible by EOR methods. This report addresses the amount of oil that may be economically recoverable by EOR methods as well as possible rates of EOR production.

In 1982, approximately 0.5 million barrels per day of crude oil were produced by EOR methods.[2] Total domestic producing rates in 1982 (including EOR and lease condensate) averaged about 8.6 million barrels per day of crude oil and 1.6 million barrels per day of natural gas liquids.[3] An approximately equivalent amount of natural gas (on a BTU basis) was also produced. Domestic oil and gas production accounted for about 52 percent of the nation's energy needs, with another 17 percent of the nation's needs being filled by imported oil. The remaining 31 percent was from other energy sources such as coal, nuclear, and hydroelectric power.

Conventional Oil Production

Crude oil accumulates over geologic time in porous underground rock formations called reservoirs, where it has been trapped by overlying and adjacent impermeable rock. Oil reservoirs sometimes exist with an overlying gas "cap," or in communication with aquifers, or both. The oil resides together with water, and sometimes free 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 microscopically and macroscopically. A complete, detailed, quantitative description of a reservoir is never possible. The detailed data that can be obtained from wells represent only an infinitesimal fraction of the reservoir volume. Nevertheless, these data are extremely important to understanding the performance of the reservoir.

Properties of crude oil and formation water in different parts of an individual reservoir

[1]Statistics derived from the American Petroleum Institute, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, Vol. 34, June 1980; and from the DOE/EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Advance Summary of 1982 Annual Report, August 1983.* Data include the North Slope of Alaska. Data do not include Tar Sands, as defined by the Department of Energy.

[2]See Chapter Two.

[3]U.S. Energy Information Administration, *1982 Petroleum Supply Annual.*

generally vary only slightly, although there are notable exceptions. For different reservoirs, crude oils display a wide spectrum of properties. Some crude oils are thinner than water, while others are thicker than cold molasses. Crude oils all contain dissolved gas in varying amounts. Most crude oils are less dense than water. The formation waters in different reservoirs vary widely in salinity and hardness.

Because of the various types of accumulations and the existence of wide ranges of both rock and fluid properties, reservoirs respond differently and must be treated individually.

Primary Oil Recovery

Primary oil recovery depends upon natural reservoir energy to drive the oil through the complex pore network to producing wells. The driving energy may be derived from liquid expansion and evolution of dissolved gas from the oil as reservoir pressure is lowered during production, expansion of free gas or a gas cap, influx of natural water, gravity, or combinations of these effects. The recovery efficiency for primary production is generally low when liquid expansion and solution gas evolution are the driving mechanisms. Much higher recoveries are associated with reservoirs having water and gas cap drives, and with reservoirs where gravity effectively promotes drainage of the oil from the rock pores. Eventually, the natural drive energy is dissipated. When this occurs, energy must be added to the reservoir to produce significant amounts of 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 injected fluids maintain reservoir pressure, or repressure the reservoir after primary depletion, and displace a portion of the remaining crude oil to production wells.

Waterflooding is the principal secondary recovery method and currently accounts for a very large part of all U.S. daily oil production. Limited use is being made of gas injection because of its high market value. When gravity drainage is effective, pressure maintenance by gas injection can be highly efficient.

Certain reservoir types, such as those with very viscous crude oils and some low-permeability carbonate (limestone, dolomite, chert) reservoirs, respond poorly to conventional secondary recovery techniques. In these reservoirs it is desirable to initiate EOR operations as early as possible. This may mean considerably abbreviating conventional secondary recovery operations or bypassing them altogether.

Efficiency of Conventional Recovery Methods

Conventional primary and secondary recovery processes are ultimately expected to produce about one-third of the original oil discovered. Recoveries from individual reservoirs can range from less than 5 percent to as high as 80 percent of the OOIP. This broad range of recovery efficiency is a result of 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

The oil remaining after conventional recovery operations 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. In portions of the reservoir that have been contacted or swept by the injection fluid, the residual oil remains as droplets (or ganglia) trapped in either individual pores or clusters of pores. It may also remain as films partly coating the pore walls. Entrapment of this residual oil is predominantly due to capillary and surface forces, and to pore geometry.

In the pores of those volumes of reservoir rock that were not well swept by displacing fluids, the oil continues to exist at higher concentrations and may exist as a continuous phase. This macroscopic bypassing of the oil occurs because of reservoir heterogeneity, the placement of wells, and the effects of viscous, gravity, and capillary forces, which act simultaneously in the reservoir. The resultant effect depends upon conditions at individual locations. The higher the mobility of the displacing fluid relative to that of the oil (the higher the mobility ratio), the greater the propensity for the displacing fluid to bypass oil. Due to fluid density differences, gravity forces cause vertical segregation of the fluids in the reservoir so that water tends to underrun, and gas to override, the oil-containing rock. These mechanisms can be controlled or utilized to only a limited extent in primary and secondary recovery operations.

The intent of enhanced oil recovery is to increase the effectiveness of oil removal from pores of the rock (displacement efficiency) and to increase the volume of rock contacted by injected fluids (sweep efficiency). EOR processes use thermal, chemical, or fluid phase behavior effects to reduce or eliminate capillary forces that trap oil within pores, to thin the oil or otherwise improve its mobility, or to alter the mobility of the displacing fluids. In some cases, the effects of gravity forces, which ordinarily cause vertical segregation of fluids of differing densities, can be minimized or even used to advantage.

The degree to which EOR methods are applicable in the future will depend on development of improved process technology; on improved understanding of fluid chemistry, phase behavior, and physical properties; and on the accuracy of geology and reservoir engineering in characterizing the physical nature of individual reservoirs.

Overview of Enhanced Oil Recovery Methods

In this report, enhanced oil recovery is defined as the incremental ultimate oil that can be *economically* recovered from a petroleum reservoir over oil that can be *economically* recovered by conventional primary and secondary methods. Since the early 1950s, a significant amount of laboratory research and field testing has been devoted to developing EOR methods. Numerous methods have been investigated, including:

- Polymer-augmented waterflooding
- Surfactant flooding
- Alkaline flooding
- Miscible fluid displacement
- Immiscible CO_2 displacement
- CO_2-augmented waterflooding
- Cyclic steam injection
- Steam drive
- In situ combustion.

Other processes, such as injection of immiscible gases, injection of oil-releasing microorganisms, and electrical heating of the reservoir have been proposed. However, this report treats only those methods that are thought to have the greatest potential for adding to domestic oil supply within the 30-year time frame of the study (through the year 2013).

Chemical, miscible, and thermal methods are the three categories of EOR processes generally recognized as most promising. The various EOR processes differ considerably in complexity, the physical mechanisms responsible for oil recovery, and the amount of experience that has been derived from field application.

- **Chemical Methods**—Chemical methods include polymer flooding, surfactant (micellar/polymer, microemulsion) flooding, and alkaline flooding processes. Polymer flooding is conceptually simple and inexpensive, and its commercial use is increasing despite relatively small potential incremental oil production. Surfactant flooding is complex and requires detailed laboratory testing to support field project design. As demonstrated by recent field tests, it has excellent potential for improving the recovery of low-to-moderate-viscosity oils. Surfactant flooding is expensive and has been used in few large-scale projects. Alkaline flooding has been used only in those reservoirs containing specific types of high acid number crude oils.
- **Miscible Methods**—Miscible floods using carbon dioxide, nitrogen, or hydrocarbons as miscible solvents have their greatest potential for enhanced recovery of low-viscosity oils. Commercial hydrocarbon miscible floods have been operated since the 1950s. CO_2 miscible flooding on a large scale is relatively recent and is expected to make the most significant contribution to miscible enhanced recovery in the future. At least 11 large-scale commercial CO_2 miscible projects were underway in December 1983, and several additional commercial projects will be started in West Texas in the near future, as CO_2 sources in Colorado and New Mexico are tapped and brought on stream. Compared to miscible processes, immiscible flooding with CO_2 is expected to have limited EOR potential.
- **Thermal Methods**—Thermal recovery methods include cyclic steam injection, steamflooding, and in situ combustion. The steam processes are the most advanced of all EOR methods in terms of field experience, and thus have the least uncertainty in estimating performance, provided that a good reservoir description is available. Steam processes are most often applied in reservoirs containing viscous oils and tars, usually in place of, rather than following, secondary or primary methods. Commercial application of steam processes has been underway since the early 1960s. In situ combustion has been field tested under a wide variety of reservoir conditions, but few projects have proved economic and advanced to commercial scale. It will continue to find some application in

moderate-scale projects under conditions where it is not feasible to use other processes.

Chemical Methods

Chemical methods of enhanced oil recovery are broadly characterized by the addition of chemicals to water in order to generate fluid properties or interfacial conditions that are more favorable for oil production. In this report, three types of chemical processes are considered: polymer flooding, surfactant (micellar/polymer, microemulsion) flooding, and alkaline flooding.

Polymer Flooding

Conventional waterflooding can often be improved by the addition of polymers to injection water (Figure 5) to improve (decrease) the mobility ratio between the injected and in-place fluids. The polymer solution affects the relative flow rates of oil and water, and sweeps a larger fraction of the reservoir than water alone, thus contacting more of the oil and moving it to production wells. Polymers currently in use are produced both synthetically (polyacrylamides) and biologically (polysaccharides).

In another type of application, polymers are cross-linked in situ to form highly viscous fluids that will divert the subsequently injected water into different reservoir strata. In this use the polymer treatment generally affects only the region of the reservoir close to the wellbore. Some polymer projects have utilized various combinations of this near-wellbore cross-linking technique and polymer flooding for improved sweep efficiency.

Polymer flooding has its greatest utility in heterogeneous reservoirs and those that contain moderately viscous oils. Oil reservoirs with adverse waterflood mobility ratios have potential for increased oil recovery through better areal sweep efficiency. Heterogeneous reservoirs may respond favorably as a result of improved vertical sweep efficiency. Because the microscopic displacement efficiency is not affected, the increase in recovery over waterflood will likely be modest and limited to the extent that sweep efficiency is improved, but the incremental cost is also moderate. Currently, polymer flooding is being used in a significant number of commercial field projects. The process may be used to recover oils of higher viscosity than those for which a surfactant flood might be considered.

Surfactant Flooding

Surfactant flooding (Figure 6) is a multiple-slug process involving the addition of surface active chemicals to water. These chemicals reduce the capillary forces that trap the oil in the pores of the rock. The surfactant slug displaces the majority of the oil from the reservoir volume contacted, forming a flowing oil/water bank that is propagated ahead of the surfactant slug. The principal factors that influence the surfactant slug design are interfacial properties, slug mobility in relation to the mobility of the oil/water bank, the persistence of acceptable slug properties and slug integrity in the reservoir, and cost.

The surfactant slug is followed by a slug of water containing polymer in solution. The polymer solution is injected to preserve the integrity of the more costly surfactant slug and to improve the sweep efficiency. Both of these goals are achieved by adjusting the polymer solution viscosity, in relation to the viscosity of the surfactant slug, in order to obtain a favorable mobility ratio. The polymer solution is then followed by injection of drive water, which continues until the project is completed.

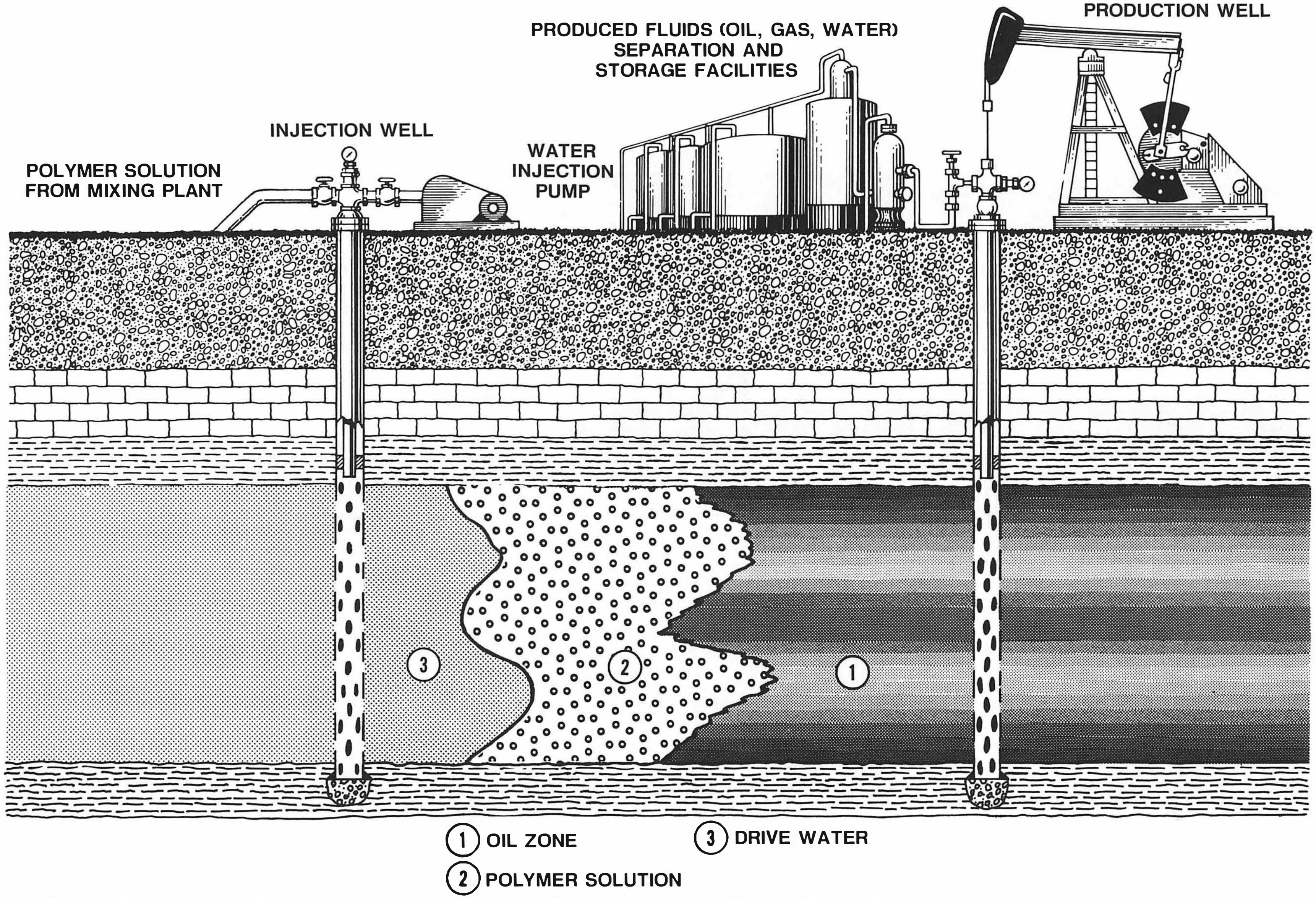
Because each reservoir has unique fluid and rock properties, specific chemical systems must be designed for each individual application. The chemicals used, their concentrations in the slugs, and the slug sizes will depend upon the specific properties of the fluids and the rocks involved, and upon economic considerations.

Surfactant flooding is receiving widespread attention, both in the laboratory and in field tests. With the current status of technology, pilot tests are necessary to evaluate the effectiveness of a process design for a specific reservoir. In several cases, successful small-scale pilots have been followed by larger commercial-demonstration projects.

Alkaline Flooding

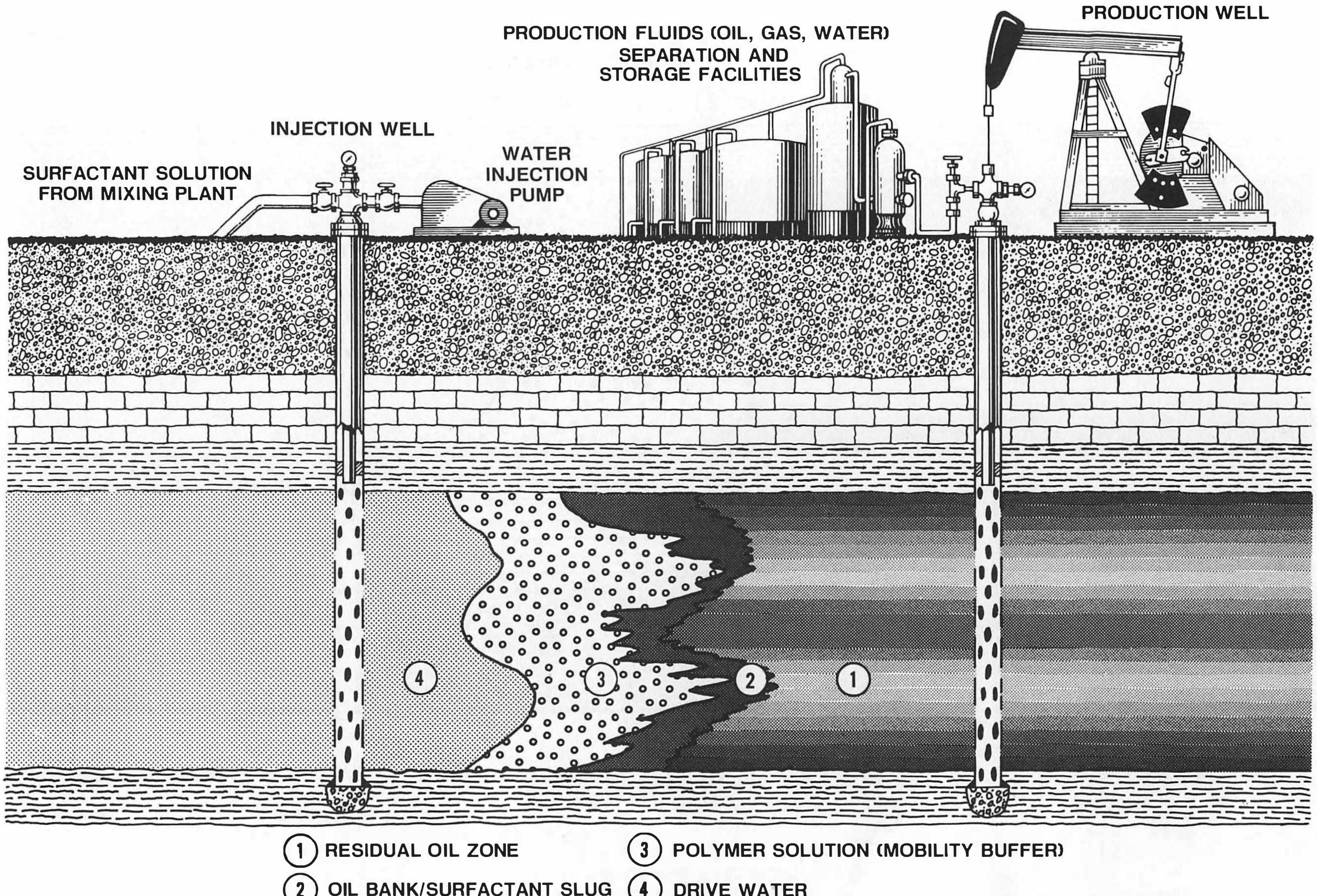
Alkaline flooding (Figure 7) adds inorganic alkaline chemicals such as sodium hydroxide, sodium carbonate, or sodium orthosilicates to flood water to enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction, spontaneous emulsification, or wettability alteration. These mechanisms rely on the in situ formation of surfactants during the neutralization of petroleum acids in the crude oil by the alkaline chemicals in the displacing fluids. Since the content of natural petroleum acids is normally higher in lower API gravity crude oils, this process seems to be applicable primarily to the recovery of moderately viscous, low-API-gravity, naphthenic crude oils.

Although emulsification in alkaline flooding processes decreases injection fluid mobility to a certain degree, emulsification alone may not provide adequate sweep efficiency. Sometimes polymer is included as an



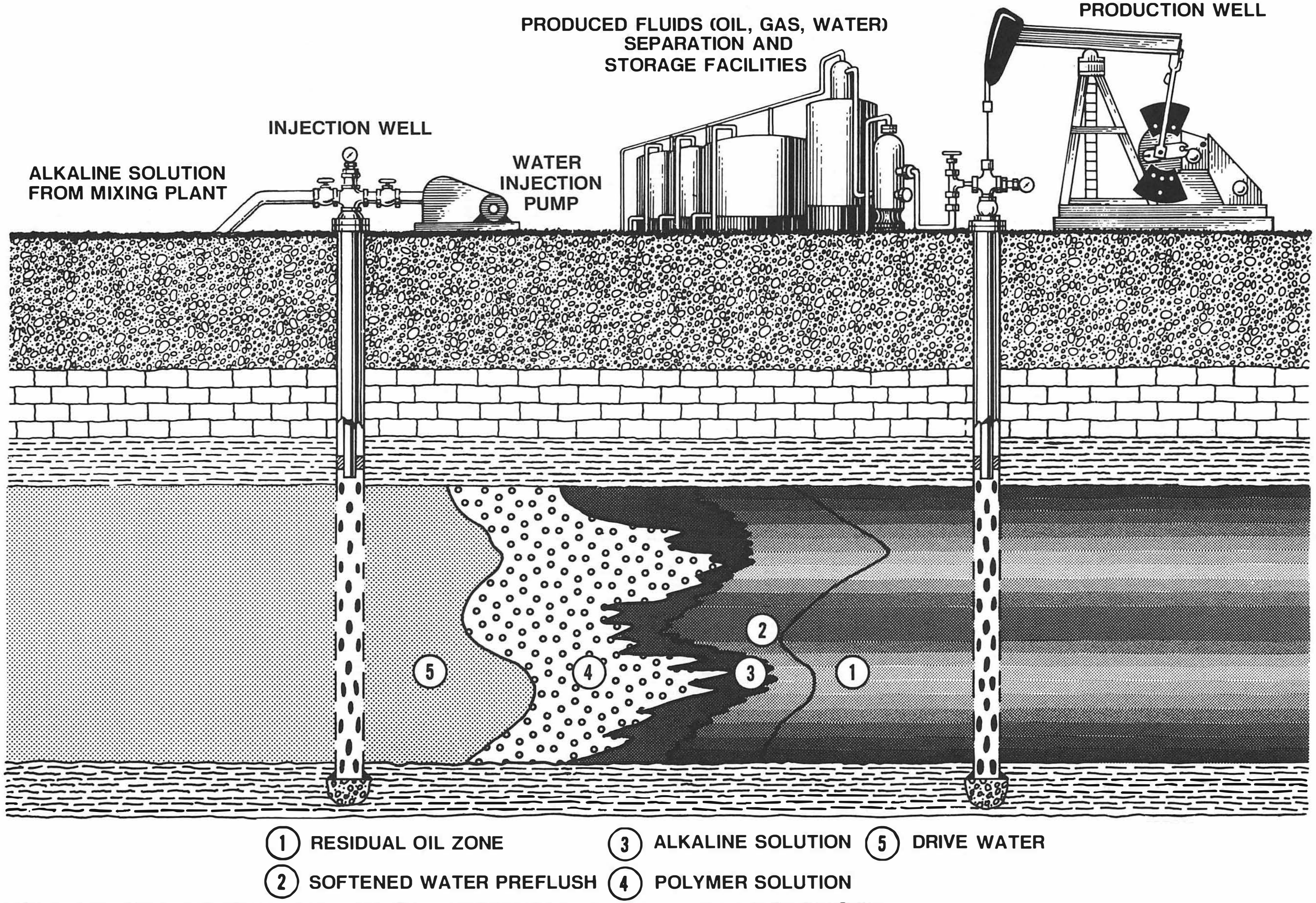
SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure 5. Polymer Flooding.



SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure 6. Surfactant Flooding.



SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure 7. Alkaline Flooding.

ancillary mobility control chemical in an alkaline waterflood to augment any mobility ratio improvements due to alkaline-generated emulsions.

Alkaline flooding has been considered to be low cost and to have low recovery potential relative to more sophisticated processes such as surfactant flooding. More than 20 field tests have been conducted, but few have been economically successful. Most were implemented as pilot projects to obtain engineering data, and in about half of these tests the results were sufficiently encouraging to warrant additional testing.

Miscible Methods

Among miscible methods of enhanced oil recovery, CO_2 miscible flooding has the greatest potential because of moderate cost and miscibility characteristics that are often favorable compared to other gases. There are notable exceptions where hydrocarbons or nitrogen are more favorable miscible solvents. CO_2 can sometimes be used as an immiscible drive agent.

CO_2 Miscible Flooding

CO_2 is capable of miscibly displacing many crude oils, thus permitting recovery of most of the oil from the reservoir rock that is contacted (Figure 8). The CO_2 is not miscible with the oil initially. However, as CO_2 contacts the in situ crude oil, it extracts some of the hydrocarbon constituents of the crude oil into the CO_2, and CO_2 is dissolved into the oil. Miscibility is achieved at the displacement front when no interfaces exist between the hydrocarbon-enriched CO_2 mixture and the CO_2-enriched in situ oil. Thus, by a dynamic (multiple-contact) process involving interphase mass transfer, miscible displacement overcomes the capillary forces that otherwise trap oil in pores of the rock.

The reservoir operating pressure must be kept at a level high enough to develop and maintain a mixture of CO_2 and extracted hydrocarbons that, at reservoir temperature, will be miscible with the crude oil. Impurities in the CO_2 stream, such as nitrogen or methane, increase the pressure required for miscibility. Dispersive mixing due to reservoir heterogeneity and diffusion tends to locally alter and destroy the miscible composition, which must then be regenerated by additional extraction of hydrocarbons. In field applications, there may actually be both miscible and near-miscible displacements proceeding simultaneously in different parts of the reservoir.

The volume of CO_2 injected is specifically chosen for each application, and usually ranges from 20 to 40 percent of the reservoir pore volume. In the later stages of the injection program, CO_2 may be driven through the reservoir by water or a lower cost inert gas. To achieve higher sweep efficiency, water and CO_2 are often injected in alternate cycles.

In some applications, particularly in carbonate (limestone, dolomite, chert) reservoirs where it is likely to be used most frequently, CO_2 may prematurely break through to producing wells. When this occurs, remedial action using mechanical controls in injection and production wells may be taken to reduce CO_2 production. However, substantial CO_2 production is considered normal. Generally this produced CO_2 is reinjected, often after processing to recover valuable light hydrocarbons.

Other Miscible Processes

Hydrocarbon gases and condensates have been used for over 100 commercial and pilot miscible floods. Depending upon the compositions of the injected stream and the reservoir crude oil, the mechanism for achieving miscibility with reservoir oil can be similar to that obtained with CO_2 (dynamic or multiple-contact miscibility), or the miscible solvent and in situ oil may be miscible initially (first-contact miscibility). Except in special circumstances, these light hydrocarbons are generally too valuable to be used commercially.

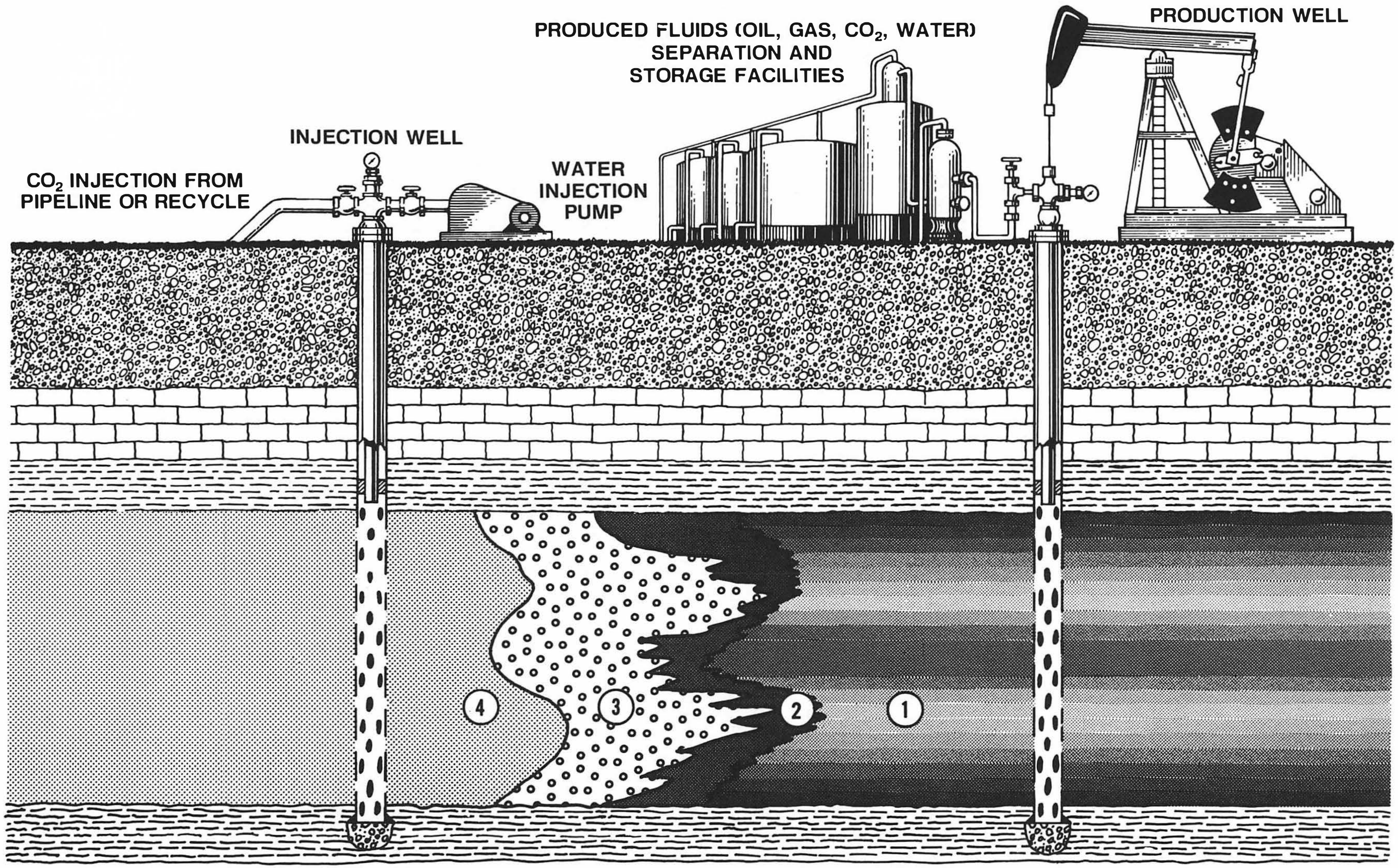
Nitrogen and flue gases have also been used for commercial miscible floods. Minimum miscibility pressures for these gases are usually higher than for CO_2, but in high-pressure, high-temperature reservoirs where miscibility can be achieved, these gases may be a cost-effective alternative to CO_2.

CO_2 Immiscible Flooding

For some reservoirs, miscibility between CO_2 and oil cannot be achieved but CO_2 can still be used to recover additional oil. CO_2 swells crude oils, thus increasing the volume of pore space occupied by the oil and reducing the quantity of oil trapped in the pores. It also reduces oil viscosity. Both effects improve the mobility of the oil. CO_2 immiscible flooding has been demonstrated in both pilot and commercial projects, but overall it is expected to make a relatively small contribution to enhanced oil recovery.

Thermal Methods

Thermal EOR processes add heat to the reservoir to reduce oil viscosity and/or to vaporize the oil. In both instances, the oil is



(1) RESIDUAL OIL ZONE (3) CO_2 AND WATER ZONE

(2) OIL BANK/MISCIBLE FRONT (4) DRIVE WATER

SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure 8. CO_2 Miscible Flooding.

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 recovery methods: steam injection and in situ combustion.

Steam Injection

Steam injection has been commercially applied in California since the early 1960s. It generally occurs in two steps:

- Steam stimulation of producing wells (Figure 9)
- Steam drive by injecting steam into some wells to increase production from nearby producing wells (Figure 10).

In actual practice, a mixture of steam and hot water is injected into the formation. Normally, high-quality steam is generated at the surface, but the fraction of steam injected into the reservoir may vary from mostly steam (high quality) to mostly water (low quality) because of heat losses from surface lines and the injection wellbore.

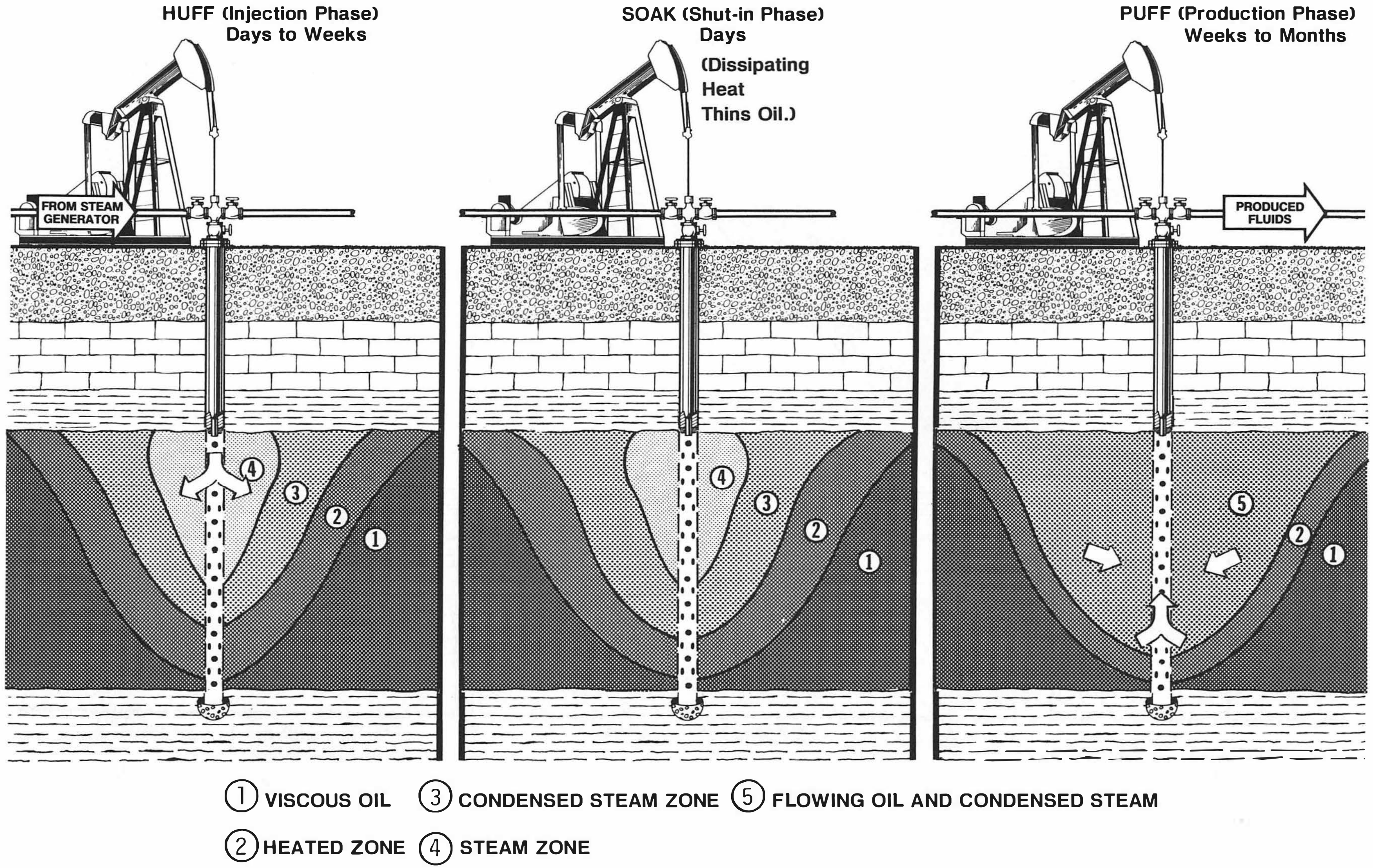
In cases where there is some natural reservoir energy, steam stimulation normally precedes steam drive. In steam stimulation, heat is applied to the reservoir by the injection of high-quality steam into the producing well. This cyclic process, also called "huff and puff" or "steam soak," uses the same well for both injection and production. The period of steam injection is followed by production of reduced-viscosity oil and condensed steam (water). One mechanism aiding 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 back on production.

Depending upon the reservoir drive mechanism, economic production rates may be sustained for a number of stimulation cycles. When natural reservoir drive energy is depleted and productivity declines, most cyclic steam injection projects are converted to steam drives. At this time, selected wells are converted to continuous steam injection to displace mobilized oil to offsetting production wells. In some projects, producing wells are periodically steam stimulated to maintain high production rates. Normally, steam drive projects are developed on relatively close well spacing to achieve thermal communication between adjacent injection and production wells. To date, steam methods have been applied almost exclusively in relatively thick reservoirs containing viscous crude oils.

In Situ Combustion

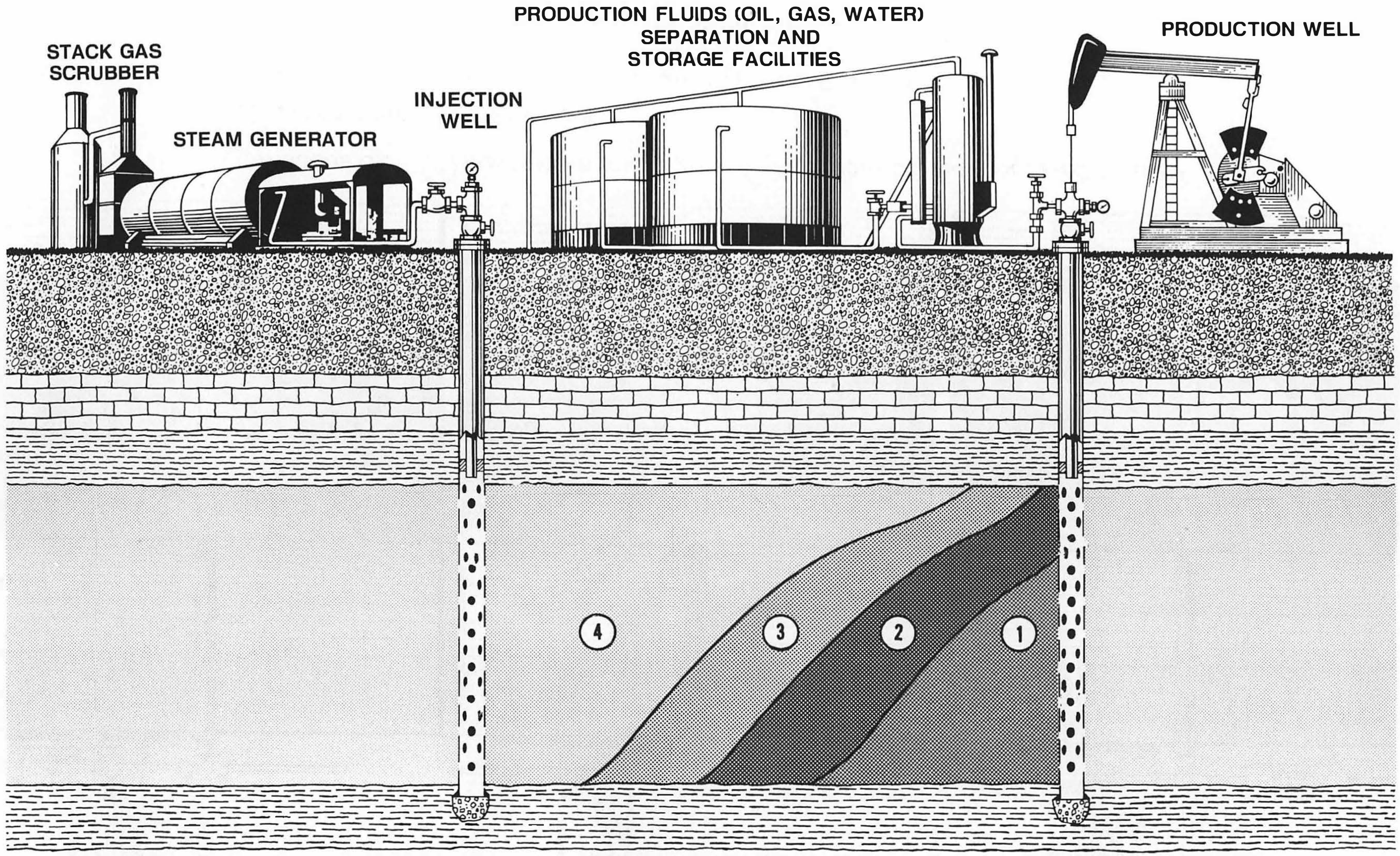
In situ combustion is normally applied to reservoirs containing low-gravity oil, but has been tested over perhaps the widest spectrum of conditions of any EOR process. Heat is generated within the reservoir by injecting air and burning part of the crude oil. This reduces the oil viscosity and partially vaporizes the oil in place. The oil is driven forward by a combination of steam, hot water, and gas drive. The relatively small portion of the oil that remains after these displacement mechanisms have acted becomes the fuel for the in situ combustion process. Production is obtained from wells offsetting the 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 11). The injected water tends to improve the utilization of heat by transferring heat from the rock behind the combustion zone to the rock immediately ahead of the combustion zone.

The performance of in situ combustion is predominantly determined by four factors: the quantity of oil that initially resides in the rock to be burned; the quantity of air required to burn the portion of the oil that fuels the process; the distance to which vigorous combustion can be sustained against heat losses; and the mobility of the air or combustion product gases. In many otherwise viable field projects, the high gas mobility has limited recovery through its adverse effect on the areal or vertical sweep efficiency of the burning front. Due to the density contrast between air and reservoir liquids, the burning front tends to override the reservoir liquids. To date, combustion has been most effective for the recovery of viscous oils in moderately thick reservoirs where reservoir dip and continuity promote effective gravity drainage, or where operational factors permit close well spacing.



SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

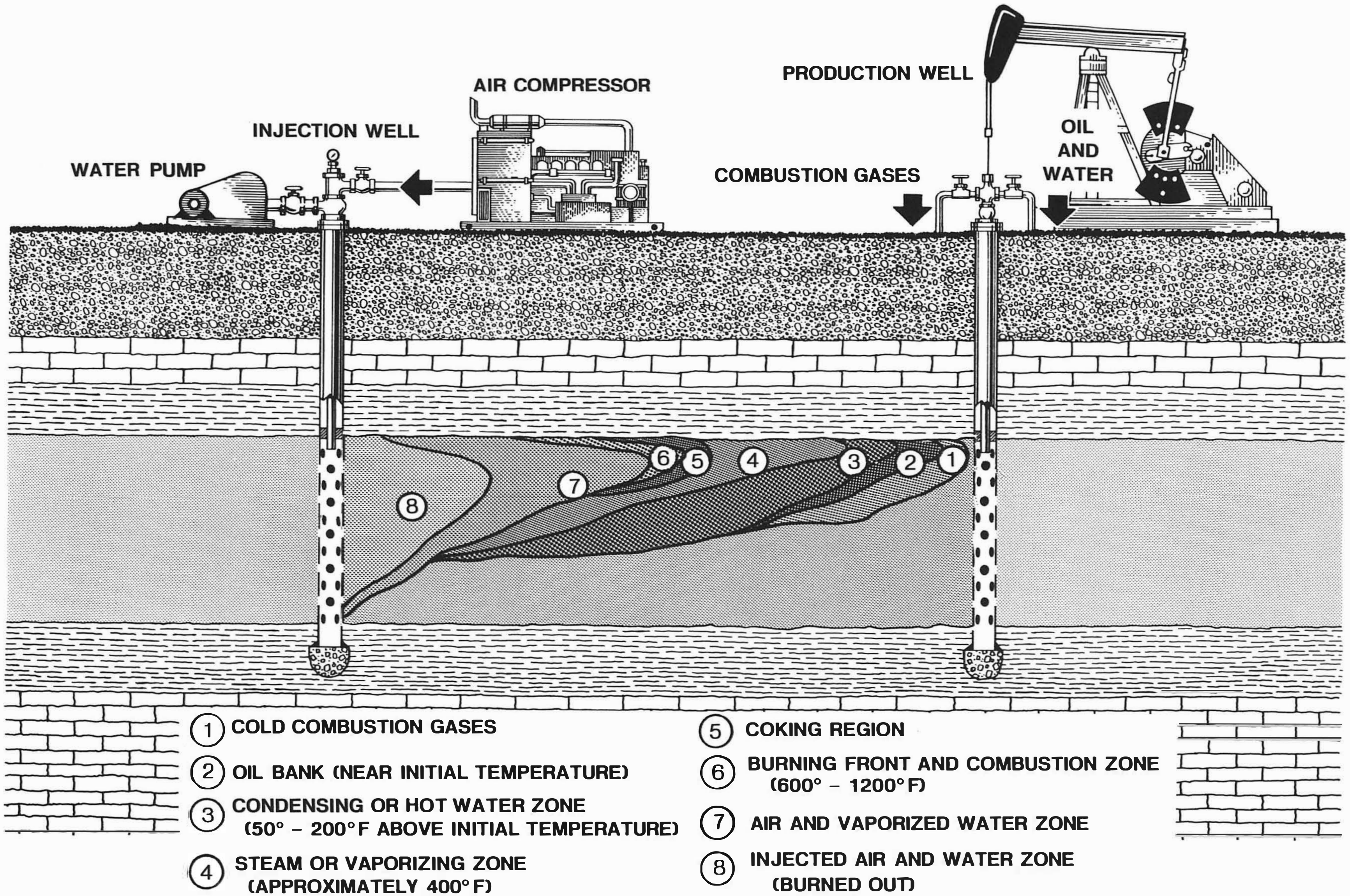
Figure 9. Cyclic Steam Stimulation.



(1) OIL AND WATER ZONE NEAR ORIGINAL RESERVOIR TEMPERATURE
(2) HEATED OIL ZONE
(3) HOT WATER ZONE
(4) STEAM AND CONDENSED WATER ZONE

SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure 10. Steam Flooding.



SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure 11. Wet In Situ Combustion.

Chapter Two

Developments Affecting Enhanced Oil Recovery Since 1976

The 1976 enhanced oil recovery study conducted by the National Petroleum Council in the aftermath of the 1973 Arab oil embargo concluded that the role of enhanced oil recovery could only be determined in the context of an overall energy policy for the United States. Since that time there have been major changes in global politics, economics, U.S. regulatory and tax policies, and EOR technologies, which require a reassessment of EOR potential. Although it may be too soon to draw final conclusions from events since 1976, the following perspectives have emerged or have been reinforced:

- For any level of EOR technology, oil prices and regulatory and tax policies determine whether and when projects are implemented.
- EOR projects must compete for capital and manpower against exploration for, and conventional development of, oil and gas, and development of other energy sources.
- More thorough and lengthy research and engineering are required for enhanced recovery than have been necessary for most conventional primary and secondary recovery projects.
- The technical potential of enhanced recovery continues to be improved through better understanding of the fundamentals of each process, through the development of new approaches and materials, and through better characterization of reservoirs, rocks, and fluids.

The basis of these changes, in perspective, are outlined here. The succeeding chapters and appendices contain more detailed discussions of economics (Chapters Three and Five and Appendix C), policy (Chapter Six and Appendix G), and technology (this chapter and Appendices D, E, F, and H) as they bear on the current perspective.

The Business Climate: Politics, Economics, and Policy

Politics and Economics

Despite significant petroleum price changes in the last 11 years, there are still no ready alternatives to petroleum as an energy source. A four-fold increase in real prices has reduced crude oil demand and illustrated its elasticity. Higher real prices and recent government decontrol of oil prices have contributed to stabilizing domestic oil production rates. To date, exploration and development of new resources have been favored over enhanced recovery. Enhanced recovery has been stimulated to some degree, and currently accounts for about 6 percent of daily U.S. oil production as compared with 4.5 percent in 1976. The rate at which EOR projects are undertaken in the future will depend in a complex manner on oil prices, taxes and government policy, and the availability of more attractive investment alternatives. The future role of enhanced recovery will also depend on improved technology, which is discussed later in this chapter.

The Perspective in 1976

Crude oil production (including production of lease condensate) in the United States peaked at 9.64 million barrels per day in 1970. From 1970 to 1973, U.S. crude oil demand[1] continued to grow at a compound annual rate of 4.5 percent while crude oil production declined at a rate of 1.5 percent (Figure 12). During this same period, net crude oil imports increased 250 percent, emphatically demonstrating the growing U.S. dependence on foreign sources. During this time, average U.S. wellhead prices were stable at $8.50 to $9.00 per barrel (real 1983 dollars) while world market prices were drifting slowly up to the U.S. level (Figure 13). Between 1971 and 1974, the number of active EOR projects declined (Table 1).

Conditions changed abruptly following the October 1973 Arab oil embargo. Oil prices increased threefold to the equivalent of $20 per barrel in 1983 dollars.

Growth in demand for crude oil barely paused, however. The United States was in a period of business expansion; the Emergency Petroleum Allocation Act of 1973[2] effectively capped average domestic wellhead prices at $12.50 to $13.50 per barrel (1983 dollars), well below world price; and there were no ready alternatives to crude oil. Between 1974 and 1977, U.S. demand for crude oil increased at an annual rate of 6.5 percent and crude oil imports nearly doubled again as domestic production declined at an average of 2.1 percent per year.

The mid-1970s was a period of gestation for national energy policy and of planning for change in energy supply and consumption patterns. In 1976, EOR production was dominated by thermal methods. The number of active EOR projects was beginning to increase, stimulated by the higher real prices, and in part augmented by cost-sharing contracts with the Energy Research and Development Administration. Significant attention was also given to the

[1]Refinery crude oil runs including crude oil used directly and losses, crude oil exports, and filling of the Strategic Petroleum Reserve (since 1977).

[2]Emergency Petroleum Allocation Act of 1973, Public Law 93-159 (87 Stat. 627), November 27, 1973.

TABLE 1

ACTIVE U.S. EOR PROJECTS*

	1971	1974	1976	1978	1980	1982	Change 1976-1982
Chemical Methods							
Polymer	14	9	14	21	22	48	34
Surfactant	5	7	13	22	14	24	11
Alkaline	0	2	1	3	6	13	12
Subtotal	19	18	28	46	42	85	57
Miscible Methods							
CO_2 Miscible	1	6	10	13	16	27	17
Other Miscible	21	13	14	17	12	18	4
Subtotal	20	19	24	30	28	45	21
Immiscible CO_2	0	0	1	4	4	5	4
Thermal Methods							
Steam	53	64	85	99	133	118	33
In Situ Combustion	38	19	21	16	17	21	0
Subtotal	91	83	106	115	150	139	33
Grand Total	**132**	**120**	**159**	**195**	**224**	**274**	**115**

*Modified from *Oil & Gas Journal*, April 5, 1982. Table includes both pilot and commercial projects.

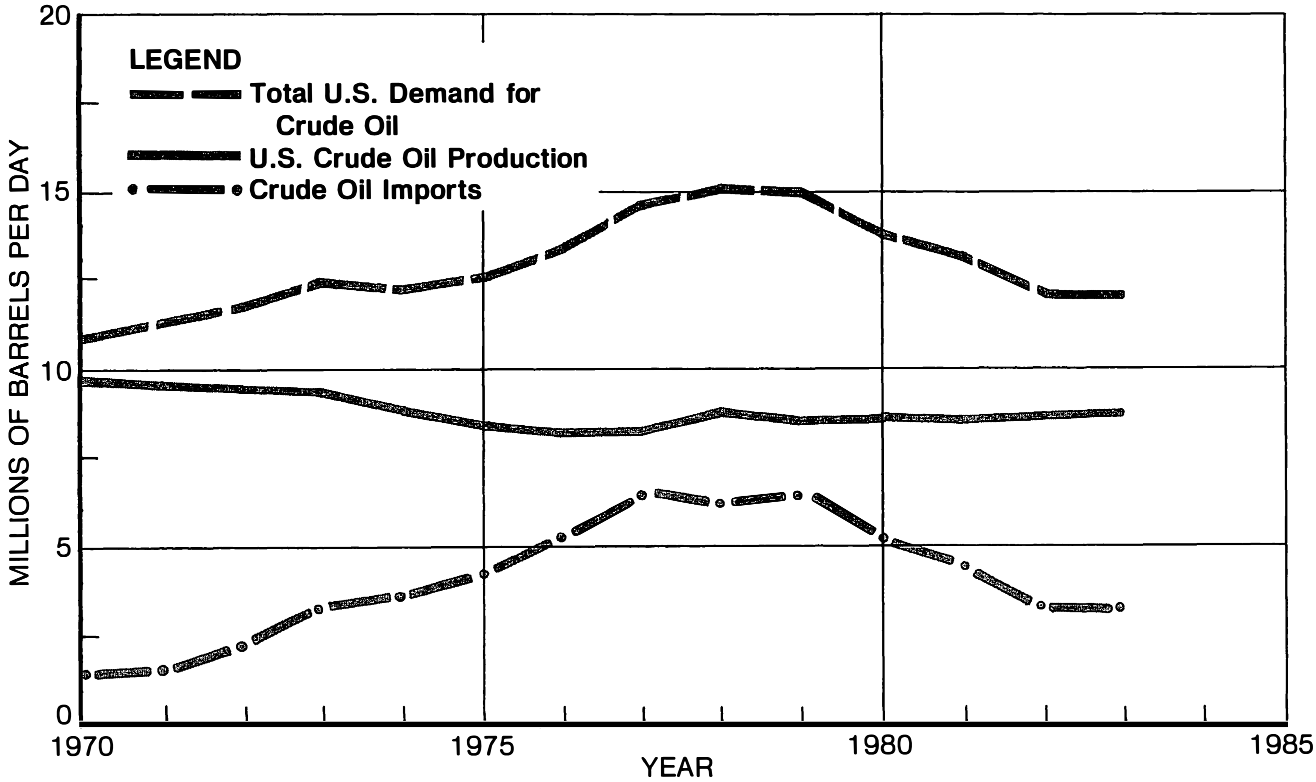


Figure 12. U.S. Production, Imports, and Demand for Crude Oil.

SOURCE: *Basic Petroleum Data Book, Petroleum Industry Statistics,* Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (November 1983).

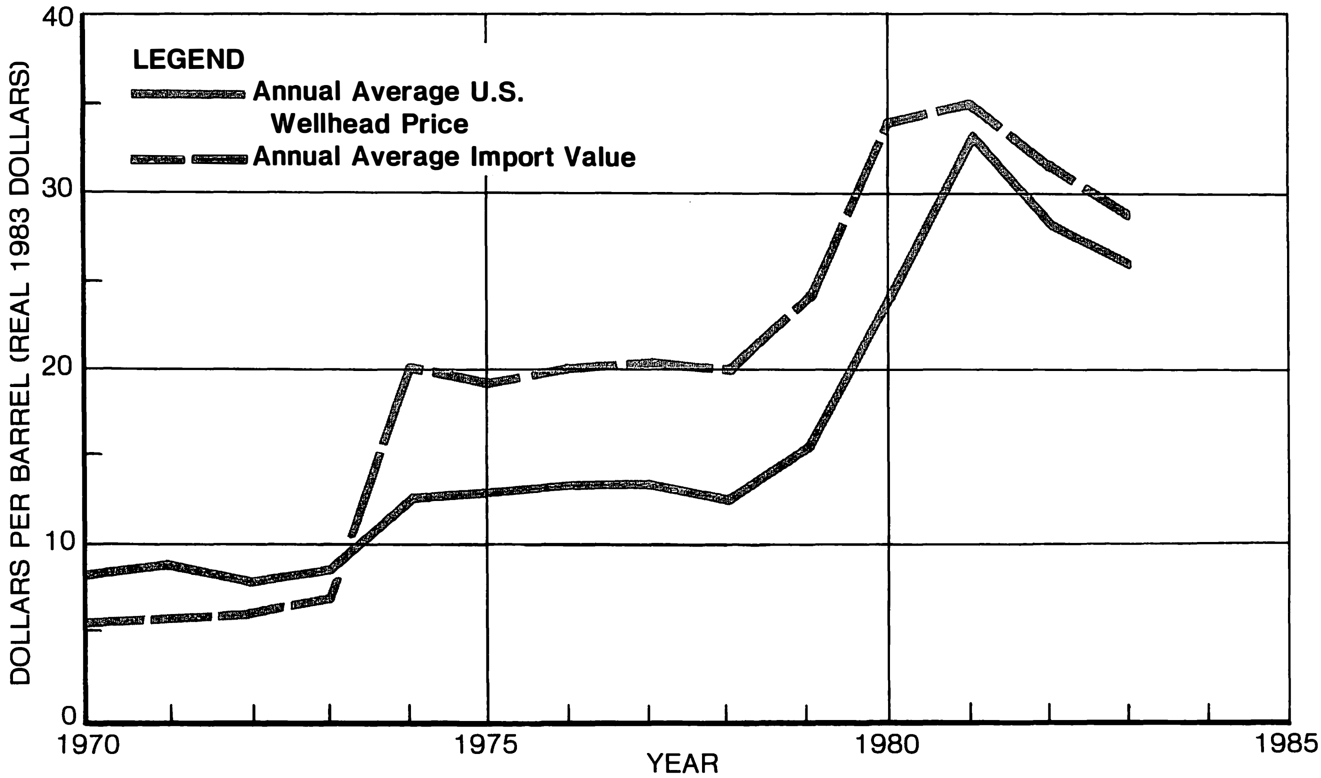


Figure 13. U.S. Average Wellhead Price and Import Value for Crude Oil.

SOURCE: *Basic Petroleum Data Book, Petroleum Industry Statistics,* Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (November 1983).

potential for other energy technologies to reduce petroleum dependence. Coal, oil shale, solar power, and nuclear power all received increased research and development support. Conservation and investments in changing to nonpetroleum fuels were encouraged by the higher real oil prices.

Since 1976

The decline of U.S. oil production in the early 1970s was arrested in 1977 with the start of deliveries from Prudhoe Bay Field on the Alaska North Slope through the Trans-Alaska Pipeline System (TAPS).[3] Production from other new fields, improved conventional recovery, and to a lesser extent enhanced recovery, also contributed to the reversal of U.S. production decline that occurred between 1976 and 1978. Despite growth of the Gross National Product at a 5 percent level between 1976 and early 1979, crude oil demand levelled through conservation efforts and slowly changing energy consumption patterns.

During the period of relatively stable oil prices between 1974 and 1978, a national energy policy began to emerge.[4] The Strategic Petroleum Reserve was created to provide a buffer against major import supply disruptions. The U.S. Department of Energy (DOE) was created to define and coordinate the emerging national energy policy and to continue established responsibilities of predecessor agencies for national security, energy technology capability, development technology transfer, and fundamental research.[5] Also during this period, the petroleum industry encouraged and participated in the national debate to decontrol oil prices, in order that further exploration for new oil and fuller development of known resources would become possible. New EOR projects were undertaken, especially at the pilot scale.

The major world supply disruption that followed from the Iranian revolution in 1979 brought about further changes in current perspectives and national energy policy. In the years following this event, average world market prices rose significantly, peaking above $35 per barrel in 1981. But U.S. crude oil demand had become more elastic than in 1973. Since 1979, domestic demand for crude oil has declined at an average rate of 5.2 percent per year, due to further conservation and substitution of other energy sources for liquid fuels. This includes the effects of the recent recession, and of oil price decontrol in 1981.[6] In response to higher oil prices, U.S. oil production has remained level at about 8.6 million barrels per day, and reduced demand has reduced imports.

In 1982, enhanced recovery contributed about 505 thousand barrels of oil per day, or about 6 percent of domestic production, up from 367 thousand barrels per day, or 4.5 percent, in 1976 (Table 2). Most of this change has been due to increasing thermal recovery, and now about seven-eighths of enhanced recovery is by thermal methods. The number of active EOR projects rose from 159 in 1976 to 274 in 1982. The greatest relative increases in activity were in chemical and miscible flooding (Table 1), but increases in producing rates by these methods have not yet occurred. Significant increases in production by CO_2 miscible flooding are expected as the result of projects that have been implemented since 1980.

Over the last several years, the outlook for near-term contributions from alternate energy sources has become much less optimistic than in 1976. Both the nuclear power and synthetic fuels industries have been beset with problems. Capital costs for these facilities have increased greatly due to more stringent design and licensing requirements. Currently, such facilities are costly to build and operate, and several proposed projects have been postponed or terminated.

Recent economic forecasts through 1990[7] typically estimate annual growth rates of Gross National Product between 2 and 3 percent, total energy demand growth rates of about 1 percent, and inflation rates of 6 to 8 percent. Real oil prices have declined from their peak in 1981 and are expected to increase at a rate of less than 2 percent annually in the absence of future oil supply disruptions. In this climate there is little incentive for large-scale development of alternative energy sources. Domestic oil production is expected to remain at current levels, but by 1990 annual industry expenditures for exploration and production are expected to grow by 50 to 80 percent, in real terms, as these activities move increasingly to Arctic and deepwater areas. Clearly, it has become more expensive to find and produce oil, and enhanced oil

[3]The development of Prudhoe Bay Field and TAPS are particularly noteworthy examples of the complex technical, environmental, financial, and legal challenges required to bring remote resources on stream. From discovery in 1968, it took nine years to make first delivery, including installation of TAPS, and a further 29 months to reach peak rate of 1.5 million barrels per day.

[4]Energy Policy and Conservation Act, Public Law 94-123 (89 Stat. 871), December 22, 1975, Title I, Part B (89 Stat. 881).

[5]Department of Energy Organization Act, Public Law 95-91 (91 Stat. 565), August 4, 1977.

[6]Decontrol of Crude Oil and Refined Petroleum Products, Executive Order 12287 (46 FR 9909), January 28, 1981.

[7]"The Energy Outlook Through 2000," Energy Economics Division, Chase Manhattan Bank, N.A., New York, March 1983.

TABLE 2

U.S. EOR PRODUCTION*
(Production in Barrels per Day)

	1976	1978	1980	1982
Chemical Methods				
Polymer	3,220	2,580	920	2,590
Surfactant	150	450	930	1,010
Alkaline	30	-	550	810
Subtotal	3,400	3,030	2,400	4,410
Miscible Methods†				
CO_2 Miscible	36,230	39,640	21,480	21,050
Hydrocarbon Miscible	30,950	20,430	14,510	12,620
Other Gas Miscible	16,000	16,000	18,830	16,990
Subtotal	83,180	76,070	54,820	50,660
Thermal Methods				
Steam	270,000‡	280,000‡	340,000‡	440,000§
In Situ Combustion	10,000	10,000	12,130	10,200
Subtotal	280,000	290,000	352,130	450,200
Grand Total	**366,580**	**369,100**	**409,350**	**505,270**
As a Percentage of Daily U.S. Oil Production	4.51	4.24	4.76	5.84

*Modified from *Oil & Gas Journal*, April 5, 1982, March 31, 1980, March 27, 1978, and April 5, 1976.
†*Oil & Gas Journal* numbers adjusted for immiscible projects.
‡California Department of Oil and Gas Annual Reports as adjusted by the study participants.
§Survey conducted for this study.

recovery should become increasingly attractive relative to conventional recovery in frontier areas.

Changes in Policy

The decontrol of oil prices[8] is the most significant change in government energy policy to occur since 1976. The decontrol policy relies on the market to set price based on supply and demand, and has had far-reaching beneficial effects on all energy markets in the United States. The Tertiary Incentive Program (TIP),[9] during the late stages of the period of controlled oil prices, provided an incentive for enhanced oil recovery by exploiting the difference between market prices and controlled prices. The Crude Oil Windfall Profit Tax Act of 1980,[10] which was implemented before decontrol and has since become an adjunct of the decontrol policy, represents a significant change to the policy on the taxation of oil revenues. Due to this taxation, the U.S. petroleum industry has not received all the revenues stemming from the difference between market oil prices and controlled prices. However, the Act does provide preferential treatment for EOR relative to conventional recovery.

Environmental policies have become more comprehensive than in 1976. A full assessment of how environmental policies affect enhanced oil recovery is contained in Appendix G, and is summarized below. Government support of field testing of EOR processes through cost-sharing agreements with industry ended in the federal 1983 fiscal year. Data from these tests continue to be analyzed and made available.

The Tertiary Incentive Program

The Tertiary Incentive Program permitted the limited early decontrol of oil prices for the

[8]Decontrol of Crude Oil and Refined Petroleum Products, Executive Order 12287 (46 FR 9909), January 28, 1981.

[9]Code of Federal Regulations, Title 10, Section 212.78.

[10]Crude Oil Windfall Profit Tax Act of 1980, Public Law 96-223 (94 Stat. 229), April 2, 1980.

purpose of off-setting certain EOR investments and expenses. The TIP was implemented by the U.S. Department of Energy pursuant to its regulatory authority and became effective on October 1, 1979. Under the program, producers were permitted to recoup up to 75 percent of the allowable investments and expenses incurred in a qualified EOR project, to a maximum of $20 million. The recoupment was effected by permitting the sale of crude oil at market prices, which were substantially higher than controlled prices. In March 1981, with crude oil price decontrol, the program was legally terminated.

Reaction to the TIP was favorable and widespread, with 101 operators certifying at least one project. As shown in Table 3, there was a reasonably even distribution of activity between chemical and miscible projects. Both pilot and commercial development projects were certified under this program. The larger number of thermal projects (177) certified under the TIP may reflect lower economic barriers to commercial development associated with relatively mature steam process technology, although many of these projects also were pilot tests.

Tax Policy

Under the Windfall Profit Tax Act of 1980, oil revenues in excess of a statutory oil price that is representative of real prices before decontrol are taxed at rates between 50 and 70 percent, depending upon producer classification and oil type. Heavy oil of 16 °API gravity or less is taxed at a 30 percent rate, and certain qualifying stripper wells (10 barrels per day per well or less) are exempt from the tax. The Act

TABLE 3

U.S. DEPARTMENT OF ENERGY TERTIARY INCENTIVE PROGRAM AND COST-SHARING PROJECTS

	Tertiary Incentive Certifications		Cost-Share Projects
	Number of Projects	Number of Operators*	Number of Projects
Chemical Methods			
Polymer	41	26	3
Surfactant	37	21	8
Alkaline	39	20	2
Subtotal	117		13
Miscible Methods			
Miscible (all types)	108	47	5
Immiscible (nonhydrocarbon)	11	11	-
Subtotal	119		5
Thermal Methods			
Conventional Steam Drive	93	18	5
Unconventional Steam Drive	33	13	-
Cyclic Steam Injection	17	7	-
In Situ Combustion	34	22	4
Subtotal	177		9
Other Methods	10	9	-
Grand Total	**423**	**101***	**27**

*Numbers do not add because some operators have certified more than one process and/or project.

gives preferred treatment to "incremental tertiary oil" from "qualified tertiary recovery projects" by placing this oil in the Tier 3, or 30 percent, tax classification. Even with the lowered tax rate, it may not be attractive for independent producers to apply EOR techniques to marginal wells that otherwise would become classified as stripper wells.

Newly discovered oil is currently taxed at a 22.5 percent rate, and so, in this respect, enhanced recovery competes for investment capital at a disadvantage with exploration. The Act also removes a significant source of capital that could otherwise be used for exploration or resource development, including enhanced oil recovery.

Environmental Policy

Environmental conservation policies at national, state, and local levels have received particular attention in the last decade. Federal laws that potentially affect oil recovery operations include the National Environmental Protection Act (1969), the Clean Air Act as amended (1970, 1977), the Clean Water Act as amended (1972, 1977), the Safe Drinking Water Act (1974), the Toxic Substances Control Act (1976), the Resource Conservation and Recovery Act (1976), and the Comprehensive Environmental Response, Compensation and Liabilities Act (1980). The petroleum industry not only complies with these laws and the regulations that implement them, but also cooperates with regulatory agencies in conducting research to define those factors that affect the environment and in setting realistic standards for environmental conservation.

The costs of compliance with environmental regulations are factors that contribute to determining the viability of particular projects. Since 1976, standards for nitrogen oxides (NO_X), sulfur oxides (SO_X), and particulate emissions have been tightened, particularly affecting thermal recovery projects. In California, where approximately 95 percent of the thermal recovery oil is produced, modified combustion techniques and flue gas scrubbers have been installed on steam generators, and casing gas gathering systems have been installed or improved in many oil fields. The industry continues to develop and invest in technologies that improve the protection of the environment in more cost-effective ways. Nevertheless, in some areas such as the Los Angeles Basin, it is the local clean-air standards that determine whether and when additional steam-generating capacity is installed (see Appendix F).

In other areas, where chemical or miscible methods are most often considered, water quality or land use could be potential environmental issues. The industry has a good record for groundwater protection during waterflood operations, and is improving upon it. In Texas, 74 groundwater problems resulted from operating 44,000 injection wells in the 15-year period from 1960 to 1975, but only three problems occurred in the last decade. Similar records exist in other oil producing states with large numbers of waterfloods. Appropriate materials and procedures are being used to maintain this record for the protection of groundwaters from contamination during EOR operations. The availability of fresh water is increasingly becoming an issue in some areas of the country. The oil industry, as a whole, uses less than 1 percent of the total national freshwater consumption. The industry is working to reduce its freshwater needs further, and is developing chemical EOR methods that are tolerant to saline waters. Land use issues stemming from the development of existing fields for enhanced oil recovery are generally minor. However, the industry is acutely aware of environmentally and archaeologically sensitive regions in which any form of petroleum exploration and development occur.

Funding for EOR Research

EOR research and field testing are conducted primarily by the petroleum industry, but both the government and universities have been actively involved in basic and exploratory research for enhanced oil recovery. Industry supports university research through a variety of means, including both contract research and research endowments. DOE project funding for EOR research between 1976 and 1983 totalled $16 million at universities, $15 million at national laboratories, and $17 million within industry. Funding for the operation of the DOE Energy Technology Centers, in support of laboratory and field research programs, was $60 million during the same period. There is a high level of communication among industry, university, and government specialists through technical meetings, seminars, and advisory groups, which serves to direct this research toward perceived needs.

Starting in 1974, the Department of Energy or its predecessor, the Energy Research and Development Administration, supported field testing of enhanced oil recovery through 27 cost-sharing agreements with industry (Table 3). About half of these projects involved chemical processes. Many of these projects emphasized acquisition of very expensive field performance data through the drilling and equipping of observation wells, time-lapse logging, or post-test coring. In several tests, process variations were compared in side-by-side tests. In others, commercial economics were to be demonstrated. Several of these tests are discussed elsewhere in this report. Cost-sharing was ended in the federal 1983 fiscal year. Data continue to be analyzed and made available.

Chemical Flooding Technology

Polymer Flooding

Since 1976, research has extended knowledge of polymer solution properties, identified ways to improve the thermal, chemical, and biological stabilities of existing polymers, and developed new polymers in order that field projects may be conducted under increasingly adverse reservoir conditions. Field activity has been stimulated recently by the relatively low front-end costs associated with polymer flooding and by the reduced tax rate provisions of the Windfall Profit Tax Act.

Laboratory Research

With very few exceptions, polymers that have been used are of two types, partially hydrolyzed synthetic polyacrylamides and xanthan biopolymers. Since 1976, polymer research has improved the characterization of these polymers and improved the knowledge of their behavior in porous media. Research has led to better understanding of polymer stability, rheology, formulation, and retention in the reservoir.

Polymer stability becomes a more important concern as projects are implemented in higher temperature reservoirs. Research has revealed limits for the thermal and chemical stability of both polyacrylamide and xanthan biopolymers. Recent tests have shown that microbial attack of both polymer types can be a potentially serious problem. Awareness of the effects of microorganisms and biocides on polymer stability has led to joint industry funding of a program at a major research institute to study this problem.

Mechanical degradation, which can occur either in surface equipment or at the sand face, and sensitivity to saline environments continue to be important problems affecting polyacrylamides. No significant success has been achieved in increasing the tolerance of polyacrylamides to either salinity or mechanical stress, but operational procedures have been developed to minimize these effects. Although biopolymers are generally insensitive to both of these factors, they have suffered in the past from poor filtration properties. Recently, significant progress has been made in improving the injectivity of xanthan biopolymers through the use of concentrated broths or enzyme treatment of the injected biopolymer solution. Many programs are underway to improve EOR polymers and to develop new ones. While some of these efforts show promise, further developments are still needed to produce cost-effective, stable polymers. Polymer cross-linking treatments have become more widespread in recent years. These treatments use gelled polymer to alter injection or production profiles by plugging watered-out zones or high-permeability streaks near the wellbore. Considerable additional research and testing are needed to determine the stability and the depth of penetration of polymer gels in a reservoir.

Field Testing

Since 1976 there has been a large increase in the number of active polymer projects. The total number of tests rose from 14 in 1976 to 48 in 1982. Results from the increased number of polymer projects are not conclusive, since many projects are still ongoing. However, the expectation is that polymer flooding will result in the recovery of a relatively small amount of additional oil, usually from 1 to 5 percent of the OOIP.

Significant improvements have been made in field handling and mixing of polymers. Field trials revealed the importance of maintaining good water quality and providing adequate mixing facilities to ensure proper dissolution of polymer before injection. New equipment and new polymer products have been introduced to facilitate polymer hydration and to optimize the properties of the injected solution.

Polymer Sources

Since 1976, manufacturers have expanded their capacities to produce both polyacrylamide and xanthan polymers. It is anticipated that polymer supplies should not be a limiting factor in applying chemical EOR technology.

Polymers have been marketed in additional forms since 1976. Synthetic polymers are now available as liquid emulsions and gels as well as powders. Biopolymer manufacturers are continuing to develop concentrated-broth polymer products to supplement existing dilute-broth and powder products. Polyacrylamide is being manufactured on site in several projects, and on-site biopolymer production is being considered.

Surfactant Flooding

Laboratory research in surfactant flooding has increased dramatically since 1976. This research has contributed to a better understanding of the process and rapid development of chemicals and formulations suitable for field use under a wider range of conditions. Improvements in technology have been demonstrated in recent pilot and field-scale projects.

Laboratory Research

The surfactant process is very complex and must be tailored for each application. Both the phase behavior and dynamic properties of the fluid banks strongly affect oil recovery. These factors have led to a high level of laboratory study of the process. Since 1976, research has produced advances in the chemistry, structure, phase behavior, and physical properties of the surfactant solutions injected to mobilize residual oil. The knowledge gained in this area has resulted in improved procedures for design of fluid systems for field use and has broadened the range of conditions over which the process may be applied.

Frequently, increased knowledge of one aspect of surfactant research has encouraged additional research on related topics. For example, field test results have emphasized the need for a better understanding of the interaction of both surfactant and polymer fluids with reservoir rock and fluids. Factors affecting surfactant adsorption on reservoir rock and the interaction of the surfactant solution with reservoir crude oil and water have been studied in the laboratory. The study of the phase behavior of surfactants with reservoir crude oil and water has facilitated the design of surfactant slugs for field applications. Field tests have also indicated that more reliable results are obtained when reservoir rock and fluids are used in laboratory process design studies. Laboratory research has continued to extend the applicability of the process to reservoirs with higher temperature, salinity, crude oil viscosity, and water hardness. Interest has continued in the use of preflushes to condition the reservoir so that available surfactants can be used for reservoirs with more extreme conditions. Progress has also been made in the development of surfactants that will perform satisfactorily without preflushes.

Research has continued to improve surfactant manufacturing processes, including the quality control of bulk surfactant, while reducing costs. Effort has been directed at the manufacture of synthetic, gas/oil, and crude oil sulfonates. Increasing attention is also being given to other types of synthetic surfactants as their potential becomes demonstrated.

Field Testing

The number of active surfactant projects increased from 13 in 1976 to 24 in 1982. Both the size and scope of the field projects increased, and several of the currently active projects are field-scale applications. The Department of Energy provided incentives through cost-sharing for eight projects between 1974 and 1980. Thirty-seven projects were certified for front-end recoupment under the Tertiary Incentive Program, before this program terminated in January 1981. A number of completed projects have been identified as technical successes because a significant amount of oil was mobilized and recovered. The inherent cost of the process, along with the costs of associated research and data acquisition, have made most of the projects conducted to date uneconomic.

Chemical Sources

Currently, usage of surfactants in enhanced oil recovery is very small and there is an excess of manufacturing capacity for preferred materials. However, full-scale application of surfactant flooding will require very large increases in this capacity, which may cause delays in implementation. The necessary sources of chemical supply are expected to become available as the market develops.

Alkaline Flooding

In recent years there has been increased activity in alkaline flooding both in the laboratory and in the field. The increased understanding gained from ongoing research, and advanced alkaline processes that involve using polymers and other ancillary chemicals, should increase the effectiveness of alkaline flooding for the recovery of high acid number crude oils.

Laboratory Research

Laboratory research has led to recognition of significant caustic consumption by reservoir rock and the temperature dependency of consumption rates. The influence of interfacial properties such as interfacial tension, interfacial viscosity, and coalescence on oil recovery have been studied. The use of ancillary cosurfactants to improve performance has been evaluated. Finally, laboratory studies have led to the recognition of the time-dependency of crude oil/alkaline interfacial tension and wettability alteration as factors in oil mobilization.

Field Testing

The number of active alkaline flood field projects increased from one in 1976 to thirteen in 1982. Field tests have shown that caustic consumption can be much greater than previously anticipated, that polymer use with caustic can provide improved mobility control, and that well plugging is a potential problem.

In addition, these tests have led to the development of improved tools and analytical techniques for evaluating project performance.

Chemical Sources

The chemicals typically used in alkaline flooding include sodium carbonate, sodium orthosilicate, sodium metasilicate, ammonia, and sodium hydroxide. No supply constraints are anticipated for any of these materials.

Miscible Flooding Technology

Carbon Dioxide Miscible Flooding

In 1976, at the time of the previous study, only design studies and preliminary results for CO_2 miscible field tests had been published, although at least three commercial projects were underway and numerous pilot tests were either in progress or complete. Confidence in the CO_2 miscible process was based on laboratory data and previous experience with multiple-contact hydrocarbon miscible displacement.

Since 1976, field results have demonstrated the levels of recovery and efficiency that may be expected of CO_2 miscible processes for a variety of reservoir types and conditions. Although uncertainties remain in forecasting results for any specific reservoir, the available field results and the business climate have justified the current large-scale development of naturally occurring CO_2 sources for use in the numerous commercial projects now being planned and implemented. This development of CO_2 resources and commercial projects is a meaningful indication of the changes affecting miscible flooding that have occurred since 1976.

Results from field tests have not been uniformly good, principally because of high CO_2 mobility and reservoir heterogeneity. In combination, these effects can cause early CO_2 breakthrough to producing wells, poor sweep efficiency, or local loss of misciblity through dispersive mixing or pressure effects. In addition to normal operating procedures, means used to control the process include the rate and quantity of CO_2 injection, and the injection of water alternating with CO_2 gas (WAG). Maintaining balanced injection and withdrawal is very important in achieving high process efficiency.

It is now generally recognized that increased understanding is required of several fundamental aspects of the CO_2 miscible process to improve project design capability. The phase behavior of the CO_2/crude oil system, including asphaltene precipitation, the wettability characteristics of the fluid and rock system, and the geologic structure of the reservoir and its heterogeneities can strongly influence process performance. These factors are being thoroughly studied and are being included with increasing degrees of sophistication into reservoir simulators for miscible processes. Recently, research has been initiated to identify and characterize chemical additives that may be used to reduce CO_2 mobility within the reservoir. Also, significant advances have been made in the technology of processing produced hydrocarbon-rich CO_2 gas streams.

Laboratory Research

Much laboratory research in miscible flooding has been directed toward improved quantitative understanding of CO_2/crude oil phase behavior. The nature of the CO_2 enrichment process that leads to the attainment of miscibility with reservoir crude oil has been examined over the practical temperature range for a variety of reservoir oils, with CO_2 containing various levels and types of impurities. This has led to improved correlations of minimum miscibility pressure (MMP) and greater confidence in the use of slim tube testing for MMP determination. The effects of impurities in the CO_2 have been studied with the noteworthy results that methane and nitrogen degrade, but hydrogen sulfide (H_2S) and liquid petroleum gases improve, the miscibility of CO_2 with reservoir oils. This means that it may not be operationally essential to treat produced gases to remove these heavier constituents before recycle injection. When the composition of the produced gas stream does not result in significantly increased MMP, the decision to install separation facilities may be mainly an economic one.

Studies that have examined the residual oil left behind during the CO_2 enrichment process find that this residual is composed of the higher molecular weight compounds that were present in the original crude oil. In some cases, precipitation of solid asphaltic material has been observed. This phenomenon is the subject of increased attention in the laboratory because certain field tests have shown that asphaltene precipitation can reduce injectivity, improve sweep efficiency, or cause plugging of production wells. Laboratory studies using field cores have reported the effects of WAG ratio, injection rate, and rock wettability state on displacement efficiency, CO_2 utilization efficiency, and breakthrough time. Generally speaking, these results are qualitatively similar to prior results for multiple-contact hydrocarbon miscible experiments.

Quite recently, research attention has begun to focus on means to reduce CO_2 mobility relative to that of the reservoir fluids. Work to date has concentrated on identification of additives to decrease CO_2 mobility. At the present time there are two approaches: the generation of dense, viscous, foam-like dispersions of CO_2 in water by adding surfactant chemicals to the brine; and the generation of viscous CO_2 by adding polymers directly to the CO_2. Considerable additional research is needed in this area.

Significant research in technologies that support CO_2-produced gas processing has been reported. The Ryan-Holmes process, which was introduced after 1976 and is finding rapid commercial acceptance, is very efficient in the separation of CO_2-rich, high H_2S content gases. Significant advances have also been made in gas separation membrane technology. Both of these advances can be incorporated in gas separation plants in order to significantly reduce operating costs.

Field Testing

Field pilot testing of the CO_2 miscible process has demonstrated the ability of CO_2 to mobilize and displace crude oil from previously waterflooded reservoirs. Successful pilot tests have been conducted in both carbonate and sandstone reservoirs using continuous CO_2 injection, injection of a slug of CO_2 that is driven by a chase fluid, and the WAG process. Gravity-stable CO_2 displacement tests have been conducted in several instances. Nonproducing pilot tests conducted since 1976 have demonstrated some important aspects of the CO_2 miscible process in heterogeneous reservoirs through the use of time-lapse logging in observation wells, periodic production from fluid sampling wells, and pressure cores. Between 1976 and 1982 the number of active CO_2 miscible field tests rose from 10 to 27.

The poor performance observed in some pilot tests can often be attributed to poor confinement of CO_2 within the project area and/or interval. The combined effects of high CO_2 mobility and reservoir heterogeneity thus have contributed most to the technical uncertainty of recent project designs, but other operating problems have also been observed.

Even with this technical uncertainty, sufficient potential exists to justify the development of naturally occurring CO_2 sources on a large scale. Over the last several years, numerous field-wide or unit-wide CO_2 miscible projects have been announced and implemented, especially in West Texas and East New Mexico. As of December 1983, there were eleven active full-scale CO_2 floods in this area, of which eight had been started since 1980. Other commercial projects with 1984 and 1985 starting dates have been announced. More projects may be expected. It will be several years, however, before large increases in production from these projects will occur.

CO_2 Sources

There are at least 40 trillion cubic feet (Tcf) of expected CO_2 reserves in the five large reservoirs indicated in Table 4. The technology for producing these reserves appears to be well in hand, even in the mountainous terrain of McElmo Dome or Sheep Mountain. Several of these reservoirs are now being developed to supply CO_2 to the prolific oil producing areas of West Texas and East New Mexico. A 500 million cubic feet (MMcf) per day capacity pipeline from Sheep Mountain and Bravo Dome is already supplying CO_2 to West Texas. A second 400 MMcf per day capacity pipeline direct from Bravo Dome is being planned. The Cortez

TABLE 4

MAJOR CARBON DIOXIDE RESERVOIRS

Reservoir	Location	Expected Reserves (Tcf)
LaBarge-Big Piney	Southwestern Wyoming	20 - 25
McElmo Dome-Doe Canyon	Southwestern Colorado	10 - 12
Sheep Mountain	Southern Colorado	1 - 1.5
Bravo Dome	Northeastern New Mexico	6 - 8
Jackson Dome	South-central Mississippi	3
	Total	**40 - 46.5**

pipeline from the McElmo Dome area to West Texas has an initial capacity of 650 MMcf per day, and can be expanded to at least 1 billion cubic feet per day by the addition of more pump capacity. Further development of naturally occurring CO_2 resources is expected.

There are also a number of other potential CO_2 sources. Early West Texas commercial CO_2 miscible projects at SACROC Unit, North Cross Unit, and Twofreds Field used CO_2 byproduct from gas processing plants in the Val Verde and Delaware Basins of West Texas. CO_2 may also be obtained from ammonia plants or from power plant stack gases. These alternative sources have undergone relatively minor development since 1976.

Other Miscible Flooding Processes

Other miscible flooding processes include the injection of hydrocarbons, nitrogen, or flue gases at miscible conditions. Because of the high sales value of light hydrocarbons, hydrocarbon miscible floods will be initiated only under special economic circumstances. Even so, several major hydrocarbon miscible floods have been started recently. A number of Miocene sandstone intervals are being flooded at South Pass Block 61 Field, offshore Louisiana. A project was also initiated recently in the Sadlerochit reservoir at Prudhoe Bay Field, Alaska. This test encompasses eleven 320-acre patterns, which had about 440 million barrels of OOIP. In both cases, enriched hydrocarbon gas is being injected.

In other reservoirs, nitrogen can be used as a miscible solvent. These reservoirs are usually rather deep because nitrogen MMPs are quite high. However, nitrogen and CO_2 MMPs may be comparable at the high temperatures encountered, and nitrogen (or flue gas) can be more cost-effective than CO_2. This was the case for selecting nitrogen for the commercial miscible project at Jay Field, Florida. Although the potential of nitrogen miscible flooding may have improved since 1976, this process is expected to make only minor contributions relative to other miscible methods.

Immiscible CO_2 Flooding

A number of CO_2 immiscible field projects conducted since 1976 have indicated potential for CO_2 immiscible flooding of moderate-viscosity or high-viscosity crude oils that occur in moderately deep reservoirs. Although CO_2 immiscible flooding can be used successfully in selected reservoirs, this process is still expected to make only minor contributions to enhanced oil recovery.

Thermal Recovery Technology

Since 1976 there has been steady growth in oil production by steam methods. Steam drive production has increased relative to production by steam stimulation. This shift toward steam drive reflects further maturing of steam projects because it is still common practice to install steam stimulation projects before initiating steam drive. Production by in situ combustion has remained unchanged. Although there have been no major breakthroughs in thermal recovery technology since 1976, potential for improving the recovery, process efficiency, and range of applicability of thermal methods has been demonstrated by numerous pilot tests of advanced thermal techniques and improved equipment. Some of these technologies are now beginning to see wide commercial application.

Steam Process Technology

Efforts to improve the reservoir conformance of steam injection have perhaps been the most significant development since 1976. Surfactant foams or other chemicals that form foams in situ are injected with the steam. In the reservoir, the foams divert steam to poorly swept areas and improve recovery. The development of foams and foaming agents has progressed from successful laboratory experiments to field testing. Field tests of this process modification are expanding, and depending upon economics may be used in full-scale projects in the near future.

Waterflooding after steam drive can improve thermal efficiency by scavenging heat and producing additional oil. Steam drive costs can be lowered by reducing the quantity of steam injected and the quantity of fuel burned. One successful post-steam waterflood has been reported since 1976 in which water injection maintained oil production rates at the same levels as before steam injection ceased. This technique is expected to see more widespread future application as ongoing steam projects mature further.

Another method to improve steam drive effectiveness is to inject noncondensible gases with the steam. Steam and gas mixtures are the result of downhole steam generation, but can also be produced by other means. The presence of CO_2 in a steam drive promotes the distillation of oil and lowers oil viscosity. Numerical simulation studies have shown that the addition of CO_2 to steam may accelerate and ultimately increase oil production for some reservoir conditions. The process has been used in several field tests, but no major projects have been implemented to date.

The technique of hydraulically fracturing the reservoir before or during steam injection is being used more often in the field. Hydraulic fracturing is used where steam could not otherwise be injected at high rates. The process is most useful for producing tar sands or thin heavy oil reservoirs. Field tests have demonstrated that the technique is technically feasible and can produce oil at significant rates. The economics of the process must still be proven, however.

The industry has also been testing steam drive in light-oil reservoirs. Laboratory studies have shown that steam is very effective in distilling light oils and that distillation would be a major recovery mechanism in light-oil steamflooding. Field tests have resulted in extremely low residual oil saturations in the steam-swept zone. Economic results from current pilot operations have not been reported, but the process is considered to have good potential in some reservoirs that have significant remaining oil saturations.

Steam Generation Technology

Steam injection equipment has shown several major improvements since 1976. Design improvements and reduced cost of insulated tubulars are allowing steam injection operations to be applied to deeper reservoirs. Steam injection operations have been successful at depths below 3,000 feet. Insulated tubing tests have also demonstrated the need for better thermal packers, which are now being developed with high-temperature elastomeric seals and with metal-to-metal seals.

Downhole steam generation is a major innovation that may improve the depth capability of steam processes. Heat losses from the injection wellbore are avoided by generating steam downhole at, or just above, the productive formation. Fuel and air, to generate heat, and water, to form steam, are supplied to the generator equipment down the injection well. Direct downhole steam generators inject the combustion product gases along with the steam. Indirect-fired generators return the product gases to the surface for cleanup before venting to the atmosphere. Several field trials of both types of downhole steam generators have proven the feasibility of operating the equipment. Future modifications and improvements, especially in corrosion resistance, will undoubtedly be required to permit prolonged use of these tools. Downhole steam generators may result in steam stimulation and steam drive in reservoirs as deep as 5,000 feet.

Fluidized bed combustion has shown promise to produce steam from cheap solid fuels such as coal or coke without significant air pollution problems. Use of solid fuels will also release to the market the more valuable liquid and gaseous fuels that are now used for steam generation. One very successful test in Texas has generated widespread interest in fluidized bed combustion. Future application of this technology may be limited by transportation costs for solid fuels.

Cogeneration is rapidly developing as a major economic improvement to steam projects. Cogeneration is the simultaneous generation of electricity and steam for thermal recovery. Cogeneration can produce electricity economically for use in oilfield operations or for sale to utility companies. Several cogeneration plants are already in operation in California. If state and federal policies continue to favor these projects, cogeneration should come into widespread use during the late 1980s.

In Situ Combustion

The use of oxygen-enriched air for in situ combustion is the major advance since 1976. Less nitrogen must be injected and produced from the reservoir when enriched air is used. This has many potential advantages, including reduced producing well sanding problems and faster production response. High CO_2 concentrations in the burned gas may improve oil mobilization. There is potential for use in light-oil reservoirs. Field tests conducted to date have demonstrated the feasibility of enriched air injection, but have not convincingly demonstrated significant reservoir benefits or improved economics.

Supporting Technologies for Enhanced Oil Recovery

A host of technologies must be brought to bear to successfully develop any petroleum reservoir, whether for primary, secondary, or enhanced recovery. In this section, a brief overview is given of some of these supporting technologies and recent developments that affect enhanced oil recovery.

The importance of improved reservoir description, computer simulation, and well completion techniques and materials has been recognized for improving reservoir management during conventional primary and secondary recovery operations. However, these technologies are especially necessary and valuable in planning and operating EOR projects. For EOR, economic success is often heavily dependent upon the accurate assessment of the fluid and formation properties, reservoir heterogeneity, and fluid distributions after conventional recovery. This information must also be integrated into reservoir simulation models in order to study operating strategies and provide projections of production for economic analysis. During operation, success depends upon attention to detail in all aspects of field operations, but particularly in the proper completion and maintenance of wells.

Reservoir Description

The reason that oil remains after primary and secondary production can be more easily understood by examining the nature and structure of reservoir rock. To illustrate, the scanning electron micrographs of Figures 14a and 14b show the fine porous network present in sandstones and carbonates, the two primary sedimentary rock types.[11] Fluids flow through these rocks but the flow paths are tortuous and the displacement process is often inefficient. The ease with which a single fluid will flow through the rock is measured by the permeability. The relative permeability to each fluid phase (oil, water, gas) will vary depending upon the quantity of each phase present and upon the types of interactions between the fluids and the rock (wettability and pore structure). It is not unusual for more than 80 percent of the original oil to remain in place after primary production, or for more than 50 percent of the OOIP to remain after a secondary waterflood. This remaining oil is a sizable resource, which is the target for enhanced oil recovery.

Planning an EOR project for a particular reservoir requires detailed information on the quantity of oil remaining, how it is distributed in the reservoir, and the specific factors, both microscopic and macroscopic, that control its flow. This information is obtained by a variety of means including well testing, coring and core analysis, tracer tests, well logging, and geological modeling. None of these methods stands alone. The best evaluation of the technical and economic feasibility of a particular EOR prospect is obtained by combining reservoir data from as many sources as possible. In recent years, significant advances in the technologies of quantitative reservoir description have improved the industry's ability to assess EOR prospects. These same technologies are also needed to monitor the progress of an EOR project.

[11]Typically, the pore space is 15 to 35 percent of the bulk rock volume in sandstones, and 3 to 20 percent of bulk volume in carbonates.

Pressure Transient Testing

Pressure transient testing is used to study macroscopic reservoir behavior. Pressure transient testing involves perturbing the flow rate of a well and observing pressure responses at the perturbed well or adjacent wells. Analysis of test data can yield information about the flow efficiency of the well, effective permeabilities, average pressure of the reservoir within the drainage volume of the well being tested, and the degree of communication between wells.

In recent years the introduction of high-precision pressure sensors, advances in computers and computer modeling, and new concepts in applied mathematics have increased the ability to obtain and analyze data from pressure transient tests. These advances have allowed pressure transient testing to be applied successfully in increasingly complex reservoirs. Pulse testing and interference testing made feasible by high-precision pressure gauges reveal information on reservoir continuity, flow conductivity, and directional permeability. Type-curves have been developed for analyzing well tests complicated by nonradial flow, fracturing, layering, afterflow, and altered near-wellbore properties.

Progress has also been made in developing analysis techniques to determine flood-front position for certain types of displacement processes for which there is high contrast between the mobilities of driving and in-place fluids. Better interpretation techniques have also increased the ability to obtain information on reservoir boundaries and heterogeneities. Future improvements in pressure transient measurements and data analysis should continue to provide better reservoir definition and characterization for enhanced oil recovery.

Coring and Core Analysis

Coring and core analysis can provide accurate and detailed information concerning the vertical distribution of porosities, permeabilities, and oil saturations. Such information is especially important in planning an EOR project. Core analysis results also are used to calibrate well log data.

Pressure coring technology was introduced years ago to avoid formation fluid loss caused by gas expansion and blowdown. This technology has continued to evolve in recent years. "Sponge" coring, an alternative to pressure coring, was introduced recently. This technique employs a core barrel lined with a porous, permeable medium (a sponge) that

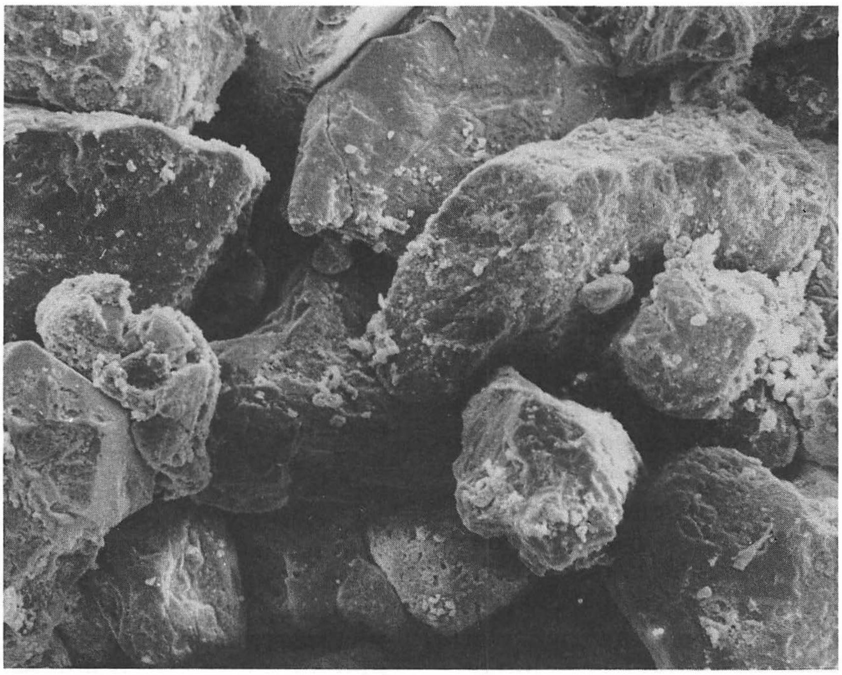


Figure 14a. Electron Micrograph Showing Reservoir Rock Pore Structure—South Louisiana Sandstone.

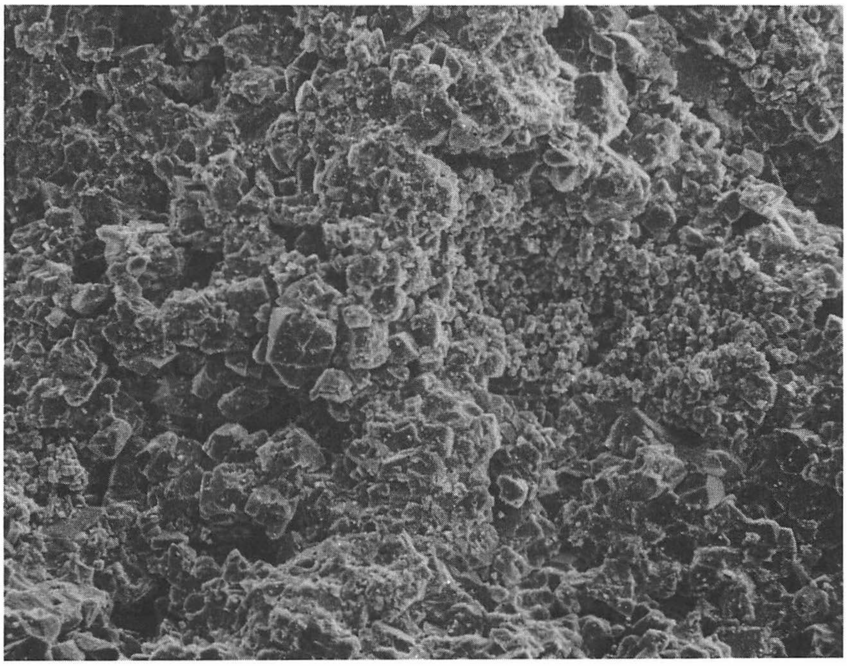


Figure 14b. Electron Micrograph Showing Reservoir Rock Pore Structure—Permian Basin Carbonate.

SCALE: 1″ = 0.2 millimeters

Photographs courtesy of Shell Development Company.

traps the oil that would otherwise be lost. Although it is too early to evaluate this technique definitively, sponge coring technology appears to be quite promising.

Core analysis techniques, both routine and specialized, have become increasingly reliable and accurate. Recent advances in laboratory techniques such as high-speed centrifuge techniques, nuclear magnetic resonance, transmission and scanning electron microscopy, and computer-assisted data acquisition have provided powerful new tools for studying the complex behavior of reservoir rocks and fluids. Factors that are receiving renewed attention for enhanced oil recovery include:

- Pore network geometry, clay content and type, rock minerology, crude oil composition, and water salinity and ion content as they affect chemical EOR flooding
- Crude oil composition, phase behavior, and wettability alteration effects important to miscible flooding
- The hysteresis and temperature dependence of relative permeabilities that affect thermal recovery.

Tracer Methods

Single-well tracer techniques have been developed specifically for determining residual oil saturations. In the standard process, a dilute solution of a primary tracer (often an ester such as ethyl acetate) in brine is injected into the interval of interest. A followup slug of brine displaces the tracer into the formation a specified distance. During the subsequent shut-in period, a portion of the primary tracer reacts to form a secondary tracer. On production, the primary tracer moves more slowly than the secondary tracer because of its greater affinity for oil. From measurements of tracer production and knowledge of distribution coefficients and reaction rates, the residual oil saturation can be calculated.

An advantage of the single-well tracer technique is that it samples a much larger volume of the reservoir than logs or cores. However, injection tends to move any remaining mobile oil. Thus, this technique is most useful when the produced fluids have less than 2 percent oil-cut; the tracer test then provides an estimate of remaining oil saturation. This technique was developed in the late 1960s and has been used extensively since then. Recent advances include the development of a theoretical basis for optimizing test design as well as new results on the effects of fluid drift, flow irreversibility, mobile oil, and reservoir heterogeneity.

Another tracer technique involves injecting nonreactive chemical or radioactive tracers into injection wells and monitoring the presence of these tracers as they are produced from surrounding wells. Tracing the interwell flow of injected water in this manner can provide information about high-permeability stringers, fractures, flow barriers, or other heterogeneities that can affect sweep efficiency.

Well Logging

Logging tools measure electrical, acoustic, or atomic properties of reservoir rocks and/or fluids. Formation porosity and oil saturation can be estimated indirectly from these measurements. EOR operations demand accurate results from well logs. This requirement for accuracy increases the importance of calibrating log data against core analysis data or other independent measurements. Well logging plays an important and growing role in determining remaining oil saturations and in project monitoring to determine saturation changes over time and to estimate sweep efficiencies. Several examples of these applications are cited in Appendix H. Lower logging costs would promote more widespread use of these techniques.

One of the most significant innovations in logging and log analysis in recent years has been the adaptation of minicomputers to wireline logging, making it possible not only to acquire and display logging data, but also to store and retrieve large amounts of log data in a form well suited to the analysis of sophisticated EOR projects.

Nuclear magnetism and pulsed neutron capture logging tools have been improved continuously. The determination of residual oil saturations using these tools requires fluid injection procedures (inject-log or log-inject-log), which complicate field testing and interpretation. Research is in progress to improve induced gamma ray spectroscopy logging by decreasing the required logging time through improvements to source and detector efficiencies, and by improved analysis techniques. Dielectric constant logging is a relatively new technique, which is currently an area of intense research activity attempting to optimize tool design.

Reservoir Simulation

Computer simulation is used during all stages of an EOR project. In research studies, simulation improves understanding of the particular process mechanism. Simulation is indispensable for pilot test planning and interpretation. Its most important use is in the design, implementation, and optimization of full field-scale projects.

Since 1976, vector processors that provide increased computational speeds and improved cost:speed ratios have become generally available. Vectorized codes have been developed to model chemical, miscible, and thermal processes. Prior to these innovations, computer modeling of complex EOR problems was often limited to computations involving simplifying assumptions and/or relatively few grid blocks. Now, more complete problem descriptions can be included, and larger, multidimensional problems can be solved with relative ease. Other advances have been made in the use of equations-of-state for improved compositional simulations and in numerical solution techniques. Future developments in these areas, and further computer technology advances, should result in additional improvements in computation time, solution accuracy and resolution, and the ability to handle even more complex problems. Interactive color graphics are beginning to increase the speed with which simulation results can be analyzed and interpreted by the engineer, as well as improve the clarity with which results are presented.

Well Completion Techniques and Materials

In enhanced oil recovery, preventing injection into unproductive strata or "thief zones" is especially important because of the cost of the injectants. Selective well completion (or recompletion) and the prevention of unwanted vertical flow near the wellbore are two aspects of subsurface engineering that have assumed increased importance for enhanced oil recovery. The design of well completions will make use of previous production history, well test and pressure transient data, and calibrated well logs. In complex reservoirs, the design of well completions requires the integration of geologic models and reservoir simulations into a project development plan that includes a comprehensive well completion strategy. The implementation of this strategy can make use of a number of improved completion techniques and materials.

Several developments are gaining increased acceptance in efforts to improve the quality of casing cement to help improve zone isolation. Among these are the use of improved cement additives and the use of cementing heads that rotate and reciprocate the casing during cementing. Also, external casing packers have been developed in an effort to ensure an improved seal between the casing and the formation.

Materials research has been devoted to improving the performance and preserving the integrity of cements, tubular steels, and production equipment. The development of nonconductive and partially conductive cements for use with resistivity/conductivity logging devices in EOR flood monitoring has been an area of active research. Fiberglass casing has been successfully used in a number of instances to complete monitor wells. Corrosion of cements and steels by CO_2 has been of particular interest. Downhole submersible pumps have been improved and are finding increased use in EOR projects. There have been numerous advances in completion equipment for thermal wells including improved tubing insulation and thermal packers.

There have been several recent developments in the areas of formation fracturing and induced fracture delineation. Knowledge of fracture orientation can be crucial in optimizing design and performance of an EOR project. New techniques for determining fracture orientation include the use of tiltmeter surveys, triaxial borehole seismic surveys, the pulse-echo ultrasonic borehole televiewer, core differential-strain analysis, and borehole geometry measurements that yield information on earth stresses.

Reservoir Monitoring Systems

Injection and Production Well Logging

Knowledge of injected fluid entry profiles is necessary to achieve good reservoir conformance—a factor critical to the success of most EOR projects, especially when large volumes of expensive chemicals are used. In the case of near-wellbore polymer treatments, reliable profiles can indicate treatment success or failure. Injection well logging techniques are available for measurement of entry profiles using viscous as well as nonviscous liquids and gases under certain conditions. Logging of production wells carries the same importance in EOR projects as in conventional primary and secondary recovery.

Appropriate injection and production well logging techniques are dictated by fluid rates and properties and, to some extent, by completion practices. Radioactive tracer methods have recently been developed for polymers and surfactants that overcome problems encountered when using conventional equipment with viscous fluids. Technology for extension of tracer techniques to injected gases is not well developed, but strides are being made in this area and spinner flowmeters can be used with success in high-rate wells. Zones of fluid entry in producing wells are delineated using conventional equipment: spinner flowmeters, density tools, temperature survey devices, and instruments to differentiate between fluids on the basis of electrical properties.

Observation Well Logging

The logging of strategically located observation wells in an EOR project can produce time-lapse records of fluid saturation changes. Monitoring the movement of formation fluids with observation well logs can provide important information for evaluating a flood including: changes in pre-flood and postflood oil saturations; arrival time of different fluid banks; size of oil bank; and estimates of vertical sweep efficiency.

The choice of a monitoring log is controlled to some extent by the rock matrix and the fluids in the reservoir or being injected into the reservoir. In order to prevent crossflow at the wellbore, the logging tool must be able to measure formation properties behind the casing. Both carbon-oxygen and induction logging techniques have been utilized for this purpose. High-resistivity fiberglass casing is commonly used across the zone of interest to accommodate the induction logging technique.

Observation well logging has been used to monitor fluid movement in surfactant flooding, polymer flooding, and CO_2 flooding. The induction logging technique detects changes in the electrical resistivity of fluids in the reservoir. It has been used to size the chemical slug by monitoring movement of fluid to determine swept volume. The conformance of drive fluids can then be monitored if a contrast in resistivity of fluid exists.

Produced Fluid Analyses

An analysis of produced fluids can provide the following information that can be used in evaluating an EOR project.

- Oil production response above that obtained from conventional primary and secondary methods. Oil-cut data provide this information.
- An indication of mobility control based on the arrival time of different fluid banks. In a chemical EOR flood, for example, sulfonate analysis would indicate breakthrough of the surfactant fluid bank. Oil-cut data indicates production of an oil bank ahead of surfactant-polymer fluid banks. When fresh water is used for the polymer solution, an analysis for chlorides indirectly indicates breakthrough of a polymer bank.
- An analysis for chemical or radioactive tracers that have been injected ahead of or during surfactant-polymer fluid injection provides an indication of volumetric sweepout efficiency and direction of fluid movement in the reservoir.
- An analysis for inorganic constituents in oilfield waters can be used to evaluate problems related to water quality control, corrosion, and pollution.

Interference effects between crude oil components and the various constituents being analyzed is a major problem in produced fluid analyses. Some of the new analytical techniques that have been developed since 1976 tend to minimize those interference effects.

A new technique called ion chromatography has been developed that employs classical ion exchange principles to separate a host of inorganic constituents and organic acids. Typical chromatograms can separate eight ions in the same sample with detection sensitivities of a few parts per million (ppm). Modern high-performance liquid chromatography can be used to analyze for petroleum sulfonates. This method characterizes sulfonates in terms of equivalent weight distribution. Turbidimetric methods are used to analyze for polymers that are present in high concentrations in clean samples. Research is being carried out on techniques to analyze for polymers that are present in low concentrations in produced fluid samples. Procedures are being perfected to analyze for sulfonate and polymer that are present in the same produced fluid sample.

Chapter Three

Analysis Considerations and Procedures

This chapter reviews the analysis considerations and procedures used in this study. It specifically concentrates on the technical and economic factors that influence the final results presented in Chapter Four. The technical and economic considerations are closely interrelated. Determination of the EOR potential is dependent both on the technical viability of specific EOR processes in specific reservoirs, and on the number of such reservoirs where application would provide an operator with sufficient economic incentive (i.e., profit) to compete favorably with other business investment opportunities and offset any disproportionate risks.

To conduct the study, the Council established an organizational structure consisting of a Committee on Enhanced Oil Recovery, a Coordinating Subcommittee, and four task groups. Three of the task groups—the Chemical Task Group, the Miscible Displacement Task Group, and the Thermal Task Group—were assigned to study the potential for the three major EOR methods. A Costs and Economics Task Group was responsible for defining the economic parameters and sensitivities to be applied in the analysis, and for developing the methodology to be used in projecting EOR production schedules. To maintain coordination among these groups, certain members from each of the process task groups served on the Costs and Economics Task Group, and the process task group chairmen served as members of the Coordinating Subcommittee.

General Overview

The 1976 NPC study of EOR potential evaluated a small group of reservoirs and extrapolated these results to obtain nationwide estimates. Recognizing the potential inaccuracies of this procedure, this study is based on a more comprehensive reservoir data base that properly represents the future target for the thermal, miscible, and chemical EOR processes. Data were obtained on more than 2,500 reservoirs containing about 325 billion barrels of OOIP. This represents over two-thirds of the oil discovered in the United States, and represents essentially all of the larger reservoirs that are candidates for the application of EOR processes. No extrapolation of results was attempted.

Screening criteria were developed for each process and were applied to the data base to identify those reservoirs to which each process might be technically applied. At this point in the analysis, it was possible for a reservoir to be a prospective candidate for more than one of the six EOR processes being considered.

Process predictive models were then used to estimate injection and production scenarios for each reservoir and recovery process. Results of the predictive models were passed to process-specific economic models, where the individual pattern results were combined on a field-wide basis in accord with specified pattern development schedules. The economic calculations took into account expenditures for surface facilities, injectants, and well equipment, together with the appropriate process-dependent and process-independent investment and operating costs. Economic calculations were repeated for nominal crude oil prices of $20, $30, $40, and $50 per barrel. Costs were adjusted for changes in nominal crude oil price. The annual and cumulative revenues, costs, taxes, royalties, and cash flows were calculated using accepted economic evaluation procedures. Rate of return calculations and related economic analyses were also made.

Predictive and economic calculations were made for two technology scenarios, the Implemented and Advanced Technology Cases. The Implemented Technology Case represents current state-of-the-art technology. The Advanced Technology Case incorporates potential technological improvements. These are discussed more fully below. The predictive and economic calculations resulted in a series of data files containing an inventory of possible EOR projects for each process at each nominal crude oil price and each technology level. The determination of projects to actually be implemented, and their respective start dates, was handled through a compositing procedure consisting of two steps: assignment of a single EOR process to each reservoir, and timing the start of each project.

The first step in the assignment was to specify the oil price and technology level. Each project was then required to provide some minimum economic return: the project had to exceed a specified minimum discounted cash flow rate of return (minimum ROR). Any project whose rate of return was less than this minimum ROR was deleted from further consideration at that specified oil price and technology level.

It was still possible at this stage for a reservoir to be included in the data files for more than one process. This situation was resolved by assigning the reservoir to the process that recovered the most oil. This had the effect of maximizing the predicted EOR potential.

The initial step in the timing process was to rank projects in decreasing order of Investment Efficiency. Project implementation began in 1984, with those having the highest Investment Efficiency being implemented first. Various factors, some process-dependent and some not, prevented all projects from beginning in the same year. The factors considered in timing of projects included:

- Amount of surfactant required
- Amount of carbon dioxide required
- Geographic location
- Industry confidence in process.

Not all factors apply to every process. Capital was assumed to be available when needed to implement projects meeting the minimum ROR criterion.

The results of the timing step included the composited annual oil production, investments, operating costs, taxes, and royalties, both for each EOR process and for all processes combined. The assignment and timing steps were each aided by the use of computer programs. However, at all stages, the engineering judgment of the study participants was used to validate and evaluate the results. This analysis and review was the most important phase of the study. Figure 15 outlines the various procedures described above.

Technology Cases

In an attempt to properly bracket the future potential for enhanced oil recovery, two sets of assumptions were made regarding the level of technology that would be available. These two scenarios are referred to as the Implemented Technology Case and Advanced Technology Case.

Implemented Technology Case

The Implemented Technology Case refers to the technology that is presently in existence, at least in the proven field test stage. This means somewhat different things for the three major EOR methods. For thermal recovery methods, it implies technology that has been used in full-scale commercial applications and is economically attractive; for miscible processes, it reflects implementation of field-scale commercial projects; among the chemical EOR processes, the same is true for polymer flooding. For surfactant and alkaline flooding, however, the Implemented Technology Case refers to reservoir characteristics and process efficiencies that apply to pilot tests. Few large-scale commercial applications have been implemented for these processes.

Advanced Technology Case

The Advanced Technology Case is based on technology that might conceivably be developed within the 30-year time frame of this study. To a large extent this is a "what if" case in that it assumes that most of the problems and limitations responsible for inefficiencies in the Implemented Technology Case described above are overcome. The objective in looking at an Advanced Technology Case is to estimate the potential increased recovery that might result from technological developments.

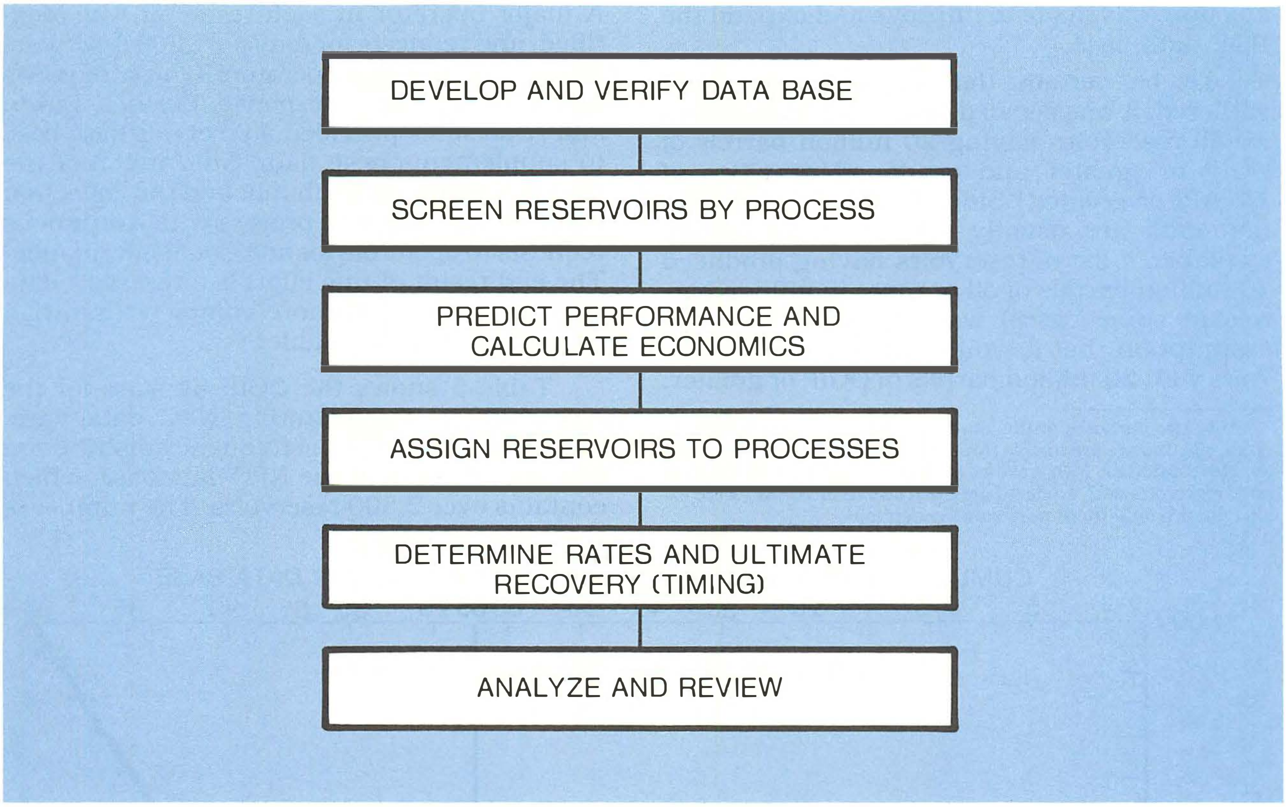


Figure 15. Simplified Schematic of Principal Study Procedures.

The types of improvements considered are based on technology that has been demonstrated in the laboratory or that is being field tested. Consequently, the magnitude of the potential technology improvements can be handled quantitatively. However, it is difficult to predict if and when they will be applicable on a commercial basis.

To make the Advanced Technology Case projections as reasonable as possible, an effort was made to estimate the time period required to develop and test the new technologies for each process. This was done by assuming an effective date at which advanced technology would be available for general application (EDAT). Projects starting prior to the EDAT were evaluated under the Implemented Technology Case assumptions, whereas those commencing after the EDAT were evaluated under the Advanced Technology Case guidelines. For most processes, the EDAT was presumed to be 1995. This allows time for laboratory work and field testing. An exception was made for ongoing steam drive projects, where the EDAT was assumed to be 1988. These projects represent an earlier opportunity for application of advanced technology.

Advanced technology for most EOR processes involves contacting more of the target oil in place. Use of chemical agents or additives that improve injection profiles near the wells and mobility control in the reservoir are typical concepts. Advanced technology also includes the ability to apply a process to reservoirs previously screened out by physical parameters. Notable examples are the application of surfactant flooding to carbonate reservoirs and of steam processes to reservoirs deeper than 3,000 feet.

Details regarding the specific Advanced Technology Case improvements that were considered for the various EOR processes are contained in Appendices D, E, and F for the chemical, miscible, and thermal methods, respectively. Appendix H contains an overview of needed research that relates to technology advancements.

Data Base Development

Data Sources

The foundation for the data base used in this study was the U.S. Department of Energy's reservoir data base as it existed in October 1982. However, an examination of the DOE reservoir data by study participants determined that additional information was required, and an effort was made to improve and expand the DOE data base.

To be certain that enough data were gathered, it was decided to seek additional data for all reservoirs having 20 million barrels of OOIP or greater and crude oil gravities of 10 °API or greater.[1] Since cumulative production data are usually accurate and readily available, a list of reservoirs having produced 10 million barrels of oil or more (5 million barrels in some cases) was compiled with the assumption that it would include most reservoirs with 20 million barrels of OOIP or greater.

[1]For the purposes of this study, the resource was limited to crude oils that are producible through the wellbore. This generally applies to crude oils with gravities of 10 °API or greater. For the most part, reservoirs with crude oil gravities less than 10 °API were excluded, although there were some exceptions.

A major operator in each reservoir was identified, and requests for data on 1,300 reservoirs were made to these operators. These requests met with a positive response. Further, Lewin and Associates provided a reservoir data base to supplement these data. Still, much of the data were difficult to obtain, and the collection effort was a reiterative process with continuous requests to operators for additional information. The end result of this effort is a reservoir data base far larger and more complete than had previously been available.

Table 5 shows the OOIP by state for the reservoirs in the resulting NPC data base. Figure 16 is a plot of the frequency distribution of reservoir sizes in the NPC data base, which contains over 2,500 reservoirs. The number of

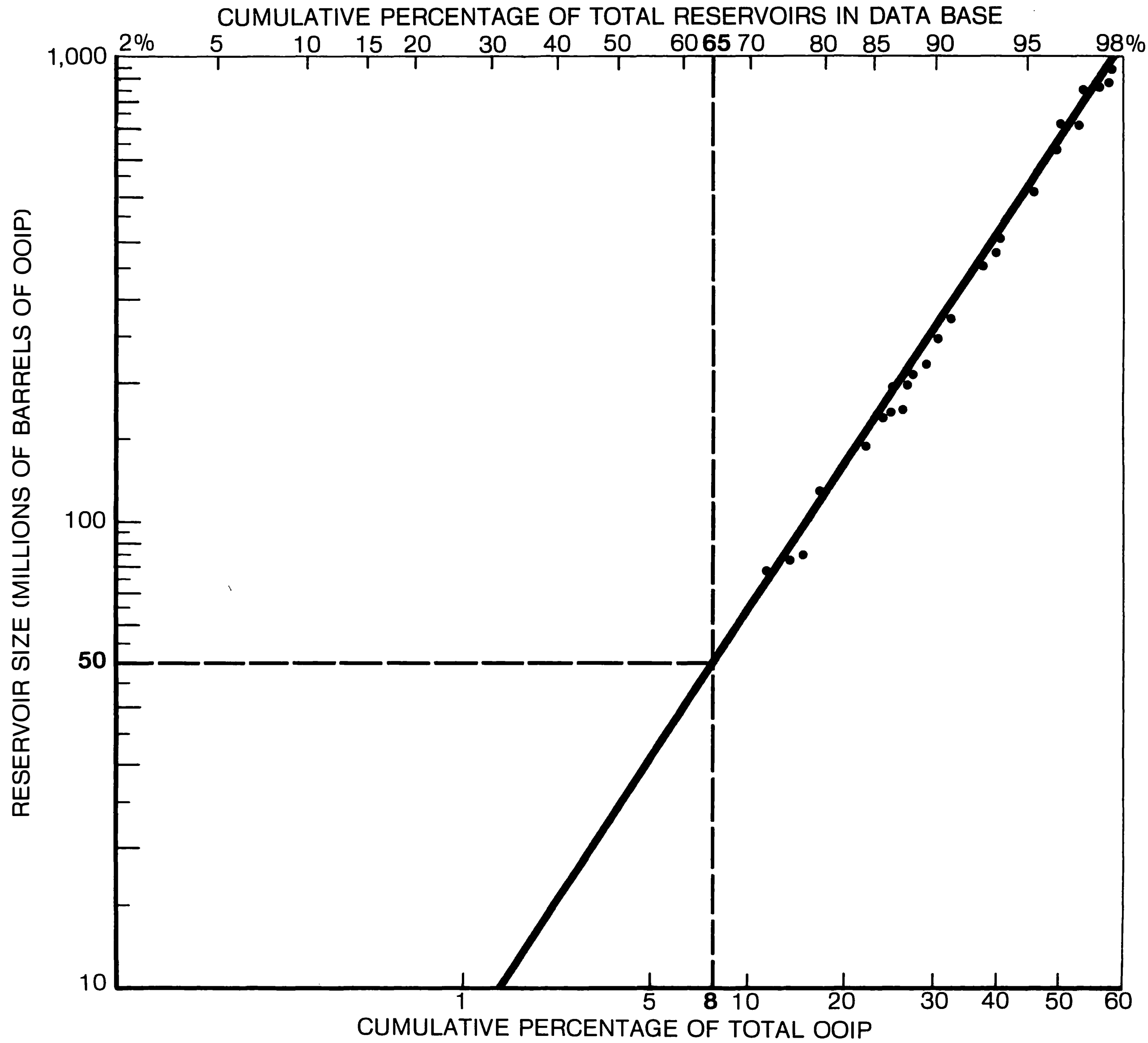


Figure 16. Frequency Distribution of NPC Data Base.

TABLE 5

1984 NPC ENHANCED OIL RECOVERY STUDY DATA BASE INFORMATION (Thousands of Barrels)

	Original Oil In Place			
State	1980 API Estimate	DOE Data Base*	NPC Data Base (20 Million Barrel Cutoff)	NPC Data Base (50 Million Barrel Cutoff)
Alabama	780,693	417,610	417,610	396,930
Alaska	30,115,540	28,666,590	28,666,590	28,666,590
Arkansas	4,317,123	3,636,260	3,477,580	3,234,470
California†	84,696,873	80,022,560	79,688,310	78,056,560
Colorado	4,339,663	3,084,700	2,691,350	2,270,600
Florida	1,054,065	923,480	923,480	846,980
Illinois	9,102,617	5,664,130	5,477,540	5,156,840
Indiana	1,651,165	282,530	282,530	198,600
Kansas	16,278,343	11,219,760	11,106,520	10,453,670
Kentucky	2,129,957	272,940	272,940	155,590
Louisiana†	41,227,666	21,742,000	19,757,520	17,321,300
Michigan	3,005,283	701,660	574,680	469,000
Mississippi	4,965,012	3,482,200	3,173,780	2,630,330
Montana	4,693,975	4,214,240	3,710,720	3,144,580
Nebraska	1,424,226	659,270	406,270	344,180
New Mexico	14,907,084	11,106,230	10,841,540	10,314,790
New York	1,117,739	0	0	0
North Dakota	2,939,572	2,717,110	2,522,060	2,230,000
Ohio	7,319,649	0	0	0
Oklahoma	39,040,687	21,596,860	21,258,430	20,435,880
Pennsylvania	6,671,170	2,187,230	2,172,230	2,172,230
South Dakota	46,595	8,710	0	0
Tennessee	38,926	0	0	0
Texas†	154,696,526	116,703,000	113,033,600	107,454,400
Utah	3,882,990	3,103,010	2,999,970	2,892,630
West Virginia	2,646,506	1,423,650	1,312,880	1,051,070
Wyoming	16,738,538	11,119,610	10,540,490	9,241,680
Miscellaneous‡	194,317	0	0	0
Total	**460,022,500**	**334,955,340**	**325,308,620**	**309,138,900**
% of API OOIP		72.8	70.7	67.2

*Includes reservoirs with OOIP less than 20 million barrels.
†Includes offshore reserves.
‡Includes Arizona, Missouri, Nevada, Virginia, and Washington.

reservoirs increases dramatically as the OOIP decreases, but these reservoirs contain only a small percentage of the total OOIP in the data base. By eliminating all reservoirs with OOIP values less than 20 million barrels, the number of reservoirs to be studied could be reduced by 46 percent while only eliminating 3 percent of the OOIP from the study. A cutoff value of 50 million barrels (indicated by the dashed lines in Figure 16) would eliminate 65 percent of the reservoirs while leaving 92 percent of the OOIP intact in the study. Accordingly, only reservoirs with OOIP values of greater than 50 million barrels were considered in the analysis, since they represent over 67 percent (309 billion barrels) of the OOIP in the United States and 92 percent of the OOIP contained in the revised data base.

Missing Data

Even after the intense effort to complete and refine the data base, some essential information required for the subsequent screening and predictive tasks was still missing. Therefore, appropriate engineering correlations were selected from the large amount of information available within the industry and used to "fill in" missing data when needed. The main objective in using the correlations was to ensure that no reservoirs were left out of the analysis due to data omissions.

Screening Criteria

The Implemented and Advanced Technology Case screening criteria used to select prospective EOR candidates for each process from the NPC data base are summarized in Tables 6 and 7, respectively. Appendices D, E, and F contain further discussion as to how these screening parameters were determined and how they impact the performance of each process. The reservoir screening task was handled by a computer model that read the pertinent reservoir data, compared it to the screening criteria for each process, and then generated a list of potential candidate reservoirs for each process. At this point reservoirs were allowed to appear in more than one process file.

All reservoirs were then reviewed by the study participants. During this second, more detailed manual screen, information concerning additional factors that would influence oil recovery from each reservoir was included whenever such information was available. Both geologic 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. Since the amount of information on reservoir heterogeneity was limited, a pseudo Dykstra-Parsons coefficient was estimated for each reservoir from waterflood performance.

Preference was given to any process that was currently being applied to a reservoir even though it might not have passed the screening criteria. To a large extent, the knowledge of the study participants was relied upon and given priority over information in the reservoir data files. The net result of this second screening pass was that some reservoirs were rejected because of their unfavorable properties, some were added, and some reservoirs were permanently assigned or mandated to a specific process on the basis that the technology was currently being, or would shortly be, applied in that reservoir.

Process Predictive and Economic Models

Process-specific predictive models were developed for each of the alkaline, polymer, surfactant, miscible, steamflood, and in situ combustion processes. These were highly simplified analytical tools as compared to the multidimensional simulators that are frequently used to conduct detailed studies of individual reservoirs. Neither the precision of the input data nor the large number of reservoirs to be handled in this study were compatible with use of more sophisticated models.

The models used for surfactant, miscible, and steamflooding were based on predictive routines originally designed for DOE and made available for this study. Additional predictive models for polymer and alkaline flooding and in situ combustion were developed specifically for this study. Throughout the study, the various models were extensively reviewed, modified, and calibrated against actual field data and against results from more complex reservoir simulators.

Each model consisted of predictive and economic programs. The predictive program used the reservoir-specific input data, including the specified injection rate, to determine the performance of a single pattern. The results consisted of water, oil, and gas production rate projections as well as the volumes of fluids and/or chemicals injected. The economic program then used pattern development schedules that were supplied for each project to scale injection and production to a field-wide basis. At the same time, all surface facilities and well-related equipment were estimated using the

TABLE 6

SCREENING CRITERIA FOR EOR CANDIDATES IMPLEMENTED TECHNOLOGY CASE

Screening Parameters*	Units	Chemical Flooding: Surfactant	Chemical Flooding: Polymer	Chemical Flooding: Alkaline	Miscible Flooding (Carbon Dioxide)	Thermal Recovery: Steam	Thermal Recovery: In Situ Combustion
Oil Gravity	°API	-	-	<30	≧25	10 to 34	10 to 35
In Situ Oil Viscosity (μ)	cp	<40	<100	<90	-	≦15,000	≦5,000
Depth (D)	Feet	-	-	-	-	≦3,000	≦11,500
Pay Zone Thickness (h)	Feet	-	-	-	-	≧20	≧20
Reservoir Temperature (T_R)	°F	<200	<200	<200	-	-	-
Porosity (ϕ)	Fraction	-	-	-	-	≧0.20‡	≧0.20‡
Permeability, Average (k)	md	>40	>20	>20	-	250	35
Transmissibility (kh/μ)	md-ft/cp	-	-	-	-	≧5	≧5
Reservoir Pressure (P_R)	psi	-	-	-	≧MMP†	≦1,500	≦2,000
Minimum Oil Content at Start of Process ($S_o \times \phi$)	Fraction	-	-	-	-	≧0.10	≧0.08
Salinity of Formation Brine (TDS)	ppm	<100,000	<100,000	<100,000	-	-	-
Rock Type	-	Sandstone	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

*Other criteria of a geological and depositional nature were also considered. Generally, reservoirs with extensive faulting, lateral discontinuities, fractures, or overlying gas caps are not prime candidates for field-wide EOR application. These factors were considered during the manual screening step when they could be identified.

†MMP denotes minimum miscibility pressure, which depends on temperature and crude oil composition.

‡Ignored if oil saturation (S_o) × porosity (ϕ) criteria are satisfied.

TABLE 7

SCREENING CRITERIA FOR EOR CANDIDATES
ADVANCED TECHNOLOGY CASE

Screening Parameters*	Units	Chemical Flooding: Surfactant	Chemical Flooding: Polymer	Chemical Flooding: Alkaline	Miscible Flooding (Carbon Dioxide)	Thermal Recovery: Steam	Thermal Recovery: In Situ Combustion
Oil Gravity	°API	–	–	<30	≥25	–	–
In Situ Oil Viscosity (μ)	cp	<100	<150	<100	–	–	≤5,000
Depth (D)	Feet	–	–	–	–	≤5,000	–
Pay Zone Thickness (h)	Feet	–	–	–	–	≥15	≥10
Reservoir Temperature (T_R)	°F	<250	<250	<200	–	–	–
Porosity (ϕ)	Fraction	–	–	–	–	≥0.15‡	≥0.15‡
Permeability, Average (k)	md	>10	>10	>10	–	≥10	≥10
Transmissibility (kh/μ)	md-ft/cp	–	–	–	–	–	–
Reservoir Pressure (P_R)	psi	–	–	–	≥MMP†	≤2,000	≤4,000
Minimum Oil Content at Start of Process ($S_o \times \phi$)	Fraction	–	–	–	–	≥0.08	≥0.08
Salinity of Formation Brine (TDS)	ppm	<200,000	<200,000	<200,000	–	–	–
Rock Type	–	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

*Other criteria of a geological and depositional nature were also considered. Generally, reservoirs with extensive faulting, lateral discontinuities, fractures, or overlying gas caps are not prime candidates for field-wide EOR application. These factors were considered during the manual screening step when they could be identified.

†MMP denotes minimum miscibility pressure, which depends on temperature and crude oil composition.

‡Ignored if oil saturation (S_o) × porosity (ϕ) criteria are satisfied.

appropriate process-dependent and process-independent costs to determine the total investment requirements as a function of time. Operating costs were handled in a similar fashion. Each model generated summaries estimating the annual and cumulative production, injection, revenue, investment, operating cost, tax, royalty and cash flow streams to be used for the rate of return and present worth calculations and to be carried forward in the subsequent compositing steps.

Detailed discussions of the process predictive models are presented in Appendices D, E, and F.

Economic Considerations

Constant Dollar Analysis

A constant dollar analysis procedure is used throughout this report. All costs and prices are expressed in 1983 dollars and are presumed to be constant throughout the study period. This allows comparison of the various study projections in real terms, undistorted by estimates of future inflation rates.

Crude Oil Prices

The historical trend of domestic crude oil prices is illustrated in Figure 17 on both an actual and a 1983 inflation-adjusted basis. Crude oil price forecasting is a very difficult and speculative task, and no attempt to do so was made in this study.

Instead, the study considers four nominal crude oil prices of $20, $30, $40, and $50 per barrel in constant 1983 dollars. These nominal prices were presumed to apply to a 40 °API mid-continent crude oil. Actual crude oil prices vary with API gravity and geographic location. Failure to account for this would have introduced a serious distortion in the results. Therefore, correlations were developed that correctly account for these factors.

Gravity and Location Adjustments. Crude oils having an API gravity of less than 40° were subjected to a price adjustment to appropriately account for their poorer quality and the fact that lower gravity crude oils yield lower value refined products. Although it may be true that crude oils with gravities greater than 40 °API produce higher value refined products,

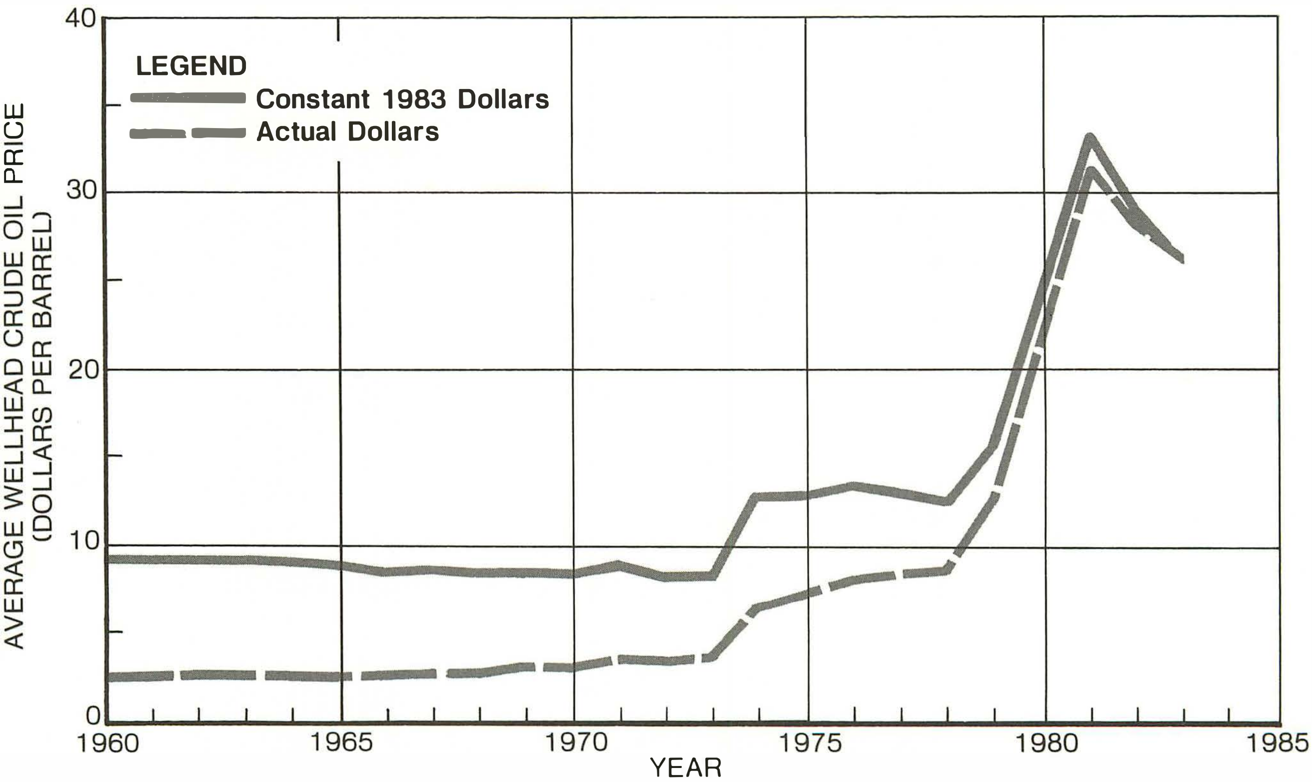


Figure 17. Historical Average U.S. Crude Oil Price Trends.

SOURCE: *Basic Petroleum Data Book, Petroleum Industry Statistics,* Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (November 1983).

and therefore are worth more to a refiner, no attempt was made to compensate for crude oil gravities of greater than 40 °API, because the price correction would have been quite small and there were very few crude oils with such gravities included in this study.

To determine the appropriate magnitude of the price adjustment, various crude oil postings from around the United States were studied. The analysis showed that relatively good crude oil price versus API gravity correlations could be developed if the California postings were correlated separately from those in the mid-continent region. Figures 18 and 19 display the California and mid-continent postings, respectively. In each case, the data indicated that there were a number of natural price breaks that could be approximated as straight line segments. This allowed the crude oil price versus gravity relationships to be easily incorporated in the economic models for each process.

Since the postings shown in Figures 18 and 19 were determined during a period when domestic crude oil prices were a nominal $30 per barrel, the curves shown in these figures were applied to the nominal $30 per barrel base case. Gravity and location adjustments were also made for the $20, $40, and $50 nominal price cases, using a procedure described in Appendix C.

For each nominal crude oil price case, all revenues, royalties, and taxes, and all oil price dependent costs, were calculated using the adjusted crude oil prices. Results are described and composited according to the nominal oil price. It is important to remember, however, that for each nominal crude oil price, the average sales price is less.

Alaska. Alaskan crude oil prices were also treated in a special manner. Because of its remoteness from conventional large market areas, Alaskan crude oil, particularly that from the North Slope, is subjected to rather large transportation differentials.

The North Slope oil is moved through the Trans-Alaskan Pipeline System to Valdez and is then shipped to other areas of the United States. North Slope crude oil was priced in accordance with the mid-continent gravity adjusted postings in Figure 19 less another $10 per barrel for transportation fees. Some $9 per barrel of the transportation fees are associated with amortized capital, port of entry charges, and fixed tariffs and hence does not vary with oil price. The remaining $1 per barrel was assumed to vary with oil price.

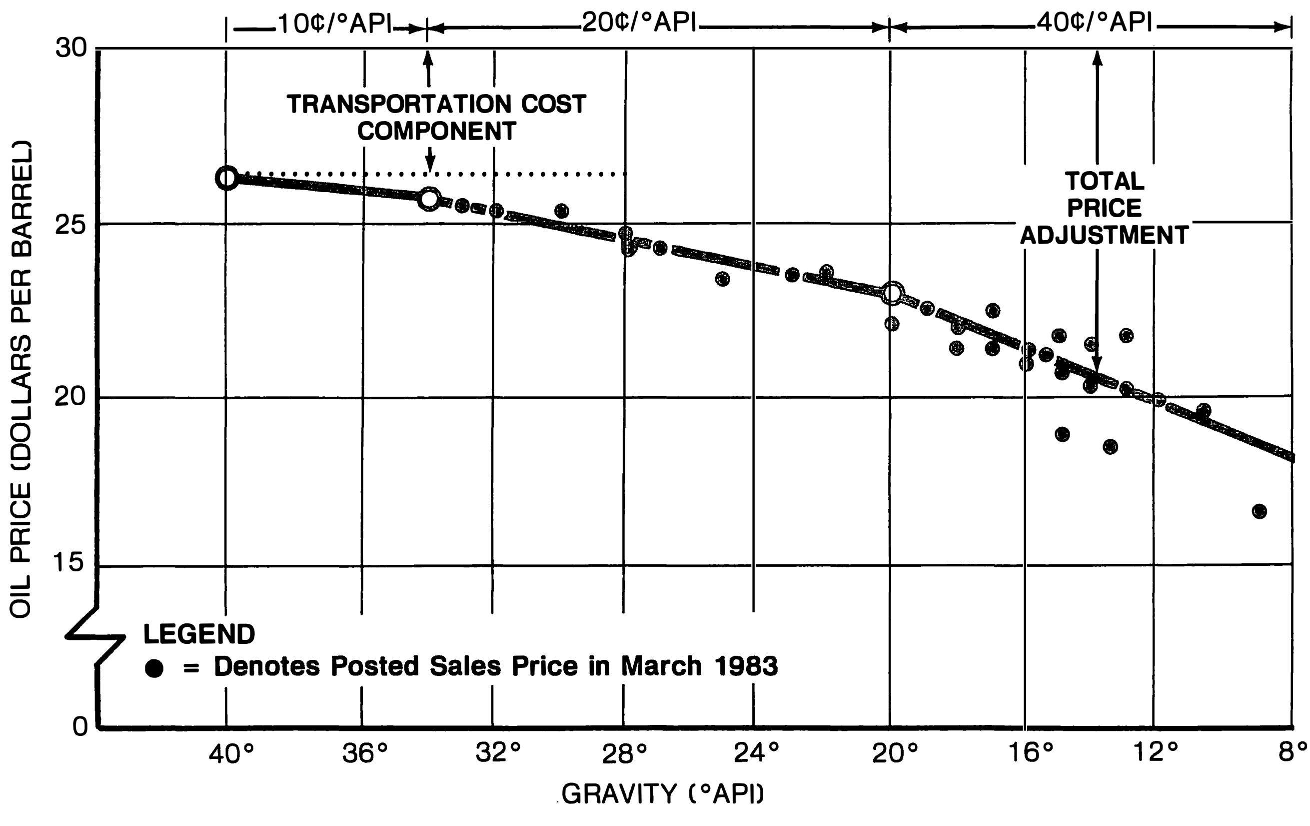


Figure 18. Posted Sales Prices for California Crude Oil in March 1983.

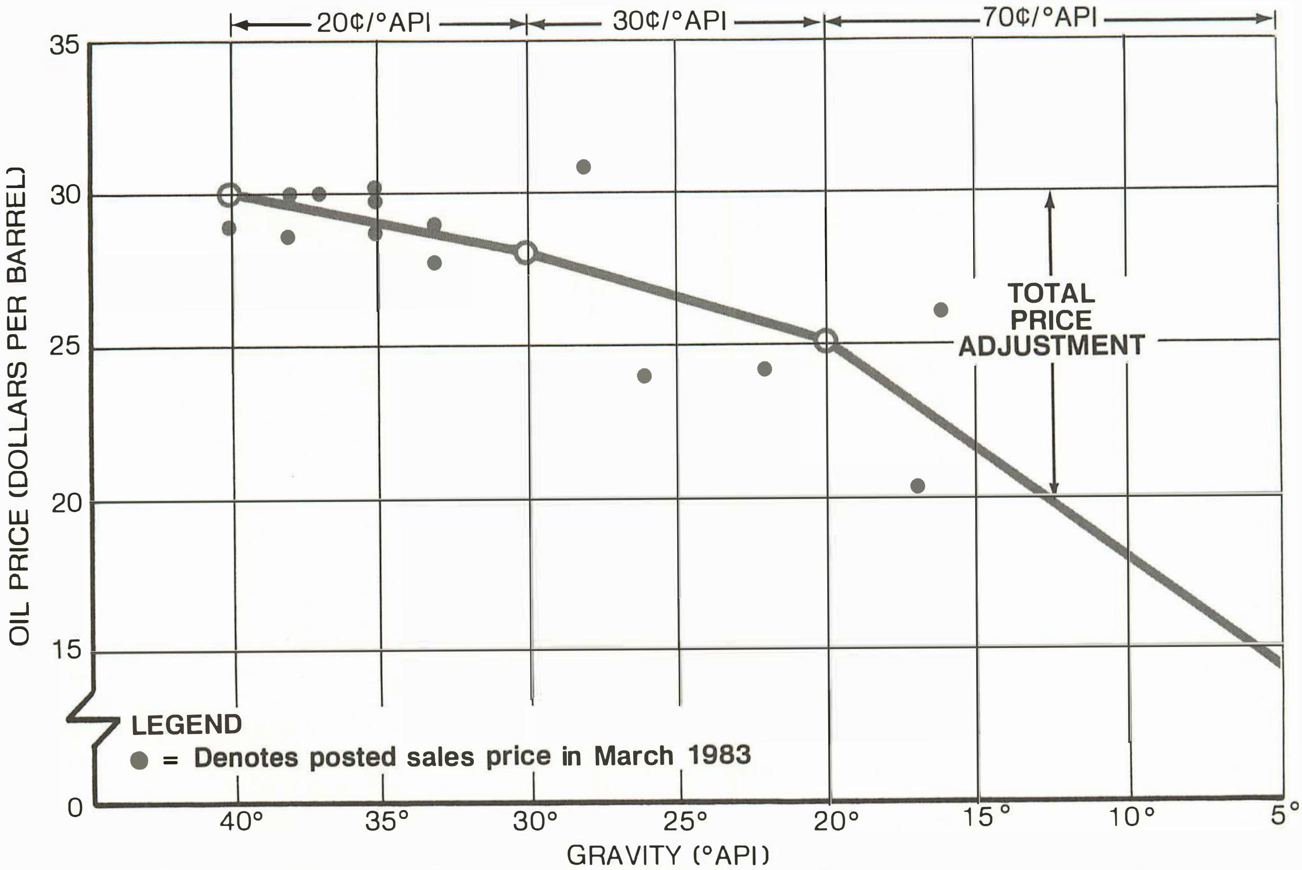


Figure 19. Posted Sales Prices for Mid-Continent Crude Oil in March 1983.

Alaskan crude oil not produced on the North Slope was priced in accordance with the California gravity adjusted postings in Figure 18.

Produced Gas Prices

As it was not practical to determine gas prices on a reservoir by reservoir basis, the decision was made to value natural gas as fuel on a BTU-equivalent basis with the (nongravity-adjusted) nominal price of crude oil. Gas prices used in this study for the various nominal crude oil price cases are summarized in Table 8.

TABLE 8

SUMMARY OF PRODUCED GAS PRICES*

Nominal Crude Oil Price ($/bbl)	California ($/Mcf or $/Million BTU)	Non-California ($/Mcf or $/Million BTU)
20	2.94	3.33
30	4.42	5.00
40	5.89	6.77
50	7.36	8.33

*Assumes that one barrel of crude oil is equal to 6 Mcf of natural gas on a BTU basis.

The small differences between the price of natural gas in California versus the rest of the United States is due to the fact that the California crude oil postings peak at $26.25 per barrel (shown in Figure 18) as opposed to the nominal base $30 per barrel value.

Further discussion of produced gas prices is contained in Appendix C.

Investment and Operating Costs

Both the investment and operating costs used in this study were categorized as being either process-independent or process-dependent. Process-independent costs include items common to all processes such as well drilling and completion costs, workover costs, well equipment costs, the cost of standard surface handling equipment, general lease operating expenses, etc. Process-dependent costs are those more specifically associated with the individual EOR process being studied. The general assumptions used for determining and applying both the process-independent and process-dependent costs are discussed below. More extensive discussions of the specific investment and operating costs are contained in Appendices C, D, E, and F.

Process-Independent Costs

Process-independent costs were estimated on a regional basis using equations that were based on conventional waterflood operations.[2] The special regional correlations used were developed by the Energy Information Administration (EIA) of the Department of Energy. Because miscible and chemical flooding methods utilize the injection of water into the reservoir, their process-independent costs were based on those for installing and operating waterfloods.

Process-Dependent Costs

Chemical Flooding. The major investments for the chemical processes are chemical injection plants and wells. Due to the complex nature of the injection fluids and the need for high fluid quality, special field facilities are required for mixing, filtering, and injecting the surfactant, polymer, and alkaline slugs. Additionally, in the case of alkaline flooding, water-softening equipment is required.

Costs of chemical injection plants are dependent upon both plant capacity and the types of fluids being handled. For each project, this cost was estimated based on the maximum injection rate needed and on the particular chemical process used. Details are given in Appendix D.

Drilling costs were a second major investment for surfactant flooding. Pattern size was chosen for each field by calculating the injection rate that would permit 1.2 pore volumes of fluid to be injected in an 8-year period. The pattern size was limited to a maximum of 40 acres and a minimum of five acres. If the calculated surfactant flood pattern size was less than the existing waterflood pattern size, additional wells were drilled. Pattern sizes for polymer and alkaline flooding were assumed to be the same as during waterflood. Therefore, no additional drilling costs were required. In all cases, the process-independent drilling costs based on waterflooding were used for the producing wells and injection wells.

The major expense for chemical flooding methods is the cost of the various chemicals. Typical chemicals used are primary surfactants, secondary surfactants, polymers, and alkaline agents. Unit costs for each of these items were determined from a confidential survey conducted among the study participants. Methods for adjusting the chemical costs at the nominal \$20, \$40, and \$50 crude oil price cases are detailed in Appendix D.

[2]DOE/EIA-0185(82) report, "Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations, 1982."

Fixed operating expenses for chemical flooding were assumed to be the same as for waterflooding, if the pattern remained the same as for the pre-existing waterflood. Incremental fixed operating expenses were considered only for those projects that required drilling new wells to reduce the pattern size.

The last major expense category considered for chemical floods was for well workovers. A workover cost, estimated to be 20 percent of the cost of drilling a new well, was included based on the assumption that each existing well would be worked over at the start of a chemical flood. A second type of workover, occurring once every eight years, was considered as part of normal waterflooding operations and therefore no additional process-dependent cost was included for these activities.

Miscible Flooding. Because the major potential for miscible flooding is expected to result from the CO_2 miscible process, the detailed process-dependent cost discussion is limited to factors dealing with CO_2. Other miscible processes such as hydrocarbon gas and nitrogen injection have somewhat different process-dependent costs, and were handled separately.

The major investment for many CO_2 projects is the produced gas processing and recycle plant. The purpose of such a plant is twofold, namely processing hydrocarbon gas and condensate products for sale and extracting a relatively pure CO_2 product for reinjection at high pressure. Two specific types of plants were considered in this study. The first are processing plants that separate hydrocarbon and CO_2 product streams and have facilities for compression of CO_2 for reinjection. The second are plants designed to reinject the entire produced gas stream, and this type requires considerably less investment than the first. The principal incentive to make the large incremental investment for the more complex type of plant is the revenue from the hydrocarbon gas and liquid product sales. It was assumed that these incremental revenues would offset the incremental investment; thus, only the investment for the second type of plant was considered for this study.

Well costs are also a major investment. Generally, if the well spacing was 80 acres or less, and injectivity would permit reasonable rates, no infill drilling was assumed. Some reservoirs, because of low injectivity or age of the wells, were assumed to require additional drilling. For the purpose of this study, no incremental process-dependent factor was added to the process-independent well costs. When pattern spacing and injectivity were considered reasonable, one new injection well was assumed to be required for every three patterns, with two producing to injection well conversions for the other two patterns.

CO_2 for injection is the major expense item for CO_2 miscible projects. The price of CO_2 varies by geographic region and distance of the reservoir from the CO_2 source. The lowest CO_2 price was for the West Texas/East New Mexico area where CO_2 is being transported in large volumes by pipeline from natural underground sources. The highest CO_2 price assumed for the purpose of this study was in isolated regions where industrial plant byproducts are the most likely source of CO_2. The CO_2 prices used in this study were regionalized in this manner and adjusted by an energy cost factor for the various nominal crude oil price cases.

Plant operating costs for CO_2 recycling are another expense specific to CO_2 projects. The operating expense for CO_2 processing and reinjection facilities was included in the economics for miscible flooding. Generally, 30 to 40 percent of the CO_2 injection requirements for a reservoir were supplied by recycled CO_2 since a reservoir is usually developed over several years with early patterns furnishing CO_2 for those patterns developed at a later date.

While the per well workover costs were assumed to be the same for a normal waterflood, the number of workovers required for a CO_2 project was doubled from one per well every eight years to one per well every four years.

Additional details regarding the process-dependent costs associated with CO_2 miscible projects are presented in Appendix E.

Thermal Recovery. The procedure used to determine the project-specific investment and operating costs for thermal processes (i.e., steamfloods and in situ combustion) differed from that used for the miscible and chemical processes in the following two ways:

- Full process costs were utilized as opposed to combining incremental process-dependent costs with the process-independent waterflood base costs.
- Significant investment was included for the surface equipment that would be necessary to dehydrate, meter, store, and ship crude oil as well as that required to clean up and dispose of produced water.

A full cost analysis approach was used for all thermal processes because these projects are almost always conducted as a primary or secondary production method, whereas miscible and chemical recovery techniques are almost always applied in a post-waterflood or tertiary mode. Consequently, the historical cost data available for thermal operations include the full cost of applying the technology and the most logical choice was to use the data in its original form.

The decision to include significant investment for central handling facilities was also unique to the thermal methods, again due to the fact that very few economical thermal projects are conducted in reservoirs that have yielded good primary and secondary recoveries. This meant that sufficient surface equipment to handle the high oil and gas rates associated with a large steamflood or in situ combustion project would need to be added as part of the thermal installation. In contrast, sufficient surface production facilities would normally be on hand from the waterflood operation for the miscible and chemical processes.

The specific investment and operating cost data for both steamflooding and in situ combustion, and other factors affecting how this information was applied, are discussed in detail in Appendix F.

Overhead Costs

Each project was subjected to certain overhead costs, which were determined by applying a factor to drilling and completion expenditures, direct operating costs, and construction costs. For drilling and completion, overhead was assumed to be 5 percent. A 20 percent factor was applied for direct operating costs (excluding the cost of injectants) and a 2 percent factor was used for construction costs. These percentages are considered to be consistent with industry experience.

Energy Cost Factors

Relationships were determined between crude oil price and major groupings of the various cost components. These relationships, called energy cost factors, were applied to all applicable cost parameters as the nominal crude oil price changed from the base $30 per barrel value.

Historical cost data were compared on an inflation adjusted basis to determine the proper relationship between crude oil price and costs. Costs were grouped into the following three categories:

- Drilling and Completion
- Facilities and Equipment

- General Operating Costs (exclusive of injectants, which were handled separately).

As a result of this analysis, energy cost factors were derived such that for each 100 percent change in crude oil price, drilling and completion costs would change by 40 percent, equipment costs by 30 percent, and general operating costs by 20 percent. Fuel costs were assumed to vary directly (i.e., energy cost factor of 1.0) with nominal crude oil price. The method of using these cost factors is described in Appendix C.

Tax and Royalty Considerations

Federal and State Income Taxes

A statutory corporate tax rate of 46 percent on ordinary income was used, which is consistent with current tax laws. Although state and local taxes vary considerably from state to state, a single representative tax rate was selected. Based on a review of the tax rates in key producing areas, a state and local tax rate of 4 percent of net profits was used in the economic model for all properties except for the Federal Offshore, where no state tax applies.

Other Taxes and Royalty

Severance tax rates also vary from state to state. A review of the data indicated that a rate of 8 percent of net revenue is a fair representation of the major oil producing states; thus, this rate was chosen for severance taxes.

A royalty of 12.5 percent of gross revenue was considered for all projects. It is recognized that this is no longer the prevailing rate as royalties range upward to 33.3 percent and beyond in some cases. However, many of the projects considered in this study are either on fee acreage or on old leases where lower rates still exist. The 12.5 percent rate was therefore considered to be representative and appropriate.

Windfall Profit Tax

The Crude Oil Windfall Profit Tax Act of 1980[3] provided for an excise tax to be levied on U.S. crude oil production. The Windfall Profit Tax (WPT) is applied as a percentage of the difference between the actual sales price of the crude oil and a specified base price that escalates with time. The WPT rate and the base price vary with crude oil production method and field history, with the maximum WPT rate being 70 percent for ongoing production at the time of the Windfall Profit Tax Act enactment. Under the Act, a reduced tax rate was established for qualified tertiary recovery projects.

The WPT rate on tertiary oil is 30 percent as compared to a 70 percent rate for most nontertiary oil production. A "base level production" is determined by averaging the daily production for the property over the six-month period ending March 31, 1979. The law provides for a statutory decline of this production rate by one percent per month until the start of EOR injection activities and thereafter a decline rate of 2½ percent per month is used. Tertiary oil (taxed at 30 percent) is defined by the Act as the amount of oil produced in excess of the statutory decline amount. As legislated, the WPT is scheduled to phase out over a 33-month period beginning when government revenue reaches a cumulative total of $227.3 billion, but no earlier than January 1988 and no later than January 1991. Because oil prices have fallen during the early 1980s, cumulative government revenue is far short of this maximum value, and therefore, the tax will most likely begin to phase out at the latter of these dates.

In order to minimize the effect on marginal properties, the maximum WPT paid is limited to 90 percent of the "taxable income" of each lease property. In addition, the specific calculations depend upon whether the producer is considered as a major or independent company.

The reduction in the WPT rate for enhanced oil recovery, coupled with the increased statutory decline rate of 2½ percent per month, was intended to provide an incentive for enhanced oil recovery. Whether this is a real incentive depends upon the balance between the benefit of the reduced tax burden and the incremental costs and risks associated with the EOR project. The Windfall Profit Tax Act tends to favor lower cost processes or higher cost processes in fields with substantial secondary oil production. The effects of the Windfall Profit Tax Act are both process and reservoir specific.

None of the results presented in this study include the effects of applying the WPT in the economic calculations. Under current law, the WPT will phase out in 1993. More than 75 percent of the production estimated in this study comes after this date. As a result, it would not be subject to the tax. To verify that the gross effects of the tax could be ignored for the general purposes of this study, a test run was made on a sample set of 100 reservoirs. Some projects were adversely affected by the tax, others benefited, and many showed little change. This observation is consistent with the

[3]Crude Oil Windfall Profit Tax Act of 1980, Public Law 96-223 (94 Stat. 229), April 2, 1980.

findings of other analyses of this nature.[4] The study participants therefore concluded that it was a good approximation to ignore the tax when determining composited results for a large number of EOR projects.

Additional discussion of the Windfall Profit Tax Act and its impact on the future of enhanced oil recovery is contained in Chapter Six.

Depreciation and Credits

Other tax considerations include an investment tax credit of 10 percent and the use of the Accelerated Capital Recovery System's five-year schedule as legislated in the Economic Recovery Tax Act of 1981. The purchase of nonhydrocarbon injectants for EOR projects was expensed in the year the fluid was injected rather than being treated as an investment. Drilling costs were assumed to be 72 percent intangible and 28 percent tangible for all projects except those employing thermal methods, which used a 60 percent intangible and 40 percent tangible split. These allocations appear to be representative of industry experience.

Economic Indicators

Rate of Return Cases

All rate versus time projections in this study (i.e., compositing runs) are based on a minimum discounted cash flow rate of return (minimum ROR) of 10 percent. This means that only projects that produced a 10 percent rate of return or greater (according to the predictive model economic analyses) are included in the rate projections described in Chapter Four. It should not be taken to imply that undertaking all of these projects will actually produce such a rate of return.

Companies invoke different investment and project evaluation criteria based upon their specific cost of capital, the portfolio of investment opportunities available, and their particular methods of compensating for the perceived technical risks, all of which vary with time. Use of the 10 percent minimum ROR in this study should not in any way be construed to imply that any one particular rate of return is universally acceptable to the petroleum industry.

The sensitivity of ultimate recovery to rate of return was measured for the Implemented Technology Case. Ultimate recovery potential was determined for each EOR process for minimum RORs of 0, 10, and 20 percent. The results for each of these rate of return cases are described in Chapter Four.

Investment Efficiency

It was necessary to use some form of ranking criterion to determine which EOR projects would be started in the early years of the study period, and which projects would be delayed. A measure of project profitability was required for this determination, and the study participants employed a ranking criterion called Investment Efficiency. This parameter is defined as the ratio of the project's total discounted cash flow to the maximum cumulative negative discounted cash flow. The discount rate used for the calculation was set equal to the minimum ROR used in compositing (i.e., 10 percent). A more detailed discussion of Investment Efficiency is contained in Appendix C.

Compositing Procedure

The purpose of the compositing procedure was to take the results from the predictive and economic models for each process and combine them to predict ultimate recovery and producing rates, both in total and for each process. This was carried out in two steps, assignment and timing, each assisted by a computer model but guided by the engineering judgment of the study participants.

The general steps in the compositing procedure are illustrated in Figure 20. The various process non-exclusive data files (resulting from the appropriate screens and economic runs) were passed to the assignment model, along with the specified ongoing projects. The assignment model determined the single best process for each reservoir and placed the reservoir in the proper file (reservoirs not economic under any process were placed in the uneconomic file). These process-exclusive files were passed to the timing model, which scheduled the projects in calendar time. Timing results were reviewed for consistency and reasonableness. A case was rerun, where necessary, with varying timing or other parameters.

The compositing procedure was generally the same for both the Implemented and Advanced Technology Cases. However, there were some differences in detail and these two cases are described separately below.

Implemented Technology Cases

Assignment Model

The first step in the compositing procedure was to assign each reservoir to only one of the

[4] "The Windfall Profit Tax and Enhanced Oil Recovery," prepared for the U.S. Department of Energy by S. Thompson, PYROS Inc., Oct. 27, 1982.

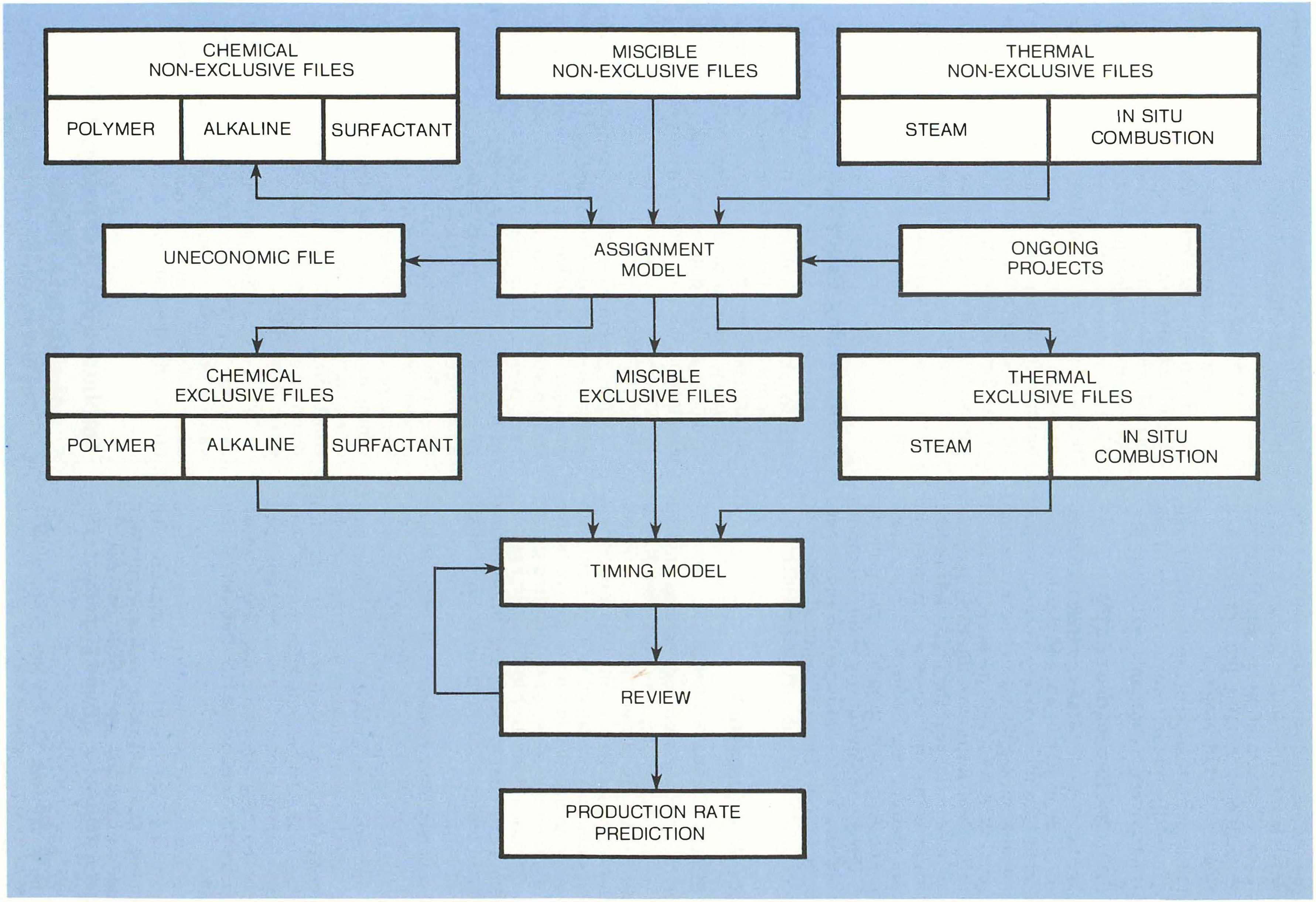


Figure 20. Outline of Compositing Procedure.

EOR processes. Specific process assignments were made on the following basis:

- Reservoirs with "ongoing" EOR projects already in place were assigned to that process regardless of the relative recovery and economic feasibility of any other process.
- Reservoirs for which specific EOR projects have been planned and publicly announced were treated as "ongoing" projects and thus were assigned to the corresponding process.
- Reservoirs that had been pre-assigned to any particular process by the study participants for any special mechanical or environmental reason were assigned accordingly.
- All remaining reservoirs where projects exceeded the minimum ROR were assigned to the process that recovered the most oil at each nominal crude oil price and minimum ROR combination. Reservoirs that had no process meeting the minimum ROR at a given nominal crude oil price were eliminated for that nominal crude oil price and minimum ROR combination.
- No reservoir was assigned to in situ combustion if it also passed the minimum ROR for steamflooding.

Timing Model

The second step in the compositing procedure was to determine the start date for each project. This was handled by a separate timing model. All projects were ranked in decreasing order of Investment Efficiency and brought on stream starting in 1984, subject to restrictions that prevented all projects from starting in the same year. The various factors that determined these restrictions were:

- The amount of surfactant the project required
- The amount of carbon dioxide required
- The geographic location of the reservoir
- The level of industry confidence in the particular EOR process; i.e., the need for additional pilot testing for surfactant flooding
- The engineering judgment of study participants.

(Some additional discussion of these factors as they impacted individual processes is contained in Appendices D, E, and F.) The timing model initiated all projects, taking the various factors into account, and produced composite oil production for each process on a year by year basis.

Advanced Technology Cases

Compositing of the Advanced Technology Cases was somewhat more complicated than the procedure for the Implemented Technology Case. The overall assignment and timing projections break down into three periods: 1984-1987, 1988-1994, and after 1995.

1984-1987

During the 1984-1987 period, no advanced technology was made available. All reservoir assignments and all oil recoveries were identical to those for the Implemented Technology Case.

1988-1994

Advanced technology was applied to ongoing steam projects in 1988. All reservoir assignments remained the same, but the thermal recovery projections included the additional costs and oil recovery associated with the Advanced Technology Case. During this time period, advanced technology was applied only to reservoirs with steam projects that were ongoing in 1984.

After 1995

Advanced technology became available to all processes in 1995. Compositing continued on the following basis:

- Any reservoir where a project was initiated prior to 1995, except those assigned to the polymer process, continued to be assigned to that process. Implemented polymer projects also remained assigned to the polymer process and continued to produce; however, these reservoirs were also subsequently allowed to be re-assigned to another process, providing it was economic when evaluated under the Advanced Technology Case conditions.
- Reservoirs where projects were not initiated prior to 1995 were assigned by a procedure identical to that described above for the Implemented Technology Case. However, the starting point for assignment and timing was the process predictive and economic output for the Advanced Technology Case.
- Projects that were (1) economic under implemented technology, (2) not initiated before 1995, and (3) uneconomic under advanced technology were made

available for assignment after 1995 using their Implemented Technology Case results.

The polymer process exception above was specified to allow additional EOR to be included in the Advanced Technology Case projections. It was justified on the basis that oil production from the polymer process occurs because of increased sweep efficiency and not because it reduces the oil content in that portion of the reservoir swept during waterflooding. Therefore, in some cases, sufficient oil may remain to permit economic application of one of the more efficient processes such as surfactant flooding or miscible flooding.

In a few cases, a project that was economic under implemented technology was not initiated before 1995, and was uneconomic under advanced technology. In these cases, the implemented technology version of the project continued to be available for timing after 1995. This situation occurred when increased production of the project's Advanced Technology Case failed to offset its increased costs. Allowing the Implemented Technology Case to be available prevented losing the project after 1995.

Once the assignment task was completed, the timing step for the Advanced Technology Case was similar to that of the Implemented Technology Case. Projects were initiated beginning in 1995 in order of decreasing Investment Efficiency and in accordance with the factors described for the Implemented Technology Case. The only difference was that the magnitudes of certain factors, such as CO_2 availability, were increased. This resulted in an accelerated rate of development and higher producing rates. Additional information on the development and use of these factors is contained in Appendices D, E, and F.

Transition Projects. The Advanced Technology Case timing model calculated the composited production on a calendar year basis for each individual EOR process and for all processes by combining the results for the various time periods. Projects completed before 1995 obviously contributed only that amount of oil attributable to implemented technology, while those starting after this date contributed all of the oil attributable to the corresponding technological improvements.

For those projects caught in the technology "transition," the prudent operator would naturally use any technological advancement that would improve future performance. Transition projects were therefore allowed to benefit from advanced technology for whatever productive life remained after 1995. In this manner, a proportional amount of the additional oil that would be recovered due to technology improvements was properly accounted for in the study results.

Other Factors

Other, less quantitative factors could not be explicitly incorporated in the timing procedure. For the most part, these factors exert periodic short-term effects as opposed to long-lasting influences. As such, they have a much greater effect on rate projections than on ultimate recovery potential.

Environmental Considerations

Environmental regulations impact all phases of oil recovery. Costs related to environmental conservation were included in this study to the extent that these factors could be included in the generalized design specifications for each project.

A more complete discussion of the pertinent environmental considerations that affect enhanced oil recovery is presented in Appendices D, E, and F (individual process appendices) and in the form of an industry overview in Appendix G.

Technological Risks

Throughout this study the industry participants used their best engineering judgment to assure that the final results reflect the technical risks associated with the various processes, as well as past experiences and perceptions of future trends. Discussions of the technological risks associated with each EOR process are contained in Appendices D, E, and F.

Skilled Manpower

The petroleum industry is a highly technical business requiring a wide variety of skilled disciplines. Enhanced oil recovery is considerably more complex from a research, engineering, and operational viewpoint than conventional operations, and it requires more skilled manpower. The skills involved are generally similar to those required for conventional production, but there is a requirement for an adequate adjustment or training period as a person begins to work on EOR projects.

Over the long term, the number of people skilled in EOR technology will have to increase, as the emphasis shifts from conventional operations to enhanced oil recovery. There may be short periods when people with the required skills may not be available to implement certain projects as fast as might be desired. In the long term, the availability of skilled manpower is not a factor that will likely limit EOR development.

Decision-Making

Two other factors that could affect the rate of EOR development are: (1) the rate at which groups of working interest owners make decisions regarding project implementation, and (2) the rate at which the required permitting and regulatory steps are handled by the appropriate agencies. The time required to satisfactorily deal with these factors is highly variable and project delays may result. For the purposes of this study, however, these factors were assumed not to affect project timing.

Chapter Four

Potential for Enhanced Oil Recovery

This chapter presents the results of the assessment of the EOR potential of known U.S. oil reservoirs. *The results presented in the study are not intended to be a forecast of what will occur. Rather they represent projections of what could happen under certain technical and economic assumptions and constraints.* Chapter Three contains a description of the organization, the methodology, and the major assumptions that are the basis for these results. Appendices D, E, and F present a complete background and documentation of the study and detailed results for chemical, miscible, and thermal processes.

These projections are the result of the effort of experts in the various areas of EOR technology, and other specialists from the petroleum industry. The participants involved in all phases of the study contributed their informed judgment as to the reasonableness of the assumptions, the methodology, and finally the results.

Two basic levels of technology were considered: an Implemented Technology Case and an Advanced Technology Case. Each of these cases was evaluated for sensitivity to crude oil price and sensitivity to rate of return. The base economic case is based on a nominal $30 per barrel oil price, and 10 percent minimum ROR.

It should be noted that these results, and all others presented in this report that include thermal recovery estimates, are gross results and *include the amount of crude oil that would be used as fuel for steam generators.* Actual net sales to market would be somewhat less than the projected volumes.

Implemented Technology—Base Economic Case

All Processes

The estimated ultimate recovery for the Implemented Technology, base economic case is 14.5 billion barrels. This ultimate recovery is distributed among the three major EOR methods as shown in Table 9.

TABLE 9

ULTIMATE RECOVERY IMPLEMENTED TECHNOLOGY, BASE ECONOMIC CASE*

Recovery Method	Ultimate Recovery (Billions of Barrels)	Percent of Total
Chemical	2.5	17
Miscible	5.5	38
Thermal	6.5	45
Total	**14.5**	**100**

*The base economic case assumptions include $30 per barrel nominal crude oil price, 10 percent minimum ROR, and no Windfall Profit Tax.

The base economic case ultimate recovery is distributed among the major EOR methods as shown in Figure 21. This figure also shows a breakdown of the recovery within major methods by process, by geographic location, or by ongoing versus new projects, as applicable.

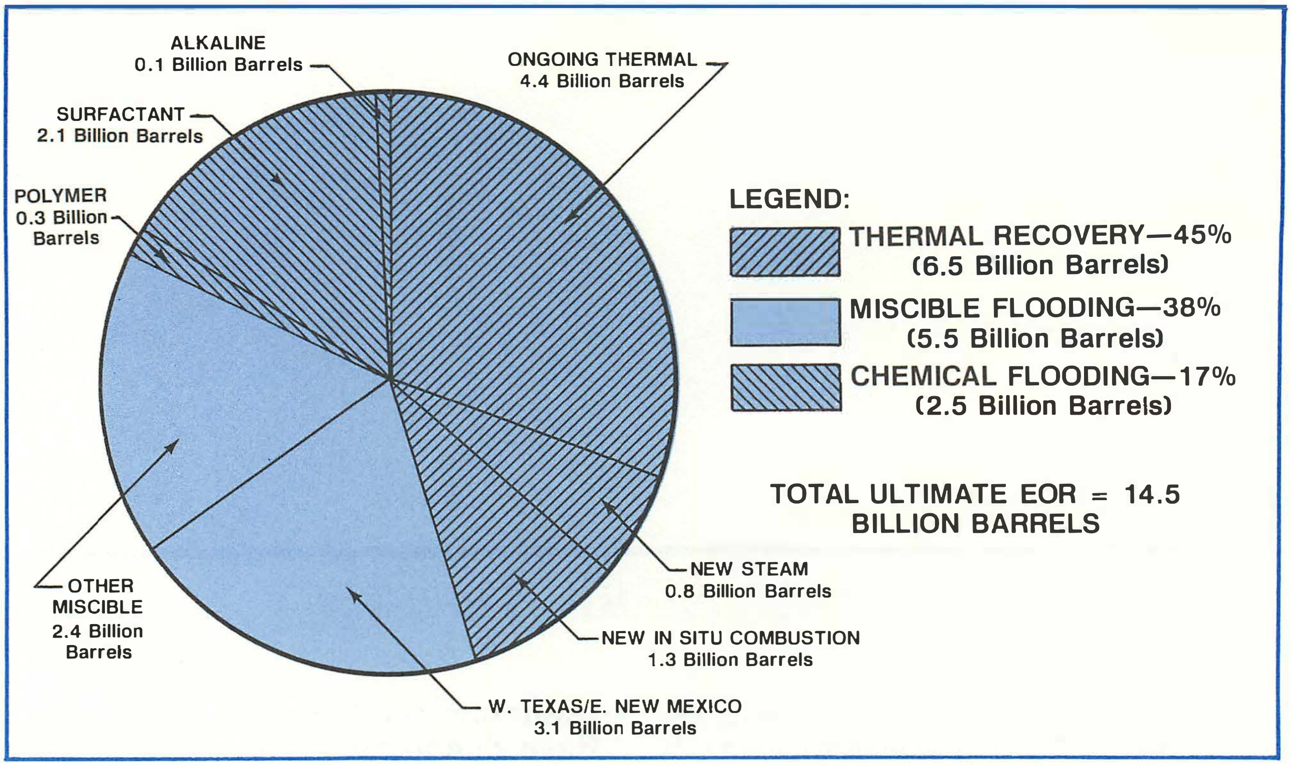


Figure 21. Ultimate Recovery—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

A peak producing rate of about 1.2 million barrels per day is projected in the base economic case. A rate of over 1 million barrels per day could be achieved by the early 1990s, and sustained beyond the year 2005. Eleven billion barrels, or 75 percent of the 14.5 billion barrel ultimate, can be produced during the 30-year projection period. The producing rate projection is shown in Figure 22 for the total, and for each major EOR method. EOR production in 1984 is expected to be 600 thousand barrels per day, mostly from ongoing thermal projects. These producing rate curves demonstrate the contribution of each of the major EOR processes to the total EOR rate. The production rate from the established thermal processes peaks in the early 1990s, and then starts into a steady decline. Production from miscible flooding is on the rise through the rest of the century and peaks after the year 2000. Production from chemical flooding is the smallest contributor during the study period and its peak rate has not yet been achieved by the end of the study period, 2013.

Chemical Flooding—Implemented Technology

For the Implemented Technology, base economic case, chemical methods make the smallest contribution to EOR potential. Of 2.5 billion barrels of total potential, 2.1 billion barrels come from surfactant flooding, 0.3 billion barrels from polymer flooding, and only 0.1 billion barrels from alkaline flooding.

As shown in Figure 23, the producing rate from surfactant flooding is projected to grow slowly throughout the study period, reaching 140 thousand barrels per day by 2013. This is a relatively small contribution to the total EOR producing rate. No significant production from surfactant flooding is foreseen before 1990. This late start and slow buildup, relative to some other EOR processes, reflect the difficult technical problems yet to be resolved. Field tests conducted to date have generally proven uneconomic and hence the process is considered high risk. The projection shown in Figure 23 is based on the presumptions that field testing will continue, and that the necessary improvements in process economics will occur.

Polymer flooding is already finding widespread application. The base economic case production rate is shown in Figure 23 at about 50 thousand barrels per day in the late 1980s, and this rate is sustained for about ten years before declining. Although this is a very modest contribution to the nation's energy

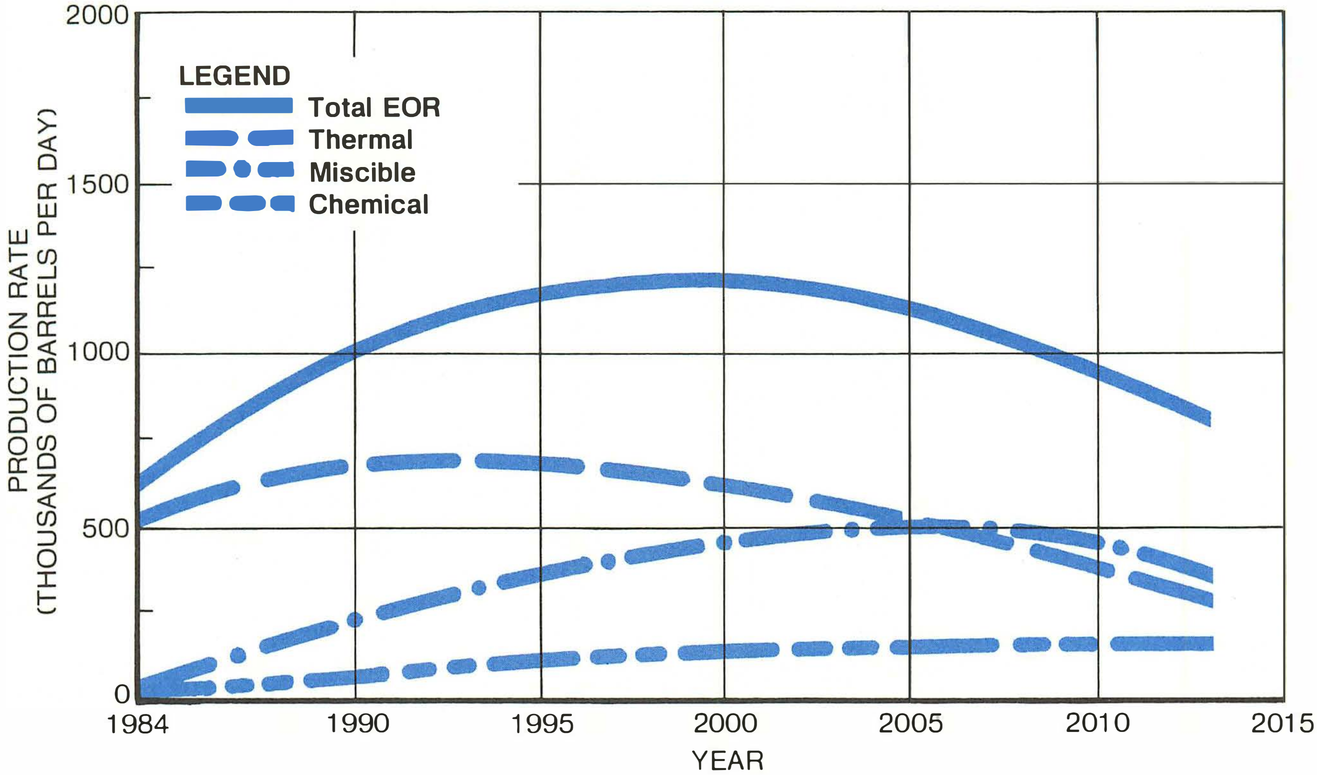


Figure 22. Production Rate—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

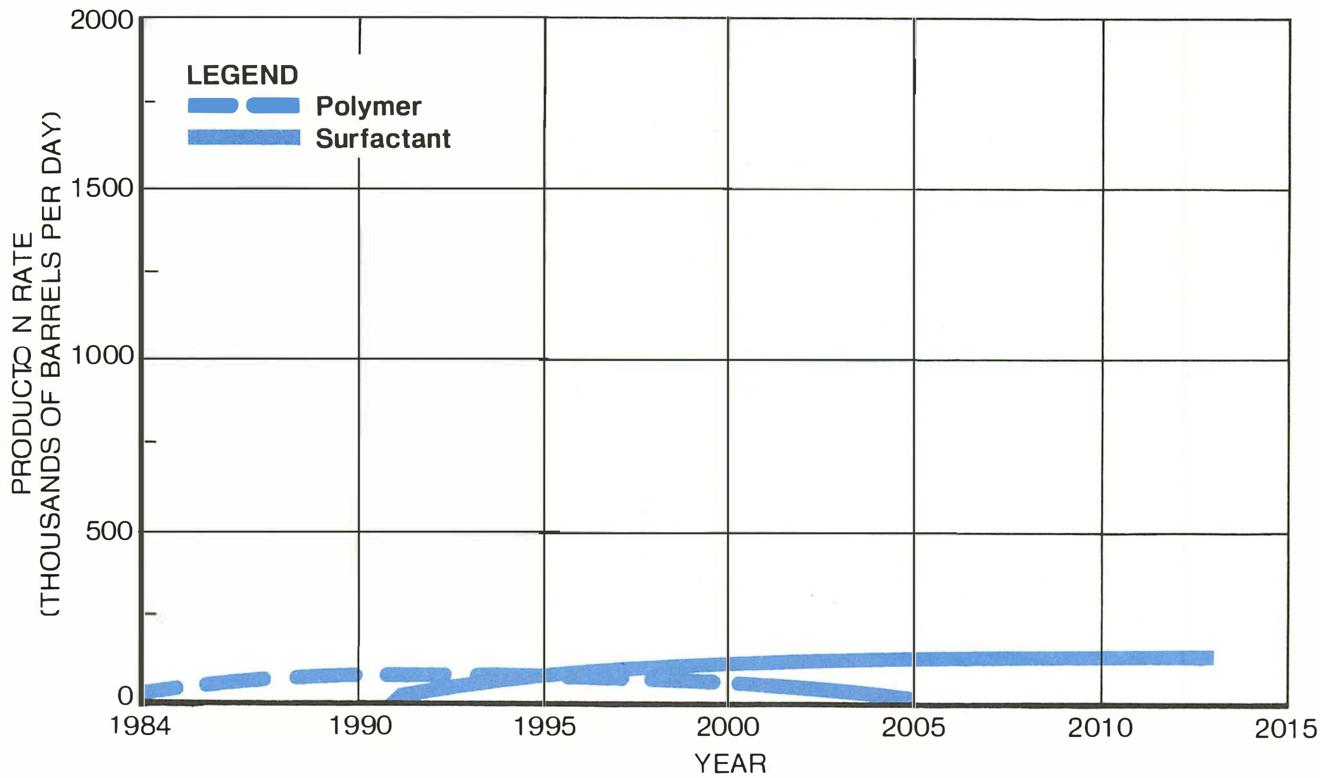


Figure 23. Production Rate for Chemical Flooding—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

supply, polymer flooding may extend the producing lifetime of many fields, thereby keeping them available for a subsequent, more efficient, EOR process.

Implemented Technology Case alkaline flooding shows very little potential. The maximum producing rate is projected to be less than 10 thousand barrels per day, and hence does not appear on Figure 23. This reflects a consensus that the process has not been adequately developed. Future research and field tests may improve the outlook. Appendix D contains further discussion of this subject.

Miscible Flooding—Implemented Technology

For the Implemented Technology, base economic case, miscible flooding contributes 5.5 billion barrels of ultimate recovery to the total potential enhanced oil recovery from known U.S. oil reservoirs. During the 30-year rate projection period, 3.8 billion barrels, or about 70 percent of the miscible flooding ultimate recovery, are produced.

West Texas/East New Mexico carbonate reservoirs represent the single most significant source of miscible flooding potential. The ultimate recovery from this one area is projected to be 3.1 billion barrels by miscible flooding with CO_2, or approximately 60 percent of the estimated total miscible recovery.

The producing rate from the miscible flooding process is projected to peak at 500 thousand barrels of oil per day shortly after the year 2000. This represents an increase in production of 450 thousand barrels per day over the 1984 production rate attributed to ongoing miscible projects. Figure 24 shows the 30-year rate projection for miscible flooding. Also shown on the figure is the contribution of the West Texas/East New Mexico area to this rate. Production from this area is projected to peak soon after the year 2000, at about 330 thousand barrels of oil per day.

Availability of CO_2 for injection is the primary timing constraint for CO_2 miscible floods. The West Texas/East New Mexico area is being supplied large volumes of CO_2 from natural sources by two major pipelines, with a third soon to be completed. The rate projections for the base economic case assume the CO_2 supply for this area will reach 2.1 billion cubic feet per day in the late 1980s. Appendix E contains further discussion of this subject.

Thermal Recovery—Implemented Technology

For the Implemented Technology, base economic case, thermal recovery methods ac-

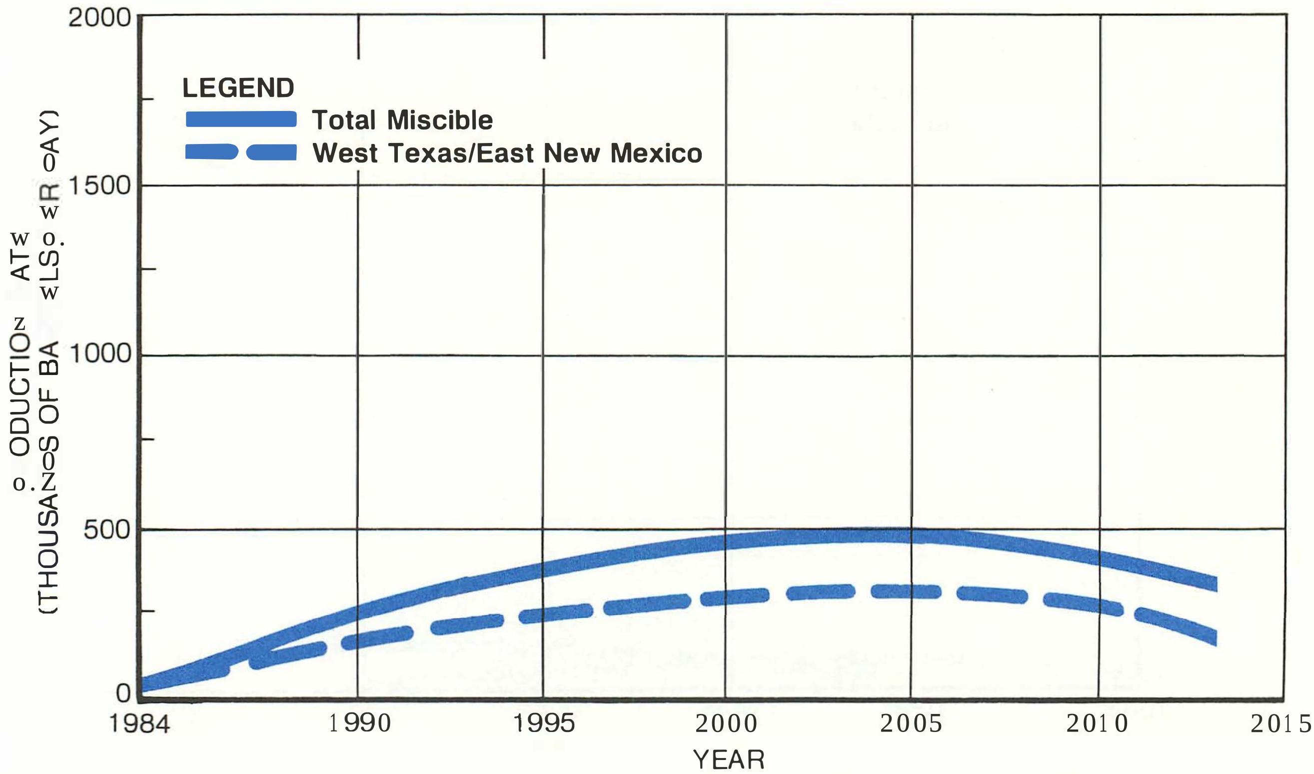


Figure 24. Production Rate for Miscible Flooding—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

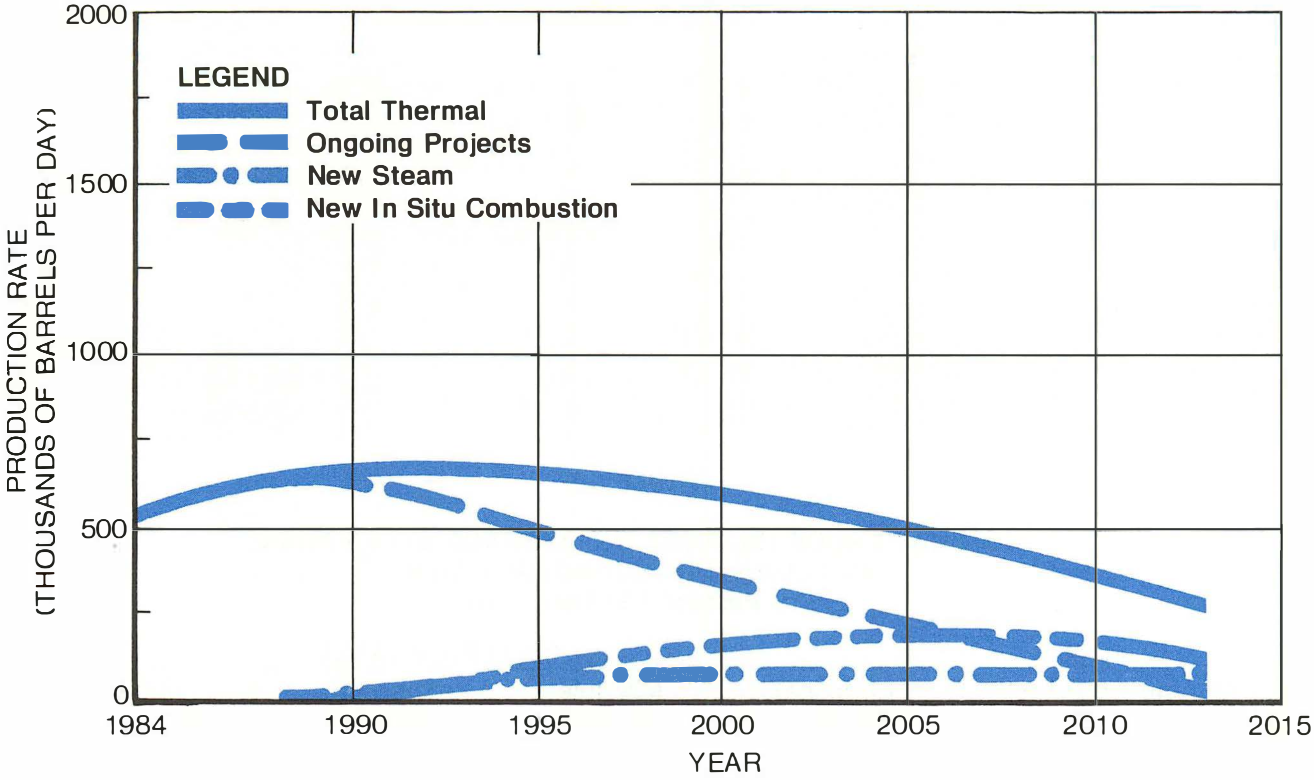


Figure 25. Production Rate for Thermal Recovery—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

count for an ultimate recovery of 6.5 billion barrels, or 45 percent of the total ultimate EOR potential. All thermal recovery shown in this study represents gross production, and includes oil to be burned as steam generator fuel. Production statistics excluding fuel are not available from public industry sources. Ongoing projects account for 4.4 billion barrels of the thermal recovery potential. New steam and new in situ combustion projects will account for 0.8 billion barrels and 1.3 billion barrels, respectively. Included in the potential from ongoing projects are proved reserves estimated at 2.8 billion barrels. These reserves should presently be included in the booked reserves of the producing companies, and therefore do not represent EOR potential incremental to published reserve statistics.

It can be seen from Figure 22 that most of the EOR production during the first 10 years of the study period is from thermal recovery methods. The maturity of thermal development results in a peak producing rate of 685 thousand barrels per day occurring in the early 1990s and declining to approximately 275 thousand barrels per day at the end of the study period. Figure 25 illustrates the producing rates for each thermal recovery category. Beginning in the year 2000, the decline rate of ongoing projects is partially offset by the increasing production from new steam and new in situ combustion projects. Appendix F contains further discussion of thermal recovery projections.

Implemented Technology—Economic Sensitivities

The sensitivities of the results to oil price and minimum ROR were examined in this analysis. Implemented Technology Case ultimate recovery projections were made for all oil price and rate of return combinations. Producing rate projections were made for all oil prices at a 10 percent minimum ROR only.

Sensitivity to Oil Price—All Processes

Three oil prices were examined for sensitivities around the base economic case oil price of a nominal $30 per barrel. For the $20, $40, and $50 per barrel sensitivities (as with the $30 per barrel case), the nominal oil price was assumed to remain constant for the entire 30-year study period. This analysis allows comparisons that demonstrate the effect of real crude oil price on EOR potential.

The nominal crude oil price applies to a 40°API, mid-continent crude oil. It should be noted that the actual average sales price of oil is considerably less than the nominal price when adjustments for API gravity (crude oil quality) and location are included. The weighted average crude oil price for each EOR projection was calculated for the mix of reservoirs in each case. Table 10 shows the results of this analysis, by major method and for all processes combined.

Drilling, equipment, and operating costs vary with oil price changes. Real cost changes were approximated by applying a series of energy cost factors, developed from historical trends. Process-dependent costs were also adjusted for changes in real crude oil price.

Oil price, as expected, significantly influences potential ultimate recovery, and greatly influences the producing rate during the 30-year period. The sensitivities to price result in a range from 7.4 billion barrels at $20 per barrel, to 19.0 billion barrels at $50 per barrel, compared to the base economic case ultimate recovery of 14.5 billion barrels.

The bar graphs in Figure 26 indicate the ultimate recovery for all EOR processes by price, and the portion of the ultimate recovery produced during the 30-year projection. As price increases, a greater percentage of the

TABLE 10

NOMINAL CRUDE OIL PRICE VS. AVERAGE SALES PRICE
IMPLEMENTED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Average Sales Price ($/bbl)			
	Chemical Flooding	Miscible Flooding	Thermal Recovery	All Processes
20	19.45	19.34	14.50	16.28
30	28.98	27.48	22.39	25.45
40	38.26	37.00	29.71	35.33
50	48.00	46.21	37.21	43.17

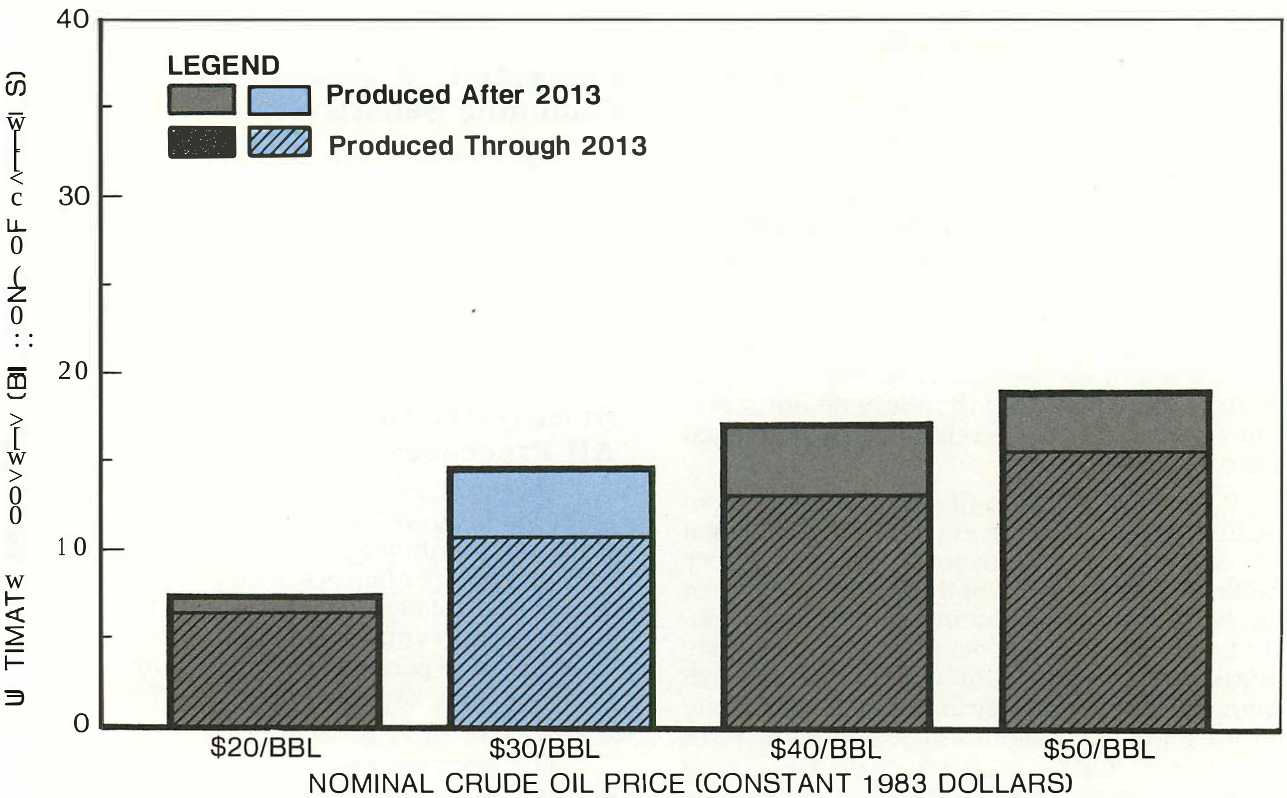


Figure 26. Ultimate Recovery for All EOR Processes vs. Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

TABLE 11

SENSITIVITY OF ULTIMATE RECOVERY TO OIL PRICE AT 10 PERCENT MINIMUM ROR (Billions of Barrels)

Recovery Method	$20/bbl	$30/bbl	$40/bbl	$50/bbl
Chemical	1.0	2.5	3.5	4.1
Miscible	2.0	5.5	7.0	7.7
Thermal	4.4	6.5	7.0	7.2
Total	**7.4**	**14.5**	**17.5**	**19.0**

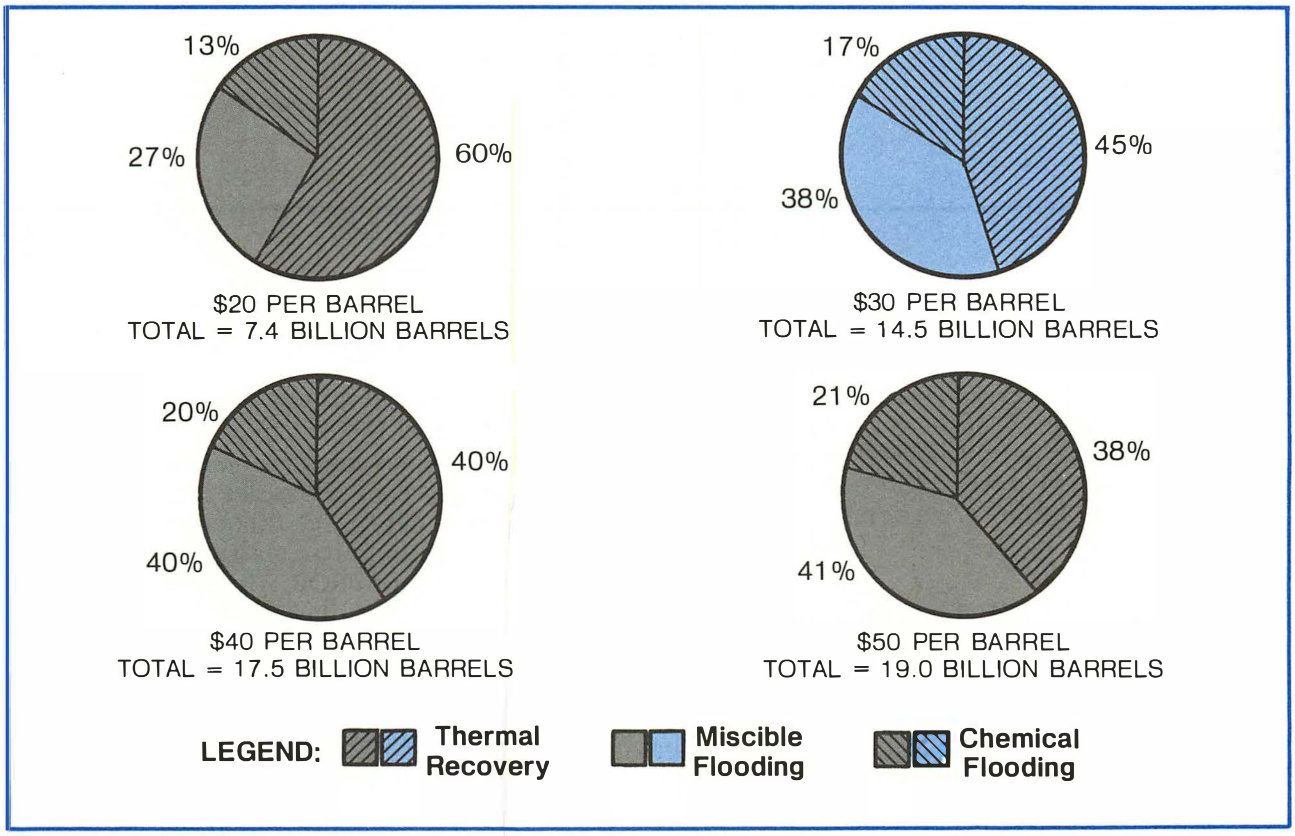


Figure 27. Sensitivity of Ultimate Recovery to Nominal Crude Oil Price (Constant 1983 Dollars) by Major EOR Method—Implemented Technology Case (10 Percent Minimum ROR).

ultimate recovery is produced during the 30-year period; 83 percent of the ultimate is produced during the 30-year period at $50 per barrel, and 75 percent at $30 per barrel. The $20 per barrel case is not comparable because few new projects would be initiated, and the ultimate potential would drop to 7.4 billion barrels, or about half the potential at $30 per barrel.

The distribution of ultimate recovery for each price is shown in Table 11. This sensitivity to price is also presented in Figure 27, which gives the distribution for each of the three major EOR methods. This distribution remains about the same for all cases except the $20 per barrel case. At $20 per barrel, ultimate recovery by thermal methods is about 60 percent of the total because few new projects would be initiated and ongoing thermal projects would account for the bulk of the production.

The sensitivity of total producing rate to real crude oil price during the projection period is shown in Figure 28. At $50 per barrel, the total rate reaches 1.8 million barrels per day

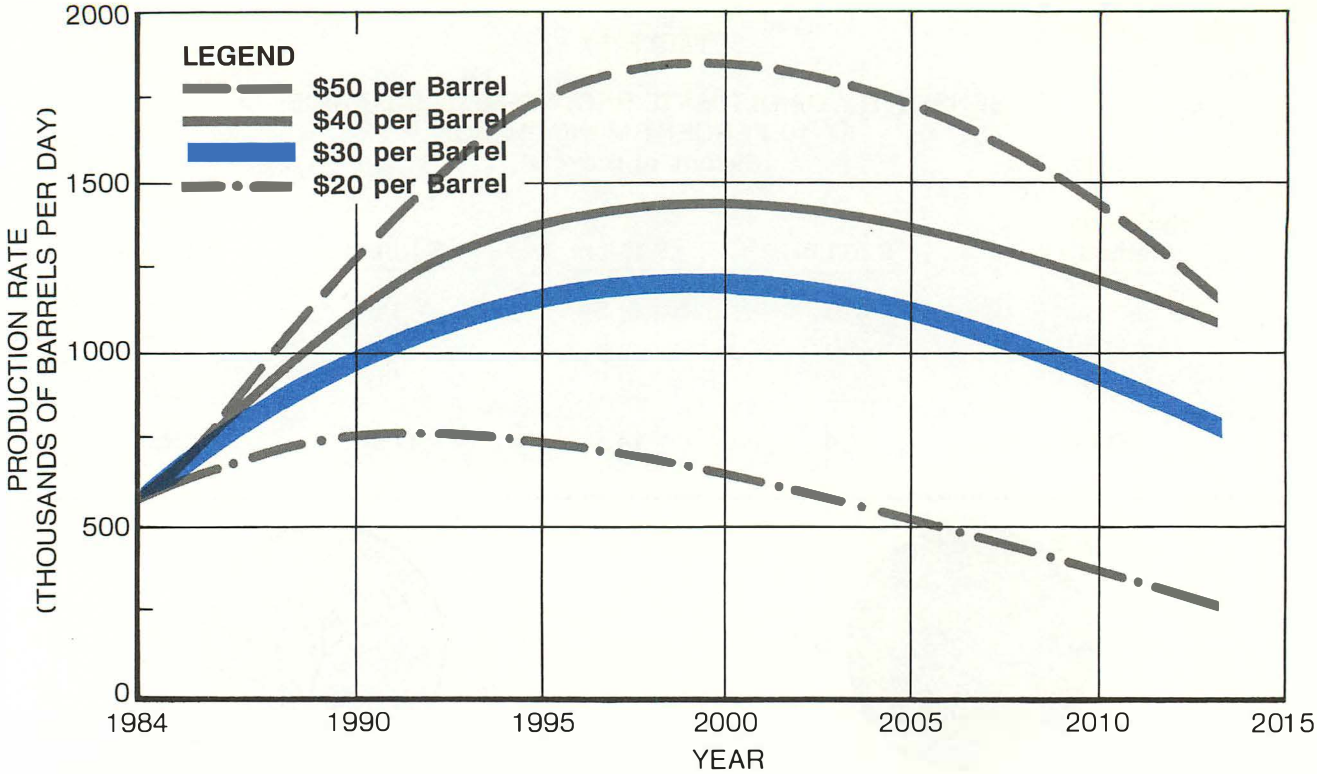


Figure 28. Sensitivity of Total Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

before the year 2000, and is sustained for about five years. Other price cases show peak rates of 1.4 million barrels per day at $40 per barrel, 1.2 million barrels per day at $30 per barrel, and less than 0.8 million barrels per day at $20 per barrel.

Sensitivity to Minimum Rate of Return—All Processes

Each investor, whether major oil company or independent, uses different criteria for making investment decisions. Cost of capital, types of investment opportunities, and perceived technical risk all influence project decisions. The use of a minimum ROR as an investment criterion in this study is a method of compensating for these factors. This does not imply that industry actually arrives at investment decisions in this manner. A minimum ROR of 10 percent was selected for the base economic case. This rate of return was used as a cutoff to identify those projects for which ultimate recovery estimates and rate projections were calculated. At each of the four prices considered, $20, $30, $40, and $50 per barrel, ultimate recovery was calculated for minimum RORs of 0, 10, and 20 percent. Rate projections were made only for the 10 percent minimum ROR cases. While 0 percent minimum ROR would not be considered by any investor as a viable opportunity, it indicates an upper target for enhanced oil recovery.

Over this spectrum of sensitivities, the total EOR ultimate recovery varies from 5.2 billion barrels at $20 per barrel, 20 percent minimum ROR, to 24.0 billion barrels, at $50 per barrel, 0 percent minimum ROR. The complete matrix of sensitivities of ultimate recovery to price and minimum ROR is shown in Table 12.

Chemical Flooding—Sensitivity to Price and ROR

As would be expected, the potential for chemical flooding grows as the oil price increases, and decreases as the minimum ROR is increased. This is illustrated in Table 13, which shows that ultimate recovery may go as low as 400 million barrels at $20 per barrel, 20 percent minimum ROR, or as high as 4.8 billion barrels at $50 per barrel, 0 percent minimum ROR. Surfactant flooding accounts for the overwhelming majority of this potential ultimate recovery, except at $20 per barrel, 10 percent minimum ROR and $20 per barrel, 20 percent minimum ROR. In these cases, polymer projects contribute a significant part of the potential chemical flooding enhanced oil recovery.

Producing rate as a function of time was estimated for all price cases at 10 percent minimum ROR, as shown in Figure 29. The

TABLE 12

ALL PROCESSES
SENSITIVITY OF ULTIMATE RECOVERY TO MINIMUM ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	10%	20%
20	11.5	7.4	5.2
30	19.1	14.5	10.1
40	22.0	17.5	13.7
50	24.0	19.0	16.1

TABLE 13

CHEMICAL FLOODING
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	10%	20%
20	2.3	1.0	0.4
30	3.6	2.5	1.4
40	4.3	3.5	2.2
50	4.8	4.1	3.0

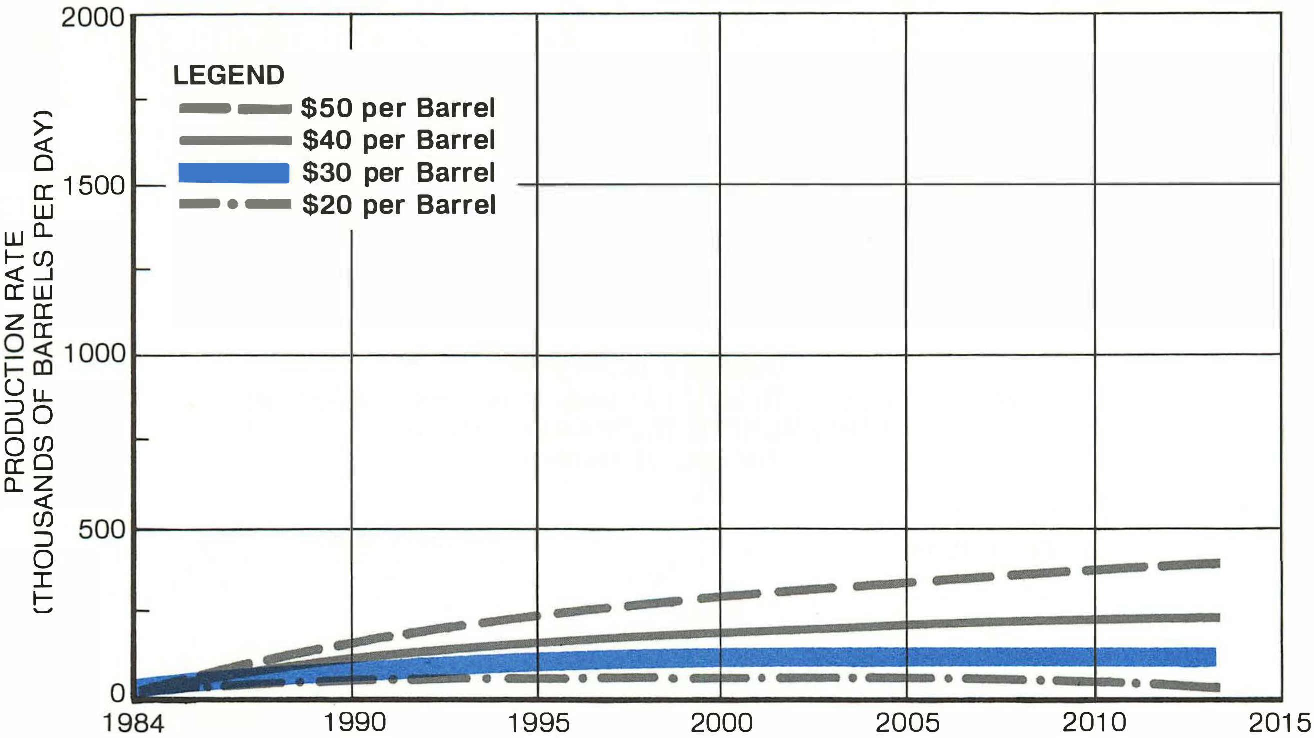


Figure 29. Sensitivity of Chemical Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

chemical flooding producing rate increases as oil price increases, reaching 400 thousand barrels per day at the end of the study period, for $50 per barrel. This is approximately three times the rate estimate in the base economic case. An increment of approximately 100 million pounds of annual surfactant manufacturing capacity must be added each year in order to meet the $50 per barrel producing rate projection. While this is well within industry capability, by historical standards it is a high rate of capacity expansion.

Figure 29 shows that chemical flooding can be a significant contributor to total EOR producing rates with current technology, but only at higher oil prices.

Miscible Flooding—Sensitivity to Price and ROR

The ultimate oil recovery projected for miscible flooding increases with oil price, and also as the minimum ROR is lowered, as illustrated in Table 14. The range in ultimate recovery is from 1.0 billion barrels at $20 per barrel, 20 percent minimum ROR, to 10.4 billion barrels at $50 per barrel, 0 percent minimum ROR. This study projects an ultimate recovery of 5.5 billion barrels for the Implemented Technology, base economic case.

Producing rates for miscible flooding were projected for the 30-year study period for all four oil prices at a 10 percent minimum ROR. The peak rate for the Implemented Technology base economic case is approximately 500 thousand barrels per day. At $50 per barrel, the peak rate exceeds 800 thousand barrels per day by the end of the century, while at $20 per barrel the peak rate reaches only 200 thousand barrels per day. Rate curves for all oil prices are shown in Figure 30.

Thermal Recovery—Sensitivity to Price and ROR

The projected ultimate recovery for thermal methods increases with nominal oil price, and decreases as the minimum ROR is increased, as shown in Table 15. The range of ultimate recovery is from 3.8 billion barrels at $20 per barrel, 20 percent minimum ROR, to 8.8 billion barrels at $50 per barrel, 0 percent minimum ROR. The results indicate that recovery is somewhat more sensitive to crude oil price than ROR, especially at minimum ROR values greater than 10 percent. This is primarily due to the influence of the ongoing thermal projects. Higher oil prices do encourage the initiation of new projects for all minimum ROR cases. However, applying a higher minimum ROR at a given oil price to mature ongoing projects, where the large "front-end" investments have previously been made, has only a moderately negative effect. This study projects an ultimate recovery of 6.5 billion barrels for the Implemented Technology, base economic case.

Producing rates for thermal recovery were projected for the 30-year study period at each of the four nominal crude oil prices at a 10 percent minimum ROR, as illustrated in Figure 31. There is a relatively small variance in rate between the $30 and $50 per barrel oil price projections, with peak rates of 685 thousand barrels per day and 770 thousand barrels per day, respectively. The influence of the mature ongoing thermal projects causes this variation to be small. It should be noted that a real oil price drop to $20 per barrel would have a very significant impact on the future production rate, indicating that the current threshold price for thermal recovery is in the $20 to $30 per barrel price range.

TABLE 14

MISCIBLE FLOODING
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	Minimum ROR 10%	Minimum ROR 20%
20	4.2	2.0	1.0
30	7.6	5.5	3.3
40	9.3	7.0	4.8
50	10.4	7.7	6.2

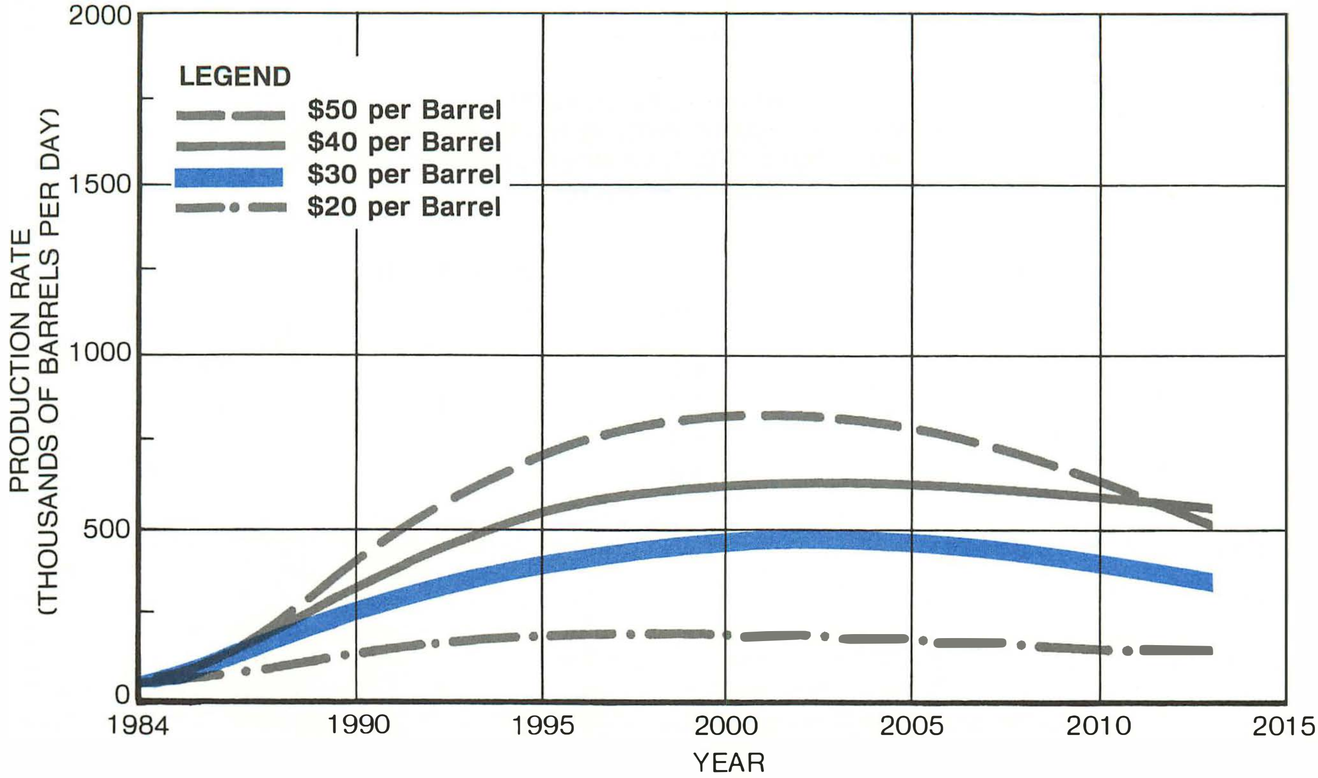


Figure 30. Sensitivity of Miscible Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

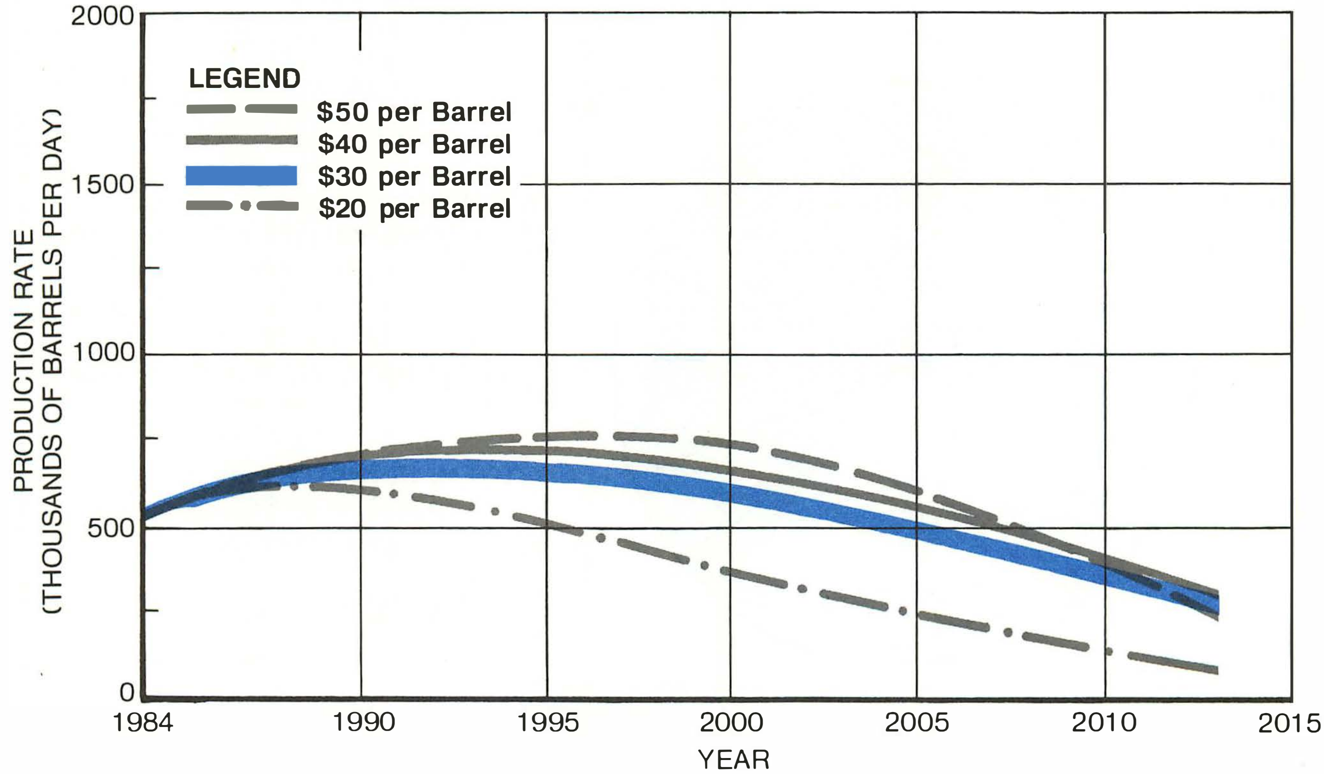


Figure 31. Sensitivity of Thermal Recovery Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

TABLE 15

THERMAL RECOVERY
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	10%	20%
20	5.0	4.4	3.8
30	7.9	6.5	5.5
40	8.4	7.0	6.7
50	8.8	7.2	7.0

Advanced Technology

All Processes

The Advanced Technology Case was chosen to illustrate the impact that technology improvements could have on enhanced oil recovery. It assumes that certain technology advances will be developed and implemented within the study period. It is not a forecast that these developments will occur, but rather an estimate of the impact if they did occur. In the cases analyzed, the Implemented Technology Case projections terminate at a specific date, and are replaced by Advanced Technology Case projections, where applicable, for the remainder of the 30-year study period. It should be noted that *the results of the Advanced Technology Case and the Implemented Technology Case are not additive*. The Advanced Technology Case results include the Implemented Technology Case results as well as the additional recovery resulting from technology advancements, where they apply. Both ultimate recovery and producing rate projections were made in this study for crude oil prices of $30, $40, and $50 per barrel with a 10 percent

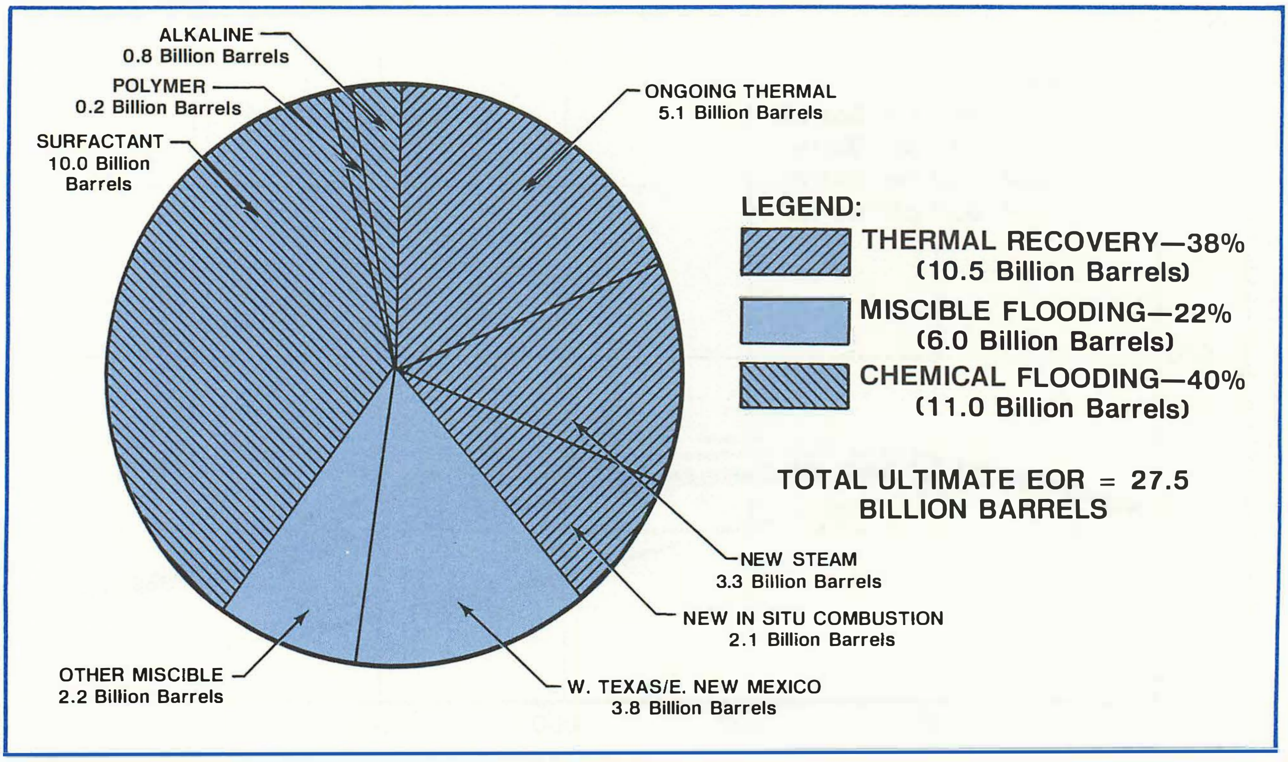


Figure 32. Ultimate Recovery—Advanced Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

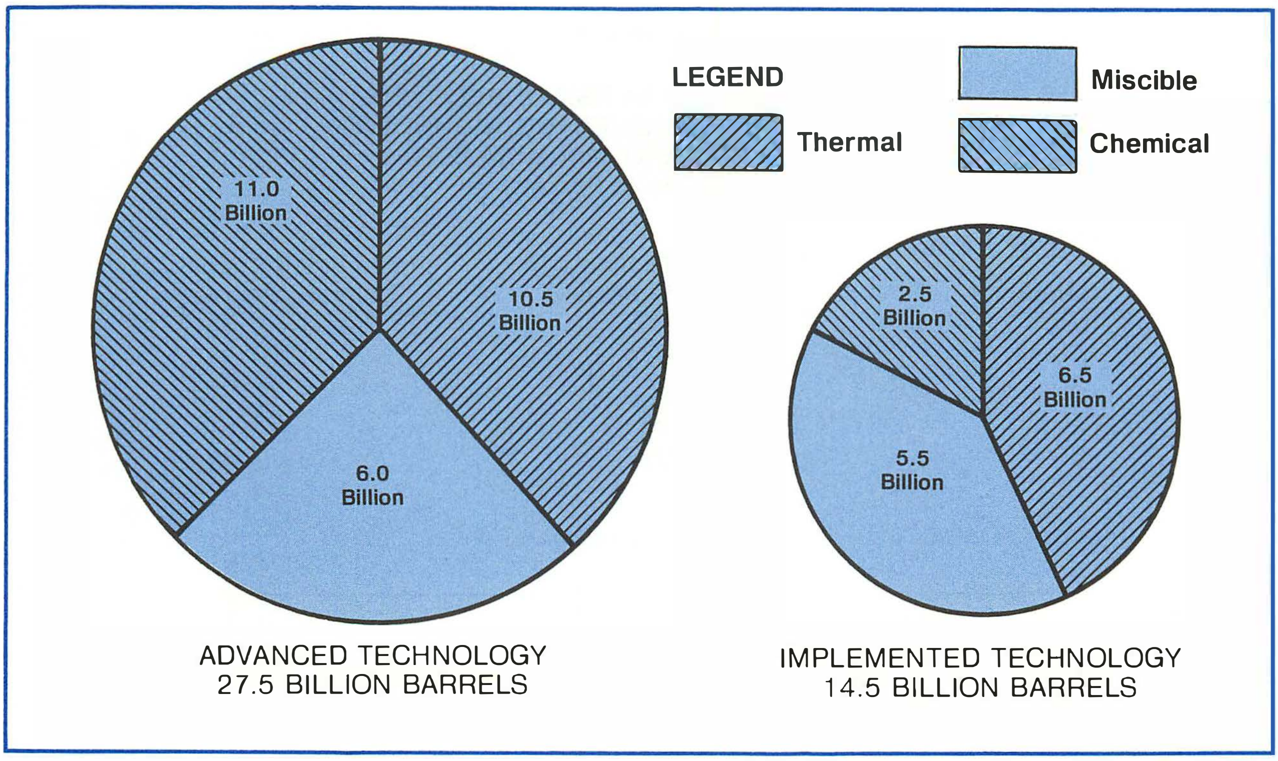


Figure 33. Comparison of Implemented and Advanced Technology, Base Economic Cases.

minimum ROR for the Advanced Technology Case. In all cases, the economic assumptions regarding oil price, and energy cost factors associated with oil price, were consistent with the Implemented Technology Case. A $20 per barrel price was not considered to be consistent with the Advanced Technology Case, because most of the Advanced Technology Case assumptions reflect higher costs.

Technology will probably gradually improve throughout the study period. For these projections, however, some simplifying assumptions were required relative to specific dates when advanced technology would be available. The participants considered the time it takes to move technology from theory, through the laboratory, through pilot testing, and into full-scale, commercial applications. The date chosen was 1995. This date, 11 years into the 30-year forecast period, may be optimistic, but is considered achievable. All processes were assumed to have the advanced technology available at the same 1995 date, with the exception of ongoing steam projects. Due to the maturity of these projects, the Advanced Technology Case was accelerated to 1988.

The results of applying the assumptions of the Advanced Technology Case, at the specified future dates of 1988 and 1995, show that the EOR potential ultimate recovery increases to 27.5 billion barrels in the base economic case ($30 per barrel, 10 percent minimum ROR). This compares to a recovery of 14.5 billion barrels in the Implemented Technology base economic case. Figure 32 shows the distribution of the ultimate recovery by EOR process. A comparison of the distribution of ultimate recoveries by method for the Advanced Technology Case and the Implemented Technology Case is shown in Figure 33. The recovery for each major method is significantly larger with advanced technology; however, chemical flooding contributes the greatest increase because it has the greatest potential for improvements. Chemical flooding recovery is a much larger fraction of the total enhanced oil recovery in the Advanced Technology Case.

Table 16 shows comparisons of ultimate recoveries for the Implemented and Advanced Technology Cases at three nominal crude oil prices. The increases in ultimate recovery as a percentage of the Implemented Technology Case value ranges from a 90 percent increase at $30 per barrel to a 79 percent increase at $50 per barrel. A further comparison on the bar graphs in Figure 34 indicates the percentage of the total ultimate recovery that is produced during the 30-year projection period.

TABLE 16

COMPARISON OF ULTIMATE RECOVERY
ADVANCED VS. IMPLEMENTED TECHNOLOGY
AT 10 PERCENT MINIMUM ROR
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Advanced Technology Ultimate Recovery	Implemented Technology Ultimate Recovery
20	NA*	7.4
30	27.5	14.5
40	31.9	17.5
50	34.0	19.0

*Advanced Technology Case at $20 per barrel is not considered applicable.

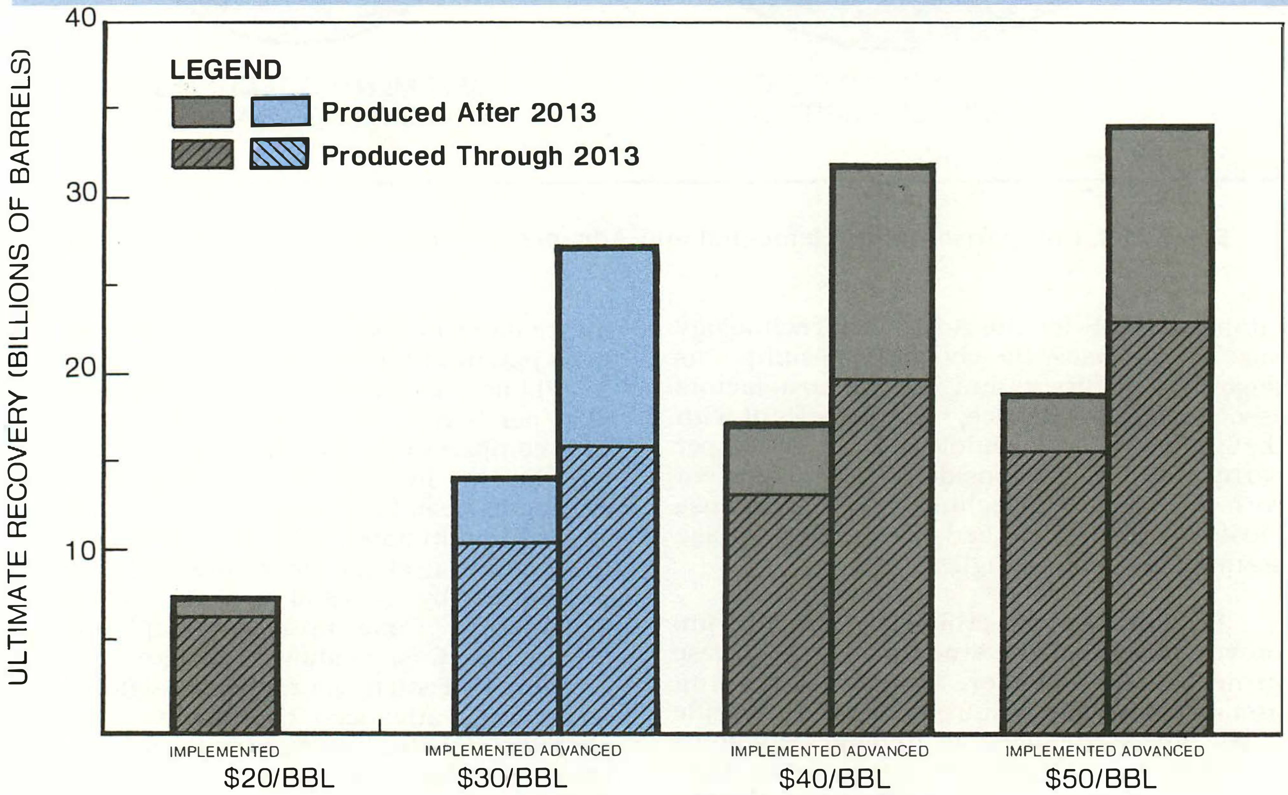


Figure 34. Comparison of Ultimate Recovery for Implemented and Advanced Technology Cases (10 Percent Minimum ROR).

The peak producing rate for the Advanced Technology, base economic case reaches 2 million barrels per day by 2005, as shown on Figure 35. The rates of production for thermal and miscible processes peak between 2000 and 2010, while the chemical flooding producing rate is still increasing at the end of the study period.

Producing rate projections for the Advanced Technology Case indicate that a peak rate of almost 3 million barrels per day could possibly be achieved during the study period with a $50 per barrel nominal crude oil price assumption. Figure 36 shows the total EOR producing rate for all of the Advanced Technology price cases.

Advanced and Implemented Technology Case producing rates are compared in Figures 37, 38, and 39 for all prices. These illustrate a significant increase in producing rate for improved technology at all oil prices.

Chemical flooding contributes the most additional potential in the Advanced Technology Cases. The more mature thermal recovery processes show a modest increase in ultimate recovery, as does miscible flooding. Figure 40 illustrates the ultimate recovery variation by price and technology, for the major EOR methods. The following is a brief discussion of the Advanced Technology Case by major EOR method. For more detailed coverage of the subject refer to Appendices D, E, and F for chemical flooding, miscible flooding, and thermal recovery, respectively.

Chemical Flooding—Advanced Technology

The Advanced Technology Case potential for chemical flooding is greatly increased compared to the Implemented Technology Case. For the base economic case, potential incremental ultimate recovery increases from 2.5 to 10.9 billion barrels. Although alkaline flooding potential increases from 0.1 to 0.8 billion barrels, most of the increase is from surfactant flooding. The incremental ultimate recovery increases from 2.1 to 9.9 billion barrels. The surfactant flood producing rate increases from 130 thousand barrels per day in 2013 in the Implemented Technology Case to 490 thousand barrels per day in the Advanced Technology Case. Actual producing rates would be dependent on surfactant availability and cost.

At $50 per barrel, chemical flooding potential increases to 13.5 billion barrels. The production rate at this price is estimated to reach 840 thousand barrels per day by the end of the

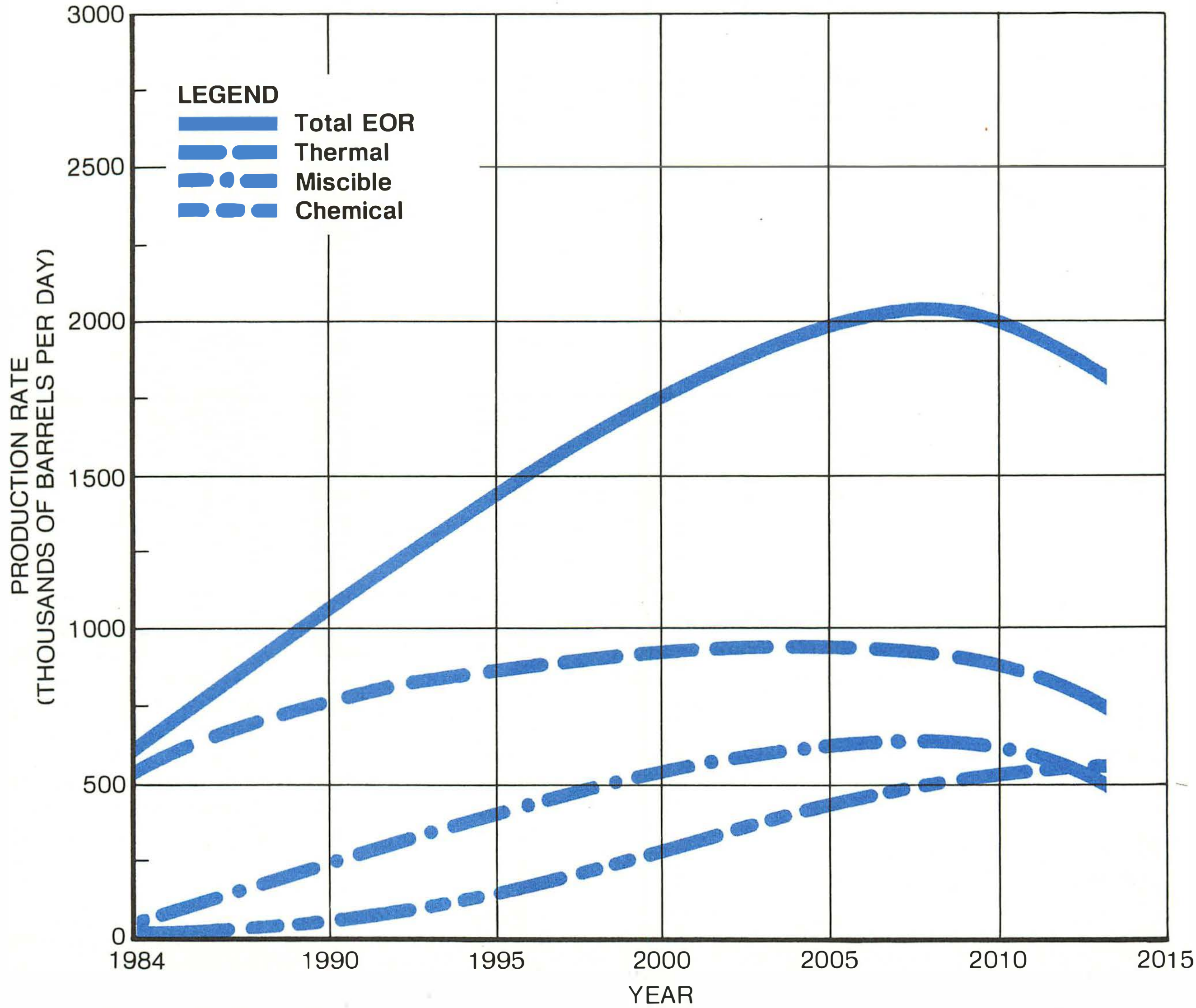


Figure 35. Production Rate—Advanced Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

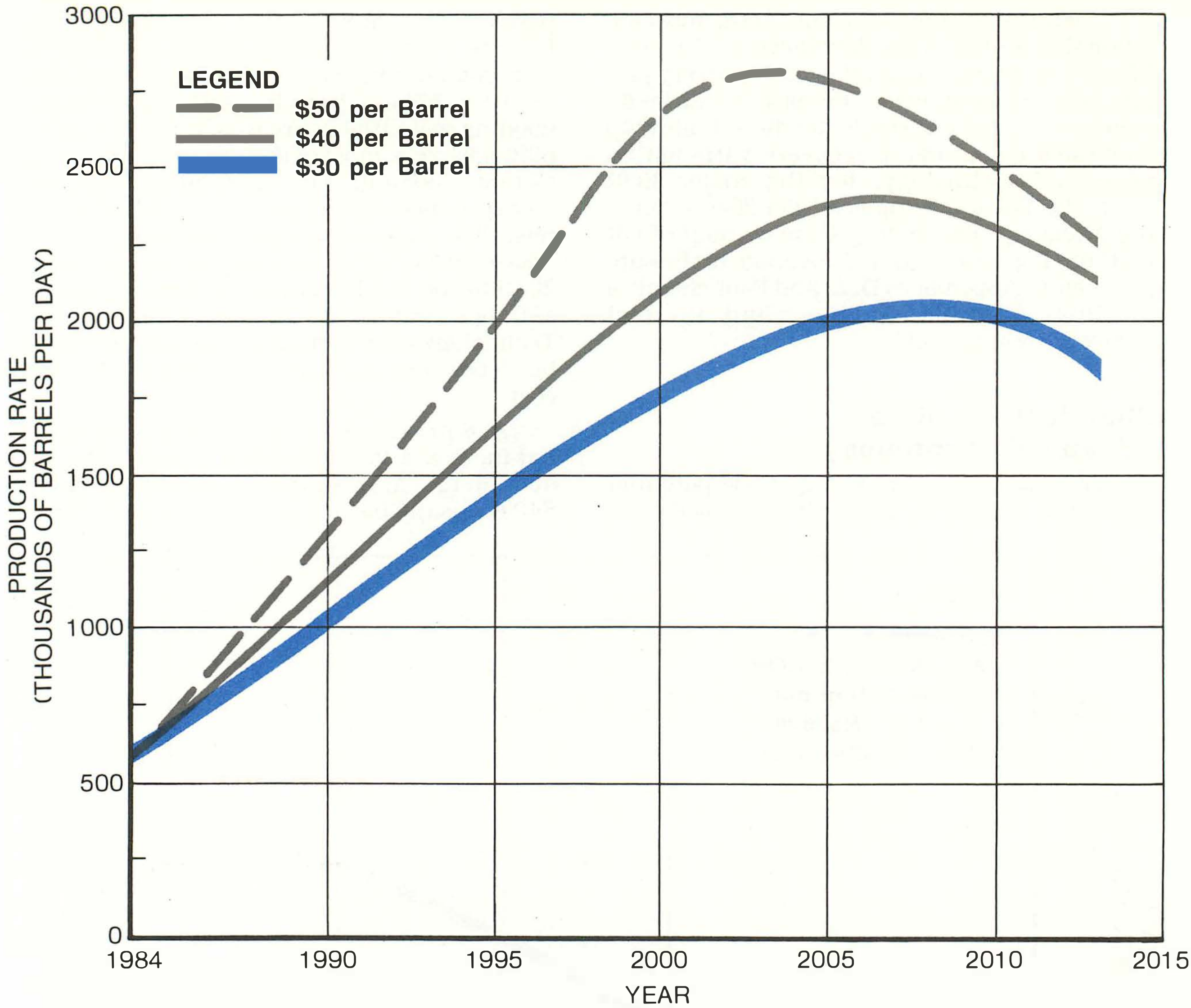


Figure 36. Sensitivity of Total Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology Case (10 Percent Minimum ROR).

study period. Again, this is highly dependent upon assumptions concerning availability of surfactant. With these producing rates, only a small proportion of the total surfactant flooding potential is actually produced before 2013. Amounts actually produced are 2.9, 3.8, and 5.3 billion barrels for $30, $40, and $50 per barrel of oil, respectively.

Miscible Flooding—Advanced Technology

The difference between the incremental ultimate recovery in the Advanced Technology Case for miscible flooding, and the incremental ultimate recovery in the Implemented Technology Case, is less than one billion barrels for all price sensitivity cases. Two forms of advanced technology for miscible flooding were considered: reservoirs that respond favorably to waterflooding and CO_2 miscible flooding, because of moderate reservoir heterogeneity, would be flooded with larger CO_2 slug sizes; and reservoirs that have a relatively high degree of reservoir heterogeneity, and perform unfavorably during waterflooding and CO_2 miscible flooding, would be flooded using foamant chemicals and other methods to attempt to contact more of the remaining oil in the reservoir. Both forms of the Advanced Technology Case require additional costs. Also at higher oil prices, more reservoirs would be developed by miscible flooding before the 1995 effective date for the Advanced Technology Case. These factors result in a limited potential for increasing ultimate recovery with advanced technology.

Producing rates for miscible flooding in the Advanced Technology Cases peak higher than in the Implemented Technology Case. At $50 per barrel, the peak rate reaches 980 thousand barrels per day compared to 820 thousand barrels per day in the Implemented Technology Case. In the $30 per barrel base economic case, the peak rate reaches 625 thousand barrels per day with advanced technology compared to 500 thousand barrels per day with implemented technology.

Thermal Methods—Advanced Technology

In the Advanced Technology Case, thermal methods are estimated to have a potential ultimate recovery of 10.5 billion barrels (including steam generator fuel) for the base economic case. This is an increase of 4.0 billion barrels from the Implemented Technology Case, and thermal methods would account for approximately 38 percent of the total potential enhanced oil recovery of 27.5 billion barrels for the Advanced Technology Case.

The ultimate recovery from thermal methods for the base economic case includes 5.1 billion barrels from ongoing thermal projects, 3.3 billion barrels from new steam drive projects, and 2.1 billion barrels from new in situ combustion projects. Compared to the Implemented Technology Case, most of the growth is attributable to increasing the number of reservoirs to which the thermal processes can be applied, as only 0.6 billion barrels of the 4.0 billion barrel increase comes from improving the sweep efficiency of the ongoing steam drive projects.

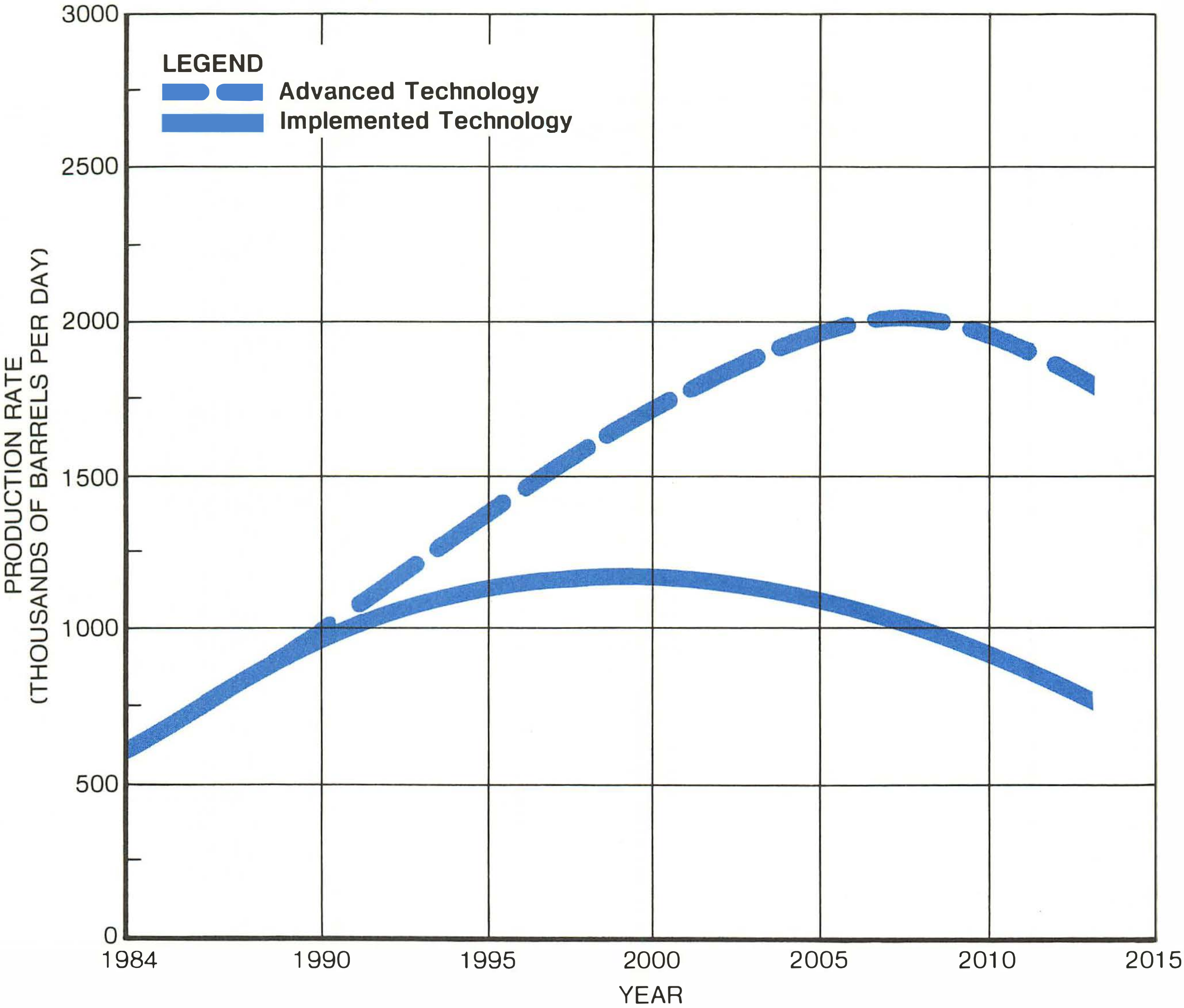


Figure 37. Comparison of Implemented and Advanced Technology Production Rates—Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

At $30 per barrel, the production rate for thermal recovery peaks at 925 thousand barrels per day near the turn of century. As the nominal crude oil price is increased to $50 per barrel, the peak production rate exceeds 1.2 million barrels per day, also around the year 2000.

Uncertainty

Although this study was conducted by experts in the field of enhanced oil recovery and other specialists from the petroleum industry, the resulting ultimate recoveries and production rate projections are nonetheless subject to a great deal of uncertainty. Comprehensive studies tend to converge on a best estimate answer. The shortcoming of such a rigorous approach is not what is included in the analysis but the unknowns that are either outside the scope of investigation, or that cannot be precisely determined. These factors lie in the areas of economics, technology, and methodology.

While there are a great many factors that may contribute to the overall economic uncertainty, oil price is considered the most significant. Indeed, most other economic factors, such as tax policy and demand variations, can be converted to an equivalent change in effective oil price.

Both present and anticipated oil prices substantially affect EOR activity. The results of the $30 per barrel base case are strongly influenced by the events that occurred from 1978 to 1982, when the real price of oil approached $40 per barrel and was projected to rise even

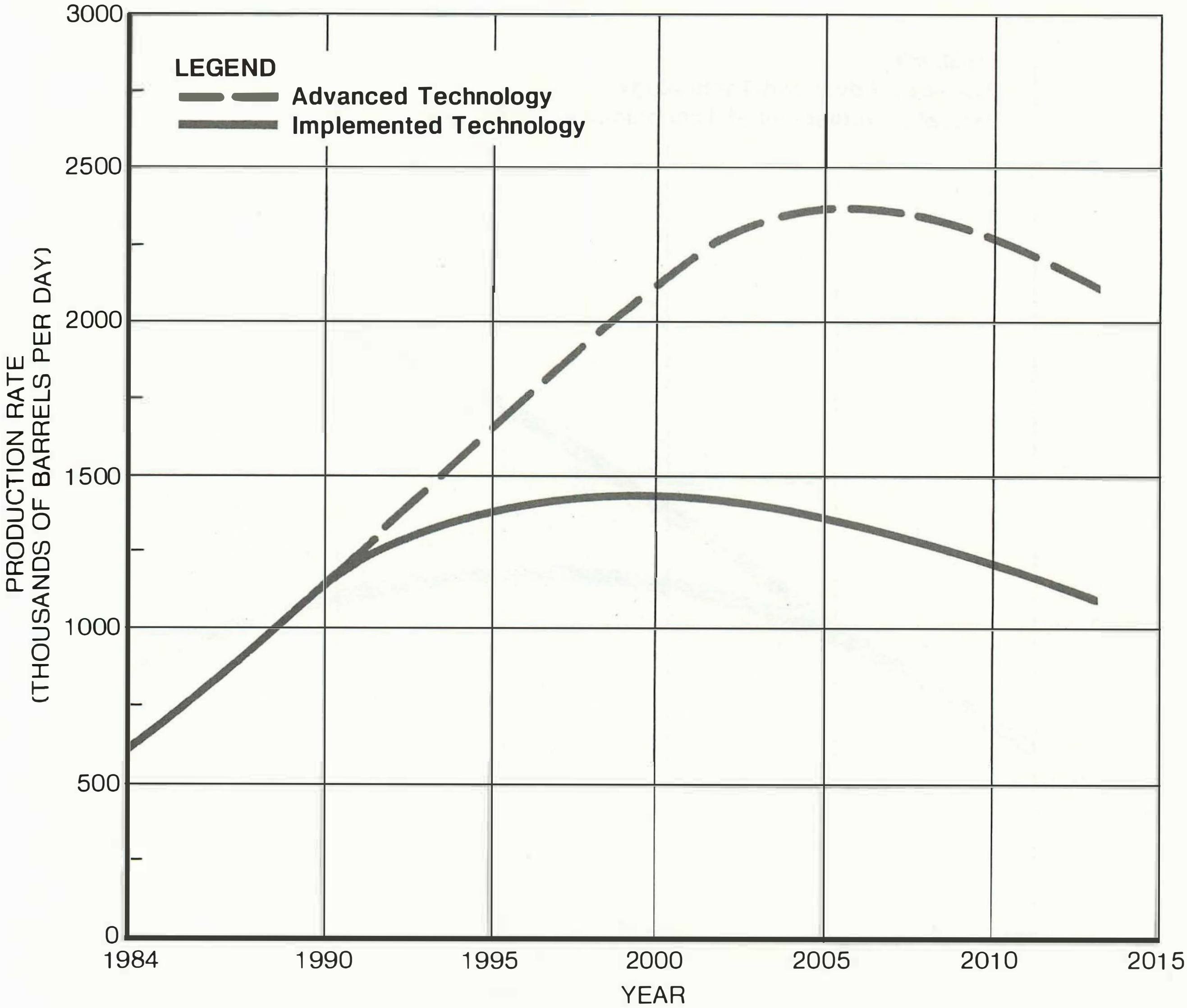


Figure 38. Comparison of Implemented and Advanced Technology Production Rates ($40 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

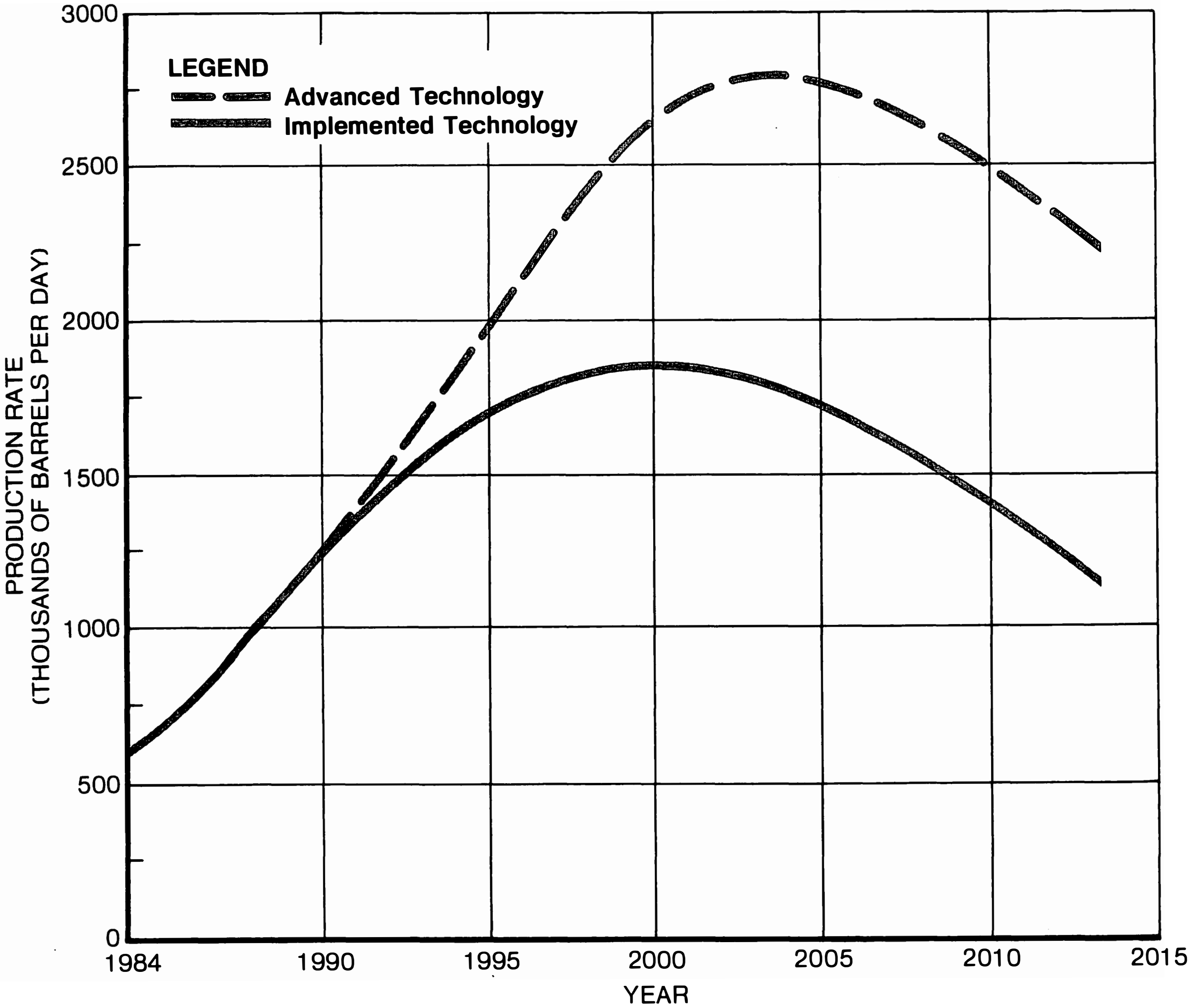


Figure 39. Comparison of Implemented and Advanced Technology Production Rates ($50 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

higher. EOR projects benefited and gained much momentum during this time, as shown by the substantial investments made to develop CO_2 resources and pipeline systems to serve the miscible flood projects in the West Texas area. Also, expansions were made to most of the large steamflood projects in California. This increased activity became part of the ongoing EOR base upon which the study results are constructed.

Uncertainty to oil price was examined in this study by varying the nominal crude oil price over a range of $20 to $50 per barrel. The effects of these price changes are more severe than what would normally occur because the prices are assumed to change instantly and remain in effect through the entire time period of the study. Under normal economic circumstances, future price changes would be gradual and, in any case, would not be in effect over the entire study period. It is felt that the range of ultimate recovery resulting from a change of the nominal base price from $20 to $50 per barrel provides a reasonable estimate of uncertainty due to economic factors.

Technology is another significant factor in uncertainty. Most technological progress in the petroleum industry is a result of its willingness to experiment with new technologies and processes. Many of these initial attempts to employ new technology end in failure, and progress is frustratingly slow. However, in many instances this continued research and field testing has led to ultimate success.

The Advanced Technology Case of this study assumed technological success. Since the Advanced Technology Case is based on the

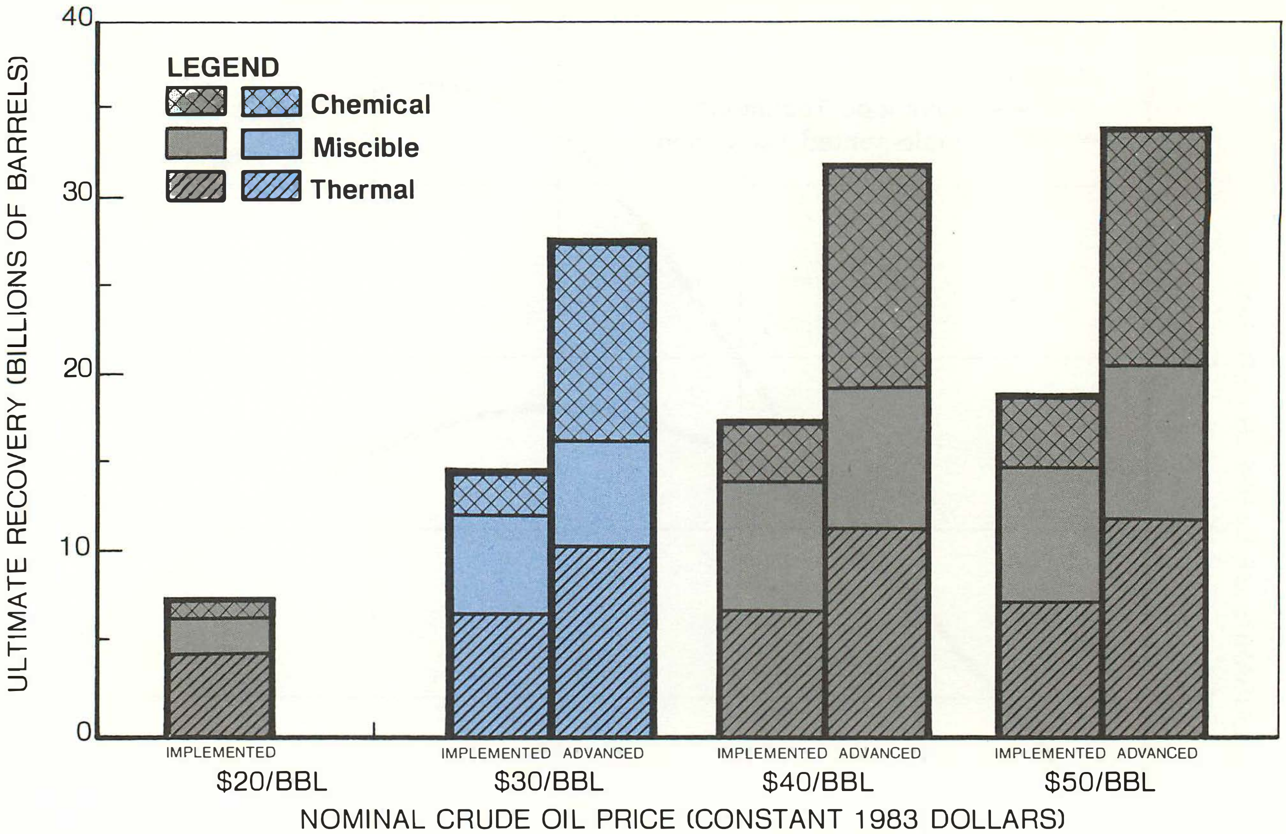


Figure 40. Ultimate Recovery by Process—Advanced and Implemented Technology Cases (10 Percent Minimum ROR).

assumption that many new technological improvements will occur, that they will have the maximum impact, and that they will be cost effective, this case is felt to represent the upper technological uncertainty limit.

In addition to the factors mentioned above, the methodology of the study introduced uncertainty in two areas: (1) "success assumption," and (2) extrapolation of resource base.

The study was based on the assumption that all projects that passed the minimum ROR screens would be successful. Actually, some projects will perform better than predicted in this study, and others will perform worse. Some projects would fail completely because of unanticipated adverse geological, technological, and mechanical factors. Since the projects that are most likely to fail are those already close to the minimum ROR, the risk of failure is often compensated for by raising the acceptable minimum ROR. For this analysis, raising the minimum ROR from 10 to 20 percent was used to estimate the adverse effect of uncertainty due to project failures.

Uncertainty also arises from the size of the data base being less than estimates of total OOIP in known fields in the United States. Much effort went into developing the best data base possible, which contains about 70 percent of all the oil discovered to date.

The upper limit of uncertainty by direct extrapolation is approximately 40 percent greater than the projected recovery for each case. In the best judgment of the study participants, direct extrapolation is not warranted. The study projected recoveries for all reservoirs with 50 million barrels or more OOIP that passed EOR screening. Some reservoirs with less than 50 million barrels of OOIP will be prone to be amenable to EOR processes. However, overall recovery from these reservoirs is not expected to be proportional to that from the larger fields because of poorer economics for small-scale floods.

Taken together, the ranges of ultimate EOR resulting from the specific factors discussed above give an indication of the effective uncertainty on ultimate EOR for each process method. Results are shown in Figure 41 and tabulated in Table 17. *Results for the individual uncertainty factors and for each process are not additive.* Many of the factors are highly interrelated, and no attempt has been made to show total or composite effects.

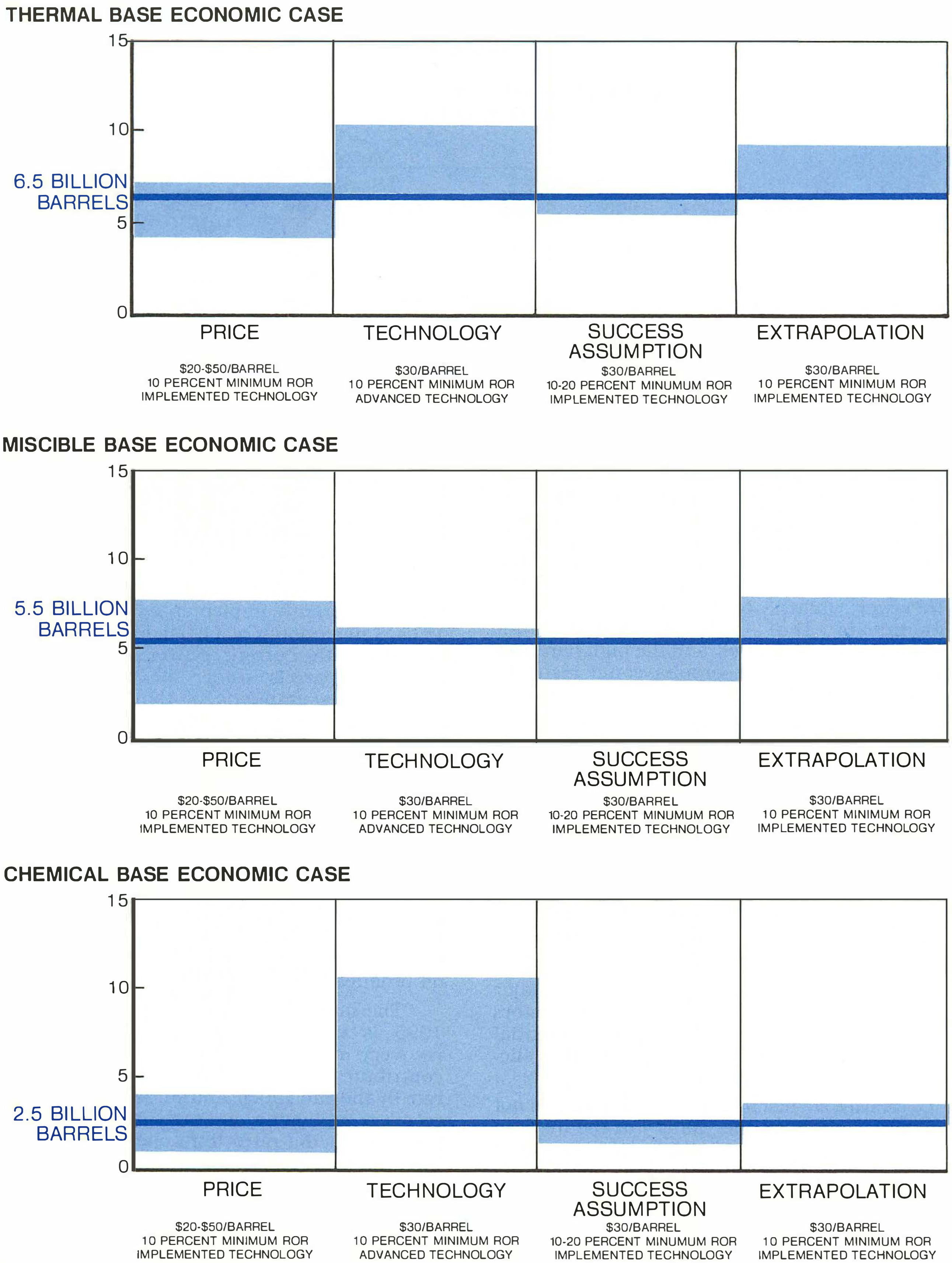


Figure 41. Factors Contributing to Uncertainty.

TABLE 17

UNCERTAINTY RANGE OF ULTIMATE RECOVERY
(Billions of Barrels)

	Method					
	Chemical		Miscible		Thermal	
Factor	High	Low	High	Low	High	Low
Price	4.1	1.0	7.7	2.0	7.2	4.4
Technology	10.9	2.5	6.1	5.5	10.5	6.5
Success Assumption	2.5	1.4	5.5	3.3	6.5	5.5
Extrapolation	3.6	2.5	7.9	5.5	9.3	6.5

The possible uncertainty in ultimate recovery from chemical processes ranges from 1 billion to 11 billion barrels around an Implemented Technology, base economic case projection of 2.5 billion barrels. Chemical flooding, being the least mature of the three major EOR methods, has the most potential from future technological improvements. However, failure to develop cost-effective chemicals that will withstand high temperatures, salinities, and the high-hardness level of carbonate reservoirs could result in rather limited application of these processes.

For miscible flooding, the potential uncertainty ranges from 2 billion to 8 billion barrels around an Implemented Technology Case projection of 5.5 billion barrels. To reach the upper-limit 8 billion barrel level will take a synergistic combination of advanced technology, high prices, and an expanded resource target.

The potential uncertainty for thermal recovery ranges from 4 billion to 11 billion barrels around an Implemented Technology Case projection of 6.5 billion barrels. Thermal processes, being the most mature, have less low-side uncertainty than the other two major methods. One of the most significant factors that will affect the ultimate high-side potential of thermal recovery is the degree of future success of the in situ combustion process.

The above discussion of uncertainty is not meant to diminish the validity or the merit of the results of this study in any way, but rather is an attempt to quantify the effect of internal and external factors that need to be considered when interpreting the study results. Further discussion of process specific factors that influence uncertainty is given in Appendices D, E, and F.

Conclusions

The results of this study demonstrate that *the application of EOR processes to known reservoirs can significantly increase the domestic crude oil supply.* The Implemented Technology, base economic case results project ultimate recovery of 14.5 billion barrels of oil, of which 3.5 billion barrels will be produced through currently implemented EOR projects. Thus, a net amount of 11 billion barrels could be added to the current recoverable reserves of 28 billion barrels, under the technical and economic assumptions of the Implemented Technology, base economic case.

Of this 14.5 billion barrel projection, almost half (45 percent) would be producible through thermal recovery methods, with miscible flooding and chemical flooding contributing 38 percent and 17 percent, respectively.

The producing rate for EOR methods is projected to reach more than one million barrels per day in the early 1990s and remain at that level until beyond 2005. This rate is the equivalent of 13 percent of current daily U.S. oil production.

The majority of EOR production through 1995 is estimated to come from thermal recovery methods. Miscible flooding methods contribute significantly to the total producing rate by the late 1990s, and surpass the thermal recovery producing rate early in the next century. Producing rates from chemical flooding methods remain low, reaching only 140 thousand barrels per day at the end of the study period.

Comparisons of results at the various nominal crude oil prices demonstrate that *the potential ultimate recovery from EOR* *methods, and the rate at which this oil is produced, are highly sensitive to oil price.* The projected Implemented Technology, base economic case recovery of 14.5 billion barrels increases by 30 percent, to 19 billion barrels, as the nominal crude oil price reaches $50 per barrel. Conversely, ultimate recovery drops by 50 percent, to 7.4 billion barrels, as the nominal crude oil price falls to $20 per barrel. Peak poducing rates are affected similarly, rising by 60 percent to 1.8 million barrels per day at $50 per barrel, and falling 30 percent, to less than one million barrels per day at $20 per barrel.

Technology is also demonstrated to have a significant impact on EOR potential. The successful development and implementation of advanced technology, as defined in this study, is projected to increase ultimate recovery potential to 27.5 billion barrels, assuming base economics. This represents an increase of 90 percent over the Implemented Technology, base economic case estimate of 14.5 billion barrels. The contributions to this increase vary among processes according to their relative maturities, with chemical flooding methods showing the greatest potential increase.

Chapter Five

Enhanced Oil Recovery in Perspective to Other Energy Sources

Having considered projections of enhanced oil recovery, it is important to put enhanced oil recovery in perspective to other sources that could contribute to the nation's energy future. Liquid fuels have furnished about 45 percent of the nation's total energy requirement since 1950, growing from 40 percent in 1950 to a peak of 49 percent in 1978 before declining to 43 percent in 1982. Natural gas, coal, hydroelectric, and nuclear power account for most of the remainder. Figure 42 illustrates graphically the pattern of energy consumption and the part supplied by each source.

Liquid fuels consumed by the United States in the past were supplied mainly from two sources: (1) production from domestic oil fields; and (2) foreign oil imports. These sources also provide lubricants and chemical feedstocks. Oil production from domestic sources includes that obtained through application of waterflooding and pressure maintenance, which have helped substantially to improve recovery in the last few decades. Declining domestic production and increasing demand for oil in the 1970s forced increasing reliance on oil from foreign sources, spurring extensive discussion and study of ways to increase domestic production.

While such studies have identified the difficulty of increasing the domestic supply, they resulted in no clear, fast, economic, and lasting solutions. Since 1979, prices have accelerated the rate of conventional exploration and development, which has temporarily moderated the rate of decline in reserves and daily production capacity. The higher prices, as well as a depressed economy and special legislation (e.g., fuel consumption specifications for automobiles) have also caused a dramatic shift toward conservation such that both the actual rate of consumption and consumption per dollar of Gross National Product (GNP) have declined. While these developments have been significant and have led to a reduction in crude oil imports, they have not solved the country's problem on a long-term basis.

Likewise, this study reveals no clear-cut, fast, or lasting solutions. Although the EOR resources projected here are large, and the projected rates would supply an important fraction of the production needed to meet anticipated domestic demand, enhanced oil recovery by itself is not the complete solution for future supply of liquid petroleum for the United States. All other sources of petroleum must be considered. Alternative sources of liquid fuels (synfuels) may increase in importance over the longer term, depending upon market conditions and technological advances. Conservation and substitution of nonpetroleum fuels remain important aspects of policy to secure the nation's energy future.

Demand for Liquid Fuels

As demonstrated in the past decade, liquid fuel consumption in the United States is predominantly influenced by six factors, some of which are interrelated:

- Availability
- Price

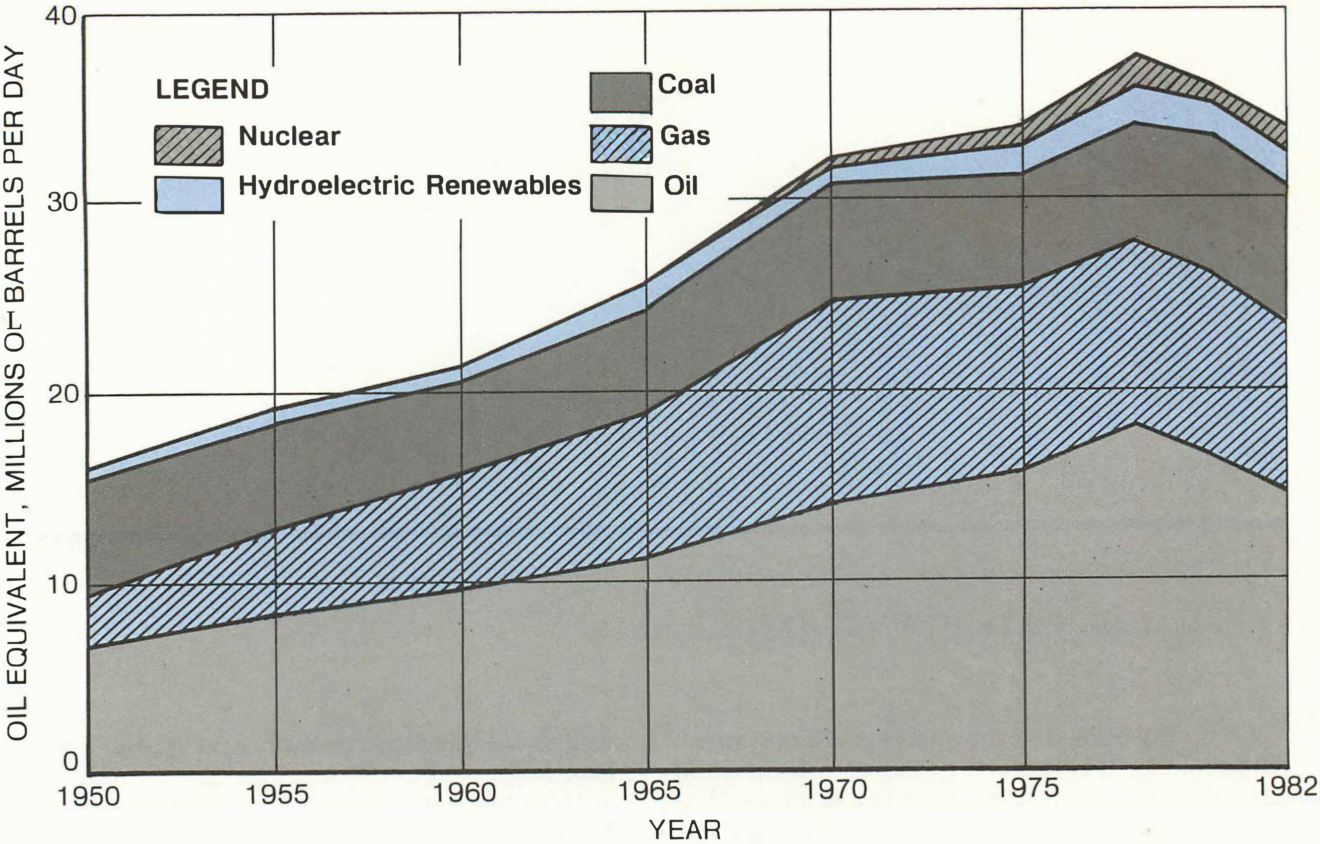


Figure 42. Historical Primary Energy Use by Energy Source.

SOURCE OF DATA: *Basic Petroleum Data Book, Petroleum Industry Statistics*, Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (September 1983).

- Economic growth
- Population growth
- Efficiency of use
- End-use regulation.

The shortage of domestic crude oil beginning in 1971, followed by the disruption of imports in 1973-1974 and 1979-1980, led to very large price increases. Over time, these price increases forced substantial changes in consumption patterns. Improved fuel usage efficiency (conservation) and consumer shifts to other fuel sources (substitution) resulted in lower consumption per capita and caused a substantial reduction in the consumption of liquid fuels. The demand for liquid petroleum[1] increased 4 to 5 percent annually prior to 1978 but declined from 18.8 million barrels per day in 1978 to 15.3 million barrels per day in 1982 (see Figure 43), illustrating the sensitivity of demand to price. Petroleum consumption per million dollars of real 1972 GNP fell from 4,780 to 3,780 barrels (Figure 44), while per capita annual consumption fell from 30.9 to 24.1 barrels in the same period.[2]

Although this study shows that enhanced oil recovery could contribute importantly to supply U.S. energy needs, it should be viewed in perspective with projected energy demand throughout the study period. Recent forecasts typically project only moderate growth in demand for liquid petroleum in the United States until 1990, and little growth or actual declines in demand for the remainder of this century and well into the next.[3,4] Such forecasts, of course, are subject to considerable uncertainty. Consumption is forecast to be 16 million barrels per day or less, including natural gas liquids and imported refined products through the remainder of the century (Figure 45).[5] As long as

[1]Petroleum liquids include imported and domestic crude oil, natural gas liquids, and imported refined products, net of exports.

[2]*Basic Petroleum Data Book, Petroleum Industry Statistics*, Vol. 3, No. 3 (September 1983), American Petroleum Institute, Washington, D.C.

[3]"Energy Projections to the Year 2010," Office of Policy, Planning, and Analysis, U.S. Department of Energy (October 1983).

[4]"The Energy Outlook Through 2000," Energy Economics Division, Chase Manhattan Bank, N.A., New York (March 1983).

[5]See footnote 3.

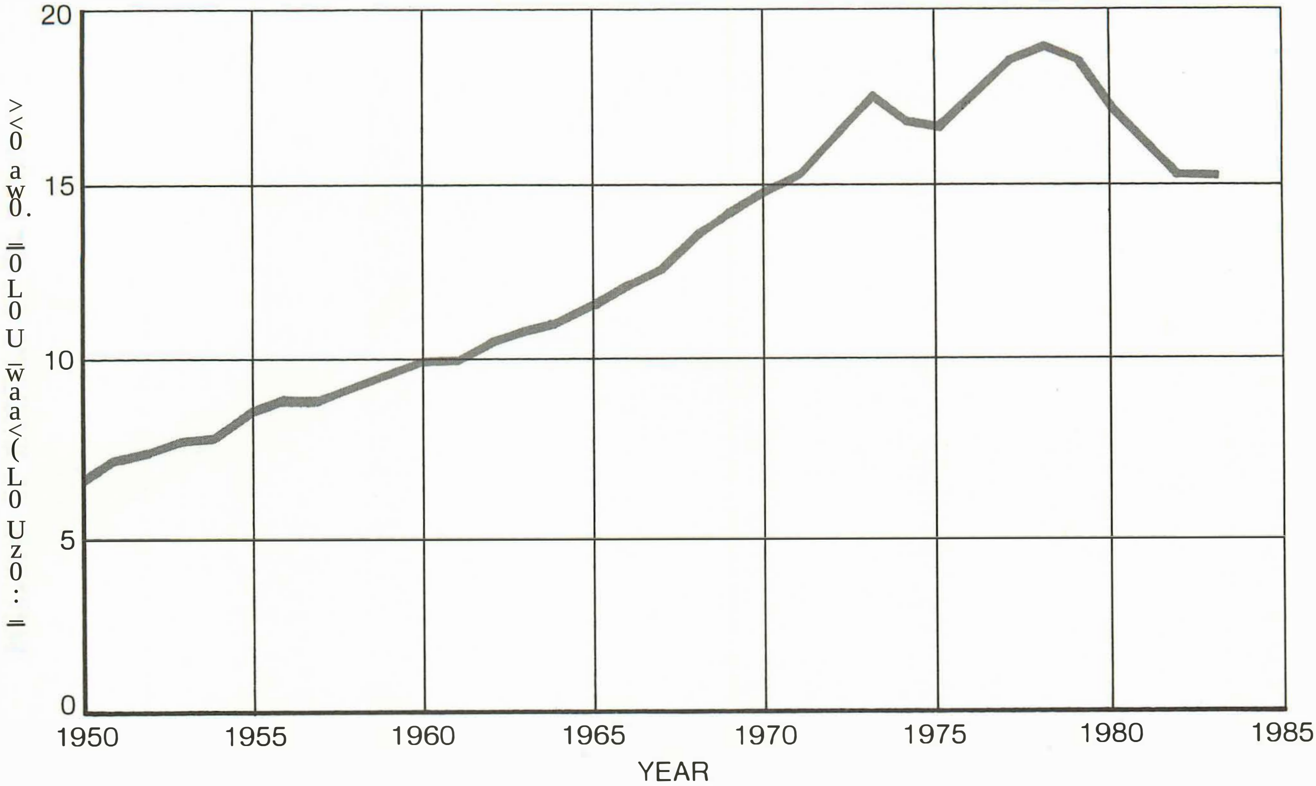


Figure 43. Petroleum Liquids Demand (Includes Imported and Domestic Crude Oil, Natural Gas Liquids, and Imported Refined Products, Net of Exports.)

SOURCE OF DATA: *Basic Petroleum Data Book, Petroleum Industry Statistics*, Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (September 1983); and the Energy Information Administration of the U.S. Department of Energy.

there are sufficient economic incentives, improvements in the efficiency of energy use will continue, and this will reduce growth in demand. However, future efficiency gains may be in small increments and will be offset to some extent by economic and population growth. The dependencies of the residential and commercial sector and the electric utility sector of the economy on liquid fuels have diminished substantially since the early 1970s (Table 18). Further gradual changes are expected.

Projections beyond the year 2000 are even less certain. Recent DOE projections indicate neutral growth or actual declines in U.S. demand for liquid fuels within the study period.[6] Energy demand will be stimulated by economic and population growth. However, the United States already is a highly developed, industrially mature nation and appears to have a declining, although high, energy consumption per dollar of GNP. This tends to moderate increases in energy consumption from economic and population growth (see Figure 44).

[6]See footnote 3.

Supply of Liquid Fuels

Potential sources of liquid fuels that will compete to fill future demand are:

- Production from known fields by conventional recovery methods
- Production from known fields by EOR methods
- Production from new fields discovered by exploration
- Imports from foreign sources
- Synthetic liquids produced from natural gas, coal, oil shale, tar sands, and biomass.

Production from Known Fields by Conventional Recovery

Recoverable oil reserves from currently producing fields in the United States were estimated to be about 28 billion barrels of oil at the end of 1982.[7] This includes about 3.5 billion

[7]U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1982 Annual Report, Office of Oil and Gas, Energy Information Administration, U.S. Department of Energy (August 1983).

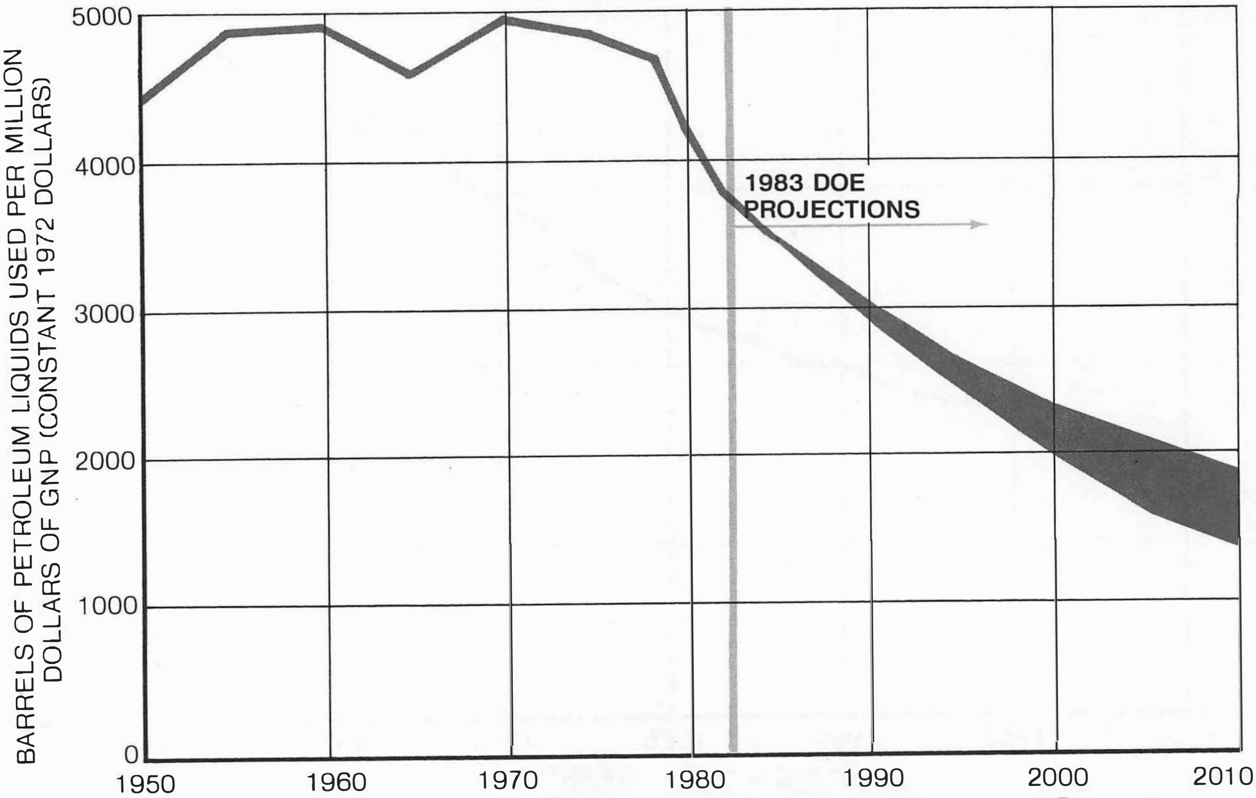


Figure 44. Trends in Demand for Petroleum Liquids (Includes Imported and Domestic Crude Oil, Natural Gas Liquids, and Imported Refined Products, Net of Exports.)

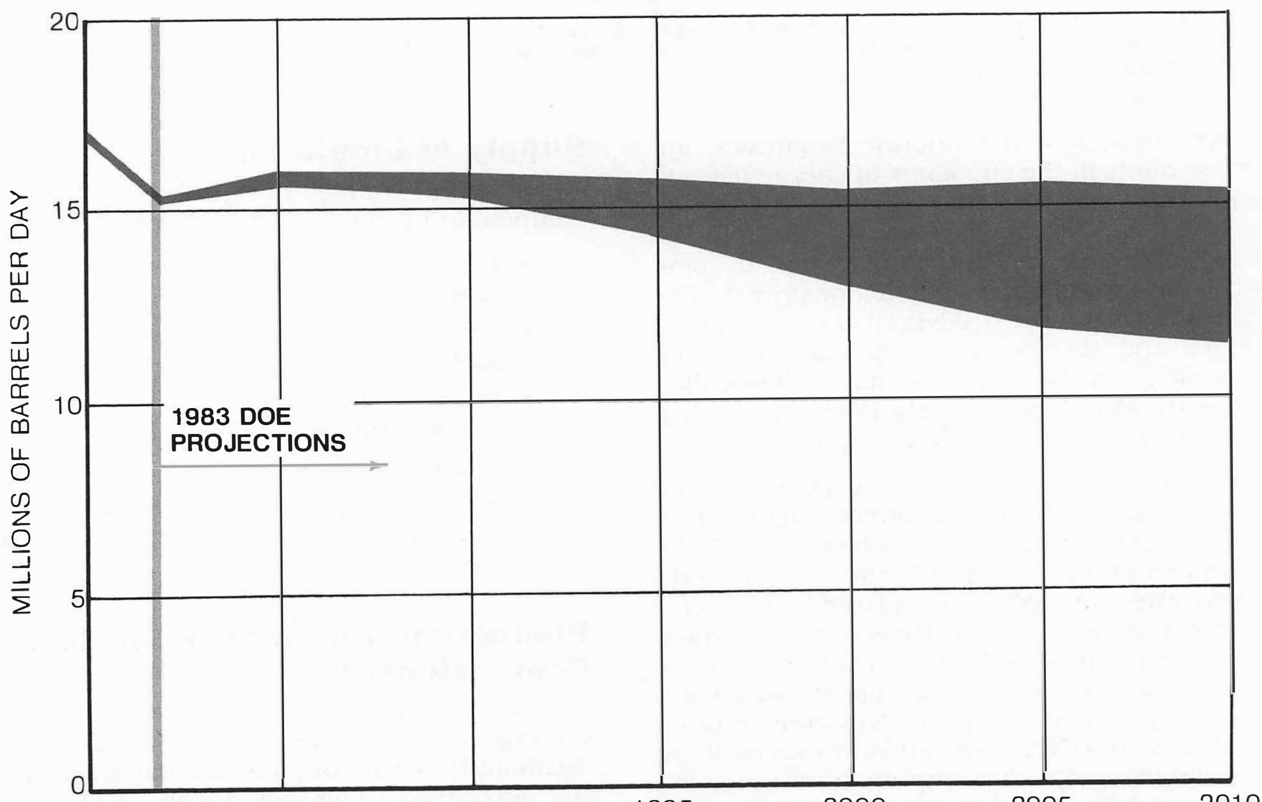


Figure 45. Projected U.S. Petroleum Liquids Demand in Millions of Barrels of Oil per Day (Includes Imported and Domestic Crude Oil, Natural Gas Liquids, and Imported Refined Products, Net of Exports.)

SOURCES OF DATA: *Basic Petroleum Data Book, Petroleum Industry Statistics,* Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (September 1983); and *Energy Projections to the Year 2010,* Office of Policy, Planning and Analysis, U.S. Department of Energy (October 1983).

TABLE 18

DEPENDENCE ON LIQUID PETROLEUM BY CONSUMING ECONOMIC SECTOR*
(Percentage of Total Energy Consumed Within Sector)

Sector	1970	1973	1976	1979	1982
Industrial	22.6	34.7	37.5	40.4	38.6
Residential and Commercial	38.0	27.5	26.0	23.1	19.5
Transportation	95.4	95.9	97.0	97.0	96.7
Electric Utilities	12.9	18.4	16.0	13.9	7.5
Total U.S. Economy	**44.0**	**46.7**	**47.2**	**47.0**	**42.9**

*Source of data: *Basic Petroleum Data Book, Petroleum Industry Statistics*, Vol. 3, No. 3 (September 1983), American Petroleum Institute, Washington, D.C.

barrels that will be produced by ongoing EOR projects (primarily steam); however, it does not include recoverable natural gas liquids and gas condensate, which amount to an additional 7.2 billion barrels. At current production rates, this represents about a 9.6-year supply of total petroleum liquids without any future additions to reserves. However, because of declining production rates, it will actually take about 30 years to produce these reserves. The 28 billion barrels of crude oil reserves are only about 17 percent of the oil forecast to be needed during the period.

Production from Known Fields by Enhanced Oil Recovery

To expand domestic crude oil supplies, producers are giving increasing attention to improving recovery of in-place reserves from known reservoirs. A potential means to accomplish this is application of enhanced oil recovery processes on a broad scale. However, any significant increase in the application of these processes on a wide scale will depend on:

- Favorable (commensurate with risks) EOR project economics that are attractive relative to other investment opportunities for developing oil or gas supplies
- The amount of capital available to the petroleum industry
- Other factors, as discussed in Chapter Six.

Potential recovery of crude oil through application of EOR processes in known reservoirs as projected in this study could be an important part of the overall U.S. supply. The potential exists to add 11 billion barrels of reserves to U.S. supplies with existing EOR technology and current economic conditions. This potential is equivalent to approximately 40 percent of current proved U.S. reserves.

Exploration and Development of New Fields

It is becoming more and more difficult to add reserves by exploratory drilling. This is illustrated in Figure 46, which shows the historical trend of reserve additions per foot of

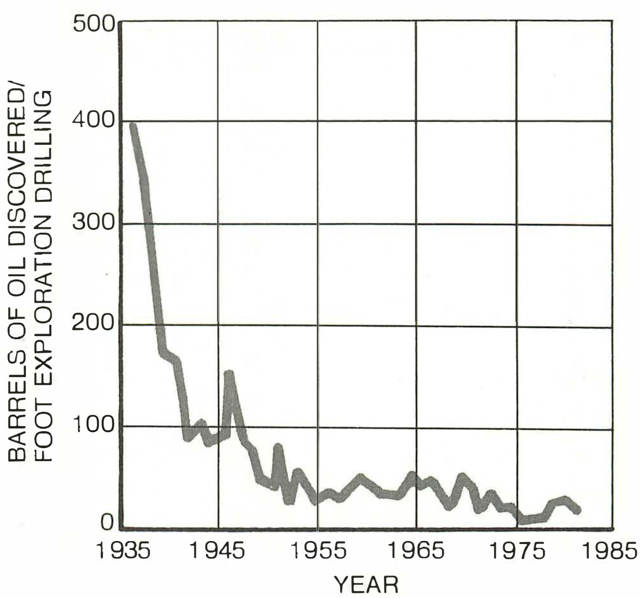


Figure 46. Barrels of Oil Discovered per Foot of Exploratory Well Drilled in the Contiguous 48 States.

SOURCE: Ivanhoe, L.F., *Free World Oil Discovery Indexes—1945-81, Oil & Gas Journal* (November 21, 1983), pp. 88-90.

hole drilled by exploratory wells in the contiguous 48 states. This trend indicates that an ever increasing amount of drilling is necessary to find an additional barrel of reserves. Ultimately, a point of diminishing returns will be reached if this trend continues, and as this happens, the economics of alternative EOR projects will become increasingly attractive relative to the economics of exploration.

Several factors could improve the chances for future exploration success, such as greater access to unexplored lands, both offshore and onshore, and the geologic attractiveness of some frontier areas such as Alaska and the deep Gulf of Mexico. However, there is agreement that harsher environments in most frontier areas will cause longer time lags between discovery and production. These harsher environments will raise development costs, which could make discoveries in these environments uneconomic unless very large accumulations having high per-well producing rates are found or real prices increase significantly. It will not be unusual for large offshore or Arctic projects to require investments of several billions of dollars.

Imports

Although imports have been dropping both in total volume and as a percentage of U.S. consumption since 1979, they will continue to be a significant future source of liquid hydrocarbons. The current plentiful supply of foreign oil could influence the rate of EOR growth in the United States by its influence on oil price. A plentiful supply of foreign oil could restrain future domestic oil prices. On the other hand, restricted availability of imported oil, by political events or cartel action, could cause oil prices to rise. Barring political events sufficient to disrupt foreign supplies, it seems likely that supply and price will remain relatively stable through the end of this decade.

Synthetic Fuels

Natural gas, oil shale, coal, tar sands, and biomass are large resource bases from which liquid fuels can be derived. Technology is available to convert all of these materials to liquid fuels. However, considering their abundance, oil shale and coal appear to be the most promising resources at present. It is, however, unlikely that coal or oil shale conversion will be pursued on a commercial scale in the forseeable future without substantial improvements in technology that would lower capital and operating costs. Considerably higher product prices most likely will be required to offset the high costs and risks of synfuel projects. Further, environmental considerations may impose constraints that could add substantially to already high manufacturing costs.

Effects of Other Energy Sources on Enhanced Oil Recovery

The surplus of foreign oil and a preference for exploration and conventional development projects probably will have the greatest influence on EOR application, especially in the near term. Synfuels, coal, and nonhydrocarbon fuels probably will have only a small influence on EOR development.

Assuming that U.S. demand for liquid fuels will be essentially constant through the end of the century, it is likely that oil produced domestically, as a result of exploration and conventional development or from EOR projects, will neither sustain the existing domestic production level nor displace imported oil. For the near term, the present worldwide surplus of oil serves to hold prices stable or even exert some downward pressure, depending upon production restraints exerted by OPEC nations. Although a dominant part of the surplus capacity resides in OPEC nations of the Middle East, where prices are controlled by political as well as market forces, the near-term prices are also affected by the availability of crude oil supplies from non-OPEC nations. It was the growth in this crude oil supply, coupled with reduced demand caused by substantial conservation and depressed economic conditions, that led to the decreasing price trend since 1981.

Overall, the very large reserves of the Middle East could dominate the worldwide supply picture through the remainder of this century. Import availability from this area will be a significant influence on crude oil prices worldwide and thus on EOR development projects in the United States for some time to come.

Exploration and conventional development activities could affect EOR in the near term by successfully competing for available investment capital. Because of the large investments and uncertainty of most EOR projects, exploration and conventional development projects may be more attractive economically. The current flow of capital to conventional projects certainly indicates that they are preferred over EOR projects today. How long this situation will continue is a matter of conjecture. The trends, however, seem to be towards higher finding costs for exploratory oil and fewer opportunities for conventional development. If continued, these trends ultimately could result in enhanced oil recovery being a more attractive alternative for investment funds than it is now.

Current forecasts through the year 2000 indicate that only minor volumes of synfuels will be produced. Combined production from oil shale and coal conversion may be no more than 200 thousand barrels per day in the year 2000.[8] Although forecasts are uncertain, the long lead times required to obtain large commercial production of synfuels preclude significant growth before the end of the century.

Coal, nuclear, hydroelectric, solar, and geothermal power generation could influence the application of enhanced oil recovery to the extent that they can be substituted for liquid fuels. Economic considerations, environmental constraints, and political circumstances applicable to these nonpetroleum sources of energy will control how fast they are substituted for conventional liquid and gaseous fuels. Any replacement of crude oil as a general energy source will reduce its demand, and perhaps price, such that EOR development

[8]See footnote 4.

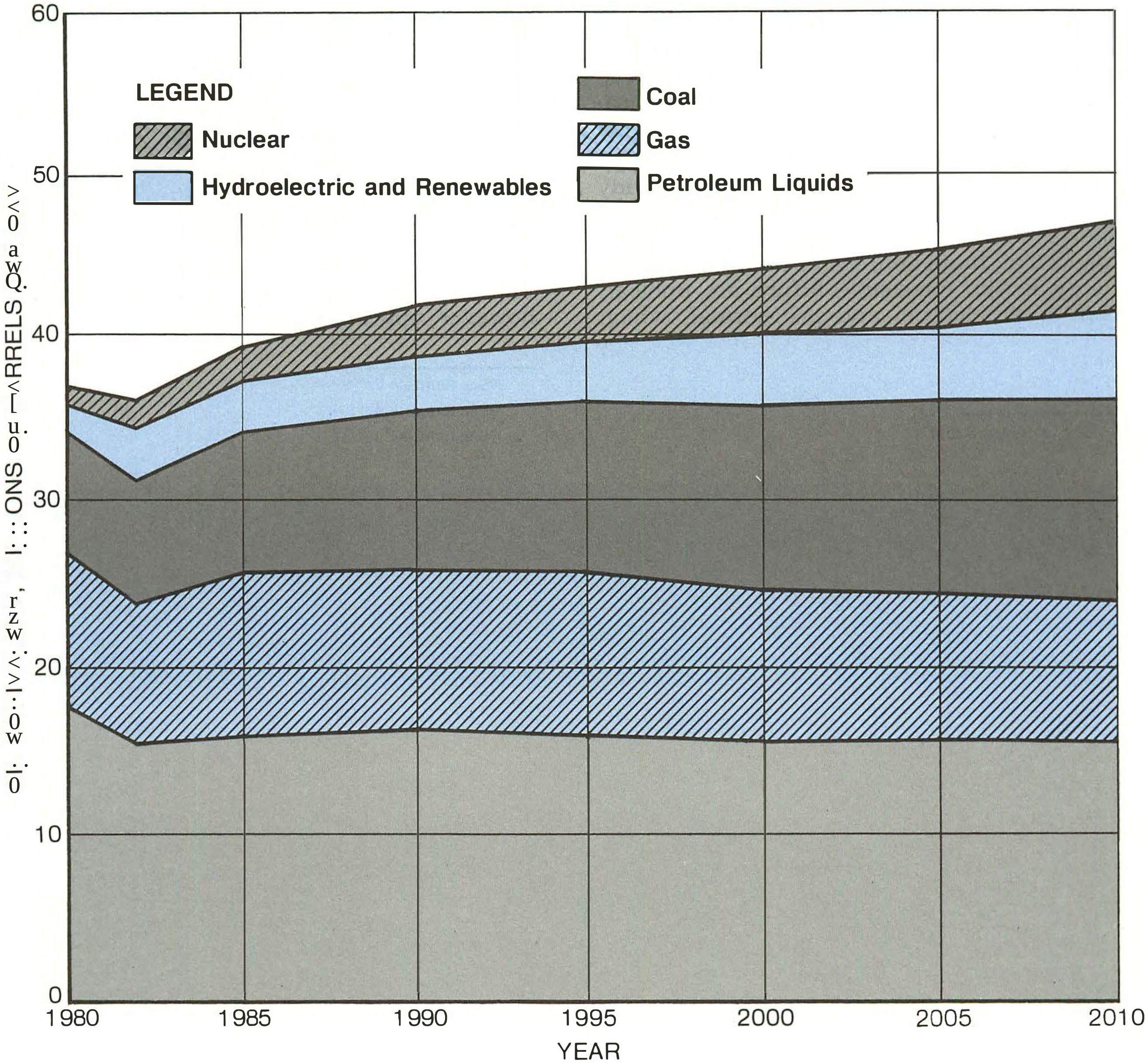


Figure 47. Projected U.S. Consumption by Primary Energy Source.

SOURCE OF DATA: *Basic Petroleum Data Book, Petroleum Industry Statistics,* Vol. 3, No. 3, American Petroleum Institute, Washington, D.C. (September 1983); and *Energy Projections to the Year 2010,* Office of Policy, Planning and Analysis, U.S. Department of Energy (October 1983).

could be suppressed. However, massive shifts from liquid fuels to alternative energy sources before well into the next century appear unlikely considering current economic conditions, overall oil supply, available infrastructure, and demand. There might be some impact from coal subsitution in power generation, however.

Although coal is a potential source for liquid hydrocarbons, it is also a significant primary energy source for electric power generation. It can be seen from the energy forecast of Figure 47 that coal consumption is projected to grow substantially through the year 2000. Its abundance and existing infrastructure make it the most logical substitute fuel for natural gas and crude oil in the power generation industry. Such substitutions could impact demand growth for petroleum-derived fuels and could retard growth in EOR applications insofar as they act to restrain oil prices to levels that discourage EOR investment.

Within the time frame covered in this study of enhanced oil recovery, the impact of nonhydrocarbon sources should be relatively small.[9] The main sources of nonhydrocarbon energy in the forseeable future are nuclear, solar, hydroelectric, and geothermal, which together in 1982 supplied about 9 percent of the nation's needs.[10]

Application of nuclear energy is, and will continue to be, limited to generation of electric power. While nuclear fission as an energy source is a reasonably mature technology, it is troubled with significant capital costs, and with a lack of public acceptance. Due to completion of nuclear power generation projects already underway, forecasts indicate near-term growth in nuclear energy supply of about 6 percent annually through 1990 and only about 1 percent annual growth after 1990.[11]

The contribution of solar energy to total energy supply by the end of this century is projected to be relatively small. There also is some potential growth in energy supplied by hydroelectric and geothermal stations. Any growth in energy supply from these sources could partially displace other sources of energy for heating, such as electricity generated by coal and nuclear fission, as well as liquid hydrocarbons. Combined growth of these sources is expected to exceed 1 percent annually,[12] and may be as high as 2.5 percent annually (Figure 47). The probable impact on EOR development, however, appears to be negligible.

[9]See footnotes 3 and 4.

[10]See footnote 2.

[11]See footnote 4.

[12]See footnote 4.

Chapter Six

Policy Considerations

Preceding sections of this report have addressed the technical and economic aspects of enhanced oil recovery. Government policy should consider more general issues. These include:

- Social costs and benefits arising from EOR activities
- The impact of existing government regulations and policies on EOR development.

This chapter addresses these broader issues, and concludes that enhanced oil recovery can have significant social benefits at minimal social cost (generally, environmental effects). Government regulations and policies should encourage EOR development. Free market oil prices will provide the proper stimulus for EOR production and industry research and development efforts. Permitting enhanced oil recovery to compete on an equal basis with other energy sources will best serve the national interest.

Environmental Effects and Benefits to Society

Environmental Effects

EOR projects can have environmental effects, and the costs of controlling these effects are considered in evaluating these projects. There are also benefits to society that are not considered in project economics and justification.

Environmental effects associated with EOR activities are essentially extensions of those experienced during primary and secondary oil recovery operations. Concerns about land use, aesthetic values, tract sizes, surface and subsurface waters, and surface disposal have been recognized and are addressed by current environmental regulations and industry practices. It is considered to be in the economic interest of industry to conduct operations in a manner that protects the environment. Environmental considerations, discussed in detail in Appendix G, are summarized below.

Surface Facilities

In existing fields, access roads, surface well locations, and process facilities are in place. Extension and expansion of these facilities for enhanced oil recovery can be accomplished with minimal additional effect.

Surface Disposal

Oil recovery operations, including enhanced recovery, generate various oilfield wastes. These are operationally monitored and disposal is subject to government regulations.

Subsurface Injection

EOR operations involve injection of gases or liquids into reservoirs in order to increase oil recovery. Injection operations pose potential threats to zones that contain potable water. Injection operations for secondary recovery have been the subject of extensive, long-term attention by both government and industry, with positive results. Continued vigilance will be required to maintain this good record for EOR operations.

EOR operations involve a wide variety of substances, some of which must be specially handled in their preparation, use, and recovery.

These include wastes from chemical mixing and injection plants, storage sites, combustion gas scrubbers, production processing sites, and gas treating facilities. Existing regulation and practices regarding these materials have produced an excellent control record.

However, the movement of injected chemicals through the reservoir into producing wells is not completely predictable. Laboratory research and field testing have contributed to the understanding of the problem, but concerns remain regarding the possible presence of chemicals in produced waters. Consequently, surface discharges of produced waters are strictly regulated and carefully monitored, both offshore and onshore.

Benefits to Society

A significant increase in enhanced oil recovery will have clear-cut social benefits. It will supply an important product and will result in more jobs and increased tax revenues. An extra benefit arises because every barrel of EOR offsets an imported barrel of oil. To the extent to which this occurs, enhanced oil recovery will improve the nation's energy security.

Briefly, those areas in which society will benefit from EOR programs are:

- **Foreign Policy and National Security**—Increases in domestic oil production will reduce foreign import requirements and decrease balance of payment deficits. Reduced dependence on oil imports would allow greater independence and flexibility in conducting U.S. foreign policy. Limiting oil imports from politically sensitive sensitive areas of the world would make the United States more secure from the disruptive effects of another embargo.

- **Increased Reserves**—With EOR technology it will be possible to recover an increased percentage of oil in place in existing reservoirs and newly discovered fields. The resulting increase in oil recovery would expand the nation's recoverable resource base.

- **Benefits to Industry**—EOR activities require more engineering, monitoring, and overall attention than conventional production methods and will require more skilled manpower. Ancillary industries will see increased employment as a result of drilling new wells, building new facilities, etc. Expanded EOR programs will cause expansion in those industries supplying materials for the individual projects and in all ancillary activities. An example would be the large amount of chemicals required for surfactant EOR.

- **Transition to Alternate Energy Sources**—Development of EOR provides more time for transition from oil and gas to alternate energy sources such as synfuels.

- **Government Revenues**—Severance, property, and income taxes and royalty payments to governments that are imposed on EOR projects will contribute to the funding of government services.

These social benefits are obvious. The social costs associated with EOR operations have been recognized as primarily environmental. Potential problems can be managed through diligent attention and action by the oil industry, working within the framework of current environmental regulations.

Government Regulation and Policy

The effect of government regulation and policy on EOR activity since 1976 is discussed to some extent in various sections of this report. Key elements that should be considered in setting future regulations and policies are discussed below.

Tax Policies

The value of oil realized by the producer is the most important factor affecting EOR application and drives the rate of technical development. This value is a result of supply and demand, combined with royalty, tax, and other regulatory policies affecting crude oil prices. A change in any of these will also change the value of crude oil realized by the producer and alter the rate of EOR development.

Oil production by enhanced recovery is more costly than production by most conventional methods. There are a few exceptions, such as high-cost frontier areas. Because of these high costs and the heavy front-end investment required for most EOR projects, economics are modest. Tax policies that reduce the value of oil realized by the producer will worsen the economics of enhanced oil recovery and decrease ultimate recovery from EOR development.

Financial Risks Associated with Enhanced Oil Recovery

A major consideration affecting the petroleum industry's willingness to commit additional funds to EOR projects is the attractiveness of these investments compared to alternative opportunities. Uncertainties about future price controls and taxes add to project risk and tend to discourage investment in long-term, low rate of return projects. Thus, some EOR projects that may be economically viable will not be implemented. Government actions that reduce the perceived risks of enhanced oil recovery will increase the number of EOR projects.

Pending Government Legislation

Lengthy delays in passing pending legislation or issuing regulations almost always cause delays within the industry regardless of whether the new policies are favorable or unfavorable. If they are favorable, industry normally cannot take advantage of them until they are approved in final form so there is very little anticipatory benefit. In contrast, if there is any doubt whether the legislation is going to have a positive or negative effect, the overwhelming tendency is to perceive the impact as worse than it actually might be. As a result, industry begins to react even before the regulations are finalized.

Over the years the petroleum industry has complied with newly enacted state and federal standards. The facts are, however, that these changes take time and lead to a period of adjustment during which delays in implementation usually occur.

Royalties and Severance Taxes

High royalities and severance taxes discourage EOR investment since they are claims on gross revenue rather than net earnings, and, thus, represent a burden that would preclude development of otherwise economic reserves and hasten abandonment of fields producing close to their economic limit. Chances of EOR development are increased by keeping economically marginal fields on production. This is especially true in mature offshore areas such as the Gulf of Mexico. Very few EOR projects could bear the costs of replacing offshore platforms in abandoned fields. In addition, lower royalties and severance taxes could actually increase total government revenue from marginal fields by keeping them on production longer.

Research and Development

The various EOR processes are not at the same state of technological development. Research and development are needed in certain areas to reduce the technical uncertainties that currently delay commercial development. Industry in conjunction with universities and government must ensure that the necessary effort is put forth to develop the required technologies that will enable the recovery of the large volume of hydrocarbons discussed in this report. Support of university research programs, by both industry and government, should be encouraged.

The full-scale development of enhanced oil recovery will continue to require the industry to spend considerable high-risk research and development funds. Appropriate tax credits that assist in the recovery of these investments should be continued and considered in developing future policy and regulations. As a general rule, the government should not directly subsidize field testing. A very promising technical innovation requiring highly instrumented field testing, however, should receive consideration for government investment when the test would otherwise not go forward, and if the industry provides substantial front-end cost-sharing.

Operational Issues

Lost Opportunities

Many oil fields in which waterfloods were started in the 1950s have now reached advanced stages of depletion. Some are approaching their economic limit and many wells are being plugged and abandoned. For these fields, it would be best if EOR projects, where feasible, were initiated while the existing wells and surface equipment are still intact and usable. Otherwise, the added cost incurred in redrilling wells and replacing production facilities will make many EOR projects uneconomic. In offshore operations, the added costs of redrilling would be compounded by the need to install new drilling platforms. Few, if any, projects could withstand this additional cost.

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 avoid pollution by preventing oil, gas, and salt water from escaping at the surface or into subsurface water-bearing formations.

Ordinarily, when field or unit operators desire to retain a well for evaluation and future re-entry or injection, they may apply to a state regulatory agency for an exception to the plugging rule. However, numerous individual operators having wells nearing the economic limits of current operations may plug and abandon such wells because they cannot foresee any economic incentive for future EOR projects in the area. Government policies that facilitate the retention of potentially useful wellbores in an environmentally safe manner are encouraged.

Unitization

Many producing reservoirs are characterized by multiple ownership and will require unitization to implement EOR projects. Unitized EOR 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 production on the basis of prearranged terms.

Regulations that create different oil price or tax treatment for different owners in the same field also create different incentives for EOR projects. This complicates unitization and may make it impossible. The present Windfall Profit Tax Act is a good example of such legislation.

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 reduce the prospect of reaching mutual agreement on unitization required for implementation of EOR projects.

Disincentives

Government policy and regulations should be carefully assessed to eliminate disincentives for the implementation of EOR. Clearly this could have dramatic results on the future potential for EOR. The current Windfall Profit Tax is a disincentive for all oil exploration and production, including EOR. While the Windfall Profit Tax is lower for EOR, the regulations still do not provide clear incentives for industry-wide development of enhanced oil recovery.

The above considerations indicate that government policy and the regulatory environment can have a significant impact on enhanced oil recovery. Free market oil prices, undistorted by multiple pricing and differential tax treatments, will provide the most efficient distribution of resources to all forms of oil recovery, including enhanced oil recovery. In the long term, this will act to maximize the supply of domestic crude oil.

Appendices

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

March 10, 1982

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

Dear Mr. Bookout:

The President has stressed that the continuing ability of our petroleum industry to develop domestic oil and gas resources is essential to ensuring a secure and reliable energy supply for the Nation. Enhanced oil recovery technology is of significant interest because of the large number of domestic fields to which it may be applied. The average recovery from conventional primary and secondary recovery methods is expected to be only about one-third of the original oil-in-place, leaving approximately 300 billion barrels in currently known reservoirs. Thus, enhanced oil recovery represents an important element in the Nation's future petroleum production.

At the request of the Department of the Interior, the National Petroleum Council conducted a study resulting in the 1976 report, Enhanced Oil Recovery. This report provided valuable information on the state-of-the-art of the technology, the economic considerations, and the estimated potential for enhanced oil recovery. Additionally, the 1976 report provided policy recommendations on research and development, economic incentives, social costs and benefits, environmental factors, and Federal policy considerations.

There have been significant changes in the technology and economics of enhanced oil recovery since the 1976 report. I, therefore, request the National Petroleum Council to undertake a new study of enhanced oil recovery, updating your previous work where appropriate and expanding upon it where necessary. For purposes of this study, I will designate Jan W. Mares, Assistant Secretary for Fossil Energy, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James B. Edwards

James B. Edwards

Description of the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- *U.S. Energy Outlook* (1971, 1972)
- *Potential for Energy Conservation in the United States: 1974-1978* (1974)
- *Potential for Energy Conservation in the United States: 1978-1985* (1975)
- *Ocean Petroleum Resources* (1975)
- *Petroleum Storage for National Security* (1975)
- *Enhanced Oil Recovery* (1976)
- *Materials and Manpower Requirements* (1974, 1979)
- *Petroleum Storage & Transportation Capacities* (1974, 1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil and Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1984)

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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Appendix C

Additional Economic Considerations

This appendix contains material referenced, but not included in, other parts of the study. In most cases this material furnishes added detail or explanation for economic concepts introduced elsewhere.

The material is organized as follows:

- Calculation of project crude oil sales price
- Produced gas prices
- Energy cost factors
- Investment Efficiency calculation
- Process-independent costs.

Calculation of Project Crude Oil Sales Price

The nominal $30 per barrel case is based on the assumption that mid-continent 40 °API oil sells for $30 per barrel, and project crude oil sales prices vary from this price due to gravity and location in accordance with Figures 18 and 19 in Chapter Three.

At nominal crude prices (NCP) other than $30, the project crude price (PCP) is assumed to vary proportionally in accordance with the following equation:

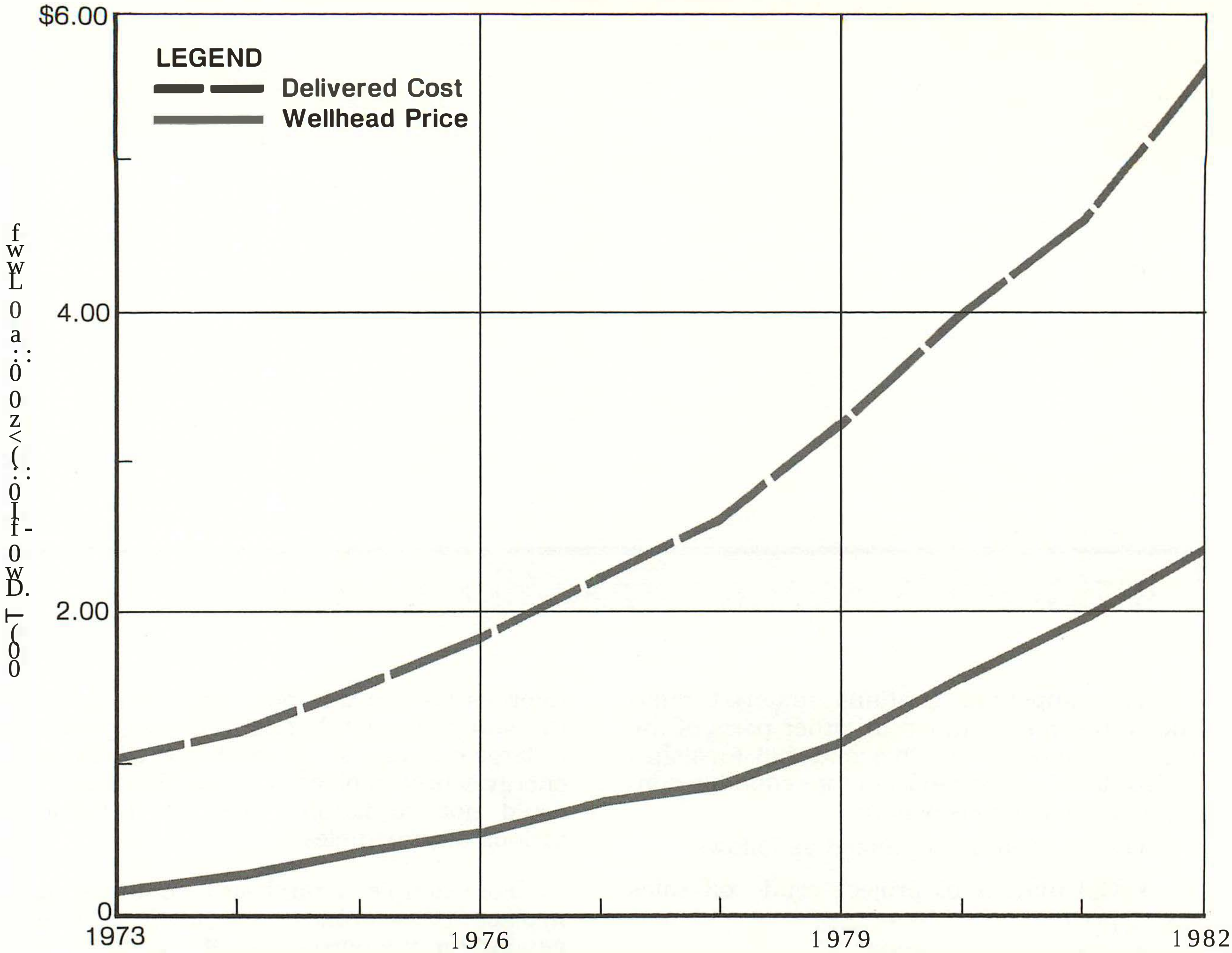
$$\text{PCP} = \text{PCP at \$30 per barrel} \times \frac{\text{NCP}}{30}$$

Produced Gas Prices

Although handling the production, sale, and consumption of produced natural gas in a rigorous fashion was not a prime objective of this study, the fact that natural gas is produced in large quantities and used in the field as an energy source in place of crude oil or electricity could not be ignored without introducing serious discrepancies.

For example, natural gas is commonly used in place of lease crude oil as boiler fuel for steam generation in environmentally sensitive areas of California, especially where severe sulfur dioxide emission regulations exist. Natural gas is also frequently used as an energy source to drive the large compressors required to inject carbon dioxide (CO_2). In the first instance, assuming that lease crude oil is burned as the generator fuel would have provided an unfair economic advantage for these projects because natural gas usually costs much more than low-gravity California crude oil. In the second instance, assuming electric driven compressors were always necessary would have imposed an unfair economic burden on CO_2 miscible projects because, on an energy basis, electricity is much more costly than natural gas.

The fact that natural gas had to be included as a fuel created another problem in that its price varies almost tenfold from less than $1 per thousand cubic feet (Mcf) under some old gas contracts to as much as $10 per Mcf for deregulated gas sources. Figure C-1 illustrates the long-term average wellhead price and delivered cost trends in the United States. However, these data ignore the fact that gas prices are source dependent.



- The average wellhead price of natural gas rose from $0.22 to $2.41 per thousand cubic feet (Mcf) and the average residential heating cost rose from $1.08 to $5.53 per Mcf over the period shown.
- The wellhead price of gas accounted for 20% of the residential heating cost in 1973 and for 44% in 1982. Other components of the residential heating cost include transmission and distribution costs, utility company profits, and sales taxes.
- U.S. wellhead gas prices currently are determined by complex federal regulations implementing the Natural Gas Policy Act. This law established more than 20 different pricing categories for natural gas, and causes a wide range of prices to be received for natural gas production.

Figure C-1. U.S. Natural Gas Prices.

SOURCES: *Monthly Energy Review*, U.S. DOE Energy Information Administration (April 1983); TIC Facts (March 1983, Feb. 1982).

Energy Cost Factors

The purpose of energy cost factors is to adjust costs in a realistic way as the assumed nominal crude oil sales price varies.

Figure C-2 shows how crude oil price and associated costs have varied on an inflation-adjusted basis from 1970 to 1982. It suggests that there is a correlation, and that some costs are more sensitive to oil price change than others.

Figure C-3 shows how various cost components have varied with oil price. The slopes of these curves give an indication of the sensitivity of each cost component to change in crude oil price.

After examining these data, energy cost factors were determined for each cost component, or grouping, as shown in the following table:

Major Cost Grouping	Energy Cost Factor
Drilling and Completion Cost	0.4
Equipment Cost	0.3
General Operating Costs	0.2
Fuel and Energy Costs	1.0

Using these factors, costs were adjusted for changes in nominal crude oil price in accordance with the following equation:

$$C = C(@\ \$30) \times [1 + (\tfrac{NCP}{30} - 1) \times F]$$

where: C = cost, adjusted for crude oil price change

C(@ $30) = cost at nominal crude oil price of $30 per barrel

NCP = nominal crude oil price

F = energy cost factor

Investment Efficiency

Investment efficiency is defined as the ratio of the total discounted cash flow to the maximum cumulative negative discounted cash flow. Figure C-4 illustrates this concept.

The upper part of Figure C-4 shows a typical discounted cash flow stream over the life of a profitable project. Initially, there is a period of negative cash flow resulting from investment,

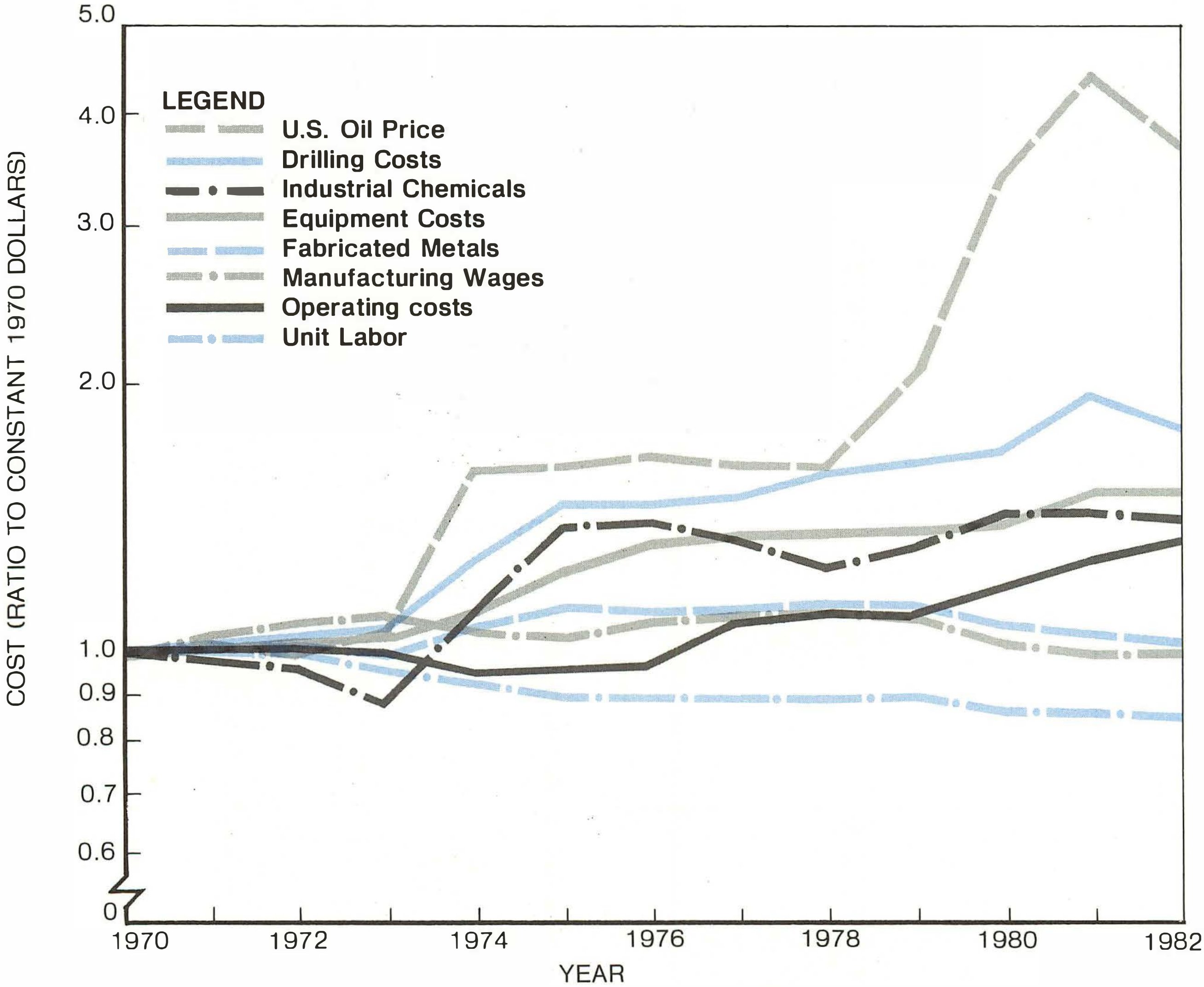


Figure C-2. Relative Price Changes, 1970-1982

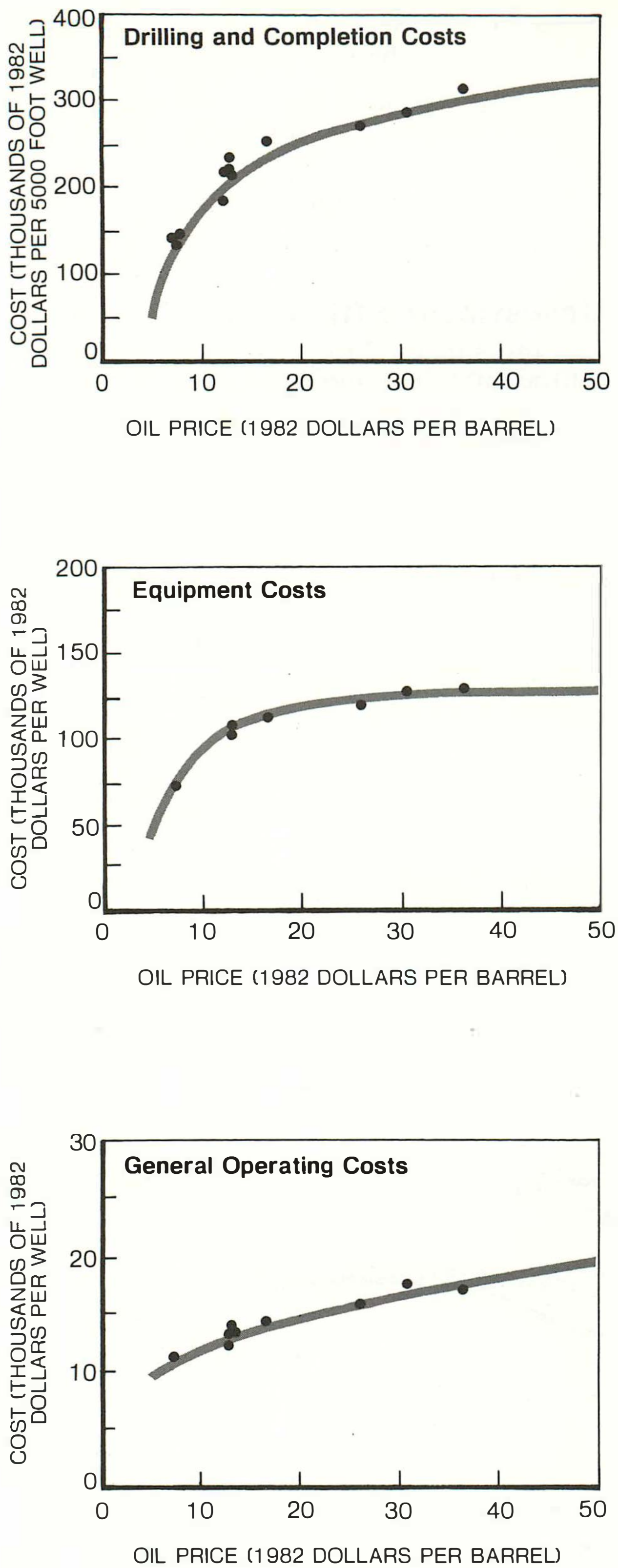


Figure C-3. Constant Dollar Cost Relationship Between Major Cost Groups and the Average Domestic Price of Crude Oil.

project startup costs, and operating expenses. During this period, the project is losing money, and the cumulative discounted cash flow (shown by the lower half of the figure), becomes increasingly negative. As the enhanced oil recovery (EOR) process takes effect, oil production rate increases and revenues begin to offset costs, eventually causing the cash flow to turn positive. This happens at time T on Figure C-4 and corresponds to the point where the cumulative discounted cash flow is at its most negative point.

Positive cash flows continue until, eventually, the oil production rate declines, and the cash flow approaches zero. This represents the economic life of the project, T_E on Figure C-4. At this time, the cumulative discounted cash flow is at its highest point. As illustrated on the figure, Investment Efficiency is simply this maximum value (P) at time T_E, divided by the absolute value of the negative cash flow (N) at time T.

Although this approach may seem somewhat complex, the Investment Efficiency technique is a valuable ranking tool. This is especially true for EOR projects, which are heavily front-end loaded, not only with capital investments, but also with exceptionally high operating expenses. Expensed injectants, such as CO_2 or surfactants, contribute to a substantially longer period of negative cash flows and to a much greater maximum negative cash flow than is the case with projects that are just capital intensive. More detailed discussions of Investment Efficiency are available in the literature.[1]

Process-Independent Costs

Introduction

Development costs, annual operating costs, and drilling costs for EOR operations can be categorized as being either process-dependent or process-independent. Because both the miscible and chemical EOR processes considered in this study will usually utilize the injection of water into the reservoir, the process-independent costs associated with these projects were determined by estimating the cost of installing and operating waterflood projects. Process-dependent costs were then added to the base waterflood costs to obtain the total cost for each process.

[1]Capen, E. C., Clapp, R. V., Phelps, W. W., "Growth Rate—A Rate-of-Return Measure of Investment Efficiency," J. Pet. Tech. (May 1976).

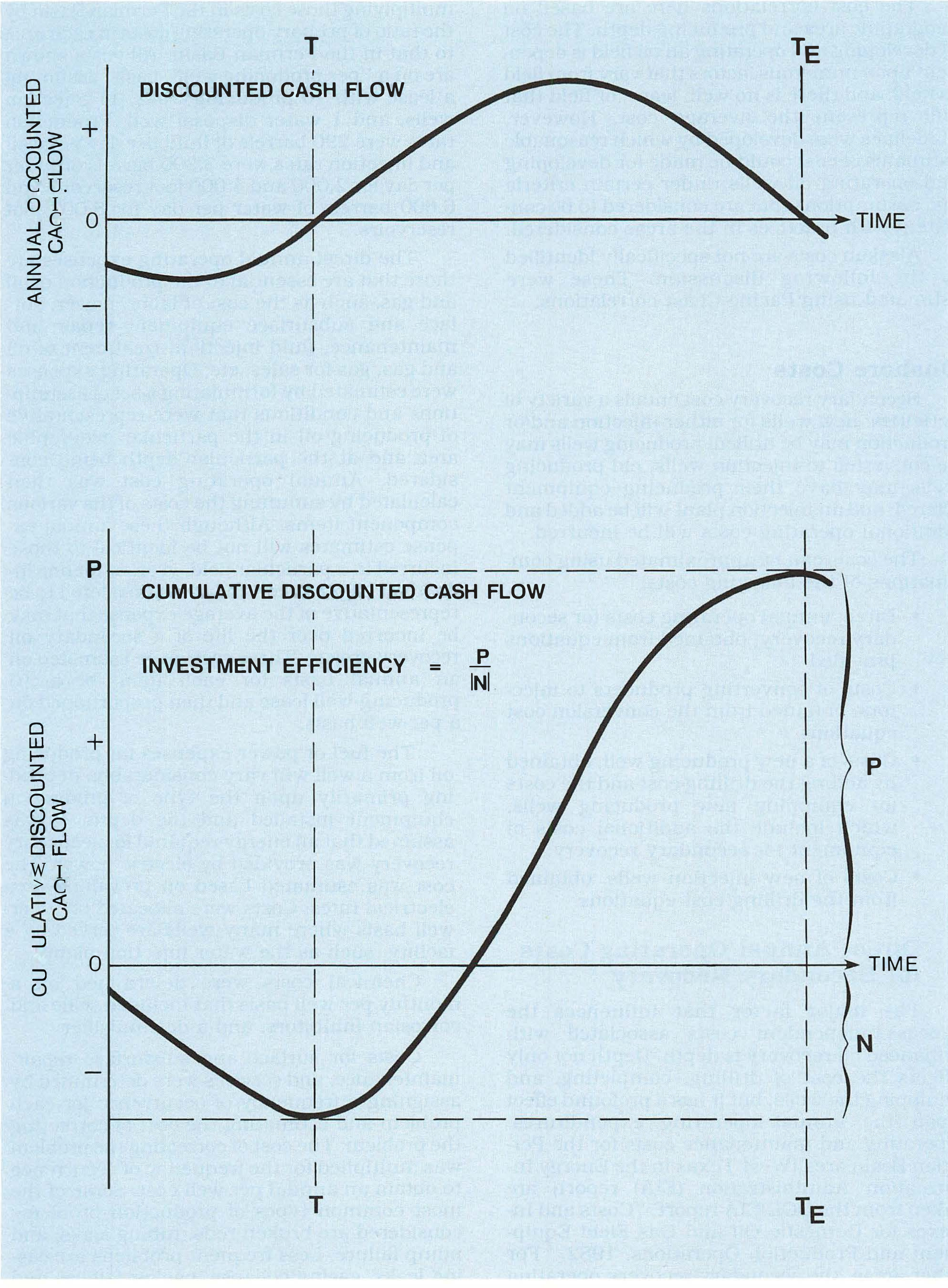


Figure C-4. Investment Efficiency.

The cost correlations here are based on geographic area and producing depth. The cost of developing and operating an oil field is dependent upon numerous factors that vary from field to field, and there is no well, lease, or field that will represent the average cost. However, guidelines were developed by which reasonable estimates of cost could be made for developing and operating oil wells under certain criteria and assumptions that are considered to be consistent with practices in the areas considered.

Alaskan costs are not specifically identified in the following discussion. These were estimated using Pacific Coast correlations.

Onshore Costs

Secondary recovery cost entails a variety of activities: new wells for either injection and/or production may be drilled; producing wells may be converted to injection wells; old producing wells may have their producing equipment altered; and an injection plant will be added and additional operating costs will be incurred.

The costs can be approximated using combinations of the following costs:

- Direct annual operating costs for secondary recovery, obtained from equations provided
- Costs of converting producers to injectors, obtained from the conversion cost equations
- Costs of a new producing well, obtained by adding the drilling cost and the costs for equipping new producing wells, which include the additional costs of equipment for secondary recovery
- Costs of new injection wells, obtained from the drilling cost equations.

Direct Annual Operating Costs for Secondary Recovery

The major factor that influences the process-independent 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. Operating and maintenance costs for the Permian Basin area [West Texas in the Energy Information Administration (EIA) report] are taken from the DOE/EIA report, "Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations, 1982." For other areas, the secondary recovery operating maintenance costs were determined by multiplying those costs in the Permian Basin by the ratio of primary operating costs in each area to that in the Permian Basin. All costs shown are on a "per producing well" basis, assuming a lease with 10 producing wells, 11 injection wells, and 1 water disposal well. Production rates were 290 barrels of fluid per day per well and injection rates were 3,300 barrels of water per day for 2,000 and 4,000 foot reservoirs and 6,600 barrels of water per day for 8,000 foot reservoirs.

The direct annual operating expenses are those that are essential to the production of oil and gas, such as the cost of labor, power, surface and subsurface equipment repair and maintenance, fluid injection, treatment of oil and gas, gas for sales, etc. Operating expenses were estimated by formulating a set of assumptions and conditions that were representative of producing oil in the particular geographic area and at the particular depth being considered. Annual operating cost was then calculated by summing the costs of the various component items. Although these annual expense estimates will not be identical to those incurred in a particular field, year, or for one individual oil producer, they are considered to be representative of the average expense that may be incurred over the life of a secondary oil recovery project. These costs were estimated on an annual basis for each item for a 10 producing-well lease and then proportioned on a per-well basis.

The fuel or power expenses for producing oil from a well will vary considerably, depending primarily upon the type of production equipment installed and the depth. It was assumed that all energy required for secondary recovery was provided by electric power. The cost was estimated based on prevailing area electrical rates. Costs were allocated on a per-well basis where many wells are served by a facility, such as the water injection plant.

Chemical costs were determined on a monthly per-well basis that included scale and corrosion inhibitors, and a de-emulsifier.

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

A summary list of all items in the process-independent direct annual operating expenses is shown below:

Normal Daily Expense

- Supervision and Overhead
- Labor (pumper)
- Auto Usage
- Chemicals
- Fuel, Power, and Water
- Operating Supplies

Surface Maintenance

- Repair and Services
- Labor (roustabout)
- Supplies and Services
- Equipment Usage
- Other

Subsurface Maintenance

- Repair and Services
- Workover Rig Services
- Remedial Services
- Equipment Repair
- Other

The equation and parameters by area for operating costs per producing well for secondary recovery are:

$$A = a_0 + a_1 D$$

where: A = annual costs in dollars per producing well
D = depth in feet

Table C-1 shows values of correlation coefficients a_0 and a_1 for the geographic regions shown in Figure C-5. Figures C-6 through C-11 show the depth-cost correlations for each region.

TABLE C-1

Region	a_0	a_1
Permian Basin	15,440	4.159
Pacific Coast	13,068	9.062
Rocky Mountains	19,459	4.384
Western Gulf Coast	19,456	5.459
Eastern Gulf Coast	21,570	5.497
Mid-Continent and North-eastern	13,205	5.222

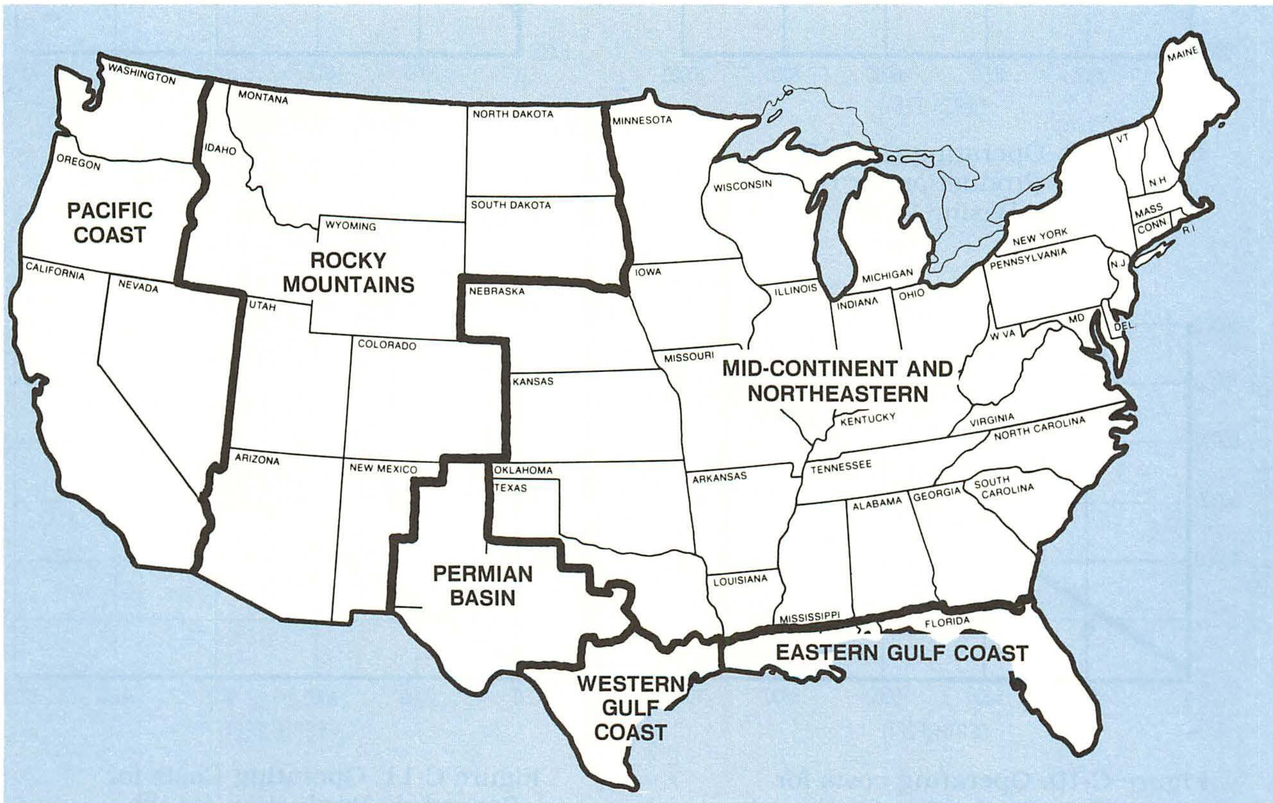


Figure C-5. Cost Regions—Operating, Conversion, and Equipping Costs.

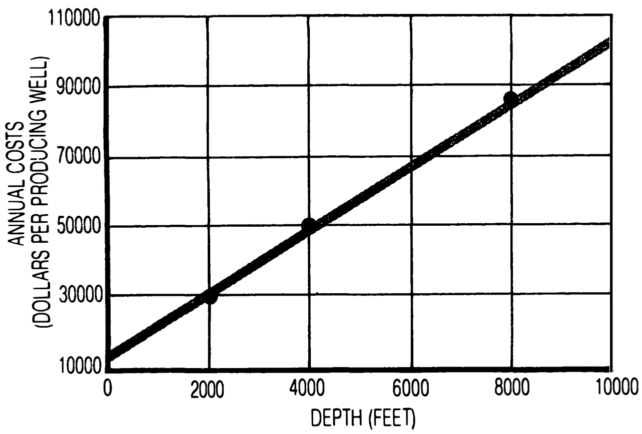


Figure C-6. Operating Costs for Secondary Production for the Pacific Coast, 1982.

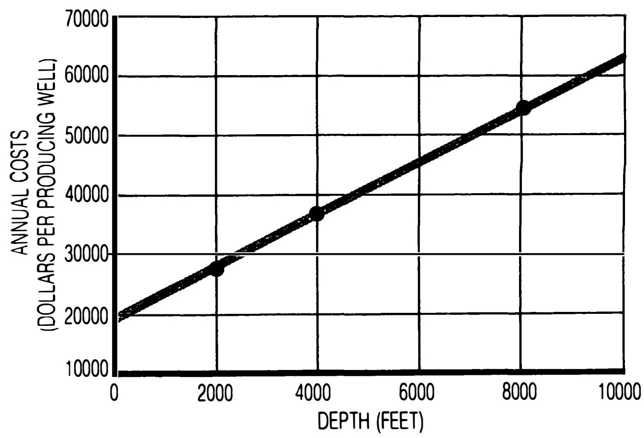


Figure C-7. Operating Costs for Secondary Production for the Rocky Mountains, 1982.

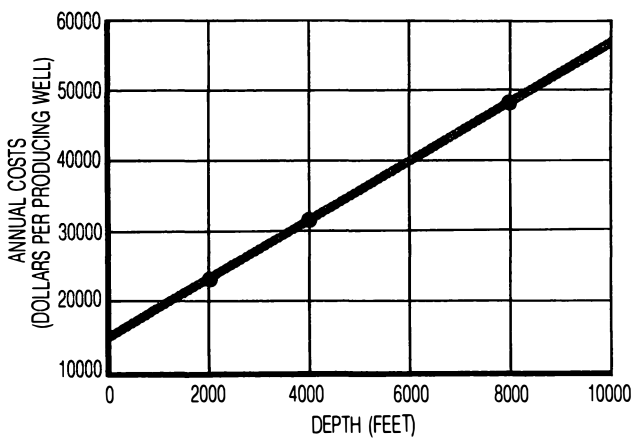


Figure C-8. Operating Costs for Secondary Production for the Permian Basin, 1982.

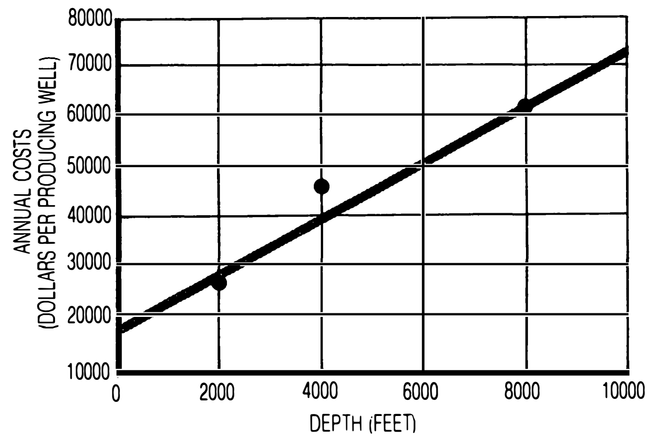


Figure C-9. Operating Costs for Secondary Production for the Western Gulf Coast, 1982.

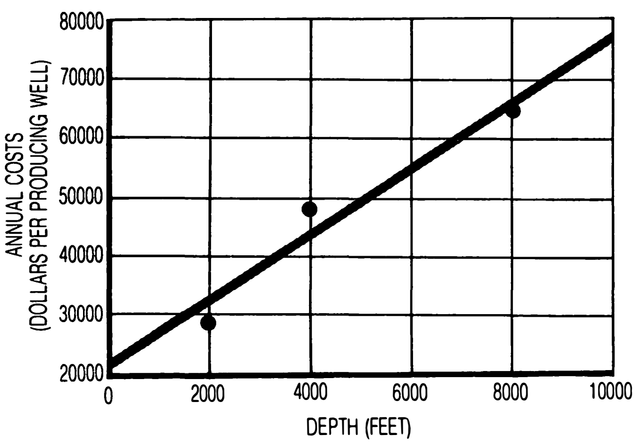


Figure C-10. Operating costs for Secondary Production for the Eastern Gulf Coast, 1982.

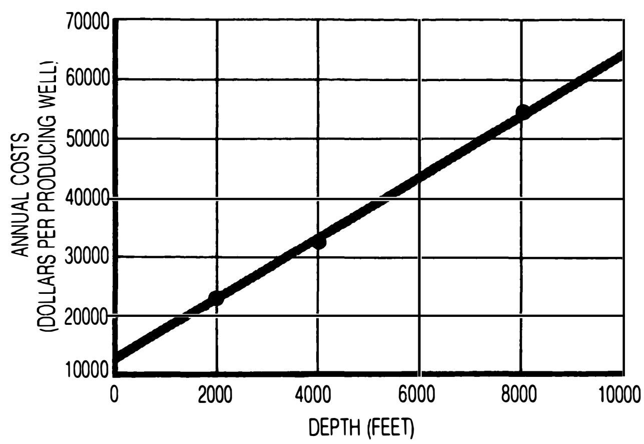


Figure C-11. Operating Costs for Secondary Production for the Mid-Continent and Northeast, 1982.

Conversion Costs from a Producing Well to an Injection Well

Producing wells may be converted to injection service because of pattern selection and the favorable cost comparison to drilling a new well. The conversion procedure consists of removing surface and subsurface equipment (including tubing), acidizing and cleaning out the wellbore, and installing new 2-7/8 inch, plastic-coated tubing and a waterflood packer (plastic-coated internally and externally). These costs were determined for 2,000, 4,000, and 8,000 foot depths for each of the areas, and linear fits were made of the costs versus depth data.

The equation and parameters by area for the cost of converting producing wells to injection wells are:

$$B = b_0 + b_1 D$$

where: B = conversion costs in dollars per well

D = depth in feet

Table C-2 shows correlation coefficients for each region and Figures C-12 through C-17 show the depth-cost correlation.

TABLE C-2

Region	b_0	b_1
Permian Basin	5,463	5.979
Pacific Coast	6,924	6.051
Rocky Mountains	6,240	6.109
Western Gulf Coast	5,679	5.921
Eastern Gulf Coast	6,280	5.950
Mid-Continent and North-eastern	6,051	5.888

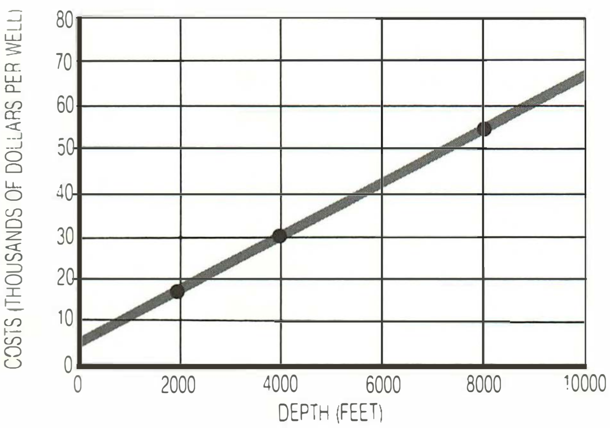


Figure C-12. Cost of Converting a Producing Well to an Injection Well in the Pacific Coast, 1982.

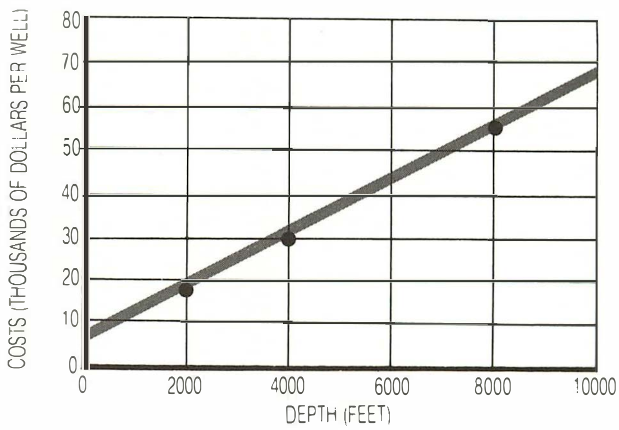


Figure C-13. Cost of Converting a Producing Well to an Injection Well in the Rocky Mountains, 1982.

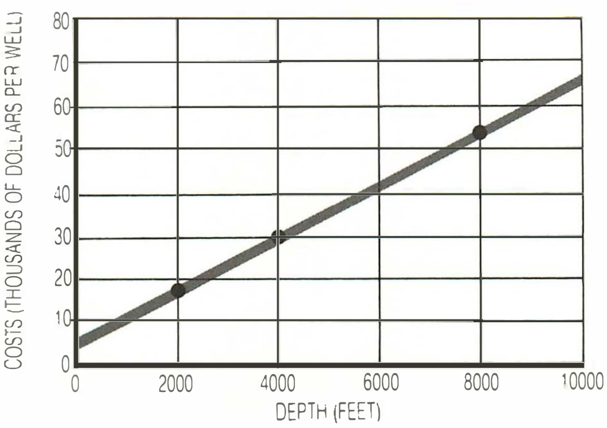


Figure C-14. Cost of Converting a Producing Well to an Injection Well in the Permian Basin, 1982.

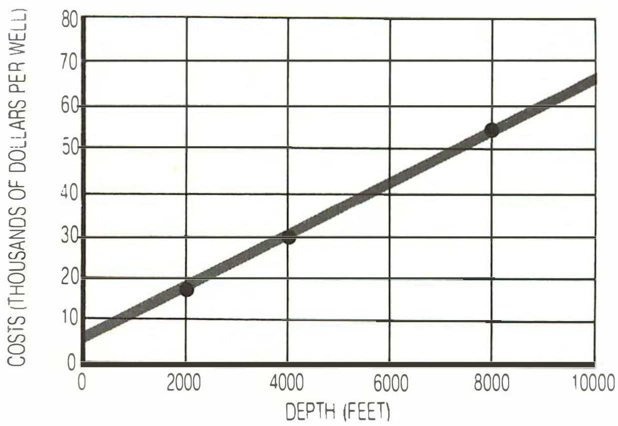


Figure C-15. Cost of Converting a Producing Well to an Injection Well in the Western Gulf Coast, 1982.

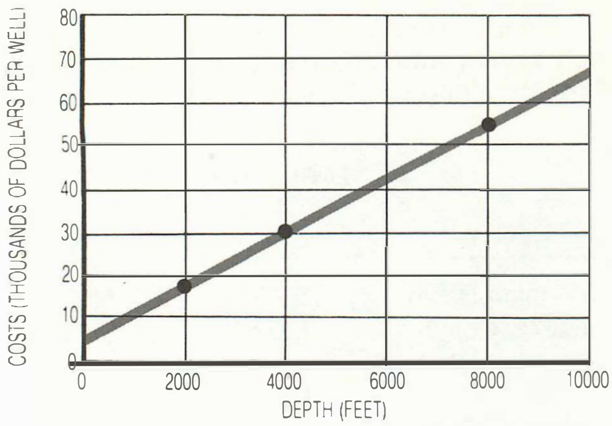


Figure C-16. Cost of Converting a Producing Well to an Injection Well in the Eastern Gulf Coast, 1982.

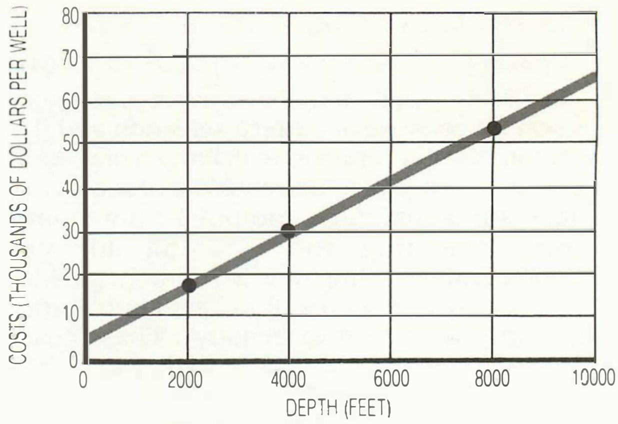


Figure C-17. Cost of Converting a Producing Well to an Injection Well in the Mid-Continent and Northeast, 1982.

Costs of Equipment for a New Producing Well

These costs consist of the additional cost to equip a new producing well for secondary recovery, excluding tubing costs, which are included in the drilling cost.

The equation and parameters by area for equipping costs for a new producing well including its share of the additional equipment needed for secondary recovery are:

$$C = c_0 + c_1 D$$

where: C = cost in dollars per well

D = depth in feet

Table C-3 shows correlation coefficients for each region and Figures C-18 through C-23 show the depth-cost correlations.

TABLE C-3

Region	c_0	c_1
Permian Basin	15,145	18.0632
Pacific Coast	17,635	29.0925
Rocky Mountains	15,615	18.2418
Western Gulf Coast	11,755	19.4718
Eastern Gulf Coast	12,585	21.0825
Mid-Continent and North-eastern	11,455	18.8818

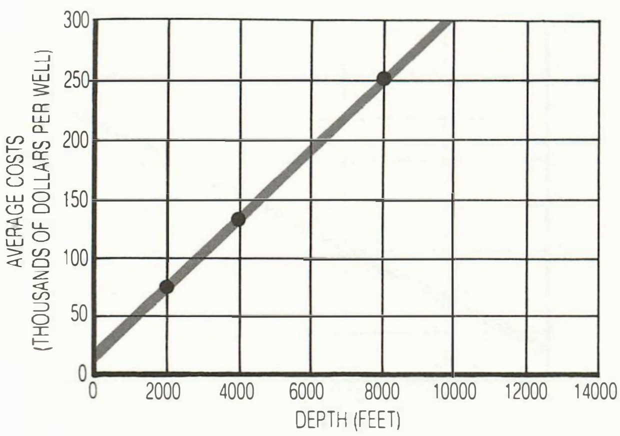


Figure C-18. Cost of Equipping New Producing Wells for the Pacific Coast, 1982.

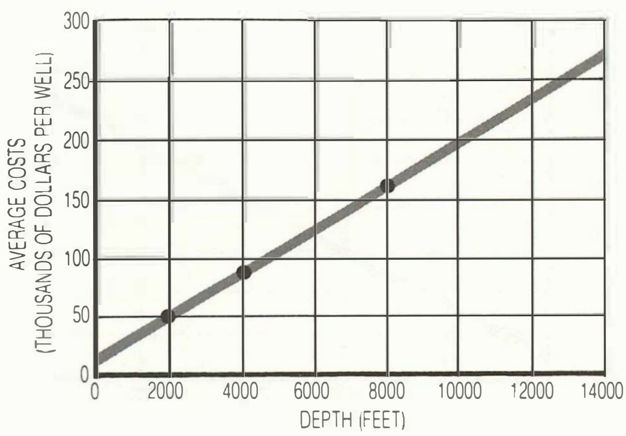


Figure C-19. Cost of Equipping New Producing Wells for the Rocky Mountains, 1982.

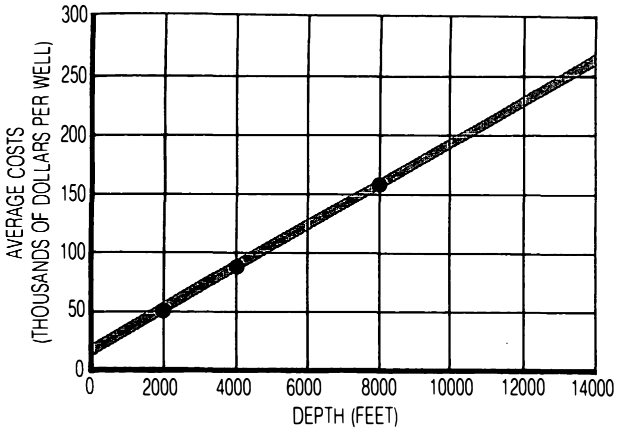


Figure C-20. Cost of Equipping New Producing Wells for the Permian Basin, 1982.

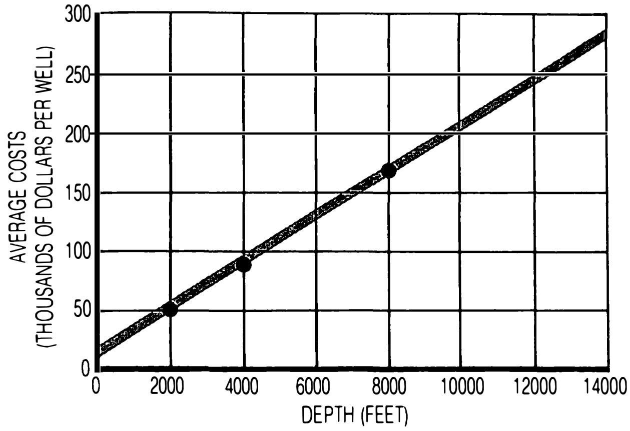


Figure C-21. Cost of Equipping New Producing Wells for the Western Gulf Coast, 1982.

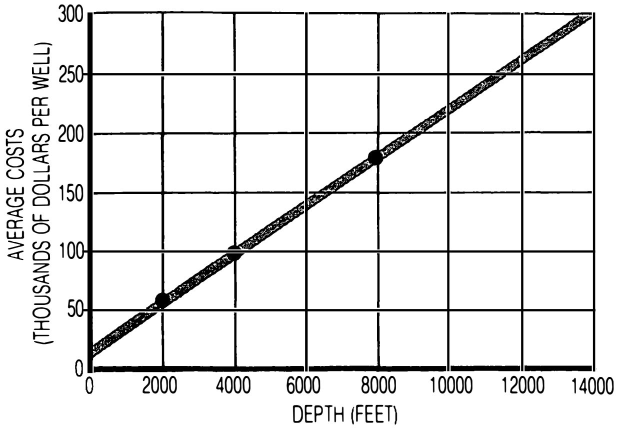


Figure C-22. Cost of Equipping New Producing Wells for the Eastern Gulf Coast, 1982.

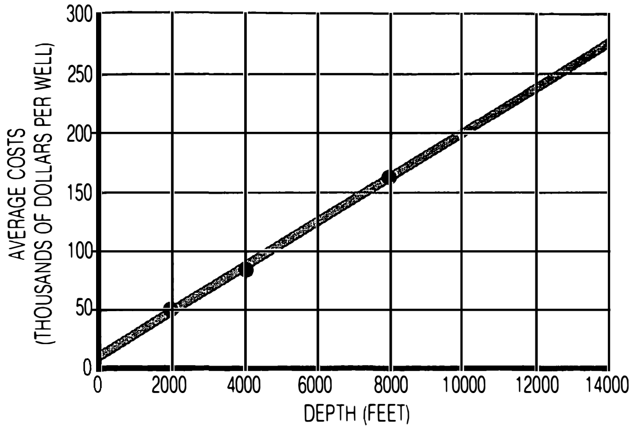


Figure C-23. Cost of Equipping New Producing Wells for the Mid-Continent and Northeast, 1982.

Cost of Drilling and Completing Production and Injection Wells

Geologic and stratigraphic variations between areas can cause large differences in the cost of drilling and completing wells. Drilling time required for the same depth well, completion technique, and formation evaluation will be different, not only by area, but for individual operators within an area.

Oil well drilling cost estimates for 1982 were prepared from data published in "Indexes and Estimates of Domestic Well Drilling Costs, 1981 and 1982," DOE/EIA-0347(81-82). The report was based on Joint Association Survey (JAS) drilling cost data through 1980. These cost estimates were used for the various NPC "Petroleum Provinces." Where NPC areas encompassed more than one EIA "drilling cost" area, the drilling costs were weighted according to the American Petroleum Institute reported drilling activity in each area for that depth for 11 months of 1982. Regression analysis was used to fit a curve that describes the functional relationship between average 1982 drilling cost and depth.

These drilling costs include the cost of drilling and completing wells through the wellhead, including tubing, and are used to represent the costs of the new injection wells. The new producing wells have additional equipment costs, which are discussed on the following pages. (Please note that the cost of pumping equipment is *not* included in this drilling cost.)

The equation and parameters for costs of drilling and completing onshore production and injection wells by area are shown below:

$$E = D\,(B_0 + B_1 D + B_2 D^{B_3})$$

where: E = cost in dollars per well
D = depth in feet

Table C-4 shows correlation coefficients for the regions shown on Figure C-24. Figures C-25 through C-30 show the depth-cost correlations.

TABLE C-4

Region	B_0	B_1	B_2	B_3
Pacific Coast	77.080	4.688 × 10"3	1.901 × 1o-lo	2.8
Rocky Mountains	95.540	-3.855 × 1Q-2	6.300 × 1o-3	1.2
Permian Basin	41.583	4.439 × 1o-4	2.530 × 1o-10	2.8
Gulf Coast	32.250	4.526 × 1o-3	2.255 × 1o-10	2.8
Mid-Continent	34.483	2.472 × 1Q•3	2.839 × 1o-10	2.8
Northeastern	33.522	1.175 × 1Q•3	1.502 × 1o-6	2.4

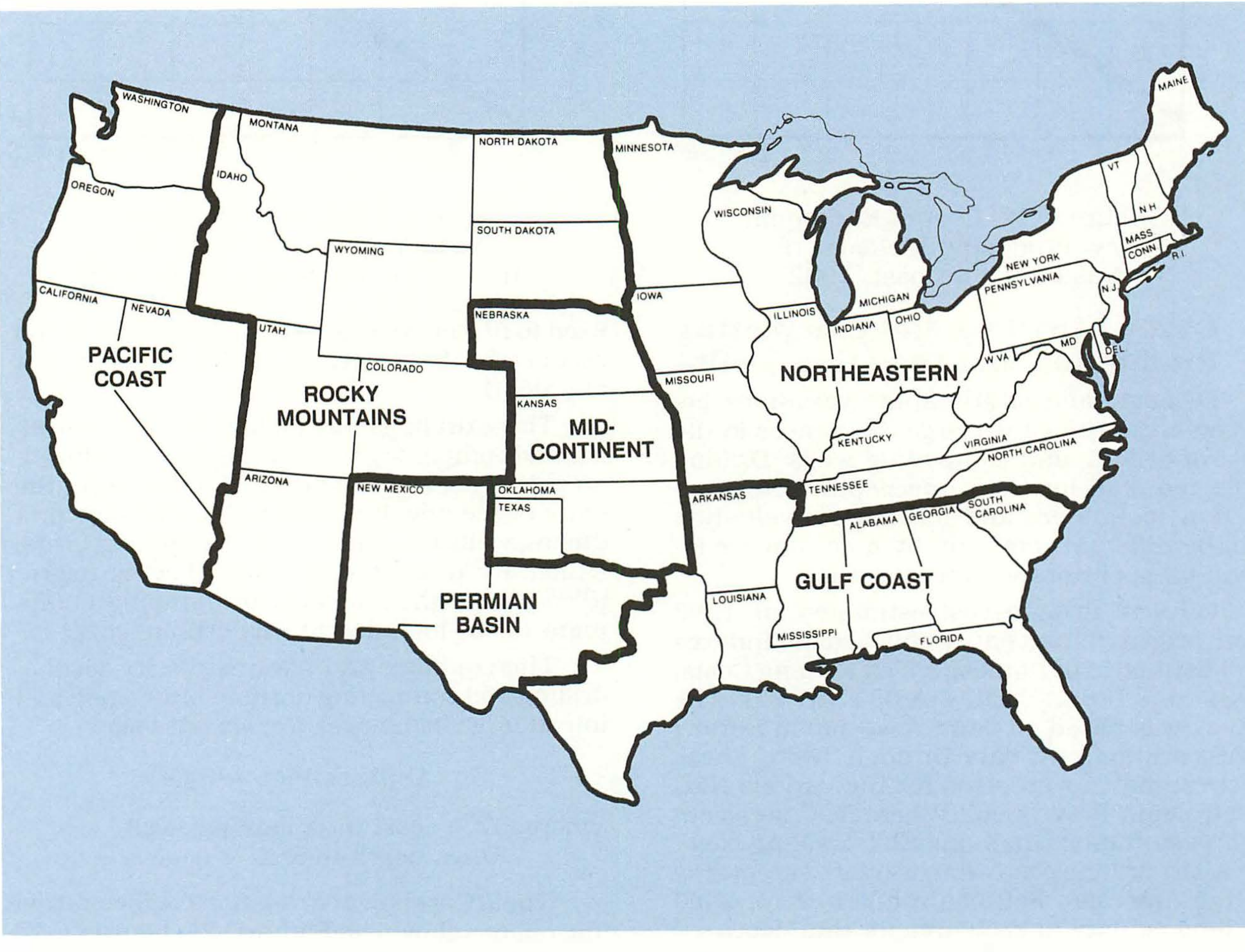


Figure C-24. Cost Regions—Drilling and Completion Costs.

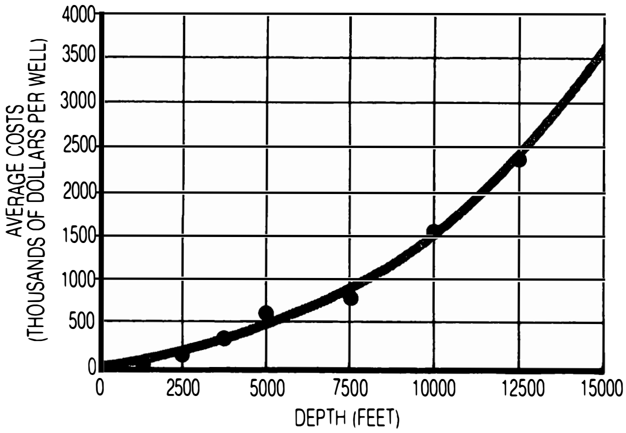


Figure C-25. Cost of Drilling and Completing Production and Injection Wells for the Pacific Coast, 1982.

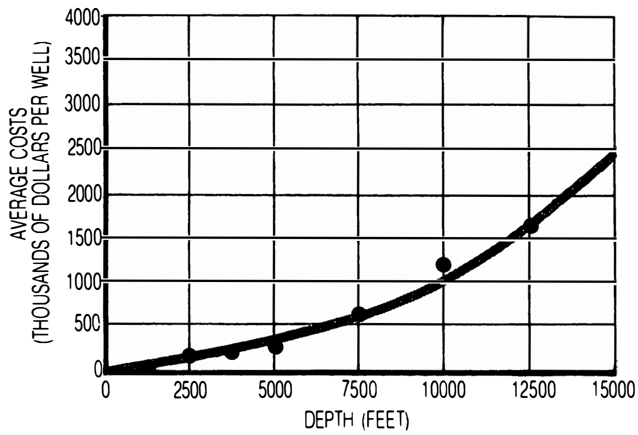


Figure C-26. Cost of Drilling and Completing Production and Injection Wells for the Rocky Mountains, 1982.

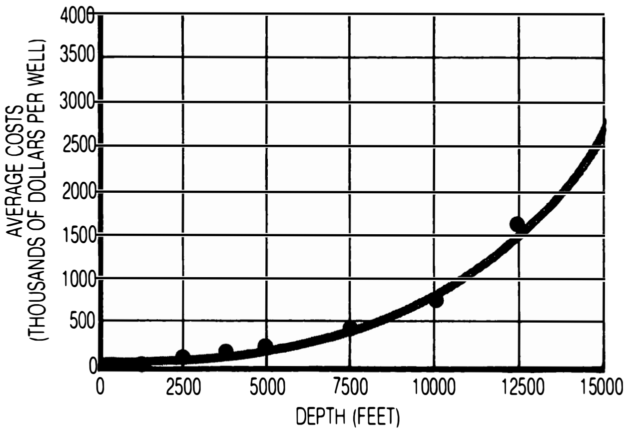


Figure C-27. Cost of Drilling and Completing Production and Injection Wells for the Permian Basin, 1982.

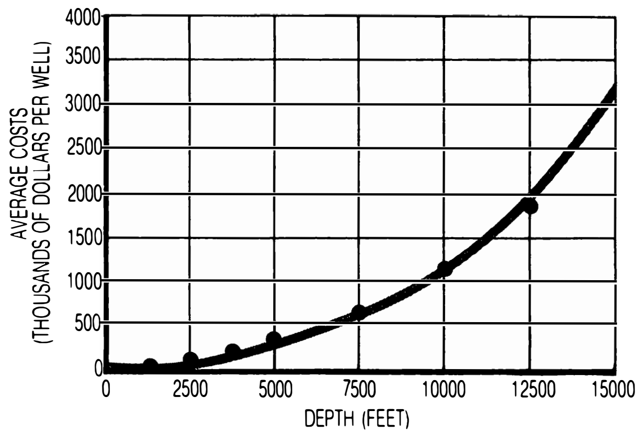


Figure C-28. Cost of Drilling and Completing Production and Injection Wells for the Gulf Coast, 1982.

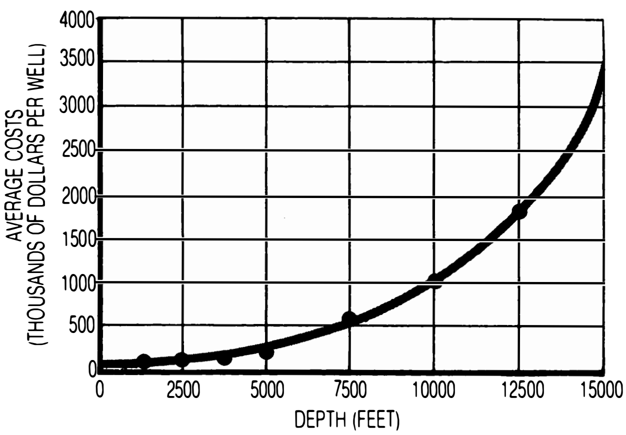


Figure C-29. Cost of Drilling and Completing Production and Injection Wells for the Mid-Continent, 1982.

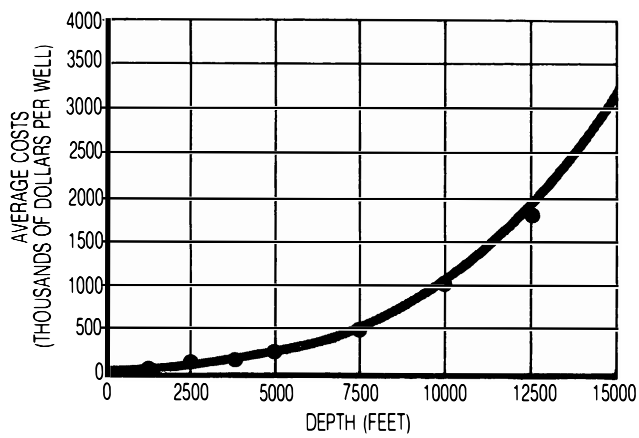


Figure C-30. Cost of Drilling and Completing Production and Injection Wells for the Northeast, 1982.

Offshore Costs

Implementing secondary recovery offshore requires special attention to details. Deck space on the platforms may not be sufficient to handle the water injection equipment; well positions may not be in the optimum location; artificial lift is limited; pattern floods may not be feasible; etc. Because of the many variables of implementing secondary recovery offshore, the water injection facilities and operating costs are given with respect to water injection rates.

The following costs have been provided from data and information for operations in the Gulf of Mexico:

- Drilling and completing costs for production and injection wells
- Conversion costs from producing to injection wells
- Installed costs of water injection facilities
- Operating costs for producing or injection wells
- Operating costs for water injection plants.

The existing well and production equipment were assumed to be sufficient for secondary production requirements.

Cost of Drilling and Completing Wells

The costs of drilling and completing wells for a representative drilling program offshore were determined under the following assumptions:

- Wells are drilled from an existing platform.
- Rig mobilization costs are shared by three wells.
- Wells are deviated 30 degrees from vertical.
- Rig day rate is $12,000 per day.
- Tubing, casing, and well service costs are as of January 1, 1983.

The equation for costs of drilling and completing offshore production or injection wells is:

$$F = 458{,}492 - 56.3271D + 0.03043D^2$$

where: F = well cost in dollars

D = true vertical depth in feet

Figure C-31 shows the depth-cost correlation.

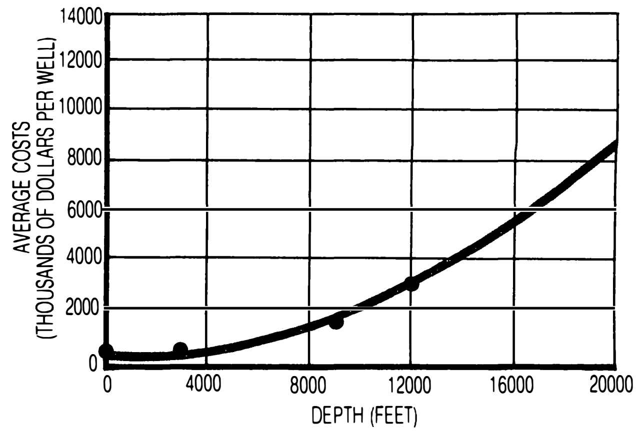


Figure C-31. Cost of Drilling and Completing Wells for Offshore Gulf of Mexico, 1983.

Cost of Converting a Producing Well to an Injection Well

The costs of converting producers to injectors for a representative conversion program were determined under the following assumptions:

- Rig mobilization costs are shared by three wells.
- Wells are deviated 30 degrees from vertical.
- Rig day rate is $12,000 per day.
- Tubing and well service costs are as of January 1, 1983.
- Producing wells were dual completions converted to single completion injection wells.

The conversion procedure consisted of removing the production tubing, squeeze cementing one set of production perforations, reperforating the zone of interest, and cleaning out the well. New plastic-lined pipe with a plastic-coated waterflood packer was installed in the well.

The equation for the cost of converting an offshore well from producing to injection is:

$$G = 171{,}366 + 21.826D$$

where: G = conversion cost in dollars

D = true vertical depth in feet

Figure C-32 shows the depth-cost correlation.

Operating Costs Per Well

Primary operating costs per well for the Gulf of Mexico were taken from the report "Cost

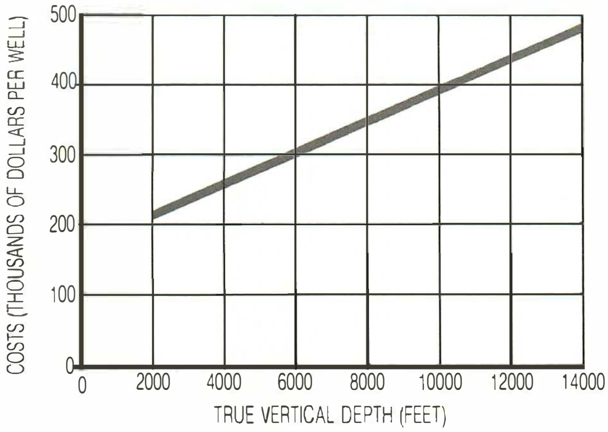


Figure C-32. Cost of Converting a Producing Well to an Injection Well for Offshore Gulf of Mexico, 1983.

and Indexes for Domestic Oil and Gas Field Equipment and Production Operations, 1982,'' DOE/EIA 0185(82), based on operating cost for 18-slot platforms assumed to be 100 miles from a supply point. Meals, platform maintenance, helicopter and boat transportation of personnel and supplies, and communication costs are included in normal production expenses. Insurance costs for platform and production equipment are included as well as administrative expenses. Crude oil and natural gas transportation costs to shore are excluded.

These operating costs for primary production are assumed to be the same for secondary production. This is justified because the same production equipment is being utilized on the same platform and the water injection plant costs are presented separately.

A constant offshore operating cost of $169,000 per well per year was used throughout the study.

Additional Operating Costs for Water Injection Plant

The additional operating costs for water injection were derived as a function of injection rate and fuel cost. These costs include direct fuel costs for water injection and maintenance costs for the water injection facility.

The equation for additional operating costs for offshore water injection is:

$$H = 40.2R + 8.08RP$$

where: H = additional operating costs in thousands of dollars per year

R = water injection rate in thousands of barrels per day

P = the price of natural gas in dollars per Mcf

Appendix D

Chemical Flooding

The purpose of this appendix is to define potential additions to U.S. crude oil reserves that might result from the large-scale application of chemical flooding processes. This has required many technical and economic assumptions. In certain respects these assumptions imply a change from current conditions. *In no sense, therefore, is this appendix a prediction of what will happen.* Rather, it is a series of estimates of what could happen under the various scenarios considered.

Several key points should be mentioned.

- Predictive models for each process were used to estimate recovery from reservoirs that passed the screening criteria discussed below. The assumption was made that all of the acreage available in these fields would be developed as chemical floods. In reality, some portion less than this would be developed. Offsetting this assumption, certain reservoirs were excluded by the screening criteria on the basis of their average properties where it is known that some portions of the field could be flooded. Also, fields with less than 50 million barrels of oil originally in place (OOIP) were not considered.
- There may be factors other than the screening criteria that make a reservoir unsuitable for a chemical flood, such as extensive fracturing, multiple sealing faults, or a strong natural water drive. This information was not always available from the data base. When Chemical Task Group members were aware of such problems, the field was deleted from further consideration. However, some of these reservoirs have inevitably been included. Total oil recovery estimates will tend to be optimistic because of this effect.
- The approach taken assumes that surfactant floods would be implemented on a large scale, using today's technology. The long lead time required for pilot testing and construction of facilities would make immediate application very difficult. To reflect this, an earliest starting date was set for full-scale surfactant flooding. This varies from 1988 to 1990, depending upon oil price. Also, chemical costs were selected assuming that large-scale plants would be built and that materials would be available in the necessary quantities. A large-scale flood initiated today would incur higher costs than those selected for the base case.
- Results are presented for both an Implemented Technology Case and an Advanced Technology Case. The Implemented Technology Case represents recovery efficiencies that are achievable with current technology. The Advanced Technology Case assumes that certain improvements, currently at the laboratory stage, will be successfully moved into field application without incurring additional costs. *This is not a prediction that such improvements will in fact be achieved at that cost.* Any increase in cost will significantly reduce potential recovery. Advanced technology was assumed to become available in 1995.

- All economic calculations ignore the Windfall Profit Tax.

The potential enhanced oil recovery (EOR) from chemical flooding was estimated to be 2.5 billion barrels of oil for the base economic case using implemented technology. There are 2.1 billion barrels contributed by surfactant flooding, with minor contributions from polymer flooding and alkaline flooding. This potential may increase to 4.1 billion barrels at the $50 per barrel crude oil price. For each oil price, producing rates are projected to increase progressively through the study period, reaching only 140 thousand barrels per day in 2013 for the base economic case of 10 percent minimum discounted cash flow rate of return (minimum ROR) and nominal $30 per barrel crude oil price. Ultimate recovery and estimated rates for each nominal crude oil price are given in Table D-1.

The Advanced Technology Case shows very large increases in potential for chemical EOR. For the base economic case, ultimate recovery could reach 10.9 billion barrels, with over 90 percent of this coming from surfactant flooding. The producing rate was projected to reach 550 thousand barrels per day by 2013. Table D-2 shows potential ultimate recovery and estimated peak rate for each nominal crude oil price. Achieving this Advanced Technology Case will require major research and development efforts.

For both the Implemented and Advanced Technology Cases, potential producing rates will be closely tied to the rate at which industry confidence in surfactant flooding is established.

State-of-the-Art Assessment

Polymer Flooding

The use of high molecular weight, water-soluble polymers in enhanced oil recovery covers a wide spectrum of applications. Most frequently the polymers are added to injection water in concentrations from 250 to 2,000 parts

TABLE D-1

CHEMICAL FLOODING
ULTIMATE RECOVERY AND PEAK PRODUCING RATE
IMPLEMENTED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
20	1.0	70	1996-2000
30	2.5	140	after 2013
40	3.5	240	after 2013
50	4.1	400	after 2013

TABLE D-2

CHEMICAL FLOODING
ULTIMATE RECOVERY AND PEAK PRODUCING RATE
ADVANCED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
30	10.9	550	2012-2013
40	12.6	660	after 2013
50	13.5	870	after 2013

per million (ppm) for improved mobility control. A relatively large volume of the polymer-containing water is injected to provide the desired mobility control throughout the life of the polymer flood. There has been a recent increase in the number of projects that improve the vertical sweep efficiency by injecting cross-linked or gelled polymers to form, in situ, highly viscous fluids that divert subsequent injection fluids. This use generally involves the injection of a relatively small amount of polymer that affects the region close to the injection well. Still other polymer projects utilize varying combinations of the near-wellbore cross-linking technique with total flood mobility control.

Heterogeneous light-oil reservoirs and those containing moderately viscous oils [less than 100 centipoise (cp)] show potential for polymer flooding. Heterogeneous reservoirs may respond by improved vertical conformance or redistribution of injected fluids. Moderately viscous oil reservoirs have potential for increased oil recovery through better flood mobility control.

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

At low salinities, polyacrylamides give a higher mobility ratio improvement through increased water viscosity and decreased permeability of the formation to water. The magnitude of the mobility ratio improvement decreases significantly with increasing water salinity and divalent ion concentration. Thus a source of relatively fresh water is desirable for the most economic use of polyacrylamides.

Polyacrylamide solution viscosity and the ability to decrease the permeability of the formation to water may be severely reduced as a result of breakdown of the polymer molecules by shearing as the polymer is injected. Care in surface handling and well completion procedures 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 still need to be filtered through micron-sized filters and treated with enzymes to remove bacterial debris that could cause well plugging. Bactericides are normally required to prevent bacterial attack. Polysaccharides currently are more expensive per pound than polyacrylamides. Current research is seeking better bactericides and ways to produce a product with fewer plugging problems.

Polymer applicability versus temperature and salinity is shown on Figure D-1. Polyacrylamides have been reported to be thermally stable in laboratory tests for extended periods at temperatures of up to 250 °F for solutions with low salinities and low concentrations of divalent cations. Apparently, amide groups on the polyacrylamides do experience hydrolysis at high temperatures, but this does not result in cleavage of the polymer backbone. However, if divalent cations are present, hydrolyzed polyacrylamides precipitate. Thus, polyacrylamides can only be used at high temperatures if the concentration of divalent cations is extremely low. Unless a chemical stabilizer is included, neither polymer appears to have satisfactory long-term thermal stability at temperatures above 160 °F in moderate-salinity or high-salinity brines. Development of formulations to stabilize polymers at high temperatures is being attempted. These stabilizers will add to the cost of attaining mobility control and it is uncertain whether they can be propagated through the reservoir.

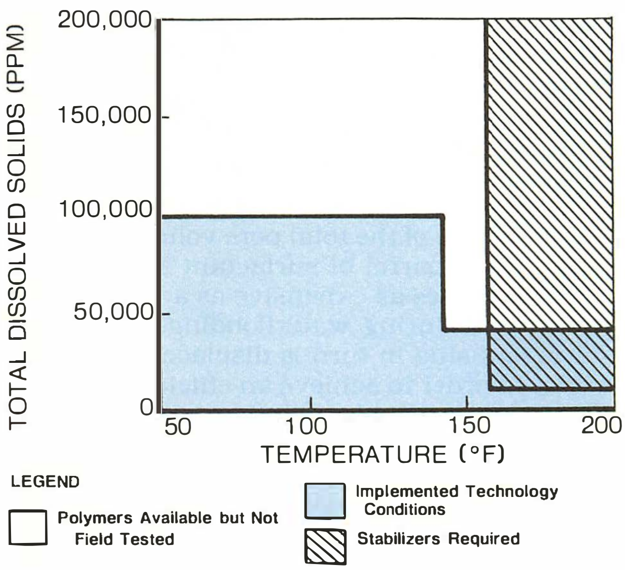


Figure D-1. Polymer Applicability vs. Salinity and Temperature.

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

Polymer flood field tests in progress or completed are summarized in Table D-3. Implemented technology shows that polymer floods are applicable in low-salinity reservoirs and in others at temperatures up to about 200 °F using a preflush (145 ° without a preflush). It is anticipated that improvement in technology will extend this limit to 250 °F.

Table D-3 shows that there are a large number of polymer tests either completed or currently underway. While the incremental recoverable oil by polymer flooding is low relative to other EOR processes, the lower chemical cost has made polymer flooding attractive.

Surfactant Flooding

Surfactant flooding is a process that utilizes 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: surfactant, water, hydrocarbons, alcohols, polymers, and inorganic salts. Mechanisms for this method of oil recovery include reduction of oil/water interfacial tension, oil solubilization, emulsification of oil and water, and mobility control.

Efficient displacement generally requires that the mobility of the displacing fluid be less than that of the fluids being displaced. The surfactant slug must therefore have a lower effective mobility than that of the oil/water bank it is pushing through the reservoir. Water-soluble polymers or various combinations of other components (alcohol, hydrocarbons, etc.) may be used to produce the required viscosity of the surfactant slug. Since this slug contains expensive chemicals, the volume injected must be a small fraction of the total pore volume of the oil reservoir. A barrel of surfactant slug is more than 100 times as expensive as a barrel of the water used during waterflooding. 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 the surfactant slug; otherwise, the drive water tends to bypass the surfactant slug as it moves through the reservoir. Polymer technology is discussed in the section on polymer flooding.

As summarized in Table D-4, field experiments with surfactant flooding have been conducted in reservoirs with temperatures ranging from 55 ° to 200 °F. Tests planned but not initiated have not been included in the table. Implemented technology indicates that surfactant flooding should be applicable at temperatures of at least 200 °F by using a preflush (145 °F without a preflush). This is limited by the polymers used in the process.

Field tests have been conducted in reservoirs with salinities ranging from 2,400 to 160,000 ppm total dissolved solids (TDS). A low-salinity preflush has been used in several of the tests to improve the compatibility between the reservoir and chemical system. It may be possible to preflush a limited number of reservoirs to decrease the original salinity level and thereby reduce process costs and increase recovery efficiency. However, the trend in research is toward development of systems applicable at higher salinities without requiring a preflush. Applications at salinity levels of 100,000 ppm (10 percent TDS) have been demonstrated, but only at temperatures around 100 °F. Chemical systems effective in salinities of 200,000 ppm (20 percent TDS) or more are expected as technology improves.

Surfactant applicability versus salinity and temperature is shown in Figure D-2. At lower salinities (below 4 percent TDS), sulfonates can be used over a wide range of temperatures. As used here, "sulfonates" refer to petroleum and synthetic surfactants, both of which are available commercially today. At lower temperatures and higher salinities, oxyalkylated sulfates and sulfonates can be used, most often in combination with petroleum sulfonates. However, sulfates begin to have stability problems at temperatures above 120 °F. While they can be applied in typical field projects up to 150 °F, the amount of sulfate used must be increased to compensate for loss from hydrolysis.

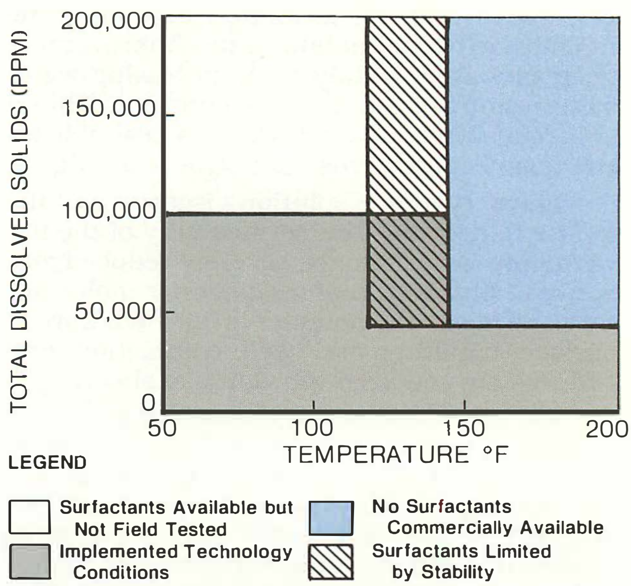


Figure D-2. Surfactant Applicability vs. Salinity and Temperature.

TABLE D-3

POLYMER FLOODING PROJECTS COMPLETED OR UNDERWAY

Field Name	State	Permeability (md)	API Gravity	Viscosity (cp)	Temperature (°F)	Reservoir Salinity (ppm TDS)
ALBA-NE SUBCLARKSVILLE	TX	–	16.0	–	–	–
ALBA-WEST	TX	–	16.0	–	–	–
ALMA PENNS.-NORTH	OK	110	22.0	29.50	126	–
BIG PINEY	WY	–	38.0	2.30	–	–
BIG SINKING	KY	40	40.0	4.00	70	–
BREA OLINDA	CA	750	16.0	40.00	135	–
BRELUM	TX	400	22.0	12.00	115	–
BYRON	WY	–	–	–	–	–
C-H	WY	230	21.0	23.00	140	–
CAPROCK-SOUTH	NM	–	34.0	–	–	–
CARTHAGE	OK	92	40.0	–	113	–
CAT CANYON	CA	260	16.0	110.00	145	–
CEMENT-EAST (8110)	OK	18	35.0	4.70	104	176,990
CEMENT-UNIT I-8111	OK	23	34.0	6.20	93	170,286
CEMENT-WEST (8106)	OK	24	35.0	6.00	112	161,368
COALINGA	CA	300	21.0	25.00	100	–
COGDELL	TX	5	41.7	0.62	–	–
COLBY (KEYSTONE)	TX	6	38.0	3.70	86	–
COLMAR-PLYMOUTH	IL	–	–	–	–	–
CUMBERLAND	OK	–	34.0	–	–	–
CUSHING	OK	25	39.0	5.00	95	115,000
DEADMAN CREEK	WY	700	20.7	34.00	120	19,500
DUGOUT CREEK	WY	120	36.0	3.00	86	–
DUNE-8110 START	TX	3	31.0	6.30	100	–
EAST TEXAS-BRADFORD	TX	–	39.0	1.90	146	–
EAST CRYSTAL FALLS	TX	1,400	40.0	0.62	120	67,000
EAST TEAPOT	WY	–	27.0	–	–	–
EAST TEXAS	TX	365	39.0	1.90	–	–
EAST TEXAS	TX	–	39.0	1.90	146	–
EASTLAND CO. REG.	TX	–	41.0	–	–	–
ELAINE	TX	–	36.0	3.00	128	–
*ELIASVILLE	TX	9	41.0	–	105	–
FARMERSVILLE	IN	–	27.0	23.00	72	–
FIDDLER CREEK-SOUTH	WY	–	–	–	–	–
FITTS EAST (8207)	OK	25	39.0	3.70	113	70,440
FRANNIE	WY	–	26.5	–	–	–
GARZA	TX	4	36.0	5.50	102	–
GUMBO RIDGE	MT	160	32.0	2.50	145	18,400
GUMBO RIDGE	MT	1,160	32.0	2.50	–	–
HAGIST RANCH	TX	340	20.0	10.00	115	–
HALLSVILLE CRANE-N	TX	50	57.0	0.07	229	–
HALLSVILLE CRANE-NE	TX	50	57.0	0.10	229	–

TABLE D-3 (Continued)

Field Name	State	Permea-bility (md)	API Gravity	Viscos-ity (cp)	Temper-ature (°F)	Reservoir Salinity (ppm TDS)
HAMM	WY	–	–	–	–	–
HEALDTON	OK	346	33.0	–	78	–
HEALDTON I UN-8207	OK	438	32.0	10.00	87	94,269
HEWITT	OK	184	35.0	8.70	95	107,000
HEWITT	OK	184	35.0	8.70	95	107,000
HIGH FIVE	MT	–	34.0	–	–	–
HIGHLIGHT	WY	50	40.0	–	234	–
HITTS LAKE	TX	500	24.0	2.70	210	110,575
HITTS LAKE	TX	20	24.0	2.70	210	–
HOOF L. KC	KS	–	41.0	–	–	–
HOWARD-GLASSCOCK	TX	25	27.0	11.00	93	–
HUNTINGTON BEACH	CA	2,300	13.0	76.00	125	–
ISENHOUR	WY	25	43.8	1.04	100	–
JACKSBORO	TX	–	40.0	1.70	90	–
KEYSTONE-6901 START	TX	300	38.0	2.00	86	–
KUEHNE RANCH	WY	88	26.0	0.50	134	–
KUMMERFIELD	WY	95	23.0	38.00	130	55,000
LANYARD D SAND	CO	151	41.0	0.50	217	1,165
LONE GROVE	OK	–	37.0	–	–	–
LONG ISLAND	WY	5	42.0	1.30	95	–
LOUDON-8211 START	IL	97	37.0	4.00	100	76,700
MABEE	TX	1	32.0	2.38	95	–
MAIN CONSOLIDATED	IL	200	–	10.00	85	–
MAIN CONSOLIDATED	IL	200	34.0	10.00	85	–
MCARTHUR RIVER	AK	–	–	–	–	–
MCCAMEY	TX	3	26.0	28.00	80	–
MCDONALD UNIT 4M205	WY	8	42.0	0.95	100	–
MCDONALD UNIT 4M475	WY	200	41.0	1.45	95	–
MCELROY	TX	5	32.0	2.60	–	–
MILL-BILLETTE	WY	123	–	0.40	–	–
MORAN	KS	100	23.0	172.00	–	–
NAVAL RESERVE	OK	20	38.0	3.50	–	–
NEBO HEMPHILL	LA	2,470	21.0	126.00	–	–
NORTH BURBANK	OK	10	39.0	3.00	120	–
NORTH BURBANK	OK	50	39.0	3.00	120	80,000
NORTH BURBANK	OK	–	–	–	–	–
NORTH LONGTON	KS	40	30.0	25.00	–	–
*NORTH STANLEY	OK	300	37.0	7.50	100	–
NORTH WARD ESTES	TX	40	34.0	1.40	83	–
NORTH WARD ESTES-8205	TX	40	34.0	1.40	83	–
O'HERN-MOBIL SOLD	TX	286	29.0	2.20	136	–
OLD LISBON	LA	45	35.0	2.50	178	–

TABLE D-3 (Continued)

Field Name	State	Permea-bility (md)	API Gravity	Viscos-ity (cp)	Temper-ature (°F)	Reservoir Salinity (ppm TDS)
OREGON BASIN	WY	–	–	10.00	–	–
PANHANDLE GRAY-WOR	TX	50	40.0	3.30	85	–
PENNFIELD 35 10/82	MI	–	24.0	–	–	–
POSTLE-HOUGH -8207	OK	43	41.0	1.03	144	145,000
POSTLE-HOVEY -8209	OK	44	41.0	1.24	146	120,000
POSTLE-UPPER -8211	OK	36	40.0	1.03	147	94,000
RED RIVER BULL BAYOU	LA	1,000	41.0	1.70	120	28,000
RICHFIELD	CA	760	18.0	57.00	117	–
ROBERTSON	TX	77	34.0	1.00	107	94,310
ROBERTSON	TX	–	34.0	–	–	–
ROBINSON-LINDSAY	IL	300	30.0	18.00	70	–
RUBEN UNIT S-3	WY	56	43.0	0.95	93	–
RUBEN UNIT S-4	WY	33	43.0	0.90	95	–
S. CENTRAL ROBERTSON	TX	–	34.0	1.00	–	12,000
S. FIDDLER CREEK	WY	250	40.0	3.00	118	77,000
S. STANLEY STRINGER-8306	OK	400	39.0	4.80	107	–
SADDLE RIDGE	WY	–	38.0	2.33	70	12,000
SADDLE RIDGE 7405	WY	110	38.0	2.33	70	24,500
SAND HILLS	TX	15	35.0	1.50	96	–
SE KUEHNE RANCH	WY	–	–	–	–	–
SEMLEK-WEST	WY	647	23.0	12.30	144	–
SEVENTY-SIX WEST	TX	1,200	20.0	12.00	100	–
SEVENTY-SIX, SOUTH SOLD	TX	900	20.0	30.00	96	43,000
SHO-VEL-TUM (8104)	OK	13	29.0	50.00	70	139,034
SHO-VEL-TUM (8207)	OK	95	38.0	15.70	112	118,500
SHO-VEL-TUM (8207)	OK	100	34.0	7.00	102	156,262
SHO-VEL-TUM (8208)	OK	39	31.0	5.60	105	134,447
SHO-VEL-TUM (8208)	OK	102	34.0	10.50	89	121,611
SHO-VEL-TUM (8208)	OK	18	39.0	2.40	110	149,598
SHO-VEL-TUM (8208)	OK	66	30.0	16.00	117	134,570
SHO-VEL-TUM (8210)	OK	240	28.0	20.00	80	165,706
SHO-VEL-TUM (8211)	OK	44	26.0	13.60	120	–
SIMPSON RANCH	WY	200	23.0	17.00	170	–
SKULL CREEK	WY	70	32.0	3.20	124	–
SKULL CREEK	WY	62	32.0	3.00	135	–
SLAUGHTER	TX	3	31.0	1.47	95	–
SMACKOVER	AR	2,000	20.0	75.00	110	100,000
SOUTH BURBANK	OK	50	39.0	3.20	120	–
SOUTH LAKE TRAMMEL	TX	30	–	–	–	–
STEPHENS CO. REG.	TX	11	38.6	3.00	115	170,000
STEPHENS CO. REG.	TX	12	40.0	2.30	106	71,700
STEWART RANCH	WY	92	22.0	24.00	136	–

TABLE D-3 (Continued)

Field Name	State	Permea-bility (md)	API Gravity	Viscos-ity (cp)	Temper-ature (°F)	Reservoir Salinity (ppm TDS)
STEWART RANCH	WY	92	20.0	24.20	–	–
*STORMS POOL	IL	300	35.0	6.00	95	38,466
STRIBLING	TX	–	41.0	–	113	–
STROUD	OK	25	44.0	2.00	100	–
SUMATRA	MT	29	33.0	2.53	140	–
TATUMS-8207 START	OK	787	25.0	68.00	83	123,705
TEETER	KS	40	41.0	3.00	60	–
TIP TOP SHALLOW	WY	70	38.0	2.30	70	–
TIP TOP SHALLOW	WY	50	39.0	2.50	70	–
TIP TOP SHALLOW	WY	110	38.0	2.33	70	–
TIPTON NORTH (MISS.)	TX	–	–	–	124	–
TODD RANCH	WY	–	–	–	–	–
TUSSY	OK	–	–	–	–	–
TYRO	KS	56	31.0	25.00	–	–
TYRO	KS	60	30.0	–	–	–
UNION-BOWMAN	IN	237	32.0	9.20	75	52,925
UPPER VALLEY	UT	–	27.0	–	–	–
UPPER VALLEY UNIT	UT	–	27.0	8.50	160	–
UTE MUDDY SAND UNIT	WY	–	42.0	–	156	–
VACUUM	NM	3	37.0	0.90	101	–
VERNON	KS	23	–	75.00	75	45,000
VOLPE (SOLD)	TX	300	31.5	4.70	124	–
W. ELIASVILLE-8012	TX	9	41.0	–	105	–
WATERLOO, SE	OK	–	–	–	–	–
WATERLOO, SE	OK	84	43.0	1.80	127	163,464
WEST BAY-8302 START	LA	–	28.0	–	–	–
WEST BAY-8303 START	LA	400	30.0	3.16	155	15,100
WEST BAY-8303 START	LA	2,000	31.0	2.48	165	–
WEST BAY-8303 START	LA	–	30.0	–	–	–
WEST YELLOW CREEK	MS	16	20.0	21.00	150	133,000
WESTBROOK	TX	4	25.0	8.00	97	41,000
WESTBROOK	TX	3	25.0	8.00	97	–
WILMINGTON-MOBIL	CA	1,550	–	30.80	135	3,500
WINNETTE JUNCTION	MT	–	–	–	–	–

*Preflush Used.

TABLE D-4

SURFACTANT PROJECTS COMPLETED OR UNDERWAY

Field Name	State	Permeability (md)	API Gravity	Viscosity (cp)	Temperature (°F)	Reservoir Salinity (ppm TDS)
ASH CREEK	MT	27	4.0	7.50	123	2,300
AUX VASES	IL	102	36.0	6.00	72	–
BATESVILLE POOL	KS	55	–	1.00	80	31,600
*BELL CREEK	MT	1,050	32.0	3.00	100	5,200
BELL CREEK	MT	1,218	32.0	3.00	110	–
BENTON	IL	60	38.0	3.50	86	–
BENTON	IL	60	38.0	3.50	86	–
BENTON (PILOT)	IL	73	38.0	3.50	86	77,000
*BIG MUDDY	WY	52	35.0	4.00	120	7,700
BIG MUDDY	WY	52	34.0	5.60	120	–
BIG SINKING	KY	–	39.0	–	–	–
BIG SINKING	KY	106	39.0	4.50	64	–
*BORREGOS	TX	434	42.0	0.36	165	19,600
BRADFORD	PA	45.0	5.00	68	–	–
BRADFORD	PA	188	45.0	4.00	68	–
*BRADFORD (LAWRY)	PA	8	45.0	5.00	64	5,000
*BRADFORD (BINGHAM)	PA	82	45.0	5.00	68	2,800
CARTHAGE, NE	OK	–	–	–	–	–
COLMAR-PLYMOUTH	IL	1,100	35.0	9.30	68	5,800
DELAWARE-CHILDERS	OK	100	33.0	9.60	86	100,000
EL DORADO-CHESNEY	KS	265	37.0	5.20	69	82,500
EL DORADO-HEGBERG	KS	208	37.0	4.80	69	85,400
GLENN POOL	OK	152	37.0	4.40	97	46,000
*GLENN POOL-BERRYHL	OK	152	37.0	4.40	100	46,000
GOODWILL HILL	PA	–	40.0	4.50	55	82,600
*GRIFFIN CONSOLIDATED	IN	87	38.0	3.60	85	–
GUERRA	TX	2,500	–	1.60	122	20,000
HOFFMAN	TX	–	–	–	–	–
INMAN EAST	IL	120	37.0	6.00	–	–
JONES CITY REG. HIGH	TX	500	37.0	4.30	95	54,000
KIRKWOOD	IL	80	–	9.00	72	14,000
LA BARGE	WY	450	26.0	17.00	60	10,000
LEWISVILLE	AR	24	43.0	0.32	191	30,800
*LOMA NOVIA	TX	454	25.0	3.30	138	12,000
*LOUDON	IL	103	38.0	5.00	80	104,000
LOUDON	IL	330	38.0	6.00	78	104,000
LOUDON	IL	164	38.0	5.00	77	107,500
MADISON	KS	42	38.0	2.90	97	–
MAIN CONSOLIDATED	IL	200	–	12.00	85	–
MAIN CONSOLIDATED	IL	200	35.0	12.00	–	–
MANVEL	TX	500	28.0	4.00	165	107,000
MONTAGUE CO. REG.	TX	394	27.0	–	75	150,000

TABLE D-4 (Continued)

Field Name	State	Permeability (md)	API Gravity	Viscosity (cp)	Temperature (°F)	Reservoir Salinity (ppm TDS)
NORTH BARTLETT	KS	654	15.0	13.47	55	–
NORTH BURBANK	OK	52	39.0	3.00	120	75,000
ROBINS	IL	398	29.0	20.00	70	–
*ROBINSON (DEDRICK)	IL	200	36.0	6.00	72	–
ROBINSON (HENRY E)	IL	102	36.0	7.00	72	–
ROBINSON (HENRY S)	IL	102	36.0	6.00	72	–
ROBINSON (HENRY W)	IL	102	36.0	6.00	72	–
ROBINSON (M-1)	IL	102	36.0	6.00	72	16,600
ROBINSON (M-2)	IL	100	35.0	7.00	70	–
ROBINSON (MT HW)	IL	200	36.0	6.00	72	–
ROBINSON (MT 1)	IL	275	36.0	6.00	72	–
ROBINSON (MT 2)	IL	126	36.0	6.00	72	–
ROBINSON (MT 4)	IL	350	36.0	6.00	72	–
ROBINSON (MT 5)	IL	–	36.0	6.00	72	–
ROBINSON (MT 6)	IL	150	36.0	6.00	72	–
ROBINSON (MT 7)	IL	–	36.0	6.00	72	–
ROBINSON (WILKIN)	IL	102	36.0	9.00	72	–
ROBINSON (118-K)	IL	75	–	–	75	–
ROBINSON (119-R)	IL	211	35.0	7.00	72	–
ROBINSON (219-R)	IL	165	35.0	7.00	72	–
SALEM	IL	87	38.0	3.60	80	72,000
*SALEM	IL	150	36.0	3.60	72	117,000
SAYLES	TX	481	38.0	–	–	–
SHADOW MOUNTAIN	OK	–	–	–	–	–
*SHO-VEL-TUM	OK	190	30.0	12.00	130	73,000
SHO-VEL-TUM	OK	–	30.0	–	–	–
SIGGINS-7506 START	IL	70	–	–	55	–
SLAUGHTER	TX	4	31.8	1.80	109	–
SLAUGHTER	TX	25	32.0	1.80	109	105,000
*SLOSS	NB	93	38.0	0.80	200	2,500
SOUTH JOHNSON	IL	300	30.0	20.00	65	–
*TORCHLIGHT	WY	92	34.0	4.12	100	2,500
TUSSY	OK	–	–	–	–	–
WESGUM	AR	36	21.0	11.00	185	–
*WEST RANCH	TX	869	31.8	0.65	171	65,500
*WICHITA CO. REG.	TX	53	42.0	2.30	89	160,000
WILMINGTON	CA	400	18.0	25.00	145	–
WIZARD WELLS	TX	50	42.0	1.10	–	–

*Preflush Used.

At this time, surfactants are not generally available for use under high-salinity, high-temperature conditions. Even though several companies have reported on chemicals that are effective at these conditions in laboratory tests, these materials are not yet available commercially at a price near that of the petroleum sulfonates. Further development is needed to reduce the cost of surfactants for the high-temperature, high-salinity region.

Surfactant flooding should be feasible over a fairly wide range of reservoir permeabilities. The average permeability of the reservoirs given in Table D-4 ranges from 4 to 2,500 millidarcies (md). Technical successes have been achieved down to about 40 md. Reservoirs having a permeability as low as 10 md may be suitable candidates with improved technology.

The crude oil viscosity range of field tests has been 0.36 to 35 cp, as shown in Table D-4. A successful European surfactant flood involved 40 cp oil. An 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. With higher reservoir oil viscosity, additional polymer is required to match the oil/water bank effective viscosity. It is anticipated that surfactant displacement of more viscous crude oil will eventually be feasible.

Reservoir characteristics desirable for surfactant flooding candidates include 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 laterally discontinuous. A successful waterflood is a good indication of a reservoir's suitability for surfactant flooding.

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. Some success in higher salinity conditions has been achieved with and without preflush.

Field test results have shown that surfactant flooding will require careful chemical formulation and handling, additional equipment and chemicals for processing produced emulsions, special care to prevent polymer degradation, and perhaps closer well spacing to achieve a reasonable project life.

Over 2.4 million barrels of incremental oil have been produced in various tests of surfactants. However, field development on an economic basis has not been demonstrated thus far and current field expansions are limited to low-temperature and low-salinity reservoirs.

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 solution neutralizes petroleum acids. Interfacial tension reduction and wettability reversal can reduce oil saturation below the waterflood residual saturation. Oil emulsification appears to reduce the mobility of the injected water.

The effectiveness of alkaline flooding requires a crude oil with a minimum acid number of about 0.5. The potential for alkaline flooding will normally be highest for recovery of moderately viscous, naphthenic, low API gravity, high acid number crude oils. 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 upon the particular oil/water/rock system investigated. However, sandstone reservoirs with low-salinity water, a low divalent cation content, and a low clay content are preferred.

Alkaline field tests in progress or completed are summarized in Table D-5. These projects indicate that alkaline floods are applicable in reservoirs at temperatures up to 200 °F. Due to the strong dependence of caustic consumption on temperature, an increase in this temperature limit is not foreseen.

There is an incomplete understanding of the displacement process during alkaline flooding. About one-half of the 20 or more field tests have been judged to be technical successes although not necessarily economical. Current research efforts are aimed at a better understanding of the mechanisms and improving the process by the addition of polymers and cosurfactants.

Environmental Considerations

Chemical EOR processes can operate without damage to the environment but certain

TABLE D-5

ALKALINE PROJECTS COMPLETED OR UNDERWAY

Field Name	State	Permea-bility (md)	API Gravity	Viscos-ity (cp)	Temper-ature (°F)	Reservoir Salinity (ppm TDS)
ALBA-SE	TX	–	16.0	–	–	–
ALBA, WEST	TX	500	13.0	750.00	–	83,300
BELL CREEK	MT	900	42.0	2.50	103	5,000
BIG SINKING	KY	–	–	–	–	–
BISON BASIN	WY	144	16.0	220.00	85	–
BREA-OLINDA	CA	–	16.0	90.00	135	–
BURNT HOLLOW	WY	300	15.0	100,000.00	70	–
CHARMOUSCA-SOUTH	TX	500	20.0	6.00	119	10,400
CRESCENT HEIGHTS	CA	550	28.0	1.60	190	–
CYCLONE CANYON	WY	530	22.0	134.00	70	–
DOMINGUEZ	CA	175	30.0	1.50	155	–
GOLDEN TREND	OK	100	43.0	0.50	138	190,000
GOOSE CREEK	TX	–	–	75.00	112	–
HARRISBURG	NB	119	–	1.50	200	8,500
HOSPAH SAND	NM	634	30.0	15.00	75	–
HUNTINGTON BEACH	CA	200	22.0	15.00	165	–
INTERSTATE	KS	–	–	–	–	–
ISENHOUR UNIT	WY	108	43.0	1.04	97	5,000
ISENHOUR UNIT	WY	21	43.0	2.80	97	–
KERN RIVER	CA	2,000	13.5	1,000.00	90	–
MIDWAY-SUNSET	CA	450	22.5	180.00	87	15,000
N. WARD-ESTES	TX	20	34.0	2.30	94	–
N. WARD-ESTES	TX	25	32.0	1.40	86	–
N. WARD-ESTES-7708	TX	39	32.0	1.40	86	–
NEBO HEMPHILL	LA	2,470	21.0	126.00	91	67,600
ORCUTT HILL	CA	70	22.0	6.00	160	–
ORCUTT HILL	CA	71	22.0	8.00	168	14,300
ORCUTT HILL	CA	70	22.0	8.00	168	14,300
PUERTO CHIQUITO	NM	–	34.0	3.43	109	29,000
QUARANTINE BAY	LA	220	33.2	1.45	185	138,000
SADDLE RIDGE	WY	–	–	–	–	–
SAN MIGUELITO	CA	36	30.0	0.70	205	31,165
SHARP MINNELUSA	WY	160	26.0	10.90	220	130,000
SINGLETON	NB	280	40.0	1.50	160	–
SMACKOVER	AR	2,000	20.0	75.00	110	–
TAYLOR-INA	TX	–	–	–	–	–
TAYLOR-INA	TX	300	24.0	200.00	80	36,000
TOBORG	TX	216	22.0	82.00	76	2,580
TORRANCE	CA	1,000	15.0	17.00	–	–
TYRO-OVERLOOK	KS	56	31.0	25.00	70	123,000
VAN-CARROLL UNIT	TX	100	34.2	2.30	135	–
VAN-S. LEWISVILLE	TX	100	34.2	2.30	135	–

TABLE D-5 (Continued)

Field Name	State	Permeability (md)	API Gravity	Viscosity (cp)	Temperature (°F)	Reservoir Salinity (ppm TDS)
VAN-SW LEWISVILLE	TX	100	34.2	2.30	135	-
WEST PERRYTON	TX	19	38.0	0.80	168	-
WHITTIER	CA	388	20.0	40.00	120	3,500
WHITTIER	CA	388	20.0	40.00	120	-
WILMINGTON	CA	238	28.0	23.00	125	-
WILMINGTON	CA	1,000	18.0	70.00	125	-

precautions and procedures are needed to ensure this and to comply with regulations. This conclusion was drawn from an extensive study, described in Appendix G, of the existing and potential environmental impacts of chemical flooding. The study included:

- Visits to currently operated chemical floods
- Discussions with field operators, industry research personnel, and regulatory agency personnel
- Review of existing literature and related studies.

The study approach identified the hazardous chemicals used and their potential environmental and human impacts, defined conditions that might lead to environmental contamination and human exposure, assessed existing waste and produced fluid disposal practices and requirements, identified the key water use issues, and examined other potential operating and compliance problems.

The study identified five significant environmental concerns associated with chemical flooding, which are listed and discussed below:

- Human exposure to toxic materials
- Protection of fresh groundwater resources
- Protection of surface waters
- Solid waste disposal
- Competition for freshwater supplies.

Some EOR chemicals are potentially toxic and of low degradability. Usually the chemicals exhibit their greatest toxicity or health hazard at the higher concentrations that might be encountered with transportation, handling, and storage of bulk chemicals. At the lower concentrations usually encountered in field injection and production systems, available data indicate little apparent toxicity or health risk.

A compilation and assessment of the nature of chemical compounds used in enhanced oil recovery has been published by the U.S. Department of Energy (DOE). A summary of the more commonly used chemicals is given in Table G-1.

The greatest potential for exposure to workers would be an accident associated with bulk chemicals, particularly when EOR chemicals are manufactured on site. Handling of bulk chemicals and mixing operations are traditional chemical industry operations. The chemical industry has an injury and sickness rate of only about two-thirds that for all U.S. industry. In the past few years, numerous laws have been adopted on the federal, state, and local level to protect the worker. In the case of chemical EOR projects, toxic and hazardous materials are appropriately marked, handled, transported, and disposed of in accordance with federal, state, and local regulations and guidelines. Requirements also include proper training of facility personnel and programs to increase worker (and public) awareness of toxic materials. It is industry's practice to maintain a spill prevention and contingency plan in case of accident. Environmental Protection Agency (EPA) regulations require that accidental spill of hazardous substances in harmful quantities into the waters of the United States be reported to the appropriate federal agency.

The nature of pure or concentrated chemicals is usually understood. While there is little indication that these chemicals at the low concentrations observed in injection systems and produced waters would be harmful to the environment and human populations, government agencies and others are uncertain as to concentrations where a potential threat may exist. Application of available data and established operational practices, and supplemental studies in some instances, are important to ensure safe operations.

Undetected leaks in injection or production systems and reservoir fractures to other horizons have the potential for releasing petroleum reservoir fluids into freshwater underground reservoirs. The presence of EOR chemicals would marginally increase the probability of damage to the freshwater resources when compared to conventional waterflooding. Conventional waterflooding has an extremely good record with respect to freshwater reservoir contamination. This record is expected to improve as the provisions of the U.S. Safe Drinking Water Act are uniformly complied with.

Surface waters can be contaminated by spills of chemicals during transportation, onsite manufacturing, or routine handling. Spill prevention and contingency planning are an integral part of a chemical EOR project. Surface waters can also be contaminated by improper disposal of produced water. Injected waters sometimes can channel to producing wells, resulting in higher chemical concentrations in the produced water. If this happens, residual concentrations may occur depending on local conditions. In most cases, produced water is disposed of by reinjection. In some limited areas where the produced water is fresh, disposal might be by surface discharge. Disposal in offshore areas is frequently by discharge to the oceans. Such surface disposal practices need to be carefully planned and monitored to ensure that the public and the environment are not exposed to harmful quantities of chemicals.

Although small in quantity compared to industrial projects of equivalent magnitude, solid waste can result from chemical EOR projects. Chemicals used in the EOR process can accumulate in some of these wastes, e.g., filter media and water treating residues. Appropriate handling procedures and employee training are used to ensure that the waste is disposed of in a safe manner and in compliance with applicable government rules.

At one time it was anticipated that chemical EOR would use large amounts of relatively fresh water. This may still be true in some cases. However, all oil and gas production processes together currently use less than 1 percent of total U.S. water supply. Also, the trend in chemical flooding is towards greater use of produced waters. Consequently, any conflict of enhanced oil recovery with general water use is likely to be localized and not a major problem.

Screening Criteria

In general, the applicability and effectiveness of chemical processes are more influenced by reservoir conditions than are secondary oil recovery processes. For this study, the screening criteria for the application of a particular chemical process were based on the characteristics of the rock (permeability, sandstone versus carbonate), oil (viscosity, API gravity), and brine (ppm dissolved solids) and on the reservoir temperature. In practice, the divalent cation content of the brine is a critical factor. This could not be used as a screening criterion because it was not available from the data base.

In this study, two sets of screening criteria have been developed for chemical processes. The Implemented Technology Case set of criteria are based on the characteristics of reservoirs in which field projects have been reported to be technically successful. The list of field projects and reservoir parameters used for this case are given in Tables D-3, D-4, and D-5. The Advanced Technology Case criteria define the reservoirs in which a process might be applicable by the year 1995. In some instances, chemicals are currently available for application in reservoirs having one or more Advanced Technology Case characteristics. However, full advanced application will only be attainable if significant technical advances are made.

Polymer Flooding

Screening criteria for the polymer flooding process are listed in Table D-6. These criteria reflect the technical limitations for applying the process. Since polymers are also used in surfactant and alkaline flooding processes, the tabulated criteria also reflect some limits of application of these processes. Similarly, Advanced Technology Case criteria for surfactant and alkaline flooding assume advancements in polymer technology.

Successful applications of polymer processes have only been in reservoirs with crude oil viscosities less than 100 cp. Since increased polymer concentrations are required as higher oil viscosities are approached, this restriction has been influenced by the economics of higher injectant costs and decreased injection rates. It is presumed that development of more-cost-effective polymers will extend this limit to 150 cp for the Advanced Technology Case.

The temperature criterion is a critical limitation. Above 200 °F, polymers undergo significant thermal degradation, and thus lose their viscosifying abilities. For the Advanced Technology Case, it is presumed that development of new, stable polymers will extend this limit to 250 °F.

The current permeability limit reflects the fact that although high molecular weight

TABLE D-6

SCREENING CRITERIA FOR POLYMER FLOODING

Criterion	Units	Implemented Technology	Advanced Technology
Rock Type	-	Sandstone & Carbonate	Sandstone & Carbonate
In Situ Oil Viscosity	cp	< 100	< 150
Temperature	°F	< 200	< 250
Permeability	md	> 20	> 10
Total Dissolved Solids in the Formation Water	ppm	< 100,000	< 200,000

polymers are excellent viscosifiers, they can rarely be effectively propagated through reservoirs with permeabilities lower than approximately 20 md. Lower molecular weight versions of these polymers can be propagated, but higher concentrations must be used to achieve desired viscosities and/or resistance factors. Further, the decreased polymer injectivity in a lower permeability rock will increase the project life and thus adversely affect its economics. Again, improvements in the cost effectiveness of polymers will be required to extend their applicability to reservoir permeabilities as low as 10 md.

The salinity of the injected polymer solution can have a significant effect on the applicability of polymer flooding. Biologically produced polysaccharide polymers are relatively insensitive to salinity and should be applicable in brines with up to 200,000 ppm TDS. The criterion set for the Implemented Technology Case indicates that a field test has not yet been successfully run in brines that are more saline than 100,000 ppm. The viscosities of less-expensive synthetic polyacrylamide polymer solutions, however, are very sensitive to salinity. The development of less salinity sensitive, more-cost-effective polymers will extend their applicability to more saline reservoirs.

Surfactant Flooding

The reservoir screening parameters for surfactant flooding applicability are listed in Table D-7. These parameters reflect the limits of both the surfactant and the polymer used in the process.

Technically successful surfactant flooding has occurred only in sandstone reservoirs. Carbonates are not considered suitable target reservoirs for implemented technology because of the sensitivity of commercially available surfactants to divalent cations.

So far, the process has been applied only in reservoirs having crude oil viscosities less than 40 cp. This limit has been governed mainly by

TABLE D-7

SCREENING CRITERIA FOR SURFACTANT FLOODING

Criterion	Units	Implemented Technology	Advanced Technology
Rock Type	-	Sandstone	Sandstone & Carbonate
In Situ Oil Viscosity	cp	< 40	< 100
Temperature	°F	< 200	< 250
Permeability	md	> 40	> 10
Total Dissolved Solids in the Formation Water	ppm	< 100,000	< 200,000

the high cost associated with the higher polymer concentrations needed for mobility control. For the Advanced Technology Case, it was presumed that crude oils with viscosities up to 100 cp would be recoverable.

The present reservoir permeability limit of 40 md has both technical and economic foundations. As in polymer flooding, low permeability adversely affects injectivity, project life, and economics. Moreover, the microscopic displacement efficiency of the process decreases and the degree of surfactant retention within the rock matrix increases with decreasing permeability. Thus, better polymers and surfactants will have to be developed before the process can be successfully applied under the Advanced Technology Case limit of 10 md.

The applicability of surfactant flooding is most severely limited by salinity and temperature, which should be considered together. The present limits of 100,000 ppm and 200 °F result from two specific field tests in (1) a high-salinity, low temperature reservoir and (2) a high-temperature, low-salinity reservoir. The Implemented Technology Case screening criteria are therefore somewhat generous, since no flood has been conducted at both 200 °F and 100,000 ppm TDS. The extension of existing technology to reservoir environments that are both high-temperature (250 °F) and high-salinity (200,000 ppm) will require the commercialization of suitable surfactants and polymers. Both of these have been demonstrated at the laboratory scale.

Alkaline Flooding

Alkaline flooding screening parameters for the Implemented and Advanced Technology Cases are shown in Table D-8. As in surfactant flooding, chemical/rock interactions have a significant impact on the effectiveness of the process. In particular, the caustic chemicals used in alkaline flooding are incompatible with carbonate rocks. Thus, both implemented and advanced technology are applicable only in sandstone reservoirs.

The process has been successfully field tested in reservoirs having crude oil viscosities up to 90 cp. It is anticipated that the Advanced Technology Case, which incorporates polymer and cosurfactants in the flooding design, will only be applicable economically in reservoirs in which the crude oil viscosity is less than 100 cp.

A major parameter determining the effectiveness of an alkaline flood is the acid number of the crude oil. This number is a measure of the amount of potentially surface active material in the oil. The acid number can be approximately correlated with the API gravity of the crude oil, although this varies with geographic location as shown in Figure D-3. An upper limit of 30 °API has been set to correspond to the acid number required for effective alkaline flooding, since the acid number itself is not available from the data base. Since this is a reservoir crude oil characteristic and cannot be changed by technical advancements in the process, the Advanced Technology Case limit has also been set to 30 °API.

The temperature, permeability, and salinity screening criteria again reflect the limits of the polymer used in the process. Although it has been shown that the process effectiveness decreases with increased temperature, due to increased alkali/rock interactions, extension of the technology from the Implemented to the Advanced Technology Case conditions will first require advancements in polymer technology.

TABLE D-8

SCREENING CRITERIA FOR ALKALINE FLOODING

Criterion	Units	Implemented Technology	Advanced Technology
Rock Type	-	Sandstone	Sandstone
In Situ Oil Viscosity	cp	<90	<100
API Gravity	°API	<30	<30
Temperature	°F	<200	<200
Permeability	md	>20	>10
Total Dissolved Solids in the Formation Water	ppm	<100,000	<200,000

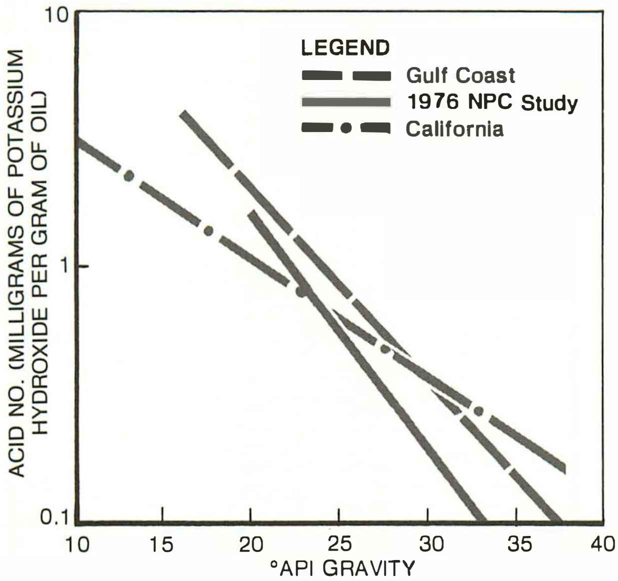


Figure D-3. Correlation of Acid Number with API Gravity.

Process-Dependent Costs

Startup Costs

Chemical Injection Plant Cost

Costs required for construction of the chemical injection plant were calculated based on the maximum injection rate needed and on the particular chemical flooding process being used. The surfactant plant cost includes the cost required to prepare and inject both surfactant slug and polymer solution. The polymer injection plant cost includes the cost of equipment necessary to mix and inject polymer. The alkaline plant cost includes the cost of equipment to mix and inject alkaline slug and to soften water.

A typical alkaline injection plant (Implemented Technology Case) costs 2.5 times more than a polymer injection plant, and a surfactant injection plant will cost 5 times more than a polymer injection plant. These factors reflect the increasing complexity of the equipment required.

Well Workover Cost

It was assumed that each existing well would be worked over at the start of a chemical flood. This one-time cost was included as part of the initial project startup costs. The well workover cost was estimated to be 20 percent of the cost of drilling a new well. New well costs are discussed in Appendix C.

Operating Expenses

Fixed Operating Expenses

Fixed operating expenses for chemical flooding were assumed to be the same as the fixed operating expenses for waterflooding. Therefore, no incremental expenses were included when the chemical flood pattern remained the same as the pre-existing waterflood pattern. The only incremental fixed operating expenses considered in economic calculations were for new injectors and producers drilled for the purpose of pattern spacing reduction. Items included in fixed operating expenses for waterflooding are discussed in detail in Appendix C.

Variable Operating Expenses

Variable operating costs shown in Table D-9 were estimated for preparation and injection of chemical slugs, water disposal, and produced oil treatment. Advanced Technology Case expenses and Implemented Technology Case expenses were considered to be the same for surfactant and polymer floods. Advanced Technology Case alkaline flood costs were set equal to surfactant flood costs since both surfactant and polymer are included in the Advanced Technology Case alkaline flood.

TABLE D-9

VARIABLE OPERATING EXPENSES FOR CHEMICAL FLOODING
(Dollars per Barrel)

	Surfactant	Polymer	Alkaline
Chemical Slug Injection	0.20	–	0.10 (0.20 Advanced)
Polymer Solution Injection	0.10	0.10	0.10* (Advanced Case Only)
Produced Water Disposal	0.03	0.03	0.03
Produced Oil Treatment	0.50	0.05	0.50 (Advanced Case Only)

*No polymer used in Implemented Technology Case alkaline flood.

Chemical Costs

Implemented Technology Case

Typical chemicals used in chemical flooding are primary surfactants, secondary surfactants, polymers, and alkaline agents. The cost of these chemicals is related to the price of oil. The Chemical Task Group, through a confidential survey, provided chemical cost values for the base case nominal crude oil price of $30 per barrel. For the $20, $40, and $50 per barrel nominal crude oil price cases, chemical costs were adjusted as shown in Table D-10.

The cost of the injected surfactant slug is dependent upon the chemical formulations of the slug. Table D-11 shows the formulation used and the slug cost calculation for the $30 per barrel nominal crude oil price. For other oil prices, the formulation was the same, but the adjusted costs from Table D-10 were used. The mobility control polymer slug size was set at 65 percent pore volume. The polymer concentration was calculated as the concentration to give proper mobility control. Surfactant slug size was nominally 15 percent pore volume, adjusted for reservoir heterogeneity as described below.

The slug size and concentration of the polymer slug for polymer flooding were 40 percent pore volume and 600 ppm, respectively.

The concentration of alkaline chemicals in the slug for alkaline flooding was set equivalent to one weight percent of sodium hydroxide. The slug size was a nominal 40 percent pore volume. The actual slug size was adjusted according to the reservoir heterogeneity as in the surfactant model.

Advanced Technology Case

All process-dependent costs, except those for alkaline flooding, were the same in both Implemented and Advanced Technology Cases. In the advanced alkaline flooding case, 2,000 ppm of surfactant and 2,000 ppm of polymer were used in combination with alkaline chemicals. Costs were adjusted accordingly. Slug sizes were the same for the Implemented and Advanced Technology Cases.

TABLE D-10

PRICE ESTIMATES FOR CHEMICALS USED IN CHEMICAL FLOODING AT VARIOUS NOMINAL OIL PRICES*

	Chemical Cost ($/Active Pound)			
Chemical	$20/bbl	$30/bbl	$40/bbl	$50/bbl
Primary Surfactants†	0.27	0.32	0.37	0.42
Secondary Surfactant	0.37	0.44	0.51	0.58
Polymers	1.42	1.60	1.78	1.96
Alkaline Agents	0.15	0.17	0.19	0.21

*Based on confidential survey conducted by NPC of member companies and consultation with companies with ongoing projects.
†Based on petroleum sulfonates and dedicated chemical plants near the field.

TABLE D-11
SURFACTANT SLUG FORMULATION

	Concentration (wt. percent)	Cost ($/lb)	Cost ($/bbl)
Primary Surfactant	3.0	0.32	3.36
Secondary Surfactant	2.0	0.44	3.08
Polymer	0.1	1.60	0.56
Average Surfactant Slug Cost ($30/bbl oil price)			$7.00

Polymer Flooding

Predictive Model

Introduction

This section briefly summarizes the predictive model used for the polymer flooding process. The polymer flood predictive model was specifically developed for the use of the National Petroleum Council in this study.

Model Description

The model is a stream tube model that represents one-eighth of a five-spot with five equal thickness noncommunicating layers and eight stream tubes in each layer. The layer permeabilities are determined from a pseudo Dykstra-Parsons coefficient of permeability variation and the mean permeability.

The saturation profiles and recovery from each stream tube are computed using the method of characteristics. This method is a modification of the Buckley-Leverett fractional flow theory, which takes into account the reduced mobility of the polymer solution and polymer retention. The saturation profile is used to compute the stream tube conductivity, which determines the change in the flow distribution between the stream tubes and the change in injectivity with time. The model first calculates recovery for continuous polymer slug injection. An empirical factor is then used to correct the recovery for finite polymer slug sizes. This factor was determined by comparison of results from the simplified model with those from a finite difference simulator.

Calibration

To establish the validity of the model, the performance from selected field projects was compared with model predictions. Sensitivities to various parameters such as oil viscosity and polymer properties were compared with results obtained from a finite difference simulator. In cases where the polymer injectivity was calculated to be excessively different compared to observed field values, an adjustment was made to the injectivity coefficient. This adjustment resulted in reasonable project lives comparable to implemented polymer projects.

Injectivity

The model initially calculates the injection rate into each layer using a formula that takes into account reservoir depth, pay thickness, and permeability, together with the fluid viscosity. The injection rate is subsequently adjusted for the change in conductivity in each stream tube and the non-Newtonian flow near the injection well. The pressure drop between the injector and producer takes into account the injection wellhead pressure and the gravity head of the fluids in the injection and production wells.

If the initial injectivity is such that it predicts less than five years for two pore volumes of water injection, then a factoı is applied to the injectivity coefficient to increase this time to five years. This adjusts predicted rates closer to actual field experience.

Polymer Properties

The mobility reduction with polymer was described by the resistance factor and the residual resistance factor. The non-Newtonian effect was quantified by the power-law exponent and the apparent polymer viscosity at a shear rate of 1.0 sec^{-1}, which is approximated by the product of the resistance factor and the water viscosity. It was assumed that the minimum apparent viscosity at the high shear rates around the well is equal to the water viscosity.

All of the predictions used a 0.4 pore volume polymer slug containing 600 ppm polymer, having a resistance factor of 8 and a residual resistance factor of 2. The adsorption was specified to be 150 pounds per acre-foot.

Incremental Recovery

The model computes the incremental recovery by comparing the predictions of the polymer flood and waterflood. Both predictions have as the initial condition the current oil saturation in the reservoir.

Implemented Technology Case Results

Polymer flood incremental oil recovery production rate as a function of time for a minimum ROR of 10 percent and $30 per barrel nominal crude oil price is shown in Figure D-4 for the Implemented Technology Case. Relative to the potential shown for other EOR processes, polymer flooding will not be a major contributor. However, because of its low cost, it will be implemented relatively early and may extend the productive lifetimes of many fields, thereby keeping them available for a subsequent, more effective EOR process. Peak rate for the base economic case is predicted to be less than 50 thousand barrels per day. This rate may be reached in the late 1980s and sustained for 8 to 10 years.

Increased oil price would result in earlier implementation of polymer projects, with resultant higher peak production rates. However, the increased price does not significantly impact the total recovery potential, as shown in Table

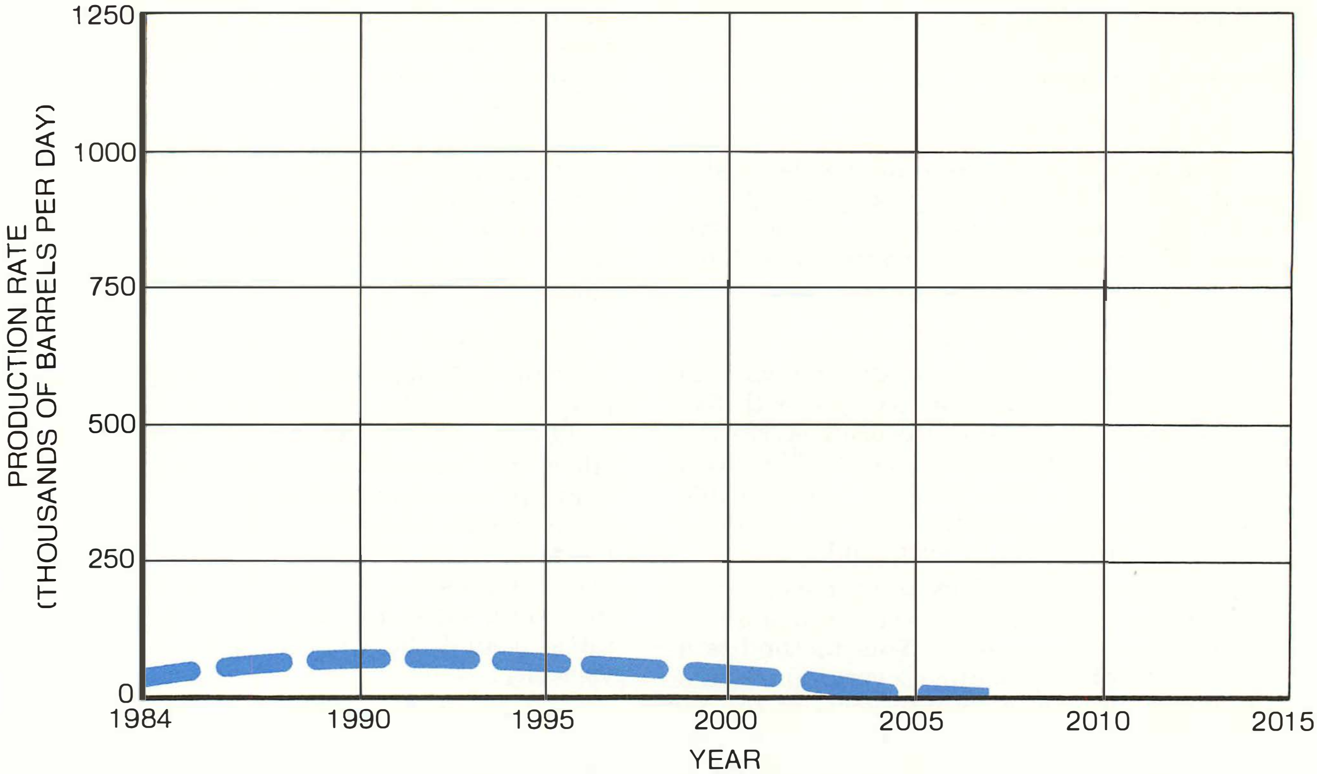


Figure D-4. Production Rate for Polymer Flooding—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

TABLE D-12

**POLYMER FLOODING
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Millions of Barrels)**

Nominal Crude Oil Price ($/bbl)	Minimum ROR		
	0%	10%	20%
20	390	250	230
30	390	280	240
40	350	260	230
50	330	270	260

D-12. This results from the priority given to other processes having higher displacement efficiency, which become economical as the price of oil is increased. Since companies may well make investment decisions based on criteria different from those used in the timing model, Table D-12 may understate polymer flood potential at high oil prices.

Advanced Technology Case Definition

Advanced Technology Case polymer uses the same model as the Implemented Technology Case. Any additional recovery by Advanced Technology Case polymer applications results from an expansion of the screening criteria. Reduced project life and improved project economics resulting from injectivity improvements might also increase the potential for the Advanced Technology Case. However, these were not specifically considered.

Advanced Technology Case Results

Composited results (Table D-13) show no significant increase in polymer flood potential for the Advanced Technology Case. Essentially,

TABLE D-13

POLYMER FLOODING ULTIMATE RECOVERY ADVANCED TECHNOLOGY CASE (10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Millions of Barrels)
30	230
40	290
50	290

this is because polymer always loses out to a more efficient process in the Advanced Technology Case. Most of this polymer flood production occurs before 1995. Producing rate versus time curves were essentially identical to those in the Implemented Technology Case (Figure D-4).

Surfactant Flooding

Predictive Model

Description

A surfactant-polymer predictive model, developed for the Department of Energy, was made available to the NPC and served as the base for the model used to predict crude oil production by surfactant flooding.

The predictive model requires the input of a large number of variables relating to oil reservoir and crude oil characteristics. A significant number of these input variables were not present in the oil reservoir data base used in this study and therefore required appropriate default values to be used as input. The model was calibrated against several completed surfactant-polymer field projects. The introduction of several calibration factors to the model was required to properly simulate the oil production schedule observed in the field tests.

These requirements (default values and calibration factors) were essential to obtain results that were considered valid for this study. Due to the introduction of these factors, the results obtained below differ significantly from those that would be obtained by a direct application of the original model.

Calibration

The surfactant model translates the input variables into an incremental oil production schedule that is triangular in shape.[1] No oil is produced for a period until breakthrough of an oil bank is calculated. Oil production increases linearly to a calculated maximum and then decreases linearly to zero to provide a calculated total recovery by the end of the project life. To establish the validity of the model, the production schedules reported from various field projects were compared to production schedules as calulated by the model, using field input values.

The model-calculated production schedules varied in a consistent manner from the observed field production schedules. Three calibration factors were added to the model in order to obtain calculated schedules that were a closer match of those observed in the field projects. These calibration factors were:

- Decrease slug velocity to increase oil breakthrough time and increase the time of peak oil production
- Decrease peak oil production rate
- Decrease injection rate.

Recovery Efficiency Factors

The chemical flood predictive model determines ultimate recovery efficiency as a product of several factors (all fractions). These are:

- Microscopic displacement efficiency
- Areal sweep efficiency
- Vertical sweep efficiency
- Mobility buffer efficiency
- Cross-flow mixing factor.

The vertical sweep efficiency, the mobility buffer efficiency, and the cross flow mixing factor are all functions of reservoir heterogeneity. This was represented in this study by a pseudo Dykstra-Parsons coefficient. This coefficient was derived by comparing actual field waterflood performance with predictions from a stream tube model for a five-spot pattern with 100 layers. The field sweep efficiency and mobility ratio were estimated from information available in the data base.

Where the calculated Dykstra-Parsons value was less than 0.5, or where it could not be calculated due to lack of data, the average value of 0.72 was assigned to that reservoir. Since the field sweep performance, and hence the pseudo Dykstra-Parsons coefficient, included both areal and vertical effects, areal sweep efficiency for this study was set equal to 1.0.

[1]Paul, G. W., Lake, L. W., Pope, G. A., Young, G. B., "A Simplified Predictive Model for Micellar-Polymer Flooding," SPE paper 10733.

For the purposes of the NPC study, a maximum value of 0.6 was set on mobility buffer efficiency and a maximum value of 1.3 was set on cross-flow mixing factor. Without these limitations, the model tended to give unrealistically high oil recoveries in heterogeneous reservoirs.

Project Design

Injectivity Coefficient. Injection rate was calculated using the same equation as for the polymer flood model. This equation takes into account the following factors:

- Reservoir permeability
- Reservoir depth
- Pay thickness
- Oil viscosity
- Distance from injection to production well
- Injectivity coefficient.

As supplied, the model used a default value of 0.3 for the injectivity coefficient. This proved unsatisfactory, tending to underestimate injection rate for shallow fields and overestimate for deep reservoirs. For this study, the injectivity correlation shown in Figure D-5 was used.

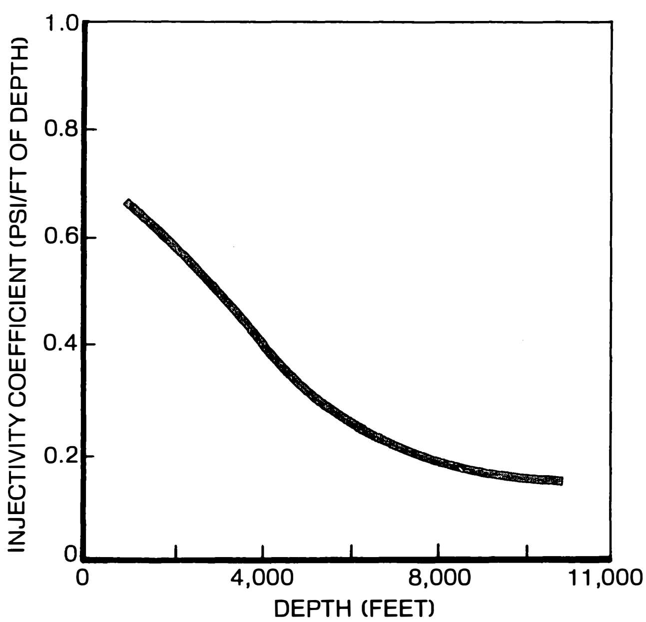


Figure D-5. Injectivity Coefficient as a Function of Reservoir Depth.

Pattern Size. Projects were designed to have a standard pattern life of eight years. To achieve this, a surfactant flood pattern size for each field was chosen that, in combination with the calculated injection rate, would permit 1.2 pore volumes of fluids to be injected in an eight-year period. The pattern size was limited to a maximum of 40 acres and a minimum of 5 acres. The reservoir data base contained information on the number of wells and/or pattern size in each field. This information was the basis for determining the present waterflood pattern spacing. The surfactant flood pattern size was not permitted to be larger than the waterflood pattern size.

In some cases, a five-acre pattern size was too large to permit an eight-year pattern life. These projects were allowed to have pattern lives longer than eight years. In other cases, the waterflood pattern size, or the 40-acre maximum, led to pattern lifetimes less than eight years. This was considered unrealistically short. Therefore, injection rate was reduced in these cases to produce an eight-year pattern life.

Surfactant Slug Size. A default value of 15 percent pore volume was initially chosen for surfactant slug size. This was then scaled according to the expected sweep efficiency in such a way that slug size was 15 percent for the most homogeneous reservoirs treated (pseudo Dykstra-Parsons = 0.5) and 7.5 percent for the most heterogeneous reservoir treated (pseudo Dykstra-Parsons = 0.97). Slug size was adjusted linearly between these limits according to the calculated vertical sweep efficiency.

Surfactant Adsorption. The predictive model calculates adsorption based on the weight fraction of clay in the reservoir. However, this information was not generally available from the data base. Therefore, a default value for the dimensionless adsorption was chosen such that a 15 percent pore volume surfactant slug was sufficient to satisfy 1.3 times the surfactant retention level in the reservoir. Vertical sweep efficiency, and hence oil recovery, is dependent upon this dimensionless adsorption.

Pattern Development Schedule. The model prediction is based on a single five-spot pattern of the surfactant flood pattern size determined previously. Each reservoir was developed over a period of time as a function of the surfactant flood pattern size and the area and depth of the reservoir. The rate at which this development might proceed cannot be determined from the relatively small-scale floods conducted so far. Therefore, the following assumptions were used to determine the number of patterns that could be developed annually:

- For reservoir depths of less than 1,000 feet, 200 patterns per year.

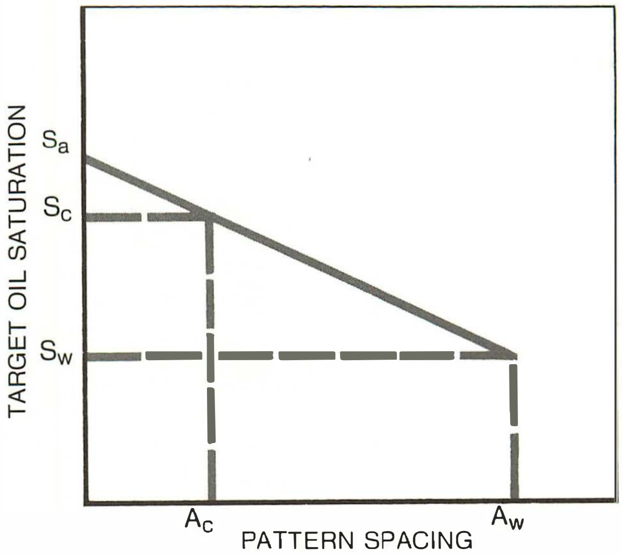
- For reservoir depths greater than 5,000 feet, 50 patterns per year.
- For reservoirs between these depth limits, the number of patterns per year was obtained by linear interpolation between the two limits based on reservoir depth.

Although arbitrary, these schedules are considered reasonable.

Once the number of patterns per year was determined, the reservoir was developed annually at that rate until the total reservoir acreage had been developed. A lesser number of patterns was sometimes developed in the final year of pattern scheduling. Some reservoirs were fully developed in one year, while others took up to 40 years for full development.

Target Oil Saturation. The reservoir data base contains oil saturation values for the average remaining saturation of the field and for the average saturation in the waterflood-swept zone. If a value for the waterflood residual saturation had not been supplied by the field operator, a default value was used. This was 25 percent for sandstones and 38 percent for carbonates.

It was assumed that the project target oil saturation would generally be less than the average remaining saturation and greater than the waterflood residual saturation. A linear relationship of target oil saturation versus pattern size was assumed where the average remaining saturation would occur at a "zero-acre" pattern size and waterflood residual saturation would be the target oil saturation at the current waterflood pattern spacing. Target oil saturation for the surfactant flood was determined by linear interpolation of this relationship based on the surfactant flood pattern size. The relationship is illustrated in Figure D-6.



LEGEND

S_a = Current Average Oil Saturation
S_c = Target Saturation for Chemical Flood
S_w = Waterflood Residual Oil Saturation
A_c = Chemical Flood Spacing
A_w = Waterflood Spacing

Figure D-6. Estimation of Surfactant Flood Target Oil Saturation.

Implemented Technology Case Results

The potential incremental oil recovery from surfactant flooding varies significantly with oil price and the economic criterion used. This is illustrated in Table D-14. Ultimate EOR is estimated as 2.1 billion barrels for the base economic case ($30 per barrel of crude oil, 10 percent minimum ROR). This increases to 3.1 billion barrels at 0 percent minimum ROR and decreases to 1.1 billion barrels at 20 percent minimum ROR.

Potential recovery becomes insignificant at a nominal crude oil price of $20, but could

TABLE D-14

SURFACTANT FLOODING
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	10%	20%
20	1.9	0.7	0.2
30	3.1	2.1	1.1
40	3.9	3.1	1.9
50	4.4	3.7	2.6

increase to as much as 3.7 billion barrels at 10 percent minimum ROR for an oil price of $50 per barrel.

For compositing purposes, the 10 percent minimum ROR results from Table D-14 were used to schedule projects in order to estimate producing rate as a function of time. In practice, whereas the industry might undertake low-risk projects expecting a 10 percent minimum ROR (and usually getting much less), it is not likely that an unproven, high-risk surfactant flood will be started unless the expected return is much higher. This is a way of compensating for the fact that many chemical EOR projects that appear economic when started will actually end up losing money. Choosing 10 percent minimum ROR for the base case almost certainly overstates the potential of surfactant flooding relative to more proven, lower risk techniques such as steamflooding.

Figure D-7 indicates possible producing rates as a function of time for each nominal crude oil price at 10 percent minimum ROR. Except for the $20 case, the producing rate is shown as increasing steadily throughout the study period.

A key parameter that influences the possible rate is the availability of suitable surfactants. There is no limit to this availability in principle, since surfactant plants can be built relatively cheaply and quickly. However, to sustain a rate of 10 thousand barrels per day of surfactant EOR requires an annual surfactant supply of at least 55 million pounds. To achieve the rates shown on Figure D-7 for $30 per barrel of crude oil will require approximately one 100 million pound annual capacity surfactant plant to be constructed every four years. Although these represent very modest capital expenditures, there is no guarantee that they will actually be built.

The rate of 260 thousand barrels per day shown for $50 per barrel of crude oil in the year 2000 will require a minimum of 1.4 billion pounds per year of surfactant usage. An average of 100 million pounds of capacity must be built each year between 1984 and 2000 to meet this demand. Clearly, surfactants in this quantity will not be available from other markets. These surfactant plants will have to be purpose-built for enhanced oil recovery. Equally clearly, surfactant will be restricted unless such plants are constructed. Therefore, although surfactant availability is not a long-term restraint, it is likely in practice to be an intermittent limitation on surfactant EOR until the technology is quite mature.

Another key point is that, at the rates indicated in Figure D-7, a large proportion of the

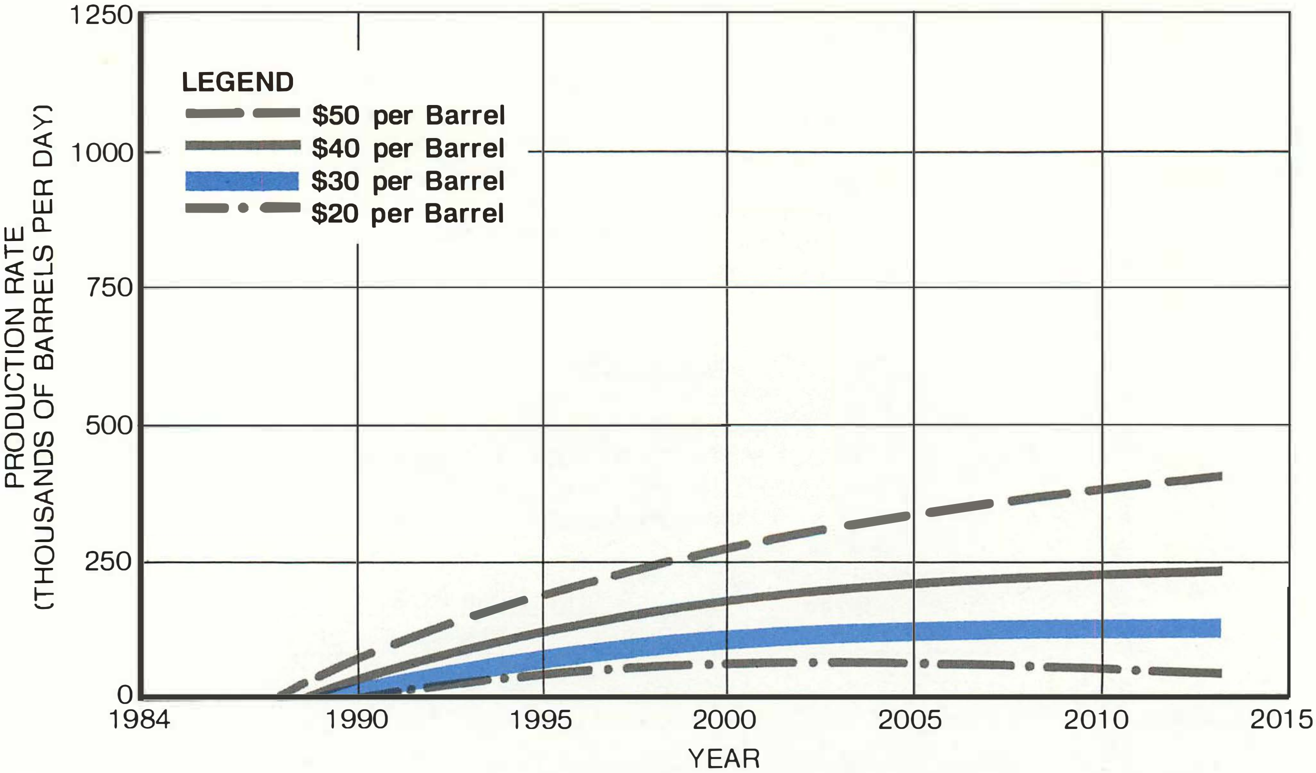


Figure D-7. Sensitivity of Surfactant Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

total surfactant flood potential remains to be produced after 2013. Only 31 percent (at $30 per barrel) to 62 percent (at $50 per barrel) is produced during the next 30 years. There is some question as to whether oil not producible within 30 years really counts as potential. Many of the fields examined in this study are in advanced stages of waterflooding. No doubt some of these will be abandoned unless surfactant flooding is initiated faster than projected in this study.

A major area of uncertainty with regard to these results concerns the economic parameters used. The economic analyses performed as part of this study are "preproject" economics. Experience with chemical EOR indicates that these are likely to be optimistic. Chemical and operating costs were chosen to correspond to large-scale application of an established technology, which will be dependent upon industry developing confidence in the technique. Industry confidence in surfactant flooding will increase only as actual successes are demonstrated in the field. The rate projections given in Figure D-7 assume that industry will continue to try field-scale surfactant floods and hence will eventually establish the necessary confidence level.

Advanced Technology Case Specifications

The Advanced Technology Case for surfactant flooding was developed on the basis of possible future technical advances (Appendix H discusses future research in detail). Specifically, improvements in injection rate, interfacial tension, and surfactant retention were chosen to illustrate the effects of possible technology improvements.

- **Increased Injectivity**—An important variable, from an economic point of view, is the oil production rate, which is controlled by the injection rate. The Advanced Technology Case assumes that injection rate will be increased by 35 percent over the implemented technology value. Increased injectivity can be achieved by improved wellbore conditions, improved polymer quality, optimized polymer rheological properties, improved mobility control methods, and improved well stimulation and chemical placement methods.
- **Improved Displacement Efficiency**—A second important variable that has an effect on economics and oil recovery is the oil displacement efficiency. This parameter directly controls oil recovery in the segments of the reservoirs contacted by chemicals. It is a function of the capillary number, which is the ratio of viscous forces (viscosity and frontal velocity) to the capillary forces (interfacial tension).

  Two changes have been incorporated for increasing the capillary number and thus oil recovery. First, based on laboratory studies, the value for interfacial tension has been reduced from 1×10^{-3} dynes per centimeter in the Implemented Technology Case to 5×10^{-4} dynes per centimeter for the Advanced Technology Case, reflecting improved surfactant formulation for reservoir environments. Several references in the bibliography report such low interfacial tension values. Second, the increase in injection rate will also moderately increase the displacement efficiency.
- **Decreased Surfactant Retention**—Increased chemical effectiveness for the Advanced Technology Case was simulated by reducing surfactant retention by 25 percent. This can be achieved by improving surfactant structure, creating high pH environments, and possibly by utilizing sacrificial agents. This improvement was simulated while keeping the surfactant slug size and concentration the same as for the Implemented Technology Case, thus increasing the portion of the reservoir contacted by surfactant slug.

The Chemical Task Group designed the Advanced Technology Case to be optimistic. It is unlikely that all aspects of advanced technology will actually be available by 1995.

Advanced Technology Case Results

The inclusion of reservoirs with more severe environments and the development of more efficient processes results in higher recovery levels than attained by implemented technology. It was assumed that advanced technology will begin to have an impact in 1995.

The potential recovery from Advanced Technology Case surfactant flooding is shown in Table D-15 for various oil prices. Possible producing rates as a function of time are shown in Figure D-8. A 10 percent minimum ROR was used in generating this information. At $30 per barrel of oil, potential recovery increases from 2.1 billion barrels in the Implemented Technology Case to 9.9 billion barrels in the Advanced Technology Case. The corresponding

TABLE D-15

SURFACTANT FLOODING
ULTIMATE RECOVERY
ADVANCED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Produced Before 2013
30	9.9	2.0 (20%)
40	11.7	2.9 (25%)
50	12.6	4.2 (33%)

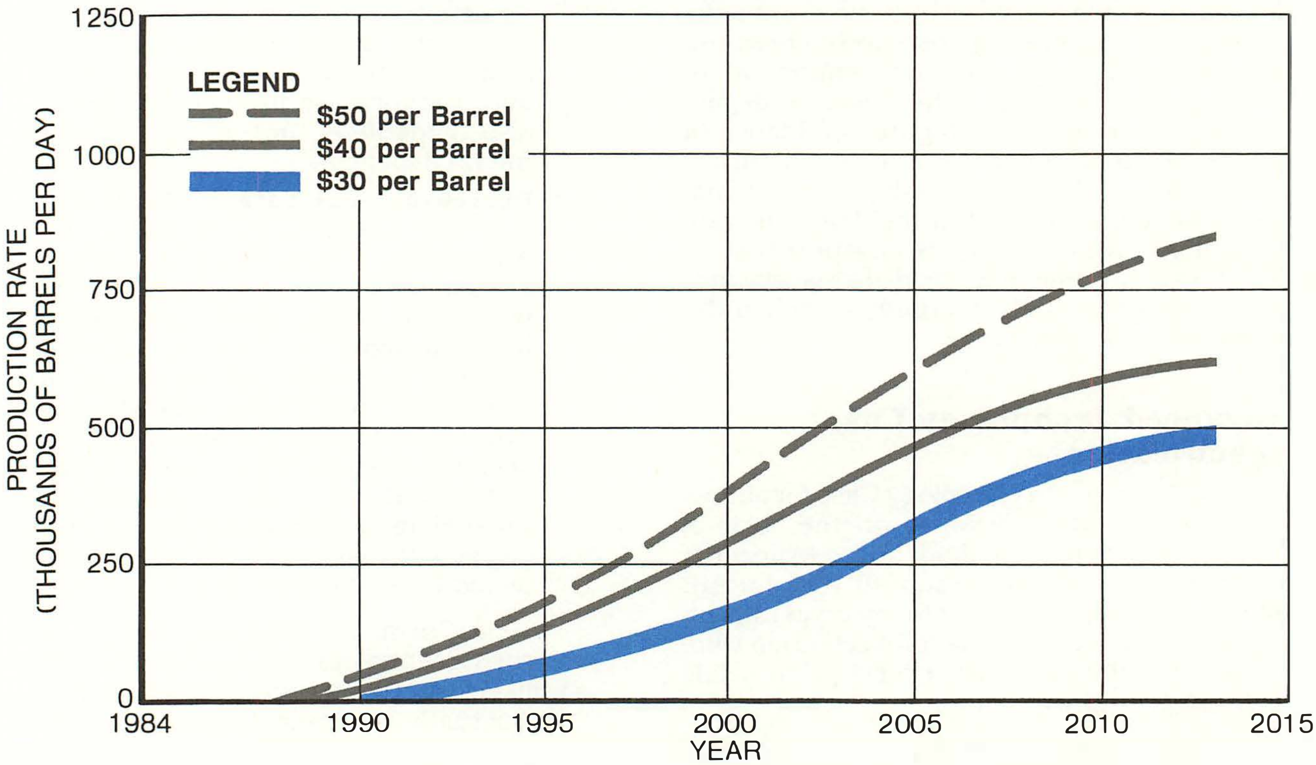


Figure D-8. Sensitivity of Surfactant Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology Case (10 Percent Minimum ROR).

recovery for $50 per barrel of oil goes from 3.7 to 12.6 billion barrels. Note, however, that at the rates shown in Figure D-8, only 20 percent of the $30 potential oil and 33 percent of the $50 potential oil is produced before 2013. More could be produced if surfactant was made available at a sufficient rate. The $50 curve requires surfactant capacity to be added at approximately 300 million pounds per year, which is extremely high by historical standards. Furthermore, this must be the Advanced Technology Case surfactant, which is unlikely to be a petroleum sulfonate.

These very large potentials for Advanced Technology Case surfactant flooding are only meaningful for the presumed costs of $0.32 and $0.44 per pound for surfactants, as listed in Table D-11. Also, as noted above, the probability of all parts of the Advanced Technology Case actually being available by 1995 is not considered to be very high.

Alkaline Flooding

Predictive Model

The predictive model used for estimating ultimate recovery and production rates for alkaline flooding is the same model, modified appropriately, that was used for surfactant flooding. The critical modifications were the assumptions that:

- In the Implemented Technology Case, total oil recovery would be 15 percent of that predicted for Implemented Technology Case surfactant flooding in the same reservoirs.
- In the Advanced Technology Case, total oil recovery would be equal to that predicted for Implemented Technology Case surfactant flooding in the same reservoirs.

Additional modifications are the use of a six-month preflush of softened water in the Implemented Technology Case, an injectivity based on the viscosity of water, and the use of a nominal slug size of 40 percent pore volume with alkalinity equivalent to 1 percent sodium hydroxide in all cases. Actual slug size was keyed to the reservoir heterogeneity as in the surfactant model.

With these modifications the model was used with the same criteria for pattern spacing and development as indicated for the surfactant model.

Justification for the assumptions regarding recovery comes primarily from laboratory data. Typically, laboratory recoveries for alkaline flooding in the implemented technology mode are in the 5 to 10 percent pore volume range. Laboratory recoveries by surfactant flooding in the implemented technology mode are in the range of 30 to 40 percent pore volume. A conservative recovery by alkaline flooding of 15 percent of the surfactant flooding recovery is assumed based on the above information. Similarly, for the alkaline flooding Advanced Technology Case, assumed recoveries of 100 percent of the implemented surfactant recoveries are based on equivalent recoveries in the laboratory experiments. While supported by results from more than one source, this is totally unproven in field use.

Implemented Technology Case Results

Incremental oil recovery projected for alkaline flooding is shown in Table D-16. The contribution is less than 100 million barrels over the spectrum of oil prices and rates of return examined. This reflects the fact that there are relatively few fields in which alkaline flooding is not pre-empted by other processes as an investment opportunity in the timing model. Note that there is no potential for a $20 per barrel oil price, and there also is no potential for an oil price of $30 per barrel and 20 percent minimum ROR. The production rates by alkaline flooding reached a plateau of about 6 thousand barrels per day for all oil prices at 10 percent minimum ROR. For the $40 per barrel and $50 per barrel cases there were short-lived increases in production rate to about 8 thousand and 13 thousand barrels per day, respectively, that reflected the admission of a couple of alkaline projects by the timing model. These are trivial, however, compared to the total EOR production rate.

Advanced Technology Case Specifications

The screening criteria for the Advanced Technology Case were relaxed over those for the Implemented Technology Case. As the industry develops the alkaline flooding technology, it is expected that the process will be applied to reservoirs with conditions less favorable than where it has been implemented in the past.

The most significant change in the Advanced Technology Case alkaline flooding process is the addition of a cosurfactant and

TABLE D-16

ALKALINE FLOODING
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Millions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	10%	20%
20	0	0	0
30	80	70	0
40	40	70	80
50	70	80	70

polymer. All experience with this process is at the laboratory level and no field tests have been reported. However, it is assumed that the recovery efficiency of this modified process will be equal to that of the Implemented Technology Case surfactant flooding process. The process, as modified, is similar to the surfactant flooding process in that polymer is used for mobility control and a cosurfactant and salt are used to achieve ultra-low interfacial tensions at the process displacement front. The process is more complex than the surfactant flooding process because the ratio of the cosurfactant to the in situ generated surfactant in the reservoir will vary. Also, there are interactions of the alkaline chemicals and the reservoir minerals that can deplete the alkali.

The cosurfactant requirement in the alkaline process is much less than that of the surfactant process due to reduced adsorption and less surfactant retention compared to the surfactant flooding process. It is expected that these effects will permit utilization of a cosurfactant concentration of about 0.2 percent active material in a 40 percent pore volume slug. This is equivalent to about 10 percent of the total surfactant used in the surfactant flooding process.

Given equivalent recovery efficiency, the advanced technology alkaline process is more cost effective than the surfactant flooding process. However, it will not completely replace surfactant flooding because it is limited to reservoirs that have crude oil with the appropriate organic acids in sufficient quantities. To estimate the reservoirs that have the appropriate crude oils, the process was limited to reservoirs containing oils having an API gravity less than 30 °API since high acid numbers correlate with low API gravity.

The 200 °F upper temperature limit of alkaline flooding was based on the assumption that stable chemicals will be available and that control of reactions with the reservoir rock is also possible. It was assumed that the silica dissolution will be controlled by adjusting the SiO_2:Na_2O ratio. However, the incongruent dissolution of clay and silica with the formation of zeolites may be more difficult to control and is a major concern. Additional research and field testing is needed to define the actual limits of applicability.

Advanced Technology Case Results

The Advanced Technology Case alkaline flood represents an enormous increase in process efficiency as compared to the Implemented Technology Case. However, as in the case of Advanced Technology Case polymer flooding, most of the potential was lost to other processes that recovered more oil—notably Advanced Technology Case surfactant and thermal processes. Total potential recovery from the advanced alkaline process is given in Table D-17. There is no real trend with oil price. This results from the loss to other processes just discussed. If investment decisions were made in favor of highest rate of return, rather than highest oil recovery, advanced alkaline potential could increase significantly. Producing rate as a function of time is estimated in Figure D-9, for \$30 and \$40 per barrel oil prices. The curve for \$50 per barrel lies very close to that for \$40 per barrel, with a slightly earlier and lower peak rate. Peak rates for all oil prices are in the 130 thousand to 160 thousand barrels per day range and are sustained for only a few years. This arises from the relatively small ultimate potential recovery, relative to other EOR processes, and the small number of projects in the composited case.

TABLE D-17

ALKALINE FLOODING ULTIMATE RECOVERY ADVANCED TECHNOLOGY CASE (10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Millions of Barrels)
30	810
40	570
50	600

Uncertainty

This study has identified a chemical EOR potential of 2.5 billion barrels for the base economic case (\$30 per barrel, 10 percent minimum ROR), of which 2.1 billion barrels comes from surfactant flooding. This is the largest part of chemical EOR for all cases considered, yet it is also subject to the most uncertainty.

Five factors were identified by the Chemical Task Group as being most likely to influence surfactant flood potential, depending on whether they turn out to be more or less favorable for the process than was assumed during the study. These were:

- Range of application (to more or less reservoirs)

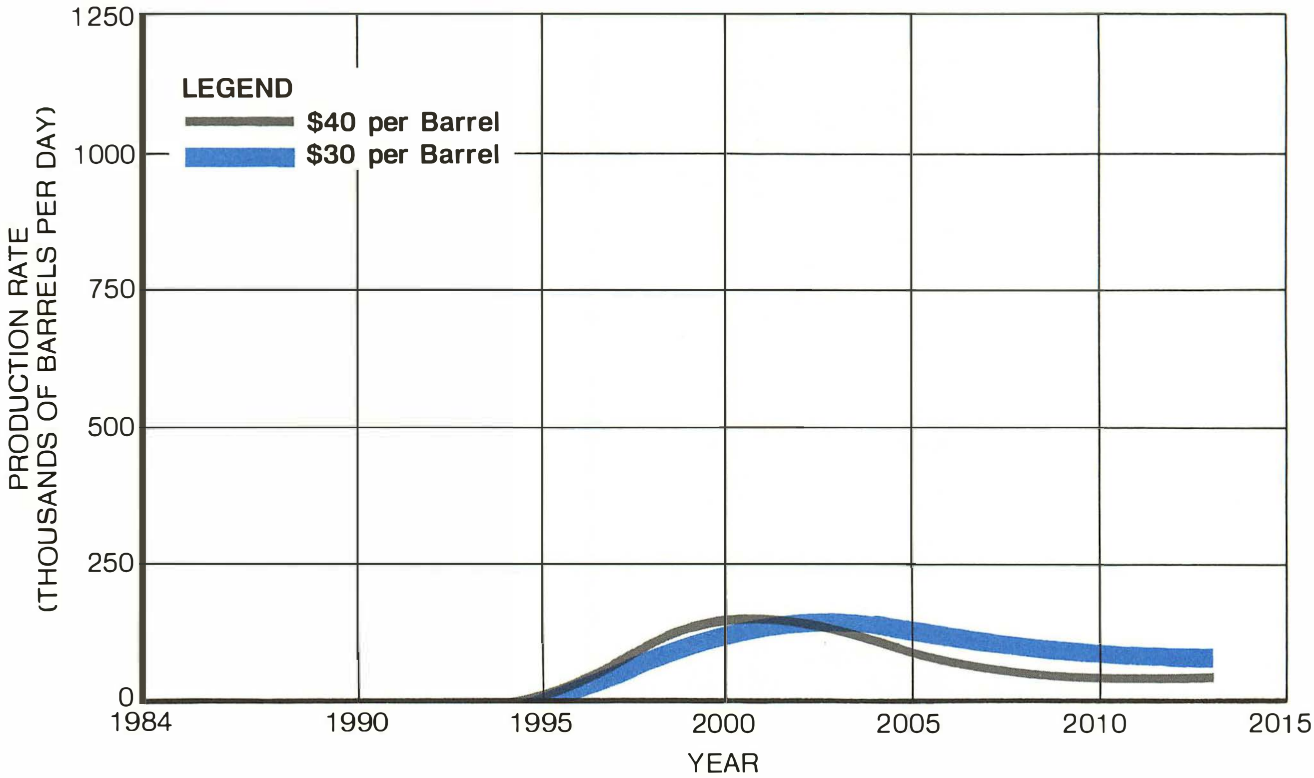


Figure D-9. Sensitivity of Alkaline Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology Case (10 Percent Minimum ROR).

- Sweep efficiency
- Displacement efficiency
- Injectivity
- Chemical cost.

The Task Group then ranked these factors according to the possible magnitude of the effect they could have on the base case potential. In order of significance for positive and negative effects, the factors were judged to be:

Positive

Broader Application
Improved Sweep
Better Oil Displacement
Improved Injectivity
Less Expensive Chemicals

Negative

Fewer Applications
More Expensive Chemicals
Poorer Injectivity
Poorer Oil Displacement
Poorer Sweep

The range of application is at the top of both lists. This reflects two things. First, that the number of reservoirs in which the process turns out to be technically viable is potentially the biggest factor determining ultimate recovery. Second, that the Task Group was equally divided as to whether the Implemented Technology Case screening criteria were too generous or whether technology improvements would gradually allow these limits to be relaxed. Overall this is the largest area of uncertainty.

The remaining factors rank in inverse order on the positive and negative lists. The Task Group felt that it was unlikely that sweep efficiency, displacement efficiency, and injectivity would be worse than in field tests conducted to date. Each of these factors has significant potential for improvement. This likelihood was judged to be highest for sweep efficiency and lowest for injectivity improvements.

It was judged to be unlikely that chemical costs will be less than specified for the base case. Conversely, there is the real possibility that costs will be higher than projected, especially when considering the requirements for the Advanced Technology Case surfactant. Hence, more expensive chemicals rank second on the list of negative factors.

Appendix E

Miscible Flooding

The purpose of this appendix is to define the potential of miscible displacement processes for increasing recovery from known oil reservoirs in the United States. Although various fluids have been and may continue to be used, miscible flooding is becoming dominated by the use of carbon dioxide (CO_2) as the miscible solvent. This study also recognizes that hydrocarbon or nitrogen solvents will be used in some reservoirs.

Two levels of technology were addressed in this study. Implemented technology was based on the application of processes and methods that have been demonstrated in actual field conditions, and which industry is currently applying on a full-scale basis. Advanced technology was assumed, for the purpose of this study, to become available in 1995. At that time, the projected advanced technology with its inherent benefits would become the typical mode of operation for the remainder of the study period.

The potential of the miscible processes for the recovery of oil from known U.S. reservoirs is assessed at 5.5 billion barrels of oil with the Implemented Technology Case at the base economic case condition of a nominal $30 per barrel oil price and a 10 percent minimum discounted cash flow rate of return (minimum ROR) investment criterion. This recovery is tertiary, i.e., after waterflood. Other economic assumptions include constant dollars and no Windfall Profit Tax. Under these conditions, the daily average producing rate from miscible flooding could reach 500 thousand barrels per day shortly after the year 2000, with a steady buildup from the current rate of some 50 thousand barrels per day. Table E-1 summarizes the potential ultimate enhanced oil recovery (EOR) assessed at various oil prices with all other assumptions consistent with the base economic case.

Advanced technology applied from 1995 forward results in the potential listed in Table E-2. Economic assumptions are consistent between Tables E-1 and E-2.

The West Texas/East New Mexico region of carbonate reservoirs has significant potential for miscible flooding. This area is currently being developed using the large CO_2 supplies from natural sources in Colorado and New Mexico. This region contributes 3.1 billion barrels, or about 60 percent of the potential EOR by miscible flooding from all known reservoirs in the United States, in the Implemented Technology, base economic case. Of the potential peak rate of 500 thousand barrels per day, this region would contribute about 330 thousand barrels per day.

State-of-the-Art Assessment

Background of Miscible Flooding

Injection of a gas into an oil reservoir to improve oil recovery is not a new idea. Traditionally, natural gas or water has been injected to delay the decline of reservoir pressure as oil is produced. In addition to delaying pressure decline, the injected gas normally displaces oil and drives it to producing wells. This displacement of oil by gas usually has been conducted at such low pressures that immiscible displacement of the oil by the gas occurred. Immiscible displacement by hydrocarbon gas has usually proved to be a relatively inefficient process.

Beginning in the early 1950s and continuing into the 1960s, an improved method of

TABLE E-1

MISCIBLE FLOODING
ULTIMATE RECOVERY AND PEAK PRODUCING RATE
IMPLEMENTED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
20	2.0	200	1998-2003
30	5.5	500	2003-2005
40	7.0	650	2003-2004
50	7.7	820	1999-2003

TABLE E-2

MISCIBLE FLOODING
ULTIMATE RECOVERY AND PEAK PRODUCING RATE
ADVANCED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
30	6.1	625	2006-2007
40	7.8	835	2006-2007
50	8.5	980	2002-2003

recovery by injection of hydrocarbon gases or liquids, called miscible displacement, was developed and pilot tested. In miscible displacement, the normally gaseous material is injected at such a high pressure and is of such a composition that it acts as a solvent for the oil. Under these conditions, interfaces and capillary forces between the oil and gas are essentially eliminated.

Under miscible displacement conditions, the injected solvent can displace most of the oil from the pore space of the reservoir rock contacted by the solvent. By displacing enough water to contact and mobilize the oil, a miscible injection fluid can displace the residual oil left in the water-swept portion of a waterflooded reservoir.

Hydrocarbon Miscible Flooding

Various miscible displacement processes using hydrocarbon gases and liquids have been extensively investigated in the laboratory, and there have been many field tests of hydrocarbon miscible flooding processes. Based upon the knowledge accumulated from these projects, hydrocarbon miscible flooding has proven to be a technically effective EOR process. It appears that hydrocarbon miscible flooding will play a very limited role in future oil recovery, however. The volume of oil recovered relative to the volume of hydrocarbons injected is inadequate to offset the current and projected high value of the hydrocarbon solvents. Generally, hydrocarbon injection fluids also are in short supply and will not be available in the quantities required for large-scale oilfield flooding in the United States. There are existing exceptions such as the South Pass Block 61 Project offshore Louisiana and special cases, such as Prudhoe Bay in Alaska, where hydrocarbon miscible floods are underway.

Nitrogen Miscible Flooding

Conditions that favor nitrogen miscibility include relatively high pressures and temperatures and light or volatile oils having a reasonable balance between methane and liquid petroleum gas components. Reservoirs fulfilling these conditions are usually deep and, under these conditions, nitrogen and CO_2 miscibility pressures may be comparable. Nitrogen miscibility pressures are generally higher than for methane, and the distances required to achieve miscibility by dynamic processes are somewhat longer. However, nitrogen may be a more cost effective miscible solvent than either CO_2 or hydrocarbon gases. Nitrogen has been selected as the miscible solvent for several projects, such as that at Jay-Little Escambia Creek Field, Florida. Compared to CO_2, however, nitrogen miscible flooding has relatively small potential. Appendix H presents an assessment of this potential.

Oil Recovery Using Carbon Dioxide

CO_2 gas is a favorable alternative injection fluid for increasing oil recovery. Like hydrocarbon gases, CO_2 can be used as either an immiscible or a miscible displacing agent, depending upon reservoir conditions and the properties of the crude oil.

Immiscible CO_2 Flooding

CO_2 is highly soluble in crude oil, and the solubility increases as pressure is increased. The dissolved CO_2 swells the oil and increases its volume so that the concentration of hydrocarbon fluid that remains trapped in the reservoir pores is reduced. Dissolved CO_2 also reduces the oil viscosity. These swelling and viscosity-lowering phenomena make the oil flow more easily, and can result in better recovery.

Because of these characteristics, CO_2 may cause an immiscible displacement of oil that is more efficient than immiscible displacement with other gases, such as natural gas or flue gas. Immiscible displacement of oil by CO_2 may be applicable in reservoirs that contain moderately viscous oils of less that 25 °API gravity. Little information has been reported on immiscible CO_2 flooding, and at this time it is not expected to make a major contribution to U.S. oil production.

Miscible CO_2 Flooding

The bulk of industry research and field testing of CO_2 has been directed toward miscible displacement. This method of using CO_2 appears to have significantly greater potential for enhanced oil recovery than either immiscible flooding or other miscible methods.

Miscible displacement between oil and CO_2 works by the extraction of hydrocarbons from the oil into the CO_2 and by the dissolving of CO_2 into the oil. At a high pressure chiefly determined by oil and gas compositions and temperature (the minimum miscibility pressure, MMP), interphase mass transfer can occur to such a degree, and so alter the composition of the invading gas front, that interfaces between the oil-rich and CO_2-rich phases disappear and miscibility results. Miscible displacement by CO_2 is a dynamic process because CO_2 is not directly miscible with oil on first contact. Mixing due to flow in the reservoir tends to alter and destroy the miscible composition, which must continually be reestablished. The pressure at which miscible displacement occurs depends upon reservoir temperature, oil composition, and purity of the CO_2. The presence of methane or nitrogen can significantly increase the pressure required for miscibility, whereas the presence of hydrogen sulfide (H_2S) or hydrocarbons of molecular weight greater than ethane can reduce the pressure requirement.

Research has been directed to defining the mechanism by which miscibility occurs and the factors that influence the MMP. Laboratory research using reservoir rocks has also demonstrated that at pressures above the MMP, CO_2 will displace most of the residual oil left after waterflooding. Research and field tests using miscible injection fluids have shown that the sweep efficiency of an injected solvent depends upon the viscosity ratio between the oil and solvent, upon the degree of gravity segregation between the solvent and oil that is caused by density differences, and upon the spatial distribution of the permeability.

As oil viscosity increases relative to the viscosity of CO_2, there is a greater tendency for the CO_2 to channel, or finger, through the reservoir, thereby reducing the volumetric efficiency of contact with the oil. The influence of an unfavorable viscosity ratio (oil viscosity greater than CO_2 viscosity) is compounded by heterogeneity of the reservoir rock, whereby the normal tendency for injected fluids to flow through the more permeable sections of the rock is aggravated.

Injection of water, either simultaneously or in small, alternate slugs with the CO_2, has been field tested as a potential technique for improving volumetric sweep efficiency. The water interferes with the flow of CO_2 through the reservoir rock and, for practical purposes, causes the CO_2 to behave as if it had a higher viscosity. Most of the full-field operations will use alternating slugs of water and CO_2. This is referred to as the WAG process, an acronym for water alternating with gas.

Gravity segregation of the injected fluid is another factor that reduces volumetric sweep efficiency in miscible flooding. The densities of oil and CO_2 are often similar at reservoir conditions. This tends to minimize segregation between these fluids in reservoirs that have not been waterflooded. In reservoirs that have been waterflooded or have had water injected with the CO_2 to counteract the effects of viscosity ratio and permeability stratification, the density contrast between the water and CO_2 may result in gravity segregation, which causes the CO_2 to flow preferentially in the upper part of the reservoir. The severity of segregation also depends upon the effective vertical flow permeability, injection rate, pattern spacing, and the distribution of horizontal permeability variations in the reservoir.

Project designs attempt to use the CO_2 in the most cost-effective manner. Currently, some designs call for a predetermined volume of CO_2 to be injected as a slug and followed by continuous water injection. The water immiscibly displaces the CO_2, leaving part of it in the reservoir. In some cases, prior water injection may be necessary in order to raise the reservoir pressure above that required for miscibility. Other designs call for alternating CO_2 and water in the same injection well (WAG process) until the desired volume of CO_2 has been injected, in order to improve volumetric contact. After the alternating cycles of CO_2 and water, continuous injection of water is commenced. Still other designs call for the alternate injection of water and CO_2 to be followed by the alternate injection of water and another less expensive gas, such as flue gas or nitrogen, in order to displace CO_2, maintain miscibility at the trailing edge of the CO_2 slug, and reduce CO_2 requirements.

Numerous factors can influence the magnitude of incremental oil recovery and the volumetric ratio of CO_2 injected to incremental oil recovered. Many of these factors will vary from reservoir to reservoir, and some may be influenced by the extent of prior waterflooding. The degree of reservoir stratification (and other heterogeneities) influences the miscible sweep efficiency, or the ability of the CO_2 to contact the reservoir volume effectively. The degree of gravity segregation of the CO_2 also influences sweep efficiency, and the severity of gravity segregation depends strongly upon the ratio of vertical to horizontal permeability, which also can vary appreciably among and within reservoirs.

Other factors that affect incremental recovery include the waterflood residual oil saturation, the final oil saturation in the CO_2-flushed region (the miscible residual saturation), the efficiency with which the displaced oil can be captured by the producing wells, and the loss of displaced oil due to resaturation of low oil-saturation zones. All of these factors also affect the CO_2 utilization, which is a measure of the gross CO_2 (including recycled solvent) that must be injected to recover an incremental barrel of oil.

Field Tests Using CO_2

A number of field projects have been undertaken to demonstrate CO_2 miscible flooding performance for specific reservoir conditions. Six of these projects are discussed in the following paragraphs, and for reference Table E-3 compiles average reservoir data and recovery estimates. The results of these projects and numerous other tests and publications were considered by the Miscible Displacement Task Group in order to define Implemented Technology Case. The reader should refer to the bibliography for additional information.

Slaughter Estate Unit—Slaughter Field, Texas

The CO_2 miscible test at Slaughter Estate Unit was conducted using a WAG ratio of 1.0 reservoir barrel of solvent per reservoir barrel of water in a waterflooded pilot area of the Slaughter Field. Field production is from the Permian-Age San Andres carbonate formation, which is moderately oil-wet and has a connate water saturation of 8 percent. As of July 1981, the enhanced oil recovery attributed to CO_2 flooding was 95,650 barrels representing 14.9 percent of the oil originally in place (OOIP) in the pilot area. The ultimate incremental recovery was projected to reach 20 percent OOIP, for a total ultimate recovery from the pilot area, including primary and secondary production, of 70 percent OOIP.

Planning the CO_2 miscible test began in the early 1970s. This led to the drilling in 1972 of the 12-acre, double five-spot pilot in an area of the field that had not been waterflooded. Waterflooding and CO_2 flooding operations for the pilot were conducted in separate steps so that the performance would allow evaluation of the CO_2 process in a waterflooded reservoir. After waterflooding, the injection of the miscible solvent began in August 1976 using a gas stream from the nearby Slaughter gasoline plant. This gas consisted of 72 percent CO_2 and 28 percent H_2S. The H_2S acts in the same manner as CO_2 in displacing oil from a reservoir, and may lower the MMP relative to pure CO_2. Despite the corrosive nature of the injected fluids, well problems were minimal.

TABLE E-3

CO_2 MISCIBLE PROJECT SUMMARY DATA

							Process Results*			
Field or Unit	Formation	Depth (feet)	Porosity (%)	Permeability (md)	Net Pay (feet)	Oil Viscosity (cp)	HCPV CO_2 (%)	WAG Ratio	Recovery (% OOIP)	CO_2 Utilization (Mcf/bbl)
Slaughter Estate Unit	San Andres	5,000	12	6	75	2.0	26	1.0	16 (20)	5 (4)
Denver Unit	San Andres	5,100	12	5	141	1.2	–	0	–	–
SACROC	Canyon Reef	6,700	7	19	213	0.4	–	0	3	15-20
North Cross Devonian†	Devonian	5,400	22	5	100	0.4	100+	0	15 (44)	11 (9)
Little Creek	Tuscaloosa	10,750	23	75	30	0.4	160	0	30	27
Rock Creek	Big Injun	2,000	22	20	32	1.9	27	0	4	13

*Numbers are latest reported. Those in ( ) are projected ultimate EOR.
†This field was not waterflooded prior to start of CO_2 injection.

Production of incremental oil began in October 1977, when CO_2 injection amounted to approximately 10 percent of the hydrocarbon pore volume. Solvent injection continued until October 1979, when it totaled 26 percent of the hydrocarbon pore volume. At that time chase gas injection started. Residue gas from the Slaughter gasoline plant and nitrogen have served at different times as the chase gas. Chase gas was also injected at a WAG ratio of 1.0 reservoir barrel of CO_2 per reservoir barrel of water initially, but was increased to 1.33 reservoir barrels of CO_2 per reservoir barrel of water in March 1981 to control chase gas mobility and thus reduce the quantity of gas being cycled. Only water has been injected since July 1982.

Denver Unit—Wasson Field, Texas

A pilot in the Denver Unit of Wasson Field indicated good recovery and sweep efficiency by CO_2 miscible displacement after waterflooding. The results were used in planning the full-scale reservoir flooding program. Denver Unit production comes from the San Andres formation, which is found at a depth of about 5,100 feet. The ultimate recovery from the Denver Unit by primary depletion and waterflooding is estimated to be 880 million barrels or 40 percent OOIP. The residual oil saturation in the swept regions is about 40 percent pore volume.

The CO_2 pilot test was conducted between 1977 and 1980 at a location that had representative reservoir properties and was depleted by waterflooding. The pilot was comprised of five closely spaced wells within a one acre area. Pilot evaluation was based on measurements of in situ oil saturations and saturation changes over time, rather than on oil production. The pilot wells consisted of a CO_2 injector, three logging observation wells, and a fluid sampling well. The observation wells were about 100 feet from the injector and equally spaced around it. The fluid sampling well was near one of the observation wells. The logging observation wells were equipped with fiberglass casing so that open-hole logging tools could be used.

Extensive pre-pilot coring and testing showed the pilot area was completely swept of waterflood oil. Pressure coring of one of the logging observation wells verified that the residual oil saturation was 40 percent pore volume. In addition, the CO_2 injector and fluid sampling well were pumped for several weeks and produced all water.

Before injecting CO_2 a preflush of 165,000 barrels of 65,000 parts per million (ppm) chloride brine was injected for the purpose of optimizing formation water salinity conditions for logging accuracy. Next, 300 million cubic feet (MMcf) of CO_2 was injected at rates starting at 1,700 thousand cubic feet (Mcf) per day and increasing slowly to 2,800 Mcf per day. This CO_2 slug was followed by 179,000 barrels of 65,000 ppm chloride brine injected at an average rate of 600 barrels per day.

Pilot evaluation was conducted by periodic logging of the observation wells with open-hole logging devices to monitor saturation changes and CO_2 frontal advance. The logging results were confirmed by a series of six pressure core holes drilled at the completion of the pilot to quantitatively determine saturation changes throughout the pilot area. The pressure core results confirmed significant oil desaturation had occurred in all layers and that oil displacement is a function of CO_2 throughput.

The fluid sampling well, which was only operated for several hours duration at each sampling period, provided valuable information that confirmed some of the fluid phase behavior effects that have been noted in the laboratory. In addition, the fluid sampling well results confirmed that good oil banks were mobilized by the CO_2 in the water-swept zones.

From the pressure cores, the nature of the remaining oil was also evaluated. The minimum oil saturation remaining after CO_2 displacement in the most thoroughly swept layers was 8 percent pore volume. This residual oil, which was found throughout the pilot area, consists of only the heaviest, tar-like fractions of the normal 34 ° API crude oil.

North Cross (Devonian) Unit—Crossett Field, Texas

High oil recovery is being achieved in the tight, high porosity, Devonian chert formation at the North Cross Unit of Crossett Field, Texas. This is an example of CO_2 flooding of a reservoir that had not been previously waterflooded. Continuous CO_2 injection has been underway for over 11 years, with a steady 18 MMcf per day of CO_2 injected into eight wells. The CO_2 injectant is obtained as a waste product from a large hydrocarbon gas treating plant in the West Texas Delaware-Val Verde basin.

Poor water injectivity made this field unsuitable for waterflooding and precluded the use of the WAG process during CO_2 flooding. The low permeability and consequent low CO_2 injectivity has had beneficial effects on vertical and areal sweep efficiencies. Pressure coring in this unit has confirmed excellent vertical conformance of the CO_2 and displacement efficiency is high. The residual oil saturation after miscible flooding was found to be only a few percent for this light, 44 °API crude oil.

The oil produced by CO_2 now amounts to 8 million barrels, or 15 percent of the OOIP in the unit. Average CO_2 utilization is 11 Mcf per barrel. Oil production rates remain high, while the CO_2:oil ratio continues to increase. Continued CO_2 injection is expected to exceed 100 percent hydrocarbon pore volume and result in enhanced oil recovery of about 44 percent OOIP.

SACROC Unit—Kelly Snyder Field, Texas

A pilot test was initiated in 1974 in a completely waterflooded area of SACROC Unit to test the recovery potential for CO_2 miscible flooding. Several factors, primarily poor confinement of CO_2 to the pattern area, are thought to have contributed to the marginal performance of this pilot.

The SACROC pilot consisted of two 40-acre five-spots with two producers and six injectors. CO_2 injection started in January 1974, and response was noted in one producer within one week. The other producer responded after about two months. CO_2 was injected as a slug, without alternating quantities of water. The CO_2 slug was followed by water injection. Oil production was still increasing when CO_2 injection ended, but fell off rapidly afterwards. The test was discontinued at the end of 1975.

A total of 2.3 billion cubic feet (Bcf) of CO_2 was injected during the test, and it was estimated that between 32 and 57 percent was captured by the pilot patterns. Production was 64,000 barrels of oil or 3 percent of OOIP, and CO_2 utilization was estimated as 15 to 20 Mcf per barrel, depending upon estimated capture factor. Based on this test, CO_2 flooding was judged to be uneconomic in the waterflooded areas of SACROC Unit for the oil prices existing at the time.

Little Creek Field—Mississippi

A CO_2 pilot in the Tuscaloosa sandstone reservoir at Little Creek Field of southwestern Mississippi showed good recovery by miscible displacement. The entire reservoir, including the pilot area, had previously been depleted by waterflooding.

In February 1974, CO_2 injection started in a 40-acre pilot that was located on the east edge of the field. The pilot pattern was essentially one-fourth of an inverted nine-spot with the CO_2 injector next to the field boundary. This location for the injector forced the CO_2 to sweep toward the three pilot producers. Water injection was continued in five wells, outside the pilot area, to control the migration of fluids out of the test pattern.

Injection ended in February 1977. The total pilot oil production through March 31, 1978, was 124,000 barrels, 30 percent of the estimated OOIP. A total of 1,590 MMcf of purchased CO_2 had been injected, and 1,783 MMcf of produced gas had been recycled. The gross CO_2 utilization was 27 Mcf per barrel.

Rock Creek Field—West Virginia

The Rock Creek Field, located in Roane County, West Virginia, has produced from the Pocono Big Injun sandstone since 1906. The reservoir lies at an average depth of 1,975 feet. Prior to CO_2 injection, approximately 20 percent OOIP had been recovered by solution-gas drive and gas recycling. Oil saturation after primary recovery was 34 percent pore volume and initial connate water saturation was 50 to 55 percent pore volume. Primary plus waterflood recovery was 3,430 barrels per acre.

The pilot area consisted of two five-spots containing 19.65 acres. The area was surrounded by 13 water injection wells, which were used to maintain pressure and to contain the CO_2 within the pilot area. The project was initiated in June 1976, and completed in December 1982. Total CO_2 injected was 600 MMcf followed by 48,000 barrels of water. CO_2 injection was not alternated with water. It is estimated that 38.6 percent of these fluids actually entered the patterns. Oil recovery by CO_2 injection was 879 barrels per acre and the estimated CO_2:oil ratio was 13.5 Mcf per barrel.

Sources and Transportation of Carbon Dioxide

Perhaps the most significant change affecting the use of the CO_2 miscible process to take place since 1976 is the development of large CO_2 resources for oilfield use. Most of this CO_2 supply is coming from naturally occurring underground sources in Colorado and New Mexico. Major defined natural sources are estimated to contain at least 40 trillion cubic feet (Tcf) of CO_2 reserves. The oil industry is also obtaining some CO_2 from flue gas discharged at electric power generating plants and as a byproduct from chemical plants and other industrial sources. In the future the recycling of produced CO_2 gas will become increasingly important. Several important natural and industrial sources of CO_2 are discussed below. Figure E-1 shows the relative location of known CO_2 natural sources, pipelines installed, and several industrial source locations.

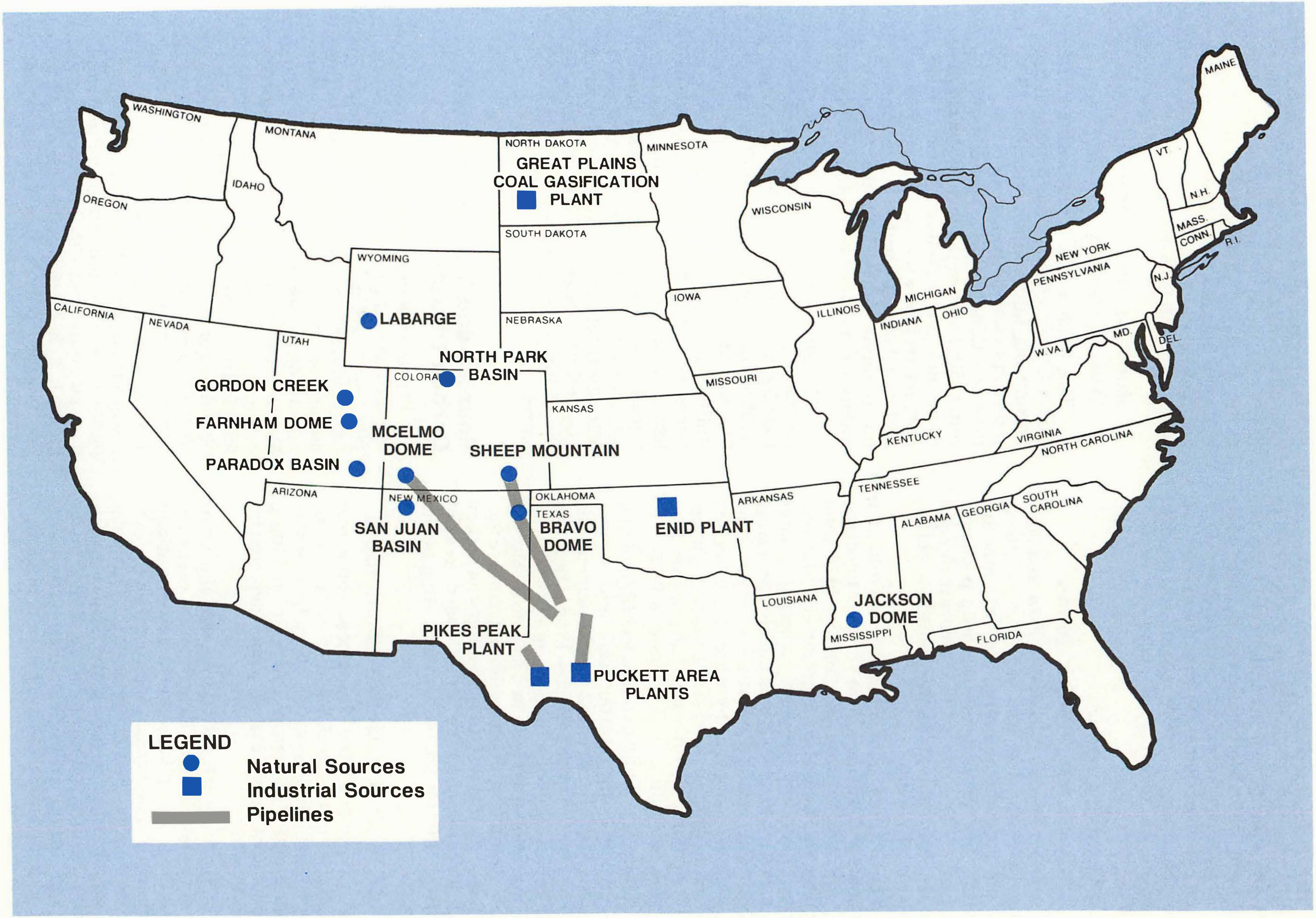


Figure E-1. Major CO_2 Sources and Pipelines.

Natural CO_2 Sources

CO_2 reserves are estimated to be 1 Tcf at Sheep Mountain in southeastern Colorado. Produced CO_2 is 97 percent pure, the principal impurities being nitrogen, methane, and other light hydrocarbons. At the present time approximately 22 wells have been drilled at Sheep Mountain. The facilities for processing the CO_2 are located at each drillsite. These facilities include provision for heating the produced CO_2 streams to prevent hydrate formation and to vaporize any liquid CO_2 that may have formed. Also included are dehydration facilities and compression for delivery through the gathering system to the pipeline.

The CO_2 pipeline from Sheep Mountain to Seminole Field in West Texas was completed and delivery started in March 1983. The first 183 miles of the 408-mile Sheep Mountain Pipeline has a capacity of 330 MMcf per day. At a point near Bueyeros, New Mexico, the line diameter is expanded to accommodate production from the Bravo Dome CO_2 Field. Capacity in this section is 500 MMcf per day.

The one million acre Bravo Dome Unit in northeastern New Mexico is estimated to have reserves of more than 6 Tcf. The Bravo Dome Unit encompasses only about half of the acreage thought to be productive. Facilities for dehydration and compression of the produced CO_2 are presently under construction. The first phase of plant development, completed around the end of 1983, is capable of handling up to 90 MMcf per day. This capacity is dedicated to the Sheep Mountain Pipeline for delivery to the Seminole Field. The remainder of the processing facility is expected to be completed in late 1984 or early 1985 and is being designed to dehydrate and compress an additional 250 Mcf per day of CO_2. An additional pipeline from Bravo Dome to Levelland, Texas, having a 400 MMcf per day capacity, is being planned.

The McElmo Dome and Doe Canyon fields have proved reserves greater than 10 Tcf of high-purity CO_2. Of the two, McElmo Dome is the larger, with reserves of 8.4 Tcf of 97 percent pure CO_2. Drilling in McElmo Dome began in 1976, and 26 productive wells have been drilled to the present time. At startup, 28 wells at 11 cluster locations will provide 350 MMcf per day of production. As additional capacity is needed, more wells and facilities will be added to reach an anticipated total of 150 wells. McElmo Dome, when fully developed, is expected to have a producing capacity approaching 1 Bcf per day of CO_2.

Production from the McElmo Dome-Doe Canyon area will be delivered to the Denver City area of West Texas through the 500-mile Cortez Pipeline. Construction of this line was started in the summer of 1982 and was recently completed. Initial design capacity is 650 MMcf per day, but additional pump stations can be installed to raise capacity to approximately 1 Bcf per day. Utilization of this additional capacity is not expected until the late 1980s.

Sufficient drilling has been done at Jackson Dome in Mississippi to prove an estimated 1 Tcf of 98 percent pure CO_2 reserves. Undrilled acreage is thought to have a potential of an additional 2 Tcf of reserves. Plans for Jackson Dome are still being developed. A 90 mile pipeline to transport the CO_2 to southern Mississippi is being considered with a possible further extension into Louisiana. Delivery of CO_2 from Jackson Dome is not likely before 1985.

The LaBarge-Big Piney area in southwestern Wyoming is considered to have CO_2 reserves in excess of 20 Tcf. Wells drilled to date indicate the productive area is extensive, possibly covering several townships. Gas produced from the Madison formation is reported to be about 70 percent CO_2, and Big Horn formation gas is about 90 percent CO_2. The costs associated with processing this relatively impure CO_2 are high. The area is also environmentally sensitive and requires special care during development activities.

Other potential sources of CO_2 exist at Gordon Creek, Farnham Dome, and in the Paradox Basin in Utah, in the North Park Basin of north central Colorado, and in the San Juan Basin of northwestern New Mexico.

CO_2 from Industrial Sources

In the past, CO_2 from nearby field gas processing plants has been used as a major source of miscible solvents. Early West Texas commercial CO_2 miscible projects at SACROC Unit and at Twofreds Field used CO_2 byproduct from gas processing plants in the Val Verde and Delaware Basins of West Texas. These sources have been less reliable than desired by the field operator because of the maintenance requirements for the gas processing plants that supply the CO_2.

CO_2 floods in Golden Trend Field and in the East Velma Field, both in Oklahoma, are supplied by separating CO_2 at a fertilizer plant near Enid, Oklahoma. The CO_2 is dehydrated and compressed before entering the 140-mile line. This 33 MMcf per day capacity line started delivery in late 1982, with about half of plant production going to each of the two fields.

The Great Plains Coal Gasification Plant, presently under construction in North Dakota, is also being considered as a CO_2 source. This plant will use lignite from nearby mines for production of about 125 MMcf per day of high-BTU gas, and will also produce about 190 MMcf per day of CO_2 contained in the flue gas. Proposals have called for purifying the CO_2 and transporting it by pipeline to Little Knife Field, approximately 55 miles away, where plans call for about 60 MMcf per day of CO_2 injection. The rest of the CO_2 could continue on by pipeline to projects contemplated on the Cedar Creek and Nesson anticlines. The scheduled completion date for the gasification project is mid-1984. However, commercial sales of the CO_2 would not be expected before 1986.

CO_2 Recycling

Significant progress has been made in developing technology for processing produced CO_2 for reinjection. Current plans for many announced projects include more than 50 percent recycle.

Proven gas treating technologies have been considered and evaluated in every conceivable combination to develop more cost-effective, optimized overall gas separation schemes with minimal technology risks. The published results of these efforts show that various combinations of proven chemical and physical gas treating solvents can be employed in a large CO_2 gas separation project to create a significantly improved overall facility compared to the application of any single technology. These combination processing schemes typically include a bulk acid gas removal process using either a physical or chemical solvent, a selective H_2S removal process, and a chemical solvent type product treating or polishing system.

The other approach has included basic research and proving completely new technologies to accomplish the separation of large quantities of CO_2 from hydrocarbon gas streams. Notable progress has been made in proving and commercializing two basic new types of separation technologies that appear to offer significant economic benefits. First, some distillative fractionation technologies are now available to make several of the separations required in processing a CO_2 gas stream. The widely reported Ryan-Holmes technology is in this class of new technologies. Distillative fractionation systems are being installed at the present time in commercial facilities. Processing systems that utilize permeable membranes to separate large quantities of CO_2 from hydrocarbon gas streams have been widely tested and reported upon. Both spiral wound and hollow fiber type membrane separators have been employed successfully. Membrane separators are currently being installed in commercial CO_2 recovery facilities.

Environmental Considerations

Miscible displacement, as other types of EOR processes, involves the injection of a tailored fluid into an oil-bearing formation. Although the environmental impacts of miscible projects tend to be of a lesser degree than with other types of EOR processes, operators must be aware of the potential problems and ensure that adverse impacts are minimized.

Reservoirs in the final stages of secondary recovery are the largest resource base targeted for miscible projects. Consequently, most of the facilities for the installation of an EOR project will be in place. However, particular attention should be given to potential additional impacts on surface waters, groundwaters, land use, and air quality.

Surface waters and groundwaters can be protected by using available technology for surface and subsurface facilities and by conscientiously maintaining these facilities. Wells used for injection purposes are normally worked over to ensure that the fluids enter the target formation, and that groundwaters are protected. Surface waters are protected by the proper maintenance of production facilities to prevent spillage or leakage.

Land use impacts will normally be restricted to the reservoir area. New wells, injection lines, processing facilities, additional gathering lines, and production facilities may be needed to accommodate the injection and additional production. In addition, use of the land will be extended for a period of several years since the economic life of the reservoir will be extended to produce the oil reserves that are developed. Land use impacts can be mitigated by maximum use of existing wells, roads, and facilities.

Atmospheric emissions will be generated by any additional processing facilities that are installed. Plants may be built to process the produced gases to remove the solvent for reinjection. Compressors, turbines, and boilers in such plants are sources of air pollutants that may require best available control technology or offsets under local, state, or federal regulations.

Other considerations are the unique geographic environments that may be encountered. Areas considered as "wetlands" are extremely active in the biological sense, and special precautions are advised to protect the biota and the natural balance. The fragility of the Arctic environment requires that the acute awareness that has evolved during conventional recovery operations be carried forward through proposed miscible recovery projects. Additional facilities in such areas must be thoroughly planned to mitigate the additional environmental impact that may accrue.

Major CO_2 pipelines that transport CO_2 from source regions to major areas of use will normally require the preparation of an Environmental Impact Statement (EIS) prior to pipeline permit approval. To support the EIS, biological and archeological surveys are conducted along the proposed rights-of-way. Pipeline construction and operation may affect flora, fauna, archeological sites, and waterways. These impacts must be recognized and action taken to mitigate them to the maximum extent possible.

Overall, the majority of environmental problems encountered in miscible displacement projects are not new to the industry, but extensions or modifications of the same problems encountered in conventional primary and secondary operations. Technology advances and the dissemination of environmentally relevant information have helped mitigate the environmental impacts associated with miscible displacement. Further advances and more intensive application of such knowledge will continue to do so in the future.

The reader is also referred to Appendix G, where a more detailed discussion of the environmental impacts of miscible displacement is presented.

Screening Criteria

Data Review Procedures

The U.S. Department of Energy (DOE) reservoir data base was used as the starting point for this study to estimate potential recovery from the miscible flooding process. This information resource, which contains basic reservoir data, was compiled, edited, and reviewed for the purposes of the present study through a cooperative effort on the part of the Department of Energy, the Coordinating Subcommittee of the NPC Committee on Enhanced Oil Recovery, other industry participants, and consultants to DOE. A full discussion of data base composition and review is given in Chapter Three. The present discussion is limited to a summary of how these data were used by the Miscible Displacement Task Group to define and evaluate miscible candidate reservoirs.

Some data required by the miscible screening procedure remained unavailable after all data base reviews. These missing data were of three types: essential data, data required for the miscible analytical model that was missing for particular reservoirs (but generally available for most), and values that were generally unavailable for any of the reservoirs. Reported data for five variables were essential for the miscible prediction and were not estimated by correlations: OOIP, oil gravity, reservoir depth, reservoir pressure, and net thickness. Either the productive area or porosity was also essential. Reservoirs lacking any of these six essential data were excluded from further consideration.

Where a value required for the predictive model was absent for a specific reservoir, a procedure was developed to estimate the missing value from other properties of the same reservoir. A series of empirical correlations and engineering relationships, drawn from the literature, were validated for this data base against the reservoirs in the data base for which all the required elements were present. In some cases, engineering correlations were developed. These correlations and engineering relationships were used to provide acceptable values that would allow reservoirs with missing data to be retained in the analysis. The more important correlations used by the Miscible Displacement Task Group are listed below:

Data Required	Estimated As a Function of
Reservoir temperature	Depth and region
Viscosity of water	Water salinity and temperature
Oil viscosity	Oil gravity, solution gas:oil ratio, and temperature
Initial formation volume factor	Solution gas:oil ratio, temperature, and oil gravity
Residual oil saturation in water-zone	Lithology
Solution gas:oil ratio	Pressure, temperature, API gravity
Recovery factor	Cumulative production, January 1, 1979 production, and reserves-to-production ratio

Values generated by these correlations were identified for attention in the Task Group review. This facilitated review of the data and correction when warranted. These correlations were also used to identify questionable data. Where the required values were present in the data base, an automated procedure was used to assist the manual validation by flagging data values not within 10 percent of the value estimated by the engineering correlations.

For data that were generally unavailable for any reservoirs but were required by the process models, more engineering analysis was required. Ad hoc study groups recommended approaches to generate estimates from data available within the industry. These recommendations were reviewed in detail by the full Task Group and coordinated with the other Task Groups facing similar problems. For CO_2 flooding:

- Minimum miscibility pressure was estimated using a two-step method. The literature supplies correlations of MMP as a function of the molecular weight of the C_{5+} components of the oil. The C_{5+} molecular weight was estimated as a function of oil gravity.
- Relative permeability was estimated by correlation with lithology.
- Residual oil saturation and fractional oil flow at the end of primary/secondary operations were estimated from empirically based assumptions of residual oil saturation in the swept zone.
- Permeability variation (pseudo Dykstra-Parsons coefficient) was estimated from waterflood performance by the cross-correlation of sweep efficiency and mobility ratio (based on the viscosity ratio of oil and water and the ratio of end-point relative permeabilities), and the results of a 100 layer, five-spot, stream tube model.

Selection of Candidates Suitable for Miscible Flooding

The first consideration in selecting reservoirs suitable for CO_2 miscible flooding was that the MMP for reservoir oil and CO_2 be within an achievable range. Laboratory data are available on the miscibility pressure for various crude oils over a range of reservoir temperatures. A correlation has been published by Holm and Josendahl[1] and extended by Mungan[2] that is based on the molecular weight of the C_{5+} components of the reservoir oil (Figure E-2). Another correlation similar to that by Lasater[3] was developed to estimate the C_{5+} molecular weight for various oil gravities (Figure E-3). These two correlations were used to estimate the MMP for all reservoirs in the DOE data base. Reservoirs with oil gravity less than 25 °API were excluded as miscible candidates.

The MMP estimated in this way was manually compared with original reservoir pressure, with a maximum operating pressure estimated using an assumed gradient of 0.6 pounds per square inch (psi) per foot of depth, and with current reservoir pressure, when this datum was available. Each candidate was required to possess an MMP lower than the lesser of the original or (estimated) maximum operating pressure. When the MMP exceeded the current pressure by more than 200 psi, the reservoir review extended to a determination of the validity of the data and/or whether repressuring would be feasible. Actual operating pressure during the miscible flood was assumed to be the greater of the MMP or the current pressure.

Data for reservoirs that cleared this screen were printed on forms to be reviewed by the Miscible Displacement Task Group. The output was checked again for reasonableness, and data necessary to run the miscible predictive model were added to the forms. In certain specific cases, reservoirs were treated as hydrocarbon or nitrogen miscible candidates, both in screening and throughout the subsequent analysis. Based on the preliminary screening, 603 reservoirs were retained for further analysis as miscible candidates.

Process-Dependent Costs

Process-dependent costs that are unique to the miscible flooding analysis include expenses for solvent; investments and operating expenses for produced gas processing and solvent recycling; drilling investments; well workover expenses; and investments for additional surface flowlines. These categories of process-dependent costs are discussed in the context of CO_2 miscible flooding. Appropriate process-dependent costs were also considered for hydrocarbon and nitrogen miscible projects.

CO_2 Supply Cost

The purchase of CO_2 is the major expense for miscible projects. In West Texas and East New Mexico, relatively pure CO_2 is delivered by

[1]Holm, L. W., and Josendal, V. A., "Mechanisms of Oil Displacement by Carbon Dioxide," J. Pet. Tech. (Dec. 1974) 1427.

[2]Mungan, N., "Carbon Dioxide Flooding Fundamentals," J. Can. Pet. Tech. (Jan.-March 1981) 87.

[3]Lasater, J. A., "Bubble Point Pressure Correlation," Trans., AIME (1958) 379.

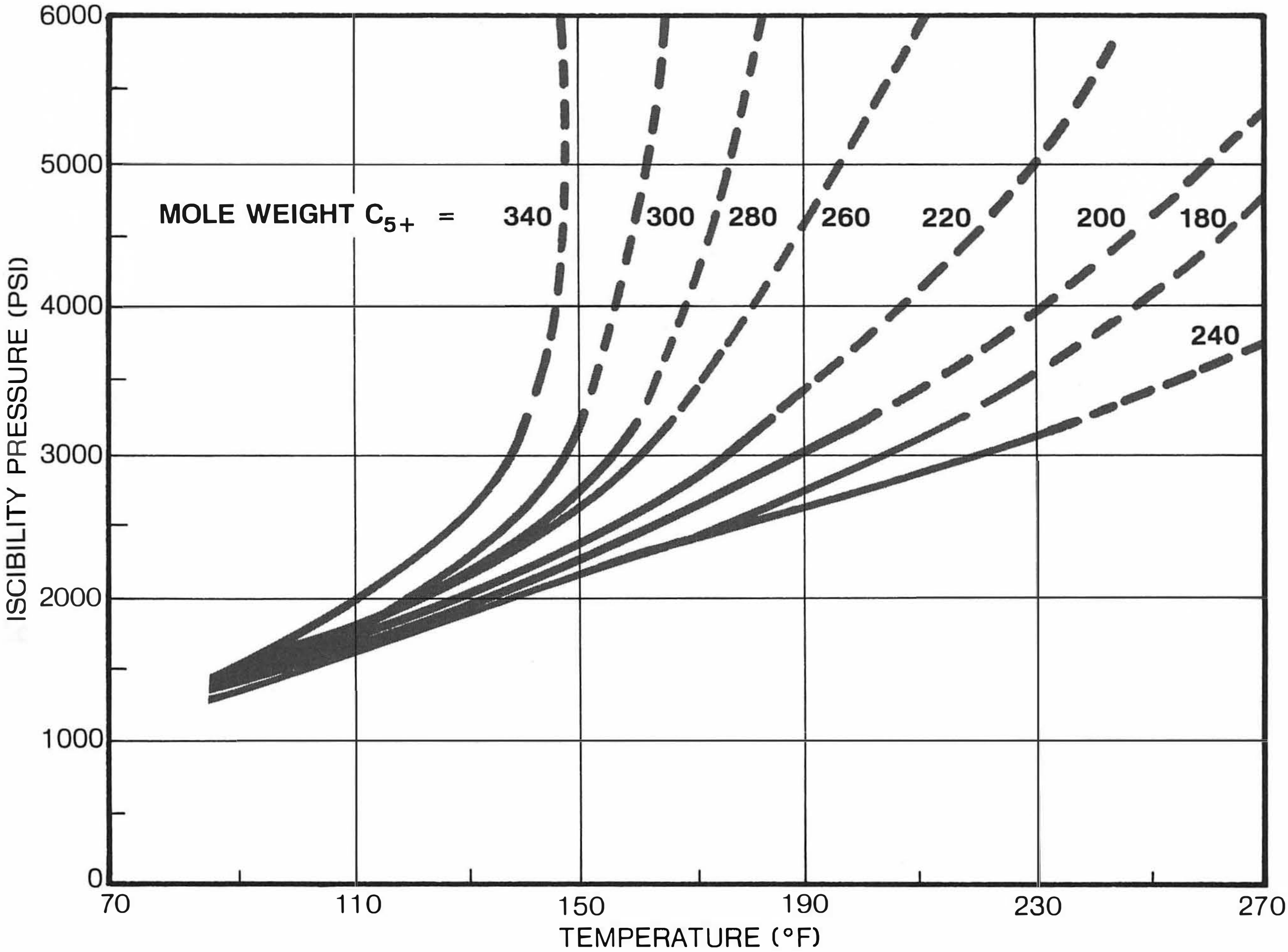


Figure E-2. Correlation for CO_2 Minimum Pressure as a Function of Temperature.
Adapted from Mungan, N., *Carbon Dioxide Flooding Fundamentals*, J. Can. Pet. Tech. (Jan.-Mar. 1981).

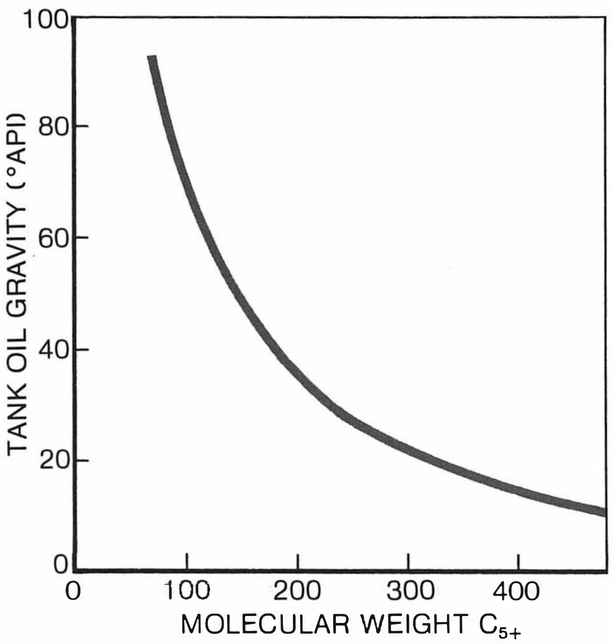


Figure E-3. Molecular Weight C_{5+} vs. Tank Oil Gravity.

pipeline from distant sources. In the West Texas area, CO_2 prices were assumed to be $1.25 per Mcf at the nominal $30 per barrel oil price of the base economic case. This price was assumed to cover the costs and investments (including amortization) for the pipelines and CO_2 source development. Costs for CO_2 were varied, in the study, for different project locations and sources, as shown in Table E-4. The most expensive CO_2 was from industrial sources, and was assumed to cost $2.50 per Mcf including pipeline costs. For the base economic case, CO_2 costs varied between these limits depending upon the geographic location of the project. For the different oil price cases, CO_2 prices were adjusted by an energy cost factor relative to the CO_2 price for the base economic case. Hydrocarbon and nitrogen costs were treated separately for the specific projects involved.

CO_2 Injection Plant Investment

The major capital investment for a CO_2 project is the processing and recycle plant that

TABLE E-4

PURCHASE PRICE OF CO_2 OR OTHER INJECTANT

Zone	Region	Calculation	Cost ($/Mcf)*
1	W. Texas, E. New Mexico, and Utah	$0.50 + 0.025 × (oil price)	1.25
2	Mississippi	(Cost, Zone 1) × 1.25	1.56
3	Florida† and Alaska‡	$1.00	1.00
4	Wyoming and N. Colorado	(Cost, Zone 1) × 1.50	1.88
5	Louisiana	(Cost, Zone 1) × 1.20	1.50
6	All other states	(Cost, Zone 1) × 2.00	2.50

*Cost at nominal crude oil price of $30 per barrel.
†Cost for nitrogen.
‡Cost for compression and injection of hydrocarbon gas.

separates the produced CO_2 and hydrocarbon gas mixture. Facilities are also required to compress the CO_2 to the required injection pressure. These investments are incremental to investments for the normal field development for conventional secondary recovery, and have been considered in these economic calculations.

A plant to separate the produced natural gas and CO_2 stream is often included in a CO_2 project. The decision on whether or not to build such a plant is based on the value of the hydrocarbons and CO_2 recovered for sale or reinjection. This was assumed to be an independent investment decision and the investment was not included in this study. Compression facilities are required to inject produced CO_2. Cost for these facilities are included in the economics for each project. A typical recycle plant as used in this study would include the following systems:

- Gas/liquid separation
- Dehydration of the gas
- Compression for reinjection.

Investment costs were developed as a function of the peak total gas production. For smaller fields with a peak gas production of less than 30 Mcf per day it was assumed that a plant would be built in the area and shared with another project. (Figure E-4 shows the investment costs used.)

Investments for Well and Surface Equipment

Additional drilling may be required to replace old wells that are unserviceable for CO_2 injection or production, or to reduce well spacing, and hence pattern area, so that an acceptable project life can be achieved. Cost for conversion of existing wells to CO_2 injection service were included. It was assumed that all wells would require workovers during the project life at an average rate of 0.25 workovers per well per year. This rate is about twice that for normal waterflood operations and was considered necessary because of the corrosive effects of CO_2/water mixtures.

Piping and valves for distribution and gathering systems in the fields are a third category of investment. Either a specific investment assumption was made or an average investment per pattern for CO_2 distribution and produced fluid gathering systems was calculated as a default.

Operating Expenses

Fixed production operating expenses for miscible flooding were assumed to be the same as a secondary waterflood. Items included are discussed in detail in Appendix C. Fixed and variable operating expenses were included for the compression and injection of CO_2. These were based on current industry costs for fixed plant operation and volume of CO_2 injected.

Process Analysis Procedures

The Miscible Predictive Model

The predictive model for miscible flooding, CO2PM, was developed for the Department of Energy and made available to the NPC for use in this study. The model was designed to identify reservoirs that may be suitable for CO_2

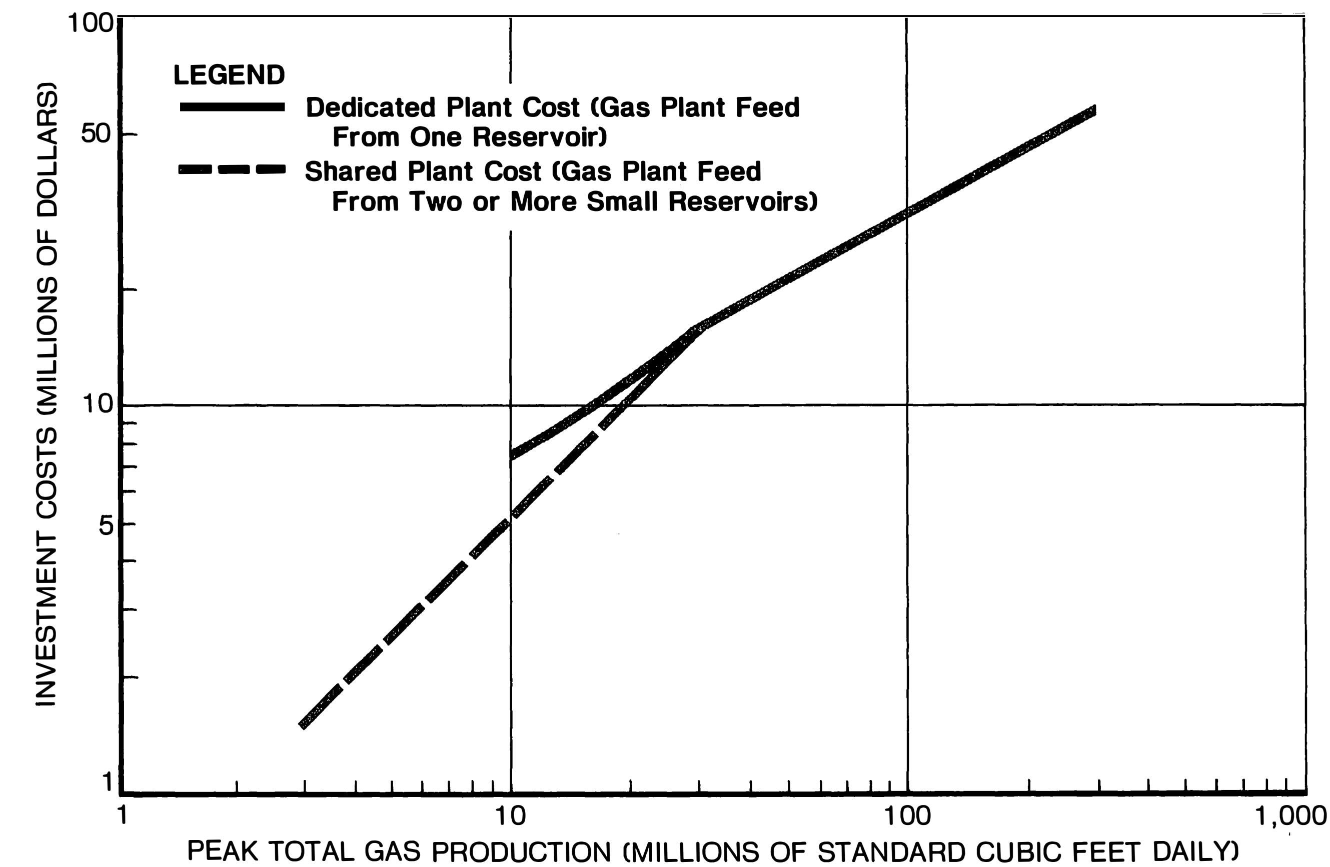


Figure E-4. Comparison of Investment Cost Estimate vs. Peak Total Gas Flow—Total Gas Recycle Plant.

miscible flooding and was extensively modified and calibrated by the Miscible Displacement Task Group before it was accepted for this study. Complete miscibility of solvent and oil is assumed. A realistic injection rate must be specified for the model. CO2PM predicts miscible flooding oil rate and recovery performance for a single five-spot pattern: these results are used as the basis for estimating field project performance.

CO2PM approximates effects of gravity segregation, viscous fingering, reservoir heterogeneity, areal sweep, and fractional flow. The effects of viscous fingering, reservoir heterogeneity, and gravity segregation within a layer are approximated by the Koval factor method.[4] The Miscible Displacement Task Group modified CO2PM to approximate permeability stratification by layers of different permeability with a permeability variation corresponding to a pseudo Dykstra-Parsons coefficient determined from waterflood performance. There is no cross-flow between layers. The model could be run using one to five layers.

For most reservoirs the five-layer model was used. In the case of reservoirs with less than 10 feet of net pay, only one layer was used. Engineering judgment was used by the Task Group in selecting the number of layers to use for reservoirs with net pay greater than 10 feet. Areal sweep is determined using modified Claridge correlations for the effects of mobility ratio.[5]

Solvent and water are injected simultaneously at the specified WAG ratio and injection conditions. The solvent is miscible with the oleic (oil-rich) phase and soluble in the aqueous (water-rich) phase. Fractional flow of the three components (oil, water, and solvent) occurs in proportion to component concentrations in the two saturated phases (oleic and aqueous phases). Fractional flow of the two phases occurs in accordance with appropriate phase properties and relative permeability relations. A water drive follows injection of the specified volume of solvent. CO2PM may be used to model secondary miscible flooding. In this study, however, it was assumed that miscible

[4]Koval, E. J., "A Method for Predicting the Performance of Unstable Miscible Displacement in Heterogeneous Media," Soc. Pet. Eng. J. (June 1963) 145-54.

[5]Claridge, E. L., "Prediction of Recovery in Unstable Miscible Flooding," Soc. Pet. Eng. J. (April 1972) 143.

solvent injection was started at an oil saturation near the waterflood residual. The model assumes no free gas is present, but solution gas is accounted for via the solution gas:oil ratio.

Required Reservoir Data

By design, CO2PM models the performance of a single five-spot pattern, which is presumed to be part of a larger project containing many identical patterns. The model allows the user to incorporate reservoir specific data. Where data are available, this provides the capability to obtain a performance prediction tailored to specific reservoir conditions and operating practices. The data include pattern volume information, general reservoir and fluid property data, reservoir rock properties, and data for process and program control. For specific reservoirs, appropriate hydrocarbon or nitrogen properties must be supplied manually. In the vast majority of cases, it was assumed that CO_2 would be used as the miscible solvent. CO_2 properties are calculated from correlations programmed into the CO2PM model.

The required data that define pattern volume are pattern area, net reservoir pay thickness, and porosity. These data allow calculation of pattern bulk volume and pore volume. Saturation data supplied to the model permit calculation of OOIP. Oil in place at the start of the miscible flood is discussed below.

General reservoir data including reservoir depth, pressure, temperature, and current producing gas:oil ratio were generally available. As discussed earlier, the MMP had been determined for each reservoir. Additional fluid property data that are necessary for the performance prediction calculations include formation volume factors and viscosities for oil, water, and carbon dioxide. These values were calculated for the appropriate flooding pressure (usually MMP) and reservoir temperature. When available in the reservoir data, oil formation volume factors and viscosities were used (after validation).

The following reservoir rock properties are used in the model calculations:

- Porosity
- Permeability
- Ratio of horizontal to vertical permeability
- Connate water saturation
- Residual oil saturation.

The calculation procedure also requires relative permeability data for oil and water flow. CO2PM contains equations for calculating the relative permeability based on end point saturations and curve exponents.[6] These data were seldom available and the factors shown in Table E-5 were used.

The average oil saturation at the start of solvent injection was back-calculated, using the above fluid property and relative permeability data, by assuming an initial oil-cut of 1 percent at the end of a previous waterflood (99 percent water-cut).

The data discussed to this point principally reflect a state of nature that cannot be changed by any actions of the field operator. Data for various operator actions that may influence the performance prediction are discussed below.

Operating Parameters

Parameters that affect ultimate recovery and that may be varied by the operator include the total quantity of solvent injection expressed in units of hydrocarbon pore volumes (HCPV), the WAG ratio, and the maximum number of pore volumes of CO_2 and water to be injected over the life of the project. Project life is determined by injection rates, pattern size, and project schedule.

For the Implemented Technology Case, the CO_2 volume was assumed to be 0.4 HCPV at

[6]Corey, A. T., "The Interrelation Between Gas and Oil Relative Permeabilities," Producers Monthly (Nov. 1954) Vol. 19, p. 38.

TABLE E-5

COEFFICIENTS OF THE RELATIVE PERMEABILITY RELATIONS

	Sandstone	Carbonate
Oil relative permeability endpoint	0.8	0.4
Water relative permeability endpoint	0.2	0.3
Oil relative permeability exponent	2.0	2.0
Water relative permeability exponent	2.0	2.0

reservoir conditions; the WAG ratio was assumed to be 1.5. These assumptions reflect both current practice in the industry and judgment of the committee members. Thus, 1 HCPV of WAG fluids (0.6 HCPV water and 0.4 HCPV CO_2) was injected into each pattern, and was followed by a maximum of three pore volumes of water. During subsequent economic calculations, injection in each pattern was stopped when the economic limit was reached.

For reservoirs currently developed on 80 acres or smaller spacing, it was assumed that current wells would be used in a conventional five-spot pattern. This gave a maximum pattern size of 160 acres. It was also assumed that one new injection well would be drilled for every two patterns to better control the placement of injection fluids. For reservoirs currently developed on greater than 80-acre spacing, sufficient wells were drilled to obtain 160-acre conventional five-spots.

Pattern life depends upon the combined CO_2 and water injection rate that can be achieved for the WAG injection well. CO_2 flood experience indicates that this rate is approximately equal to that obtained during a preceding waterflood. For all reservoirs for which this information was provided by the operators on the basic input data forms, waterflood injection rates were used, after applying appropriate judgment, as the WAG injection rates. For those reservoirs for which such data were not provided, a pattern injection rate was assumed on the basis of the pattern pore volume. For example, a 40-acre pattern in the San Andres formation of West Texas received an annual WAG injection volume equivalent to 7.5 percent pore volume. For an 80-acre pattern in this same formation (probably having somewhat better characteristics permitting the wider spacing), the annual WAG volume was 5 percent of this larger pore volume. Generally the tighter formations, such as the West Texas Clearfork, were given lower injection rates (only 2.5 percent pore volume per year for an 80-acre pattern).

It was further assumed that, because of various geologic and operational factors, the entire reservoir acreage would not be flooded with CO_2. Therefore, the number of patterns required to flood 80 percent of the total reservoir pay volume were used as a maximum in most cases. When specific data were known, more or less area was developed. The area to be developed was usually scheduled in five equal groups of patterns in years 1, 3, 5, 7, and 9. When existing or announced projects were known to have specific development programs, these were used. Rate of return and ultimate EOR were found to be relatively insensitive to development schedules that resulted in complete project development over a 10-year period, or less.

Model Calibration

CO2PM was calibrated against the field performance of several miscible pilots. Comparison of field performance and model predictions led to the decision that a multilayered reservoir model would be required for predictions of database reservoirs. Therefore, the Miscible Displacement Task Group specified the model changes, designed the methodology, and validated the resulting code for the multilayered CO2PM. Layered-model predictions were also compared to predictions made with larger, more sophisticated reservoir simulators by several of the participating companies. The performance predicted by CO2PM was qualitatively similar to the performance predicted by numerical simulators. However, when calculations were made for the suite of data base reservoirs, the CO2PM results were found to need further adjustment to reflect the performance that is indicated by current field tests and major reservoir engineering studies. Accordingly, adjustments based on engineering judgment were made to the injected CO_2 volume to account for injection losses, and to predicted oil production rates to make the average predicted performance for the data base reservoirs consistent with more sophisticated projections of CO_2 miscible flooding performance.

To validate the performance results obtained with the model, operator oil recovery and CO_2 utilization estimates for 11 projects were compared with the model results for these reservoirs. These comparisons are shown on Figures E-5 and E-6. Although these results are predicted with a necessarily simplified model, they agree very well with the operator estimates, which are based on intensive pilot and engineering studies and are the basis for very large planned or committed expenditures. The significant departures from the NPC prediction can be readily explained. For instance, two of the fields have significantly higher oil recovery, but both of these projects anticipate using large CO_2 slug sizes, about twice the 40 percent HCPV used in our analysis.

All 11 of the projects considered in this validation are either underway or proceeding toward full-scale implementation by 1986 or earlier. These projects are predominately from West Texas and New Mexico; 7 of the 11 are Permian Basin carbonates. Other projects include sandstone reservoirs. The 11 projects

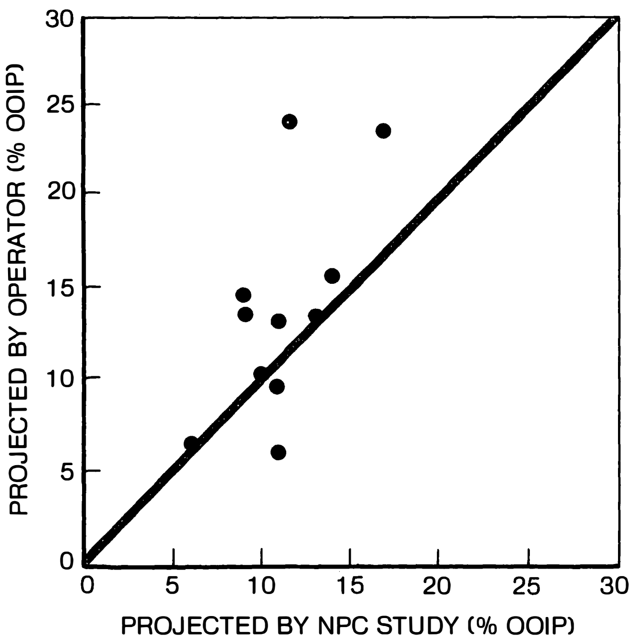


Figure E-5. Comparison of Operator and NPC Projections of Enhanced Oil Recovery for Selected Fields.

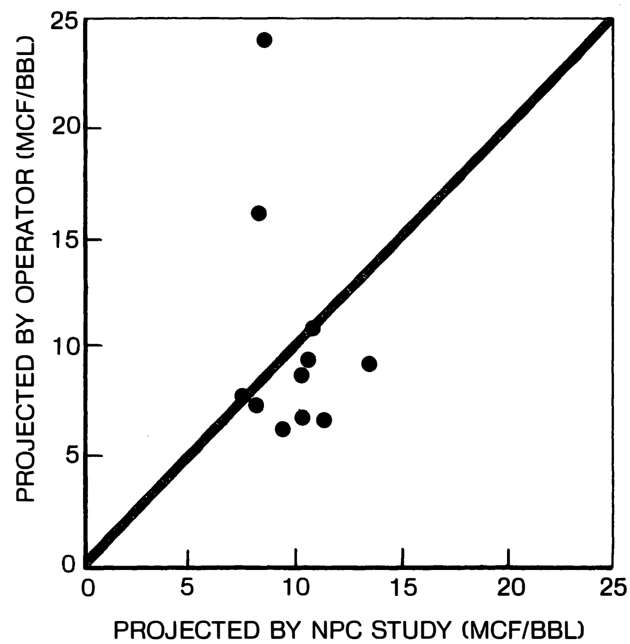


Figure E-6. Comparison of Operator and NPC Projections of Gross CO_2 Utilization for Selected Fields.

represent a large sampling of the fields identified as potentially economic for miscible flooding for the $30 per barrel oil price, 10 percent minimum ROR case. The 11 projects represent reservoirs that contain 25 percent of the OOIP, and 18 percent of the expected recovery for the 142 reservoirs identified as potentially economic under the $30 per barrel, 10 percent minimum ROR base economic case assumptions.

Selection of Final Candidates for Miscible Flooding

All reservoirs meeting the miscible screening criteria and having the required reservoir information were evaluated using CO2PM. These projections for each candidate reservoir consisted of a recap of individual layer (maximum of five) and pattern performance and a field-wide projection of future injection and production to be used as input to the economic model. In addition, the computer printout for each reservoir contained a detailed summary of input variables. A close examination of this output information was conducted by the individual group members responsible for specific geographic areas. The purpose of these examinations was to eliminate possible input errors and data inconsistencies that would cause incorrect predictions.

The model performance predictions were used directly for economic analysis. This was a three-step procedure. In the first step, single pattern data (including oil, gas, water, and CO_2 production in addition to water and CO_2 injection) were combined with the yearly pattern initiation schedule provided by the reviewing engineer. The pattern production and injection data were expanded to field-wide flooding by using a super-position routine guided by the pattern initiation schedule. The resulting field-wide projections contained the same types of production and injection information as the single-pattern results. In the second step, all economic assumptions necessary to complete the economic analysis were combined with individual project production and injection schedules. In the third step, the expense, investment, and income streams were calculated for the field-wide project. The annual cash flow was calculated for the entire project life. When the annual net income for an individual pattern switched from positive to negative, the patterns were shut in. The following investment analysis parameters were calculated from the resulting data: discounted cash flow (DCF); discounted cash flow rate of return; and Investment Efficiency. The economic analysis program calculated before-tax and after-tax cash flow for the total project. To expedite review and checking, a one-line summary was developed for each candidate reservoir. This summary contained information such as OOIP, incremental oil recovery, volume of solvent purchased, gross volume of solvent injected, total investment, and discounted cash flow rate of return, and was used in the final selection of miscible flooding candidates by the Task Group.

The result of the preliminary screening procedure was an inventory of 603 reservoirs that had a total OOIP of 190 billion barrels. These reservoirs were reviewed quantitatively as well as qualitatively for factors influencing the overall success of miscible flooding. Performance and preliminary economic projections were made for all of these candidate reservoirs, and a review of the one line summary output for each reservoir was performed by the Miscible Displacement Task Group members jointly. During this review process, reservoirs were dropped from further consideration for the Implemented Technology Case because of specific factors known about the reservoir that could not be taken into account in the model. Some decisions were based on the experience and consensus opinions of the group and were therefore subjective in nature. Some 500 reservoirs remaining after this process were then reviewed with the other process task groups to resolve which process would be applied when more than one process was applicable. After these reviews, 436 reservoirs remained as miscible process candidates. These reservoirs contained 150 billion barrels of OOIP, or about one-third of the total OOIP discovered to date in the United States.

Miscible Flooding Results

Implemented Technology Case Results

Several nominal oil price and minimum ROR cases were processed, all using the 603 reservoir base that met the miscible screening criteria, under miscible Implemented Technology Case assumptions. The miscible results were composited with the results of the other processes for each economic case to select a single process for each reservoir. The base economic case, as defined for this study, was a nominal crude oil price of $30 per barrel, constant 1983 dollars, no Windfall Profit Tax, and a 10 percent minimum ROR as the investment criterion. After gravity and location adjustments, the average price received for miscible EOR was $27.50 per barrel, at the nominal crude oil price of $30 per barrel.

For this base economic case, the total miscible EOR potential from known U.S. reservoirs is 5.5 billion barrels, or 38 percent of the EOR potential from all processes in the Implemented Technology, base economic case. During the 30-year period for which detailed projections were made in this study, 3.8 billion barrels, or about 70 percent of the total miscible resource, is produced.

The peak rate of production from the 5.5 billion barrel resource was projected to be about 500 thousand barrels per day. The peak rate occurred some 20 years into the future, shortly after the year 2000. This rate is achieved by a steady buildup from the current estimated production rate for ongoing miscible projects of about 50 thousand barrels per day. The projected rate declines over the last eight years of the forecast period from the 500 thousand barrels per day peak to about 360 thousand barrels per day by 2013.

The rate of oil production is driven primarily by the assumed rate of injectant supply. Hydrocarbon miscible projects, using enriched hydrocarbon gas available in the same field, and nitrogen miscible projects, which often use on-site plants, may not be time or resource constrained. However, the great bulk of miscible recovery potential is closely tied to the availability of CO_2 solvent coming through pipelines from the natural sources of supply. The CO_2 supply is the driving force for the miscible EOR rate projection, and by assumption, is closely tied to the existing capacity of the major pipelines delivering CO_2 into the West Texas area.

For the base economic case, the availability of CO_2 for the West Texas/East New Mexico area is assumed to reach 2.1 Bcf per day in 1987 and remain level thereafter. Most of this supply will be furnished by the three major pipelines discussed earlier. For the areas of the United States other than West Texas/East New Mexico, the availability of CO_2 and other solvents were assumed to be tied to the availability in the West Texas region as a growing percentage. The rationale for this assumption is that miscible resource development will follow the lead of the area of greatest potential, as success is demonstrated and operating experience is gained. Figure E-7 is a plot of projected oil recovery rates over the 30-year study period for the Implemented Technology base economic case.

Other resources required to develop the miscible EOR potential include capital and expense funds. The capital investments presented here exclude CO_2 source development and pipeline investments and are limited to investments for reservoir development subsequent to or during waterflood operations. Purchase prices for CO_2 were assumed to be used by the CO_2 suppliers to amortize the pipeline and CO_2 source development investments. The most significant costs are the purchase of CO_2 and the processing of the CO_2-laden produced gas.

At the current stage of maturity of enhanced oil recovery by miscible flooding, only

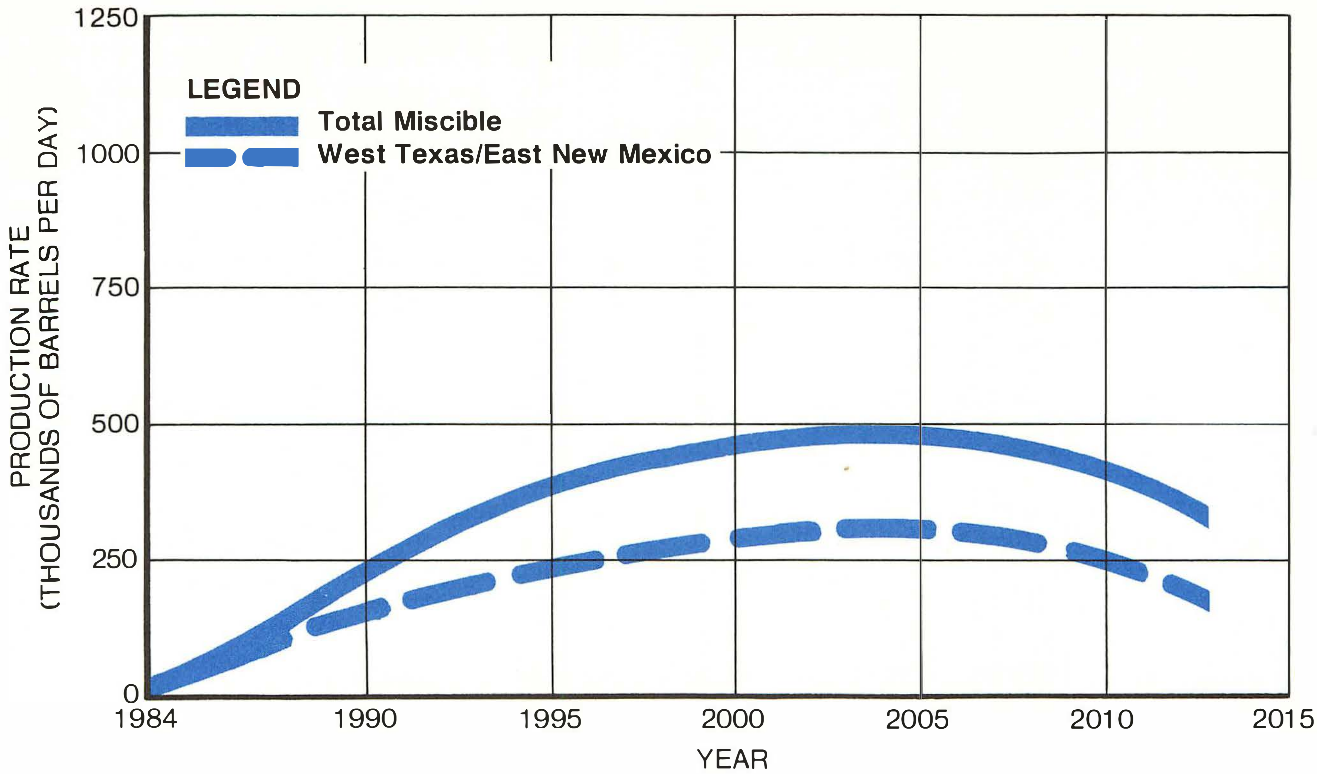


Figure E-7. Production Rate for Miscible Flooding—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

a small portion of the projected EOR potential has been booked as proved reserves. Less than 500 million barrels of the miscible potential is carried and reported as proved reserves. The full future potential of 5.5 billion barrels is included in the projections for miscible processes.

Sensitivities relative to the base economic case for implemented technology were run at nominal crude oil prices of $20, $40, and $50 per barrel. Table E-6 shows the results of this sensitivity analysis. In each of the sensitivities shown, the miscible potential was assessed in competition with the other EOR processes. There is no duplication of potential.

Figure E-8 displays the ultimate recovery for miscible processes versus price as a bar graph. The total height of the bars indicate ultimate potential while the shaded areas indicate recovery during the 30-year study period, through 2013. At higher crude oil prices the percentage of the resource recovered during the 30-year period increases with price from 70 percent at $30 per barrel, to 74 percent at $40 per barrel, to 84 percent at $50 per barrel. The tim-

TABLE E-6

MISCIBLE FLOODING
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	Minimum ROR 10%	Minimum ROR 20%
20	4.2	2.0	1.0
30	7.6	5.5	3.3
40	9.3	7.0	4.8
50	10.4	7.7	6.2

ing and rate of recovery are influenced by price more than any other factor, assuming the process proves technically successful. The single exception in the study was at the $20 per barrel nominal crude oil price. In this case, 81 percent of the 2 billion barrel resource is produced during the study period. If prices were to fall to this level immediately, only ongoing and committed projects would continue. Relatively few, if any, additional projects would be added over the study period. With only the 2 billion barrel developed potential, a great percentage would be produced during the 30-year period.

Oil producing rate projections for the price sensitivity cases are shown in Figure E-9. The potential miscible flooding peak rates are reached earlier and are higher as price increases, again with the exception of the $20 per barrel case for which the ultimate recovery is much lower. The peak rates and the interval over which these peak rates are maintained is shown in Table E-7.

West Texas and East New Mexico, a relatively concentrated geographic area, is projected to produce a significant fraction of the total miscible EOR potential under all economic assumptions. Figure E-10 indicates how the rate projections for this area are influenced by oil price. Table E-8 gives peak rates and the intervals over which peak rates are maintained for the West Texas/East New Mexico area alone.

The miscible EOR potential and rate of production is very dependent on the availability of solvent. This is especially the case in the West Texas/East New Mexico area, where CO_2 miscible projects will predominate. CO_2 will be furnished to this area via pipelines from natural sources in Colorado and New Mexico. For each price case, a schedule of solvent availability was projected by the Miscible Displacement Task Group based on their collective knowledge of CO_2 pipeline design capacities and assumptions related to how oil price changes would affect CO_2 resource and pipeline development for the West Texas/East New Mexico area. Also, CO_2 costs were indexed to oil prices in the Economic Model. (Different combinations of availability and price were assumed to prevail in other regions of the country.) Figure E-11 is a graphical comparison, for the West Texas/East New Mexico area, of the CO_2 availability and the projected CO_2 purchases for each of the oil price cases. The remainder of the United States, outside the West Texas/East New Mexico area, was handled in a similar manner, but CO_2 prices were incremented for distance from natural sources, or for the cost from industrial sources. Hydrocarbon or nitrogen solvent costs were handled appropriately.

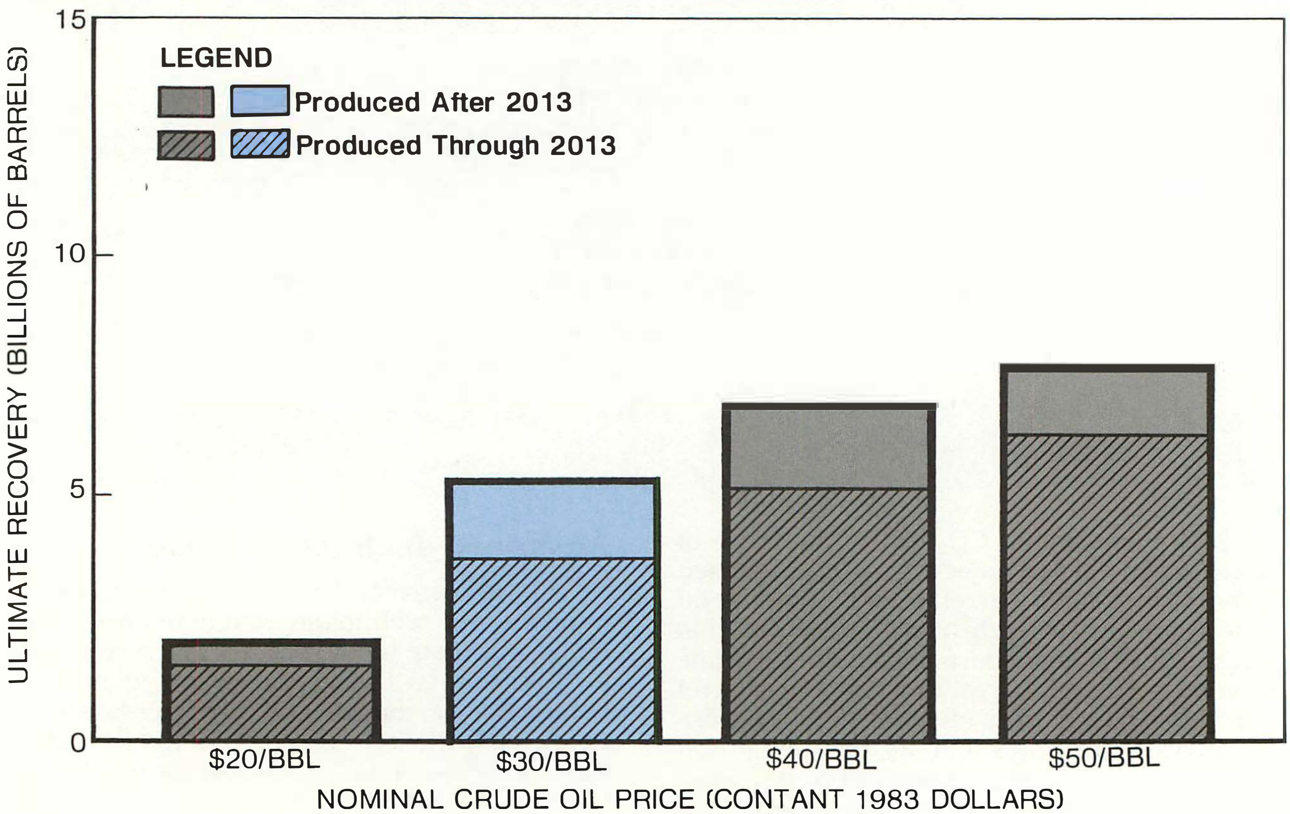


Figure E-8. Miscible Flooding Ultimate Recovery vs. Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technolgy Case (10 Percent Minimum ROR).

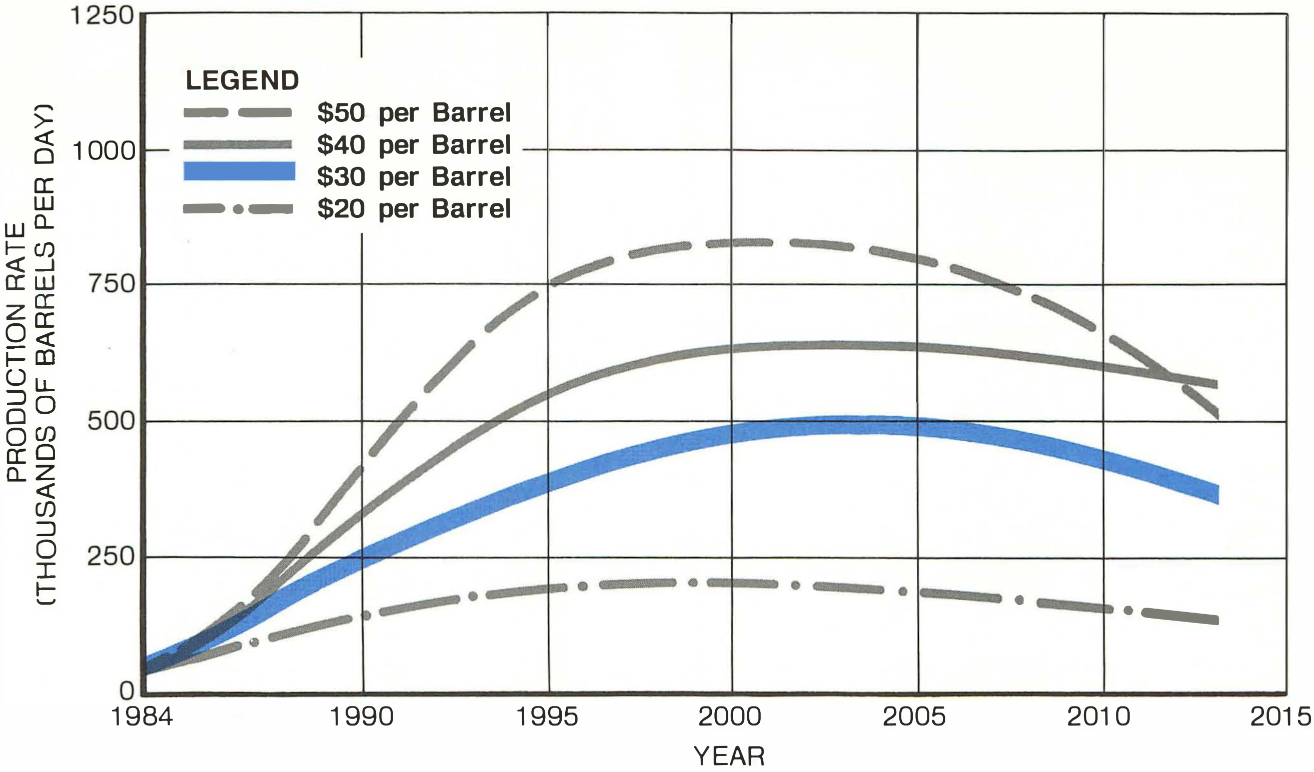


Figure E-9. Sensitivity of Miscible Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

TABLE E-7

MISCIBLE FLOODING PEAK PRODUCING RATE IMPLEMENTED TECHNOLOGY CASE (10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
20	200	1998-2003
30	500	2003-2005
40	650	2003-2004
50	820	1999-2003

The overall gross CO_2 utilization (ratio of gross volume of CO_2 injected, both purchased and recycled, per barrel of incremental oil recovered) varied slightly with price in this study, from 8 Mcf per barrel at a nominal crude oil price of $30 per barrel to 8.6 Mcf per barrel at $50 per barrel. Less efficient projects cross the investment threshold at the higher oil prices. Approximately 70 percent of the gross injected CO_2 volume was purchased CO_2. The remaining 30 percent was produced gas recycle.

Advanced Technology Case

There are several improvements to current implemented technology that could result in a higher ultimate recovery for a given reservoir. In reservoirs with only moderate degrees of heterogeneity, larger CO_2 slug sizes should cause increased recovery, providing the cost of the additional slug is not economically prohibitive and providing other economic factors affecting the project are favorable. Higher recovery could also result for reservoirs with unfavorable heterogeneities if technology should be developed that decreases CO_2 mobility significantly. Both possibilities were examined for the Advanced Technology Case.

For the Advanced Technology Case, it was assumed that neither development would be practiced until after 1995. This date was selected because of the time required for research and testing to prove mobility-reduction technology, and because approximately this much field experience would be required to judge whether or not larger slug sizes would be of significant benefit. These elements of the Advanced Technology Case scenario are discussed further in the following paragraphs.

The volume of injected CO_2 assumed in the Implemented Technology Case was 40 percent HCPV, following the precedent set by recent field projects. For reservoirs of moderate heterogeneity, those with good waterflood sweep efficiency, a larger volume of CO_2 throughput is

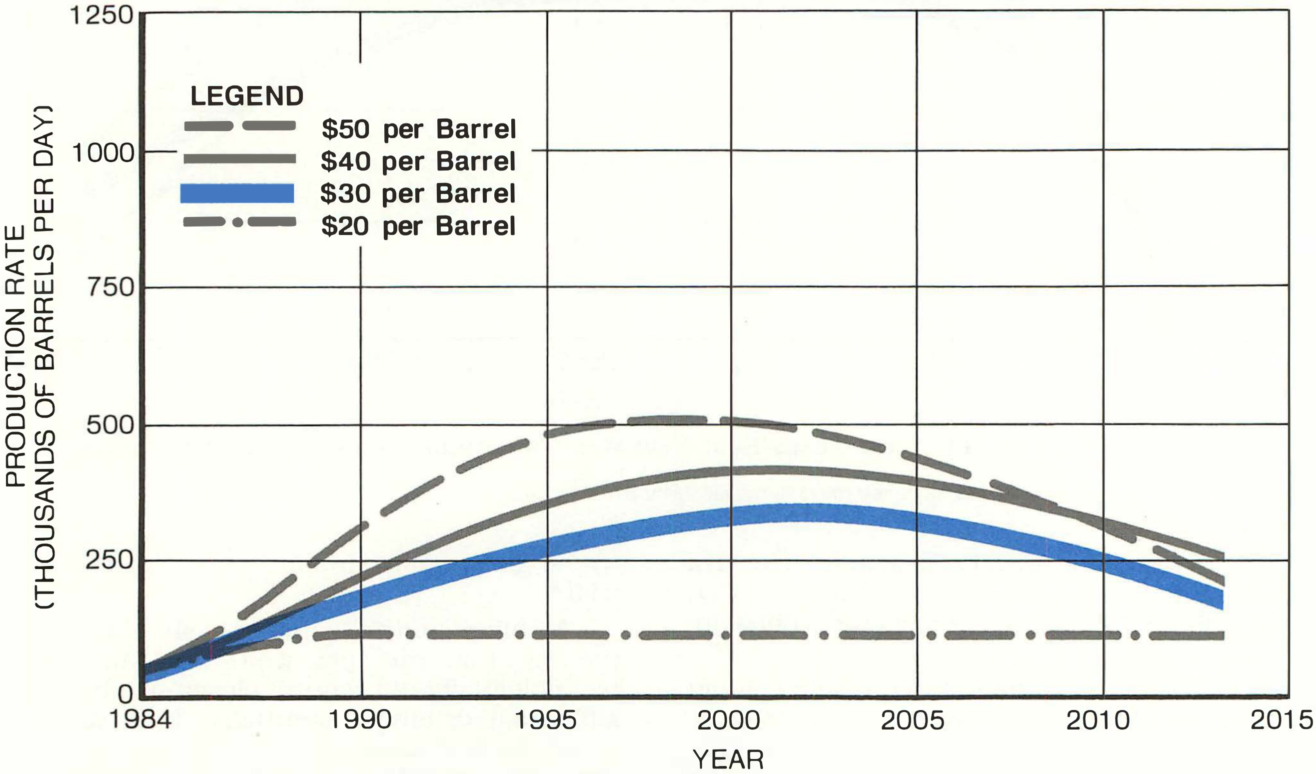


Figure E-10. Sensitivity of Miscible Flooding Production Rate, West Texas/East New Mexico Area, to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technolgy, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

TABLE E-8

MISCIBLE FLOODING
PEAK PRODUCING RATE
WEST TEXAS/EAST NEW MEXICO AREA
IMPLEMENTED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
20	120	1990-2013
30	330	2003-2005
40	405	2002-2003
50	500	1997-2000

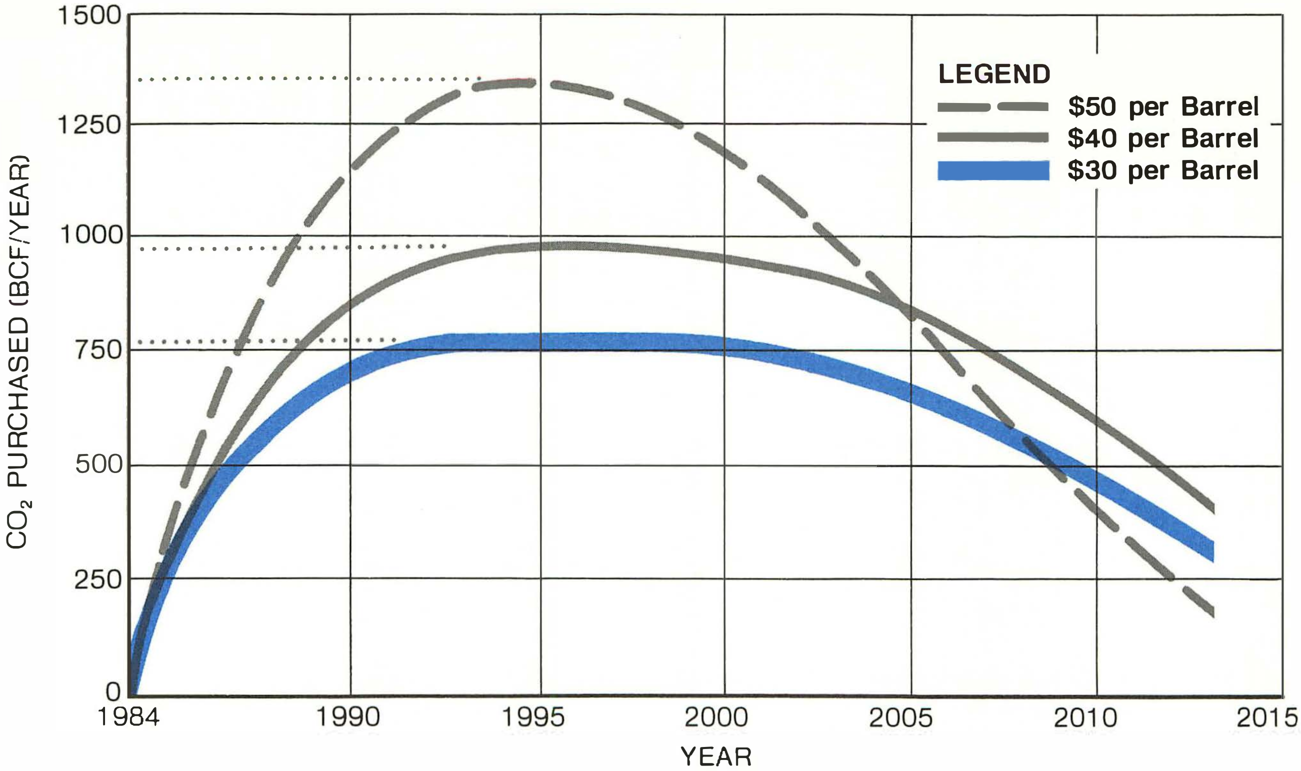


Figure E-11. West Texas/East New Mexico, Annual CO_2 Purchased Volumes.

Note: ················ indicates assumed maximum availability by oil price.

likely to recover more oil at a sustained level of profitability. However, increasing the CO_2 throughput does not result in a proportional increase in oil.

Much of the additional CO_2 would contact previously swept regions, and thus would be inefficient in recovering additional oil. For these highly stratified, heterogeneous reservoirs, the objective is to develop a practical technology for injecting chemicals to control the CO_2 sweep efficiency (see Appendix H). These chemicals create a "foam" in the reservoir rock that impedes the flow of CO_2. If successful, this process will divert CO_2 from the more permeable strata to the less permeable, thus improving sweep efficiency and recovering additional oil.

Foam technology is, at present, not well understood. There are some laboratory data in the literature and only one published field trial related to this technology. For this study, the projected behavior of foamant chemicals was modeled by making the appropriate CO2PM parameter changes required to match the foamant core flood studies of Bernard and Holm,[7] and estimating the relative improvement in injection profile and decreased injectivity that would give results similar to the Siggins Field trial.[8]

Mobility control technology should reduce the injection rate per well. This advanced technology should require closer spacing and additional drilling. Potentially, infill drilling could result in more reservoir being contacted than was possible at the prior waterflood well spacing, thereby also improving recovery. However, the additional drilling burdens the project with a significant investment, which also affects economics. Based on data from the the Siggins pilot test, per-well injection rate was assumed to be reduced by a factor of two, and pattern size was drilled down to half the spacing used in the Implemented Technology Case in order to compensate for the reduced injection rate. A modest credit was also taken for the additional oil that would be captured by infill drilling: the oil-cut used to initialize reservoir oil saturation was increased from 1 percent to 2.5 percent.

Project economics must also include the cost of the chemical injected. These costs were estimated based on an active chemical cost of $1.60 per pound, giving a cost of $0.40 per Mcf of injected CO_2.

[7]Bernard, G. G., and Holm, L. W., "Use of Surfactant to Reduce CO_2 Mobility in Oil Displacement," Soc. Pet. Eng. J. (Aug. 1980) 281-92.

[8]Holm, L. W., "Foam Injection Test in the Siggins Field, Illinois." J. Pet. Tech. (Dec. 1970) 1499-1506.

The miscible screening parameters were not changed for the Advanced Technology Case. The reservoirs evaluated for Advanced Technology were the same as those evaluated in the Implemented Technology Case. All other assumptions were the same as used for calculating Implemented Technology Case results.

Advanced Technology Case Results

For the purposes of this study, the Advanced Technology Case described in the preceding section was assumed to be available in 1995. Before then, implemented technology would be applied to all active reservoirs. After 1995, all reservoirs in which EOR implemented technology had not yet been initiated were reconsidered for either implemented or advanced technology for each applicable EOR process. The process meeting the minimum ROR criterion and recovering the most oil was the process selected for the particular reservoir under consideration. Miscible floods that had been started in a reservoir under the Implemented Technology Case prior to 1995, but that had not completed the scheduled pattern development by 1995, were permitted to switch to the Advanced Technology Case, if the minimum ROR criterion was met.

Three oil price sensitivity cases were run for the Advanced Technology Case. These are $30, $40, and $50 per barrel. A $20 per barrel case was not judged to be an assumption compatible with a generally more expensive advanced technology. Results of the three Advanced Technology Cases are shown in Figure E-12 in the form of a series of bar graphs. This figure shows ultimate recovery as well as recovery during the 30-year study period. The amount of the EOR potential for the Advanced Technology Cases that is recovered during the 30-year study period varies from 75 percent at $30 per barrel, to 79 percent at $40 per barrel, and to 86 percent at $50 per barrel. For comparison purposes, the ultimate miscible EOR potential for the various price cases, at a 10 percent minimum ROR, and for both the Advanced and Implemented Technology Cases is shown in Table E-9.

For miscible EOR processes, there is a relatively small incremental Advanced Technology Case potential: 600 million barrels at the $30 per barrel oil price, and only slightly more at the $40 and $50 per barrel prices. Two factors dictate this result: incremental oil from the Advanced Technology Case is more expensive than under the Implemented Technology Case, and reservoirs that are substantially

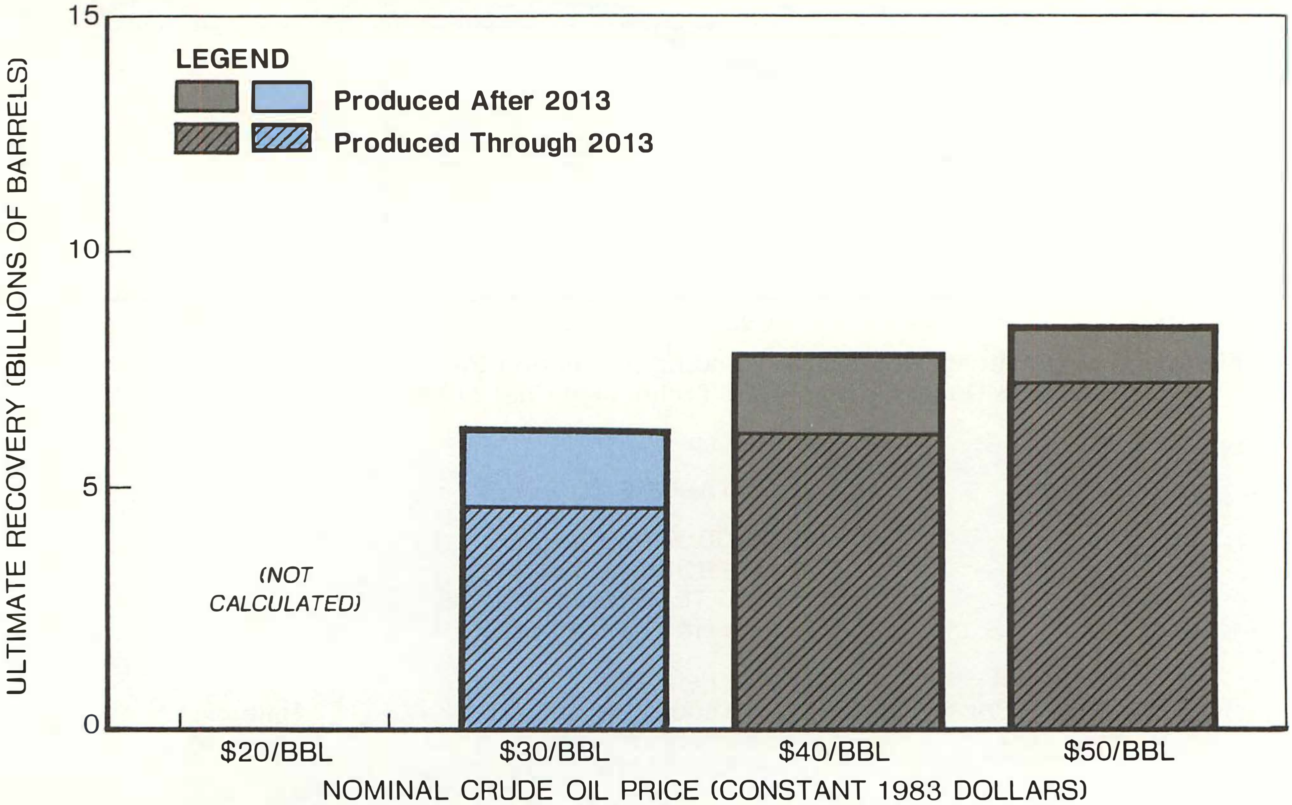


Figure E-12. Miscible Flooding Ultimate Recovery vs. Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology Case (10 Percent Minimum ROR).

TABLE E-9

MISCIBLE FLOODING
COMPARISON OF ULTIMATE RECOVERY
IMPLEMENTED VS. ADVANCED TECHNOLOGY
AT 10 PERCENT MINIMUM ROR
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Implemented Technology Case Ultimate Recovery	Advanced Technology Case Ultimate Recovery
30	5.5	6.1
40	7.0	7.8
50	7.7	8.5

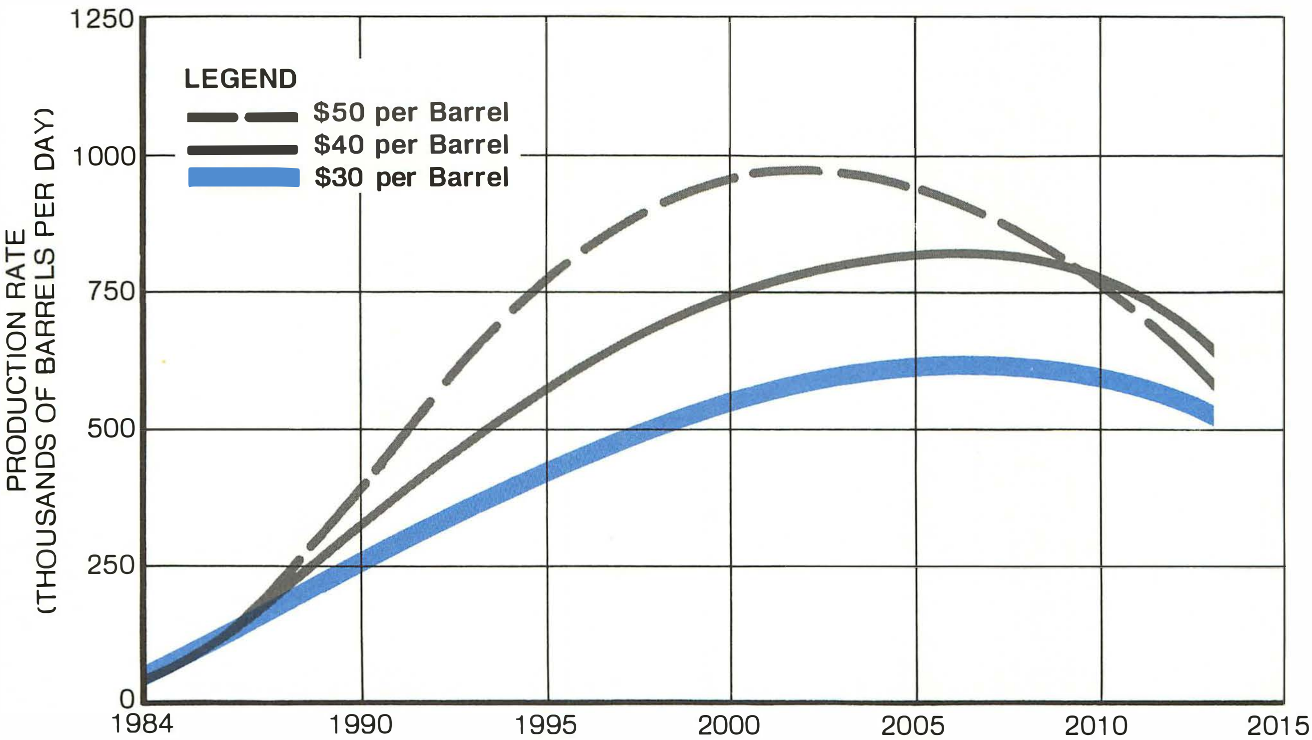


Figure E-13. Sensitivity of Miscible Flooding Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology Case (10 Percent Minimum ROR).

TABLE E-10

MISCIBLE FLOODING
PEAK PRODUCING RATE
ADVANCED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Peak Rate (Thousands of Barrels Per Day)	Time of Peak Rate
30	625	2006-2007
40	830	2005-2007
50	980	2002-2003

developed between 1984 and 1995 are not available for the Advanced Technology Case.

The Advanced Technology Case rate projections are shown in Figure E-13 for the three price sensitivity cases. The peak rate achieved and the interval of its duration are summarized in Table E-10 for the various nominal crude oil prices.

Rate comparisons, for the various price cases, between implemented and advanced technology are shown in Figure E-14 for the $30 per barrel cases; Figure E-15 for the $40 per barrel cases; and Figure E-16 for the $50 per barrel cases. Incremental recovery due to advanced technology is spread over the last 20 years of the projection period.

Table E-11 compares the West Texas/East New Mexico area ultimate EOR potential from miscible processes against the total for the entire United States. The percentage of the total U.S. miscible resource in the West Texas/East New Mexico area does not significantly change between the Implemented and Advanced Technology Cases; the potential for this area remains about 60 percent of the total.

Uncertainty

Even though the results presented above represent the best possible estimate of recovery by miscible flooding, the Miscible Displacement Task Group recognizes the uncertainty of the results. The Task Group thus identified the major positive and negative factors that could influence the degree of technical success of the miscible process on a composite basis. In doing so, the Task Group attempted to examine technical sensitivity while ignoring price and economic considerations.

The major technical factors that lead to uncertainty in the estimates of ultimate miscible EOR are identified in the following table, by generic names:

Positive Factors

- Mobility Control
- Density Control
- Increased Floodable Area
- Increased Infill Drilling
- Reduction of Effective Dykstra-Parsons Factor
- Increased CO_2 Availability

Negative Factors

- Channeling:Mobility Ratio
- Gravity Override
- Incomplete Development
- Poor Well Conditions
- Gas Cap
- Injectivity Problems
- Higher Residual Oil Saturation to CO_2/Lower Residual Oil Saturation to Waterflood

The above factors have not been placed in order of expected significance. For any given reservoir, both positive and negative factors may be operative, and direct action on the part of the operator to influence one factor may in fact affect one or more other factors.

TABLE E-11

MISCIBLE FLOODING
ULTIMATE RECOVERY
ADVANCED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	West Texas and East New Mexico (Billions of Barrels)	Total U.S. (Billions of Barrels)
30	3.8	6.1
40	4.8	7.8
50	5.0	8.5

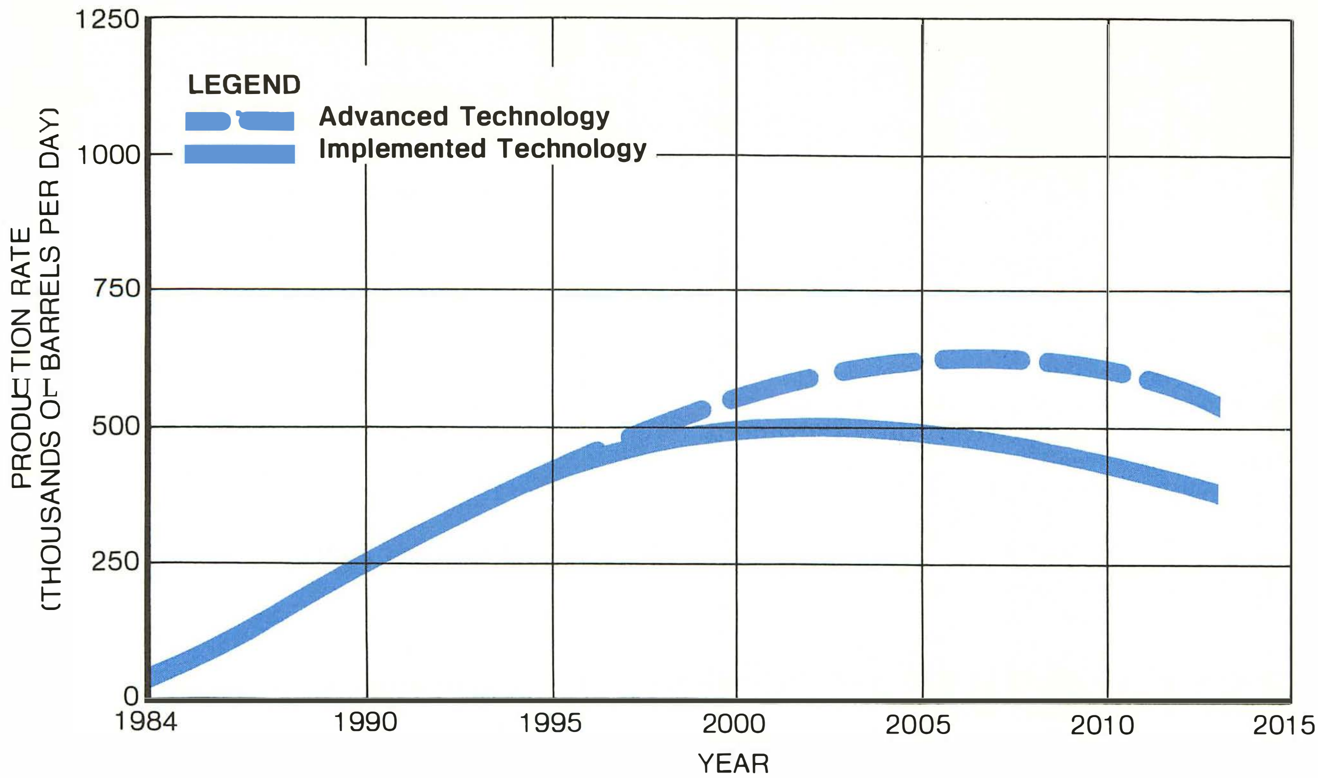


Figure E-14. Comparison of Miscible Flooding Implemented and Advanced Technology Production Rates—Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

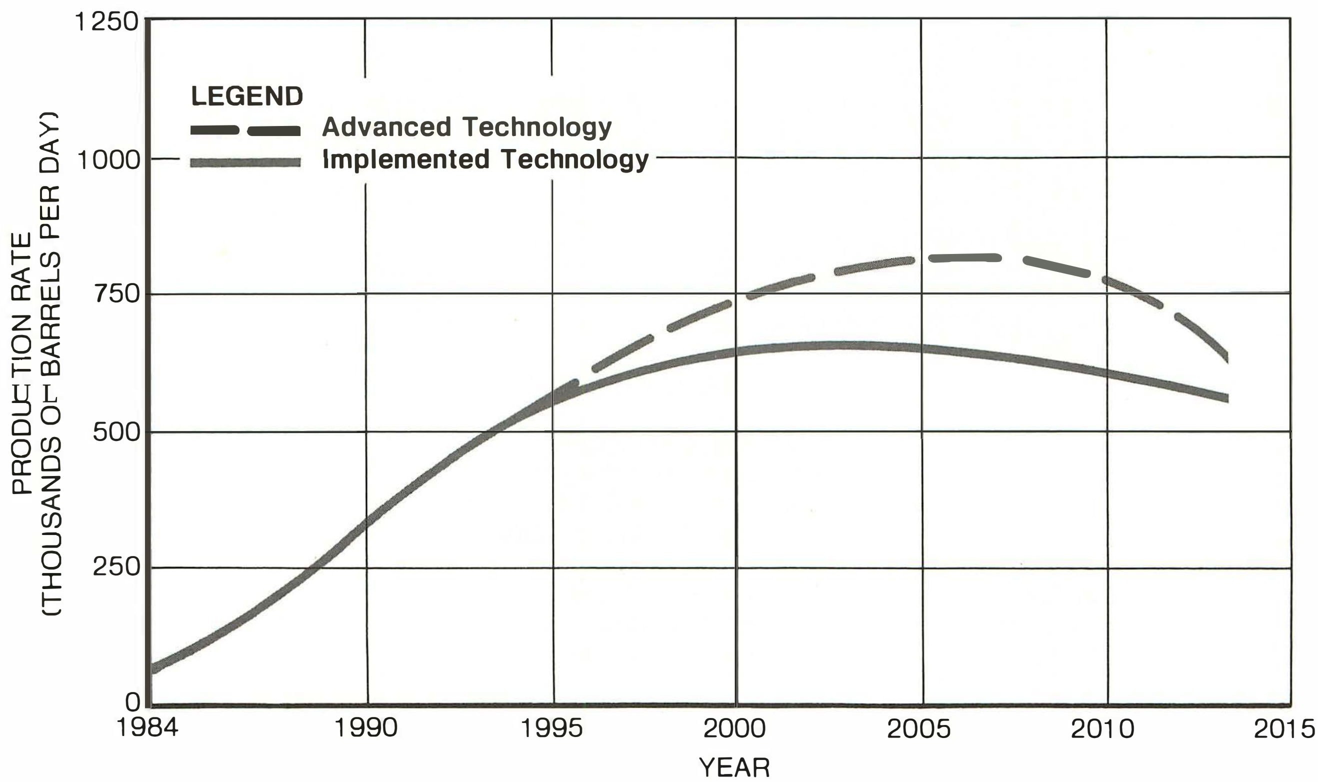


Figure E-15. Comparison of Miscible Flooding Implemented and Advanced Technology Production Rates ($40 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

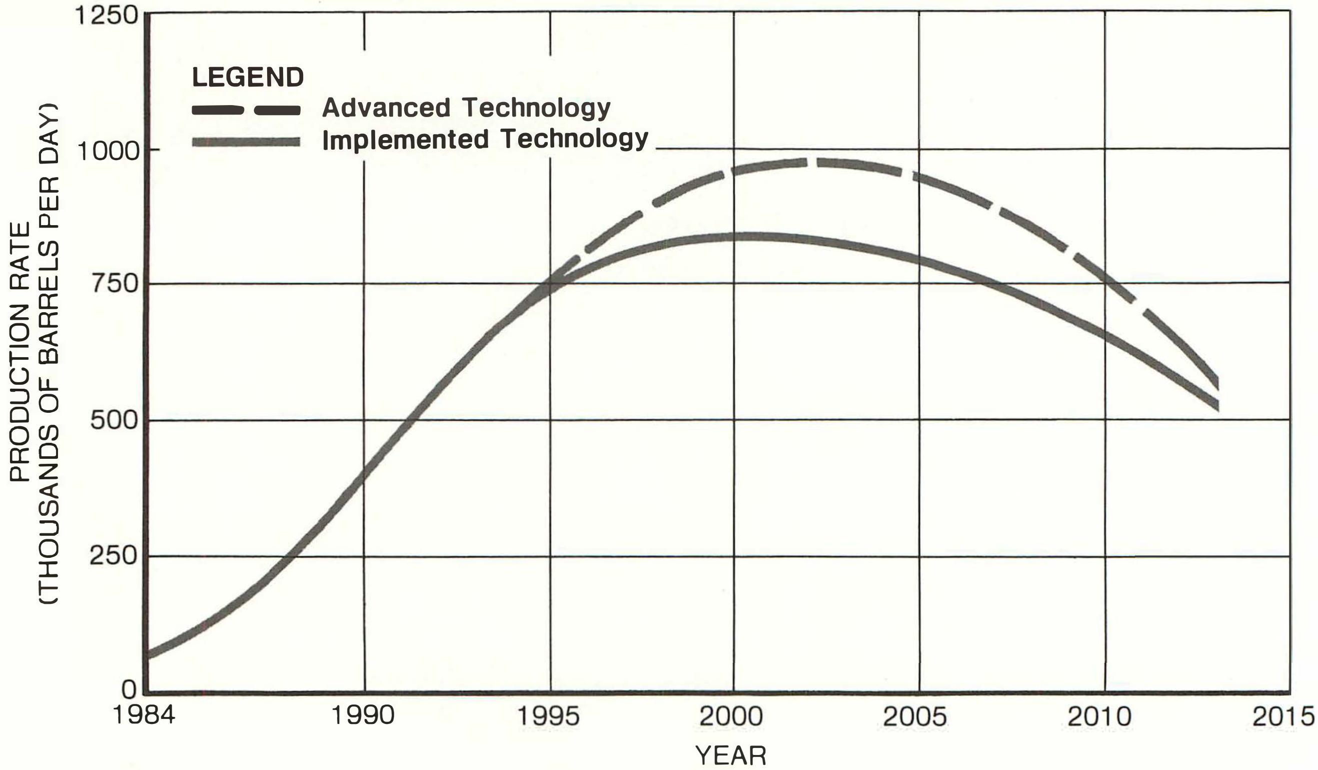


Figure E-16. Comparison of Miscible Flooding Implemented and Advanced Technology Production Rates ($50 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

Appendix F

Thermal Recovery

This appendix assesses the enhanced oil recovery (EOR) potential by thermal methods from known reservoirs in the United States. Thermal recovery projects produced in excess of 450 thousand barrels of oil per day during 1983; this production should continue to increase during the first 10 years of this study period. Thermal methods are widely used, proven technology with current application dominated by steam injection processes. The EOR potential of developed reserves from ongoing projects included in this study should be currently reported in the booked reserves of the producing companies. Public production statistics for ongoing thermal projects are gross values and include fuel oil burned in steam generators; therefore, all volumes reported in this study are likewise gross volumes.

The Thermal Task Group studied two categories of technological development. The Implemented Technology Case considers processes and equipment that are proven today; the Advanced Technology Case includes improvements that could possibly be proven from research and development currently underway. It was assumed that advanced technology becomes available for ongoing steam projects in 1988 and in 1995 for all other projects.

The potential for thermal recovery in the United States under the Implemented Technology Case is estimated at 6.5 billion barrels under the base economic case assumptions of a nominal crude oil price of $30 per barrel and a minimum discounted cash flow rate of return (minimum ROR) of 10 percent. It must be recalled that both steam generator fuel oil and some previously booked reserves from ongoing thermal projects are included in this value. Key economic factors included in the evaluation are the use of constant dollar analysis procedure and the assumption of no Windfall Profit Tax. Producing rates for the Implemented Technology Case under these assumptions could reach a peak rate of 685 thousand barrels per day by the early 1990s.

The study also examined the sensitivity of the thermal recovery potential to price. Nominal crude oil prices representing 40°API midcontinent oil were adjusted for API gravity and for a California transportation cost differential when applicable. The potential ultimate recovery and peak producing rates for the Implemented and Advanced Technology Cases at a minimum 10 percent ROR are shown in Tables F-1 and F-2. These values range from an ultimate potential of 4.4 billion barrels and a peak producing rate of 610 thousand barrels per day for the Implemented Technology Case at $20 per barrel to an ultimate potential of 12 billion barrels and a peak rate of 1.2 million barrels per day for the Advanced Technology Case at $50 per barrel.

State of the Art

Introduction

Only a short introduction on thermal methods will be given here due to the large volume of literature already available on the subject. The interested reader is referred to the references mentioned below for additional information. The most comprehensive review of thermal recovery is the monograph by Prats.[1]

[1]Prats, M., *Thermal Recovery*, Society of Petroleum Engineers Monograph, New York, 1982.

TABLE F-1

THERMAL RECOVERY
ULTIMATE RECOVERY AND PEAK PRODUCING RATE
IMPLEMENTED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
20	4.4	610	1987-1990
30	6.5	685	1990-1994
40	7.0	725	1991-1995
50	7.2	760	1994-1996

TABLE F-2

THERMAL RECOVERY
ULTIMATE RECOVERY AND PEAK PRODUCING RATE
ADVANCED TECHNOLOGY CASE
(10 Percent Minimum ROR)

Nominal Crude Oil Price ($/bbl)	Ultimate Recovery (Billions of Barrels)	Peak Rate (Thousands of Barrels per Day)	Time of Peak Rate
30	10.5	925	2003-2006
40	11.6	1,000	2001-2005
50	12.0	1,175	2001-2003

Also recently published is a book on EOR processes by the Interstate Oil Compact Commission.[2] Over the years a number of excellent review articles have appeared in the literature. Some early reviews of thermal processes were written by Ramey[3,4] and Farouq Ali.[5,6] Burns reviewed steam stimulation projects in 1969.[7] Recently, steamflooding has been reviewed by Farouq Ali,[8] Matthews,[9] and Chu.[10] Chu has also presented recent reviews of in situ combustion.[11,12,13] These articles include descriptions of thermal projects, predictive techniques, operational practices, screening criteria, and laboratory research. Thermal recovery research is also discussed in Appendix H. Information on active thermal projects is collected by the *Oil & Gas Journal*,[14] the Conservation Committee of California Oil Producers,[15] and the California Division of Oil and Gas.[16]

[2]Bond, D. C., et al., *Improved Oil Recovery*, Interstate Oil Compact Commission, Oklahoma City, 1983.

[3]Ramey, H. J., Jr., "A Current Review of Oil Recovery by Steam Injection," Proceedings of the Seventh World Petroleum Congress, Mexico City, 1967, Vol. 3, pp. 471-476.

[4]Ramey, H. J., Jr., "In-Situ Combustion," Proceedings of the Eighth World Petroleum Congress, Moscow, 1971, Vol. 3, pp. 253-262.

[5]Farouq Ali, S. M., "A Current Appraisal of In-Situ Combustion Field Tests," J. Pet. Tech. (April 1972) pp. 477-485.

[6]Farouq Ali, S. M., "Current Status of Steam Injection as a Heavy Oil Recovery Method," J. Pet. Tech. (January-March 1974) pp. 54-68.

[7]Burns, J., "A Review of Steam Soak Operations in California," J. Pet. Tech. (January 1969) pp. 25-34.

[8]Farouq Ali, S. M., and Meldau, R. F., "Current Steamflood Technology," J. Pet. Tech. (October 1979) pp. 1332-1342.

[9]Matthews, C. S., "Steamflooding," J. Pet. Tech. (March 1983) pp. 465-471.

[10]Chu, C., "State-of-the-Art Review of Steamflood Field Projects," SPE 11733, presented at the 53rd Annual California Regional Meeting, Ventura, California, March 23-25, 1983.

[11]Chu, C., "A Study of Fire Flood Field Projects," J. Pet. Tech. (February 1977) pp. 111-119.

[12]Chu, C., "State-of-the-Art Review of Fire Flood Field Projects," SPE/DOE 9772, presented at the 2nd Joint SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, April 5-8, 1981.

[13]Chu, C., "Current In-Situ Combustion Technology," J. Pet. Tech. (August 1983) pp. 1412-1418.

[14]"Annual EOR Report," Oil & Gas J. (April 2, 1984) pp. 83-105.

[15]"Annual Review of California Oil and Gas Production," Conservation Committee of California Oil Producers, Los Angeles, California, 1981.

[16]"67th Annual Report of the State Oil and Gas Supervisor," California Department of Conservation, Division of Oil and Gas, Sacramento, California, 1982.

Historical Perspective

In general, heavy, low-gravity crude oils do not flow to a well under ambient reservoir pressures and temperatures. This is due to the high viscosity of the oil. The oil's viscosity is drastically reduced, however, at elevated temperatures. Heat may be applied to a reservoir by injecting hot fluids such as steam or hot water, or it may be generated directly in the reservoir by burning a fraction of the oil in place. This latter process is called in situ combustion.

The use of heat to recover oil dates back to the early 1900s, when downhole heaters were used to heat the oil in the wellbore to prevent the deposition of solids such as paraffins and asphaltenes. Fluid injection into the reservoir for heating purposes did not begin until the 1920s and 1930s when both steam injection and in situ combustion field tests were reported in the United States and the U.S.S.R. (Some early air injection field tests may have unintentionally caused in situ combustion due to spontaneous ignition of the crude oil.) These early field tests were isolated incidents, and no concerted effort was made by the oil industry to routinely apply thermal recovery methods until the 1950s. Several in situ combustion field tests began in the early 1950s. By the late 1950s and early 1960s, steam drive, steam stimulation, and hot waterflooding were being field tested in earnest. In addition to field tests in the United States, thermal methods were being extensively tested in the Netherlands and Venezuela.

The results of these field tests produced an emphasis on steam drive and steam stimulation. It was quickly recognized that the latent heat of steam was able to carry more heat to the reservoir than hot water. The early success of steam injection caused reduced growth of in situ combustion and discontinuation of hot waterflooding. All three technologies are normally applied to reservoirs containing heavy oil. As shown in Figure F-1, the number of in situ combustion projects has remained constant at about 20 since 1974, while the number of steam injection projects has increased significantly to more than 120. Oil produced by steam injection processes has risen dramatically since 1977 while production due to in situ combustion has remained relatively insignificant at its current level of about 10 thousand barrels per day. The increasing success and maturity of thermal recovery is shown in Figure F-2. This figure shows that oil production from thermal projects in California averaged 370 thousand barrels per day in 1982, almost all of which came from the injection of steam. Since most thermal recovery

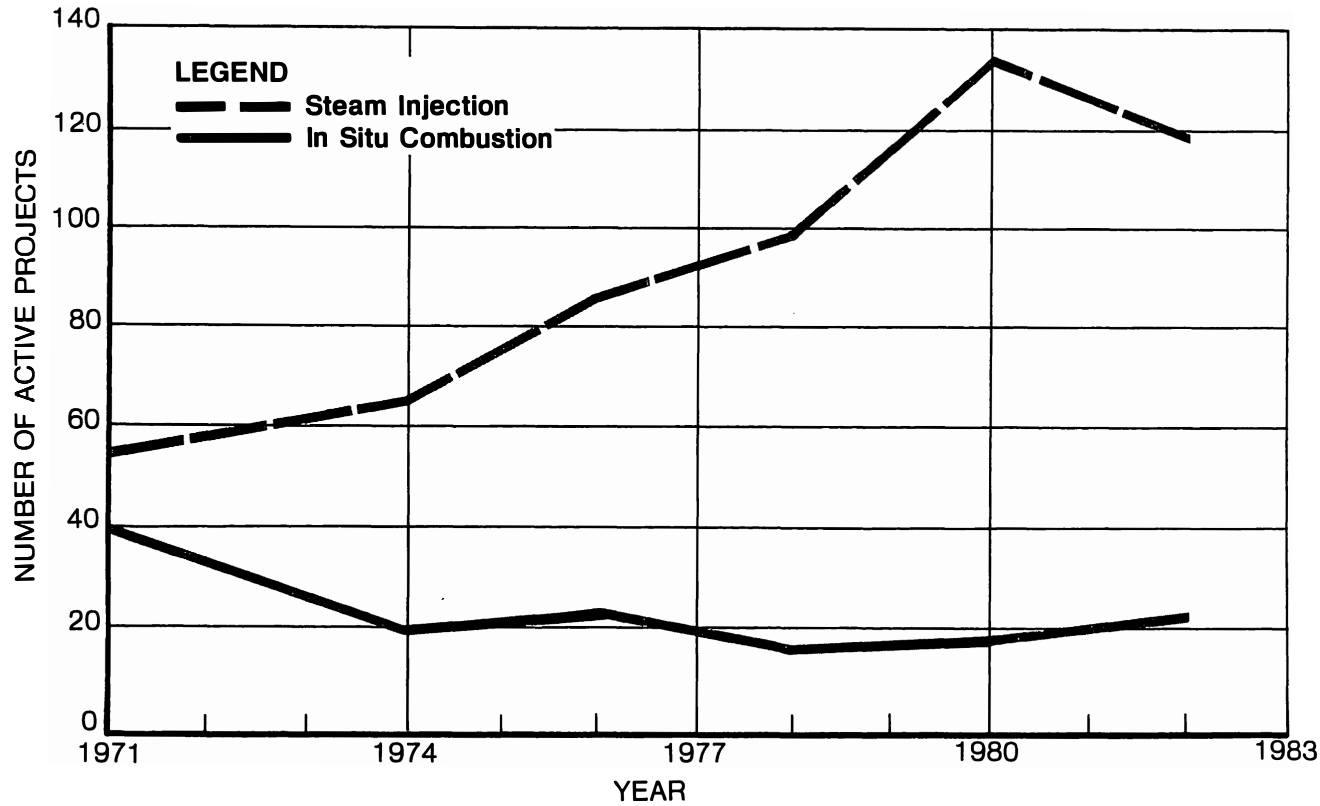


Figure F-1. Number of Active Thermal Recovery Projects in the United States from 1971 to 1982.

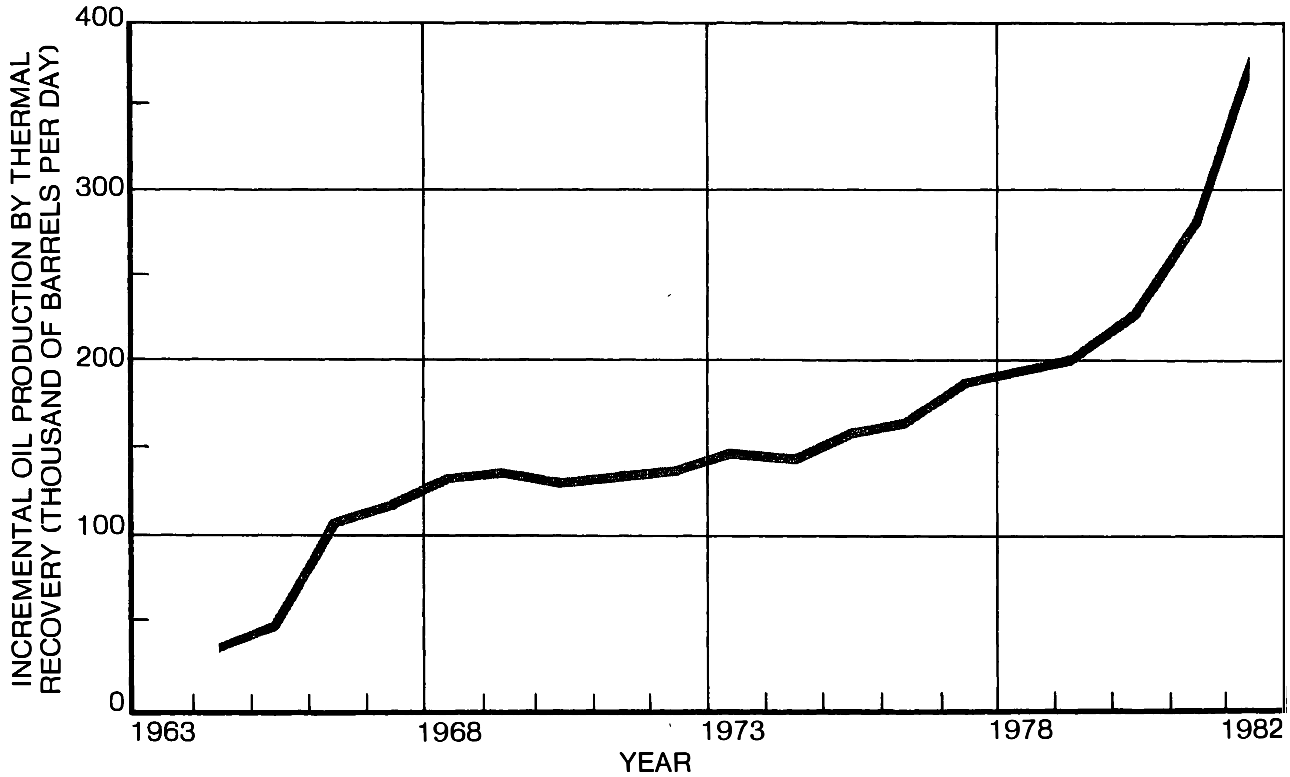


Figure F-2. Production Rate Due to the Application of Thermal Recovery Methods in California from 1964 to 1982.

projects are located in California, thermal processes accounted for 33 percent of all oil produced in the state during 1982.

Steam Drive

Prior to initiating a steam drive the wells are usually steam stimulated. This process is also called "steam soak," "huff and puff," or cyclic steam injection and it is normally applied to heavy oil reservoirs that have at least some natural reservoir energy either due to solution gas or gravity. A volume of steam on the order of 5,000 to 15,000 barrels, on a cold water equivalent basis, is injected into the well over a one- to four-week period. The well is then produced for a period of time ranging from a few months to a year. The well may also be shut in for a short time between the injection and production periods. The use of steam stimulation prior to steam drive has several advantages. The process provides wellbore cleanup, and for an injection well in a future steam drive project may increase the injectivity of steam into the reservoir. Incremental oil production can occur rapidly and aid in paying for the cost of surface steam injection facilities. The utility of steam stimulation, however, is usually limited to a recovery of approximately 15 percent of the oil originally in place (OOIP), based on conventional pattern spacings of 2.5 to 5 acres. Because steam stimulation is normally expanded to a continuous steam drive, no attempt was made in this study to project recoveries for each individual process, and therefore all recovery has been accredited to the more efficient steam drive process.

Steam drive, or steamflooding, consists of continuous steam injection into the reservoir as shown in Chapter Two. The steam heats the oil and either pushes or drags it towards a production well where it is pumped to the surface. Typically, one injection well is surrounded by four production wells. When steam flows into the reservoir, it condenses as the latent heat is transferred to the rock and reservoir fluids. Heating of the adjacent formations above and below the reservoir also occurs as the steam expands outward from the injection well. The steam vapor tends to rise to the top of the reservoir, while the condensed water tends to underrun the steam zone. This separation of the vapor and liquid phase is due to their different densities and it is frequently referred to as gravity segregation.

As the oil is heated, its viscosity is reduced, thus making it possible for both the steam and condensed water phases to displace the oil towards a production well. Significant distillation of the lighter components in the oil can also occur in the steam (vapor) region of the reservoir. The vaporized hydrocarbon will move with the steam (vapor) and condense in a cooler portion of the reservoir. This can result in residual oil saturations as low as 5 to 10 percent in the steam region. The condensed hydrocarbons may also create a solvent bank that further enhances oil displacement. Oil recovery may reach a maximum of 65 to 70 percent of the OOIP for ideal reservoirs and should average at least 40 percent for current ongoing projects.

In most steam injection projects, single-pass boilers are used. The boilers produce steam of approximately 80 percent quality; that is, 80 percent of the injected fluid has been transformed into water vapor and 20 percent remains as liquid water. The fuel used is typically the produced crude oil, although natural gas is also frequently used as a boiler fuel when it is readily available at a favorable price. Natural gas is also the fuel of choice in environmentally sensitive areas where sulfur oxide (SO_x) emissions are being limited. The average steam drive requires the equivalent of 1 barrel of fuel burned for every 3 to 4 barrels of oil produced, resulting in 2 to 3 barrels of net oil sales. *All oil production volumes shown in this report are gross values and include the oil to be burned as fuel in steam generators.* This practice is common throughout industry as government agencies and most publications normally report gross production.

In Situ Combustion

The in situ combustion process, or fire flooding, uses air injection to supply oxygen to a burning front in the reservoir. When air injection is initiated, the crude oil near the injection wellbore begins to oxidize. If the oxidation reaction is rapid (which is the usual case for heavy crude oils in Venezuela and California), the oil will ignite spontaneously and begin to burn. If the oxidation reaction is slow, ignition can be achieved by lowering a heater into the injection well to heat the air. After ignition is achieved, continued air injection will cause the burning front to move out through the reservoir and away from the air injection well. Combustion gases flow on ahead and are produced with oil and water at the production well.

Heat generated at the burning front (where the peak temperature is normally in the range of 600 °F to 1,800 °F) vaporizes formation water near the front and develops a steam zone ahead of the burning front. Water formed in the combustion reaction also contributes to this steam zone. The steam mobilizes and displaces much of the heavy oil from the steamed region, leaving a relatively low oil saturation to be overtaken by the burning front. The high temperatures just ahead of the burning front vaporize and crack the oil, leaving only a coke-like residue to be burned. The light vapors from distillation and cracking flow ahead with the combustion gas and are absorbed in the oil ahead of the steam front. The coke that is burned is the least valuable asphaltic portion of the crude oil and as a result most in situ combustion projects produce a slightly lighter (higher API gravity) crude oil than is originally in place.

As combustion continues, steam vapor and combustion gases flow to the upper part of the reservoir. The combustion front also moves into the upper part of the reservoir in response to the concentration of gas flow.

When the heat front arrives at the producer, the oil production rate usually increases because of the reduction in oil viscosity with increase in temperature. There may also be an oil bank at the steam zone ahead of the combustion front. However, as the burning front nears the producing well, preventive measures (such as circulating water through the annulus) must be taken to protect the well from damage while production continues.

A widely used innovation in combustion process technology is the injection of water with the air, either simultaneously or with alternating cycles of air injection. This process is called wet combustion. Water, flowing through the burned out region, absorbs heat and is vaporized; as steam, it carries the heat through the burning front to the steam zone ahead of the combustion front. Producing well operation is benefited by a longer period of warm production from the first heat-front breakthrough until the arrival of the burning front.

Perhaps the most important benefit of wet combustion is that the amount of residual oil (or coke) left to be burned as fuel by the burning front is substantially decreased. Another effect of wet combustion on fuel consumption is that not all of the fuel may be burned due to lower temperatures. Thus, more oil is displaced and less air injection is required to burn a unit volume of the reservoir. It has been observed that water injection can reduce fuel and air requirements by as much as 30 to 50 percent. Water-to-air ratios vary widely depending upon specific reservoir applications, but generally range from a low of 100 barrels per million cubic feet (MMcf) to 2 thousand barrels per MMcf for what is known as fully quenched combustion.

Environmental Considerations

Summary

The emphasis of this discussion will be on identification of environmental or resource constraints on current and future thermal projects.

More detailed analyses of environmental issues and regulatory programs developed to address these issues are presented in Appendix G.

Process-specific environmental costs (e.g., equipment, operating and maintenance costs) are presented in a subsequent section of this appendix on process-specific cost data. The economic subroutines of the thermal models require the use of these unitized data, which include the current costs of specific pollution control technologies. The costs for providing offsets in environmentally sensitive areas were not included. Offset costs are the major factor that limits thermal expansion in the coastal regions of Southern California (Los Angeles and Santa Barbara counties).

Concerns

Environmental issues of greatest potential concern in planning, developing, and operating thermal projects include air quality, water supply, water quality, and solid waste disposal. Other environmental considerations, discussed in greater detail in Appendix G, include occupational safety and health, heat and sound emissions, and land use planning.

Air Quality

Concerns for emissions from fossil fuel fired steam generators or air compressors currently focus on sulfur dioxides (SO_2), nitrogen oxides (NO_x), particulates, and related issues including ozone and visibility. Additionally, carbon monoxide, hydrogen sulfide, and hydrocarbon emissions from producing wells and other oilfield equipment have received considerable attention.

Water Supply

Most thermal projects, even those with produced water treatment/recycle capabilities, require a substantial amount of process water. The availability and distribution of water, particularly in arid and semi-arid areas, may be a site-specific issue of overriding concern.[17]

Water Quality

Thermal projects may affect surface water or groundwater quality through the discharge of produced water/process water or through spills/leaks of water, oil, or process-specific chemicals. However, over the years the industry has learned to minimize any adverse effects on potentially potable water resources and, similarly, has achieved an excellent spill and accidental discharge record.

[17]U. S. Department of Energy, "Environmental Regulations Handbook for Enhanced Oil Recovery," 1980, DOE/BC/00050-15.

Solid Waste

The final disposition of oilfield solid wastes, particularly scrubber wastes, requires the development and availability of properly designed and operated disposal facilities. The number of approved disposal sites has decreased over the last several years, thus significantly increasing the transportation cost component for waste materials.

Screening Criteria

The screening criteria for thermal recovery are given in Table F-3. The Implemented Technology Case criteria shown are based mainly on published data for existing projects that are thought to be successful. The Advanced Technology Case criteria is such that it will include those reservoirs that are not amenable to thermal recovery under the constraints of currently proven technology but that have characteristics making them reasonable candidates when improved thermal techniques and/or equipment are developed. For a discussion of improved thermal techniques and equipment, see Appendix H.

Depth and Current Reservoir Pressure

The depth and current reservoir pressure are interrelated screening criteria. Wellbore heat loss increases with depth. Also with increasing depth, the steam injection pressure and temperature increases. This causes an increase in the heat loss to the overburden and underburden. A reasonable limit for implemented technology steam injection is 3,000 feet. For in situ combustion, an increase in injection pressure creates higher compression costs. Exceptionally high reservoir pressures can exceed the limits of current air compression technology. The deepest publicized injection depths for in situ combustion is 11,500 feet; however, for this study, the reservoir pressure is below 2,000 pounds per square inch gauge (psig).

Net Pay

The net pay screen is important because excessive heat loss occurs in thin reservoirs, thus causing the thermal processes to become inefficient and economically unattractive. Presently it appears that successful field application is limited to net pay zones that exceed 20 feet.

Oil Content

Oil content is defined as the product of oil saturation and porosity. If this information was

TABLE F-3

THERMAL RECOVERY SCREENING CRITERIA

	Steam Injection		In Situ Combustion	
	Implemented Technology	Advanced Technology	Implemented Technology	Advanced Technology
Depth (ft)	$\leq$3,000	$\leq$5,000	$\leq$11,500	-
Net Pay (ft)	$\geq$20	$\geq$15	$\geq$20	$\geq$10
Porosity*	$\geq$0.20	$\geq$0.15	$\geq$0.20	$\geq$0.15
Oil Saturation x Porosity	$\geq$0.10	$\geq$0.08	$\geq$0.08	$\geq$0.08
Permeability (md)	$\geq$250	$\geq$10	$\geq$35	$\geq$10
Oil Gravity (°API)	10 to 34	-	10 to 35	-
Oil Viscosity (cp)	$\leq$15,000	-	$\leq$5,000	$\leq$5,000
Transmissibility (md-ft/cp)	$\geq$5	-	$\geq$5	-
Current Reservoir Pressure (psia)	$\leq$1,500	$\leq$2,000	$\leq$2,000	$\leq$4,000

*Ignored if oil saturation x porosity criteria are satisfied.

not available, porosity alone was used as a screening criteria. As the porosity decreases, the amount of energy required to heat the greater amount of reservoir rock increases. Also, a minimum oil content is necessary to justify the high cost of a thermal project and to offset the intrinsic fuel requirements. An oil content of 0.10 is equivalent to 776 barrels per acre foot of rock.

Oil Gravity and Viscosity

Viscous, low-gravity crude oils are prime candidates for thermal recovery methods because of the effectiveness of heat in lowering oil viscosity. However, a minimum oil mobility is necessary at reservoir temperature. Therefore, a lower limit was used on oil gravity and an upper limit was imposed on viscosity. Higher gravity, less viscous oils can usually be more economically produced by conventional water injection methods.

Permeability and Transmissibility

Transmissibility is the product of permeability and reservoir thickness divided by oil viscosity. Sufficient permeability or transmissibility is necessary to permit injection rates high enough to successfully propagate a steam or combustion front. A value of 5 millidarcy-feet per centipoise (cp) was used for both steam drives and in situ combustion.

Other Considerations

Some reservoirs that have ongoing thermal projects did not pass the Implemented Technology Case thermal screen. These reservoirs were added to the screened list of thermal candidates to ensure completeness of the performance predictions. The Cat Canyon Field in California is an example of this addition.

This study also excluded generally recognized tar sands or bitumen deposits from consideration for either the Implemented or Advanced Technology Cases. A tar sand is defined as a hydrocarbon deposit having an in situ viscosity greater than 10,000 centipoise (cp) at reservoir conditions, or a hydrocarbon with a gravity less than 10°API. A few fields having crude oils exceeding these limits, but showing response to steam injection, are included in the study.

Low-Gravity Crude Oil Price Adjustments

The low-gravity crude oils typical of most thermal recovery applications are normally discounted in price below the level for medium gravity (mid-continent) crude oils because of their poorer quality, which leads to lower value refined products. This fact is illustrated in Figure F-3 where several 1983 posted sales prices for California crude oil are plotted versus API gravity. It is important to realize that during 1983, when the average price for 40°API mid-continent crude oil was approximately $30 per barrel, the average California price for comparable gravity crude oil was only $26.25 per barrel, thus reflecting about a $3.75 per barrel transportation cost for getting crude oil to the Gulf Coast region. Similarly, the 13°API crude oil most typical of the active California thermal projects at that time sold for only $20 per barrel. The use of gravity adjusted crude oil prices serves to put the thermal recovery methods in a proper frame of reference.

Process-Dependent Cost Data

Steam Injection Specific Costs

A summary of process-dependent costs utilized for steam injection is shown in Table F-4. Enhanced oil recovery from steam injection has been a viable and growing process for more than 25 years. Major thermal operators have a wealth of experience in installing and operating projects in widely different circumstances. There are shallow steamfloods with large-scale facilities and lower per-barrel cost compared to smaller and deeper projects utilizing high-cost materials with high per-barrel costs. Based on industry data, three different cost options (low-medium-high) were developed for this study. The medium cost values represent normal facilities with steam generators operating up to 2,500 psig and injecting into wells as deep as 2,000 feet.

The economic model used the medium-cost options as default values. Well costs based upon historical experience were set at a medium value of $100 per foot of depth. Oil fired steam generator investment costs include scrubbing equipment and installation. The medium cost includes SO_x and NO_x scrubbing to meet environmental requirements such as those that exist in the San Joaquin Valley in California. A single-pass, 2,500 psig pressure steam generator burning lease crude oil and rated at 50 million BTU per hour is the basic equipment. The normal two- to five-acre pattern steamfloods are estimated to require flowlines and surface production facility capital of $21,500 per acre with the central plant cost based on $400 per barrel of maximum daily oil producing rate.

Excluding fuel and water treating costs, the oil fired steam generators have a normal operating cost of $0.36 per barrel of steam (BS).

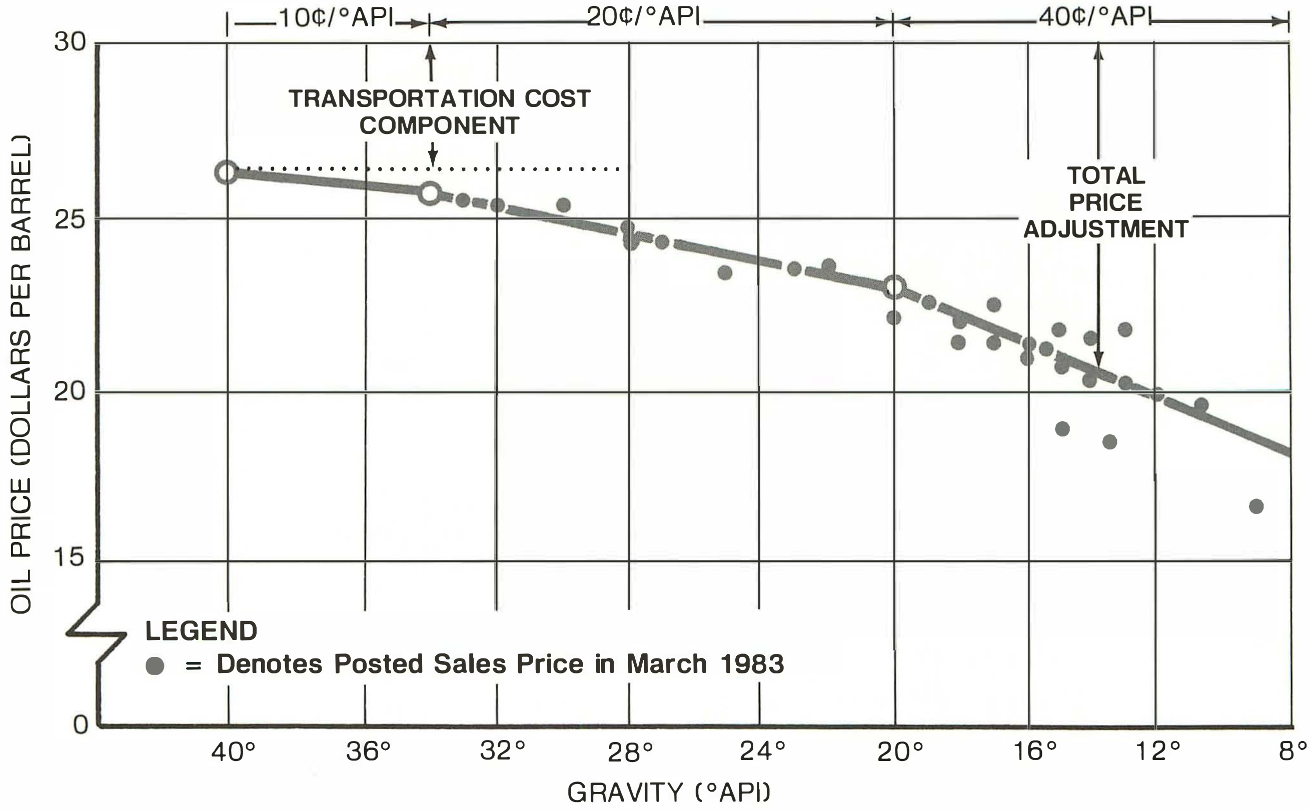


Figure F-3. Posted Sales Prices for California Crude Oil in March 1983.

TABLE F-4

STEAM INJECTION SPECIFIC COSTS

Item		Cost High	Cost Medium	Cost Low
I.	Produced Water Recycle Plant			
	A) Installed Capital ($/BS)*	100	75	50
	B) Operating Cost ($/BS)	0.15	0.125	0.10
II.	Steam Generators—Oil Fired (50 Million BTU/hr and 3,500 BWPD)†			
	A) Installed Capital ($)	850,000	800,000	750,000
	B) Fuel Operating Costs ($)	Fuel volume × oil price; oil price = the gravity adjusted produced oil price		
	C) Other Operating Costs ($/BS)			
	Electricity	0.12	0.11	0.10
	Maintenance and Labor	0.13	0.12	0.10
	Chemicals	0.17	0.13	0.10
		0.42	0.36	0.30
	D) Availability (%)	85	85	85
III.	Steam Generators—Gas Fired (50 Million BTU/hr and 3,500 BWPD)			
	A) Installed Capital ($)	all generators = $650,000		
	B) Fuel Operating Cost	Fuel volume × gas price based on oil price and site locality ($4.42 per Mcf in California at $30 per barrel crude oil price for 40°API mid-continent crude oil)		
	C) Other Operating Costs	$0.24 per Mcf for all cases		
IV.	Steam Manifold and Flowlines			
	A) Capital Costs ($/Acre)	10,000	8,750	7,500
V.	Surface Production and Vapor Recovery			
	A) Surface Production Lines ($/Acre)	10,000	8,500	7,000
	B) Vapor Recovery ($/Acre)	5,000	4,500	4,000
		15,000	13,000	11,000
VI.	Central Plant Facilities (Treaters, Test Equipment, Separators, Etc.)			
	A) Capital Costs ($/BOPD)‡	500	400	300
VII.	Fixed Operating Costs			
	A) Vehicles, Electricity, Company Labor ($/Prod-Yr)	20,000	18,000	16,000
VIII.	Variable Operating Costs			
	A) Chemicals, Treater Fuel, Contract Labor, Etc. ($/BO)§	3.00	2.50	2.00
IX.	Water Disposal			
	A) Operating Cost ($/Barrel)	0.025 × BS		
X.	Well Cost (D&C&E)($)	120 × depth	100 × depth	80 × depth
	Advanced Technology Case			
XI.	Plant Facilities Capital Cost ($)			
	A) Mobility Control Chemicals	$2 per barrel of incremental oil per full cycle of single pattern life. Incremental oil = 10% of OOIP		
XII.	Variable Operating Costs ($/Barrel)	Cost of conformance improvement chemical = $0.25/BS		
XIII.	Deep Well Completion ($)	For depth greater than 3,000 feet, use high cost option plus incremental cost of $20,000 per pattern		

*BS denotes barrel of steam.
†BWPD denotes barrels of water per day.
‡BOPD denotes barrels of oil per day.
§BO denotes barrel of oil.

Fixed operating costs for a medium-cost steamflood (such as electricity, vehicles, and company labor) are estimated at $18,000 per producing well per year. Variable operating costs, such as chemicals and contract labor, are estimated at $2.50 per barrel of oil produced. Water disposal costs are estimated at $0.10 per barrel of produced water. These costs are considered normal for California steamfloods.

For oil fired generators, the purchased fuel necessary for startup operations is estimated from the generator energy requirements. The annual fuel requirement is based on steam generated, the heat content of the steam, a generator efficiency of 85 percent with steam quality of 75 percent, and a fuel energy value of 6.3 million BTU per barrel of oil. Fuel purchased equals the fuel required less oil produced with the cost based on the sales price of the produced oil.

Where practical, natural gas is often utilized as steam generator fuel. In some cases environmental considerations force operators to utilize gas. Gas fired generators do not require scrubbing equipment but NO_x controls are needed. Gas fired generators are estimated to cost $650,000 each and have an operating cost of $0.24 per barrel of steam. Fuel per million BTU for gas fired steam generators is estimated at $4.42 in California for the nominal $30 per barrel price. See Table 8 in Chapter Three for gas price range.

In Situ Combustion Specific Costs

A summary of in situ combustion process specific costs is given in Table F-5. As for the steam drive process, producer and injector drilling and completion costs were specified at $100 per foot of depth rather than using the process-independent drilling costs listed in Appendix C. The installed cost of electrically driven reciprocating compressors was estimated at $1,000 per horsepower (hp). Air distribution systems were assumed to cost $8,500 per acre based on a conclusion that most wet combustion projects would have 10-acre spacing or less. Additional costs of $8,000 per acre and $10,000 per acre were included to cover the waste gas gathering system and the oil production system, respectively. The central oil, water, and gas handling plant was assumed to cost $500 per daily barrel of oil. A waste gas treatment and incineration facility with SO_x removal was included at a cost of $50 per thousand cubic feet (Mcf) per day of waste gas requirement. The cost of water treatment facilities for wet combustion was set at $75 per barrel of water per day capacity.

Operating cost for air compression was set at $1.33 per hp per day based on an average electricity cost of $0.07 per kilowatt hour. Compressor plant maintenance costs were estimated at $0.03 per Mcf of air, and an additional operating expense of $0.04 per Mcf was added to cover the costs of various technical support and specialized lab tests. Fixed pattern operating costs were set at $20,000 per year, while variable production costs were assumed to be $3.00 per barrel of oil. Additional operating costs of $0.125 and $0.10 per barrel of water were included for injection water treating and water disposal, respectively. Operating costs for waste gas treatment were assumed to be negligible since it is believed that most projects will produce gas with sufficient BTU content to make the gas usable as a fuel source.

The costs shown in Table F-5 are based on data from a sparse number of active projects. Examination of the raw data from these projects indicates that the capital and operating costs for in situ combustion projects are highly variable and site specific. Where sufficient project-specific information was available, some adjustments were made to the cost assumptions. Due to the high sensitivity of the process economics to the cost of injecting air, air compression capital and operating costs were linked to compressor horsepower, which was in turn linked to reservoir pressure, well depth, and flow rate as indicated by the equation shown in Table F-5.

Cost of Environmental Control

The environmental cost included in the process-specific costs discussed above represent a major component of thermal investment and operating costs. Steam generator costs are increased by more than 30 percent to scrub the effluent gas. Generator operating costs to handle the scrubbing chemicals and maintain the equipment are also increased by more than 30 percent. Similarly, for in situ combustion the vapor recovery system and waste gas treatment facilities represent process-specific costs to protect the environment. Future trends in environmental requirements may increase these costs considerably.

Process Analysis Procedures

Ongoing Thermal Recovery

It was recognized early in this study that the large volume of existing thermal production in the United States would require a different approach for predicting future ultimate

TABLE F-5

IN SITU COMBUSTION SPECIFIC COSTS

Capital Costs		Operating Costs	
Item	**Cost**	**Item**	**Cost**
1. Air Compressor—including electricity; prime mover on all installation cost to outlet header $hp = (a/1000)\ (48.13)\ P_D^{.25}$ P_D = compressor discharge in psia $P_D = 1.2\ [1.81 \times 10^{-6}\ L\ a^2 + P_i^2]^{1/2}$ L = well depth + 1500' a = air rate P_i = injection pressure	$1,000/ hp	1A. Energy = Assumes Electric Drive w/94% Efficiency $KW = \frac{hp \times 0.746 \times hp}{0.94} = 0.79 \times hp$ $KWHR/Day = KW \times 24 = 19 \times hp$ Using $0.07/KWHR Power Cost = $1.33/hp Day	$1.33/hp Day
		1B. Maintenance & Labor = 3% of installed compressor capital per year	
		Other Operating Costs Cooling Water Make-up 24-Hour Operator	 $0.01/Mcf 0.02/Mcf $0.03/Mcf
2. Waste Gas Treatment—including all costs to header from vapor recovery	$50/Mcf per day	2. If gas has usable BTU content, it is assumed that heating value lines offsets costs. If BTU content is low, it may be incinerated with auxiliary fuel at no additional cost.	None

TABLE F-5 (Continued)

Capital Costs: Item	Capital Costs: Cost	Operating Costs: Item	Operating Costs: Cost
3. Water Treatment—including recycle for wet combustion only. Use medium steam case. Since the model uses 1 bbl/Mcf, this can be computed as: 75 × a	$75/bbl of of daily capacity	3. Use steam case medium Operating cost can be computed as: 0.125 × a	$0.125/bbl
4. Air Distribution System—highly dependent on pattern size High side = steam case, med. based on 2½ acre patterns	$8,500/acre	4&5. Technicians and instruments plus lab work, etc., for monitoring and controlling	$0.04/Mcf
5. Vapor Recovery—higher than steam due to individual measurement and sampling requirements—based on 2½ acre 9-spot	$8,000/acre		
6. Incremental Production—well costs	Negligible	6. Fixed operating costs (includes workover costs)	Same as high steam case ($20,000 Producer Yr.)
7. Incremental Injection—well costs 6 & 7 will be absorbed into a total $100/ft cost/foot for wells that will be very close to the steam case. $100/foot will be assumed as an initial default value	Negligible $100/foot	7. Variable operating costs ± 10%	Same as high steam case ($3.00/BO)
8. Surface Production Lines—same as high steam case	$10,000/acre	8. Water disposal	$0.10/bbl
9. Central Plant Facilities—same as high steam case	$500/BOPD		

recovery and producing rates than was used for chemical and miscible flooding. Instead of attempting to predict thermal recovery by geologic province or by state, or to model each reservoir that either had or would qualify for thermal recovery processes, it was decided to survey those companies that were the most actively involved in thermal recovery operations.

Each operator who had over one thousand barrels per day attributable to thermal operations was requested by the NPC to provide his best estimate of production rate for (1) proved developed reserves, (2) proved undeveloped reserves, and (3) probable and possible reserves. In addition to the total production predicted for these properties, the operators were requested to provide a listing of all fields in which current thermal operations were being conducted, and an estimate of the amount of corresponding production acreage.

These data, as received from 16 responding companies, were assembled on a confidential basis, and then were provided to the Thermal Task Group in the form of aggregated composite curves for the three reserve categories listed above. These curves are shown in Figure F-4 and indicate that reported production from thermal recovery projects in the United States in December 1982 was approximately 425 thousand barrels per day.

The Thermal Task Group then determined if the fields represented on the aggregate curve were reported in full. For example, only 70 percent of the Midway-Sunset Field, which produces approximately 110 thousand barrels per day, was reported. Therefore, an adjustment

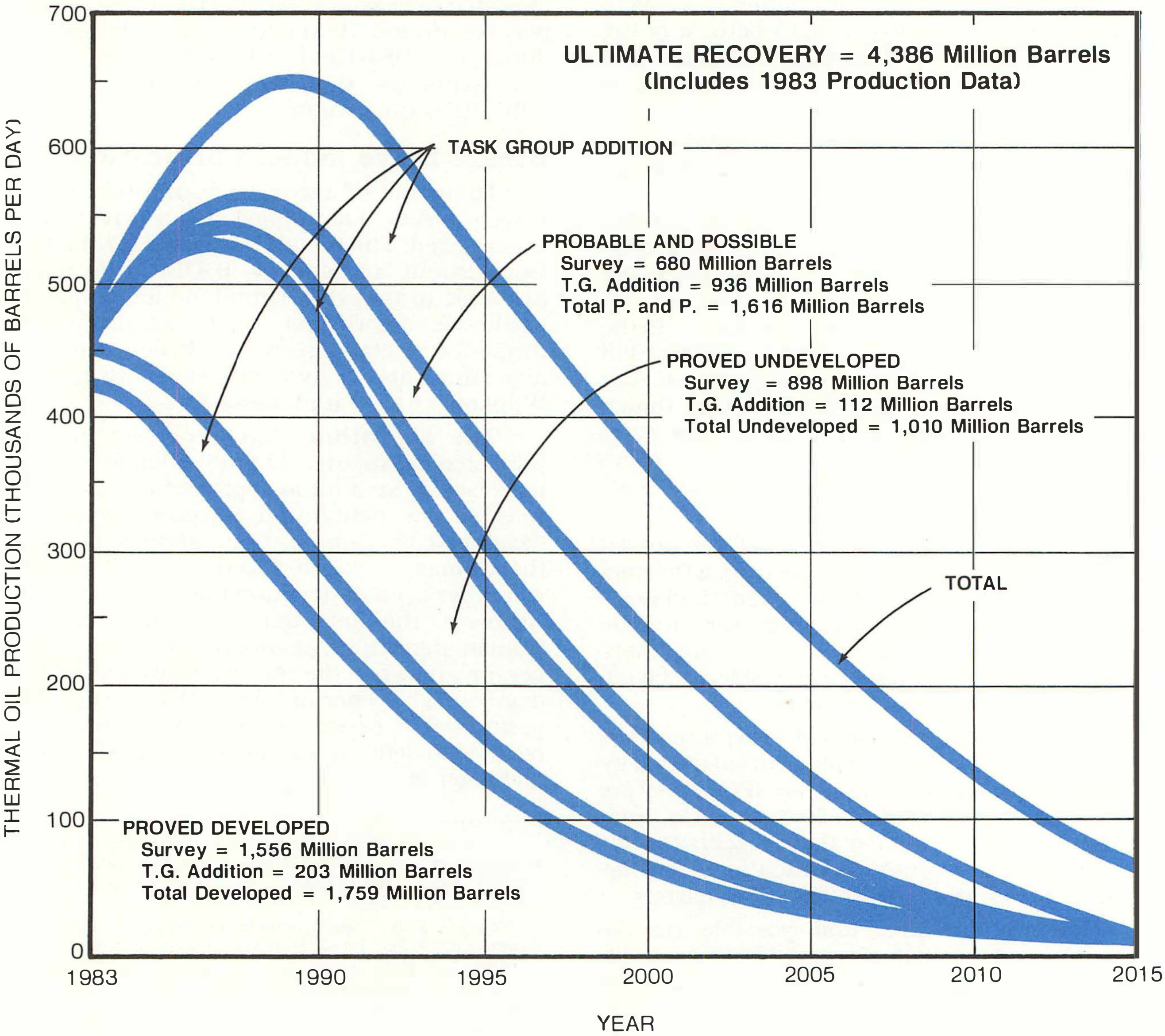


Figure F-4. Composite of Total U.S. Thermal Production.

had to be made. In cases where the Task Group believed a field was only partially reported, a method to improve or change the projection was developed. The method included review of the total field production reported by any available public source, such as state records[18] or the *Oil & Gas Journal* EOR survey.[19] If it appeared that the field was underreported, the best estimate of the missing production was added to the aggregate curve. The necessary parameters for a model run to predict the decline of this unreported incremental production were then determined, such as acreage, net thickness, and existing saturations. These parameters were compiled from sources such as the NPC data base, state records, or other published data.

The steam drive model was used for both steam stimulation cases and steam drive predictions. The steam stimulation cases were constrained to a recovery of 15 percent of the current oil in place. This approach for the steam stimulation cases was believed preferable to arbitrarily declining such unreported projects at the decline rate of the aggregate curve.

The Thermal Task Group reviewed nearly 50 individual fields where thermal methods are currently being employed to develop a most realistic Implemented Technology Case projection for the proved developed classification. The production not reported in the NPC survey added about 25 thousand barrels per day to the NPC aggregate curve, making the total 1983 production for the proved developed category some 450 thousand barrels per day as shown in Figure F-4. *Again, both the production rates and ultimate recovery values represent gross production and include the oil to be burned as fuel in steam generators.*

The Task Group also reviewed the proved undeveloped category for each known thermal project and developed the acreage, thickness, and saturation parameters necessary for the model runs to complete this classification. Unreported acreage was only considered if it offset proven steamflood projects.

The 2.8 billion barrels of proven reserves (both developed and undeveloped) submitted by the producers responding to the NPC survey are included in reported booked reserves and, therefore, identification of these reserves in this study does not represent an addition to the current U.S. reserve base of 28 billion barrels.

For the probable and possible reserve category, each operator most likely used different criteria for estimating future production potential, so the Task Group did not attempt to separate probable and possible reserves. Unreported acreage was treated as if it were a new steamflood candidate. The Task Group used its knowledge of individual field developments to determine appropriate inputs for the steamflood predictive model, which yielded the results shown in Figure F-4. The recovery potential of the add-on probable and possible acreage was estimated at approximately 900 million barrels.

Considering all three categories in Figure F-4, the potential production for reservoirs with ongoing thermal projects is estimated to total 4.4 billion barrels during the 30-year study period from 1984 to 2013. This is not the ultimate recovery, as the producing rate in 2013 is estimated at 70 thousand barrels per day. Production from these ongoing projects is expected to peak at some 650 thousand barrels per day around 1990 with most of the growth during the 1984-1990 period being attributable to expansions that were initiated in the 1981-1984 time frame.

Steam Drive Model Calibration

To predict oil recovery from future steam drive projects, a simplified steam drive model was utilized. The model, developed for the U.S. Department of Energy (DOE) and made available to the NPC, contained four different predictive algorithms. Each algorithm was evaluated by comparison to field data. The four algorithms are by Aydelotte et al.,[20] Gomaa,[21] Williams et al.,[22] and Jones.[23]

The algorithm that most accurately predicted cumulative oil production for several large-scale steamflood projects that were selected for calibration purposes was that developed by Gomaa. Comparisons between the Gomaa correlation and actual field data were very good for nondipping reservoirs. However, the field data indicated that the Gomaa algorithm became progressively more pessimistic when the reservoir dip exceeded 10 degrees. The Thermal Task Group therefore performed a series of calibration runs that resulted in defining a suitable dip correlation for inclusion in the steam drive model.

[18]See footnote 16.

[19]See footnote 14.

[20]Aydelotte, S. R., and Pope, G. A., "A Simplified Predictive Model for Steam Drive Performance," SPE 10748, presented at the 52nd Annual California Regional Meeting, San Francisco, California, March 24-26, 1982.

[21]Gomaa, E. E., "Correlations for Predicting Oil Recovery by Steamflood," J. Pet. Tech. (February 1980) pp. 325-332.

[22]Williams, R. L., Ramey, H. J., Jr., Brown, S. C., and Sanyal, S. K., "An Engineering Economic Model for Thermal Recovery Methods," SPE 8906, presented at the 50th Annual California Regional Meeting, Los Angeles, California, April 9-11, 1980.

[23]Jones, J., "Steam Drive Model for Hand-Held Programmable Calculators," J. Pet. Tech. (September 1981) pp. 1583-1598.

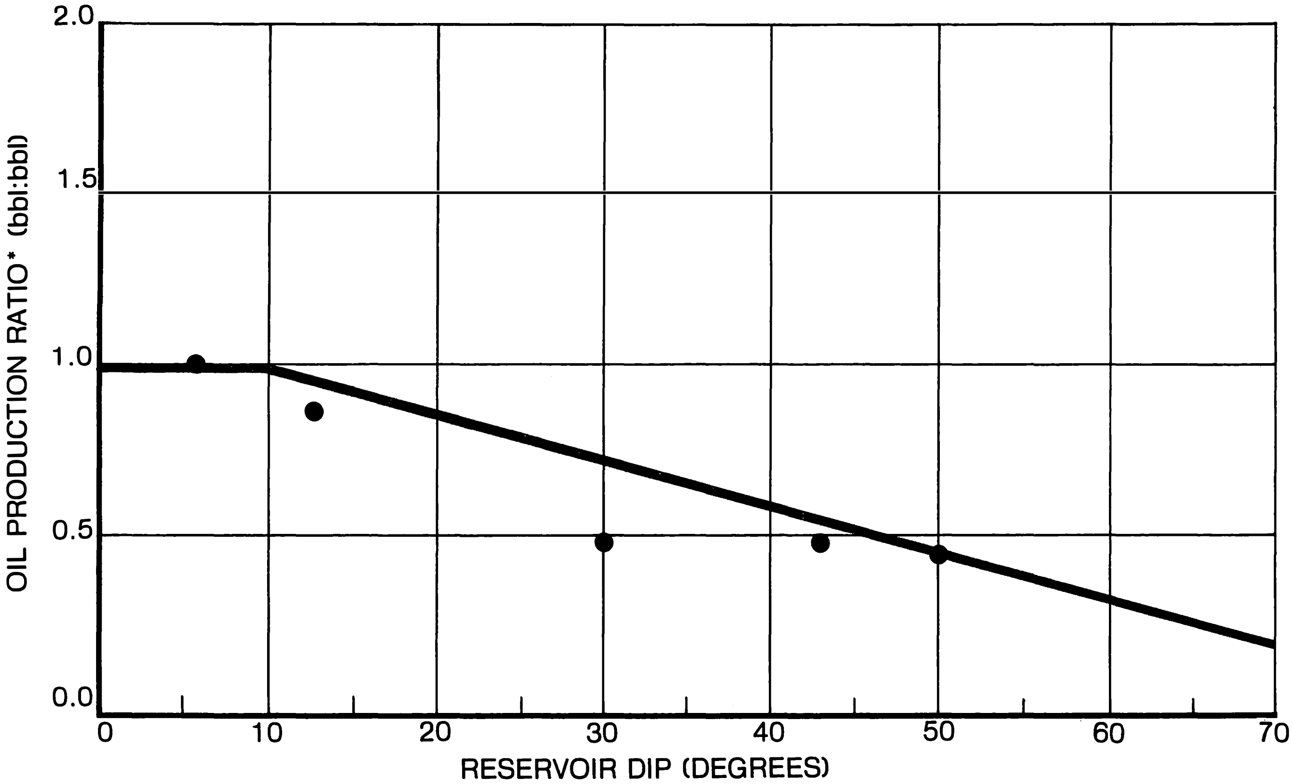


Figure F-5. Comparison of Steamflood Predictive Model and Field Results.

*Cumulative Oil Recovery Predicted Using Gomaa Model ÷ Actual Oil Recovery.

Figure F-5 compares results from the modified model against reservoirs with dip angles up to 50 degrees. The field data were obtained from the Kern River, Midway-Sunset, Poso Creek, and Yorba Linda Fields. Some fields are represented by data from multiple types of well patterns. The field data include line drive and inverted five-spot patterns. The curve shown in the figure was used to correct the Gomaa prediction for reservoir dip. For dip less than 10 degrees, no correction was applied. At higher values of dip, the Gomaa prediction was multiplied by a constant representing the slope of the correlation curve.

Gomaa's original model was developed through a simulation study of a Kern River Field reservoir. By varying input values and observing the effect on oil recovery, a set of calibration curves was obtained. The calibration curves are based on the amount of heat injected into the reservoir, reservoir heat loss, and mobile oil saturation. The Gomaa algorithm in the DOE Steam Flood Predictive Model was found to be very stable in comparison to the other algorithms, and it worked surprisingly well with a variety of reservoir types.

In Situ Combustion Model Calibration

The model used to predict in situ combustion performance was based on the correlation of Brigham, Satman, and Soliman.[24] The correlation relates oil affected (oil burned and oil produced) to the amount of air injected and the reservoir volume.

Data from three field cases were used to test the in situ combustion model. The simplified model predictions matched field results reasonably well, as shown in Figure F-6. The correlation is for dry combustion only, so a technique to predict wet combustion performance was developed using laboratory data from Garon and Wygal[25] and Prats.[26] The wet combustion correlations are based on laboratory experiments conducted in linear slim tube systems and are somewhat optimistic because of the lack of gravity effects.

Oil burned was estimated assuming a constant air-to-fuel ratio of 70 Mcf of air per barrel of oil burned. This air-to-fuel ratio was chosen from field data that ranged from 65 to 80 Mcf per barrel. Oil production is the difference between the amount of oil affected and the amount of oil burned.

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[24]Brigham, W. E., Satman, A., and Soliman, M. Y., "Recovery Correlations for In-Situ Combustion Field Projects and Application to Combustion Pilots," J. Pet. Tech. (December 1980) pp. 2132-2138.

[25]Garon, A. M. and Wygal, R. J. Jr., "A Laboratory Investigation of Fire-Water Flooding," Soc. Pet. Eng. J. (December 1974) pp. 537-544.

[26]See footnote 1.

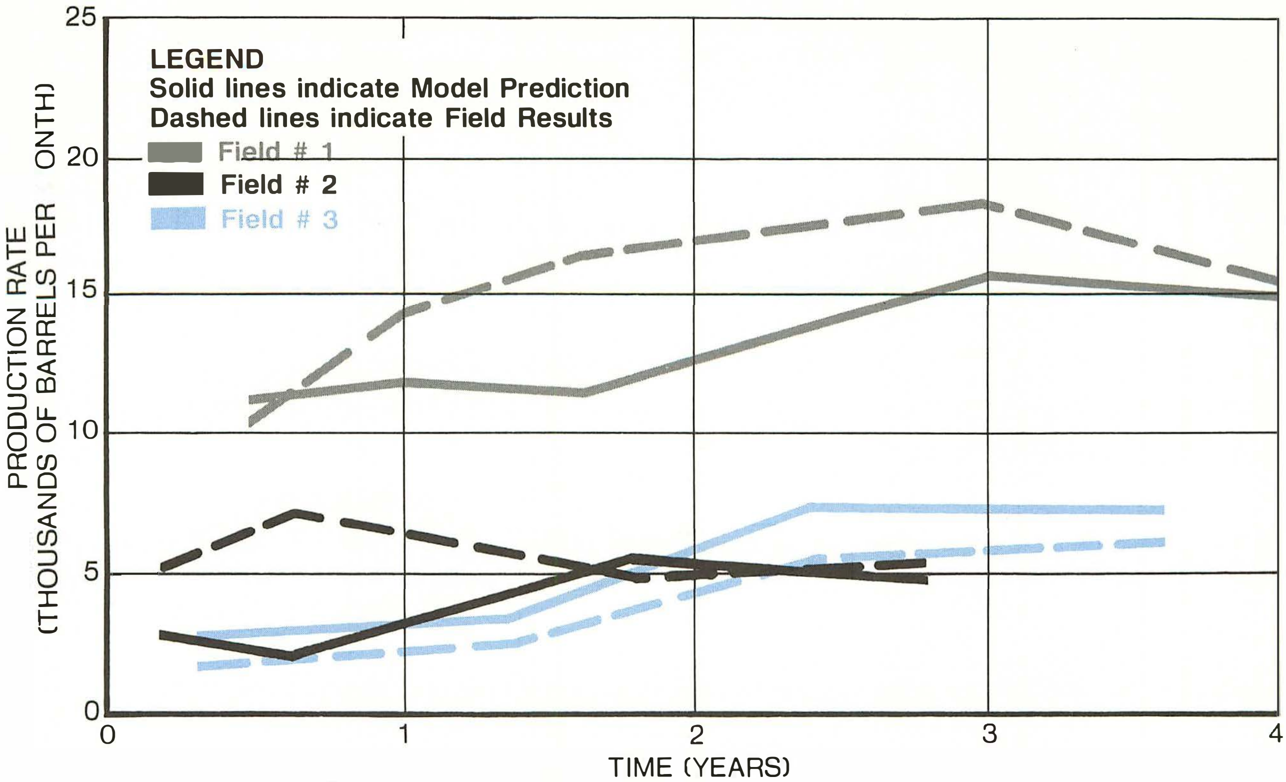

Figure F-6. In Situ Combustion Model Prediction vs. Actual Field Data.

Estimates of water and gas production were needed to evaluate the economic aspects of the process. Produced water was calculated as being equal to the injected water plus water displaced during the combustion process minus the water remaining in the burned volume. A water saturation in the burned volume of 20 percent for wet combustion and 0 percent for dry combustion was assumed.

Produced gas was equal to injected nitrogen plus gaseous reaction products minus gas contained in the burned volume. The amount of reaction gases was assumed to be two-thirds of the injected oxygen. The gas saturation in the burned volume was assumed to be 80 percent for wet combustion and 100 percent for dry combustion.

The decision to apply wet or dry combustion was based on oil viscosity and rock permeability. If the oil viscosity was above 10 cp and the permeability of the reservoir was above 100 millidarcies, wet combustion was the preferred process. At lower viscosities, inadequate oil residue to support combustion may be left; at lower permeabilities, injected water may excessively reduce the rate at which air can be injected. For simplicity, a constant water-to-air ratio of 1 barrel of water per Mcf of air was chosen for the wet combustion process. This ratio is in the range of values reported in field data and by Prats.[27]

Because high temperatures are present during ignition at the injection well, it was decided to drill new injection wells for the combustion process and to use existing wells as producers. The number of wells drilled was determined assuming a production-to-injection well ratio of 2:1. This value represents an inverted seven-spot pattern, or a midpoint between an inverted five-spot pattern and nine-spot pattern development. Within limits, pattern size was normally calculated by dividing the field area by the number of injection wells. The lower limit was set at two acres per pattern with a minimum pattern volume of 200 acre-feet. The upper limit was set at 40 acres per pattern. If the Thermal Task Group had site-specific knowledge regarding an individual reservoir development, this pattern acreage was used.

The air injection rate was calculated assuming a 10-year pattern life. The amount of air needed to burn a certain fraction of the pattern volume was determined, and the injection rate was calculated by dividing this volume of air by 10 years. The ultimate percentage of pattern volume burned was based on pattern area:

[27]See footnote 1.

40 percent if the pattern area was 20 acres or greater, 50 percent if the pattern area was between 5 and 20 acres, and 60 percent if it was less than 5 acres. The injection rate for the first year was assumed to be 50 percent of the average calculated rate, but the model uses a constant injection rate after the first year. The injection pressure was calculated from the radial flow equation and the calculated injection rate. The injection pressure and flow rate, along with reservoir depth, dictated the compressor horsepower requirements, per the equation in Table F-5.

Reservoir Development

For both the steam drive and in situ combustion projects, one of the key parameters to predict oil recovery over the life of a reservoir requires a prediction of how fast the acreage is developed. This was accomplished by defining the well pattern size and the number of patterns developed each year. It was assumed that each reservoir was fully developed during its productive life, meaning that no acreage was left undeveloped.

A first estimate of the pattern size was obtained by dividing the reservoir acreage by the number of existing wells. Next, the reservoirs were individually evaluated by the Thermal Task Group and the pattern size was adjusted based on personal experience and knowledge of the reservoir. The pattern sizes thus selected ranged from 2 acres to a maximum of 15 acres for the steam drive projects. Larger maximum pattern sizes were permitted for in situ combustion because this process is less sensitive to reservoir heat losses.

The predictive correlation for in situ combustion was modified for a few reservoirs whose net thickness substantially exceeded the thicknesses of the reservoirs used for the correlation. The modification assumed that the reservoir was developed in zones, each of which had a maximum thickness of less than 150 feet.

The number of patterns developed per year was calculated from the total time necessary to fully develop the reservoir. Full reservoir development was assumed to be 10, 20, or 30 years depending upon the reservoir size. Larger reservoirs were assumed to have longer reservoir development times. Again, personal experience of the Thermal Task Group was used to select development times for each reservoir. If no site-specific reservoir data were available, 20 years was selected as a reasonable development period.

Thermal Recovery Results

Implemented Technology

Implemented technology represents technology currently in place and proven by successful field tests. The Implemented Technology Case category of reservoirs consists of those reservoirs satisfying the Implemented Technology Case screening criteria. The reservoirs were divided into three classes that are unique to thermal recovery processes: ongoing thermal projects, future steamflood candidates, and future in situ combustion candidates. Over 95 percent of the ongoing thermal projects production is from steam processes.

Advanced Technology

Advanced technology represents technology that may reasonably be expected to be field proven within the next 30 years. The Advanced Technology Case category of reservoirs consists of those reservoirs considered in the Implemented Technology Case plus those additional reservoirs that met the more liberal Advanced Technology Case screening criteria in Table F-3. The Advanced Technology Case screening criteria increases the number of reservoirs to which thermal recovery methods are applicable by allowing for improved heat delivery efficiencies, thereby extending the depth and pressure limits. Another change that was made for the Advanced Technology Case was that the steam drive predictive model was revised to predict higher oil recovery than for the Implemented Technology Case. The additional production is estimated to result from improved vertical and/or areal conformance due to the use of foams and other special additives designed to reduce gravity segregation and increase sweep efficiency. The additional ultimate recovery attributable to use of these materials was assumed to be 10 percent of OOIP. No such modifications were made to the in situ combustion model used for the Advanced Technology Case. Although the Thermal Task Group realized that innovations such as using pure oxygen or oxygen-enriched air for combustion may improve performance or economics in some reservoirs, not enough information was available to estimate the magnitude of such benefits. Also, preliminary results from laboratory and field tests indicate that the combustion mechanisms may remain the same and, therefore, the primary advantage of using enriched air or pure oxygen may be entirely operational and cost related.

It was further assumed for the Advanced Technology Case that environmental control research would lead to better equipment by 1995 such that new projects in Los Angeles and Santa Barbara counties of California could be considered in the Advanced Technology Case. Therefore, some reservoirs in these areas that were specifically excluded from the Implemented Technology Case were included under the Advanced Technology Case assumptions.

For the Advanced Technology Case, ongoing steam drive projects were permitted to benefit from the use of foams and other sweep improvement agents beginning in 1988. Other features of the Advanced Technology Case became available in 1995.

Oil Recovery Projections

Figure F-7 shows the Implemented Technology Case producing rate for the ongoing thermal projects, new steamfloods, new in situ combustion projects, and total thermal enhanced oil recovery for the $30, 10 percent minimum ROR base economic case. Over 80 percent of the oil production is from fields in California, where the average oil price is approximately $21 per barrel due to the API gravity and transportation adjustment made to the nominal $30 per barrel price.

The ultimate recovery potential for thermal projects represented by Figure F-7 is estimated at 4.4 billion barrels for ongoing projects, 0.8 billion barrels for new steamflood projects, and 1.3 billion barrels for in situ combustion projects, giving a total of 6.5 billion barrels of ultimate thermal recovery.

The effect of nominal crude oil price over the range of $20 to $50 per barrel at a 10 percent minimum ROR is shown for the Implemented Technology Case in Figure F-8. The peak production rate from thermal processes increases from 610 thousand barrels per day at $20 per barrel to some 760 thousand barrels per day at $50 per barrel. Furthermore, the peak rate occurs much later during the study and lasts much longer as the nominal crude oil price increases. The ultimate recovery for each oil price is given in Table F-1 and displayed graphically in Figure F-9. The ultimate recovery at $20 per barrel is 4.4 billion barrels, and this value increases to 7.2 billion barrels for the nominal $50 per barrel case.

The sensitivity of the Implemented Technology Case potential to minimum RORs of 0 percent, 10 percent, and 20 percent is shown in Table F-6. This matrix shows a range from a minimum potential of 3.8 billion barrels for a nominal price of $20 per barrel and a 20 percent minimum ROR to 8.8 billion barrels for a nominal price of $50 per barrel and a 0 percent minimum ROR. It is not implied that a

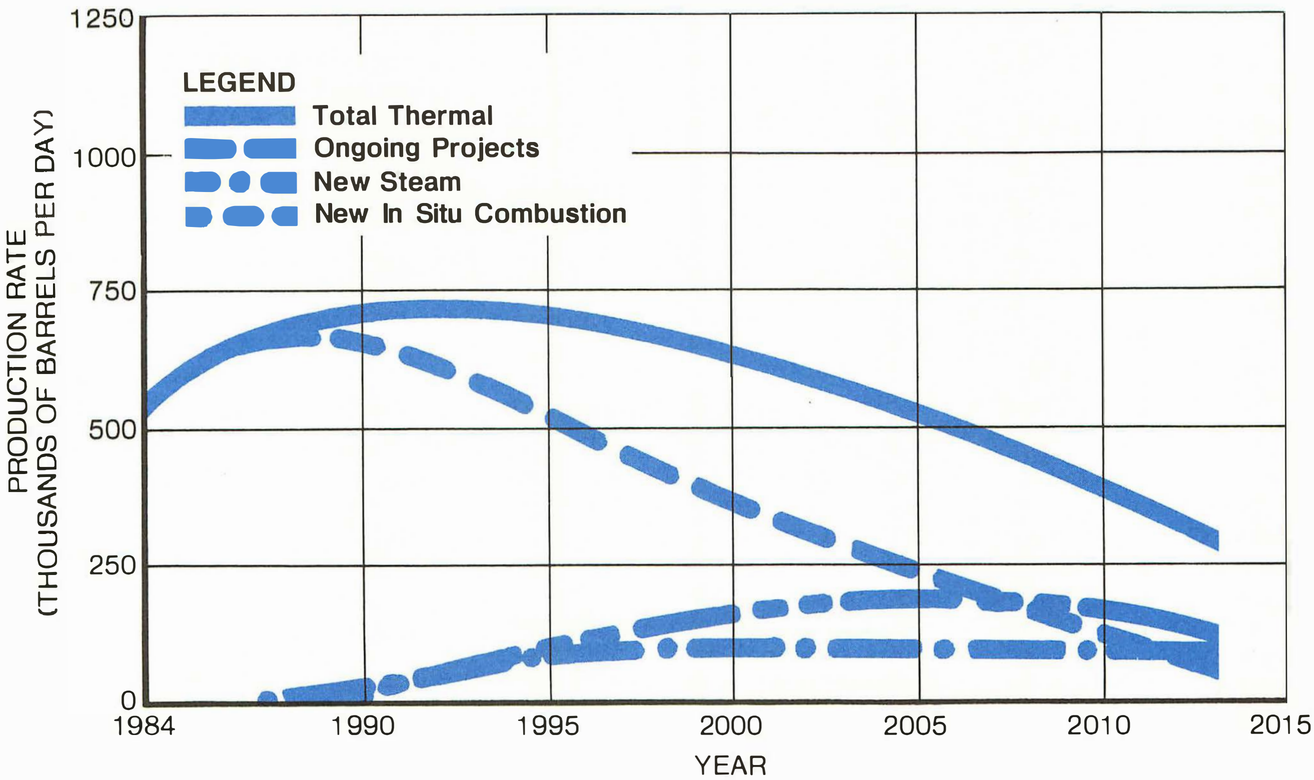

Figure F-7. Production Rate for Thermal Recovery—Implemented Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

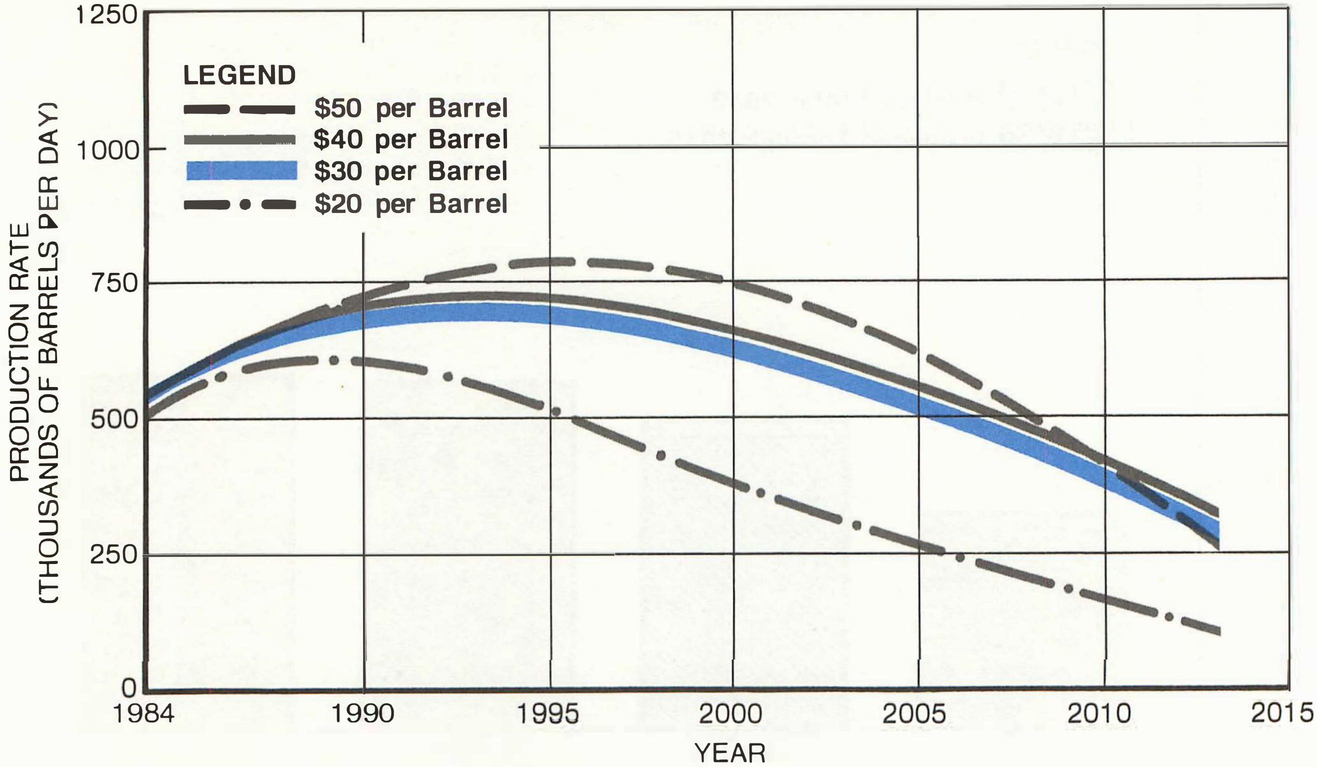

Figure F-8. Sensitivity of Thermal Recovery Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

0 percent minimum ROR project would be intentionally implemented, but this value might be considered a topside potential for Implemented Technology Case thermal recovery.

The potential recovery during the time span of this study for each of the four nominal crude oil price cases is also shown in Figure F-9. The maturity of existing thermal operations, particularly steam processes, results in more than 90 percent of the ultimate potential being produced during the 30-year study period. The relatively high recovery of 4 billion barrels for the nominal $20 per barrel case directly reflects the magnitude and maturity of the ongoing projects where the major capital investment is already in place. The use of produced oil to fire steam generators also tends to insulate ongoing projects from price variance.

Figure F-10 presents the Advanced Technology Case for thermal recovery at the nominal $30 per barrel, 10 percent minimum ROR base economic case. This projection shows

TABLE F-6

THERMAL RECOVERY
SENSITIVITY OF ULTIMATE RECOVERY TO PRICE AND ROR
IMPLEMENTED TECHNOLOGY CASE
(Billions of Barrels)

Nominal Crude Oil Price ($/bbl)	Minimum ROR 0%	Minimum ROR 10%	Minimum ROR 20%
20	5.0	4.4	3.8
30	7.9	6.5	5.5
40	8.4	7.0	6.7
50	8.8	7.2	7.0

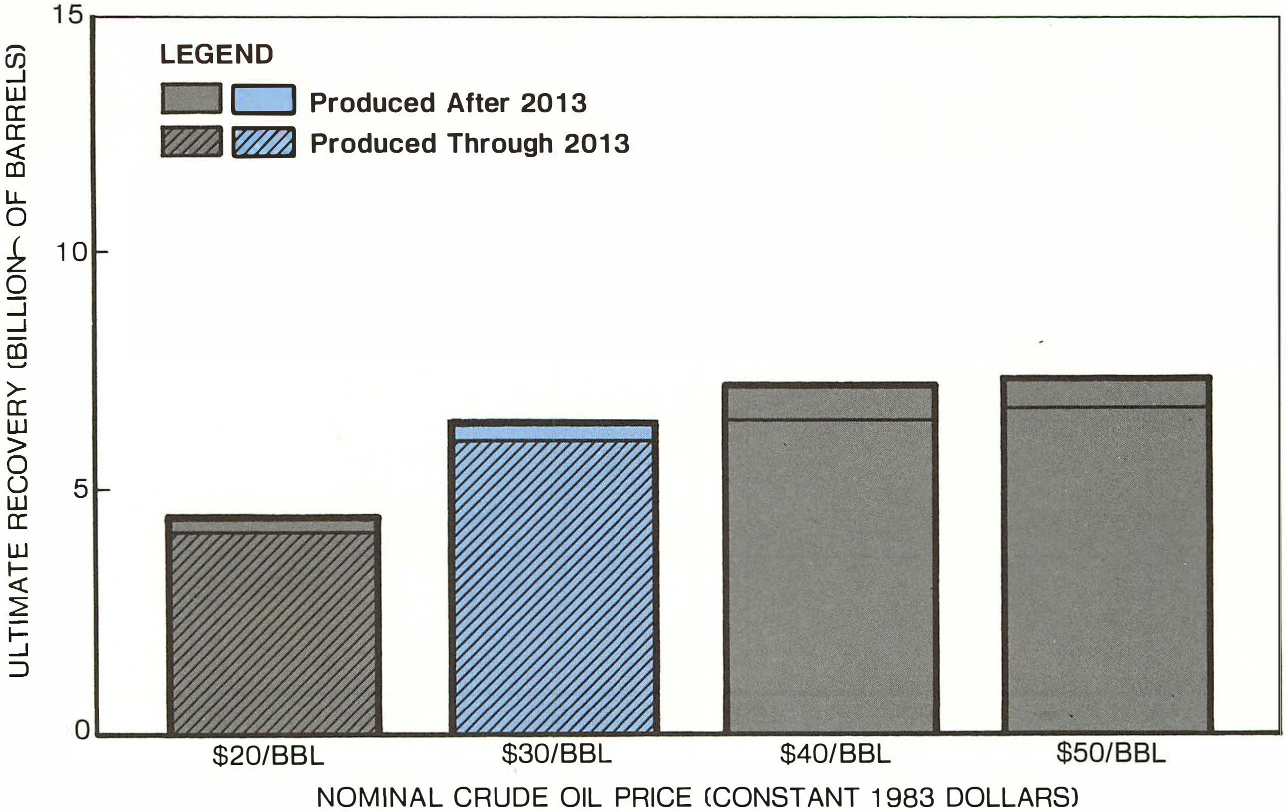

Figure F-9. Ultimate Thermal Recovery vs. Nominal Crude Oil Price (Constant 1983 Dollars)—Implemented Technology Case (10 Percent Minimum ROR).

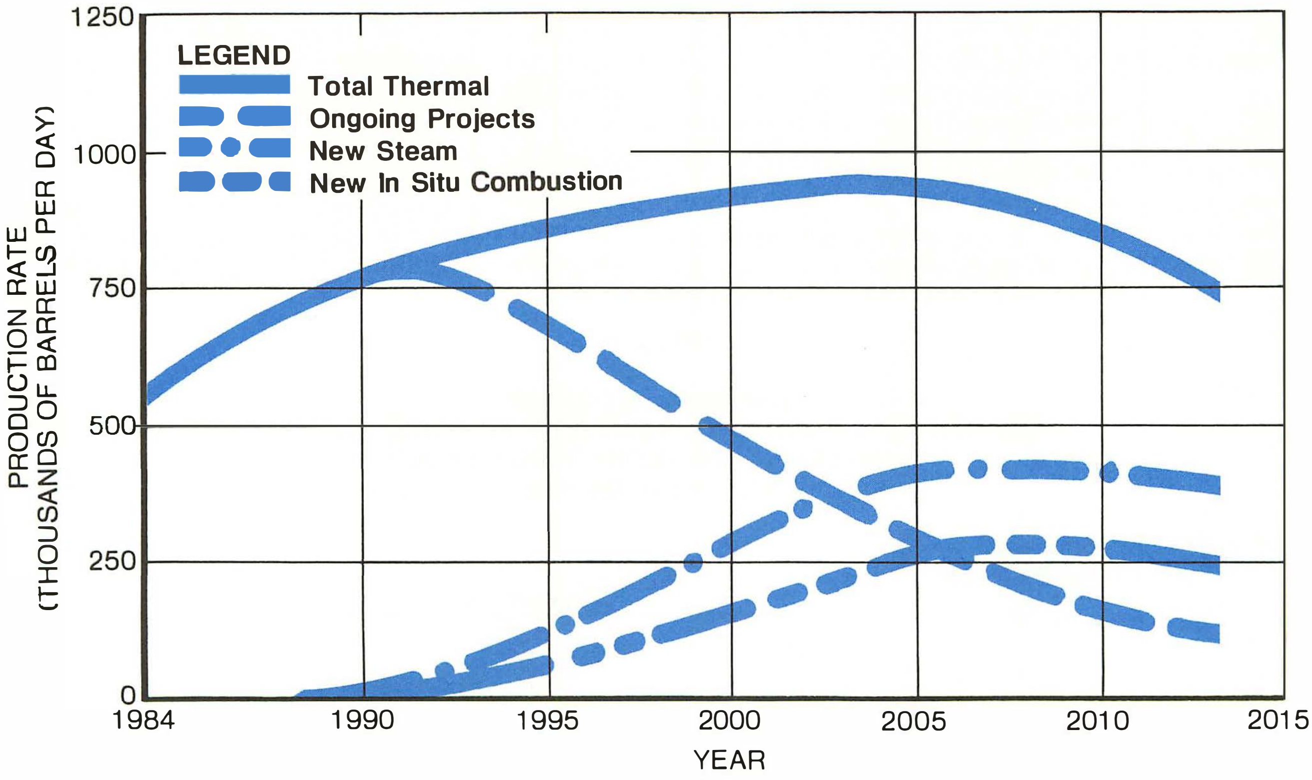

Figure F-10. Production Rate for Thermal Recovery—Advanced Technology, Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

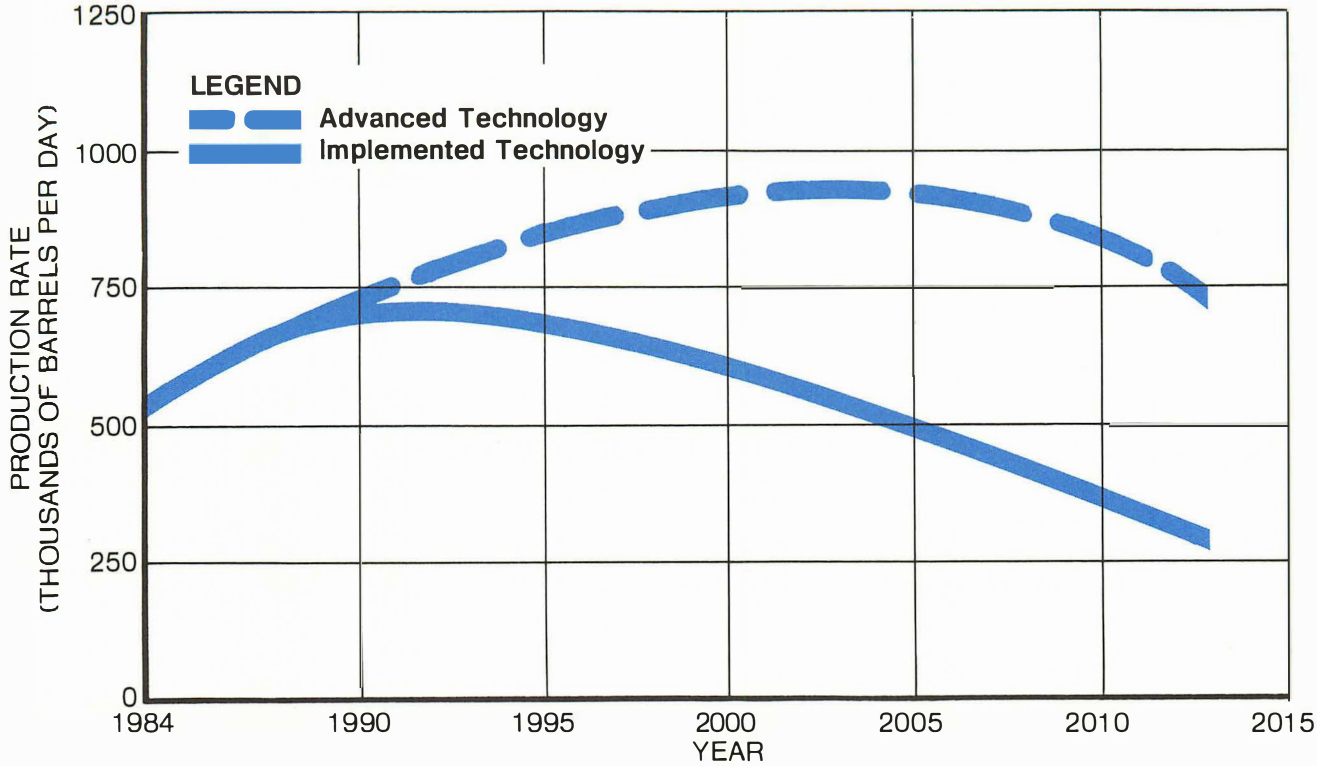

Figure F-11. Comparison of Thermal Recovery Implemented and Advanced Technology Production Rates—Base Economic Case ($30 per Barrel Nominal Crude Oil Price, 10 Percent Minimum ROR).

that if research and development allowed the industry to achieve the Advanced Technology Case goals, total thermal production could exceed 750 thousand barrels per day from 1990 through the year 2013. Figure F-11 and Table F-7 compare producing rates and ultimate recovery of the Advanced Technology Case with the Implemented Technology Case for the nominal $30 per barrel, 10 percent minimum ROR base economic case. Ultimate recovery for the Implemented Technology Case is 6.5 billion barrels compared to 10.5 billion barrels for the Advanced Technology Case, a potential increase of 4.0 billion barrels. These values include produced oil burned in steam generators.

Figure F-12 shows the effect of oil price on Advanced Technology Case production rates at a 10 percent minimum ROR. Peak rates vary from 925 thousand barrels per day near the year 2000 for the nominal $30 per barrel case to 1.2 million barrels per day at a comparable time for the $50 per barrel nominal oil price. Figure F-13 presents the ultimate recovery potential for the $30, $40, and $50 per barrel

TABLE F-7

THERMAL RECOVERY
COMPARISON OF ULTIMATE RECOVERY
IMPLEMENTED VS. ADVANCED TECHNOLOGY CASES
AT $30 PER BARREL AND 10 PERCENT MINIMUM ROR
(Billions of Barrels)

	Implemented Technology Case	Advanced Technology Case
Ongoing Projects	4.4	5.1
New Steamfloods	0.8	3.3
New In Situ Combustion Projects	1.3	2.1
Total	**6.5**	**10.5**

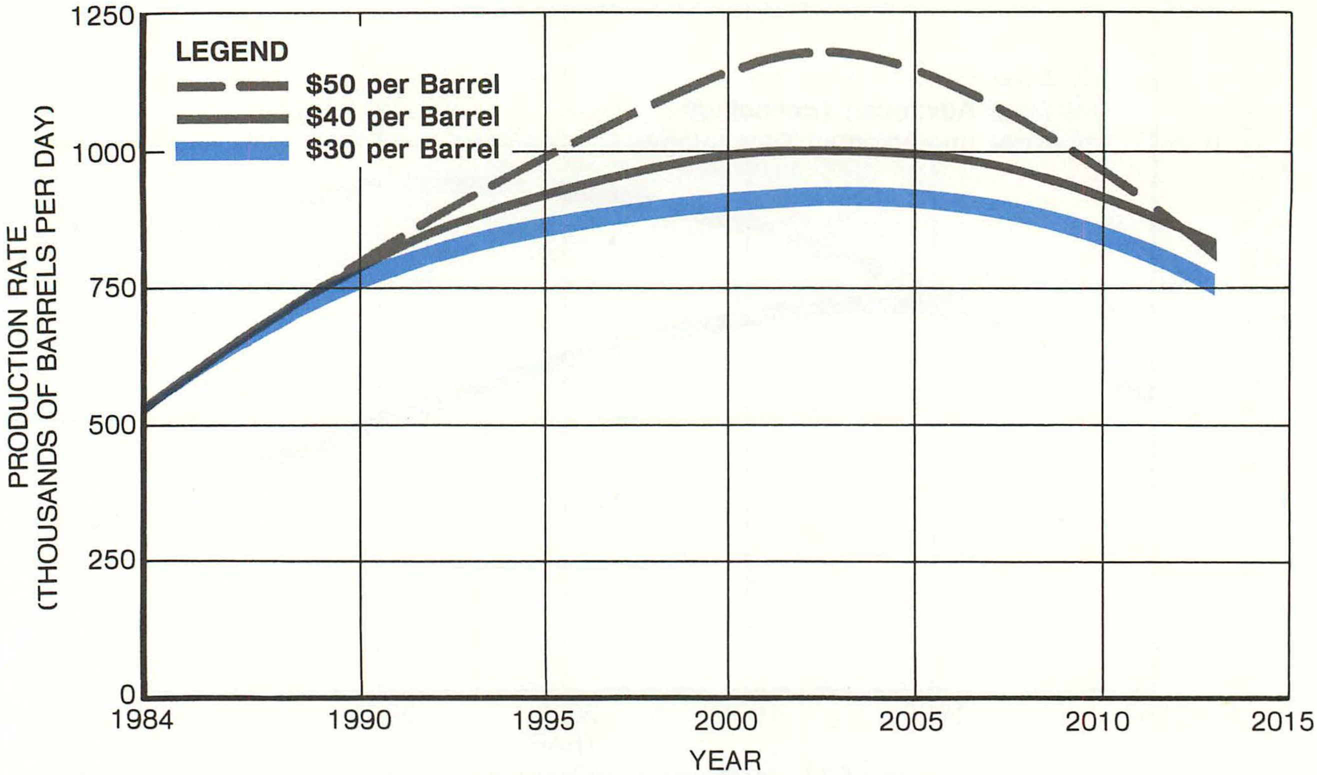

Figure F-12. Sensitivity of Thermal Recovery Production Rate to Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology, Base Economic Case (10 Percent Minimum ROR).

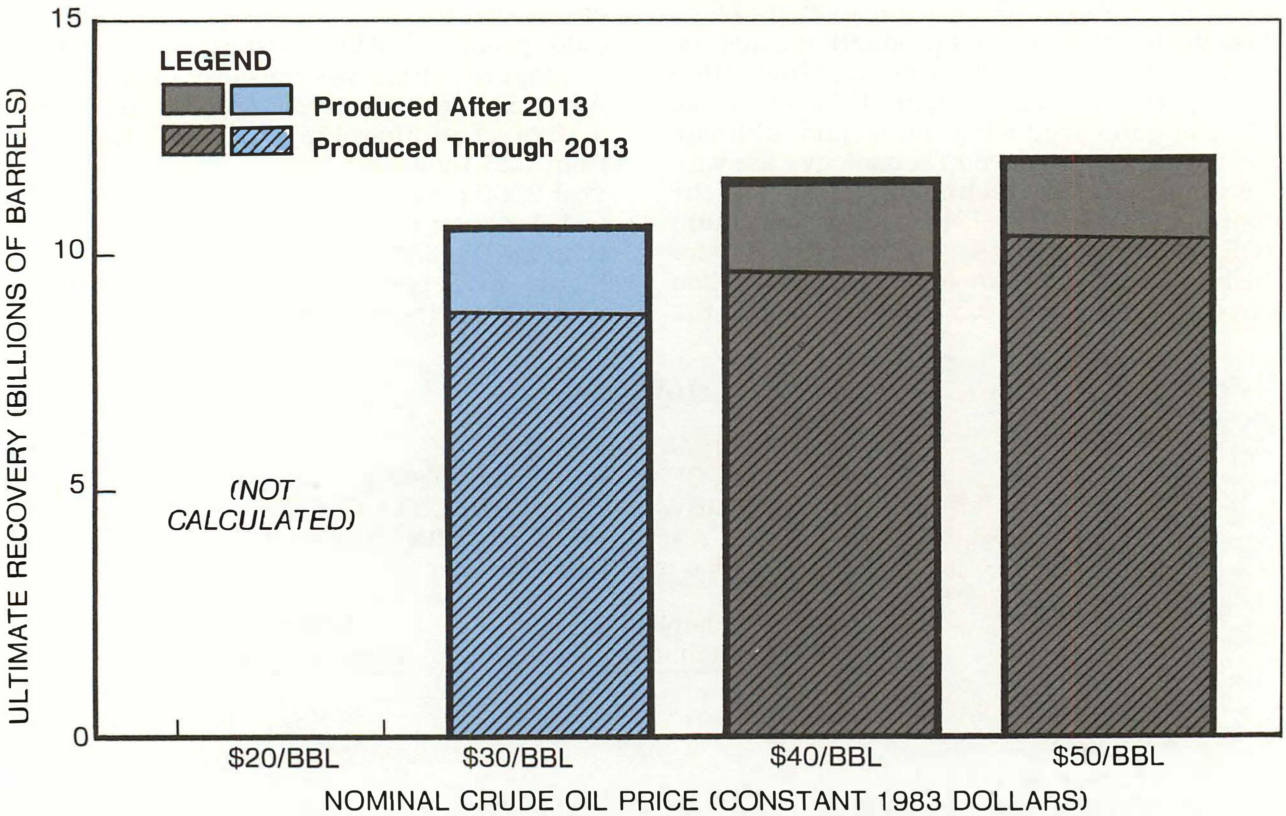

Figure F-13. Ultimate Thermal Recovery vs. Nominal Crude Oil Price (Constant 1983 Dollars)—Advanced Technology Case (10 Percent Minimum ROR).

nominal crude oil price cases. It also shows the amount of oil to be produced within the 30-year time span of this study. For the nominal $30 per barrel price, 8.8 billion barrels or 84 percent of ultimate potential is recovered during the study period. This large recovery percentage reflects both the maturity of the thermal processes and the fact that new projects can be implemented on a timely basis.

Environmentally Impacted Reserves

As further discussed below, environmental constraints will impact heavily on thermal recovery processes in Los Angeles County and Santa Barbara County in California. Up to 1.2 billion barrels of potential recovery from in situ combustion were omitted from the Implemented Technology Case because of air quality restrictions. This volume was included, however, in the Advanced Technology Case, which assumes that some of the current environmental limitations will be offset by improved technology.

Environmental Constraints

It is important to point out that on a project-by-project, site-specific basis a number of environmental issues may constrain thermal development or expansion. Boiler feedwater availability might constrain development in one location, while land use conflicts or fish and wildlife concerns may limit development in another. It is not the purpose of this section to document all such possibilities. Rather, the intent here is to summarize available information regarding constraining environmental elements and to provide realistic projections on the quantitative impact of these elements on future thermal projects.

Since nearly 90 percent of thermal enhanced oil recovered by 1990 is projected to be produced in California, analysis must focus on that state.[28] It has long been recognized that air quality regulations would be likely to limit expansion of thermal processes in the state and a detailed analysis of their impact on thermal projects was recently completed by the U.S. Department of Energy.[29,30] The DOE study indicates that expansion is already limited in some specific air basins and that large-scale expansion is not likely to occur. More specifically, when the DOE projections are modified relative to 1982 production figures, it appears that only about 300 thousand to 400 thousand barrels per day of expansion could occur in California by 1990. The most important constraining elements may include permit delays, emission control costs, control equipment availability, and the availability of emission offsets.

A summary and analysis of environmental regulations affecting EOR projects has been published and is currently being revised by the Department of Energy.[31] This document identifies both state and federal regulations and provides a basis for identifying potentially constraining regulatory activities for individual projects. While it appears true that air quality regulations will play a significant role in determining national thermal production levels, it is also true that process water availability, solid waste disposal, and underground injection of liquid wastes may represent significant project-specific issues. In the final analysis, diligent and early environmental planning and regulatory coordination are the only logical means of identifying potentially constraining environmental issues.

Uncertainties in Thermal Recovery Process Predictions

The Thermal Task Group determined that the total Implemented Technology Case and Advanced Technology Case steam injection and in situ combustion potential for the nominal $30 per barrel, 10 percent minimum ROR case is 10.5 billion barrels.

The Task Group also identified factors that could lead to uncertainty in its estimates of thermal ultimate recovery. Among the major positive factors that could influence the degree of technical success are:

- Methods to improve flood conformance and/or infill drilling resulting from cheaper drilling techniques
- New technology that would increase the thermal target above that perceived by the Task Group
- Widespread application of downhole steam generators to thinner or deeper reservoirs
- Improvements in steam delivery systems, the use of oxygen-enriched air systems for in situ combustion, the application of combined processes that use

[28] U. S. Department of Energy, *The Impact of Air Pollution Control Regulations on Thermal Enhanced Oil Recovery Production in the United States*, Washington, D.C., 1982.

[29] See footnote 28.

[30] Office of Technology Assessment, *Enhanced Oil Recovery Potential in the United States*, Washington, D.C., 1978.

[31] See footnote 28.

both the in situ combustion and steam projection principles, and the installation of large-scale cogeneration facilities.

Negative factors that could influence the degree of technical success include:

- Inadequate level of knowledge about target reservoirs
- Inability to achieve current conformance factors expected for the Advanced Technology Case
- Environmental constraints resulting from unforeseen events
- Advanced Technology Case for in situ prospects not feasible due to unknown reasons.

Appendix G
Environmental Considerations

The purpose of this appendix is two-fold: first, to provide a thorough examination of the environmental issues associated with enhanced oil recovery (EOR); and second, to make more readily accessible the information that will be of most importance to those whose interest in enhanced oil recovery is focused primarily on environmental issues. To assist these readers, abbreviated descriptions of the technical matters necessary to an understanding of the various EOR processes accompany the thorough development of the environmental issues set forth in this appendix. (A more complete discussion of any technical issue treated in this appendix can be readily accessed by reference to the appropriate appendix of this report.)

No previous study has involved such a broad technical examination of the environmental issues associated with enhanced oil recovery.

A working group of environmental specialists visited facilities representative of each EOR process. Each facility visited was carefully scrutinized to identify the potential environmental problems associated with it, and the strategies (existing or in the developmental stage) utilized to deal with those problems. In addition, the working group attempted to identify potential environmental problems—those not yet experienced—that might develop out of any EOR process. Particular attention has been directed to determining ways to avoid or mitigate any environmental impacts associated with enhanced oil recovery that have arisen or that could develop in the future.

Study participants visited EOR operations in the unique environments of the California Coast, California Central Valley, Louisiana Coastal wetlands, Cook Inlet offshore and the North Slope of Alaska, and the high plains of West Texas, seeking to identify and evaluate environmental impacts that might be imposed on those environments through application of enhanced recovery operations.

Enhanced oil recovery is defined for the purposes of this study as the incremental ultimate oil that can be *economically* recovered from a petroleum reservoir over that which can be *economically* recovered by conventional primary and secondary methods. (Conventional recovery methods are described in Chapter One.)

EOR processes are divided into the following general categories:

- Chemical flooding methods
- Miscible flooding methods
- Thermal recovery methods.

In each section devoted to a process:

- The process is described briefly.
- Potential environmental impacts are examined.
- Avoidance or mitigation of such impacts is discussed.
- Potential impacts not adequately addressed in current field operations are identified and discussed.

Those potential environmental impacts that are common to two or more of the EOR processes are discussed in a section entitled "Common Impacts."

In addition, "Activities in Environmentally Unique Areas" are addressed.

Finally, this appendix includes:

- A discussion of federal and state regulatory programs that address environmental impacts associated with enhanced oil recovery.
- An examination of efforts currently underway to enable industry to effectively avoid or mitigate those environmental problems associated with enhanced oil recovery.
- An assessment of the environmental risks associated with enhanced oil recovery.

Activities in Environmentally Unique Areas

Whenever any EOR activity occurs in an environmentally unique area, particular attention must be paid to minimizing those impacts that may accompany it.

EOR projects almost always take place where oil and gas production activities are already well established. Therefore, the nature of any unique environmental areas to be affected are usually known, and appropriate operating procedures should already have been established.

Substantial economic incentives exist for utilization of existing facilities to the fullest extent possible. Where additional surface equipment, new storage areas, and additional wells are required, however, the resulting impacts can be minimized through careful planning. Only minor changes should occur in land use practices.

The environmental working group chose to pay particular attention to offshore operations, wetlands, and production areas located in the Arctic as examples of unique environments in which EOR development might take place.

The risk of negatively impacting environments on the Outer Continental Shelf is slight, given the nature of EOR processes. Activities most apt to cause harm to the environment are routine operations. However, safe operating practices of the kind carried out on any offshore facility should minimize such risks.

Given the biological productivity of wetlands, special precautions are required if EOR activities are to avoid damaging these valuable resources. Activities that will result in modification of hydroperiods or changes in salinity regimes, or that will otherwise cause loss of habitat, should be avoided. Every effort should be made to confine EOR activities in wetlands to existing well drilling sites, roads, and canals.

Since the flora and fauna of the Arctic may be slow to recover from environmental insults, EOR operations conducted in the unique environments found there need to be planned and carried out with great care. The attention that has been focused on the Arctic, the harsh nature of the environments associated with it, and the economics of exploration and production in such areas have resulted in operating practices that minimize negative environmental impacts. Such practices have been applied to the first pilot EOR project on the North Slope. There is reason to believe that future operations will be approached with similar concern for the environment.

Of particular importance in Arctic areas such as the North Slope of Alaska is the need to minimize loss of habitat. Economic considerations make the use of existing facilities imperative. Nevertheless, particular attention needs to be focused on the minimization of gravel pad extensions and additional roadway development. The presence of permafrost makes it imperative that special precautions be taken in the design of facilities and in the insulation of lines and equipment for thermal enhanced recovery projects.

EOR activities do not usually impose significant additional negative impacts in areas where primary and secondary recovery has already occurred. However, continuation of activities in an area can preclude its use by species of wildlife not readily adaptable to man's presence. Careful planning can result in a considerable reduction of such negative consequences.

Common Impacts

The EOR methods discussed in this report (chemical, miscible, and thermal) have certain environmental impacts that are common to all three methods. A key common feature is the need to inject liquids or gases to mobilize and displace oil. This commonality extends to the need for injection wells, lines, and facilities and contributes to the environmental impacts shared by EOR processes. These common impacts are:

- Expanded land use through more intensive field development; i.e., more wells, roads, injection lines, and facilities
- Extended duration of land use and environmental impacts generated by primary or secondary operations.

- Increased emissions of pollutants generated from added injection and production facilities
- Increased potential for pollution of surface and underground sources of drinking water by injected fluids.

Increased land use for EOR operations results from the need to drill infill and replacement wells for injection and production service, to lay new injection and gathering lines, to build injection plants, chemical mixing or processing plants, and expanded production facilities. With the exception of long-distance CO_2 pipelines, land use impacts will generally be confined to existing field boundaries. Within developed fields, land use impacts will vary in severity depending upon the amount of infill drilling and new facilities that are required and upon the terrain. The impact of this is mitigated by maximum use of existing wells, roads, and facilities.

Land use impacts that have been created by primary or secondary development may be extended by EOR operations. The period can vary from a few years to several decades. This is an unavoidable impact that results from the time required to produce the increased crude oil reserves that are developed.

Increased emissions from EOR projects can come from steam generators used in thermal processes, from internal combustion engines used to drive gas compressors for miscible processes, from chemical mixing plants for chemical processes, and from gas and production processing facilities that may be used for any process. Nonroutine air emissions can result from accidental spills or releases of chemicals and gases. Installation of facilities with significant air emissions is subject to local, state, or federal regulations and permits. Permits generally require control measures and may require offsets.

All EOR processes require the use of injection wells that introduce air, steam, carbon dioxide, nitrogen, natural gas, or chemical solutions into the reservoir. Surface injection pressures range from a few hundred pounds per square inch to several thousand pounds per square inch. The mechanical completion of an injection well in compliance with regulatory requirements is designed to prevent loss of injected fluids to any part of the wellbore other than the intended injection zone. Failure of these mechanical systems could lead to potential pollution of subsurface drinking water supplies. Potential pollution of surface water supplies can result from leaks at injection plants, injection lines, and wellheads.

State permitting procedures, monitoring and reporting requirements, and industry operating practices are designed to detect and prevent any loss or migration of injected fluids away from the intended injection zone. The excellent record compiled by industry in a long history of secondary recovery and saltwater disposal operations suggests that the risk of groundwater contamination from EOR operations is negligible. The Office of Technology Assessment study concludes that groundwater contamination would be minimal and that this is supported by the lack of groundwater contamination problems associated with conventional waterfloods.[1] Only 74 groundwater injection problems resulted from the operation of 44,000 injection wells in Texas from 1960 to 1975 (1.1 per 10,000 per year incident rate); and only three problems in the last decade (0.02 per 10,000 per year). EOR injections are mechanically similar to conventional waterfloods, and with current injection well completion technology and efforts to conserve chemicals, even fewer injection well problems are expected in the future. While EOR process-specific chemicals may be different from conventional injection chemicals, it is logical to assume that mechanical injection well protection devices will function similarly.

Surface pollution risks are reduced by careful attention to the location and design of the injection facilities and to the selection of construction materials.

Chemical Flooding Methods

Chemical EOR processes include: (1) polymer flooding, (2) surfactant flooding, and (3) alkaline flooding. Field application of all three processes is an extension of conventional waterflooding technology with facilities to permit mixing and proper handling of chemicals to increase the recovery of oil.

Polymer Flooding

Polymer floods generally utilize a concentration of 250 to 2,000 parts per million (ppm) of a high molecular weight polymer in water, although the concentration can range as high as 5,000 ppm in special applications. The solution is injected into the reservoir over months to years with a total injected volume equivalent to 5 percent to near 100 percent of the reservoir pore volume. This volume is called the polymer slug and is followed by water injection until oil

[1]Office of Technology Assessment, *Enhanced Oil Recovery in the United States*, Washington, D.C., 1978.

production is abandoned. The polymer increases the viscosity of the injected solution. This can decrease the flow through water-swept parts of the reservoir, cause the waterflood to enter otherwise bypassed pore spaces, and move the oil from these pore spaces to the production wells. Polymers are also used to obtain profile modifications in injection wells. This is commonly called near-wellbore treatment and uses lesser amounts of polymer than full-field polymer flooding.

The two polymer types currently used are partially hydrolyzed polyacrylamides and the biologically produced polysaccharides (biopolymers). Polyacrylamides are generally preferred when the reservoir water is of low salinity and hardness. Relatively fresh, low-hardness water is used in the formulation of the polymer slug, and the reservoir may be preflushed with relatively fresh water in order to improve the compatibility between the chemical system and the reservoir. However, preflushing is usually not practiced. Polysaccharides are less sensitive to salinity and divalent ion concentrations, but are more subject to bacterial attack, and may require extensive filtering to remove suspended solids. Bactericides and oxygen scavengers are normally used to minimize biodegradation of the biopolymer solution. Sodium dichlorophenol, sodium pentachlorophenol, and formaldehyde are the bactericides most frequently used, while sodium hydrosulfite and hydrazine are the most commonly used oxygen scavengers. Chemical stabilizers are usually required by both polymer types at elevated temperatures to control degredation. The stabilizers include thiourea with isopropyl alcohol; propyl, butyl, and amyl alcohols with carbonates; sodium N, N-dimethyldithiocarbamate; and 2-mercaptobenzimidazole with 2, 2' methylene bis methyl 6-tertiary butylphenol.

Polyacrylamides are available in liquid and gel as well as in powder forms. Biopolymers are available in broth and powder products. On-site production is being considered for biopolymers while some polyacrylamides are now being polymerized on-site.

Each polymer flood is tailored to the unique properties of the particular reservoir. Concentrations and volumes will vary and other chemicals may be added to produce the desired properties. A listing of the more commonly used chemicals is given in Table G-1.

Surfactant Flooding

Surfactant flooding is a multiple-slug process. Normally, a slug amounting to only 5 to 10 percent of the reservoir pore volume to be processed and containing a 2 to 10 percent solution of the surfactant material is injected into the reservoir. The surfactant lowers the interfacial tension between the injected fluid and the reservoir oil and water and minimizes the capillary forces, thereby improving the oil displacement efficiency. The surfactant slug is followed by a larger slug of a solution of a high molecular weight polymer (e.g., 1,000 ppm). The polymer slug usually varies in size between 25 and 100 percent of the total pore volume of the reservoir to be processed. It preserves the integrity of the small, but more costly surfactant chemical slug and improves the sweep efficiency. The polymer slug is followed by water injection (waterflood) until the project is completed. Relatively fresh water may be used for the preparation of the surfactant slug and the reservoir may be preflushed with low-salinity, low-hardness water in order to condition the reservoir.

Although the literature describes a number of chemicals that can be used in the surfactant flooding process, those that have found extensive use are limited to petroleum sulfonates, sulfated ethoxylated alcohols, and ethoxylated alcohols. Concentrations of the chemicals used are low; e.g., 5 percent petroleum sulfonate with 1 percent alcohol and 10 to 20 percent of available crude oil. The polymer solution used to follow the surfactant slug is usually limited to polyacrylamides and polysaccharide polymers, and the application is similar to that discussed above for polymer flooding.

Since the surfactant tends to emulsify oil and water, additional treatment of the produced fluid may be required to separate the oil and water. This treatment involves greater use of emulsion breaking chemicals and heat, and longer settling times (i.e., larger holding vessels).

Alkaline Flooding

Alkaline flooding uses chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate added to flood water to enhance oil recovery by interfacial tension reduction, spontaneous emulsification of the oil and water, or wettability alteration of the reservoir rock. These mechanisms are related to the in situ formation of surfactants from the neutralization of indigenous petroleum acids by the alkaline chemicals.

The surfactants produced in situ are in low concentrations and their effectiveness is diminished with increased water hardness. Further, divalent ions precipitate at high pH and

TABLE G-1

CHEMICALS IN CHEMICAL EOR

Polymers

Commonly Used:
- Acrylamide
- Polyacrylamide
- Polysaccharide

Proposed or Infrequent Use:
- Adloses B Series
- Adloses L Series
- Carboxymethylcellulose
- Carboxyvinyl polymer
- Conjugated saccharides
- Deoxyribonucleic acid
- Dextrans
- Disaccharides
- Ketoses B Series
- Ketoses L Series
- Monosaccharides
- Polyethlene oxide
- Polyisobutylene in benzene
- Tetrasaccharides

Alkaline

Commonly Used:
- Sodium carbonate
- Sodium hydroxide
- Sodium silicate

Proposed or Infrequent Use:
- Ammonium hydroxide
- Potassium hydroxide

Surfactants

Commonly Used:
- Broad spectrum petroleum sulfonates
- Synthetic petroleum sulfonates

Proposed or Infrequent Use:
- Alcohols
- Ethoxylated alcohols
- Sulfated ethoxylated alcohols

Bactericide

Commonly Used:
- Acrolein
- Formaldehyde
- Sodium dichlorophenol
- Sodium petachlorophenol

Proposed or Infrequent Use:
- Acetate salts of coco amines
- Acetate salts of coco diamines
- Acetate salts of tallow diamines
- Alkyl amino
- Alkyl dimethyl ammonium chloride
- Alkyl phosphates
- Calcium sulfate
- Coco dimethyl ammonium chloride
- Gluteraldehyde
- Paraformaldehyde
- Sodium hydroxide
- Sodium salts of phenols
- Substituted phenols

Oxygen Scavengers

Commonly Used:
- Hydrazine
- Sodium bisulfite
- Sodium hydrosulfite
- Sulfur dioxide

Others

Commonly Used:
- Butyl alcohols
- Calcium chloride
- Crude oil
- Isopropyl alcohol
- Sodium chloride

this tends to plug the formation. Thus, water with a low hardness is used for mixing the alkaline slug, and preflush of the reservoir with relatively fresh water or a sodium chloride solution may be carried out in an attempt to maintain the integrity of the slug. Where sufficiently soft water is not available, water may be softened using conventional water softening systems (e.g., zeolite and other ion exchange softeners). Acids and/or salt solutions may be used to recondition the water treatment units. A representative alkaline flood is a 0.5 normal sodium chloride preflush solution with a volume representing 20 percent of the reservoir pore volume; a caustic slug of 40 percent reservoir pore volume with alkalinity equivalent to 1 percent sodium hydroxide (e.g., a mixture of sodium hydroxide and sodium silicate in a ratio to prevent silica dissolution within the reservoir) and small concentrations of cosurfactant and polymer for mobility control; a freshwater (or sodium chloride solution) postflush; and finally, continued waterflooding until oil production is abandoned.

Because of the tendency for solids to precipitate and plug the producing formation near the wellbore, injection wells may require periodic treatment; e.g., washing the injection zone with an acid solution (acidizing) once per year to maintain the injectivity. As with the surfactant process, alkaline flooding emulsifies produced oil and water and additional treatment of fluids may be required to reduce the water content of the produced crude oil to pipeline specifications.

Potential Environmental Impacts

Previous studies have generally concluded that the environmental impacts of chemical EOR techniques are not expected to be significantly different in type and magnitude from those of primary and secondary production operations.[2,3] Procedures and technology for environmental protection in primary and secondary processes are well established and overall the record for environmental protection has been good. Environmental assessments for field projects made pursuant to the National Environmental Policy Act generally conclude "no significant" impacts are expected from the projects, or impacts are of "low probability."[4-8] It is generally assumed that EOR processes can operate without significant damage to the environment, but there are precautions needed beyond those established for primary production and secondary waterflood.

These added precautions are primarily because of the chemicals added to the waterflood system and, to a lesser degree, the potential for utilization of large volumes of relatively good quality water. The potential environmental concerns associated with chemical and water use that merit particular attention include the following:

- Exposure to toxic materials
- Protection of fresh groundwater resources
- Protection of surface waters
- Solid waste disposal
- Competition for freshwater supplies.

The principal hazards at chemical EOR sites that are greater than those at traditional oil production sites are associated with the delivery, storage, mixing, and injection of EOR chemicals. Concern has been expressed relative to the toxicity, low degradability, and synergistic effects of the chemicals. Some of the chemicals exhibit moderate toxicity or health hazards at higher concentrations, particularly the biocides and oxygen scavengers. At the lower concentrations usually encountered in field injection and production systems, available data indicate they have little apparent impact on health and they are relatively nontoxic.

Large quantities of chemicals will be injected into the reservoir, but this will be at low concentrations over extended periods of time. Chemicals are delivered, handled, and mixed at relatively high concentrations and plants are sometimes located at the site for the manufacture of chemicals (e.g., polymerization) and the raw materials frequently are more toxic than the end products. These high concentrations in most cases pose the greatest potential for employee exposure to toxic chemicals and damaging spills to the environment.

Relative to these plant operations, field operating problems are spread over a large area. Further, the fluids contain only dilute concentrations of the chemicals and these concentrations are lowered even more in the subsurface reservoir by mixing with reservoir fluids, degradation, absorption of reservoir rock, etc., so that low concentrations of the chemical, if any, are anticipated in the produced fluids. A high fraction of injected chemicals is retained in the reservoir.

A compilation and assessment of the toxicological nature of chemical compounds used in enhanced oil recovery has been published by the U.S. Department of Energy (DOE).[9] A summary of currently used chemicals is given in Table G-1. Tables G-2 and G-3 list some of the uses and properties associated with these chemicals.

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[2]See footnote 1.

[3]National Petroleum Council, *Enhanced Oil Recovery*, Washington, D.C., December 1976.

[4]Energy & Environmental Analysis, Inc., *Environmental Assessment of the Department of Energy/Energy Resource Company Polymer—Improved Waterflooding Enhanced Oil Recovery Project, White County, Illinois*, 1979.

[5]Oak Ridge National Laboratory, *Environmental Assessment: Pennzoil Company's Enhanced Recovery Project, Roane County, West Virginia*, Oak Ridge, Tennessee, 1978.

[6]O'Banion, K., *Environmental Impact Assessment: Enhanced Oil Recovery by Caustic Flood, Long Beach, California*, Lawrence Livermore Laboratory, Livermore, California, 1978.

[7]U.S. Department of Energy, *Environmental Assessment of the Department of Energy/Marathon Oil Company Commercial—Seal Micellar Polymer Flooding Enhanced Oil Recovery Project, Crawford County, Illinois*, Washington, D.C. 1979.

[8]U.S. Department of Energy, *Draft Environmental Impact Assessment: Phillips Petroleum Company Enhanced Oil Recovery Project. Osage County, Oklahoma*, 1978.

[9]U.S. Department of Energy, *Toxicity of Chemical Compounds Used for Enhanced Oil Recovery*, DOE/BC/10014-5, 1980a.

TABLE G-2

COMMON USAGE OF CHEMICAL EOR CHEMICALS

Chemical	Primary Uses (non-EOR)	Production	Maximum Concentration Expected in EOR (ppm)	Maximum Concentration Expected in Handling (%)
Polymers				
Polyacrylamides	Food additives.	50 million lb/yr	5,000	80
Polysaccharides (Xanthan Gums)	Food additives. Cosmetics. Emulsifier.	40 million lb/yr	5,000	80
Surfactants				
Petroleum Sulfonates	Detergents.	600 million lb/1966	100,000	95
Synthetic Sulfonates (Alkylaryl Sulfonates)	Industrial & household. Detergents.	8 million lb/1966	100,000	95
Alkaline Agents				
Sodium Hydroxide	Chemical & metal processing. Paper & pulp manufacture.	9.6 million tons/1975	50,000	50
Sodium Carbonate (Soda Ash)	Industrial processes.	8.7 million tons/1979	20,000	–
Sodium Silicate	Chemical manufacture. Adhesives, soaps, fireproofing.	–	20,000	38

TABLE G-2 (Continued)

Chemical	Primary Uses (non-EOR)	Production	Maximum Concentration Expected in EOR (ppm)	Maximum Concentration Expected in Handling (%)
Biocides				
Acrolein	Chemical manufacture (acrylic acid and esters). Biocide.	38,500 tons/1979	150	–
Formaldehyde	Chemical manufacture (resins). Biocide.	3.0 million tons/1975	150	37
Dichlorophenols	Chemical intermediate. Industrial and agriculture products.	–	150	–
Pentachlorophenol	Almost 100% usage as wood preservative. Biocide.	18,200 tons/1975	150	–
Oxygen Scavengers				
Sodium Hydrosulfite	70% dye industry. 18% pulp & paper industry.	50,000 tons/1975	20,000	90
Hydrazine	Solar Flux. Industrial water treatment. Rocket fuel.	–	20,000	98
Others				
Butanols	Industrial solvent (surface coatings). Chemical manufacture.	237,000 tons/1976	40,000	99
Isopropyl Alcohol	Chemical manufacture. Solvent, medical, and cosmetic.	881,000 tons/1972	–	99

TABLE G-3

HAZARDS OF CHEMICAL EOR CHEMICALS

Chemical	Major Hazard(s)	Other Hazard(s)	OSHA-NIOSH*	IDLH†	Comment
Polymers					
Polyacrylamides	Monomer impurity may by a neurotoxin.	Dust accumulations may be explosive. May cause allergy.	N/A	N/A	Low hazard.
Polysaccharides (Xanthan Gums)	Impurities in commercial xanthans may be irritants or allergens.	Dust accumulations may be explosive. May cause allergy.	N/A	N/A	Low hazard.
Surfactants					
Petroleum Sulfonate	Some constituent or impurities may be carcinogens.	Irritating to tissues. Flammable.	N/A	N/A	Low to moderate hazard.
Synthetic Sulfonate (Alkylaryl Sulfonates)	Impurities potential carcinogen.	Irritating to tissues.	N/A	N/A	Low to moderate hazard.
Alkaline Agents					
Sodium Hydroxide	Severely corrosive to tissue.	–	2 mg/m^3	200 mg/m^3	High hazard. Avoid inhalation, ingestion, & eye/skin contact.
Sodium Carbonate (Soda Ash)	Severely corrosive to tissue.	–	N/A	N/A	Moderate to high hazard Avoid inhalation, ingestion, & eye/skin contact.
Sodium Silicates	Irritant to tissues.	–	N/A	N/A	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.

TABLE G-3 (Continued)

Chemical	Major Hazard(s)	Other Hazard(s)	OSHA-NIOSH*	IDLH†	Comment
Biocides					
Acrolein	Inhalation toxicity.	Irritant. Fire hazard.	0.1 ppm	5 ppm	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Formaldehyde	Irritant to membranes.	Potential carcinogen.	3 ppm (5 ppm ceiling) (10 ppm peak)	100 ppm	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Dichlorophenols	Aquatic wildlife toxicity.		N/A	N/A	Moderate to high hazard. Avoid inhalation, ingestion, & eye/skin contact.
Pentachloropenol	Toxicity to organisms. Potential carcinogen, mutagen teratogen.	Persistent in environment.	0.5 mg/m³	150 mg/m³	High hazard. Avoid inhalation, ingestion, & eye/skin contact.
Oxygen Scavengers					
Sodium Hydrosulfite	Spontaneous combustion.	Irritant to tissues.	N/A	N/A	Moderate hazard.
Hydrazine	Explosive.	Corrosive to tissue Potential carcinogen.	1 ppm	80 ppm	High hazard. Avoid inhalation, ingestion, & skin/eye contact.
Others					
Butanols	Flammable.	May be irritant to tissues.	100-150 ppm	8,000-10,000 ppm	Low to moderate hazard.
Isopropyl Alcohol	Flammable.	Irritant to respiratory tract.	400 ppm	20,000	Low hazard. Do not take internally.

*OSHA-NIOSH as found in 29 CFR 1910.1000 as of January 1, 1977.

†IDLH—"Immediately Dangerous to Life or Health." Maximum level from which one could escape within 30 minutes without any escape-impairing symptoms or any irreversible health effects. From "Respiratory Protection Reference Document for Chemical Hazards." Standards Completion Program.

N/A—not available.

An undetected leak in an injection or producing well has the potential of releasing brine into freshwater reservoirs. If the flood water contains EOR chemicals, the probability of detrimental effects would increase.

Surface waters can be contaminated by spills of chemicals during transportation, onsite manufacturing and handling, or by improper disposal of produced water. As stated above, waters produced from the reservoir are expected to contain little or no EOR chemicals. However, injected waters sometimes can channel to producing wells, resulting in higher (but still low) chemical concentrations in the produced water. Residual concentrations may occur in any case. In most cases, the produced water is disposed of by reinjection. In some limited areas where the produced water is fresh, it is used as a valuable supplement to agricultural water supplies under the provisions of the Clean Water Act. Disposal in offshore areas is frequently by discharge to the oceans.

Chemicals can accumulate in solid waste; e.g., in filter media or from water treating. The chemical characteristics of these wastes will be similar to those encountered in other industries and the quantities will be relatively small. These solid wastes must be disposed of in approved disposal sites or neutralized by approved methods.

Conventional waterflooding requires significant quantities of water; however, water of relatively poor quality can generally be used. Chemical EOR methods presently use relatively fresh water for the surfactant, polymer, and alkaline slugs and, in some cases, for reservoir preflushing and postflushing. In some cases, water will be treated to reduce hardness and salinity. Waste solutions, sludges, and solids can be generated depending upon the treatment process.

More than 10 barrels of fresh water could be required to produce one additional barrel of oil. However, the tendency is towards process changes that require less fresh water. There is a potential for competition with domestic, agricultural, and other industrial uses of fresh water supplies. The greatest potential for conflict is in California and West Texas where water use is high and supplies are short. The drawdown of freshwater supplies could adversely affect aquatic flora and fauna in an area.

A number of additional environmental issues were assessed in this study to be of secondary concern relative to the issues discussed above. Some of these are discussed in the Common Impacts section of this appendix, which describes impacts common to all EOR processes.

Avoidance and Mitigations

As mentioned earlier, technology and operating procedures for chemical EOR are extensions of conventional waterflooding technology. Chemical EOR employs chemicals and methods that have been used to some degree for many years in primary and secondary production. Even the relatively new chemical EOR techniques have been field-tested. The data collected and the experience gained during the evolution of these techniques will aid in avoiding or mitigating detrimental environmental effects in the future.

Each proposed chemical EOR project is evaluated to assure good operating practices and compliance with local, state, and federal laws. Environmental Impact Statements (EIS) are one of the more comprehensive environmental evaluations and are required for all federal actions and proposals significantly affecting the quality of the environment and for certain activities in several states.

The chemicals used in the EOR processes require special attention by the operators so as to minimize exposure of workers and the public. The greatest threat to the workers is an accident associated with bulk chemicals at the site. Handling of bulk chemicals and mixing operations are essentially traditional chemical industry type operations, and are relatively predictable and controllable. While employee exposures can occur, most chemical handling operations are mechanized with the operator located away from the operation. The chemical industry has an injury and sickness rate of only about two-thirds that for all U.S. industry.[10] In the past few years, numerous laws have been adopted on the federal, state, and local level to protect the worker, and implementing regulations continue to evolve. In the case of chemical EOR projects, toxic and hazardous materials are appropriately marked, handled, transported, and disposed of in accordance with federal, state, and local regulations and guide lines. In addition to safe working conditions, requirements include proper training of facility personnel and programs to increase worker (and public) awareness of toxic materials.

The U.S. Safe Drinking Water Act contains provisions to protect underground drinking water supplies, and states can administer the program by adopting Environmental Protection Agency (EPA) approved regulatory programs.

[10]Occupational Safety and Health Administration, OSHA Statistics, published in Federal Register, December 1983.

All oil and gas producing states have statutes and regulations governing oil and gas well completions. State regulations address safety and inspection procedures to avert waste and pollution by preventing oil, gas, and reservoir water from escaping at the surface or into other subsurface water-bearing formations. Supervised plugging of wells upon abandonment (or within a specified time after production ceases) following government standards is required to prevent leakage of fluids from the underground reservoir.

Because of the low concentrations of the chemicals in the reservoir, chemical EOR processes are expected to pose only a slightly greater threat to underground water supplies than conventional waterflooding. Most important, conventional waterflooding has an extremely good record.

Chemicals used in these systems pose no environmental threat as long as they are contained within the system, as is the case with routine operations. Environmental problems result only when nonroutine events allow materials to escape to the environment; e.g., spills or leaks. Failure of equipment, materials, and operational procedures, therefore, are the most significant threat to the environment and a properly designed, operated, and maintained system is the most signficant factor for ensuring adequate protection of the environment. Safe technology and operating practices have been developed by industry and these will be applied to EOR systems. Nevertheless, the potential for spills and leaks will continue to exist and will require vigilance by the operator. It is industry's practice to maintain a spill prevention and contingency plan in case of such accidents. EPA regulations require that accidental spills of hazardous substances in harmful quantities into the waters of the United States be reported to the appropriate federal agency.

Disposal of produced water is usually by reinjection into a producing formation or other subsurface reservoir. When other subsurface reservoirs are used for disposal, they are normally saltwater aquifers and are not hydraulically connected to freshwater aquifers. Subsurface disposal into saline formations is a proven, environmentally acceptable technology that requires a state or federal permit and is subject to federal standards pursuant to the Safe Drinking Water Act. In those cases where the produced water is relatively fresh and may have a beneficial use in an area, disposal may be by surface discharge. In offshore areas disposal may also be by surface discharge. In both cases, the surface discharge is regulated through the EPA's National Pollutant Discharge Elimination System (NPDES) permit program and requires the application of Best Practical Technology. Surface discharge of toxic substances in harmful quantities is prohibited.

Current chemical EOR methods have the potential of using large volumes of fresh water, thereby creating water shortages or environmental impacts due to freshwater drawdown. However, freshwater usage for chemical EOR may not be as great as some EOR environmental reviews suggest.

Chemical EOR processes are anticipated to make maximum use of recycled water. Further, economic considerations will force the industry to eliminate the preflush (and postflush) as quickly as possible. Widespread use of chemical EOR probably will only occur with the development of systems that do not require extensive freshwater usage.

Currently, all oil and gas production processes utilize less than 1 percent of the total water usage in the United States.[11] Chemical EOR processes presently produce only about 4,400 barrels of oil per day and utilize only a very small fraction of the total water used in the industry. Any water use conflict or environmental impact is very likely to be limited to localized areas.

Process wastes, e.g., filter backwash or water softening system spent materials, are recycled in the EOR system, injected into saltwater aquifers, or disposed of in surface facilities after treatment to be in compliance with state and federal requirements.

Potential Environmental Impacts Not Adequately Addressed in Current Field Practices

Industry has developed the technology and experience to operate chemical EOR projects in an environmentally sound manner. In general, the petroleum industry utilized well-trained engineers and field personnel for the implementation of the technology. Although not unique to chemical EOR processes, the operators are faced with a problem of operating many miles of field pipelines with associated pumps and valves handling saline waters, and numerous injection and production wells. Since salt water can be corrosive, line and valve failures occur that sometimes cause spills or leaks. Generally,

[11] U.S. Department of Energy, *Assessment of Water Issues Associated with Enhanced Oil Recovery: A User's Guide*, DOE/BC/10412-40, 1983.

these leaks and spills are small in volume and limited in their impact.

Although the system initially may be designed to handle corrosive saline waters, material failures can occur. Selection of replacement valves and material by field operating personnel tends to be a prudent trial and error method to select the equipment that provides the best service. Systematic personnel training and material selection programs help to avoid many of the leaks and small spills experienced in field operations. High turnover of field operating personnel in some areas aggravates training and operating problems.

Most chemicals used in chemical flooding methods have been used in other industrial operations for many years. They are considered to be relatively nontoxic at concentrations usually encountered in EOR field operations. Most major companies utilize industrial toxicologists and other professionals in the evaluation of potential health and safety hazards and appropriate safety practices. However, some additional research and review of the chemicals is needed to ensure safeguards from potential toxic and carcinogenic effects. This would include studies of chemicals used in combination, or synergistic effects.

In some areas where produced water is relatively fresh and may have a beneficial surface use, produced water disposal from primary and secondary recovery by discharge to surface ponds or drainage channels has been permitted by regulatory policy. With the application of chemical EOR processes, some federal and state regulatory agencies as well as some operators have questioned the impact that trace amounts of these added chemicals would have on the environment and human health. Agencies generally have required subsurface disposal of the produced waters from chemical EOR projects. While there is little indication that these chemicals at the low concentrations observed in produced waters would be harmful to the environment and human health, state agencies and others have not been convinced. Thus, many operators are treating essentially all produced fluids as potentially harmful. Additional data and improved data reduction and interpretation will help clarify these matters.

Chemical EOR methods have the potential of using large volumes of fresh water and creating water shortages in local areas and environmental damage due to freshwater drawdown. Widespread application of chemical EOR will be encouraged with the development of chemical systems effective at higher reservoir salinities. Research programs for development of such chemical systems will encourage field applications as well as reduce conflicts and environmental impacts due to usage of large volumes of fresh water.

Miscible Flooding Methods

Miscible Displacement Processes

Miscible displacement processes entail the injection of a solvent into oil-bearing formations. The solvent becomes miscible with the oil and reduces the capillary forces, swells the reservoir fluid, and reduces the viscosity, thus allowing the oil to flow more readily through the porous media. Field applications of miscible displacement have been narrowed to five solvents, namely: (1) carbon dioxide (CO_2), (2) nitrogen (N_2), (3) natural gas liquids (NGLs, liquids extracted from natural gas streams), (4) hydrocarbon gases, and (5) flue gas. Of the five solvents mentioned, CO_2 and N_2 are considered to be the most cost effective and the industry is tending to converge on these two. However, special circumstances can make the others economically attractive.

Miscible displacement requires the injection of solvent into the formation at pressures that are experimentally determined to optimize oil recovery. The laboratory-determined pressure will vary with the solvent used and with the reservoir fluid characteristics. Appendix E contains a more complete discussion of the miscible recovery process.

Of the two commonly used fluids, CO_2 attains miscibility with reservoir oils at a lower pressure than N_2. Since its applicability encompasses more reservoirs than N_2, CO_2 is being used or contemplated for use in almost all major miscible displacement projects. Consequently, this discussion will be concerned mainly with CO_2.

CO_2 is transported to location by either of two methods. In smaller projects, it is usually moved to the site by tanker truck and/or railroad tank car. Larger projects that require much larger volumes of CO_2 are usually supplied by pipelines laid from the source. Federal regulatory agencies (Department of Transportation, Interstate Commerce Commission, Federal Energy Regulatory Commission) do not consider CO_2 to be hazardous or toxic. In pilot scale projects, insulated storage tanks are normally used to store CO_2 on site. Tank size varies with the size of the project. The tanks are designed to maintain the CO_2 in a liquid state (0 ° F, 300 psig) with facilities available to pump the CO_2 from the transporter and also to feed the well distribution system.

Potential Environmental Impacts

Although some advantages may accrue from initiating miscible displacement in the early stages of primary or secondary operations, by far the largest resource base target for miscible projects are reservoirs that are in the late stages of secondary operations. Since most of the surface facilities will already be in place, the additional environmental impacts of miscible injection will be minimal in their scope. Nevertheless, operators should be aware of the potential environmental concerns that deserve particular attention. These are:

- Groundwater resources
- Surface waters
- Land use
- Air quality.

The quality of groundwaters is maintained by proper injection well completion and monitoring programs. The industry's record of groundwater protection has been excellent. Miscible fluid injection normally uses the same injection wells used in secondary operations. Since economics dictate that these relatively expensive miscible fluids must not be lost, wells are usually "worked-over" to ensure that the fluids enter the target formation. Occasionally, new wells will be drilled or injection patterns changed to replace wells that are unrepairable. New materials and procedures are continually evolving for well completions and it can be expected that the industry will maintain its record of groundwater protection.

The need for freshwater supplies is minimal in miscible displacement projects. The injection fluids used are not sensitive to the salinity or hardness of water, and in those projects where the injection fluid (gas) is alternated with water (WAG process), produced waters are normally used for injection.

Land use impact will be of some concern in the larger miscible projects. Pipelines will be laid to transport CO_2 from the source to the target reservoir and will have a land use impact during the construction period.

CO_2 transmission lines will normally require the preparation of an EIS prior to pipeline permit approval. Biological surveys are conducted for the proposed rights-of-way to determine the presence of any endangered plants or animals. Archeological surveys may also be required. Impacts of pipeline construction and operation on flora, fauna, archeological sites, and waterways are examined, and mitigation of recognized impacts is required.

Separate plants are built on-site for N_2 injection projects. More infrequently, processing plants may be installed to remove NGLs from the produced gases for use as a miscible fluid.

Gases produced from miscible flooding projects may be processed to recover the CO_2 (or other miscible solvent) for reinjection. Additional land use will be required for these plant installations, but normally construction will be confined to the field area in the form of additions or modifications to existing facilities.

Sources of air emissions from miscible EOR projects include exhaust gases from internal combustion engines or turbines used to drive generators, pumps, and compressors and from process heaters and boilers. These emissions will include nitrogen oxides (NO_X), carbon monoxide, carbon dioxide, and hydrocarbons. Also, sulfur oxides (SO_X) may be emitted if sulfur is present in the fuel. Hydrocarbons and other vapors may be emitted from leaking valves, fittings, and pump seals located in production processing and injection facilities. If project air pollutant emissions threaten the maintenance or attainment of ambient air quality standards, the operator may be required (by local, state, or federal regulations) to install control devices on the emitting facilities. In some areas, operators may also be required to provide emissions offsets.

The toxicity level of CO_2 is very low. CO_2 is harmless at low concentrations and must reach 2 to 3 percent by volume in air before any deleterious effects are noted. The eight-hour exposure limit recommended by industrial toxicologists is 5,000 ppm or 0.5 percent by volume in air. At a 3 percent concentration in air, lung ventilation is increased by 100 percent and a slight narcotic effect is noted. At 5 percent concentration in air, lung ventilation is increased by 300 percent and symptoms of intoxication will be evident. Concentrations of 7 to 10 percent will render persons unconscious within a few minutes. The escape of N_2 to the atmosphere would only return it to where it originated and involve no toxicity risk.

Fugitive emissions or accidental discharges in NGL systems would pose a fire and/or an explosion hazard. Also, a continual loss of NGLs, which contain reactive hydrocarbons, would be detrimental in an air basin where "smog" is prevalent. In all instances, a properly designed and well-maintained system is the most significant factor in protecting the environment from recurring nonroutine events.

Miscible fluids do not form any toxic wastes in the reservoir. However, hydrogen sulfide (H_2S) is present in many of the produced gas streams that may be injected. H_2S is an air pollutant and highly toxic.

Hydrogen sulfide is a problem frequently encountered in primary/secondary operations, and operators are well aware of its toxicity. Regulations have been adopted by various governmental agencies that require all stages of operations where H_2S is present to conform to safety and environmental standards. Texas Rule 36 and similar regulations adopted by other states have been formulated to protect the environment and to give adequate warning if nonroutine releases of H_2S occur. Operators should be aware that in CO_2 recycling systems, concentration of H_2S in the processed gases may occur. Special metallurgy should be considered in the construction of processing plants if H_2S is present. Also, special training and operating procedures should be in place to protect health and safety of employees.

Many processing plants for recycling systems use a physical solvent process for removing the CO_2 from the produced gases. Spent liquors from some of these plants may be hazardous wastes as defined by EPA Resource Conservation and Recovery Act regulations or state regulations. If they are hazardous wastes they must be disposed of properly at approved hazardous waste facilities. Those spent liquors that are not hazardous wastes should be disposed of in accordance with appropriate state requirements.

Mitigation of Potential Environmental Impacts

Potential environmental impacts from miscible displacement EOR processes are relatively minor. When the injected and produced fluids are contained in closed systems, the environment is protected and the economics tend to be more attractive. Hence, for miscible processes, environmental protection and process economics usually go hand-in-hand.

Spills and leaks are always a potential problem with supposedly closed systems. They can be mitigated by competent personnel who are well trained in handling procedures and in the maintenance of the injection and production systems.

Improvements in metallurgy and coating techniques have reduced the incidence of spills and leaks caused by corrosion. New alloys, coatings, and methods of applying coatings have been developed to inhibit the corrosive effect of wet CO_2 on ferrous materials. The use of nonferrous tubulars in low-pressure production systems has been found to be cost effective in many instances.

A notable advance in processing technology is the separation of CO_2 from the produced gases by using permeable membranes. The method is passive in nature, using no chemicals, and with further development, may completely eliminate the spent liquor disposal problem associated with a number of the present CO_2 purification plants.

Major Producing Areas—Unique Environments

The foremost potential application of miscible displacement will be in West Texas and East New Mexico. The large oil resource base and reservoir properties amenable to CO_2 miscible flooding heighten the potential of enhanced recovery in this particular geographic area. Pipelines now exist or are under construction to transport naturally occuring CO_2 from Colorado and northeastern New Mexico to the West Texas area. The major concern in the West Texas area is protection of usable groundwaters. Operators should ensure that injection wells are in good mechanical condition.

Another area where the CO_2 miscible EOR process may be extensively employed is the offshore area of the Gulf Coast. Although individual reservoirs are usually smaller in size, the presence of multiple reservoirs in most fields lends itself to repeated use of CO_2 in successive reservoirs. As CO_2 injection is completed in one reservoir, the produced CO_2 is reclaimed and reinjected into another reservoir. This cycle is repeated over time until all reservoirs are depleted.

Impacts on the land would be minimal with the installation of EOR projects in producing fields, but land use will be extended for the years during the economic life of the project. The wetlands areas are extremely active biologically and special precautions are advised to protect the biota within the area.

Special environmental considerations are required on the North Slope of Alaska. Logistics and supply dictate that NGL injection is the preferred EOR process, and one operator has initiated an NGL pilot flood. The acute environmental awareness that has evolved and has been practiced in primary and secondary operations on the North Slope is also being applied to the miscible injection project. These practices are also influencing new operators on the slope in their exploration efforts and will no doubt carry over into other EOR projects.

Thermal Recovery Methods

Thermal EOR methods include steam injection processes and in situ combustion. Both processes add heat to the reservoir to reduce oil viscosity and hence increase oil mobility. At the present time, steam injection processes are generally applied to reservoirs less than 3,000 feet in depth while in situ combustion can be applied to much deeper reservoirs. In 1982, approximately 97 percent of the national production volume by thermal recovery methods resulted from steam injection projects, while 3 percent resulted from in situ combustion projects. It is relevant to note that more than 90 percent of all thermal oil is presently produced in California, primarily in Kern County, and it is projected that this figure will not change significantly before 1990.[12]

Steam Processes

There are two types of steam injection processes: steam stimulation and steam drive. The steam stimulation process is also referred to as cyclic steam injection or "huff and puff." A mixture of steam and hot water is injected into a producing well for a period of days or weeks. The well is "shut-in" for a few days or weeks to allow the heat to disperse through the formation and is then placed on production, normally for a period of months. Depending upon formation characteristics, oil viscosity, and steam quality, between one and eight barrels of water are required to produce one barrel of oil. In normal field practice this process is repeated several times. Often, steam stimulation is used as a reservoir treatment prior to initiating steam drive, and may continue to be used during steamflooding to enhance the productivity of producing wells.

The steam drive process, also referred to as continuous steam injection or steamflooding, requires a pattern of steam injection and production wells. The objective is to develop a continuous heated zone in the formation that permits the effective displacement of oil from steam injection wells toward producing wells. It is estimated that approximately five barrels of water are required to produce one barrel of oil from many of the California steam drive reservoirs, although the reported range is from two to ten barrels of water per barrel of oil.[13]

[12]U.S. Department of Energy, *The Impact of Air Pollution Control Regulations on Thermal Enhanced Oil Recovery Production in the United States*, 1982.

[13]See footnote 11.

In Situ Combustion Processes

The in situ combustion process requires the burning of some reservoir oil in place. Compressed air or oxygen is injected to initiate and maintain controlled combustion. As the combustion front moves away from the injection wells, the heat vaporizes formation water, which in turn mobilizes a portion of the oil in place. This process is referred to as dry combustion. In many applications, however, the efficiency of the process can be improved by alternating water and air injection—a process known as wet combustion.

The Thermal Recovery Methods section of Chapter One contains a diagrammatic representation of thermal processes. A more detailed description of the processes is contained in Appendix F.

Environmental Impacts and Mitigation Techniques

It is anticipated that thermal EOR techniques will be significantly improved and expanded in the future. Such projections require that a thorough analysis of environmental impacts potentially associated with EOR procedures be conducted. The scope and format of this report section necessitate a condensed discussion of environmental issues associated with the planning, development, and operation of thermal EOR projects. For more detailed or issue-specific analyses, interested individuals are referred to several other reports.[14,15,16]

At the present time, thermal EOR projects are:

- Generally initiated in shallow reservoirs containing heavy oil
- Limited in geographic distribution
- Responsible for about 5 percent of total U.S. domestic production
- Subject to state and federal regulatory programs addressing emissions, effluents, and solid waste concerns.

Concern for the potential environmental effects of thermal projects concentrate on the following issues:[17]

- Air quality
- Land use

[14]See footnotes 1, 3, 9,11, and 12.

[15]U.S. Department of Energy, *Environmental Regulations Handbook for Enhanced Oil Recovery*, DOE/BC/00050-15, 1980b (October 1983 update available).

[16]Beck, R., Shore, R., Scriven, T. A., and Lindquist, M., *Potential Environmental Problems of Enhanced Oil and Gas Recovery Techniques*. Industrial Environmental Research Laboratory, U.S. EPA, Cincinnati, Ohio, 1979.

[17]See footnote 16.

- Heat and sound emissions
- Occupational safety and health
- Water supply
- Water quality
- Solid waste
- Toxic substances.

Air Quality

Air quality concerns with regard to thermal operations generally focus on emissions from steam generators used in steam injection processes, and fossil-fuel-fired air compressors used for in situ combustion projects, as well as produced combustion gases. Additionally, H_2S and hydrocarbon emissions from producing wells and other field process equipment are subject to controls or offsets.

As suggested earlier, the majority of thermal operations is located in California and this trend is expected to continue into the 1990s. A detailed analysis of California air quality regulations addressing sulfur dioxide, nitrogen oxide, and/or particulate emissions from steam generators and air compressors was completed by the Department of Energy in 1982.[18] That publication documents applicable regulations, existing and state-of-the-art emission control equipment, and costs associated with emission controls. The following information is drawn from that study:

- California SO_X ambient air quality standards are designed to be met through flue gas desulfurization (scrubber) requirements on new generators, offset of remaining emissions, and source performance testing.
- Ambient air quality standards for NO_X are protected by requirements for NO_X emission controls on new steam generators (i.e., low NO_X burners and free oxygen controllers) and offset of remaining NO_X emissions.
- Further restrictions on SO_X and NO_X emissions may be imposed based upon emission inventory and monitoring data.
- Hydrocarbon emissions from new steam generators must be offset, usually by installing vapor recovery systems on wellheads and production tanks.
- Particulate emissions from steam generators must be offset. Offsets have been obtained by paving lease roads to control dust.

It is anticipated that thermal projects in other areas of the United States might be similarly regulated, if subject to the intensive development and meteorological conditions similar to those in Kern County.

Wellhead casing emissions from producing wells, especially H_2S and hydrocarbons, and fugitive emissions from other field equipment and operations have been well studied. Wellhead casing gas collection systems have been installed, where required, and can contain and transmit such gases for treatment.

Land Use

Since thermal projects are generally initiated within existing fields and require few additional support facilities, it is not likely that significant land use conflicts will arise. The extension of the productive lifetime of the field is a potentially notable exception, depending upon site-specific considerations. It is anticipated that both human and biological communities will have adapted to oil production impacts during primary/secondary operations and acclimation to enhanced production would not be expected to be incrementally more difficult.

In some heavy-oil fields where thermal processes are initiated, a substantial increase in the number of production wells can be anticipated. Depending upon land use characteristics of areas adjoining such fields, aesthetic issues may be raised.

Heat and Sound Emissions

Steam injection processes require the production, transportation, and injection of high-temperature, high-pressure steam. Steam flow lines may travel above ground for substantial distances, posing a potential burn hazard to persons or animals who accidentally contact the lines. Steam generators and steam injection wells may also pose a similar hazard. Normal field practices include the insulation of above-ground steam transmission lines and, in urban areas, the protective enclosure of injection wells.

Both steam generators and air compressors operate at substantial noise levels. Hearing protection is required, where necessary, by existing regulations. Sound-absorbing housings are normally constructed where noise levels are anticipated to be substantial. It is presumed that animal populations avoid areas where noise levels are excessive.

[18]See footnote 12.

Explosion Hazards

Compressed air injection lines necessary for in situ combustion projects tend to accumulate lube oil that, when present in the form of droplets, may present an explosion hazard. A combination of periodic steam-cleaning and mist suppressor systems is believed to be successful in reducing such hazards. Synthetic lubricants that prevent explosion hazards at normal compressor operating temperatures are generally used.

In addition, some operators fit air injection wells with water pumps triggered to fill the wellbore with water during compressor failure. This reduces the possibility of "burnback" or return of the burn front to the injection well. In addition, safe operating procedures include monitoring of production well fluid temperatures to detect an approaching combustion front or steam breakthrough. If well fluid temperatures reach prescribed limits, the well must be shut-in and secured.

Well workovers require contingency procedures in the event that high-temperature or high-pressure gases are encountered.

Perhaps the best procedures for ensuring occupational safety and health are the assignment of highly trained, well-qualified personnel to EOR fields and the careful monitoring and control of operating field equipment.

Water Supply

Previous studies of the environmental impacts associated with thermal operations have all focused on conflicts between water consumption and anticipated freshwater supply. While it is true that water supply conflicts may present significant difficulties in selected areas of the country,[19] such water resource conflicts are not anticipated in the near future. There are a number of considerations that substantiate this conclusion:

- Even if Kern County (California) thermal production volume doubles by 1990, water consumption in the county would increase by less than 1 percent.
- Produced water recycle systems are now standard project design features. Some operators are effectively recycling more than 60 percent of their produced water, significantly reducing the demand for fresh makeup water.
- Due to other constraining factors, thermal projects are not likely to expand either as quickly or as significantly as previously anticipated, thereby reducing projected demand.

Water Quality

Concern for water quality generally focuses on the following issues:

- Discharges of process-related wastewater or produced water to surface waterbodies or groundwater aquifers.
- Spills/leaks of process-related chemicals.
- Stormwater runoff or natural drainage over or through facility sites.

Wastewater and produced water discharges are conducted in accordance with existing regulatory programs. For surface water effluents the objective is to avoid discharges of wastewater and produced water in toxic or hazardous concentrations. This is generally achieved through the stipulation of maximum allowable pollutant concentrations and periodic monitoring.

Wastewater and produced water may also be injected into groundwater aquifers, which are otherwise unsuitable for drinking water. Existing regulatory programs require the construction, operation, and monitoring of wastewater injection wells in such a way that the physical integrity of the well is clearly documented. These requirements are designed to protect aquifers of potable water in neighboring geologic strata.

Spills and/or leaks of oil, produced water, or process-related chemicals are dealt with through the development of spill contingency plans. These plans are documents that identify company personnel, agencies, spill cooperatives, and equipment locations for responding to local spills.

Some operators, especially those developing new projects or significantly expanding older ones, are designing stormwater and surface drainage collection/treatment systems. These systems are designed to minimize nonpoint-source contamination of surface waterbodies neighboring production and process sites. These same systems, in some cases, may also be useful in containing larger volume spills.

Solid Waste

Solid waste disposal is generally to approved landfills. Any wastes that are classified as hazardous wastes by the EPA or state regulatory agencies must go to licensed hazardous waste disposal facilities under a manifest record procedure. Scrubber wastes make up a

[19]See footnote 11.

significant proportion of the solid waste associated with steam injection projects. Disposal of liquid scrubber waste by underground injection in accordance with applicable underground injection control regulations has been demonstrated to be an acceptable and practical method of disposal; it is anticipated that this may become the primary disposal method.

Toxic Substances

Both steam injection and in situ combustion processes require the use of various process and treatment chemicals. Combustion agents (hydrazine, quinoline), thermal efficiency enhancers, biocides (formaldehyde), emission control chemicals (ammonia, caustic soda), corrosion inhibitors, and others may be used in varying quantities. In general, fewer toxic chemicals are used for thermal processes than are used in chemical processes.

The Department of Energy sponsored a study of some mammalian and environmental toxicological characteristics of chemical compounds used for enhanced oil recovery operations. That document is a valuable compendium of toxicological data, many of which are cited in Table G-3. In the past few years, considerable emphasis has been placed on toxicity research and a number of technical journals (e.g., *Archives of Environmental Contamination and Toxicology, Environmental Pollution, Aquatic Toxicology,* etc.) and computerized data bases have been developed. Readers are referred to the DOE study and more recent data for a review of chemical-specific toxicological characteristics.[20]

In normal field practice, toxic/hazardous materials are appropriately marked, handled, transported, and disposed of in accordance with federal and state guidelines. Spills or leaks of toxic materials are generally contained and cleaned up by personnel familiar with the requirements of such procedures.

It is possible that some process chemicals, particularly those injected into the producing formation, may become incorporated into the produced water. Cost-effectiveness considerations suggest that this problem should not be widespread or long-term. Nevertheless, where this occurs and the produced water is discharged to the surface, a potential for environmental harm may exist. If toxic concentrations are detected in produced waters, subsurface disposal may be a viable alternative.

[20]See footnote 9.

Potential Environmental Impacts Not Adequately Addressed in Current Field Practices

A variety of chemicals may be injected into producing formations to enhance thermal recovery efficiencies. It is likely that these procedures will continue, and perhaps expand in the future. Where produced water from such formations is discharged to surface water bodies, there is a possibility that treatment chemicals could be incorporated into these effluents. This would not be expected to be a widespread or chronic problem due to cost-effectiveness considerations, which dictate avoidance of this "breakthrough" phenomenon. Whether or not such occurrences pose a threat to natural or human populations would be a site-specific consideration and would depend upon variables such as toxicity characteristics, effluent concentration, and many others. It would be prudent, nevertheless, for operators to be aware of this possibility. Where there is an indication that effluent hazards may exist, operators should consider chemical identification and/or toxicity testing procedures.

Federal and State Regulatory Programs

Major federal/state environmental regulatory programs, which affect all EOR projects, flow from the National Environmental Policy Act, the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act (the Solid Waste Act), the Safe Drinking Water Act, and the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, also known as the "Superfund").

The federally legislated environmental protection programs are implemented by federal agencies, primarily the EPA, or by the states. With the exception of CERCLA, states can be delegated the responsibility to administer all or portions of federal programs. For example, the Clean Air Act mandates that states enact laws and regulations that allow for delegation of federal authority to the states to regulate and enforce policies that meet the minimum requirements of the federal program. States are free to adopt more stringent requirements and standards for air quality, hazardous waste disposal, and underground drinking water protection than those mandated by federal programs. One federal pre-emption is that states cannot prohibit transportation of hazardous wastes across their borders when disposal is destined for a licensed facility.

Federal funds or grants are available to assist the states in the development and enforcement of their regulations. No state has achieved primacy for all federally mandated environmental programs; however, several states are approaching total control. When a state does not have primacy for a program, the EPA regulations prevail. In some situations, an EOR project must satisfy both state and federal regulations. This can occur when the state regulatory program is in conflict with the federal regulations and the state has not applied for or has not yet received EPA approval for the specific regulatory program involved.

There are no regulatory gaps that would allow a project to escape the requirements of the Clean Air Act, the Clean Water Act, or other federal environmental programs. It is recognized that EOR projects may be exempt from certain permit requirements when air emissions or other regulated discharges are at or below de-minimus levels.

The Clean Air Act and the Clean Water Act are senior federal environmental programs and have extensive application to enhanced oil recovery projects. The Safe Drinking Water Act is a more recent program that also has universal application to EOR projects by virtue of the Underground Injection Control Program. EOR projects that generate air emissions and liquid or solid wastes will come under the regulatory programs of the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, and CERCLA (Superfund). Projects must also comply with state and local zoning or land use regulations.

Air Emissions

Under the Clean Air Act of 1970 as amended, EPA established primary and secondary air quality standards for the following list of air pollutants:

- Oxidants (measured as ozone)
- Sulfur dioxide
- Nitrogen dioxide
- Carbon monoxide
- Particulates
- Lead.

The 1977 Amendment to the Clean Air Act basically divided the United States into attainment and nonattainment areas. Attainment areas are those where the federal primary air quality standards for a specific pollutant are met. Areas may be attainment areas for one or more pollutants and nonattainment areas for others. Nonattainment areas are those in which the concentration of the regulated pollutant exceeds the federal primary ambient air quality standard for that pollutant.

The regulatory program in attainment areas is designed to maintain the existing status and to prevent significant degradation of air quality in the area. This regulatory program is more popularly known as Prevention of Significant Deterioration. An EOR project that falls under the purview of this program is required to use best available control technology for all regulated pollutants and may, under some state programs, be required to provide offsets for remaining emissions.

EOR projects in nonattainment areas will be required to install the most efficient emission control devices in practice (this may exceed Best Available Control Technology) for nonattainment pollutants and to offset all regulated pollutants at a ratio greater than one to one in order to demonstrate noninterference with the plan for attainment of air quality in the area.

Hazardous Air Pollutants

Seven substances have been designated as hazardous air pollutants under Section 112 of the Clean Air Act. These are:

- Asbestos
- Beryllium
- Mercury
- Vinyl chloride
- Benzene
- Radionuclides
- Inorganic arsenic.

The EPA has promulgated rules for asbestos, beryllium, mercury, and vinyl chloride. Regulations that address the other listed hazardous air pollutants are under development. Also, other materials or compounds are under consideration for designation as hazardous air pollutants. None of the listed hazardous air pollutants are commonly associated with EOR projects.

Surface Wastewater Discharges

Section 402 of the Clean Water Act established the National Pollutant Discharge Elimination System. This NPDES program requires that every discharge to navigable waters of the United States must have a permit. Currently, dischargers to navigable waters must meet the EPA's performance standards for the type of discharge involved. This requires the use of wastewater treatment methods known as Best Practical Technology.

Oil and gas fields located in outer continental shelf areas are allowed, in most instances, to discharge produced waters, deck drainage, drilling muds, sewage, and other potential waste streams under effluent limitations contained in individual facility or general NPDES permits issued by the EPA.

After June 30, 1984, dischargers must meet new EPA source performance standards (for each class of discharger) based on the use of Best Available Technology. This may mean more stringent effluent guidelines.

Current effluent guidelines for the bulk of the onshore oil and gas extraction industry is a "no discharge" standard for produced water. Subsurface disposal is identified as Best Practical Technology for these onshore oil and gas operations. Subsurface disposal of produced water is expected to be a continued requirement onshore. An exception to this requirement is made for certain areas in the western United States where some produced waters are "fresh" and have a beneficial surface use. Discharge of produced waters is permitted for certain coastal areas in Louisiana and Texas and the Santa Maria Basin in California.

A few of the major oil producing states have obtained primacy to administer the NPDES program. When a state program has not been approved by EPA, both state and federal regulations apply.

Under Section 311 of the Clean Water Act, it is unlawful to accidentally or intentionally discharge oil or any listed hazardous materials to navigable waters.

To further protect navigable waters from inadvertent or accidental spills of hazardous substances, Section 311 provides that every facility located near navigable waters that handles or stores oil or any listed hazardous substance must have an approved Spill Prevention Control and Countermeasures (SPCC) plan. The SPCC plan must contain a detailed description of the facility and must identify the potential sources of a hazardous spill, the avenues by which such a spill could reach navigable waters, and the protective measures employed to prevent spills and to contain and clean up spills if they occur.

Underground Injection Controls

Regulation of subsurface disposal of produced water falls within the Underground Injection Control (UIC) Program as authorized by the Safe Drinking Water Act. The EPA or authorized states administer the program. The UIC Program is designed to protect all usable supplies of drinking water from contamination by subsurface disposal operations.

Five classes of subsurface injection wells are identified in the regulatory program. The classification scheme is based on the nature of the fluids injected and the proximity and location of the injection zone to a usable supply of drinking water. Obviously, more stringent mechanical and monitoring requirements are placed on wells injecting hazardous or toxic fluids.

Injection wells used in oil and gas field operations for disposal of produced waters, injection of repressuring fluids, and injection of chemicals or gases for enhanced oil recovery are identified in the UIC regulatory programs as Class II wells and are subject to extensive controls. Wells used for disposal of produced water sometimes inject into a subsurface zone other than an oil or gas producing zone. However, no Class II well is allowed to inject into any zone containing water that meets the regulatory definition of an underground source of drinking water unless the zone has been exempted by the state and the EPA.

The UIC regulatory program includes permitting, monitoring, and enforcement actions to be observed by the permittee and the regulatory agency. Stringent mechanical requirements are placed on Class II injection wells to assure that injected fluids are confined to the intended injection zone. These requirements cover logging, casing, cementing, tubing, packer, and maximum injection pressure.

Monitoring requirements include periodic observations and reports of wellhead injection rates, pressures, and tubing-casing annulus pressures to detect any changes that might indicate the movement of injection fluids to a zone other than the intended injection zone. Any indicated escape of injected fluids must be investigated. If a leak is verified, it must be repaired or the well must be shut-in.

State enforcement programs include review of periodic monitoring data and unannounced, on-site inspections by trained personnel. Any observed violations of the rules can be grounds for immediate shut-in and significant civil and criminal penalties.

Besides the "good citizen" desire to comply with applicable UIC regulations, the operator of an EOR project has a strong economic incentive to confine the injection of expensive fluids to the target zone. The ultimate success of an EOR project would be jeopardized by significant loss of injected fluids to other zones.

Hazardous Wastes

Any liquid or solid wastes generated by an EOR project that must go to ground disposal would be regulated under authority of the Solid Waste Disposal Act as amended by Title II of the Resource Conservation and Recovery Act of 1976 (RCRA).

If a liquid or solid waste is deemed to be hazardous (either by its inclusion in a listing of hazardous or toxic materials under RCRA or when its chemical and physical properties meet the RCRA definition of a hazardous waste) the material must be treated or disposed of at an approved hazardous waste facility. Some wastes may also be suitable for reclamation or recycling. If the facility is a disposal site at a different location from where the waste is generated, the waste must be transported by a licensed hauler. Each load is documented by manifest, copies of which are retained by the operator, the hauler, and the site operator. Failure of a load to arrive at the disposal facility designated on the manifest is cause for state or EPA enforcement action. RCRA places responsibility on the generator to ensure that hazardous wastes arrive at the designated disposal site.

Hazardous wastes may be deposited in an on-site land disposal facility if the generator has applied for and received a hazardous waste disposal permit for that site or has obtained "Interim Status." However, the technical, reporting, recordkeeping, and financial requirements are prohibitive. Very limited use of on-site disposal is anticipated.

Chemical or Hazardous Material Spills

The Comprehensive Environmental Response Compensation and Liability Act of 1980 established a fee system for chemical feedstocks and products (including crude oil) to generate a 1.38 billion dollar Hazardous Substance Response Fund. The fund is to provide for immediate response to accidental spills of hazardous materials and to properly close abandoned or active disposal sites that present a serious threat to the environment.

A second 200 million dollar fund will be established under CERCLA to assure proper closure of approved surface disposal facilities in the future. This fund is generated by a tax on hazardous wastes when received at a permitted hazardous waste disposal facility. Collection of this tax started on September 30, 1983.

CERCLA also established a national chemical and hazardous material spill reporting system to supplement the spill reporting requirements under the Clean Water Act. Under CERCLA, any significant spill or release of listed hazardous or toxic materials to air, land, or water must be reported immediately to the National Response Center.

The regulations identify reportable quantities for each listed material that presents a significant threat to human health or the environment. Depending upon the material, this volume ranges from one pound or more for highly toxic materials to five thousand pounds or more for less hazardous materials.

Producers who routinely store or use listed hazardous chemicals in excess of reportable quantities are required to prepare a hazardous spill contingeny plan. This plan is generally incorporated into a facility oil spill contingency plan. If a hazardous material spill occurs, the National Response Center evaluates all available information to determine the spiller's ability to contain and clean up the spill. If the EPA judges the spiller capable of performing proper cleanup, EPA takes no further action. If the spiller is unknown, unwilling to respond, or incapable of adequately responding to the spill, the EPA will arrange for containment and cleanup with qualified contract personnel at the spiller's expense. In addition, many communities have trained their police and fire departments in the proper response to hazardous spills.

State or local community "right to know" laws are a growing trend in the regulation of hazardous materials. Such ordinances have been adopted by some communities and legislation has been passed or is under consideration by various states. Under these laws or ordinances, any facility that produces or handles hazardous material must provide local law enforcement agencies and fire departments with information these agencies would require to protect the public and fire and police department personnel in the event of fire, accidental spills, or other emergencies that might occur at the facility. Another requirement is proper training of facility personnel in handling hazardous materials and the correct response to a fire or accidental release of hazardous materials.

Maturation of Regulatory Programs and Industry Attitudes

The 1970s were aptly called the decade of the environment. The explosion of environmental legislation during this period was the product of a growing concern by the public that this nation's land, air, and water resources were being seriously threatened by careless developments and irresponsible waste disposal and discharge practices.

Congress responded with a slate of environmental laws starting with the National Environmental Policy Act of 1969, which established the requirement for Environmental Impact Statements for major federal actions and which led to the formation of the Environmental Protection Agency. This Act was followed by the Clean Air Act Amendments of 1970 and 1977, the Clean Water Act of 1972, and the Clean Water Act Amendments of 1977. The Safe Drinking Water Act passed in 1974. The Toxic Substance Control Act and the Resource Conservation and Recovery Act (Hazardous Waste Disposal) were passed in 1976. And, a final massive piece of environmental legislation, the Comprehensive Environmental Response, Compensation and Liability Act, was passed during 1980.

Amendments to existing legislation have been adopted from time to time and can be expected in the future, but no relaxation of the current body of environmental legislation is anticipated. Significant legislative attention to acid rain is expected. Anticipated revision in regulatory programs will flow from the increasing ability to detect trace amounts of toxic compounds in air and water and the ability to measure the impacts of such trace amounts on the environment.

In retrospect, the promulgation of environmental legislation and the implementing regulations have proven to be a sobering and educational experience for both the environmental community and the regulated community. Outspoken advocates for an improved environment were disappointed that the environmental abuses of 200 years of industrial development could not be eliminated overnight by simply passing legislation. As for industry, who resented any intrusion into what was considered their private domain, the discovery that operations could meet new environmental safeguards and still survive economically was a victory over dire predictions to the contrary.

There has been a maturation in the attitudes of all groups—the concerned public sector, the legislators, the regulatory agencies, and the regulated community. The environmental goals are now generally agreed upon by all concerned. The major issues today are: how to best achieve environmental objectives, in what time frame, and at what cost.

There is an obvious and accepted need to maintain effective guidelines that will protect air quality, freshwater resources, scenic values, and public and employee health. The record of compatibility of these goals over the long period of secondary recovery activities in the United States suggests that this can be accomplished while developing the nation's enhanced oil reserves.

Environmental evaluations and permitting procedures have not significantly delayed recovery projects nationwide, although some extensive delays in permitting EOR projects have occurred.

EOR projects require numerous permits and reviews by local, state, and federal agencies. The regulatory process, which allows all concerned parties an opportunity to express their views on the environmental impacts of any project seeking permit approval, must be based on fact. Those environmental risks perceived to exist must be subject to prompt and careful examination. If determined to pose a real threat, such risks must be considered when evaluating the viability of an EOR project. A poorly conceived regulatory program that seeks to deal with imagined as well as real environmental problems could unnecessarily limit the implementation of some EOR projects.

During the last decade, the oil industry has demonstrated a greater awareness and commitment to environmental conservation. This awareness has motivated the industry to develop equipment, procedures, and materials that offer improved environmental protection while allowing the continued development of EOR projects.

The most concerted effort at abating pollution has been directed towards thermal methods, and air contaminants associated with steam and combustion processes. Over 80 percent of the oil produced by EOR methods is by thermal processes, and over 90 percent of thermally recovered oil is produced in the state of California. The concentration of thermal projects in this relatively compact geographic area has given impetus to the resolution of environmental problems associated with EOR projects.

The major problem in thermal processes is air emissions from steam generators, with the major pollutants being SO_x, NO_x, hydrocarbons, and particulates. In most cases, these emissions must be controlled and offsets may be required. Hydrocarbons and carbon monoxide are normally the result of inefficient combustion and can usually be corrected by retuning the burner. Particulates are harder to control, but can be minimized by using low-ash, low-sulfur fuels. An exhaust gas scrubber controls SO_x emissions and also helps control particulate emissions. Modified burners, which significantly reduce NO_x emissions, are employed when regulatory agencies require use of Best Available Control Technology for NO_x.

New technology being investigated to further reduce steam generator emissions are:

- **Cogeneration of Steam and Electricity**—Overall thermal efficiency is improved and additional air emissions are not generated.
- **Solar Powered Steam Generators**—No emissions are generated.
- **Downhole Steam Generators**—The potential pollutants are injected and retained in the formation.
- **Fluidized Bed Coal Combustors**—Crushed limestone is mixed with the coal to absorb SO_x. NO_x emissions are also lowered.
- **Ammonia Injection**—Inhibits the formation of both thermal and organic NO_x.

Water usage may be a constraint for enhanced oil recovery. Water quality is the overriding factor for thermal and chemical processes. Softened water is preferable for use in steam generators and softened low-salinity waters are frequently used as a preflush in some chemical processes. The industry, aware of the possible impact on freshwater reserves, is increasingly turning towards use of produced waters for these purposes. Produced waters are being softened for use in boilers, and development of polymers amenable to high-salinity "hard" waters should lead to elimination of the preflush. The upward trend in treating and reinjecting produced waters is continuing. In one known instance, treated produced water is of such quality that excess supply is used for agricultural irrigation.

The industry has a good record for groundwater protection, a record supported by minimal problems associated with waterfloods. As previously pointed out, only 74 groundwater problems resulted from operating 44,000 injection wells in Texas between 1960 and 1975 and only three of these in the last decade. Similar records exist in other oil producing states with large numbers of waterfloods. However, the potential exists for increased problems with the injection of EOR fluids. Awareness of the materials and procedures available to protect tubular goods from corrosion will help protect groundwaters and improve on the already excellent record.

In general, as the number of EOR projects increases, the normal dissemination of knowledge and technology throughout the industry will include techniques and procedures used to protect the environment. As more experience is gained, the development and use of improved environmental control measures will accelerate.

Government and Industry Research Programs and Industry Committee Activities that Address Environmental Impacts Associated with EOR Activities

Published information on government sponsored and industry sponsored research on environmental impacts exclusively associated with EOR activities is limited. Lack of research dedicated specifically to EOR activities is not surprising when one considers that the atmospheric emissions and waste discharges from EOR projects are common to many other processes and industries. Thus, research on emission control devices, wastewater treatment systems, or solid waste disposal practices is applicable to EOR projects.

One specific research project recently completed is titled "Evaluation of Ground Water Contamination from Enhanced Oil Recovery Operations." This study was conducted by Brookhaven National Laboratory under contract from the Department of Energy's Bartlesville Energy Technology Center (now named National Institute of Petroleum and Energy Research). Computerized mathematical models were used to predict the movement of pollutants in an aquifer. The analysis considered only those EOR processes that inject substances that clearly presented a risk to aquifer contamination and focused on those substances for which sufficient data were available. Another specific study was completed recently for DOE by Gulf Universities Research Consortium. The subject was impacts of water requirements for EOR projects on water resources. An example of future studies is a DOE proposal for 1984 to study environmental impacts of EOR projects conducted offshore.

In 1978, the Interstate Oil Compact Commission conducted a study entitled "Impact of Oil and Gas Production on Salinity of Major Fresh Water Aquifers," which was carried out at the request of the National Drinking Water Advisory Council. This study covered the states of Arkansas, Louisiana, New Mexico, Oklahoma, and Texas. The study concluded that no pollution can be attributed to oil and gas field saltwater injection operations.

Environmental research conducted by individual companies is believed to be concentrated on emission control technology that would be applicable to a wide range of industrial activities. Any progress in emission control technology would benefit EOR projects. Company proprietary research on EOR processes could also include research on the environmental impacts of the materials involved in the process.

The American Petroleum Institute (API) is funding a wide range of environmental studies that relate to oil and gas producing activities. While these studies do not specifically address EOR processes, many of the results are pertinent to EOR operations. Some examples of API studies are listed as follows:

- "NO_x Emissions from Petroleum Industry Operations," API Publication No. 4311, completed in 1979
- "Cost Effectiveness of NO_x Control in Petroleum Production Operations," API Publication No. 4331, completed in 1980
- "Fugitive Hydrocarbon Emissions from Petroleum Production Operations," API Publication No. 4322, completed in 1980
- "SO_x Emissions Control: A Continuing Surveillance of SO_x Emission Control Technology Developments for Application in the Petroleum Industry"
- "NO_x Emissions Control: A Continuing Surveillance of NO_x Emission Control Technology for Application to the Petroleum Industry."

The API has two very active environmental committees, one at the national level in Washington, D.C., and one under the Division of Production in Dallas. These committees have a major role in identifying and recommending environmental studies for API funding. In addition, these committees have interacted with federal and state agencies in molding workable environmental regulatory programs that cover oilfield operations in general and will apply to EOR projects.

An example of industry committee action in response to environmental impacts associated with EOR operations was observed in Kern County, California. The rapid growth of thermal operations in the mid-1970s generated both government and industry concern over potential air quality impacts from the large number of steam generators to be installed. In response to these concerns, the industry conducted extensive studies to quantify the potential air emission problems. This committee was also responsible for organizing and funding a network of air monitoring stations, which are still in use today.

Operators tested various types of equipment designed to control SO_x emissions and NO_x emissions. Test information was shared with county and federal regulatory agencies to determine the best control technology for steam generators and heaters. The committee then worked with county and state regulatory agencies to develop effective, enforceable air regulations for thermal operations in Kern County.

As the need for specific research on the environmental impacts of a tertiary recovery process is recognized by government or industry, it is expected that the necessary funds will be made available. Also, when a potential environmental problem with ongoing or proposed tertiary activity has been recognized, industry has demonstrated the willingness to openly and cooperatively work with government agencies and environmental groups to resolve the problems.

Conclusions

Environmental impacts associated with EOR activities are basically an extension and expansion of impacts associated with primary and secondary oil recovery operations. EOR processes are applied to fields that have been developed for primary or secondary recovery operations. Older fields that are candidates for EOR operations have usually been subject to some method of secondary recovery; i.e., gas reinjection or waterflooding. Newer fields and future discoveries are more likely to be developed for EOR operations during the early years of primary production.

Environmental impacts of primary and secondary developments are related to land use, aesthetic values, threats to surface and subsurface waters, and surface disposal of production wastes. EOR operations can impose an extension and expansion of these impacts.

Primary development of an oil field requires land for surface well locations, production and process facilities, and roads to access wells and facilities. The impact of this land use depends on variables such as physical terrain, i.e., flat, hilly, mountainous, wetlands, desert, etc.; primary land use, i.e., agricultural, grazing; intensity of development, i.e., well spacing; and size of individual tracts, i.e., field developed under multiple, diverse ownership or under one lease or unit. Land use impacts under EOR operations are minimized by making maximum use of existing wells, facilities, and roads.

Aesthetic values generally vary in proportion to land use impacts. Some modern oilfield developments have overcome or eliminated visual impacts. Examples are the THUMS Islands in Long Beach Harbor and the various city production sites in Los Angeles. Where aesthetic values are paramount, reasonable measures can be taken to protect those values.

Secondary operations and EOR operations involve the injection of gases or liquids into the reservoir to increase oil recovery. Subsurface injection operations pose a potential threat to zones containing usable supplies of drinking water. This aspect of secondary and EOR operations has received extensive, long-term attention from industry and government. The good record compiled during the long history of secondary water injection operations and the current body of regulations in place give assurance that the risk of groundwater pollution will be kept under excellent control.

Primary and secondary operations generate various wastes that go to surface disposal. These oilfield wastes are regarded by EPA as nonhazardous and generally go to on-site surface disposal. EOR operations can generate additional wastes from chemical mixing and injection plants, from combustion gas scrubbers, from production processing sites, and from produced gas treating facilities. Some of these wastes may be classified as hazardous wastes under EPA or state regulations and must be handled and disposed of in an approved manner.

Many EOR processes, and especially the various chemical processes, deal with toxic materials that are stored and mixed on the surface and then injected into the target reservoir. Special attention should be given to all phases of this operation to assure that none of these materials escape to surface or to subsurface waters.

Most EOR chemical processes have been subject to limited full-scale field testing. The carry through of injected chemicals to producing wells is not completely understood or predictable. This raises the concern about the presence of toxic concentrations of various process chemicals in the produced waters. While surface discharge of produced waters is extremely limited in area and scope, some onshore discharges are allowed as well as offshore discharges.

For EOR projects, monitoring of produced fluids discharged to the surface is expected to be a routine operating practice. Reservoir management has a need to know the presence and concentration of injected materials in produced fluids. Also, EPA has announced a new policy on water quality based controls on toxic pollutants that may be applied to all surface water discharges.

Organizations that conduct research on EOR processes, particularly chemical EOR processes, are expected to include the environmental and health impacts of the materials involved, so that this knowledge is available when the process is transported from the laboratory to the field.

The study participants' visits to active EOR projects in various geographic areas revealed a high level of awareness to potential environmental impacts associated with these projects. Considerable attention was devoted to identification and mitigation of recognized impacts and to compliance with all applicable environmental regulations. Concerted efforts to operate in an environmentally conscientious way are expected to minimize recognized as well as unanticipated impacts associated with EOR projects.

Appendix H

Research Progress and Future Implications

This appendix reviews recent research progress and discusses broad objectives for future research in chemical, miscible, and thermal process technologies. Improvements to surfactants and polymers can significantly increase the range of conditions for which chemical processes are applicable. In terms of the target resource base, there are large incentives for continued development of chemical recovery processes. Miscible recovery can benefit from continued research in process optimization and mobility control additives. Technologies that will most effect increases in thermal recovery include improved thermal efficiency, mobility control, and the use of oxygen-enriched air injection for in situ combustion.

Chemical Flooding Technology

Polymer Flooding

Since 1976, research has extended knowledge of polymer solution properties, identified ways to improve the thermal, chemical, and biological stabilities of existing polymers, and developed new polymers in order that field projects may be conducted under increasingly adverse reservoir conditions. Polymer flooding technology has been implemented in reservoirs with salinities up to 10 percent total dissolved solids (TDS) and temperatures up to 200 °F. Although polymer flooding has not yet been implemented in higher salinity reservoirs, existing biopolymers should be applicable in lower temperature reservoirs with salinities up to 20 percent TDS.

Major advances will be required to extend polymer use to reservoirs having temperatures up to 250 °F. Polymers must be developed that can be satisfactorily injected and propagated in lower permeability reservoirs [less than 20 millidarcies (md)]. More cost-effective polymers are required to effect an increase in the target oil viscosity above 100 centipoise (cp). Many of the current restrictions on all chemical processes result from limitations on polymer use. As a result, polymer research leading to wider limits of application will have a significant impact on the enhanced oil recovery (EOR) potential of other EOR processes.

Research Progress Since 1976

Successful polymer applications require a process design tailored to the specific reservoir and careful control of chemical properties to help ensure that the polymer solution remains effective in the reservoir. Polymer performance depends to a large extent on the rheological properties of the specific polymer used, and on how well these properties are maintained during the life of a project. With very few exceptions, polymers that have been used are of two types, partially hydrolyzed synthetic polyacrylamides and xanthan biopolymers. Since 1976, polymer research has improved the characterization of these polymers, improved the knowledge of their behavior in porous media, and developed improved polymers for harsher field conditions. Research has led to better understanding of polymer stability, rheology, formulation, and retention in the reservoir.

Polymer stability has become a more important concern as projects are implemented in higher-temperature reservoirs. Polyacrylamides in particular undergo increasingly rapid hydrolysis above 160 °F. In the presence of divalent cations, hydrolysis can cause polymer precipitation even at much lower temperatures. Concern has also been expressed over the thermal and chemical stability of xanthan biopolymers. Recent tests have shown that microbial attack of both polymer types can be a potentially serious problem. Although progress has been made in the development of chemical additives to stabilize polymer properties at high temperatures and in the development of biocides to minimize the effects of microbial attack, considerable additional research is needed. Awareness of the effects of microorganisms and biocides on polymer stability has led to joint industry funding of a program at a major research institute to study this problem.

Mechanical degradation, which can occur either in surface equipment or at the sand face, and sensitivity to saline environments continue to be important problems affecting polyacrylamide rheology. Research has begun to characterize the effects of mechanical degradation on in situ polymer properties, but significant success has not been achieved to date in increasing the tolerance of polyacrylamides to either salinity or mechanical stress. Operational procedures have been developed to minimize these effects, but some of these practices, such as freshwater preflushing for salinity tolerance, are expensive and may not be possible in some cases. Although biopolymers are generally insensitive to both of these factors, they have suffered in the past from poor filtration properties. Recently, significant progress has been made in improving the injectivity of xanthan biopolymers through the use of concentrated broths or by the addition of enzyme to the biopolymer solution.

Many programs are underway to improve EOR polymers and to develop new ones. Some of these efforts involve grafting polyacrylamides to biopolymers and chemically modifying existing polymers. In other programs, new polymers have been synthesized by incorporating various combinations of different monomers during polymerization. Still other efforts seek biological organisms to produce biopolymers through fermentation. While some of these polymers show promise, further developments are still needed to produce cost-effective, stable polymers.

Polymer cross-linking treatments have become more widespread in recent years. These treatments use gelled polymer to alter injection or production profiles by plugging watered-out zones or high-permeability streaks near the wellbore. A variety of techniques has been developed to form and place the cross-linked polymer in the formation. In order to better design these treatments, work has been done to characterize polymer gellation times, gel strengths, and the abilities of polymers and gels to selectively plug porous media.

There has been a large increase in the number of active polymer projects, both near-wellbore treatments using cross-linked polymers and polymer floods to improve the waterflood mobility ratio. These involve applications in a wide variety of reservoir types, including sandstones and carbonates with permeabilties ranging from 20 to 2,000 md, temperatures up to 200 °F, and in situ oil viscosities up to 100 cp. Results from the increased number of polymer projects are not conclusive, since many projects are still ongoing. However, the expectation is that polymer flooding will result in the recovery of a relatively small amount of additional oil, usually from 1 to 5 percent of the oil originally in place (OOIP).

Significant improvements have been made in field handling and mixing of polymers. Field trials revealed the importance of maintaining good water quality and providing adequate mixing facilities to ensure proper dissolution of polymer before injection. New equipment and new polymer products have been introduced to facilitate polymer hydration and to optimize the properties of the injected solution.

Future Research Needs

A major need is the development of mobility control agents (polymers) that will be thermally stable and provide satisfactory resistance factors at high temperatures. Since existing polymers are inadequate for high temperature use, development and testing of new EOR polymers will be essential. There is still uncertainty concerning how polymer rheology and stability depend quantitatively on temperature, dissolved oxygen content, salinity, divalent cation concentration, iron, pH, and rock and oil properties. An understanding of the mechanisms of polymer degradation may aid in improving stability. Progress has been reported on the use of stabilizers to prolong xanthan and polyacrylamide effectiveness. However, many questions remain concerning potential chromatographic separation of the stabilizers from the polymer solution, the mechanisms by which stabilizers work, and the influences of temperature and reservoir fluids on the performance of the stabilizers. Complex interactions may occur between hydrogen sulfide (H_2S) in the reservoir and oxygen scavengers and biocides added to injection fluids. Also, the addition of expensive stabilizers to polymer solutions can have a significant impact on field project economics.

Presently, biologically produced polysaccharides are the only polymers whose properties would not be affected by salinities up to 20 percent TDS. In general these polymers are more expensive than the salinity-sensitive polyacrylamides. New synthetic polymers that are less salinity-sensitive, and manufacturing techniques to lower the cost of both polyacrylamides and polysaccharides are needed.

Improvement in the cost effectiveness (or resistance factor per unit cost) of EOR polymers is also a major need. Polymer project economics are often marginal with the effective viscosity-to-cost ratios provided by currently used xanthans and polyacrylamides. This is true even for applications where stability, retention and injectivity are not serious problems. Lower cost polymers and new, more effective viscosifiers would improve project economics and could improve process efficiencies as well. Increased cost effectivenesss could also make the use of higher polymer concentrations more affordable. This could, in turn, provide effective viscosities high enough to make polymer flooding effective in reservoirs with crude oil viscosities as high as 150 cp.

There is concern over the ability of present polymers to be propagated through low-permeability rock. Permeability restrictions for current applications result from the pore-plugging and decreased injectivity observed when many polymers are injected into low-permeability rocks. As a result, many polymers that might be injected into tight formations have low molecular weights. Since these polymers tend to be poor viscosifiers, high concentrations are required to achieve the desired performance. Improvements leading to lower cost polymers may permit higher polymer concentrations to be used in low-permeability reservoirs.

Additional research is needed to study general polymer propagation and retention. Before a polymer-based process (including surfactant and modified alkaline flooding processes) can be applied in the field, experimental techniques for determining polymer retention must be used. Improved techniques are required to reduce the experimental errors associated with these measurements, the influences of complicating factors such as ions, and the time and expense involved in determining reliable retention values. Research should continue to investigate the effects of permeability, pore size and shape, minerology, oil saturation and type, polymer size and type, resident water composition, and rock wettability state on retention. These factors could play key roles in extending the potential of all polymer-based processes to lower-permeability reservoirs.

Further studies are needed to characterize polymer injectivity over the full range of rock permeabilities. Because field project economics are very sensitive to the rate at which fluids are injected and produced, an understanding of the factors that affect injectivity is important to project planning. The relationship between field injectivities and filter tests and other laboratory measurements needs to be firmly established. Presently, there are many different types of filter tests and core injectivity tests in use, but there is no common agreement as to how the results of various tests are related to field injectivity. Besides characterization of injectivity, the development of polymers with improved injectivity characteristics (e.g., shear-thinning polymers) would have a significant impact on the economics of all polymer-based processes.

A significant research effort is needed to characterize the effects of microorganisms and biocides on polymers. Areas requiring study include the important mechanisms by which microorganisms attack polymer molecules, the types of organisms that can degrade polymers, the most effective biocides for controlling polymer-degrading organisms, and the effects of biocides on polymer performance.

Polymer cross-linking treatments can also be improved. Work has been done to characterize polymer gelation times, gel strengths, and the abilities of polymers and gels to selectively plug porous media. However, considerable additional research is needed in the areas of selective placement and stability and depth of penetration of polymer gels in a reservoir. Gelling systems (polymer and gelling agents) must be developed that are stable at temperatures up to 250 °F and in salinities up to 20 percent TDS.

Surfactant Flooding

Since 1976, major advances have been made in the understanding and characterization of surfactant behavior in both laboratory experiments and field tests. These advances have in turn led to more efficient design procedures, recognition of factors that can adversely affect recovery, and development of more effective chemicals having broader ranges of applicability.

Continued research will be required to further extend the ranges of reservoir conditions to which the surfactant flooding process applies (i.e., the Advanced Technology Case considered in this study). Some of this research will deal only with improvements in the surfactant solution. Other research will be needed on the polymer solution mobility buffers. Some of the polymer solution research will be common to polymer and alkaline flooding, but total system research will also be required. The conditions adopted to represent the Advanced Technology Case in this report include: a thermal stability limit for the surfactant/polymer system increase from 200 °F to 250 °F; a salinity limit increase from 10 percent to 20 percent TDS; carbonate as well as sandstone reservoirs; a permeability limit decrease from 40 to 10 md; and a viscosity limit increase from 40 to 100 cp. The technology development required to achieve these goals is discussed below. In a later section, the incentives for this further development are shown to be significant.

Research Progress Since 1976

Phase behavior tests have been of particular importance in surfactant screening and process design. Correlations between simple phase properties and recoveries in corefloods have allowed surfactants to be evaluated much more rapidly by test tube experiments. These tests also have greatly elucidated the effects of surfactant structure on performance. In addition to the more efficient identification of the best available surfactant for a particular reservoir, these tests also help to characterize the conditions (such as salinity) under which each surfactant will best perform.

The system salinity and hardness have been shown to be fundamental to the performance of a surfactant. In particular, laboratory phase behavior and coreflood tests have shown that for a given crude oil, each surfactant possesses a specific salinity at which its effectiveness becomes optimal. These tests have also shown that even low levels of hardness can significantly affect the phase behavior and effectiveness of many commercially available surfactants. This has led to increased study of the effects of ion exchange on surfactant behavior and process performance.

In addition to indicating the interfacial tensions that develop in situ, phase behavior tests have also given insight into other physical mechanisms and have led to new areas of research. Surfactant precipitation through interaction with divalent cations and surfactant/polymer phase behavior have been studied. As in other areas, increased awareness and understanding of these mechanisms have led to better, more efficient system designs.

Although most research and field projects performed to date have used gas/oil and crude oil sulfonates, the period since 1976 has seen a significant increase in the evaluation and use of synthetic surfactants and cosurfactants. Synthetic surfactants, though more expensive, hold the promise of being more effective in oil mobilization under more severe reservoir conditions. Cosurfactants, such as ethoxylated alcohols and sulfated ethoxylated alcohols, have shown the ability to extend the salinity ranges under which other surfactants can effectively recover oil.

The increased sophistication of laboratory experiments has been accompanied by advances in data collection/analysis and in process modeling. Both laboratory and field tests have greatly benefited from the advent of computerized data acquisition systems. Models have been developed that range from simple analyses for qualitative studies to complex, three-dimensional models for use in reservoir simulation. The development of high-speed vector processors has dramatically reduced the computational times required for the more complex models.

Advances in understanding of the process mechanisms through laboratory tests and computer modeling have been reflected by the increased number of field tests and by the number of technically successful projects. These tests have continued to provide valuable information concerning the process. For example, field data indicate that the surfactant and polymer requirements are larger than previously anticipated. This result may be due to chemical retention, fluid degradation, and/or lack of mobility control.

Synthetic, gas/oil, and crude oil surfactants have been tested under a broad range of reservoir conditions. A recently completed test in the Loudon Field in Illinois gave good recovery results without a preflush in a reservoir with a resident water salinity of 104,000 parts per million (ppm). Another test in the Wilmington Field in California was a success in a reservoir with a moderately high crude oil viscosity of 35 cp at a 145 °F reservoir temperature. These field tests have helped extend the range of applicability of the process.

A result common to all field tests has been the recognition of the greater need for operational control of the process in the field. The sensitivity of the process effectiveness to the attainment of stable chemical banks in heterogeneous environments will require greater project management than usually required for successful secondary recovery projects.

Future Research Needs

Surfactant solution thermal stability above the present temperature limit of 200 ° F needs further study. Thermal decomposition and hydrolysis significantly decrease recoveries when some existing surfactants are used at these higher temperatures. New surfactants and cosurfactants are being considered to extend the present temperature limitations. The ability of polymers (included in the mobility buffer that is used to displace the surfactant slug) to withstand higher temperatures is also vital to extending the temperature range for surfactant flooding. Research needs for improving polymer thermal stability are discussed in the Polymer Flooding section of this appendix.

Resident water salinity also has an effect on the stability of the surfactant solution slug in the reservoir. Higher salinity formation fluids often contain excessive amounts of divalent ions such as calcium and magnesium, which are known to promote the instabilities observed in many of the presently available surfactant and polymer systems. Freshwater preflushing is not necessarily desirable, nor possible, in many field situations, and research is emphasizing the development of salt-tolerant surfactant and polymer systems. Surfactants useful to 200,000 ppm TDS at low temperatures appear well within reach, but will require extensive development to achieve both high-temperature and high-salinity tolerances.

Although all successful surfactant floods have been conducted in sandstone reservoirs, there are some pilot projects currently being conducted in carbonate reservoirs. The effect of the carbonate rock matrix on surfactant adsorption and other rock-surface-related mechanisms need to be examined in greater detail. New types of surfactants may need to be developed to reduce adsorption on carbonate surfaces. Cost-effective nonionic surfactants may be another way to attack this problem. There appear to be no insurmountable problems with the surfactant that would prohibit the use of the surfactant process in nonsandstone reservoirs. However, new types of mobility buffers or different types of polymers may need to be developed for advanced surfactant flooding processes in carbonate reservoirs. Although polymers have been used effectively in some high-permeability carbonate reservoirs, the screening out of polymers in the tighter carbonate formations may be a concern.

Very tight (low-permeability) reservoirs have not responded well to the surfactant process. Laboratory floods with the same fluid systems and cores of different permeabilities but from the same reservoir give lower recoveries from the lower permeability cores. These results indicate that the displacement efficiency decreases with decreasing rock permeability. This effect may be related to the effect of pore size on capillary number. Injectivity and pattern size are also areas that must be addressed to achieve satisfactory performance in lower permeability reservoirs.

Successful surfactant flood field projects to date have been in reservoirs containing relatively low-viscosity oils (40 cp or less). Laboratory floods indicate a potential capability to formulate surfactant processes capable of displacing 100 cp oil. Research will be needed to ensure that mobility buffers (polymer solutions) are available to displace the surfactant slug. Advances in the design of project pattern size and type to account for known reservoir heterogeneities will also assist in applying such advanced technology processes in the future.

Improvements in displacement and sweep efficiencies of the surfactant flooding process are also expected as a result of future research. Recent advances in the understanding of process mechanisms, for example interfacial tension reduction, must be continued to permit better slug design and optimization for improved displacement efficiency in the field. Methods to alter effective reservoir permeabilities and to overcome fracture communication are required to improve volumetric sweep efficiency. Improved selection of flood patterns and shapes and completion intervals through the application of advanced reservoir description methods can also result in improved sweep efficiency.

Reduction of surfactant adsorption by the reservoir matrix is an additional area of research that holds promise for cost reductions through more effective use of the surfactant slug. Sacrificial agents, pH control, surfactants with altered functional groups, and wettability alteration effects should all be explored to improve process economics.

Because a significant portion of the expenses of a surfactant project occurs early in the project life due to the costs of the injected chemicals, reductions in these costs will most directly influence process economics. Other factors are also important, however. These include pattern size and type, injection well completion practices, and the selection of facilities for fluid mixing and injection. Injection rate is especially important from the standpoint of the time value of money.

Alkaline Flooding

Since 1976, research in alkaline flooding has resulted in a better understanding of oil recovery mechanisms and the interactions between the injected alkaline chemicals and the reservoir rock and fluids. Methods have been developed to improve the alkaline flooding process by the use of ancillary chemicals such as polymers and added surfactants.

Areas needing attention to achieve improved alkaline flooding capability are an expansion to additional reservoirs with more hostile environments, improved displacement efficiency, improved volumetric sweep efficiency, and improved economics resulting from factors such as reduced alkali consumption, cheaper ancillary chemicals (polymers, cosurfactants) for modified alkaline flood processes, improved injectivity, and improved project design. It is anticipated that advanced technology may encompass salinities to 20 percent TDS, in situ viscosities to 100 cp, and rock permeabilities as low as 10 md. To achieve this extension of the limits of process applicability, specific research in slug design and the development of polymers that are compatible with the more hostile reservoir environments will be required.

Research Progress Since 1976

The alkaline recovery process is very complex. Studies have shown that several acidic functional groups on components of the crude oil can be responsible for the reactivity of the alkali, but that not all reactions yield surface-active materials. Research has provided insight into the components of the crude oil that provide high interfacial activity, and into the formation and role of interfacial films. Additional information has been obtained on optimizing the concentration of alkali and on the influence of salt concentration.

Other studies have given detailed information on the reactions of alkalis with hardness ions, the precipitates that form by these reactions, and their potential for modification of flow. The effect of the type of alkali on both the hardness ion activity and on the interfacial tension have also been investigated.

Alkali/rock interactions have been studied extensively. Consumption of alkali by the rock has been investigated over wide ranges of temperature and contact time with different minerals and alkalis. Alkali reactions with the rock include dissolution, ion exchange, and the conversion of clays such as kaolinite or smectite to albite or feldspar. Increasing alkali consumption with increasing temperature and the reversible nature of ion exchange reactions are of particular significance.

There was an increase in active alkaline flood field projects from one in 1976 to thirteen in 1982. Alkaline projects have encompassed a wide range of reservoir parameters. In some of these projects the processes have included the addition of polymers and other ancillary chemicals. The field tests have demonstrated the complex nature of the process in the reservoir, and the need for larger volumes of alkali and better mobility control. Total oil production from these tests has been small. The degree of technical success as measured by oil production has varied from modest to disappointing.

Future Research Needs

Alkali and salt concentrations both influence the interfacial tensions, emulsion stability, and the basic mechanisms of movement of the the oil. Laboratory results on the influence of salt concentration correlate with surfactant flooding results and suggest some similarities. Improved slug designs also result from the use of cosurfactants and may therefore benefit from improved surfactant flooding technology. Thus, some of the more general surfactant work has applicability to alkaline flooding. Research is needed relating salt concentration, cosurfactant type and concentration, and the concept of optimal salinity in the context of alkaline flooding. Of prime importance is the rock/solution interaction and how this influences performance in reservoir with typical clay contents.

Acceptable economics of alkaline flooding processes are greatly dependent on improved recovery. Slugs with improved performance are likely to be more costly. Factors that could improve the specific economics of alkaline flooding are reductions in the cost of polymers and cosurfactants. Improvements in pattern design and injectivity will benefit alkaline flooding as they will other EOR processes.

Maximum utilization of the potential of the alkaline flooding process will require improvements in both displacement efficiency and volumetric sweep efficiency. Both of these efficiencies are influenced by the consumption of the alkali from the slug by the rock (and the adsorption of any ancillary surfactant that may be included in the slug). Alkali consumption depends on the composition of both the rock and the slug, as well as on formation conditions. Accordingly, improved process design requires that research adequately address the alkali/rock reaction mechanisms, quantify consumption of the caustic (and adsorption of the surfactant, if present), and investigate the use of ancillary chemicals to mitigate these effects. The introduction of ancillary chemicals to improve process performance or reduce alkali consumption has received minor attention to date. The use of polymers for mobility control was quickly recognized as a possible improvement, but polymer use is constrained by the limitations of the polymers (discussed above).

The alkali/rock interactions are extremely important aspects of the process. At least two types of interactions occur: reaction of the alkali with mineral components of the rock, and ion exchange with clay minerals. Either of these reactions can result in changes in the chemical content of the slugs that can influence the consumption of the alkali and the generation of surface active materials. The importance of the reactions is influenced greatly by the minerology, and specifically by the clay content. Additional research is needed to quantify the effects of these factors on chemical consumption and oil recovery over a wide range of clay contents, temperatures, and contact times.

Plugging of production wells has been observed in some field tests. A better understanding of the interaction between injected and reservoir fluids in the vicinity of the wellbore and of the subsequent formation of plugging materials such as inorganic precipitates, is needed.

Resource Incentives for Improved Chemical Flooding Technology

Advancements in chemical EOR technology are expected to make chemical processes applicable to many more petroleum reservoirs. In order to evaluate the potential incentives for improved chemical flooding technology, a subgroup of reservoirs from the NPC data base was assembled by including only those reservoirs with greater than 50 million barrels of OOIP and with complete sets of values for all five of the screening parameters outlined in Appendix D. These reservoirs were then evaluated against the screening criteria for the three chemical flooding processes.

Table H-1 compares the percentages of the OOIP in the data subgroup that meet the screening criteria for polymer, surfactant, and alkaline flooding under Implemented Technology and Advanced Technology Case conditions. The remaining oil that is a target for enhanced recovery is expressed as a percentage of the OOIP in the entire data subgroup. As shown in Table H-1, the impact of potential technology improvements varies among the processes. For surfactant flooding there is almost twice as much target oil in the Advanced Technology Case potential as in the Implemented Technology Case potential. This is a significant incentive for continued research to extend the limits of applicability of surfactant flooding. Recall, however, that surfactant flooding potential is in many respects limited by the applicability of polymers to restricted ranges of reservoir conditions. To achieve the potential indicated, technology development for these two processes must proceed in parallel.

Miscible Flooding Technology

In recent years most miscible displacement research efforts and field tests have been focused on the use of carbon dioxide (CO_2) as the miscible solvent. This emphasis on the CO_2 miscible process is the result of several interrelated factors. First, CO_2 has been demonstrated to be an effective miscible solvent in both laboratory and field tests. Several variations of the CO_2 miscible process have been successful under different reservoir conditions. Second, several large natural deposits of CO_2 have been developed that are capable of producing the rates and volumes necessary to sustain the flooding of numerous large target reservoirs. These deposits are often located several hundred miles from the candidate reservoirs, but pipelines have been built to deliver the CO_2 at prices that make CO_2 miscible flooding economically attractive in many target reservoirs. Finally, the increase in demand and price for natural gas and liquified petroleum gases (LPGs) has rendered hydrocarbon materials much less economically attractive as injectants. Nitrogen or flue gases are generally less expensive than CO_2, and under those conditions where miscibility can be achieved these gases have been used.

For these reasons the present discussion will focus primarily on recent CO_2 miscible flooding research. Some additional discussion of nitrogen miscible flooding and CO_2 immiscible flooding is warranted by advances achieved since 1976 in these areas.

CO_2 Miscible Flooding

Field test results that have been reported since 1976 have added significantly to knowledge of and confidence in the CO_2 miscible displacement process. Field projects have greatly improved understanding of the process and help to focus needs for future research. In the laboratory, research efforts have improved techniques for determination of minimum miscibilty pressure (MMP), understanding of how miscibility is achieved and maintained,

TABLE H-1

RESOURCE INCENTIVES FOR IMPROVED CHEMICAL FLOODING TECHNOLOGY

	Potential Target Oil Percentage of OOIP in NPC Data Subgroup*		
	Implemented Technology	Advanced Technology	Incremental Incentive
Polymer Flooding	32.9	45.5	12.6
Surfactant Flooding	22.4	43.1	20.7
Alkaline Flooding	17.6	18.9	1.3

*Approximately 309 billion barrels of OOIP.

understanding of the factors that determine the residual oil remaining after miscible displacement, and computational methods for scaling laboratory results to field performance estimates. Methods for controlling CO_2 mobility in the reservoir, including water alternating with gas (WAG) injection and the use of ancillary mobility-modifying chemicals, have also been investigated and continue to be a topic of special interest. Since 1976, research has led to improved technologies for processing of gases produced in field projects, and has adapted technology to unique problems encountered in the production of CO_2 from reservoirs located in mountainous, and environmentally sensitive terrain.

Field Testing

Field pilot testing of the CO_2 miscible process has demonstrated the ability of CO_2 to mobilize and displace crude oil, even in previously waterflooded reservoirs. Field tests in carbonate reservoirs have used both WAG and continuous solvent injection processes. The WAG process can be used to control CO_2 mobility and improve sweep efficiency in stratified, heterogeneous reservoirs. Examples of this process are the Slaughter Estate Unit pilot test, the SACROC Unit field project, and the Little Knife mini-test. Continuous CO_2 injection has been used in carbonate reservoirs where water injectivity is poor, or where both adequate sweep efficiency and low gas cycling costs permit continuous solvent injection to be used. Examples are the project at the North Cross (Devonian) Unit, and the Denver Unit pilot test.

The best performance reported to date for a WAG flood has been in the Slaughter Estate Unit pilot test. This pilot was conducted in the San Andres carbonate formation, which is one of several prolific carbonate formations in West Texas. A 26 percent hydrocarbon pore volume (HCPV) slug of CO_2 was injected at a WAG ratio of 1.0 (reservoir barrel of CO_2 per reservoir barrel of water). Confirmed production response from the two well-confined six-acre patterns was 16 percent of the OOIP. A recovery of 20 percent of the OOIP was projected. Estimated solvent utilization efficiency was about 5.5 thousand cubic feet (Mcf) of solvent per barrel of incremental oil. The Slaughter Estate Unit pilot test is unique in that the solvent stream contained 28 percent H_2S.

The preponderance of field tests in sandstone reservoirs has used a continuous CO_2 injection process, or slugs of CO_2 driven by a less expensive gas and/or water. The use of WAG injection can be less efficient in sandstone reservoirs, where water-blocking of waterflood residual oil can significantly reduce displacement efficiency at moderate or high WAG ratios. In the deep, hot Tuscaloosa formation at Little Creek Field, Mississippi, 30 percent OOIP was recovered by continuous injection of 1.6 HCPV of CO_2. The injection of 25 percent HCPV of CO_2 into the east side of the Twofreds Delaware Sand Unit, Texas, resulted in good production response without severe gas channeling. Plans for further field development included evaluation of switching the bulk of CO_2 injection to the west side of the unit and displacing the CO_2 in the east side with inert gas or water. The early field test at Mead Strawn Unit, Texas, showed that the displacement of a relatively small CO_2 slug by water can be effective, but the efficiency of inert gas displacement of CO_2 is less certain in light of rapid breakthroughs observed when this displacement method has been used in hydrocarbon miscible tests in sandstone reservoirs, and also in the later displacement phase of the Slaughter Estate Unit test.

A number of field tests in both sandstones and carbonates has emphasized that high CO_2 mobility and reservoir heterogeneity may have significant impacts on field performance. The pilots in the Pocono Big Injun Sand at Granny's Creek Field, West Virginia, and in the SACROC Unit (Canyon Reef carbonate) tertiary pilot test at Kelly-Snyder Field, Texas, are examples. The SACROC tertiary pilot test was conducted in an unsuccessfully isolated interval of the Canyon Reef formation and suffered severe CO_2 losses (42 to 68 percent of total injection). The effective slug size in the test interval was 10 to 18 percent HCPV, recovery was approximately 3 percent OOIP, and CO_2 utilization was 12 to 20 Mcf (gross) CO_2 per incremental barrel of oil recovered from the test interval.

Pilot tests conducted in the Denver Unit (San Andres formation) of Wasson Field, Texas, and in the Mission Canyon formation at Little Knife Field in the Williston Basin in North Dakota, have demonstrated some important details of the CO_2 miscible process in heterogeneous carbonate reservoirs. Both pilots were conducted as nonproducing tests. Performance information was obtained by time-lapse logging in observation wells, periodic production from fluid sampling wells, and pressure cores. Successive logs showed oil bank passage, oil saturation reductions, and the presence of CO_2. Intervals of miscible, immiscible, and water displacement were observed, and vertical sweep efficiencies could be estimated. In the Denver Unit test the miscible residual was observed to be tarry and is thought to have reduced the mobility of the displacing CO_2, and favorably influenced the observed sweep efficiency. Pressure cores obtained after the test showed residual oil saturations in the miscibly swept zones of about 8 percent in the Denver Unit. At Little Knife the residual saturation in the miscibly swept zones varied from 3 to about 20 percent, and from 20 to 30 percent in the immiscibly swept zones. Such low miscible residual saturations would not be expected for WAG floods in the water-wet Mission Canyon rock because of water-blocking of residual oil. Lab tests of Little Knife cores indicated the possibility of a wettability shift from water-wet to non-water-wet.

A mini-test conducted in the Means San Andres Unit, Texas, using similar test procedures addressed recovery of oil from below the accepted field oil/water contact. In the lower San Andres pilot interval, oil saturations below the contact were estimated to be 32 percent pore volume in comparison with 36 percent saturations in waterflooded zones above the contact. Although conduct and interpretation of the Means test was complicated by poor injection conformance due to the presence of a local high-permeability interval, the test indicated that the 6 cp oil could be effectively displaced under miscible conditions. Plans for the Means San Andres Unit include development of a portion of the lower San Andres below the original oil/water contact where favorable reservoir conditions exist. Similar situations may exist in other fields and may represent substantial targets for EOR by miscible flooding.

Gravity-stabilized CO_2 displacements have also been conducted with encouraging results. The Weeks Island S-Sand project, which was partly sponsored under a U.S. Department of Energy cost-sharing agreement, demonstrated that a CO_2 solvent bank could be inserted at the existing gas/oil contact and could mobilize and displace significant quantities of the waterflood residual oil.

Gravity-stable displacements must be conducted at displacement rates less than a critical rate, which is determined by the density difference between the oil and solvent, by oil and solvent mobilities, and by the formation permeability and dip angle. Massive, homogeneous, high-permeability sand members possessing significant dip angles favor gravity-stable displacements. These are not uncommon attributes of Gulf Coast reservoirs, and have permitted a number of hydrocarbon miscible gravity-stable floods in the past. In both the Weeks Island test and another test at Bay St. Elaine Field, Louisiana, light hydrocarbons were used to adjust the CO_2 density to a lower value and thereby increase the critical displacement rate. The use of gravity-stable miscible CO_2 displacements may prove well-suited to many reservoirs located along the Gulf Coast, if it can be shown that acceptable trade-offs exist to achieve displacement rates high enough to be economic. Depending upon the eventual evaluation of these and other prospects in Mississippi and Louisiana (some of which may involve immiscible CO_2 displacements, see below), it may prove feasible to develop Jackson Dome as the regional CO_2 supply. Currently, projects in the Gulf Coast area must rely on relatively expensive CO_2 from industrial sources.

Minimum Miscibility Pressure

Since 1976, numerous technical papers have been published refining procedures for estimating MMP for CO_2/crude oil systems. It is now possible to obtain an accurate estimate of

MMP by using these correlations with known values of reservoir temperature and oil properties and composition. The effects of impurities in the CO_2 stream have also been included in some MMP correlations. Although such correlations are useful for deciding if a reservoir should be further considered for miscible flooding, reservoirs passing this screen are normally subjected to a much more extensive battery of laboratory screening tests.

Slim tube testing has become the preferred method for the laboratory determination of MMP. Individual slim tube tests are performed at a number of pressure levels in order to obtain recoveries (defined as a percentage of original oil volume recovered after some specified throughput of solvent, usually 1.2 HCPV) as a function of operating pressure. The MMP is often defined as the minimum pressure above which the recovery both exceeds 90 percent and is relatively insensitive to further pressure increases. These data are normally supplemented by visual observations of the produced fluids to detect multiple phases. The industry has not found it necessary to adopt uniform criteria for miscibility determination.

Studies of the effects of impurities in the injected CO_2 stream have resulted in the observation that methane and nitrogen increase MMP, and that H_2S and ethane and higher hydrocarbons reduce MMP relative to pure CO_2. These observations have two interesting implications. First, under conditions where the produced gas is enriched in H_2S and higher hydrocarbons so that the MMP of the produced gas is lowered, it may not be necessary to install gas separation facilities. For relatively small reservoirs, gas cycling operations can involve only produced gas recompression plants, and the decision to install gas separation facilities rests on the economics of the separation facility itself. Second, in some cases it may prove necessary and possible to achieve miscibility by augmenting pipeline CO_2 with enriching components, rather than attempting to raise reservoir pressure above the CO_2 MMP by waterflooding or gas injection.

Phase Behavior and Process Efficiency

Phase behavior studies may include any of numerous types of tests that are conducted to obtain understanding of the role of fluid phase equilibration in determining the quantity and composition of the miscible residual, to obtain quantitative understanding of the mechanisms by which miscibility is achieved, and to obtain physical properties and compositions of the oil/solvent system for use in developing compositional submodels for reservoir simulation of the miscible process. Analyses for composition, molecular weight, density, viscosity, compressibility, bubble point, formation volume factor, and gas-to-oil ratio are routine tests in the petroleum industry. For CO_2 miscible flood design, these data are normally supplemented with constant-composition expansion tests at several levels of added CO_2 to determine equilibrium phase boundaries and phase densities, viscosities and compositions. A variety of discrete multiple-contact equilibrium techniques have been used to study the changes in composition and properties of the upper, lower, and precipitate phases using staged pressure cells. More recently, a continuous multiple-contact test apparatus has been developed, and new techniques for continuous measurement of phase viscosities and compositions are being developed.

Core floods are used to examine swept-zone miscible residual saturations in the presence of small-scale dispersive effects and phase behavior effects (including asphaltene precipitation). Core floods can be conducted to investigate the sensitivity of displacement efficiency and CO_2 utilization efficiency to operating parameters such as injection rate, WAG ratio, and pressure level, or to understand the effects of reservoir properties such as rock pore structure or wettability. In some cases in which wettability alteration and/or asphaltene precipitation are suspected, these core floods may be supplemented by special relative permeability measurements. For fluid/rock systems that remain strongly water-wet during the miscible process, water may prevent effective contact of the residual oil droplets by the miscible solvent. This so-called water-blocking of the waterflood residual oil may have a pronounced effect on the displacement efficiency and the quantity and composition of the miscible residual, and therefore may exert a dominant influence in the selection of optimal process parameters (slug size and WAG ratio) for the field project.

Since 1976, laboratory studies have resulted in a considerably improved appreciation of the effects of CO_2/crude oil system phase behavior, especially in the temperature range from the CO_2 critical point (88 °F) to 150 °F. Studies that have examined the residual oil left behind during the CO_2 enrichment process find that this residual is composed of the higher molecular weight compounds that were present in the original crude oil. In one study, phase behavior data were used in computer simulations to illustrate how both phase behavior and dispersive mixing can contribute to determining the quantity and composition of the miscible residual.

The precipitation of solid asphaltic material has been observed in some CO_2/crude oil systems. Presently, this phenomenon is not well understood. In particular, it does not necessarily occur in single-contact phase equilibration. It may be related to the enrichment of CO_2 with light hydrocarbons that occurs during multiple-contact processes. It is important to understand asphaltene precipitation because it has been observed to occur in field tests. In different tests, precipitated asphaltenes are reported to have fouled production wells, reduced injectivity, or improved sweep efficiency by reducing the effective permeability to the nonaqueous phases. (See the previous discussion of the Denver Unit pilot, for example.)

Reservoir Simulation

The primary roles of reservoir simulation are field project design and subsequent project surveillance studies, pilot test interpretation and laboratory test interpretation. In recent years there have been significant improvements in computers and computational methods that yield higher computational speed at reduced cost, and permit increasingly complex problem descriptions and increased solution accuracy. Specific improvements include the introduction of vector processors and vectorized miscible simulator codes, and faster and more accurate matrix inversion methods. These improvements have led directly to the use of finite difference procedures that are more accurate, convergent, or stable.

Unfortunately, in some applications it is still the case that numerical dispersion effects are several orders of magnitude larger than physical dispersion, thus obscuring the important physical processes. Although numerical dispersion can be reduced to some extent by improved choice of differencing procedure, grid refinement or time-step size reduction, this can be prohibitively expensive for the modeling of problems on a reservoir scale as opposed to a laboratory scale. Under these circumstances, the use of complex multicomponent phase-behavior submodels is often inappropriate, for example, and for miscible problems, numerous ad hoc techniques have been developed to circumvent the numerical dispersion problem. The problem of numerical dispersion is not unique to the simulation of miscible flood processes but can also affect compositional simulations of chemical floods and thermal recovery processes, especially in situ combustion and steamfloods with noncondensible gases. Additional research and the development of new approaches are needed for all these EOR processes.

Confidence in the results of simulation of project performance and economics may be reduced by the lack of accurate reservoir description data. Improved reservoir description is always needed. Often, project design optimization through reservoir simulation can provide little better than a starting point for field optimization of the process as operating experience is gained. Nevertheless, the simulation effort is useful for the insight it can provide concerning which factors most affect and most limit process performance. For example, flooding in highly stratified, low-permeability reservoirs often can be optimized for slug size, WAG ratio, well density, and completion interval, and by operating at the maximum injection rate achievable without formation parting. Injection rate in thick, high-permeability reservoirs with good vertical permeability must often be optimized to avoid undesirable gravity or viscous fingering effects. In some cases, gravity-stabilized floods may be optimal, but these also entail injection and/or withdrawal rate restrictions.

Project studies (or field tests) often lead to the conclusion that high CO_2 mobility and/or reservoir heterogeneity limit the achievable sweep efficiency, and thereby overall process efficiency and project economics. Because an acceptable margin of risk must be provided, the initial process design may specify a relatively small quantity of solvent injection, or will involve high-grading the project area. Both of these means of controlling project economic risk tend to improve projected economics and efficiency while reducing projected ultimate oil recovery. Projects that prove by operation to have been too highly risk-discounted during initial design may then be extended through more lengthy solvent injection and/or by extension to lesser quality reservoir areas, in addition to normal field process optimization.

Additional experience in the application of miscible processes to more reservoirs, and refinements to methods for field project interpretation and design are expected to lead to less conservative initial process designs in the future. By extrapolation from current results, it may be expected that these will entail larger initial slug sizes and longer periods of CO_2 recycling for the high-quality reservoirs. More heterogenous reservoirs that respond with early breakthrough of solvent, low oil-producing rates and poor sweep efficiency may not respond appropriately to this type of optimization. In anticipation of these cases, increasing attention is being given to means to improve injection profiles and decrease solvent mobility by the use of mobility control additives.

Mobility Control Additives

The use of mobility control additives is an idea dating back at least to the early 1960s, but until recently very little research has been directed at the improvement of miscible (particularly CO_2 miscible) processes by this technique. Early laboratory efforts showed that various anionic or nonionic surfactants, placed in a formation by injection at low concentrations in slugs of brine, would induce the formation of gas/water foams when contacted by trailing slugs of gas. The formation of foams occurs by the reduction of interfacial tension between the gas and water phases. Typically, gas mobility and injectivity are reduced significantly and breakthrough of gas is retarded. The extent of these effects depends upon the choice and concentration of surfactant, brine and gas compositions, type and quantity of oil and/or hydrocarbon gas present in the rock, rock type, pressure, and temperature. The persistence of foams in the reservoir is affected by chemical degradation or adsorption of the surfactant on the reservoir rock.

Recently, work has begun to focus on the identification and characterization of additives suitable for use in CO_2 flooding. Surfactant additives have been found that do not interfere with the generation of miscible conditions between the oil and solvent, but that promote desirable reductions of water-solvent interfacial tension over useful ranges of temperature and brine salinity in the presence of reservoir rock and residual oil. Polymers for the viscosification of dense-phase (supercritical) CO_2 have also been investigated. In particular, it has been shown that polyacrylamide polymers, which are effective viscosifiers for water, do not provide adequate viscosification for CO_2. This may be due to inadequate solubility in CO_2, or more fundamentally due to the significant differences in the molecular structure of water and CO_2. Polymer additives are currently considered to have less potential than surfactant foams for the control of CO_2 mobility.

Field test results for miscible floods supplemented by mobility control agents have not been published, although some tests are known to have been conducted or are in progress. A limited number of immiscible-gas foam process field tests have indicated reduced water and gas mobility, reduced injectivity, or improved injection profiles. For example, air at low pressures was used in the test at Siggins Field, Illinois. This test demonstrated a 65 percent reduction in water mobility and significant reductions in air channeling and producing water to oil ratio after the injection of a 0.06 pore volume bank of foam without adversely affecting oil producing rates. Field testing of foams consisting of dense-phase (supercritical) CO_2 and water is required to confirm laboratory results.

Presently, there is an inadequate basis for assessing the ultimate feasibility of miscible floods augmented with mobility control agents. In particular, one can easily note that beyond the design issues of surfactant choice, concentration and slug size, the use of mobility control agents will incur additional costs, and can potentially delay the onset of incremental oil production where injection rates are seriously affected through reduced injectivity, or where gas breakthrough and associated oil production are too seriously retarded. These factors carry economic consequences that must be offset through significantly improved recovery, sweep efficiency, or solvent utilization efficiency. However, further research on mobility control additives does hold considerable promise.

CO_2 Gas Processing

The production of large quantities of hydrocarbon-rich CO_2 gas is a common feature of CO_2 miscible projects. However, requirements for gas separation facilities vary significantly from one project to another. A CO_2 separation facility that is optimum for use in a totally new facility can be economically unattractive for use in a facility that must allow some existing plant operations to remain in service. The need to separate H_2S and recover sulfur can favor a different facility design than that used for low-H_2S streams.

In recent years, proven gas treating technologies using physical and chemical solvents have been exploited in numerous combinations to provide highly optimized gas treating facilities that are superior to plants using any single technology. These combination schemes typically include bulk acid gas removal by either a physical or chemical solvent, a selective H_2S removal process, and a chemical solvent product treating or polishing system. Relative to traditional single-process gas treating facilities, operating cost reductions of 20 to 35 percent have been achieved, depending upon the criteria and circumstances existing in a given project.

Notable progress has also been made in proving and commercializing two new types of basic separation technologies. First, distillative fractionation technologies, such as the widely reported Ryan-Holmes process, are now available to make several of the separations required in processing CO_2 produced gas streams. Second, processing systems that utilize permeable membranes to separate large quantities of CO_2 from hydrocarbon gas streams have been widely tested. Both spiral wound and hollow fiber membranes have been employed, and sufficient data have been gathered to allow some suppliers to offer service life warranties on membranes employed in commercial separation operations. Designers are now investigating these new technologies in combination with the older technologies. Careful use of old and new technologies can today result in a gas separation facility having about the same capital cost as a facility employing the best combination of the traditional technologies, but that offers a 15 to 25 percent improvement in net operating costs, or increased product revenues.

CO_2 Production Technology

The development of large CO_2 resources that has taken place since 1976 has resulted in several interesting adaptations of standard production technology. For example, downhole submersible pumps are being used at McElmo Dome to maintain CO_2 as a single-phase fluid in the wellbore to prevent operational problems and increase production. At reservoir conditions, CO_2 is a supercritical fluid and would separate into liquid and gas phases under flowing conditions in the wellbore. At Sheep Mountain, all wells are being drilled directionally from a limited number of drillsites. Each drillsite is able to accommodate production from six or more wells. Facilities include provision for heating the CO_2 to vaporize any liquid CO_2 and prevent hydrate formation, dehydration facilities, and compressors for delivering CO_2 through a gathering system to the pipeline. These examples indicate that production technology will not limit CO_2 supply.

Nitrogen Miscible Flooding

Nitrogen can be used as a miscible solvent in some reservoirs. The conditions that favor nitrogen miscibility include relatively high pressures and temperatures, and light or volatile oils having a reasonable balance between methane and LPG components. Reservoirs fulfilling these conditions are usually rather deep. Under these conditions, nitrogen and CO_2 MMPs may be comparable, and nitrogen may be more cost effective than CO_2. This was the case for selecting nitrogen for the commercial field project at the Jay-Little Escambia Creek Fields Unit, Florida, for example.

Published nitrogen MMP data are sparse, and correlations of an accuracy comparable to that of CO_2 MMP correlations do not presently exist. Data that are available indicate that MMPs for nitrogen are generally higher than for methane, and that the distances required to achieve miscibility by dynamic processes are somewhat longer. Nitrogen is therefore a less efficient solvent, and may be expected to yield somewhat lower recoveries than methane or CO_2. Although nitrogen miscible flooding may be the process of choice for enhanced oil recovery in selected reservoirs, a general focusing of research on nitrogen miscible flooding, similar to previous efforts to develop hydrocarbon and CO_2 miscible methods, does not appear likely to occur.

Immiscible Carbon Dioxide Flooding

The results of a number of CO_2 immiscible field projects have been reported since 1976. At Lick Creek Field, Arkansas, CO_2 is being used to mobilize and displace 160 cp crude oil from the Meakin sand reservoir. This field was not previously waterflooded because of the extremely adverse waterflood mobility ratio. Favorable preliminary results have also been announced for a field test of an immiscible CO_2 WAG flood at East Eucutta Field, Mississippi. This field produces 20 cp crude oil from the highly heterogeneous Eutaw formation. The 20-acre pilot area was thoroughly waterflooded and repressured before initiation of the WAG flood. Over 10 percent OOIP was recovered at a CO_2 utilization less than 6 Mcf per barrel of incremental oil. These results indicate potential for CO_2 immiscible flooding of moderate-viscosity or high-viscosity crude oils that occur in moderately deep reservoirs.

Thermal Recovery Technology

The current status of research in the most promising new technologies of thermal recovery are described below. Only the most recent field tests, laboratory experiments, and numerical simulation studies are discussed. The interested reader should refer to the references cited for prior field tests and laboratory or numerical studies. The conceptual basis of many of these technologies is not new. For example, downhole steam generation and oxygen-enriched air injection are ideas that originated over 20 years ago. However, significant development and field testing of these technologies has taken place recently.

In general, the purpose of a new technology is to extend the range of applicability or to increase the performance of thermal recovery. Some of the technologies, such as insulated tubing, can do both. The specific benefits of each technology are also given below.

Steam Process Technology

Gas Foam

The addition of gas foam to steam is being evaluated as a means to increase oil recovery through improved reservoir sweep. Steam is less dense than reservoir liquids, and less viscous. The gravity force acting on this density difference causes steam to segregate to the top of a formation, and the high mobility promotes rapid channeling of steam to producing wells. The creation of foam in the steam zone can prevent further steam from entering the swept zone. Thus steam can be diverted to previously unswept regions of the reservoir.

A field test of gas foam and steam injection was conducted in 1980 and 1981 in the Kern River Field, California. The field test included four 2½-acre inverted five-spot patterns. The reservoir was 1,100 feet deep and 49 feet thick. The surfactants used were an alkylbenzene sodium sulfonate and two alpha olefin sodium sulfonates. Surfactant and salt concentrations in the injected water phase were ½ percent and 4 percent by weight, respectively. Continuous nitrogen and steam injection rates were 3.6 cubic feet per minute and 250 to 270 barrels per day. Steam quality was 0.50. This combination was injected continuously for over one year. During surfactant injection the steam injection pressure increased 4 to 7 times from previous values of 20 to 40 pounds per square inch gauge (psig). Oil production approximately doubled over the test period.

In another test of gas foam in the Kern River Field, the test pattern was a 2.25-acre inverted five-spot. Steam had been injected previously for two years into the 344-foot deep and 95-foot thick reservoir. Two 22,000-gallon slugs of an alkyl toluene sulfonate surfactant and nitrogen were injected with steam. The first slug used 300 Mcf of nitrogen and the second slug used 500 Mcf. Injection profiles were altered during surfactant injection and returned to normal a few days later. An incremental 1,560 barrels of oil production was attributed to the first slug, but incremental recovery for the second test has not yet been reported.

Gas foam and steam field tests were also conducted at Cat Canyon, San Ardo, and Midway-Sunset Fields from 1981 to 1982. The field tests at the Midway-Sunset Field produced the most encouraging results and are described below. The test was conducted with a single 1.5-acre inverted five-spot pattern. The reservoir was 1,000 feet deep and 500 feet thick. The oil gravity was 11 °API. Steam had previously been injected for 10 years. The steam drive exceeded an economic steam-to-oil ratio of 12.5 before surfactant injection began. Every four days a slug of 10 to 20 barrels of 3 percent active surfactant and 17 to 34 Mcf of air were injected. Steam was injected continuously except during air injection (one to two hours of each four-day cycle). Slug injections were continued over a six-month period. Oil production remained steady for three months; then it increased significantly for six months. Each incremental barrel of oil required 0.35 pounds of surfactant, 32 standard cubic feet of air, and 3 barrels of steam. The test was repeated a second time with similar results.

Side-by-side foam field tests were conducted at the Kern Front Field, California, in two 10-acre inverted nine-spot patterns. Each had two years of previous steam injection. The reservoir was 1,500 feet deep and 50 to 60 feet thick. In one pattern, a surfactant blend of sodium and amino oxyethylene sulfates were injected weekly in 55-gallon quantities with steam. This injection period lasted 30 months. In another well pattern, the surfactant was combined with a polymer gel to allow penetration of the surfactant into the reservoir before formation of the foam. It was injected weekly in 165-gallon slugs. Numerous injection profiles from both tests showed that the positive effects of a surfactant treatment lasted six days. Incremental recoveries reported were 78,000 barrels for the surfactant test and 18,000 barrels for the surfactant and gel.

Noncondensible Gas

The injection of a noncondensible gas with steam may improve thermal oil recovery by accelerating production and/or increasing the ultimate oil recovered. Interest in using noncondensible gas with steam injection has coincided with the development of direct downhole steam generation and light-oil steamflooding.

A field test of air and steam injection was conducted in the Paris Valley Field, California. The field test consisted of air and steam stimulation of two production wells. These wells were part of a wet combustion fireflood. Air-to-steam ratios were 91 to 394 standard cubic feet per barrel. The resulting oil production was twice the previous value obtained from steam injection alone. The reservoir was 800 feet deep and 50 feet thick. The oil gravity was 10.5 °API.

Laboratory studies were conducted with combinations of steam, CO_2, and nitrogen injection. These studies included a linear core flood and a physically scaled model. Oil recovery was accelerated by the addition of noncondensible gases. From these studies it appears that the ultimate oil recovered with and without noncondensible gas are similar.

Numerical simulations of gas and steam injection have also been conducted. These simulations included thermal stimulation of heavy oil and bitumen and thermal drive of heavy and light oils. The effects of CO_2 included with steam were minimal for heavy-oil recovery. Results were more promising for CO_2 with steam for recovery of bitumen or light oil. Increased oil production and ultimate recovery were observed with both.

Light-Oil Steamflooding

Thermal recovery is normally used for heavy oils. However, a very low residual oil saturation is obtained by steamflooding light oils due to in situ steam distillation. Light-oil steamflooding may be attractive due to high oil recovery efficiency.

A light-oil steamflood was conducted at the Shiells Canyon Field, California, beginning in 1973. Primary recovery by solution gas drive had recovered only 9.5 percent of the OOIP. The reservoir is 850 feet deep with a gross thickness of 160 feet. The viscosity of the 34 °API crude oil is 6 cp at reservoir temperature. In this reservoir, which has a 35 degree dip, steam was injected updip to form an expanding steam vapor gas cap. Steam was injected at 480 to 680 pounds per square inch (psi) and 560 to 700 barrels per day. The field test originally consisted of a 5.5-acre six-well inverted pattern at the top of the structure. Oil saturations in the steam zone were reduced from 0.45 to 0.03. Due to good response, the field test was expanded to additional wells. The cumulative steam-to-oil ratio was 3.3.

Since 1976 five steamfloods have been initiated in light-oil reservoirs. Three of these reservoirs are located in the United States: Lost Hills Field, California; Buena Vista Hills Field, California; and Humble Field, Texas. The oil viscosities are 100 cp or less at reservoir conditions. The range of several reservoir parameters is given below:

- Porosity—0.25 to 0.36 fraction bulk volume
- Permeability—20 to 500 md
- Initial oil saturation—0.33 to 0.70 fraction bulk volume.

Numerical simulations of light-oil steamflooding have also been reported. These simulations were used to show that light-oil steamflooding is economically attractive.

Hydraulic Fracturing

Hydraulic fracturing may make it possible to produce heavy oil from reservoirs where the steam injection rate would normally be too low. Examples of this type of reservoir are tar sands and thin heavy-oil reservoirs. Horizontal fracturing in conjunction with steam drive has been tested in the Loco Field, Oklahoma. The field test included three inverted five-spot patterns. The pattern size was 2.5 acres. The wells were completed in two unconsolidated sands at depths of 200 feet and 500 feet. The sands were 12 feet and 18 feet thick and required high steam injection rates to reduce heat loss. Both producers and injectors were hydraulically fractured without proppant. Steam was injected above fracture pressure at rates of 1,000 to 1,500 barrels per day. The process was successful where communication had been established between the production and the injection wells. The cumulative steam-to-oil ratio was 6.

Horizontal fracturing is also a key element of steam-drive production from south Texas for sands such as at the Saner Ranch Field, Texas. This field test consisted of a 5-acre inverted five-spot pattern and observation wells. The reservoir depth was 1,500 feet and its thickness was 52 feet. The oil gravity was −2 °API. This low gravity created low steam injectivity, in spite of the relatively high reservoir permeability of 250 to 1,000 md. At the initiation of the field test the production wells were hydraulically fractured and steam stimulated. Then the injection well was hydraulically fractured and steam was injected above fracture pressure at 20 barrels per day per acre-foot for 174 days. This period was considered a preheating of the reservoir. After preheating, steam was injected at rates below fracture pressure to steamflood the preheated matrix for a period of 595 days. Post-steam waterflooding concluded the field test. The field test was technically and operationally successful. The initial oil saturation of 0.55 was reduced to 0.18 and the cumulative steam-to-oil ratio was 10.9.

Field tests have been conducted in the Cold Lake Tar Sand, Alberta, since 1964. The reservoir is 1,500 feet deep and 164 feet thick. It contains a 10 °API oil (bitumen). Reservoir permeability is 1.5 darcies; however, steam cannot be injected into the formation below fracture pressure. The last completed field test was the Leming Pilot, which contained multiple inverted seven-spot patterns. Well spacings were 7.2 and 1.8 acres. From prior experience, it was observed that the formation fractured along a northeast to southwest direction. Wells were steam stimulated above fracture pressures at injection rates of 1,500 barrels per day. The steam injected per cycle was 40 to 70 thousand barrels. After each steam injection interval, the wells were produced from five to eight months. After multiple steam stimulations, the steam-to-oil ratios were 2 to 3. A commercial development of the Cold Lake Tar Sand using this technology has been planned.

Another Cold Lake Tar Sand field test was initiated in 1978. This field test consisted of a 21.5-acre inverted seven-spot pattern and observation wells. Negligible steam injectivity and a northeast-southwest fracture orientation were also observed. Each well was steam stimulated from three to five times. Steam was injected above fracture pressure at rates ranging from 230 to 1,120 barrels per day. Total steam injected per cycle was from 3.7 to 6.3 thousand barrels. Good steam drive response was observed between adjacent wells located along the fracture direction. Continuous steam injection was initiated in the center well on November 1981. The cumulative steam-to-oil ratio at that time was 6.

Post-Steam Waterflooding

Post-steam waterflooding consists of water injection at the conclusion of steam drive. The purpose of water injection is to scavenge residual heat in the reservoir, prevent possible subsidence and oil migration into the flooded area after abandonment, and improve overall project economics by recovering additional oil at lower operating costs. Post-steam waterflooding was initiated in 1975 in the Ten-Pattern Steamflood in the Kern River Field, California. This reservoir had been under steam injection for seven years. By October 1979, an additional 8.87 million barrels of water were injected and 1.26 million barrels of oil were recovered. The cumulative oil recovery was increased from 47 percent of the OOIP at the end of the steam drive to 62 percent of the OOIP. It is projected that 70 percent of the OOIP will be recovered before the water-to-oil ratio exceeds 100. During waterflooding the production wells were steam stimulated. Water production increased significantly in the down dip wells. The reservoir is at a depth of 700 feet and contains 14 °API oil. Its permeability and porosity are 4,000 md and 0.34, respectively. The original oil saturation was 0.52.

Steam Generation Technology

Insulated Tubing

The use of insulated tubing in injection wells can reduce heat losses during steam injection. This improves thermal efficiency and can make it possible to inject steam into deeper reservoirs. Recently six types of insulated tubing were field tested in the Aberfeldy Field, near Lloydminster, Saskatchewan. The insulated tubulars consist of a tube within an outer tube. The annulus between the tubes is packed with insulation materials consisting of ceramic fibers or calcium silicate. To further reduce heat losses, the annulus is purged with a low thermal conductivity gas such as argon or krypton. The inner tube is prestressed, flared, and welded to the outer tube to seal the annulus. The effective thermal conductivity of the tubing is low (0.12 to 0.16 BTU-in/ft-hr-° F) and the majority of the heat losses occur at couplings and centralizers. In the Aberfeldy tests insulated tubing reduced heat loss by 71 to 89 percent compared to bare tubing. However, the advantages of insulated tubing were found to be drastically lower when a packer failure resulted in a wet tubing-casing annulus. Only a 30 to 40 percent reduction in heat loss was observed with the wet tubing-casing annulus. Better thermal packer technology, and efforts to reduce coupling and centralizer heat losses are required.

Downhole Steam Generation

Generating steam downhole also would eliminate surface and wellbore heat losses. Downhole steam generation is an alternative means to improve thermal efficiency and extend thermal recovery to deeper reservoirs. The direct downhole steam generator design uses a compact combustion chamber where the exhaust gases are comingled with steam and injected simultaneously into the reservoir. This design may also reduce or eliminate the need for scrubbing the exhaust gases and improve oil recovery due to the additional injection of CO_2 and nitrogen. A disadvantage of the direct-fired downhole steam generator is that it requires high-pressure air or oxygen to operate. For this reason, indirect-fired downhole steam generators have also been studied. In this design, water is circulated in tubing around the combustion chamber and the (low-pressure) combustion products are returned to the surface. Disadvantages of the indirect-fired downhole steam generators include larger bulk, poor combustion efficiency, and the need to treat the exhaust gases before venting to the atmosphere.

Air-diesel fuel and oxygen-diesel fuel direct downhole steam generators were field tested in the Wilmington Field, California. The air-diesel fuel generator was tested over a four-month period at a depth of 2,000 feet. The oxygen-diesel fuel generator was tested over a five-month period on the surface. The generators operated successfully; however, severe corrosion problems must be overcome before long-term operation is possible. The air-diesel fuel and oxygen-diesel fuel generators were operated 1,934 and 1,170 hours, respectively. No overall change in oil production from the surrounding wells was observed. Both carbon monoxide and CO_2 generated during combustion were absorbed in the reservoir. The injection rates were 300 to 350 barrels per day of steam (as cold water equivalent) at 40 to 60 percent quality. Injection pressure ranged from 1,200 to 1,380 psi. Both generators were 44 inches long and had a 4.5-inch diameter.

An air-diesel fuel direct downhole steam generator was also field tested in the Kern River Field, California. The generator was six feet long and had a six-inch diameter. It was designed for 7.1 million BTU per hour. The field test consisted of two steam stimulation cycles with the generator operated at the surface. A total of 1,930 barrels of steam were injected at rates and pressures of 150 to 275 barrels per day and 225 to 425 psi, respectively. The oil-to-steam ratios for the two cycles were considerably higher than achieved with a conventional steam generator. None of the sulfur dioxide generated was produced as a vapor.

Field testing a direct downhole steam generator is also planned at Texaco's San Ardo Field, California. Only preliminary tests have been conducted to date. The generator is 20 feet long and has a 5½-inch diameter. The air-diesel fuel steam generator is designed for 15 million BTU per hour at 1,500 psi. The reservoir is at 2,000 to 2,300 feet in depth and contains 11 to 14 °API oil.

Current downhole steam generators suffer from poor corrosion resistance and require use of relatively expensive fuels such as diesel fuel. Continued development should address improved metallurgy and the use of lease crude oil as fuel in order to reduce costs and extend effective service life.

Cogeneration

Cogeneration consists of the simultaneous generation of process heat (as steam) and electricity. By utilizing steam for generating electricity and thermal recovery, electrical generation efficiency is increased. The electricity can be used in oilfield operations or sold to a utility company.

In mid-1982, two gas turbine cogeneration plants were installed in Kern County, California. These plants contain four axial flow gas turbines and electrical generators, each producing 2,500 kilowatts (kW). Compressed natural gas is burned and expanded through a turbine to run the electrical generator. The turbine exhaust gas, at 850 °F, is vented through a heat exchanger to generate steam for thermal recovery. Heat is also supplied to the heat exchanger through supplementary combustion. In 10 months of operation the plants have been "on line" 95 percent of the time. Operation of the plants was found to be economical. An additional, novel, crude oil-burning cogeneration plant was installed in June 1983. In this plant the steam from conventional steam generators will be vented through a radial flow turbine to run an electrical generator.

As of March 1983, a cogeneration plant was being installed in the Placerita Oil Field, California. The cogenerator consists of an axial flow gas turbine, electrical generator, and exhaust gas steam generator. Only natural gas will be burned due to local air quality regulations. The electrical and steam generators are rated at 7,600 kW and 50 million BTU per hour, respectively.

Another cogeneration plant was being installed in the Kern River Field, California, in late 1980. The cogenerator is the type described above. The plant is designed to burn natural gas or crude oil and its overall efficiency is expected to be 80 percent. The electrical and steam generators are rated at 1,492 kW and 50 million BTU per hour, respectively.

Fluidized Bed Combustion

Fluidized bed combustion is a process in which inexpensive, low-grade solid fuel can be burned with reduced emission of air pollutants. Recently, a nine-month test of a 50 million BTU per hour steam generator using fluidized bed combustion was completed as part of a South Texas Tar Sands project 125 miles west of San Antonio. The steam generator was an economic, technical, and operational success. The fuel used was low-grade and high-grade coal and petroleum coke ranging in size from two inches to fines. These fuels and limestone, used in the combustion process, were obtained locally. Measurements of the exhaust gas indicated 95 percent of the reactive sulfur content of the fuels was removed. Nitrogen oxide and carbon monoxide emissions met air quality standards of 100 ppm. The overal thermal efficiency of the steam generator was 80 percent. The generator used low-hardness, high-TDS feedwater to produce 80 percent quality steam at 2,000 to 2,450 psi. After initial problems were solved, the only major operational downtimes were due to power interruptions.

In Situ Combustion

Enriched Air Combustion

Oxygen-enriched air injection is being evaluated as a means to improve the performance of in situ combustion by reducing or eliminating excess nitrogen. Nitrogen, which is inert during combustion, increases compression costs, promotes channeling, and aggravates production well sanding problems. Reducing the nitrogen content of combustion gases also increases the partial pressure of CO_2 and promotes the lowering of the oil viscosity by dissolution of CO_2.

Oxygen-enriched air was used in an in situ combustion project operated in the Forest Hill Field, Texas. In a single well test, 21 percent to 90 percent oxygen by volume was injected into the reservoir from January 1980 through December 1981. Surrounding well patterns continued with compressed-air injection. Increased productivity was observed in the producing wells surrounding the enriched-air injection well. Safety precautions pertaining to the use of oxygen were implemented and operational problems were found to be minimal. The total injection rate was 200 to 300 Mcf per day at 1,750 to 2,500 psig. The reservoir is 15 feet thick and 4,800 feet deep. The crude oil is 10 °API. The porosity and permeability are 0.28 and 626 md, respectively.

A laboratory study of oxygen injection was conducted recently in preparation for a field test in the Lindbergh Field, Alberta. Different combinations of air, oxygen, and water were injected into a five-foot combustion tube. Oxygen injection resulted in a higher oil production rate. Ultimate oil recoveries were similar for air and oxygen. Oxygen reaction rates for both cases were also similar.

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Alkaline Flooding

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Glossary

NOTE: *This glossary is intended to assist readers who are generally unfamiliar with words used in describing petroleum production technology. The definitions below refer to the way in which words are used in this report.*

acid number—a measure of reactivity of crude oil with caustic solution, in terms of milligrams of potassium hydroxide needed to react with one gram of crude oil.

acre-foot—a measure of bulk rock volume where the area is one acre and the thickness is one foot.

adsorption—the physical/chemical phenomenon whereby a molecule or aggregate of molecules attaches itself to the rock surface.

after-flow—flow from the reservoir into the wellbore that continues for a period after the well has been shut in. After-flow can complicate the analysis of a pressure transient test.

alkaline—a material that causes a high pH when dissolved in water; sodium hydroxide, sodium orthosilicate, and sodium carbonate are typical alkaline materials used in enhanced oil recovery.

alkaline flooding—enhanced oil recovery with an alkaline solution.

API—American Petroleum Institute.

API gravity—an index of specific gravity; units are degrees of API gravity (°API).

apparent viscosity—the apparent viscosity of a fluid, or several fluids flowing simultaneously, measured in a porous medium (rock), which includes both viscosity and permeability effects. Also called effective viscosity.

aquifer—a subsurface rock interval that will produce water. Many oil reservoirs are underlaid by an aquifer.

areal sweep efficiency—the fraction of the flood pattern area that is effectively swept by the injected fluids.

bank—a concentration of oil (oil bank) or other fluid in a reservoir that moves cohesively through the reservoir.

barrel—a unit of volume used to measure petroleum equal to 42 U.S. gallons.

bbl—barrel(s).

biocides—any chemical capable of destroying bacteria.

biological degradation—the loss of fluid properties of polymer solutions caused by bacterial attack on the polymer molecule.

BTU—British Thermal Unit; a unit of energy approximately equal to the energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

Buckley-Leverett Method—a theoretical method of determining frontal advance rates and saturations from a fractional flow curve.

capillary forces—interfacial forces between immiscible fluid phases, resulting in interfacial curvature and pressure differences between the two phases.

capillary number—N_c, the ratio of viscous forces to capillary forces, and equal to viscosity times velocity divided by interfacial tension.

cash flow—net profit after taxes, plus depreciation.

caustic consumption—the amount of caustic lost from chemically reacting with the minerals in the rock.

CERCLA—the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (Superfund).

chemical flooding—*See* EOR process.

chromatographic separation—the separation of different species of compounds according to their size and interaction with the rock as they flow through a porous medium.

CO_2—carbon dioxide.

CO_2 augmented waterflooding—waterflooding by injection of a brine that is fully or nearly saturated with carbon dioxide. Also called carbonated waterflooding.

CO_2 miscible flooding—*See* EOR process.

CO2PM—predictive model for miscible flooding.

coalescence—the union of two or more oil droplets to form a larger oil droplet, and ultimately a continuous oil phase.

cogeneration—an energy conversion method by which electrical energy is produced along with steam generated for EOR use.

combustion zone—the volume of reservoir rock wherein petroleum is undergoing combustion during enhanced oil recovery.

completion interval—that portion of the reservoir formation placed in fluid communication with the well by selectively perforating the wellbore.

condensate—a mixture of light hydrocarbon liquids obtained by condensation of hydrocarbon vapors: predominately butane, propane, and pentane with some heavier hydrocarbons and relatively little methane or ethane. (*See also* natural gas liquids.)

conductivity—a measure of the ease of flow through a fracture, a perforation, or a pipe.

conformance—the uniformity with which a volume of the reservoir is swept by injection fluids, both in the areal and vertical sense.

constant 1983 dollars—dollars with the purchasing power of the U.S. dollar in the year 1983. This term is used to provide a measure of comparability to project costs, revenues, rates of return, and capital requirements that might otherwise be distorted by varying estimates of inflation in future years.

conventional recovery—primary and/or secondary recovery.

conversion cost—the cost of changing a producing well to an injection well, or some other change in the function of an oilfield installation.

corefloods—laboratory flow tests through small samples (cores) of reservoir rock.

cosurfactant—a chemical compound, typically an alcohol, that enhances the effectiveness of a surfactant.

cp—centipoise, a unit of viscosity.

cross-linking—the combining of two or more polymer molecules into an aggregate of molecules by the use of a chemical that mutually reacts or bonds with a part of the chemical structure of the polymer molecules.

crude oil sulfonate—sulfonate made from crude oil.

differential-strain analysis—measurement of isothermal stress relaxation in a recently cut core.

dispersion—a measure of the convective mixing of fluids due to flow in a reservoir.

displacement efficiency—ratio of the amount of oil moved from the zone swept by the recovery process to the amount of oil present in the swept zone prior to start of the process.

distribution coefficient—a coefficient that describes the distribution of a tracer material in reservoir fluids, usually defined as the ratio of the tracer's equilibrium concentrations in the oil and aqueous phases.

divalent cation—an ion, such as calcium on magnesium, having two positive charges. (*See also* ions.)

downhole steam generator—a generator that is installed downhole in an oil well to which air or oxygen-rich air, fuel, and water are supplied for the purposes of generating steam for injection into the reservoir. Its major advantage over a surface steam generating facility is that heat losses to the wellbore and surrounding rock are eliminated between the surface and the oil zone.

Dykstra-Parsons coefficient—an index of reservoir heterogeneity arising from permeability variation and stratification.

EDAT—effective date at which advanced technology would be available.

effective viscosity—*See* apparent viscosity.

EIA—Energy Information Administration.

EIS—Environmental Impact Statement.

emulsion—a dispersion of very small drops of one liquid in another liquid, such as oil in water.

enhanced oil recovery (EOR)—the incremental ultimate oil that can be economically recovered from a petroleum reservoir over oil that can be economically recovered by conventional primary and secondary methods.

EOR—enhanced oil recovery.

EOR process—a known technique for recovering additional oil from a petroleum reservoir beyond that economically recoverable by conventional primary and secondary recovery methods. Three such methods are discussed in this report:

chemical flooding: injection of water with added chemicals into a petroleum reservoir. In this study, three chemical processes are considered: surfactant flooding, polymer flooding, and alkaline flooding.

miscible flooding: injection into a petroleum reservoir of a material that is miscible, or can become miscible, with the oil in the reservoir. In this study, carbon dioxide is the primary material considered. Nitrogen and hydrocarbon gases are considered for specific projects.

thermal recovery: injection of steam into a petroleum reservoir, or propagation of a combustion zone through a reservoir by air or oxygen-enriched air injection. Steam drive, cyclic steam injection, and in situ combustion are thermal recovery processes.

EPA—Environmental Protection Agency.

ester—a compound formed by the reaction between an organic acid and an alcohol.

ethoxylated alcohols—alcohols having ethylene oxide functional groups attached to the alcohol molecule.

field-scale—the application of EOR processes to a significant portion of a field.

first contact miscibility—*See* miscibility.

five-spot—an arrangement or pattern of wells with four injection wells at the corners of a square and a producing well in the center of the square.

flood, flooding—the process of displacing petroleum from a reservoir by the injection of fluids.

flue gases—the gaseous products of the combustion process, mostly comprised of carbon dioxide (CO_2), nitrogen (N_2), and water vapor (H_2O).

fluid—a gas or a liquid.

fluidized bed combustion—a process used to burn low-quality solid fuels in order to remove some of the offensive byproducts of combustion from the gases and vapors that result from the combustion process.

formation—an interval of rock with distinguishable geologic characteristics.

fractional flow—the ratio of the volumetric flow rate of one fluid phase to the total fluid volumetric flow rate within a volume of rock.

fractional flow curve—the relationship between the fractional flow of one fluid and its saturation during simultaneous flow of fluids through a rock.

functional group—the part of a molecule that may be chemically reactive.

gas cap—a part of a hydrocarbon reservoir at the top that will produce only gas.

gas/oil sulfonate—sulfonate made from a specific refinery stream, the gas/oil stream.

gas-to-oil ratio—ratio of the number of cubic feet of gas measured at atmospheric (standard) conditions to barrels of produced petroleum measured at stock tank conditions.

gravity—*See* API gravity.

gravity drainage—the movement of oil in a reservoir, which results from the force of gravity.

gravity segregation—partial separation of fluids in a reservoir caused by the gravity force acting on differences in density. (*See* override.)

gravity-stable displacement—the displacement of oil from a reservoir by a fluid of a different density, in which the density difference is utilized to prevent dispersion of the injected fluid.

H_2S—hydrogen sulfide.

hardness—the concentration of calcium and magnesium in solution in water.

heterogeneity—lack of uniformity in reservoir properties such as permeability.

HCPV—hydrocarbon pore volume.

hp—horsepower.

hydration—the association of molecules of water with a substance.

hydraulic fracturing—the opening of fractures in a reservoir by high-pressure, high-volume injection of liquids through an injection well.

hydrocarbons—chemical compounds containing hydrogen and carbon.

hydrolysis—a chemical reaction in which water reacts with another substance to form one or more new substances.

immiscible—two or more fluids that do not have complete mutual solubility and co-exist as separate phases.

immiscible displacement—a displacement of oil by a fluid (gas or water) conducted under conditions so that interfaces exist between the driving fluid and the oil.

Analogy: At room temperature and pressure, air and water are immiscible, although each is slightly soluble in the other (i.e., humid air or aerated water). Filling a sink causes an immiscible displacement of air from the sink by the water.

incremental ultimate recovery—the difference between the quantity of oil that can be economically recovered by EOR methods and the quantity of oil that can be economically recovered by conventional recovery methods. Synonym for enhanced oil recovery. (*See also* ultimate recovery.)

infill drilling—drilling additional wells within an established pattern.

injection profile—the vertical flow rate distribution of fluid flowing from the wellbore into a reservoir.

injection well—a well in an oil field used for injecting fluids into a reservoir.

injectivity—the relative ease with which a fluid is injected into a porous rock.

in situ—in the reservoir.

in situ combustion—an EOR process consisting of injection of air or oxygen-enriched air into a reservoir under conditions that favor burning part of the in situ petroleum; advancing this burning zone; and recovery of oil from a nearby producing well.

integrity—maintenance of a slug or bank at its preferred composition without too much dispersion or mixing.

interface—the thin surface area separating two immiscible fluids that are in contact with each other.

interfacial film—the film between two immiscible fluids, e.g., oil and water, or microemulsion and oil.

interfacial tension—the strength of the film separating two immiscible fluids, e.g., oil and water, or microemulsion and oil, measured in dynes (force) per centimeter or millidynes per centimeter.

interfacial viscosity—the viscosity of the interfacial film between two immiscible liquids.

interference testing—a type of pressure transient test in which pressure is measured over time in a closed-in well while nearby wells are produced. Flow and communication between wells can sometimes be deduced from an interference test.

interphase mass transfer—the net transfer of chemical compounds between two or more phases.

ion exchange—the exchange of two different cations on active sites on the surface of the reservoir rock, e.g., replacement of calcium ions with sodium ions.

ion exchange capacity—a measure of the available cations for ion exchange. (*See* ion exchange.)

ions—chemical substances possessing positive or negative charges in solution in water.

lease—a part of a field belonging to one owner or owner group; an owner commonly "leases" the (mineral) rights to an operator who produces oil and gas and pays for the "lease" with part of the production (royalty).

light hydrocarbons—hydrocarbons with molecular weights less than that of heptane.

lithology—the characteristics of the reservoir rock.

lower-phase microemulsion—a microemulsion phase containing a high concentration of water that, when viewed in a test tube, resides at the bottom with oil floating on the top. (*See also* microemulsion.)

LPG—liquified petroleum gas.

M—thousand.

Mcf—unit of gas volume equal to 1,000 standard cubic feet.

md—millidarcy, a unit of permeability.

mechanical degradation—the loss of fluid properties of polymer solutions caused by permanent mechanical deformation of the polymer molecule.

membrane technology—gas separation processes that use membranes that permit different components of a gas to diffuse through the membrane at significantly different rates.

methane (CH_4)—the simplest hydrocarbon molecule; normally the predominant chemical in natural gas.

micellar fluid (surfactant slug)—an aqueous mixture of surfactants, cosurfactants, salts, and hydrocarbons. The term micellar is derived from the word micelle, which is a submicroscopic aggregate of surfactant molecules.

microemulsion—a stable, finely dispersed mixture of oil, water, and chemicals (surfactants and alcohols).

microorganisms—animals or plants of microscopic size, such as bacteria.

microscopic displacement efficiency—the efficiency with which an oil displacement process removes the oil from individual pores in the rock.

middle-phase microemulsion—a microemulsion phase containing a high concentration of both oil and water that, when viewed in a test tube, resides in the middle with the oil phase above it and the water phase below it. (*See also* microemulsion.)

minimum miscibility pressure (MMP)—*See* miscibility.

miscibility—an equilibrium condition, achieved after mixing of two or more fluids, that is characterized by the absence of interfaces between the fluids.

first-contact miscibility: miscibility in the usual sense, whereby two fluids can be mixed in all proportions without any interfaces forming. Example: At room temperature and pressure, alcohol and water are first-contact miscible.

multiple-contact miscibility (dynamic miscibility): miscibility that is developed by repeated enrichment of one fluid phase with components from a second fluid phase with which it comes into contact.

minimum miscibilty pressure: the minimum pressure at which two fluids become miscible, or can become miscible, by dynamic processes.

miscible flooding—*See* enhanced recovery process.

MM—million.

MMcf—unit of gas volume equal to a million standard cubic feet.

MMP—minimum miscibility pressure. (*See* miscibility.)

mobility—a measure of the ease with which a fluid moves through reservoir rock; the ratio of rock permeability to fluid viscosity.

mobility buffer—the bank that protects the surfactant slug from water invasion and dilution, and assures mobility control.

mobility control—ensuring that the mobility of the displacing fluid, or bank, is equal to or less than that of the displaced fluid, or bank.

mobility ratio—ratio of mobility of an injection fluid to mobility of fluid being displaced.

modified alkaline flooding—the addition of a cosurfactant and polymer to the alkaline flooding process.

monomer—small molecules that can be combined in large numbers to make polymers.

multiple-contact miscibility—*See* miscibility.

natural gas—hydrocarbons and other chemicals produced as a gas, usually predominantly methane.

natural gas liquids (NGLs)—the hydrocarbon liquids that condense during the processing of hydrocarbon gases that are produced from oil or gas reservoirs. (When produced from an oil reservoir and mixed with the oil sales stream, natural gas liquids are called lease condensate.)

NGL—natural gas liquid.

NO_x—nitrogen oxides.

nominal crude oil price—an oil price in constant 1983 dollars that is assigned, for the purposes of this study, to a 40 °API mid-continent crude oil. Crude oil prices that are used in the study are adjusted from this nominal price to account for various other factors such as crude oil gravity and field location.

nonionic surfactant—a surfactant molecule containing no ionic charge.

non-Newtonian—the change of viscosity with flow rate.

North Slope—the north coast of Alaska.

nuclear magnetic resonance spectroscopy—an analysis procedure that permits the identification of complex molecules based on the magnetic properties of the atoms they contain.

observation wells—wells that are completed and equipped to measure reservoir conditions and/or sample reservoir fluids, rather than to inject or produce reservoir fluids.

oil breakthrough (oil breakthrough time)—the time at which the oil-water bank arrives at the producing well.

oil originally in place (OOIP)—the quantity of petroleum existing in a reservoir before oil recovery operations begin.

OOIP—oil originally in place.

OPEC—Organization of Petroleum Exporting Countries.

optimum salinity—the salinity at which a middle-phase microemulsion containing equal concentrations of oil and water results when a micellar fluid (surfactant slug) is mixed with oil.

override—the gravity-induced flow of a lighter fluid in a reservoir above another heavier fluid.

OSHA—Occupational Safety and Health Administration.

particulates—finely divided material generally considered large enough to be filtered but small enough to be suspended in the air as contaminants. Particulates include soot, ash, and dust.

partition—the mass transfer of a chemical from one liquid phase to another liquid phase, resulting in concentration changes.

pattern—the areal pattern of injection and producing wells selected for a secondary or enhanced recovery project.

pattern life—the length of time a flood pattern participates in oil recovery.

permeability—a measure of the ability of reservoir rock to transmit fluid under the influence of a pressure gradient.

pH—a measure of hydrogen ion concentration, which in turn is a measure of acidity and alkalinity.

phase—a separate fluid that co-exists with other fluids at reservoir conditions; oil and water do not mix and therefore form separate phases.

phase behavior—the relationships between interfaces and fluid properties that are observed as a result of changing temperature, pressure, or the bulk composition of the fluids or of individual fluid phases.

phase properties—types of fluids, compositions, densities, viscosities, and relative amounts of oil, microemulsion or solvent, and water formed when a micellar fluid (surfactant slug) or miscible solvent (e.g., CO_2) is mixed with oil.

pilot-scale—a relative term that connotes the development of a relatively small portion of a field for the purpose of investigating, evaluating, or developing concepts, materials, equipment, or procedures that may later be used for fuller development of oil production from the same or some other fields. (*See also* field-scale.)

pilot test—an experimental test of an EOR process in a small part of a field.

polymer—any large molecule that is added to water for polymer flooding.

polymer stability—the ability of a polymer to resist degradation and maintain its original properties.

pore space—a small hole in reservoir rock that contains fluid or fluids. (A fist-sized volume of reservoir rock may contain millions of interconnected pore spaces.)

pore volume—total volume of all pores and fractures in a reservoir or part of a reservoir.

porosity—ratio of the pore volume and fracture volume to the total volume of reservoir rock, usually expressed as a fraction.

porous medium—any solid that contains pore spaces.

Power-Law exponent—a measure of the degree of viscosity change of a non-Newtonian liquid.

ppm—parts per million.

precipitates—insoluble chemical compounds that drop out of solution (i.e., precipitate) as a result of chemical reactions or changes in phase equilibrium.

preflush—a conditioning slug injected into a reservoir as the first step of an EOR process.

pressure cores—cores extracted in a special coring barrel that maintains reservoir pressure when brought to the surface. This prevents the loss of reservoir fluids that usually accompanies the drop in pressure from reservoir to atmospheric conditions.

pressure gradient—rate of change of pressure with distance.

pressure maintenance—augmenting the pressure (and energy) in a reservoir by injecting gas or water through one or more wells.

primary oil recovery—oil recovery utilizing only naturally occurring forces.

primary tracer—a chemical that, when injected into a test well, reacts with reservoir fluids to form a different chemical compound that is detectable.

producibility—the rate at which oil or gas can be produced from a reservoir through a wellbore.

producing well—a well in an oil field used for removing fluids from a reservoir.

psi—pounds per square inch.

psig—pounds per square inch gauge.

pulse-echo ultrasonic borehole televiewer—a well-logging system wherein a pulsed, narrow acoustic beam scans the well as the tool is pulled up the borehole. The amplitude of the reflected beam is displayed on a cathode-ray tube, resulting in a pictorial representation of the wellbore.

RCRA—Resource Conservation and Recovery Act of 1976.

relative permeability—the permeability of the rock to either oil or water, when both are flowing, expressed as a fraction of the single phase permeability of the rock.

reserves—recoverable oil; unless qualified, means economically recoverable oil with proved technology.

proved developed reserves: oil and gas reserves recoverable from existing wells with present operating methods and expense.

proved undeveloped reserves: oil and gas reserves recoverable from additional wells yet to be drilled, or major deepening of existing wells.

probable reserves: oil and gas reserves that are based on geologic evidence of producible oil or gas within the limits of a geologic feature or reservoir but located beyond the proved reserves.

possible reserves: oil and gas reserves characterized by less defined geologic control than probable reserves, based largely on subsurface geology utilizing seismic, electric logs and widespread evidence of oil and gas saturation.

reservoir—a rock formation below the Earth's surface, containing petroleum or natural gas.

reservoir simulation—analysis of reservoir performance with a computer model.

residual oil—petroleum remaining in situ after oil recovery.

residual oil saturation—*See* waterflood residual.

residual resistance factor—the reduction in permeability of rock to water caused by the adsorption of polymer.

resistance factor—a measure of resistance to flow of a polymer solution relative to the resistance to flow of water.

retention—the loss of chemical components due to adsorption on the rock's surface or to trapping within the reservoir.

rock matrix—the granular structure of a rock or porous medium.

Ryan-Holmes process—gas separation process that utilizes gas phase behavior to effect the separation of the components of the gas.

SO_2—sulfur dioxide, a gaseous waste product generated from the combustion of sulfur-containing fuels.

SO_x—sulfur oxides.

salinity—the concentration of salt in water.

sandface—the cylindrical wall of the wellbore through which the fluids must flow to or from the reservoir.

saturation—the ratio of the volume of a single fluid in the pores to pore volume, expressed as a percent and applied to water, oil, or gas separately. Sum of the saturations of each fluid in a pore volume is 100 percent.

scrubber—a device that uses water and chemicals to clean air pollutants from combustion exhaust.

secondary recovery—oil recovery resulting from injection of water or an immiscible gas into a petroleum reservoir.

secondary tracer—the product of the chemical reaction between reservoir fluids and an injected primary tracer.

sedimentary—formed by or from deposits of sediments, especially from sand grains or silts transported from their source and deposited in water, as sandstone and shale; or from calcareous remains of organisms, as limestone.

shear—mechanical deformation or distortion, or partial destruction of a polymer molecule as it flows at a high rate.

shear rate—a measure of the rate of deformation of a liquid under mechanical stress.

shear-thinning—the characteristic of a fluid whose viscosity decreases as it is mechanically sheared.

slim tube testing—laboratory procedure for the determination of minimum miscibility pressure using long, small-diameter, sand-packed, oil-saturated, stainless steel tubing.

slug—a quantity of fluid injected into a reservoir during enhanced oil recovery.

solvent gas—an injected gaseous fluid that becomes miscible with oil under reservoir conditions and improves oil displacement.

specific gravity—the ratio of the density of oil (or other substances) to the density of water.

steam drive—*See* EOR process.

steamflooding—*See* EOR process.

steam stimulation—injection of steam into a well and the subsequent production of oil from the same well.

stream tube model—a computer model that represents fluid flow through a reservoir by an array of individual flow paths, or tubes.

sulfated ethoxylated alcohols—obtained by sulfation of ethoxylated alcohol. (*See also* ethoxylated alcohols.)

sulfonate—a type of surfactant made up of a hydrocarbon with one or more SO_3 functional groups attached to it.

Superfund—the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA).

surface active material—a chemical compound, molecule, or aggregate of molecules whose physical properties cause it to attach itself to the interface between two immiscible liquids, resulting in a reduction of interfacial tension, or formation of a microemulsion.

surfactant—a type of chemical, characterized as one that reduces interfacial resistance to mixing between oil and water or changes the degree to which water wets reservoir rock.

sweep efficiency—the ratio of the pore volume of reservoir rock contacted by injected fluids to the total pore volume of reservoir rock in the project area. (*See also* areal sweep efficiency *and* vertical sweep efficiency.)

swept zone—the volume of rock that is effectively swept by injected fluids.

tar sand—a sandstone containing tar-like hydrocarbons that do not readily flow into a wellbore.

target oil—petroleum in situ at the start of an EOR process that remains in the reservoir after conventional recovery.

Tcf—unit of gas volume equal to a trillion standard cubic feet.

TDS—total dissolved solids.

Tertiary Incentive Program (TIP)—government program administered by the U.S. Department of Energy. (*See* Chapter Two.)

thermal recovery—*See* EOR process.

thief zone—any geologic stratum, not intended to receive injected fluids, in which significant amounts of injected fluids are lost. Fluids may reach the thief zone due to an improper completion or a faulty cement job. Also, a zone in the oil bearing horizon that receives excessive amounts of injected fluids.

tiltmeter survey—a method of monitoring reservoir processes through analysis of near-surface ground deformation measured with very sensitive bubble level indicators (tiltmeters), which are placed in shallow boreholes around the area of interest.

time-lapse logging—the repeated use of calibrated well logs to quantitatively observe changes in measurable reservoir properties over time.

TIP—Tertiary Incentive Program.

transmissibility (transmissivity)—an index of producibility of a reservoir.

triaxial borehole seismic survey—a technique for detecting the orientation of hydraulically induced fractures, wherein a tool holding three mutually perpendicular seismic detectors is clamped in the borehole during fracturing. Fracture orientation is deduced through analysis of the detected microseismic events that are generated by the fracturing process.

type curves—graphical correlations among physical parameters that permit estimation of an unknown parameter from experimental data by the matching of curve shapes.

ultimate recovery—the cumulative quantity of oil that has been recovered when revenues from further production will no longer justify the costs of the additional production. (*See also* incremental ultimate recovery.)

upper-phase microemulsion—a microemulsion phase containing a high concentration of oil that, when viewed in a test tube, resides on top of a water phase. (*See also* microemulsion.)

vector processor—an advanced computer capable of high-speed calculations.

vectorized codes—computer instruction sets (programs) that are written to take advantage of the parallel processing capabilities of vector processors to the fullest possible extent.

vertical sweep efficiency—the fraction of the layers or vertically distributed zones of a reservoir that are effectively contacted by displacing fluids.

viscosity—a fluid property that determines its resistance to flow through reservoir rock.

volumetric sweep—the fraction of the total reservoir volume within a flood pattern that is effectively contacted by injected fluids.

WAG process—injection of alternating slugs of water and gas into an injection well.

waterflood residual—the waterflood residual oil saturation; the saturation of oil remaining after waterflooding in those regions of the reservoir that have been thoroughly contacted by water.

waterflooding—a secondary recovery process.

waterflood mobility ratio—mobility ratio of water displacing oil during waterflooding. *See also* mobility ratio.

wellbore—the hole in the earth comprising a well.

well completion—the complete outfitting of an oil well for either oil production or fluid injection. Also the technique used to control fluid communication with the reservoir.

well conversion cost—the cost of changing a producing well to an injection well.

wellhead—that portion of an oil well above the surface of the ground.

wellhead price—value of the crude oil at the producing well.

wettability—the relative degree to which a fluid will spread on (or coat) a solid surface in the presence of other immiscible fluids.

wettability reversal—the reversal of the preferred fluid wettability of a rock, e.g., from water-wet to oil-wet.

WPT—Windfall Profit Tax.

xanthan—a polysaccharide (high molecular weight carbohydrate) produced during fermentation by the Xanthamonis bacteria.

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