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Tertiary Oil Recovery: Potential Application and Constraints

June 1978

Pacific Northwest Laboratory
Richland, Washington 99352
Operated for the
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Under Contract EY-76-C-06-1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22151

Price: Printed Copy \$____*; Microfiche \$3.00

*Pages	NTIS Selling Price
001-025	\$4.50
026-050	\$5.00
051-075	\$5.50
076-100	\$6.00
101-125	\$6.50
126-150	\$7.00
151-175	\$7.75
176-200	\$8.50
201-225	\$8.75
226-250	\$9.00
251-275	\$10.00
276-300	\$10.25

TERTIARY OIL RECOVERY: POTENTIAL APPLICATION AND CONSTRAINTS

by C. A. Geffen

June 1978

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FOREWORD

The Office of the Assistant Secretary for Environment of the Department of Energy provides environmental policy guidance based on environmental, health, and safety research. The Office of Technology Impacts (OTI) supports the Assistant Secretary through energy system assessments and policy analyses that concentrate on environmental, health, and safety perspectives. In OTI the Division of Technology Overview (DTO) maintains a state-of-the-art awareness of existing and emerging technologies. Among DTO's responsibilities is the comprehensive assessment of the impacts of technologies as they emerge or are deployed. This report is sponsored by DTO as part of its Oil, Gas and Oil Shale Assessment.

The focus of this report is land-based tertiary recovery operations, although the technology is theoretically transferrable to offshore reservoirs. According to a recent report by the Office of Technology Assessment, ^(a) the CO₂ miscible process alone is generally economical in offshore reservoirs at world oil prices. However, application would require a highly accelerated development program and would probably be prohibitively expensive, due to added material and equipment transportation costs and the difficulties of operating offshore. The environmental impacts of tertiary recovery processes offshore do not appear to have been investigated.

Until tertiary recovery becomes economical for use in land-based reservoirs, it will not be contemplated for use offshore. It does not appear that tertiary techniques will play a significant role offshore for another 15 to 20 years.

D. L. Brenchley
Project Manager

(a) Enhanced Oil Recovery Potential in the United States, Office of Technology Assessment. January 1978

ABSTRACT

This report describes the technology of tertiary oil recovery methods and identifies potential economic and environmental constraints to future commercial application. Oil recoverable by tertiary techniques represents a domestic resource of between 11- and 42-billion barrels. Estimates of additional oil supplies from tertiary methods by the year 2000 range from 1 to 8 million barrels per day, depending on the price of oil and the rate of technological development.

The principal constraints to large-scale application of tertiary methods at the present time include environmental, economic and technological concerns. Regulatory action associated with the Clean Air Act Amendments of 1977 currently delay the expansion of thermal recovery operations in California and may discourage future projects. The high production costs of tertiary projects also hamper process implementation. Further testing and research is necessary to develop the technology of tertiary recovery methods and prove these techniques successful on a field-wide scale.

To enable tertiary oil recovery to play a significant role in augmenting domestic energy supplies, further research and development is necessary. More accurate methods of determining reservoir structure and residual oil saturations are required, as well as means for assuring the technical feasibility and success of a tertiary method in different reservoir types. Technical process limitations must also be resolved. The severity of potential environmental impacts and constraints identified in this report should be determined. These concerns include the air pollutant emissions from steam generation in thermal processes; acceptable methods of brine disposal; damage due to runoff or accidental discharge of oil-rich chemicals into surface waters; the impacts of fluid injection on deep aquifers and the prevailing geological structure; and an adequate supply of high quality fresh water.

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1.0 SUMMARY

Tertiary recovery methods are highly specialized processes which use chemicals or heat to stimulate oil recovery from depleted reservoirs. There are three general classes of tertiary recovery processes: thermal, miscible and chemical. These techniques have the potential for recovering up to sixty or seventy billion barrels of oil at prices ranging from \$10 to \$25 per barrel (see Table 1.1). Estimates of the rates of oil production in 1985 from these technologies range from 0.4 to 2.3 million barrels per day. Most of the oil to be produced by tertiary techniques will come from known reservoirs and fields which have a successful history of primary and secondary production. The majority of these reservoirs are located in Texas, California, Louisiana and Oklahoma.

1.1 THERMAL RECOVERY METHODS

Thermal recovery methods use heat to reduce the viscosity of oils, facilitating the flow of fluids within the reservoir and toward production wells. The three thermal processes discussed are steam soak, steam drive and in situ combustion. Steaming processes involve the generation of heat in the form of steam at the well surface. Crude oil from the reservoir is usually used to fuel the steam generators. The steam is injected into the reservoir, thinning the oil. Steaming processes perform best in shallow, sand reservoirs, where heat losses are minimal. In situ combustion processes generate heat within the reservoir itself by burning part of the crude oil. Air is injected into the reservoir; the oil is then ignited. The combustion of the reservoir oil produces heat, which thins the remaining oil. The least valuable portion of the crude, the tar fraction, is burned to generate the heat.

Thermal methods, although best suited to the recovery of viscous crudes, may also theoretically be used for lighter oils. These processes are currently being used on a commercial scale, almost entirely in California reservoirs, and are producing over 120,000 barrels of oil per day. Because many of the California reservoirs contain viscous crude oils, the highest potential for these

TABLE 1.1 Tertiary Recovery-Potential and Constraints

	Thermal	Miscible	Chemical
Processes	Cyclic Steam Injection Steam Drive In Situ Combustion	CO ₂ miscible LPG drive, enriched gas, lean gas and high-pressure gas drives	Alkaline Polymer Micellar-Polymer
Most promising methods	Cyclic Steam Injection	CO ₂ miscible	Micellar-Polymer
Location of most promising reserves	California	Texas, Kansas, Oklahoma, Louisiana, New Mexico	California, Texas, Illinois, Louisiana, Oklahoma
Current technological status	Fairly advanced; being applied widely on commercial scales.	Less developed; some commercial application Further testing needed	Still in the research and field testing stages
Primary research needs	Techniques to Determine Residual Oil Saturations and Detailed Reservoir Structures		
	<ul style="list-style-type: none"> • overcoming emission problems • using cheaper, nonpetroleum fuels to generate steam • improve recovery efficiencies • extend process application to deeper and heavy oil reservoirs 	<ul style="list-style-type: none"> • develop adequate, cheap supplies of carbon dioxide • extend process application to sandstone and low oil saturation depleted reservoirs 	<ul style="list-style-type: none"> • develop cheaper, adequate surfactant supplies • develop an improved micellar solution which can tolerate higher salinities and temperatures • extend process application and develop to the point of commercial application
Potential production by 1990	M bbl/day	M bbl/day	M bbl/day
at \$10/bbl oil	0.3 - 0.4	0.1 - 0.3	0.05 - 0.1
at \$15/bbl oil	0.6 - 0.8	0.2 - 0.4	0.2 - 0.3
at \$25/bbl oil	0.9 - 1.1	0.6 - 0.8	0.5 - 1.0
Primary Environmental Impacts			
<u>Air</u>	<ul style="list-style-type: none"> • Air emissions of combustion products from steam generation: SO₂, NO_x, HC, CO, CO₂ 	<ul style="list-style-type: none"> • Possible H₂S emissions 	<ul style="list-style-type: none"> • minimal impacts
<u>Water</u>	<ul style="list-style-type: none"> • Regional shortages of surface water • Handling of produced water 	<ul style="list-style-type: none"> • minimal impact 	<ul style="list-style-type: none"> • Regional shortages of surface water • Handling of produced water • Contamination from chemical spills or leaks

processes is in that state. However, market constraints arising from competition with heavy Prudhoe Bay crude oil and low oil prices may limit the development of thermal methods in California. A real or perceived weak market for heavy oils produced by thermal techniques may deter the development of enhanced oil recovery. The Economic Regulatory Administration is attempting to mitigate this problem and has announced proposed allocation and pricing measures which are aimed at making the heavy California crude oil more attractive to refiners.

The major environmental impacts of thermal processes are on air quality. The combustion processes used to generate heat, particularly in steam generation, lead to air pollution. These emissions include sulfur dioxide, oxides of nitrogen, hydrocarbons, carbon monoxide, carbon dioxide and particulates. The actual emissions will vary with the content of sulfur and other compounds in the crude oil used as fuel. The emissions from in situ combustion processes seem to be highly dependent on the reservoir formation and the type of crude oil present, although few data are available regarding in situ projects.

The emissions from heat generation in thermal processes are expected to have major impacts on air quality, particularly in areas of low inversions, low wind speeds and current pollution problems, as exist in California's coastal plains and central valley. Since the greatest potential for thermal recovery is in California, air quality concerns may severely limit the application of enhanced recovery in that state. Major constraints to the application of thermal recovery methods may be imposed by the 1977 amendments to the Clean Air Act and related state laws. Current uncertainties in the enforcement procedures of the new laws and different state and federal policies have already delayed planned expansions of thermal projects in California (see Section 7.1.1). Although the processes do not appear to impact water quality significantly, a shortage of fresh water supplies in water-short areas may also hamper the development of thermal recovery methods.

1.2 MISCIBLE RECOVERY METHODS

Miscible recovery processes improve oil recovery by reducing the viscosity of reservoir oils. A fluid is injected into the reservoir at a high pressure, followed by water injections. At these pressures, usually at least 1100 psia, the injected material dissolves into the oil, forming a single, oil-like liquid that flows through the soil and rock matrix more easily than the original crude. Both carbon dioxide and petroleum hydrocarbons, such as propane, may be used to achieve this effect. The use of the latter, however, has been declining because of the rising cost of propane and butane and the difficulty in obtaining sufficient supplies of these materials. Should the carbon dioxide (CO_2) process be applied in the future on a large scale, there may also be problems in obtaining sufficient CO_2 supplies. Although several major natural sources of CO_2 are known, these are not located very close to many oil reservoirs. CO_2 extracted from industrial stack gases may provide a possible supply source, although this alternative requires more feasibility studies.

The CO_2 miscible process appears to be quite versatile in application to a variety of reservoirs. However, it is still very much in the testing stage. Field experience with the process has only recently begun to accumulate, with most projects begun since 1972. Only a few commercial CO_2 recovery projects have been established.

The most promising candidate fields for CO_2 miscible recovery are located in Texas, Louisiana, Mississippi and California, although much of the future success of CO_2 flooding will depend on the availability of inexpensive CO_2 supplies. Carbon dioxide processes currently recover about 40,000 barrels of oil per day; hydrocarbon miscible methods produce about 70,000 barrels per day, although this figure is expected to drop dramatically. Several hydrocarbon projects are already converting to other injection fluids, mostly CO_2 .

The environmental impacts of carbon dioxide miscible processes are relatively minimal. Air quality impacts could occur from hydrogen sulfide contaminants which may be present in CO₂ gases. However, H₂S also occurs naturally in some oil reservoirs and emissions of H₂S have been regulated and monitored by the industry for many years. Emissions of hydrogen sulfide are thus not expected to be a major concern for tertiary recovery processes. Miscible recovery methods appear to have little effect on surface water or groundwater quality. Major land use impacts may result, however, from the construction of CO₂ supply pipelines, which may be required.

Injection material constraints and process economics seem to most severely limit future application of this process, although further field testing is required.

1.3 CHEMICAL RECOVERY METHODS

Chemical recovery processes include polymer, alkaline and micellar-polymer flooding. In polymer flooding, a polymer solution of polyacrylamides or polysaccharides is injected into the reservoir, followed by water injection. The polymers increase the viscosity of water to move oil more evenly through the reservoir to producing wells. The process does not substantially alter the viscosity of the crude oil. In alkaline flooding, caustic chemicals are added to injection water. These chemicals react with the acidic components of the reservoir crude oil to form detergent-like compounds which loosen oil from surrounding reservoir rock. In the micellar-polymer process, both a micellar solution, composed of detergent agents, and a polymer solution are injected in sequence, followed by water. The efficiency of this process is very high; almost all of the oil contacted in this way can be recovered.

Chemical recovery methods are still in a developmental state. There has been some difficulty in transferring lab knowledge of the process to field conditions; little is known about the actual behavior of micellar-polymer systems

under reservoir conditions. One of the biggest problems is adjusting the chemical solutions for compatibility with particular reservoir oils, waters and rock chemistry. The process is also limited by the sensitivity of the injection chemicals to reservoir temperature and salinity.

Chemical processes, mostly pilot projects and tests, currently produce less than 20,000 barrels of oil per day. The techniques seem to work well in sandstone reservoirs of low temperature and salinity and can potentially be applied in most major oil reservoirs. However, the expense of the process presently prohibits large scale application. Chemical supplies may be unavailable in the quantities required for future widespread use of chemical recovery, limiting process application.

The environmental impacts of chemical recovery techniques most severely affect water quality. Indirect air quality impacts may result from the manufacture of required chemicals, although these emissions are controlled by existing industry regulations and are not expected to cause major environmental problems. Chemical processes require large volumes of fresh water, which may constrain future application in water-short areas. The handling and disposal of chemical-saturated produced waters, the impacts of chemical spills on surface water, and the risk of contamination to groundwater supplies by injected chemicals seem to be the most severe potential environmental effects of chemical recovery methods. The processes have not been developed to the point where actual impacts can be quantified. It appears that environmental protection regulations governing the disposal of produced brines, chemical spills and underground injection, and low well leakage probabilities result in little potential for harm to groundwater by tertiary techniques. However, further study of the potential environmental impacts associated with a widespread implementation of chemical recovery methods is necessary.

1.4 FUTURE PROCESS APPLICATION

Major economic and technological uncertainties presently constrain the application of tertiary oil recovery methods. Both the amounts and timing of potential tertiary production are sensitive to crude oil prices. The processes involve large initial investments, and their experimental nature makes project success and return on investment money uncertain. Furthermore, project lead-times can be as long as ten years; a reliable, long-term price of oil is necessary to encourage operators to invest the money in developing these new technologies.

Tertiary oil recovery techniques are generally performed in oil fields that have been under production for many years. Environmental impacts of drilling and exploration operations are thus minimized. However, there are other environmental impacts which need to be identified and realistically evaluated as process technologies become more developed. Tertiary oil can significantly augment domestic petroleum supplies. However, the present constraints to process development and widespread application must first be resolved.

2.0 INTRODUCTION

During the first half of 1977, the U. S. demand for liquid hydrocarbons was about 18.5 million barrels per day (Mbb1/day); imports were required to supply almost half of this demand.⁽¹⁾ The domestic demand for petroleum and petroleum products is predicted to climb as high as 25 Mbb1/day by the early 1990's.⁽²⁾ Domestic production has been declining in recent years and may not exceed 7 Mbb1/day in 1990.⁽³⁾ Means of checking the growth of the gap between oil supply and demand must be found.

A near-term alternative for augmenting oil supplies is increasing production from known domestic oil fields. Conventional recovery methods extract only about one-third of the original oil in a reservoir. Enhanced recovery techniques (or tertiary recovery, if applied after the secondary recovery stage of waterflooding) can potentially recover another 30 to 60% of that oil.⁽⁴⁾

The primary purpose of this report is to describe the technology of tertiary oil recovery methods and to identify potential environmental and other constraints to future process applications. An overview of each recovery process is presented, including costs, operational problems, and desirable reservoir characteristics for optimum process performance. Possible constraints to widespread implementation of tertiary recovery methods are discussed throughout the report. The information provided in this report may be used by the Department of Energy to evaluate research and development needs and priorities and to structure future program plans regarding enhanced oil recovery.

The balance of this report is organized as follows:

- Section 3 presents background information on the characteristics of oil reservoirs and methods of oil recovery. Mechanisms of reservoir fluid flow and the means by which tertiary recovery processes facilitate this flow are discussed.
- Section 4 discusses the operation and costs of thermal tertiary recovery methods, including steam stimulation, steam drive and in situ combustion. Desirable reservoir characteristics for successful process application are also outlined.

- Section 5 discusses the operation and costs of miscible tertiary recovery methods, including hydrocarbon and carbon dioxide miscible methods. Desirable reservoir characteristics for successful process application and possible injection material constraints are also outlined.
- Section 6 discusses the operation and costs of chemical tertiary recovery methods, including polymer, alkaline and micellar polymer flooding. Desirable reservoir characteristics for successful process application and possible chemical supply constraints are also outlined.
- Section 7 presents potential environmental impacts resulting from the widespread use of tertiary recovery techniques. Effects on air quality, surface water and groundwater quality, and land use are discussed.
- Section 8 outlines projected growth scenarios for the use of tertiary recovery. The economics of the processes, particularly the issue of crude oil pricing, and other constraints which may affect these forecasts are briefly discussed.

References are listed at the end of each section and supplemental information is presented in the appendices.

The technology of tertiary recovery is still in a developmental stage; many of the process descriptions and constraints described in this report may not apply to future developments and the final application of commercial-scale recovery projects. The situation described herein is representative of the state-of-the-art as reflected by industry journals and contacts as of early 1978.

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3.0 RESERVOIR CHARACTERISTICS

Oil reservoirs are formed by sedimentary formations which have been deposited under water and later covered by impenetrable layers of a harder rock. Oil, being lighter than water, rises within an underground formation until stopped by an impervious rock layer.⁽¹⁾

Petroleum is found in the void areas between sand grains, or pore spaces, of sedimentary rocks. The pore spaces contain oil, gas and brine, a water which is saturated with minerals from the surrounding rock structure (see Figure 3.1). Fluid flow within an oil reservoir takes place through the pore spaces of the rock and is influenced by the size and geometrical spacing of rock pores. Permeability is the ability of a particular type of rock to allow fluid flow in the presence of a pressure gradient.⁽²⁾

FIGURE 3.1 Oil and Water in Reservoir Pore Spaces.
Redrawn from Reference 1.

Most crude oil reservoirs have very complex, nonuniform patterns of pore space variation and rock framework. The area of the reservoir is divided into "pay zones", vertical or areal subdivisions that are separated by impermeable

rock units, within which the petroleum is contained.⁽³⁾ There is usually little uniformity in fluid flow characteristics between reservoirs. Crude oil and formation water properties also vary significantly between reservoirs and may even vary between pay zones.⁽²⁾ Crude oil is classified by its density, which is measured in American Petroleum Institute (API) degrees, also called API gravity. Low-gravity crude oils (less than 10° API) are highly viscous, heavy, tar-like oils. As the API gravity increases, the density of the petroleum decreases; oils of over 50° API are light, highly volatile crudes. Because of current refining techniques and product requirements, the lighter crude oils are the most valuable; value decreases with API gravity.⁽³⁾

3.1 FLUID FLOW CHARACTERISTICS

Reservoir fluid flow characteristics are important in determining the response to and ultimate recovery efficiencies of various enhanced recovery mechanisms. These properties are determined by the way in which the sedimentary rock was deposited, the structure of the pay zone and the internal features of the rock.

The environment of deposition affects both the vertical and lateral fluid flow patterns within a reservoir. Sandstones are usually deposited as fairly thin sand layers separated by shale units, which prevent crossflow of the fluids. Vertical flow between sands is often prevented, allowing each sand section to act as a completely separate reservoir.⁽⁴⁾ Figure 3.2 shows separate pay zones within a rock formation.

FIGURE 3.2 Oil Trapped Within Shale Layers.
Redrawn from Reference 1.

The rock structure and the way in which oil is trapped within that structure can also affect reservoir fluid flow patterns. Although oil deposits may have originally been laid relatively horizontal, as in Figure 3.2, the creation of faults or other earth movement can shift the direction of the pay zone from the horizontal, forming a dip (see Figure 3.3). A fault can create a vertically permeable pay zone out of a previously permeable lateral formation by pushing an impermeable rock layer to block fluid flow, as in Figure 3.3. Dips can also be created by the formation of salt domes, as in Figure 3.4. Recovery in a dipped formation is often aided by natural gravity flow characteristics.⁽³⁾

FIGURE 3.3 Oil Accumulation Created by a Fault.
Redrawn from Reference 1.

FIGURE 3.4 Oil Accumulation Around a Salt Dome. The salt is impervious to the oil.
Redrawn from Reference 1.

The internal features of a rock can also affect reservoir flow patterns. The amount of pore space and permeability can vary widely within an individual sand unit. Coarser sand grains result in more porous and permeable formations, affecting fluid flow and ultimate oil recovery. The degree of internal rock variation depends on the depositional processes that developed the rock framework. Stream and deltaic deposits show more variability in sand grain sizes, and thus pore space patterns, than do marine or beach deposits. Compaction of sand grains decreases the size of pore spaces and thus formation permeability, as does cementation, a process by which pore spaces are filled with mineral matter, often clays. The results of compaction and cementation processes may greatly modify reservoir storage capacity and fluid flow conditions.⁽³⁾

3.2 PRIMARY AND SECONDARY RECOVERY

In primary recovery, oil and other reservoir fluids are driven through reservoir rock to the producing well by the relatively large pressure differences between the initial field pressure and that in the well. The driving energy is from the expansion of gas, from the influx of reservoir water or from gravity forces. Once this natural energy is depleted, energy must be added to the reservoir to produce more oil and the operation is converted to secondary recovery.⁽²⁾

The secondary stages of oil production involve injecting water or steam into a pattern of injection wells in order to force oil into production wells. Generally, the injection of one or more barrels of water is required for each barrel of oil recovered.⁽⁵⁾ The procedure is called waterflooding and was first used over 100 years ago, although use of the technique was not widespread until the 1950's. The number of waterflood projects initiated annually reached a peak in the mid-1960's.⁽⁶⁾ Oil recovery by the combination of primary and waterflooding techniques usually averages between 38 and 43% of the original oil in place.⁽¹⁾ Fluid flow patterns within a reservoir will result in a waterflood bypassing some regions of the pay zone and not recovering oil which is located there; even all of the oil which is contacted by the water is not pushed to producing wells. The oil which is not recovered by waterflooding and is retained or trapped by water and reservoir rock, is called residual oil. There may be a residual

oil saturation of 25% to 50% pore volume after a conventional water-flood.⁽⁷⁾ The oil may be trapped by water in rock pores or reside as a film on sand grains. The forces which hold the oil to reservoir rock surfaces are capillary, gravity and viscous, or drag, forces. Tertiary recovery techniques minimize these forces through chemical or thermal means, thereby increasing oil recovery.⁽²⁾

Capillary forces are a result of the adhesion, cohesion and surface tension present in liquids which are in contact with solids. When water is injected into reservoir rock, it will follow the most permeable path. Since more oil must be pushed out of a large pore space by the water than a small one, the small space will be cleared first, forming a preferential fluid flow path. Although some of the oil in the large pore is displaced, as flow proceeds through the smaller pore, the static pressure of the water behind the oil plug is not sufficient to displace the remaining oil; capillary forces trap the remaining oil in the larger pore.⁽⁶⁾

To overcome the capillary forces, the injection pressure can be increased or the interfacial tension holding the oil in the pore spaces may be decreased to near zero. The first alternative is expensive and impractical, since the resultant pressure changes across individual pore spaces will be quite small and insufficient to dislodge trapped oil. The second alternative is the basis for several tertiary recovery techniques which decrease the interfacial tension by chemical means. Once the capillary forces are eliminated, the contacted oil moves more easily through the formation.⁽⁷⁾

Gravity forces cause lighter fluids to rise to the top portion of the reservoir and may prevent injected fluids from contacting all of the reservoir oil. Tertiary methods which are designed to improve the sweep efficiency of, or the amount of reservoir volume contacted by injected fluids minimize the effect of gravity forces.⁽⁸⁾

Viscous, or drag forces, limit the mobility of oil within a reservoir. These forces are overcome by reducing the viscosity of the oil so that it will flow more readily.⁽²⁾ Tertiary recovery methods decrease oil viscosity by adding heat to the reservoir or by chemical means.⁽⁷⁾

3.3 DETERMINATION OF RESIDUAL OIL

The amount of residual oil available for recovery by tertiary methods is difficult to determine. After two previous recovery stages, the remaining oil is not distributed evenly in the reservoir. Because there are so many unknowns about the reservoir structure, usually only an average oil saturation value can be obtained. These values are determined by means of special tests, mainly log, core and tracer tests.⁽⁸⁾

Residual oil is measured either by estimating the original oil in place and subtracting production volumes or by measuring the remaining oil in place at various wells. The uncertainties of the inner geological structure of a reservoir, combined with variations in the effectiveness of waterfloods in removing oil from reservoir rock, cause wide ranges in values for residual oil saturation. Values may vary from 10% to 60% in one well and only from 25% to 35% in a similar well a few hundred feet away.⁽⁹⁾ A knowledge of the amount of residual oil left in a reservoir is important to avoid the failure of an expensive tertiary project simply because there was not sufficient oil available to recover.⁽⁸⁾ For a reservoir which is a candidate for primary recovery, the estimated reservoir oil saturation can be in error by as much as 10% without adversely affecting the project. But this margin of error in evaluating a tertiary recovery project could mean the difference between profit and economic disaster.⁽⁹⁾

3.4 PROJECT DESIGN

One of the biggest challenges in the application of tertiary oil recovery techniques is designing the optimum process for any particular reservoir. Enhanced recovery methods do not work equally well in all reservoirs; each method is subject to unique constraints.⁽⁷⁾

Enhanced oil recovery processes involve the injection of fluids into a reservoir which are often as expensive as the oil to be recovered, representing a heavy front-end financial burden for the oil industry. An accurate description of reservoir characteristics is essential for the successful application of enhanced recovery methods. Vertical or lateral reservoir rock variations may result in large amounts of oil being bypassed; natural fractures also constitute preferential fluid flow pathways. A detailed description of reservoir non-uniformities can help operators formulate preventive measures against undesired flow patterns.⁽¹⁰⁾ This information is obtained by means of detailed geological studies.

Project development for an enhanced recovery process begins with extensive studies of the reservoir to determine flooding patterns to be developed. These include site evaluation, field testing of injection fluids and injectivity tests to evaluate potential injection problems in the project.⁽¹¹⁾ Data on flow patterns can also be obtained from reviewing reservoir performance during previous waterflooding operations. Pressure falloff tests seem to reflect the influence of fractures on injection well performance.⁽¹²⁾

Rock studies are used to identify existing reservoir rock types and to interpret the depositional origin of the rock, yielding information on pay zone patterns and pore-space variations. Framework studies yield maps and cross-sectional views of the geometric configuration of the reservoir and also show the vertical and lateral distributions of rock types within the reservoir. They basically deal with determining reservoir structure, continuity and overall thickness trends. Reservoir quality studies use well log, core analysis and well test data to identify pay zones within the reservoir and the distribution of fluid saturation. Integration studies complete the reservoir description, combining permeability maps with net thickness maps to provide pore-volume information.⁽³⁾

3.5 PROCESS EFFICIENCY

The amount of residual oil which will ultimately be recovered by tertiary methods depends on the sweep and displacement efficiencies of a particular process. The sweep efficiency is the amount of the reservoir between injection and producing wells actually contacted by the injected fluids. Although fluids may pass through a complete section of a reservoir, variations in reservoir rock, including permeability variations, faults and shale barriers, may result in small regions, or islands, of reservoir rock being bypassed; large oil-bearing areas of the reservoir may remain unswept. For typical reservoirs, the contact factor ranges between 75 and 90%.

The mobility ratio of the injected fluid to the displaced fluid (oil) will ultimately determine how much of the project pattern is flooded. Every fluid has a certain mobility in an oil reservoir, defined as the permeability of the rock to that fluid, or the ease with which a fluid flows between the sand grains of a formation, divided by the viscosity of the fluid. A mobility ratio is the ratio of the mobilities of two fluids, for example, oil and water ($M = k_w/\mu_w \div k_o/\mu_o$). If $M = 1$, water and oil flow equally well through the formation rock. If $M = 10$, water flows 10 times more easily than oil, and may readily bypass oil deposits, instead of pushing them towards producing wells. The best sweep efficiencies are obtained at lower mobility ratios.

Although process sweep efficiencies may be quite high, capillary forces may not permit the recovery of contacted oil. The displacement efficiency is the fraction of original oil saturation that is actually displaced from the reservoir pores,⁽⁶⁾ or the

$$\frac{\text{initial oil saturation } (S_{oi}) - \text{residual oil saturation } (S_{or})}{\text{initial oil saturation } (S_{oi})}$$

Tertiary recovery methods with the highest potential for widespread application are those which provide both high displacement and high sweep efficiencies. This is often difficult to achieve, however, as procedures which may increase displacement efficiencies usually have a detrimental effect on sweep efficiencies.⁽⁸⁾

3.6 TERTIARY RECOVERY

Current methods of tertiary recovery fall into three main groups: thermal, miscible and chemical methods, each of which will be discussed in the following chapters of this report. All methods of tertiary recovery require the addition of energy to the oil reservoir by gas, water or solvents under pressure. However, each technique has its own advantages and limitations.⁽¹³⁾ Unlike water-flooding, which seems effective over a wide range of reservoir and rock properties, enhanced oil recovery processes are very specialized. The type of tertiary process to be applied is highly dependent on reservoir rock and fluid characteristics. Each technique seems to require a slightly different set of reservoir properties and rock-fluid and pressure-temperature conditions for optimum results.⁽¹⁴⁾

Thermal recovery methods are designed to reduce the viscosity of oils, facilitating the flow within the reservoir and toward production wells. Steam soak and steam injection processes utilize steam as the injected fluid and the heat carrier. In situ combustion injects air, burning part of the crude oil in the reservoir to generate heat.⁽¹⁾ These methods are best suited to the recovery of viscous crude oils, although they are not limited to use with heavier crudes. The techniques are not applicable to all reservoirs, however, because of the required formation porosity for a successful project.

In miscible recovery techniques, the injected fluid dissolves in the contacted oil, forming a single oil-like liquid that flows through the reservoir more easily than the original crude. A variety of injection fluids may be used to achieve this effect, including carbon dioxide and petroleum hydrocarbons such as propane.⁽¹⁾ Hydrocarbon miscible techniques will probably be used little because of the rising expense and general unavailability of propane and ethane, and problems in controlling the flood in the reservoir and achieving the pressures required for miscibility. Carbon dioxide miscible floods also suffer from operational problems, in addition to scarcities of supply sources of carbon dioxide, particularly in proximity to potential project sites.⁽¹³⁾

Chemical recovery processes include micellar-polymer, polymer and alkaline flooding. In micellar or surfactant flooding, detergent-like materials are injected to modify the chemical interaction of oil with its surroundings, and partially dissolve the oil within the formation. In polymer flooding, chemicals such as polyacrylamides or polysaccharides are added to the injection water to improve the efficiency of oil displacement. Alkaline solutions react with components in crude oil or at the reservoir rock surface to form detergent-like materials which reduce the ability of the formation to retain oil.⁽¹⁾

The chemical flooding techniques, which reduce the interfacial tension between oil and injected fluids, seem to be the most widely applicable methods. However, presently-used chemicals and systems can be applied only in sandstone reservoirs where salt contained in the reservoir is less than 50,000 ppm and calcium and magnesium contents are less than 500 ppm (see explanation in Chapter 6). Furthermore, these processes remain largely in the experimental stages. Lab work and pilot projects have not yet proved the commercial viability of chemical techniques on a large scale.⁽¹³⁾ The choice of which tertiary recovery process to use for a particular oil reservoir will depend on the viscosity of the crude oil, reservoir properties such as porosity and rock type and the availability of injection materials.⁽⁵⁾ Tertiary recovery methods each have different economic considerations and environmental impacts. Local environmental regulation and injection material costs may also impact the decision of which recovery process to use.

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4.0 THERMAL RECOVERY METHODS

Thermal methods of tertiary oil recovery use heat to reduce the viscosity of crude oil and facilitate its flow to producing wells. The injection of hot water was one of the first ways of improving oil recovery by thermal methods. Field testing of hot water injection began in the 1950's. As laboratory testing revealed the improved heat-carrying capacity of steam, steam injection began to replace hot-water methods of recovery.⁽¹⁾

Because of the low heat content of hot water, a reservoir had required from 2.5 to 3 pore volumes of water to bring its temperature near that of the injected water and sufficiently heat the oil. Although hot water flooding may still be useful in certain reservoirs (those sensitive to the fresh water used in steam floods, or those at high pressures where the steam temperature would be excessive), steam is generally preferred as an injection material. In the pressure range in which most thermal projects operate (100-1500 psia), steam carries much more heat than does hot water at the same temperature,⁽²⁾ and is thus more efficient than hot water injection; steam at 350°F can carry up to 1,192 Btu/lb, while hot water carries only 322 Btu/lb.⁽³⁾

Steam soak methods were developed in California in the late 1960's. The production rate from steam soak methods reached about 130 thousand barrels per day in 1968. Through 1971, some 20,000 out of 38,000 active wells in California had been steamed at least once; some wells have reportedly had as many as 16 cycles of steaming and production. Since 1968, there has been a large increase in continuous steam injection for flooding operations; the incremental oil production rate from steam flooding is now exceeding 100 thousand barrels per day.⁽¹⁾ Steaming techniques are usually used in recovering low quality oils from sand reservoirs of high permeability.⁽⁴⁾

In situ combustion generates heat within the reservoir by burning part of the oil within the pores of reservoir rock. The process was tested in Russia as early as 1930, although field tests in the U. S. were not begun

until the 1950's. There are currently about 30 field tests in operation worldwide, two of which are large scale commercial operations and have been underway for 14 years: one is the Midway-Sunset Field and another is the West Newport Field, both in California. Other California fields have been undergoing in situ combustion recovery operations for 9 years or more. Combustion projects are usually applied to low gravity, viscous crude oils, although they are not technically limited to these oils.

Commercial application of thermal processes has been ongoing for at least 10 years and has contributed about 200 thousand barrels per day to the nation's oil supply.⁽¹⁾

4.1 STEAM INJECTION

Steam injection recovery methods generate heat at the surface in the form of steam and inject this heat, usually a mixture of steam and hot water, into oil reservoirs. Usually, part of the recovered crude oil is used to generate the steam. Cost considerations make the use of a cheaper fuel, such as coal, desirable, although this seems to be precluded by environmental concerns. The ratio of steam to water injected may vary from mostly steam (high quality) to mostly water (low quality).⁽¹⁾ The quality of the steam is the weight fraction of water converted to steam, and is usually 70 to 80 percent for steam injection projects.⁽²⁾

There are a variety of mechanisms in operation during reservoir steaming which improve the displacement efficiencies of oil recovery. Besides the reduction of oil viscosity, which facilitates the flow of oil to producing wells, crude expansion and steam distillation also help increase oil recovery.⁽¹⁾

Reduction of oil viscosity is the most obvious effect of thermal recovery methods. The rate of viscosity reduction is greatest at the initial temperature increases. After reaching a certain temperature, the viscosity tends to stabilize at a particular level; additional reduction in viscosity is difficult to achieve. The viscosity can be reduced to a greater degree in the more viscous low gravity crudes than in the higher gravity crudes.

Heating from 100°F to 200°F reduces viscosity 98% for 10° API crude oils, but only 73% for 30° API oils.⁽²⁾

Crude expansion also contributes to improved oil recovery. The injection of heat into the oil reservoir causes the oil to expand or swell, resulting in additional energy to push the oil through reservoir pore spaces toward producing wells. Depending on the composition of the oil, crude may swell by 10-20% during a steam flood.⁽²⁾ The added energy and volume may improve the relative permeability of the oil through the rock, as well as improving the mobility ratio and sweep efficiency of the process.⁽¹⁾

Another benefit of steam processes is steam distillation. As a volatile oil is displaced by high temperature steam, the lighter fractions of the oil may be vaporized. These lighter fractions, while moving through the reservoir, condense as they contact the colder formation, creating a miscible or solvent bank ahead of the steam zone.⁽²⁾ The miscible displacement makes very low residual oil saturations possible, since more of the oil is contacted and produced. The produced oil, being the first to condense, is also a higher gravity, and more valuable, crude.⁽¹⁾

Steam injection is currently used in two ways. Cyclic steam stimulation uses the same well for injection of steam and oil production; steam flooding injects steam into an injection well to push the oil towards and increase production from nearby producing wells. Cyclic stimulation often precedes the use of steam drive in a tertiary recovery project.

4.1.1 Cyclic Steam Stimulation

Cyclic steam stimulation, also termed steam soak, or "huff-and-puff," uses the same well for the injection of steam and the production of oil. High quality steam (about 80% quality) is produced in generators at the surface and injected into the reservoir.⁽¹⁾ A soak period follows injection, during which the well is shut in, allowing the injected heat to distribute itself more widely in the reservoir (see Figure 4.1).⁽²⁾ Once reopened, increased production from the well may continue for as long as a year, after which the cycle is repeated. The average increase in oil production rate is from 10 to 30 times, although increases of as much as

FIGURE 4.1 Schematic of the Cyclic Steam Stimulation Process

100 times the pretreatment rate have been reported immediately after stimulation in some reservoirs.⁽³⁾

The optimum number of steaming cycles is somewhat dependent upon reservoir type. In California reservoirs, which are generally steep, dipping structures, many cycles are possible as the heated, less viscous oil flows downward by gravity drainage to producing wells. Cases have been reported of more than 20 steaming cycles being used in these dipping reservoirs. In flat reservoirs, where gravity does not aid flow, the number of profitable cycles is much more limited.

Cyclic steam injection generally becomes less efficient as the number of steaming cycles increases. A good indicator of project performance is the produced oil to injected water ratio. Best results indicate early cycles recovering as much as 30 barrels of oil per barrel of water injected as steam.⁽²⁾

The volume of steam injected ranges from 5,000 to 15,000 barrels (feedwater volume).⁽¹⁾ Generally, only 20 to 40 percent of this injected water is recovered during the first production cycle. However, this proportion increases rapidly, and by the last cycle, most of the injected water has been produced.⁽⁵⁾ After several steaming cycles, the project will usually be converted to a steam drive.⁽¹⁾

Steam stimulation has proved most economically successful in the California reservoirs. However, the overall recovery of steam soak projects tends to be low, since the injected heat only affects the reservoir area near the injection well.⁽³⁾ Steam drives have a larger area of influence and can result in higher oil recovery.

4.1.2 Steam Flooding

Steam flooding, also referred to as a steam drive, uses thermal as well as mechanical energy to increase oil recovery.⁽²⁾ Steam is injected into the reservoir to heat and thin the oil, as in a steam soak. The continued injection of steam displaces the thinned oil toward separate producing wells.⁽¹⁾

As the steam is injected, a series of zones forms around each injection well (see Figure 4.2). The zone nearest to the well is steam, with a temperature approximately equal to that of the injected steam; this zone expands as more steam is injected into the well. The next zone contains condensed steam, or water. The temperature across this zone decreases from that of the steam to that of the reservoir; pressure also decreases across this zone until the reservoir pressure is reached.⁽⁶⁾ The condensed hot water at the steam front will tend to settle below the steam vapor, since it is much denser than the vapor. The steam thus flows in the upper part of the oil-bearing sand as the steam front moves out from the injection well. The amount of the upper reservoir layer which is actually contacted (the vertical invasion efficiency) seems to be dependent upon steam injection rates, well spacing, formation thickness and permeability distribution. The zone farthest away from the injection well is one of cooled water. An ordinary waterflood thus precedes warm and hot waterflooded regions.

The flooding sequence in a steam drive results in a gradual reduction of residual oil saturation throughout the flooded area.⁽¹⁾ In the steam zone, steam distillation contributes to the reduction of residual oil saturation. Oil saturation is reduced most, however, in the condensed water zone because of lower oil viscosities and high temperatures and crude swelling effects.⁽²⁾ Before the steam zone arrives at, or breaks through to, producing wells, additional heat may be supplied by intermittently steaming and producing the production wells, as in a cyclic steam project.⁽⁶⁾

The sweep efficiency of the steam drive, or volumetric coverage, is determined to a certain extent by the arrangement of production wells around injection wells. The areal sweep of a steam flooding operation is fairly high in a relatively uniform sand. However, the vertical sweep is affected by any heterogeneities in reservoir structure, by the channeling, or fingering, of steam through depleted reservoir zones (which have already had oil removed) and by the gravity segregation of vapor and condensed steam. Since the condensed steam is not as effective a displacement agent as vapor (it does not reduce residual oil saturation to as low a value)

FIGURE 4.2 Schematic of the Steam Flooding Process

the overall reservoir recovery is limited.⁽⁶⁾ When the vertical distribution of steam in the reservoir presents problems, the injection of lower quality steam (less than 80% quality) may be desirable. The added volume of hot water in the injected fluid could aid recovery of oil from the lower strata of very thick permeable zones.

During steam drives, much of the heat injected as steam is transferred to the reservoir rock. Added process efficiency can result if, in the final phases of the recovery operation, unheated water is injected to recover heat from the reservoir rock. The heat will then be carried forward as a hot waterflood. This method uses the heat more economically, since a complete process using only steam would require the use of fuel costing more than the value of the incremental oil that could be recovered with steam at that particular stage of production.⁽¹⁾ The injection of unheated water can also prevent land subsidence, by taking the place of the recovered oil underground. If the flooding pattern is to be expanded from a pilot to a commercial scale, filling the old pattern with water will equalize underground pressures and prevent the movement of reservoir oil to already-swept patterns.

4.1.3 Operation

The success of a steaming project depends on the rapid, continued growth of a steam zone with resulting high oil displacement rates. To achieve this end, heat losses must be minimized. Heat losses during steam injection are a function of injection temperature, the equipment used and reservoir characteristics.

Heat losses increase as temperature increases. It is thus preferable to apply steam injection at lower pressures to minimize heat losses, since high pressures require higher temperatures to convert water to steam.⁽²⁾ This limits the process to relatively shallow reservoirs - usually less than 2000 feet deep.⁽⁶⁾ The injection temperature is also affected by the permeability of the oil-bearing zone, since permeability affects injection rates and pressures. Low-permeability zones require higher pressure and temperature injection, increasing process heat losses.⁽²⁾ Heat losses through

surface lines and in injection wellbores may be quite severe. The equipment used in steaming projects basically consists of steam generators; water softeners and related equipment and materials (since fairly fresh water is required to make steam); downhole packers that are specially constructed for high temperature use; and insulation for lines and wellheads, to minimize heat losses.⁽⁷⁾ Heat losses may be further minimized by placing generators close to injection wells. Burying injection lines is normally sufficient to keep surface heat losses below 10%. In addition to depth, wellbore heat losses depend on the type of well completion used.⁽²⁾

The largest source of heat loss in a steaming operation is by conduction through the surrounding reservoir rock. The rate of heat loss depends on the surface area available for heat flow and increases with steam zone growth. Because of high heat losses of costly surface-generated heat, steaming cannot be used in deep, thin or low permeability reservoirs.⁽²⁾ In deep reservoirs, radial heat losses from the injection string and difficulties in maintaining the mechanical integrity of the string itself place a depth limitation on steam drive. In heterogeneous formations, the steam channels through the highly permeable zones and bypasses less conductive zones which may contain a large fraction of the oil. Moderately thick formations are preferred to reduce heat losses to adjacent strata. High reservoir water saturations are undesirable because water production becomes very high when formation water and steam condensate are combined.⁽⁶⁾

Isolating the geologic zone to be steamed, pumping of hot wells and excessive water production are a few of the major operating problems encountered. There are also difficulties in obtaining accurate production measurements in hot wells.⁽⁸⁾ Sand control, however, seems to be the major problem (both produced sand and sand-plugged lines), along with deleterious high temperature effects on casing and other tubular equipment.⁽⁶⁾ Failures of thermal packers are also a major operating problem. The current packers apparently cannot meet the extreme operating conditions encountered in a steam injection project (pressures up to 1,375 psi and temperatures of 590°F).⁽⁹⁾

Weather conditions can also adversely affect a project. Besides water freeze-ups, the cold weather severely affects the startup of air compressors--the lubricating oil becomes so viscous that the crankshaft cannot be spun fast enough to start.⁽¹⁰⁾ Other surface problems which have been mentioned in connection with steam injection projects are a scarcity of source water for steam generators, limited generator capacity, and limited availability of low-sulfur fuel to power the generators.⁽¹¹⁾ Low sulfur fuel is necessary for steaming projects to meet current air pollution regulations regarding emissions. This limitation will be discussed further in Section 7.1.1. Cement failure in conventionally completed wells is frequent in thermal recovery operations. New wells must be completed and equipped to operate at high temperature.⁽²⁾

4.2 IN SITU COMBUSTION

In steaming processes, heat is generated at the surface and injected into the reservoir as steam. In in situ combustion techniques, heat is produced inside the oil reservoir itself by burning a fraction of the reservoir crude oil. The heat of combustion partially vaporizes the remaining oil and reduces its viscosity. Separate production and injection wells are employed in this process. There are three basic types of in situ processes: conventional, or forward combustion; wet combustion, also called COFCAW (combination of forward combustion and waterflood); and reverse combustion.⁽¹²⁾

In all of the in situ combustion processes, the reservoir oil is first ignited, either spontaneously or with the aid of a downhole heater. Chemical reactions which occur between the oxygen in the injected air and the reservoir oil generate heat, even though combustion may not spontaneously occur. Depending on the composition of the crude oil, the speed of this oxidation process may be sufficient to develop temperatures which ignite the oil. If not, ignition is aided by using downhole heaters to raise the oil temperature or by preheating the injection air or preceding the air injection with an oxidizable chemical such as linseed oil. Once ignition is accomplished, the fire is sustained by continuous injection of air. As in any combustion

reaction, the oxygen in the air combines with the fuel (crude oil), forming carbon dioxide and water and releasing heat. The high temperatures of combustion vaporize the lighter fractions of the oil ahead of the flame and leave a heavy residual coke deposit as the fuel to be burned. The vaporized light components and steam formed by combustion are carried forward to cooler portions of the reservoir, where they condense. The flame will move forward through the reservoir only after it has burned all of the coke which was deposited as fuel.⁽¹³⁾

4.2.1 Forward Combustion

In the forward combustion process, also called fireflooding, there are a variety of zones formed within the reservoir (see Figure 4.3). There is a heat zone, which causes decomposition of the oil in place, and a combustion zone. In the heat zone, the lighter, volatile hydrocarbons are extracted from the reservoir oil and a tar or coke layer (the fuel to be burned) is left in the reservoir. In the combustion zone, the oxygen from the injected air contacts the coke and combustion occurs. This process moves forward through the reservoir rock with the combustion zone, or burning fire, providing heat to form a layer of coke ahead of it.⁽¹⁴⁾

A burned zone through which the fire has progressed is left near the injection well. In this zone, all of the liquid has been removed from the rock, leaving only air in the pore spaces of the rock. The temperatures here range from near reservoir temperature at the injection well to a peak at the flame front.⁽¹³⁾ At the flame front, where the heavy fuel is burned, the temperatures normally range between 600° and 1200°F, although they may in some cases reach 1800°F.

Ahead of the flame is a vaporizing zone, which contains combustion products, vaporized light hydrocarbons, and steam, formed by the vaporization of reservoir water near the flame front. Water formed in the combustion reaction also contributes to this steam zone. The steam mobilizes and displaces much of the heavy oil, leaving a relatively low oil saturation of heavier fractions to be burned by the flame front. The coke that is burned is the least

4-12

FIGURE 4.3 Schematic of the Forward In Situ Combustion Process

valuable, asphaltic portion of the crude.⁽¹⁾ Temperatures across the vaporizing zone range from the high temperatures of combustion to that just necessary to boil water at the prevailing reservoir pressure, usually near 400°F.

The next zone is the condensing zone, where condensed light hydrocarbons mix with the reservoir oil to help displace that oil, aided by the hot water-flood caused by the condensed steam and the gas drive provided by combustion gases. Temperatures in this zone usually range from 50 to 200°F above the initial reservoir temperature.⁽¹³⁾ The condensed water tends to settle below the steam vapor and combustion gases. The combustion or burning front, however, because of the concentration of gas flow, will tend to move in the upper part of the reservoir, sweeping only the upper portion of the oil zone.⁽¹⁾

The oil bank, the final zone, is where the displaced oil accumulates. Pore space in this region is occupied by reservoir water, displaced oil and some of the combustion gases. Since the temperatures in this region are very near the initial reservoir temperatures, there is little improvement in oil viscosity. Ahead of this zone lies the undisturbed reservoir.⁽¹³⁾

Once the steam front arrives at the producing well, the oil production rate increases because of the lowered oil viscosity. However, as the flame front nears the well, measures must be taken (such as circulating water through the well annulus) to protect the well from damage as production continues.⁽¹⁾

The amount of coke which a particular reservoir crude oil will deposit upon being heated is one of the most important parameters in a fireflood. Coke deposited as fuel is measured in lb/ft³ of reservoir rock. If this value is too low, combustion cannot be supported; if too high, flame movement is too slow since all the fuel must be burned before the flame advances. The amount of fuel deposited will also determine the amount of air required to advance the flame through a specific volume of reservoir rock. The more fuel that is deposited, the greater are the air requirements.⁽¹³⁾

The amount of air injected per unit area of flame front, or air flux, is another important factor in combustion projects. Air flux is measured in scf/hr/ft² of flame front and usually ranges from 10 to 30. Below a minimum

value (which is dependent on reservoir conditions and crude oil type), oxidation of the oil is too slow to generate the heat required for sustained combustion. Increasing the air flux will increase the speed of the flame front but will also reduce the contact time of the injected air with the flame, and result in poor utilization of the oxygen in the air.

The forward combustion process does not utilize heat very efficiently. Because of the poor heat-carrying capacity of air, only about 20 percent of the heat generated is moved ahead of the flame front where it works to improve oil recovery. The remaining heat is absorbed by reservoir rock above and below the oil bearing strata.⁽¹³⁾ The wet combustion process was developed to improve the efficiency of the in situ processes.

As the flame moves from the air injection well to the producing well, the oil must pass through a cold region of the reservoir. If the oil is very viscous, liquid blocking could occur, terminating the combustion process.⁽¹⁶⁾ Reverse combustion is designed to alleviate this problem.

4.2.2 Wet Combustion

The efficiency of in situ combustion can be improved by an alternate injection of air and water. The water, as steam, transfers the heat left in the rock behind the burning zone to the rock immediately ahead of that zone, resulting in better heat distribution and reduced air requirements. The injected water also improves the mobility control, and thus the sweep efficiency, of the process.⁽⁴⁾ As the water saturation accumulates in the burned-out region, the volume available for the accumulation of injected air is reduced, causing more of the injected air to flow through the combustion front.

In the wet combustion, or CUFCAW, process, the amount of coke left to be burned as a fuel by the flame front is substantially decreased. More oil is thus displaced from the reservoir and less air is required to burn a unit volume of the reservoir. Water injection in a ratio of 0.3 to 0.5 barrels of water per thousand cubic feet of air can reduce fuel and air requirements by as much as 30 to 50 percent.⁽¹⁾ A water-air ratio is usually chosen to move the heat forward at about the same rate as the combustion front, while

maintaining high combustion temperatures.⁽¹⁵⁾ Water can be injected with air at ratios of up to 1000 to 2000 scf of air per barrel of water without completely quenching the fire front. The injected water develops a steam zone in front of the combustion zone. The major benefit of the COFCAW process is that there can be a threefold reduction in the air required to produce 1 barrel of crude oil.⁽³⁾

The wet combustion, or COFCAW, process uses heat more efficiently than dry combustion, taking advantage of the high heat content of water, as well as its latent heat of vaporization, to recover energy that would otherwise remain stored in the burned-out region. However, although the process does have a higher thermal efficiency than dry combustion processes, it does not avoid the problem of minimum oil mobility in the cold regions of the reservoir.⁽¹⁶⁾

4.2.3 Reverse Combustion

In reverse combustion, the flame front travels in a direction opposite to that of air flow. Air is initially injected into a well, which will later be the producing well, to start combustion. After ignition has occurred, further air injection takes place through a different well. Combustion gases, steam and oil in the burning region flow through the previously burned area to the producing well.⁽¹⁾ Thus, oil is constantly moving through heated areas of the reservoir. This method allows the production of oil which is too viscous to flow under reservoir conditions.

In actual application, the process has very low efficiency. A valuable fraction of the crude oil is burned as fuel, leaving the undesirable tar fractions in the region behind the combustion front. Also, if spontaneous combustion occurs near the air injection well, it could use up all the air required for reverse combustion.⁽¹⁶⁾ Thus, the process is limited to crudes of relatively low reactivity to oxygen, since it can continue only as long as spontaneous combustion does not occur at the injection well.⁽⁶⁾ The reservoir must also have adequate air permeability for the process to work. Reverse combustion is expected to have limited use, if any, because of its low efficiency.⁽¹³⁾

4.2.4 Operation

The most important (and most expensive) equipment requirements for in situ combustion methods are the air compressors, which should be capable of handling several million scf/day of air at pressures ranging up to 4,000 psi.⁽⁷⁾ At the Heidelberg oil field near Laurel, MS, Gulf Oil Company has an ongoing fireflood operation. In this project, a 6-stage compressor is injecting 1,000,000 scf/day at an injection pressure of 2,500 psi.⁽¹⁷⁾

Other equipment requirements include air filters, high-pressure well-heads for injection wells and chokes for controlling the rate of air injection. Downhole ignition equipment, such as bottom-hole electric heaters, gas burners, or catalytic heaters, is also required. Because of the extreme corrosion environments created by combinations of air, water (in COFCAW processes) and high temperatures, corrosion control programs are important, as well as a special alloy steel for the lower part of the injection well tubes.⁽⁷⁾

Most of the operating problems encountered with in situ combustion project relate to the high temperatures involved. The thermal stresses on cement, tubular goods and pumping equipment increase the frequency of equipment failure. Sand production creates pumping problems and severe wear. The composition of the combustion gases, together with high temperatures, accelerate corrosion problems.⁽¹⁴⁾ Other problems which have been encountered in in situ combustion operations include poor air distribution (which results in poor vertical and areal sweep) and inability to keep the burning front going when the spacing between injection and producing wells became too large (perhaps a 10 acre spacing of wells).⁽⁸⁾ A possible environmental problem may be emissions of combustion gases from the well, although there is as yet no data on this problem. It is uncertain whether these gases are regulated by current air pollution laws.

4.3 RESERVOIR APPLICABILITY

Thermal recovery methods are designed to increase oil recovery by reducing the viscosity of oil and enabling it to flow more readily toward producing wells. The technology for these processes is fairly well developed, and both steamflooding and in situ combustion have been employed on

commercial scales. Thus, thermal enhanced recovery methods are said to be among the lowest risk investment of the tertiary recovery techniques.

The success of any tertiary recovery project depends quite heavily on matching the process desired with an appropriate reservoir. Not all methods work equally well in all reservoirs. Thermal methods seem to work best when applied to heavier crude oils, usually those of less than 25° API gravity, and in sandstone reservoirs.⁽¹²⁾ Screening parameters have been developed (see Table 4.1) which help to decide whether thermal methods will work well in any particular reservoir. The most critical parameters for steam drive seem to be reservoir depth, zone thickness and crude oil viscosity.

Virtually all of the oil produced by steam injection is from high saturation, high porosity, shallow reservoirs, containing low API gravity crude oils.⁽¹⁸⁾ A reservoir depth of less than 3000 ft minimizes heat losses, and the latent heat of steam is highest at low pressures. Thus, more heat per pound of steam injected can be transported in low pressure, shallow reservoirs than in the deeper zones which are at higher pressures.⁽²⁾ Other favorable factors for steam injection projects are existing wells which are adaptable to steam injection; an available fuel supply for steam generation; and an available supply of water which is cheap, slightly alkaline, free of H₂S, oil, dissolved iron and turbidity. Some of the factors which increase the risk of steam drive operations include low residual oil saturation and extensive reservoir fractures.⁽¹⁹⁾

The majority of steam flood projects are located in California. As of 1975, there were 33 active steamflood projects in the United States, 26 of which are in California. Most of the remaining projects are in the Texas-Louisiana area. The largest project is in the Kern River field in California and has 781 injectors. Nineteen of the projects have been deemed to be profitable; the others are either indeterminate at this time or are economic failures.⁽⁶⁾

In situ combustion processes must also be carefully designed for formation characteristics.⁽¹⁾ The process has been applied mainly to reservoirs with high viscosity crude oils, although it has been used for tertiary recovery in reservoirs with oils in the gravity range of 20 to 40° API.⁽¹³⁾

TABLE 4.1 Reservoir Screening Criteria for Thermal Recovery Methods^(a)

NI=Not Included NC=Not Critical		Steam Drive				In Situ Combustion			COFCAW
Screening Parameters	Units	NPC ⁽¹⁾	GEFFEN ⁽¹⁹⁾	OTA ⁽²⁰⁾	GURC ⁽²¹⁾	NPC	OTA	GURC	GEFFEN
Oil Gravity	°API	≤25	>10	NC	10-25	≤25	≤45	10-25	<45
Oil Viscosity, (μ)	cp	≥20	NI	NC	NI	≥20	NC	NI	NI
Reservoir Temperature	°F	NI	NC	NI	NC	NI	NI	NC	NC
Operating Pressure	psia	NI	<2500	NI	NI	NI	NI	NI	>250
Average Permeability, ($\bar{K}$)	md	NI	NC	NI	≥100	NI	NI	≥50	NC
Depth (D)	ft	200-5000	<4000	500-5000	200-5000	>500 ^(b)	>500	≥500	>500
Zone Thickness (h)	ft	>20	>20	NI	≥20	>10	NI	≥10	>10
Transmissability ($\frac{Kh}{\mu}$)	$\frac{\text{md-ft}}{\text{cp}}$	100	>20	NI	NI	20	NI	NI	>100
Minimum Oil Content at Start of Process (Scr)	$\frac{\text{bbl}}{\text{acre-ft}}$	>500	>780	NI	NI	>500	NI	NI	>390 ^(c)
Rock Type		Sandstone or Carbonate	NI	NI	NC	Carbonate	Sandstone	NC	NI

(a) The abbreviations refer to the individuals or organizations who present these screening criteria. The numbers in parentheses correspond to references at the end of the section which denote these sources by their full names.

(b) If the zone thickness and transmissability are satisfactory for steam drive methods, industry practice tends to favor the use of steam drives over in situ combustion, using the latter only when depths are greater than 5000 ft. ⁽¹⁾

(c) However, an oil content greater than 700 bbl/acre-ft may be necessary for the process to be economic, since large amounts of oil may be burned during project operation. ⁽¹³⁾

In situ combustion was once thought to be a very promising recovery technique. However, operational and economic problems have resulted in a declining application of the process, from 38 active projects in 1970 to 21 active projects in 1975. Of the currently ongoing projects, eight have been termed profitable and seven unprofitable; others have yet to be evaluated.⁽⁶⁾

The largest potential for thermal recovery on an extensive scale is in California's central valley (see Figure 4.4); about 90% of the entire enhanced oil recovery potential resource is in California.⁽¹²⁾ Appendix A lists many of the current thermal recovery projects nationwide.

4.4 ECONOMICS

Thermal recovery methods, technologically the most advanced of the tertiary recovery techniques, are currently being applied on a commercial scale. Most of the costs for these methods are in field development and fuel for generating heat. The thermal stresses to which project wells are subjected often requires the drilling and completion of new wells or the conversion of existing wells to attain desired quality standards.⁽⁶⁾

Another factor affecting the economics of thermal recovery operations is the price differential for low-gravity crude oil. The low-gravity crudes normally recovered by thermal operations are lower priced because of their poorer quality and lower product value refining yield, and currently bring about \$1.20 per barrel less than a medium-gravity crude oil.⁽¹⁾ The overall effect of high project investment and operating costs and low crude oil prices is a relatively low profit per barrel of recovered oil.⁽²⁾

Market constraints arising from competition with heavy Prudhoe Bay crude oil and low oil prices may limit the development of thermal methods in California. A real or perceived weak market for heavy oils produced by thermal techniques may deter the development of enhanced oil recovery.⁽²⁰⁾ The Economic Regulatory Administration is attempting to mitigate this problem and has announced proposed allocation and pricing measures which are aimed at making the heavy California crude oil more attractive to refiners.⁽²²⁾

FIGURE 4.4 Current and Pctential Thermal Tertiary Recovery Projects
(Redrawn from Reference 24)

4.4.1 Steam Injection

The economic efficiency of steam drive projects is determined primarily by the steam injection rate, well spacing, thickness of the oil-bearing zone, porosity of the reservoir rock and residual oil saturation.⁽¹⁸⁾ The cost of the water to make steam is usually negligible, although in some areas of the country the availability of suitable fresh water supplies may be a problem. Steam costs are thus usually determined by the cost of fuel for steam generation. The economic limit for steam injection is reached when the costs to produce steam and operate the project equal the value of the produced crude oil. Steam generators and water treaters represent a large initial investment, usually from \$200,000 to \$500,000, including the generator, auxiliary lines and other surface equipment.⁽⁶⁾ Frequent well tests during operation are necessary to compare prior and project well responses, requiring the close attention of qualified engineering and operating personnel and increasing costs of operation.⁽²⁾

The operating costs of steam drive projects are dominated by the cost of fuel for steam generation. Most projects require one barrel of crude oil generator fuel for every three barrels of oil recovered.⁽⁴⁾ The use of cheaper fuels for generating steam, such as coal, lignite or refinery bottoms, would improve the economics of steam recovery processes and might increase the number of economically attractive candidate reservoirs.⁽¹⁸⁾ However, these fuels generally generate more pollutants than does oil and their use will probably be prohibited. The environmental problems of emissions from the generation of steam, discussed in Section 7, are already a major constraint to further implementation of the process.

4.4.2 In Situ Combustion

In situ combustion projects also require very high capital investment. The cost of operation and maintenance of air compressors, however, seems to be the biggest expense.⁽⁶⁾ The size of the compressors is determined by the desired flame front movement within the reservoir and the necessary air injection rates.⁽¹³⁾ Large volumes of air at high pressures must be handled in in situ combustion recovery. Air requirements ranging from 4,000 to

20,000 scf/bbl of oil recovered have been reported. Compressor operating costs can range from 40 cents to more than \$8 per barrel of oil produced; the energy of compression can represent as much as 25 percent of the heating value of the recovered oil.⁽²³⁾ The air-to-oil ratio is thus a good indicator of economic project operation. Economically successful projects have air-to-oil ratios of less than 20 thousand scf/bbl.⁽¹³⁾

The amount of coke available for combustion (fuel content), deposited as a result of distillation and thermal cracking, can also affect air requirements. If the fuel content is too low, combustion cannot be self-sustained; if too high, there will be a high air requirement and excessive power costs, along with a low oil production. Field projects have shown the fuel content to be a complex function of reservoir and crude oil properties, including reservoir thickness, permeability, oil saturation, viscosity and depth.⁽¹⁶⁾

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5.0 MISCIBLE RECOVERY METHODS

Improved recovery of crude oil by miscible displacement was first researched and tested in the early 1950's. The method generally involves the injection of a gaseous material whose composition acts as a solvent for the oil. The interfacial and capillary forces between the gas and the oil are eliminated and the two materials mix together, facilitating the flow of oil through the reservoir.⁽¹⁾

In miscible flooding, the injection of a small amount of an expensive solvent material is followed by a less expensive drive fluid to move the solvent and the crude oil and reservoir water toward producing wells. The solvent is used to scrub the oil from reservoir pores, achieving a high displacement efficiency; the driving fluid is used to obtain high sweep efficiencies. The solvent usually consists of intermediate molecular weight hydrocarbons (C_2-C_6) which have either been injected into the reservoir or are formed by a chemical transfer between the reservoir crude oil and the injected fluid. The driving fluid is selected by its ability to mix with the injected material. Methane is often used if a hydrocarbon has been injected, whereas inert gas or water may be used as driving agents if carbon dioxide is the injected material.⁽²⁾

Liquefied petroleum gas (LPG) flooding was one of the first uses of a miscible flooding technique. Beginning in 1956, LPG was used as a method for increasing both oil recovery and production rates. LPG at that time was only pennies per gallon and was viewed as a useful, economical injection material. However, it was found that variations in reservoir structure and poor mobility ratios of the injected fluids resulted in poor project economics; the ratio of produced oil to injected gas was too low to achieve economic success. At this point, carbon dioxide (CO_2) was introduced as a solvent material to increase oil recovery,⁽³⁾ since CO_2 is a relatively inexpensive fluid, particularly if there is a large natural source near the project oil field.

The miscible flooding techniques may be divided into those which employ hydrocarbon gases as injection materials and those which use carbon dioxide.

Regardless of the material injected, miscible techniques are designed so that the fluids in the reservoir and the injection gases will exist as a single phase in the reservoir at some design composition and pressure.⁽⁴⁾

5.1 HYDROCARBON MISCIBLE FLOODING

As with all miscible processes, the purpose of hydrocarbon miscible methods is to inject a substance which mixes with the reservoir oil, overcoming the capillary forces which lock residual oil droplets in reservoir pores. Any liquid hydrocarbon, such as kerosene or gasoline, is miscible with most reservoir oils, as are liquefied petroleum gas products such as ethane, propane, or butane. These liquid hydrocarbons are miscible with reservoir oil immediately on contact, and thus have first contact miscibility.⁽⁵⁾ Other injection materials which may be used require several contacts between the injected fluids and the reservoir oil to form a solvent. These processes are said to have multiple contact miscibility.⁽⁴⁾

5.1.1 LPG Miscible Flooding

In the LPG miscible flooding process, a design volume, or a slug, of propane or other liquefied petroleum gas, of about 5 percent of reservoir pore volume, is injected into the reservoir. The propane is followed by natural gas or gas and water which push the propane through the reservoir. The propane displaces reservoir crude oil and water, with the oil forming a bank in front of the propane slug. The water moves ahead of the oil and is produced (see Figure 5.1).⁽⁵⁾

As long as the propane is liquid, miscibility between the propane and oil will be maintained. Propane exists as a liquid at reservoir pressures above 617 psi (critical pressure) and will form a single phase with crude oils having gravities above about 30° API. With lower-gravity crudes, asphalt or wax separation may be a problem. The reservoir temperature may also affect miscibility between crude oil and the propane as well as between the propane and the driving gas.⁽⁶⁾

The pressures necessary to maintain miscibility between the propane slug

FIGURE 5.1 Schematic of the LPG Miscible Flooding Process

and a lean (mostly methane) driving gas are about 1100 to 1300 psi over the normal ranges of reservoir temperature. This places a limitation on the use of the process, since it must be applied in a reservoir deep enough to attain the necessary pressure without fracturing the reservoir. If propane is used as the injection material, the formation depth must be at least 1500 ft and possibly as much as 2500 ft, to avoid exceeding the formation fracturing pressure with the 1300 psi required to maintain miscibility.

The propane displaces all of the residual oil and movable water, resulting in a near 100 percent displacement efficiency. However, the low viscosities and high permeabilities of the gas and propane result in unfavorable mobility ratios and low sweep efficiencies. The alternate injection of water and gas behind the propane and gas slugs improves the sweep efficiency of the process.⁽⁵⁾

The main advantage of LPG miscible flooding is that it essentially displaces all of the residual oil from the reservoir rock which it contacts. However, the sweep efficiency is usually very poor, so the propane does not actually contact much of the reservoir. The propane and gas, being lighter than the reservoir oil, tend to rise over the oil, sweeping only the upper portion of the reservoir. Natural gas, propane and other hydrocarbon liquids are in great demand, and their already high prices are increasing.⁽⁵⁾ The LPG process will thus most likely be used in the future to only a limited extent.

5.1.2 Enriched Gas Miscible Flooding

The enriched gas process, or condensing gas drive, is similar to the propane process, although it relies on multiple contact, instead of first contact, miscibility. The injected gas must contain a large amount of C_2-C_6 (ethane through hexane) hydrocarbon components. As the gas contacts reservoir oil, these C_2-C_6 compounds are stripped from the gas and absorbed into the oil. Once the gas loses its heavier components, it moves forward through the reservoir (see Figure 5.2). It is followed by newly injected enriched gas and repetition of the transfer of C_2-C_6 compounds. After multiple contacts, there is no longer a sharp division between the gas and oil, but

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FIGURE 5.2 Schematic of the Enriched Gas Miscible Flooding Process

rather a gradation in fluid composition from injected gas to reservoir crude oil. Continued injection results in the gas displacing the crude oil as it sweeps through the formation.⁽⁷⁾

A sufficiently large volume of enriched gas must be injected to maintain the miscible front over a large part of the pattern area. An enriched gas slug of 10 to 20 percent reservoir pore volume is usually used, followed by less valuable lean gas or lean gas and water. The pressure required to develop the hydrocarbon exchange between gas and oil and to achieve miscibility between them depends on the composition of fluids and on the reservoir temperature. For a given crude oil at reservoir temperature, either reservoir pressure or the composition of the enriched gas can be changed to achieve miscibility, allowing considerable flexibility in process design. Increasing the richness of the injected gas by adding propane or LPG reduces the pressure required to achieve miscibility. As long as the enriched gas slug is present and the original conditions of temperature and pressure prevail, miscibility between fluids can always be regenerated.

Although the process is subject to high gas costs, as are the other hydrocarbon miscible methods, it does cost less than the propane or LPG method. This makes it economically feasible to use larger slugs of enriched gas and minimizes slug design problems. With larger slugs, it is more likely that miscibility will be maintained over a greater portion of the area to be swept.⁽⁷⁾

5.1.3 High-Pressure Gas Miscible Flooding

In the high pressure gas drive, the solvent consists mostly of intermediate hydrocarbon compounds which are vaporized from the reservoir crude oil.⁽⁴⁾ Natural gas, injected at a sufficiently high pressure, can generate miscible displacement without being enriched with hydrocarbons. As in the enriched gas drive, miscibility occurs by a transfer of C_2 - C_6 hydrocarbon components after multiple contacts between the gas and the oil. In this process, however, the direction of transfer is from the oil to the gas.

The successful operation of a high-pressure gas drive thus requires the reservoir crude oil to contain a high concentration of the lighter hydrocarbon compounds (C_2-C_6).⁽⁶⁾

As the miscible front moves from the injection well to the production well (refer to Figure 5.2), miscibility is continuously being broken and regained by the multiple contact process. The oil is thus continuously vaporized until only an asphaltine residue is left behind.

The phase relationships between the injected gas and the reservoir oil will determine the pressure required for miscible displacement. In most cases, this pressure will exceed 3,500 psi.⁽⁶⁾ From an operating viewpoint, a practical upper limit for application of the process is about 6,000 psi, since equipment and compressor operating costs become excessive above this pressure. The high pressure gas drive provides a fairly high displacement efficiency, removing about 95% of the oil contacted, although the sweep efficiency still is generally lower than that of waterflooding.⁽⁸⁾

An alternative low-cost injection material for the high-pressure lean gas miscible process is nitrogen gas. The nitrogen gas at high pressure works the same way as the hydrocarbon gas, becoming enriched with light and intermediate hydrocarbons until miscibility occurs.⁽⁹⁾ However, experiments have indicated that the pressures required to achieve miscibility will be higher for nitrogen gas. "One oil which required a pressure of 3500 psi with hydrocarbon gas to achieve a miscible displacement required 7870 psi with nitrogen. A second oil which was miscibly displaced with hydrocarbon gas at 3400 psi needed 4300 psi with nitrogen."⁽⁸⁾

5.1.4 Operation

In all of the hydrocarbon miscible flooding methods, the solvents and drive fluids are less dense and less viscous than the reservoir liquids. The injected fluids thus tend to override the oil, and preferentially penetrate the more permeable reservoir zones. The availability and the high costs of the hydrocarbon injection materials used will be critical factors in any widespread or increased use of hydrocarbon miscible methods,

particularly since the demand for these materials increases directly with the demand for the crude to be recovered.⁽⁴⁾

Although several miscible displacement processes using hydrocarbon materials have been extensively researched and tested, it appears that these techniques will actually play very limited roles in future oil recovery. Only one hydrocarbon miscible project was initiated between 1974 and 1976.⁽²³⁾ The volumes of oil recovered compared to the volume of injected hydrocarbons required is generally not large enough to offset the current and projected high value of the hydrocarbon solvents.⁽¹⁾ Current costs of \$10/bbl for propane are not unusual.⁽⁵⁾ Furthermore, these materials will most likely not be available in the quantities which would be required for large-scale oil field flooding in the United States.⁽¹⁾

5.2 CARBON DIOXIDE MISCIBLE FLOODING

The injection of carbon dioxide in an oil reservoir can increase oil recovery and production rates by a variety of mechanisms. CO_2 is highly soluble in crude oils, and causes these oils to swell when contacted. The added volume and energy of the expanded oil helps push it through the pores of reservoir rock. As the oil becomes saturated with CO_2 , its viscosity is also reduced, facilitating the flow of oil to producing wells. A larger percentage viscosity reduction occurs with the more viscous crudes. Carbon dioxide is also highly soluble in water and expands the reservoir brine when it goes into solution (from perhaps 2 to 7 percent). Saturation of oil and water by CO_2 also increases the density of oil and decreases the density of water, bringing the two densities closer to each other, thus lessening the chances for gravity segregation of the fluids.⁽¹⁾

Most importantly, however, CO_2 generates a miscible solvent in situ, as do the hydrocarbon miscible processes. The miscible zone between the CO_2 and the oil, like that of the lean gas process, is formed by a transfer of hydrocarbon components from the oil to the CO_2 after multiple contacts. However, carbon dioxide can extract heavier components, in the $\text{C}_6\text{-C}_{30}$ range, from crude oil, concentrating them at the CO_2 -oil displacement front, and

is not limited to the lighter hydrocarbons in the C_2 - C_6 range. CO_2 can thus mix with crude oils having few C_2 - C_6 components and may be applied to a wider range of oil reservoirs, including fields which were initially rich in C_2 - C_6 , but lost most of this component during primary production.⁽¹²⁾

The extraction of hydrocarbon components from reservoir oil takes place only above a certain pressure, which is dependent upon the temperature of the crude oil in the system. When injected into the porous reservoir rock, CO_2 first saturates the crude oil in the front portion of the system, vaporizing the light ends from the oil and developing an equilibrium gas. As more CO_2 is injected, other hydrocarbons (C_6 - C_{30}) are extracted to form the transition zone separating the CO_2 from the reservoir oil (see Figure 5.3). The extent of this transition zone is a function of the flood pressure. In a laboratory test, a higher concentration of hydrocarbons was present in the transition zones of higher-pressured floods; a lower total residual saturation was left in the sand packs after the flood, confirmed by higher oil recoveries at the higher pressures. The high pressure floods also extract a higher concentration of the more viscous hydrocarbons into the transition zone. Floods at lower pressures, however, have advantages of improved mobility ratios with improved flood conformance.⁽¹¹⁾

In a successful carbon dioxide flood, the reservoir operating pressure must be maintained high enough so that miscibility may be generated and maintained. This pressure will vary for each reservoir and depends upon the reservoir temperature, the composition of the crude oil (which also influences the amount of oil extracted by the CO_2), and the purity of the CO_2 . Contaminants such as methane or nitrogen in the injected CO_2 result in a higher pressure requirement for miscibility, as do higher reservoir temperatures and lower gravity crudes.⁽¹³⁾

The injection of alternate slugs of CO_2 and water has been found to be the most feasible recovery design. The size of the initial CO_2 slug is usually about 5 percent hydrocarbon pore volume (the volume of space in the reservoir rock filled by oil); it is followed by the alternate injection of water and CO_2 until the desired volume of CO_2 has been injected.

FIGURE 5.3 Schematic of the CO₂ Miscible Process

A CO_2 to water ratio of .5 has been found to work very well, although each reservoir will demand its own particular design. Once the desired level of CO_2 has been reached, injection of water alone is used to complete the process (see Figure 5.3).⁽¹⁴⁾

The injected volume of CO_2 must be specifically designed for application to a particular reservoir. Depending on the relative permeability of the reservoir rock and the actual injection schedule to be used, the required slug size will range from 15 to 25 percent pore volume at reservoir conditions.⁽⁶⁾ Increasing the amount of CO_2 injected, however, does seem to increase the amount of tertiary oil produced.⁽¹⁴⁾ Results of a field test in the Mead Strawn reservoir indicate that between one and two barrels of residual oil can be recovered per barrel of CO_2 injected. Where CO_2 is available in a field for \$1.50/bbl or less, there is an excellent chance for recovering residual oil at a profit.⁽¹⁵⁾

5.2.1 Operation

The success of a carbon dioxide miscible tertiary recovery project depends a great deal on the sweep efficiency of the process. The mobile oil is not necessarily always pushed toward the producing well; it may be forced downward through the reservoir rock instead, as a result of gravity segregation of the fluids in the reservoir.⁽¹⁴⁾ Although the densities of oil and carbon dioxide are similar at many conditions, the density differences between water and CO_2 may cause gravity segregation, and result in the CO_2 sweeping only the upper portion of the reservoir. The severity of this phenomena depends on the permeability variations in the rock, a characteristic of the reservoir which is rarely known with much certainty. If the oil viscosity is much greater than that of the CO_2 , there is a tendency for the carbon dioxide to finger or channel through the oil, further reducing sweep efficiency.⁽¹⁾

The equipment requirements for carbon dioxide miscible flooding projects are a little more extensive than those for steaming projects. Compressors are very important and should be multistage, with interstage coolers, to handle several million standard cubic feet per day (scf/d) at pressures ranging up to 5000 psi. High pressure wellheads are also necessary, because of the pressures required to generate miscibility. Wellheads may require some sort of modification to allow the handling of both gas and water.⁽¹⁷⁾ Some of the wells may have been drilled and completed as early as the 1900's. Many times, casing, tubing and rods will have to be replaced.⁽¹⁸⁾

A problem in the operation of CO₂ projects is corrosion. When combined with water, carbon dioxide forms carbonic acid, a highly corrosive substance. This requires the use of special metal alloys and coatings for project facilities. If alternate injection of CO₂ and water is to be used, dual injection systems will be required--one for CO₂ and the other for water.⁽¹²⁾ The presence of salt in the water accentuates the corrosive action of CO₂. Corrosivity seems also to be a function of system pressure, temperature and flow velocity.⁽¹⁸⁾ Corrosion-inhibition facilities are thus an important component of the system. Some sort of facility is also needed to remove CO₂ from the produced gases, such as by amine stripping or cryogenics.⁽¹⁷⁾

Insulated tank trucks are often used for transporting CO₂ to the test site. There, the material must be stored, often in the liquid state. From the storage tanks, it must be pressurized, and may be heated, to the desired design state.⁽¹⁹⁾ Injection water supplies may have to be chemically treated for both bacteria and scale prevention. Treatment for scale prevention may be accomplished by continuous chemical injection while bacteria prevention is accomplished by a batch biocide treatment. The water may also be filtered, to eliminate any solid impurities.⁽¹⁸⁾

5.2.2 Carbon Dioxide Supply

The availability of CO₂ at a reasonable price may be a severe limitation to the widespread application of carbon dioxide miscible flooding. The total availability of CO₂ is dependent upon economic factors--especially the price

of CO₂ delivered in the proper form, purity and concentration to oil fields. Major potential sources of CO₂ include natural sources, natural gas fertilizer plants, coal gasification plants, stack gases, etc. The gas may even be manufactured onsite, by combustion of a hydrocarbon, or in situ, as in the case of the underground combustion recovery process. Recent changes in the economic value of CO₂ have led to renewed interest in discovering and capturing CO₂ supplies. Major improvements, however, are needed in the transportation and recycling of CO₂ in order to realize the full potential of this miscible flooding process. (20)

A minimum of one barrel of CO₂ is required to replace one barrel (bbl) of oil at reservoir conditions. However, more CO₂ will probably be needed because of CO₂ lost by solution in the injected water and reservoir oil and because of the possible losses of CO₂ by channeling. Table 5.1 shows the volume of CO₂ in Mcf at standard conditions needed to fill one bbl of space at 100° and 160°F and for different pressures. Because CO₂ is sold either by weight or volume, a convenient conversion factor is that one ton of CO₂ contains 17.25 Mcf at standard conditions. (12)

TABLE 5.1 Volume of CO₂ to Fill One Barrel at Varying Pressures and Temperatures(a)

<u>Pressure (psia)</u>	<u>Mcf to Equal 1 bbl @ 100°F</u>	<u>Mcf to Equal 1 bbl @ 160°F</u>
1000	0.60	0.42
1500	2.08	0.78
2000	2.35	1.32
2500	2.50	1.76
3000	2.60	2.01
3500	2.68	2.18
4000	2.74	2.30
4500	2.80	2.40
5000	2.84	2.47
6000	2.93	2.60

(a) Based on Sage and Lacey.
Source: Reference 12.

Cheap, naturally occurring supplies of CO₂ near suitable oil fields are quite limited, although they do exist. Significant quantities of CO₂ occur naturally in reservoirs in west Texas, New Mexico, Utah and Colorado (see Table 5.2).⁽¹⁰⁾

To be applied at maximum efficiency, CO₂ must have a purity of 90 percent or more. Acceptable CO₂ can be extracted from natural gas or nitrogen, though the costs of compression and transportation must be considered in the economics of the oil recovery project. Carbon dioxide of acceptable purity is also available from oil refineries, fertilizer plants and synthetic natural gas (SNG) plants, and in smaller quantities from plants producing methanol, ethyleneoxide, sugar fermentation and lime. These plants are located throughout the country. Several of the SNG plants and their estimated potential supply appear in Table 5.3.⁽⁶⁾

TABLE 5.2 CO₂ Potential from Reservoir Production

	<u>Estimated CO₂ Reserves</u>
Solano, NM	>50 Bcf
North and South McCallum Units, Walden, CO	200 Bcf
Farnham Dome Unit, Price, UT	?
Gordon Creek Unit, Price, UT	300 Bcf
Escalante, UT	?
Big Piney, WY	>50 Bcf
Lower Smackover, Rankin and Scott Counties, MS	"
Pecos and Reeves Counties, TX (Ellenburger and Siluro-Devonian)	1 Tcf

Source: Reference 6.

TABLE 5.3 CO₂ Potential from SNG Plants

<u>Plant Location</u>	<u>Company Involved</u>	<u>Estimated CO₂ Available (short tons stream day)</u>	<u>Estimated Time Available</u>
Corpus Christi, TX	Coastal States Gas Co.	2,800	1975
Green Springs, OH	Columbus Gas Co.	3,000	1975
Marysville, MI	Consumers Power Co.	3,400	on stream
Morris, IL	Northern Illinois Gas Co.	2,400	on stream
Jackson, IL	Peoples Gas Light and Coke Co.	3,000	1976
Donaldsonville, LA	Texas Eastern Gas Transmission Co.	19,000	?

Mcf x 0.0579 = a short ton (at atmospheric conditions)

~25 ft³ CO₂/100 ft³ SNG from naphtha

~45 ft² CO₂/100 ft³ SNG from coal

Source: Reference 6.

The potential for oil recovery by carbon dioxide miscible methods seems to be very good; however, this potential hinges on the finding of sufficient supplies of low cost carbon dioxide.⁽¹⁾

5.3 RESERVOIR APPLICABILITY

The current limited availability and high prices of hydrocarbon injection materials suggests that these processes will have only limited commercial application, if any.⁽²⁾ The CO₂ miscible displacement process does not require expensive liquefied petroleum gas solvents, since it vaporizes LPG and heavier hydrocarbons from the crude oil to generate miscibility, lowering the viscosity of the oil and increasing its mobility. CO₂ injection processes are very efficient, potentially recovering more than 90% of the original oil in some fields.⁽²⁰⁾

However, regardless of the costs of the injected fluids, the choice of which material to use as a solvent is highly dependent upon reservoir conditions. In the LPG or enriched gas processes, the lighter hydrocarbon components of the gas are dissolved into the reservoir crude oil, increasing

the volume of the oil and decreasing its viscosity. In the high-pressure gas process, the gas is injected at high pressure, reaches equilibrium with the in-place oil and strips certain hydrocarbon fractions from the crude oil. It is best used in reservoirs having highly volatile oils.⁽²¹⁾ Table 5.4 shows some of the preferred reservoir criteria for the application of miscible flooding methods.

The composition of the reservoir crude oil is very important in designing a miscible flood. The crude should be above about 28° API gravity, to avoid potential problems caused by asphalt precipitation and large differences in viscosity between the oil and the CO₂.⁽⁶⁾ The crude oil need not have an extensive range of lighter gas and LPG components if being flooded by CO₂, which is capable of extracting a wide range of hydrocarbons. The presence of methane in reservoir crude oil, however, has been found to reduce the overall recovery efficiency of the CO₂ displacement process. As little as 10% methane in the injected CO₂ can also cause an appreciable decrease in oil recovery efficiency.⁽¹¹⁾

The oil content of the waterflooded reservoir is another important consideration in designing a miscible flood project. Difficulties are encountered in mobilizing and producing oil from sands in which the oil saturations are very low.⁽⁶⁾ Problems of low oil saturation are compounded by adverse mobility ratios between the CO₂ and the oil, causing the gas to finger through the oil. The efficiency of CO₂ floods, in terms of the recovery of oil to CO₂ ratio, decreases with the saturation of oil in the reservoir.⁽²⁰⁾ Hydrocarbon or CO₂ miscible flooding works best in reservoirs with low permeabilities.⁽⁶⁾

The CO₂ displacement process has been used to recover additional oil under a variety of conditions. CO₂ miscible flooding techniques have been applied to reservoirs with depths of 10,800 ft, and at bottom hole temperatures up to 248°F, with no known limitations. The crude oils recovered have varied in gravity from 16° to 45° API and the reservoir oil saturation (Sor) from 28 to 64%. The process has been used in sandstone, limestone and dolomite rock types and in formations varying from 8 to 600 ft in thickness, with considerable heterogeneity.⁽¹⁶⁾

TABLE 5.4 Reservoir Screening Criteria for Miscible Recovery Methods^(a)

Screening Parameters	Units	Carbon Dioxide Miscible					LPG Slug	High Pressure Gas
		NPC ⁽¹⁾	GEFFEN ⁽⁴⁾	REF. ⁽¹⁶⁾	OTA ⁽²²⁾	GURC ⁽²³⁾	GEFFEN	GEFFEN
Oil Gravity	°API	≥27	≥30	≥35	NI	>27	>30	>40
Oil Viscosity, (μ)	cp	≤10	<3	<5	≤12	NI	<5	<1
Reservoir Temperature	°F	<250	NI	NC	NI	NC	NI	NI
Operating Pressure	psia	NI	>1100	NI	NI	NI	>1300	>1300
Average Permeability, ($\bar{K}$)	md	NI	NI	>5	NI	NC	NI	NI
Depth (D)	ft	>2300	NI	>2000	(b)	≥2000	NI	NI
Zone Thickness (h)	ft	NC	NI	NC	NI	NC	NI	NI
Minimum Oil Content at Start of Process (Sor)	$\frac{\text{bbl}}{\text{acre-ft}}$	NC	>25%	>25%	NI	NI	NC	NC
Rock Type		Sandstone or Carbonate	NI	NI	NI	NC	NI	NI

(a) The abbreviations refer to the individuals or organizations who present these screening criteria. The numbers in parentheses correspond to references at the end of the section which denote these sources by their full names.

(b) Depth is correlated to miscibility pressure:
 <27° API, ≤7200
 27-30° API, >5500
 ≥30° API, ≥2500

The technology of CO₂ miscible flooding, while not as advanced as that of the thermal methods, is being improved. At least two CO₂ miscible projects are underway at the commercial level; several pilot tests are also being planned to evaluate the process efficiency in different reservoir types (see Appendix B for a listing of ongoing CO₂ and hydrocarbon miscible projects).⁽¹⁾ The largest CO₂ injection project is the Sacroc unit in west Texas, operated by Chevron. The project covers 50,000 acres and produces 35,000 barrels of oil per day.⁽²⁰⁾ Chevron estimates ultimate incremental oil recovery at 280,000,000 bbl.⁽¹⁶⁾

As shown in Figure 5.4, the most promising candidate fields for CO₂ miscible recovery are located in Texas, Louisiana, Mississippi and California. The estimated potential of these fields is described in Table 5.5. Much of the success of CO₂ miscible flooding will depend on the availability of inexpensive CO₂ supplies.

5.4 ECONOMICS

Much of the cost of miscible recovery processes is in field development, well workover and equipment expenditures. However, the major cost components are those of injection materials and compression costs. In this report, only the economics of the CO₂ miscible process will be considered. The cost of propane and other hydrocarbon gases is quite high, with prices of \$10 per barrel not uncommon; the value of these materials further increases with that of crude oil. The addition of transportation and other project costs are expected to result in an extremely high process cost,⁽⁵⁾ severely limiting the future use of hydrocarbon miscible recovery methods.

In CO₂ miscible recovery, a minimum materials requirement is one barrel of CO₂ for every barrel of recovered oil, both at reservoir conditions. Higher CO₂ requirements are generally expected because of carbon dioxide losses in the reservoir.⁽¹²⁾ It appears that the lowest-cost carbon dioxide would be from a natural source containing by-product natural gas, which could offset the cost of producing the CO₂; above-ground sources of CO₂ will be more expensive.⁽²⁴⁾ The major costs are incurred in the transportation of CO₂.

FIGURE 5.4 Current and Potential CO₂ Miscible Tertiary Recovery Projects
(Redrawn from Reference 25.)

TABLE 5.5 Candidate Fields for CO₂ Miscible Flooding

State No. of fields/reservoirs	Estimated potential oil recoverable by carbon dioxide miscible flooding, millions of barrels	Scf/bbl ¹	Estimated quantity of carbon dioxide required for miscible flooding, Bscf
West Texas: ^{2,3}			
40	2,038	2,660	6,139
Texas Gulf Coast:			
11	225	2,542	572
South Louisiana: ³			
18	269	3,461	931
Southwest Mississippi: ³			
4	129	2,527	326
California:			
10	322	3,963	1,197
Totals - 83	3,253	3,031 (avg.)	9,165

¹Net CO₂-injected minus recycled.

²"Full scale" project currently underway.

³Field test planned or in progress.

Source: Reference 24.

If the gas is available free of charge from the stacks of a coal gasification or other plant, compressing and transporting it over a distance of 500 miles would cost about \$1/Mscf. Natural CO₂ can be delivered to reservoirs by pipeline at lower cost, from about \$.60 to \$.90 per thousand cubic feet (Mcf) although the costs of building a pipeline must be taken into account. Manufactured CO₂ delivered by truck will cost about \$2.75 per Mcf.⁽²²⁾ An investment and cost summary for CO₂ from different sources is presented in Table 5.6.

Assuming that 6 Mscf of carbon dioxide must be injected to recover one barrel of crude oil, the project operating cost could reach \$10/bbl, including the costs of recycling CO₂ and corrosion protection measures. If CO₂ must be manufactured, recovered from stack gases, shipped 1,000 miles or used in greater quantities, the direct operating cost could jump to over \$20/bbl of oil recovered.⁽³⁾

TABLE 5.6 Investment and Cost Summary for CO₂ Supplies

Carbon dioxide source aboveground	Carbon dioxide capacity, MMscfd	Investment millions of U.S. dollars		\$/Mscf CO ₂
Ammonia plant vents	184	Transmission system .	\$134.8	\$ 1.15
Power plant flue gas	125	Recovery plant.	34.1	1.04
		Transmission system .	19.2	0.21
		Total	53.3	1.25
Natural sources:				
Case 1 (98 pct CO ₂ -2 pct CH ₄).	125	Transmission system .	62.9	0.72
Case 3 (50 pct CO ₂ -50 pct CH ₄).	125	Recovery plant.	11.4	-1.62
		Transmission system	67.9	0.87
		Total	79.3	-0.75
Case 4 (48 pct CO ₂ -50 pct CH ₄ -2 pct H ₂ S).	125	Recovery plant.	48.0	-1.19
		Transmission system .	68.3	0.89
		Total	\$116.3	\$-0.30

Source: Reference 24.

Notes: U.S. Gulf Coast location is assumed.

Investment cost 2nd quarter 1977.

All investment ± 25 percent.

Transmission systems pipelines:

Ammonia plant vents--145 mile trunkline.

Power plant--25 mile.

Natural sources--100 mile.

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6.0 CHEMICAL RECOVERY METHODS

Chemical flooding techniques are the most complex tertiary oil recovery processes and have the highest uncertainty of success; they may also have the greatest potential of achieving maximum oil recovery from depleted reservoirs.⁽¹⁾ Each of the three methods of chemical recovery--polymer, alkaline and micellar-polymer flooding--augment oil production in a different way. The discussion of chemical recovery methods necessitates the use of some specialized terminology. A brief summary of surfactants, emulsions and micellar solutions is given in Appendix C.

Polymer flooding adds high molecular weight polymers to injection water to decrease the mobility contrast between the drive water and reservoir fluids, increasing process sweep efficiency. The added polymer reduces the tendency of water to bypass crude oil and improves the oil recovery of normal waterflooding operations.⁽¹⁾ First introduced in the 1940's,⁽²⁾ polymers have been used for years to reduce water production from oil wells and for mobility control in waterflood injection wells.⁽³⁾

Alkaline flooding uses caustic chemicals such as sodium hydroxide (NaOH) or sodium silicate (NaSi) to reduce the interfacial tension between the injected fluids and the reservoir oil. These chemicals, added to injection water, form surfactants (detergent-like substances which lower the tension at the interface of the oil and water) within the reservoir by the neutralization of petroleum acids.⁽¹⁾ The first patent on the injection of caustic to improve waterflood recovery was issued in 1927; there have since been many laboratory experiments and a few field tests.⁽⁴⁾

Micellar-polymer, or surfactant, flooding combines the high displacement efficiencies of miscible recovery methods and the high sweep efficiencies of polymer injection to improve oil recovery. Although water-soluble surfactants were described as an aid to improve oil recovery in patents filed in the 1930's, the micellar-polymer process, which seems to have the highest potential for widespread future use, was not extensively investigated until the late 1960's.⁽⁵⁾

The chemical recovery methods are the least developed and most expensive of the tertiary recovery processes, requiring, more than other methods, an extensive and accurate knowledge of the reservoir structure and flow patterns to which the process is to be applied. These recovery methods are being tested in the laboratory and in field environments (especially the micellar-polymer process) although most field tests have resulted in a necessity for further lab research to improve the designs of chemical formulations.⁽¹⁾

6.1 POLYMER FLOODING

Polymer flooding improves waterflood sweep efficiencies by reducing the mobility ratio. Recall that a fluid's mobility is the permeability of the rock to that fluid, divided by fluid viscosity. The mobility ratio of a waterflood is the mobility of the injected water divided by the mobility of the crude oil; a favorable ratio is one or less. Polymers are chemicals which increase the viscosity of water and can also decrease the effective permeability of reservoir rock to water. More of the reservoir area is thus swept by the water, increasing oil recovery. Note that little change in displacement efficiency occurs, since the polymer is not miscible with the crude oil.⁽⁶⁾

Reservoirs rarely have uniform permeability characteristics, and fluid which is injected into a vertical interval of reservoir rock will seldom travel through that zone as a uniform flooding front. The fluid will preferentially traverse those areas of higher permeability, leaving oil behind in the less permeable areas. Polymer injection can redistribute the flow of injected fluids by reducing the permeability in more conductive sections to achieve a more uniform distribution profile for maximum oil recovery.⁽²⁾

Certain polymers are highly polar, and will readily adhere to water, and sandstone and limestone surfaces. Oil, being essentially nonpolar, flows relatively unimpeded through a polymerized zone. Lab tests show that although polymers do reduce oil permeability up to 10%, they reduce water flow by as much as 90%.⁽⁷⁾

6.1.1 Polymers

A polymer is a large chain molecule formed by thousands of repeating blocks called monomers. Polymers have long been used in the oil industry for drilling and fracturing fluids and water blocking agents. They are also used in the manufacture of paint and polishes. Polysaccharide biopolymers and partially hydrolyzed polyacrylamides are the polymers most commonly used in polymer flooding operations.

Polysaccharides are the remains of a protective coating or shell grown by a microorganism. The polysaccharide is recovered by treating a culture of the microorganisms with isopropyl alcohol, followed by washing and drying.

Polyacrylamides are synthetically produced by the combination of carbon, hydrogen and oxygen into basic monomer units, which are polymerized to form a long chain molecule.⁽⁶⁾ Currently available commercial polyacrylamides are provided in dry, powdered form or concentrated in a water-and-oil emulsion. The dry polymer must be dissolved at the wellsite. The emulsion polymers dissolve uniformly and easily in water and are easier to control; however, they are usually more expensive.⁽³⁾ The extent of hydrolyzation (a process which changes some of the amide monomer groups to carboxylate groups) that a polymer undergoes determines the chemical effect on fluid viscosity.⁽⁶⁾ Nonionic polyacrylamides usually have low degrees of hydrolysis and are compatible with a wide variety of brines. An anionic polyacrylamide, however, having a high degree of hydrolysis, will be compatible only with fresh-water or soft-water brines.⁽³⁾

6.1.2 Operation

In a polymer flooding operation, a slug of polymer solution is injected into the reservoir, followed by drive water. Most polymer floods use about a 20% pore volume slug, or concentrations between 250 and 1500 ppm.⁽⁶⁾ A field test in Campbell County, Wyoming, in the Minnelusa geologic formation, has a projected recovery of between 3 and 5 bbl of additional oil per pound of injected anionic acrylamide. In one of the four patterns included in the testing area, 1,200,000 lb of anionic polymer were required for injection with a projected oil recovery of 3 bbl/lb.⁽⁸⁾

Polymers are non-toxic and non-corrosive.⁽⁶⁾ In most waterflood projects, the conversion to a polymer flood requires minimal capital expenditures, the principal additions being the polymer mixing and filtering equipment.⁽⁹⁾ The use of polymers reduces the producing water-oil ratios, so that more oil is produced while handling less water, reducing operating costs significantly.⁽⁶⁾

Polyacrylamides should be mixed in fresh water since the magnitude of mobility ratio improvement achievable with these chemicals decreases with water salinity and divalent ion concentration. Polyacrylamides are also adversely affected by shearing, which may reduce the ability to decrease the permeability of the formation to water.⁽¹⁾ Special care must be taken to reduce excessive shear in surface pumps, valves and wellhead equipment; high flow rates, particularly through perforations, should be avoided.⁽⁶⁾

Polysaccharides are less sensitive to water salinity and less likely to shear during injection. However, these polymers may need to be filtered through micron-sized filters to prevent well plugging, and will normally require bactericides since they are also susceptible to bacterial attack. Polysaccharides are currently more expensive per pound than polyacrylamides, and have been less extensively tested.⁽¹⁾

At the beginning of 1976, 14 polymer field tests were in progress, although results regarding process profitability were mixed. The incremental ultimate oil recovery achievable by polymer flooding is expected to be modest.⁽¹⁾ A much more prevalent use of polymers will most likely be in combination with micellar solutions. Current polymer flooding projects are listed in Appendix D.

6.2 ALKALINE FLOODING

The mechanisms by which alkaline, or caustic flooding improves oil recovery include entrainment, which reduces interfacial tension, entrapment, which improves sweep efficiency, and wettability reversal, which improves mobility ratios. Each of these mechanisms requires somewhat different initial conditions with respect to reservoir oil, rock and injection water properties, and may or may not be included in any one caustic flooding project.⁽⁴⁾

Entrainment and entrapment mechanisms form surfactant emulsions in situ by reactions between the acids in reservoir oil and the injected alkaline chemicals. Since the lower API gravity crude oils seem to have a higher content of natural petroleum acids, alkaline flooding processes seem almost exclusively relegated to the recovery of moderately viscous, low API gravity crude oils.⁽¹⁾ The number of naturally occurring emulsifiers^(a) in a single crude oil may range into the hundreds or higher. The surfactants which are created at the crude oil-water interface reduce interfacial tension and form an emulsion^(b) of the reservoir oil. This emulsion lowers the mobility of the injected water and improves process sweep efficiency.⁽¹⁰⁾

In the entrainment mechanism, oil droplets are suspended or entrained in the alkaline drive water by the formation of an emulsion. As the continuously flowing alkaline-water phase nears the producing well, the entrained oil is produced. However, it is difficult to maintain low interfacial tension while moving the alkaline mixture through reservoir rock, since much of the caustic is lost by reactions with the reservoir rock.⁽¹¹⁾ Nearly all reservoir rocks will tend to react with and neutralize sodium hydroxide to some extent. Limestone and dolomite rocks are fairly unreactive, and the reaction of the caustic with the silica component in sandstone is too slow and incomplete to present much of a problem. The clay component of reservoir rocks, however, has a significantly rapid and complete reaction with the caustic.⁽¹⁰⁾ Sufficient caustic must be injected to compensate for losses through chemical reactions (one of which is the ion exchange between the Ca^{++} and Mg^{++} of clay minerals and the Na^+ of the caustic solution).⁽¹¹⁾

Entrapment mechanisms are designed to improve process sweep efficiency. Residual oil is emulsified in the reservoir and begins to move toward the producing well with the alkaline drive water. On the way, the emulsion is

(a) Emulsifiers are primarily oil soluble carboxylic acids that are converted to sodium soap in contact with caustic solution.

(b) An emulsion is formed by the suspension of a very finely divided oily or resinous liquid in another liquid.

trapped in pore capillary restrictions which are too small for the oil emulsion droplets to penetrate, diverting the flow of alkaline water to other open flow channels. This process results in a reduced water mobility that improves both vertical and areal sweep efficiency, and is especially important in waterflooding viscous oils, where waterflood sweep efficiency is usually very poor. Although the emulsified trapped oil is not recovered, and no significant reduction in the capillary-retained residual oil saturation is achieved, the process is useful because in heterogeneous reservoirs of heavy oils where sweep efficiency is very poor, an improvement in vertical and areal sweep efficiency through an improved mobility ratio can be much more important economically than recovery of residual oil from the small volume of the reservoir normally swept.⁽⁴⁾

The third mechanism of improved recovery by caustic flooding is wettability reversal. Reservoir wettability depends on the extent to which naturally occurring polar compounds are present in crude oil. These polar compounds adsorb on hydrophilic (water-attracting) mineral surfaces, making them less hydrophilic or even hydrophobic (water-repelling).⁽¹²⁾ The changes in wettability are caused by adsorption of soap molecules (which were formed by interfacial reaction) onto the solid surface.⁽¹³⁾ Sandstone wettability is affected by a variety of compounds associated with the higher molecular weight fractions of crude oil; limestone wettability is affected mostly by basic nitrogen compounds.⁽¹²⁾ On water-wet reservoir rock surfaces, the residual oil is present in immobile and discontinuous droplets. In an oil-wet porous medium, the residual oil is present as a film on the rock, with droplets of reservoir water held immobile. A reversal from oil-wet to water-wet in a region where oil is still flowing changes the relative oil and water permeability and provides a more favorable mobility ratio, improving oil recovery. In converting from water-wet to oil-wet rock, a discontinuous residual oil is converted to a continuous wetting phase, providing a flow path for what would otherwise be trapped oil.⁽⁴⁾

The efficiency of the alkaline flooding process will depend on the chemistry of the reservoir oil and water, the physics and chemistry of the reservoir rock and specific flooding conditions such as rate of injection and temperature.⁽¹⁴⁾

6.2.1 Operation

Alkaline flooding processes are still in a testing state. The amount and concentration of caustic injected appear to vary depending on the recovery mechanism to be used. Concentrations are generally lowest for the emulsification (entrapment and entrainment) mechanisms, from about 0.001 to 0.500 weight percent. Higher concentrations ranging from about 0.500 to 3.0 or even as high as 15.0 weight percent, are usually required for wettability reversal. A slug of caustic is nearly as effective as continuous injection of the chemical, although the volume injected must be large enough to combat losses from rock reaction.⁽¹³⁾

Laboratory experiments have shown that the success of caustic flooding is highly dependent on the chemical and physical properties of the reservoir materials. The composition of the crude oil itself is important, since it is the nature of the polar compounds in the oil that determine whether caustic can improve recovery.⁽¹³⁾ Reaction of alkali with different acidic compounds will generate surfactants of different degrees of effectiveness; some alter wettability, while others cause changes in surface films or promote low-tension displacement. The relationship between crude oil composition and the mechanisms of oil recovery has not yet been determined, although it is known that the occurrence of different recovery mechanisms are related to the presence of general classes of chemical compounds (asphaltenes, acids, etc.).⁽¹²⁾

Chemical composition of both reservoir and injection water is also important. Factors such as pH and salinity can change the soap distribution between the oil and water phase and its properties at the interface, affecting flooding results. The concentration of polyvalent ions, such as calcium and magnesium, must also be controlled, since these ions will react with organic acids to form less surface-active soaps. Rock properties are another factor in caustic flooding, since reaction with the rock consumes caustic.⁽¹³⁾

Field experience for alkaline flooding has been limited, although there are some field tests ongoing (see Appendix D). Because the potential for

this process seems to be greatest for recovering high viscosity crude oils, polymer flooding or thermal methods might be considered as alternative recovery techniques, depending on reservoir conditions.⁽¹⁾

6.3 MICELLAR-POLYMER FLOODING

The typical micellar-polymer process has four basic stages of fluid injection (see Figure 6.1). The first injection, a brine preflush, adjusts the salinity of the waterflooded reservoir to provide maximum compatibility with the micellar solution. This slug primarily serves to reduce concentrations of divalent ions in the reservoir fluids which might cause the solution to adsorb to rock surfaces.⁽¹⁵⁾ However, the preflush is also useful in obtaining final information on reservoir flow characteristics, and as a means of applying chemicals to control bacterial action, which may be required for polysaccharides.⁽¹⁶⁾ The preflush also tends to inactivate clays by removing bound water and can, in some cases, increase the volume of the reservoir ultimately contacted by the chemical slugs which follow.⁽¹⁷⁾

The micellar solution is the second chemical slug injected. The chemicals in the solution cause the reservoir oil and water to become miscible by lowering the interfacial tension. The process has a high displacement efficiency; essentially all of the contacted oil is recoverable.⁽¹⁵⁾

To allow the micellar chemicals to contact a maximum amount of reservoir oil, a third fluid, consisting of polymer chemicals in water, is injected.⁽¹⁶⁾ The polymer solution contains either polyacrylamide or polysaccharide and operates in the same way as the previously-described polymer flooding process. In the micellar-polymer process, mobility control must be maintained between the micellar slug and the oil-water bank as well as between the mobility buffer and the micellar slug. The former is maintained by adjusting the viscosity of the micellar slug in the original solution design. The latter is achieved by polymer solutions, which move through a reservoir more uniformly than would water alone.⁽¹⁸⁾ The concentration of polymer in solution (and thus, buffer viscosity) is gradually decreased as injection proceeds, resulting in

FIGURE 6.1 Schematic of a Micellar-Polymer Flooding Process

high viscosity fluids near the micellar slug and low viscosity next to the drive water. This graduated bank is less costly than a uniform concentration and yields a more favorable mobility ratio between the drive water and the polymer bank.⁽¹⁹⁾

Since the micellar slug represents a significant cost, every effort is made to reduce the slug size while maintaining its chemical integrity. With adequate mobility control behind the slug, the pore volume of micellar solutions may be minimized. The mobility buffer also protects the micellar slug from water invasion.

Reservoir crude oil and water are displaced ahead of the micellar slug, forming a stabilized oil and water bank.^(a) The movement of the slug through the reservoir is stabilized by the mobility buffer. A water drive is the final injection stage, pushing the micellar slug and mobility buffer through the desired reservoir zone to producing wells.⁽²⁰⁾

The combination of a micellar fluid followed by polymer buffer seems to be an ideal displacing fluid. It provides the high unit displacement and oil recovery of miscible floods, while allowing an optimal and highly efficient, areal sweep.⁽¹⁹⁾

The efficiency of micellar-polymer flooding is dependent upon a number of complex factors. Among the most important variables are the amount of oil which will actually be contacted by the surfactant and how evenly the mobility buffer pushes the preceding fluids through the reservoir.⁽¹⁶⁾ Other factors affecting process efficiency include the extent of surfactant adsorption and retention in reservoir rock, deterioration of the micellar slug as a result of aging or excessive formation salinity and nonhomogeneity of the reservoir rock, all resulting in poor sweep efficiencies.⁽¹⁵⁾ Although laboratory work is yielding knowledge regarding process principles, there are still no models to reliably predict the performance of the recovery technique in various reservoirs.⁽¹⁶⁾

(a) Since the bank saturations are independent of original oil and water saturations, the process could also be easily applied to a secondary recovery operation, in which oil would be produced first.

At the beginning of 1976, 14 active field pilot tests in micellar-polymer flooding were underway; 11 projects were tentatively scheduled for a FY 1977 start-up. Ongoing micellar-polymer projects are listed in Appendix D. The data generated from these tests will help to evaluate the technical and economic feasibility of the process in the field.⁽¹⁵⁾

6.3.1 Micellar Solutions

The three basic components of a micellar solution are hydrocarbon, surfactant and water. Alcohol is often added as a co-surfactant, enabling the micelles to solubilize greater quantities of water or oil and stabilizing the solution.⁽²⁰⁾ The co-surfactant also helps reduce adsorption of the surfactant to the reservoir rock. An electrolyte, a salt such as sodium chloride or ammonium sulfate, is also often added to the micellar solution to help adjust viscosity, which is an important factor in attaining good mobility control.⁽¹⁹⁾

The compositional design of the micellar slug is heavily dependent on particular reservoir properties. Compatibility with crude oil, reservoir brine and the mobility buffer must be considered, as these are the fluids which the slug will contact. Although it is less expensive to use water as the surfactant carrier base, water-external systems have mobilities which are different from that of the mobilized oil bank and may cause possible difficulties in mobility control. Water external systems also lack the saline resistance to reservoir brine which oil external systems have, and often must have hydrocarbon derivatives added to improve compatibility.⁽²¹⁾ Table 6.1 lists the general composition of various micellar solutions.

TABLE 6.1 Typical Range of Micellar Solution Compositions

Component	Overall Range ^(a)	VOLUME PERCENT		
		Low Water Oil External ^(b)	High Water Oil External ^(b)	High Water Water External ^(b)
Surfactant	4-10	> 5	> 4	> 4
Hydrocarbon	4-80	35-80	4-40	2-50
Water	10-92	10-55	55-90	40-95
Cosurfactant	4	> 4	0.01-20	0.01-20
Electrolyte ^(c)	1	-5	0.001-4	0.001-4

(a) Reference 63.

(b) Reference 16.

(c) Weight percent based on water.

There are two injection schemes currently being used for micellar solutions. One method involves the injection into the reservoir of a solution containing a low concentration of surfactant. This requires the injection of large pore volumes of solution (15-60%) to reduce the interfacial tension between oil and water. Residual oil saturation at a given point in the reservoir will approach zero only after large volumes of surfactant solution have traversed the reservoir.

A second process injects a relatively small pore volume (3-20%) of a higher concentration surfactant solution into the reservoir. The high concentration surfactant solutions displace the contacted oil much more rapidly; as the slug moves through the reservoir and is diluted by formation fluids, the process reverts to a low concentration flood.

For any particular crude oil, a suitable micellar solution can only be found by empirically testing a large number of different mixtures. Independent research by various oil companies has resulted in a variety of surfactant processes. All of these procedures differ as to the size and surfactant concentration of the slug to be injected, whether the slug should contain a

co-surfactant and even whether the slug should be an oil-external or water-external phase. At present, there is no fundamental way to determine whether one of the processes is inherently superior to the others or whether some modified process might be even better.⁽²¹⁾

Ongoing laboratory and field research is attempting to determine which is the best injection method. At present, however, each company has its own, often proprietary, process. Much more research is needed to determine optimum injection schemes.⁽⁵⁾

6.3.2 Operation

The operation of a micellar-polymer flooding process is little different from that of a waterflood, except for the addition of mixing and filtering equipment.⁽¹⁹⁾ Storage tanks for the brine, fresh water and micellar-fluid concentrates are required, as well as proportioning pumps for mixing the micellar fluid.⁽⁹⁾ Some of the components of the micellar solution will require special handling. Petroleum sulfonate, for example, is very viscous and must be heated before use. A project operator at Phillip's Petroleum North Burbank unit transferred sulfonate from rail cars to a storage tank to heat the sulfonate to 160°F, although at another project in Long Beach, CA, the sulfonate will be heated while it is still in the rail cars.⁽²²⁾

Monitoring equipment is necessary to determine the salinity of the micellar solution⁽⁹⁾ and for overall quality control. All of the fluids injected into the reservoir are subjected to continual testing to ensure that only specification materials are injected.⁽²²⁾

Blenders or mixers are necessary to form the polymer solution. Filters will be required if polysaccharides are used; oxygen scavengers will be necessary if polyacrylamides are used, since the oxygen can severely degrade the quality of the solution.⁽⁹⁾

The material of the injection pipelines must be compatible with the injected chemicals. Problems of iron contamination may arise if the chemical slugs are exposed to mild steel. The use of stainless steel alloys or internally-coated mild steel pipe may resolve the problem.⁽²²⁾

The adsorption of surfactants onto reservoir rock is a major operational problem, although preflushing appears to reduce surfactant loss.⁽⁵⁾ The extent to which adsorption occurs seems to depend on the surfactant molecular weight and structure and on the electrical state of the mineral surface. Surfactant adsorption can be reduced by making the surfactant more water soluble, although this also lowers interfacial activity and decreases the oil displacement efficiency. A sacrificial agent may also be used in the preflush to cover the surface of the reservoir rock, blocking the adsorption of nonionic surfactants on mineral oxide. Changes in reservoir pH characteristics may be effective solutions for anionic surfactants.⁽²¹⁾

Recent study has pointed to the aging of surfactants as another possible problem for chemical recovery processes. Aqueous solutions of petroleum sulfonate seem to change with time; the aging of the surfactants seems to affect their efficiency. The aging states develop slowly and may not be of much importance in a pilot test lasting only a few weeks. They could, however, be significant in the time frame over which a tertiary oil recovery project is conducted.⁽²³⁾ The impact of this phenomena is not well understood and further research is needed to identify its actual importance.

The combination of petroleum sulfonate and polymer in the producing wells aggravates the production of hard-to-handle crude oil emulsions, although this problem can be mitigated by increasing the brine or salt content of the water, or by the use of chemicals and heat.⁽²⁴⁾ The disposal of produced water is another problem encountered in tertiary oil recovery. When micellar flooding follows a depleted waterflood, only water is produced for 1/2 to 2 years, depending upon the residual oil saturation and pattern size. If the water is not of sufficient quality for use in mixing the micellar and polymer solutions, it must be disposed of on the surface or in another well.⁽¹⁹⁾ Surface disposal will require substantial salt removal.⁽²¹⁾ In some field projects, produced water is separated, clarified, metered and disposed of in the existing waste-water system.⁽²²⁾

6.3.3 Injection Materials Supply

A major limitation on the potential of micellar-polymer flooding (and other chemical processes) is the available supply of required chemicals. For every barrel of incremental oil recovered, it is estimated that at least 10 pounds of sulfonates, 3 pounds of alcohol and one pound of polymer will be required.⁽²⁴⁾ The current industrial capacity to manufacture sulfonates is estimated to be between 500-700 million lb/yr; current production is about 300 million lb/yr. The current supply capabilities for alcohol (2 billion lb/yr of isopropyl alcohol) are sufficient for gradual escalation of a test program; however, to meet the demand which might be presented by commercial-scale fields, new construction would be required.⁽²⁵⁾ Current production of polysaccharides and polyacrylamides is estimated at about 30 million lb/yr.⁽¹⁵⁾ The percentage expansion required for polymer production, should micellar flooding be promoted on a wide scale, is much larger than that required for alcohol or sulfonate production.⁽²⁵⁾

The potential chemical supply constraints for micellar-polymer flooding have been described as being economic rather than technological in nature. It is felt that price increases in the basic chemical inputs will serve to provide the necessary supply.⁽¹⁵⁾

Water supplies are also very important in micellar-polymer and chemical flooding processes, being used in all phases of oil recovery. Large volumes of water are used in preflushing, in the formation of micellar and polymer solutions and in the follow-up water drive. The water used must be relatively high quality; reservoir water, which usually has high ion concentrations, cannot generally be used. A micellar-polymer project could require as much as 19 bbl of water per bbl of oil produced, of which at least 14 barrels must be of acceptably high quality.⁽¹⁶⁾ The application of chemical recovery processes may thus conceivably be limited in areas of the country which are experiencing scarcities in freshwater supplies.

6.4 RESERVOIR APPLICABILITY

Chemical recovery techniques are the least developed of the tertiary recovery methods and field experience with these techniques has been comparatively limited. The commercial feasibility of chemical recovery methods is as yet unproven despite extensive laboratory work. Screening criteria for chemical recovery schemes are shown in Table 6.2.

Polymer flooding has its greatest potential in reservoirs containing viscous oils or where the mobility ratio for ordinary waterflooding is unfavorable.⁽¹⁾ Since the injectivity of the viscous polymer solution is lower than that of water, the reservoir must have good permeability. If the permeability is too low or the crude viscosity too high, an economical injection rate cannot be attained.⁽⁶⁾

The polymer to be used must be screened for efficiency for each reservoir. The best polymer to use is that which gives optimum mobility control with minimum adsorption for any particular reservoir rock.⁽¹¹⁾ The adsorption of polyacrylamides is greatest on clays, although it varies with the type of clay, water and polymer used. Adsorption is much lower on sand or carbonate rock. Anionic polyacrylamides are more effective on carbonates than on sands; nonionic and anionic polyacrylamides are equally effective on sands.⁽³⁾ Polymer flooding will probably be most widely used as a mobility buffer in micellar-polymer flooding.

Alkaline flooding involves the in situ generation of surfactants by the reactions of injected bases with crude oil acids. Alkaline flooding can be used to improve flood sweep efficiency, displace residual oil, or reverse the wettability of the reservoir rock to increase oil recovery. This versatility suggests a significant potential for future field application.⁽⁴⁾

The alkaline flooding process can be considered primarily in reservoirs whose crude oil contains organic acids.⁽¹³⁾ The effectiveness of the process usually improves as the acid content of the crude increases (this generally occurs as the API gravity of the oil decreases). Reservoirs with low-salinity water, a low divalent cation content and a low clay content are preferred for the application of alkaline flooding.⁽¹⁾ Most of the acidic

TABLE 6.2 Reservoir Screening Criteria for Chemical Recovery Methods^(a)

NI=Not Included NC=Not Critical		Micellar - Polymer Flooding					Polymer Flooding		Alkaline Flooding	
Screening Parameters	Units	NPC ⁽¹⁾	GEFFEN ⁽²⁶⁾	ERDA ⁽²¹⁾	OTA ⁽²⁷⁾	GURC ⁽²⁸⁾	NPC	OTA	GURC	NPC
Oil Gravity	°API	≥25	VI	20-35	NI	≥25	NI	NC	≥18	≤35
Oil Viscosity, (μ)	cp	≤30	<10	<20	≤10 ^(b)	NI	≤200	≤200	NI	≤200
Reservoir Temperature	°F	≤250	≤200	<175	≤120 ^(c)	≤175	≤200	≤120 ^(c)	≤200	≤200
Average Permeability, (K)	md	≥20	>20-50	>10	≥20	≥20	≥20	≥20	≥20	≥20
Depth (D)	ft	NC	NI	NI	NI	NC	NI	NI	NC	NI
Zone Thickness (h)	ft	NC	NC	>10	NI	NC	NI	NI	NC	NI
Salinity of Formation Brine (TDS)	ppm	≤200,000	NI	<50,000	≤200,000	NI	NI	NC	NI	NI
Minimum Oil Content at Start of Process (Sor)	bbl acre-ft	NI	>25%	>30%	NI	NI	NI	NI	NI	NI
Rock Type		Sandstone		Sandstone	Sandstone	Sandstone	NC	NC	NI	Sandstone

(a) The abbreviations refer to the individuals or organizations who present these screening criteria. The numbers in parentheses correspond to references at the end of the section which denote these sources by their full names.

(b) This constraint is projected to decrease as technology improves:
1976: ≤10; 1980: ≤20; 1995: ≤30.⁽²⁷⁾

(c) This constraint is projected to decrease as technology improves:
1976: ≤120; 1980: ≤170; 1985: ≤200; 1990: ≤225; 1995: ≤250.⁽²⁷⁾

crudes appear to be concentrated in California and in the Gulf Coast area of Texas and Louisiana. Although the percentage of reservoirs containing high acid number crude oils is not particularly great, the actual number of barrels of oil that may be recoverable by alkaline flooding is significant.⁽¹³⁾

Micellar-polymer flooding will probably have its greatest application in reservoirs which have been successfully waterflooded, although it can also be used as a secondary recovery method. The process is mostly applicable to sandstone reservoirs, with only limited use projected in carbonate reservoirs or where reservoir brines contain excessive calcium or magnesium ions and surfactant adsorption is high. Further research may extend the use of the process to more reservoirs as optimum recovery chemicals and compositions are determined.⁽¹⁹⁾ Temperature and reservoir salinity are currently the greatest limiting factors to the successful application of micellar flooding. Most field tests have been limited to temperatures of 170°F and salinity ranges of from 2,400 to 160,000 parts per million (ppm) total dissolved solids. Future research is aimed at increasing these limits to about 250°F and 200,000 ppm or more by 1995.

The process should be feasible over a fairly wide range of reservoir permeabilities⁽¹⁾ and is best applied to reservoirs with medium-gravity crude oils. A low-gravity, high-viscosity crude would necessitate increases in the viscosity of the micellar and polymer slugs to maintain a favorable mobility ratio, and result in higher costs.⁽¹⁹⁾ The most successful micellar-polymer test floods to date have been conducted in low-temperature, low-salinity, sandstone reservoirs with a moderate-to-high permeability and containing relatively low-viscosity crude oils.⁽¹⁾ The geographic location of current and potential micellar-polymer projects is portrayed in Figure 6.2.

Industry and government activities indicate an increased interest in the field testing of micellar-polymer recovery processes. Responses from 16 companies to a questionnaire in December 1974 showed 10 active and 9 planned tests of these recovery methods. The U.S. Energy Research and Development Administration (ERDA) has also contracted several companies to perform field testing of the process. However, in all of the chemical recovery techniques,

FIGURE 6.2 Current and Potential Micellar-Polymer Flooding Projects
(Redrawn from Reference 16.)

caution must be used in extrapolating recovery factors from small-scale tests to field-wide projects. Changes in reservoir characteristics, well spacing, fluid properties, etc., may dramatically affect the performance of large projects.⁽⁵⁾

Chemical flooding methods are far from well developed and require a great deal more testing and research. However, they do have a potential for improving the efficiency of oil recovery operations.

6.5 ECONOMICS

Economic projections for chemical recovery methods are difficult to make, since industry has had little experience with large-scale commercial field projects.⁽⁵⁾ However, laboratory experiments and pilot projects indicate that the major cost items for these processes are the chemicals.

Polymer flooding uses polymer concentrations of between 250 and 1500 ppm, at polymer costs of from \$1.65 to \$2.50 per pound. A 1000 ppm polymer solution contains 0.35 pounds of polymer per barrel, costing 70¢/bbl (using \$2/lb polymer). There are also costs of mixing the solution and handling produced water. An example of equipment costs for polymer mixing and feed is shown in Table 6.3. The costs are either for a 700-lb/day unit or the largest size available from the manufacturer.⁽⁸⁾

The economics of polymer flooding are fairly good. A comparison of conventional waterflood economics with a polymer flood is shown in Table 6.4. At 1975 crude oil and polyacrylamide prices, the polymer flood has a present-worth value of \$450,000 more than that of the conventional flood. However, studies of a polymer project in Kansas show that the present-worth values attributed to polymer recovery are far more sensitive to crude-oil price changes than to increases in chemical expense or development costs.⁽²⁹⁾

Caustic flooding is the lowest-cost chemical recovery method, using relatively low concentrations of inexpensive chemicals. Basically an improved waterflooding technique, it has comparatively low initial costs and investments, since little new equipment is required.⁽⁴⁾

TABLE 6.3. Commercially Available Polymer Feed Units

Number of Manufacturers	Type of Wetting System	Maximum Rated Capacity for Polyacrylamide	Approximate List Price June, 1977	Cost Per Daily Pound of Throughput
1	Rotating drum	200 lb/day	\$12,000	\$60
1	Wetting plane	700 lb/day	\$11,500	\$16
2	Wetting cone	700 lb/day	\$18,000	\$26
2	Spray chamber	100 lb/day	\$ 7,500	\$75
1	Eductor	700 lb/day	\$ 8,500	\$12

Source: Reference 8.

TABLE 6.4 Effects of Chemical and Crude Prices on Project Profitability

Recovery method	Crude price \$/bbl	Chemical cost, \$/lb	Present worth @ 15%, \$
Polymer flood	10.70	1.98	3,950,000
Polymer flood	10.70	3.96	3,820,000
Conventional waterflood	10.70		3,500,000
Polymer flood	5.48	1.98	1,700,000

Source: Reference 29.

Micellar-polymer flooding is presently the most expensive of the tertiary recovery techniques. Micellar solutions cost from \$8 to \$15/bbl and tend to rise with the price of crude oil.⁽¹⁹⁾ Large-scale applications of the process will require large volumes of sulfonates and polymers. Current industrial capacity is not sufficient to provide all the chemical needs that a significant expansion would require. The development of additional manufacturing facilities by oil companies may provide part of the future chemical supply, although shortages of qualified technical personnel may prevent this solution.

The economics of micellar flooding depend on the amount of oil available for recovery and the efficiency of the process.⁽⁵⁾ However, it must be recognized that micellar-polymer flooding techniques are still in the developmental stages. Both the species of chemicals used and the amounts required may change significantly in the future,⁽²⁵⁾ impacting the economics of the process.

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7.0 ENVIRONMENTAL IMPACTS

In developing the new technology of tertiary recovery techniques, it is important to be aware of the potential environmental problems. By the time an enhanced oil recovery project is undertaken, a great deal is usually known about reservoir structure and subsurface conditions. The high reservoir pressures which cause "blow-outs" in exploratory wells have been reduced by primary and secondary operations, essentially eliminating this risk for tertiary recovery operations. Federal regulations, such as the amendments to the Clean Air Act and the Safe Drinking Water Act, ensure protection of the environment, although they may also hamper oil recovery operations. State laws regarding well abandonment and underground fluid injection also serve to protect the environment.

The expense of tertiary recovery methods mitigates many environmental risks. Operators are very careful to maintain control over expensive injection chemicals; well failure and resulting leakage or loss of these chemicals can result in substantial economic losses. Since the front-end investment in tertiary recovery projects is large and the returns often marginal, efforts are made to minimize foreseeable fluid losses and thus, associated risks to the subsurface environment.⁽¹⁾

Each of the tertiary recovery methods has impacts on both air and water quality. Potentially serious problems are air quality impacts resulting from heat generation in thermal methods and water quality impacts of accidental chemical spills in the application of chemical methods. The fresh water requirements of all of the tertiary processes may also create water shortages in certain regions of the country if enhanced oil recovery is implemented on a large scale.

7.1 AIR QUALITY IMPACTS

Direct impacts on air quality primarily stem from the combustion products which emanate from heat generation in thermal recovery processes and possible emissions of hydrogen sulfide contaminants which may be present in CO₂ gases. Indirect impacts may result from the manufacture and transport of the chemicals required for other processes.

7.1.1 Thermal Recovery Methods

The major environmental impact of steam injection and in situ combustion processes is on air quality. Air pollutant emissions from cyclic steaming or steam drive processes emanate from the boilers required to generate the steam. Actual emissions depend on the size of the recovery project, the oil recovery efficiency of the process and the heat losses which occur. Boilers may be fueled with natural gas or fuel oils, although generally the crude oil from the project lease is used. Generator emissions include sulfur dioxide (SO₂), oxides of nitrogen (NO_x), hydrocarbons, carbon monoxide (CO), carbon dioxide (CO₂), particulates and other combustion products. Hydrocarbons, hydrogen sulfide (H₂S) and other emissions may escape from production wells, although these are products of primary and secondary oil production processes as well.

Commercial-scale steam generation operations in the San Joaquin Valley in California generally require one barrel of oil as boiler fuel for every three barrels of oil recovered. Table 7.1 reflects estimated emission factors from steam generators in pounds of pollutant emitted per 1000 barrels of oil produced. Coal has been considered as a less expensive substitute fuel for steam generation. However, the use of coal could cause higher emissions in every pollutant category.⁽²⁾ It must also be noted that emissions will vary with the content of sulfur and other compounds in the crude oil used as fuel.⁽¹⁾ The actual emissions from the type of crude used in different geographic areas should be determined to help evaluate the severity of local environmental impacts. Some states do not even allow the use of oil as a fuel if it contains greater than 0.5 weight percent sulfur, although areas of heavy oil production are generally permitted the use of high sulfur fuel (2.0% or greater).⁽³⁾

TABLE 7.1 Steam Generator Emissions

	<u>Pollutants Emitted/1000 Barrels of Gross Oil Produced, lb</u>
Hydrocarbons	40
SO ₂ [*]	4000
NO _x	800
Particulates	280

*For crude containing 2% sulfur, without flue gas desulfurization

NOTE: This table assumes that 0.3 barrel of fuel oil is burned for every 1.0 barrel of gross production.

Source: Reference 2.

To estimate the overall air pollution impact of a steamflood project, a probable density of generators and a required level of steam generation for a given well production rate must be considered. Take, for example, the Wilmington oil field in California, which produced 37 million barrels of crude oil in 1973 by primary production. Reservoir and crude oil characteristics of the field fulfill screening criteria for steam recovery operations. The potential production of 30 million barrels per year by steamflooding from this field would involve the combustion of some 9 million barrels per year of fuel in the field steam generators. Using the emission factors of Table 7.1, this combustion rate corresponds to the air pollutant emission rates given in Table 7.2

TABLE 7.2 Projected Emissions from Steamflooding of a Major Oil Field Compared to Los Angeles County Emissions

<u>Pollutant</u>	<u>Emissions from a 30 million bbl/yr field, ton/day</u>	<u>Los Angeles County Total, ton/day</u>
NO _x	32	1000
Particulates	12	120
SO ₂	81*	300
Hydrocarbons	2	1000

*An oil sulfur content of 2% was assumed

Source: Reference 2.

The current total air emissions for Los Angeles County are also shown in Table 7.2; enhanced oil recovery emissions of particulates and SO_2 would be a significant fraction of this total. Even with measures to reduce SO_2 emissions, such as exhaust gas scrubbing, consumption of low-sulfur fuel and reduced scales of operation, emissions will still be significant on a local scale, since they are being released into a heavily polluted area.⁽²⁾

The steam generators used in thermal oil recovery are not required to meet New Source Performance Standards. The largest oil field steam generator is 240 million Btu/hr; slightly less than the minimum size (250 million Btu/hr) regulated by the national standards.⁽¹⁾ However, these sources are subject to emission offset policies delineated in the Significant Deterioration Clause of the Clean Air Act. A policy regarding these movable generators and the rules to which they will be subjected needs to be formulated. At present, conflicting state and federal regulations, especially in California, where most large thermal projects are operating, serve only to block further development of tertiary recovery processes.

Operators of thermal recovery projects are employing means to reduce air emissions from steam injection processes. In the San Ardo oil field in California, an emission scrubbing process was used to remove SO_2 by reaction with alkaline-produced project water. The process begins by clarifying the produced water by flotation to remove suspended oil and solids, after which the clean water is sent through the emission scrubbers. From the scrubbers, water is pumped through a hydroclone for removal of fly ash; part of the water is filtered and softened for use as feedwater to the steam generators. The process has proved successful in decreasing SO_2 emissions; recycling produced water has resulted in a better use of water resources. Similar SO_2 removal facilities have been installed in 29 oil-fired steam generators in the San Ardo field.⁽⁴⁾

Produced gases from steam injection projects may also impact air quality. The gas normally consists of nitrogen, water vapor, carbon dioxide, carbon monoxide, and methane and heavier hydrocarbons.⁽⁵⁾ These gases are normally handled in closed systems, minimizing environmental problems. Hydrocarbon vapors are collected and condensed, and toxic or explosive gas concentrations are monitored to avoid occupational health hazards.⁽⁶⁾

A Kern River field project in California, operated by Getty Oil Company, employs a system which scavenges heat and hydrocarbons from the produced steam, preventing pollution around well sites. Produced gases from the well are collected, condensed and mixed with other produced fluids to be carried to a central treating station. It is estimated that the amount of heat salvaged by the system is already equal to two 50 million Btu generators and that fuel savings approach 400 bbl/day. Liquid hydrocarbon recovered from the system is a light condensate, representing the top end of the crude.⁽⁷⁾

The emissions from in situ combustion processes are highly dependent on the reservoir formation, the type of crude oil and the manner in which the project is operated.⁽²⁾ Pollutants from in situ combustion, normally consisting of CO₂, CO, nitrogen, oxygen and hydrocarbons, appear at producing wells. The reaction temperatures are generally too low to form NO_x, although some may be present in the produced gas.⁽¹⁾ It is also possible for hydrogen sulfide (H₂S) concentrations to reach toxic levels (1000 ppm) during fireflood operation.⁽⁸⁾

To date, there are very few data available regarding emissions from in situ combustion projects. It is expected that gas collection and treatment systems, such as those used in steam injection operations, will be required to meet air quality pollution control standards.⁽²⁾

Thermal recovery techniques are expected to have a major impact on air quality, particularly in areas of low inversions, low wind speeds and current pollution problems, such as California's coastal plains and central valley.⁽²⁾ Since the greatest potential for thermal recovery methods is in California, air quality concerns may severely limit the application of enhanced recovery in that state.

Major constraints to the application of thermal recovery methods are imposed by the Federal Clean Air Act and related state laws. The 1977 amendments to the Clean Air Act seek to prevent additional pollution in areas not meeting national air quality standards and to avoid deterioration of air quality in areas which do meet the standards.⁽⁹⁾

The national ambient air quality standards (NAAQS), are set by the Environmental Protection Agency (EPA). These standards are defined by permissible concentrations of carbon monoxide, photochemical oxidants, nitrogen dioxide, hydrocarbons,

sulfur oxides and particulates and are designed to protect human health and the general environment. Some states, particularly California, have established additional air quality standards which are more stringent than federal standards.⁽⁶⁾

An area which has better air quality than that defined by the national standards is designated a Prevention of Significant Deterioration (PSD) area; if air quality is worse than the national standards, the region is designated a nonattainment (NA) area. The 1977 amendments limit pollution levels to specific incremental increases for PSD areas (see Table 7.1) and require emission offset policies for NA areas, meaning that air pollutant emissions from an old source must be decreased before a new source in the same area may be approved, resulting in no overall emission increase. The amendments also require states to submit state implementation plans (SIP's) which reflect the new requirements of the law.⁽¹⁰⁾

TABLE 7.3 PSD Permitted Increments, $\mu\text{g}/\text{m}^3$ ^(a)

	<u>Class I</u>	<u>Class II</u>	<u>Class III</u>	<u>NAAQS</u>
SO ₂ Annual	2	20	40	80
24-hr	8	91	182	365
3-hr	25	512	700	1,300(s)
TSP Annual	5	19	37	7,560(s)
24-hr	10	37	75	260,150(s)

(a) All 24-hr and 3-hr values may be exceeded once per year.

(b) Total suspended particulates

(s) Indicates a secondary standard

Source: Reference 10.

Class I zones allow only extremely small emission sources; new sources with moderate emissions are allowed in Class II zones as long as the addition of these sources does not result in exceeding the allowable increment of air

quality deterioration. In Class III zones, emissions must meet national or more stringent state ambient air quality standards.⁽⁶⁾ The new amendments, which go into effect March 1, 1978, will require further project studies and more extensive review of permit applications for the installation of steam generators.

The way in which thermal recovery operations may be constrained is easily seen in California. A local pollution control board in California, under pressure from the state Air Resources Board, revoked its tentative approval of applications to install 400 steam generators in Kern County, because they would add to air emissions. These permit applications must now be resubmitted under the new law, and must be reviewed again by the Environmental Protection Agency and the state agencies. According to Chevron Oil Company, this reapplication will delay imminent projects by a minimum of two years. The new regulations require extensive air modeling and monitoring and additional emission controls on wells, steam generators and related facilities. An analysis of the effects of any project on population and industrial growth would also be required, as well as studies on climate, meteorology, terrains, soils, vegetation and visibility.⁽¹¹⁾ The use of best available control technology (BACT) would be mandated, presenting additional delays since no definition of BACT for portable steamers has even been written.⁽⁹⁾

New permits will be increasingly difficult to obtain under EPA's emission offset policy. As industries are required to upgrade air pollution control devices at existing facilities, there will be fewer sources of pollution for companies to clean up as offsets for emissions from proposed new facilities.

The problem for tertiary recovery is complicated by the well abandonment policies in effect in most oil-producing states. These statutes require oil and gas wells to be plugged within a specified time after production ceases. Although exceptions to the abandonment rule may sometimes be obtained from state regulatory agencies, some operators may not apply for these exceptions if they see no incentive for future enhanced oil recovery projects in the area. The costs of opening a plugged well are enormous, and effectively prevent any consideration of that well for future tertiary recovery.⁽⁶⁾

Stringent new review requirements, emission offset policies and well abandonment statutes have the potential for turning a two-or-three-year delay

into a cessation of field expansion of thermal tertiary recovery in California. Depending on various state regulations, the same situation could occur in other areas in which thermal recovery is implemented on a large scale. Environmental agencies, regional and local, should work with industry to develop reasonable emission control strategies which will allow the implementation of new oil recovery techniques.⁽¹²⁾

7.1.2 Miscible Recovery Methods

Carbon dioxide miscible flooding techniques may also have impacts on air quality. While carbon dioxide is not toxic, it is heavier than air and could be suffocating if it settled in a low spot in calm weather and was not dispersed by wind. The main danger with the use of carbon dioxide is the possible presence of lethal concentrations of hydrogen sulfide.⁽⁶⁾ Although CO₂ gas can contain some H₂S, hydrogen sulfide also occurs naturally in many oil reservoirs, and is not a danger specific to enhanced oil recovery processes.⁽²⁾

Regulations have been adopted for drilling and producing operations involving hydrogen sulfide gas. The Texas Railroad Commission's Rule 36, for example, is aimed at protecting the public from accidental releases of hazardous amounts of H₂S. The rule applies to operations which generate a 50-ft radius of H₂S exposure of 100 ppm. Warning equipment and contingency plans to protect the public in the event of an accidental release are required.⁽¹³⁾ Similar regulations have been adopted by other states. The H₂S problem exists with oil production in general and is not expected to be a major problem with tertiary recovery processes.⁽²⁾

7.1.3 Chemical Recovery Methods

Chemical processes should not produce air emissions during field operations. However, indirect environmental impacts may result from the manufacture of required chemicals, although these impacts are covered by existing air quality control regulations, and are not expected to cause major environmental problems.⁽²⁾

7.2 SURFACE WATER IMPACTS

All of the tertiary recovery methods require large amounts of fresh water, from 1 to 6 barrels for every barrel of oil recovered. California, Texas and western Louisiana are areas where water usage is high and supplies relatively restricted; severe shortages are predicted for these areas by the year 2000.⁽²⁾ Yet, these are the areas which have the most potential for widespread application of tertiary recovery. It is anticipated that tertiary recovery processes will take advantage of recycling where possible, reducing water requirements substantially.

A more important concern is the handling and disposal of produced water, which is often saturated with chemicals, and the impacts of chemical spills as a result of transportation, on-site manufacturing and handling. The 1972 amendments to the Federal Water Pollution Control Act are designed to protect surface waters from pollution. Under this Act, a National Pollutant Discharge Elimination System Permit is required before a waste water discharge to surface waters is permitted from a point source. The purpose of the permits and the Act is to protect public water supplies, fish and wildlife and recreational activities, and is aimed at a zero discharge level.⁽⁶⁾

7.2.1 Thermal Recovery Methods

Thermal recovery processes do not severely impact water quality, although some local pollution may occur as a result of leaks or spills during transport and storage of some of the chemicals used in treating produced waters.⁽⁸⁾

The primary impacts of thermal methods are through surface water use and the handling of produced water. In a steamflooding project in the Kern River field in California, almost 80% of produced fluids is water. This water is treated for recycle to the portable generators and the permanent boilers. Oil, suspended solids and oxygen are removed and the water is filtered and softened. The amount of treated water is more than that needed for generating steam; surplus water is being used for irrigation in nearby farms.⁽⁷⁾ Wise use of water resources seems to minimize the environmental impacts of thermal recovery methods on surface water.

7.2.2 Miscible Recovery Methods

Miscible enhanced recovery methods will have the least environmental effect on surface water. Water consumption in water-short areas can be reduced by the use of recycling. Disposal of produced water is regulated by the Federal Water Pollution Control Act and would probably not adversely impact surface waters.⁽²⁾

7.2.3 Chemical Recovery Methods

Chemical techniques have the greatest potential for adverse impacts on surface water resources. Fresh water requirements are the greatest for these processes.⁽²⁾ It is estimated that a micellar polymer flood, with a preflush, could require as much as 14 barrels of fresh, high quality water per barrel of oil produced.⁽¹⁾ The application of chemical recovery methods on a large scale may adversely affect water supplies in water-short areas.

Chemical spills during transportation and storage present the greatest environmental danger to water supplies. The actual effects that a chemical release will have on the environment depends on the amount spilled.⁽¹⁾ Although large quantities of chemicals will be injected in any commercial application of chemical recovery, injection will occur over a long time period, limiting on-site storage to much smaller quantities, perhaps tank car lots. Although limited spills are possible, major quantities of spilled chemicals are unlikely. Furthermore, chemicals currently contemplated for use are relatively nontoxic.⁽⁶⁾

Disposal of produced water may be a problem, although most chemicals will be absorbed within the reservoir. Surface water biological impacts, such as a potential increase in biological oxygen demand (BOD), can be avoided by treatment of produced water or by reinjecting it into the oil-producing reservoir.

Any widespread use of chemical recovery methods will require a substantial increase in chemical production, especially of surfactants. The expansion of manufacturing capacity could result in localized adverse environmental impacts through loss of wildlife habitat and potential air and water emissions.⁽²⁾

The supply and use of the chemicals required for tertiary recovery techniques could conceivably be limited by the Toxic Substances Control Act of 1976.

Although not yet implemented, the Act gives the EPA regulatory control over chemicals from their initial manufacture, processing and use to the distribution and final disposal stages. The EPA is also given the authority to investigate the hazards associated with a particular chemical and to require premarket testing for new and existing chemicals which are found to have deleterious effects on man or the environment.

The chemicals most commonly used in tertiary recovery operations include petroleum sulfonates, alcohols, polymers, sodium hydroxide and sodium silicate. These chemicals are not particularly hazardous in the concentrations used in recovery operations.⁽²⁾ However, EPA may choose to regulate the handling or disposal of these chemicals, particularly if chemical recovery techniques are implemented on a wide scale.

Current laws, such as the Federal Water Pollution Control Act, seem to mitigate environmental impacts of releases to surface water. Effluent guidelines have been established which regulate the amount of contaminants allowed in effluent for different industries.

The EPA has also announced new, stricter rules governing the spills of hazardous chemicals in the nation's waterways. These regulations should minimize the potential for chemical releases during handling and transport. Companies who are proved to have spilled dangerous chemicals must pay civil fines of up to \$5 million and can be required to pay cleanup costs up to \$50 million. In cases of "willful negligence," there is no upper limit to cleanup costs. Criminal penalties of up to \$10,000 fine and one year in jail can also be assessed to offending companies and individuals. The regulations cover 271 chemicals other than oil; EPA will add chemicals to the list as needed. The program applies to all potential discharge sources, including transportation systems, such as trucks, trains and ships, and fixed facilities, such as industrial plants.⁽¹⁴⁾ This new rule should substantially limit the environmental impacts of enhanced oil recovery on surface waters of the U.S.

7.3 GROUNDWATER IMPACTS

Detrimental effects on groundwater quality may occur as a result of chemical spills or leaks from well casings and from seepage through the walls of disposal wells. The concentration of chemicals in the reservoir will decrease with time and with distance traveled in the reservoir because of the physical and chemical mechanisms acting on the material, including dilution, entrapment, absorption and degradation. The time of contamination of groundwater aquifers depends on the chemical and rock type.

The impacts of leaks from disposal wells are minimized by state laws regarding well abandonment. All producing states have regulations which require oil and gas wells to be plugged within a specified time after production ceases. These rules are designed to avoid pollution by the leakage of reservoir fluids into surface or subsurface waters.⁽⁶⁾

7.3.1 Thermal Recovery Methods

Thermal processes have very little impact on groundwater quality. There are long-term possibilities of groundwater pollution from well casing damage due to expansion and contraction stresses and corrosion.⁽¹³⁾ This possibility, however, is felt to be very small, based on the lack of groundwater contamination problems associated with conventional waterfloods. Only 74 groundwater injection problems resulted from operating 44,000 injection wells in Texas between 1960 and 1975; only three of these occurred during the last decade (an incidence rate of 0.02/10,000/yr).⁽²⁾

Steam injection processes may possibly induce chemical reactions in the hot reservoir, releasing compounds which may enter solution in reservoir water and leak into groundwater systems. In situ combustion processes may also impact water quality. The residue of trace metals and metal oxides from the crude may be dissolved by the acidic water left in the reservoir.⁽¹⁾ The extent of these problems and their actual impact on water quality is as yet unknown. Further study of the process effluents and chemistry of the depleted reservoir is required to resolve this issue.

7.3.2 Miscible Recovery Methods

Environmental impacts associated with CO₂ miscible recovery methods are mostly related to the transport of the chemical. However, it is possible that the release of CO₂ under pressure to groundwater aquifers, as a result of well failure or reservoir leakage, could result in a decrease in pH of the water body. If this groundwater connects to surface water bodies, the change in pH could affect aquatic life, especially freshwater fish, which are particularly susceptible to increased acidity. The potential for this occurrence is, however, extremely small.⁽²⁾

7.3.3 Chemical Recovery Methods

The main concern with chemical recovery methods is the risk of contamination of groundwater supplies, since chemicals used in micellar polymer floods may be left in the reservoir after the project is completed. These chemicals may possibly have both direct and synergistic effects on water and organisms.⁽¹⁾

The actual amount of chemicals which may be left in the reservoir is, as yet, not well known, although the following range has been suggested: out of the 5 to 15 lb of surfactant injected, 1 to 12 lb may be left in the reservoir; out of 2 to 10 lb of injected co-surfactant, 0 to 3 lb may remain in the reservoir; and of 1 lb of polymer injected, 0.8 to 1 lb will remain in the reservoir.⁽¹⁾ The impact of these chemicals, which are, by design, compatible with the reservoir structure should be minimal.

The possibility of leakage and concomitant groundwater pollution seems very small. The wells are separated from groundwater aquifers; oil-bearing zones are usually much deeper than the shallower freshwater aquifers. Since the chemical concentration decreases as the chemical is adsorbed on reservoir rock and diluted, the potential consequences of a leak from one or more wells would be minimal, no more severe than they currently are for conventional water-flooding.⁽⁶⁾

State and federal laws also help protect the subsurface environment by regulating the injection of materials into the ground. California, for instance, has very strict well construction controls to protect its groundwater sources.

The state's Division of Oil and Gas regulates the maximum pressure at which fluids can be injected into a well, and runs pressure tests and well surveys to make sure that this pressure is not exceeded during the life of the project.

The EPA, under the Safe Drinking Water Act of 1974, is required to regulate subsurface injection and waste discharges to protect groundwater quality. Section 1421 of the Safe Drinking Water Act calls for state programs to protect underground drinking water sources from contamination by fluid injection. Injection of produced fluids and all injections for secondary or tertiary oil recovery techniques will be regulated by permits.⁽¹⁶⁾

Draft EPA underground-injection control (UIC) regulations require the re-permitting of all existing injection wells by state. The permitting process for an injection well could take as long as 195 days, causing delays for tertiary recovery projects. Producers will be required to re-evaluate the mechanical integrity of their wells at 5-year intervals; existing wells will also have to be tested for mechanical integrity before they can be re-permitted. Operators will have to meet periodic monitoring and reporting requirements for their wells. So far, the regulations specify pressure monitoring on a weekly basis for disposal wells and on a monthly basis for enhanced recovery wells. These rules would reduce the potential for leakage from wells.⁽¹⁷⁾

It appears that environmental protection regulations and low leakage probabilities result in little potential for harm to groundwater by tertiary oil recovery techniques, although further study is needed. The impact of the Safe Drinking Water Act on tertiary project operations is as yet uncertain.

7.4 LAND USE

Enhanced recovery will occur in existing oil fields and should require little change in land use practices. Although some additional surface equipment and storage area may be needed, and wells may require drilling or repair, the overall appearances of the field should remain about the same. Major local impacts may result from the construction of CO₂ supply pipelines. Right-of-ways must be obtained and ditching, construction and burying of the line will be necessary for completion.⁽⁶⁾

There are concerns that enhanced oil recovery may result in land subsidence. When compared with primary recovery methods, it seems that the possibilities of subsidence will actually be reduced with tertiary recovery, since the fluids will be left in the reservoir after the oil is removed, equalizing underground pressures and filling the volume emptied by the recovered oil.⁽²⁾

California appears to be the only major area of widespread tertiary recovery potential affected by severe seismic disturbances. It should be noted that the occurrence of an earthquake in the vicinity of a tertiary oil recovery operation could result in the release of reservoir fluids to surrounding waters, perhaps deteriorating water quality. However, since thermal recovery techniques, which use few chemicals and have little adverse impact on water quality, are the preferred recovery method for the California valley, the effects on water quality would probably not be too severe.⁽¹⁾

7.5 ENVIRONMENTAL IMPACT SUMMARY

The major environmental impacts of tertiary recovery processes seem to be air quality impacts of steam recovery methods and water quality impacts of chemical spills in chemical recovery methods. The air emissions problem of steam injection is doubly severe since these methods are being applied primarily in California, an area already suffering from extreme air pollution.

The expense of the chemicals used in tertiary recovery will cause operators to minimize leakage and loss of the chemicals. Federal regulations governing the discharge of polluted process waters will also help protect the water environment.

Because tertiary recovery methods, especially CO₂ miscible and chemical recovery, are still in the developmental stages, more research needs to be done to define the process effluents which will actually emanate from a widespread application of the techniques. Many of the environmental impacts appear similar to those encountered in primary and secondary operations; some impacts are even lessened in tertiary operations, such as the possibilities of well blowouts and land subsidence. Although current state and federal regulations seem to mitigate many environmental impacts, the degree to which these rules

will be enforced must be determined. There is a great deal of uncertainty as to how these laws will impact tertiary recovery. The technology of many tertiary processes is not far enough advanced to accurately determine the impacts which they may have on the environment. Similarly, it is not yet known how the various environmental regulations may constrain the widespread application of tertiary recovery. An intensive study of the environmental problems of tertiary recovery methods and their severity should be performed, and should reflect possible constraints imposed by current regulations.

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8.0 GROWTH SCENARIOS FOR ENHANCED OIL RECOVERY

During the first half of 1977, the U.S. demand for liquid hydrocarbons was about 18.5 million barrels per day; imports supplied nearly half of these requirements.⁽¹⁾ The demand for petroleum and petroleum products has been continuously rising and is predicted to reach at least 25 million barrels per day (Mbbbl/day) by the early 1990's. Domestic production, however, has not been able to keep pace with increasing demand.⁽²⁾ Domestic production in 1977 was 8.0 Mbbbl/day, following a continuous decline from a 1970 peak value of 9.6 Mbbbl/day.⁽³⁾ Under conventional technology and optimistic exploration assumptions, total domestic production in 1990 may not exceed 7 Mbbbl/day, resulting in an enormous gap between supply and demand. Rising prices and synthetic alternatives to petroleum could increase production in the future, although gains of this sort will be small relative to overall supply requirements. Enhanced oil recovery is a viable near-term option for supplementing domestic energy sources.⁽⁴⁾

Conventional recovery methods extract only about one-third of the original oil-in-place in a reservoir. The American Petroleum Institute (API) estimates original oil resources at 442 billion barrels of crude oil. As of 1976, almost one-fourth of this oil had been produced. Another 32.7 billion barrels are categorized as proved reserves, believed to be recoverable in the future from known reservoirs under existing economic and operating conditions. The real promise of enhanced recovery techniques lies in the 300 billion barrels of oil estimated as presently unrecoverable by current technology under present pricing schemes.⁽⁵⁾ Although some of this remaining oil may be physically unrecoverable by any means, at least 120 billion barrels is thought to be theoretically recoverable by present or future enhanced oil recovery methods under suitable economic conditions.⁽²⁾

The successful application of tertiary recovery methods is highly dependent on economic, regulatory and technological factors. The uncertainty of future governmental policies in these areas has resulted in a wide range of predictions for the potential of enhanced oil recovery. Recent studies have estimated that enhanced techniques may recover from 7 to 76 billion barrels of oil at prices ranging from \$10 to \$25 per barrel. Table 8.1 presents the results of some of these studies. Estimates of the rate of production in 1985 range from 0.4 Mbbbl/day to 2.3 Mbbbl/day.⁽³⁾

TABLE 8.1 Estimates of Enhanced Oil Recovery Potential ^(a)

	Potential for Recovery, billions of barrels	Production in 1985 millions of barrels/day
NPC Study ⁽⁷⁾		
\$10/bbl oil	7.2	0.4
\$15/bbl oil	13.2	0.9
\$25/bbl oil	24.0	1.7
(1976 dollars)		
GURC ^(8,9)		
\$10/bbl oil	18-36	1.1
\$15/bbl oil	51-76	-
(1974 dollars)		
FEA/PIR ⁽¹⁰⁾		
business as usual, \$11/bbl oil	-	1.8
accelerated development, \$11/bbl oil	-	2.3
EPA ⁽¹¹⁾		
\$8-12/bbl oil	7	-
\$12-16/bbl oil	16	-
(1975 dollars)		
FEA/Energy Outlook ⁽¹²⁾		
\$12/bbl oil	-	0.9
FEA ⁽¹³⁾ (3 states)		
upper bound \$11.28/bbl oil	30.5	2.0
lower bound, \$11.28/bbl oil	15.6	1.1
(1975 dollars)		
ERDA ⁽²⁾		
\$11.63/bbl oil (1976 dollars)	12	0.6
Elkins ⁽¹⁴⁾		
\$20/bbl oil (1977 dollars)	55	0.75
OTA ⁽³⁾		
\$11.62/bbl oil	8-21 ^(b)	0.4-0.5 ^(b)
\$13.75/bbl oil	11-29	0.5-1.0
\$22.00/bbl oil	25-42	0.9-1.3
(1977 dollars)		

(a) The abbreviations represent the organization or individual which presented these estimates. The numbers in parentheses correspond to the full

reference, which can be found in the back of the section.

(b) The low and high values represent the differences between low- and high-process performance cases.

Most of the oil produced by enhanced recovery techniques will come from known reservoirs and fields which have a successful history of primary and secondary production.⁽²⁾ Four states have, to date, contributed 71% of our discovered ultimate recovery: Texas with 35%, California with 14%, Louisiana with 13% and Oklahoma with 9%.⁽⁶⁾ Figure 8.1 shows the location of oil reservoirs nationwide. Because of the limited applicability of each of the tertiary methods, the processes will be applied in different reservoir types (and correspondingly different geographic areas).

The potential for recovery of oil by enhanced processes is 2.5 times greater in sandstone reservoirs than in carbonates because of technical limitations of current processes. The potential California tertiary recovery lies entirely within sandstone reservoirs, and will most likely be recovered by thermal, or perhaps chemical, methods. Texas has both sandstone and carbonate reservoirs and seems to be most amenable to recovery by CO₂ miscible methods, particularly since there are sources of CO₂ relatively nearby. Successful carbonate enhanced recovery processes (mainly miscible techniques) may also predominate in New Mexico, Kansas, North Dakota and Ohio, where carbonate potentials are significantly higher than those for sandstone.⁽²⁾

A basic requirement for the successful implementation of tertiary oil recovery is an oil price that will make these projects economically viable. The price level must be sufficient to cover all project costs and include an adequate operator profit. In general, tertiary recovery techniques add at least \$2 to \$10 to the cost of each additional barrel of oil produced; some of the chemical recovery methods are expected to have production costs of \$20 to \$25 per barrel of oil.⁽⁵⁾

Fifty to eighty percent of the incremental cost of tertiary production is for front-load items such as facilities and injection fluids. Total production costs also include normal well operating costs, the costs of lifting and disposing of water left from previous waterflooding operations and the time value of investment money due to the time delay in income from the project.⁽¹⁶⁾ A capital requirement of \$2 billion for each 100,000 b/d

FIGURE 8.1 Location of Oil and Gas Fields in the Continental United States
(Redrawn from Reference 15.)

produced by tertiary methods and a manpower need of one engineer for each 1,000 b/d of production has been predicted.⁽¹⁷⁾

Recognizing the need for a price incentive scheme to encourage the implementation of tertiary recovery techniques, the Economic Regulatory Administration (ERA), in the new Department of Energy (formerly the Federal Energy Administration) has proposed price incentives for tertiary recovery projects.

Under the proposed rules, the price permitted for incremental tertiary production will be the market clearing price. Crude oil produced by tertiary techniques will not be limited by a price ceiling, and would thus be exempt, in a sense, from price controls. However, to qualify for this pricing scheme, a producer must show that the project would be uneconomic in the absence of the pricing incentive. Only incremental production -- that which would not have been produced from the project area in the absence of the tertiary project -- will be entitled to the incentive price. The producer must project the amount of incremental oil which will be produced from the project and the date on which this production is expected to occur. The pricing incentive will apply only after this date.

The burden is put upon the producer to establish that the project qualifies for the price incentive on economic grounds and to establish the amount of incremental crude oil to be produced. He may then receive certification for the project. However, if production during any 18-month period varies from the certified volumes by more than 20 percent or by more than an average of 50 barrels per day, whichever is greater, the governmental agency may require recertification. It is postulated that monthly reports would also be required of producers receiving certification to obtain price incentives.⁽¹⁸⁾

These provisions, while perhaps a step in the right direction, are not sufficient to establish the kind of certainty required by producers if they are to implement tertiary recovery projects.⁽¹⁸⁾ The experimental nature of many of the tertiary techniques, particularly when applied to different types of reservoirs, makes it quite difficult to predict the actual amount of incremental oil which would ultimately be produced by any one project.

The ultimate application of tertiary recovery techniques is highly dependent on the economics of the processes. As long as the price of crude oil remains relatively low, the expensive, more experimental processes cannot possibly be implemented on a large scale by industry operators. As seen in

Table 8.2, an increase in oil prices will most likely lead to a more widespread use of the advanced recovery technologies.

Enhanced oil recovery techniques are currently producing over 240,000 barrels of oil per day (including hydrocarbon miscible but not cyclic steaming). Steam drive accounts for most of this production, 110,000 barrels per day (bbl/day); hydrocarbon miscible provides 70,000 bbl/day; carbon dioxide miscible recovers 40,000 bbl/day; in situ combustion, micellar polymer flooding and polymer or caustic improved waterflooding techniques provide the remaining 20,000 bbl/day. The portion contributed by hydrocarbon miscible flooding is expected to decline dramatically due to recent increases in natural gas prices. Several of the current projects are already converting to other injection fluids, mostly carbon dioxide.⁽¹⁹⁾ The projected potential oil recovery, from 1980 to 2000, of each of the tertiary recovery methods is shown in Table 8.2. The amount of oil to be recovered by each method and the date by which that production may occur vary with the expected price of crude oil.

8.1 THERMAL RECOVERY METHODS

Thermal methods are relatively low risk investments compared to other tertiary recovery processes and are being applied today on a commercial scale. Yet there are constraints to increasing recovery by thermal techniques. Although the areal sweep of a steam drive in a uniform sand is very high, the vertical sweep is affected by nonuniform reservoir structure and by the segregation of the vapor and the steam condensate (which is not as effective a displacement agent as the steam). Steam drives are energy-intensive, consuming nearly one-third of produced crude to generate steam. The process is limited to a major extent by reservoir depth; the majority of current developments and economic pilot projects are at less than 1500 ft. These constraints limit recovery efficiency.

In situ combustion techniques are hampered by relatively low sweep due to the unstable fire front, high incidence of well corrosion and burnout and costs of air compression.⁽¹⁹⁾

Environmental and water supply concerns, particularly in California, and limited market opportunities for the heavy crude produced by thermal methods also constrain the expected production rates of oil from thermal methods.⁽¹⁴⁾

TABLE 8.2. Potential Oil Recovery by Each Method^(a)

	Potential Production Rate, million barrels/day		
	1980	1990	2000
<u>Thermal Methods</u>			
OTA ⁽³⁾ (b)			
\$11.62/bbl	0.2-0.3	0.4-0.5	0.3-0.4
\$13.75/bbl	0.2-0.3	0.5-0.6	0.4-0.5
\$22/bbl	0.3-0.4	0.8-1.1	0.5-0.7
(1977 dollars)			
NPC ⁽⁷⁾			
\$10/bbl	0.2	0.3-0.4	0.2-0.3
\$15/bbl	0.2-0.3	0.6-0.8	0.2-0.3
\$25/bbl	0.3-0.5	0.9-1.1	0.4-0.5
(1976 dollars)			
ERDA ⁽²⁾			
\$11.63/bbl (1976 dollars)	0.16	0.17	-
<u>CO₂ Miscible Methods</u>			
OTA ⁽³⁾ (c)			
\$11.62/bbl	0.1	0.05-0.3	0.6-1.6
\$13.75/bbl	0.1	0.1-0.6	1.1-2.8
\$22/bbl	0.1	0.5-0.8	3.3-5.6
(1977 dollars)			
NPC ⁽⁷⁾			
\$10/bbl	-	0.1	0.5
\$15/bbl	-	0.2-0.3	0.9-1.0
\$25/bbl	-	0.6-0.7	1.1-1.2
(1976 dollars)			
ERDA ⁽²⁾			
\$11.63/bbl (1976 dollars)	-	0.4	0.4
<u>Chemical Methods</u>			
OTA ⁽³⁾			
\$11.62/bbl	-	0.1-0.3	0.2-0.9
\$13.75/bbl	*	0.1-0.5	0.2-1.9
\$22/bbl	*	0.5-0.8	1.3-2.5
(1977 dollars)			
NPC ^{(7)(d)}			
\$10/bbl	*	*	*
\$15/bbl	*	0.3	0.2
\$25/bbl	*	1.0	1.2
(1976 dollars)			
ERDA ⁽²⁾			
\$11.63/bbl (1976 dollars)	*	*	*

(a) The abbreviations represent the organization which presented these estimates.

(b) Range represents difference between low- and high-process performance cases.

(c) Includes both onshore and offshore reservoirs.

(d) Micellar-polymer only.

* Less than 0.05 million barrels of daily production.

8.2 MISCIBLE RECOVERY METHODS

Field experience has only recently begun to accumulate with CO₂ miscible flooding, with most projects begun since 1972. The process is much less advanced than thermal recovery methods and seems to be much less efficient in reservoirs with lower oil saturations, such as after waterflooding. Yet, if used in the future as a tertiary technique, as it will be in Texas reservoirs which are currently being waterflooded, low oil saturations will be the rule. Project uncertainty regarding the amount of residual oil and its distribution in the reservoir is a major limitation.⁽¹⁹⁾ Mobility control and multiple contact miscibility also seem to present operational problems. Further experimentation seems necessary to advance the technology of this process to a more predictable state. The supply of CO₂ necessary for widespread application is another process limitation. Although several major natural sources of CO₂ are known, these are not located very close to applicable reservoirs.⁽¹⁴⁾ The extraction of CO₂ from industrial stack gases, although a possible supply source, has not really been studied in sufficient economic detail.⁽¹⁹⁾

8.3 CHEMICAL RECOVERY METHODS

While chemical techniques may theoretically achieve almost perfect oil recovery and have been tested and demonstrated in the laboratory, the theory has not been shown widely successful in field applications. There has been great difficulty in transferring lab knowledge to field conditions; little is known about the actual behavior of micellar polymer systems under reservoir conditions.⁽¹⁹⁾ One of the biggest problems is adjusting chemical solutions for compatibility with particular reservoir oils, waters and rock chemistry. Mobility control and maintaining integrity of the chemical slug as it advances through the reservoir are other problems encountered with chemical processes.⁽¹⁴⁾

The surfactants used in micellar polymer flooding processes are costly and are sensitive to water salinity and hardness as well as temperature. Current tolerance levels for these chemicals are for salinities up to about 50,000 ppm, hardness up to 1,000 ppm and temperature up to 200°F.⁽²⁰⁾

8.4 PERSPECTIVE

Major economic and technological uncertainties presently constrain the application of enhanced oil recovery methods. Both the amounts and timing of potential enhanced oil recovery production are sensitive to crude oil prices. As prices rise to cover the higher costs of tertiary recovery, the risk will be reduced. Incentive pricing policies may help reduce investment risks by assigning a higher price to tertiary oil production. However, present proposed policies create problems in deciding what fractions of total oil production should receive higher prices when primary and secondary methods are being used at the same reservoir. This incremental oil production must be defined in a way which will neither discourage the use of new technology nor distort decisions concerning primary and secondary production.⁽³⁾

Enhanced oil recovery techniques are new, developing technologies, whose widespread success remains generally unproven on large scales. Uncertainties in determining the oil content of reservoirs, a critical parameter for the economic application of tertiary recovery, and other uncertainties present major process limitations. Better methods for measuring residual oil saturation are needed.⁽²⁰⁾ Other research needs include improving process recovery efficiencies and advancing the technology of miscible and chemical methods to facilitate widespread process application. Environmental impacts of tertiary methods are not clear and need to be quantified and evaluated for actual severity. A summary table of tertiary recovery methods, the potential application and constraints, is shown in Table 8.3.

TABLE 8.3 Tertiary Recovery-Potential and Constraints

	Thermal	Miscible	Chemical
Processes	Cyclic Steam Injection Steam Drive In Situ Combustion	CO ₂ miscible LPG drive, enriched gas, lean gas and high-pressure gas drives	Alkaline Polymer Micellar-Polymer
Most promising methods	Cyclic Steam Injection	CO ₂ miscible	Micellar-Polymer
Location of most promising reserves	California	Texas, Kansas, Oklahoma, Louisiana, New Mexico	California, Texas, Illinois, Louisiana, Oklahoma
Current technological status	Fairly advanced; being applied widely on commercial scales.	Less developed; some commercial application Further testing needed	Still in the research and field testing stages
Primary research needs	Techniques to Determine Residual Oil Saturations and Detailed Reservoir Structures		
	<ul style="list-style-type: none"> • overcoming emission problems • using cheaper, nonpetroleum fuels to generate steam • improve recovery efficiencies • extend process application to deeper and heavy oil reservoirs 	<ul style="list-style-type: none"> • develop adequate, cheap supplies of carbon dioxide • extend process application to sandstone and low oil saturation depleted reservoirs 	<ul style="list-style-type: none"> • develop cheaper, adequate surfactant supplies • develop an improved micellar solution which can tolerate higher salinities and temperatures • extend process application and develop to the point of commercial application
Potential production by 1990	M bbl/day	M bbl/day	M bbl/day
at \$10/bbl oil	0.3 - 0.4	0.1 - 0.3	0.05 - 0.1
at \$15/bbl oil	0.6 - 0.8	0.2 - 0.4	0.2 - 0.3
at \$25/bbl oil	0.9 - 1.1	0.6 - 0.8	0.5 - 1.0
Primary Environmental Impacts			
<u>Air</u>	<ul style="list-style-type: none"> • Air emissions of combustion products from steam generation: SO₂, NO_x, HC, CO, CO₂ 	<ul style="list-style-type: none"> • Possible H₂S emissions 	<ul style="list-style-type: none"> • minimal impacts
<u>Water</u>	<ul style="list-style-type: none"> • Regional shortages of surface water • Handling of produced water 	<ul style="list-style-type: none"> • minimal impact 	<ul style="list-style-type: none"> • Regional shortages of surface water • Handling of produced water • Contamination from chemical spills or leaks

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APPENDIX A

ONGOING THERMAL RECOVERY PROJECTS

TABLE A.1 Steam Soak Projects

Field	State	County	Operator	Start date	Area, acres	Number wells		Pay* zone
						Prod.	Inj.	
Steam soak								
Coalingua	Cal.	Fresno	Shell	2/67	2,520	385		Tembler
W. Coalingua	Cal.	Fresno	Socal	66	1,280			Tembler
Asphalto	Cal.	Kern	Getty	3/75	120	4		Tulare
S. Belridge	Cal.	Kern	McCulloch	70	100			Tulare
Cymric	Cal.	Kern	Getty	1/68	70	22		Tulare
Cymric	Cal.	Kern	Gulf	6/66		8		Tar
Cymric	Cal.	Kern	Mobil	7/65	170	46		Welpert, Amnicola
Cymric	Cal.	Kern	Socal	66	700			Tulare
Edison	Cal.	Kern	Exxon	65	1,100	75		Kern River
Kern Front	Cal.	Kern	ARCO	11/64	160	56		Chanac
Kern Front	Cal.	Kern	Getty	5/66	1,080	132		Chanac-Etch.
Kern Front	Cal.	Kern	Mobil	5/74	600	100		Chanac-Etch.
Kern Front	Cal.	Kern	Socal	70	640			Chanac
Kern River	Cal.	Kern	Chans.-West.	5/64	240	172		300 ft
Kern River	Cal.	Kern	Getty	60	3,000	1,271		Kern River
Kern River	Cal.	Kern	Getty	74	9	3		Kern River
Kern River	Cal.	Kern	Shell	4/63	1,300	443		Kern River
Kern River	Cal.	Kern	Socal	66	1,400			Kern River
Lost Hills	Cal.	Kern	ARCO	6/67	15	7		Etchegoin
Lost Hills	Cal.	Kern	Getty	1/68	150	61		Etchegoin
Lost Hills	Cal.	Kern	Gulf	8/64		43		Tar
Lost Hills	Cal.	Kern	Gulf	2/75	1	3		Zone "A"
McKittrick	Cal.	Kern	Getty	64	500			Potter
McKittrick	Cal.	Kern	Getty	6/74	3			Potter
McKittrick	Cal.	Kern	Occidental	4/65	46			Olig. sand
McKittrick	Cal.	Kern	Socal	71	120			Tulare
Midway-Sunset	Cal.	Kern	ARCO	9/63	1,000	216		Etch. & Potter
Midway-Sunset	Cal.	Kern	Chans.-West.	3/64	1,970	821		200 ft
Midway	Cal.	Kern	Getty	6/64	215	21		Etch. Spellacy
Midway	Cal.	Kern	Getty	9/64	125	71		Potter
N. Midway	Cal.	Kern	Getty	11/64	155	70		Potter
Midway	Cal.	Kern	Getty	11/67	86	16		Potter A-B-C
Midway-Sunset	Cal.	Kern	Getty	1/71	35	44		Potter
Midway-Sunset	Cal.	Kern	Mobil	11/67	350	200	0	Potter
Midway-Sunset	Cal.	Kern	Mobil	10/70	950	50	0	Monarch
Midway-Sunset	Cal.	Kern	McCulloch	65	60	117		Potter
Midway-Sunset	Cal.	Kern	Occidental	9/64	23			Monarch
Midway-Sunset	Cal.	Kern	Shell	1/64	565	530		Potter
Midway-Sunset	Cal.	Kern	Socal	66	160			Potter
Midway-Sunset	Cal.	Kern	Sun	64	226	198	cylic	Potter
Poso Creek	Cal.	Kern	Getty	9/74	84	14		Chanac Etch.
Poso Creek	Cal.	Kern	Socal	70	240			Chanac
Santiago	Cal.	Kern	Gulf	4/66		18		Tar
S. Belridge	Cal.	Kern	Socal	66	150			Tulare
S. Belridge	Cal.	Kern	McCulloch	70	100	40		Tulare
Huntington Beach	Cal.	Orange	Burmah	64	50	9	0	Tar
Huntington Beach	Cal.	Orange	Burmah	64	710	48	0	TM
Huntington Beach	Cal.	Orange	Socal	4/65	300			Tar Zone
Yorba Linda	Cal.	Orange	Gulf	10/62		86		Tar & Repetto
Yorba Linda	Cal.	Orange	Shell	3/61	180	202	23	Up. cong.
Cat Canyon	Cal.	Santa Barbara	Conoco	63	650	130		Sisquoc
Cat Canyon	Cal.	Santa Barbara	Getty	64	1,700	100	0	S1-B
Cat Canyon	Cal.	Santa Barbara	Getty	65	300	13	0	S8-16
White Castle	La.	Iberville	Shell	11/74	57	2		V
White Castle	La.	Iberville	Shell	3/75	37	2		U
Anderson Ranch	Tex.	Zavala	Exxon	7/74	2	1	1	San Miguel
Uvalde	Tex.	Zavala	Gulf	2/75	3			San Miguel

TABLE A.1 Steam Soak Projects (continued)

Depth, ft	Reservoir oil			Previous production†	Residual oil saturation, %		Project maturity	Enhanced prod., bo/d	Project S eval.	Profitable
	°API	cp	@ °F.		Start	End				
900-2,800	16-18	200-5.5M	@ 90-160	Prim.	89	69	HF	3,900	Succ.	Yes
1,200	14	1.2M	@ 90	Prim.	85	75	90% compl.		Succ.	Yes
1,400	12	780	@ 140	Prim.	100	85	HF	100	TETT	
800	12			Prim.	60	40	HF		Prom.	No
1,000	12	2.7M	@ 100	Prim.	95	85	NC	500	Succ.	Yes
1,000	10								Succ.	Yes
400-900	12-13	1.5M	@ 95	Undev.	99	75	32% compl.	400		
1,000	13	2.4M	@ 85	Prim.	90	75	60% compl.		Succ.	Yes
1,100	16	310	@ 95	Prim.			HF	600	Succ.	Yes
1,600	13.7	400	@ 120	Prim.					Succ.	Yes
2,300	13.5	406	@ 90	Prim.	82	77	HF	1,676	Succ.	Yes
1,800	14.4	800	@ 100	Prim.	84	73	JS	450		
2,400	12	3M	@ 110	Prim.	80	75	75% compl.		Succ.	Yes
100-800	13	4M	@ 90	Prim.	80	40		900	Succ.	Yes
900	13.5	4.1M	@ 90	Prim.	90	86	NC	14,588	Succ.	Yes
900	13.5	4.1M	@ 90	Prim.	86	76	HF	10	Prom.	Yes
300-1,300	11-13	3M	@ 85	Prim.	90	73	HF	9,000	Succ.	Yes
1,000	14	4M	@ 85	Prim.	85	78	85% compl.		Succ.	Yes
500	12.5	1M	@ 100	Prim.			NC		Succ.	Yes
500	13	1M	@ 100	Prim.	90	80	HF	500	Succ.	Yes
200-400	16								Succ.	Yes
700	15			Prim.			JS		TETT	No
1,200	15	600	@ 100	Prim.	75	52	HF	7,600	Succ.	Yes
1,200	15	600	@ 100	SS	68	65	NC		Disc.	No
900	14			Prim.			HF		Succ.	Yes
820	15	4M	@ 100	Prim.	98	75	80% compl.		Succ.	Yes
1,000-2,500	12-17	200-200M	@ 100	Prim.					Succ.	Yes
400-1,800	12	4M	@ 100	Prim.	85	40		20,000	Succ.	Yes
850+	13.5	775	@ 100	Prim.	94	91	HF	390	Succ.	Yes
1,150										
1,200	14	405	@ 100	Prim.	69	51	HF	2,100	Succ.	Yes
1,400	13.4	1.1M	@ 100	Prim.	91	81	HF	1,800	Succ.	Yes
1,800	11	1M	@ 150	Prim.	99	91	HF	60	Succ.	Yes
1,700	12	4.8M	@ 100	Prim.	82	53	JS	2,150	Succ.	Yes
1,000	13	1M	@ 100	Prim.	85	70	HF	3,500		
950	13.5	800	@ 85	Prim.	95	81	40% compl.	504		
1,100	12	5M	@ 80	Prim.	75	40	60% compl.	3,000	Succ.	Yes
1,000	12.6			Prim.			HF		Succ.	Yes
600-1,900	10-14	2.4-5M	@ 80-100	Prim.	95	70	HF	9,000	Succ.	Yes
1,200	14	1.1M	@ 100	Prim.	80	70	HF		Succ.	Yes
1,000-1,500	12	3M	@ 60	Prim.	90	50	HF	4,300	Succ.	Yes
2,000	13.1	4.1M	@ 90	Prim.	82	76	JS	128	TETT	
2,500	14	1M	@ 120	Prim.	90	80	80% compl.		Succ.	Yes
550-1,250	14			Prim.					Succ.	Yes
550-1,250	14	4.8M	@ 92	Prim.	85	50	HF		Succ.	Yes
800	12			Prim.	60	40	HF	150	Prom.	Yes
2,800	14	25	@ 130	Prim.	95	70	HF	200	Succ.	Yes
2,000	13	80	@ 125	Primary	98	60	HF	1,500	Succ.	Yes
2,000	12.7	2M	@ 140		88	50	60% compl.		Succ.	Yes
200-2,000	12			Primary					Succ.	Yes
400-830	12	6.4M	@ 85	Primary	96	50	HF	8,500	Succ.	Yes
3,000	10	1.3M	@ 130	Primary	95-100	80	HF	4,000	Succ.	Yes
2,300	9	2.5M	@ 100	None	99	85	HF	2,000	Succ.	Yes
3,000	12	2M	@ 130	Primary	99	85	HF	163	Succ.	Yes
1,350	16	500	@ 80	Primary	99	50	JS	200	Prom.	
1,000	15	1.1M	@ 80	Primary	99	50	JS	200	Prom.	
525	9	10M	@ 80	None			Term. 5-75	2-100	Disc.	No
300	10			None			Term. 8-75		Disc.	No

TABLE A.3 Steam Drive Projects

Field	State	County	Operator	Start date	Area, acres	Number wells		Pay* zone
						Prod.	Inj.	
Steam drive								
Smackover	Ark.	Ouachita	Phillips	71	985	120	9	20 ft
Belridge	Cal.	Kern	Mobil	6/64	2,381	250	38	Tulare
Coalingua	Cal.	Fresno	Shell	1/63	700	104	73	Temblor
W. Coalingua	Cal.	Fresno	Socal	73	30			Temblor
Cymric	Cal.	Kern	Socal	5/75	18	21	9	Tulare
Kern River	Cal.	Kern	Chans.-West.	76	15	13	11	60 ft
Kern River	Cal.	Kern	Getty	8/62	2,000	1,373	781	Kern River
Kern River	Cal.	Kern	Getty	5/73	22.5	16	9	Kern River
Lost Hills	Cal.	Kern	Getty	11/75	11	9	4	Tulare
Kern River	Cal.	Kern	Chans.-West.	3/72	1¼	4	10	120 ft
Kern River	Cal.	Kern	Socal	66	1,400			Kern River
N. E. McKittrick	Cal.	Kern	Socal	9/75	90	29	16	Amnicola
Midway-Sunset	Cal.	Kern	ARCO	6/69	6	12	2	Potter
Midway-Sunset	Cal.	Kern	ARCO	1/72	3.7	7	1	Etchegoin
Midway-Sunset	Cal.	Kern	ARCO	3/72	12.2	10	3	Potter
Midway-Sunset	Cal.	Kern	Chans.-West.	1/67	20	16	4	110 ft
Midway-Sunset	Cal.	Kern	Chans.-West.	1/68	1¼	4	1	200 ft
Midway-Sunset	Cal.	Kern	Chans.-West.	10/72	5	4	1	130 ft
Midway-Sunset	Cal.	Kern	Chans.-West.	10/75	6.5	8	4	50 ft
Midway-Sunset	Cal.	Kern	Shell	8/71	120	51	17	Potter
Midway-Sunset	Cal.	Kern	Socal	11/75	21	15	6	Monarch
Midway-Sunset	Cal.	Kern	Texaco	72	10	8	1	Tulare
Mount Poso	Cal.	Kern	Shell	10/71	500	60	11	Upper Vedder
San Ardo	Cal.	Monterey	Mobil	6/63	3,041	450	40	Lombardi & Aurignac
San Ardo	Cal.	Monterey	Texaco	65	1,725	192	39	Aurignac
San Ardo	Cal.	Monterey	Texaco	69	80	29	2	Lombardi
Brea-Olinda	Cal.	Orange	Chans.-West.	3/74	15	10	1	144 ft
Caddo Pine Isl.	La.	Caddo	Texaco	7/75	36	4	1	Nacatoch
Port Barre	La.	St. Landry	Texaco	8/74	6.4	4	1	1,500-ft sand
Slocum	Tex.	Anderson	Shell	3/67	258	259	49	Carrizo
Slocum	Tex.	Anderson	Texaco	8/70	18	15	3	Carrizo
Toborg	Tex.	Pecos	Gulf	6/75	20	9	4	Toborg
Winkelman Dome	Wyo.	Fremont	Amoco	3/64	100	21	13	Nugget

TABLE A.3 Steam Drive Projects (continued)

Depth, ft	°API	Reservoir oil cp	@ °F.	Previous production	Residual oil saturation, %		Project† maturity	Enhanced prod., bo/d	Project§ eval.	Profitable
1,920	20	75	@ 110	Prim.	71	50	HF	1,300	Succ.	
1,000	14	1.3M	@ 90	Prim.	94	56	14% compl.	5,400		
1,500	22	160	@ 100	SD	51	38	NC	1,300	Succ.	Yes
1,200	14	1.2M	@ 90	SS	80	50	40 % compl.		Succ.	Yes
900	13	4M	@ 90	Prim.	50	15	JS	400	Prom.	No
660	13	4M	@ 90	None	95	40	JS		TETT	...
900	14	4M	@ 90	Prim.	89	52		39,200	Succ.	Yes
900	14	4M	@ 90	Prim.	89	47	HF		TETT	...
200	14	577	@ 100	Prim.	99	45	JS		TETT	...
700	13	4M	@ 90	Prim.	78	40	JS	270	Succ.	Yes
1,000	14	4M	@ 85	Prim.	85	78	85% compl.		Succ.	Yes
1,200	11	5M	@ 110	Prim.	57	15	JS	900	Prom.	No
1,000-2,500	12-17	200-200M	@ 100	Prim.	..	..	HF		Prom.	Yes
2,000	12	1M	@ 100	Prim.	..	..	HF		Prom.	Yes
2,500	13	1M	@ 100	Prim.	..	..	HF		Prom.	Yes
1,500	11	4M	@ 100	Prim.	95	20	HF	980	Succ.	Yes
1,200	11	4M	@ 100	Prim.	90	40	Term. 2-74		Succ.	Yes
1,000	11	4M	@ 100	Prim.	90	50	JS	95	Prom.	Yes
600	11	4M	@ 100	None	100	20	JS	80	TETT	...
1,200	11	5M	@ 90	SS	91	45		3,000	Succ.	Yes
1,200	13	1.2M	@ 90	SS	50	15	JS	0	TETT	No
1,200	12	4M	@ 100	Prim.	..	..	HF	103	Prom.	Yes
1,800	16	280	@ 110	Prim.	60	30		8,000	Succ.	Yes
2,100 & 2,300	11	3.1M	@ 125	Prim.	92	64	23% compl.	8,000		...
2,200	13	4.5M	@ 100	SS	..	..	HF	22,900	Succ.	Yes
1,900	11	11M	@ 100	SS	..	..	HF	100	Prom.	Yes
800	12	3.1M	@ 100	Prim.	97	77	JS	127	Prom.	Yes
800	21	160	@ 100	None	100	71	JS	9	TETT	No
1,450	19	60	@ 95	Prim.	72	57	JS	9	Prom.	No
520	19	2M	@ 75	Prim.	97	50	NC	1,900	Succ.	Yes
580	19	1.8M	@ 82	NP	..	..	Term. '74	29	Disc.	No
	22			Prim.	..	..	JS	30	TETT	No
1,225	14	900	@ 81	Prim.	..	50	HF	720	Succ	Yes

TABLE A.2 Combustion Projects

Field	State	County	Operator	Start date	Area, acres	Number wells		Pay* zone
Combustion projects								
Kern River	Cal.	Kern	Chans.-West.	6/75	5	4	1	60 ft
Lost Hills	Cal.	Kern	Mobil	4/61	140	50	5	300 ft
Midway-Sunset	Cal.	Kern	Chans.-West.	1/72	157	12	3	.182 ft
Midway-Sunset	Cal.	Kern	Mobil	1/60	150	31	5	Moco
Midway-Sunset	Cal.	Kern	Mobil	1/67	390	40	5	Int. Webster
Paris Valley	Cal.	Monterey	Husky-ERDA	1/75		18	5	Ansberry
Brea-Olinda	Cal.	Orange	Union	3/72	44	20	2	Miocene
Cat Canyon	Cal.	Santa Barbara	Conoco	2/74	3	4	1	Sisquoc
Russel Ranch	Cal.	Santa Barbara	ARCO	4/71	20	6	1	Dibblee
Robinson	Ill.	Crawford	Marathon	8/61	130	41	3	Robinson
Bellevue	La.	Bossier	Cities	3/71	10	21	4	Nacatoch
Bellevue	La.	Bossier	Cities	6/74	10	21	4	Nacatoch
Bellevue	La.	Bossier	Getty	63	513	194	55	Nacatoch
Pine Island	La.	Caddo	Conoco	4/73	60	17	6	Nacatoch
W. Heidelberg	Miss.	Jasper	Gulf	12/71	300	6	1	Cotton Valley
W. Heidelberg	Miss.	Jasper	Gulf	7/75	5	3	1	Christmas 10
Red Bank	Ok.	Creek	Sun	6/66	200	6	2	Dutcher
Loco	Ok.	Stephens	Conoco	5/75	24	25	5	J-Shallow
West 76	Tex.	Duval	Mobil	10/68	546	8	1	Cole
Talco	Tex.	Franklin & Titus	Exxon	7/72	20	7	1	Paluxy
Gloriana	Tex.	Wilson	Sun	5/69	513	9	2	Poth "A"
Glen Hummel	Tex.	Wilson	Sun	1/68	600	18	4	Poth "A"
Little Tom	Tex.	Zavala	Hanover-ERDA	1/75	14	3	1	San Miguel

*All reservoirs are sandstones. †Prim. = primary; Undev. = under developed; SS = steam soak; SD = steam drive; NP = non-productive; TETT = too early to tell; Prom. = promising; Disc. = discouraging.

TABLE A.2 Combustion Projects (continued)

Depth, ft	Reservoir oil			Previous production	Residual oil saturation, %		Project maturity	Enhanced prod., bo/d	Project eval.	Profitable
	°API	cp	@ °F.		Start	End				
400	13	4M	@ 90	SS	55	15	JS	20	TETT	...
300	16	410	@ 95	Prim.	99	66	HF	500	...	...
1,550	12	5M	@ 95	SS	90	35	JS	300	Succ.	Yes
2,700	15	110	@ 125	NR	99	52	75% comp.	507	...	...
1,600	14	600	@ 113	Prim.	89	69	30% comp.	293	...	...
800	11	188M	@ 75	...	99	...	JS	...	...	...
3,500	22	20	@ 135	Prim.	72	50	HF	3-500	Succ.	Yes
3,900	9	1.7M	@ 70	Prim.	97	70	JS	...	TETT	No
3,500	32	0.99	@ 140	WF	...	...	NC	0	Disc.	No
1,000	23	18-80	@ 60	WF	40	...	NC	...	Disc.	...
400	19	226	@ 60	Prim.	95	68	NC	300	Succ.	...
...	19	226	@ 60	Prim.	95	...	JS	...	TETT	...
330	19	500	@ 80	Prim.	92	40	HF	2,000	Succ.	Yes
1,023	21	320	@ 102	Prim.	95	50	HF	50	TETT	No
11,750	24	...	...	Prim.	...	...	HF	430	Prom.	Yes
5,000	21	...	...	Prim.	...	...	JS	100	TETT	No
3,300	20	60	@ 120	Prim.	...	...	NC	100	Prom.	Yes
220	19	2	@ 70	Prim.	100	50	JS	30	TETT	No
1,350	20	25	@ 96	Prim.	90	83	NC	90	Succ.	Yes
4,200	22	26	@ 147	WF	...	...	Term. 10-75	30-40	Disc.	No
1,600	21	174	@ 112	Prim.	92	81	Term. 1-74	...	Prom.	Yes
2,300	21	45	@ 114	Prim.	85	70	NC	...	Succ.	Yes
2,700	17	90	@ 125	...	57	...	JS	0	TETT	No

WF = waterflood; HF = half finished; NC = nearing completion; JS = just started; Term. = terminated. \$Succ. = successful;

Source: "U.S. Thermal Recovery Activity Growing Steadily." Oil and Gas Journal, pp. 108-119, April 5, 1976.

APPENDIX B

ONGOING MISCIBLE RECOVERY PROJECTS

TABLE B.1 Hydrocarbon-Miscible Projects

Field	State	County	Operator	Start date	Area, acres	Number wells		Pay zone	Type†	Porosity, %
Greeley	Cal.	Kern	Mobil	8-64	550	8	1	Olcese	SS	20
Midway-Sunset	Cal.	Kern	Socal	57	530			Exeter	SS	24
Ventura	Cal.	Ventura	Shell	1-66	325	18	15	5th N-Zone	SS	17
Black Bayou	La.	Cameron	Shell	7-66	6.2	2	1	M	SS	37
Black Bayou	La.	Cameron	Shell	10-68	8.8	3	1	L	SS	37
Black Bayou	La.	Cameron	Shell	9-72	16.7	1	1	0-0	SS	34
Weeks Island	La.	Iberia	Shell	4-74	679	10	2	S sand	SS	23
Block 31	Tx.	Crane	ARCO	6-49	7,840	86	27		LS	15
Levelland	Tx.	Hockley	Amoco	5-71	1,200	40	28	San Andres	Dolo.	10.2
Levelland	Tx.	Hockley	Amoco		13	2	6	San Andres	Dolo.	9.4
Slaughter	Tx.	Hockley	Amoco		12	2	6	San Andres	Dolo.	10.5
Bridger Lake	Utah/Wyo.	Summit/Uinta	Phillips	4-70	3,800	7	1	Dakota	SS	12.8
Charlton*	N. Dak.	McKenzie	Texaco	9-74	9,100	24	7	Madison	LS	11
E. Velma*	Ok.	Carter-Stephans	Amoco	12-73	50	17	3	Sims	SS	16
Fairway*	Tx.	Anderson & Henderson	Hunt	3-66	22,618	118	47	James	LS	12
Winkleman Dome*	Wyo.	Fremont	Amoco	5-70	752	39	13	Tensleep	SS	15
Dugout Creek*	Wyo.	Johnson	Texaco	64		3	2	Shannon	SS	22
Lick Creek	Ark.	Bradley-Union	Phillips	1-76	1,640	32	14	Meakin	SS	33
McCallum Unit	Colo.	Jackson	Conoco	12-73	601	19	4	Pierre "B"	SS	20
Little Creek	Miss.	Pike	Shell	2-74	40	3	1	L. Tuscaloosa	SS	23
Crosset	Tx.	Crane & Upton	Shell	5-72	1,700	17	9	Devonian	LS	22
N. Cowden	Tx.	Ector	Amoco		12	2	6	Grayburg	Dolo.	11
S. Gillock	Tx.	Galveston	Amoco	2-72	5,700	38	11	Frio	SS	28
Slaughter	Tx.	Hockley	Amoco		12	2	6	San Andres	Dolo.	10
Two Freds	Tx.	Loving, Reeves, Ward	HNG	1-74		17	11	Delaware		
Kelly-Snyder	Tx.	Scurry	Socal	1-72	50,000			Canyon	LS	8
Wasson	Tx.	Yoakum	ARCO	11-72	320		9	San Andres	Dolo.	11

*Alternate gas-water injection. †SS=Sand stone; LS=Limestone; Dolo.=dolomite. ‡Prim.=Primary; Gas Inj.=gas injection; Gas Cap Inj.=Gas completed; JS=just started; Susp.=suspended. §Succ.=Successful; Disc.=discouraging; TETT=too early to tell; Prom.=promising.

TABLE B.1 Hydrocarbon-Miscible Projects (continued)

Permeability, md	Depth ft	Reservoir oil			Previous prod.‡	Residual oil saturation		Project maturity§	Enhanced prod. bo/d	Project eval.¶	Profitable
		°API	cp	@ °F.		Start	End				
18	10,600	35	0.4	@ 244	Prim.	92	44	Term. 10-75	600		
400	5,200	31	1	@ 180	Prim.	82	52	Term. 1974		Succ.	Yes
20	10,000	30	0.9	@ 215	Prim.	70	60	HF	800	Succ.	Yes
1,200	4,800	24	0.8	@ 138	Prim.	45	3	NC	180	Succ.	Yes
750	4,710	24	1.0	@ 138	Prim.	91	36	NC	65	Disc.	Yes
1,500	5,700	35	0.55	@ 156	Gas inj.	46	11	NC	100	Succ.	Yes
1,000	14,000	33	0.15	@ 240	Prim.	67	15	JS		TETT	
1.0	8,500	46	0.3	@ 140	Prim.	85	32	74% compl.	16,000	Succ.	Yes
1.9	4,800	30	2.0	@ 105	Prim.	84	30	JS		Prom.	
3.5	4,800	30	2	@ 105	Prim.	84	32			TETT	No
4.3	4,950	28	1.4	@ 105	Prim.	84	32			TETT	No
79	15,600	40	0.53	@ 225	Prim.	94		25% compl.	1,000	Succ.	Yes
0.1	8,500	42	11	@ 77	WF			HF		TETT	
67	5,500	10	2	@ 100	Gas cap inj.	70	45	HF	300	TETT	No
22	9,900	48	15	@ 265	Prim.	73	33	HF	28,500	Succ.	Yes
106	3,300	25	11	@ 125	WF	78	59	HF		TETT	Yes
120	2,000	36	3	@ 86	WF			NC		Prom.	
1,200	2,500	17	188	@ 118	Prim.	81	64	JS			
98	1,250	20	10	@ 70	Prim.	100		HF		Disc.	No
65	10,800	39	0.34	@ 235	WF	54		NC	133	Prom.	No
5	5,300	44	0.36	@ 106	Gas inj.	86	55	JS	1,100	Prom.	
7	4,300	35	1.4	@ 94	Prim.	74	32			TETT	No
900	9,000	38	0.35	@ 214	Nat. WD	100	15	HF		TETT	Yes
8.1	4,950	28	1.4	@ 105	Prim.	84	21			TETT	No
	4,900				WF	84		JS		TETT	
19	6,900	43	0.35	@ 130	WF	80	48	35% compl.	35,000	Succ.	Yes
2	5,100	32	0.97	@ 107	WF	85		Susp. 2-75		TETT	No

Cap injection; WF=Waterflood; Nat. WD=Natural water drive. §Term.=terminated; HF=half finished; NC=nearing completion; Compl.=

Source: "Gas Miscible Projects Move at Slow Pace." Oil and Gas Journal, pp. 126-127, April 5, 1976.

TABLE B.2 CO₂ Miscible Projects

Field	Formation	Depth Ft	BHT deg F	Oil Gravity deg/API	Perme- ability md	Porosity %	Sand Thickness Ft		Miscibility Pressure- Psi	Field Spacing Ac/Well	Date Test Initiated	Field Produc- tive Acres
							Gross	Net				
Arkansas												
Richie-Union Co.	Baker-SS	2600	126	16	2750	31	8	8	None	20	1969	250
Lick Creek-Bradley Co.	Meakin-SS	2250	118	17	1500	29	16	12	None	20	1976	1120
Mississippi												
Little Creek-Lincoln Co.	Tusc-SS	10700	248	39	65	23	360	29	5000	40	1974	6310
Texas												
North Cowden-Ector Co.	Grayburg-Dol	4300	94	35	7	11	409	125	NA	40	1973	37000
Crossett-Crane Co.	Devonian-Ch	5300	106	44	3	22	110	80	1650	40	1972	1120
South Gillock-Galveston Co.	Frio-SS	9000	214	38	900	28	61	36	NA	40	1972	5900
Kelly-Snyder-Scurry Co.	Canyon-LS	6700	132	42	19	8	213	139	1600	51	1972	50600
Mead-Strawn-Jones Co.	Strawn-SS	4475	135	41	9	9	NA	9	850	NA	1964	NA
Slaughter-Hockley Co.	San Andres-Dol	4950	105	28	8	10	150	89	1075	34	1976	87000
Twofreds-Loving Co.	Delaware-SS	4800	104	36	33	20	42	25	1400	40	1974	3000
Wasson-Yoakum Co.	San Andres-Dol	4890	107	32	2	11	450	111	1250	20	1972	63500
West Virginia												
*Granny's Creek-Clay Co.	Big Injun-SS	2000	75	45	5	18	40	34	1000	10	1976	3000
*Griffithville-Lincoln Co.	Berea-SS	2300	83	43	8	11	22	12	1000	10	1976	10000
*Rock Creek-Roane Co.	Big Injun-SS	2000	73	45	20	22	40	35	1000	10	1976	11200

*EFDA Supported

Source: Boyd C. McRee, "CO₂: How it Works, Where it Works." Petroleum Engineer, pp. 52-63, November, 1977.

APPENDIX C

DEFINITIONS OF SURFACTANTS, EMULSIONS AND MICELLAR SOLUTIONS

Surfactants

Surfactants, or surface-active agents, are chemicals that act like soap when added to water. When injected into oil reservoirs, these chemicals wash oil from the surface of the rock by reducing the interfacial tension between water and oil.⁽¹⁾ Surfactant molecules have a dual nature that enables them to solubilize oil and water: one end of the molecule is attracted to water, hydrophilic; the other is attracted to oil, oleophilic. The surfactant used in micellar solutions is a petroleum sulfonate, manufactured from hydrocarbons ranging from LPG to crude oil.⁽²⁾

Solutions and Emulsions

Solutions are mixtures of one substance in another in which the dissolved substance subdivides to molecular size. Solutions are optically clear and the dissolved substance does not settle out, even after a long period of time. Colloids are suspensions of one substance (subdivided to microscopic size) in another. A colloidal mixture of two immiscible liquids, such as oil and water, forms an emulsion. Colloidal mixtures are cloudy and will separate or settle-out if given sufficient time.

Micellar Solutions

A surfactant mixed in water (or oil) at a low concentration forms a solution. As the concentration is increased to some critical level, the surfactant molecules begin to cling together in clusters called micelles.⁽²⁾ The micellar aggregates dissolve other fluids into their centers, swelling to accommodate these solubilized liquids. If oil was the solvent, water will be contained within the micelles, and it is termed an oil external or water-in-oil solution; these mixtures are also called soluble oils. If the solvent was water, oil will be solubilized within the micelles, leading to a water external or oil-in-water solution.⁽³⁾ These mixtures are micro-emulsions, since they contain dispersed particles of submicroscopic size; however, they also have solution properties in that they are transparent and stable against settling out.⁽²⁾

REFERENCES

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2. E. F. Herbeck, R. C. Heintz and J. R. Hastings, "Micellar Solution Flooding." Fundamentals of Tertiary Oil Recovery, Part 6, Petroleum Engineer, pp. 44-56, June, 1976.
3. W. B. Gogarty and W. C. Tosch, "Miscible - Type Waterflooding: Oil Recovery with Micellar Solutions." Journal of Petroleum Technology, pp. 1407-1414, December, 1968.

APPENDIX D

ONGOING CHEMICAL RECOVERY PROJECTS

TABLE D.1 Alkaline Waterflooding Field Trials

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

* Porosity in percent; permeability in millidarcies.

† Residual oil: Gravity in degrees API; viscosity in centipoises; acid number.

‡ Reservoir temperature, degrees Fahrenheit.

§ Salinity -- total dissolved solids, parts per million.

¶ Wettability reversal -- oil to water wet.

** Wettability reversal -- water to oil wet.

Source: Enhanced Oil Recovery, National Petroleum Council, December, 1976.

TABLE D.2 Polymer and Caustic Projects

Field	State	County	Operator	Start date	Area, acres	Number wells		Pay* zone	Porosity, %
						Prod.	Inj.		
Main Consol.	Il.	Crawford	Getty	72	1.15	1	4	Robinson	22
Main Consol.	Il.	Crawford	Getty	75	22	2	8	Robinson	22
Teeter	Ks.	Greenwood	M. L. Brown	9/71	20	2	6	Bartlesville	17
Stroud	Okla.	Lincoln	Sun	8/70	600	28	19	Prue	18
Stanley	Okla.	Osage	Kewanee/ERDA	7/75	1,560	27	17	Burbank	18
Tatums	Okla.	Carter	Mobil	10/68	70	43	8	Tatums	22
Bratum	Tx.	Duval	Texaco	4/69	427	8	12	Wells	29
Hagist Ranch	Tx.	Duval	Texaco	4/73	145	11	9	Argo	31
Seventy-six West	Tx.	Duval	Texaco	11/72	90	3	1	Cole	30
Stephens Cty. Reg.	Tx.	Stephens	Mobil	3/73	1,680	41	25	50 ft	15
Stewart Ranch	Wyo.	Campbell	NCRA	11/70	1,920	16	10	Minnelsua "B"	16
Hiligh	Wyo.	Campbell	Inexco	3/75	1,440	8	1	Muddy	17
Kummerfeld	Wyo.	Crook	Terra	4/75	800	7	3	Minnelsua	17
W. Semlek	Wyo.	Crook	Terra	5/73	640	4	1	Minnelsua	20
Skull Creek	Wyo.	Weston	Texaco	3/74	920	20	11	Newcastle	16
Skull Creek	Wyo.	Weston	Fira	9/67	740			Newcastle	16
Orcutt Hill (caustic)	Cal.	Santa Barbara	Union	2/74	420	21	15	Point Sal	23
Charamousca, S. (caustic)	Tx.	Duval	Mobil	3/73	330	13	1	Miranda	32
N. Ward (caustic)	Tx.	Ward	Gulf	7/73	40	5	4	Queen	
W. Perryton (caustic)	Tx.	Ochilfree	Sun	6/72	1,000	4	4	Morrow	13

*Stevens County reg. field (Mobil) reservoir is a limestone; all other reservoirs are sandstones. WFF = waterflood; Prim. = primary; GI = gas; TETI = too early to tell; Disc. = discouraging.

TABLE D.2 Polymer and Caustic Projects (continued)

Depth, ft	Reservoir oil			Previous prod.	Residual oil saturation		Project maturity	Enhanced prod., bo/d	Project eval.	Profitable
	°API	cp	@ °F.		Start	End				
1,000	34	10	@ 75	WF	65	..	NC	2	Prom.	No
1,000	34	10	@ 75	WF	65	..	JS	12	..	..
2,550	41	3	@ 60	Prim.	25	..	NC	200	Succ.	Yes
2,900	44	2	@ 100	WF	..	..	NC	30	Prom.	Poss.
3,000	39	..	@ 105	WF	60	57	JS	..	TETT	..
2,400	26	68	@ 83	WF	64	52	Term. 12-74	65	Disc.	No
1,950	23	12	@ 115	WF	..	..	HF	90	Succ.	Yes
1,900	20	10	@ 115	WF	..	..	HF	120	Succ.	Yes
1,350	20	12	@ 100	Prim.	..	..	HF	150	Succ.	Yes
3,200	40	3.0	@ 60	WF	78	76	HF	284	Prom.	Yes
8,000	22	24	@ 136	WF	94	67	HF	2,083	Succ.	Yes
9,600	40	0	@ 234	WF	..	..	JS	..	TETT	No
7,600	19	38	@ 130	WF	88	46	JS	..	TETT	..
7,240	23	12.3	@ 144	WF	82	57	HF	250	Succ.	Yes
2,450	32	3	@ 135	WF	..	..	HF	..	Prom.	..
3,300	32	3.2	@ 124	WF	82	75	NC	..	Succ.	Yes
2,950	22	25	@ 140	WF	74	74	Term. 11-75	200	Prom.	No
1,500	20	18	@ 110	Prim.	86	71	Term. 5-74	150	TETT	No
3,100	36	..	..	Prim.	..	..	NC	30	..	No
8,100	38	0.8	@ 168	GI	..	..	Term. 3-75	..	Disc.	No

†NC = nearing completion; JS = just started; Term. = terminated; HF = half finished; \$Prom. = promising; Succ. = successful;

Source: "Polymer and Caustic Methods on Rebound." Oil and Gas Journal, pp. 124-125, April 5, 1976.

TABLE D.3 Micellar/Surfactant Projects

Field	State	County	Operator	Start date	Area, acres	Number wells		Pay* zone	Porosity, %
						Prod.	Inj.		
Robinson	Ill.	Crawford	Marathon	9/63	40	27	18	Robinson	20
Robinson	Ill.	Crawford	Marathon	10/75	116	55	35	Robinson	20
Benton	Ill.	Crawford	Shell	11/72	160	12	6	Tar Springs	19
Salem	Ill.	Crawford	Texaco	3/74	5	1	4	Benoist	15
Griffin	Ind.	Gibson	Conoco	11/73	.8	4	1	Upper Cypress	20
El Dorado	Ks.	Butler	Cities-ERDA	6/74	51	8	18		25
Delaware-Childers	Ok.	Nowata	B & M-ERDA	75	10	4	2	Bartlesville	21
N. Burbank	Ok.	Osage	Phillips-ERDA	75	90	16	9	47 ft	15
Bradford	Penn.	McKean	Pennzoil-ERDA	10/75	16	16	9	Bradford	15
Bradford	Penn.	McKean	Pennzoil	3/71	46	25	16	Bradford	22
County Reg.	Tx.	Wichita	Mobil	11/73	209	20	10	Gunsight	22
Slaughter	Tx.	Hockley	Texaco	10/73	4	1	4	San Andres	11
W. Ranch	Tx.	Jackson	Mobil	6/74	2.5	1	1	41-A	31
Big Muddy	Wyo.	Converse	Conoco	73	5	6	4	2nd Wall Creek	19
La Barge	Wyo.	Sublette	Texaco	1/75	1.7	1	4	Almy	26

*Slaughter field San Andres pay zone is limestone, all rest are sandstones. tWF = waterflood; PM = pressure maintenance; Prim = primary. ‡NC = full; Prom. = promising

TABLE D.3 Micellar/Surfactant Projects (continued)

Permeability, md	Depth, ft	Reservoir oil			Previous prod.	Residual oil saturation		Project† maturity	Enhanced prod., bo/d	Project§ eval.	Profitable
		API°	cp	@ °F.		Start	End				
200	1,000	35	7	@ 60	WF	40	..	NC	..	..	..
200	1,000	35	3.5	@ 85	WF	40	..	JS	..	TETT	..
165	2,100	38	3.5	@ 85	WF	55	..	HF	40	..	..
87	1,800	38	3.6	@ 85	WF	30	..	NC	..	Disc.	No
75	2,400	37	..	..	WF	..	..	JS	..	TETT	No
162	650	37	4.8	..	WF	33	..	JS	..	TETT	..
80	620	37	10.9	@ 86	WF	35	..	JS	..	TETT	..
30	3,000	39	2.5	@ 122	WF	40	20	JS	..	TETT	..
10	1,100	45	4	@ 68	WF	40	20	JS	..	TETT	..
100	1,900	45	4	@ 71	WF	40	20	NC	36	Succ.	No
53	1,700	42	2.3	@ 75	WF	44	19	HF	..	TETT	..
4	5,000	32	68	@ 109	WF	..	..	HF	..	TETT	..
950	5,700	32	0.7	@ 169	PM	77	23	Term. 11-74	..	Succ.	..
39	3,100	34	5.6	@ 114	WF	30	..	HF	70	Prom.	No
450	700	26	17	@ 60	Prim	..	..	JS	..	TETT	..

nearing completion; JS = just started; HF = half finished; Term. = terminated. §TETT = too early to tell; Disc. = discouraging; Succ. = success-

Source: "Operators Accelerate Testing of Micellar/Surfactant Potential." Oil and Gas Journal, pp. 120-122, April 5, 1976.

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