

Enhanced Oil Recovery

Second Edition

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Petroleum Engineering University of Kansas*

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Henry L. Doherty Memorial Fund of AIME

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Dedication

This book is dedicated to the memory of Fred H. Poettmann in recognition of his contributions and encouragement.

About the Authors

Don W. Green is Emeritus Distinguished Professor of Chemical and Petroleum Engineering at the University of Kansas. His career began in 1962 in the Production Research Division of Continental Oil Company before he joined the University of Kansas in 1964. At the University of Kansas, Green was chair of his department from 1970 to 1974 and from 1996 to 2000. He was codirector of the Tertiary Oil Recovery Project with G. Paul Willhite from 1974 to 2007. Green has authored or coauthored 70 refereed publications, more than 100 technical meeting presentations, is editor of the 6th, 7th and 8th editions of Perry's *Chemical Engineers' Handbook*, and is currently editing the 9th edition. He holds a BS degree in petroleum engineering from the University of Tulsa, and MS and PhD degrees in chemical engineering from the University of Oklahoma. Green has won numerous teaching awards at the University of Kansas, including the Honors for Outstanding Progressive Educator (HOPE) Award and the Chancellor's Club Career Teaching Award. He has also been featured as an outstanding educator in the American Society for Engineering Education journal *Chemical Engineering Education*. Green was an SPE Distinguished Lecturer, recipient of the SPE Distinguished Achievement Award for Petroleum Engineering Faculty, the Improved Oil Recovery (IOR) Pioneer Award and was named an Honorary Member of SPE in 2007. He is also a Fellow of the American Institute of Chemical Engineers. Green received the University of Kansas School of Engineering Distinguished Engineering Service Award (DESA) in 2015, and was named to the University of Tulsa College of Engineering and Natural Sciences Hall of Fame in 2017.

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Preface

The development of enhanced-oil-recovery (EOR) processes has been ongoing since the end of World War II, when operators who owned reservoirs with declining reserves recognized that significant quantities of oil remained in their reservoirs after primary and secondary recovery (primarily waterflooding). Research and field activity increased as production from major reservoirs declined, worldwide consumption of oil increased, and discoveries of major new reservoirs became infrequent. Intense interest in EOR processes was stimulated in response to the oil embargo of 1973 and the following energy “crisis.” The period of high activity lasted until the collapse of worldwide oil prices in 1986.

Over the years, interest in EOR has been tempered by the increase in oil reserves and production. The discovery of major oil fields in the North Slope of Alaska, the North Sea, regions such as Indonesia and South America, and the Athabasca oil sands of Canada have added large volumes of oil to the worldwide market. The development of horizontal drilling combined with hydraulic fracturing in shale oil reservoirs has added large volumes of light crude oil to the worldwide market. In addition, estimates of reserves from reservoirs in the Middle East increased significantly, leading to the expectation that the oil supply will be plentiful and that the oil price would remain in the vicinity of USD 20 to 25/bbl (constant dollars) for many years.

Although large volumes of oil remain in mature reservoirs, the oil will not be produced in large quantities by EOR processes unless these processes can compete economically with the cost of oil production from conventional sources. Thus, as reservoirs age, a dichotomy exists between the desire to preserve wells for potential EOR processes and the lack of economic incentive because of the existence of large reserves of oil in the world.

Enhanced Oil Recovery describes technologies that can be applied to recover oil that cannot be produced by primary recovery or waterflooding or to recover oil that remains after application of these processes. While many of the technologies were economical at the oil prices that existed in 2013 and most of 2014, they may not be at the oil prices of 2015 through 2017. Development of these processes represents significant technological advances in our understanding of oil recovery from petroleum reservoirs and may be the stimulus for future technological developments.

Approach

This text is written as an introduction to EOR processes, which are processes normally applied after waterflooding. These include polymer, micellar-polymer, and CO₂ flooding and thermal-recovery processes that are typically implemented following primary production. Written for seniors and first-year graduate students in petroleum engineering, we assume that those using this text have a basic understanding of petrophysics (porosity and permeability, saturation), fluid properties (viscosity, density, formation volume factor, and phase behavior), and material balances (volumetrics and elementary depletion calculations). We also assume that students have some grasp of the complexity of reservoirs through exposure to geology courses. These topics can be found in other texts.

We have included three background, or review, chapters that cover microscopic (pore-level)-displacement efficiency, linear-displacement theory, and macroscopic (volumetric) -displacement efficiency, respectively. These chapters can be used by petroleum engineering students for review or by those in other engineering or science disciplines as background information for the study of the different EOR processes treated in the book. The text has been used in a one-semester graduate course in our master’s degree program taken by students majoring in both petroleum and chemical engineering. The text contains more material than can be covered in a one-semester course, allowing the instructor to place more emphasis on some processes than others.

Chapter 1 introduces EOR processes and methods of screening reservoirs that are candidates for potential application. Chapter 2 reviews fundamental concepts for oil recovery from porous rocks at the microscopic or pore scale. Chapter 3 develops linear-displacement theory on the basis of fractional-flow concepts. In Chapter 4, we introduce volumetric-displacement efficiency of processes. Chapter 5 covers polymer flooding, and Chapter 6 introduces miscible-displacement processes, including CO₂ miscible flooding. Chapter 7 presents chemical flooding, and Chapter 8 covers thermal recovery. A number of EOR commercial field applications have been in operation since publication of the first edition and several of these are described in the chapters covering the different processes.

In describing the different EOR processes, we focus on the fundamental concepts of each process. However, we also present methods of predicting oil recovery when the processes are applied to oil reservoirs. Many methods are available to calculate displacement performance, ranging from simple models based on volumetric sweep to sophisticated reservoir simulators. The use of reservoir simulators is beyond the scope of this text. We chose a middle course that reinforces fundamental mechanisms

but requires the mathematical skills expected of students taking this as a first course on EOR. In some cases, the computations are tedious, but they can be done easily with short computer programs. Selected programs are included in the Appendices.

While this text was being written, important developments in EOR technology took place in laboratories and oil fields throughout the world. We have included those developments where appropriate. This was possible because we had access to numerous high-quality technical publications prepared by our colleagues in universities and the petroleum industry.

This book began as a comprehensive text on oil-recovery processes authorized by the SPE Textbook Committee. The chapter on waterflooding in the original outline was expanded into the text *Waterflooding* (published in 1986); writing of this text resumed following completion of *Waterflooding*. In the years that followed, development of micellar-polymer-flooding technology was phased out as a direct result of the collapse of oil prices in 1986 and the development of new oil supplies throughout the world, which led to projections of oil prices in the vicinity of USD 20 to 25/bbl (in constant dollars) for many years. We attempted to preserve the important parts of this technology in the text, even though at initial writing it appeared unlikely that the technology would be applied for many years.

By 2012, there was a steady rise in oil price from USD 20/bbl when the first edition was prepared to more than USD 100/bbl, which stimulated application of EOR processes throughout the world. The SPE Textbook Committee requested the preparation of a second edition with emphasis on field applications of EOR processes. As the preparation of the second edition was nearing completion, oil prices declined to the vicinity of USD 35 to 50/bbl, as the effect of large volumes of oil produced from horizontal wells impacted the worldwide oil market.

Thermal-recovery processes continue to be the major contributor to production from EOR processes. The chapter on thermal-recovery processes is extensive and could be used for a single course. In Canada, the extensive deposits of tar sands has stimulated the development and application of steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). These topics have been added to the text.

The development of CO₂ miscible flooding in west Texas created increased application of this process. We have added several field case histories from major reservoirs to the chapter on miscible-displacement processes. There will be continued development and application of this technology in addition to the material covered in this text. We anticipate that a wealth of field case histories will be developed from ongoing projects; therefore, students and instructors should look for additional material as they use the text.

Extensive field application of polymer flooding is occurring in the Daqing field in China, where oil production from polymer flooding is estimated to be in excess of 1.5 Bbbl. Polymer flooding by use of horizontal wells is under development in some heavy-oil reservoirs in Canada.

Although there have been substantial developments in surfactant formulations since the first edition and some pilot field tests, no information was available on field tests. Consequently, the revision of the chapter on chemical flooding focuses primarily on the development and testing of surfactant formulations that are effective over a wide range of reservoir conditions in laboratory tests.

During the past 10 years, laboratory research has demonstrated that waterflood recovery from oil-wet and intermediately wetted cores can be increased by injecting water containing low salinity (Low Sal). Mechanisms contributing to this increase in oil recovery are not well understood and continue to be a major area of research. Although field tests are in progress, the topic of Low Sal is in an early stage of development and is not covered in this revision.

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We are also indebted to many on the staffs at the University of Kansas and at the Society of Petroleum Engineers (SPE) in Dallas, who helped us in the completion of the text. At the University of Kansas, Ruth Sleeper and Shari Gladman prepared some of the text and Vera Sehon, Megan Gannon, and Jim Busse of the Center for Research Incorporated prepared graphics for several chapters and provided emergency repairs to other figures. The writing of this book spanned several years and several editors at SPE. We appreciate the editorial work of Flora Cohen, Carla Atwal, and Holly Hargadine. We also appreciate the review by our colleague, Shapour Vossoughi, and a number of students who took the course at the University of Kansas.

For the second edition, revisions made to Chapters 5 through 8 were reviewed by several colleagues at other institutions. These include Randy Srighit (New Mexico Institute of Mining and Technology), Gary Pope (University of Texas at Austin), George Hirasaki (Rice University), and Sayed Farouq Ali (University of Calgary). Field case histories of application of miscible-flooding processes (Chapter 6) were provided by several individuals. These include Lanny Schoeling, Mark Linroth, Steve Pennell, and Reza Barati (Kinder Morgan Company) for assistance in data gathering and reviewing the material for the Scurry Area Canyon Reef Operations Committee (SACROC) Unit field case; Gary F. Teletzke (Exxon Mobil Upstream Research Company) for his review and guidance of the Means San Andres Unit field case; Charles A. Peterson and Bob Schwager (Devon Energy Company), who provided more-recent data and information resulting from field monitoring in discussion of the

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G. Paul Willhite
Don W. Green
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Chapter 1

Introduction to EOR Processes

1.1 Definition of EOR

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. Historically, these stages described the production from a reservoir in a chronological sense. Primary production, the initial production stage, resulted from the displacement energy naturally existing in a reservoir. Secondary recovery, the second stage of operations, usually was implemented after primary production declined. Traditional secondary recovery processes are waterflooding, pressure maintenance, and gas injection, although the term secondary recovery is now almost synonymous with waterflooding. Tertiary recovery, the third stage of production, was that obtained after waterflooding (or whatever secondary process was used). Tertiary processes used miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process became uneconomical.

The drawback to consideration of the three stages as a chronological sequence is that many reservoir production operations are not conducted in the specified order. A well-known example is production of the heavy oils that occur throughout much of the world. If the crude is sufficiently viscous, it may not flow at economic rates under natural energy drives, so primary production would be negligible. For such reservoirs, waterflooding would not be feasible; therefore, the use of thermal energy might be the only way to recover a significant amount of oil. In this case, a method considered to be a tertiary process in a normal, chronological depletion sequence would be used as the first, and perhaps final, method of recovery.

In other situations, the so-called tertiary process might be applied as a secondary operation instead of waterflooding. This action might be dictated by such factors as the nature of the tertiary process, availability of injectants, and economics. For example, if a waterflood before application of the tertiary process would diminish the overall effectiveness, then the waterflooding stage might reasonably be bypassed.

Because of such situations, the term “tertiary recovery” fell into disfavor in petroleum engineering literature and the designation of “enhanced oil recovery” (EOR) became more accepted. This latter term is used throughout this book. Another descriptive designation commonly used is “improved oil recovery” (IOR), which includes EOR but also encompasses a broader range of activities (e.g., reservoir characterization, improved reservoir management, and infill drilling). The term IOR is not used in this book.

Because of the difficulty of chronological oil-production classification, classification based on process description is more useful and is now the generally accepted approach, although the naming of the processes still incorporates the earlier scheme based on chronology. Oil recovery processes now are classified as primary, secondary, and EOR processes. A classification scheme is clearly useful in that it establishes a basis for communication among technical persons. However, it also has a pragmatic utility in the implementation of tax laws and accounting rules.

Primary recovery results from the use of natural energy present in a reservoir as the main source of energy for the displacement of oil to producing wells. These natural energy sources are solution gas drive, gas-cap drive, natural waterdrive, fluid and rock expansion, and gravity drainage. The particular mechanism of lifting oil to the surface, once it is in the wellbore, is not a factor in the classification scheme.

Secondary recovery results from the augmentation of natural energy through injection of water or gas to displace oil toward producing wells. Gas injection, in this case, is either into a gas cap for pressure maintenance and gas-cap expansion or into oil-column wells to displace oil immiscibly according to relative permeability and volumetric sweepout considerations. Gas processes that are based on other mechanisms, such as oil swelling, oil viscosity reduction, or favorable phase behavior, are considered EOR processes. An immiscible gas displacement is not as efficient as a waterflood and is used infrequently as a secondary recovery process today. (Its use in earlier times was much more prevalent.) Today, waterflooding is almost synonymous with the secondary recovery classification.

EOR results principally from the injection of gases or liquid chemicals and/or the use of thermal energy. Hydrocarbon gases, carbon dioxide (CO₂), nitrogen, and flue gases are among the gases used in EOR processes. In this book, the use of a gas is considered an EOR process if the recovery efficiency significantly depends on a mechanism other than immiscible frontal displacement characterized by high-interfacial-tension (IFT) permeabilities. A number of liquid chemicals are commonly used, including polymers, surfactants, and hydrocarbon solvents. Thermal processes typically consist of the use of steam or hot water, or rely on the in-situ generation of thermal energy through oil combustion in the reservoir rock.

EOR processes involve the injection of a fluid or fluids of some type into a reservoir. The injected fluids and injection processes supplement the natural energy present in the reservoir to displace oil to a producing well. In addition, the injected

fluids interact with the reservoir rock/oil system to create conditions favorable for oil recovery. These interactions might, for example, result in lower IFTs, oil swelling, oil viscosity reduction, wettability modification, or favorable phase behavior. The interactions are attributable to physical and chemical mechanisms and to the injection or production of thermal energy. Simple waterflooding and the injection of dry gas for pressure maintenance or oil displacement are excluded from the definition.

EOR processes often involve the injection of more than one fluid. In a typical case, a relatively small volume of an expensive chemical (primary slug) is injected to mobilize the oil. This primary slug is displaced with a larger volume of a relatively inexpensive chemical (secondary slug). The purpose of the secondary slug is to displace the primary slug efficiently with as little deterioration as possible of the primary slug. In some cases, additional fluids of even lower unit cost are injected after a secondary slug to reduce expenses. In such a case of multiple fluid injection, all injected fluids are considered to be part of the EOR process, even though the final chemical slug might be water or dry gas that is injected solely to displace volumetrically the fluids injected earlier in the process.

1.2 Target Oil Resource for EOR Processes

Several studies (Energy Research and Development Administration 1976; National Petroleum Council 1976, 1984; US Office of Technology Assessment 1978; US DOE 1989, 1990) in the US have estimated the potential oil recovery through the application of EOR processes. Part of the objectives of these studies was estimating the target oil resource for EOR (i.e., the amount of oil that would remain after exhaustion of recovery through primary and secondary processes). Fig. 1.1, which shows the total US oil resources, is a recent example. In the US as of the end of 1993, approximately 536×10^9 bbl of oil had been discovered. The cumulative production through 1993 was approximately 162×10^9 bbl, and the proven reserves amounted to 23×10^9 bbl (US DOE 1989, 1990). Proven reserves is the oil remaining in known reservoirs that can be expected to be recovered through application of current proven technology at economic conditions on the specified date. Thus, the proven reserves at the end of 1993 include primary and waterflood recovery. A small amount of EOR oil is also included in the proven reserves and is principally oil expected to be recovered through the application of steam processes in California.

As Fig. 1.1 shows, cumulative production plus oil reserves accounts for approximately one-third of the original oil in place (OOIP). Thus, the total target for EOR processes is large, amounting to approximately 351×10^9 bbl in the US alone. If this one-third recovery fraction for primary plus secondary production holds worldwide, then the EOR target approaches 2×10^{12} bbl for the world, not including countries that formerly had centrally planned economies.

The physical/chemical characteristics of the target oil are varied and range from high-API-gravity, volatile crudes of low viscosity to low-API-gravity, heavy crudes of very high viscosity. Significant amounts of oil exist across this physical/chemical spectrum, and, therefore, EOR technology cannot focus on a particular oil type without eliminating a large fraction of the target resource. Clearly, no single EOR process will be applicable to all crudes, and a number of different processes will have to be developed.

A parallel difficulty is that the oil resource exists in reservoirs of widely varying characteristics. Oil reservoir types range from very thick carbonate reef formations at significant depths to relatively shallow, thin sandstone bodies. Subsequent chapters will show that reservoir rock type and structure have an effect on most EOR processes and are important variables. Willhite (1986) describes the role of geology and its significance for displacement processes.

Finally, the saturation, distribution, and physical state of the oil in a reservoir as a result of past production operations are important factors in the implementation of an EOR process. Typically, a reservoir will undergo primary production followed by waterflooding. Recovery by those processes in individual reservoirs might have approached 35 to 50% OOIP when the waterflood reached an economic limit. The residual oil in the part of the reservoir swept by the waterflood remains largely

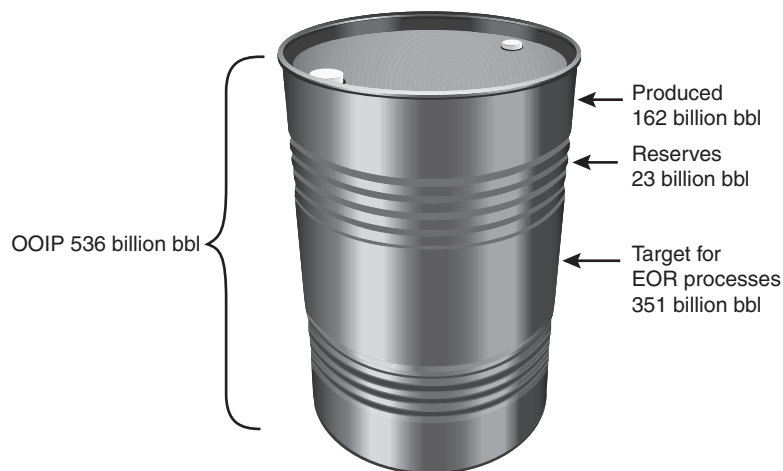


Fig. 1.1—US oil barrel showing oil produced, proven reserves, and target for EOR at end of 1993 (after US DOE 1996¹)

¹ Personal communication, BDM/US DOE, Bartlesville, Oklahoma, June 1996.

as isolated, trapped droplets (or ganglia) in the pores or films around the rock particles, depending on the rock wettability. Residual saturation typically is approximately 20 to 35% in swept regions. An EOR process must be able to mobilize the droplets or oil blobs and to create an oil bank that can be efficiently propagated to producing wells.

In other circumstances, an EOR process might be applied after primary production (i.e., as a secondary recovery operation in a chronological sense). In this case, the oil may exist at a relatively high saturation, perhaps approximately 50 to 60%, and may still exist in a connected state with a relative permeability to oil significantly greater than zero. A gas saturation might also be present, depending on the primary recovery mechanism. In this case, the EOR process would be expected to build an oil bank, much in the manner of a waterflood. The displacement efficiency, however, must be better than for a waterflood in that only small amounts of trapped oil should be left behind. That is, the residual oil saturation following the displacement must be low relative to waterflooding because the economic attractiveness of an EOR process applied as a secondary operation normally is compared with the alternative of waterflooding [i.e., recovery (and costs) greater than that expected from a standard waterflood].

In some instances, EOR processes are implemented as the initial or primary production stage. The usual situation is a viscous oil that would not be produced in economic quantities by primary mechanisms or waterflooding. The use of thermal energy, which decreases oil viscosity, is generally the preferred process in such cases. Again, the EOR process must mobilize the oil and displace it efficiently toward production wells.

In summary, the target oil resource is very large and occurs under diverse conditions. Oil type, reservoir rock, and formation type, as well as the oil's distribution, saturation, and physical state resulting from past operations, must all be considered in the design of an EOR process for a particular reservoir. This diversity has led to the development of several different EOR processes that can be considered for implementation.

1.3 Idealized Characteristics of an EOR Process

1.3.1 Efficient Microscopic and Macroscopic Displacement. The overall displacement efficiency of any oil recovery displacement process can be considered conveniently as the product of microscopic and macroscopic displacement efficiencies. In equation form,

$$E = E_D E_V, \dots \dots \dots (1.1)$$

where E = overall displacement efficiency (oil recovered by process/oil in place at start of process), E_D = microscopic displacement efficiency expressed as a fraction, and E_V = macroscopic (volumetric) displacement efficiency expressed as a fraction. Microscopic displacement relates to the displacement or mobilization of oil at the pore scale. That is, E_D is a measure of the effectiveness of the displacing fluid in moving (mobilizing) the oil at those places in the rock where the displacing fluid contacts the oil. E_D is reflected in the magnitude of the residual oil saturation, S_{or} , in the regions contacted by the displacing fluid.

Macroscopic displacement efficiency relates to the effectiveness of the displacing fluid(s) in contacting the reservoir in a volumetric sense. Alternative terms conveying the same general concept are sweep efficiency and conformance factor. E_V is a measure of how effectively the displacing fluid sweeps out the volume of a reservoir, both areally and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells. Both areal and vertical sweeps must be considered, and it is often useful to further subdivide E_V into the product of areal and vertical displacement efficiencies. E_V is reflected in the magnitude of average or overall residual oil saturation, S_{or} , because the average is based on residual oil in both swept and unswept parts of the reservoir.

Consider the magnitude of these efficiencies in a typical waterflood. For an example in which initial oil saturation, S_{oi} is 0.60 and S_{or} in the swept region is 0.30,

$$E_D = \frac{S_{oi} - S_{or}}{S_{oi}} = \frac{0.60 - 0.30}{0.60} = 0.50. \dots \dots \dots (1.2)$$

A typical waterflood sweep efficiency, E_V , at the economic limit is 0.7. Therefore,

$$E = E_D E_V = 0.50 \times 0.70 = 0.35. \dots \dots \dots (1.3)$$

Thus, for a typical waterflood, the overall displacement efficiency is on the order of one-third, which also represents the oil recovery efficiency (neglecting volume changes associated with pressure changes). This one-third figure is by no means a universal result applicable to all reservoirs. Individual reservoirs yield higher or lower recovery efficiencies, depending on the oil and reservoir characteristics. The result, however, does indicate that significant amounts of oil remain following the completion of a waterflood. And it is seen that this oil remains as a result of two factors. First, a residual oil saturation remains in those places swept by the water. Second, a large portion of the reservoir is not contacted by the injected water and thus oil has not been displaced from these regions and has not been displaced to production wells. In addition, some oil from the swept region may be displaced into unswept regions and increase the oil saturation in those regions over what it was before the flood began.

It is desirable in an EOR process that the values of E_D and E_V , and consequently E , approach 1.0. An idealized EOR process would be one in which the primary displacing fluid (primary slug) removed all oil from the pores contacted by the fluid ($S_{or} \rightarrow 0$), and in which the displacing fluid contacted the total reservoir volume and displaced oil to production wells. A secondary fluid slug used to displace the primary slug would behave in a similar manner in that it would displace the primary slug efficiently

both microscopically and macroscopically. As will be seen, the development of a “magic” displacing fluid or fluids having properties that will yield this result and still be economical is a monumental and unfulfilled task.

Several physical/chemical interactions occur between the displacing fluid and oil that can lead to efficient microscopic displacement (low S_{or}). These include miscibility between the fluids, decreasing the IFT between the fluids, oil volume expansion, and reducing oil viscosity. The maintenance of a favorable mobility ratio between displaced and displacing fluids also contributes to better microscopic displacement efficiency. EOR processes are thus developed with consideration of these factors. Fluids used as primary displacing slugs have one or more of the favorable physical/chemical interactions with the oil. Fluids used to displace the primary slug ideally should also have similar favorable interactions with the primary slug. The goal with an acceptable EOR fluid is to maintain the favorable interaction(s) as long as possible during the flooding process.

Macroscopic displacement efficiency is improved by maintenance of favorable mobility ratios between all displacing and displaced fluids throughout a process. Favorable ratios contribute to improvement of both areal and vertical sweep efficiencies. An ideal EOR fluid then is one that maintains a favorable mobility ratio with the fluid being displaced. Another factor important to good macroscopic efficiency is the density difference between displacing and displaced fluids. Large density differences can result in gravity segregation (i.e., the underriding or overriding of the fluid being displaced). The effect is to bypass fluids at the top or bottom of a reservoir, reducing E_v . If density differences do exist between fluids, this might be used to advantage by flooding in an updip or downdip direction. Reservoir geology, and in particular geologic heterogeneity, is an important factor in the consideration of macroscopic displacement efficiency. The effects of mobility and density differences can be amplified or diminished by the nature of the geology. An ideal EOR fluid thus is one that has a favorable mobility ratio with the fluid(s) being displaced and, further, maintains this favorable condition throughout the process. In addition, the density of an ideal EOR fluid should be comparable with that of the displaced fluid unless flooding can be performed in an updip or downdip direction.

1.3.2 Practical Considerations. Fluids that possess the properties required for good microscopic and macroscopic displacement efficiencies are certainly known or can be developed. A practical concern, however, is that the fluids are expensive, or for the case of thermal processes, the cost of developing the thermal energy that the fluids carry is high.

As described later, the nature of flow in porous media and rock/fluid interactions lead to the diminished effectiveness of injected fluid slugs. For example, fluid/fluid mixing causes injected fluid concentrations to change and physical adsorption causes the loss of certain chemical components. For thermal processes, heat conduction to overburden and underburden rocks results in a loss of thermal energy from the process. Such chemical losses, changes in composition, or losses of thermal energy mean that the injected fluid slug size must be large enough to sustain the losses or changes and still operate effectively. Thus, the size of the fluid slugs that are injected and their unit costs become major considerations in the design of an EOR process. In fact, injected fluid cost and crude oil price (and instability in price) are the two most important factors controlling the economic implementation of EOR processes.

Another consideration is the ease of handling an EOR fluid and its general compatibility with the physical injection/production system. Highly toxic or corrosive fluids, or fluids that are not readily injected, are not very amenable to use in EOR processes. While such fluids might be used with installation of special equipment, the cost is usually prohibitive.

The availability of an EOR fluid is also a consideration. If an EOR process is applied in a major reservoir, the fluid requirements for that single reservoir can be quite large. And if that process is widely accepted for application across the country or the world, the volume requirements can become an important limiting factor for its application. CO_2 is an example of this. A study by the US Office of Technology Assessment (1978) indicated that the total CO_2 required could ultimately reach 50×10^{12} scf. While CO_2 occurs naturally in underground reservoirs and is a byproduct of some commercial operations, such as fertilizer production, this projected demand could be difficult to satisfy, especially when geographic factors are considered.

The implementation and success or failure of an EOR process are always affected by reservoir geology and reservoir geologic heterogeneities. Processes that are well-understood in a laboratory environment and properly designed for the reservoir fluids may fail when implemented in the reservoir because of geologic factors. Reports of such failures are numerous in petroleum engineering literature. Geologic factors may lead to unexpected losses of chemicals or bypassing of fluids because of channeling in high-permeability zones or fractures. Similarly, fluid movement may be very nonuniform because of variations in rock properties. Unexpected chemical adsorption can sometimes occur, causing a deterioration of fluid slugs. Factors of this type, unless properly identified and understood before the start of a process, will likely cause a project failure. A number of procedures exist that can be used before implementation of an EOR process in an attempt to describe the reservoir geology. These procedures include geologic evaluations of well cores and logs, single-well and well-to-well tracer tests, pressure-transient analysis, and seismic surveys.

1.4 General Classifications and Description of EOR Processes

EOR processes can be classified into five categories: mobility-control, chemical, miscible, thermal, and other processes, such as microbial EOR.

Mobility-control processes, as the name implies, are those that are based primarily on maintaining favorable mobility ratios to improve the magnitude of E_v . Examples are thickening of water with polymers and reducing gas mobility with foams. Chemical processes are those in which certain chemicals, such as surfactants or alkaline agents, are injected to use a combination of phase behavior and IFT reduction to displace oil, thereby improving E_D . In some cases, mobility control is also a part of the chemical process, providing the potential of improving both E_v and E_D . In miscible processes, the objective is to inject fluids that are directly miscible with the oil or that generate miscibility in the reservoir through composition alteration. Examples are injection of hydrocarbon solvents or CO_2 . Phase behavior is a major factor in the application of such processes.

Thermal processes rely on the injection of thermal energy or the in-situ generation of heat to improve oil recovery. Steam injection and in-situ combustion from air or oxygen injection are examples. Alteration of oil viscosity, favorable phase behavior, and in some cases, chemical reaction are the primary mechanisms leading to improved oil recovery. “Other processes” is a

catch-all category. Examples of processes in this category are microbial-based techniques, immiscible CO₂ injection, and mining of resources at shallow depths. Such methods are not considered in this book.

The classification scheme is not altogether satisfactory in that there is a certain lack of precision in the terms used. For example, chemical processes is one category but chemicals clearly are used in all the processes. Also, there is some overlap in mechanisms between the categories. For example, the chemical processes rely on phase behavior and at least a limited solubility between the different fluids, which is similar to the miscible processes. Despite these shortcomings, the indicated names are used throughout this book, principally because they are deeply embedded in the petroleum engineering literature and are quite useful, with proper clarification, to divide the discussions in the book.

The following discussion of the processes acquaints the reader with the methods in general. This overview will be particularly useful for the material discussed in Chapters 2 through 4 on microscopic and macroscopic displacement efficiencies and linear displacement processes.

1.4.1 Mobility-Control Processes. A widely applied mobility-control process is the polymer-augmented waterflood shown schematically in Fig. 1.2. In a typical application, a solution of partially hydrolyzed polyacrylamide polymer in brine, at a concentration of a few hundred to several hundred ppm of polymer, is injected to displace oil (and associated water) toward production wells. The size of the polymer slug might be as much as 50 to 100% pore volume (PV) and might be varied in composition. That is, the highest polymer concentration used is injected for a period of time followed by slugs at successively lower concentrations. The final fluid injected is water or brine.

Polymer solutions are designed to develop a favorable mobility ratio between the injected polymer solution and the oil/water bank being displaced ahead of the polymer. The purpose is to develop a more uniform volumetric sweep of the reservoir, both vertically and areally, as illustrated in Fig. 1.2 for one-quarter of a five-spot pattern. In a conventional waterflood, if the mobility ratio is unfavorable, the water tends to finger by the oil and to move by the shortest path to the production well. This effect is amplified by reservoir geologic heterogeneities.

A polymer solution moves in a more uniform manner, as Fig. 1.2 shows. While flow still tends to be greatest in high-permeability zones and along the shortest path between the injection and production wells, the effect is damped because polymer solution mobility is less than water mobility. Thus, at the economic limit, E_v is larger for a polymer flood than for a waterflood. It is generally accepted that polymer solutions do not significantly affect final, or endpoint, residual oil saturation. But, depending on the nature of the fractional flow curve and the volume of water injected, the “effective” residual oil saturation at the economic level of a flood may be lower for polymer displacing a viscous oil than for a waterflood. The primary mechanism in a polymer flood, however, is an increase in the macroscopic sweep efficiency.

Partially hydrolyzed polyacrylamide polymers affect mobility in two ways. First, solutions of polymers have apparent viscosities that are larger than that of water. The polymer solutions are non-Newtonian, however, and can exhibit significant sensitivity to shear (i.e., apparent viscosity can be a function of the shear rate to which a solution is subjected). The solutions are also sensitive to brine type and concentration, which can affect the apparent viscosity. Second, polyacrylamide polymers adsorb on porous media and/or are mechanically entrapped as a result of their large physical size. This polymer retention reduces the amount of polymer in solution but also causes a decrease in the effective permeability of the porous medium. The mobility of a polyacrylamide polymer solution is thus reduced to less than that of the displaced oil/water bank by a combination of viscosity and effective permeability reduction.

Polymer types other than partially hydrolyzed polyacrylamides may also be used. The most common alternatives are called bio-polymers and are produced by fermentation manufacturing processes. These polymers affect the apparent solution viscosity but have little effect on apparent rock permeability because retention is much smaller.

The most serious limitation to polymer-augmented waterflooding is that projected ultimate recoveries are small compared with those of other EOR processes. Polymer flooding works primarily to improve macroscopic efficiency rather than microscopic efficiency. The process also is affected by the production operations that preceded the polymer flood. A previous successful waterflood, for example, can result in a polymer flood having only a minimal effect.

Other processes exist that are based on the application of foams, relative permeability alteration, or permeability blockage in high-permeability zones in an attempt to increase oil recovery. As discussed later, mobility-control processes also are used extensively with other EOR methods to improve overall process efficiency.

1.4.2 Chemical Processes. Chemical processes involve the injection of specific liquid chemicals that effectively displace oil because of their phase-behavior properties, which result in decreasing the IFT between the displacing liquid and oil. The surfactant/polymer

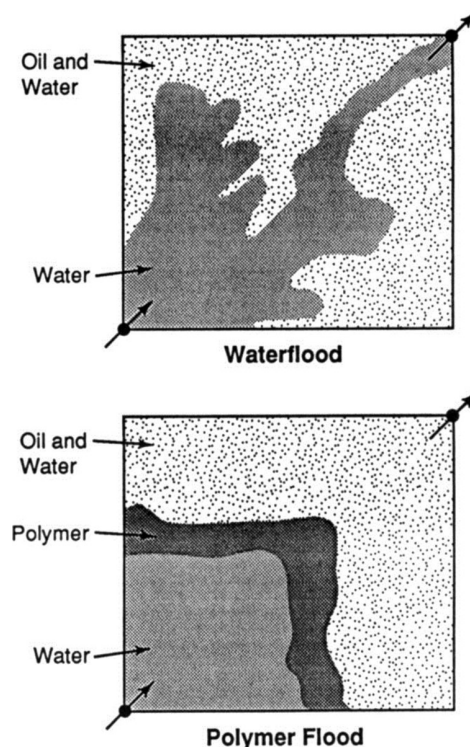


Fig. 1.2—Schematic of macroscopic displacement efficiency improvement with polymer-augmented waterflooding (one-quarter of a five-spot pattern).

process illustrated in **Fig. 1.3** has been demonstrated to have the most potential in terms of ultimate oil recovery in this category of EOR methods. In this process, the primary displacing liquid slug is a complex chemical system called a micellar solution. This solution contains a surfactant (usually a petroleum sulfonate), cosurfactant (an alcohol), oil, electrolytes, and water. The surfactant slug is relatively small, typically 10% PV. The surfactant slug is followed by a mobility buffer, a solution that contains polymer at a concentration of a few hundred ppm. This polymer solution is often graded in concentration, becoming more dilute in polymer as more of the solution is injected. The total volume of the polymer solution is typically approximately 1 PV.

The micellar solution has limited solubility with the oil and is designed to have an ultralow IFT with the oil phase. When this solution contacts residual oil drops, the drops, under a pressure gradient, are deformed as a result of the low IFT and are displaced through the pore throats. Coalescence of oil drops results in an oil bank that, along with water, moves ahead of the displacing chemical slug. The micellar slug also is designed to have a favorable mobility ratio with the oil bank and the water flowing ahead of the slug to prevent viscous fingering of the slug into the oil bank and to increase the macroscopic displacement efficiency.

The polymer-solution mobility buffer is injected to displace the micellar solution efficiently. The IFT between the polymer and micellar solutions is quite low, and only a small residual saturation of the micellar slug is trapped. The existence of a favorable mobility ratio between the polymer and micellar solutions also contributes to an efficient displacement.

In this process, the displacements are immiscible; that is, complete solubility does not exist between the micellar solution and oil or between the micellar and polymer solutions. A low IFT between displacing fluids is desirable at both ends of the micellar slug. A low IFT between the micellar solution and oil is required to mobilize discontinuous oil drops or films. At the back of the micellar slug, a low IFT results in minimal trapping and bypassing of the micellar solution. Clearly, if the micellar solution were not efficiently displaced by the polymer solution, then the micellar slug would deteriorate rapidly.

The surfactant processes have significant potential because of the possibility of designing a process where both E_v and E_d increase. There are important problems, however. The process is complex technologically and can be justified only when oil prices are relatively high and when residual oil after waterflooding is substantial. The chemical solutions, which contain surfactant, cosurfactant, and sometimes oil, are expensive. Chemical losses can be severe. Such losses can occur as a result of adsorption, phase partitioning and trapping, and bypassing owing to fingering if mobility control is not maintained. These losses must be compensated for by increasing the volume of micellar solution injected. The stability of surfactant systems in general is known to be sensitive to high temperatures and high salinity. Systems that can withstand these conditions must be developed if the process is to have wide applicability. For example, early applications have essentially excluded carbonate reservoirs, in part because of the high salinity usually associated with such formations and high concentrations of divalent ions.

There are several variations to the surfactant process, and some of these will be described later in this book. Other chemical methods have also been developed. Alkaline flooding is a process in which injected alkaline chemicals react with certain components in the oil to generate a surfactant in situ. The process has potential but apparently is limited in scope of application. Various alcohol processes also have been tested under laboratory conditions, but these have not been attempted in the field. These processes will be discussed but only in a limited manner.

1.4.3 Miscible Processes. The primary objective in a miscible process is to displace oil with a fluid that is miscible with the oil (i.e., forms a single phase when mixed at all proportions with the oil) at the conditions existing at the interface between

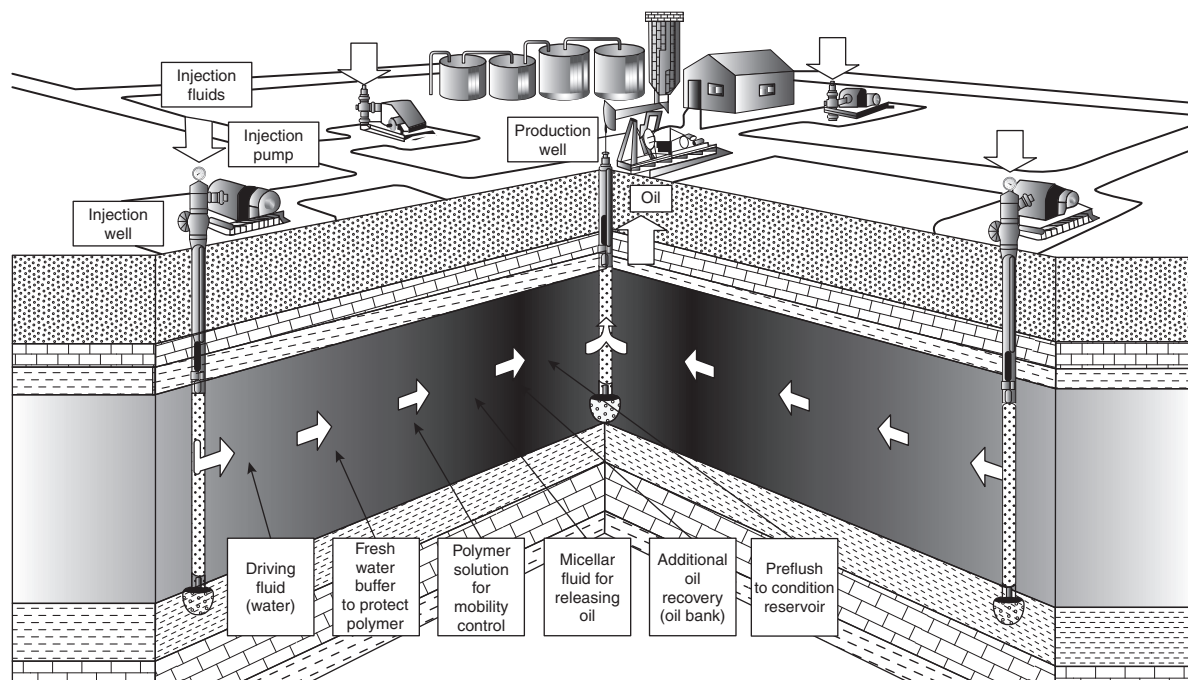


Fig. 1.3—Surfactant/polymer process (after US DOE).

the injected fluid and the oil bank being displaced. There are two major variations in this process. In one, called a first-contact-miscible (FCM) process, the injected fluid is directly miscible with the reservoir oil at the conditions of pressure and temperature existing in the reservoir. **Fig. 1.4** illustrates the FCM process. A relatively small slug of a hydrocarbon fluid, such as liquefied petroleum gas (LPG), is injected to displace the oil. The primary slug size would be approximately 10 to 15% PV. The LPG slug, in turn, is displaced by a larger volume of a less-expensive gas that is high in methane concentration (dry gas). In some cases, water may be used as the secondary displacing fluid.

The process is effective primarily because of miscibility between the primary slug and the oil phase. Primary-slug/oil interfaces are eliminated, and oil drops are mobilized and moved ahead of the primary slug. Miscibility between the primary slug and the secondary displacing fluid (dry gas in Fig. 1.4) is also desirable. Otherwise, the primary slug would be trapped as a residual phase as the process progresses.

The other variation of the miscible processes is the multiple-contact-miscible (MCM) process. In this, the injected fluid is not miscible with the reservoir oil on first contact. Rather, the process depends on the modification of composition of the injected phase, or oil phase, through multiple contacts between the phases in the reservoir and mass transfer of components between them. Under proper conditions of pressure, temperature, and composition this composition modification will generate miscibility between the displacing and displaced phases in situ.

The CO₂ miscible process illustrated in **Fig. 1.5** is one such process. A volume of relatively pure CO₂ is injected to mobilize and displace residual oil. Through multiple contacts between the CO₂ and oil phase, intermediate- and higher-molecular-weight hydrocarbons are extracted into the CO₂-rich phase. Under proper conditions, this CO₂-rich phase will reach a composition that is miscible with the original reservoir oil. From that point, miscible or near-miscible conditions exist at the displacing front interface. Under ideal conditions, this miscibility condition will be reached very quickly in the reservoir and the distance required to establish multiple-contact miscibility initially is negligible compared with the distance between wells.

The critical temperature of CO₂ is 87.8°F, and thus, in most cases it is injected as a fluid above its critical temperature. The viscosity of CO₂ at injection conditions is small, approximately 0.06 to 0.10 cp, depending on reservoir temperature and pressure. Oil and water are therefore displaced by CO₂ under unfavorable-mobility-ratio conditions in most cases. As described earlier, this leads to fingering of the CO₂ through the oil phase and also to poor macroscopic displacement efficiency.

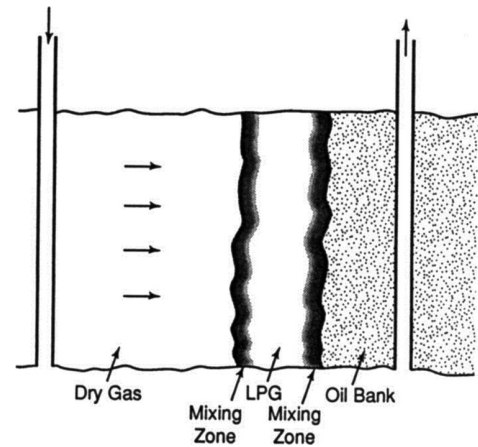


Fig. 1.4—FCM process with LPG and dry gas.

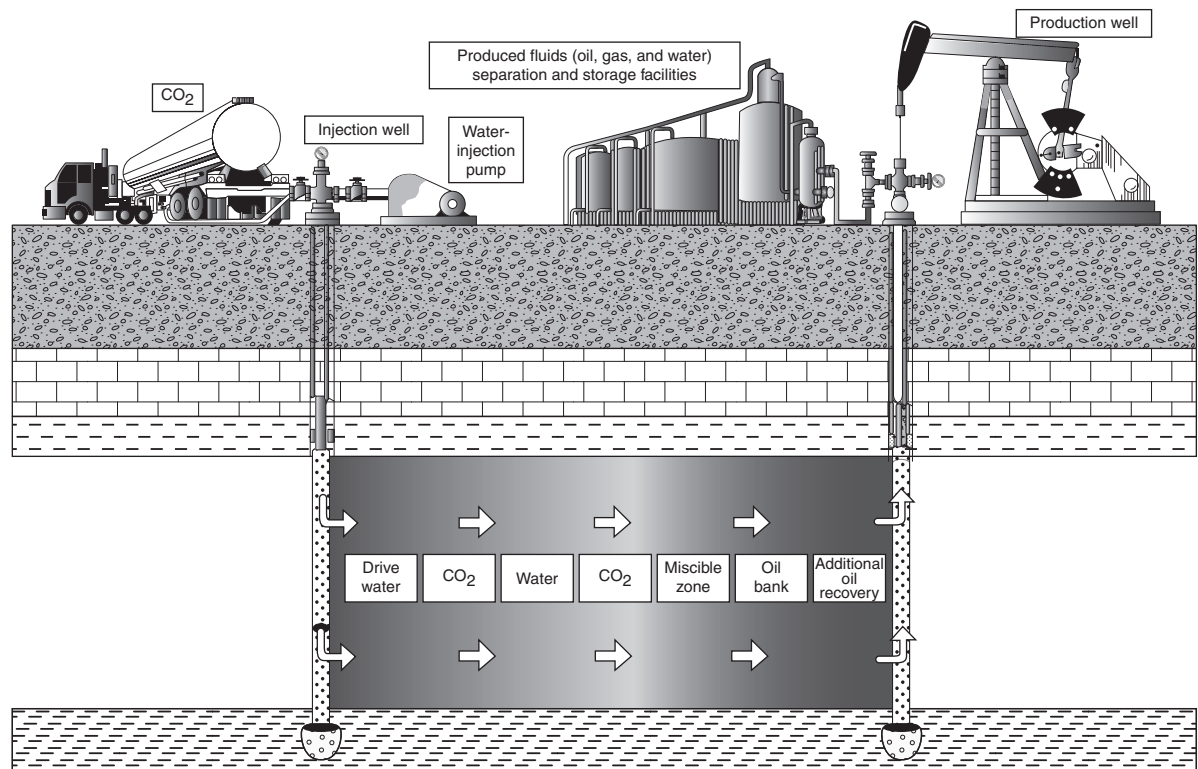


Fig. 1.5—CO₂ miscible process (after US DOE).

One approach to overcoming this difficulty has been to inject slugs of CO_2 and water alternately. This method is called the water-alternating-gas (WAG) process. The purpose of the water injection is to reduce the relative permeability to CO_2 and thereby to reduce its mobility. Another advantage of the WAG process is that it spreads the demand for CO_2 over time. Other methods of mobility control are being tested. These include the use of foams and polymers in conjunction with CO_2 injection. Another problem with the CO_2 process results from the density difference between CO_2 and water and sometimes between CO_2 and the oil. At injection conditions, CO_2 has a specific gravity of approximately 0.4 (again depending on the specific reservoir conditions). Depending on oil density, CO_2 can tend to move to the top of the formation and to override the displaced fluids. In some cases, this gravity effect is exploited by flooding from the top of the reservoir and displacing fluids downdip, but this can be done only where the reservoir structure is suitable.

For the reasons cited, CO_2 often channels in a reservoir and breaks through at production wells relatively early in the process. Because the fuel value of CO_2 is zero, it is usually separated from other produced gases, recompressed, and reinjected. Recycling of CO_2 adds to the cost of a project, but is typically less expensive than purchasing all new CO_2 . The separated natural gas has its normal fuel value and is thus salable.

Other gases are suitable for application as MCM displacement fluids in a manner similar to that described for CO_2 . These include relatively dry hydrocarbon gases (high CH_4 content), nitrogen, or flue gases. The difference is that these gases usually require much higher pressures to achieve miscibility than CO_2 . These other gases are more suitable for deep reservoirs where high pressures can be achieved without fracturing the reservoir rock. A rough rule of thumb for fracturing pressures is 0.6 psi/ft of depth. If fracture pressure is exceeded in the process, the reservoir rock will fail and injected fluids will channel through the fractures, bypassing most of the oil. Thus, the process design and choice of displacing fluid depend on operating pressure, which in turn depends on reservoir depth.

Another modification of the MCM process uses a hydrocarbon fluid that is rich in components such as ethane and propane. In this process, these injected components condense into the oil phase, enriching the oil with the lighter components. Again, under proper conditions, the oil-phase composition can be modified so that it becomes miscible with the injected fluid and in-situ generation of miscibility occurs.

Problems with the miscible processes are primarily those described for the CO_2 MCM process. The miscible fluids generally have small viscosities and therefore fingering and poor volumetric sweeps result. Reservoir heterogeneities magnify this problem. The development of methods to control mobility has proved to be a difficult task. Density differences also contribute to poor volumetric contact because of gravity override unless these density differences can be used to advantage in dipping reservoirs. Finally, the fluids applicable at moderate reservoir pressures are expensive and, in some cases, in limited supply.

1.4.4 Thermal Processes. Thermal processes may be subdivided into hot waterfloods, steam processes, and in-situ combustion. The hot waterflood has been used only sparingly and with limited success and will not be considered here. Steam is used in two different ways: cyclic steam stimulation and steamdrive (steamflood). **Fig. 1.6** shows steam stimulation, sometimes called steam soak or the huff 'n' puff process. This is a single-well method in which steam is injected into a production well for a specified period. The well is then closed in for a while, the so-called "soak" part of the process. The well

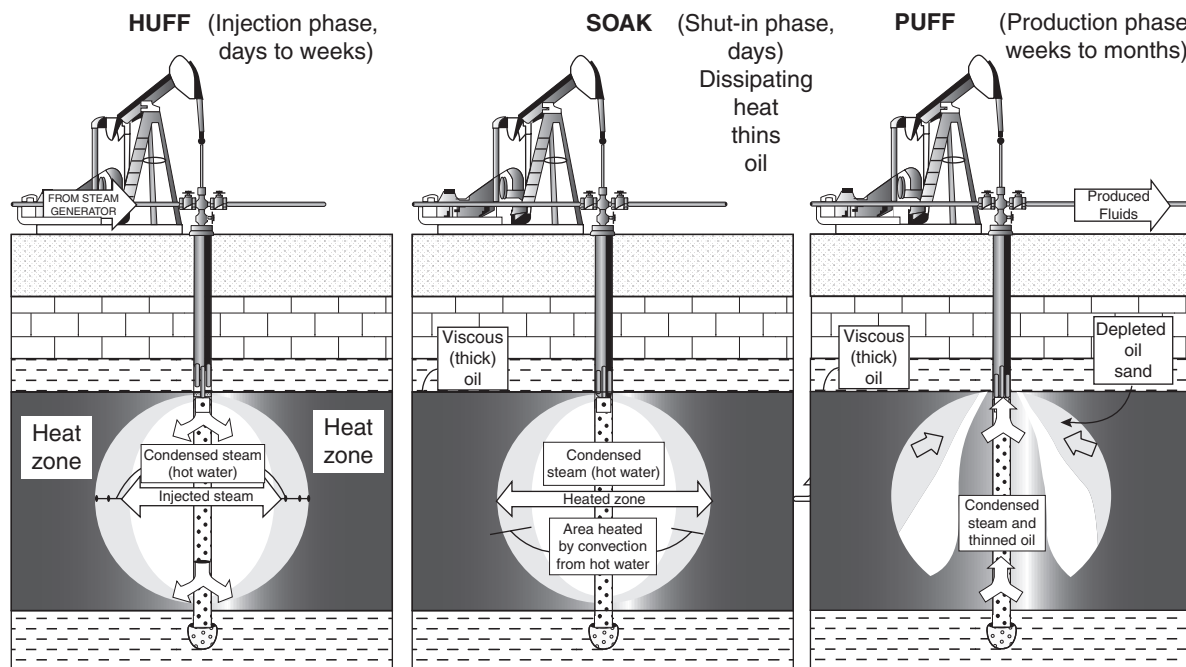


Fig. 1.6—Cyclic-steam-stimulation process (after US DOE).

is next opened for production, which continues until flow rates diminish to a point when the entire procedure is repeated. A typical well may go through several cycles, with the effect of the steam gradually diminishing with continued applications.

Production is increased through a combination of mechanisms, including viscosity reduction, steam flashing, oil swelling, and steam stripping. The cumulative effect of these mechanisms is greatest on heavier (low-API-gravity) oils with high viscosities. Steam injection therefore tends to be used on viscous, low-API-gravity oils.

The second general method of steam application is the steamdrive, or steamflood, process shown in **Fig. 1.7**. In this method, steam is injected through injection wells and the fluids are displaced toward production wells that are drilled in specified patterns.

Recovery mechanisms in this method also are based on viscosity reduction, oil swelling, steam stripping, and steam-vapor drive. As the steam loses energy in its movement through the reservoir, condensation to liquid water occurs. Therefore, the process consists of a hot waterflood in the region of condensation followed by steam displacement. The process has been applied primarily to low-API-gravity, high-viscosity oils but is also applicable to lighter crudes.

A major problem with steam processes is that the steam density is much lower than that of oil and water and therefore the steam tends to move to the top of a reservoir, overriding a large part of the oil body. This is compensated for partially by heat conduction away from the zone of actual contact by the steam, however, and the heated portion of a reservoir can be a high percentage of total reservoir volume. The heated volume depends significantly on the reservoir structure. Mobility control is also a problem with the steamdrive process because steam viscosity is small compared with the viscosities of liquid water and oil. Other points of concern include heat losses, equipment problems from operating at high temperatures, and pollutant emissions resulting from surface steam generation.

In Canada, the extensive heavy oil and tar sands deposits represent a hydrocarbon resource estimated to contain 1.845 Bbbl of hydrocarbon (Alberta Energy Regulator 2014, Table 1). The resource is immobile at reservoir temperature. The capability to drill and complete long horizontal wells in these deposits led to the development of steam-assisted gravity drainage (SAGD). SAGD is based on reservoir heating through a set of parallel horizontal wells, as shown in **Fig. 1.8**. In this process, well pairs are completed so that they are approximately 5 m apart in the vertical plane. The upper well is used for steam injection and the lower well is the production well. Gravity segregation of steam and condensate occur because of the differences in densities, and the steam eventually rises to the top of the steam chamber, as shown in Fig. 1.8 (Butler 1994). As the reservoir heats, bitumen is mobilized and flows by gravity to the production well.

In-situ combustion, shown schematically in **Fig. 1.9**, is another thermal process. In this process, thermal energy is generated in the reservoir by combustion, which may be initiated with either an electric heater or gas burner or may be spontaneous. Oxygen, as air or in a partially purified state, is compressed at the surface and continuously injected (dry process), often together with water (wet process). In the heating and combustion that occur, the lighter components of the oil are vaporized and moved ahead. Depending on the peak temperature attained, thermal cracking may occur, and vapor products from this reaction also move downstream. Part of the oil is deposited as a coke-like material on the reservoir rock, and this solid material serves as the fuel in the process. Thus, as oxygen injection is continued, a combustion front slowly propagates through the reservoir, with the reaction components displacing vapor and liquids ahead toward production wells.

Recovery mechanisms include viscosity reduction from heating, vaporization of fluids, and thermal cracking. Injected gases and water pick up energy as they pass through the burned zone and move toward the combustion front. Ahead of the combustion front, a steam plateau exists (i.e., a region of condensing steam in which the temperature is almost constant at

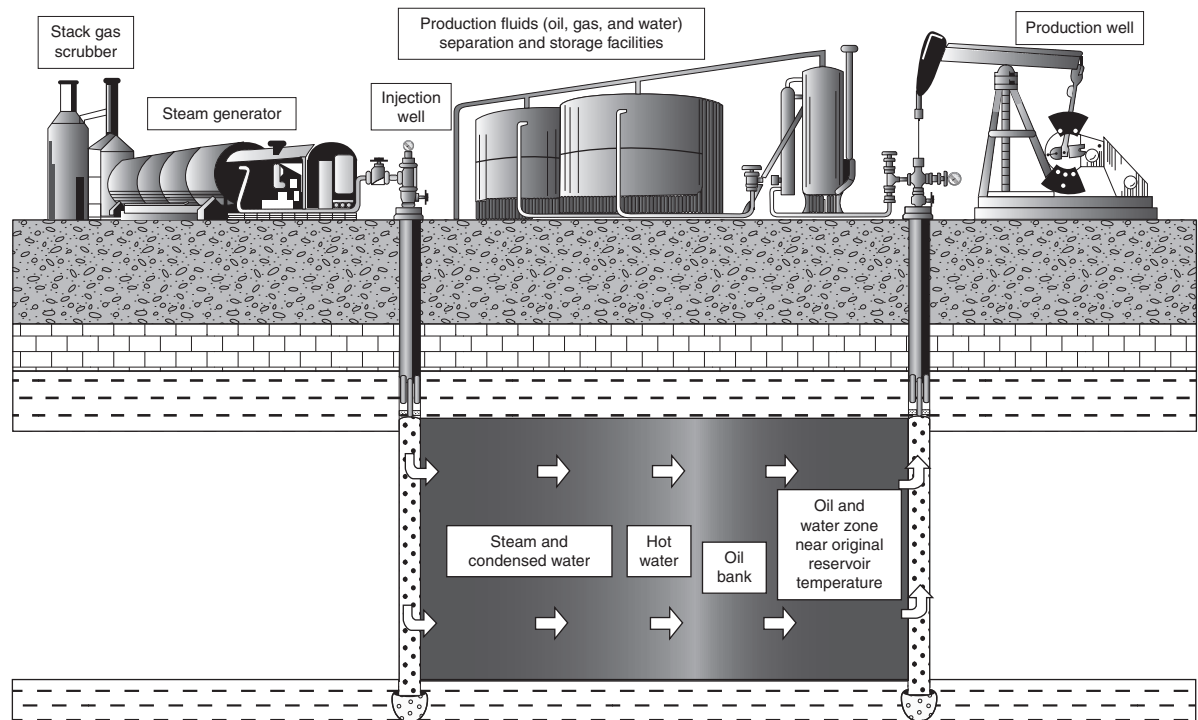


Fig. 1.7—Steamflooding process (after US DOE).

Vertical Cross-Section Through Growing Steam Chamber

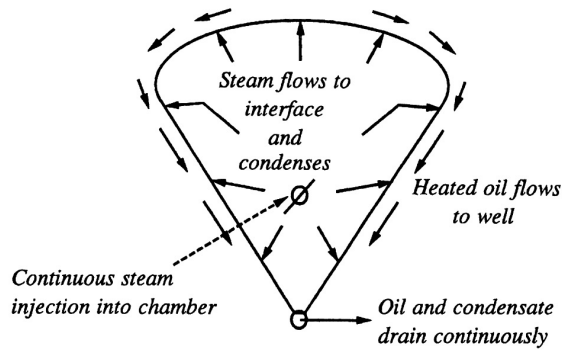


Fig. 1.8—Schematic of the SAGD process (Butler 1994). Printed in Horizontal Wells for the Recovery of Oil, Gas and Bitumen, Petroleum Society Monograph No. 2, CIM, Calgary. Reproduced with permission from the Canadian Institute of Mining, Metallurgy and Petroleum.

may move in a nonuniform manner through the reservoir, with resulting poor volumetric contact. Also, if proper conditions are not maintained at the combustion front, the combustion reaction can weaken and cease completely. The process effectiveness is lost if this occurs. Finally, because of the high temperatures generated, significant equipment problems can occur at the wells. Pollutant emission control also can be of concern in some cases.

1.5 Potential of the Different Processes

As mentioned previously, the potential recoveries in the US by the different EOR processes were estimated in a number of relatively early studies (Energy Research and Development Administration 1976; National Petroleum Council 1976, 1984; US Office of Technology Assessment 1978; US DOE 1989, 1990). While specific recovery estimates for the different processes vary, the general conclusions are similar. Results from the study by the National Petroleum Council (NPC) (1984) are summarized in **Figs. 1.10 through 1.12**. Data shown in these figures indicate the general magnitude of oil recovery predicted from the use of the different processes, giving the reader a feel for their relative predicted importance. In the NPC study, mobility-control processes were included within the chemical-process category. Most of the recovery within this category, however,

the steam saturation temperature corresponding to the reservoir pressure). A hot waterflood essentially exists in this region, much in the same manner as in a steamdrive process. Ahead of the steam plateau, the temperature decreases to the original reservoir temperature.

There are variations to the in-situ combustion process. In wet combustion, water is injected along with air. The water effectively picks up energy in the burned zone behind the front. It also has beneficial effects on the combustion process and reduces the combustion-zone temperature. In another variation, not often applied, the combustion is carried out in a reverse manner. Combustion is started at the production wells. Oxygen is still injected at injection wells and so the combustion zone moves in the direction opposite to the fluid flow.

The in-situ combustion process effectively displaces oil in the regions contacted. Approximately 30% of the oil in place is required as fuel in the burning. This percentage varies, of course, depending on the oil composition and saturation, combustion conditions, and rock properties.

A major problem with this method is control of the movement of the combustion front. Depending on reservoir characteristics and fluid distributions, the combustion front

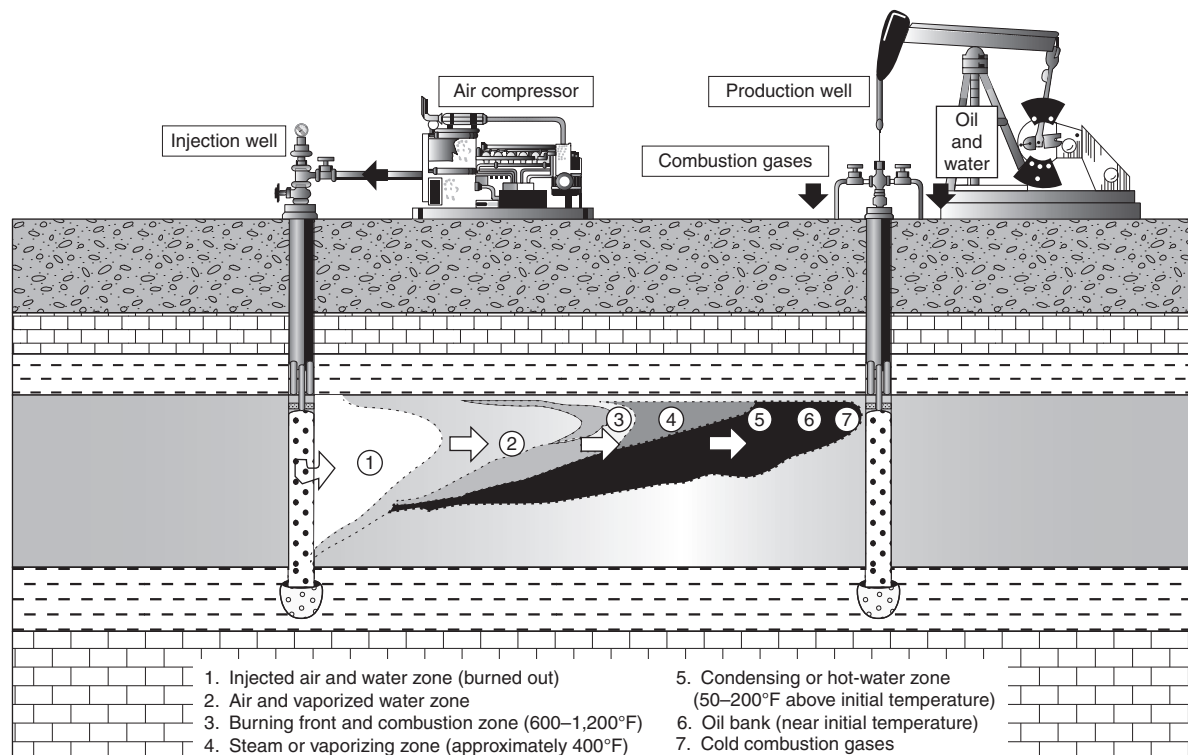


Fig. 1.9—In-situ combustion process (after US DOE).

results from the use of chemicals that decrease the IFT between the displacing fluid and the oil.

The NPC study was based on examination of reservoirs having more than 50×10^6 bbl OOIP. This data base encompassed approximately 67% of the total OOIP in the US as of 1980. Fig. 1.10 shows projected ultimate recoveries for reservoirs in the data base for each of the major processes and cumulative ultimate recoveries for two different technology scenarios, both at an assumed oil price of USD 30/bbl (constant 1983 dollars) and a minimum rate of return of 10%. The implemented-technology case was based on application of technology in existence at the time of the study. In the advanced-technology case, use of new technology that might be developed over the next 30 years was assumed (which is the reason for the distinction in recovery through and after 2013 in Fig. 1.11).

The effect of price on recovery is shown in Fig. 1.11, where crude oil prices from USD 20 to 50/bbl were assumed for the two technology scenarios. Oil price has a significant effect in the USD 20 to 30/bbl range, but little effect above approximately USD 40/bbl. Predicted potential production rates for the different processes and cumulative rates are presented in Fig. 1.12 for the advanced-technology case at an oil price of USD 30/bbl.

Other projections (US Office of Technology Assessment 1978; US DOE 1990) were more optimistic in terms of ultimate recovery. All the studies projected that a significant amount of incremental oil could be recovered by EOR processes under favorable economic conditions. Recovery rates could increase over the next several years beyond the dates of the studies. However, ultimate recoveries will not be achieved until well into the 21st century.

Actual cumulative production rates for all EOR projects in the US for the years 1984–95 are shown in Fig. 1.12 (Moritis 1990, 1996) along with the NPC projections. As of the beginning of 1996, thermal processes contributed approximately 424,000 B/D, miscible and immiscible gas processes contributed approximately 299,000 B/D, and chemical processes (including polymer processes) added less than 1,000 B/D. Moritis (1996) reports data on the status of EOR projects around the world as of the beginning of 1996.

The *Oil & Gas Journal* has presented biennial summaries of EOR projects in the US and around the world since 2000. Fig. 1.13 summarizes the data from the 2014 report for the US (Koottungal 2014). Comparison of the data presented in Fig. 1.12 shows that the predictions made in the 1970s and 1980s for the US, both for the individual process and the total production rates, were overly optimistic. Production from miscible/immiscible gas projects has come the closest to the projections for the US, while production

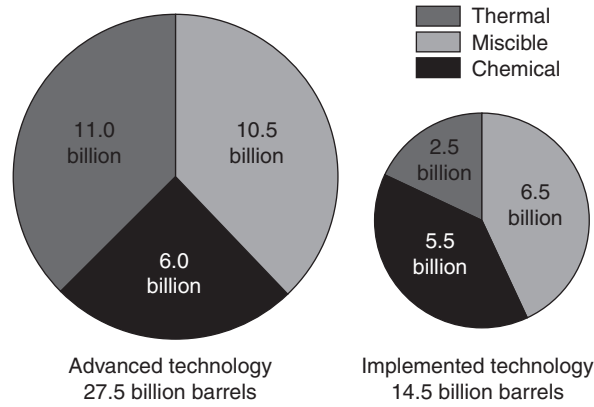


Fig. 1.10—Potential EOR ultimate recovery (National Petroleum Council 1984).

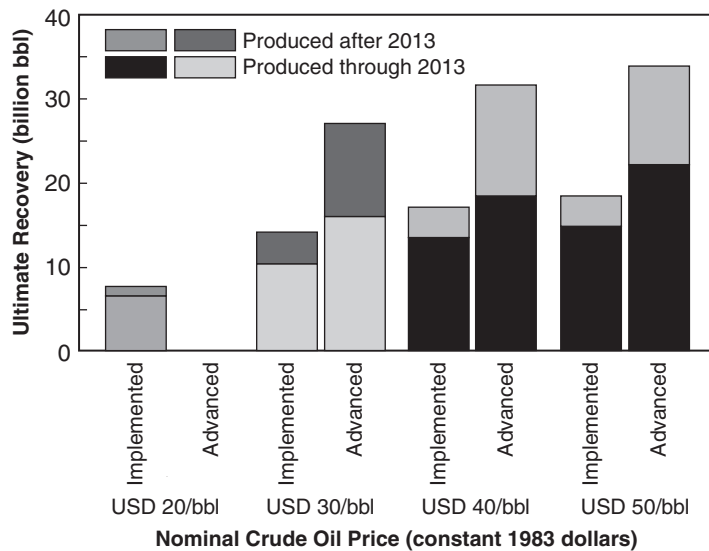


Fig. 1.11—Potential EOR ultimate recovery as a function of oil price (National Petroleum Council 1984).

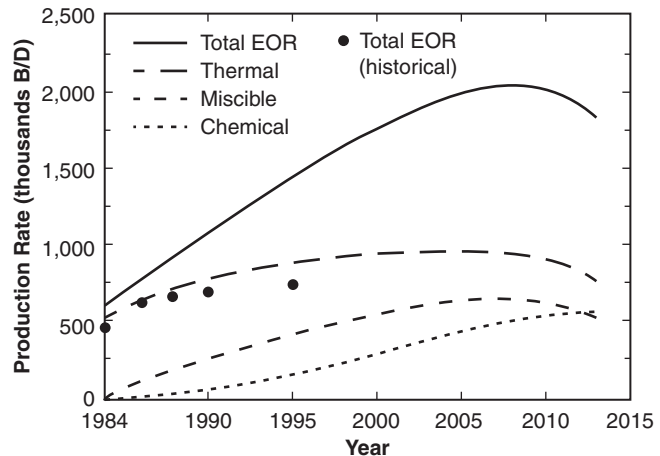


Fig. 1.12—Potential EOR production rates (National Petroleum Council 1984).

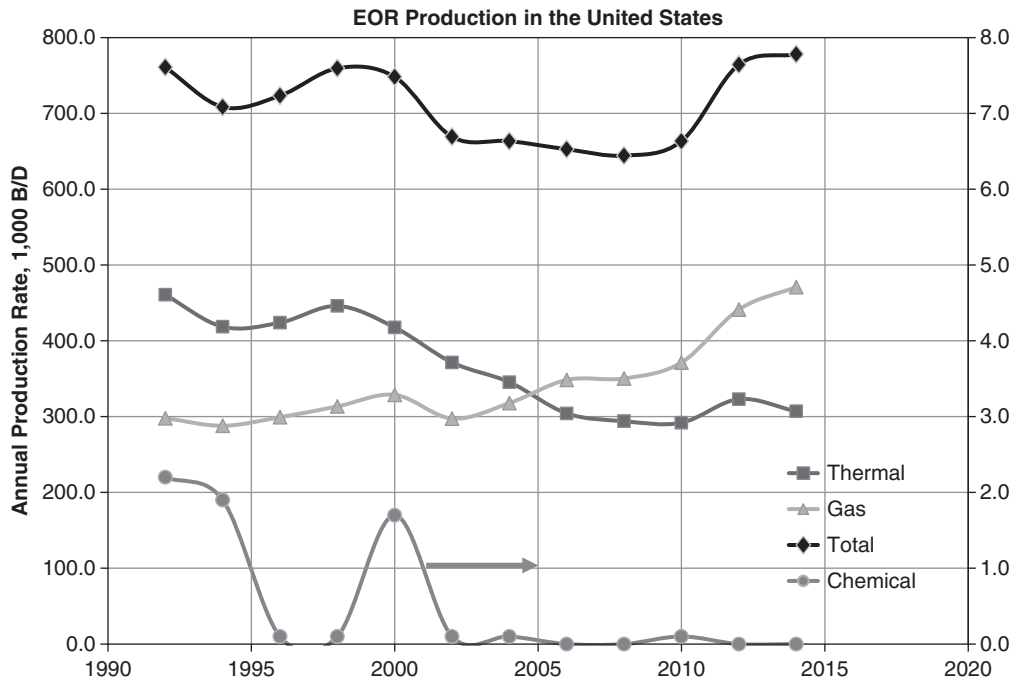


Fig. 1.13—EOR recoveries in the US, 1992–2014 (Kooftungal 2014).

from thermal processes has fallen short and is declining, and major chemical projects have not materialized. This shortfall is attributed, in part, to large fluctuations in oil price over this period and the development of technologies (other than EOR) that compete for development of expanded production. However, for thermal and chemical processes, there are major projects outside the US, including, for example, SAGD in Canada and polymer flooding in China. In later chapters of this book, a number of industrial-scale field projects for the different processes are described in some detail. While the US EOR production has not met the earlier predictions, the magnitude of production has been very significant, accounting for approximately 10% of total US crude production as of 2014.

1.6 Screening Criteria for Process Applicability

The US national studies (Energy Research and Development Administration 1976; National Petroleum Council 1976, 1984; US Office of Technology Assessment 1978; US DOE 1989, 1990) used general, or rule-of-thumb, technical screening criteria in the process evaluations. These criteria reflect current estimates of the range of oil and reservoir properties over which the different processes are applicable. **Table 1.1** gives a more recent set of such criteria (Taber et al. 1996). Restrictions on the application of the processes exist. For example, the CO₂ miscible process is limited to reservoirs with sufficient depth to obtain the miscibility pressure and to oils that have relatively high API gravity because of miscibility pressure and/or mobility problems. Steamdrive has reservoir depth limitations because of heat losses and the steam temperatures obtainable. Surfactant/polymer processes are generally limited because of salinity and temperature and the associated difficulty of designing stable surfactant/polymer systems. The screening criteria shown in Table 1.1 are only approximate. In specific cases, successful designs may be developed to exceed the published criteria, and thus, each potential reservoir situation should be considered individually. Also, as the technology develops, the limitations will be relaxed to reflect new knowledge about known processes, variations of known processes, or even new processes.

1.7 Organization of the Textbook

The first four chapters present a general overview of the major EOR processes and a discussion of reservoir engineering principles that relate to oil recovery. The topics have been subdivided into principles that relate to displacement on a microscopic scale (Chapter 2), to linear displacement (Chapter 3), and to macroscopic (or volumetric) displacement (Chapter 4). For those familiar with trapping and mobilization processes in porous media, Chapters 2 through 4 will be a review.

The different classifications of processes are described in the remainder of the book. For each general type of process, a chapter deals with the fundamental displacement mechanisms for the process type. EOR technology is advancing relatively rapidly. A difficulty in writing a book is determining which technologies are reasonably well-established and which are speculative and largely unproved. The purpose of each chapter about the different process types is to describe the principles established to relate to the recovery mechanisms. In the different chapters, certain specific processes are described in more detail, including current design procedures. Practical problems associated with the processes are discussed. Because of space limitations, all the variations of the different process types cannot be described in detail. For example, Chapter 6 emphasizes a description of the CO₂ miscible process. Other miscible processes such as condensing-gas drive and nitrogen displacement, however, are presented in less detail. The discussions given are intended to provide the reader with a basis for proceeding to other, related processes.

Oil Properties				Reservoir Characteristics					
EOR Method	Gravity °API	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)									
Nitrogen (& Flue Gas)	>35/ <u>48</u> / ¹	<0.4\ <u>0.2</u> \	High % of C ₁ -C ₇	>40/ <u>75</u> / ¹	Sandstone or carbonate	Thin unless dipping	N.C. ²	>6,000	N.C.
Hydrocarbon	>23/ <u>41</u> / ¹	<3\ <u>0.5</u> \	High % of C ₂ -C ₇	>30/ <u>80</u> / ¹	Sandstone or carbonate	Thin unless dipping	N.C.	>4,000	N.C.
Carbon Dioxide	>22/ <u>36</u> / ¹	<10\ <u>1.5</u> \	High % of C ₅ -C ₁₂	>20/ <u>55</u> / ¹	Sandstone or carbonate	(Wide range)	N.C.	>2,500	N.C.
Chemical									
Micellar/Polymer, Alkaline/Polymer (ASP), and Alkaline Flooding	>20/ <u>35</u> / ¹	<35\ <u>13</u> \	Light, intermediate; some organic acids for alkaline floods	>35/ <u>53</u> / ¹	Sandstone preferred	N.C.	>10/ <u>450</u> / ¹	<9,000\ <u>3,250</u>	<200\ <u>80</u>
Polymer Flooding	>15 ≤ 40	<150, >10	N.C.	>70/ <u>80</u> / ¹	Sandstone preferred	N.C.	>10 ³ / <u>800</u> / ¹	<9,000	<200\ <u>140</u>
Thermal									
Combustion	>10/ <u>16</u> ->?	<5,000→ <u>1,200</u>	Some asphaltic components	>50/ <u>72</u> / ¹	High porosity sand/sandstone	>10	>50 ⁴	<11,500\ <u>3,500</u>	>100/ <u>135</u>
Steam	>8- <u>13.5</u> ->?	<200,000\ <u>4,700</u>	N.C.	>40/ <u>66</u> / ¹	High porosity sand/sandstone	>20	>200 ⁵	<4,500\ <u>1,500</u>	N.C.

1. Underlined values represent the approximate mean or average for current field projects. ¹ indicates that higher value of parameter is better.

2. N.C. = not critical.

3. >5 md from some carbonate reservoirs.

4. Transmissibility > 20 md-ft/cp.

5. Transmissibility > 50 md-ft/cp.

Table 1.1—Summary of screening criteria for enhanced recovery methods (Taber et al. 1996).

Nomenclature

Parameter definitions followed by dimensions and typical units used in text.

D	= depth, L, ft	S_o	= oil saturation, L^3/L^3 , volume fraction
E	= overall displacement efficiency, L^3/L^3 , volume fraction	S_{oi}	= initial oil saturation, L^3/L^3 , volume fraction
E_D	= microscopic displacement efficiency, L^3/L^3 , volume fraction	S_{or}	= residual oil saturation, L^3/L^3 , volume fraction
E_V	= macroscopic (volumetric) displacement efficiency, L^3/L^3 , volume fraction	\bar{S}_{or}	= average residual oil saturation (averaged over entire reservoir volume), L^3/L^3 , volume fraction
h	= pay-zone thickness, L, ft	T_R	= reservoir temperature, T, °F
k	= permeability, L^2 , md	ϕ	= porosity, L^3/L^3 , volume fraction
p_R	= reservoir pressure, mL/t ² , psi	μ	= viscosity, mL/t, cp

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SI Metric Conversion Factors

bbl	× 1.589 873	E-01	= m ³
cp	× 1.0*	E-03	= Pa·s
ft	× 3.048*	E-01	= m
ft ³	× 2.381 685	E-02	= m ³
°F	(°F - 32)/1.8		= °C
psi	× 6.894 757	E+00	= kPa

*Conversion factor is exact.