FUNDAMENTALS OF ENHANCED OIL RECOVERY

Larry W. Lake, Russell T. Johns, William R. Rossen, and Gary A. Pope

Fundamentals of Enhanced Oil Recovery

Fundamentals of Enhanced Oil Recovery

Larry Lake
University of Texas at Austin

Russell T. Johns
The Pennsylvania State University

William R. Rossen
Delft University of Technology

Gary A. Pope
University of Texas at Austin

Society of Petroleum Engineers

Disclaimer

This book was prepared by members of the Society of Petroleum Engineers and their well-qualified colleagues from material published in the recognized technical literature and from their own individual experience and expertise. While the material presented is believed to be based on sound technical knowledge, neither the Society of Petroleum Engineers nor any of the authors or editors herein provide a warranty either expressed or implied in its application. Correspondingly, the discussion of materials, methods, or techniques that may be covered by letters patents implies no freedom to use such materials, methods, or techniques without permission through appropriate licensing. Nothing described within this book should be construed to lessen the need to apply sound engineering judgment nor to carefully apply accepted engineering practices in the design, implementation, or application of the techniques described herein.

Contents

Foreword

This book is the second edition of the 1989 book by the name *Enhanced Oil Recovery*. As such, it reflects the substantial changes that have taken place in enhanced oil production technology since that time: from a collection of minor technologies in the early 1980s to a significant and growing portion of the worldwide oil production today.

While it is true that a textbook is out of date the day it is published, there are a couple of ways to head off obsolescence:

First, broaden the topical material. Although the current book is on enhanced oil recovery (EOR), and EOR is *not* waterflooding, there is substantial coverage on waterflooding, as there is on basic equations, petrophysics, and phase behavior. Indeed, the 1989 book has served as a text for courses (or portions thereof) in numerical simulation, waterflooding, thermodynamics, and petrophysics.

Second, stick to the fundamentals. The fundamentals change slowly if at all, and the current text continues to focus on the basics of material and energy balances, phase behavior, and fractional flow theory.

The target audience remains the same as for the 1989 text: It is a graduate-level textbook whose material is intended to be taught over two long semesters.

So what are the differences with the 1989 text? We have done the following:

- Added example calculations to several of the chapters
- Included explanations of combined condensing and vaporizing displacements in gas floods and their impact on the developed miscible process
- Expanded coverage of foam EOR to an entire chapter

- Added discussion of EOR types, such as steam-assisted gravity drainage and alkaline-surfactant polymer flooding, that were not prominent in 1989
- Deleted coverage of material that did not readily lend itself to classroom instruction (based on many years of classroom experience)
- Added new material on dispersion, decline curves, and the use of so-called Walsh diagrams
- Added material on new technological advances, most notably in the coverage of chemical EOR

The biggest change is that the current text now has four co-authors whose classroom and research expertise in their respective technologies has made the text much stronger than before. It also helps to have four sets of eyes to spot inconsistencies, unclarities, errors, and all around goofs, especially in the equations.

Even with the new version, we are aware of several omissions:

- Low or adjusted salinity water flooding
- Gravity stable surfactant floods
- Hybrid methods such as heated surfactant floods and polymer floods
- Technologies involving in-situ modification of polymers
- Electromagnetic oil recovery
- Seismic oil recovery

These could become glaring omissions depending on future practice. However, we continue to think that reliance on fundamentals—conservation laws, phase behavior, and fractional flow theory—will at least make extension to new methods easier.

Acknowledgments are owed all around:

Larry W. Lake would like to thank Joanna Castillo for substantial and consistent help with the figures, and Mary Pettengill for tirelessly looking up and correcting the references.

Russell T. Johns would like to acknowledge Hung Lai who did the unenviable task of scanning in the first edition of the book and

formatting it in preparation for the second edition.

Chapter 1

Defining Enhanced Oil Recovery

Enhanced oil recovery (EOR) is oil recovery by the injection of materials not normally present in petroleum reservoirs. This definition covers all modes of oil-recovery processes (drive, push-pull, and well treatments) and most oil-recovery agents. EOR technologies are also being used for in-situ extraction of organic pollutants from permeable media. In these applications, the extraction is referred to as *cleanup* or *remediation* and the pollutant as *product.* Aspects of these technologies also apply to carbon dioxide (CO_2) storage.

The definition does not restrict EOR to a particular phase (primary, secondary, or tertiary) in the producing life of a reservoir. Primary recovery is oil recovery by natural drive mechanisms: solution gas, water influx, gas-cap drive, or gravity drainage, as illustrated in **Fig. 1.1.** Secondary recovery refers to techniques, such as gas or water injection, that have the main purpose of boosting or maintaining reservoir pressure. Tertiary recovery is any technique applied after secondary recovery. Nearly all EOR processes have been at least field tested as secondary displacements. Many thermal methods are commercial in both primary and secondary modes. Much interest has been focused on tertiary EOR, but our definition does not impose any such restriction.

A related definition is *improved* oil recovery, which is EOR plus several technologies that are also intended to increase ultimate oil recovery. Examples of these are hydraulic fracturing, horizontal and multilateral wells, infill drilling, well stimulation, and optimizing the production or injection rates of individual wells.

Definitions of EOR can be important in areas where regulatory agencies give tax or price credits to promote use of EOR. The definition given above is the one used throughout this text.

The definition does exclude waterflooding and is intended to exclude all pressure-maintenance processes. The distinction between pressure maintenance and displacement is fuzzy because displacement occurs in many pressure-maintenance processes. Moreover, agents such as methane in a high-pressure gas drive, or carbon dioxide in a reservoir with substantial native CO_2, do not satisfy the definition, yet both are clearly EOR processes. The same can be said of CO_2 storage. Usually, the EOR cases that fall outside the definition can be clearly classified by the intent of the process.

Fig. 1.1 also shows the major categories of EOR. This text is largely organized around the solvent (Chapter 7), chemical (Chapters 8–10), and thermal (Chapter 11) categories. Although EOR does not include waterflooding, this technology is the mother of all displacement techniques, and some (in fact extensive) coverage is provided in Chapters 3–6. Note that so-called unconventional recovery, or oil and gas recovery from very low-permeability media through fracturing, is part of primary recovery.

Another perspective on the recovery phases is provided in **Fig. 1.2.** This figure shows oil rate (top in std volumes/time) on the upper plot, pressure (well pressure P_{wf}, average reservoir pressure $\overline{P}$, and injection well pressure P_{Inj}) on the middle plot, and average oil saturation on the bottom plot, all on a common time axis. The figure is a schematic that treats injection and production as occurring through a single well (in reality, most fields have many wells). The time axis is divided into primary, secondary, and tertiary recovery phases as indicated.
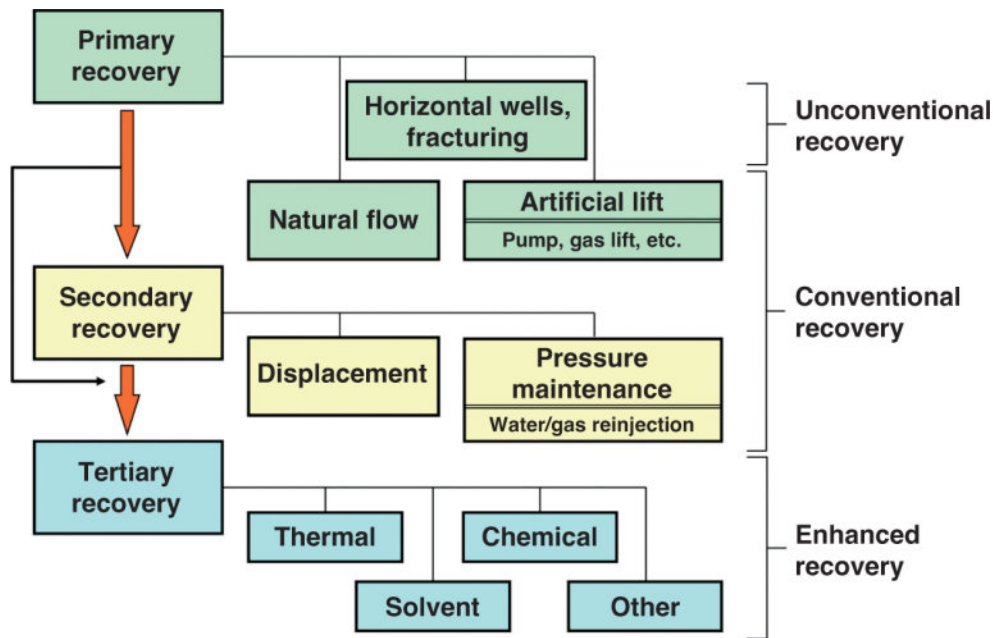
Fig. 1.1—Oil-recovery classifications (adapted from *Oil & Gas Journal*).

Much depends on the economically limiting rate (labeled EL) and the limiting pressure (P_{Lim}) on the upper and middle plots respectively. EL is the rate at which the revenue from production equals the operating costs of the field. P_{Lim} is the well pressure below which fluids cannot flow to the surface without external support. Of the two, EL is the most important because it is the portal between the engineering and economic worlds.

Primary production is typically production by fluid expansion and pore-volume contraction caused by pressure decline. In this period, there is no injection and average oil saturation stays roughly constant (there are exceptions). The rate is characterized by a rapid increase, limited mainly by the rate at which wells are drilled, followed by a plateau period and then a decline. The plateau period ends when the well pressure falls to P_{Lim}. The average pressure falls throughout, and primary recovery ends when the *drawdown* pressure ($\overline{P} - P_{Lim}$) is insufficient to maintain the oil rate above the EL. There is usually little or no water production during primary production. The absence of water production and the prevalence of natural (unassisted) flow usually make this the most profitable phase of the field life.
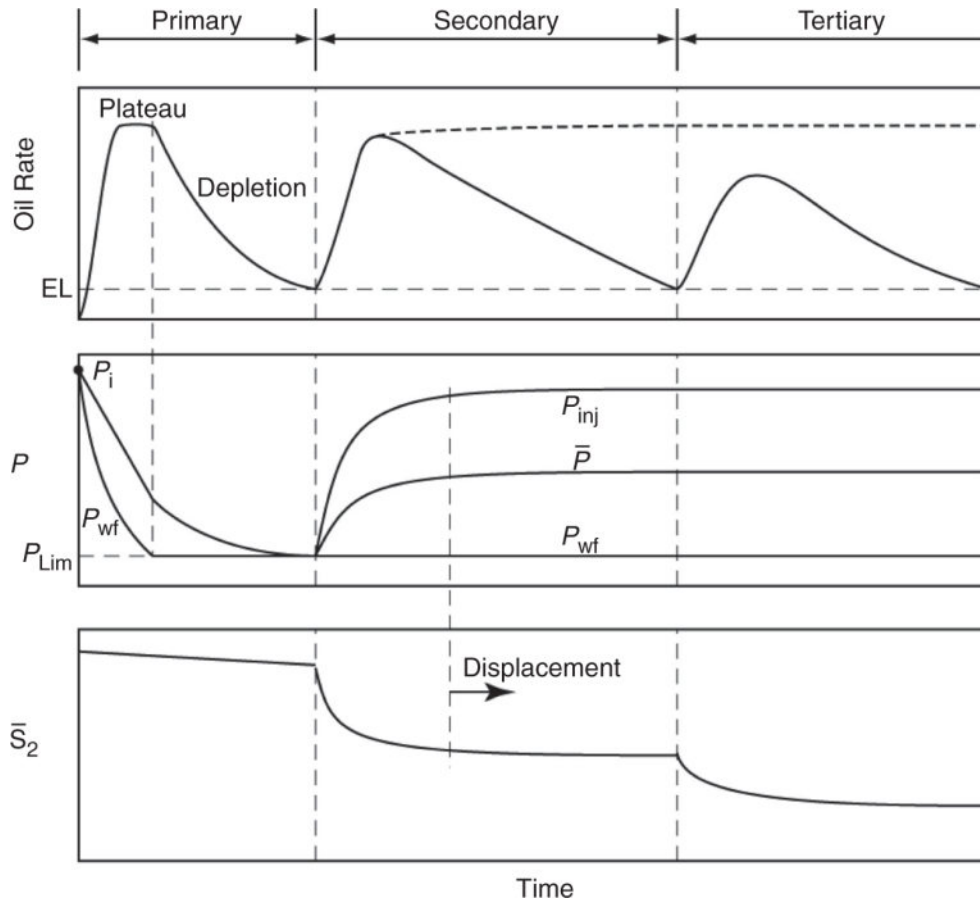
Fig. 1.2—Schematic of production phases.

Secondary production is production by injection of a second fluid, occasionally natural gas, but most commonly water. In this period and throughout the remainder of the field life, the producing well pressure is at P_{Lim} (wells are said to be pumped off), and the average pressure rises. There is a new pressure P_{Inj} for the injection well. Of course we must have $P_{Inj} > \overline{P} > P_{wf} = P_{Lim}$ to maintain flow. When $\overline{P}$ becomes constant, the pressure is said to be "maintained," and, of course, production rises because of the increased drawdown.

The increased drawdown, however, causes the injected fluid to be produced, as indicated by the dotted line in the upper plot. An increase in $\overline{P}$ would cause fluids to contract; therefore, production would proceed from this point mainly by displacement. The displacement causes the average oil saturation to decline. Secondary production ends when the rate again approaches the EL, at which point water production can be many times the oil production.

Tertiary production commences when waterflooding becomes uneconomical or when the rate falls below the EL. At this time, chemical agents (surfactants or solvents) or heat are injected that cause physical or chemical changes in the oil. The entire nature of the recovery is based on displacement now, and the pressures change little with time. All the production occurs because of declining average oil saturation.

Several points deserve to be summarized from [Fig. 1.2](#).

1. Production can be increased by lowering P_{Lim} throughout the life of the field. Much oilfield technology is directed to exactly this goal.
2. In the same fashion, production can be increased by increasing the proportionality constant between drawdown and rate, the so-called productivity index (PI) of a producer. Much oilfield technology, including some forms of EOR, is devoted to this.
3. As conditions change, EL need not be constant. Indeed, it is probable that EL will increase during tertiary recovery when agent costs become a principal factor in production. EL is exceptionally sensitive to oil price.
4. The lengths of the periods in the figure are highly variable; usually, primary production occurs over a shorter time than secondary production. The lengths for primary and tertiary production are approximately the same. The total field life can exceed 100 years.
5. Typical ultimate recoveries for primary, secondary, and tertiary recovery are 10%, 25%, and 10% of the original oil in place (OOIP), but with much variation. This gives a typical ultimate recovery of 35% with conventional production. In most cases,

the peak waterflood oil rate is less than the primary plateau. The ultimate recoveries are the areas under the rate plot in [Fig. 1.2](#).

6. Remember that the plot in [Fig. 1.2](#) is a schematic. There are many varieties of primary production (Walsh and Lake 2003). For example, sometimes there is no primary plateau. In others, economic conditions do not justify EOR regardless of other favorable factors. Moreover, of course, wells can be added and removed (which is roughly equivalent to changing the PI) throughout the life of the field. For steeply dipping reservoirs, flow potentials should replace pressures in [Fig. 1.2](#).

7. In practice, operations in a reservoir are normally converted or switched before the rate reaches the EL. The switching occurs in anticipation of the time that the rate attains the EL.

8. Although the sequence shown in [Fig. 1.2](#) is typical, sometimes entire phases are missing. As discussed previously, many thermal projects have not undergone primary or even secondary recovery. Furthermore, the times of switching from one phase to another may be different from those shown. Parra-Sanchez (2010) has shown that earlier switching times (i.e., switching from primary to secondary production before reaching the economic limit) can be more profitable.

This text is about the displacement part of the figure, which includes waterflooding and, of course, EOR. Because the pressures are constant during these phases, the fluids behave as though they were incompressible, a fact that justifies the widespread use of this assumption throughout this text. Incompressibility also moves the drawdown pressure and pressure changes to the background in most of our discussion, although it must be remembered that if there is no drawdown, there can be no production.

1.1 Introduction to EOR

1.1.1 The EOR Target. Interest in EOR centers on the amount of oil to which it can be applied. This EOR target oil is the amount that is unrecoverable by conventional means ([Fig. 1.1](#)). A large body of

statistics shows that conventional ultimate oil recovery (the percentage of the OOIP at the time that further conventional recovery becomes uneconomical) is approximately 35%. This means, for example, that a field that originally contained 1 billion barrels will have 650,000,000 barrels left in it at the end of its conventional life. Considering the OOIP in all the reservoirs in the United States, this value is much larger than targets from exploration or increased drilling.

The ultimate recovery efficiency expected after primary and secondary recovery is shown in **Fig. 1.3.** This figure also shows that there is enormous variability in ultimate recovery within a single geographic region, which is why we cannot target reservoirs with EOR by region. Fig. 1.3 shows also that the median ultimate recovery is the same for most regions, a fact no doubt bolstered by the large variability within each region. The median ultimate recovery of approximately 35% shows that 65% remains, a significant target for EOR.

1.2 The Need for EOR

Enhanced oil recovery is one of the technologies needed to maintain reserves. What follows is only a brief discussion of reserves because this is a complex and extensive subject. See Cronquist (2001) for more details.
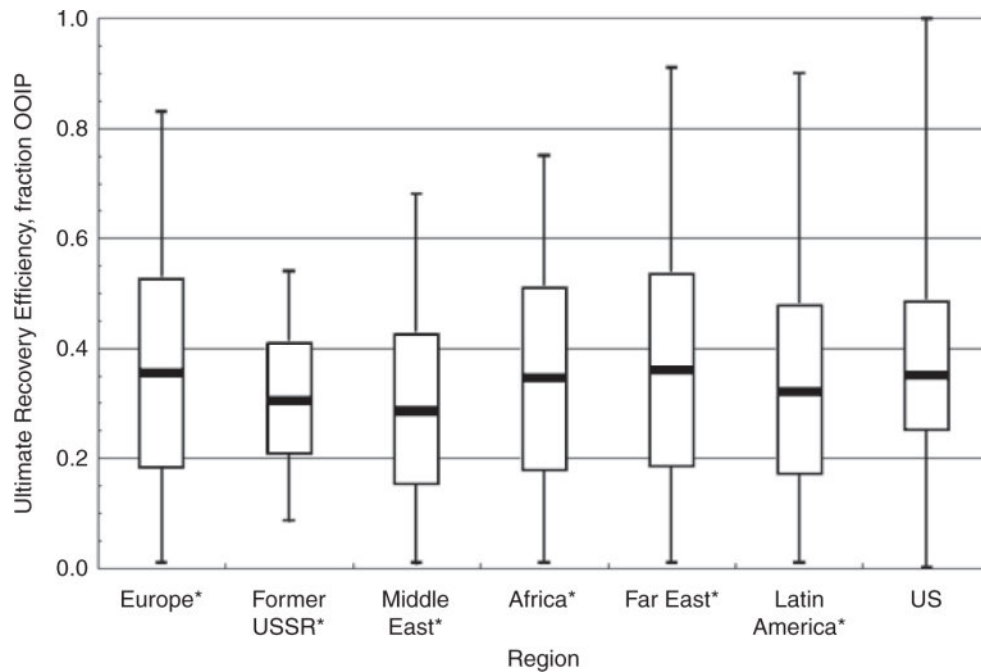
Fig. 1.3—Box plots of ultimate oil recovery efficiency. 75% of the ultimate recoveries in a region fall within the vertical boxes; the median recovery is the horizontal line in the box; the vertical lines give the range. Ultimate recovery is highly variable, but the median is approximately the same everywhere [data from Laherrere (2001); US data from TORIS].

1.2.1 Reserves. One definition of reserves is that they are petroleum (crude and condensate) recoverable from known reservoirs under prevailing economics and technology. They are given by the following material-balance equation:

$$\begin{pmatrix} \text{Present} \\ \text{reserves} \end{pmatrix} = \begin{pmatrix} \text{Past} \\ \text{reserves} \end{pmatrix} + \begin{pmatrix} \text{Additions} \\ \text{to reserves} \end{pmatrix} - \begin{pmatrix} \text{Production} \\ \text{from} \\ \text{reserves} \end{pmatrix}.$$

There are actually several categories of reservoirs (proven, probable, etc.); the distinctions between these are very important to economic evaluation (Rose 2001; Cronquist 2001). Reserves can change with time because the last two terms on the right can change with time. It is in the best interests of producers to maintain reserves constant with time, or even for them to increase.

1.2.2 Adding to Reserves. The four categories of reserve additions are

1. Discovering new fields
2. Discovering new reservoirs
3. Finding more oil in known fields
4. Redefining reserves because of changes in the economics of extraction technology

We discuss Category 4 in the remainder of this text.

EOR is in competition with conventional oil recovery because most producers have assets or access to assets in all the categories in Fig. 1.1. The competition is based largely on economics in addition to reserve replacement. Currently, many EOR technologies are competitive with drilling-based reserve additions. The key to economic competitiveness is how much oil can be recovered with EOR. The estimation of this is the next topic to be discussed.

1.3 Incremental Oil

1.3.1 Definition. A universal technical measure of the success of an EOR process is the amount of incremental oil recovered, or IOR. (We note the possible confusion between IOR as improved oil recovery and IOR as incremental oil recovery. What is meant should be clear from the context of the text. IOR as improved oil recovery is not used further here.) **Fig. 1.4** defines the concept of incremental oil. Imagine a field, reservoir, or well in which the oil rate is declining, for example, from *A* to *B*. At *B*, an EOR project is initiated, and, if this is successful, the rate should show a deviation from the projected decline at some time after *B*. Incremental oil is the difference between what was actually recovered, *B* to *D*, and what would have been recovered had the process not been initiated, *B* to *C*. Because areas under rate vs. time curves are amounts, this is the shaded region in Fig. 1.4.

As simple as the concept in Fig. 1.4 is, IOR is difficult to determine in practice. There are several reasons for this.

1. Combined (commingled) production from EOR and non-EOR wells. Such production makes it difficult to allocate the EOR-produced oil to the EOR project. Commingling occurs when, as is usually the case, the EOR project is phased into a field undergoing other types of recovery.
2. Oil from other sources. Usually the EOR project has experienced substantial well cleanup or other improvements before startup. The oil produced as a result of such treatment is not easily differentiated from EOR oil.
3. Inaccurate estimate of the hypothetical decline. The curve from *B* to *C* in Fig. 1.4 must be estimated accurately. However, because the decline did not occur, there is no way of assessing this accuracy.
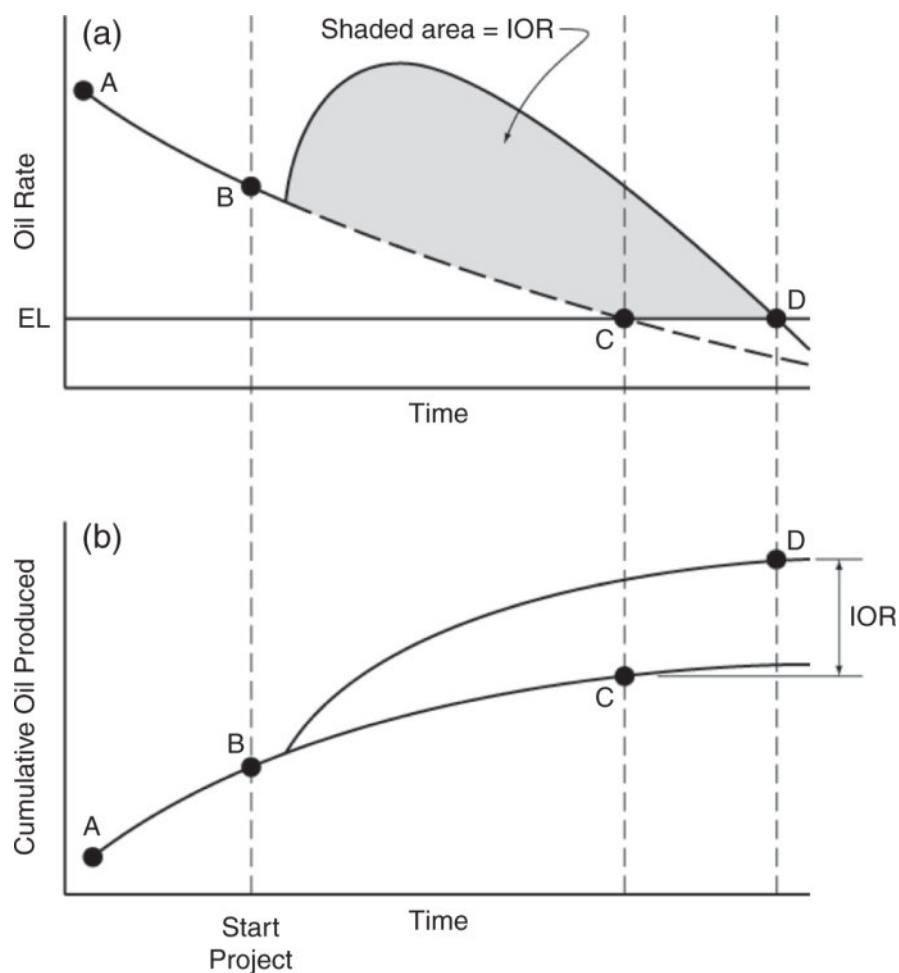
Fig. 1.4—Schematic of IOR from typical EOR response: (a) rate vs. time and (b) cumulative vs. time.

Ways to infer IOR from production data range from highly sophisticated numerical models to graphical procedures. One of the latter, based on decline-curve analysis, is covered in the next section.

1.3.2 Estimating IOR Through Decline Curves. Decline-curve analysis can be applied to almost any hydrocarbon-production operation. The following is an abstraction of the practice as it applies to EOR. See Walsh and Lake (2003) for a more in-depth discussion. The basic idea was outlined in the classic paper by Arps (1956); see also Fetkovich (1980). The objective is to derive relations between oil rate and time, and then between cumulative production and rate.

The oil rate q changes with time t in a manner that defines a decline rate D according to

$$\frac{1}{q}\frac{dq}{dt} = -D. \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (1.1)$$

The rate has units of (or [=]) amount or standard volume per time and D [=]1/time. Time is in units of days, months, or even years consistently with q. D itself can be a function of rate, but here it is assumed to be constant (representing an exponential decline). Integrating Eq. 1.1 gives

$$q = q_i e^{-Dt}, \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (1.2)$$

where qi is the initial rate or q evaluated at $t = 0$, the start of the decline-curve period. Eq. 1.2 suggests a semilogarithmic relationship between rate and time, as illustrated in **Fig. 1.5a**. Exponential decline is the most common type of analysis used.

Fig. 1.5 illustrates schematically a set of data points that begin an exponential decline at the ninth point, where by definition $t = 0$. The solid line represents the fit of the decline-curve model to the data points. q_i is the rate given by the model at $t = 0$, not necessarily the measured rate at this point. The slope of the model is the negative of the decline rate divided by 2.303 because the semilog scale plots base-10 rather than natural logarithms.
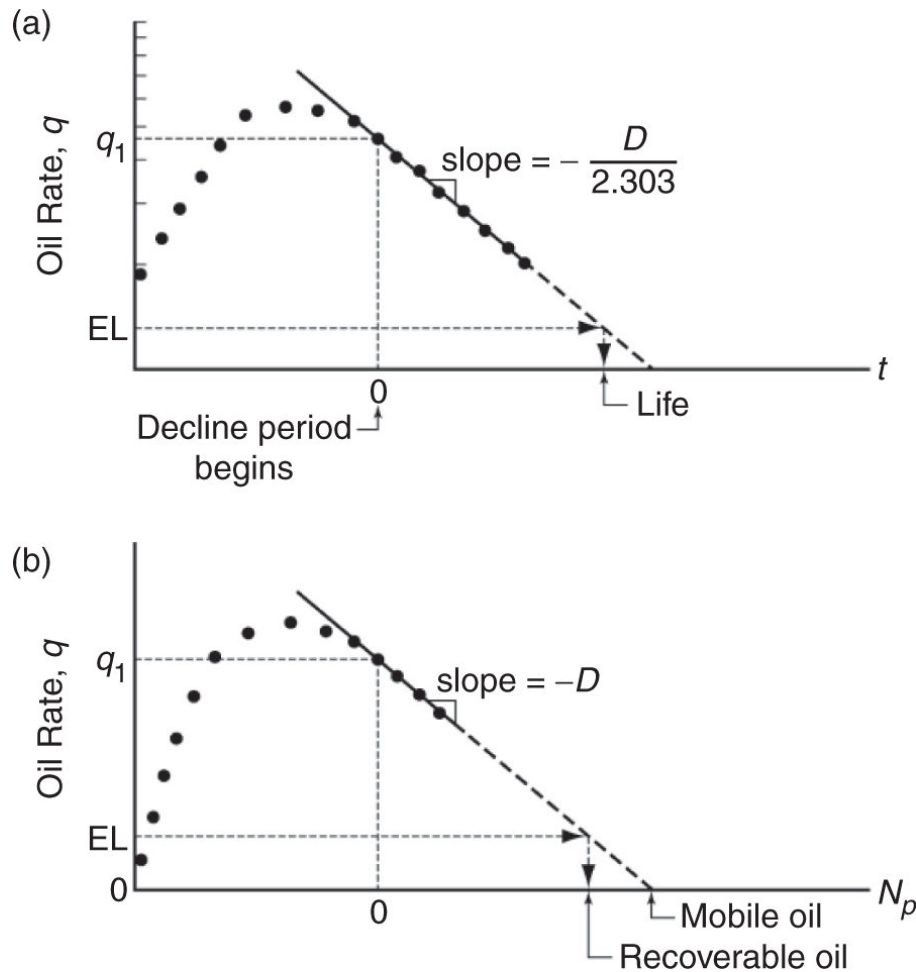
Fig. 1.5—Schematic of exponential decline on (a) rate vs. time and (b) rate vs. cumulative plots.

Because the model plot is a straight line, it can be extrapolated (solid line in Fig. 1.5) to some future rate. If q_{EL} designates the EL (the *economic limit* discussed previously) of the project under consideration, then the point at which the model extrapolation reaches q_{EL} is an estimate of the project's (or well's) economic life. The economic limit is a nominal measure of the rate at which the revenues become equal to operating expenses plus overhead. q_{EL} can vary from a fraction to a few hundred barrels per day depending on operating conditions. It is also a function of the prevailing economics: as the oil price increases, q_{EL} decreases, which is an important factor in reserve calculations.

The rate vs. time analysis is useful, but the rate vs. cumulative curve is more helpful for estimating IOR. The cumulative oil produced is given by

$$N_p = \int_{\xi=0}^{\xi=t} q \, d\xi. \; \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \; (1.3)$$

The definition in this equation is general and will be used throughout the text, but especially in Chapter 2. To derive a rate vs. cumulative expression, insert Eq. 1.1, integrate, and identify the resulting terms with (again) Eq. 1.1. This gives

$$q = q_i - DN_p. \; \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \; (1.4)$$

Eq. 1.4 says that a plot of oil rate vs. cumulative production should be a straight line on linear coordinates, as illustrated in Fig. 1.5b.

Note that the cumulative oil points plotted on the horizontal axis of this figure come from the oil-rate data, not from the decline curve. If this were not so, the rate vs. cumulative plot would provide no additional information. Calculating N_p normally requires numerical integration of the rate data.

Using the model Eqs. 1.3 and 1.4 to interpret data, as illustrated in Fig. 1.5, is the essence of reservoir engineering practice, which can be described as follows:

1. Develop a model as we have done to arrive at Eqs. 1.3 and 1.4. Often the model equations are far more complex than these, but the method is the same regardless of the complexity.
2. Fit the model to the data. Remember that the points in Fig. 1.5 are data. The lines are the model.
3. With the model as fitted to the data (the model is now calibrated), extrapolate the model to make predictions.

At the onset of the decline period, the data again start to follow a straight line through which one can fit a linear model. In effect, what has occurred on this plot is that we have replaced time in Fig. 1.3 with cumulative oil produced in Fig. 1.5b, but there is one very important

distinction: both axes in [Fig. 1.5b](#) are now linear. This linearity has three important consequences:

1. The slope of the model is now –*D* because no correction for log scales is required.
2. The origin of the model can be shifted in either direction by simple additions.
3. The rate can now be extrapolated to zero.

Point 2 means that we can plot the cumulative oil produced for all periods before the decline-curve period (or for previous decline-curve periods) on the same rate vs. cumulative plot. Point 3 means that we can extrapolate the model to find the total mobile oil (when the rate is zero) rather than just the recoverable oil (when the rate is at the economic limit).

Rate vs. cumulative plots are simple yet informative tools for interpreting EOR processes because they allow estimates of IOR by distinguishing between recoverable and mobile oil. We illustrate how this comes about through some idealized cases.

[**Fig. 1.6**](#) shows rate vs. cumulative plots for cases that feature an exponential decline just before and immediately after the initiation of an EOR process. We are showing the model lines (not the points) only for ease of presentation. Placing both periods on the same horizontal axis is permissible because of the scaling arguments mentioned previously.

In the case shown in [Fig. 1.6a](#), the EOR process did not accelerate production because the decline rates in both periods are the same; however, the process did increase the amount of mobile oil, which in turn caused some incremental oil production. In this case, incremental recovery and mobile oil are the same. Such idealized behavior would be characteristic of thermal, surfactant/polymer (SP), and solvent processes.

[Fig. 1.6b](#) shows another extreme case in which production is only accelerated, the pre- and post-EOR decline rates being different. Now the curves extrapolate to a common value of mobile oil, but still with a positive IOR. We expect correctly that processes that behave

this way will produce less oil than those that increase mobile oil, but they can still be profitable, particularly if the agent used to bring about this result is inexpensive. Processes that ideally behave in this manner are polymer floods and polymer gel processes, which do not affect residual oil saturation, but displace previously bypassed oil and cause it to be produced. Acceleration processes are especially sensitive to the economic limit; large economic limits imply large IOR.
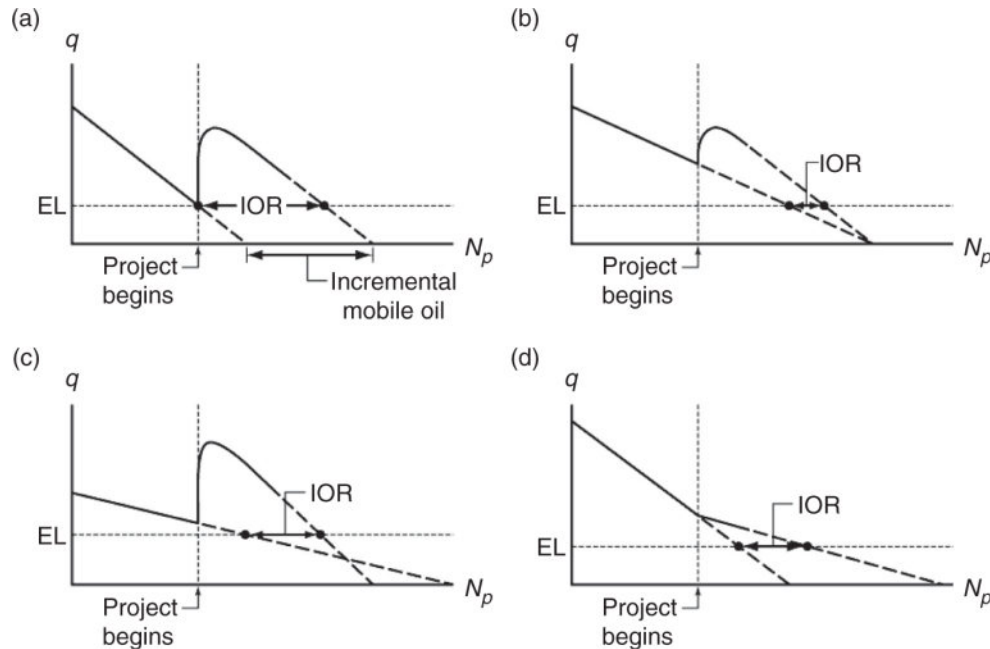
Fig. 1.6—Schematic of rate vs. cumulative plots for various EOR responses. All projects show a positive IOR: (a) the mobile oil increases; (b) the mobile oil is unchanged; (c) the mobile oil decreases; and (d) the mobile oil increases, but there is no peak in the oil rate.

Fig. 1.6c shows an unfavorable case in which the process actually reduced mobile oil. We would never deliberately try to reduce mobile oil in practice, but the project could still be profitable if, as in the case shown, the accelerated production offsets the loss of mobile oil enough so that the IOR is still nonzero. Behavior like this probably indicates a target for a future EOR application.

Fig. 1.6d illustrates another common case. Here, the EOR process increases mobile oil, but also reduces the decline rate. Processes like these are common in solvent floods.

1.4 Category Comparisons

1.4.1 Comparative Performances. Most of this text covers the details of EOR processes. At this point, we compare the performance of the three basic EOR processes and introduce some issues to be discussed later in the form of screening guides. The performance is represented as typical oil recoveries (IOR expressed as a percent of OOIP) and by various utilization factors. Both are based on actual experience. Utilization factors represent the amount of an EOR agent required to produce a barrel of incremental oil. They are a rough measure of process profitability.

Table 1.1 shows these summaries for chemical EOR processes. Sensitivity to high brine salinities is common to all chemical-flooding EOR. Total dissolved solids should be less than 100,000 g/m^3, and hardness should be less than 2,000 g/m^3. See Chapters 8 and 9 for more details. Chemical agents are also susceptible to loss through rock-fluid interactions. Maintaining adequate injection rates is a persistent issue with chemical methods.

Historical oil recoveries have ranged from small for polymer floods (5%) to moderately large (15%) for other methods. Chemical utilization factors have meaning only when compared with the costs of the individual agents; polymer, for example, is usually three to four times as expensive (per unit mass) as surfactants. The average for polymer floods is based on data that include both mobility-control floods and profile-control treatments. The latter generally recovers less oil. Mobility-control floods, particularly those performed recently, have averaged approximately 10% recovery. The alkaline-flooding process is generally not used today, having been supplanted by alkaline/surfactant/polymer (ASP) flooding. The latter technology is too new to report summary statistics, but initial results indicate that it performs as well or better than SP floods.

TABLE 1.1—CHEMICAL EOR PROCESSES

Process	Recovery Mechanism	Issues	Typical Recovery (%)	Typical Agent Utilization*
Polymer	Increases volumetric sweep by mobility reduction	Injectivity Stability High salinity	5	1 lb polymer per incremental bbl
Surfactant/ polymer	Same as polymer, plus reduces capillary forces	Same as polymer, plus chemical availability, retention, and high salinity	15	15–25 lb surfactant per incremental bbl
Alkaline/ polymer	Same as SP, plus oil solubilization and wettability alteration	Same as SP, plus oil composition	5	35–45 lb chemical per incremental bbl
Alkaline/ surfactant/ polymer	Same as SP	Same as SP with lower salinity requirements, mineral precipitation	–	–

*1 lb/bbl $\cong$ 2.86 kg/m³.

TABLE 1.2—THERMAL EOR PROCESSES

Process	Recovery Mechanism	Issues	Typical Recovery (%)	Typical Agent Utilization*
Steam (drive and stimulation)	Reduces oil viscosity; vaporization of light ends	Depth Heat losses Override Pollution	50–65	0.5 bbl oil consumed per incremental bbl
In-situ combustion	Same as steam, plus cracking	Same as steam, plus control of combustion	10–15	10 Mcf air per bbl oil produced*
SAGD	Same as steam	Vertical permeability; surface handling of heavy crudes	Same as steamdrive	Same as steamdrive
EM heating	Same as steam, plus some cracking and distillation	Propagation of heat	–	–

*1 Mcf/STB $\cong$ 178 std m³ gas/std m³ oil.

Table 1.2 shows a similar comparison for thermal processes. These methods are usually directed toward recovery of heavy to extra-heavy crudes. Recoveries are larger for these processes than for chemical methods. Again, the issues are similar within a given category, centering on heat losses, override, and air pollution. Steam is usually generated by burning a portion of the resident oil or an equivalent amount of other fuel. In many locations, natural gas is used as the fuel rather than crude. If this burning occurs on the

surface, the emission products contribute to air pollution; if the burning is in situ, production wells can be a source of pollutants. A recent variation of in-situ combustion is high-pressure air injection (HPAI).

Two recent entries in this category are steam-assisted gravity drainage (SAGD) and electromagnetic (EM) heating. SAGD is similar to a steam drive except that injection and production are done through paired horizontal wells. The principal mechanism for oil recovery is gravity drainage, not viscous forces. SAGD is also too new for a good statistical base to exist, although there are many ongoing projects. As of the time of writing, it appears to be comparable to steam drives.

EM heating is also a new technology that is intended for so-called stranded oil. Its field recoveries have not been compiled, but its thermal efficiency appears to be equivalent to the other thermal methods.

Table 1.3 compares the solvent-flooding processes. Only two groups of processes are in this category, corresponding to whether or not the solvent develops miscibility with the oil. Oil recoveries are generally lower than in SP and thermal recoveries. The solvent utilization factors as well as the relatively low cost of the solvents have brought these processes, particularly CO_2 flooding in the United States, to commercial application. The distinction between a miscible and an immiscible process is one of degree: an immiscible flood can achieve good oil recovery if the process is close to miscibility and poor recovery if the reservoir pressure is substantially below the minimum pressure for miscibility.

TABLE 1.3—SOLVENT EOR METHODS				
Process	Recovery Mechanism	Issues	Typical Recovery (%)	Typical Agent Utilization*
Immiscible	Reduces oil viscosity Oil swelling Solution gas	Stability Override Supply	5–15	10 Mcf solvent per incremental bbl
Miscible	Same as immiscible, plus development of miscible displacement	Same as immiscible	5–10	10 Mcf solvent per incremental bbl

*1 Mcf/STB $\cong$ 178 SCM solvent/SCM oil.

1.4.2 Screening Guides. Many of the issues in Tables 1.1 through 1.3 can be better illustrated by giving quantitative limits. These binary screening guides can also serve as a first approximation of when a process would apply to a given reservoir.

Table 1.4 gives screening guides for EOR processes in terms of oil and reservoir properties. These should be regarded as rough guidelines, not as hard limits, because other considerations (e.g., economics and gas supply) and reservoir properties (e.g., vertical permeability, fractures, and thief zones) can extend or prohibit the applications.

The limits have a physical basis, as we will see. For example, the restriction of thermal processes to relatively shallow reservoirs exists because of potential heat losses through lengthy wellbores. The restriction on many of the processes to light crudes comes about because of sweep-efficiency considerations; displacing viscous oil is difficult because of the propensity of a displacing agent to channel through the fluid being recovered. Some of the categorizations in Table 1.4 are fairly coarse. Steam methods, in particular, contain additional divisions into steam-soak, steamdrive, and gravity-drainage methods. There are likewise several variations of combustion and chemical methods. Furthermore, the property boundaries are somewhat diffuse and continually subject to revision. The viscosity limits on polymer flooding, for example, are likely a little too low. Finally, the information in Table 1.4 represents a road map for the material to be covered in later chapters. The information in the table

is only a first step toward screening, which itself requires much more information and effort (Dickson and Leahy-Dios 2010).

TABLE 1.4—SUMMARY OF SCREENING CRITERIA FOR EOR METHODS [ADAPTED FROM TABER ET AL. (1997)]								
	Oil Properties				Reservoir Characteristics			
EOR Method	Gravity (°API)	Reservoir Viscosity (mPa·s)	Composition	Initial Oil Saturation (% PV)	Formation Type	Net Thickness (m)	Average Permeability (md)	Depth (m)
Solvent Methods								
Nitrogen and flue gas	>35	<0.4	Large percent of C_1 to C_7	>40	NC*	NC	NC	>1800
Hydrocarbon	>23	<3	Large percent of C_2 to C_7	>30	NC	NC	NC	>1250
CO_2	>22	<10	Large percent of C_5 to C_{12}	>20	NC	NC	NC	>750
Immiscible gases	>12	<600	NC	>35	NC	NC	NC	>640
Chemical Methods								
Micellar/ polymer, ASP, and alkaline flooding	>20	<35	Light, intermediate, some organic acids for alkaline floods	>35	Sandstone preferred	NC	>10	<2700
Polymer flooding	>15	10–150	NC	>50	Sandstone preferred	NC	>10	<2700
Thermal Methods								
Combustion	>10	<5,000	Some asphaltic components	>50	–	>3	>50	<3450
Steam	13.5	<200,000	NC	>40	–	>6	>200	<1350
*NC = Not critical.								

1.4.3 Cash Flow. Many of the screening guides are implicit assessments of the ability of an EOR process to make money (sometimes called the economics). Performing such calculations is an important part of the decision to implement EOR. See Flaaten (2012) for a discussion of oilfield economics and of how to calculate cumulative discounted case flow. The key variables in this calculation are the oil rate (the subject of this text and of **Fig. 1.7b**), the price of oil, and the discount rate.

Each EOR process has its unique economic profile, but there are common features for all, as illustrated in Fig. 1.7. Fig. 1.7a shows the cumulative discounted cash flow (CDCF) as a function of time. The time axis in the figure is aligned with the figure below it. As the name

implies, the CDCF is the accumulation (or integration) of the discounted cash flow or DCF. The CDCF is the net amount of money returned by a project over time.

Fig. 1.7b shows a rate vs. time history of an EOR project that is approaching its economic limit. The economic limit occurs when the slope of the CDCF curve vs. time is zero. Remember that the DCF is the derivative of the CDCF curve.

All EOR processes require some capital investment, labeled as CAPEX in Fig. 1.7b. The figure shows this decline as taking place at the onset of the project, but often it is spread out over several years.

EOR agents are generally expensive, especially compared to injecting water. For this reason, the CDCF decreases even further beyond the CAPEX. However, once revenue from oil production starts, the curve begins to increase at the time labeled "positive cash flow." For many EOR processes, positive cash flow begins within a year of initiation. Payout occurs when the CDCF reaches a positive value. (Recall that all costs and revenue are being discounted with time).

The CDCF now begins to level off as a consequence of the declining oil rate. The project life is reached when the CDCF is at maximum or when the cash flow becomes negative. The value of the CDCF at its maximum is the net present value or NPV.

The NPV is the primary decision variable determining whether to go forward with an EOR project. It should be compared with (a) what the CDCF was before the process began (a project with NPV less than this amount should not be performed); (b) alternatives within the portfolio of the producer (there may be other non-EOR projects that will result in a larger NPV); and, (c) when divided by some measure of expenditure (this quotient is called the rate of return), targets set by the producer.
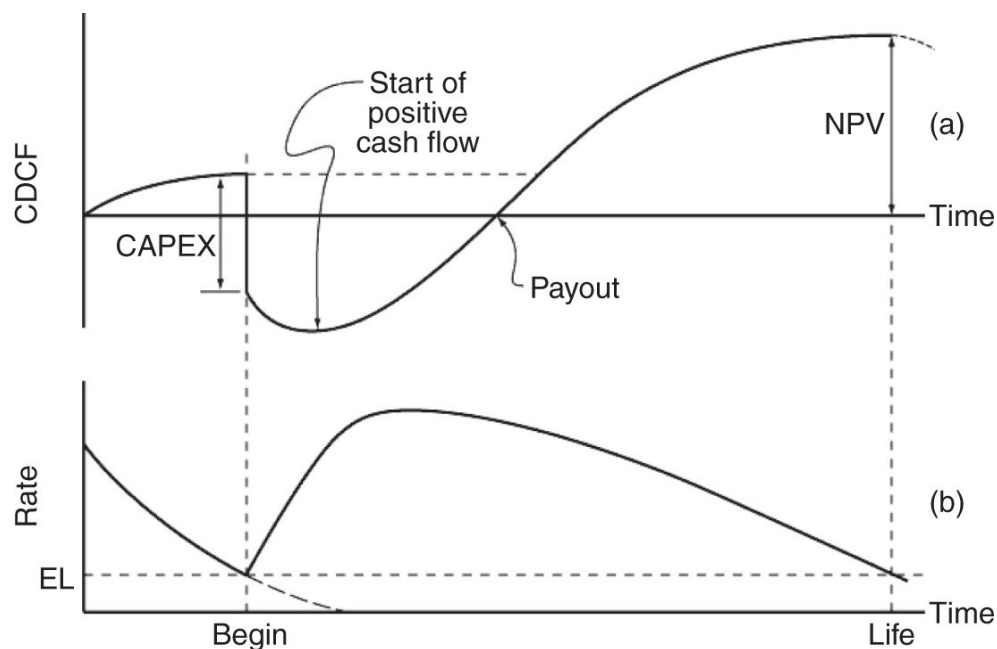
Fig. 1.7—Schematic of the behavior of the CDCF for an EOR project.

We end by noting that Fig. 1.7 contains several aspects that are not part of this text: oil price, discount rate, and CAPEX to name a few. Projects that produce incremental hydrocarbon, but fall short of an NPV limit, are *technical* successes. There are several of these projects in the history of EOR. Other factors always play a role in the EOR decision. Some of these are access to alternate projects, competition for capital, or both. However, the basic idea, with much more complexity to be sure, is always of the form shown in Fig. 1.7.

1.5 Summary

No summary can do justice to what is a large, diverse, continuously changing, and complex technology. An excellent example of such changes is the current emphasis on so-called unconventional oil recovery (Fig. 1.1). This technology is now producing more crude than EOR, and the oil production rate is likely to go up. On the other hand, there is no reason to suspect that the ultimate oil recovery for these processes will be any greater than that for waterflooding. Hence, unconventional production will leave a target for EOR.

The *Oil & Gas Journal* has provided an excellent service in documenting the progress of EOR, and you should consult those

surveys for up-to-date information. The fundamentals of the processes change more slowly than the applications, and it is to these fundamentals that the remainder of the text is devoted.

1.6 Units and Notation

1.6.1 SI Units. The basic set of units in the text is the Système International (SI). We cannot use SI units exclusively because a great body of figures and tables has been developed in more traditional units. It is impractical to convert these; therefore, we give a list of the more important conversions in **Table 1.5** and provide some helpful pointers in this section.

TABLE 1.5—AN ABRIDGED SI UNITS GUIDE [ADAPTED FROM CAMPBELL ET AL. (1977)]			
SI Base Quantities and Units			
Base Quantity or Dimension	SI Unit	SI Unit Symbol (Use Roman Type)	SPE Dimensions Symbol (Use Roman Type)
Length	Meter	M	L
Mass	Kilogram	kg	m
Time	Second	s	t
Thermodynamic temperature	Kelvin	K	T
Amount of substance	Mole*	mol	–
Some Common SI Derived Units			
Quantity	Unit	SI Unit Symbol (Use Roman Type)	Formula (Use Roman Type)
Acceleration	Meters per second squared	–	m/s^2
Area	Square meters	–	m^2
Density	Kilograms per cubic meter	–	kg/m^3
Energy, work	Joules	J	N·m
Force	Newtons	N	$kg·m/s^2$
Pressure	Pascals	Pa	N/m^2
Velocity	Meters per second	–	m/s
Viscosity, dynamic	Pascal-seconds	–	Pa·s

Viscosity, kinematic	Square meters per second	–	m^2/s
Volume	Cubic meters	–	m^3

Selected Conversion Factors

To Convert From	To	Multiply By
Acre (US survey)	Meter^2 (m^2)	4.046 872 E+03
Acres	Feet^2 (ft^2)	4.356 000 E+04
Atmosphere (standard)	Pascal (Pa)	1.013 250 E+05
Bar	Pascal (Pa)	1.000 000 E+05
Barrel (for petroleum, 42 gal)	Meter^3 (m^3)	1.589 873 E–01
Barrel	Feet^3 (ft^3)	5.615 E+00
British thermal unit (International Table)	Joule (J)	1.055 056 E+03
Darcy	Meter^2 (m^2)	9.869 232 E–13
Day (mean solar)	Second (s)	8.640 000 E+04
Dyne	Newton (N)	1.000 000 E–05
Gallon (US liquid)	Meter^3 (m^3)	3.785 412 E–03
Gram	Kilogram (kg)	1.000 000 E–03
Hectare	Meter^2 (m^2)	1.000 000 E+04
Mile (US survey)	Meter (m)	1.609 347 E+03
Pound (lbm)	Kilogram (kg)	4.535 924 E–01
Ton (short, 2,000 lbm)	Kilogram (kg)	9.071 847 E+02

Selected SI Unit Prefixes				
Factor	SI Prefix	SI Prefix Symbol (Use Roman Type)	Meaning (US)	Meaning in Other Countries
10^{12}	tera	T	One trillion times	Billion
10^9	giga	G	One billion times	Milliard
10^6	mega	M	One million times	–
10^3	kilo	K	One thousand times	–
10^2	hecto	H	One hundred times	–
10	deka	Da	Ten times	–
10^{-1}	deci	D	One tenth of	–
10^{-2}	centi	C	One hundredth of	–
10^{-3}	milli	M	One thousandth of	–
10^{-6}	micro	μ	One millionth of	–
10^{-9}	nano	N	One billionth of	Milliardth

*When the mole is used (by convention, the *gram*-mole), the elementary entities must be specified; they may be atoms, molecules, ions, electrons, other particles, or specified groups of such particles in petroleum work. The terms *kilogram mole*, *pound mole*, and so on are often erroneously shortened to mole.

1. There are several cognates, quantities having the exact or approximate numerical value, between SI and practical units. The most useful for EOR are

$$1 \text{ cp} = 1 \text{ mPa.s}$$
$$1 \text{ dyne/cm} = 1 \text{ mN/m}$$
$$1 \text{ Btu} \cong 1 \text{ kJ}$$
$$1 \text{ Darcy} \cong 1 \text{ μm}^2$$
$$1 \text{ ppm} \cong 1 \text{ g/m}^3$$
$$1 \text{ atm} \cong 0.1 \text{ MPa}$$

2. Use of the unit prefixes (lower part of Table 1.5) requires care. When a prefixed unit is raised to an exponent, the exponent applies to the prefix as well as the unit. Thus, $1 \text{ km}^2 = 1(\text{km})^2 =$

$1(10^3 \text{ m})^2 = 1 \times 10^6 \text{ m}^2$. An example is $1 \text{ μm}^2 = 10^{-12} \text{ m}^2 \cong 1$ darcy.

3. Two troublesome conversions are between pressure (147 psia $\cong$ 1 MPa) and temperature (1 K = 1.8 R). Because neither the Fahrenheit scale nor the Celsius scale is absolute, an additional translation is required:

$$°C = K - 273$$

and

$$°F = R - 460.$$

The superscript "°" is not used on absolute temperature scales.

4. The volume conversions are complicated by the interchangeable use of mass and standard volumes. Therefore, we have

$$0.159 \text{ m}^3 = 1 \text{ reservoir barrel, or bbl}$$

and

$$0.159 \text{ std. m}^3 = 1 \text{ standard barrel, or STB.}$$

The standard cubic meter, std m^3, is not standard SI; it represents the amount of mass contained in one cubic meter evaluated at standard temperature and pressure.

1.6.2 Consistency. Maintaining unit consistency is important in all exercises. Both units and numerical values should be carried in all calculations. This ensures that the unit conversions are calculated correctly and indicates whether the calculation procedure itself is appropriate. In maintaining consistency, three steps are required.

1. Clear all unit prefixes.
2. Reduce all units to the most primitive level necessary. For many cases, this will mean reverting to the fundamental units given in Table 1.5.
3. After calculations are complete, reincorporate the unit prefixes so that the numerical value of the result is as close to unity as

possible. Many adopt the convention of using only the prefixes representing multiples of 1,000.

The physical laws are valid regardless of the system of units used. This text eschews the now-standard petroleum-engineering practice of writing equations in a specific set of units (i.e., with conversion factors embedded).

1.6.3 Naming Conventions. The diversity of EOR makes it impossible to assign symbols to components without some duplication or undue complication. In the hope of minimizing the latter by adding a little of the former, **Table 1.6** gives the naming conventions of phases and components used throughout this text. The nomenclature section defines other symbols.

TABLE 1.6—NAMING CONVENTIONS FOR PHASES AND COMPONENTS

Phases

Index j	Identity	Text Locations
1	Water-rich or aqueous	Throughout
2	Oil-rich or oleic	Throughout
3	Gas-rich, gaseous, or light hydrocarbon	Section 5.4; and Chapters 7 and 10
	Microemulsion	Chapter 9
s	Solid	Chapters 2, 3, and 8–10
w	Wetting	Throughout
nw	Nonwetting	Throughout

Components

Index i	Identity	Text locations
1	Water	Throughout
2	Oil or intermediate hydrocarbon	Throughout
3	Gas	Section 5.4
	Light hydrocarbon	Chapter 7
	Surfactant	Chapter 9 (not Chapter 10)
4	Polymer, foaming surfactant	Chapters 8, 9, and 10
5	Anions	Sections 3.6 and 9.5
6	Divalents	Sections 3.4 and 9.3
7	Divalent-surfactant component	Section 9.6
8	Monovalents	Section 3.6 and Chapter 9

Phase always carries the subscript j, which occupies the second position in a doubly subscripted quantity. $j = 1$ is always a water-rich, or aqueous, phase, thus freeing up the symbol w for wetting (and nw

for nonwetting). The subscript *s* designates the solid, nonflowing phase. Singly subscripted quantities are phase properties.

A subscript *i* occurring in the first position indicates the component. In general, $i = 1$ is always water; $i = 2$ is oil or hydrocarbon; and $i = 3$ refers to a displacing component, whether surfactant or light hydrocarbon. Component indices greater than three are used exclusively in Chapters 8–10, the chemical-flooding portion of the text.

Exercises

1.1 Determining Incremental Oil Production. The easiest way to estimate IOR is through decline-curve analysis, which is the subject of this exercise. The oil rate and cumulative oil produced vs. time data for the Sage Spring Creek Unit A field are shown below (Mack and Warren 1984).

Date	Oil Rate, std m^3/d
1/76	274.0
7/76	258.1
1/77	231.0
7/77	213.5
1/78	191.2
7/78	175.2 (Start Polymer)
1/79	159.3
7/79	175.2
1/80	167.3
7/80	159.3
1/81	159.3
7/81	157.7
1/82	151.3
7/82	148.2
1/83	141.8
7/83	132.2

1/84	111.5
7/84	106.7
1/85	95.6
7/85	87.6
1/86	81.2
7/86	74.9
1/87	70.1
7/87	65.3

In July 1978, the ongoing waterflood was replaced with a polymer flood. (A polymer-gel treatment was conducted in 1984, but we neglect it here.) The economic limit is 50 std m^3/d in this field.

a. Plot the oil rate vs. cumulative oil produced on linear axes. The oil-rate axis should extend to $q = 0$.
b. Extrapolate the straight-line portion of the data to determine the ultimate economic oil to be recovered from the field and the total mobile oil, both in Mstd m^3, for both the water and the polymer flood. Determine the IOR and the incremental mobile oil caused by the polymer flood.
c. Determine the decline rates appropriate for the waterflood and the polymer flood.
d. Use the decline rates determined in Step c to determine the economic life of the polymer flood (when the oil rate reaches the EL). Also determine what the economic life would have been if there had been no polymer flood.