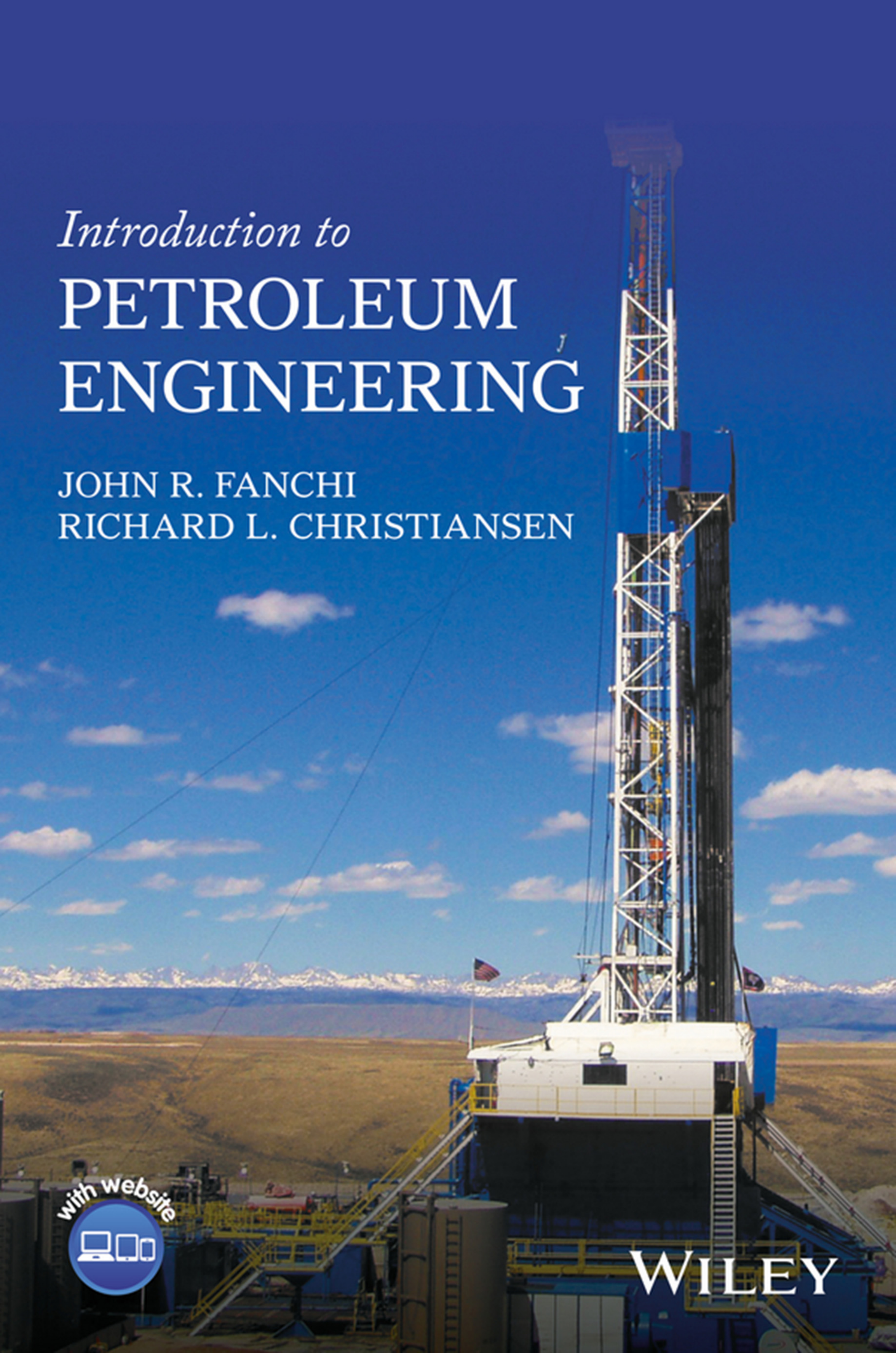

Introduction to

PETROLEUM ENGINEERING

JOHN R. FANCHI
RICHARD L. CHRISTIANSEN

with website

WILEY

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PREFACE

Introduction to Petroleum Engineering introduces people with technical backgrounds to petroleum engineering. The book presents fundamental terminology and concepts from geology, geophysics, petrophysics, drilling, production, and reservoir engineering. It covers upstream, midstream, and downstream operations. Exercises at the end of each chapter are designed to highlight and reinforce material in the chapter and encourage the reader to develop a deeper understanding of the material.

Introduction to Petroleum Engineering is suitable for science and engineering students, practicing scientists and engineers, continuing education classes, industry short courses, or self-study. The material in *Introduction to Petroleum Engineering* has been used in upper-level undergraduate and introductory graduate-level courses for engineering and earth science majors. It is especially useful for geoscientists and mechanical, electrical, environmental, and chemical engineers who would like to learn more about the engineering technology needed to produce oil and gas.

Our colleagues in industry and academia and students in multidisciplinary classes helped us identify material that should be understood by people with a range of technical backgrounds. We thank Helge Alsleben, Bill Eustes, Jim Gilman, Pradeep Kaul, Don Mims, Wayne Pennington, and Rob Sutton for comments on specific chapters and Kathy Fanchi for helping prepare this manuscript.

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Richard L. Christiansen, Ph.D.
June 2016

ABOUT THE COMPANION WEBSITE

This book is accompanied by a companion website:

www.wiley.com/go/Fanchi/IntroPetroleumEngineering

The website includes:

- Solution manual for instructors only

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INTRODUCTION

The global economy is based on an infrastructure that depends on the consumption of petroleum (Fanchi and Fanchi, 2016). Petroleum is a mixture of hydrocarbon molecules and inorganic impurities that can exist in the solid, liquid (oil), or gas phase. Our purpose here is to introduce you to the terminology and techniques used in petroleum engineering. Petroleum engineering is concerned with the production of petroleum from subsurface reservoirs. This chapter describes the role of petroleum engineering in the production of oil and gas and provides a view of oil and gas production from the perspective of a decision maker.

1.1 WHAT IS PETROLEUM ENGINEERING?

A typical workflow for designing, implementing, and executing a project to produce hydrocarbons must fulfill several functions. The workflow must make it possible to identify project opportunities; generate and evaluate alternatives; select and design the desired alternative; implement the alternative; operate the alternative over the life of the project, including abandonment; and then evaluate the success of the project so lessons can be learned and applied to future projects. People with skills from many disciplines are involved in the workflow. For example, petroleum geologists and geophysicists use technology to provide a description of hydrocarbon-bearing reservoir rock (Raymond and Leffler, 2006; Hyne, 2012). Petroleum engineers acquire and apply knowledge of the behavior of oil, water, and gas in porous rock to extract hydrocarbons.

Introduction to Petroleum Engineering, First Edition. John R. Fanchi and Richard L. Christiansen.

Companion website: www.wiley.com/go/Fanchi/IntroPetroleumEngineering

Some companies form asset management teams composed of people with different backgrounds. The asset management team is assigned primary responsibility for developing and implementing a particular project.

Figure 1.1 illustrates a hydrocarbon production system as a collection of subsystems. Oil, gas, and water are contained in the pore space of reservoir rock. The accumulation of hydrocarbons in rock is a reservoir. Reservoir fluids include the fluids originally contained in the reservoir as well as fluids that may be introduced as part of the reservoir management program. Wells are needed to extract fluids from the reservoir. Each well must be drilled and completed so that fluids can flow from the reservoir to the surface. Well performance in the reservoir depends on the properties of the reservoir rock, the interaction between the rock and fluids, and fluid properties. Well performance also depends on several other properties such as the properties of the fluid flowing through the well; the well length, cross section, and trajectory; and type of completion. The connection between the well and the reservoir is achieved by completing the well so fluid can flow from reservoir rock into the well.

Surface equipment is used to drill, complete, and operate wells. Drilling rigs may be permanently installed or portable. Portable drilling rigs can be moved by vehicles that include trucks, barges, ships, or mobile platforms. Separators are used to separate produced fluids into different phases for transport to storage and processing facilities. Transportation of produced fluids occurs by such means as pipelines, tanker trucks, double-hulled tankers, and liquefied natural gas transport ships. Produced hydrocarbons must be processed into marketable products. Processing typically begins near the well site and continues at refineries. Refined hydrocarbons are used for a variety of purposes, such as natural gas for utilities, gasoline and diesel fuel for transportation, and asphalt for paving.

Petroleum engineers are expected to work in environments ranging from desert climates in the Middle East, stormy offshore environments in the North Sea, and

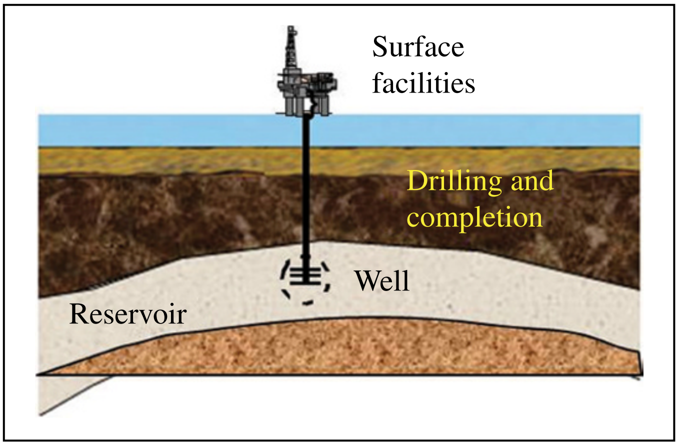

FIGURE 1.1 Production system.

arctic climates in Alaska and Siberia to deepwater environments in the Gulf of Mexico and off the coast of West Africa. They tend to specialize in one of three subdisciplines: drilling engineering, production engineering, and reservoir engineering. Drilling engineers are responsible for drilling and completing wells. Production engineers manage fluid flow between the reservoir and the well. Reservoir engineers seek to optimize hydrocarbon production using an understanding of fluid flow in the reservoir, well placement, well rates, and recovery techniques. The Society of Petroleum Engineers (SPE) is the largest professional society for petroleum engineers. A key function of the society is to disseminate information about the industry.

1.1.1 Alternative Energy Opportunities

Petroleum engineering principles can be applied to subsurface resources other than oil and gas (Fanchi, 2010). Examples include geothermal energy, geologic sequestration of gas, and compressed air energy storage (CAES). Geothermal energy can be obtained from temperature gradients between the shallow ground and surface, subsurface hot water, hot rock several kilometers below the Earth's surface, and magma. Geologic sequestration is the capture, separation, and long-term storage of greenhouse gases or other gas pollutants in a subsurface environment such as a reservoir, aquifer, or coal seam. CAES is an example of a large-scale energy storage technology that is designed to transfer off-peak energy from primary power plants to peak demand periods. The Huntorf CAES facility in Germany and the McIntosh CAES facility in Alabama store gas in salt caverns. Off-peak energy is used to pump air underground and compress it in a salt cavern. The compressed air is produced during periods of peak energy demand to drive a turbine and generate additional electrical power.

1.1.2 Oil and Gas Units

Two sets of units are commonly found in the petroleum literature: oil field units and metric units (SI units). Units used in the text are typically oil field units (Table 1.1). The process of converting from one set of units to another is simplified by providing frequently used factors for converting between oil field units and SI (metric) units in Appendix A. The ability to convert between oil field and SI units is an essential skill because both systems of units are frequently used.

TABLE 1.1 Examples of Common Unit Systems

Property	Oil Field	SI (Metric)	British
Length	ft	m	ft
Time	hr	sec	sec
Pressure	psia	Pa	lbf/ft^2
Volumetric flow rate	bbl/day	m^3/s	ft^3/s
Viscosity	cp	Pa·s	lbf·s/ft^2

1.1.3 Production Performance Ratios

The ratio of one produced fluid phase to another provides useful information for understanding the dynamic behavior of a reservoir. Let q_o, q_w, q_g be oil, water, and gas production rates, respectively. These production rates are used to calculate the following produced fluid ratios:

Gas–oil ratio (GOR)

$$\mathrm{GOR} = \frac{q_g}{q_o} \tag{1.1}$$

Gas–water ratio (GWR)

$$\mathrm{GWR} = \frac{q_g}{q_w} \tag{1.2}$$

Water–oil ratio (WOR)

$$\mathrm{WOR} = \frac{q_w}{q_o} \tag{1.3}$$

One more produced fluid ratio is water cut, which is water production rate divided by the sum of oil and water production rates:

$$\mathrm{WCT} = \frac{q_w}{(q_o + q_w)} \tag{1.4}$$

Water cut (WCT) is a fraction, while WOR can be greater than 1.

Separator GOR is the ratio of gas rate to oil rate. It can be used to indicate fluid type. A separator is a piece of equipment that is used to separate fluid from the well into oil, water, and gas phases. Separator GOR is often expressed as MSCFG/STBO where MSCFG refers to one thousand standard cubic feet of gas and STBO refers to a stock tank barrel of oil. A stock tank is a tank that is used to store produced oil.

Example 1.1 Gas–oil Ratio

A well produces 500 MSCF gas/day and 400 STB oil/day. What is the GOR in MSCFG/STBO?

Answer

$$\mathrm{GOR} = \frac{500\ \mathrm{MSCFG/day}}{400\ \mathrm{STBO/day}} = 1.25\ \mathrm{MSCFG/STBO}$$

1.1.4 Classification of Oil and Gas

Surface temperature and pressure are usually less than reservoir temperature and pressure. Hydrocarbon fluids that exist in a single phase at reservoir temperature and pressure often transition to two phases when they are produced to the surface

TABLE 1.2 Rules of Thumb for Classifying Fluid Types

Fluid Type	Separator GOR (MSCF/STB)	Gravity (°API)	Behavior in Reservoir due to Pressure Decrease
Dry gas	No surface liquids		Remains gas
Wet gas	>50	40–60	Remains gas
Condensate	3.3–50	40–60	Gas with liquid dropout
Volatile oil	2.0–3.3	>40	Liquid with significant gas
Black oil	<2.0	<45	Liquid with some gas
Heavy oil	≈0		Negligible gas formation

Data from Raymond and Leffler (2006).

where the temperature and pressure are lower. There are a variety of terms for describing hydrocarbon fluids at surface conditions. Natural gas is a hydrocarbon mixture in the gaseous state at surface conditions. Crude oil is a hydrocarbon mixture in the liquid state at surface conditions. Heavy oils do not contain much gas in solution at reservoir conditions and have a relatively large molecular weight. By contrast, light oils typically contain a large amount of gas in solution at reservoir conditions and have a relatively small molecular weight.

A summary of hydrocarbon fluid types is given in Table 1.2. API gravity in the table is defined in terms of oil specific gravity as

$$\text{API} = \left(\frac{141.5}{\gamma_o}\right) - 131.5 \tag{1.5}$$

The specific gravity of oil is the ratio of oil density ρ_o to freshwater density ρ_w:

$$\gamma_o = \frac{\rho_o}{\rho_w} \tag{1.6}$$

The API gravity of freshwater is 10°API, which is expressed as 10 degrees API. API denotes American Petroleum Institute.

Example 1.2 API Gravity

The specific gravity of an oil sample is 0.85. What is its API gravity?

Answer

$$\text{API gravity} = \frac{141.5}{\gamma_o} - 131.5 = \frac{141.5}{0.85} - 131.5 = 35°\text{API}$$

Another way to classify hydrocarbon liquids is to compare the properties of the hydrocarbon liquid to water. Two key properties are viscosity and density. Viscosity is a measure of the ability to flow, and density is the amount of material in a given volume.

TABLE 1.3 Classifying Hydrocarbon Liquid Types Using API Gravity and Viscosity

Liquid Type	API Gravity (°API)	Viscosity (cp)
Light oil	>31.1	
Medium oil	22.3–31.1	
Heavy oil	10–22.3	
Water	10	1 cp
Extra heavy oil	4–10	<10 000 cp
Bitumen	4–10	>10 000 cp

Water viscosity is 1 cp (centipoise) and water density is 1 g/cc (gram per cubic centimeter) at 60°F. A liquid with smaller viscosity than water flows more easily than water. Gas viscosity is much less than water viscosity. Tar, on the other hand, has very high viscosity relative to water.

Table 1.3 shows a hydrocarbon liquid classification scheme using API gravity and viscosity. Water properties are included in the table for comparison. Bitumen is a hydrocarbon mixture with large molecules and high viscosity. Light oil, medium oil, and heavy oil are different types of crude oil and are less dense than water. Extra heavy oil and bitumen are denser than water. In general, crude oil will float on water, while extra heavy oil and bitumen will sink in water.

1.2 LIFE CYCLE OF A RESERVOIR

The life cycle of a reservoir begins when the field becomes an exploration prospect and does not end until the field is properly abandoned. An exploration prospect is a geological structure that may contain hydrocarbons. The exploration stage of the project begins when resources are allocated to identify and assess a prospect for possible development. This stage may require the acquisition and analysis of more data before an exploration well is drilled. Exploratory wells are also referred to as wildcats. They can be used to test a trap that has never produced, test a new reservoir in a known field, and extend the known limits of a producing reservoir. Discovery occurs when an exploration well is drilled and hydrocarbons are encountered.

Figure 1.2 illustrates a typical production profile for an oil field beginning with the discovery well and proceeding to abandonment. Production can begin immediately after the discovery well is drilled or several years later after appraisal and delineation wells have been drilled. Appraisal wells are used to provide more information about reservoir properties and fluid flow. Delineation wells better define reservoir boundaries. In some cases, delineation wells are converted to development wells. Development wells are drilled in the known extent of the field and are used to optimize resource recovery. A buildup period ensues after first oil until a production plateau is reached. The production plateau is usually a consequence of facility limitations such as pipeline capacity. A production decline will eventually occur. Production continues until an economic limit is reached and the field is abandoned.

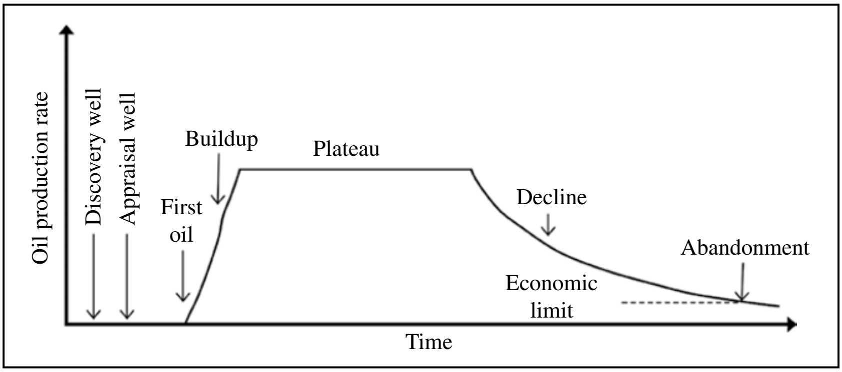

FIGURE 1.2 Typical production profile.

Petroleum engineers provide input to decision makers in management to help determine suitable optimization criteria. The optimization criteria are expected to abide by government regulations. Fields produced over a period of years or decades may be operated using optimization criteria that change during the life of the reservoir. Changes in optimization criteria occur for a variety of reason, including changes in technology, changes in economic factors, and the analysis of new information obtained during earlier stages of production.

Traditionally, production stages were identified by chronological order as primary, secondary, and tertiary production. Primary production is the first stage of production and relies entirely on natural energy sources to drive reservoir fluids to the production well. The reduction of pressure during primary production is often referred to as primary depletion. Oil recovery can be increased in many cases by slowing the decline in pressure. This can be achieved by supplementing natural reservoir energy. The supplemental energy is provided using an external energy source, such as water injection or gas injection. The injection of water or natural gas may be referred to as pressure maintenance or secondary production. Pressure maintenance is often introduced early in the production life of some modern reservoirs. In this case the reservoir is not subjected to a conventional primary production phase.

Historically, primary production was followed by secondary production and then tertiary production (Figure 1.3). Notice that the production plateau shown in Figure 1.2 does not have to appear if all of the production can be handled by surface facilities. Secondary production occurs after primary production and includes the injection of a fluid such as water or gas. The injection of water is referred to as water flooding, while the injection of a gas is called gas flooding. Typical injection gases include methane, carbon dioxide, or nitrogen. Gas flooding is considered a secondary production process if the gas is injected at a pressure that is too low to allow the injected gas to be miscible with the oil phase. A miscible process occurs when the gas injection pressure is high enough that the interface between gas and oil phases disappears. In the miscible case, injected gas mixes with oil and the process is considered an enhanced oil recovery (EOR) process.

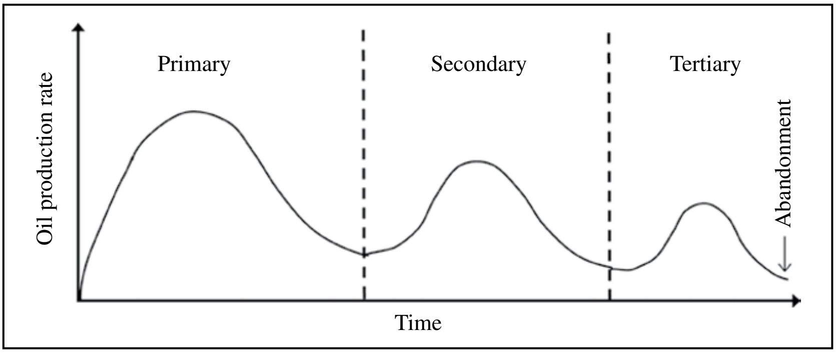

FIGURE 1.3 Sketch of production stages.

EOR processes include miscible, chemical, thermal, and microbial processes. Miscible processes inject gases that can mix with oil at sufficiently high pressures and temperatures. Chemical processes use the injection of chemicals such as polymers and surfactants to increase oil recovery. Thermal processes add heat to the reservoir. This is achieved by injecting heated fluids such as steam or hot water or by the injection of oxygen-containing air into the reservoir and then burning the oil as a combustion process. The additional heat reduces the viscosity of the oil and increases the mobility of the oil. Microbial processes use microbe injection to reduce the size of high molecular weight hydrocarbons and improve oil mobility. EOR processes were originally implemented as a third, or tertiary, production stage that followed secondary production.

EOR processes are designed to improve displacement efficiency by injecting fluids or heat. The analysis of results from laboratory experiments and field applications showed that some fields would perform better if the EOR process was implemented before the third stage in field life. In addition, it was found that EOR processes were often more expensive than just drilling more wells in a denser pattern. The process of increasing the density of wells in an area is known as infill drilling. The term improved oil recovery (IOR) includes EOR and infill drilling for improving the recovery of oil. The addition of wells to a field during infill drilling can also increase the rate of withdrawal of hydrocarbons in a process known as acceleration of production.

Several mechanisms can occur during the production process. For example, production mechanisms that occur during primary production depend on such factors as reservoir structure, pressure, temperature, and fluid type. Production of fluids without injecting other fluids will cause a reduction of reservoir pressure. The reduction in pressure can result in expansion of *in situ* fluids. In some cases, the reduction in pressure is ameliorated if water moves in to replace the produced hydrocarbons. Many reservoirs are in contact with water-bearing formations called aquifers. If the aquifer is much larger than the reservoir and is able to flow into the reservoir with relative ease, the reduction in pressure in the reservoir due to hydrocarbon production will be much less that hydrocarbon production from a reservoir that is not receiving support from an aquifer. The natural forces involved in primary production are called reservoir drives and are discussed in more detail in a later chapter.

Example 1.3 Gas Recovery

The original gas in place (OGIP) of a gas reservoir is 5 trillion ft^3 (TCF). How much gas can be recovered (in TCF) if recovery from analogous fields is between 70 and 90% of OGIP?

Answer
Two estimates are possible: a lower estimate and an upper estimate.
The lower estimate of gas recovery is 0.70×5 TCF = 3.5 TCF.
The upper estimate of gas recovery is 0.90×5 TCF = 4.5 TCF.

1.3 RESERVOIR MANAGEMENT

One definition of reservoir management says that the primary objective of reservoir management is to determine the optimum operating conditions needed to maximize the economic recovery of a subsurface resource. This is achieved by using available resources to accomplish two competing objectives: optimizing recovery from a reservoir while simultaneously minimizing capital investments and operating expenses. As an example, consider the development of an oil reservoir. It is possible to maximize recovery from the reservoir by drilling a large number of wells, but the cost would be excessive. On the other hand, drilling a single well would provide some of the oil but would make it very difficult to recover a significant fraction of the oil in a reasonable time frame. Reservoir management is a process for balancing competing objectives to achieve the key objective.

An alternate definition (Saleri, 2002) says that reservoir management is a continuous process designed to optimize the interaction between data and decision making. Both definitions describe a dynamic process that is intended to integrate information from multiple disciplines to optimize reservoir performance. The process should recognize uncertainty resulting from our inability to completely characterize the reservoir and fluid flow processes. The reservoir management definitions given earlier can be interpreted to cover the management of hydrocarbon reservoirs as well as other reservoir systems. For example, a geothermal reservoir is essentially operated by producing fluid from a geological formation. The management of the geothermal reservoir is a reservoir management task.

It may be necessary to modify a reservoir management plan based on new information obtained during the life of the reservoir. A plan should be flexible enough to accommodate changes in economic, technological, and environmental factors. Furthermore, the plan is expected to address all relevant operating issues, including governmental regulations. Reservoir management plans are developed using input from many disciplines, as we see in later chapters.

1.3.1 Recovery Efficiency

An important objective of reservoir management is to optimize recovery from a resource. The amount of resource recovered relative to the amount of resource originally in place is defined by comparing initial and final *in situ* fluid volumes.

The ratio of fluid volume remaining in the reservoir after production to the fluid volume originally in place is recovery efficiency. Recovery efficiency can be expressed as a fraction or a percentage. An estimate of recovery efficiency is obtained by considering the factors that contribute to the recovery of a subsurface fluid: displacement efficiency and volumetric sweep efficiency.

Displacement efficiency E_D is a measure of the amount of fluid in the system that can be mobilized by a displacement process. For example, water can displace oil in a core. Displacement efficiency is the difference between oil volume at initial conditions and oil volume at final (abandonment) conditions divided by the oil volume at initial conditions:

$$E_D = \frac{(S_{oi}/B_{oi}) - (S_{oa}/B_{oa})}{S_{oi}/B_{oi}} \tag{1.7}$$

where S_{oi} is initial oil saturation and S_{oa} is oil saturation at abandonment. Oil saturation is the fraction of oil occupying the volume in a pore space. Abandonment refers to the time when the process is completed. Formation volume factor (FVF) is the volume occupied by a fluid at reservoir conditions divided by the volume occupied by the fluid at standard conditions. The terms B_{oi} and B_{oa} refer to FVF initially and at abandonment, respectively.

Example 1.4 Formation Volume Factor

Suppose oil occupies 1 bbl at stock tank (surface) conditions and 1.4 bbl at reservoir conditions. The oil volume at reservoir conditions is larger because gas is dissolved in the liquid oil. What is the FVF of the oil?

Answer

$$\text{Oil FVF} = \frac{\text{vol at reservoir conditions}}{\text{vol at surface conditions}}$$

$$\text{Oil FVF} = \frac{1.4\,\text{RB}}{1.0\,\text{STB}} = 1.4\,\text{RB/STB}$$

Volumetric sweep efficiency E_{Vol} expresses the efficiency of fluid recovery from a reservoir volume. It can be written as the product of areal sweep efficiency and vertical sweep efficiency:

$$E_{Vol} = E_A \times E_V \tag{1.8}$$

Areal sweep efficiency E_A and vertical sweep efficiency E_V represent the efficiencies associated with the displacement of one fluid by another in the areal plane and vertical dimension. They represent the contact between *in situ* and injected fluids. Areal sweep efficiency is defined as

$$E_A = \frac{\text{swept area}}{\text{total area}} \tag{1.9}$$

and vertical sweep efficiency is defined as

$$E_V = \frac{\text{swept net thickness}}{\text{total net thickness}} \tag{1.10}$$

Recovery efficiency RE is the product of displacement efficiency and volumetric sweep efficiency:

$$\text{RE} = E_D \times E_{\text{Vol}} = E_D \times E_A \times E_V \tag{1.11}$$

Displacement efficiency, areal sweep efficiency, vertical sweep efficiency, and recovery efficiency are fractions that vary from 0 to 1. Each of the efficiencies that contribute to recovery efficiency can be relatively large and still yield a recovery efficiency that is relatively small. Reservoir management often focuses on finding the efficiency factor that can be improved by the application of technology.

Example 1.5 Recovery Efficiency

Calculate volumetric sweep efficiency E_{Vol} and recovery efficiency RE from the following data:

S_{oi}	0.75
S_{oa}	0.30
Area swept	750 acres
Total area	1000 acres
Thickness swept	10 ft
Total thickness	15 ft
Neglect FVF effects since $B_{oi} \approx B_{oa}$	

Answer

$$\text{Displacement efficiency:} \quad E_D = \frac{(S_{oi}/B_{oi}) - (S_{oa}/B_{oa})}{S_{oi}/B_{oi}} \approx \frac{S_{oi} - S_{oa}}{S_{oi}} = 0.6$$

$$\text{Areal sweep efficiency:} \quad E_A = \frac{\text{swept area}}{\text{total area}} = 0.75$$

$$\text{Vertical sweep efficiency:} \quad E_V = \frac{\text{swept net thickness}}{\text{total net thickness}} = 0.667$$

$$\text{Volumetric sweep efficiency:} \quad E_{\text{vol}} = E_A \times E_V = 0.5$$

$$\text{Recovery efficiency:} \quad \text{RE} = E_D \times E_{\text{Vol}} = 0.3$$

1.4 PETROLEUM ECONOMICS

The decision to develop a petroleum reservoir is a business decision that requires an analysis of project economics. A prediction of cash flow from a project is obtained by combining a prediction of fluid production volume with a forecast of fluid price.

Production volume is predicted using engineering calculations, while fluid price estimates are obtained using economic models. The calculation of cash flow for different scenarios can be used to compare the economic value of competing reservoir development concepts.

Cash flow is an example of an economic measure of investment worth. Economic measures have several characteristics. An economic measure should be consistent with the goals of the organization. It should be easy to understand and apply so that it can be used for cost-effective decision making. Economic measures that can be quantified permit alternatives to be compared and ranked.

Net present value (NPV) is an economic measure that is typically used to evaluate cash flow associated with reservoir performance. NPV is the difference between the present value of revenue R and the present value of expenses E:

$$\mathrm{NPV} = R - E \tag{1.12}$$

The time value of money is incorporated into NPV using discount rate r. The value of money is adjusted to the value associated with a base year using discount rate. Cash flow calculated using a discount rate is called discounted cash flow. As an example, NPV for an oil and/or gas reservoir may be calculated for a specified discount rate by taking the difference between revenue and expenses (Fanchi, 2010):

$$\begin{aligned} \mathrm{NPV} &= \sum_{n=1}^{N} \frac{P_{\mathrm{o}n} q_{\mathrm{o}n} + P_{\mathrm{g}n} q_{\mathrm{g}n}}{(1+r)^n} - \sum_{n=1}^{N} \frac{\mathrm{CAPEX}_n + \mathrm{OPEX}_n + \mathrm{TAX}_n}{(1+r)^n} \\ &= \sum_{n=1}^{N} \frac{P_{\mathrm{o}n} q_{\mathrm{o}n} + P_{\mathrm{g}n} q_{\mathrm{g}n} - \mathrm{CAPEX}_n - \mathrm{OPEX}_n - \mathrm{TAX}_n}{(1+r)^n} \end{aligned} \tag{1.13}$$

where N is the number of years, $P_{\mathrm{o}n}$ is oil price during year n, $q_{\mathrm{o}n}$ is oil production during year n, $P_{\mathrm{g}n}$ is gas price during year n, $q_{\mathrm{g}n}$ is gas production during year n, CAPEX_n is capital expenses during year n, OPEX_n is operating expenses during year n, TAX_n is taxes during year n, and r is discount rate.

The NPV for a particular case is the value of the cash flow at a specified discount rate. The discount rate at which the maximum NPV is zero is called the discounted cash flow return on investment (DCFROI) or internal rate of return (IRR). DCFROI is useful for comparing different projects.

Figure 1.4 shows a typical plot of NPV as a function of time. The early time part of the figure shows a negative NPV and indicates that the project is operating at a loss. The loss is usually associated with initial capital investments and operating expenses that are incurred before the project begins to generate revenue. The reduction in loss and eventual growth in positive NPV are due to the generation of revenue in excess of expenses. The point in time on the graph where the NPV is zero after the project has begun is the discounted payout time. Discounted payout time on Figure 1.4 is approximately 2.5 years.