PETROLEUM PRODUCTION SYSTEMS

SECOND EDITION

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Foreword

I have waited on this book for the last 10 years. It is a modernized version of the classic first edition, thousands of copies of which have been distributed to my former trainees, engineers, and associates. The authors of the book have worked with me in a number of capacities for 25 years and we have become kindred spirits both in how we think about oil and gas production enhancement and, especially, in knowing how bad production management can be, even in the most unexpected places and companies.

It is a comprehensive book that describes the "production system," or what I refer to as "nodal analysis," artificial lift, well diagnosis, matrix stimulation, hydraulic fracturing, and sand control.

There are some important points that are made in this book, which I have made repeatedly in the past:

1. To increase field production, well improvement can be more effective than infill drilling, especially when the new wells are just as suboptimum as existing wells. We demonstrated this while I was managing Yukos E&P in Russia. During that time appropriate production enhancement actions improved field production by more than 15% even after stopping all drilling for as long as a year.
2. In conventional reservoirs, optimized well completions do not sacrifice ultimate field recovery as long as they are achieved with adequate reservoir pressure support from either natural gas cap or water drive mechanisms or through injection wells.
3. Many, if not most, operators fail to address well performance, and few wells are produced at their maximum flow potential. This book takes great steps to show that proper production optimization is far more important to success than just simply executing blindly well completions and even stimulation practices. In particular, I consider the Unified Fracture Design (UFD) approach, the brainchild of the lead author, to be the only coherent approach to hydraulic fracture design. I have been using it exclusively and successfully in all my hydraulic fracture design work.

This book provides not only best practices but also the rationale for new activities. The strategies shown in this book explain why unconventional oil and gas reservoirs are successfully produced today.

The book fills a vacuum in the industry and has come not a moment too soon.

—Joe Mach
Inventor, Nodal Analysis
Former Executive VP, Yukos
Former VP, Schlumberger

Preface

Since the first edition of this book appeared in 1994, many advances in the practice of petroleum production engineering have occurred. The objective of this book is the same as for the first edition: to provide a comprehensive and relatively advanced textbook in petroleum production engineering, that suffices as a terminal exposure to senior undergraduates or an introduction to graduate students. This book is also intended to be used in industrial training to enable nonpetroleum engineers to understand the essential elements of petroleum production. Numerous technical advances in the years since the first edition have led to the extensive revisions that readers will notice in this second edition. In particular, widespread use of horizontal wells and much broader application of hydraulic fracturing have changed the face of production practices and justified critical updating of the text. The authors have benefited from wide experience in both university and industrial settings. Our areas of interest are complementary and ideally suited for this book, spanning classical production engineering, well testing, production logging, artificial lift, and matrix and hydraulic fracture stimulation. We have been contributors in these areas for many years. Among the four of us, we have taught petroleum production engineering to literally thousands of students and practicing engineers using the first edition of this book, both in university classes and in industry short courses, and this experience has been one of the key guiding factors in the creation of the second edition.

This book offers a structured approach toward the goal defined above. Chapters 2–4 present the inflow performance for oil, two-phase, and gas reservoirs. Chapter 5 deals with complex well architecture such as horizontal and multilateral wells, reflecting the enormous growth of this area of production engineering since the first edition of the book. Chapter 6 deals with the condition of the near-wellbore zone, such as damage, perforations, and gravel packing. Chapter 7 covers the flow of fluids to the surface. Chapter 8 describes the surface flow system, flow in horizontal pipes, and flow in horizontal wells. Combination of inflow performance and well performance versus time, taking into account single-well transient flow and material balance, is shown in Chapters 9 and 10. Therefore, Chapters 1–10 describe the workings of the reservoir and well systems.

Gas lift is outlined in Chapter 11, and mechanical lift in Chapter 12. For an appropriate production engineering remedy it is essential that well and reservoir diagnosis be done. Chapter 13 presents the state-of-the-art in modern diagnosis that includes well testing, production logging, and well monitoring with permanent downhole instruments.

From the well diagnosis it can be concluded whether the well is in need of matrix stimulation, hydraulic fracturing, artificial lift, combinations of the above, or none. Matrix stimulation for all major types of reservoirs is presented in Chapters 14, 15, and 16, while hydraulic fracturing is treated in Chapters 17 and 18. Chapter 19 is a new chapter dealing with advances in sand management.

To simplify the presentation of realistic examples, data for three characteristic reservoir types—an undersaturated oil reservoir, a saturated oil reservoir, and a gas reservoir—are presented in the Appendixes. These data sets are used throughout the book.

Revising this textbook to include the primary production engineering of the past 20 years has been a considerable task, requiring a long and concerted (and only occasionally contentious!) effort from the authors. We have also benefited from the efforts of many of our graduate students and support staff. Discussions with many of our colleagues in industry and academia have also been a key to the completion of the book. We would like to thank in particular the contributions of Dr. Paul Bommer, who provided some very useful material on artificial lift; Dr. Chen Yang, who assisted with some of the new material on carbonate acidizing; Dr. Tom Blasingame and Mr. Chih Chen, who shared well data used as pressure buildup and production data examples; Mr. Tony Rose, who created the graphics; and Ms. Katherine Brady and Mr. Imran Ali for their assistance in the production of this second edition.

As we did for the first edition, we acknowledge the many colleagues, students, and our own professors who contributed to our efforts. In particular, feedback from all of our students in petroleum production engineering courses has guided our revision of the first edition of this text, and we thank them for their suggestions, comments, and contributions.

We would like to gratefully acknowledge the following organizations and persons for permitting us to reprint some of the figures and tables in this text: for Figs. 3-2, 3-3, 5-2, 5-4, 5-7, 6-15, 6-16, 6-18, 6-19, 6-20, 6-21, 6-22, 624, 6-24, 6-26, 6-27, 6-28, 6-29, 7-1, 7-9, 7-12, 7-13, 7-13, 7-14, 8-1, 8-4, 8-6, 8-7, 8-17, 13-13, 13-19, 14-3, 15-1, 15-2, 15-4, 15-7, 15-10, 15-12, 16-1, 16-2, 16-4, 16-5, 16-6, 16-7, 16-8, 16-14, 16-16, 16-17, 16-20, 17-2, 17-3, 17-6, 17-11, 17-12, 17-13, 17-14, 17-15, 17-16, 17-17, 17-18, 17-19, 18-20, 18-21, 18-22, 18-23, 18-25, 18-26, 19-1, 19-6, 19-7, 19-8, 19-9, 19-10, 19-17, 19-18, 19-19, 19-20, 19-21a, 19-21b, and 19-22, the Society of Petroleum Engineers; for Figs. 6-13, 6-14, 13-2, 13-18, 18-13, 18-14, 18-19, 19-2, and 19-3, Schlumberger; for Figs. 6-23, 12-5, 12-6, 15-3, 15-6, 16-17, and 16-19, Prentice Hall; for Figs. 8-3, 8-14, 12-15, 12-16, and 16-13, Elsevier Science Publishers; for Figs. 4-3, 19-12, 19-13, 19-14, and 19-15, Gulf Publishing Co., Houston, TX; for Figs. 13-5, 13-6, 13-8, 13-9, 13-11, and 13-12, Hart Energy, Houston, TX; for Figs. 7-11 and 8-5, the American Institute of Chemical Engineers; for Figs. 7-6 and 7-7, the American Society of Mechanical Engineers; for Figs. 8-11 and Table 8-1, Crane Co., Stamford, CT; for Figs. 12-8, 12-9, and 12-10, Editions Technip, Paris, France; for Fig. 2-3, the American Institute of Mining, Metallurgical & Petroleum Engineers; for Fig. 3-4, McGraw-Hill; for Fig. 7-10, World Petroleum Council; for Fig. 12-11, Baker Hughes; for Fig. 13-1, PennWell Publishing Co., Tulsa, OK; for Fig. 13-3, the Society of Petrophysicists and Well Log Analysts; for Fig. 18-16, Carbo Ceramics, Inc.; for Figs. 12-1, 12-2, and 12-7, Dr. Michael Golan and Dr. Curtis Whitson; for Fig. 6-17, Dr. Kenji Furui; for Fig. 8-8, Dr. James P. Brill; for Fig. 15-8, Dr. Eduardo Ponce da Motta; for Figs. 18-11 and 18-15, Dr. Harold Brannon. Used with permission, all rights reserved.

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CHAPTER 1

The Role of Petroleum Production Engineering

1.1 Introduction

Petroleum production involves two distinct but intimately connected general systems: the reservoir, which is a porous medium with unique storage and flow characteristics; and the artificial structures, which include the well, bottomhole, and wellhead assemblies, as well as the surface gathering, separation, and storage facilities.

Production engineering is that part of petroleum engineering that attempts to maximize production (or injection) in a cost-effective manner. In the 15 years that separated the first and second editions of this textbook worldwide production enhancement, headed by hydraulic fracturing, has increased tenfold in constant dollars, becoming the second largest budget item of the industry, right behind drilling. Complex well architecture, far more elaborate than vertical or single horizontal wells, has also evolved considerably since the first edition and has emerged as a critical tool in reservoir exploitation.

In practice one or more wells may be involved, but in distinguishing production engineering from, for example, reservoir engineering, the focus is often on specific wells and with a short-time intention, emphasizing production or injection optimization. In contrast, reservoir engineering takes a much longer view and is concerned primarily with recovery. As such, there may be occasional conflict in the industry, especially when international petroleum companies, whose focus is accelerating and maximizing production, have to work with national oil companies, whose main concerns are to manage reserves and long-term exploitation strategies.

Production engineering technologies and methods of application are related directly and interdependently with other major areas of petroleum engineering, such as formation evaluation, drilling, and reservoir engineering. Some of the most important connections are summarized below.

Modern formation evaluation provides a composite reservoir description through three-dimensional (3-D) seismic, interwell log correlation and well testing. Such description leads to the identification of geological flow units, each with specific characteristics. Connected flow units form a reservoir.

Drilling creates the all-important well, and with the advent of directional drilling technology it is possible to envision many controllable well configurations, including very long horizontal sections and multilateral, multilevel, and multibranched wells, targeting individual flow units. The drilling of these wells is never left to chance but, instead, is guided by very sophisticated measurements while drilling (MWD) and logging while drilling (LWD). Control of drilling-induced, near-wellbore damage is critical, especially in long horizontal wells.

Reservoir engineering in its widest sense overlaps production engineering to a degree. The distinction is frequently blurred both in the context of study (single well versus multiple well) and in the time duration of interest (long term versus short term). Single-well performance, undeniably the object of production engineering, may serve as a boundary condition in a fieldwide, long-term reservoir engineering study. Conversely, findings from the material balance calculations or reservoir simulation further define and refine the forecasts of well performance and allow for more appropriate production engineering decisions.

In developing a petroleum production engineering thinking process, it is first necessary to understand important parameters that control the performance and the character of the system. Below, several definitions are presented.

1.2 Components of the Petroleum Production System

1.2.1 Volume and Phase of Reservoir Hydrocarbons

1.2.1.1 Reservoir

The reservoir consists of one or several interconnected geological flow units. While the shape of a well and converging flow have created in the past the notion of radial flow configuration, modern techniques such as 3-D seismic and new logging and well testing measurements allow for a more precise description of the shape of a geological flow unit and the ensuing production character of the well. This is particularly true in identifying lateral and vertical boundaries and the inherent heterogeneities.

Appropriate reservoir description, including the extent of heterogeneities, discontinuities, and anisotropies, while always important, has become compelling after the emergence of horizontal wells and complex well architecture with total lengths of reservoir exposure of many thousands of feet.

Figure 1-1 is a schematic showing two wells, one vertical and the other horizontal, contained within a reservoir with potential lateral heterogeneities or discontinuities (sealing faults), vertical boundaries (shale lenses), and anisotropies (stress or permeability).

While appropriate reservoir description and identification of boundaries, heterogeneities, and anisotropies is important, it is somewhat forgiving in the presence of only vertical wells. These issues become critical when horizontal and complex wells are drilled.

The encountering of lateral discontinuities (including heterogeneous pressure depletion caused by existing wells) has a major impact on the expected complex well production. The well branch trajectories vis à vis the azimuth of directional properties also has a great effect on well production. Ordinarily, there would be only one set of optimum directions.

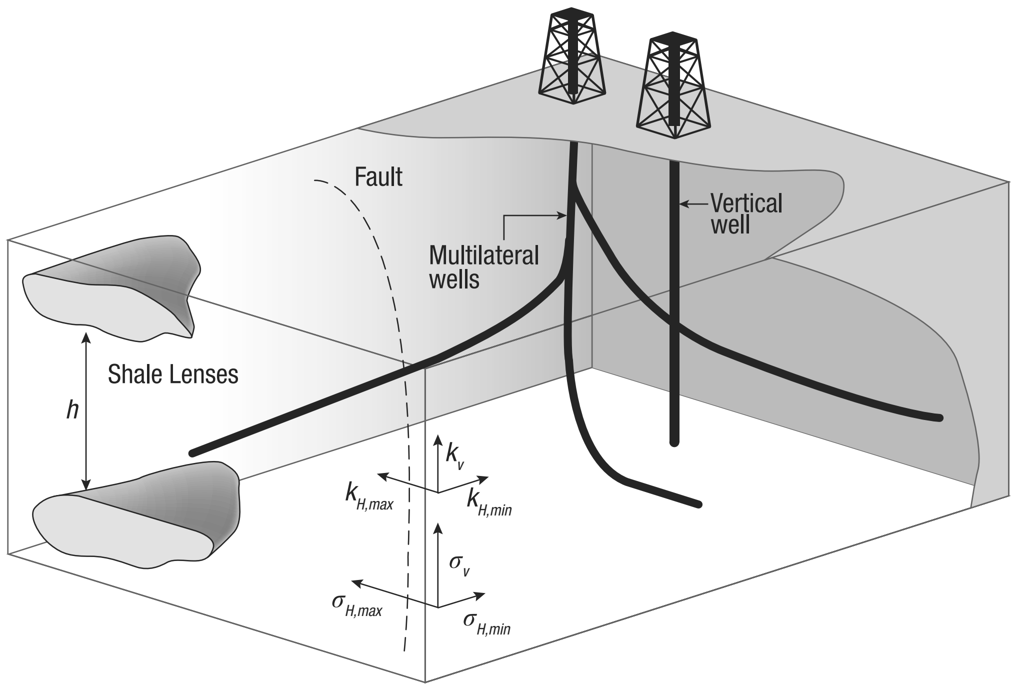

Figure 1-1 Common reservoir heterogeneities, anisotropies, discontinuities, and boundaries affecting the performance of vertical, horizontal, and complex-architecture wells.

Understanding the geological history that preceded the present hydrocarbon accumulation is essential. There is little doubt that the best petroleum engineers are those who understand the geological processes of deposition, fluid migration, and accumulation. Whether a reservoir is an anticline, a fault block, or a channel sand not only dictates the amount of hydrocarbon present but also greatly controls well performance.

1.2.1.2 Porosity

All of petroleum engineering deals with the exploitation of fluids residing within porous media. Porosity, simply defined as the ratio of the pore volume, V_p, to the bulk volume, V_b,

$$\phi = \frac{V_p}{V_b} \tag{1-1}$$

is an indicator of the amount of fluid in place. Porosity values vary from over 0.3 to less than 0.1. The porosity of the reservoir can be measured based on laboratory techniques using reservoir cores or with field measurements including logs and well tests. Porosity is one of the very first measurements obtained in any exploration scheme, and a desirable value is essential for the continuation of any further activities toward the potential exploitation of a reservoir. In the absence of substantial porosity there is no need to proceed with an attempt to exploit a reservoir.

1.2.1.3 Reservoir Height

Often known as "reservoir thickness" or "pay thickness," the reservoir height describes the thickness of a porous medium in hydraulic communication contained between two layers. These layers are usually considered impermeable. At times the thickness of the hydrocarbon-bearing formation is distinguished from an underlaying water-bearing formation, or aquifer. Often the term "gross height" is employed in a multilayered, but co-mingled during production, formation. In such cases the term "net height" may be used to account for only the permeable layers in a geologic sequence.

Well logging techniques have been developed to identify likely reservoirs and quantify their vertical extent. For example, measuring the spontaneous potential (SP) and knowing that sandstones have a distinctly different response than shales (a likely lithology to contain a layer), one can estimate the thickness of a formation. Figure 1-2 is a well log showing clearly the deflection of the spontaneous potential of a sandstone reservoir and the clearly different response of the adjoining shale layers. This deflection corresponds to the thickness of a *potentially* hydrocarbon-bearing, porous medium.

The presence of satisfactory net reservoir height is an additional imperative in any exploration activity.

1.2.1.4 Fluid Saturations

Oil and/or gas are never alone in "saturating" the available pore space. Water is always present. Certain rocks are "oil-wet," implying that oil molecules cling to the rock surface. More frequently, rocks are "water-wet." Electrostatic forces and surface tension act to create these wettabilities, which may change, usually with detrimental consequences, as a result of injection of fluids, drilling, stimulation, or other activity, and in the presence of surface-acting chemicals. If the water is present but does not flow, the corresponding water saturation is known as "connate" or "interstitial." Saturations larger than this value would result in free flow of water along with hydrocarbons.

Petroleum hydrocarbons, which are mixtures of many compounds, are divided into oil and gas. Any mixture depending on its composition and the conditions of pressure and temperature may appear as liquid (oil) or gas or a mixture of the two.

Frequently the use of the terms *oil* and *gas* is blurred. Produced oil and gas refer to those parts of the total mixture that would be in liquid and gaseous states, respectively, after surface separation. Usually the corresponding pressure and temperature are "standard conditions," that is, usually (but not always) 14.7 psi and 60° F.

Flowing oil and gas in the reservoir imply, of course, that either the initial reservoir pressure or the induced flowing bottomhole pressures are such as to allow the concurrent presence of two phases. Temperature, except in the case of high-rate gas wells, is for all practical purposes constant.

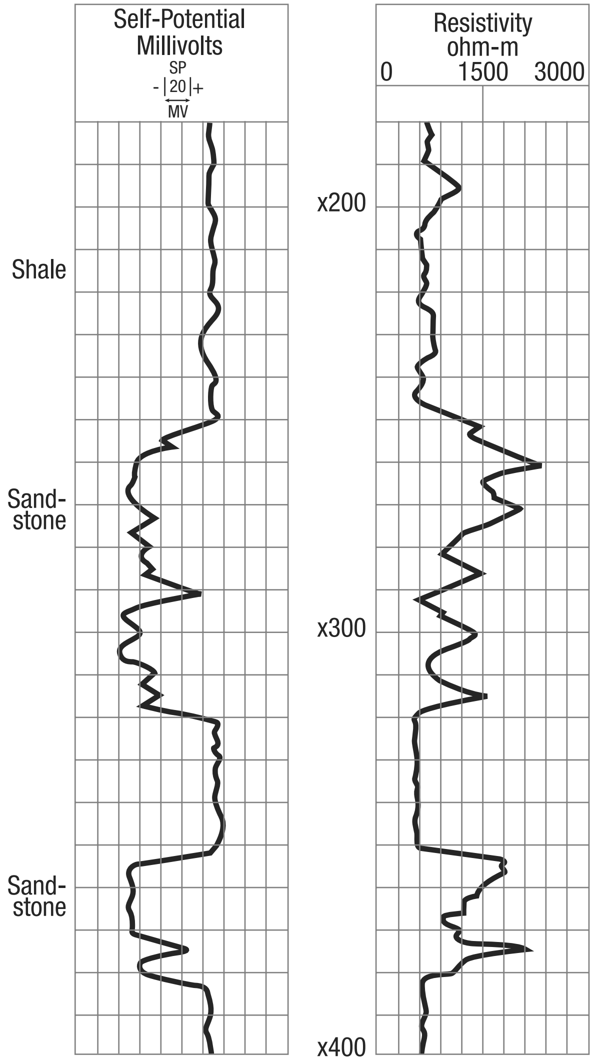

Figure 1-2 Spontaneous potential and electrical resistivity logs identifying sandstones versus shales, and water-bearing versus hydrocarbon-bearing formations.

An attractive hydrocarbon saturation is the third critical variable (along with porosity and reservoir height) to be determined before a well is tested or completed. A classic method, currently performed in a variety of ways, is the measurement of the formation electrical resistivity. Knowing that formation brines are good conductors of electricity (i.e., they have poor resistivity) and hydrocarbons are the opposite, a measurement of this electrical property in a porous formation of sufficient height can detect the presence of hydrocarbons. With proper calibration, not just the presence but also the hydrocarbon saturation (i.e., fraction of the pore space occupied by hydrocarbons) can be estimated.

Figure 1-2 also contains a resistivity log. The previously described SP log along with the resistivity log, showing a high resistivity within the same zone, are good indicators that the identified porous medium is likely saturated with hydrocarbons.

The combination of porosity, reservoir net thickness, and saturations is essential in deciding whether a prospect is attractive or not. These variables can allow the estimation of hydrocarbons near the well.

1.2.1.5 Classification of Reservoirs

All hydrocarbon mixtures can be described by a phase diagram such as the one shown in Figure 1-3. Plotted are temperature (x axis) and pressure (y axis). A specific point is the *critical point*, where the properties of liquid and gas converge. For each temperature less than the critical-point temperature (to the left of T_c in Figure 1-3) there exists a pressure called the "bubble-point" pressure, above which only liquid (oil) is present and below which gas and liquid coexist. For lower pressures (at constant temperature), more gas is liberated. Reservoirs above the bubble-point pressure are called "undersaturated."

If the initial reservoir pressure is less than or equal to the bubble-point pressure, or if the flowing bottomhole pressure is allowed to be at such a value (even if the initial reservoir pressure is above the bubble point), then free gas will at least form and will likely flow in the reservoir. This type of a reservoir is known as "two-phase" or "saturated."

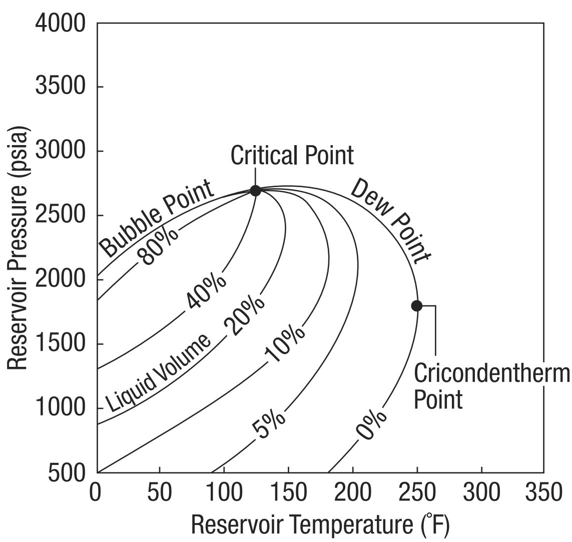

Figure 1-3 Oilfield hydrocarbon phase diagram showing bubble-point and dew-point curves, lines of constant-phase distribution, region of retrograde condensation, and the critical and cricondentherm points.

For temperatures larger than the critical point (to the right of T_c in Figure 1-3), the curve enclosing the two-phase envelop is known as the “dew-point” curve. Outside, the fluid is gas, and reservoirs with these conditions are “lean” gas reservoirs.

The maximum temperature of a two-phase envelop is known as the “cricondentherm.” Between these two points there exists a region where, because of the shape of the gas saturation curves, as the pressure decreases, liquid or “condensate” is formed. This happens until a limited value of the pressure, after which further pressure reduction results in revaporization. The region in which this phenomenon takes place is known as the “retrograde condensation” region, and reservoirs with this type of behavior are known as “retrograde condensate reservoirs.”

Each hydrocarbon reservoir has a characteristic phase diagram and resulting physical and thermodynamic properties. These are usually measured in the laboratory with tests performed on fluid samples obtained from the well in a highly specialized manner. Petroleum thermodynamic properties are known collectively as *PVT* (*pressure–volume–temperature*) properties.

1.2.1.6 Areal Extent

Favorable conclusions on the porosity, reservoir height, fluid saturations, and pressure (and implied phase distribution) of a petroleum reservoir, based on single well measurements, are insufficient for both the decision to develop the reservoir and for the establishment of an appropriate exploitation scheme.

Advances in 3-D and wellbore seismic techniques, in combination with well testing, can increase greatly the region where knowledge of the reservoir extent (with height, porosity, and saturations) is possible. Discontinuities and their locations can be detected. As more wells are drilled, additional information can enhance further the knowledge of the reservoir’s peculiarities and limits.

The areal extent is essential in the estimation of the “original-oil (or gas)-in-place.” The hydrocarbon volume, V_{HC}, in reservoir cubic ft is

$$V_{HC} = Ah\phi(1 - S_w) \tag{1-2}$$

where A is the areal extent in ft^2, h is the reservoir thickness in ft, ϕ is the porosity, and S_w is the water saturation. (Thus, $1 - S_w$ is the hydrocarbon saturation.) The porosity, height, and saturation can of course vary within the areal extent of the reservoir.

Equation (1-2) can lead to the estimation of the oil or gas volume under standard conditions after dividing by the oil formation volume factor, B_o, or the gas formation volume factor, B_g. This factor is simply a ratio of the volume of liquid or gas under reservoir conditions to the corresponding volumes under standard conditions. Thus, for oil,

$$N = \frac{7758Ah\phi(1 - S_w)}{B_o} \tag{1-3}$$

where N is in stock tank barrels (STB). In Equation (1-3) the area is in acres. For gas,

$$G = \frac{Ah\phi(1 - S_w)}{B_g} \tag{1-4}$$

where G is in standard cubic ft (SCF) and A is in ft^2.

The gas formation volume factor (traditionally, res ft^3/SCF), B_g, simply implies a volumetric relationship and can be calculated readily with an application of the real gas law. The gas formation volume factor is much smaller than 1.

The oil formation volume factor (res bbl/STB), B_o, is not a simple physical property. Instead, it is an empirical thermodynamic relationship allowing for the reintroduction into the liquid (at the elevated reservoir pressure) of all of the gas that would be liberated at standard conditions. Thus the oil formation volume factor is invariably larger than 1, reflecting the swelling of the oil volume because of the gas dissolution.

The reader is referred to the classic textbooks by Muskat (1949), Craft and Hawkins (revised by Terry, 1991), and Amyx, Bass, and Whiting (1960), and the newer book by Dake (1978) for further information. The present textbook assumes basic reservoir engineering knowledge as a prerequisite.

1.2.2 Permeability

The presence of a substantial porosity usually (but not always) implies that pores will be interconnected. Therefore the porous medium is also "permeable." The property that describes the ability of fluids to flow in the porous medium is permeability. In certain lithologies (e.g., sandstones), a larger porosity is associated with a larger permeability. In other lithologies (e.g., chalks), very large porosities, at times over 0.4, are not necessarily associated with proportionately large permeabilities.

Correlations of porosity versus permeability should be used with a considerable degree of caution, especially when going from one lithology to another. For production engineering calculations these correlations are rarely useful, except when considering matrix stimulation. In this instance, correlations of the *altered* permeability with the *altered* porosity after stimulation are useful.

The concept of permeability was introduced by Darcy (1856) in a classic experimental work from which both petroleum engineering and groundwater hydrology have benefited greatly.

Figure 1-4 is a schematic of Darcy's experiment. The flow rate (or fluid velocity) can be measured against pressure (head) for different porous media.

Darcy observed that the flow rate (or velocity) of a fluid through a specific porous medium is linearly proportional to the head or pressure difference between the inlet and the outlet and a characteristic property of the medium. Thus,

$$u \,\alpha\, k\Delta p \tag{1-5}$$

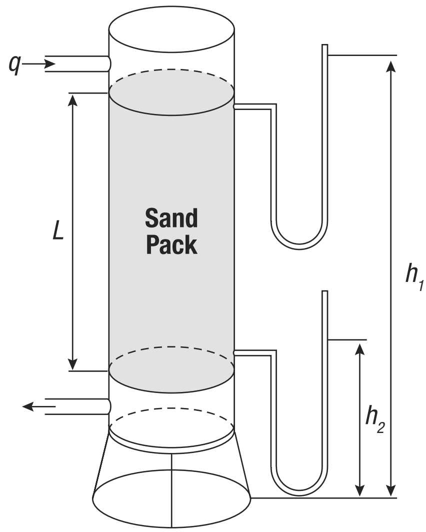

Figure 1-4 Darcy's experiment. Water flows through a sand pack and the pressure difference (head) is recorded.

where k is the permeability and is a characteristic property of the porous medium. Darcy's experiments were done with water. If fluids of other viscosities flow, the permeability must be divided by the viscosity and the ratio k/μ is known as the "mobility."

1.2.3 The Zone near the Well, the Sandface, and the Well Completion

The zone surrounding a well is important. First, even without any man-made disturbance, converging, radial flow results in a considerable pressure drop around the wellbore and, as will be demonstrated later in this book, the pressure drop away from the well varies logarithmically with the distance. This means that the pressure drop in the first foot away from the well is naturally equal to that 10 feet away and equal to that 100 feet away, and so on. Second, all intrusive activities such as drilling, cementing, and well completion are certain to alter the condition of the reservoir near the well. This is usually detrimental and it is not inconceivable that in some cases 90% of the total pressure drop in the reservoir may be consumed in a zone just a few feet away from the well.

Matrix stimulation is intended to recover or even improve the near-wellbore permeability. (There is damage associated even with stimulation. It is the net effect that is expected to be beneficial.) Hydraulic fracturing, today one of the most widely practiced well-completion techniques, alters the manner by which fluids flow to the well; one of the most profound effects is that near-well radial flow and the damage associated with it are eliminated.

Many wells are cemented and cased. One of the purposes of cementing is to support the casing, but at formation depths the most important reason is to provide zonal isolation. Contamination of the produced fluid from the other formations or the loss of fluid *into* other formations

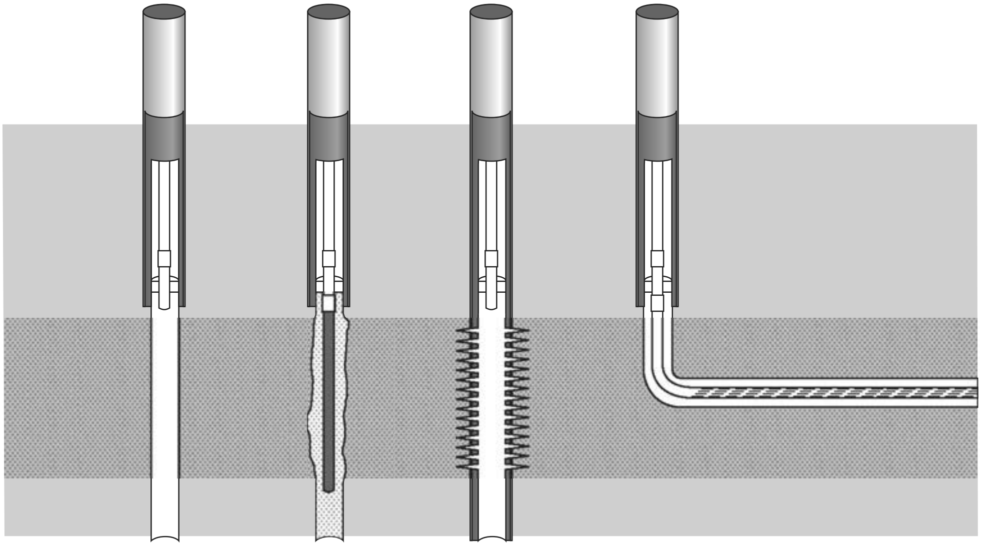

Figure 1-5 Options for well completions.

can be envisioned readily in an open-hole completion. If no zonal isolation or wellbore stability problems are present, the well can be open hole. A cemented and cased well must be perforated in order to reestablish communication with the reservoir. Slotted liners can be used if a cemented and cased well is not deemed necessary and are particularly common in horizontal wells where cementing is more difficult.

Finally, to combat the problems of sand or other fines production, screens can be placed between the well and the formation. Gravel packing can be used as an additional safeguard and as a means to keep permeability-reducing fines away from the well.

The various well completions and the resulting near-wellbore zones are shown in Figure 1-5.

The ability to direct the drilling of a well allows the creation of highly deviated, horizontal, and complex wells. In these cases, a longer to far longer exposure of the well with the reservoir is accomplished than would be the case for vertical wells.

1.2.4 The Well

Entrance of fluids into the well, following their flow through the porous medium, the near-well zone, and the completion assembly, requires that they are lifted through the well up to the surface.

There is a required flowing pressure gradient between the bottomhole and the well head. The pressure gradient consists of the potential energy difference (hydrostatic pressure) and the frictional pressure drop. The former depends on the reservoir depth and the latter depends on the well length.

If the bottomhole pressure is sufficient to lift the fluids to the top, then the well is "naturally flowing." Otherwise, artificial lift is indicated. Mechanical lift can be supplied by a pump. Another technique is to reduce the density of the fluid in the well and thus to reduce the hydrostatic pressure. This is accomplished by the injection of lean gas in a designated spot along the well. This is known as "gas lift."

1.2.5 The Surface Equipment

After the fluid reaches the top, it is likely to be directed toward a manifold connecting a number of wells. The reservoir fluid consists of oil, gas (even if the flowing bottomhole pressure is larger than the bubble-point pressure, gas is likely to come out of solution along the well), and water.

Traditionally, the oil, gas, and water are not transported long distances as a mixed stream, but instead are separated at a surface processing facility located in close proximity to the wells. An exception that is becoming more common is in some offshore fields, where production from subsea wells, or sometimes the commingled production from several wells, may be transported long distances before any phase separation takes place.

Finally, the separated fluids are transported or stored. In the case of formation water it is usually disposed in the ground through a reinjection well.

The reservoir, well, and surface facilities are sketched in Figure 1-6. The flow systems from the reservoir to the entrance to the separation facility are the production engineering systems that are the subjects of study in this book.

1.3 Well Productivity and Production Engineering

1.3.1 The Objectives of Production Engineering

Many of the components of the petroleum production system can be considered together by graphing the inflow performance relationship (IPR) and the vertical flow performance (VFP). Both the IPR and the VFP relate the wellbore flowing pressure to the surface production rate. The IPR represents what the reservoir can deliver, and the VFP represents what the well can deliver. Combined, as in Figure 1-7, the intersection of the IPR with the VFP yields the well deliverability, an expression of what a well will actually produce for a given operating condition. The role of a petroleum production engineer is to maximize the well deliverability in a cost-effective manner. Understanding and measuring the variables that control these relationships (well diagnosis) becomes imperative.

While these concepts will be dealt with extensively in subsequent chapters, it is useful here to present the productivity index, J, of an oil well (analogous expressions can be written for gas and two-phase wells):

$$J = \frac{q}{p - p_{wf}} = \frac{kh}{\alpha_r B\mu} J_D. \quad \textbf{(1-6)}$$

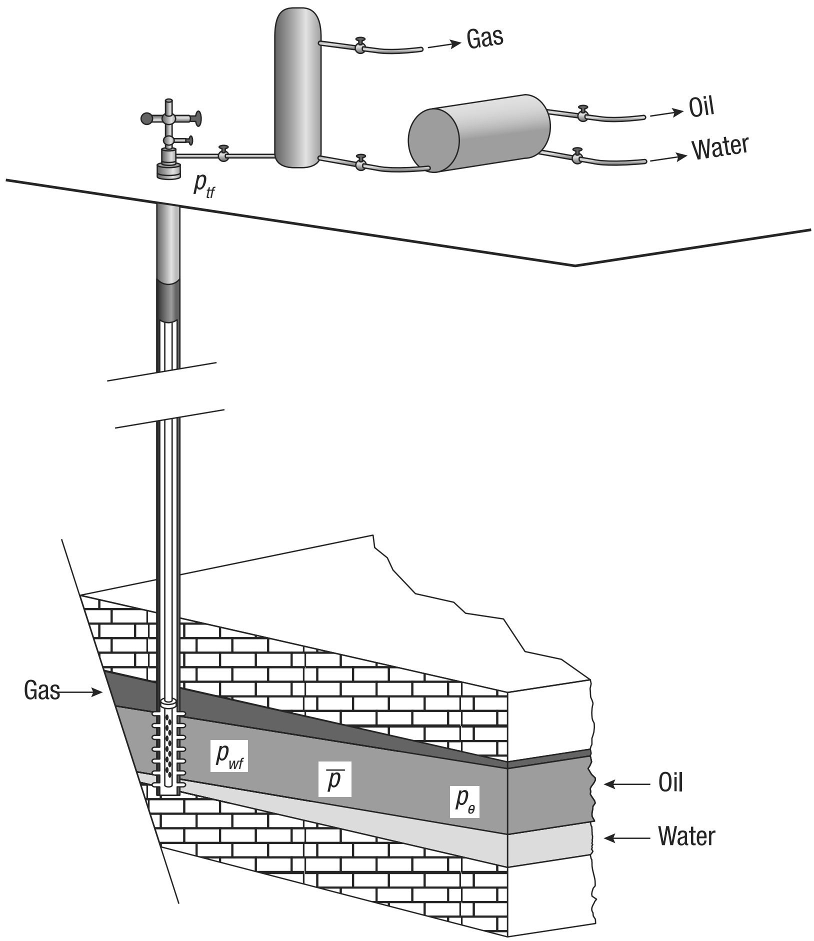

Figure 1-6 The petroleum production system, including the reservoir, underground well completion, the well, wellhead assembly, and surface facilities.

Equation (1-6) succinctly describes what is possible for a petroleum production engineer. First, the dimensioned productivity index with units of flow rate divided by pressure is proportional to the dimensionless (normalized) productivity index J_D. The latter, in turn, has very well-known representations. For steady-state flow to a vertical well,

$$J_D = \frac{1}{\ln\left(\frac{r_e}{r_w}\right) + s}. \tag{1-7}$$

For pseudosteady state flow,

$$J_D = \frac{1}{\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s}, \tag{1-8}$$

and for transient flow,

$$J_D = \frac{1}{p_D + s} \tag{1-9}$$

where p_D is the dimensionless pressure. The terms steady state, pseudosteady state, and transient will be explained in Chapter 2. The concept of the dimensionless productivity index combines flow geometry and skin effects, and can be calculated for any well by measuring flow rate and pressure (reservoir and flowing bottomhole) and some other basic but important reservoir and fluid data.

For a specific reservoir with permeability k, thickness h, and with fluid formation volume factor B and viscosity μ, the only variable on the right-hand side of Equation (1-6) that can be engineered is the dimensionless productivity index. For example, the skin effect can be reduced or eliminated through matrix stimulation if it is caused by damage or can be otherwise remedied if it is caused by mechanical means. A negative skin effect can be imposed if a successful hydraulic fracture is created. Thus, stimulation can improve the productivity index. Finally, more favorable well geometry such as horizontal or complex wells can result in much higher values of J_D.

In reservoirs with pressure drawdown-related problems (fines production, water or gas coning), increasing the productivity can allow lower drawdown with economically attractive production rates, as can be easily surmised by Equation (1-6).

Increasing the drawdown $(p - p_{wf})$ by lowering p_{wf} is the other option available to the production engineer to increase well deliverability. While the IPR remains the same, reduction of the flowing bottomhole pressure would increase the pressure gradient $(p - p_{wf})$ and the flow rate, q, must increase accordingly. The VFP change in Figure 1-7 shows that the flowing bottomhole pressure may be lowered by minimizing the pressure losses between the bottomhole and the separation facility (by, for example, removing unnecessary restrictions, optimizing tubing size, etc.), or by implementing or improving artificial lift procedures. Improving well deliverability by optimizing the flow system from the bottomhole location to the surface production facility is a major role of the production engineer.

In summary, well performance *evaluation* and *enhancement* are the primary charges of the production engineer. The production engineer has three major tools for well performance evaluation: (1) the measurement of (or sometimes, simply the understanding of) the

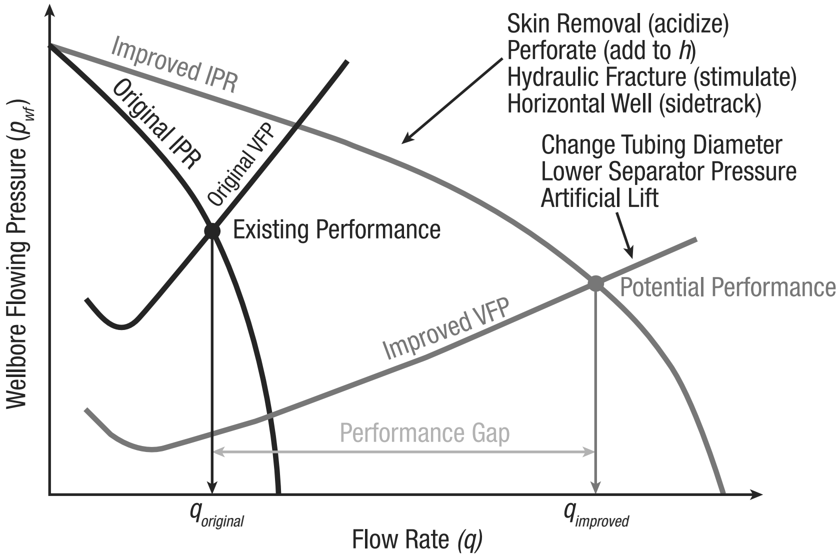

Figure 1-7 Well deliverability gap between the original well performance and optimized well performance.

rate-versus-pressure drop relationships for the flow paths from the reservoir to the separator; (2) well testing, which evaluates the reservoir potential for flow and, through measurement of the skin effect, provides information about flow restrictions in the near-wellbore environmental; and (3) production logging measurements or measurements of pressure, temperature, or other properties by permanently installed downhole instruments, which can describe the distribution of flow into the wellbore, as well as diagnose other completion-related problems.

With diagnostic information in hand, the production engineer can then focus on the part or parts of the flow system that may be optimized to enhance productivity. Remedial steps can range from well stimulation procedures such as hydraulic fracturing that enhance flow in the reservoir to the resizing of surface flow lines to increase productivity. This textbook is aimed at providing the information a production engineer needs to perform these tasks of well performance evaluation and enhancement.

1.3.2 Organization of the Book

This textbook offers a structured approach toward the goal defined above. Chapters 2–4 present the inflow performance for oil, two-phase, and gas reservoirs. Chapter 5 deals with complex well architecture such as horizontal and multilateral wells, reflecting the enormous growth of this area of production engineering since the first edition of the book. Chapter 6 deals with the condition of the near-wellbore zone, such as damage, perforations, and gravel packing. Chapter 7 covers the flow of fluids to the surface. Chapter 8 describes the surface flow system, flow in horizontal pipes, and flow in horizontal wells. Combination of inflow performance and well performance versus time, taking into account single-well transient flow and material balance, is shown in Chapters 9 and 10. Therefore, Chapters 1–10 describe the workings of the reservoir and well systems.

Gas lift is outlined in Chapter 11, and mechanical lift in Chapter 12.

For an appropriate product engineering remedy, it is essential that well and reservoir diagnosis be done.

Chapter 13 presents the state-of-the-art in modern diagnosis that includes well testing, production logging, and well monitoring with permanent downhole instruments.

From the well diagnosis it can be concluded whether the well is in need of matrix stimulation, hydraulic fracturing, artificial lift, combinations of the above, or none.

Matrix stimulation for all major types of reservoirs is presented in Chapters 14, 15, and 16. Hydraulic fracturing is discussed in Chapters 17 and 18.

Chapter 19 is a new chapter dealing with advances in sand management.

This textbook is designed for a two-semester, three-contact-hour-per-week sequence of petroleum engineering courses, or a similar training exposure.

To simplify the presentation of realistic examples, data for three characteristic reservoir types—an undersaturated oil reservoir, a saturated oil reservoir, and a gas reservoir—are presented in Appendixes. These data sets are used throughout the book. Examples and homework follow a more modern format than those used in the first edition. Less emphasis is given to hand-done calculations, although we still think it is essential for the reader to understand the salient fundamentals. Instead, exercises require application of modern software such as Excel spreadsheets and the PPS software included with this book, and trends of solutions and parametric studies are preferred in addition to single calculations with a given set of variables.

1.4 Units and Conversions

We have used "oilfield" units throughout the text, even though this system of units is inherently inconsistent. We chose this system because more petroleum engineers "think" in bbl/day and psi than in terms of m^3/s and Pa. All equations presented include the constant or constants needed with oilfield units. To employ these equations with SI units, it will be easiest to first convert the SI units to oilfield units, calculate the desired results in oilfield units, then convert the results to SI units. However, if an equation is to be used repeatedly with the input known in SI units, it will be more convenient to convert the constant or constants in the equation of interest. Conversion factors between oilfield and SI units are given in Table 1-1.

Table 1-1 Typical Units for Reservoir and Production Engineering Calculations

Variable	Oilfield Unit	SI Unit	Conversion (Multiply SI Unit)
Area	acre	m^2	2.475×10^{-4}
Compressibility	psi^{-1}	Pa^{-1}	6897
Length	ft	m	3.28
Permeability	md	m^2	1.01×10^{15}
Pressure	psi	Pa	1.45×10^{-4}
Rate (oil)	STB/d	m^3/s	5.434×10^5
Rate (gas)	MSCF/d	m^3/s	3049
Viscosity	cp	Pa-s	1000

Example 1-1 Conversion from Oilfield to SI Units

The steady-state, radial flow form of Darcy's law in oilfield units is given in Chapter 2 as

$$p_e - p_{wf} = \frac{141.2 q B \mu}{kh}\left(\ln\frac{r_e}{r_w} + s\right) \tag{1-10}$$

for p in psi, q in STB/d, B in res bbl/STB, μ in cp, k in md, h in ft, and r_e and r_w in ft (s is dimensionless). Calculate the pressure drawdown $(p_e - p_{wf})$ in Pa for the following SI data, first by converting units to oilfield units and converting the result to SI units, then by deriving the constant in this equation for SI units.

Data

$q = 0.001\ m^3/s$, $B = 1.1$ res $m^3/ST\ m^3$, $\mu = 2 \times 10^{-3}$ Pa-s, $k = 10^{-14}\ m^2$, $h = 10$ m, $r_e = 575$ m, $r_w = 0.1$ m, and $s = 0$.

Solution

Using the first approach, we first convert all data to oilfield units. Using the conversion factors in Table 1-1,

$$q = \left(0.001\frac{\text{m}^3}{\text{s}}\right)(5.434 \times 10^5) = 543.4\ \text{STB/d} \tag{1-11}$$

$$B = 1.1\ \text{res bbl/STB} \tag{1-12}$$

$$\mu = (2 \times 10^{-3}\ \text{Pa-s})(10^3) = 2\ \text{cp} \tag{1-13}$$

$$k = (10^{-14}\ \text{m}^2)(1.01 \times 10^{15}) = 10.1\ \text{md} \tag{1-14}$$

$$h = (10\ \text{m})(3.28) = 32.8\ \text{ft.} \tag{1-15}$$

Since r_e is divided by r_w, the units for these radii do not have to be converted. Now, from Equation (1-10),

$$p_e - p_{wf} = \frac{(141.2)(543.4)(1.1)(2)}{(10.1)(32.8)}\left[\ln\left(\frac{575}{0.1}\right) + 0\right] = 4411\ \text{psi} \tag{1-16}$$

and converting this results to Pascals,

$$p_e - p_{wf} = (4411\ \text{psi})(6.9 \times 10^3) = 3.043 \times 10^7\ \text{Pa} \tag{1-17}$$

Alternatively, we can convert the constant 141.2 to the appropriate constant for SI units, as follows (including only-to-be-converted variables):

$$p_e - p_{wf}(\text{Pa}) = \frac{(141.2)[q(\text{m}^3/s)(5.43 \times 10^5)][\mu(Pa - s)(10^3)]}{[k(\text{m}^2)(1.01 \times 10^{15})][h(\text{m})(3.28)]}(6.9 \times 10^3) \tag{1-18}$$

or

$$p_e - p_{wf} = \frac{0.159qB\mu}{kh}\left(\ln\frac{r_e}{r_w} + s\right) = \frac{qB\mu}{2\pi kh}\left(\ln\frac{r_e}{r_w} + s\right). \tag{1-19}$$

The constant derived, 0.159, is $1/2\pi$, as it should be for this consistent set of units. Substituting the parameters in SI units directly into Equation (1-19), we again calculate that $p_e - p_{wf} = 3.043 \times 10^7$ Pa.

Often, in regions where metric units are customary, a mix of SI and non-SI units is sometimes employed. For example, in using Darcy's law, the units for flow rate may be m^3/d; for viscosity, cp; for permeability, md; and so on. In this instance, units can be converted to oilfield units in the same manner demonstrated here for consistent SI units.

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