HANDBOOK OF HYDRAULIC FRACTURING

JAMES G. SPEIGHT
CD&W Inc.,
Laramie, WY, USA

WILEY

Copyright © 2016 by John Wiley & Sons, Inc. All rights reserved

Published by John Wiley & Sons, Inc., Hoboken, New Jersey
Published simultaneously in Canada

No part of this publication may be reproduced, stored in a retrieval system, or transmitted in any form or by any means, electronic, mechanical, photocopying, recording, scanning, or otherwise, except as permitted under Section 107 or 108 of the 1976 United States Copyright Act, without either the prior written permission of the Publisher, or authorization through payment of the appropriate per-copy fee to the Copyright Clearance Center, Inc., 222 Rosewood Drive, Danvers, MA 01923, (978) 750-8400, fax (978) 750-4470, or on the web at www.copyright.com. Requests to the Publisher for permission should be addressed to the Permissions Department, John Wiley & Sons, Inc., 111 River Street, Hoboken, NJ 07030, (201) 748-6011, fax (201) 748-6008, or online at http://www.wiley.com/go/permissions.

Limit of Liability/Disclaimer of Warranty: While the publisher and author have used their best efforts in preparing this book, they make no representations or warranties with respect to the accuracy or completeness of the contents of this book and specifically disclaim any implied warranties of merchantability or fitness for a particular purpose. No warranty may be created or extended by sales representatives or written sales materials. The advice and strategies contained herein may not be suitable for your situation. You should consult with a professional where appropriate. Neither the publisher nor author shall be liable for any loss of profit or any other commercial damages, including but not limited to special, incidental, consequential, or other damages.

For general information on our other products and services or for technical support, please contact our Customer Care Department within the United States at (800) 762-2974, outside the United States at (317) 572-3993 or fax (317) 572-4002.

Wiley also publishes its books in a variety of electronic formats. Some content that appears in print may not be available in electronic formats. For more information about Wiley products, visit our web site at www.wiley.com.

Library of Congress Cataloging-in-Publication Data:

Names: Speight, James G.
Title: Handbook of hydraulic fracturing / James G. Speight.
Description: Hoboken, New Jersey : John Wiley & Sons, Inc., [2016] | Includes bibliographical references and index.
Identifiers: LCCN 2015045701 | ISBN 9781118672990 (cloth)
Subjects: LCSH: Hydraulic fracturing. | Gas wells–Hydraulic fracturing. | Oil wells–Hydraulic fracturing. | Hydraulic fracturing–Environmental aspects.
Classification: LCC TD195.G3 S745 2016 | DDC 622/.3381–dc23
LC record available at http://lccn.loc.gov/2015045701

Cover image courtesy of Getty Images/Robert Ingelhart.

Set in 10/12pt Times by SPi Global, Pondicherry, India

Printed in the United States of America

10 9 8 7 6 5 4 3 2 1

CONTENTS

PREFACE

Hydraulic fracturing is an extractive method used by crude oil and natural gas companies to open pathways in tight (low-permeability) geologic formations so that the oil or gas trapped within can be recovered at a higher flow rate. When used in combination with horizontal drilling, hydraulic fracturing has allowed industry to access natural gas reserves previously considered uneconomical, particularly in shale formations.

Although hydraulic fracturing creates access to more natural gas supplies, the process requires the use of large quantities of water and fracturing fluids, which are injected underground at high volumes and pressure. Oil and gas service companies design fracturing fluids to create fractures and transport sand or other granular substances to prop open the fractures. The composition of these fluids varies by formation, ranging from a simple mixture of water and sand to more complex mixtures with a multitude of chemical additives.

Hydraulic fracturing has opened access to vast domestic reserves of natural gas that could provide an important stepping stone to a clean energy future. Yet questions about the safety of hydraulic fracturing persist, and the technology has been the subject of both enthusiasm and increasing environmental and health concerns in recent years, especially in relation to the possibility (some would say *reality*) of contaminated drinking water because of the chemicals used in the process and the disturbance of the geological formations.

It is not the purpose of this book to advocate the use or the termination of hydraulic fracturing practices. It is the purpose of this book to alleviate much of the confusion that exists in regard to hydraulic fracturing. It is also the purpose of the book to present the facts as they are currently available and understood. The book will present an up-to-date description of current and new hydraulic fracturing. The process descriptions describe how hydraulic fracturing is performed and consequences of those actions. As always, but not always mentioned in this text, in favor of presenting the technical aspects of hydraulic fracturing, economics is also a major consideration.

The book is written in an easy-to-read style, using a language that is understandable by scientists, engineers, and nontechnical persons. It will give the reader a full understanding of the concept and practice of hydraulic fracturing as well as the various environmental aspects of the process.

DR. JAMES G. SPEIGHT
Laramie, WY, USA
July 2015

1

DEFINITIONS

1.1 INTRODUCTION

Hydraulic fracturing (also known as *hydrofracturing*, *hydrofracking*, *fracking*, *fraccing*, or *fracture stimulation technology*, or various other derivatives of the term) is a method by which access to crude oil and natural gas trapped in impermeable and hard-to-reach geologic formations is achieved.

The hydraulic fracturing process involves the pressurized injection of a fluid (fracturing fluid) into geologic formations (shale formations or unusually tight rock formations consisting of a clastic sedimentary rock composed of silt- to clay-sized grains) until the reservoir rock cracks (causing fractures in the formations) and then extending that fracture by continued injection of fluid. A solid proppant, typically sand, is also injected into the formation with the fracturing fluid so that the fracture cannot close and remains *propped open* by the proppant left behind. This creates a flow path for reservoir fluids to be rapidly produced from the reservoir. In terms of project timing, the process may take less than 1 month with reward being decadelong production of crude oil and natural gas. Thus, a general timeline might by on the order of:

Timeline (approximate, site specific):

Drilling (2–4 weeks)   Fracturing (3–5 days)   Producing oil/gas (decades)

Once the formation is fractured, the fluid pressure is reduced, which reverses the direction of fluid flow in the well toward the ground surface. Both the hydraulic fracturing fluid and any naturally occurring substances released from the underground formation are allowed to *flow back* to the ground surface. Thus, the term *flowback* is the portion of the injected fracturing fluid that flows back to the surface, along with oil, gas, and brine, when the well is produced.

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

In addition, hydraulic fracturing for enhancing crude oil and natural gas production can be categorized into three general subcategories according to process applied to the target formation to induce fracturing:

1. *Hydraulic fracturing* involves a relatively low rate of pressure loading that results in a bidirectional fracture extending outward from the well and oriented perpendicular to the least principal rock stress. Because of the creation of a single fracture and the ability to pump large volumes of fluids at (relatively) low rates, the potential penetration for the fracture into the formation can be extensive—on the order of hundreds of feet. This method is currently the most widely used in the coal-mine methane/coalbed methane (CMM/CBM) industry.
2. On the other hand, *explosive fracturing* involves rapid pressurization of the target formation, which results in a highly fractured zone around the wellbore, but usually not exceeding of approximately 10 ft. Because the peak pressures exceed both the minimum and maximum horizontal *in situ* stresses, a radial fracture pattern is created, which can exhibit advantageous fracture geometry where near-wellbore stimulation is the primary objective.
3. The third case involves *pulse fracturing* (Walter and Thompson, 1982), which is characterized by pressures exceeding both the maximum and minimum *in situ* stresses and which also creates a radial fracture pattern. This technique results in multiple vertical fractures extending radially from the wellbore, with penetrations on the order of 10–20 ft.

When used in combination with horizontal drilling (Chapter 5), hydraulic fracturing has allowed access to crude oil and natural gas reserves previously considered uneconomical because of the difficulty of access. The energy crises of the 1970s highlighted the importance of energy security, and governments took a more active role in encouraging domestic sources of supply, including unconventional sources of crude oil and natural gas (Speight, 2011). In addition, these reserves of crude oil and natural gas have the potential to assert a measure of energy independence that is necessary for countries that are experiencing a depletion of conventional crude oil and natural gas reserves and must rely upon imports of crude oil and natural gas from countries that, in many cases, do not have stable governments or stable energy policies (Speight, 2011, 2014a; Trembath et al., 2013).

On the US domestic scenario, hydraulic fracturing has been employed in the United States since 1947 but has only recently been used to produce large quantities of crude oil and natural gas from shale formations, as new technology for drilling horizontal wells has been deployed (Chapter 5) and, in spite of a variety of negative (often emotional rather than scientific) comments in various media, is projected to continue to play a central role in future domestic energy policy. Nevertheless, caution is advised because although hydraulic fracturing creates access to more crude oil and natural gas supplies, the process requires the use of large quantities of water and fracturing fluids, which are injected underground at high volumes and pressure. The composition of the fracturing fluids varies by formation (therefore is site specific) and can range from a simple benign mixture of water and sand to more complex mixtures with a variety of chemical additives.

Despite the length of time that hydraulic fracturing has been used and despite the fact that the process has helped to create a benefit to energy production and economic growth (Chapter 5), there has been much negative attention that has given rise to serious concerns about the application of the technology. This is especially true in relation to the possibility (some would say *reality*) of contaminated drinking water because of the chemicals used in the process and the disturbance of the geological formations.

Because of the need for a thorough understanding of petroleum and natural gas and the associated technologies for recovery of these energy resources, it is essential that the definitions and the terminology of petroleum science and technology and associated resources (Table 1.1) be given prime consideration. This will aid in a better understanding of the variation in types of petroleum (with the exception of tar sand bitumen, which is not classed as petroleum), its constituents, the various fractions, and petroleum products. Of the many forms of terminology that have been used, not all have survived, but the more commonly used are illustrated here. Particularly troublesome, and more confusing, are those terms that are applied to the more viscous materials, for example, the use of the terms *tar sand bitumen* and *asphalt* (Speight, 2014a, 2015a, 2015c).

It is the purpose of this chapter to alleviate much of the confusion that exists, but it must be remembered that the terminology of petroleum and natural gas is still open to personal choice and historical usage. As always, but not always mentioned in this text, in favor of presenting the technical aspects of hydraulic fracturing, economics is also a major consideration.

1.2 DEFINITIONS

The types of liquids produced by fracturing and nonfracturing recovery processes from reservoirs and deposits vary substantially in character to the point where there can be considerable confusion when attempting to categorize the different liquids. It is valuable to place these liquids into various categories as defined by properties and/or by recovery methods. Thus, the definitions by which the various liquids are known are a valuable asset in the petroleum and natural gas industries.

Definitions are the means by which scientists and engineers communicate the nature of a material to each other and to the world, through either the spoken or the written word. Furthermore, the definition of a material can be extremely important and have a profound influence on how the technical community and the public perceive that material.

The *definition* of petroleum and natural gas has been varied, unsystematic, diverse, and often archaic and is a product of many years of growth. Thus the long established use of an expression, however inadequate it may be, is altered with

TABLE 1.1 Simplified Differentiation between Conventional Crude Oil, Heavy Oil, Extra Heavy Oil, Tar Sand Bitumen, Oil Shale Kerogen, Tight Oil, and Coal

Conventional Crude Oil
- Mobile in the reservoir
- High-permeability reservoir
- Primary recovery
- Secondary recovery

Heavy Crude Oil
- Mobile in the reservoir
- High-permeability reservoir
- Secondary recovery
- Tertiary recovery (enhanced oil recovery (EOR), e.g., steam stimulation)

Extra Heavy Oil
- Mobile in the reservoir
- High-permeability reservoir
- Secondary recovery
- Tertiary recovery (enhanced oil recovery (EOR), e.g., steam stimulation)

Tar Sand Bitumen
- Immobile in the deposit
- High-permeability reservoir
- Mining (often preceded by explosive fracturing)
- Steam-assisted gravity drainage (SAGD)

Oil Shale Kerogen
- Immobile in the deposit
- Low-permeability reservoir
- May involve explosive fracturing
- *In situ* thermal decomposition to produce shale oil
- Mining followed by thermal decomposition to produce shale oil

Tight Oil
- Immobile in the reservoir
- Low-permeability reservoir
- Horizontal drilling into reservoir
- Fracturing (typically multifracturing) to release fluids/gases

Coalbed Methane
- Low- to medium-permeability reservoir (coal seam)
- Gas exists in pore spaces
- *In situ* thermal decomposition to produce liquid products
- Mining (often preceded by explosive fracturing), followed by thermal decomposition to produce liquid products

difficulty, and a new term, however precise, is at best adopted only slowly. Thus, because of the need for a thorough understanding of petroleum and the associated technologies, it is essential that the definitions and the terminology of petroleum and natural gas science and technology be given prime consideration here. Of the many forms of terminology that have been used, not all have survived, but the more common are illustrated here.

1.2.1 Petroleum

Petroleum (and the equivalent term *crude oil*) covers a wide assortment of naturally occurring liquids consisting of mixtures of hydrocarbons and other compounds containing variable amounts of sulfur, nitrogen, and oxygen, which may vary widely in volatility, specific gravity, and viscosity along with varying physical properties as illustrated in the variation in color from colorless to black (Fig. 1.1) (Speight, 2012a, 2014a; US EIA, 2014). Metal-containing constituents, notably those compounds consisting of derivatives of vanadium and nickel, usually occur in the more viscous crude oils in amounts up to several thousand parts per million and can have serious consequences for the equipment and catalysts used in processing of these feedstocks (Speight and Ozum, 2002; Parkash, 2003; Hsu and Robinson, 2006; Gary et al., 2007; Speight, 2014a).

Petroleum exists in reservoirs that consist of more porous and permeable sediments, such as *sandstone* and *siltstone*. A series of reservoirs within a common rock structure or a series of reservoirs in separate but neighboring formations is commonly referred to as an *oil field*. A group of fields is often found in a single geologic environment known as a *sedimentary basin* or *province*. In the underground locale, petroleum is much more fluid than it is on the surface and is generally mobile under reservoir conditions because the elevated temperatures (the *geothermal gradient*) in subterranean formations decrease the viscosity. Although the geothermal gradient varies from place to place, it is generally on the order of 25–30 °C/km (15 °F/1000 ft or 120 °C/1000 ft, i.e., 0.015 °C per foot of depth or 0.012 °C per foot of depth).

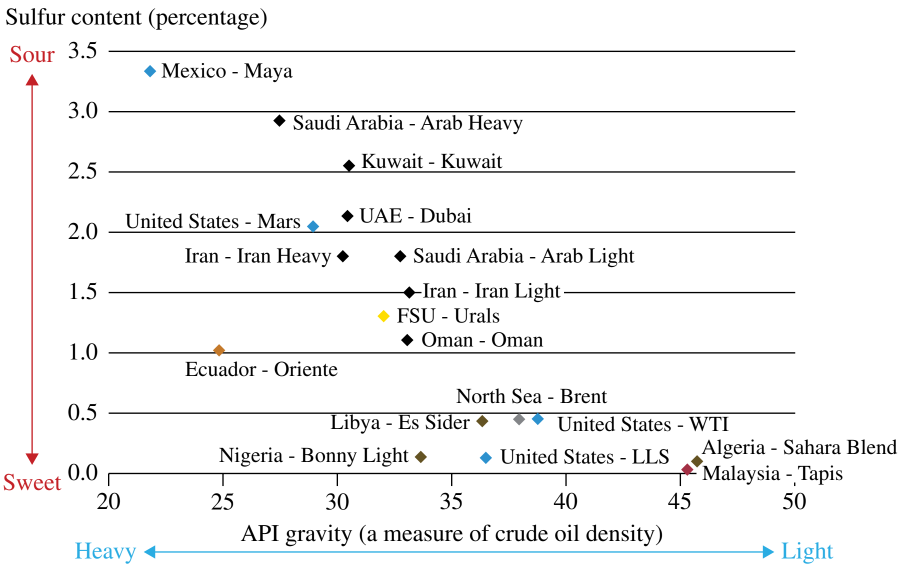


FIGURE 1.1 Properties of different crude oils. Source: US Energy Information Administration, US Department of Energy, Washington, DC (US EIA, 2014).

The major components of conventional petroleum are *hydrocarbons* and *nonhydrocarbons*, which display great variation in their molecular structure. The simplest hydrocarbons are a large group of chain-shaped molecules known as the *paraffins*. This broad series extends from methane, which forms natural gas, through liquids that are refined into gasoline to the highly crystalline wax. The *nonhydrocarbon constituents* of petroleum include organic derivatives of nitrogen, oxygen, sulfur, and the metals nickel and vanadium and are often referred to as polar aromatics, which include asphalt and resin constituents (Fig. 1.2). In the case of heavy oils and tar sand bitumen, there is a lesser amount of hydrocarbon constituents (volatile constituents) in favor of increasing amounts of nonhydrocarbon constituents (low-volatile and nonvolatile constituents) (Fig. 1.3). While most of these impurities are removed during refining by conversion of hydrocarbon products (Fig. 1.4), the low-volatile and nonvolatile constituents greatly influence the choice and effectiveness of recovery processes and whether or not fracturing is to be entertained as a recovery process enhancement (Chapter 3) (Speight, 2009, 2014a).

Geologic techniques can determine only the existence of rock formations that are favorable for petroleum occurrence, but drilling is the only sure way to ascertain the presence of petroleum in the formation. With modern rotary equipment, wells can be drilled to depths of more than 30,000 ft (9000 m). Once oil is found, it may be recovered (brought to the surface) by the pressure created by natural gas or water within the reservoir. Crude oil can also be brought to the surface by injecting water or steam into the reservoir to raise the pressure artificially or by injecting such substances as carbon dioxide, polymers, and solvents to reduce crude oil viscosity. Thermal recovery methods are frequently used to enhance the production of heavy crude oils, especially when extraction of the heavy oil is impeded by viscous resistance to flow at reservoir temperatures.

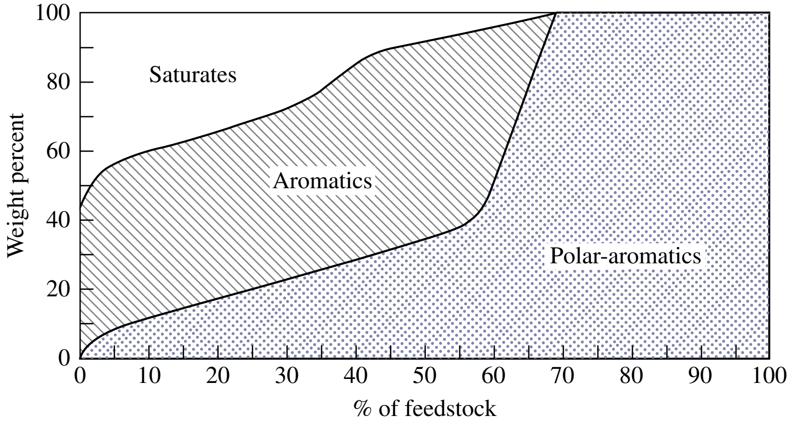


FIGURE 1.2 Schematic representation of petroleum composition.

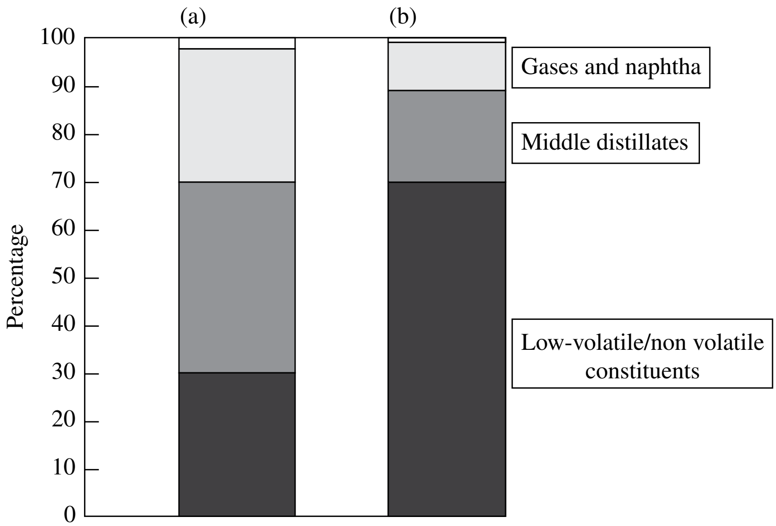


FIGURE 1.3 Schematic comparison of the (a) composition of light crude oil with the (b) composition of heavy crude oil.

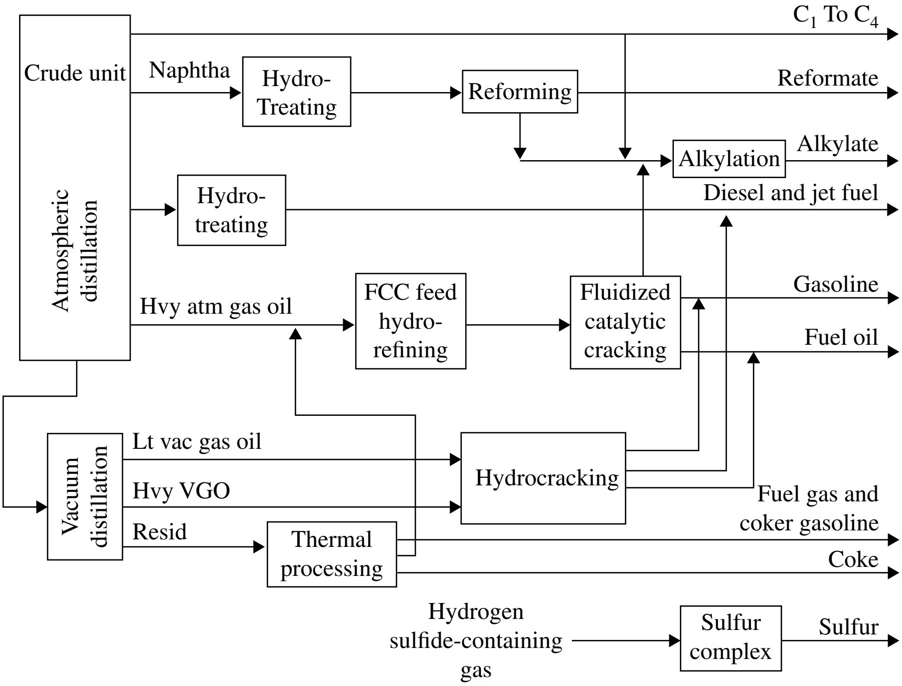


FIGURE 1.4 Schematic of a petroleum refinery.

1.2.2 Oil and Gas from Tight Formations

Tight formations scattered through North America have the potential to produce not only gas (*tight gas*) and crude oil (*tight oil*) (Fig. 1.5) (Law and Spencer, 1993; US EIA, 2011, 2013; Speight, 2013a). Such formations might be composted of shale sediments or sandstone sediments. In a conventional sandstone reservoir the pores are interconnected so gas and oil can flow easily from the rock to a wellbore. In tight sandstones, the pores are smaller and are poorly connected by very narrow capillaries, which results in low permeability. Tight gas and tight oil occur in sandstone sediments that have an effective permeability of less than 1 millidarcy (<1 mD).

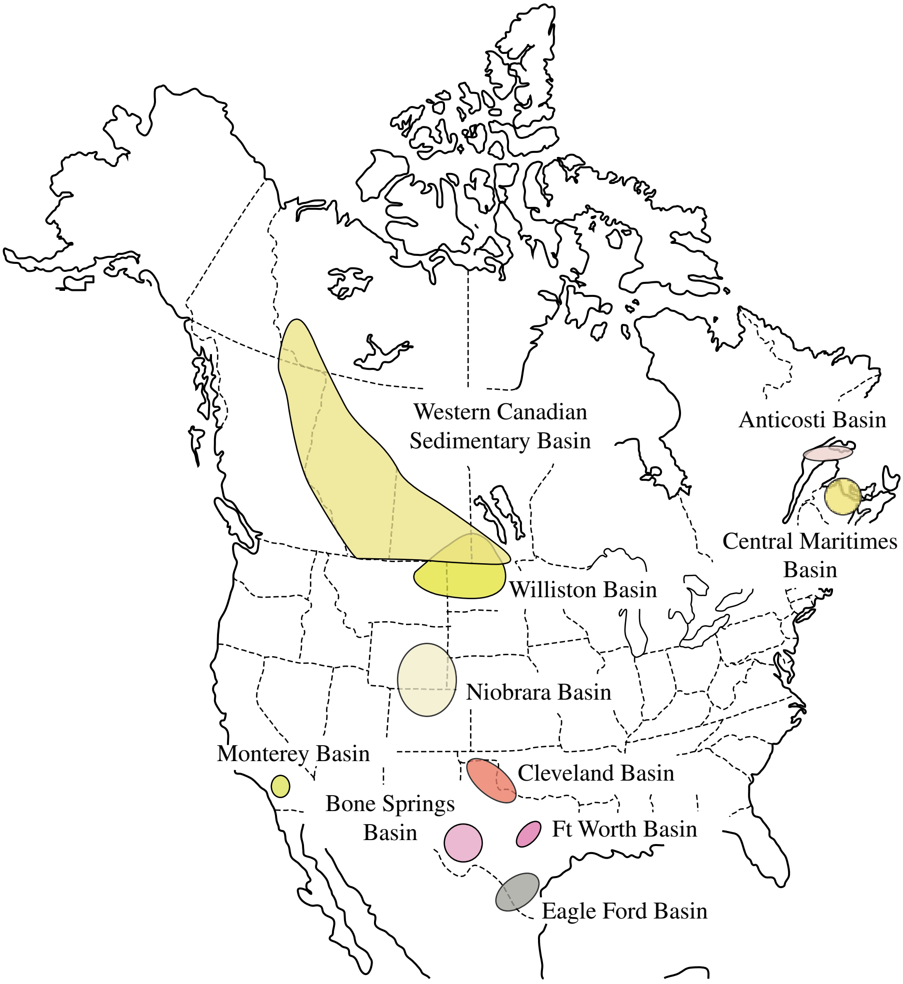


FIGURE 1.5 Basins with the potential for tight oil production. Source: Energy Information Administration, US Department of Energy, Washington, DC.

One of the newest terms in the petroleum lexicon is the arbitrarily named (even erroneously named) *shale oil*, which is crude oil that is produced from tight shale formations and should not be confused with the older term *shale oil*, which is crude oil that is produced by the thermal treatment of oil shale and the ensuing decomposition of the kerogen contained within the shale (Scouten, 1990; Speight, 2012b). Oil shale represents one of the largest unconventional hydrocarbon deposits in the world with an estimated 8 trillion barrels (8×10^{12} bbl) of oil in place. Approximately 6 trillion barrels of oil in place is located in the United States including the richest and most concentrated deposits found in the Green River Formation in Colorado, Utah, and Wyoming. Documented efforts to develop oil shale to produce shale oil in the United States go back to approximate 1900, even earlier in Scotland (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b). These prior efforts have produced a wealth of knowledge regarding the geological description as well as technical options and challenges for development. Thus far, however, none of these efforts have produced a commercially viable business in the United States. There need to be economically viable, socially acceptable, and environmentally responsible development solutions.

Recently, the introduction of the term *shale oil* to define crude oil from tight shale formations is the latest term to add confusion to the system of nomenclature of petroleum–heavy oil–bitumen materials. The term has been used without any consideration of the original term shale oil produced by the thermal decomposition of kerogen in oil shale (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b). It is not quite analogous, but is certainly similarly confusing, to the term *black oil* that has been used to define petroleum by color rather than by any meaningful properties or recovery behavior (Speight, 2014a, 2015a).

Generally, unconventional tight oil and natural gas are found at considerable depths in sedimentary rock formations that are characterized by very low permeability. While some of the tight oil plays produce oil directly from shales, tight oil resources are also produced from low-permeability siltstone formations, sandstone formations, and carbonate formations that occur in close association with a shale source rock. It is important to note that in the context of this report, the term tight oil does not include resources that are commonly known as “oil shales,” which refers to oil or kerogen-rich shale formations that are either heated *in situ* and produced or if surface accessible mined and heated (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b).

The most notable tight oil plays in North America include the Bakken shale, the Niobrara Formation, the Barnett shale, the Eagle Ford shale, the Miocene Monterey play of California’s San Joaquin Basin in the United States, and the Cardium play in Alberta. In many of these tight formations, the existence of large quantities of oil has been known for decades, and efforts to commercially produce those resources have occurred sporadically with typically disappointing results. However, starting in the mid-2000s, advancements in well drilling and stimulation technologies combined with high oil prices have turned tight oil resources into one of the most actively explored and produced targets in North America.

Of the tight oil plays, perhaps the best understood is the Bakken, which straddles the border between Canada and the United States in North Dakota, Montana, and

Saskatchewan. Much of what is known about the exploitation of tight oil resources comes from industry experiences in the Bakken, and the predictions of future tight oil resource development described in this study are largely based on that knowledge. The Bakken tight oil play historically includes three zones, or members, within the Bakken Formation. The upper and lower members of the Bakken are organic-rich shales that serve as oil source rocks, while the rocks of the middle member may be siltstone formations, sandstone formations, or carbonate formations that are also typically characterized by low permeability and high oil content. Since 2008 the Three Forks Formation, another tight oil-rich formation that directly underlies the lower Bakken shale, has also yielded highly productive oil wells. Drilling, completion, and stimulation strategies for wells in the Three Forks Formation are similar to those in the Bakken, and the light sweet crude oil that is produced from both plays has been geochemically determined to be essentially identical. Generally, the Three Forks Formation is considered to be part of the Bakken play, though the authors of published works will sometimes refer to it as the Bakken/Three Forks play.

Other known tight formations (on a worldwide basis) include the R'Mah Formation in Syria; the Sargelu Formation in the northern Persian Gulf region; the Athel Formation in Oman; the Bazhenov Formation and Achimov Formation in West Siberia, Russia; the Coober Pedy in Australia; the Chicontepec Formation in Mexico; and the Vaca Muerta field in Argentina (US EIA, 2011, 2013). However, tight oil formations are heterogeneous and vary widely over relatively short distances. Thus, even in a single horizontal drill hole, the amount of oil recovered may vary as may recovery within a field or even between adjacent wells. This makes evaluation of *shale plays* and decisions regarding the profitability of wells on a particular lease difficult, and tight reservoirs that contain only crude oil (without natural gas as the pressurizing agent) cannot be economically produced (US EIA, 2011, 2013).

By way of definition, a shale play is a defined geographic area containing an organic-rich fine-grained sedimentary rock that underwent physical and chemical compaction during diagenesis to produce the following characteristics: (i) clay- to silt-sized particles; (ii) high % of silica, and sometimes carbonate minerals; (iii) thermally mature; (iv) hydrocarbon-filled porosity, on the order of 6–14%; (5) low permeability, on the order of <0.1 mD; (6) large areal distribution; and (7) fracture stimulation required for economic production.

Success in extracting crude oil and natural gas from shale reservoirs depends largely on the hydraulic fracturing process (Chapter 5) that requires an understanding of the mechanical properties of the subject and confining formations. In hydraulic fracturing design, Young's modulus is a criterion used to determine the most appropriate fracturing fluid and other design considerations. Young's modulus provides an indication of the fracture conductivity that can be expected under the width and embedment considerations. Without adequate fracture conductivity, production from the hydraulic fracture will be minimal, or nonexistent (Akrad et al., 2011).

Typical of the crude oil from tight formations (*tight oil*, *tight light oil*, *and tight shale oil* have been suggested as alternate terms) is the Bakken crude oil, which is a light highly volatile crude oil. Briefly, Bakken crude oil is a light sweet (low-sulfur) crude oil that has a relatively high proportion of volatile constituents.

The production of the oil also yields a significant amount of volatile gases (including propane and butane) and low-boiling liquids (such as pentane and natural gasoline), which are often referred to collectively as (low-boiling or light) naphtha. By definition, natural gasoline (sometime also referred to as *gas condensate*) is a mixture of low-boiling liquid hydrocarbons isolate from petroleum and natural gas wells suitable for blending with light naphtha and/or refinery gasoline (Mokhatab et al., 2006; Speight, 2007, 2014a). Because of the presence of low-boiling hydrocarbons, low-boiling naphtha (*light naphtha*) can become extremely explosive, even at relatively low ambient temperatures. Some of these gases may be burned off (flared) at the field wellhead, but others remain in the liquid products extracted from the well (Speight, 2014a).

Bakken crude oil is considered to be a low-sulfur (*swee*t) crude oil, and there have been increasing observations of elevated levels of hydrogen sulfide (H_2S) in the oil. Hydrogen sulfide is a toxic, highly flammable, corrosive, explosive gas (hydrogen sulfide), and there have been increasing observations of elevated levels of hydrogen sulfide in Bakken oil. Thus, the liquids stream produced from the Bakken Formation will include the crude oil, the low-boiling liquids, and gases that were not flared, along with the materials and by-products of the hydraulic fracturing process. These products are then mechanically separated into three streams: (i) produced salt water, often referred to as brine, (ii) gases, and (iii) petroleum liquids, which include condensates, natural gas liquids, and light oil. Depending on the effectiveness and appropriate calibration of the separation equipment that is controlled by the oil producers, varying quantities of gases remain dissolved and/or mixed in the liquids, and the whole is then transported from the separation equipment to the well-pad storage tanks, where emissions of volatile hydrocarbons have been detected as emanating from the oil.

Oil from tight shale formation is characterized by low asphaltene content, low sulfur content, and a significant molecular weight distribution of the paraffinic wax content (Speight, 2014a, 2015a). Paraffin carbon chains of C_{10} to C_{60} have been found, with some shale oils containing carbon chains up to C_{72}. To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously (Speight, 2014a, 2014b, 2014c, 2015a, 2015b). In addition, scale deposits of calcite ($CaCO_3$), other carbonate minerals (minerals containing the carbonate ion, CO_3^{2-}), and silicate minerals (minerals classified on the basis of the structure of the silicate group, which contains different ratios of silicon and oxygen) must be controlled during production or plugging problems arise. A wide range of scale additives is available, which can be highly effective when selected appropriately. Depending on the nature of the well and the operational conditions, a specific chemistry is recommended, or blends of products are used to address scale deposition.

Another challenge encountered with oil from tight shale formations—many of which have been identified but undeveloped—is the general lack (until recently) of transportation infrastructure. Rapid distribution of the crude oil to the refineries is necessary to maintain consistent refinery throughput—a necessary aspect of refinery design. Some pipelines are in use, and additional pipelines are being (and need to be) constructed to provide consistent supply of the oil to the refinery. During the interim, barges and railcars are being used, along with a significant expansion in trucking to bring the various crude oil to the refinery. For example, with development of suitable transportation infrastructure, production of Eagle Ford tight oil is estimated to increase by a substantial amount to approximately 2,000,000 bpd by 2017. Similar expansion in crude oil production is estimated for Bakken and other identified (and perhaps as yet unidentified and, if identified, undeveloped) tight formations.

While the basic approach toward developing a tight oil play is expected to be similar from area to area, the application of specific strategies, especially with respect to well completion and stimulation techniques, will almost certainly differ from play to play and often even within a given play. The differences depend on the geology (which can be very heterogeneous, even within a play) and reflect the evolution of technologies over time with increased experience and availability.

Finally, the properties of tight oil are highly variable. Density and other properties can show wide variation, even within the same field. The Bakken crude is light and sweet with an API of 42° and a sulfur content of 0.19% w/w. Similarly, Eagle Ford is a light sweet feed, with a sulfur content of approximately 0.1% w/w and with published API gravity between 40° API and 62° API.

In terms of refining, although tight oil is considered sweet (low sulfur content) and amenable to refinery options, this is not always the case. Hydrogen sulfide gas, which is flammable and poisonous, comes out of the ground with the crude oil and must be monitored at the drilling site as well as during transportation. Amine-based hydrogen sulfide scavengers are added to the crude oil prior to transport to refineries. However, mixing during transportation due to movement, along with a change in temperature that raises the vapor pressure of the oil, can cause the release of entrained hydrogen sulfide during offloading, thereby creating a safety hazard. For example, such crude that is loaded on railcars in winter and then transported to a warmer climate becomes hazardous due to the higher vapor pressure. The shippers and receivers of the oil should be aware of such risks.

Paraffin waxes are present in tight oil and remain on the walls of railcars, tank walls, and piping (Chapter 4). The waxes are also known to foul the preheat sections of crude heat exchangers (before they are removed in the crude desalter). Paraffin waxes that stick to piping and vessel walls can trap amines against the walls, which can create localized corrosion (Speight, 2014c). *Filterable solids* also contribute to fouling in the crude preheat exchangers, and a tight crude can contain over seven times more filterable solids than a traditional crude oil. To mitigate filter plugging, the filters at the entrance of the refinery require automated monitoring because they need to capture large volumes of solids. In addition, wetting agents are added to the desalter to help capture excess solids in the water, rather than allowing the undesired solids to travel further downstream into the process.

In many refineries, *blending two or more crude oils* as the refinery feedstock is now standard operating procedure that allows the refiner to achieve the right balance of feedstock qualities. However, the blending of the different crude oils may cause problems if the crude oils being mixed are incompatible (Speight, 2014a). When crude oils are incompatible, increased deposition of the asphaltene constituents occurs (Chapter 4), which accelerates fouling in the heat exchanger train downstream of the crude desalter. Accelerated fouling increases the amount of energy that must be supplied by the crude fired heater, which limits throughput when the fired heater reaches its maximum duty and may also necessitate an earlier shutdown for cleaning.

Mixing stable crude oil blends with asphaltic and paraffinic oils creates the potential for precipitating the unstable asphaltenes—the high naphtha content of tight oils also creates favorable conditions for asphaltenes to more readily precipitate (Chapter 4) (Speight, 2014a, 2014c). It should be noted that the ratio of crude oils in a blend may have an impact on crude incompatibility. For example, a low amount of tight oil in a blend may not cause accelerated fouling, whereas a blend containing a higher amount of tight oil may cause fouling.

1.2.3 Opportunity Crudes

There is also the need for a refinery to be configured to accommodate *opportunity crude oils* and/or *high-acid crude oils*, which, for many purposes, are often included with heavy feedstocks (Speight, 2014a, 2014b; Yeung, 2014). *Opportunity crude oils* are either new crude oils with unknown or poorly understood properties relating to processing issues or are existing crude oils with well-known properties and processing concerns (Ohmes, 2014). Opportunity crude oils are often, but not always, heavy crude oils but in either case are more difficult to process due to high levels of solids (and other contaminants) produced with the oil, high levels of acidity, and high viscosity. These crude oils may also be incompatible with other oils in the refinery feedstock blend and cause excessive equipment fouling when processed either in a blend or separately (Speight, 2015b).

In addition to taking preventative measure for the refinery to process these feedstocks without serious deleterious effects on the equipment, refiners need to develop programs for detailed and immediate feedstock evaluation so that they can understand the qualities of a crude oil very quickly and it can be valued appropriately and management of the crude processing can be planned meticulously. For example, the compatibility of opportunity crudes with other opportunity crudes and with conventional crude oil and heavy oil is a very important property to consider when making decisions regarding which crude to purchase. Blending crudes that are incompatible can lead to extensive fouling and processing difficulties due to unstable asphaltene constituents (Speight, 2014a, 2015b). These problems can quickly reduce the benefits of purchasing the opportunity crude in the first place. For example, extensive fouling in the crude preheat train may occur, resulting in decreased energy efficiency, increased emissions of carbon dioxide, and increased frequency at which heat exchangers need to be cleaned. In a worst-case scenario, crude throughput may be reduced, leading to significant financial losses.

Opportunity crude oils, while offering initial pricing advantages, may have composition problems that can cause severe problems at the refinery, harming infrastructure, yield, and profitability. Before refining, there is the need for comprehensive evaluations of opportunity crudes, giving the potential buyer and seller the needed data to make informed decisions regarding fair pricing and the suitability of a particular opportunity crude oil for a refinery. This will assist the refiner to manage the ever-changing crude oil quality input to a refinery—including quality and quantity requirements and situations, crude oil variations, contractual specifications, and risks associated with such opportunity crudes.

1.2.4 High-Acid Crude Oil

High-acid crude oils are crude oil that contains considerable proportions of naphthenic acids, which, as commonly used in the petroleum industry, refers collectively to all of the organic acids present in the crude oil (Shalaby, 2005; Rikka, 2007; Speight, 2014b). By the original definition, a naphthenic acid is a monobasic carboxyl group attached to a saturated cycloaliphatic structure. However, it has been a convention accepted in the oil industry that all organic acids in crude oil are called naphthenic acids. Naphthenic acids in crude oils are now known to be mixtures of low to high molecular weight acids, and the naphthenic acid fraction also contains other acidic species.

Naphthenic acids can be very water soluble to oil soluble depending on their molecular weight, process temperatures, salinity of waters, and fluid pressures. In the water phase, naphthenic acids can cause stable reverse emulsions (oil droplets in a continuous water phase). In the oil phase with residual water, these acids have the potential to react with a host of minerals, which are capable of neutralizing the acids. The main reaction product found in practice is the calcium naphthenate soap (the calcium salt of naphthenic acids). The total acid matrix is therefore complex, and it is unlikely that a simple titration, such as the traditional methods for measurement of the total acid number, can give meaningful results to be used in predictions of problems. An alternative way of defining the relative organic acid fraction of crude oils is therefore a real need in the oil industry, both upstream and downstream.

High-acid crude oils cause corrosion in the refinery—corrosion is predominant at temperatures in excess of 180 °C (355 °F) (Kane and Cayard, 2002; Ghoshal and Sainik, 2013) and occurs particularly in the atmospheric distillation unit (the first point of entry of the high-acid crude oil) and also in the vacuum distillation units. In addition, overhead corrosion is caused by the mineral salts, magnesium, calcium, and sodium chloride, which are hydrolyzed to produce volatile hydrochloric acid, causing a highly corrosive condition in the overhead exchangers. Therefore these salts present a significant contamination in opportunity crude oils. Other contaminants in opportunity crude oils that are shown to accelerate the hydrolysis reactions are inorganic clays and organic acids.

In addition to taking preventative measure for the refinery to process these feedstocks without serious deleterious effects on the equipment, refiners will need to develop programs for detailed and immediate feedstock evaluation so that they can understand the qualities of a crude oil very quickly and it can be valued appropriately and management of the crude processing can be planned meticulously.

1.2.5 Foamy Oil

Foamy oil is oil-continuous foam that contains dispersed gas bubbles produced at the wellhead from heavy oil reservoirs under solution gas drive. The nature of the gas dispersions in oil distinguishes foamy oil behavior from conventional heavy oil. The gas that comes out of solution in the reservoir does not coalesce into large gas bubbles nor into a continuous flowing gas phase. Instead it remains as small bubbles entrained in the crude oil, keeping the effective oil viscosity low while providing expansive energy that helps drive the oil toward the producing. Foamy oil accounts for unusually high production in heavy oil reservoirs under solution gas drive.

Thus, foamy oil is formed in solution gas drive reservoirs when gas is released from solution as reservoir pressure declines. It has been noted that the oil at the wellhead of these heavy oil reservoirs resembles the form of foam, hence the term *foamy oil*. The gas initially exists in the form of small bubbles within individual pores in the rock. As time passes and pressure continues to decline, the bubbles grow to fill the pores. With further declines in pressure, the bubbles created in different locations become large enough to coalesce into a continuous gas phase. Once the gas phase becomes continuous (i.e., when gas saturation exceeds the critical level)—the minimum saturation at which a continuous gas phase exists in porous media—traditional two-phase (oil and gas) flow with classical relative permeability occurs. As a result, the production gas–oil ratio (GOR) increases rapidly after the critical gas saturation has been exceeded.

1.2.6 Heavy Oil

When petroleum occurs in a reservoir that allows the crude material to be recovered by pumping operations as a free-flowing dark- to light-colored liquid, it is often referred to as *conventional petroleum*. Heavy oil is a *type* of petroleum that is different from the conventional petroleum insofar as they are much more difficult to recover from the subsurface reservoir. These materials have a much higher viscosity (and lower API gravity) than conventional petroleum, and primary recovery of these petroleum types usually requires thermal stimulation of the reservoir (Speight, 2009, 2014a). Heavy oil is more difficult to recover from the subsurface reservoir than light oils. The definition of heavy oils has been based on the API gravity or viscosity, and the definition is quite arbitrary although there have been attempts to rationalize the definition based upon viscosity, API gravity, and density.

For many years, petroleum and heavy oil were very generally defined in terms of physical properties. For example, heavy oils were considered to be those crude oils that had gravity somewhat less than 20° API with the heavy oils falling into the API gravity range 10–15°. For example, Cold Lake heavy crude oil has an API gravity equal to 12°, and extra heavy oils, such as tar sand bitumen, usually have an API gravity in the range 5–10° (Athabasca bitumen = 8° API). Residua would vary depending upon the temperature at which distillation was terminated, but usually vacuum residua are in the range 2–8° API (Speight, 2000; Speight and Ozum, 2002; Parkash, 2003; Hsu and Robinson, 2006; Gary et al., 2007).

Heavy oil has a much higher viscosity (and lower API gravity) than conventional petroleum, and recovery of these petroleum types usually requires thermal stimulation of the reservoir. The generic term *heavy oil* is often applied to a crude oil that has less than 20°API and usually, but not always, a sulfur content higher than 2% by weight (Speight, 2000). Furthermore, in contrast to conventional crude oils, heavy oils are darker in color and may even be black.

The term *heavy oil* has also been arbitrarily used to describe both the heavy oils that require thermal stimulation of recovery from the reservoir and the bitumen in bituminous sand (tar sand, *q.v.*) formations from which the heavy bituminous material is recovered by a mining operation.

1.2.7 Extra Heavy Oil

Briefly, extra heavy oil is a material that occurs in the solid or near-solid state and generally has mobility under reservoir conditions. However, *extra heavy oil* is a recently evolved term (related to viscosity) of little scientific meaning. While this type of oil may resemble tar sand bitumen and does not flow easily, extra heavy oil is generally recognized as having mobility in the reservoir compared to tar sand bitumen, which is typically incapable of mobility (free flow) under reservoir conditions. For example, the tar sand bitumen located in Alberta, Canada, is not mobile in the deposit and requires extreme methods of recovery to recover the bitumen. On the other hand, much of the extra heavy oil located in the Orinoco Belt of Venezuela requires recovery methods that are less extreme because of the mobility of the material in the reservoir.

Whether the mobility of extra heavy oil is due to a high reservoir temperature (that is higher than the pour point of the extra heavy oil) or due to other factors is variable and subject to localized conditions in the reservoir.

1.2.8 Tar Sand Bitumen

The term *bitumen* (also, on occasion, referred to as *native asphalt* and *extra heavy oil*) includes a wide variety of reddish-brown to black materials of semisolid, viscous to brittle character that can exist in nature with no mineral impurity or with mineral matter contents that exceed 50% by weight. Bitumen is frequently found filling pores and crevices of sandstone, limestone, or argillaceous sediments, in which case the organic and associated mineral matrix is known as *rock asphalt*.

Bitumen is a naturally occurring material that is found in deposits where the permeability is low and passage of fluids through the deposit can only be achieved by prior application of fracturing techniques. Tar sand bitumen is a high-boiling material with little, if any, material boiling below 350 °C (660 °F), and the boiling range approximates the boiling range of an atmospheric residuum.

Tar sands have been defined in the United States (FE-76-4) as

> *...the several rock types that contain an extremely viscous hydrocarbon which is not recoverable in its natural state by conventional oil well production methods including currently used enhanced recovery techniques. The hydrocarbon-bearing rocks are variously known as bitumen-rocks oil, impregnated rocks, oil sands, and rock asphalt.*

The recovery of the bitumen depends to a large degree on the composition and construction of the sands. Generally, the bitumen found in tar sand deposits is an extremely viscous material that is *immobile under reservoir conditions* and cannot be recovered through a well by the application of secondary or enhanced recovery techniques.

The expression *tar sand* is commonly used in the petroleum industry to describe sandstone reservoirs that are impregnated with a heavy, viscous black crude oil that cannot be retrieved through a well by conventional production techniques (FE-76-4, as mentioned previously). However, the term *tar sand* is actually a misnomer; more correctly, the name *tar* is usually applied to the heavy product remaining after the destructive distillation of coal or other organic matter (Speight, 1994). The bitumen in tar sand formations requires a high degree of thermal stimulation for recovery to the extent that some thermal decomposition may have to be induced. Current recovery operations of bitumen in tar sand formations that involve use of a mining technique and nonmining techniques are continually being developed (Speight, 2009, 2014a).

It is incorrect to refer to native bituminous materials as *tar* or *pitch*. Although the word tar is descriptive of the black, heavy bituminous material, it is best to avoid its use with respect to natural materials and to restrict the meaning to the volatile or near-volatile products produced in the destructive distillation of such organic substances as coal (Speight, 1994). In the simplest sense, pitch is the distillation residue of the various types of tar. Thus, alternative names, such as *bituminous sand* or *oil sand*, are gradually finding usage, with the former name (bituminous sands) more technically correct. The term *oil sand* is also used in the same way as the term *tar sand*, and these terms are used interchangeably throughout this text.

However, in order to define bitumen, heavy oil, and conventional petroleum, the use of a single physical parameter such as viscosity is not sufficient. Physical properties such as API gravity, elemental analysis, and composition fall short of giving an adequate definition. It is the properties of the bulk deposit and, most of all, the necessary recovery methods that form the basis of the definition of these materials. Only then is it possible to classify petroleum, heavy oil, and tar sand bitumen (Speight, 2009, 2014a).

1.2.9 Natural Gas

The generic term *natural gas* applies to gases commonly associated with petroliferous (petroleum-producing, petroleum-containing) geologic formations. Natural gas generally contains high proportions of methane (a single carbon hydrocarbon compound, CH_4), and some of the higher molecular weight paraffins (C_nH_{2n+2}) generally containing up to six carbon atoms may also be present in small quantities (Table 1.2). The hydrocarbon constituents of natural gas are combustible, but nonflammable nonhydrocarbon components such as carbon dioxide, nitrogen, and helium are often present in the minority and are regarded as contaminants.

TABLE 1.2 Constituents of Natural Gas

Name	Formula	Vol. %
Methane	CH_4	>85
Ethane	C_2H_6	3.8
Propane	C_3H_8	1–5
Butane	C_4H_{10}	1–2
Pentane[a]	C_5H_{12}	1–5
Carbon dioxide	CO_2	1–2
Hydrogen sulfide	H_2S	1–2
Nitrogen	N_2	1–5
Helium	He	<0.5

[a] Pentane and higher molecular weight hydrocarbons up to approximately C_{10}, including benzene, toluene, ethylbenzene, and xylenes.

In addition to the natural gas fund in petroleum reservoirs, there are also those reservoirs in which natural gas may be the sole occupant. The principal constituent of natural gas is methane, but other hydrocarbons, such as ethane, propane, and butane, may also be present. Carbon dioxide is also a common constituent of natural gas. Trace amounts of rare gases, such as helium, may also occur, and certain natural gas reservoirs are a source of these rare gases. Just as petroleum can vary in composition, so can natural gas. Differences in natural gas composition occur between different reservoirs, and two wells in the same field may also yield gaseous products that are different in composition (Speight, 1990, 2009, 2014a).

There are several general definitions that have been applied to natural gas. Thus, *lean* gas is gas in which methane is the major constituent. W*et* gas contains considerable amounts of the higher molecular weight hydrocarbons. S*our* gas contains hydrogen sulfide, whereas *sweet* gas contains very little, if any, hydrogen sulfide. *Residue gas* is natural gas from which the higher molecular weight hydrocarbons have been extracted, and *casing head gas* is derived from petroleum but is separated at the separation facility at the wellhead.

To further define the terms *dry* and *wet* in quantitative measures, the term *dry* natural gas indicates that there is less than 0.1 gallon (1 gallon, US, = 264.2 m^3) of gasoline vapor (higher molecular weight paraffins) per 1000 ft^3 (1 ft^3 = 0.028 m^3). The term *wet natural gas* indicates that there are such paraffins present in the gas, in fact more than 0.1 gal/1000 ft^3.

Associated or *dissolved* natural gas occurs either as free gas or as gas in solution in the petroleum. Gas that occurs as a solution in the petroleum is *dissolved* gas, whereas the gas that exists in contact with the petroleum (*gas cap*) is *associated* gas.

Other components such as carbon dioxide (CO_2), hydrogen sulfide (H_2S), mercaptans (thiols; RSH), as well as trace amounts of other constituents may also be present. Thus, there is no single composition of components that might be termed *typical* natural gas. Methane and ethane constitute the bulk of the combustible components; carbon dioxide (CO_2) and nitrogen (N_2) are the major noncombustible (inert) components.

Thus, sour gas is natural gas that occurs mixed with higher levels of sulfur, creating hydrogen sulfide (H_2S), a corrosive gas. This sour gas requires additional processing for purification (Mokhatab et al., 2006; Speight, 2007).

Natural gas condensate (*gas condensate*, *natural gasoline*) is a low-density, low-viscosity mixture of hydrocarbon liquids that are present as gaseous components in the raw natural gas produced from natural wells. The constituents of *condensate* separate from the untreated (raw) gas if the temperature is reduced to below the hydrocarbon dew-point temperature of the raw gas. Briefly, the dew point is the temperature to which a given volume of gas must be cooled, at constant barometric pressure, for vapor to condense into liquid. Thus, the dew point is the saturation point.

There are many condensate sources worldwide and each has its own unique gas-condensate composition. However, in general, gas condensate has a specific gravity on the order of ranging from 0.5 to 0.8 and is composed of hydrocarbons such as propane, butane, pentane, hexane, heptane and even octane, nonane, and decane in some cases. In addition, condensate may contain additional impurities such as hydrogen sulfide, thiols (RSH, also called mercaptans), carbon dioxide, cyclohexane, and low molecular weight aromatics such as benzene, toluene, ethylbenzene, and xylenes (Mokhatab et al., 2006; Speight, 2007, 2014a).

When condensation occurs in the reservoir, the phenomenon known as condensate blockage can halt flow to the wellbore. Hydraulic fracturing is the most common mitigating technology in siliciclastic reservoirs (reservoirs composed of clastic rocks), and acidizing is used in carbonate reservoirs. Both techniques increase the effective contact area with a formation. Production can be improved with less drawdown in the formation. For some gas-condensate fields, a lower drawdown means single-phase production above the dew-point pressure can be extended for a longer time. However, hydraulic fracturing does not generate a permanent conduit past a condensate saturation buildup area. Once the pressure drops below the dew point, saturation will increase around the fracture, just as it did around the wellbore. Horizontal or inclined wells are also being used to increase contact area within formations.

1.2.10 Shale Gas

Shale gas (also called *tight gas*) is a description for a field in which natural gas accumulation is locked in tiny bubble-like pockets within layered low-permeability sedimentary rock such as shale. The terms *shale gas* and *tight gas* are often used interchangeably, but there are differences—while shale gas is trapped in rock, tight gas describes natural gas that is dispersed within low-porosity silt or sand areas that create a tight-fitting environment for the gas. Typically, tight gas refers to natural gas that has migrated into a reservoir rock with high porosity but low permeability. These types of reservoirs are not usually associated with oil and commonly require horizontal drilling and hydraulic fracturing to increase well output to cost-effective levels. In general, the same drilling and completion technology that is effective with shale gas can also be used to access and extract tight gas. Shell uses proven technology in responsible ways to access this needed resource.

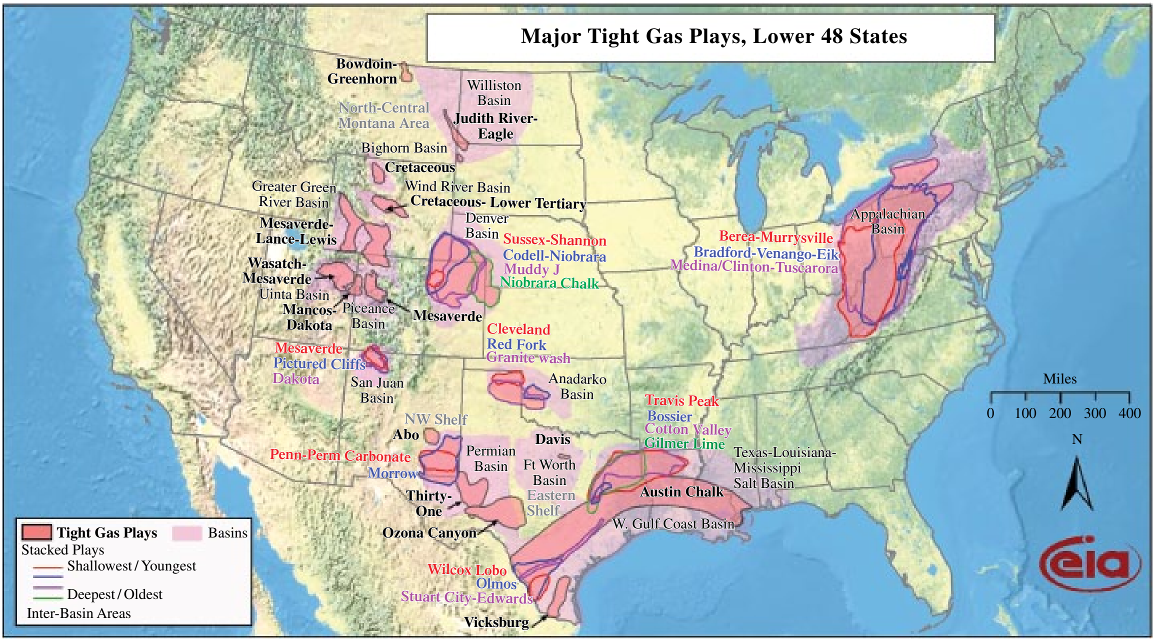


FIGURE 1.6 Tight Gas Plays of the United States. Source: Energy Information Administration, US Department of Energy, Washington, DC.

Tight gas is the fastest-growing natural gas resource in the United States and worldwide as a result of several recent developments (Fig. 1.6). Advances in horizontal drilling technology allow a single well to pass through larger volumes of a shale gas reservoir and thus produce more gas. The development of hydraulic fracturing technology has also improved access to shale gas deposits. This process requires injecting large volumes of water mixed with sand and fluid chemicals into the well at high pressure to fracture the rock, increasing permeability and production rates.

To extract tight gas, a production well is drilled vertically until it reaches the shale formation, at which point the wellbore turns to follow the shale horizontally. As drilling proceeds, the portion of the well within the shale is lined with steel tubing (casing). After drilling is completed, small explosive charges are detonated to create holes in the casing at intervals where hydraulic fracturing is to occur. In a hydraulic fracturing operation, the fracturing fluid is pumped in at a carefully controlled pressure to fracture the rock out to several hundred feet from the well. Sand mixed with the fracturing fluid acts to prop these cracks open when the fluids are subsequently pumped out. After fracturing, gas will flow into the wellbore and up to the surface, where it is collected for processing and sales.

1.2.11 Coalbed Methane (CBM)

Natural gas is often located in the same reservoir as with petroleum, but it can also be found trapped in gas reservoirs and within coal deposits. The occurrence of methane in coal seams is not a new discovery, and methane (called *firedamp* by the miners because of its explosive nature) was known to coal miners for at least 150 years (or more) before it was *rediscovered* and developed as CBM (Speight, 2013b).

The natural gas can originate by thermogenic alteration of coal or by biogenic action of indigenous microbes on the coal. There are some horizontally drilled CBM wells and some that receive hydraulic fracturing treatments. However, some CBM reservoirs are also underground sources of drinking water, and as such, there are restrictions on hydraulic fracturing operations. The CBM wells are mostly shallow, as the coal matrix does not have the strength to maintain porosity under the pressure of significant overburden thickness.

In coalbeds (coal seams), methane (the primary component of natural gas) is generally adsorbed to the coal rather than contained in the pore space or structurally trapped in the formation. Pumping the injected and native water out of the coalbeds after fracturing serves to depressurize the coal, thereby allowing the methane to desorb and flow into the well and to the surface. Methane has traditionally posed a hazard to underground coal miners, as the highly flammable gas is released during mining activities. Otherwise inaccessible coal seams can also be tapped to collect this gas, known as CBM, by employing similar well drilling and hydraulic fracturing techniques as are used in shale gas extraction.

CBM is a gas formed as part of the geological process of coal generation and is contained in varying quantities within all coal. CBM is exceptionally pure compared to conventional natural gas, containing only very small proportions of higher molecular weight hydrocarbons such as ethane and butane and other gases (such as hydrogen sulfide and carbon dioxide). Coalbed gas is over 90% methane and, subject to gas composition, may be suitable for introduction into a commercial pipeline with little or no treatment (Levine, 1993; Rice, 1993; Mokhatab et al., 2006; Speight, 2007, 2013a). Methane within coalbeds is not structurally trapped by overlying geologic strata, as in the geologic environments typical of conventional gas deposits (Speight, 2007, 2013a, 2014a). Only a small amount (on the order of 5–10% v/v) of the CBM is present as free gas within the joints and cleats of coalbeds. Most of the CBM is contained within the coal itself (adsorbed to the sides of the small pores in the coal).

The primary (or natural) permeability of coal is very low, typically ranging from 0.1 to 30 mD, and because coal is a very weak (low modulus) material and cannot take much stress without fracturing, coal is almost always highly fractured and cleated. The resulting network of fractures commonly gives coalbeds a high secondary permeability (despite coal's typically low primary permeability). Groundwater, hydraulic fracturing fluids, and methane gas can more easily flow through the network of fractures. Because hydraulic fracturing generally enlarges preexisting fractures in addition to creating new fractures, this network of natural fractures is very important to the extraction of methane from the coal.

1.2.12 Other Sources of Gas

Methane hydrates, which consist of methane molecules trapped in a cage of water molecules, occur as crystalline solids in sediments in Arctic regions and below the floor of the deep ocean. Although taking on the appearance of ice, methane hydrates will burn if ignited. Methane hydrates are the most abundant unconventional natural gas source and the most difficult to extract. Methane hydrates are conservatively estimated to hold twice the amount of energy found in all conventional fossil fuels, but the technical challenges of economically retrieving the resource are significant. There is also a significant risk that rising temperatures from global warming could destabilize the deposits, releasing the methane—a potent greenhouse gas—into the atmosphere and further exacerbating the problem.

Biogenic gas (predominantly methane) is produced by certain types of bacteria (methanogens) during the process of breaking down organic matter in an oxygen-free environment. Livestock manure, food waste, and sewage are all potential sources of biogenic gas, or biogas, which is usually considered a form of renewable energy. Small-scale biogas production is a well-established technology in parts of the developing world, particularly Asia, where farmers collect animal manure in vats and capture the methane given off while it decays.

Landfills offer another underutilized source of biogas. When municipal waste is buried in a landfill, bacteria break down the organic material contained in garbage such as newspapers, cardboard, and food waste, producing gases such as carbon dioxide and methane. Rather than allowing these gases to go into the atmosphere, where they contribute to global warming, landfill gas facilities can capture them, separate the methane, and combust it to generate electricity, heat, or both.

1.3 UNCONVENTIONAL OIL

Unconventional oil is an all-encompassing definition that can also include several of the crude oil, heavy oil, and tar sand bitumen toys defined earlier. For general purposes, the term *unconventional oil* is synonymous with crude oil, heavy oil, extra heavy oil, and tar sand bitumen that cannot be produced, transported, or refined using traditional techniques of which oil produced by hydraulic fracturing of shale formations and tight formations is also included. But caution is advised at this point since fracturing techniques have been in used since the 1940s to recover residual crude oil from depleted and difficult-to-produce formations.

In the more recent sense of the use of the term, unconventional heavy oil occurs throughout the world—the largest resources are the extra-heavy-oil-bearing deposits in Venezuela and the tar sand deposits of Athabasca (northeastern Alberta, Canada). The United States also has oil sand deposits. However, not all unconventional oils are heavy, and a growing source of unconventional supply is tight oil, which is produced from low-permeability siltstone formations, sandstone formations, and carbonate formations. The crude oil produced from such formations has the same properties (such as API gravity, viscosity, and sulfur content) as conventional oil.

Historically, the crude oil in tight formations was locked in the formations and could not flow through the tight formation rock. However, recent advancements in horizontal drilling and well fracturing technologies are now enabling production of the tight oil—notable plays include the Bakken play (which underlies parts of North Dakota, Montana, Saskatchewan, and Manitoba), the Eagle Ford play in Texas, the Cardium play in Alberta, and the Miocene Monterey play in California. The Bakken is the largest tight oil play and produces a highly volatile light sweet crude oil. Unconventional oil is also produced from oil shale deposits, but this oil does not occur naturally and is produced by the thermal decomposition of kerogen—the organic compound of oil shale. Unlike conventional oil and gas operations, the kerogen is heated *in situ* or mined (as a component of the mined rock) and thermally into a crude oil-like product (*shale oil*) (Scouten, 1990; Lee, 1991; Lee et al., 2007; Speight, 2008, 2012b).

REFERENCES

Akrad, O., Miskimins, J., and Prasad, M. 2011. The Effects of Fracturing Fluids on Shale Rock-Mechanical Properties and Proppant Embedment. Paper No. SPE 146658. Proceedings. SPE Annual Technical Conference and Exhibition, Denver, CO, October 30–November 2. Society of Petroleum Engineers, Richardson, TX.

Gary, J.G., Handwerk, G.E., and Kaiser, M.J. 2007. *Petroleum Refining: Technology and Economics*, 5th Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Ghoshal, S., and Sainik, V. 2013. Monitor and Minimize Corrosion in High-TAN Crude Processing. *Hydrocarbon Processing*, 92(3): 35–38.

Hsu, C.S., and Robinson, P.R. (Editors) 2006. *Practical Advances in Petroleum Processing Volume 1 and Volume 2*. Springer Science, New York.

Kane, R.D., and Cayard, M.S. 2002. *A Comprehensive Study on Naphthenic Acid Corrosion. Corrosion 2002*. NACE International, Houston, TX.

Law, B.E., and Spencer, C.W. 1993. Gas in Tight Reservoirs—An Emerging Major Source of Energy. Professional Paper No. 157. In: *The Future of Energy Gases*. D.G. Howell (Editor). United States Geological Survey, Reston, VA. Page 233–252.

Lee, S. 1991. *Oil Shale Technology*. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Lee, S., Speight, J.G., and Loyalka, S.K. 2007. *Handbook of Alternative Fuel Technologies*. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Levine, J.R. 1993. Coalification: The Evolution of Coal as a Source Rock and Reservoir Rock for Oil and Gas. *American Association of Petroleum Geologists, Studies in Geology*, 38: 39–77.

Mokhatab, S., Poe, W.A., and Speight, J.G. 2006. *Handbook of Natural Gas Transmission and Processing*. Elsevier, Amsterdam, The Netherlands.

Ohmes, R. 2014. Characterizing and Tracking Contaminants in Opportunity Crudes. Digital Refining. http://www.digitalrefining.com/article/1000893,Characterising_and_tracking_contaminants_in_opportunity_crudes_.html#.VJhFjV4AA; accessed November 1, 2014.

Parkash, S. 2003. *Refining Processes Handbook*. Gulf Professional Publishing, Elsevier, Amsterdam, The Netherlands.

Rice, D.D. 1993. Composition and Origins of Coalbed Gas. *American Association of Petroleum Geologists Studies in Geology*, 38: 159–184.

Rikka, P. 2007. Spectrometric Identification of Naphthenic Acids Isolated from Crude Oil. MSc Thesis. Department of Chemistry and Biochemistry Texas State University, San Marcos, TX.

Scouten, C.S. 1990. Oil Shale. In: *Fuel Science and Technology Handbook*. J.G. Speight (Editor). Marcel Dekker Inc., New York. Chapter 25–31. Page 795–1053.

Shalaby, H.M. 2005. Refining of Kuwait's Heavy Crude Oil: Materials Challenges. Proceedings. Workshop on Corrosion and Protection of Metals, Kuwait, December 3–7. Arab School for Science and Technology.

Speight, J.G. (Editor) 1990. *Fuel Science and Technology Handbook*. Marcel Dekker, New York.

Speight, J.G. 1994. Chemical and Physical Studies of Petroleum Asphaltenes. In: *Asphalts and Asphaltenes, 1*. T.F. Yen and G.V. Chilingarian (Editors). Elsevier, Amsterdam, The Netherlands. Chapter 2.

Speight, J.G. 2000. *The Desulfurization of Heavy Oils and Residua*, 2nd Edition. Marcel Dekker, New York.

Speight, J.G. 2007. *Natural Gas: A Basic Handbook*. GPC Books, Gulf Publishing Company, Houston, TX.

Speight, J.G. 2008. *Synthetic Fuels Handbook: Properties, Processes, and Performance*. McGraw-Hill, New York.

Speight, J.G. 2009. *Enhanced Recovery Methods for Heavy Oil and Tar Sands*. Gulf Publishing Company, Houston, TX.

Speight, J.G. 2011. *An Introduction to Petroleum Technology, Economics, and Politics*. Scrivener Publishing, Salem, MA.

Speight, J.G. 2012a. *Crude Oil Assay Database*. Knovel, New York. http://www.knovel.com/web/portal/browse/display?_EXT_KNOVEL_DISPLAY_bookid=5485&VerticalID=0; accessed November 6, 2015.

Speight, J.G. 2012b. *Shale Oil Production Processes*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G. 2013a. *Shale Gas Production Processes*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G. 2013b. *The Chemistry and Technology of Coal*, 3rd Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Speight, J.G. 2014a. *The Chemistry and Technology of Petroleum*, 5th Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Speight, J.G. 2014b. *High Acid Crudes*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G. 2014c. *Oil and Gas Corrosion Prevention*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G. 2015a. *Handbook of Petroleum Product Analysis*, 2nd Edition. John Wiley & Sons, Inc., Hoboken, NJ.

Speight, J.G. 2015b. *Fouling in Refineries*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G. 2015c. *Asphalt Materials Science and Technology*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G., and Ozum, B. 2002. *Petroleum Refining Processes*. Marcel Dekker Inc., New York.

Trembath, A., Luke, M., Shellenberger, M., and Nordhaus, T. 2013. *Coal Killer: How Natural Gas Fuels the Clean Energy Revolution*. Breakthrough Institute, Oakland, CA.

US EIA. 2011. *Review of Emerging Resources. US Shale Gas and Shale Oil Plays*. Energy Information Administration, United States Department of Energy, Washington, DC.

US EIA. 2013. *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*. Energy Information Administration, United States Department of Energy, Washington, DC.

US EIA. 2014. *Crude oils and Different Quality Characteristics*. Energy Information Administration, United States Department of Energy, Washington, DC. http://www.eia.gov/todayinenergy/detail.cfm?id=7110; accessed November 6, 2015.

Walter, G.R., and Thompson, G.M. 1982. A Repeated Pulse Technique for Determining the Hydraulic Properties of Tight Formation. *Ground Water*, 20(2): 186–193.

Yeung, T.W. 2014. Evaluating Opportunity Crude Processing. Digital Refining. http://www.digitalrefining.com/article/1000644; accessed October 25, 2014.

2

RESERVOIRS AND RESERVOIR FLUIDS

2.1 INTRODUCTION

The term *reservoir fluid* is used in this text to describe (predominantly) any organic fluid that exists in a reservoir, which includes gases, liquids, and solids; water may also be included in this terminology. The type of fluids in a reservoir must be determined very early after the discovery of the reservoir—fluid type is a critical consideration in the decisions that must be made about producing the fluids such as natural gas and crude oil. Furthermore, fluid properties play a key role in the design and optimization of injection/production strategies and surface facilities for efficient reservoir management and longevity. Inaccurate fluid characterization will lead to uncertainty in the amount of the resource that is in place as well as predictions of recovery efficiency. Prior to production and determination of the fluid properties (Chapter 4), these measurements only represent in-place properties, but once production commences, variations in fluid composition because of pressure changes and flow throughout the reservoir will become apparent from which a measure of reservoir longevity can be assessed.

Moreover, reservoir fluids, including heavy oil and the immobile tar sand bitumen, vary greatly in composition. In some fields, the fluid is in the gaseous state and in others it is in the liquid state, but generally gases and liquids frequently coexist in a reservoir—in some reservoirs (or deposits) solids may exist as a wax or as a *tar mat* (Wilhelms and Larter, 1994a, 1994b; Zhang and Zhang, 1999). The rocks that contain these reservoir fluids also vary considerably in composition and can influence the physical properties and the flow properties. Other factors such as producing area, height of the fluid column, natural fracturing, or faulting, and water production also serve to distinguish one reservoir from another, which also affect the choice of the production method.

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

The production of crude oil and natural gas occurs in two classes of rock, (i) source rocks and (ii) reservoir rocks, although it is generally believed that most reservoir rocks are not the source rock. Source rocks are sedimentary rocks in which natural gas and crude oil commence formation from organic debris. After forming in the source rock, the hydrocarbons and any hydrocarbon-forming constituents, which can vary from simple structures such as methane (Table 2.1) to more complex structures, such as those constituents of heavy oil and tar sand bitumen, can migrate to the reservoir rock after which further maturation processes can take place (Speight, 2014).

Geologic formations that contain oil and gas include clastic or detrital rocks (pertaining to rock or rocks composed of fragments of older rocks or minerals), chemical rocks (formed by chemical precipitation of minerals), and organic rocks (formed by biological debris from shells, plant material, and skeletons). The three most common sedimentary rock types encountered in oil and gas fields are (i) shale, (ii) sandstone, and (iii) carbonate. Classifying these rock types primarily depends on characteristics such as grain size and composition, porosity (pore space within and between grains), and cementitious character (the manner in which the rock grains are held together), each of which can influence oil and gas production (Bustin et al., 2008). Historically, the majority of the crude oil and natural gas produced in the United States were withdrawn from carbonate and sandstone reservoirs. However, over the past decade, the production of natural gas and crude oil from shale formations and other tight rock formations has increased dramatically.

By way of explanation because of pertinence to this text, *shale* is formed by the accumulation of very small sediments deposited in deep water, at the bottoms of rivers, lakes, and oceans. Shale formations are the most abundant clastic sedimentary rock, and because of their potential for a high organic content, shale formations are considered to be the primary source rocks for hydrocarbons. *Sandstone* is the second most abundant clastic sedimentary rock and is the most commonly encountered reservoir rock in hydrocarbon production, and sandstone formations are created by larger sediment particles, deposited in deserts, river channels, deltas, and

TABLE 2.1 Constituents of Natural Gas

Name	Formula	Vol. %
Methane	CH_4	>85
Ethane	C_2H_6	3.8
Propane	C_3H_8	1–5
Butane	C_4H_{10}	1–2
Pentane[a]	C_5H_{12}	1–5
Carbon dioxide	CO_2	1–2
Hydrogen sulfide	H_2S	1–2
Nitrogen	N_2	1–5
Helium	He	<0.5

[a] Pentane and higher molecular weight hydrocarbons up to approximately C_{10}, including benzene and toluene.

shallow sea environments. These formations tend to be more porous than shale formations and consequently make excellent reservoir rocks—as long as impermeable basement rocks and cap rocks are present. The third most abundant formations, *carbonate formations*, are created by the accumulation of shells and skeletal remains of water-dwelling organisms in marine environments. Carbonate formations are also very good reservoirs and are commonly encountered during hydrocarbon production.

Geologic age of the sediments is also an important determinant of the potential to produce crude oil and natural gas. While many rocks of different ages produce oil and natural gas, in the United States the areas of prolific production include formations from several different geologic periods: (i) the Devonian period, approximately 405–345 million years ago; (ii) the Carboniferous period, approximately 345–280 million years ago; (iii) the Permian period, approximately 280–225 million years ago; and (iv) the Cretaceous period, approximately 136–71 million years ago (Table 2.2). During these periods, organic-rich materials accumulated with the sediments, and, over time, chemical changes (induced by pressure from the overlying sediments and heat) changed originally the organic detritus, thereby producing natural gas and oil.

TABLE 2.2 The Geologic Timescale[a]

Era	Period	Epoch	Approximate Duration (Millions of Years)	Approximate Number of Years Ago (Millions of Years)
Cenozoic	Quaternary	Holocene	10,000 years ago to the present	
		Pleistocene	2	0.01
	Tertiary	Pliocene	11	2
		Miocene	12	13
		Oligocene	11	25
		Eocene	22	36
		Paleocene	71	58
Mesozoic	Cretaceous		71	65
	Jurassic		54	136
	Triassic		35	190
Paleozoic	Permian		55	225
	Carboniferous		65	280
	Devonian		60	345
	Silurian		20	405
	Ordovician		75	425
	Cambrian		100	500
Precambrian			3380	600

[a] The numbers are approximate (±5%) due to variability of the data in literature sources; nevertheless, the numbers do give an indication of the extent of geologic time.

2.2 SEDIMENTARY ROCKS

Sedimentary rocks are types of rock that are formed by the deposition of material within bodies of water. Sedimentation is the process that causes mineral and/or organic particles (detritus) to settle and accumulate or minerals to precipitate from a solution. In most cases, before being deposited, sediment was formed by weathering and erosion in a source area and then transported to the place of deposition by water, wind, ice, mass movement, or glaciers.

The sedimentary rock cover of the continents of the crust of the Earth is extensive, but the total contribution of sedimentary rocks is estimated to be only 8% of the total volume of the crust. Sedimentary rocks are only a thin veneer over a crust consisting mainly of igneous and metamorphic rocks. Sedimentary rocks are deposited in layers (strata) and form a bedding structure and can provide information about the subsurface, leading to discovery and development of natural resources, such as (in the context of this book) crude oil, natural gas, and coal seams as sources of coalbed methane.

2.2.1 Types

Some of the more common types of clastic sedimentary rocks are (i) sandstone formations, (ii) shale formations, and (iii) conglomerate formations. Clastic rocks are composed of fragments, or clasts, of preexisting minerals and rock. A clast is a fragment of geological detritus, chunks, and smaller grains of rock broken off other rocks by physical weathering. The term clastic is used with reference to sedimentary rocks as well as to particles in sediment transport whether in suspension or as bed load and in sedimentary deposits (Marshak, 2012).

Sandstone formations are composed essentially of cemented sand and comprise approximately one-third of all sedimentary rocks. The most abundant mineral in sandstone is quartz (SiO_2), along with lesser amounts of calcite ($CaCO_3$), gypsum ($CaSO_4.2H_2O$), and various iron compounds.

Shale formations consist of consolidated clay and other fine particles (mud) that have hardened into rock. These formations are the most abundant of all sedimentary rocks, comprising approximately two-thirds of the sedimentary rocks. Typically, these formations are fine-grained and thinly bedded and readily split along dividing (bedding) planes. Shale is classified or typed by composition; for example, shale containing large amounts of clay is referred to as *argillaceous shale*, and shale containing appreciable amounts of sand is known as *arenaceous shale*. Shale with a high content of organic matter (*carbonaceous shale*) is typically black in color. Shale that contains large amounts of lime (*calcareous shale*) is used in the manufacture of Portland cement. Another type of shale, *oil shale*, is currently of great interest worldwide because of the supply and demand and increasing cost of crude oil. Oil shale contains kerogen, a fossilized insoluble organic material that is converted into petroleum products.

Conglomerate formations are the least abundant sediment type. They are typically consolidated gravel deposits with variable amounts of sand and mud between the pebbles. Conglomerates accumulate in stream channels, along the margins of mountain ranges, and on beaches. Conglomerates are composed largely of angular pebbles (*breccias*), and some (*tillites*) are formed in glacial deposits.

Chemical and organic sedimentary rocks are the other main group of sediments besides clastic sediments. They are formed by weathered material in solution precipitating from water or as biochemical rocks made of dead marine organisms. Usually special conditions are required for these rocks to form, such as high temperature, high evaporation, and high organic activity. Some chemical sediment is deposited directly from the water in which the material is dissolved—for example, solution upon evaporation of seawater. Such deposits are generally referred to as *inorganic chemical sediments.* Chemical sediments that have been deposited by or with the assistance of plants or animals are said to be *organic* or *biochemical sediments.* Accumulated carbon-rich plant material may form coal. Deposits made mostly of animal shells may form limestone, chert, or coquina.

Sedimentary rocks formed from sediments created by inorganic processes include (i) limestone, dolomite, evaporites, and biochemical sedimentary rocks. *Limestone* ($CaCO_3$, calcite) is precipitated by organisms usually to form a shell or other skeletal structures. Accumulation of these skeletal remains results in the most common type of chemical sediment, limestone. Limestone may form by inorganic precipitation as well as by organic activity. *Dolomite* (magnesium limestone ($CaCO_3.MgCO_3$)) occurs in the same settings as limestone. Dolomite is formed when some of the calcium in limestone is replaced by magnesium. *Evaporite minerals* are sedimentary rocks (true chemical sediments) that are derived from minerals precipitated from seawater. Rock salt, which is composed of halite (NaCl), and rock gypsum ($CaSO_4.2H_2O$) are the most common types of evaporite minerals. High evaporation rates cause concentration of solids to increase due to water loss by evaporation.

Biochemical sedimentary rocks consist of sediments formed from the remains or secretions of organisms. They include *fossiliferous limestone*, *coquina* (limestone composed of shells and coarse shell fragments), *chalk* (porous, fine-textured variety of limestone composed of calcareous shells), *lignite* (brown coal), and *bituminous* (soft) *coal.*

2.2.2 Characteristics

Sedimentary rocks possess definite physical characteristics and display certain features that make them readily distinguishable from igneous or metamorphic rocks. Some of the most important sedimentary characteristics include the following: (i) stratification, (ii) cross-bedding, (iii) graded bedding, (iv) texture, (v) ripple marks, (vi) mud cracks, (vii) concretions, (viii) fossils, and (ix) color.

Stratification. Probably the most characteristic feature of sedimentary rocks is their tendency to occur in strata or beds. These strata are formed when geological agents such as wind, water, or ice gradually deposit sediment.

Cross-bedding. This refers to sets of beds that are inclined relative to one another. The beds are inclined in the direction that the wind or water was moving at the time of deposition. Boundaries between sets of cross-beds usually represent an erosional surface. They are very common **in** beach deposits, sand dunes, and river-deposited sediment.

Graded bedding. In a stream, as current velocity wanes, first the larger or denser particles are deposited, followed by smaller particles. This results in bedding showing a decrease in grain size from the bottom of the bed to the top of the bed (fine sediment on top and coarse at the bottom).

Texture. The size, shape, and arrangements of materials derived by processes of weathering, transportation, deposition, and diagenesis determine the texture of sedimentary rocks. The texture in sediment and sedimentary rocks is dependent on processes that occur during each stage of formation, which include source materials, the nature of wind and water currents present, the distance that materials were transported or time spent in the transportation process, biological activity, and exposure to various chemical environments.

Ripple marks. These are characteristic of shallow water deposition and are caused by small waves or winds that leave ripples of sand on the surface of a beach or on the bottom of a stream. Ripples of this type have also been preserved in certain sedimentary rocks and may provide geologists with information about the conditions of deposition when the sediment was originally deposited.

Mud cracks. It is not uncommon to find *mud cracks* that result from the drying out of wet sediment on the bottom of dried-up lakes, ponds, or stream beds. These many-sided (polygonal) shapes give a honeycomb appearance on the surface. If preserved in sedimentary rocks, such shapes suggest that the rock was subjected to alternating periods of flooding and drying.

Concretions. These spherical or flattened masses of rock enclosed in some shale formations or limestone formations are generally harder than the rock enclosing them. Because concretions are usually harder than the enclosing rock, they are often left behind after the surrounding rock has been eroded away.

Fossils. These are the remains or evidence of once-living organisms that have been preserved in the crust of the Earth. Because life has evolved, fossils give clues to the relative age of the sediment and can be important indicators of past climates.

Color. Finally, the minerals in some sediments impart color to the sediment. *Hematite* (iron oxide, Fe_2O_3, also spelled haematite) produce a pink or red color.

2.3 RESERVOIR EVALUATION

The evaluation of any reservoir, including a tight sandstone reservoir and a shale reservoir, should always begin with a thorough understanding of the geologic characteristics of the formation. The important geologic parameters for a trend or basin are (i) the structural and tectonic regime, (ii) the regional thermal gradients, (iii) the regional pressure gradients, (iv) the depositional system, (v) the genetic facies, (vi) textural maturity, (vii) mineralogy, (viii) diagenetic processes, (ix) reservoir dimensions, and (x) the presence of natural fractures, all of which can affect drilling, evaluation, completion, and stimulation. Without understanding the above-listed factors can lead to guesswork in determining reservoir behavior, performance, and longevity.

One of the most difficult parameters to evaluate in tight gas reservoirs is the drainage area size and shape of a typical well. In tight reservoirs, months or years of production are normally required before the pressure transients are affected by reservoir boundaries or well-to-well interference. As such, it may be necessary to estimate the drainage area size and shape for a typical well in order to estimate reserves. Knowledge of the depositional system and the effects of diagenesis on the rock are needed to estimate the drainage area size and shape for a specific well. In blanket tight gas reservoirs, the average drainage area of a well largely depends on the number of wells drilled, the size of the fracture treatments pumped on the wells, and the time frame being considered. In lenticular or compartmentalized tight gas reservoirs, the average drainage area is likely a function of the average sand-lens size or compartment size and may not be a strong function of the size of the fracture treatment.

A main factor controlling the continuity of the reservoir is the depositional system. Generally, reservoir drainage per well is small in continental deposits and larger in marine deposits. Fluvial systems tend to be more lenticular, whereas barrier–strand plain systems tend to be more blanket and continuous. To date, most of the more successful tight gas plays are those in which the formation is a thick, continuous marine deposit.

Thus, an understanding of the geology of a reservoir is essential to reservoir development, oil and gas production, and management, including reservoir longevity and environmental management. Furthermore, reservoir evaluation includes both the external geology of the reservoir (the forces responsible for the formation of the reservoir) and the internal geology of the reservoir (the nature of the rocks that constitute the reservoir). These aspects are even more important when hydraulic fracturing methodology is to be applied to the reservoir. In addition, the efficient extraction of crude oil and natural gas requires that the reservoir be visualized in three dimensions, which can only be adequately provided through a variety of scientific and geological studies (Solano et al., 2013).

The critical elements of a petroleum system are (i) the source rock, which is the rock containing the organic precursors, which were converted into petroleum reservoir fluid; (ii) the migration path, which is the path taken by the crude oil, or immature crude oil that is not fully matured, from the source rock to the reservoir; (iii) the reservoir, which is a rock formation, such as sandstone, limestone, or dolomite, that has sufficient porosity to store the fluid and sufficient permeability for fluid mobility; and (iv) the seal, which is impermeable basement rock and cap rock that prevent the escape of the petroleum. For the purpose of this test, the critical part of the crude oil and/or natural gas system is the reservoir.

Crude oil (conventional crude or heavy oil) cannot be retained as an accumulation unless there is a trap, and this requires that there is a boundary between the cap rock or other sealing agent but the exact form of the boundary varies widely. The simplest forms are the flat-lying convex lens, the anticline, and the dome, each of which has a convex upper surface. Many oil and gas accumulations are trapped in anticlines or domes, structures that are generally more easily detected than some other types of traps, such as fault traps and salt dome traps (Hunt, 1996; Dandekar, 2013; Speight, 2014).

Thus, reservoir evaluation is an important aspect of oil and gas production. A reservoir is a subsurface porous permeable rock body or formation that has been created by the sequential steps of deposition, conversion, migration, and entrapment and has the ability to store fluids, such as natural gas, crude oil, and water. As such, each reservoir will exhibit individual properties that are specific to that reservoir (site-specific properties). Indeed, within a reservoir, these properties may even change with longitudinal extent and with vertical height of the reservoir.

Typically, reservoir rocks exhibit porosity—a measure of the openings in a rock in which crude oil and natural gas can exist. Another characteristic of reservoir rock is that it must be permeable—the pores of the rock must be interconnected, thereby allowing so that crude oil and/or natural gas mobility within the reservoir and thence flow to a production well. A reservoir with high porosity but low permeability is a general indication of immobility of the gas and/or oil within the reservoir. In such a case, variations in gas composition and crude oil composition from different locations within the reservoir might be expected. Thus, reservoirs that are to be developed for crude oil and/or natural gas production are characteristically large and extensive in volume with a good fluid-holding capacity (high porosity) and also have the capability to transmit fluids once penetrated by geological disturbances (such as earthquakes) or anthropological disturbances, such as drilling a well into the reservoir.

An important geologic aspect of the reservoir is the external geometry of the reservoir, defined by seals that inhibit the further migration of the natural gas and crude oil. Migration will cease, and a hydrocarbon reservoir will form, only where hydrocarbons encounter a trap, which are composed of a suitable gas-holding or oil-holding rock with the following types of seals: (i) top, (ii) lateral, and (iii) bottom seals. In addition, the geometry of traps can be (i) structural, (ii) sedimentary, and (iii) diagenetic (Hunt, 1996; Dandekar, 2013; Speight, 2014).

Another important geologic aspect of the reservoir is the internal architecture that involves the lateral distribution of depositional textures, which is related to depositional environments, and the vertical stacking of textures, which is described by stratigraphy, which is the geological study of the following aspects of rock strata: (i) form, (ii) arrangement, (iii) geographic distribution, and (iv) chronologic succession. Diagenesis, which refers to the changes that happen to the sediment after deposition, can also control the lateral continuity and vertical stacking of reservoir rock types. This phenomenon is an important aspect of carbonate reservoirs, in which the conversion of limestone to dolostone and the dissolution of carbonate have a large effect on internal reservoir architecture (Tucker and Wright, 1990; Blatt and Tracy, 1996).

Briefly, dolostone or dolomite rock is a sedimentary carbonate rich that contains a high proportion of dolomite ($CaCO_3.MgCO_3$), which has also been referred to as *magnesian limestone*. Most dolostones formed as magnesium replacement of calcium in limestone ($CaCO_3$) prior to lithification—the process in which sediments compact under pressure, expel connate fluids, and gradually become solid rock. Dolostone is resistant to erosion and can act as an oil and natural gas reservoir.

In terms of reservoir evaluation, reservoirs are generally evaluated on the basis of (i) structural types, (ii) heterogeneity, and (iii) porosity and permeability.

2.3.1 Structural Types

Reservoirs are created by structural deformation of the geological strata, and there are three basic forms of a structural trap in petroleum geology: (i) anticline trap, (ii) fault trap, and (iii) salt dome trap (Hunt, 1996; Dandekar, 2013; Speight, 2014). The *anticline trap* (Fig. 2.1) is a typical *structural trap* that is produced by compressional folding, by uplift, and by drape over older tectonically created features. An anticline is an example of rocks that were previously flat but have been bent into an arch. The rocks have been folded or bucked into the form of a dome, and hydrocarbons accumulate in the hinge area of an anticline. The *fault trap* (Fig. 2.2) is formed by the movement of permeable and impermeable layers of rock along a fault line. The permeable reservoir rock faults such that it is now adjacent to an impermeable rock, preventing hydrocarbons from further migration. In some cases, there can be an impermeable substance smeared along the fault line (such as clay) that also acts to prevent migration. Another form of trap is the *stratigraphic trap* that is formed when other geologic formations seal a reservoir or when the permeability changes through a change in lithology, that is, a change due to the presence of rock with

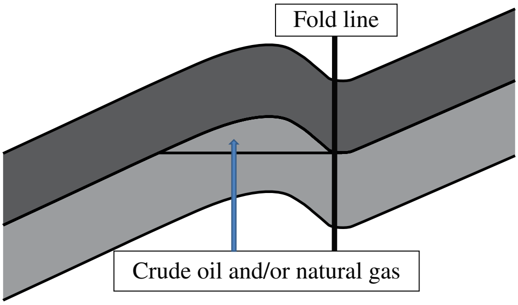


FIGURE 2.1 Anticline trap (fold trap).

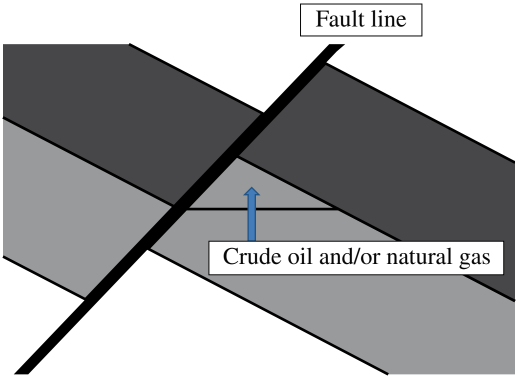


FIGURE 2.2 Fault trap.

characteristics different to those of the reservoir rock. *Salt domes* are formed by flow of salt or removal of salt deposits.

Reservoir rocks tend to show greater variations in permeability than in porosity, and in addition, these two properties, as measured on core samples from reservoir rocks, are not always identical with the values indicated for the bulk rock in the underground formation because of the nonrepresentative nature of many core samples. Generally, porosity is on the order of 5–30%, while permeability falls between 0.005 darcy (5 millidarcies (mD)) and several darcies (several thousand millidarcies) (Kovscek, 2002).

2.3.2 Heterogeneity

In addition to understanding the petrophysics of the reservoir, oil recovery requires an understanding of displacement and flow through porous media—however, flow through porous media is complicated (Dawe, 2004; Maxwell and Norton, 2012). Within the reservoir there can be displacements and miscible and/or immiscible flow, with one, two, or sometimes three mobile phases (oil, gas, and water) (Grattoni and Dawe, 2003). Furthermore, heterogeneity in the form of layers, lenses, cross-beds, and quadrants can have a significant effect on fluid displacement patterns.

Low-permeability crude oil and natural gas reservoirs exhibit a high degree of bodily heterogeneity encompassing different scales within the hosting geological formation. Local variations of porosity, permeability, and pore geometry are variably affected by the compositional nature of the sediments and the depositional environment in which they formed, as well as the evolving diagenetic and tectonic history of the reservoir rocks.

Physically, natural gas and crude oil reservoirs are not the homogeneous porous media that are often envisaged on paper and used in calculations using data from laboratory simulations. Heterogeneity means that a specific property of interest will vary vertically and longitudinally within the reservoir (Dawe, 2004) much like the coal in a seam that varies in composition from one part of the seam to another (Speight, 2013). For example, well log and core analysis reports show that all reservoirs are heterogeneous with rock properties (such porosity and pore saturation) varying within the reservoir. In addition, permeability heterogeneity causes variations in the fluid movements compared to a homogeneous system (Dawe, 2004). Furthermore, reservoir heterogeneity can arise from variations in permeability or variations in wettability. In fact, wettability of the reservoir rock by the crude oil (particularly adsorption of the polar constituents in heavy oil) can have significant effects on crude oil recovery (Anderson, 1986; Caruana and Dawe, 1996a, 1996b; Dawe, 2004).

The *wettability* of reservoirs rocks refers to the tendency of the fluid (e.g., crude oil) to spread on or adhere to a solid surface in the presence of other immiscible fluids and is determined by complex *interface boundary conditions* acting within pore space of sedimentary rocks. The term *oil wet* refers to reservoir rock that is preferentially in contact with crude oil, which occupies the small pores and contacts the majority of the rock surface. Conversely, the term *water wet* refers to reservoir rock that is preferentially in contact with water. The minerals present in reservoir rocks are generally known as being intrinsically *hydrophilic* (i.e., preferentially water wet) or *oleophilic* (i.e., preferentially oil wet).

2.3.3 Porosity and Permeability

Porosity and permeability are related properties of any rock or loose sediment (Fig. 2.3). Most oil and gas have been produced from sandstones. These rocks usually have high porosity and are usually of high permeability. Porosity and permeability are necessary to make a productive oil or gas well and are the result of both depositional and diagenetic factors.

The characterization of porosity and permeability is of fundamental importance for the proper evaluation of a reservoir. At the microscopic scale, porosity and permeability are highly dependent on the geometry of the pores and pore throats within volumetrically finite homogeneous systems. These microscopic, locally homogeneous domains are usually found as layered sediments and/or clusters, which confer different degrees of heterogeneity to the reservoir (Radlinski et al., 2004). Thus, porosity is the proportion of void space to the total volume of rock and is a measure

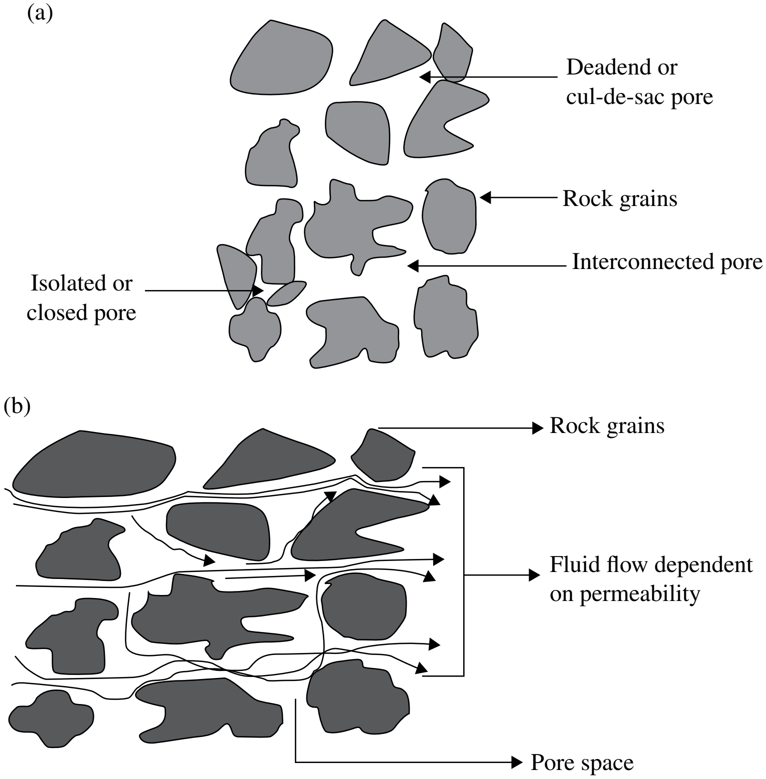


FIGURE 2.3 Representation of (a) porosity and (b) permeability.

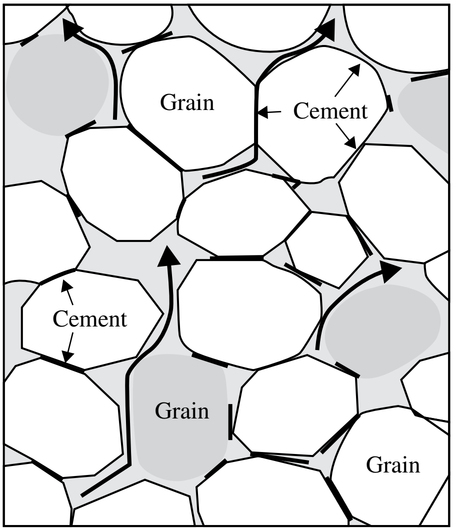


FIGURE 2.4 Representation of rock grains, pore space, and permeability.

of the ability of the rock to hold fluids (including gas) (Fig. 2.4). Mathematically, porosity is the open space in a rock divided by the total rock volume and is normally expressed as a percent of the total rock, which is taken up by pore space. For example, sandstone may have 8% porosity—the other 92% is solid space-filling rock. In newly deposited sand formations and poorly consolidated sandstone formations, grain size correlates well with pore size and hence is a primary control on permeability.

The porosity of rock samples is traditionally calculated from helium pycnometer measurements—as used for petroleum coke and other solids (ASTM D2638)—from which an accurate value of grain density is obtained. The relatively small size of helium molecules ensures that even subnanometer-sized pores and pore throats are probed. In addition, the low sorptive capacity of these molecules reduces the errors that might be introduced due to the absorption processes during the measurements. However, helium may be accessible to finer pores than crude oil and natural gas constituents in shale formations, thereby overestimating accessible porosity (Cui et al., 2009).

On the other hand, permeability is the ability of fluid to move through the pores and is a measure of the ease with which fluids (including gas) pass through a rock. Thus, it is extremely important to know the values of formation permeability in every rock layer. The values of permeability control everything from gas flow rate to fracture fluid leak-off. It is impossible to optimize the location of the perforations, the length of the hydraulic fracture, the conductivity of the hydraulic fracture, and the well spacing, if one does not know the values of formation permeability in every rock layer. In addition, one must know the formation permeability to forecast gas reserves and to analyze postfracture pressure buildup tests. To determine the values of formation permeability, one can use data from logs, cores, production tests, and prefracture pressure buildup tests or injection falloff tests (Ahmed et al., 1991).

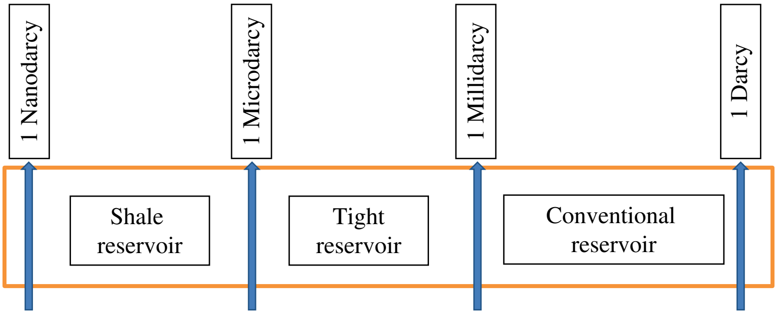


FIGURE 2.5 Representation of differences in permeability of shale reservoirs, tight reservoirs, and conventional reservoirs.

Permeability in petroleum-producing rocks is usually expressed in millidarcies, and most oil and gas reservoirs have permeability in the range up to several hundred millidarcies (Fig. 2.5). The extremely low permeability of shale formations determines the effectiveness of basement rock and cap rock seals for many conventional reservoirs. Permeability values from these tight rocks usually fall into a range from the submicrodarcy ($<10^{-3}$ mD) up to one hundred of millidarcies. Permeability is usually measured either with core plugs or full-diameter core samples using unconfined, unsteady-state techniques. For the measurements of ultra-low-permeability samples, crushed rock pressure decay techniques are used instead.

Accumulations of petroleum and natural gas can only occur if all of the essential elements (source rock, reservoir rock, seal rock, and overburden rock) and processes (generation–migration–accumulation–trap formation) have operated adequately and in the proper time–space framework (Magoon and Dow, 1994; Speight, 2014). Absence or inadequacy of even one of the elements or processes eliminates any chance of economic success. Thus, reservoir parameters (reservoir size, porosity, and permeability) are among the geologic controls that have to be included in the consideration of risk factors for reservoir development (Berg, 1970; Ahmed et al., 1991; Rose, 1992; White, 1993; Ramm and Bjørlykke, 1994; Yao and Holditch, 1996). The three major causes of anomalously high porosity are (i) grain coats and grain rims, (ii) early emplacement of hydrocarbons, and (iii) shallow development of fluid overpressure.

Grain coats are the result of authigenic processes and form subsequent to burial by growth outward from framework grain surfaces, except at points of grain-to-grain contact (Wilson and Pittman, 1977). Grain coats include clay minerals and microcrystalline quartz. Grain coats and grain rims retard quartz cementation and concomitant porosity and/or permeability reduction by blocking potential nucleation sites for quartz overgrowths on detrital-quartz seed grains. The effectiveness of grain coats or grain rims in preserving porosity is a function of the thermal history, grain size, and the abundance of quartz grains (Walderhaug, 1996; Bonnell et al., 1998). Grain coats and grain rims have no effect on porosity where the primary control of reservoir quality is the occurrence of cements such as carbonate minerals, sulfate minerals, or zeolites (Pittman et al., 1992).

Porosity and permeability generally decrease with increasing depth (thermal exposure and effective pressure); however, a significant number of deep (approximately 13,000 ft) sandstone reservoirs worldwide are characterized by anomalously high porosity and permeability (Bloch et al., 2002). Anomalous porosity and permeability can be defined as being statistically higher than the porosity and permeability values occurring in typical sandstone reservoirs of a given lithology (composition and texture), age, and burial/temperature history.

In tight gas (shale) reservoirs, areas where the reservoir quality and completion are high (*sweet spots*) are confined to areas that have high clay rim coverages but relatively low volume of clay minerals. By contrast, interstratified clay-free and coarse-grained nonreservoir rock is tightly cemented by quartz overgrowth (Wescott, 1983; Weimer and Sonnenberg, 1994). Furthermore, drilling success in any reservoir is dependent on finding the most prospective areas, or the *sweet spots*, and aligning the wellbore for maximum borehole exposure to these zones. In shale reservoirs this means placing the well in the zones most conducive to fracturing. This requires a thorough understanding of the shale gas reservoir characteristics. Aiming for a middle-of-the-road operation is rarely a successful strategy—shale formations can have significant variance in thickness and composition.

In summary, the success or failure of a hydraulic fracture treatment will depend on the quality of the candidate well selected for the treatment. Evaluation and selection of a suitable candidate reservoir for stimulation is a move in the depiction of success, while choosing a poor candidate normally results in failure. To select the best candidate for stimulation, the design engineer must consider many variables of which the most critical parameters for hydraulic fracturing are (i) formation permeability, (ii) the *in situ* stress distribution, (iii) viscosity of the reservoir fluid, (iv) reservoir pressure, (v) reservoir depth, (vi) the condition of the wellbore, and (vii) prior stimulation of, or damage to, the reservoir.

The best candidate wells for hydraulic fracturing treatments have a substantial volume of oil and gas in place and need to increase the productivity index. The characteristics of such reservoirs include (i) a thick pay zone, (ii) medium to high pressure, (iii) *in situ* stress barriers to minimize vertical height growth, and (iv) either a low-permeability zone or a zone that has been damaged. On the other hands, reservoirs that are poor candidates for hydraulic fracturing are those with little oil or gas in place because of thinness (lack of thickness or depth) as well as low reservoir pressure and small areal extent. Reservoirs with extremely low permeability may not produce enough hydrocarbons to pay all the drilling and completion costs, even if successfully stimulated; thus, such reservoirs would not be good candidates for stimulation.

2.4 TIGHT FORMATIONS

The term *tight formation* refers to a formation consisting of extraordinarily impermeable, hard rock. Tight formations are relatively low-permeability, nonshale, sedimentary formations that can contain oil and gas. As in shale formations, which are believed to be the source rocks in which oil and gas form during geological time, crude oil and gas are contained in the pore space of the formation—which can include sandstone formations, siltstone formations, and carbonate formations. While a conventional formation containing crude oil and/or natural gas can be relatively easily drilled and extracted from the ground, tight gas and tight oil (natural gas and crude oil in tight formations) require more effort to extract from a tight reservoir. In such formations, the pores in the formation in which the gas is trapped are either irregularly distributed, or interconnection of the pores is poor, which adversely affects permeability. Without secondary production methods, gas and/or oil from a tight formation would flow at very slow rates, making production uneconomical.

While vertical wells may be easier and less expensive to drill, they are not the most conducive to developing tight formations. In a tight formation, it is important to expose as much of the reservoir as possible, making horizontal and directional drilling a necessity. Here, the well can run along the formation, opening up more opportunities for the gas and/or oil to enter the wellbore. A more common technique for developing tight gas reserves includes drilling more wells, which enhances the ability of the oil and gas to leave the formation and enter the wellbore This can be achieved through drilling several myriad directional wells (the number of wells is formation specific) from one location, which lessens the environmental footprint of the drilling operation. After seismic data has illuminated the best well locations and the wells have been drilled, production stimulation (through both fracturing and acidizing) is employed on tight reservoirs to promote a greater rate of flow.

Fracturing involves breaking apart the rocks in the formation (Chapter 5). After the well has been drilled and completed, hydraulic fracturing is achieved by pumping the well full of fracturing fluids under high pressure to cause rock fracturing in the reservoir and improve permeability. Additionally, acidizing the well is employed to improve permeability and production rates of tight gas formations, which involves pumping the well with acids that dissolve the limestone, dolomite, and calcite cement between the sediment grains of the reservoir rocks. This form of production stimulation helps to reinvigorate permeability by reestablishing the natural fissures that were present in the formation before compaction and cementation.

Typically, North American crude oil and natural gas formations that require fracturing are located one mile or more below the water table and below many layers of impermeable rock. These thousands of feet of rock overlying the tight gas formations, combined with the low permeability of the tight gas formations themselves, ensure that the natural gas and crude oil remain contained within the target formation and also help prevent migration of any hydraulic fracturing fluids that may be pumped into such formations. Drilling, casing, and cementing procedures must be designed to at least to meet (or even) exceed regulatory requirements to protect groundwater by isolating the well from any groundwater supplies.

The upper portions of the well, where the wellbore passes through the water table, should be reinforced to prevent either gas or oil (and any fracturing fluids) from escaping into the surrounding ground. Wells are lined with steel pipes and sealed in place with cement from the surface to below the level of drinking water supplies, typically to a depth of 1000 ft or more. These barriers help to contain the fracturing fluid and, along with the depth at which fracturing takes place, prevent the fluid from mingling with drinking water close to the surface. During and after hydraulic fracturing, wells are monitored with pressure sensors to check that they are firmly sealed. Shell also periodically monitors the fractures and the fluids using microseismic technology to map the formation, which helps to make production as efficient as possible and protects the environment (Chapters 5 and 8).

The manner in which gas and oil are trapped within tight formations and shale formations requires advanced technology to access these resources. Horizontal and directional drilling techniques are used to access a large underground area from a single well pad and when followed by hydraulic fracturing technology stimulate the release of the encapsulated oil and gas to flow into the wellbore. One of the most difficult parameters to evaluate in tight reservoirs is the drainage area size and shape of a typical well. Knowledge of the depositional system and the effects of diagenesis on the rock are needed to estimate the drainage area size and shape for a specific well.

In tight reservoirs, the typical drainage area of a well largely depends on (i) the number of wells drilled, (ii) the size of the fracture treatments, and (iii) the time frame being considered. In lenticular or compartmentalized tight reservoirs, the drainage area is usually a function of the sand-lens size or compartment size and may not be a strong function of the size of the fracture treatment. A main factor controlling the continuity of the reservoir is the depositional system. Generally, reservoir drainage per well is small in continental deposits and larger in marine deposits. Fluvial systems tend to be more lenticular, whereas barrier–strand plain systems tend to be more continuous.

The best method for determining the depositional system is to analyze cores both from rock above and below the main pay interval, especially in the case of shale formations and mudstone formations. The core descriptions can be correlated with open-hole logging data to determine the logging signature for the various depositional environments. Once these correlations are made, logs from additional wells can be analyzed to generate maps of the depositional patterns in a specific area that can be useful in developing field optimization plans.

2.5 EVALUATION OF RESERVOIR FLUIDS

While the various test methods for evaluating reservoir fluids such as crude oil are presented elsewhere (Chapter 4) (Speight, 2014, 2015a), it is pertinent at this point to present an overview of the evaluation of reservoir fluids.

The physical (bulk) composition of reservoir fluids is a subset of fluid characterization and evaluation (Chapter 4) and distribution within the reservoir, which helps in defining reservoir continuity and communication among various zones. Interpretation of well-test data and the design of surface facilities and processing plants require accurate fluid information and its variation with time. In addition to initial reservoir fluid samples, periodic sampling is necessary for reservoir surveillance.

Reservoir fluid characterization consists of several key steps: (i) acquisition of representative samples, (ii) identification of reliable service laboratories to perform PVT measurements, (iii) implementation of QA/QC procedures to ensure data quality, and (iv) development of mathematical models to capture fluid property changes accurately as functions of pressure, temperature, and composition. The fluid type and production processes dictate the type and the volume of required fluid data. This paper outlines recommended sampling techniques, PVT data acquisition strategies, and modeling methods and presents field examples covering a wide range of fluid types from heavy oils to lean gas condensates and production processes such as depletion, pressure maintenance, and miscible recovery.

The term *physical composition* (or *bulk composition*) refers to the composition of crude oil as determined by various physical techniques. For example, the separation of petroleum using solvents and adsorbents (Speight, 2014, 2015a) into various bulk fractions determines the physical composition of crude oil. These methods of separation are not always related to chemical properties, and the terminology applied to the resulting fractions is often a *terminology of convenience*.

Proper management of production of fluids from a reservoir can maximize the recovery of the oil originally in the reservoir. Developing proper management strategies requires accurate knowledge of the characteristics of the reservoir fluid as long as fluid samples obtained from the reservoir fluid reflect the pertinent properties of the fluid, as determined by subsequent laboratory tests (Chapter 4).

Each reservoir has its own range of fluids, which are usually identified by some distinguishing physical or chemical property. In order the understand the concept of reservoir fluids and the means of recovery—which typically specific to the reservoir—it is necessary to understand the different types of crude oil and heavy crude oil as well as tar sand bitumen. Tar sand formations require fracturing of the rock to create channels through which heated bitumen can move to the wellbore, and it is the purpose of this section to describe the means by which reservoir fluids can be evaluated.

Reservoirs contain complex mixtures of fluids and the behavior of the fluids is strongly dependent on the chemical makeup of the fluid as well as the properties of the reservoir. Conventional crude oil is a complex mixture of hydrocarbons and nonhydrocarbons with molecular weight varying from 16 (methane) to several hundred and even into the thousands (resin and asphaltene constituents). Heavy oil is a fluid that is also a multicomponent mixture, composed of nonhydrocarbons and a variety of hydrocarbons. The fluid found in tar sand deposit is even more complex chemically and physically (Speight, 2009, 2014).

More generally, reservoirs typically contain three main *fluids*—(i) natural gas, (ii) oil, and (iii) water—with minor constituents being acid gases (carbon dioxide and hydrogen sulfide). For the purposes of the present text, near-solid and solid components of reservoirs (such as wax deposits and tar mats) are not discussed here. The focus is on the gaseous and liquid components of the reservoir, which exhibit considerable variations in composition in combination and proportion within each reservoir.

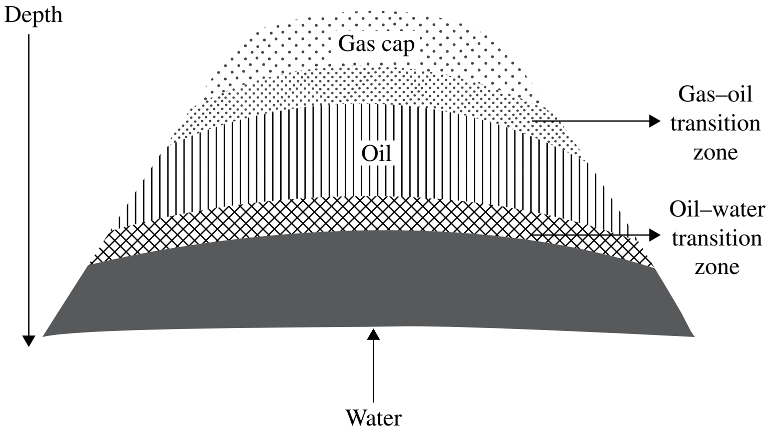


FIGURE 2.6 Representation of the zones in a reservoir. Source: Adapted from Speight, J.G. 2009. Enhanced Recovery Methods for Heavy Oil and Tar Sands. Gulf Publishing Company, Houston, TX.

The distribution of the fluids in a reservoir rock is dependent on the density of the fluids as well as on the properties of the rock. If the pores are of uniform size and evenly distributed, there is (i) an upper zone where the pores are filled mainly by gas (the gas cap), (ii) a middle zone in which the pores are occupied principally by oil with gas in solution, and (iii) a lower zone with its pores filled by water (Fig. 2.6). A certain amount of water (approximately 10–30%) occurs along with the oil in the middle zone. There is a transition zone from the pores occupied entirely by water to pores occupied mainly by oil in the reservoir rock, and the thickness of this zone depends on the densities and interfacial tension of the oil and water as well as on the sizes of the pores. Similarly, there is some water in the pores in the upper gas zone that has at its base a transition zone from pores occupied largely by gas to pores filled mainly by oil.

The water found in the oil and gas zones (*interstitial water*) (Fig. 2.6) usually occurs as collars around grain contacts, as a filling of pores with unusually small throats connecting with adjacent pores, or, to a much smaller extent, as wetting films on the surface of the mineral grains when the rock is preferentially wet by water. The water may occur as wetting films, or collars, around the sand grains as well as in some completely filled pores. The so-called gas–oil and oil–water contacts are generally horizontal but have been known to exist as a very gentle incline. On occasion, part of an accumulation of the oil or gas has its lower boundary marked, not by the water-bearing zone of the reservoir rock but by an adjacent sealing rock that has characteristics similar to those of the cap rock. When the pressure and temperature conditions are suitable in relation to the proportions and the nature of the gas and oil, there may be no gas cap but only oil, with dissolved gas overlying the water.

The water (brine) produced with oil has been trapped with the oil and is brought to the surface along with oil. Because the water has been in contact with the oil, it contains some of the chemical characteristics of the formation and the oil itself. Oil and gas wells produce more water than oil (as much as seven barrels of water per barrel of oil in some fields). The composition (salt content) of coproduced water determines the need for antiscaling additives. There are strict regulations to limit disposal and beneficial use options as well as environmental impacts that pertain to oil field waters.

Reservoir temperatures may vary up to 90 °C (195 °F) or even higher, while surface conditions are typically on the order of 20–30 °C (68–86 °F). Pressure can vary from its atmospheric value (or lower in the case of vacuum distillation) to several thousand pounds per square inch (psi). Within such an ample range of conditions, reservoir fluids undergo severe transformations and exist as a single phase (gas, liquid, or solid) or coexist in several forms (liquid plus gas, solid plus liquid, vapor plus solid, or even in liquid-plus-liquid combinations).

Reservoir fluids are brought to the surface as a mixture of oil, gas, and water, which is sent to a surface production facility before they can be disposed or sold to an industrial customer (e.g., a refinery). A surface production facility is the system in charge of the separation of the well stream fluids into its three single-phase components—oil, gas, and water—and of their transport and processing into marketable products and/or their disposal in an environmentally acceptable manner. Once separated, the oil, natural gas, and water follow different paths. Water is typically reinjected for reservoir pressure maintenance operations. The oil usually goes through a process of dehydration, which removes basic sediments, and hydrocarbon fluids are assumed to comprise two components—stock tank oil and surface gas.

Furthermore, many types of crude oil and heavy oil are available throughout the world, and the quality of crude oil is reflected in various properties such as sulfur content and API gravity (Speight, 2014, 2015b). Light crude oils (higher API gravity) and sweet crude oils (low sulfur content) are preferred to heavy crude oil (low API gravity) and sour crude oils (high sulfur)—the light sweet crude oils can be recovered with far less sophisticated and energy-intensive processes.

Reservoir fluid PVT properties are critical for efficient reservoir management throughout the life of the reservoir, from discovery to abandonment (Honarpour et al., 2006; Nagarajan et al., 2007). In fact, reliable data related to the properties of *in situ* fluids are essential for the determination of in-place volumes and recovery-factor calculations as well as for technical evaluation of reservoir development–depletion plans. Fluid characterization and distribution within the reservoir help in defining reservoir continuity and communication among various zones (Moffatt et al., 2013).

Reservoir fluid characterization consists of several key steps: (i) acquisition of representative samples, (ii) identification of reliable service laboratories to perform PVT measurements, (iii) implementation of QA/QC procedures to ensure data quality, and (iv) development of mathematical models to capture fluid property changes accurately as functions of pressure, temperature, and composition. The fluid type and production processes dictate the type and the volume of required fluid data.

2.5.1 Sampling Methods

The main objective of a successful sampling campaign is to obtain representative fluid samples for determining properties, and adequate volumes should be collected for analysis, geochemical analysis for fluid-source identification and reservoir continuity, as well as crude assay for refinery processes (Speight, 2001, 2015a). The sampling program should focus on selecting an appropriate sampling method and developing sound sampling, sample transfer, and QC procedures. In addition, sample character and specific sampling issues should be addressed in the form of a sample history that details the acquisition, storage, and text carried out on the sample (Speight, 2001, 2015a).

As already stated, the objective of reservoir fluid sampling is to collect a sample that is representative of the fluid present in the reservoir at the time of sampling (Speight, 2001, 2015a). Adequate volumes should be collected for plant and process analysis, geochemical analysis for fluid-source identification and reservoir continuity, and crude assay for refinery processes. The critical steps in any successful sampling program are avoiding two-phase flow in the reservoir, minimizing fluid contamination introduced by drilling and completion fluids, and preserving sample integrity. A sampling program should focus on the key issues of selecting an appropriate sampling method and associated tools, customizing the tool string, and developing sound sampling, sample transfer, and QC procedures. In addition, specific sampling issues should be addressed related to fluid type and condition, saturated versus undersaturated, and fluids with nonhydrocarbon components or fluids. If the sampling procedure is incorrect or if samples are collected from an improperly conditioned well, the resulting samples may not be representative of the reservoir fluid.

A nonrepresentative sample may not exhibit the same properties as the reservoir fluid. The use of fluid property data obtained from nonrepresentative samples, however accurate the laboratory test methods, may result in errors in reservoir management. Poor planning can also result in incomplete data being taken during the sampling program. Incomplete data can make it difficult or impossible for laboratory personnel to perform and interpret tests that provide accurate and meaningful fluid property information.

When a reservoir is relatively small, a properly taken sample from a single well can be representative of the fluid throughout the entire reservoir. For reservoirs that are large or complex, samples from several wells and/or depths may be required. Significant variations in fluid composition often occur in very thick formations, in really large reservoirs, or in reservoirs subjected to recent tectonic disturbances. Additional sampling during the later life of a reservoir is not uncommon because production experience can show that the reservoir is more complex than earlier information indicated.

Methods for sampling reservoir fluids fall into two general categories. They are referred to as subsurface sampling or surface sampling, and, as the names imply, each category reflects the location at which the sampling process occurs. Subsurface sampling may also be referred to as downhole or bottom-hole sampling. Modern open-hole wireline formation testers now provide the means of recovering representative samples before the effects of subsequent production take place. Selection of one particular method over another is influenced by the type of reservoir fluid, the producing characteristics and mechanical condition of the well, the design and mechanical condition of the surface producing equipment, the relative expense of the various methods, and safety considerations.

The choice of either the surface or downhole sampling method cannot be considered a simple or routine matter. Each reservoir usually presents certain constraints or circumstances peculiar to it. For example, field operation requirements can impose restrictions on the preparation and execution of a sampling program; sand production or downhole equipment in the well may limit the use of some of the equipment normally used in the sampling operation. Wells that exhibit rapid variations in production rate present special problems in making the necessary measurements with acceptable accuracy. Seasonal or daily weather changes can also influence the sampling operation. Thus, the details of a given sampling procedure often require modification to circumvent local problems. These modifications are usually made based upon on-the-spot judgments.

Conditioning a well before sampling is almost always necessary. Initial well testing or normal production operations often result in the fluid near the wellbore having a composition that has been altered from that of the original reservoir fluid (for reasons described later). The objective of conditioning the well is to remove this altered (nonrepresentative) fluid. Well conditioning consists of producing the well at a rate that will move the altered fluid into the wellbore and allow it to be replaced by unaltered (representative) fluid flowing in from further out in the reservoir. Well conditioning is especially important when the reservoir fluid is at or near its saturation pressure at the prevailing reservoir conditions because reduction in pressure near the wellbore, which inevitably occurs from producing the well, will alter the composition of the fluid flowing into the wellbore.

Reservoir fluids found in gas and oil fields around the world vary greatly in composition. In some fields, the fluid is in the gaseous state, and in others it is in the liquid state; frequently, gas and liquid coexist in a given reservoir. The rocks that contain these reservoir fluids also vary considerably in composition as well as in physical and flow properties. In certain cases, this can serve to complicate the sampling procedure. Other factors such as producing area, height of the column of hydrocarbon fluid, fracturing or faulting, and water production also serve to distinguish one reservoir from another. The combination of all these factors affects the choice of sampling methods and preparations for sampling.

When a reservoir is relatively small, a properly taken sample from a single well can be representative of the fluid throughout the entire reservoir. For reservoirs that are large or complex, samples from several wells and/or depths may be required. Significant variations in fluid composition often occur in very thick formations, in really large reservoirs, or in reservoirs subjected to recent tectonic disturbances. Additional sampling during the later life of a reservoir is not uncommon because production experience can show that the reservoir is more complex than earlier information indicated.

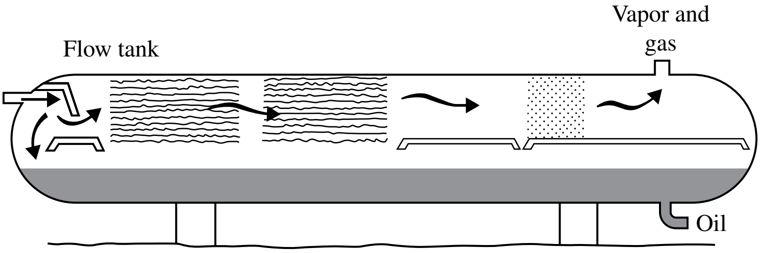


FIGURE 2.7 A field separation tank.

Methods for sampling reservoir fluids fall into two general categories. They are referred to as subsurface sampling or surface sampling, and, as the names imply, each category reflects the location at which the sampling process occurs. Subsurface sampling may also be referred to as downhole or bottom-hole sampling.

The two commonly used sampling methods are bottom-hole sampling and surface sampling. Bottom-hole sampling attempts to capture samples close to reservoir conditions, while surface sampling aims at capturing gas and oil samples from the separator under stable flow conditions (Fig. 2.7). Separator fluids then are recombined at a measured producing gas–oil ratio (GOR) to prepare representative reservoir fluid.

In bottom-hole sampling operations, adequate cleaning of near-wellbore regions and controlled drawdown are critical for obtaining uncontaminated representative samples (Witt and Crombie, 1999). Controlled drawdown helps avoid two-phase flow in the reservoir. Downhole fluid analyzers are used to monitor sample contamination and ensure single-phase flow prior to sample capture. In surface sampling operations, proper well conditioning with minimum drawdown is the key to acquiring high-quality samples. Well conditioning requires that the well be flowed at an optimum rate for an extended period of time with a stable producing GOR, but it must be recognized that sample quality and separator efficiency introduce uncertainties in the quality of the fluids.

Modern open-hole wireline formation testers now provide the means of recovering representative samples before the effects of subsequent production take place. Selection of one particular method over another is influenced by the type of reservoir fluid, the producing characteristics and mechanical condition of the well, the design and mechanical condition of the surface producing equipment, the relative expense of the various methods, and safety considerations.

While bottom-hole sampling has the advantage of capturing fluids at reservoir conditions, surface sampling operation has a potential for obtaining cleaner samples as a result of large volumes of fluid production before sampling. The choice of either the surface or downhole sampling method cannot be considered a simple or routine matter. Each reservoir usually presents certain constraints or circumstances peculiar to it. For example, field operation requirements can impose restrictions on the preparation and execution of a sampling program; sand production or downhole equipment in the well may limit the use of some of the equipment normally used in the sampling operation. Wells that exhibit rapid variations in production rate present special problems in making the necessary measurements with acceptable accuracy. Seasonal or daily weather changes can also influence the sampling operation. Thus, the details of a given sampling procedure often require modification to circumvent local problems. These modifications are usually made based upon on-the-spot judgments. Some of the modifications that can be made to accommodate special situations are presented herein.

Conditioning a well before sampling is almost always necessary. Initial well testing or normal production operations often result in the fluid near the wellbore having a composition that has been altered from that of the original reservoir fluid (for reasons described later). The objective of conditioning the well is to remove this altered (nonrepresentative) fluid. Well conditioning consists of producing the well at a rate that will move the altered fluid into the wellbore and allow it to be replaced by unaltered (representative) fluid flowing in from further out in the reservoir. Well conditioning is especially important when the reservoir fluid is at or near its saturation pressure at the prevailing reservoir conditions because reduction in pressure near the wellbore, which inevitably occurs from producing the well, will alter the composition of the fluid flowing into the wellbore.

Once the sample has been obtained, storage protocols must be observed, and the application of standardized test methods can then commence (Chapter 4).

2.5.2 Data Acquisition and QA/QC

The objective of the data-gathering phase is to obtain reliable high-quality data for reservoir evaluation and development. The data requirement depends on the fluid type and the expected development and production strategies (Whitson and Brule, 2000). In addition, some heavy oils require customized PVT cells and experimental procedures to accelerate the time needed for attaining equilibrium conditions because of the slow (sometime, nonexistent) gas liberation. On the other hand, more complex near-critical fluids and miscible gas injection processes need special PVT tests and precise measurement techniques to capture the complex phase behavior exhibited by these fluids. Gas condensates in the presence of water require PVT cells that can handle three-phase mixtures of gas, water, and condensate.

A heavy oil sampling program requires extra steps to obtain adequate volumes of representative single-phase oil samples for laboratory analysis. This includes adequate near-wellbore cleaning to minimize sample contamination by drilling mud filtrate and optimal drawdown to minimize sand production and avoid two-phase flow while mobilizing the oil from the reservoir into the sample chamber (Reddie and Robertson, 2004). During surface sampling, measurement uncertainty in the producing GOR is a concern because of large drawdown and incomplete gas separation from the oil. Another issue with surface samples is the slow dissolution of gas while recombining them to prepare reservoir fluid. The main advantage of bottom-hole sampling over surface sampling is that the former offers a viable means to capture single-phase samples and eliminate uncertainties associated with surface samples.

The C7+ fraction of the reservoir fluid contains numerous compounds of different homologues (paraffinic, naphthenic, and aromatic) and plays a dominant role in determining the PVT behavior of the fluid. For example, in a gas-condensate fluid, the dew-point pressure is (as anticipated) a strong function of C7+ molecular weight and its relative amount in the fluid. On the other hand, in heavy oils, the C7+ components dictate the viscosity behavior and control the asphaltene deposition and wax deposition characteristics of the oil. Similarly, in volatile oils and rich condensates, the oil volumes and other properties below the saturation pressure are determined by the amounts of intermediate and heavy components.

Therefore, it is important to characterize them accurately, and several methods are used to lump these components into pseudocomponents for equation-of-state models (Whitson, 1983) in which the C7+ distribution is represented by a continuous gamma distribution that is optimally discretized into a specific number of fractions (i.e., pseudocomponents) in which fluid type and the production process involved further guide the component selection.

Because of slow gas liberation and dissolution in heavy oil, special care should be exercised in selecting equipment and procedures for sample preparation and PVT measurements (Cengiz et al., 2004). It is essential to measure the true bubble point pressure as well as the viscosity by means of, for example a capillary-flow viscometer. Because the oil is saturated at each pressure step in the differential liberation experiment, small pressure drops in the capillary viscometer caused by the flow will liberate the gas. Therefore, it may be necessary to conduct several viscosity measurements above the saturated pressure and use an extrapolation technique to determine the viscosity at the desired differential liberation pressure.

PVT data interpretation and modeling for heavy oils require reliable treatment of C7+ components because a majority of components in heavy oils fall in this range (Ancheyta and Speight, 2007). Solid-forming compounds, such as resin constituents and asphaltene constituents, should be characterized properly for flow assurance needs.

Thus, it is imperative that reservoir fluid characterization studies should relate where possible, considering the nature of heavy oil, to the following issues: (i) acquisition of representative samples at various depths to quantify initial fluid gradients and for PVT studies; (ii) PVT measurements to capture near-critical behavior, evaluate gas injection strategies, and design the surface-separator train; (iii) fluid modeling to predict observed near-critical behavior and property changes during gas injection; and (iv) development of thermodynamically consistent compositional gradient models for use in reservoir studies.

Fluid characterization strongly affects in-place volume, recovery factor, injectivity/productivity, and well deliverability calculations. Accurate fluid characterization minimizes technical uncertainties and, thus, provides a reliable representation of the asset value. However, fluid sampling programs must be tailored to the fluid type, reservoir rock and fluid conditions, and fluid distribution. The fluid type and production processes dictate PVT data requirements, measurement methods, and data accuracy. In addition, the C7+ components must be characterized accurately, and rigorous modeling methods, such as energy minimization, and robust solution techniques are needed to model near-critical fluids and processes.

Finally, ensuring high-quality data requires routine laboratory visits, evaluation of laboratory procedures and methods, and spot QC as data become available. The QA/QC methods can range from simple graphical techniques to sophisticated material balance calculations (Whitson and Brule, 2000). In summary, reliable compositional gradient models are needed to capture fluid property variations in reservoirs with high relief and/or near-critical fluids.

REFERENCES

Ahmed, U., Crary, S.F., and Coates, G.R. 1991. Permeability Estimation: The Various Sources and Their Interrelationships. *Journal of Petroleum Technology*, 43(5): 578–587. Paper No. SPE-19604-PA.

Ancheyta, J., and Speight, J.G. 2007. Heavy Oils and Residua. In: *Hydroprocessing of Heavy Oils and Residua*. J. Ancheyta and J.G. Speight (Editors). CRC Press, Taylor & Francis Group, Boca Raton, FL.

Anderson, W.G. 1986. Wettability Literature Survey: Part 1. Rock-Oil-Brine Interactions and the Effects of Core Handling on Wettability. *Journal of Petroleum Technology*, 38(10): 1125–1144.

ASTM D2638. 2015. *Standard Test Method for Real Density of Calcined Petroleum Coke by Helium Pycnometer*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

Berg, R.R. 1970. Method for Determining Permeability from Reservoir Rock Properties. In: *Transactions of the GCAGS*, Volume 20. Gulf Coast Association of Geological Societies, Houston, TX. Page 303.

Blatt, H., and Tracy, R.J. 1996. *Petrology: Igneous, Sedimentary, and Metamorphic*, 2nd Edition. W.H. Freeman and Company, Macmillan Publishers, New York.

Bloch, S., Lander, R.H., and Bonnell, L. 2002. Anomalously High Porosity and Permeability in Deeply Buried Sandstone Reservoirs: Origin and Predictability. *AAPG Bulletin*, 86(2): 301–328.

Bonnell, L.M., Lander, R.H., and Sundhaug, C. 1998. Grain Coatings and Reservoir Quality Preservation: Role of Coating Completeness, Grain Size and Thermal History. Proceedings. AAPG Annual Convention, Volume 7. American Association of Petroleum Geologists, Washington, DC. Page A81.

Bustin, R.M., Bustin, A.M.M., Cui, X., Ross, D.J.K., and Murthy Pathi, V.S. 2008. Impact of Shale Properties on Pore Structure and Storage Characteristics. Paper No. SPE 119892. Proceedings. SPE Conference on Shale Gas Production, Fort Worth, TX, November 16–18. Society of Petroleum Engineers, Richardson, TX.

Caruana, A., and Dawe, R.A. 1996a. Effect of Heterogeneities on Miscible and Immiscible Flow Processes in Porous Media. *Trends in Chemical Engineering*, 3: 185–203.

Caruana, A., and Dawe, R. 1996b. Flow Behavior in the Presence of Wettability Heterogeneities. *Transport in Porous Media*, 25: 217–233.

Cengiz, S., Robertson, C., Kalpacki, B., and Gupta, D. 2004. A Study of Heavy Oil Solution Gas Drive for Hamaca Field: Depletion Studies and Interpretations. Paper SPE 86967-MS. SPE International Thermal Operations and Heavy Oil Symposium and Western Regional Meeting, Bakersfield, CA, March 16–18. Society of Petroleum Engineers, Richardson, TX.

Cui, X., Bustin, A.M.M., and Bustin, R.M. 2009. Measurements of Gas Permeability and Diffusivity of Tight Reservoir Rocks: Different Approaches and Their Applications. *Geofluids*, 9: 208–223.

Dandekar, A.Y. 2013. *Petroleum Reservoir Rock and Fluid Properties*, 2nd Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Dawe, R.A. 2004. Miscible Displacement in Heterogeneous Porous Media. Proceedings. Sixth Caribbean Congress of Fluid Dynamics, University of the West Indies (UWI), January 22–23. The University of the West Indies, St. Augustine.

Grattoni, C.A., and Dawe, R.A. 2003. Consideration of Wetting and Spreading in Three-Phase Flow in Porous Media. In: *Progress in Mining and Oilfield Chemistry*, Volume 5. Recent Advances in Enhanced Oil and Gas Recovery. I. Lakatos (Editor). Akad. Kiado, Budapest, Hungary.

Honarpour, M.M., Nagarajan, N.R., and Sampath, K. 2006. Rock/Fluid Characterization and Their Integration—Implication on Reservoir Management. *Journal of Petroleum Technology*, 58(9): 120.

Hunt, J.M. 1996. *Petroleum Geochemistry and Geology*, 2nd Edition. W.H. Freeman and Co., New York.

Kovscek, A.R. 2002. Heavy and Thermal Oil Recovery Production Mechanisms. Quarterly Technical Progress Report. Reporting Period: April 1 through June 30, 2002. DOE Contract Number: DE-FC26-00BC15311. July. United States Department of Energy, Washington, DC.

Magoon, L.B., and Dow, W.G. 1994. The Petroleum System—From Source to Trap. Memoir No. 60. American Association of Petroleum Geologists, Washington, DC.

Marshak, S. 2012. *Essentials of Geology*, 4th Edition. W.W. Norton & Company, New York.

Maxwell, S., and Norton, M. 2012. The Impact of Reservoir Heterogeneity on Hydraulic Fracture Geometry: Integration of Microseismic and Seismic Reservoir Characterization. Proceedings. AAPG Annual Convention and Exhibition, Long Beach, CA, April 22–25. http://www.searchanddiscovery.com/documents/2012/40993maxwell/ndx_maxwell.pdf; accessed April 15, 2015.

Moffatt, B., Fawcett, M., Maurera, J., and Bruzco, A. 2013. Reservoir Fluid Characterization from Tests on Tight Formations. Paper No. SPE-164887-MS. Proceedings. EAGE Annual Conference & Exhibition Incorporating SPE Europec, London, United Kingdom. June 10–13. Society of Petroleum Engineers, Richardson, TX.

Nagarajan, N.R., Honarpour, M.M., and Sampath, K. 2007. Reservoir-Fluid Sampling and Characterization—Key to Efficient Reservoir Management. SPE 103501 and 101517. Presented at the 2006 Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, November 5–8. Society of Petroleum Engineers, Richardson, TX.

Pittman, E.D., Larese, R.E., and Heald, M.T. 1992. Clay Coats: Occurrence and Relevance to Preservation of Porosity in Sandstones. In: *Origin, Diagenesis, and Petrophysics of Clay Minerals*, Special Publication Volume 47. D.W. Houseknecht and E.D. Pittman (Editors). SEPM Society for Sedimentary Geology, Tulsa, OK.

Radlinski, A.P., Ioannidis, M.A., Hinde, A.L., Hainbuchner, M., Baron, M., Rauch, H., and Kline, S.R. 2004. Angstrom-to-Millimeter Characterization of Sedimentary Rock Microstructure. *Journal of Colloidal and Interface Science*, 274: 607–612.

Ramm, M., and Bjørlykke, K. 1994. Porosity/Depth Trends in Reservoir Sandstones: Assessing the Quantitative Effects of Varying Pore-Pressure, Temperature History and Mineralogy, Norwegian Shelf Data. *Clay Minerals*, 29: 475–490.

Reddie, D.R., and Robertson, C.R. 2004. Innovative Reservoir Fluid Sampling Systems. Paper SPE 86951-MS. SPE International Thermal Operations and Heavy Oil Symposium and Western Regional Meeting, Bakersfield, CA, March 16–18. Society of Petroleum Engineers, Richardson, TX.

Rose, P.R. 1992. Chance of Success and Its Use in Petroleum Exploration. In: *The Business of Petroleum Exploration*. R. Steinmetz (Editor). AAPG Treatise of Petroleum Geology. Association of Petroleum Geologists, Washington, DC. Page 71–86.

Solano, N.A., Clarkson, C.R., Krause, F.F., Aquino, S.D., and Wiseman, A. 2013. On the Characterization of Unconventional Oil Reservoirs. *CSEG Recorder*, 38(4): 1. http://csegrecorder.com/articles/view/on-the-characterization-of-unconventional-oil-reservoirs; accessed July 20, 2015.

Speight, J.G. 2001. *Handbook of Petroleum Analysis*. John Wiley & Sons, Inc., New York.

Speight, J.G. 2009. *Enhanced Recovery Methods for Heavy Oil and Tar Sands*. Gulf Publishing Company, Houston, TX.

Speight, J.G. 2013. *The Chemistry and Technology of Coal*, 3rd Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Speight, J.G. 2014. *The Chemistry and Technology of Petroleum*, 5th Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Speight, J.G. 2015a. *Handbook of Petroleum Product Analysis*, 2nd Edition. John Wiley & Sons, Inc., Hoboken, NJ.

Speight, J.G. 2015b. *Fouling in Refineries*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Tucker, M.E., and Wright, V.P. 1990. *Carbonate Sedimentology*. John Wiley & Sons, Inc., Hoboken, NJ.

Walderhaug, O. 1996. Kinetic Modelling of Quartz Cementation and Porosity Loss in Deeply Buried Sandstone Reservoirs. *AAPG Bulletin*, 80: 731–745.

Weimer, R.J., and Sonnenberg, S.A. 1994. Low Resistivity Pays in J Sandstone, Deep Basin Center Accumulations, Denver Basin. Proceedings. AAPG Annual Convention, Volume 3. American Association of Petroleum Geologists, Washington, DC. Page 280.

Wescott, W.A. 1983. Diagenesis of Cotton Valley Sandstone (Upper Jurassic), East Texas: Implications for Tight Gas Formation Pay Recognition. *AAPG Bulletin*, 67: 1002–1013.

White, D.A. 1993. Geologic Risking Guide for Prospects and Plays. *AAPG Bulletin*, 77: 2048–2061.

Whitson, C.H. 1983. Characterizing Hydrocarbon Plus Fractions. *SPE Journal*, 23(4): 683.

Whitson, C.H., and Brule, M. 2000. *Phase Behavior*. Monograph Series. Society of Petroleum Engineers, Richardson, TX.

Wilhelms, A., and Larter, S.R. 1994a. Origin of Tar Mats in Petroleum Reservoirs. Part I: Introduction and Case Studies. *Marine and Petroleum Geology*, 11(4): 418–441.

Wilhelms, A., and Larter, S.R. 1994b. Origin of Tar Mats in Petroleum Reservoirs. Part II: Formation Mechanisms for Tar Mats. *Marine and Petroleum Geology*, 11(4): 442–456.

Wilson, M.D., and Pittman, E.D. 1977. Authigenic Clays in Sandstones: Recognition and Influence on Reservoir Properties and Paleoenvironmental Analysis. *Journal of Sedimentary Petrology*, 47: 3–31.

Witt, C.J., and Crombie, A. 1999. A Comparison of Wireline and Drillstem Test Fluid Samples from a Deep Water Gas-Condensate Exploration Well. Paper SPE 56714-MS. SPE Annual Technical Conference and Exhibition, Houston, TX, October 3–6. Society of Petroleum Engineers, Richardson, TX.

Yao, C.Y. and Holditch, S.A. 1996. Reservoir Permeability Estimation from Time-lapse Log Data. Paper No. SPE-25513-PA. Proceedings. SPE Symposium on Formation Evaluation, 11(1): 69–74. Society of Petroleum Engineers, Richardson, TX.

Zhang, M., and Zhang, J. 1999. Geochemical Characteristics and Origin of Tar Mats from the Yaha Field in the Tarim Basin, China. *Chinese Journal of Geochemistry*, 18(3): 250–257.

3

OIL AND GAS PRODUCTION

3.1 INTRODUCTION

Crude oil and natural gas accumulate over geological time in porous underground rock formations (*reservoirs*) that are at varying depths in the Earth's crust, and in many cases elaborate, expensive equipment is required to get it from there. The oil is usually found trapped in a layer of porous sandstone, which lies just beneath a dome-shaped or folded layer of some nonporous rock (cap rock) (Chapter 2), while in other formations the oil is trapped at a fault or break in the layers of the crust (Speight, 2009, 2014).

Petroleum is found in the microscopic pores of sedimentary rocks such as sandstone and limestone (Speight, 2014). Not all of the pores in a rock will contain petroleum—some are filled with water that is saturated with minerals (brine). In many cases, water is the predominant fluid found in subsurface strata, since petroleum and natural gas have a low specific gravity relative to water and pass through the more porous sections of reservoir rock from their source area to the surface unless restrained by a trap. Typically, reservoir rock consists of sand, sandstone, limestone, or dolomite and must acts as a trap insofar as the reservoir rock is overlain by a dense cap rock or a zone of very low or no porosity that restrains migrating hydrocarbon. Petroleum-bearing reservoirs can exist from surface seeps to subsurface depths over 4 miles below the surface of the Earth. In addition, reservoirs vary in size up to several thousands of acres in area and range in thickness from a few inches to hundreds of feet or more.

Generally, crude oil reservoirs sometimes exist with an overlying *gas cap*, or in communication with aquifers, or both. The oil resides together with water and free gas or dissolved gas in very small holes (pore spaces) and fractures. The size, shape, and degree of interconnection of the pores vary considerably from place to place in an individual reservoir. Moreover, after an exploration effort has successfully discovered

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

a petroleum reservoir, the challenge is to optimize extraction of the recoverable reserves. Production rates can increase over natural production rates by fracturing the reservoir to open new channels for flow, injecting gas and water to increase the reservoir pressure, or lowering oil viscosity with heat or chemicals. The variability of each of the above criteria for different reservoirs virtually guarantees that production methods and profiles differ reservoir to reservoir.

Thus, once a reservoir is discovered and identified, many challenges still remain. For example, oil production rates will vary and depend on a number of factors, such as (i) reservoir geometry, such as formation thickness and reservoir continuity; (ii) reservoir pressure; (iii) reservoir depth; (iv) rock type; (v) permeability; (vi) fluid saturations; (vii) fluid properties, including oil viscosity; (viii) extent of fracturing; (ix) number of wells; (x) well locations; and (xi) the ratio of the permeability of the formation to the viscosity of the oil (Taber and Martin, 1983; US DOE, 1996; Jayasekera, and Goodyear, 1999; Speight, 2009, 2014).

The process of evaluating how to best optimize extraction of recoverable reserves begins with a development plan that must consider all of the available geological, chemical, and engineering data to make an initial estimate of reserves in place and to project recovery efficiencies and optimal recoverable reserve levels under various producing scenarios, and there must always by a *plan B*. Alternative scenarios should include (i) the number of wells to be drilled and completed for production or injection, (ii) well spacing, (iii) well pattern, (iv) requirements for any form of wellhead processing, (v) transportation options, (vi) plans for reservoir depletion, and (vii) economic studies.

As might be expected, the type of exploration technique employed depends upon the nature of the site. In other words, and as for many environmental operations, the recovery techniques applied to a specific site are dictated by the nature of the site and are, in fact, *site specific*—the site specificity is due to differences in reservoir properties and oil properties (Fig. 3.1). For example, in areas where little is known about the subsurface, preliminary reconnaissance techniques are necessary to identify potential reservoir systems that warrant further investigation. Once an area has been selected for further investigation, more detailed methods (such as the *seismic reflection* method) are brought into play. Drilling is the final stage of the exploratory program and is in fact the only method by which a petroleum reservoir can be conclusively identified. However, in keeping with the concept of site specificity, drilling

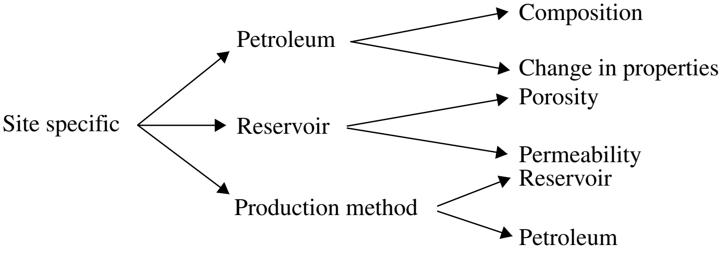


FIGURE 3.1 Illustration of reservoir site specificity.

may be the only option in some areas for commencement of the exploration program. The risk involved in the drilling operation depends upon previous knowledge of the site subsurface. Thus there is the need to relate the character of the exploratory wells at a given site to the characteristics of the reservoir.

Thus, in conventional oil production, the concept of applying more than one recovery technology, one after the other, to a reservoir is well established. When primary production declines and becomes less economic, producers investigate the opportunity to waterflood the reservoir as a secondary recovery technology. Finally, tertiary methods may be applied when waterfloods yield diminishing returns. Heavy oil reservoirs and tar sand deposits (called *oil sand deposits* in Canada) have a shorter history, and generally reservoirs have only been subject to only one recovery technology. In the case of tar sand bitumen, primary and secondary recovery technologies, as defined and used for recovery of conventional crude oil, are not applicable because bitumen is not mobile at deposit conditions. Therefore, tar sand development involves a mining operation in which the tar sand is removed from the deposit and sent to a bitumen recovery plant (Speight, 2009, 2014). However, as the development of heavy oil and tar sands matures, the concept of applying more than one recovery technology in a specific order is likely to also be applied to heavy oil and bitumen reservoirs (Yang and Gu, 2005a, 2005b; UEG, 2008). In particular, in the Lloydminster area, researchers and producers have already been investigating for several years the concept of follow-up recovery technologies once primary production is no longer economic.

This chapter, for the most part, deals with those recovery methods that are applied to recovery of conventional crude oil, heavy oil, and tar sand bitumen (UEG, 2008; Speight, 2009, 2014).

3.2 WELL COMPLETION AND PRODUCTION

Throughout this process, the initial design parameters need to be taken into consideration include the various well-types and volumes of fluids to be produced, downhole and surface temperatures, production zone depths, production rates, well location, and surrounding environment.

3.2.1 Well Completion

Drilling conventional wells and those to be used in hydraulic fracturing (Chapter 5) are very similar processes. The basic well construction involves placement of a length of steel pipe (conductor casing) into inserted into a vertical wellbore soon after drilling begins. This stabilizes the well as it passes through the shallow sediments and soils near the surface. Once the conductor casing is set, drilling is continued and a second casing (surface casing) is inserted and extends from the ground surface beyond any groundwater aquifers. After allowing the cement behind the casings to set, drilling is continued for approximately 10–50 ft before halting to test the integrity of the cement process by pressurizing the well. In horizontal wells, after drilling the horizontal section of the well, a string of production casing is placed (run) into the well and cemented in place. The production casing is then perforated by use of small explosive charges at intervals along the horizontal wellbore where the intent is to hydraulically fracture the formation.

Thence follows an *acid stage*, which consists of several thousand gallons of water mixed with a dilute acid (hydrochloric acid, also called muriatic acid, is the common example). This serves to clear cement debris in the wellbore and provide an open conduit for other fluids by dissolving carbonate minerals and opening fractures near the wellbore. In the *pad stage*, the wellbore is filled with the slickwater solution, which opens the formation and helps to facilitate the flow and placement of proppant material. The prop sequence stage follows and may consist of several substages of water combined with proppant material (consisting of a fine mesh sand or ceramic material, intended to keep open (prop open) the fractures created and/or enhance natural fractures after the pressure is reduced). This stage may use several hundred thousand gallons of water. Proppant material (Chapter 7) may vary from a finer particle size to a coarser particle size throughout this sequence. In the *flushing stage*, a volume of freshwater is used to flush the excess proppant from the wellbore.

Other additives (Chapter 6) commonly used in the fracturing solution employed include (i) a dilute acid solution, which is used during the initial fracturing sequence to cleans out cement and debris around the perforations to facilitate the subsequent slickwater solutions employed in fracturing the formation; (ii) a biocide or disinfectant, which is used to prevent the growth of bacteria in the well that may interfere with the fracturing operation (biocides typically consist of bromine-based solutions or glutaraldehyde); (iii) a scale inhibitor, such as ethylene glycol, which is used to control the precipitation of certain carbonate and sulfate minerals; (iv) an iron control stabilizing agent such as citric acid or hydrochloric acid, which is used to solubilize iron compounds and inhibit precipitation of the iron compounds; (v) a friction reducing agents, such as potassium chloride or polyacrylamide-based compounds, which are used to reduce tubular friction and subsequently reduce the pressure needed to pump fluid into the wellbore (such additives may reduce tubular friction by 50–60%); (vi) corrosion inhibitors, such as *N*,*N*-dimethylformamide, and oxygen scavengers, such as ammonium bisulfite, which are used to prevent degradation of the steel well casing; and (vii) a gelling agent, such as guar gum, which is used small amounts to thicken the water-based solution to help transport the proppant material to the fracture site where it is to be used.

Occasionally, a cross-linking agent will be used to enhance the characteristics and ability of the gelling agent to transport the proppant material. These compounds may contain boric acid (H_3BO_3) or ethylene glycol ($HOCH_2CH_2OH$). When cross-linking additives are added, a breaker solution is commonly added later in the frack stage to cause the enhanced gelling agent to break down into a simpler fluid so it can be readily removed from the wellbore without carrying back the sand/proppant material.

As the final part of the *pad stage*, a multivalve structure (the *Christmas tree*) (Fig. 3.2) is installed at the top of the tubing and cemented to the top of the casing to allow control the flow of oil from the well.

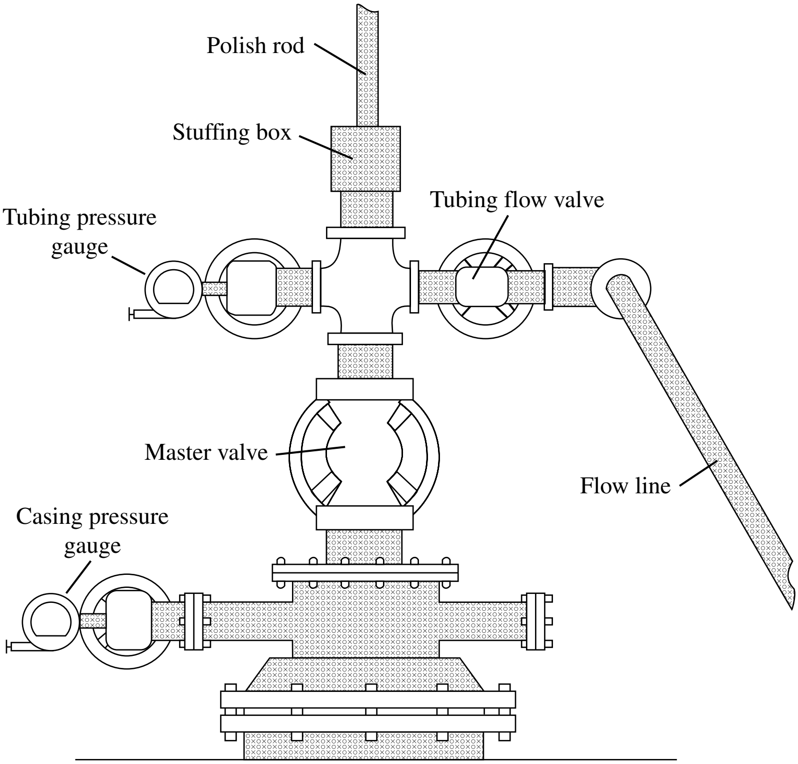


FIGURE 3.2 The Christmas tree: a collection of control valves at the wellhead. Source: Adapted from Speight, J.G. 2009. Enhanced Recovery Methods for Heavy Oil and Tar Sands. Gulf Publishing Company, Houston, TX.

Tight formations are occasionally encountered and it becomes necessary to encourage flow. Several methods are used, one of which involves setting off small explosions to fracture the rock. If the formation is mainly limestone, hydrochloric acid is sent down the hole to dissolve channels in the rock. The acid is inhibited to protect the steel casing. In sandstone, the preferred method is hydraulic fracturing. A fluid with a viscosity high enough to hold coarse sand in suspension is pumped at very high pressure into the formation, fracturing the rock. The grains of sand remain, helping to hold the cracks open.

Choice of the most appropriate completion fluid (API RP 13M, 2015) is essential in order to get the most productivity out of a crude oil or natural gas well (Caenn et al., 2011). Virtually any liquid that is free of solids can function as a completion fluid, but matching the density, flow, and pH content to the characteristics of the wellbore and production well will lengthen the life of the production zone. However, finding a completion fluid that complements the characteristics of a particular oil or gas well increases the capacity of the well and is typically site specific (well specific). It also makes site preparation easier and limits site erosion and/or possible damage to the site. The right completion fluid may also make it easier to repair a well should that become necessary, and at the time of well closure and abandonment, choice of the appropriate completion fluid will make the process much easier. Use of correct completion fluids from the outset of the preproduction phase can eliminate costly seepage throughout production. The right choice of completion fluids also makes it easier to produce crude oil and natural gas from the secondary arteries of a production zone—this is particularly true of fractured zones.

All crude oil wells and natural gas wells have distinctive characteristics, which means that a completion fluid tailored to each well will be a better approach and having a completion fluid that is designed with the specifications of a particular well in mind will increase production. In fact, it is advisable that each well should have a completion fluids expert on-site and she/he can ensure that the proper fluids are chosen and that they are delivered to the well in the appropriate manner. Furthermore, investigating the proper completion fluids for a well should begin as soon as the production zone has been penetrated. It will take the ongoing work of a completion fluids expert to make sure that the liquid and the well are ideally suited. Working from the start of the drilling with this choice in mind will increase both the life and the productivity of just about any well.

When completion or workover operations (such as perforating and gravel packing) are conducted on a well, the fluid present in the wellbore must minimize the impact on the near-wellbore permeability. In the past, the use of drilling fluids during completions was found to be inappropriate because of the severe damage that such fluids caused to the production zone (Patton and Phelan, 1985). A wide variety of fluids are now available as completion or workover fluids (Table 3.1). For example, formates are often used as completion fluids as are chlorides and bromides. The structure and composition of the well and specifically the production zone are the keys to picking the right completion fluid (site specificity and well specificity). In addition, the fluid must be free of particulate matter, and a highly filtered and completely solid-free completion fluid will add to both the productivity and the dependability of any well

TABLE 3.1 Fluids Available as Completion Fluids or Workover Fluids

Water-Based Fluids
  - Clear brines
  - Oil-soluble resins and waxes
  - Polymer fluids
  - Water-soluble solids (sodium chloride)
  - Acid-soluble particles
  - Biodegradable polymers

Emulsions
  - Usually oil in water (12.5 Ibm/gal)

Oil-Based Fluids
  - Lease crude
  - Invert-emulsion muds
  - Asphalt pitches

Foams

over the long term. An issue that arises from the use of water-based fluid (typically clear brine) is that the brine may not be truly clear and may contain solids and should be tested accordingly (API RP 13J, 2015). The only problem with clear brines is that they are not ever really clear and have a tendency to contain some solids, including (i) corrosion products, (ii) bacteria, and (iii) debris from the wellbore and surface tanks (Eaton and Smithey, 1971; Morgenthaler, 1986; Azari and Leimkuhler, 1990).

The test method (API RP 13J, 2015) covers the physical properties, potential contaminants, and test procedures for heavy brine fluids manufactured for use in oil and gas well drilling, completion, fracturing, and workover fluids. The method provides the means for assessing the performance and physical characteristics of heavy brines for use in field operations. It includes procedures for evaluating the density or specific gravity, the clarity or amount of particulate matter carried in the brines, the crystallization point or the temperature (both ambient and under pressure) at which the brines make the transition between liquid and solid, the pH, and iron contamination. It also contains a discussion of gas hydrate formation and mitigation, brine viscosity, corrosion testing, buffering capacity, and a standardized reporting form.

The density of the brine is maintained large enough so that the bottom-hole pressure exceeds the reservoir pressure by a safe margin (typically 300–600 psi). Substantial amounts of solids can be pushed into the formation, resulting in a loss of permeability in the near-wellbore region. Surface filtration facilities are often used to clarify and filter completion brines, which can help to reduce the permeability impairment substantially. It is also important to note that, unlike drilling fluids, completion fluids, such as brine, do not contain solids that were produced during the drilling operation and, thus, there is no effective bridging material available to reduce fluid leak-off.

When fluid leak-off rates are high, fluid leak-off control additives may be used to minimize leak-off and damage to the formation. Use of acid-soluble granular additives such as calcium carbonate is the most common strategy. If this method proves to be ineffective, polymers that change the viscosity of the fluid can be used to reduce the amount of fluid loss. Hydroxyethyl cellulose (HEC) is commonly used because of the solubility in hydrochloric acid, but at temperatures above 122 °C (>250 °F) HEC can be damaging. Polymer-based fluids suffer from similar drawbacks, and severe formation damage can occur if large amounts of polymer are lost to the formation—this problem is particularly acute if the polymer is not completely hydrolyzed in the brine.

If the density requirements of the completion fluid are relatively modest, emulsions can be used as completion fluids. In these instances, the droplets that form the dispersed phase act as a filtration control agent. Both water and oil external emulsions have been used when reservoir pressures are low. Oil-based fluids such as crude oil and invert-emulsion muds can be used as completion fluids. It is important to ensure that the crude oil does not contain constituents or paraffin wax constituents that might precipitate under changes in pressure and temperature as the fluid is circulated into the well.

Depending on the character of the formation, it may be necessary to perform a *well test*, which may be carried out through a *drill stem test* (DST) valve attached to the bottom of a string of tubing or drill pipe (the *work string*). The DST valve can be opened from the surface and the well fluids flowed through a *separator*—a device that separates crude oil, natural gas, water, and completion fluids at the surface. By measuring the rates of water, natural gas, and crude oil produced, information will be obtained that will allow some measure of prediction to make deductions about future well performance. Well tests also provide extensive information about the character and extent of the reservoir.

At this time, there are several options for completion that arise from knowledge of the characteristics of the formation. For example, if the permeability of the formation is low, *hydraulic fracturing* (Chapter 5) becomes an option. In the process, water and sand or other materials are pumped through the perforations and into the formation at high pressure. Pump pressure builds against the unyielding formation until the rock yields and cracks open. The slurry is then pumped into the newly created formation fractures. When the pumps are turned off and the well opened, the water flows out, leaving behind the sand—this *proppant* holds open the newly created fractures. The result is a high-permeability pathway for the crude oil and/or natural gas to flow from the formation to the wellbore.

While oil and gas flow readily through permeable rocks, such formations may be unconsolidated (the tar sands of Alberta are such formations) and subject to breaking into small sand particles that may flow into the wellbore with produced fluids. These particles may plug perforation tunnels and stop fluids from entering the well. To prevent the migration of these particles through the formation, engineers may inject chemicals into the formation to bind the sand grains together. To prevent sand from entering the wellbore, engineers may also opt for a sand control technique—or a combination of techniques—that includes various types of *sand screens* and *gravel packing* systems. Designed to block the migration of sand, these systems allow fluids to freely flow through them.

The next stage in completion includes placing various pieces of hardware (often referred to as *jewelry*) into the well—the *jewelry* is attached to *production tubing*. The production—the conduit between the producing formation and the surface—is the infrastructure upon which almost all completions are built. The strength, material, and size (the weight/unit length and internal diameter) are chosen according to expected production rates, production types, pressures, depths, temperatures, and corrosive potential of produced fluids. Once the *jewelry* is deployed, refinements are possible depending on the specific well. For example, *intelligent completions* are often used in situations or locations where entering the well to change downhole settings is costly or otherwise problematic. Intelligent completions include permanent, real-time remote pressure and temperature sensors and a remotely operable flow control valve deployed at each formation.

In other wells, the formation pressure is, or eventually becomes, insufficient to lift the formation fluids out of the well. These wells must be equipped with pumps or gas lift systems. *Electric submersible pumps* (ESPs, sometime referred to as downhole pumps) pump fluids to the surface using a rotor and stator. Pump rotor drives can be located on the surface. Reciprocating pumps (*pump jacks*) may be used to lift the fluid to the surface through a reciprocating vertical motion.

Gas lift systems pump gas down the annulus between two casing strings. The gas enters the tubing at a depth below the top of the fluid column. This decreases the fluid density enough for buoyancy to lift the fluid out of the well. The amount of gas entering the well may be regulated through a sequence of valves located along the length of tubing, or it may be streamed in at one or more locations. Also in low-pressure formations, water or gas may be injected down one well to push oil through the formation to the production wells. The producers may be fitted with *injection control devices* that regulate how much and where fluid enters the wellbore.

3.2.2 Production Methods

There are several methods by which crude oil and natural gas can be recovered from reservoirs. However, the effect of the method on the oil and on the reservoir must be considered before application (Speight, 2009, 2014). However, the anatomy of a reservoir is complex and is site specific in terms of the microstructure and macrostructure of the reservoir (Chapter 2). Because of the various types of accumulations and the existence of wide ranges of both rock and fluid properties, reservoirs respond differently and must be treated individually.

Generally, conventional crude oil reservoirs sometimes exist with an overlying *gas cap*, in communication with aquifers, or both. The oil resides together with water and free gas in very small holes (pore spaces) and fractures. The oil in such formation is usually under such great pressure that it flows naturally, and sometimes with great force, from the well. However, in some cases this pressure later diminishes so that the oil must be pumped from the well. Natural gas or water is sometimes pumped into the well to replace the oil that is withdrawn (*well repressurizing*).

Directional drilling is also used to reach formations that are not directly below the penetration point or drilling from shore to locations under water. A controlled deviation may also be used from a selected depth in an existing hole to attain economy in drilling costs (Fig. 3.3). Various types of tools are used in directional drilling along with instruments to help orient their position and measure the degree and direction of deviation; two such tools are the *whipstock* and the *knuckle joint*. The whipstock is a gradually tapered wedge with a chisel-shaped base that prevents rotation after it has been forced into the bottom of an open hole. As the bit moves down, it is deflected by the taper about 5° from the alignment of the existing hole.

There are several methods by which this can be achieved that range from recovery due to reservoir energy (i.e., the oil flows from the well hole without assistance) to enhanced recovery methods in which considerable energy must be added to the reservoir to produce the oil. However, the effect of the method on the oil and on the reservoir must be considered before application. All of the recovery methods can be incorporated into any one of three general methods (Fig. 3.4): (i) primary recovery, (ii) secondary recovery, and (iii) tertiary recovery, also called enhanced oil recovery (EOR).

Primary recovery refers to production using the energy inherent in the reservoir from gas under pressure or a natural water drive that forces fluids into the wellbore and thence to the surface. *Secondary recovery* occurs when artificial energy is applied to

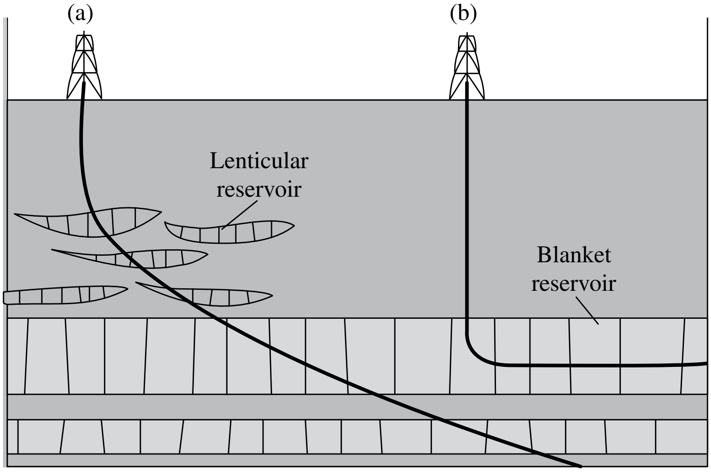


FIGURE 3.3 Types of nonvertical drilling: (a) slant-hole well and (b) horizontal well.

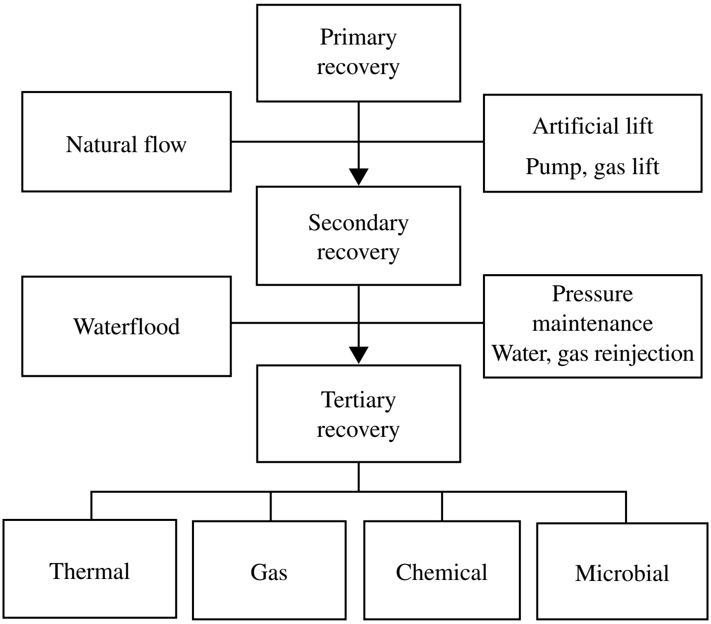


FIGURE 3.4 Methods for oil recovery.

lift fluids to the surface and may be accomplished by injecting gas down a hole to lift fluids to the surface, installing a subsurface pump, or injecting gas or water into the formation itself. Secondary oil recovery may also include the terms *improved oil recovery* (IOR) and *advanced oil recovery* (AOR), which have a similar meaning. *Tertiary recovery* (*enhanced oil recovery, EOR*) is a method of increasing fluid mobility

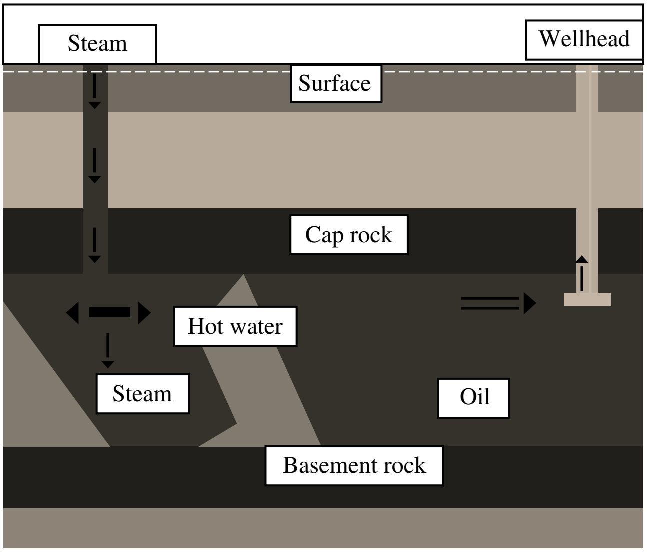


FIGURE 3.5 Illustration of a steam-based recovery process. Source: Adapted from Chakma et al., 1991; Speight, 2009, 2014.

within the reservoir, which may be accomplished by introducing heat into the formation to lower the viscosity of the oil and improve its ability to flow to the wellbore. Heat may be introduced by either injecting steam, such as a *steam flood* (Fig. 3.5), or by injecting oxygen to enable the ignition and *in situ* combustion of the oil within the reservoir (*fireflood*) (Chakma et al., 1991; Speight, 2009, 2014). Tertiary recovery operations may be commenced *before* secondary oil recovery techniques are no longer enough to sustain production.

Recovery of crude oil and natural gas when a well is first opened is usually by natural flow forced by the pressure of the gas or fluids that are contained within the deposit. There are several means that serve to drive the petroleum fluids from the formation through the well and to the surface, and these methods are classified as either natural or applied flow.

3.2.2.1 Primary Recovery Methods A conventional reservoir usually starts with a formation pressure high enough to force crude oil into the well and sometimes to the surface through the tubing (Lake and Walsh, 2004). However, since production is invariably accompanied by a decline in reservoir pressure, *primary recovery* (*primary oil production*, *primary oil recovery*, *natural flow*) diminishes. The driving energy for primary recovery is derived from (i) liquid expansion and evolution of dissolved gases from the oil as reservoir pressure is lowered during production (dissolved gas drive), (ii) expansion of free gas or a gas cap (gas cap drive), (iii) influx of natural water (water drive), and (iv) gravity drive, or even combinations of these effects. Thus, early recognition of the type of drive involved is essential to the efficient development of an oil field.

Typically, the gas in a gas cap (*associated natural gas*) contains methane and other hydrocarbons that may be separated out by compressing the gas. A well-known example is *natural gasoline* (also referred to as *casinghead gasoline* or *natural gas gasoline*). However at high pressures, such as those existing in the deep reservoirs, the density of the gas increases, and the density of the oil decreases until they form a single phase in the reservoir forming *retrograde condensate pool* because a decrease (instead of an increase) in pressure brings about condensation of the liquid hydrocarbons. When this reservoir fluid is brought to the surface and the condensate is removed, a large volume of residual gas remains. In many production operations, the gas is recycled back into the reservoir, thus maintaining adequate pressure within the gas cap, and condensation in the reservoir is prevented.

In natural *water drive*, the pressure of the water forces the lighter recoverable oil out of the reservoir into the production wells. In a typical anticlinal reservoir (Chapter 2), the structurally lowest wells around the flanks of the dome are the first to come into contact with the water. As production proceeds, the oil–water contact plane moves upward until only the wells at the top of the anticline are still producing oil after which these also must be abandoned as the water displaces the oil. *Gravity drive* is an important factor when oil columns of several thousands of feet exist, as they do in some North American fields. Another source of energy during the early stages of withdrawal from a reservoir containing undersaturated oil is the expansion of that oil as the pressure reduction brings the oil to the bubble point (the pressure and temperature at which the gas starts to come out of solution).

The recovery efficiency for primary production is generally low when liquid expansion and solution gas evolution are the driving mechanisms. The overall recovery efficiency is related to how the reservoir is delineated by the production wells. Thus for maximum recovery by primary recovery it is often preferable to sink several wells into a reservoir, thereby bringing about recovery by a combination of the methods outlined here. The rate of production from a flowing well tends to decline as the natural reservoir energy is expended. When a flowing well is no longer producing at an efficient rate, a pump is installed to bring the oil or gas to the surface (*artificial lift*) (Speight, 2009, 2014).

3.2.2.2 Secondary Recovery Methods

Over the lifetime of the well, the pressure will fall, and at some point there will be insufficient underground pressure to force the oil to the surface. If economical, and it often is, the remaining oil in the well is extracted using secondary oil recovery methods. It is at this point that secondary recovery methods must be applied.

When a large part of the crude oil in a reservoir cannot be recovered by primary means, a method for supplying extra energy must be found. Most often, secondary recovery is accomplished by injecting gas or water into the reservoir to replace produced fluids and thus maintain or increase the reservoir pressure. When gas alone is injected, it is usually put into the top of the reservoir, where petroleum gases normally collect to form a gas cap. Gas injection can be a very effective recovery method in reservoirs where the oil is able to flow freely to the bottom by gravity. When this gravity segregation does not occur, however, other means must be sought.

Secondary oil recovery methods use various techniques to aid in recovering oil from depleted or low-pressure reservoirs. Sometimes pumps on the surface or submerged (ESPs) are used to bring the oil to the surface. There are also *secondary oil recovery* operations that involve the injection of water or gas into the reservoir. When water is used (*waterflood*), separate wells are usually used for injection and production. The injected fluids maintain reservoir pressure or repressure the reservoir after primary depletion and displace a portion of the remaining crude oil to production wells. In fact, the first method recommended for improving the recovery of oil was probably the reinjection of natural gas (*gas flood*), and there are indications that gas injection was utilized for this purpose before 1900 (Craft and Hawkins, 1959; Frick, 1962). These early practices were implemented to increase the immediate productivity and are therefore classified as pressure maintenance projects. Recent gas injection techniques have been devised to increase the ultimate recovery, thus qualifying as secondary recovery projects.

In secondary recovery, the injected fluid must dislodge the oil and propel it toward the production wells. Reservoir energy must also be increased to displace the oil. Using techniques such as gas and water injection, there is no change in the state of oil. Similarly, there is no change in the state of the oil during miscible fluid displacement technologies. The analogy that might be used is that of a swimmer (in water) in which there is no change to the natural state of the human body.

During the withdrawal of fluids from a well, it is usual practice to maintain pressures in the reservoir at or near the original levels by pumping either gas or water into the reservoir as the hydrocarbons are withdrawn. This practice has the advantage of retarding the decline in the production of individual wells and considerably increasing the ultimate yield. It also may bring about the conservation of gas that otherwise would be wasted and the disposal of brines that otherwise might pollute surface and near-surface potable waters.

3.2.2.3 Tertiary Recovery Methods *Tertiary recovery methods* (more commonly called *enhanced recovery methods* or *EOR*) are methods applied to the incremental ultimate oil that can be recovered from a petroleum reservoir that cannot be obtained by primary and secondary recovery methods (Fig. 3.4) (Craft and Hawkins, 1959; Prats, 1986; Lake, 1989; Arnarnath, 1999; Speight, 2009, 2014). EOR is, to some extent, synonymous with IOR as well as AOR although these terms also apply to primary and secondary methods. The EOR methods involve technologies that induce the flow of the oil to the well which is the incremental ultimate oil that can be recovered from a petroleum reservoir over oil that can be obtained by primary and secondary recovery methods. Certain reservoir types, such as those with very viscous crude oils and some low-permeability carbonate (limestone, dolomite, or chert) reservoirs, respond poorly to conventional secondary recovery techniques.

In these reservoirs it is desirable to initiate EOR operations as early as possible. This may mean considerably abbreviating conventional secondary recovery operations or bypassing them altogether. Thermal floods using steam and controlled *in situ* combustion methods are also used. Thermal methods of recovery reduce the viscosity of the crude oil by heat so that it flows more easily into the production well.

Thus tertiary techniques are usually variations of secondary methods with a goal of improving the *sweeping* action of the invading fluid. Thus, EOR methods are designed to reduce the viscosity of the crude oil (i.e., to reduce the pour point of the crude oil relative to the temperature of the reservoir), thereby increasing oil production. EOR methods are applied starting when secondary oil recovery techniques are no longer enough to sustain production.

For tax purposes, the Internal Revenue Service of the United States has defined the projects that qualify as EOR projects (CFR 1.43-2, 2004), and these are discussed in the following text.

Thermal Methods Thermally EOR methods are tertiary recovery techniques that heat the oil and make it easier to extract. Steam injection is the most common form of this process and is used extensively to increase oil production. *In situ* combustion is another form of thermally EOR, but instead of using steam to reduce the crude oil viscosity, some of the oil is burned to heat the surrounding oil. Detergents are also used to decrease oil viscosity and improve the recovery (Schumacher, 1980; Speight, 2009, 2014). These methods have found most use when the oil in the reservoir has a high viscosity. For example, heavy oil is usually highly viscous (hence the use of the adjective *heavy*), with a viscosity ranging from approximately 100 centipoises to several million centipoises at the reservoir conditions. In addition, oil viscosity is also a function of temperature and API gravity (Speight, 2000, 2009, 2014).

Steam drive injection is the continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells). *Cyclic steam injection* is the alternating injection of steam and production of oil with condensed steam from the same well or wells. *In situ combustion* is the combustion of oil or fuel in the reservoir sustained by injection of air, oxygen-enriched air, oxygen, or supplemental fuel supplied from the surface to displace unburned oil toward the production wells. This process may include the concurrent, alternating, or subsequent injection of water.

In steam drives, the gravity of the crude oil does not play a major role in the technical considerations just listed except as it might affect plugging and, thus, the ability to maintain adequate communication between wells in reservoirs containing relatively heavy crudes. With regard to loss in injectivity or productivity, gravity override (or bypassing) of steam reduces the tendency of the formation to plug. Also, hydraulic fracturing, control of the injection temperature, and cyclic steam injection have been used successfully in thermal operations to avoid or minimize plugging. Thus, it seems impractical to place a limit on the range of API gravity of crudes to be considered for steam drive processes.

Steam drive injection (*steam injection*) has been commercially applied since the early 1960s. The process occurs in two steps: (i) steam stimulation of production wells, that is, direct steam stimulation, and (ii) steam drive by steam injection to increase production from other wells (indirect steam stimulation). When there is some natural reservoir energy, steam stimulation normally precedes steam drive. In steam stimulation, heat is applied to the reservoir by the injection of high-quality steam into the production well. This cyclic process, also called *huff and puff* or *steam* *soak*, uses the same well for both injection and production. The period of steam injection is followed by production of reduced viscosity oil and condensed steam (water). One mechanism that aids production of the oil is the flashing of hot water (originally condensed from steam injected under high pressure) back to steam as pressure is lowered when a well is put back on production.

Cyclic steam injection is the alternating injection of steam and production of oil with condensed steam from the same well or wells. Thus, steam generated at the surface is injected in a well, and the same well is subsequently put back on production. A cyclic steam injection process includes three stages. The first stage is injection, during which a measured amount of steam is introduced into the reservoir. The second stage (*the soak period*) requires that the well be shut in for a period of time (usually several days) to allow uniform heat distribution to reduce the viscosity of the oil (alternatively, to raise the reservoir temperature above the pour point of the oil). Finally, during the third stage, the now-mobile oil is produced through the same well. The cycle is repeated until the flow of oil diminishes to a point of no returns.

Alternatively, cyclic steam injection may also involve the addition of chemical to the steam and hydraulic fracturing. The concept of combining cyclic steam stimulation (CSS) with hydraulic fracturing arose when both steam injection and completion (sand control) techniques generated potential formation damage. Thus, the permeability near the wellbore creating a choke was lowered, which further reduces crude oil mobility.

Creating fractures allows a more efficient placement of injected steam, heating up larger volume of reservoir and reducing residual oil saturation. This combination is usually considered for low-permeability heavy oil reservoirs such as those in California or the Athabasca tar sand deposits (oil sand deposits) (Settari and Raisbeck, 1981; Manrique, 1996; Gomez et al., 2012). As a result of follow-up investigations (Alvarez and Han, 2013), oil recovery by cyclic steam injection has improved by the use of chemical additives and by better understanding of the geometry and mineralogy of the wells. In fact, cyclic steam injection combined with unconventional technologies such as coinjection with chemical additives, horizontal drilling, and hydraulic fracturing has been highly successful. The techniques have shown imported crude oil recovery for results for low-permeability formations.

In situ combustion is normally applied to reservoirs containing low-gravity oil but has been tested over perhaps the widest spectrum of conditions of any EOR process. In the process, heat is generated within the reservoir by injecting air and burning part of the crude oil. This reduces the oil viscosity and partially vaporizes the oil in place, and the oil is driven out of the reservoir by a combination of steam, hot water, and gas drive. *Forward combustion* involves movement of the hot front in the same direction as the injected air. *Reverse combustion* involves movement of the hot front opposite to the direction of the injected air. The relatively small portion of the oil that remains after these displacement mechanisms have acted becomes the fuel for the *in situ* combustion process. Production is obtained from wells offsetting the injection locations. In some applications, the efficiency of the total *in situ* combustion operation can be improved by alternating water and air injection. The injected water tends to improve the utilization of heat by transferring heat from the rock behind the combustion zone to the rock immediately ahead of the combustion zone.

The performance of *in situ* combustion is predominantly determined by the four following factors: (i) the quantity of oil that initially resides in the rock to be burned, (ii) the quantity of air required to burn the portion of the oil that fuels the process, (iii) the distance to which vigorous combustion can be sustained against heat losses, and (iv) the mobility of the air or combustion product gases. Both forward and reverse combustion methods have been used with some degree of success when applied to tar sand deposits. The forward combustion process has been applied to the Orinoco deposits (Terwilliger et al., 1975) and in the Kentucky sands (Terwilliger, 1975). The reverse combustion process has been applied to the Orinoco deposit (Burger, 1978) and the Athabasca deposit. In tests such as these it is essential to control the airflow and to mitigate the potential for spontaneous ignition (Burger, 1978). A modified combustion approach has been applied to the Athabasca deposit (Mungen and Nicholls, 1975). The technique involved a heat-up phase and a production (or blow-down phase) followed by a displacement phase using a fireflood–waterflood (COFCAW) process.

Gas Flood Methods

(i) *Miscible fluid displacement*—The injection of gas (e.g., natural gas, enriched natural gas, a liquefied petroleum slug driven by natural gas, carbon dioxide, nitrogen, or flue gas) or alcohol into the reservoir at pressure levels such that the gas or alcohol and reservoir oil are miscible.

(ii) *Carbon dioxide augmented waterflooding*—The injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency.

(iii) *Immiscible carbon dioxide displacement*—The injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained; this process may include the concurrent, alternating, or subsequent injection of water.

(iv) *Immiscible nonhydrocarbon gas displacement*—The injection of nonhydrocarbon gas (e.g., nitrogen) into an oil reservoir, under conditions in which miscibility with reservoir oil is not obtained, to obtain a chemical or physical reaction (other than pressure) between the oil and the injected gas or between the oil and other reservoir fluids; this process may include the concurrent, alternating, or subsequent injection of water.

Miscible fluid displacement (*miscible displacement*) includes the use of an alcohol, a refined hydrocarbon, a condensed petroleum gas, carbon dioxide, liquefied natural gas, or even exhaust gas being injected into an oil reservoir, at pressure levels such that the injected gas or alcohol and reservoir oil are miscible; the process may include the concurrent, alternating, or subsequent injection of water (Stalkup, 1983). Miscible displacement occurs when oil flows to the production wellbores from deep within the reservoir, displacing the oil near the wellbore or water moving within the aquifer. Oil can also move to the wellbore by immiscible displacement when the oil is displaced by water or gas (Caruana and Dawe, 1996; Dawe, 2004). There can also be mass transport across phase boundaries (e.g., gas from liquid to vapor in solution gas processes, liquid dropout from gas in condensate reservoirs, multiple-contact processes in miscible gas EOR processes, and transfer of chemicals such as in surfactant EOR). Additionally, there can be temperature changes with corresponding physical changes as in thermal EOR and cooling during long-term waterflooding of a reservoir with cold water.

When carbon dioxide is used for oil displacement, the carbon dioxide enters the oil-bearing porous media at reservoir temperature, which is usually between 26 and 120 °C (80 and 250 °F). The carbon dioxide is introduced at a pressure that is high enough to enable miscible displacement to be achieved, referred to as the minimum miscibility pressure (MMP). The foremost disadvantage of carbon dioxide as an oil displacement fluid is its low viscosity, 0.03–0.10 cP at these reservoir conditions. The brine in a reservoir has a viscosity on the order of 1 cP, while the reservoir oil viscosity varies between 0.1 and 50 cP. The carbon dioxide slug therefore has a much higher mobility (the ratio of a fluid permeability in porous media to viscosity) than the fluid it is displacing, resulting in an unfavorably low mobility ratio (the ratio of the carbon dioxide mobility to the fluid it is displacing is much less than unity). As a result, the areal sweep efficiency of the flood can be very low as the carbon dioxide *fingers* toward the production wells rather than uniformly displacing the oil ahead of it toward the production wells. Even though the displacement efficiency of the carbon dioxide may be very high *for the oil it contacts*, these fingers result in the carbon dioxide bypassing *much of the oil* in the reservoir. Consequently, if the carbon dioxide viscosity could be elevated to a level comparable with the oil it is displacing, typically a 1–2 order of magnitude increase, substantial improvements in sweep efficiency and oil recovery could result.

The procedures for miscible displacement are the same in each case and involve the injection of a slug of solvent that is miscible with the reservoir oil, followed by injection of either a liquid or a gas to sweep up any remaining solvent. It must be recognized that the miscible *slug* of solvent becomes enriched with oil as it passes through the reservoir and its composition changes, thereby reducing the effective scavenging action. However, changes in the composition of the fluid can also lead to wax deposition (Weingarten and Euchner, 1986; Majeed et al., 1990; Skovborg et al., 1991; Erickson et al., 1993; Pan and Firoozabadi, 1996; Calange et al., 1997) as well as deposition of asphaltene constituents (Leontaritis et al., 1987 and references cited therein; Leontaritis, 1989; Chung, 1992; Nghiem et al., 1993; Nor-Aziam and Adewumi, 1993; Kamath et al., 1994; Deo et al., 1995; Rassamdana et al., 1999). Therefore, caution is advised.

Carbon dioxide is capable of displacing many crude oils, thus permitting recovery of most of the oil from the reservoir rock that is contacted (*carbon dioxide miscible flooding*). The carbon dioxide is not initially miscible with the oil. However, as the carbon dioxide contacts the *in situ* crude oil, it extracts some of the hydrocarbon constituents of the crude oil into the carbon dioxide, and carbon dioxide is also dissolved in the oil. Miscibility is achieved at the displacement front when no interfaces exist between the hydrocarbon-enriched carbon dioxide mixture and the carbon dioxide-enriched oil. Thus, by a *dynamic* (*multiple-contact*) process involving interphase mass transfer, miscible displacement overcomes the capillary forces that otherwise trap oil in the pores of the rock.

For some reservoirs, miscibility between the carbon dioxide and the oil cannot be achieved and is dependent upon the oil properties. However, carbon dioxide can still be used to recover additional oil. The carbon dioxide swells crude oils, thus increasing the volume of pore space occupied by the oil and reducing the quantity of oil trapped in the pores. It also reduces the oil viscosity. Both effects improve the mobility of the oil. Carbon dioxide-immiscible flooding has been demonstrated in both pilot and commercial projects, but overall it is expected to make a relatively small contribution to EOR.

Chemical Flood Methods Three EOR processes involve the use of chemicals—surfactant/polymer, polymer, and alkaline flooding (OTA, 1978).

Surfactant flooding is a multiple-slug process involving the addition of surface-active chemicals to water (Reed and Healy, 1977). These chemicals reduce the capillary forces that trap the oil in the pores of the rock. The surfactant slug displaces the majority of the oil from the reservoir volume contacted, forming a flowing oil–water bank that is propagated ahead of the surfactant slug. The principal factors that influence the surfactant slug design are interfacial properties, slug mobility in relation to the mobility of the oil–water bank, the persistence of acceptable slug properties and slug integrity in the reservoir, and cost. Furthermore, each reservoir has unique fluid and rock properties, and specific chemical systems must be designed for each individual application. The chemicals used, their concentrations in the slugs, and the slug sizes depend upon the specific properties of the fluids and the rocks involved and upon economic considerations.

Microemulsion flooding, also known as *surfactant/polymer flooding*, involves injection of a surfactant system (e.g., a surfactant, hydrocarbon, cosurfactant, electrolyte, and water) to enhance the displacement of oil toward the production wells, and *caustic flooding* is the injection of water that has been made chemically basic by the addition of alkali metal hydroxides, silicates, or other chemicals (Reed and Healy, 1977; Dreher and Gogarty, 1979). Injecting water in turn displaces the mobility buffer. Depending on the reservoir environment, a preflood may or may not be used (Venuto, 1989). The microemulsion is the key to the process. Oil and water are displaced ahead of the microemulsion slug, and a stabilized oil and water bank develops. The displacement mechanism is the same under secondary and tertiary recovery conditions. In the secondary case, water is the primary produced fluid that continues until the oil bank reaches the well.

Mobility control is important to the success of the process. The mobility of the microemulsion can be matched to that of the stabilized water–oil bank by controlling the microemulsion viscosity. The mobility buffer following the microemulsion slug prevents rapid slug deterioration from the rear and thus minimizes the slug size required for efficient oil displacement. Water external emulsions and aqueous solutions of high molecular weight polymers have been used as mobility buffers.

Polymer augmented waterflooding is the injection of polymeric additives with water to improve the areal and vertical sweep efficiency of the reservoir by increasing the viscosity and decreasing the mobility of the water injected; polymer augmented waterflooding does not include the injection of polymers for the purpose of modifying the injection profile of the wellbore or the relative permeability of various layers of the reservoir, rather than modifying the water–oil mobility ratio (Sorbie, 1991). The polymer solution affects the relative flow rates of oil and water and sweeps a larger fraction of the reservoir than water alone, thus contacting more of the oil and moving it to production wells. Polymers currently in use are produced both synthetically (polyacrylamides) and biologically (polysaccharides). The polymers may also be cross-linked *in situ* to form highly viscous fluids that will divert the subsequently injected water into different reservoir strata.

Alkaline flooding involves the use of aqueous solutions of certain chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate that are strongly alkaline. These solutions will react with constituents present in some crude oils or present at the rock/crude oil interface to form detergent-like materials that reduce the ability of the formation to retain the oil. These chemicals enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction, spontaneous emulsification, or wettability alteration. These mechanisms rely on the *in situ* formation of surfactants during the neutralization of petroleum acids in the crude oil by the alkaline chemicals in the displacing fluids. Other variations on this theme include the use of steam and the means of reducing interfacial tension by the use of various solvents (Ali, 1974; Ali and Abad, 1975). The solvent approach has had some success when applied to bitumen recovery from mined tar sand, but when applied to nonmined material losses of solvent and dissolved bitumen are always an issue. However, this approach should not be rejected out of hand since a novel concept may arise that guarantees minimal (acceptable) losses of bitumen and solvent.

3.2.3 Fracturing Methods

EOR processes use *thermal*, *chemical*, or *fluid phase behavior* effects to reduce or eliminate the capillary forces that trap oil within pores, to thin the oil or otherwise improve its mobility, or to alter the mobility of the displacing fluids. In some cases, the effects of gravity forces, which cause vertical segregation of fluids of different densities, can be minimized or even used to advantage. The various processes differ considerably in complexity, the physical mechanisms responsible for oil recovery, and the amount of experience that has been derived from field application. The degree to which the EOR methods are applicable in the future will depend on the development of improved process technology. It will also depend on improved understanding of fluid chemistry, phase behavior, and physical properties and on the accuracy of geology and reservoir engineering in characterizing the physical nature of individual reservoirs (Borchardt and Yen, 1989). However, no single EOR technique is the cure-all for oil recovery. Most reservoirs are complex and the oil reservoir system must be considered as a whole rather than as individual, but equally complex, entities.

EOR is not the same as hydraulic fracturing, which is part of a group of methods known as *oil production intensification*. The aim of hydraulic fracturing is to locally increase oil flow by changing the physical nature of the underlying rock strata (Chapter 5). Thus, once the well is completed, the flow of oil into the well is commenced. For limestone reservoir rock, acid is pumped down the well (*acid fracturing*), and the acid dissolves channels in the limestone that lead oil into the well. For sandstone reservoir rock, a specially blended fluid containing *proppants* (sand, walnut shells, aluminum pellets) is pumped down the well and out the perforations. The pressure from this fluid makes small fractures in the sandstone that allow oil to flow into the well, while the proppants hold these fractures open. Once the oil is flowing, the oil rig is removed from the site, and production equipment is set up to extract the oil from the well.

Hydraulic fracturing has also been applied to EOR processes. In one common technique liquids or steam and other gases are injected into a well, and an underground explosive charge is set off, forcing the liquids into the surrounding rock, fracturing it, and opening myriad small flow channels into the main wellbore. However, unlike EOR operations that rely on changing the nature of water and oil that impacts the way it flows through the oil field, hydraulic fracturing changes the physical nature of the rock strata, and, instead, the underlying structure of the rock is left in place and is unchanged.

Hydraulic fracturing can, and is, also used with oil wells, but it is less commonly used in limestone reservoirs. In limestone ($CaCO_3$) reservoirs, drillers preferentially use a process known as *acidizing* (acidization, acid fracturing), which may also use the high-pressure/explosive techniques of hydraulic fracturing (Chapter 6). The oil industry uses these terms ambiguously to refer to cleanup as well as stimulation of the wellbore.

Thus, after drilling and cementing of the wellbore, smallish pieces of cement may remain in the wellbore, threatening to impede oil flow. Relatively small amounts of (typically) hydrochloric acid are pumped into the well to dissolve this cement and pump it out of the well. For *stimulation* purposes, much larger quantities of acid are pumped into the well. Technically, acid fracturing stimulation does not technically fracture the oil-bearing rock surrounding the wellbore; it *dissolves* the limestone, effectively increasing the diameter of the well.

In *modified in situ extraction* processes (Fig. 3.6), combinations of *in situ* and mining techniques are used to access the reservoir. A portion of the reservoir rock must be removed to enable application of the *in situ* extraction technology. The most common method is to enter the reservoir through a large-diameter vertical shaft, excavate horizontal drifts from the bottom of the shaft, and drill injection and production wells horizontally from the drifts. Thermal extraction processes are then applied through the wells. When the horizontal wells are drilled at or near the base of the tar sand reservoir, the injected heat rises from the injection wells through the reservoir, and drainage of produced fluids to the production wells is assisted by gravity.

Although not technically a hydraulic fracturing process, in a *modified in situ extraction* processes, a combination of *in situ* and mining techniques is used to access the reservoir when the heavy oil proves too difficult to move to the production well. Such processes are amenable to recovery of bitumen from tar sand deposits and serve as the basis of the steam-assisted gravity drainage (SAGD) process and the variants

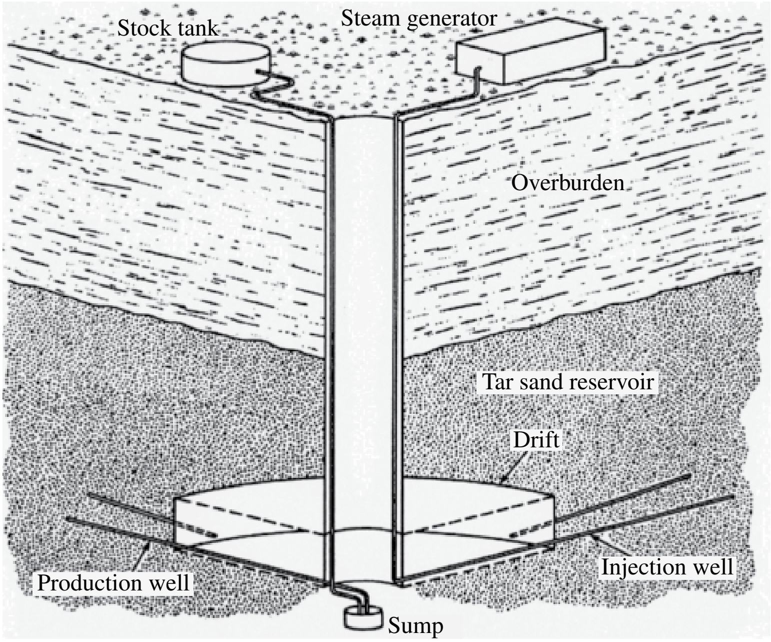


FIGURE 3.6 Modified *in situ* extraction.

of the process, which may also include a degree of fracturing especially when steam injection occurs at fracture pressure.

Operating the SAGD injection and production wells at approximately reservoir pressure eliminates the instability problems that plague all high-pressure steam processes and produces a smooth, even production that can be as high as 70–80% of oil in place in suitable reservoirs. The process is relatively insensitive to shale streaks and other vertical barriers to steam and fluid flow because, as the rock is heated, differential thermal expansion causes fractures in it, allowing steam and fluids to flow through. This allows recovery rates of 60–70% of oil in place, even in formations with many thin shale barriers. Thermally, SAGD is twice as efficient as the older CSS process, and it results in far fewer wells being damaged by high pressure. Combined with the higher oil recovery rates achieved, this means that SAGD is much more economic than pressure-driven steam process where the reservoir is reasonably thick.

Technologies that upgrade value, drive down costs, and reduce environmental impacts will have the greatest effect on increasing the production of heavy oil. There are a large number of technologies that can have an impact, but there is no single technology that can be generally applied owing to the variability of heavy oil properties as well as reservoir properties. In recent years there has been a renewed interest in the *in situ* combustion technologies that have the potential to partially upgrade the oil and produce a product at the surface that is more valuable than the original oil.

In addition to the recovery processes described earlier, hydraulic fracturing may also be necessary to contribute to improvements in oil production. In the process, hydraulic fracturing is used to create additional passageways in the oil reservoir that can facilitate the flow of oil to a production well. Tight reservoirs (shale formations), where the gas-containing and oil-containing rocks have restricted pore volume and connectivity that impede the flow of oil through the reservoir, are commonly fractured by injecting a fluid containing sand or other proppant under sufficient pressure to create fractures in the rock through which the oil can more easily flow (Cramer, 2008). Care is also taken to contain the fracturing within the oil reservoir to avoid intersecting adjoining aquifers that would introduce excess water into the oil-producing zone.

The focus of current-day attention in terms of crude oil and natural gas production has been the cured oil and natural gas in tight formation. In many of these tight formations, the existence of large quantities of crude oil and natural gas has been known for decades, usually dating to the earliest exploration efforts within any given basin. In some areas multiple attempts were made to commercially produce from these oil-rich but tight zones. While initial production rates were often promising, or even exciting, productivity would typically decrease off significantly within months or even days of initial production. As a result, there is very little available data on the production history of most of the tight oil and gas formations. Unfortunately, for most states and provinces the reporting of production statistics on a formation-by-formation basis is not typically readily available to the public, which makes it difficult to quantify and/or verify reports of tight oil production in many of the identified plays. North Dakota is a notable exception, with annual production data for each oil-producing formation in the state being available through the state government (National Petroleum Council, 2011). Thus, during the first Williston Basin oil boom, many wells in the 1950s and early 1960s were perforated both in the Bakken Formation and more conventional carbonate reservoirs of the overlying Madison Group. These early attempts at Bakken exploitation were through vertical wells, resulting in initial production values ranging from 150 to 450 barrel per day and typical cumulative production of 85,000 barrel per well. These statistics indicate that most early Bakken wells had productive lifetimes of less than 2–3 years. As such, very little oil was produced from the Bakken throughout most of the productive history of the Williston Basin. In the early 1990s the advent of horizontal drilling technology brought new interest to the Bakken, and IP values were increased to 230–500 B/D, with typical cumulative production also increasing to 145,000 barrels per well. However these improvements in production were not enough to economically sustain wide-scale exploitation of the Bakken, and by the late 1990s the Bakken was once again considered an economically unattractive resource. In the early to mid-2000s a combination of high oil price environment, improved understanding of the geology of the Bakken, and improvements in well drilling, completion, and stimulation technologies sparked renewed interest in Bakken exploitation. From the information that is available, the Bakken appears to account for a vast majority of the current tight oil production. However recent reports of success and active development within the

Niobrara and Eagle Ford plays suggest that their productivity may be comparable to that of the Bakken within just a few years (National Petroleum Council, 2011).

More recently, several alternative fracturing techniques designed to accomplish specific tasks are (i) tailored pulse fracturing, (ii) foam fracturing, and (iii) carbon dioxide–sand fracturing. *Tailored pulse fracturing* is employed to control the extent and direction of the produced fractures. Precise quantities of solid rocket fuel-like propellants are ignited in the wellbore to create a controlled pressure pulse, which creates fractures in a more predictable pattern. *Foam fracturing*, using foam under high pressure in gas reservoirs, has the advantage over high-pressure water injection because it does not create as much damage to the formation, and well cleanup operations are less costly. *Carbon dioxide–sand* fracturing increases production by eliminating much of the inhibiting effects of pumped fluids such as (i) plugging by solids, (ii) water retention, and (iii) chemical interactions.

Finally, when sandstone rocks contain crude oil or natural gas in commercial quantities but the permeability is too low to permit good recovery, a process called fracturing may be used to increase permeability to a practical level. Basically, to fracture a formation, a fracturing service company pumps a specially blended fluid down the well and into the formation under great pressure. Pumping continues until the fracture occurs in the formation after which specially blended fluid containing *proppants* (sand, walnut shells, aluminum pellets) is pumped down the well and out of the perforations. Since the fractures tend to close after the pressure on the well is released, the proppant is needed to hold or prop the fractures open. These propped-open fractures provide passages for oil or gas to flow into the well and thence to the surface.

3.3 BITUMEN RECOVERY FROM TAR SAND DEPOSITS

Generally, as opposed to conventional oil recovery and heavy oil recovery, bitumen recovery from tar sand deposits requires a higher degree of thermal stimulation because bitumen, in its immobile state, is extremely difficult to move to a production well. Extreme processes are required, usually in the form of a degree of thermal conversion that produces free-flowing product oil that will flow to the well and reduce the resistance of the bitumen to flow. In addition, with the continued application of *in situ* recovery methods for tar sand bitumen, because of the nature of tar sand deposits, sand control technology should also be in place.

Bitumen recovery processes can be conveniently divided into two categories: (i) mining methods, also called *oil mining*, and (ii) nonmining methods. In the former type of process, the tar sand must first be removed from the formation by a mining technique and then transported to a bitumen recovery center. In the latter type of process, usually (but not always correctly) termed *in situ*, bitumen (or a portion of the bitumen in place) is recovered from the formation by a suitable thermal method, leaving the formation somewhat less disturbed than when the mining method is employed.

3.3.1 Mining Methods

The long-term tried and true method for recovery of bitumen from tars and deposits is a mining method. The bitumen occurring in oil sand deposits poses a major recovery problem. The material is notoriously immobile at formation temperatures and must therefore require some stimulation (usually by thermal means) in order to ensure recovery. Alternately, proposals have been noted, which advocate bitumen recovery by solvent flooding or by the use of emulsifiers. There is no doubt that with time one or more of these functions may come to fruition, but the initial bitumen recovery methods relied and continue to rely on the mining technique (Speight, 2009, 2014).

The deposit properties, which can affect the efficiency of heavy oil or bitumen production by mining technology, can be grouped into three classes: (i) primary properties, (ii) secondary properties, and (iii) tertiary properties. The *primary properties* are those properties that have an influence on the fluid flow and fluid storage properties and include rock and fluid properties, such as porosity, permeability, wettability, crude oil viscosity, and pour point. The *secondary properties* are the properties that significantly influence the primary properties, including pore size distribution, clay type, and content. The *tertiary properties* are the other properties that mainly influence oil production operation (fracture breakdown pressure, hardness, and thermal properties) and the mining operations (e.g., temperature, subsidence potential, and fault distribution). There are also important rock mechanical parameters of the formation in which a tunnel is to be mined and from where all oil mining operations will be conducted. These properties are mostly related to the mining aspects of the operations, and not all are of equal importance in their influence on the mining technology. Their relative importance also depends on the individual reservoir.

Surface mining is the mining method that is currently being used by Suncor Energy and Syncrude Canada Limited to recover oil sand from the ground. There are two methods of mining currently in use in the Athabasca oil sands. Suncor Energy uses the truck and shovel method of mining, whereas Syncrude uses the truck and shovel method of mining, as well as draglines and bucket-wheel reclaimers. These enormous draglines and bucket-wheel reclaimers are being phased out and soon will be completely replaced with large trucks and shovels. The shovel scoops up the oil sand and dumps it into a heavy hauler truck. The heavy hauler truck takes the oil sand to a conveyor belt that transports the oil sand from the mine to the extraction plant. Presently, there are extensive conveyor belt systems that transport the mined oil sand from the recovery site to the extraction plant. With the development of new technologies, these conveyors are being phased out and replaced with hydrotransport technology. Hydrotransport is a combination of ore transport and preliminary extraction. After the bituminous sands have been recovered using the truck and shovel method, it is mixed with water and caustic soda to form a slurry and is pumped along a pipeline to the extraction plant. The extraction process thus begins with the mixing of the water and agitation needed to initiate bitumen separation from the sand and clay.

Underground mining options have also been proposed but for the moment have not been developed because of the fear of collapse of the formation onto any operation/equipment. This particular option should not, however, be rejected out of hand because a novel aspect or the requirements of the developer (which remove the accompanying dangers) may make such an option acceptable. Currently, bitumen is recovered commercially from tar and deposits by a mining technique. This produces tar sand that is sent to the processing plant for separation of the bitumen from the sand prior to upgrading.

3.3.2 Nonmining Methods

In principle, the *nonmining recovery of bitumen from tar sand deposits* is a modified enhanced recovery technique and requires the injection of a fluid into the formation through an injection wall. This leads to the *in situ* displacement of the bitumen from the recovery and bitumen production at the surface through an egress (production well). There are, however, several serious constraints that are particularly important and relate to bulk properties of the tar sand and the bitumen. In fact, both must be considered *in toto* in the context of bitumen recovery by nonmining techniques. For example, such processes need a relatively thick layer of overburden to contain the driver substance within the formation between injection and production wells.

For example, the Canadian deposits are unconsolidated sands with a porosity ranging up to about 45%, whereas other deposits may range from predominantly low-porosity, low-permeability consolidated sand to, in a few instances, unconsolidated sands. Moreover, the bitumen properties are not conducive to fluid flow under deposit conditions. Nevertheless, where the general nature of the deposits prohibits the application of a mining technique, a nonmining method may be the only feasible bitumen recovery option.

Another general constraint to bitumen recovery by nonmining methods is the relatively low injectivity of tar sand formations. Thus it is usually necessary to inject displacement or recovery finds at a pressure such that fracturing (parting) is achieved. Such a technique therefore changes the reservoir profile and introduces a series of channels through which fluids can flow from the injection well to the production well. On the other hand, the technique may be disadvantageous insofar as the fracture occurs along the path of least resistance, giving undesirable (i.e., inefficient) flow characteristics within the reservoir between the injection and production wells, leaving a large part of the reservoir relatively untouched by the displacement or recovery fluids.

If the viscous bitumen in a tar sand formation can be made mobile by admixture of either a hydrocarbon diluent or an emulsifying fluid, a relatively low-temperature secondary recovery process is possible (*emulsion steam drive*). If the formation is impermeable, communication problems exist between injection and production wells. However, it is possible to apply a solution or dilution process along a narrow fracture plane between injection and production wells.

Two expected problems inherent in the steam drive process are steam override and reservoir plugging. Any *in situ* thermal process tends to steam override because of differential density of the hot and cold fluids. These problems can be partially mitigated by rapid injection of steam at the bottom or below the target interval through a high-permeability water zone or fracture. Each of these options will raise the temperature of the entire reservoir by conduction and, to a lesser degree, by convection. The bitumen will be at least partially mobilized, and the effectiveness of the following injection of steam into the target interval will be enhanced.

In the *fracture-assisted steam technology* (FAST) process, steam is injected rapidly into an induced horizontal fracture near the bottom of the reservoir to preheat the reservoir. This process has been applied successfully in three pilot projects in southwest Texas. Shell has accomplished the same preheating goal by injecting steam into a high-permeability bottom water zone in the Peace River (Alberta) field. Electrical heating of the reservoir by radio-frequency waves may also be an effective method.

Inert gas injection (IGI) is a technology for conventional oils in reservoirs where good vertical permeability exists or where it can be created through propped hydraulic fracturing. It is generally viewed as a *top-down* process with nitrogen or methane injection through vertical wells at the top of the reservoirs, creating a gas–oil interface that is slowly displaced toward long horizontal production wells. As with all gravity drainage processes, it is essential to balance the injection and production volumes precisely so that the system does not become pressure driven, but remains in the gravity-dominated flow regime.

The SAGD process, as for all gravity-driven processes, is extremely stable because the process zone grows only by gravity segregation, and there are no pressure-driven instabilities such as channeling, coning, and fracturing. It is vital in the SAGD process to maintain a volume balance, replacing each unit volume withdrawn with a unit volume injected, to maintain the processes in the gravity-dominated domain. If bottom-water influx develops, this indicates that the pressure in the water is larger than the pressure in the steam chamber, and steps must be taken to balance the pressures. Because it is not possible to reduce the pressure in the water zone, the pressure in the steam chamber and production well region must be increased. This can be achieved by increasing the operating pressure of the steam chamber through the injection rate of steam or through reduction of the production rate from the lower well. After some time, the pressures will become more balanced and the water influx ceases. Thereafter, maintaining a volume balance carefully is essential.

The SAGD process seems to be relatively insensitive to shale streaks and similar horizontal barriers, even up to several meters thick (3–6 ft), that otherwise would restrict vertical flow rates. This occurs because as the rock is heated, differential thermal expansion causes the shale to be placed under a tensile stress, and vertical fractures are created, which serve as conduits for steam (up) and liquids (down). As high temperatures hit the shale, the kinetic energy in the water increases, and adsorbed water on clay particles is liberated. Thus, instead of expanding thermally, dehydration (loss of water) occurs, and this leads to volumetric shrinkage of the shale barriers. As the shale shrink, the lateral stress (fracture gradient) drops until the pore pressure exceeds the lateral stress, which causes vertical fractures to open. Thus, the combined processes of gravity segregation and shale thermal fracturing make SAGD so efficient that recovery ratios of 60–70% are probably achievable even in cases where there are many thin shale streaks, although there are limits on the thickness of shale bed that can be traversed in a reasonable time. In the *fracture-assisted steam technology-SAGD* (Fast-SAGD) operation, steam has a tendency to bypass other wells during the injection period due to the operation of the CSS wells. Hence live steam will be produced at producer, which has an adverse effect on the thermal efficiency of the process, thereby causing the production rate to decrease significantly.

The hybrid SAGD (HSAGD) process uses a similar well configuration to the Fast-SAGD method. However, the wells are operated very differently in terms of the operating conditions. In Fast-SAGD process, the SAGD wells are operated first, and CSS wells (offset wells) start later and require higher injection pressure and injection rate. Therefore steam is easy to bypass to other wells, but the HSAGD process can improve this phenomenon. In the HSAGD process, all CSS wells are placed in a staggered pattern, and the wells are operated at the same pressure and placed in operation earlier than SAGD wells (Coskuner, 2009).

Cold heavy oil production with sand (CHOPS) is now widely used as a production approach in unconsolidated sandstones. The process results in the development of high-permeability channels (*wormholes*) in the adjacent low-cohesive-strength sands, facilitating the flow of oil foam that is caused by solution gas drive. The key benefits of the process are improved reservoir access, order-of-magnitude higher oil production rates (as compared to primary recovery), and lower production costs. The outstanding technical issues involve sand handling problems, field development strategies, wormhole plugging for water shutoff, low ultimate recovery, and sand disposal. Originally, cold production mechanisms were thought to apply only to vertical wells with high-capacity pumps. It is now believed that addition of resins, similar to addition of dispersants, increased foam stability, presumably by decreasing the size of asphaltene aggregates (McLean and Kilpatrick, 1997; Zaki et al., 2002) (Chapters 12 and 13).

Vapor-assisted petroleum extraction (VAPEX) is a process in which the physics of the process are essentially the same as for SAGD and the configuration of wells is generally similar. The process involves the injection of vaporized solvents such as ethane or propane to create a vapor chamber through which the oil flows due to gravity drainage (Butler and Mokrys, 1991, 1995; Butler and Jiang, 2000). The process can be applied in paired horizontal wells, single horizontal wells, or a combination of vertical and horizontal wells. The key benefits are significantly lower energy costs, potential for *in situ* upgrading, and application to thin reservoirs, with bottom-water or reactive mineralogy.

In the process a pair of horizontal wells are drilled as production and injection similar to SAGD process. The injection well is located above production well and a mixture of solvents will be injected through that. The solvents start to move toward cap rock, when it reaches to that (or a barrier bed), and then spread along that barrier till solvents start to move downward to production well by gravity drainage force. Well configurations are very important, and deasphalting and the effect of that on the diluted heavy oil or bitumen can relate to well configuration.

VAPEX can undoubtedly be used in conjunction with SAGD methods. As with SAGD and IGI, a key factor is the generation of a three-phase system with a continuous gas phase so that as much of the oil as possible can be contacted by the gaseous phases, generating the thin oil film drainage mechanism. As with IGI, vertical permeability barriers are a problem and must be overcome through hydraulic fracturing to create vertical permeable channels or undercut by a the lateral growth of the chamber beyond the lateral extent of the limited barrier, or "baffle."

3.4 SAND CONTROL

Whether or not the recovery of crude oil, and to some extent natural gas, involves the application of tried and true recovery methods or the application of hydraulic fracturing to tight sandstone formations or shale formations (Chapter 5), there is the need to guard against excessive (unwanted) sand production during crude oil recovery as well as during recovery from tight sandstone formations (or, in the case of shale formations, the control of solids released from the formation) during the recovery process (Hollabaugh and Dees, 1993; Dees and Handren, 1994).

3.4.1 Methods

Several techniques are available for minimizing sand production from wells, and the choices range from simple changes in operating practices to expensive completions, such as sand consolidation or gravel packing. The sand control method selected depends on site-specific conditions, operating practices, and economic considerations. Some of the sand control techniques available are (i) maintenance and workover, (ii) rate exclusion, (iii) selective completion practices, (iv) plastic consolidation, (v) resin coated gravel, (vi) slotted liners or screens, and (vii) gravel packing.

Maintenance and workover involves tolerating the sand production and dealing with its effects. This an approach requires bailing, washing, and cleaning of surface facilities routinely to maintain well productivity and can be successful in specific formations and operating environments. The maintenance and workover method is primarily used where there are (i) minimal sand production, (ii) low production rates, and (iii) economically viable well service.

Rate restriction involves restricting the flow rate of the well to a level that reduces sand production. The procedure should reduce or increase the flow rate until an acceptable value of sand production is achieved. The object of this technique is to attempt to establish the maximum sand-free flow rate and is a trial-and-error method that may have to be repeated as the reservoir pressure, flow rate, and water cut change. However, the maximum flow rate required to establish and maintain sand-free production is often less than the flow potential of the well, which may represent a significant loss in productivity and revenue.

Selective completion practices involve production only from sections of the reservoir that are capable of withstanding the anticipated drawdown. Only the higher compressive strength sections of the formation are perforated, which allows higher drawdown. The high compressive strength sections will likely have the most cementation and, unfortunately, the lowest permeability, but while eliminating sand production, the most valuable reserves will not be in communication with the production well.

Plastic consolidation involves the injection of plastic resins that are attached to the formation sand grains—the resin hardens and forms a consolidated mass in which the sand grains are bound together at the contact points. Generally, the increase in formation compressive strength may be sufficient to withstand the drag forces while producing crude oil at the desired rates. The types of resins commercially available are (i) epoxy resins; (ii) furan resins, including furan/phenolic blends; and (iii) phenolic resins. The resins are in a liquid form when they enter the formation, and a catalyst or curing agent is required for hardening—internal catalysts are mixed into the resin solution at the surface and require time and/or temperature to harden the resin, while external catalysts are injected after the resin is in place. The internal catalysts have the advantage of positive placement because all resins will be in contact with the catalyst required for efficient curing, but there is always the disadvantage of premature hardening in the work string. The amounts of both resin and catalyst must be carefully chosen and controlled for the specific well conditions. Epoxy resins and phenolic resins can be placed with either internal or external catalysts; however, the rapid curing times of the furans (and furan/phenolic blends) require that external catalysts be used.

There are two types of plastic consolidation systems: (i) phase separation systems and overflush systems. In the *phase separation systems*, which contain approximately 15–25% w/w active resin in an inert solution, the resin is preferentially attracted to the sand grains, leaving the inert portion that will not otherwise affect the pore spaces. These systems use an internal catalyst. On the other hand, *overflush systems* contain a high percentage of active resin, and, when first injected, the pore spaces are completely filled with resin, and an overflush is required to push the excess resin away from the wellbore area to reestablish permeability. Only a residual amount of resin saturation, which should be concentrated at the sand contact points, should remain following the overflush. Most overflush systems use an external catalyst, although some include an internal catalyst.

Both phase separation and overflush systems require a multistage preflush to remove reservoir fluids and make the sand grain oil wet. In the first stage, diesel oil is generally used to displace the reservoir oil. Since epoxy resins are incompatible with water, isopropyl alcohol is used after the diesel treatment to remove formation water. The final stage is a spacer (brine) that is used to prevent the isopropyl alcohol from contacting the resin.

Plastic consolidation leaves the wellbore fully open, which is necessary when where large-outside-diameter downhole completion equipment is required. Also, plastic consolidation can be done through tubing or in wells with small-diameter casing. However, the permeability of a formation is always decreased by plastic consolidation because the resin occupies a portion of the original pore space and is oil wet.

In addition, perforation plugging or permeability variations often cause some perforations to take more plastic than others. In systems that use an external catalyst, there is no sand control in areas that are not contacted by both resin and catalyst.

Resin-coated gravel treatment is used as a sand control technique involves pumping the gravel into the well to completely fill the perforations and casing. One method uses dry, partially catalyzed phenolic resin-coated gravel—the resin coating is about 5% w/w of the sand. When exposed to heat, the resin cures, resulting in a consolidated sand mass. The bottom-hole temperature of the well, or injection of steam, causes the resin to complete the cure into a consolidated pack. After curing, the consolidated gravel-pack sand can be drilled out of the casing, leaving the resin-coated gravel in the perforations. The remaining consolidated gravel in the perforations acts as a permeable filter to prevent the production of formation sand. The main use of resin-coated gravel is in prepacked screens, which is discussed later.

Another method such as wet resins (epoxy resins or furan resins) can also be used in which the well is usually prepacked with gravel after which the resin is pumped and catalyzed to harden the plastic. After curing, the consolidated plastic–sand mixture is drilled out of the well, leaving the resin-coated sand in the perforations. For the project to be successful, all of the perforations must be completely filled with the resin-coated gravel, and the gravel must cure. Complete filling of the perforations becomes increasingly difficult, as zone length and deviation from vertical increase. In addition, the resin-coated gravel must cure with sufficient compressive strength.

Slotted liners or screens (which can serve as filters) have been used as a means of controlling sand production in this service. However, unless the formation is a well-sorted, clean sand with a large grain size, the liners/screens can have a short in-service life before becoming plugged. When used alone as sand exclusion devices, the slotted liners or screens are placed across the productive interval, and the formation sand mechanically bridges on the slots or openings in the wire-wrapped screen. When this technique is used to control sand production, the slotted liner or screen diameter should be as large as possible to maximize inflow area and minimize the amount of resorting that can occur. Using a slotted liner or screen without gravel packing is generally not a good sand control technique because, in most cases, the screen will eventually restrict well rates because of plugging. Screens or slotted liners should be avoided in cased-hole completions as the sole sand control technique because, when the annulus and perforations become filled with sand, production rates decrease drastically.

Gravel packing consists of placing a screen or slotted liner in a well opposite the completion interval and placing gravel concentrically around it. The gravel is actually large-grained sand that prevents sand production from the formation but allows fluids to flow into the well; the slotted liner or screen retains the gravel. Gravel packing creates a permeable downhole filter that allows the production of the formation fluids but restricts the entry and production of formation sand. If the gravel is tightly packed between the formation and the screen, the bridges formed are stable, which prevents shifting and resorting of the formation sand. If properly designed and executed, a gravel pack will maintain its permeability under a broad range of production conditions.

3.4.2 Guidelines for Process Selection

There are many alternatives for sand control and each alternative has its advantages and disadvantages. Even techniques that are not widely used may have a potential application in which its use might be superior to others. Gravel packing is currently the most widely used technique, but should remedial operations be required on a gravel pack, the screen and completion assembly must be removed from the well, which could involve a lengthy maintenance period. Sand consolidation and resin-coated sand are attractive for tubingless completions because no mechanical equipment is left in the hole; however, the following conditions all present problems with the plastic systems: (i) low-permeability formations, (ii) small-interval-length formations, (iii) high-temperature formations, and (iv) formations requiring completion longevity, such as when the wells sanded up or are low-productivity wells.

REFERENCES

Ali, S.M.F. 1974. *Tar Sands Fuel of the Future*. L.V. Hills (Editor). Canadian Society of Petroleum Geologists, Calgary, Alberta, Canada, p. 199.

Ali, S.M.F., and Abad, B. 1975. Proceedings of the Twenty-Sixth Annual Meeting Petroleum Society. Canadian Institute of Mining, Banff, Alberta, Canada.

Alvarez, J., and Han, S. 2013. Current Overview of Cyclic Steam Injection Process. *Journal of Petroleum Science Research*, 2(3): 116–127.

API RP 13J. 2015. *Testing of Heavy Brines*. American Petroleum Institute, Washington, DC.

API RP 13M. 2015. *Recommended Practice for the Measurement of Viscous Properties of Completion Fluids*. American Petroleum Institute, Washington, DC.

Arnarnath, A. 1999. *Enhanced Oil Recovery Scoping Study*. Report No. TR-113836. Electric Power Research Institute, Palo Alto, CA.

Azari, M., and Leimkuhler, J.M. 1990. Formation Permeability Damage Induced by Completion Brines. Paper No. SPE-17149-PA. *Journal of Petroleum Technology*, 42(4): 486–492.

Borchardt, J.K., and Yen, T.F. 1989. Oil Field Chemistry. Symposium Series No. 396. American Chemical Society, Washington, DC.

Burger, J. 1978. Developments in Petroleum Science, No. 7, Bitumens, Asphalts and Tar Sands. G.V. Chilingarian and T.F. Yen (Editors). Elsevier, New York. Page 191.

Butler, R.M., and Jiang, Q. 2000. Improved Recovery of Heavy Oil by VAPEX with Widely Spaced Horizontal Injectors and Producers. *Journal of Canadian Petroleum Technology*, 39(1): 48–56.

Butler, R.M., and Mokrys, I.J. 1991. A New Process (VAPEX) for Recovering Heavy Oils Using Hot Water and Hydrocarbon Vapor. *Journal of Canadian Petroleum Technology*, 30(1): 97–106.

Butler, R.M., and Mokrys, I.J. 1995. Process and Apparatus for the Recovery of Hydrocarbons from a Hydrocarbon Deposit. United States Patent 5,407,009. April 18.

Caenn, R., Darley, H.C.H., and Gray, G.R. 2011. *Composition and Properties of Drilling and Completion Fluids*, 6th Edition. Elsevier, Amsterdam, The Netherlands.

Calange, S., Ruffier-Meray, V., and Behar, E. 1997. Onset of Crystallization Temperature and Deposit Amount for Waxy Crudes: Experimental Determinations and Thermodynamic Modeling. Paper No. SPE 37239. Proceedings. Annual Technical Conference and Exhibition, Houston, TX. February 18–21. Society of Petroleum Engineers, Richardson, TX.

Caruana, A., and Dawe, R.A. 1996. Effect of Heterogeneities on Miscible and Immiscible Flow Processes in Porous Media. *Trends in Chemical Engineering*, 3: 185–203.

CFR 1.43-2. 2004. Internal Revenue Service, Department of the Treasury. Government of the United States, Washington, DC.

Chakma, A., Islam, M.R., and Berruti, F. (Editors). 1991. Enhanced Oil Recovery. AIChE Symposium Series No. 280, Volume 87. American Institute of Chemical Engineers, New York.

Chung, T.H. 1992. Thermodynamic Modeling for Organic Solids Precipitation. Paper No. SPE 24851. Proceedings. 67th Annual Technical Conference, Washington, DC, October 4–7. Society of Petroleum Engineers, Richardson, TX.

Coskuner, G. 2009. A New Process Combining Cyclic Steam Stimulation and Steam-Assisted Gravity Drainage: Hybrid SAGD. *Journal of Canadian Petroleum Technology*, 48(1): 8–13.

Craft, B.C., and Hawkins, M.F. 1959. *Applied Petroleum Reservoir Engineering*. Prentice-Hall, Englewood Cliffs, NJ.

Cramer, D.D. 2008. Stimulating Unconventional Reservoirs: Lessons Learned, Successful Practices, Areas for Improvement. Paper No. SPE 114172. Society for Petroleum Engineers, Richardson, TX.

Dawe, R.A. 2004. Miscible Displacement in Heterogeneous Porous Media. Proceedings. Sixth Caribbean Congress of Fluid Dynamics, UWI, January 22–23. University of the West Indies, St. Augustine.

Dees, J.M., and Handren, P.J. 1994. A New Method of Overbalanced Perforating and Surging of Resin for Sand Control. Paper No. SPE-26545-PA. *Journal of Petroleum Technology*, 46(5): 431–435.

Deo, M.D., Miharia, A., and Kumar, R. 1995. Solids Precipitation in Reservoirs Due to Non-isothermal Injections. Paper No. 28967. San Antonio, TX, February 14–17. Society of Petroleum Engineers, Richardson, TX.

Dreher, K.D., and Gogarty, W.B. 1979. An Overview of Mobility Control in Micellar—Polymer Enhanced Oil Recovery. *Journal of Rheology*, 23(2): 209–229.

Eaton, B.A., and Smithey, M. 1971. Formation Damage from Workover and Completion Fluids. Paper No. SPE-3707-MS. Proceedings. SPE California Regional Meeting, Los Angeles, CA, November 4–5. Society of Petroleum Engineers, Richardson, TX.

Erickson, D.D., Nielsen, V.G., and Brown, T.S. 1993. Thermodynamic Measurement and Prediction of Paraffin Precipitation in Crude Oil. Paper No. SPE 26604. Proceedings. 68th Annual Technical Conference and Exhibition, Houston, TX, October 3–6. Society of Petroleum Engineers, Richardson, TX.

Frick, T.C. 1962. *Petroleum Production Handbook*, Volume II. McGraw-Hill, New York.

Gomez, J., Morales, H., Toyo, D., and Bracho, J. 2012. Fracturing with Viscoelastic Surfactant Fluid in Cyclic Steam Injection Wells—A Synergy for Heavy Oil Recovery. Paper No. SPE 153536-MS. Society of Petroleum Engineers, Richardson, TX.

Hollabaugh, G.S., and Dees, J.M. 1993. Propellant Gas Fracture Stimulation of a Horizontal Austin Chalk Wellbore. Paper No. SPE-26584-MS. Proceedings. SPE Annual Technical

Conference and Exhibition, Houston, TX, October 3–6. Society of Petroleum Engineers, Richardson, TX.

Jayasekera, A.J., and Goodyear, S.G. 1999. The Development of Heavy Oil Fields in the UK Continental Shelf: Past, Present, and Future. SPE 54623. Society of Petroleum Engineers, Richardson, TX.

Kamath, V.A., Kakade, M.G., and Sharma, G.D. 1994. An Improved Molecular Thermodynamic Model for Asphaltene Equilibria. In: *Asphaltene Particles in Fossil Fuel Exploration, Recovery, Refining, and Production Processes*. M.K. Sharma and T.F. Yen (Editors). Plenum Press, New York.

Lake, L.W. 1989. *Enhanced Oil Recovery*. Prentice-Hall Inc., Englewood Cliffs, NJ.

Lake, L.W., and Walsh, M.P. 2004. *Primary Hydrocarbon Recovery*. Elsevier, Amsterdam, The Netherlands.

Leontaritis, K.J. 1989. Asphaltene Deposition: A Comprehensive Description of the Problem, Manifestations, and Modeling Approaches. Paper No. SPE 18892. Proceedings. Symposium on Production Operations, Oklahoma City, OK, March 13 and 14. Society of Petroleum Engineers, Richardson, TX.

Leontaritis, K.J., Mansoori, G.A., and Mansoori, U. 1987. Asphaltene Flocculation during Oil Production and Processing: A Thermodynamic Colloidal Model. Paper No. SPE 16258. Proceedings. International Symposium on Oilfield Chemistry, San Antonio, TX. February 4–6.

Majeed, A., Bringedal, B., and Overå, S. 1990. Model Calculates Wax Deposition for N. Sea Oils. *Oil & Gas Journal*, 88(June 18): 63–69.

Manrique, J.F. 1996. Optimization of Thermal Processes Through Combined Application of Horizontal Wells and Hydraulic Fracturing Technology. Proceedings. International Conference on Horizontal Well Technology, Calgary, Alberta, Canada. Society of Petroleum Engineers, Richardson, TX.

McLean, J.D., and Kilpatrick, P.K. 1997. Effects of Asphaltene Solvency on Stability of Water-in-Crude-Oil Emulsions. *Journal of Colloid and Interface Science*, 189: 242–253.

Morgenthaler, L.N. 1986. Formation Damage Tests of High-Density Brine Completion Fluids. Paper No. SPE-13811-PA. *SPE Production Engineering*, 1(6): 432–436.

National Petroleum Council. 2011. *Unconventional Oil*. Paper No. 1–6. Working Document of the NPC North American Resource Development Study. Prepared by the Unconventional Oil Subgroup of the Resource & Supply Task Group, September 15. https://www.npc.org/Prudent_Development-Topic_Papers/1-6_Unconventional_Oil_Paper.pdf; accessed January 15, 2015.

Nghiem, L.X., Hassam, M.S., Nutakki, R., and George, A.E.D. 1993. Efficient Modeling of Asphaltene Precipitation. Paper No. SPE 26642. Proceedings. 68th Annual Technical Conference, Houston, TX, October 4–7. Society of Petroleum Engineers, Richardson, TX.

Nor-Aziam, N., and Adewumi, M.A. 1993. Development of Asphaltene Phase Equilibria Predictive Model. Paper No. SPE 26905. Proceedings. Eastern Regional Conference and Exhibition, Pittsburgh, PA, November 2–4. Society of Petroleum Engineers, Richardson, TX.

OTA. 1978. Enhanced Oil Recovery Potential in the United States. NTIS Order #PB-276594. Office of Technology Assessment, Washington, DC.

Pan, H., and Firoozabadi, A. 1996. Pressure and Composition Effects on Wax Precipitation: Experimental Data and Model Results. Paper No. SPE 36740. Proceedings. Annual

Technical Conference and Exhibition, Denver, CO, October 6–9. Society of Petroleum Engineers, Richardson, TX.

Patton, J.T., and Phelan, P.F. 1985. Well Damage Hazards Associated with Conventional Completion Fluids. Paper No. SPE-13800-MS. Proceedings. SPE Production Operations Symposium, Oklahoma City, OK, March 10–12. Society of Petroleum Engineers, Richardson, TX.

Prats, M. 1986. *Thermal Recovery*. Volume 7. Society of Petroleum Engineers, New York.

Rassamdana, H., Farhani, M., Dabir, B., Mozaffarian, M., and Sahimi, M. 1999. *Energy & Fuels*, 13: 176–187.

Reed, R.L., and Healy, R.N. 1977. *Improved Oil Recovery by Surfactant and Polymer Flooding*. D.O. Shah and R.S. Schechter (Editors). Academic Press, New York.

Schumacher, M.M. 1980. *Enhanced Recovery of Residual and Heavy Oils*. Noyes Data Corp., Park Ridge, NJ.

Settari, A. and Raisbeck, J.M. 1981. Analysis and Numerical Modeling of Hydraulic Fracturing During Cyclic Steam Stimulation in Oil Sands. *Journal of Petroleum Technology*, 33(11): 2201–2212.

Skovborg, P., Rønningsen, H.P., and Pedersen, K.S. 1991. Wax Precipitation from North Sea Crude Oils. 4. Thermodynamic Modeling. *Energy & Fuels*, 5: 924–932.

Sorbie, K.S. 1991. *Polymer-Improved Oil Recovery*. Springer Science and Business Media, New York.

Speight, J.G. 2000. *Desulfurization of Heavy Oils and Residua*, 2nd Edition. Marcel Dekker Inc., New York.

Speight, J.G. 2009. *Enhanced Recovery Methods for Heavy Oil and Tar Sands*. Gulf Publishing Company, Houston, TX.

Speight, J.G. 2014. *The Chemistry and Technology of Petroleum*, 5th Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Stalkup, F.I., 1983. *Miscible Displacement*. SPE Monograph No. 8. Society of Petroleum Engineers, Richardson, TX.

Taber, J.J, and Martin, F.D. 1983. Technical Screening Guides for the Enhanced Recovery of Oil. SPE 12069. Proceedings. 58th SPE Annual Technical Conference and Exhibition, San Francisco, CA, October 5–8.

Terwilliger, P.L. 1975. Paper 5568. Proceedings. 50th Annual Fall Meeting. Society of Petroleum Engineers, American Institute of Mechanical Engineers. American Institute of Mechanical Engineers, Washington, DC.

Terwilliger, P.L., Clay, R.R., Wilson, L.A., and Gonzalez-Gerth, E. 1975. *Journal of Petroleum Technology*, 27: 9.

UEG. 2008. Enhanced Oil Recovery. United Energy Group, National Energy Technology Laboratory, Pittsburgh, Pennsylvania and Morgantown West Virginia. US Department of Energy, Washington, DC.

US DOE. 1996. Maintaining Oil Production from Marginal Fields: A Review of the Department of Energy's Reservoir Class Program. Panel on the Review of the Oil Recovery Demonstration Program of the Department of Energy, Committee on Earth Resources, Board on Earth Sciences and Resources, Commission on Geosciences, Environment, and Resources, National Research Council. National Academy Press, Washington, DC.

Venuto, P.B. 1989. Tailoring EOR Processes to Geologic Environments. World Oil, 209(November): 61–68.

Weingarten, J.S., and Euchner, J.A. 1986. Methods for Predicting Wax Precipitation and Deposition. SPE Paper No. 15654. Proceedings. 61st Annual Technical Conference and Exhibition, New Orleans, LA, October 5–8. Society of Petroleum Engineers, Richardson, TX.

Yang, C., and Gu, Y. 2005a. A Novel Experimental Technique for Studying Solvent Mass Transfer and Oil Swelling Effect in a Vapor Extraction (VAPEX) Process. Paper No. 2005-099. Proceedings. 56th Annual Technical Meeting, The Canadian International Petroleum Conference, Calgary, June 7–9.

Yang, C., and Gu, Y. 2005b. Effects of Solvent-Heavy Oil Interfacial Tension on Gravity Drainage in the VAPEX Process. Paper No. SPE 97906. Society of Petroleum Engineers International Thermal Operations and Heavy Oil Symposium, Calgary, Alberta, Canada, November 1–3.

Zaki, N.N., Poindexter, M.K., and Kilpatrick, P.K. 2002. Factors Contributing to Petroleum Foaming. 2. Synthetic Crude Oil Systems. *Energy & Fuels*, 16: 711–717.

4

ANALYSIS AND PROPERTIES OF FLUIDS

4.1 INTRODUCTION

Petroleum provides not only raw materials for the ubiquitous plastics and other products but also fuel for energy, industry, heating, and transportation. From a chemical standpoint petroleum is an extremely complex mixture of hydrocarbon compounds, with minor amounts of nitrogen-, oxygen-, and sulfur-containing compounds as well as trace amounts of metal-containing compounds. Many types of petroleum and heavy oil exist (tar sand bitumen stands outside of the *petroleum–heavy oil property-recovery envelope*), and a variety of production processes are being used and developed to recover it (Speight, 2009, 2014). However, technologies used for the recovery conventional oil also face limitations and potential recovery problems that are similar (but often more emphatic) than those faced with heavy oil. In fact, there are many producers of heavy oil that do not experience severe paraffin or asphaltene problems, while there are numerous conventional oil production operations that experience severe problems related to the deposition of paraffin (wax deposition) or deposition of asphaltene constituents (asphaltene deposition) (Fig. 4.1) (Speight, 2014, 2015a, 2015b).

Thus, it is the purpose of this chapter to present the properties of crude oil and natural gas and to comment of the effects of these properties on recovery. In fact, the properties of reservoir fluids (particularly crude oil) are an important aspect of recovery operations. It is not just a matter of drilling a well into the reservoir (the producing formation), and lo and behold crude oil of natural gas ascends through the well to the surface. In addition, heavy oil exhibits recovery problems that are not typical of conventional petroleum. For example, heavy oil typically has relatively low proportions of volatile constituents with low molecular weights and high proportions of constituents with high molecular weights (Speight, 2009, 2014). The high molecular weight fraction of heavy oils are comprised of compounds (not necessarily

---

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

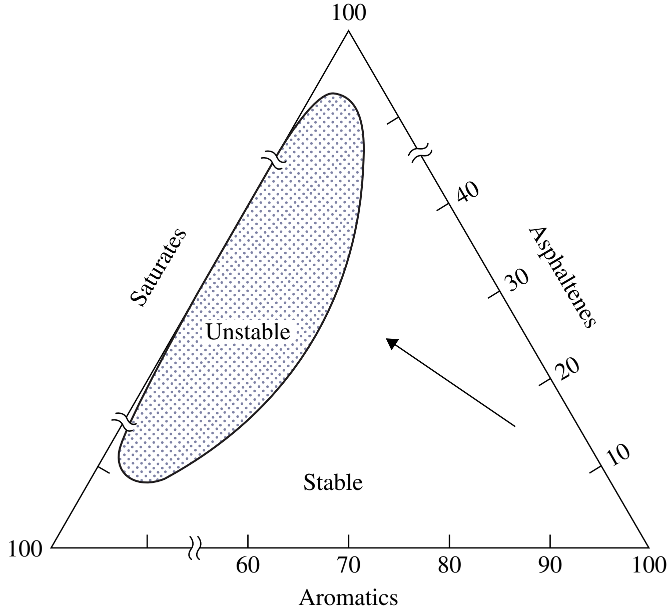


FIGURE 4.1 Representation of the instability of asphaltene constituents as the composition of the fluid becomes more paraffinic. For wax deposition, the unstable region would be more prone to temperature effects and flow regimes rather than composition. Source: Adapted from Speight, 2014, 2015b.

paraffin derivatives or asphaltene constituents) with high melting points and high pour points that greatly contribute to the fluid properties of heavy oil and hence to reduced mobility compared to conventional petroleum. It is typically this poor mobility of the crude, as opposed to accumulations of paraffins or asphaltene constituents in formation rock pore throats or production lines, that is usually the cause of production problems. Some, but not all, heavy oils do contain moderate to high levels of asphaltene constituents. However, the asphaltene constituents do not become a problem unless they *precipitate* or *phase separate* from the oil and build up in the formation or production string.

Thus, the amount of oil that is recoverable is determined by a number of factors including the permeability of the rocks, the strength of natural drives (the gas present, pressure from adjacent water, or gravity), and the viscosity of the oil. In sandstone reservoirs that typically exhibit medium to high permeability, conventional crude oil flows freely to the well and thence to the surface. Heavy oil is somewhat more sluggish and often (depending upon the reservoir temperature) requires additional stimulation, often through the application of steam or carbon dioxide (Chapter 3).

However, when the reservoir rocks exhibit low permeability such as in tight formations and shale formations, oil generally cannot flow to the well. The flow of oil is often helped by natural pressures surrounding the reservoir rocks including natural gas that may be dissolved in the oil–natural gas present above the oil, water below the oil, and the strength of gravity. Whatever the method chosen for the recovery of natural gas and crude oil, it may only partially satisfy the extent of the recovery. Additional technique, such as fracturing, may need to be applied.

In fact, the problems of producing conventional crude oil and heavy crude oil from the reservoir are typically a result of disturbing the molecular balance, which, in turn, influences the mobility of the oil (Speight, 2009, 2014). Success depends as much on understanding the fluid properties of the reservoir as it does on knowing the geology of the reservoir itself.

Tight formation and shale formations typically have permeability less than 1 mD, and the reservoir rocks in such formations show a strong stress sensitivity of the fluid transport properties and a considerable productivity decline due to changing stress conditions during the production process. Furthermore, in a typical convention the speed at which pressure transients move through porous media is not only a function of the formation permeability but also a function of (i) the fluid viscosity and (ii) the fluid compressibility, as well as other fluid properties. For example, in a high-permeability gas reservoir (say, 100 mD), a pressure transient will reach the reservoir boundary in a relatively short time (hours to days). However, in a low-permeability reservoir (ca. 0.1 mD), the pressure transients move much slower, and it may require years of production before well-to-well interference or a boundary can be recognized by studying pressure transient or production data. Thus fluid (gas and liquid) properties can exert a considerable influence on the productivity of fluids from tight formations and shale formations.

To satisfy specific needs with regard to the recovery of crude oil and natural gas as well as to the nature of the recovered product, various standard test methods are available from organizations, such as the ASTM International (Speight, 2014, 2015b). Thus, it is appropriate that in any discussion of the physical properties of reservoir fluids, reference should be made to the corresponding test and, accordingly, the various test numbers have been included in the text. Application of standard text methods to reservoir fluids and inspection of the data provide indications of the most logical means of recovery. Indeed, careful evaluation from physical property data is a major part of the initial study of reservoir fluids, and *proper* interpretation of the data resulting from the inspection of crude oil requires an understanding of their significance (Speight, 2014, 2015b). But before any analysis occurs, it is necessary to ensure that the sample is consistent with (and a representative sample of) the fluid in the reservoir and that the data can be reproduced within the limits of accuracy (Speight, 2015b).

4.2 CRUDE OIL

Conventional petroleum and heavy oil exhibit a wide range of physical properties, and several relationships can be made between various physical properties (Speight, 2007). Whereas the properties such as viscosity, density, and boiling range may vary widely, the ultimate or elemental analysis varies over a narrow range for a large number of samples (Speight, 2014, 2015b). However, heavy oil containing 9.5% w/w heteroatoms (nitrogen, oxygen, sulfur, and metals such as nickel and vanadium) may contain few pure hydrocarbon constituents insofar as the constituents contain *at least one or more* nitrogen, oxygen, and/or sulfur atoms within the molecular structures. And it is the heteroelements that can have substantial effects on mobility in the reservoir and the overall result of the recovery process. Thus, initial inspection of the oil (conventional examination of the physical properties) is necessary from which it is possible to make deductions about the propensity for easy or difficult recovery. In fact, evaluation of reservoir fluids from physical property data as to which recovery sequences should be employed for any particular crude oil is a predominant part of the initial examination of reservoir fluids.

The chemical composition of crude oil is a much truer indicator of recovery behavior. Whether the composition is represented in terms of compound types or, more likely, in terms of generic compound classes, it can assist in the determination of the nature and type of any potential interactions of the oil with the reservoir rock or the potential for changes in oil composition that can be affected by changes in pressure and temperature (Speight, 2014). Hence, chemical composition can play a large part in determining the nature of the products that arise from the recovery operations. It can also play a role in determining the means by which a particular feedstock should be processed (Speight, 2014), and this becomes particularly important when partial upgrading in the reservoir (*in situ* upgrading) is considered as an option during recovery.

4.2.1 Sampling

The composition of a reservoir fluid is determined by acquiring a representative sample of the fluid. Surface samples can be obtained relatively easily by collecting liquid and gas samples from test or production separators after which the samples are recombined in a laboratory. However, the result can be (or more than likely be) unrepresentative of reservoir conditions, particularly when sampling from a gas-condensate reservoir. Some examples of potential problems include (i) recombining the gas and liquid samples at an incorrect ratio, (ii) changing production conditions prior to or during sampling, and (iii) commingling samples from different zones where the samples have different properties. If the liquid content is low when acquiring surface samples, a small loss of the liquid in production tubulars or separators will render the condensate sample unrepresentative of the formation fluid.

On the other hand, samples can also be collected downhole from wellbore fluids in gas-condensate reservoirs or in volatile crude oil reservoirs (such as oil held in tight formations and in shale formations) (Table 4.1), which is practical if the wellbore flowing pressure is above the dew-point pressure, but it is generally not recommended if the pressure anywhere in the tubing is lower than the dew-point pressure. If there is two-phase flow in the wellbore, any liquid forming in the tubing during or prior to the sampling may segregate to the bottom of the tubing string—where a bottom-hole sampler collects fluids—potentially resulting in an unrepresentative sample with too much of the heavier components. In the case of a highly volatile crude oil (such as the Bakken crude oil), this would give anomalous data, which would indicate that the crude is not as volatile (and less dangerous) than it actually is.

TABLE 4.1 Typical Properties of Fluids Occurring in Tight Formations and Shale Formations

Constituents (%v/v)	Dry Gas	Wet Gas	Condensate	Volatile Oil[a]
CO_2	0.10	1.41	2.37	1.82
N_2	2.07	0.25	0.31	0.24
C_1	86.12	92.46	73.19	57.60
C_2	5.91	3.18	7.80	7.35
C_3	3.58	1.01	3.55	4.21
Butanes (C_4)	1.72	0.52	2.16	2.84
Pentanes (C_5)	0.50	0.21	1.32	1.48
Hexanes (C_{6+})		0.14	1.09	1.92
Heptanes (C_{7+})		0.82	8.21	22.57

[a] Representative of crude oil from tight formations and tight shale formations.

Thus, as a result of the complexity (and variation in the composition) of petroleum and the conditions in the reservoir (or deposit), the importance of the correct *sampling* cannot be overstressed (Wallace, 1988; Speight, 2014, 2015b). Properties such as elemental analysis, metal content, density (specific gravity), and viscosity (to mention only a few properties) are affected by the homogeneity (or heterogeneity) of the sample. In addition, adequate records of the circumstances and conditions during sampling have to be made; for example, in sampling from oil field separators, the temperatures and pressures of the separation plant and the atmospheric temperature would be noted. An accurate sample handling and storage log should be maintained and should include information such as (i) the precise source of the sample, that is, the exact geographic location or locale from which the sample was obtained; (ii) a description of the means by which the sample was obtained; (iii) the protocols that have been used to store the sample; (iv) chemical analyses, such as elemental composition; (v) physical property analyses, such as API gravity, pour point, and distillation profile; (vi) the standard test methods used to determine the properties in items (iv) and (v); and (vii) the number of times that the samples have been retrieved from storage to extract a portion, that is, indications of the exposure of the sample to the air or to oxygen. Attention to factors such as these enables standardized comparisons to be made when subsequent samples are taken from the stored material.

However, before this occurs there are several protocols involved in initial isolation and cleanup of the sample. In fact, considerable importance attaches to the presence of *water* or *sediment* in crude oil (ASTM D1796, ASTM D4007), for they lead to difficulties during transportation and during refining, for example, corrosion of pipelines and equipment, uneven running on the distillation unit, blockages in heat exchangers, and adverse effects on product quality. Typically, the *sediment* consists of finely divided solids that may be dispersed in the oil or carried in water droplets. The solids may be drilling mud or sand or scale picked up during the transport of the oil or may consist of chlorides derived from evaporation of brine droplets in the oil. In any event, the sediment can lead to serious plugging of the equipment, corrosion due to chloride decomposition, and a lowering of residual fuel quality.

Water may be found in the crude either in an emulsified form or in large droplets and can cause flooding of distillation units and excessive accumulation of sludge in tanks. The quantity is generally limited by pipeline companies and by refiners, and steps are normally taken at the wellhead to reduce the water content as low as possible. However, water can be introduced during shipment, and, in any form, water and sediment are highly undesirable in a refinery feedstock, and the relevant tests (ASTM D954, ASTM D1796, ASTM D4006) are regarded as important in crude oil quality examinations. Prior to assay it is sometimes necessary to separate the water from a crude oil sample, and this is usually carried out by one of the procedures described in the preliminary distillation of crude oil. In addition, some crude oils and heavy oils form persistent (difficult-to-break) emulsions that can interfere during testing wax-bearing crude oils for sediment and water insofar as wax suspended in the sample (unless brought into solution prior to the test) will be recorded as sediment.

There is a great variation in the *salt content* of crude oil depending mainly on the source and possibly on the producing wells or zones within a reservoir or field. In addition, at the refinery, salt water introduced during shipment by tanker may have contributed to this total salt content. These salts have adverse effects on refinery operations especially in increasing maintenance following corrosion in crude units and heat exchangers. It is common practice to monitor wells in a producing field for high salt content, and it is also general practice to desalt the crude at the refinery. The determination of the salt content of crude oil is often made, but as with water and sediment tests, careful sampling is necessary.

4.2.2 Physical Properties

4.2.2.1 Density and Specific Gravity *Density* is the mass of a unit volume of material at a specified temperature and has the dimensions of grams per cubic centimeter (a close approximation to grams per milliliter). *Specific gravity* is the ratio of the mass of a volume of the substance to the mass of the same volume of water and is dependent on two temperatures, those at which the masses of the sample and the water are measured. When the water temperature is 4 °C (39 °F), the specific gravity is equal to the density in the centimeter–gram–second (cgs) system, since the volume of 1 g of water at that temperature is, by definition, 1 ml. Thus the density of water, for example, varies with temperature, and its specific gravity at equal temperatures is always unity. The standard temperatures for a specific gravity in the petroleum industry in North America are 60/60 °F (15.6/15.6 °C).

The *density* and *specific gravity* of petroleum and heavy oil are two properties that have found wide use in the industry for preliminary assessment of the character of the oil. In particular, heavy oil with a high content of resin constituents and asphaltene constituent and poor mobility at ambient temperature and pressure, thereby requiring vastly different processing sequences, may have a specific gravity (density) of about 0.95. Density or specific gravity or API gravity may be measured, depending upon the properties of the heavy oil sample, by means of a hydrometer (ASTM D287, ASTM D1298) or by means of a pycnometer (ASTM D941, ASTM D1217, ASTM D1555). The variation of density with temperature, effectively the coefficient of expansion, is a property of great technical importance, since most crude oils are sold by volume and specific gravity is usually determined at the prevailing temperature (21 °C, 70 °F) rather than at the standard temperature (60 °F, 15.6 °C). The tables of gravity corrections (ASTM D1555) are based on an assumption that the coefficient of expansion is a function (at fixed temperatures) of density only.

Specific gravity is influenced by chemical composition, but quantitative correlation is difficult to establish. Nevertheless, it is generally recognized that increased amounts of aromatic compounds result in an increase in density, whereas an increase in saturated compounds results in a decrease in density. It is also possible to recognize certain preferred trends between the API gravity of crude oils and residua and one or more of the other physical parameters. For example, a correlation exists between the API gravity and sulfur content, Conradson carbon residue, and viscosity (Speight, 2000). However, the derived relationships between the density of heavy oil and its fractional composition are valid only when applied to a certain type of heavy oil and may lose their significance when applied to heavy oil from different sources.

The values for density (and specific gravity) cover an extremely narrow range considering the differences in fluid behavior. In an attempt to inject a more meaningful relationship between the physical properties and processability of the various crude oils, the American Petroleum Institute devised a measurement of gravity devised upon the Baumé scale for industrial liquids. The Baumé scale for liquids lighter than water was used initially:

$$^\circ\text{Baumé} = 140 / \text{sp gr @ } 60/60^\circ\text{F} - 130$$

However, a considerable number of hydrometers calibrated according to the Baumé scale were found to be in error by a consistent amount, and this led to the adoption of the equation

$$^\circ\text{API} = 141.5 / \text{sp gr @ } 60/60^\circ\text{F} - 131.5$$

The specific gravity of conventional crude oil usually ranges from about 0.8 (45.3° API) to about 1.0 (10° API) for heavy oil. This is in keeping with the general trend that a lower atomic hydrogen/carbon ration (increased aromaticity) leads to a decrease in API gravity (or, more correctly, an increase in specific gravity).

4.2.2.2 Elemental Analysis The elemental (ultimate) analysis to determine the percentages (% w/w) of carbon, hydrogen, nitrogen, oxygen, and sulfur is perhaps the first method used to examine the general nature, and perform an evaluation, of the fluid). The atomic ratios of the various elements to carbon (i.e., H/C, N/C, O/C, and S/C) are frequently used for indications of the overall character of the oil. It is also of value to determine the amounts of trace elements, such as vanadium and nickel, in a feedstock since these materials can have serious deleterious effects on catalyst performance during partial upgrading during recovery or even using a partial upgrading process at the surface before transportation.

There are procedures for the elemental analysis of petroleum and heavy oil, but many such methods may have been designed for other materials. For example, *carbon content* can be determined by the method designated for coal and coke or by the method designated for municipal solid waste. There are also methods designated for:

1. *Hydrogen content* (Speight, 2015b)
2. *Nitrogen content* (Speight, 2015b)
3. *Oxygen content* (Speight, 2015b)
4. *Sulfur content* (Speight, 2015b)

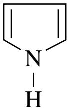
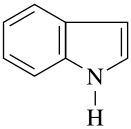
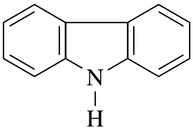
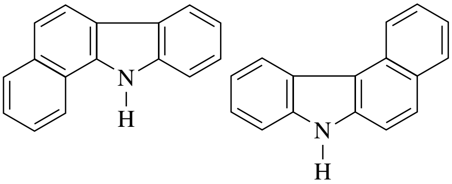
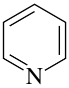
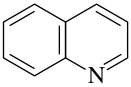
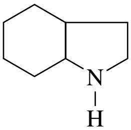
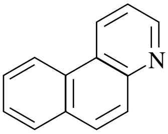
Of the data that are available, the proportions of the elements vary only slightly over narrow limits. Perhaps the more pertinent property in the present context is the nitrogen content and the *sulfur content*, which along with the API gravity represent the two properties that have the greatest influence on the behavior of reservoir fluids. The nitrogen content is typically lower than 1.0% w/w, which represents a variety of nitrogen-containing constituents (Table 4.2), while the sulfur content varies from about 0.1% to about 5% w/w, which represents a variety of sulfur-containing constituents (Table 4.3) (Speight, 2014, 2015b). Both of these heteroatom compounds (i.e., nitrogen-containing and sulfur-containing) can be the formative agents in oil–rock interactions, which influence recovery operations and dictate the need for enhanced oil recovery accompanied by fracturing operations.

4.2.2.3 Metal Content *Metals* (particularly *vanadium* and *nickel*) are found in every most crude oils. Heavy oil contains relatively high proportions of metals (compared to conventional crude oil) either in the form of salts or as organometallic constituents (such as the metalloporphyrins), which are extremely difficult to remove from the feedstock. Indeed, the nature of the process by which residua are produced virtually dictates that all the metals in the original crude oil are concentrated in the residuum (Speight, 2014, 2015b). The metallic constituents may actually *volatilize* under the thermal recovery operations and appear in the reservoir or in the production lines.

A variety of tests have been designated for the determination of metals in petroleum and heavy oil (ASTM D1026, ASTM D1262, ASTM D1318, ASTM D1368, ASTM D1548, ASTM D1549, ASTM D2547, ASTM D2599, ASTM D2788, ASTM D3340, ASTM D3341, ASTM D3605). Determination of metals in whole feeds can be accomplished by combustion of the sample so that only inorganic ash remains. The ash can then be digested with an acid and the solution examined for metal species by atomic absorption (AA) spectroscopy or by inductively coupled argon plasma (ICP) spectrometry.

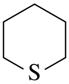
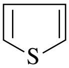
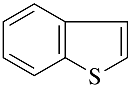
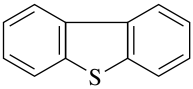
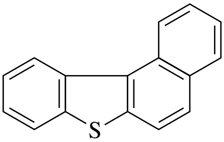
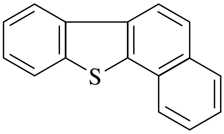
4.2.2.4 Viscosity *Viscosity* is the most important single fluid characteristic governing the motion of crude oil and is actually a measure of the internal resistance to motion of a fluid by reason of the forces of cohesion between molecules or molecular groupings. By definition, *viscosity* is the force in dynes required to move a plane of $1\,cm^2$ area at a distance of 1 cm from another plane of $1\,cm^2$ area through a distance

TABLE 4.2 Hypothetical Structures for Nitrogen-Containing Compounds in Petroleum

Nonbasic		
Pyrrole	C_4H_5N	
Indole	C_8H_7N	
Carbazole	$C_{12}H_9N$	
Benzo(a)carbazole	$C_{16}H_{11}N$	
Basic		
Pyridine	C_5H_5N	
Quinoline	C_9H_7N	
Indoline	C_8H_9N	
Benzo(f)quinoline	$C_{13}H_9N$	

of 1 cm in 1 s. In the cgs system the unit of viscosity is the *poise* (P) or *centipoise* (cP) (1 cP = 0.01 P). Two other terms in common use are *kinematic viscosity* and *fluidity*. The kinematic viscosity is the viscosity in centipoise divided by the specific gravity. The unit of kinematic viscosity is the *stoke* (cm^2/s), although *centistokes* (0.01 cSt) is in more common usage; fluidity is simply the reciprocal of viscosity. Furthermore, although there are several standard test methods that can be used for determination of viscosity, like the determination of the density, the choice of an instrument depends upon the properties of the oil (Speight, 2015b). The viscosity (ASTM D445, ASTM D88, ASTM D2161, ASTM D341, ASTM D2270) varies markedly over a very wide

TABLE 4.3 Hypothetical Structures for Sulfur-Containing Compounds in Petroleum

RSH	Thiols (mercaptans)
RSR’	Sulfides
	Cyclic sulfides
RSSR’	Disulfides
	Thiophene
	Benzothiophene
	Dibenzothiophene
 	Naphthobenzothiophene

range. Values vary from several hundred centipoises at room temperature to many thousands of centipoises at the same temperature.

Of the many types of instruments that have been proposed for the determination of viscosity, the simplest and most widely used are capillary types (ASTM D445), and the viscosity is derived from the equation

$$\mu = \pi r^4 P / 8nl$$

In the equation, r is the tube radius, l the tube length, P the pressure difference between the ends of a capillary, n the *coefficient of viscosity*, and μ the quantity discharged in unit time. Not only are such capillary instruments the most simple, but when designed in accordance with known principle and used with known necessary correction factors, they are probably the most accurate viscometers available. It is usually more convenient, however, to use relative measurements, and for this purpose the instrument is calibrated with an appropriate standard liquid of known viscosity.

Batch flow times are generally used; in other words, the time required for a fixed amount of sample to flow from a reservoir through a capillary is the datum that is actually observed. Any features of technique that contribute to longer flow times are usually desirable. Some of the principal capillary viscometers in use are those of Cannon-Fenske, Ubbelohde, Fitzsimmons, and Zeitfuchs.

The *Saybolt universal second* (SUS) (ASTM D88) is the time in seconds required for the flow of 60 ml of oil, at constant temperature, through a calibrated orifice. The *Saybolt furol second* (SFS) (ASTM D88) is determined in a similar manner except that a larger orifice is employed.

As a result of the various methods for viscosity determination, it is not surprising that much effort has been spent on interconversion of the several scales, especially converting Saybolt to kinematic viscosity (ASTM D2161):

$$\text{Kinematic viscosity} = a \times \text{Saybolt } s + b / \text{Saybolt } s$$

In this equation, a and b are constants.

The SUS equivalent to a given kinematic viscosity varies slightly with the temperature at which the determination is made because the temperature of the calibrated receiving flask used in the Saybolt method is not the same as that of the oil. Conversion factors are used to convert kinematic viscosity from 2 to 70 cSt at 38 °C (100 °F) and 99 °C (210 °F) to equivalent Saybolt universal viscosity in seconds. Appropriate multipliers are listed to convert kinematic viscosity over 70 cSt. For a kinematic viscosity determined at any other temperature the equivalent Saybolt universal value is calculated by use of the Saybolt equivalent at 38 °C (100 °F) and a multiplier that varies with the temperature:

$$\text{Saybolt } s \text{ at } 100°\text{F}(38°\text{C}) = \text{cSt} \times 4.635$$

$$\text{Saybolt } s \text{ at } 210°\text{F}(99°\text{C}) = \text{cSt} \times 4.667$$

Various studies have also been made on the effect of temperature on viscosity since the viscosity of the oil decreases as the temperature increases:

$$\log\log(n + c) = A + B\log T$$

In this equation, n is absolute viscosity, T is temperature, and A and B are constants. This equation has been sufficient for most purposes and has come into very general use. The constants A and B vary widely with different oils, but c remains fixed at 0.6 for all oils having a viscosity over 1.5 cSt; it increases only slightly at lower viscosity (0.75 at 0.5 cSt). The viscosity–temperature characteristics of any oil, so plotted, thus create a straight line, and the parameters A and B are equivalent to the intercept and slope of the line. To express the viscosity and viscosity–temperature characteristics of an oil, the slope and the viscosity at one temperature must be known; the usual practice is to select 38 °C (100 °F) and 99 °C (210 °F) as the observation temperatures.

Suitable conversion tables are available (ASTM D341), and each table or chart is constructed in such a way that for any given oil the viscosity–temperature points result in a straight line over the applicable temperature range. Thus, only two viscosity measurements need to be made at temperatures far enough apart to determine a line on the appropriate chart from which the approximate viscosity at any other temperature can be read.

4.2.3 Thermal Properties

The thermal properties of petroleum and heavy oil are those properties (or characteristics) that determine how the fluid will behavior (or react) when it is subjected to excessive heat, or heat fluctuations over time. As with all properties (Speight, 2014, 2015b), a collection of standard test methods is available for the evaluation and assessment of the thermal properties.

4.2.3.1 Carbon Residue The carbon residue (ASTM D189 and ASTM D524) is a property that can be correlated with several other properties of the oil and may be used to evaluate the propensity for depositing carbonaceous materials during thermal recovery. There are two older well-used methods for determining the carbon residue: the Conradson method (ASTM D189) and the Ramsbottom method (ASTM D524)—both methods are applicable to heavy oil, but the metallic constituents will give erroneously high carbon residues. The metallic constituents must first be removed from the oil, or they can be estimated as ash by complete burning of the coke after carbon residue determination. There is no exact correlation between the two methods—it is possible to interconnect the data.

Another method (ASTM D4530) requires smaller sample amounts and was originally developed as a *thermogravimetric method*. The carbon residue produced by this method is often referred to as the *microcarbon residue* (*MCR*). Agreements between the data from the three methods are good, making it possible to interrelate all of the data from carbon residue tests (Long and Speight, 1989).

4.2.3.2 Heat of Combustion The heat of combustion is the energy released as heat when a compound undergoes complete combustion with oxygen under standard conditions. The chemical reaction is typically shown as a hydrocarbon reacting with oxygen to form carbon dioxide, water, and heat. The heat of combustion is conventionally measured using a bomb calorimeter and may also be calculated as the difference between the heat of formation of the products and reactants. Also, the gross heat of combustion is given with a reasonable degree of accuracy by the equation

$$Q = 12{,}400 - 2100d^2$$

In the equation, d is the 60/60 °F specific gravity. Deviation is generally less than 1% although highly aromatic oil may show considerably higher values.

For thermodynamic calculation of equilibria, combustion data of extreme accuracy are required because the heats of formation of water and carbon dioxide are large in comparison with those in the hydrocarbons. Great accuracy is also required of the specific heat data for the calculation of free energy or entropy. Much care must be exercised in selecting values from the literature for these purposes, since many of those available were determined before the development of modern calorimetric techniques.

4.2.3.3 Liquefaction and Solidification The liquefaction and solidification of oil are important properties to be taken into consideration at both the wellhead and in the refinery. In fact, since heavy oil can be a borderline liquid or near solid at ambient temperature, problems may arise from solidification during normal use or storage.

The *melting point* is a test (ASTM D87, ASTM D127) that is widely used by suppliers of wax and by the wax consumers that can also be applied to heavy oil, but it is the *softening point* (ASTM D36, ASTM D2398), defined as the temperature at which a disk of the material softens and sags downward a distance of 25 mm under the weight of a steel ball under strictly specified conditions, that finds wider use for heavy oil. The *dropping point* (ASTM D566) is the near-equivalent test that is used for lubricating greases.

The *pour point* of a crude oil was originally applied to crude oil that had a high wax content. More recently, the pour point, like the viscosity, is determined principally for use in pumping arid pipeline design calculations. To determine the *pour point* (ASTM D97), the sample is first heated to 46 °C (115 °F) and cooled in air to 32 °C (90 °F) before the tube is immersed in the same series of coolants as used for the determination of the *cloud point*. The sample is inspected at temperature intervals of 2 °C (3 °F) by withdrawal and holding horizontal for 5 s until no flow is observed during this time interval.

The pour point can also be used as an indicator of the temperature at which residual oil or heavy oil will flow during *in situ* recovery operations (Fig. 4.2) (Speight, 2009, 2014). For example, for asphaltic crude oils where paraffin precipitation will not occur, if 21 °C (70 °F) is the pour point of heavy oil in a reservoir where the temperature is 38 °C (100 °F), the oil is liquid under reservoir conditions and will be mobile and will flow under those conditions. On the other hand, tar sand bitumen (pour point: 60 °C, 140 °F) in a deposit (temperature: 10 °C, 50 °F) will be solid and immobile. This state of the oil in the reservoir can also have consequences on the ability of gases and liquids (e.g., steam, hot water) used for recovery operations to penetrate the reservoir/deposit. Although pressure can have some influence on the pour point, the effect is not large and unlikely to affect any general conclusions. Indeed, there is a relationship between API gravity and pour point. Thus, any

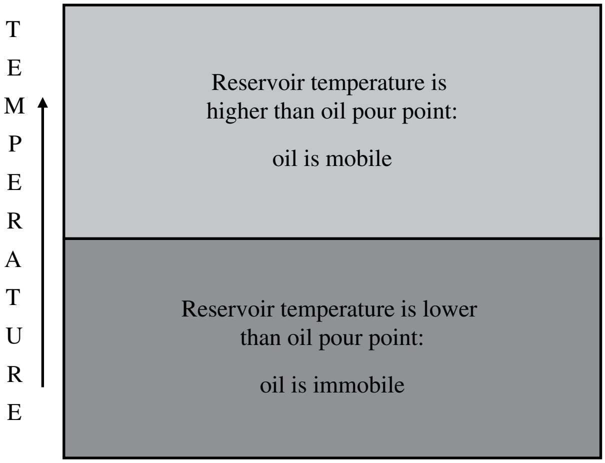


FIGURE 4.2 Relationship of pour point and reservoir temperature. Source: Adapted from Speight, 2009, 2014.

increase in pour point due to an increase in pressure (surface compared to reservoir or deposit pressure) will be most likely be negated as the API gravity decreases with increase in temperature (60 °F compared to reservoir temperature).

The use of the pour point offers an alternate to the use of a single parameter to predict fluid behavior, and the use of two parameters gives a more realistic view of oil behavior.

4.2.3.4 Specific Heat *Specific heat* is the quantity of heat required to raise a unit mass of material through one degree of temperature (ASTM D2766). It is an extremely important engineering quantity in practice and is used in all calculations on heating and cooling heavy oil. Many measurements have been made on various hydrocarbon materials, but the data for most purposes may be summarized by the general equation

$$C = 1/d\left(0.388 + 0.00045t\right)$$

where C is the specific heat at t °F of an oil whose specific gravity 60/60 °F is d; thus, specific heat increases with temperature and decreases with specific gravity.

4.2.3.5 Solubility Although not truly a thermal property, the solubility parameter of crude oil and its constituent fractions is of interest during thermal methods of recovery.

The solubility parameter of crude oil fraction, especially the asphaltene constituent fractions, has been the subject of study with some interesting results emerging (Speight, 2007). In fact, phase separation as can occur during thermal recovery of heavy oil can be explained by use of the solubility parameter, δ, for petroleum fractions and for the solvents. As an extension of this concept, there is sufficient data to draw a correlation between the atomic hydrogen/carbon ratio and the solubility parameter for hydrocarbons and the constituents of the lower boiling fractions of petroleum. There is recognition that hydrocarbon liquids can dissolve polynuclear hydrocarbons in which there is usually less than a three-point difference between the lower solubility parameter of the solvent and the higher solubility parameter of the solute. Thus, a parallel, or near-parallel, line can be assumed that allows the solubility parameter of the resin constituents (as the resin fraction) and the asphaltene constituents (as the asphaltene fraction) to be estimated (Speight, 2014, 2015b). By this means, the solubility parameter of asphaltene constituents can be estimated to fall in the range 9–12, which is in keeping with the asphaltene constituents being composed of a mixture of different compound types with an accompanying variation in polarity. As the thermal reaction proceeds (especially if the recovery process employs superheated steam or combustion), removal of alkyl side chains from the asphaltene constituents decreases the hydrogen-to-carbon atomic ratio and increases the solubility parameter. Concurrently changes occur to the oil medium but are of lesser effect, thereby bringing about a higher solubility parameter differential between the reacted asphaltene constituents and resin constituents and the oil. As a result deposition ensues (Speight, 2014). The deposited reacted material is usually a product of the action of the highest molecular weight and/or the highest polarity constituents in the asphaltene and resin fractions (Speight, 2014). This is of benefit to the refiner but not always to the producer of crude oil insofar as deposition of high molecular weight polar material causes blockage of the reservoir flow channels.

Another aspect of this reaction is the order of deposition relative to models applied to the system. The more polar constituents (e.g., the amphoteric constituents) of the asphaltene and resin fractions are more thermally labile than the lower-polarity constituents (e.g., the neutral polar constituents) (Speight, 2014). As a result products from the amphoteric constituents will exceed the solubility parameter differential more quickly and will separate first from the oil medium first and at an earlier time that could be predicted if an average property is used for any model applied to the system.

4.2.3.6 Volatility The volatility of a liquid or liquefied gas may be defined as its tendency to vaporize, that is, to change from the liquid to the vapor or gaseous state. Because one of the three essentials for combustion in a flame is that the fuel be in the gaseous state, volatility is a primary characteristic of liquid fuels. The distillation profile is also a measure of the relative amounts of these liquid fuels (albeit small and unrefined) in heavy oil.

Similarly there must also be some estimate of the ability of the constituents of heavy oil to distill, or steam distill, from the oil during thermal methods of enhanced oil recovery. However, before any volatility tests are carried out, it must be recognized that the presence of more than 0.5% water in test samples of heavy oil can cause several problems during distillation procedures. Water has a high heat of vaporization, necessitating the application of additional thermal energy to the distillation flask. Water is relatively easily superheated and therefore excessive *bumping* can occur, leading to erroneous readings, and the potential for destruction of the glass equipment is real. In addition, steam formed during distillation can act as a carrier gas, and high-boiling-point components may end up in the distillate (often referred to as *steam distillation*).

Centrifugation can be used to remove water (and sediment) if the sample is not a tight emulsion. Other methods that are used to remove water include (i) heating in a pressure vessel to control loss of light ends, (ii) addition of calcium chloride as recommended in ASTM D1160, (iii) addition of an azeotroping agent such as *iso*propanol or *n*-butanol, (iv) removal of water in a preliminary low-efficiency or flash distillation followed by reblending the hydrocarbon that codistills with the water into the sample, and (v) separation of the water from the hydrocarbon distillate by freezing.

For some purposes it is necessary to have information on the initial stage of vaporization and the potential hazards, even with heavy oil, that such a property can cause. To supply this need, flash and fire, vapor pressure, and evaporation methods are available. The data from the early stages of the several distillation methods are also useful. For other uses it is important to know the tendency of a product to partially vaporize or to completely vaporize and in some cases to know if small quantities of high-boiling components are present. For such purposes, chief reliance is placed on the distillation methods.

The *flash point* of petroleum or a petroleum product is the temperature to which the product must be heated under specified conditions to give off sufficient vapor to form a mixture with air that can be ignited momentarily by a specified flame (Speight, 2015b). The Pensky–Martens apparatus using a closed or open system (ASTM D93) is the standard instrument for flash points above 50 °C (122 °F). The *fire point* is the temperature to which the product must be heated under the prescribed conditions of the method to burn continuously when the mixture of vapor and air is ignited by a specified flame (ASTM D92).

The Pensky–Martens apparatus consists of a brass cup, mounted in an air bath and heated by a gas flame. A propeller-type stirrer, operated by a flexible drive, extends from the center of the cover into the cup. The cover has four openings: one for a thermometer and the others fitted with sliding shutters for the introduction of a pilot flame and for ventilation. The temperature of the oil in the cup is raised at 5–6 °C/min (9–11 °F/min). The stirrer is rotated at approximately 60 rpm. When the temperature has risen to approximately 15 °C (27 °F) from the anticipated flash point, the pilot flame is dipped into the oil vapor for 2 s for every 1 °C (1.8 °F) rise in temperature up to 105 °C (221 °F). Above 105 °C (221 °F), the flame is introduced every 2 °C (3.6 °F) rise in temperature. The flash point is the temperature at which a distinct flash is observed when the pilot flame meets the vapor in the cup. The *open-cup flash point* is determined after the closed-cup flash point by removing the cover and continuing the heating until a distinct flash occurs across the open cup.

The Abel *closed-cup* apparatus (IP 170) consists of a brass cup sealed in a small water bath that is immersed in a second water bath. The cover of the brass cup is fitted in a manner similar to that in the Pensky–Martens apparatus. For crude oils and products with flash point <30 °C (<86 °F), the outer bath is filled with water at 55 °C (131 °F) and is not heated further. The oil under test is then placed inside the cup. When the temperature reaches 19 °C (66 °F), the pilot flame is introduced every 0.5 °C (1 °F) until a flash is obtained. For oils with flash points in excess of 30 °C (>86 °F) and less than 50 °C (<122 °F), the inner water bath is filled with cold water to a depth of 35 mm. The outer bath is filled with cold water and heated at a rate of 1°C/min (1.8 °F/min). The flash point is obtained as before.

From the viewpoint of safety, information about the *flash point* is of most significance at or slightly above the maximum temperatures (30–60 °C, 86–140 °F)) that may be encountered in storage, transportation, and use of crude oil, heavy oil, and their products, in either closed or open containers. In this temperature range the relative fire and explosion hazard can be estimated from the flash point. For products with flash point below 40 °C (104 °F), special precautions are necessary for safe handling. Flash points above 60 °C (140 °F) gradually lose their safety significance until they become indirect measures of some other quality. The flash point of heavy oil can also be used to detect contamination. A substantially lower flash point than expected for a product is a reliable indicator that a product has become contaminated with a more volatile product, such as naphtha, and the flash point is also an aid in establishing the identity of a particular hydrocarbon contaminant.

A further aspect of volatility that receives considerable attention is the vapor pressure of heavy oil, which may be close to zero. The *vapor pressure* is the force exerted on the walls of a closed container by the vaporized portion of a liquid. Conversely, it is the force that must be exerted on the liquid to prevent it from vaporizing further (ASTM D323). The vapor pressure increases with temperature, and the temperature at which the vapor pressure of a liquid, either a pure compound of a mixture of many compounds, equals 1 atmosphere pressure (14.7 psi, absolute) is designated as the boiling point of the liquid.

Heavy oil can be subdivided by distillation into a variety of fractions of different *boiling ranges* (*cut points*) (the lower boiling fractions are de-emphasized because of the nature of heavy oil) using a variety of standard methods specifically designed for this task (Speight, 2015b). Distillation involves the general procedure of vaporizing the petroleum liquid in a suitable flask either at *atmospheric pressure* (ASTM D86, ASTM D447, ASTM D2892) or at *reduced pressure* (ASTM D1160). There are also test methods for the distillation of pitch (ASTM D2569) and cutback asphalt (ASTM D402) that can be applied to heavy oil. However, most of the methods specify an upper atmospheric equivalent temperature (AET) limit of 360 °C (680 °F) and therefore are too limited to be of value in the analysis of low-volatility API gravity heavy oil. In the simplest case, the distillation method involves using a standard round-bottom distillation flask of 250-ml capacity attached to a water-cooled condenser. The thermometer bulb is placed at the opening to the side arm of the flask. One hundred milliliters of sample is placed in the flask and heated by a small gas flame so as to produce 10 ml of distillate every 4 or 5 min. The temperature of initial distillation is recorded; the temperature at which each further 10 ml distils and the final boiling point are also recorded.

The ASTM D2892 method describes the procedure for distilling crude petroleum up to 400 °C (750 °F) AET. This method is often referred to as the *true boiling point distillation* method and is adequate for oil where an estimation of volatiles and non-volatiles is all that is required. The ASTM D1160 method is used to determine the boiling ranges of petroleum products to a maximum liquid temperature of 400 °C (752 °F) at pressures as low as 1 mm Hg and is suitable for use with heavy oil. In the method, a 200-ml sample is weighed to the nearest 0.1 g in a distillation flask. The distillation assembly is evacuated to the desired pressure, and heat is applied to the flask as rapidly as possible using a 750-W heater. When refluxing liquid appears, the rate of heating is adjusted so that the distillate is recovered at 4–8 ml/min until the distillation is complete. However, because of the thermal sensitivity of heavy oil, cracking will most likely occur before the liquid temperature reaches 400 °C (752 °F). An increase in distillation rate accompanied by a drop in head temperature, loss of vacuum in the system that is restored when heat to the still is reduced, and production of vapor clouds in the system are all evidence of cracking.

The *vacuum pot-still method* (ASTM D5236) is a procedure for the distillation of heavy oil samples having initial boiling points above 150 °C (300 °F). The method employs a pot still with a low-pressure drop entrainment separator. The method also provides for the determination of standard distillation profiles to the highest atmospheric equivalent temperature possible by conventional distillation.

Generally, the distillation tests are planned so that the data are reported in terms of one or more of the following items: (i) initial boiling point, which is the thermometer reading in the neck of the distillation flask when the first drop of distillate leaves the tip of the condenser tube; (ii) distillation temperatures, which are usually observed when the level of the distillate reaches each 10% mark on the graduated receiver, with the temperatures for the 5 and 95% marks often included; (iii) end point, or the maximum temperature, which is the highest thermometer reading observed during distillation; (iv) recovery, which is the total volume of distillate recovered in the graduated receiver (and residue is the liquid material, mostly condensed vapors, left in the flask after it has been allowed to cool at the end of distillation); and (v) total recovery, which is the sum of the liquid recovery and residue; distillation loss is determined by subtracting the total recovery from 100%.

It is often useful in this type of crude oil assay to be able to extend the boiling point data to higher temperatures than are possible in the fractionating distillation method previously described, and for this purpose a vacuum distillation in a simple still, with no fractionating column (similar to the ASTM D1160), can be carried out. This distillation, which is done under fractionating conditions equivalent to one theoretical plate, allows the boiling point data to be extended to about 600 °C (1110 °F) (corrected to 760 mm of mercury absolute) with many crude oils.

4.2.4 Fractionation

Evaluation of the suitability of petroleum for relative ease of recovery or relative ease of refining by separation into various fractions has been used successfully for several decades. The knowledge of the bulk fractions of heavy oil (Fig. 4.3) on a *before recovery* (core sample analysis) and *after recovery* (well fluid analysis) basis, as well as variations of the composition of the crude oil over time since a well was first opened, has been a valuable aid to recovery process development.

4.2.4.1 Asphaltene Separation The *asphaltene fraction* is that portion of heavy oil feedstock that is precipitated when a large excess (40 volumes) of a low-boiling liquid hydrocarbon (e.g., *n*-pentane or *n*-heptane) is added to the crude oil (1 volume) (Speight, 1994, 2014, 2015b). *n*-Heptane is the preferred hydrocarbon with *n*-pentane still being used although hexane is used on occasion (Speight, 2014, 2015b). Although *n*-pentane and *n*-heptane are the solvents of choice in the laboratory, other solvents can be used (Speight, 1979) and cause the separation of the asphaltene fraction as a brown-to-black powdery solid material. In the refinery, supercritical low molecular weight hydrocarbons (e.g., liquid propane, liquid butane, or mixtures of both) are the solvents of choice, and the product is a semisolid (tacky) to solid asphalt. The amount of asphalt that settles out of the paraffin/residuum mixture depends on the size of the paraffin, the temperature, and the paraffin-to-feedstock ratio (Girdler, 1965; Mitchell and Speight, 1973; Speight et al., 1982, 1984).

At this point, a mention of the phase behavior of asphaltene and fluids containing asphaltene constituents requires consideration (Speight, 2014, 2015b). The phase behavior of fluid containing asphaltene constituents is complex. Chemically, asphaltene constituents are difficult to define in general, and the physics and chemistry underlying the definition of this fraction are not open to debate; the fraction is a

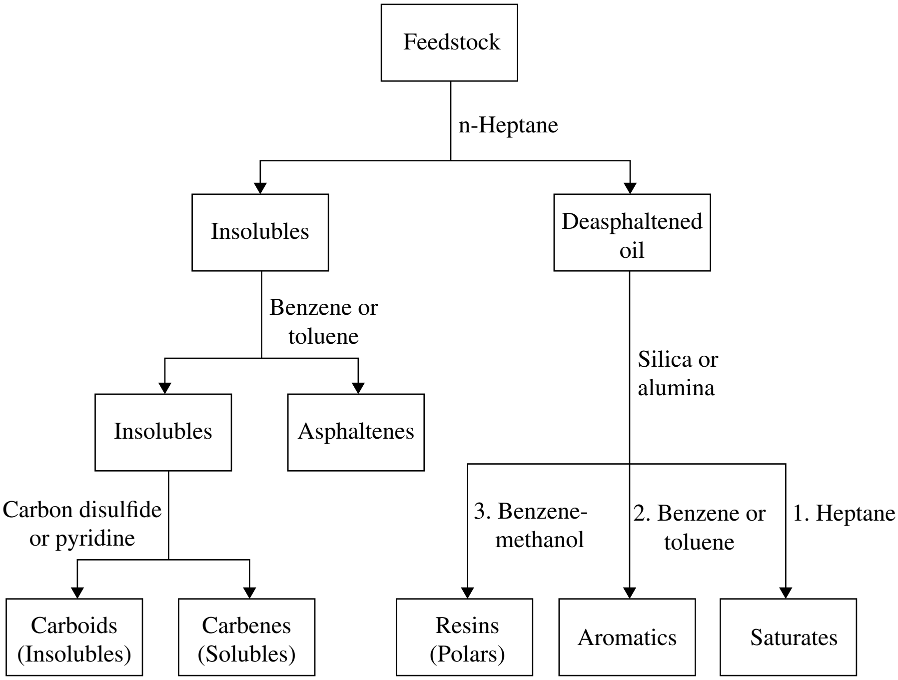


FIGURE 4.3 Schematic of the separation of crude oil into various bulk fractions—the fractions designated as carbenes and carboids are generally considered to be products of thermal reactions.

solubility fraction and is, in reality, an artifact of the separation method (Speight, 2014, 2015b). In fact, asphaltene fractions possessing similar constituents may exhibit different properties in their native fluids and in solvent/nonsolvent mixtures. Asphaltene constituents intra-act and interact with one another and with solvent media (Speight, 2014). Phase behavior and precipitation models must capture the relevant physics and chemistry if derived models are to be truly predictive. But the issue is the use of *average parameters* rather than the recognition that the asphaltene fraction is collection of different molecular types that vary from crude oil to crude oil because of the complexities of the maturation process (Speight, 2014) and should be represented as such in any models. In fact, analytical methods such as high-performance liquid chromatography (HPLC) have shown conclusively that the asphaltene fraction is a mix of unknown (at best *speculative*) molecular types (Speight, 2014, 2015b).

4.2.4.2 Fractionation after Asphaltene Removal Fractionation of crude oil into components after removal of the asphaltene constituents (Fig. 4.3) has also been of interest in following recovery procedures. By careful selection of a characterization scheme, it may be possible to obtain a detailed overview of oil composition that can be used for process predictions. Thus, fractionation methods also play a role, along with the physical testing methods, in evaluating crude oil and the various recovery processes, especially when determining whether or not *in situ* upgrading occurs (Long and Speight, 1989, 1998; Speight, 2014, 2015b).

After removal of the asphaltene fraction, further fractionation of petroleum is also possible by variation of the hydrocarbon solvent. For example, liquefied gases, such as propane and butane, precipitate as much as 50% by weight of the residuum or bitumen. The precipitate is a black, tacky, semisolid material, in contrast to the pentane-precipitated asphaltene constituents, which are usually brown, amorphous solids. Treatment of the propane precipitate with pentane then yields the insoluble asphaltene constituents and soluble, near-black semisolid resins, which are, as near as can be determined, equivalent to the resins isolated by adsorption techniques. Separation by adsorption chromatography essentially commences with the preparation of a porous bed of finely divided solid, the adsorbent. The adsorbent is usually contained in an open tube (column chromatography); the sample is introduced at one end of the adsorbent bed and induced to flow through the bed by means of a suitable solvent. As the sample moves through the bed, the various components are held (adsorbed) to a greater or lesser extent depending on the chemical nature of the component. Thus, those molecules that are strongly adsorbed spend considerable time on the adsorbent surface rather than in the moving (solvent) phase, but components that are slightly adsorbed move through the bed comparatively rapidly.

There are three standard test methods that provide for the separation of heavy oil into four or five constituent fractions (Speight, 2014, 2015b). It is interesting to note that as the methods have evolved there has been a change from the use of pentane (ASTM D2007) to heptane (ASTM D4124) to separate the asphaltene constituents. This is, in fact, in keeping with the production of a more consistent fraction that represents the higher molecular weight, more complex constituents of petroleum (Girdler, 1965; Speight et al., 1982, 1984; Speight, 2015b).

Methods used for the separation of crude oil into various fractions are often identified by the acronyms for the names: PONA (paraffins, olefins, naphthenes, and aromatics), PIONA (paraffins, *iso*paraffins, olefins, naphthenes, and aromatics), PNA (paraffins, naphthenes, and aromatics), PINA (paraffins, *iso*paraffins, naphthenes, and aromatics), or SARA (saturate constituents, aromatic constituents, resin constituents, and asphaltene constituents). However, it must be recognized that the fractions produced by the use of different adsorbents will differ in content and will also be different from fractions produced by solvent separation techniques. However, for heavy oil fractions, the absence of paraffins in the sample usually precludes many of these acronyms, and the most common method is the SARA method.

4.2.5 Molecular Weight

Even though recovery processes, in general, do not (or should not) affect the quality of the oil, there is still the need to determine the molecular weight of the original constituents as well as the molecular weights of the products as a means of understanding the process. For those original constituents and products, for example, resin constituents and asphaltene constituents, that have little or no volatility, *vapor pressure osmometry* (*VPO*) has been proven to be of considerable value.

Currently, there are several standard test methods that are recognized as being useful for determining the molecular weight of petroleum fractions (ASTM D2502, ASTM D2503, ASTM D2878). Methods for molecular weight measurement are also included in other more comprehensive standards (ASTM D128, ASTM D3712), and there are several indirect methods that have been proposed for the estimation of molecular weight by correlation with other, more readily measured physical properties. They are satisfactory when dealing with the conventional type of crude oils or their fractions and products and when approximate values are desired.

Vapor pressure osmometry (ASTM D2503), also called vapor phase osmometry, is a relatively simple and cheap method for the determination of molecular weight. Most osmometers can operate over a range of temperature through the use of probes that cover specific temperature ranges. This gives the number average molecular weight and not the molecular weight distribution. A common solvent for vapor pressure osmometry is toluene that is satisfactory for hydrocarbons and moderately polar compounds. However, for the highly polar fractions, such as asphaltene constituents, more polar solvents such as pyridine are required. The molecular weight of such fractions measured by vapor pressure osmometry in pyridine is distinctly lower than those measured in toluene (Speight et al., 1985; Speight, 2014, 2015b) indicating a lower degree of aggregation, assuming that contamination with trace amounts of previously used solvent in the separation of the samples can truly be excluded.

The method using the concept of *freezing point depression* determines the average molecular weight of various fractions using simple equipment. The samples must be completely soluble and chemically inert in the solvent (benzene). Molecular weight values represent a number average molecular weight for the sample components. In the test method, the freezing points for benzene and for a benzene solution containing a known weight of sample are determined from their cooling curves. From the depression of the freezing point due to the sample, the average molecular weight is calculated by application of Raoult's law, namely, the vapor pressure lowering of a solvent is directly proportional to the concentration of the solute.

Boiling point elevation (*ebullioscopic*) methods are, in general use, more rapid and equally accurate but tend to fall short when applied to the higher molecular weight fractions of petroleum, heavy oil, and tar sand bitumen. Molecular weights in the low range (<500 Da) are readily determined by vapor-density methods.

For any one sample the boiling point elevation is determined at a series of concentrations of solute. Such determinations were carried out in practice by comparing the boiling point of pure solvent, measured in an ebulliometer, with the boiling points, determined in a second ebulliometer, of a series of solutions prepared by adding successive portions of the sample to the solvent. The first ebulliometer serves as the control experiment.

There is a method for determining the molecular weight of petroleum, heavy oil, and bitumen and their constituent fraction using *size exclusion* (*gel permeation*) *chromatography* (ASTM D5296). The principle of size exclusion chromatography is the exclusion of larger sample molecules from smaller pores in the packing. As a result, larger molecules cannot reside in the entire column volume but are restricted to smaller regions. In the extreme, the largest ones are restricted to the interstitial volume, that is, the space between particles, whereas the smallest ones can penetrate the entire open column volume, that is, the interstitial and all the pore volume. As a consequence, the large molecules elute first and the smallest ones last (Speight, 2014, 2015b).

It is important to remember that size exclusion chromatography separates by molar volume rather than by molecular weight. The method will, therefore, differentiate by structure in addition to molecular weight. In principle, size exclusion chromatography is very powerful method for separating petroleum fractions by molecular weight. It is used frequently in petroleum analysis despite the components toward adsorption and aggregation and other potential problems.

4.3 NATURAL GAS

Petroleum-related gas (natural gas) is a category of saturated gaseous hydrocarbons, predominantly C_1 to C_4, and may also contain hydrocarbons as high as C_{10}. Natural gas may also contain inorganic compounds, such as hydrogen, nitrogen, hydrogen sulfide, carbon monoxide, and carbon dioxide. Separation and natural gas processing typically begin at the wellhead where the composition of the raw natural gas extracted from producing wells depends on the type, depth, as well as the geology and location of the underground reservoir (Mokhatab et al., 2006; Speight, 2007, 2014).

Raw natural gas varies greatly in composition and the constituents can be several of a group of hydrocarbons and nonhydrocarbons (Table 4.4). In addition, a natural gas stream typically has high proportions of *natural gas liquids* (NGLs) and is referred to as *rich gas*. NGLs are constituents such as ethane, propane, butane, and

TABLE 4.4 Composition of Associated Natural Gas from a Petroleum Well

Category	Component	Amount (%)
Paraffinic	Methane (CH_4)	70–98
	Ethane (C_2H_6)	1–10
	Propane (C_3H_8)	Trace–5
	Butane (C_4H_{10})	Trace–2
	Pentane (C_5H_{12})	Trace–1
	Hexane (C_6H_{14})	Trace–0.5
	Heptane and higher (C_7^+)	None–trace
Cyclic	Cyclopropane (C_3H_6)	Traces
	Cyclohexane (C_6H12)	Traces
Aromatic	Benzene (C_6H_6), others	Traces
Nonhydrocarbon	Nitrogen (N_2)	Trace–15
	Carbon dioxide (CO_2)	Trace–1
	Hydrogen sulfide (H_2S)	Trace occasionally
	Helium (He)	Trace–5
	Other sulfur and nitrogen compounds	Trace occasionally
	Water (H_2O)	Trace–5

pentanes and higher molecular weight hydrocarbon constituents. The higher molecular weight constituents (i.e., the C_{5+} product) are commonly referred to as *natural gasoline*. Rich gas will have a high heating value and a high hydrocarbon dew point. When referring to NGLs in the gas stream, the term *gallon per thousand cubic feet is* used as a measure of high molecular weight hydrocarbon content. On the other hand, the composition of nonassociated gas (sometimes called *well gas*) is deficient in NGLs. The gas is produced from geological formations that typically do not contain much, if any, hydrocarbon liquids.

Gas production from unconventional shale gas reservoirs (such as tight shale formations) has become more common in the past decade (Speight, 2013). In terms of chemical makeup, shale gas is typically a dry gas composed primarily of methane (60–95% v/v), but some formations do produce wet gas. The Antrim and New Albany plays have typically produced water and gas. Gas shale formations are organic-rich shale formations that were previously regarded only as source rocks and seals for gas accumulating in the strata near sandstone and carbonate reservoirs of traditional onshore gas.

Produced shale gas observed to date has shown a broad variation in compositional makeup, with some having wider component ranges, a wider span of minimum and maximum heating values, and higher levels of water vapor and other substances than pipeline tariffs or purchase contracts may typically allow. Indeed, because of these variations in gas composition, each shale gas formation can have unique processing requirements for the produced shale gas to be marketable.

Ethane can be removed by cryogenic extraction, while carbon dioxide can be removed through a scrubbing process. However, it is not always necessary (or practical) to process shale gas to make its composition identical to *conventional* transmission-quality gases. Instead, the gas should be interchangeable with other sources of natural gas now provided to end users. The interchangeability of shale gas with conventional gases is crucial to its acceptability and eventual widespread use in the United States.

Although not highly sour in the usual sense of having high hydrogen sulfide content, and with considerable variation from play to resource to resource and even from well to well within the same resource (due to extremely low permeability of the shale even after fracturing) (Speight, 2013), shale gas often contains varying amounts of hydrogen sulfide with wide variability in the carbon dioxide content. The challenge in treating such gases is the low (or differing) hydrogen sulfide/carbon dioxide ratio and the need to meet pipeline specifications. In a traditional gas processing plant, the olamine of choice for content for hydrogen sulfide removal is *N*-methyldiethanolamine (MDEA) (Mokhatab et al., 2006; Speight, 2007, 2014), but whether or not this olamine will suffice to remove the hydrogen sulfide without removal of excessive amounts of carbon dioxide is another issue.

Gas treatment may begin at the wellhead—condensates and free water usually are separated at the wellhead using mechanical separators. Gas, condensate, and water are separated in the field separator and are directed to separate storage tanks and the gas flows to a gathering system. After the free water has been removed, the gas is still saturated with water vapor and, depending on the temperature and pressure of the gas stream, may need to be dehydrated or treated with methanol to prevent hydrates as the temperature drops. But this may not be always the case in actual practice.

4.3.1 Sampling

One of the more critical aspects for the analysis of low-boiling hydrocarbons is the question of volumetric measurement (ASTM D1071) and sampling (ASTM D1265). However, sampling liquefied petroleum gas from a liquid storage system is complicated by existence of two phases (gas and liquid), and the composition of the supernatant vapor phase will, most probably, differ from the composition of the liquid phase. Furthermore, the compositions of both phases will vary as a sample (or sample) is removed from one or both phases. An accurate check of composition can only be made if samples are taken during filling of the tank or from a fully charged tank.

For reservoirs that consists of tight formations and shale formations and where the gas likely contains gas-condensate constituents that are at pressures above the dew point in the reservoir, it is important (in fact, necessary) to acquire and maintain the sample as a single-phase fluid. If the fluid pressure drops below the dew point, it may take a considerable period to recombine the sample. Moreover, changes that occur in a sample in the wellbore to the surface may be irreversible. Thus, a sample that is single phase when collected should be kept in a single phase when brought to the surface. Sample bottle designed for this purpose is available. A single-phase sample bottle uses a nitrogen cushion to increase the pressure in the sample, and although the sample cools as it is brought to the surface, the nitrogen cushion on the sample maintains the pressure above the dew-point pressure, which is the pressure at which the first drop of liquid is formed when the sample passes from the vapor phase to a two-phase system.

In addition, natural gas under certain conditions may undergo the phenomenon known as retrograde condensation. This phenomenon is associated with the behavior of the gas mixture in the critical region wherein, at constant temperature, the vapor phase in contact with the liquid phase may be condensed by a decrease in pressure or at constant pressure where the vapor is condensed by an increase in temperature. Caution is advised when dealing with gas from tight formations and tight shale formations where condensation of the liquid from the gaseous phase can cause blockages in the flow channels, thereby negating the benefit (increased flow of the gas) of the hydraulic fracturing process.

In general, the sampling of gaseous constituents is the subject of a variety of sampling methods (ASTM D5503), such as the manual method (ASTM D1265, ASTM D4057), the floating piston cylinder method (ASTM D3700), and the automatic sampling method (ASTM D4177, ASTM D5287). Methods for the preparation of gaseous and liquid blends are also available (ASTM D4051, ASTM D4307) including the sampling and handling of fuels for volatility measurements (ASTM D5842). Sampling methane (CH_4) and ethane (C_2H_6) hydrocarbons is usually achieved using stainless steel cylinders, either lined or unlined. However, other containers may also be employed depending upon particular situations. For example, glass cylinder containers or polyvinyl fluoride (PVT) sampling bags may also be used but, obviously, cannot be subjected to pressures that are far in excess of ambient pressure. The preferred method for sampling propane (C_3H_8) and butane (C_4H_{10}) hydrocarbons is by the use of piston cylinders (ASTM D3700) although sampling these materials as gases is also acceptable in many cases.

4.3.2 Test Methods

Bulk physical property tests, such as density and heating value, as well as some compositional tests, such as the Orsat analysis and the mercuric nitrate method for the determination of unsaturation, were widely used. More recently, mass spectrometry has become a popular method of choice for compositional analysis of low molecular weight and has replaced several older methods (ASTM D2421, ASTM D2650). Gas chromatography (ASTM D1945) is another method of choice for hydrocarbon identification in gases.

4.3.2.1 Calorific Value The calorific value (heat of combustion) gives an indication of the satisfactory combustion of hydrocarbon gases, which depends upon the matching of burner and appliance design with certain gas characteristics. Various types of test methods are available for the direct determination of calorific value (ASTM D1826, ASTM D3588). The most important of these are the Wobbe Index (or Wobbe number = calorific value/specific gravity) and the flame speed, usually expressed as a factor or an arbitrary scale on which that of hydrogen is 100. This factor can be calculated from the gas analysis. In fact, calorific value and specific gravity can be calculated from compositional analysis (ASTM D3588).

4.3.2.2 Composition Carbon dioxide (ASTM D1945, ASTM D4984) in excess of 3% is normally removed for reasons of corrosion prevention (ASTM D1838). Hydrogen sulfide (ASTM D2420, ASTM D4084, ASTM D4810) is also removed, and the odor of the gas must not be objectionable (ASTM D6273) so mercaptan content (ASTM D1988) is important. A simple lead acetate test (ASTM D2420, ASTM D4084) is available for detecting the presence of hydrogen sulfide and is an additional safeguard that hydrogen sulfide not be present (ASTM D1835). The odor of the gases must not be objectionable. Methyl mercaptan, if present, produces a transitory yellow stain on the lead acetate paper that fades completely in less than 5 min. Other sulfur compounds (ASTM D5504, ASTM D6228) present in liquefied petroleum gas do not interfere.

In the lead acetate test (ASTM D2420), the vaporized gas is passed over moist lead acetate paper under controlled conditions. Hydrogen sulfide reacts with lead acetate to form lead sulfide, resulting in a stain on the paper varying in color from yellow to black, depending on the amount of hydrogen sulfide present. Other pollutants can be determined by gas chromatography (ASTM D5504, ASTM D6228).

Analytical methods are available in standard form for determining the volatile sulfur content and certain specific corrosive sulfur compounds that are likely to be present. Volatile sulfur determination is made by a combustion procedure (Speight, 2015b) that uses a modification of the standard wick-fed lamp. Many laboratories use rapid combustion techniques with an oxyhydrogen flame in a Wickbold or Martin–Floret burner (ASTM D2784). This test method (ASTM D2784) is valid for sulfur levels of >1 µg/g in liquefied petroleum gas, but the samples should not contain more than 100 µg/g of chlorine. In the test, the sample is bummed in an oxyhydrogen bummer or in a lamp in a closed system in a carbon dioxide–oxygen atmosphere. The latter is not recommended for trace quantities of sulfur due to inordinately long combustion times needed. The sulfur oxides produced are absorbed and oxidized to sulfuric acid in a hydrogen peroxide solution. The sulfate ions are then determined by either titrating with barium perchlorate solution using a thorin–methylene blue mixed indicator or by precipitating as barium sulfate and measuring the turbidity of the precipitate with a photometer.

Important constituents of natural gas not accounted for in many analytical test methods include moisture (water) and hydrogen sulfide, as well as other sulfur compounds (ASTM D1142, ASTM D1988, ASTM D4888, ASTM D5504, ASTM D5454, ASTM D6228). Mercury in natural gas is also measured by atomic fluorescence spectroscopy (ASTM D6350) and by AA spectroscopy (ASTM D5954).

4.3.2.3 Density and Relative Density The density of light hydrocarbons can be determined by several methods (ASTM D1070) including a hydrometer method (ASTM D1298) or by a pressure hydrometer method (ASTM D1657). The specific gravity (relative density) (ASTM D1070, ASTM D1657) by itself has little significance compared to its use for higher molecular weight liquid petroleum products and can only give an indication of quality characteristics when combined with values for volatility and vapor pressure. It is important for stock quantity calculations and is used in connection with transport and storage.

The statement is often made that *natural gas is lighter than air*. This statement often arises because of the continued insistence by engineers and scientists that the properties of a mixture are determined by the mathematical average of the properties of the individual constituents of the mixture. Such mathematical bravado and inconsistency of thought are *detrimental to safety* and need to be qualified.

The *relative density* (*specific gravity*) is the ratio of the density (mass of a unit volume) of a substance to the density of a given reference material. As it pertains to gases, particularly in relation to safety considerations at commercial and industrial facilities in the United States, the relative density of a gas is usually defined with respect to air, in which air is assigned a *vapor density* of one (unity). With this definition, the vapor density indicates whether a gas is denser (greater than one) or less dense (less than one) than air. The vapor density has implications for container storage and personnel safety—if a container can release a dense gas, its vapor could sink and, if flammable, collect until it is at a concentration sufficient for ignition. Even if not flammable, it could collect in the lower floor or level of a confined space and displace air, possibly presenting a smothering hazard to individuals entering the lower part of that space.

Methane is the only hydrocarbon constituent of natural gas that is lighter than air (Table 4.5). The higher molecular weight hydrocarbons have a higher vapor density than air and are likely, after a release, to accumulate in low-lying areas and represent

TABLE 4.5 Relative Density (Specific Gravity) of Natural Gas Hydrocarbons Relative to Air

Gas	Specific Gravity[a]
Air	1.0000
Methane, CH_4	0.5537
Ethane, C_2H_6	1.0378
Propane, C_3H_8	1.5219
Butane, C_4H_{10}	2.0061
Pentane, C_5H_{12}	2.4870
Hexane, C_6H_{14}	2.9730

[a] For ease of comparison, the specific gravity of air is shown to be 1.0000.

a danger to the investigator (of the release). However, the other hydrocarbon constituents of unrefined natural gas (i.e., ethane, propane, butane, etc.) are denser than air. Therefore, should a natural gas leak occur in field operations, especially where the natural gas contains constituents other than methane, only methane dissipates readily into the air, whereas the other hydrocarbon constituents that are heavier than air do not readily dissipate into the atmosphere. This poses considerable risk if these constituents of natural gas accumulate or pool at ground level when it has been erroneously assumed that natural gas is lighter than air.

4.3.2.4 Sulfur Content Total sulfur in gas can be determined by combustion (ASTM D1072), by the lamp method (ASTM D1266), or by hydrogenation (ASTM D4468). Trace total organic and bound nitrogen is determined (ASTM D4629). The current test method for heavy residues in liquefied petroleum gas (ASTM D2158) involves evaporation of a liquefied petroleum gas sample, measuring the volume of residue, and observing the residue for oil stain on a piece of filter paper.

Corrosive sulfur compounds can be detected by their effect on copper and the form in which the general copper strip corrosion test (ASTM D1838) for petroleum products is applied to liquefied petroleum gas. Hydrogen sulfide can be detected by its action on moist lead acetate paper, and a procedure is also used as a measure of sulfur compounds. The method follows the principle of the standard doctor test.

4.3.2.5 Volatility and Vapor Pressure Volatility is expressed in terms of the temperature at which 95% of the sample is evaporated and presents a measure of the least volatile component present (ASTM D1837). Vapor pressure is, therefore, a measure of the most extreme low temperature conditions under which initial vaporization can take place. By setting limits to vapor pressure and volatility jointly, the specification serves to ensure essentially single-component products for the butane and propane grades (ASTM D1267, ASTM D2598). By combining vapor pressure/volatility limits with specific gravity for propane–butane mixtures, essentially two-component systems are ensured.

For natural gasoline, the primary criterion is volatility (vapor pressure and knock performance). Determination of the vapor pressure (ASTM D323, ASTM D4953, ASTM D5191) and distillation profile (ASTM D2161) are essential. Other considerations for natural gasoline are copper corrosion (ASTM D130) and specific gravity (ASTM D1298), the latter determination being necessary for measurement and transportation.

4.3.2.6 Water It is a fundamental requirement that liquefied petroleum gas should not contain free water (ASTM D2713). Dissolved water may give trouble by forming hydrates and giving moisture vapor in the gas phase. Both of these will lead to blockages. Therefore, test methods are available to determine the presence of water using electronic moisture analyzers (ASTM D5454), dew-point temperature (ASTM D1142), and length-of-stain detector tubes (ASTM D4888).

REFERENCES

ASTM D1026. 2015. Standard Test Method of Test for Sodium in Lubricating Oils and Additives (Gravimetric Method) (Withdrawn 1990). ASTM International, West Conshohocken, PA.

ASTM D1070. 2015. *Standard Test Methods for Relative Density of Gaseous Fuels*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1071. 2015. *Standard Test Methods for Volumetric Measurement of Gaseous Fuel Samples*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1072. 2015. *Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1142. 2015. *Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew-Point Temperature*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1160. 2015. *Standard Test Method for Distillation of Petroleum Products at Reduced Pressure*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1217. 2015. *Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1262. 2015. *Method of Test for Lead in New and Used Greases (Withdrawn 1990)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1265. 2015. *Standard Practice for Sampling Liquefied Petroleum (LP) Gases, Manual Method*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1266. 2015. *Standard Test Method for Sulfur in Petroleum Products (Lamp Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1267. 2015. *Standard Test Method for Gage Vapor Pressure of Liquefied Petroleum (LP) Gases (LP-Gas Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D127. 2015. *Standard Test Method for Drop Melting Point of Petroleum Wax, Including Petrolatum*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D128. 2015. *Standard Test Methods for Analysis of Lubricating Grease*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D1298. 2015. *Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D130. 2015. *Standard Test Method for Corrosiveness to Copper from Petroleum Products by Copper Strip Test*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1310. 2015. *Standard Test Method for Flash Point and Fire Point of Liquids by Tag Open-Cup Apparatus*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1318. 2015. *Standard Test Method for Sodium in Residual Fuel Oil (Flame Photometric Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1368. 2015. *Test Method for Trace Concentrations of Lead in Primary Reference Fuels (Withdrawn 1994)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1548. 2015. *Standard Test Method for Vanadium in Navy Special Fuel Oil (Withdrawn 1997)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1549. 2015. *Standard Test Method of Test for Zinc in Lubricating Oils and Additives (Polarographic Method) (Withdrawn 1984)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1555. 2015. *Standard Test Method for Calculation of Volume and Weight of Industrial Aromatic Hydrocarbons and Cyclohexane*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1657. 2015. *Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1796. 2015. *Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1826. 2015. *Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1835. 2015. *Standard Specification for Liquefied Petroleum (LP) Gases*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1837. 2015. *Standard Test Method for Volatility of Liquefied Petroleum (LP) Gases*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1838. 2015. *Standard Test Method for Copper Strip Corrosion by Liquefied Petroleum (LP) Gases*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D189. 2015. *Standard Test Method for Conradson Carbon Residue of Petroleum Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1945. 2015. *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D1988. 2015. *Standard Test Method for Mercaptans in Natural Gas Using Length-of-Stain Detector Tubes*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2007. 2015. *Standard Test Method for Characteristic Groups in Rubber Extender and Processing Oils and Other Petroleum-Derived Oils by the Clay-Gel Absorption*

Chromatographic Method. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D2158. 2015. *Standard Test Method for Residues in Liquefied Petroleum (LP) Gases*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2161. 2015. *Standard Practice for Conversion of Kinematic Viscosity to Saybolt Universal Viscosity or to Saybolt Furol Viscosity*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2270. 2015. *Standard Practice for Calculating Viscosity Index from Kinematic Viscosity at 40 and 100°C*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2398. 2015. *Test Method for Softening Point of Bitumen in Ethylene Glycol (Ring-and-Ball) (Withdrawn 1984)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2420. 2015. *Standard Test Method for Hydrogen Sulfide in Liquefied Petroleum (LP) Gases (Lead Acetate Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2421. 2015. *Standard Practice for Interconversion of Analysis of C5 and Lighter Hydrocarbons to Gas-Volume, Liquid-Volume, or Mass Basis*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2502. 2015. *Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D2503. 2015. *Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D2547. 2015. *Method of Test for Lead in Gasoline, Columetric Chromate Method (Withdrawn 1989)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2569. 2015. *Standard Test Method for Distillation of Pitch*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2598. 2015. *Standard Practice for Calculation of Certain Physical Properties of Liquefied Petroleum (LP) Gases from Compositional Analysis*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2599. 2015. *Methods of Test for Lead in Gasoline by X-Ray Spectrometry (Withdrawn 1992)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2650. 2015. *Standard Test Method for Chemical Composition of Gases by Mass Spectrometry*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2713. 2015. *Standard Test Method for Dryness of Propane (Valve Freeze Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2766. 2015. *Standard Test Method for Specific Heat of Liquids and Solids*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2784. 2015. *Standard Test Method for Sulfur in Liquefied Petroleum Gases (Oxy-Hydrogen Burner or Lamp)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2788. 2015. *Method of Test for Trace Metals in Gas Turbine Fuels (Atomic Absorption Method) (Withdrawn 1983)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D287. 2015. *Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2878. 2015. *Method for Estimating Apparent Vapor Pressures and Molecular Weights of Lubricating Oils*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D2887. 2015. *Standard Test Method for Boiling Range Distribution of Petroleum Fractions by Gas Chromatography*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2892. 2015. *Standard Test Method for Distillation of Crude Petroleum (15-Theoretical Plate Column)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D323. 2015. *Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D3340. 2015. *Standard Test Method for Lithium and Sodium in Lubricating Greases by Flame Photometer*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D3341. 2015. *Standard Test Method for Lead in Gasoline-Iodine Monochloride Method*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D341. 2015. *Standard Test Method for Viscosity-Temperature Charts for Liquid Petroleum Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D3588. 2015. *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D36. 2015. *Standard Test Method for Softening Point of Bitumen (Ring-and-Ball Apparatus)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D3605. 2015. *Standard Test Method for Trace Metals in Gas Turbine Fuels by Atomic Absorption and Flame Emission Spectroscopy*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D3700. 2015. *Standard Practice for Obtaining LPG Samples Using a Floating Piston Cylinder*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D3712. 2015. *Standard Test Method of Analysis of Oil-Soluble Petroleum Sulfonates by Liquid Chromatography*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D4006. 2015. *Standard Test Method for Water in Crude Oil by Distillation*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4007. 2015. *Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D402. 2015. *Standard Test Method for Distillation of Cut-Back Asphaltic (Bituminous) Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4051. 2015. *Standard Practice for Preparation of Low-Pressure Gas Blends*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4057. 2015. *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4084. 2015. *Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4124. 2015. *Standard Test Methods for Separation of Asphalt into Four Fractions*. Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D4177. 2015. *Standard Practice for Automatic Sampling of Petroleum and Petroleum Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4307. 2015. *Standard Practice for Preparation of Liquid Blends for Use as Analytical Standards*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D445. 2015. *Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4468. 2015. *Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D447. 2015. *Test Method for Distillation of Plant Spray Oils (Withdrawn 1997)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4530. 2015. *Standard Test Method for Determination of Carbon Residue (Micro Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4629. 2015. *Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4810. 2015. *Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4888. 2015. *Standard Test Method for Water Vapor in Natural Gas Using Length-of-Stain Detector Tubes*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4953. 2015. *Standard Test Method for Vapor Pressure of Gasoline and Gasoline-Oxygenate Blends (Dry Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4984. 2015. *Standard Test Method for Carbon Dioxide in Natural Gas Using Length-of-Stain Detector Tubes*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5191. 2015. *Standard Test Method for Vapor Pressure of Petroleum Products (Mini Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5236. 2015. *Standard Test Method for Distillation of Heavy Hydrocarbon Mixtures (Vacuum Potstill Method)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D524. 2015. *Standard Test Method for Ramsbottom Carbon Residue of Petroleum Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5287. 2015. *Standard Practice for Automatic Sampling of Gaseous Fuels*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5296. 2015. *Standard Test Method for Molecular Weight Averages and Molecular Weight Distribution of Polystyrene by High Performance Size-Exclusion Chromatography*.

Annual Book of Standards. American Society for Testing and Materials, West Conshohocken, PA.

ASTM D5454. 2015. *Standard Test Method for Water Vapor Content of Gaseous Fuels Using Electronic Moisture Analyzers*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5503. 2015. *Standard Practice for Natural Gas Sample-Handling and Conditioning Systems for Pipeline Instrumentation*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5504. 2015. *Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D56. 2015. *Standard Test Method for Flash Point by Tag Closed Cup Tester*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D566. 2015. *Standard Test Method for Dropping Point of Lubricating Grease*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5842. 2015. *Standard Practice for Sampling and Handling of Fuels for Volatility Measurement*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D5954. 2015. *Standard Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D6228. 2015. *Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D6273. 2015. *Standard Test Methods for Natural Gas Odor Intensity*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D6350. 2015. *Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D87. 2015. *Standard Test Method for Melting Point of Petroleum Wax (Cooling Curve)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D88. 2015. *Standard Test Method for Saybolt Viscosity*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D92. 2015. *Standard Test Method for Flash and Fire Points by Cleveland Open Cup Tester*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D93. 2015. *Standard Test Methods for Flash Point by Pensky-Martens Closed Cup Tester*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D941. 2015. *Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer (Withdrawn 1993)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D954. 2015. *Standard Test Methods of Test for Apparent Density and Bulk Factor of Nonpouring Molding Powers (Withdrawn 1961)*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D97. 2015. *Standard Test Method for Pour Point of Petroleum Products*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

Girdler, R.B. 1965. Constitution of Asphaltene Constituents and Related Studies. *Proceedings of Association of Asphalt Paving Technologists*, 34: 45.

Long, R.B., and Speight, J.G. 1989. Studies in Petroleum Composition. I: Development of a Compositional Map for Various Feedstocks. *Revue de l'Institut Français du Pétrole*, 44: 205.

Long, R.B., and Speight, J.G. 1998. The Composition of Petroleum. In: *Petroleum Chemistry and Refining*. J.G. Speight (Editor). Taylor & Francis, Washington, DC. Chapter 2.

Mitchell, D.L., and Speight, J.G. 1973. The Solubility of Asphaltenes in Hydrocarbon Solvents. *Fuel*, 52: 149.

Mokhatab, S., Poe, W.A., and Speight, J.G. 2006. *Handbook of Natural Gas Transmission and Processing*. Elsevier, Amsterdam, The Netherlands.

Speight, J.G. 1979. Information Series No. 84. Alberta Research Council, Edmonton, Alberta, Canada.

Speight, J.G. 1994. In: *Asphaltenes and Asphalts, I. Developments in Petroleum Science*, 40. T.F. Yen and G.V. Chilingar (Editors). Elsevier, Amsterdam, The Netherlands. Chapter 2.

Speight, J.G. 2000. *The Desulfurization of Heavy Oils and Residua*, 2nd Edition. Marcel Dekker Inc., New York.

Speight, J.G. 2007. *Natural Gas: A Basic Handbook*. Books—Gulf Publishing Company, Houston, TX.

Speight, J.G. 2009. *Enhanced Recovery Methods for Heavy Oil and Tar Sands*. Gulf Publishing Company, Houston, TX.

Speight, J.G. 2013. *Shale Gas Production Processes*. Gulf Professional Publishing, Elsevier, Oxford, United Kingdom.

Speight, J.G. 2014. *The Chemistry and Technology of Petroleum*, 5th Edition. CRC Press, Taylor and Francis Group, Boca Raton, FL.

Speight, J.G. 2015a. *Fouling in Refineries*. Gulf Professional Publishing, Elsevier, Oxford, United Kingdom.

Speight, J.G. 2015b. *Handbook of Petroleum Product Analysis*, 2nd Edition. John Wiley & Sons, Inc., Hoboken, NJ.

Speight, J.G., Long, R.B., and Trowbridge, T.D. 1982. On the Definition of Asphaltene Constituents. *Preprints of Papers—Division of Fuel Chemistry, American Chemical Society*, 27(3/4): 268.

Speight, J.G., Long, R.B., and Trowbridge, T.R. 1984. Factors Influencing the Separation of Asphaltene Constituents from Heavy Petroleum Feedstocks. *Fuel*, 63: 616.

Speight, J.G., Wernick, D.L., Gould, K.A., Overfield, R.E., Rao, B.M.L., and Savage, D.W. 1985. *Revue de l'Institut Français du Pétrole*, 40: 27.

Wallace, E.D. (Editor). 1988. *A Review of Analytical Methods for Bitumens and Heavy Oils*. AOSTRA Technical Publication Series No. 5. Alberta Oil Sands Technology and Research Authority, Edmonton, Alberta, Canada.

5

HYDRAULIC FRACTURING

5.1 INTRODUCTION

Traditional oil and gas extraction involves drilling through impervious rock that traps concentrated underground reservoirs of petroleum and natural gas and may even involve a mining operation for heavy oil and tar sand bitumen (Chapter 3). With conventional petroleum, extraction occurs simply due to the change in pressure caused by the drilling. However, not all of the petroleum and natural gas is conveniently located in conventional and accessible reservoirs. Many oil and gas resources are trapped in the pore spaces and cracks within impermeable sedimentary rock formations—shale and tight sandstone formations are an example of such reservoirs (Chapter 2). These reservoirs can vary in thickness—the shale formations are relatively thin layers (albeit deep under the ground) but cover extensive horizontal areas, and a vertically drilled well will only access a small area of the reservoir and, by inference due to the impermeable nature of the formation, a minimal part of the resource. However, when the drilling operation can deviate from the conventional vertical plane and move in the horizontal plane, much more of the reservoir resource becomes accessible (Ely, 1985; Gidley et al., 1990).

Thus, conventional petroleum reservoirs depend on the pressure of their gas cap and oil-dissolved gas to lift the oil to the surface (i.e., *gas drive*) (Chapter 3). Water trapping the petroleum from below also exerts an upward hydraulic pressure (i.e., *water drive*). The combined pressure in petroleum reservoirs produced by the natural gas and water drives is known as the *conventional drive.* As a reservoir's production declines, lifting further petroleum to the surface, like the lifting of water, requires pumping, or *artificial lift.* In the late 1940s, drilling companies began inducing hydraulic pressure in wells to fracture the producing formation. This stimulated further production by effectively increasing the contact of a well with a formation. Moreover, advances in directional drilling technology have allowed wells to deviate

---

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

from nearly vertical to extend horizontally into the reservoir formation, which further increases contact of a well with the reservoir. Directional drilling technology also enables drilling a number of wells from a single well pad, thus cutting costs while reducing environmental disturbance. Combining hydraulic fracturing with directional drilling has opened up the production of tight (less permeable) petroleum and natural gas reservoirs, particularly unconventional gas shales such as the Marcellus Shale Formation.

In the past three to four decades, hydraulic fracturing has been increasingly used in formations that were known to be rich in natural gas that was locked so tightly in the rock that it was technologically and economically difficult to produce. The application of hydraulic fracturing to tight sands revitalized old fields and allowed establishment of new fields. Subsequently, the application of hydraulic fracturing to shale opened up new areas to development, including the Marcellus shale in the eastern United States, the Barnett shale in Texas, and the Fayetteville shale in Arkansas, among others (Fig. 5.1). In fact, the rise in production of natural gas and crude oil from these and other shale plays has affected the move of natural gas and crude oil prices to lower (currently) more stable levels (Fisher, 2012; Scanlon et al., 2014; US EIA, 2014).

Briefly, the process involves use of a perforating gun, which is lowered into a newly drilled well and lined up precisely within the target formation using seismic images, well logs, global positioning systems, and other indicators to target the spots from which tight gas and oil are most likely to occur. When fired, the gun punches small holes in the well casing, cement, and rock after which fracturing fluid is pushed out the perforations under high pressure, creating small cracks in the formation that allow the gas and oil to flow from the rock. In practice, the well is fractured in stages and a plug set between each stage. When all of the stages have been completed and plugged, the plugs are removed (drilled out), which allows the gas or oil to flow up through the well to begin production. This fracturing fluid contains proppants such as sand, coarsely ground walnut shells, and other similarly sized materials in order to maintain many cracks (fractures) created by the pressure treatment in the open position, thus preventing closure when the pressure treatment is cased. Although the fluid (*slickwater*) used for hydraulic fracturing is predominantly water, it does contain chemicals (in addition to the proppant) that can pose an environmental risk.

Thus, hydraulic fracturing has become an essential part of petroleum and natural gas production, especially petroleum and natural gas that are otherwise trapped in low-permeability (shale) formations (Agarwal et al., 1979). The procedure significantly improves the recovery from the reservoir by stimulating the movement of petroleum and natural gas. Since the late 1940s, over 1 million wells have been hydraulically fractured in the United States, and more than 2 million have been fractured on a worldwide basis. When used in conjunction with horizontal drilling, an advanced drilling technology, hydraulic fracturing, has made it possible to develop vast unconventional resources.

The goal of hydraulic fracturing is to create a highly conductive fracture system that will allow flow of fluids and/or gases through the formation to the production well. Hydraulic fracturing fluids are used to initiate and/or expand fractures, as well

FIGURE 5.1 Shale plays in the United States, Canada, and Mexico. Source: Energy Information Administration, US Department of Energy, Washington, DC.

as to transport proppant into fractures in coalbed formations. Proppants are sand or other granular substances injected into the formation to hold or prop open the formation fractures created by hydraulic fracturing. The viscosity of fracturing fluids is considered when they are formulated to provide for efficient transport and placement of proppant into a fracture. Most of the fracturing fluids injected into the formation are pumped back out of the well along with water, crude oil, and natural gas.

Without hydraulic fracturing and horizontal drilling, resources like tight sands, coalbed methane, and shale gas would remain largely undeveloped. In fact, many modern oil field production operations would not exist without hydraulic fracturing, and as the global balance of supply and demand forces the petroleum and natural gas industry toward more unconventional resources including shale formations such as the Barnett, Haynesville, Bossier, and Marcellus plays, hydraulic fracturing will continue to play a substantive role in unlocking otherwise unobtainable reserves.

Hydraulic fracturing is not a new technology, and use of the technology can be traced to the 1860s, when liquid (and later, solidified) nitroglycerin was used to stimulate shallow, hard rock wells in Pennsylvania, New York, Kentucky, and West Virginia (Table 5.1). The use of nitroglycerin is, to state it simply, is extremely hazardous and was often used (illegally) for oil well *shooting*, which is the breakup or rubblization of an oil-bearing formation to increase both initial flow and ultimate recovery of the oil. This same fracturing principle was soon applied with equal effectiveness to water and gas wells. In fact, rubblization is a more complete form of fracturing that results in rock destruction compared to hydraulic fracturing, which creates fracture channels within the rock.

In the 1930s, the idea of injecting a nonexplosive fluid (acid) into the ground to stimulate a well began to be tried, and as the technology evolved, it became possible to establish a relationship between observed well performance and treatment pressures, and formation breakdown during acidizing, water injection, and squeeze cementing became better understood. From this, there arose the concept of hydraulically fracturing a formation to enhance production from oil and gas wells.

Hydraulic fracturing is essential to produce oil and natural gas that is otherwise trapped in low-permeability rock formations. It significantly improves the recovery from the reservoir by stimulating the movement of oil and natural gas. This chapter stresses the importance of understanding where hydraulic fracturing fits into the entire drilling, well construction/completion, and production phases of oil and natural gas activities—hydraulic fracturing is not a method for drilling or constructing a well.

Moreover, reservoir characteristics must always be considered when designing hydraulic fracturing. For example, in moderate- to high-permeability reservoirs, fractures are designed to improve production by bypassing near-wellbore formation damage (Veatch, 1983; Reinicke et al., 2010). In these reservoirs, the most important fracture characteristic is dimensionless fracture conductivity, which is a function of the width, permeability, and length of the fracture and of formation matrix permeability. In permeable but weakly consolidated reservoirs, fracturing methods are used in conjunction with gravel packing to reduce the pressure drop and fluid velocities around a wellbore during production and therefore mitigate sand production.

TABLE 5.1 Highlights in the Development of Hydraulic Fracturing

Date	Comment
Early 1900s	Natural gas extracted from shale wells
	Vertical wells fractured with foam
1947	Klepper gas unit no. 1: first well to be fractured to increase productivity
1949	Stephens County, Oklahoma: first commercial fracturing treatment
1950	Fracturing with cement pumpers
1950s	Evolution of fracture geometry
	Increasing well productivity
1960s	Fracturing pumpers and blenders
1970s	Massive hydraulic fracturing
	Increase recoverable reserves
	Hydraulic fracturing in Europe
1983	First gas well drilled in Barnett shale in Texas
1980s	Evolution of proppant transport
	Fracture conductivity testing
	Cross-linked gel fracturing fluids developed; used in vertical wells
1990s	First horizontal well drilled in Barnett shale
	Orientation of induced fractures identified
	Foam fracturing
1996	Slickwater fracturing fluids introduced
1996	Microseismic postfracturing mapping developed
1997	Hydraulic fracturing in Barnett shale
	Slickwater fracturing developed
1998	Slickwater refracturing of originally gel-fractured wells
2002	Multistage slickwater fracturing of horizontal wells
2003	First hydraulic fracturing of Marcellus shale
2004	Horizontal wells become dominant
2005	Increased emphasis on improving the recovery factor
2007	Use of multiwell pads and cluster drilling

In fact, in low-permeability reservoirs (often referred to as tight shale formations) and the most common reservoir type to be fracture stimulated, fracture length is the overriding factor for increased productivity and recovery. In addition, and from a reservoir development standpoint, understanding the fracture geometry and orientation is crucial for determining well spacing (Holditch et al., 1978) and field development strategies designed to extract more hydrocarbons petroleum or natural gas. Furthermore, natural fractures, which are often the primary means for fluid flow in low-permeability reservoirs, can (and often do) compromise the ability to predict the geometry of hydraulic fractures and the effect on production and drainage. In fact, understanding the interaction between hydraulic fractures with natural fracture systems (such as open channels and mineral-filled channels) requires knowledge of both hydraulic and natural fracture types. Hydraulic fractures tend to propagate according to the direction of the applied stress and the direction of least resistance, such as natural fractures, which reflect geological stress regimes. Thus, while it is possible to have knowledge and understanding of existing natural fracture systems, geological discontinuities such as fractures and faults will most likely influence fracture geometry, thereby rendering the prediction of hydraulic fracture behavior difficult.

The evolution of techniques for hydraulic fracturing in high-permeability formations has advanced in leaps and bounds over the decades since the 1950s (Smith and Hannah, 1996). The first fracture treatments in the 1950s were pumped in moderate- to high-permeability formations and were designed to remove formation damage that typically occurred during the drilling and well completion operations.

Briefly, whether or not a reservoir is high, moderate, and low permeability can be defined on the basis of both the formation permeability and the reservoir fluid viscosity (the k/μ ratio, where k is the formation permeability in millidarcies (mD) and μ is the formation fluid viscosity in centipoises (cP)). For a gas well, the viscosity of the gas is assumed to be approximately 0.02 cP. Thus, for a typical gas well (i) a low-permeability formation might be $k < 0.1$ mD, (ii) medium-permeability reservoir might be $10 > k > 1$ mD, and (iii) a high-permeability reservoir might be 25 md $> k$. If the formation contains crude oil with a fluid viscosity of 2 cP, all the permeability values must be multiplied by a factor of 100 to determine whether or not the reservoir is a low-permeability, medium-permeability, or high-permeability formation. Thus, the definition of reservoir permeability depends on the value of the viscosity of the reservoir fluid. In heavy oil reservoirs, in which the viscosity of the fluid is on the order of several thousand centipoises, formations with a permeability of the order of several darcies is considered to be a low-permeability reservoir. By inference, if the reservoir is a formation containing either natural gas or conventional (light) crude oil, a permeability on the order of several hundred millidarcies or more can be considered to be a high-permeability reservoir.

Furthermore, the main reasons for fracture treating high-permeability formations are (i) to improve both the reservoir and wellbore communication, (ii) to bypass formation damage, (iii) to reduce the drawdown around the wellbore, (iv) to increase the back stress on the formation, (v) to control sand production, (vi) to reduce fines migration, (vii) to reduce asphaltene deposition, and (viii) to reduce water coning (Valko et al., 1998). The early fracture treatments were pumped to break through damage near the wellbore and increase the productivity index of the formation. In more modern systems, fracture treatments in high-permeability wells are pumped to bypass damage as well as for sand control purposes. By creating a short, highly conductive fracture connecting the reservoir to the wellbore, the productivity index is increased; thus, more oil and gas can be produced with a lower drawdown. As the drawdown is reduced, the tendency of a poorly consolidated reservoir to produce sand is also reduced.

In certain formations, the reduction in drawdown also helps to deter (i) fines migration, (ii) deposition of asphaltene deposition, and (iii) water coning—the phenomenon in which bottom water gradually and frequently suddenly displaces a part or all of the oil production when a certain rather critical production rate from the well is exceeded.

Most fracture treatments in high-permeability formations are designed to achieve a tip screen-out (Smith et al., 1987). A tip screen-out design is one in which the pad volume is designed carefully so that the pad leaks off during the treatment, causing the propping agent to bridge at the tip of the fracture near the end of the job. At this point, the fracture ceases to grow in length, but pumping continues. As pumping continues, the pressure in the fracture increases, which leads to increasing width and, sometimes, increasing height. The fracture continues to inflate and is packed with the propping agent. The purpose of a tip screen-out design is to create a short, extremely wide fracture that is completely packed with the propping agent.

In summary, fracture treatment technology was first developed in the 1950s to break through damage in high-permeability reservoirs. In the 1960s, gelled water fluids were used successfully to fracture treat both low-permeability and high-permeability crude oil and natural gas wells. The technology evolved in the 1970 and 1980s when hydraulic fracture treatments in applied to microdarcy reservoirs. However, in the 1990s, because of the tip screen-out design process and fracturing operations—which combine gravel packing with fracturing, creating wide, highly conductive fractures connecting the reservoir to the wellbore—stimulation of high-permeability reservoirs is once again an important aspect of hydraulic fracturing to reduce the effects of formation damage and to enhance gravel packing.

Finally, success or failure of a hydraulic fracture treatment often depends on the quality of the candidate well selected for the treatment. Choosing an excellent candidate for stimulation often ensures success, while choosing a poor candidate normally results in economic failure. To select the best candidate for stimulation, the design engineer must consider many variables. The most critical parameters for hydraulic fracturing are formation permeability, the *in situ* stress distribution, reservoir fluid viscosity, skin factor, reservoir pressure, reservoir depth, and the condition of the wellbore. The skin factor refers to whether the reservoir is already stimulated or, perhaps, damaged. If the skin factor is positive, the reservoir is damaged and will likely be an excellent candidate for stimulation.

The best candidate wells for hydraulic fracturing treatments in a tight gas reservoir have a substantial volume of original gas in place (OGIP) or original oil in place (OOIP) and good barriers to vertical fracture growth above and below the net pay intervals. Such reservoirs have (i) a thick pay zone, (ii) medium to high pressure, (iii) *in situ* stress barriers to minimize vertical height growth, and (iv) substantial areal extent. Tight reservoirs that are not good candidates for hydraulic fracturing are those with (i) a small volume of gas in place because of thin reservoirs, (ii) low reservoir pressure, and (iii) small areal extent. Also, reservoirs that do not have enough clean shale above or below the pay interval to suppress vertical fracture growth are considered to be poor candidates. Reservoirs with extremely low permeability might not produce enough gas or oil hydrocarbons to pay all the drilling and completion costs, even if successfully stimulated. Thus, such reservoirs would not be good candidates for stimulation.

In terms of offshore reservoirs, a form of hydraulic fracturing has been in commercial use since the early 1990s. Similar to hydraulic fracturing that is being used to develop unconventional resources onshore (shale and tight sand), hydraulic fracturing offshore has combined two mature oil and gas technologies—hydraulic fracturing and gravel pack completions. The result has been a significant improvement in well life and reliability, productivity, and oil and gas recovery.

In many offshore regions, the geologic formations that produce oil and gas are unconsolidated, which means the sand that makes up these formations is loose or poorly bonded, much like the sand on a beach. As a result, this loose sand can end up inside the production piping in the well or production equipment on the surface. Sand production is highly undesirable since it can plug pipes and equipment, erode piping (much like sandblasting), and lead to corrosion of pipe and equipment. Eliminating sand production has been one of the main production challenges faced by engineers since the early days of offshore oil and gas development.

The basic operation of hydraulic fracturing is similar, but the scale is significantly different than onshore operations due in large part to the geologic formations and the cost and logistical constraints that occur with offshore platforms. Typical water usage for offshore hydraulic fracturing is 2% of the liquids that is used routinely for onshore hydraulic fracturing (e.g., like those used in the Marcellus shale play). Full-scale hydraulic fracturing has been tried in the offshore shales but with limited success to date, due to lithological properties of the Monterey shale offshore, California (it is naturally fractured), and equipment and cost constraints involved with working offshore.

Hydraulic fracturing is utilized offshore primarily during the well completion phase of developing a well for production to enhance safety and security of the well while optimizing production. This constitutes the majority of hydraulic fracturing activities that are conducted offshore. Hydraulic fracturing can also be used to prepare a well for enhanced oil recovery or to work over the well to increase production when the well has been under production for some time.

To stimulate gas and/or oil flow from tight sand formation or from shale formations, where gas is trapped in tiny pores in the rock (rather than accumulated in large pools or more porous rock), hydraulic fracturing is applied. In spite of the various negative attitudes to hydraulic fracturing, it is proven technique and has been used for decades in many kinds of oil and gas wells but is particularly valuable in tight gas and shale gas formations. However, hydraulic fracturing must be applied with diligence and caution and use of multidisciplinary team, like all reservoir management operations (Fig. 5.2). Starting the process on the basis that *one person knows all* is guaranteed to cause a multitude of problems and result in failure.

Thus, coupled with hydraulic fracturing, the crude oil and natural gas resources in shale formation and in tight formations (often referred to as *tight oil* and *tight gas*, respectively) become accessible and recoverable. Furthermore, horizontal drilling makes it possible for a well to be drilled vertically several thousand feet or meters and then curved to extend at an angle parallel to the Earth's surface, threading the well through the horizontal gas formation to capture more pockets of gas. On the other hand, in some geological settings, it is more appropriate to directionally drill *S-shaped wells* from a single pad to minimize surface disturbance. These types of wells are drilled vertically several thousand feet and then extend in arc shapes beneath the surface of the Earth. Whatever the type of well, multiple wells can be drilled from a central location to proceed in different directions within the reservoir. During drilling, mobile drilling units are moved between wells on a single drilling location (pad), which avoids dismantling and reassembling drilling equipment for each well,

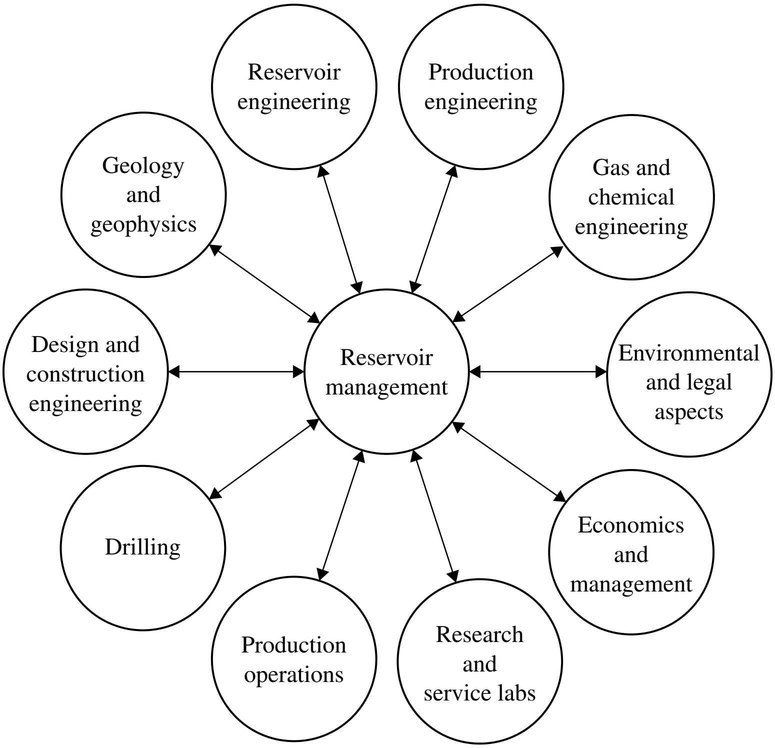


FIGURE 5.2 The various facets of reservoir management.

making the process shorter. This procedure limits the number of drilling pads on the surface and, as a consequence, leaves a smaller environmental footprint on the surface (Chapter 8).

5.2 FORMATION EVALUATION

Conventional natural gas and crude oil can be produced from reservoirs relatively easily, but unconventional gas and crude oil in tight formations are more difficult to develop and more costly to produce from the tight formations. The term *tight formation* refers to a formation consisting of impermeable, hard rock, which makes the underground formation extremely *tight*. As a point of references, typical conventional crude oil and natural gas reservoirs have a permeability level on the order of 0.01–1 D, but the formations termed *tight formations* (*tight reservoirs*) typically have permeability levels on the order of millidarcies (darcy × 10^{-3}) or microdarcies (darcy × 10^{-6}) even down to nanodarcies (darcy × 10^{-9}) (Table 5.2).

Shale formations are example of such tight formations, but crude oil and natural gas can also be trapped in sandstone or limestone formations that are atypically impermeable or nonporous (*tight sands*). While a conventional gas formation can

TABLE 5.2 Reservoir Types Based on Permeability and Production Methods

Permeability			
1 nD	1 μD	1 mD	1 D
Reservoir type:			
Shale	Tight		Conventional
Production method:			
Fracturing and horizontal drilling for production	Fracturing required for production		Fracturing used to stimulate production

be relatively easily drilled and extracted from the ground unassisted, tight gas and tight oil (natural gas and crude oil in tight formations) require more effort to extract them from the reservoir. There is also a subtle differentiation between the types of tight formations—there are (i) tight or compressed sandstone formations, which were compressed during geological time and after the crude oil and natural gas had migrated into the formations, and (ii) tight shale formations, which in some case might actually be the original source rock that retained the oil and gas as it was formed.

Shale formations are termed unconventional formations because the low permeability of the shale causes difficulty in extracting resources by merely drilling into the formation. Hydraulic fracturing is not a new technique, as the first fracturing test was done in 1947 and was commercialized in 1950 (King, 2012). Another key technology germane to shale gas development is horizontal drilling, which started in the 1930s. The popularity of hydraulic fracturing as a means to obtain natural gas and crude oil has been heightened by the large distribution of shale deposits in the United States, Canada, and Mexico (Fig. 5.1). The Society of Petroleum Engineers (SPE) have estimated that in the last 60 years, about 2.5 million hydraulic fracturing operations have taken place worldwide; 1 million in the United States alone and tens of thousands of horizontal wells have been drilled (King, 2012). Many of the shale gas sediments also produce gas liquids or light high-volatility crude oil.

In such formations, the pores in the rock in which the gas and oil are trapped are either irregularly distributed or badly connected with overly narrow capillaries, lessening permeability and/or the ability of the gas to travel through the rock. Without secondary production methods, gas and/or oil from a tight formation would flow at very slow rates, making production uneconomical. In order to overcome the challenges that tight formations present, there are a number of additional procedures that can be enacted to help produce tight gas and/or tight oil. Deviating drilling practices and more specific seismic data can help in tapping tight gas, as well as artificial stimulation, such as fracturing and acidizing.

Tight formations vary considerably and for this reason no single technique for hydraulic fracturing has universally worked. Each play has unique properties that need to be addressed through fracture treatment and fluid design. For example, numerous fracture technologies have been applied in the Appalachian Basin alone, including the use of carbon dioxide, nitrogen, carbon dioxide foam, and slickwater fracturing. The composition of fracturing fluids must be altered to meet specific reservoir and operational conditions. Slickwater hydraulic fracturing, which is used extensively in shale basin of the United States and Canada, is suited for complex reservoirs that are brittle and naturally fractured and are tolerant of large volumes of water. Ductile reservoirs require more effective proppant placement to achieve the desired permeability. Other fracture techniques, including carbon dioxide polymer foam and nitrogen foam, are occasionally used in ductile rock (for instance, in the Montney shale in Canada).

One of the most important aspects of drilling for any petroleum is predetermining the success rate of the operation. Operators do not just drill on an a "let's do it" basis, and extensive seismic data is gathered and analyzed to determine where to drill and just what might be located below the Earth's surface. These seismic surveys can help to pinpoint the best areas to tap tight gas reserves. A survey might be able to locate an area that portrays an improved porosity or permeability in the rock in which the gas is located. If drilling is sufficiently accurate to directly penetrate the best area to develop the reservoir, the cost of development and recovery can be minimized.

Most tight gas and oil formations are found onshore, and land seismic techniques are undergoing transformations to better map out where drilling and development of these unconventional plays. Typical land seismic techniques include exploding dynamite and *vibroseis*, or measuring vibrations produced by purpose-built trucks. While these techniques can produce informational surveys, advancements in marine seismic technologies are now being applied to land seismic surveys, enhancing the information available about the world below.

Fracturing a well involves breaking the rocks in the formation apart. Performed after the well has been drilled and completed, hydraulic fracturing is achieved by pumping the well full of fracturing fluids under high pressure to break the rocks in the reservoir apart and improve permeability, or the ability of the gas to flow through the formation. Additionally, acidizing the well is employed to improve permeability and production rates of tight gas formations, which involves pumping the well with acids that dissolve the limestone, dolomite, and calcite cement between the sediment grains of the reservoir rocks. This form of production stimulation helps to reinvigorate permeability by reestablishing the natural fissures that were present in the formation before compaction and cementation.

While vertical wells may be easier and less expensive to drill, they are not the most conducive to developing tight gas. In a tight gas formation, it is important to expose as much of the reservoir as possible, making horizontal and directional drilling a necessity. Here, the well can run along the formation, opening up more opportunities for the natural gas to enter the wellbore. A more common technique for developing tight gas reserves includes drilling more wells. The more the formation is tapped, the more the gas will be able to escape the formation. This can be achieved through drilling myriad directional wells from one location, which lessens the drilling footprint and lowers the costs. After seismic data has illuminated the best well locations and the wells have been drilled, production stimulation is employed on tight gas reservoirs to promote a greater rate of flow. Production stimulation can be achieved on tight gas reservoirs through both fracturing and acidizing the wells.

Formation evaluation is the process of interpreting a combination of measurements taken inside a wellbore to detect and quantify oil and gas reserves in the rock adjacent to the well. A formation consists of rock layers (strata) that have similar properties (Chapter 2), and thus, formation evaluation is an important aspect of the fracturing process, especially in low-permeability reservoirs because of the presence of alternating layers with various properties. Hence, it is necessary to define these properties, which include thickness, fluid saturation, porosity, Young's modulus, *in situ* stress, permeability, formation conductivity, etc. (Holditch et al., 1987).

Thus, formation evaluation is used to determine the ability of a well (borehole) to produce crude oil and/or natural gas. Typically, the well is drilled by a rotary drill that uses a heavy mud (drilling mud) as a lubricant and as a means of producing a confining pressure against the formation face in the borehole, preventing blowouts.

A blowout is an uncontrolled release of fluids during the drilling, completion, or production of crude oil and natural gas. In former times, the blowout may have been referred to as a gusher, which was spectacular but (Hollywood movies not withstanding) was a waste of crude oil and an environmental nightmare.

When a blowout occurs, it is typically when unexpectedly high pressures are encountered in the subsurface or due to valve or some other type of mechanical failure. Blowouts may take place at the surface (wellhead or elsewhere) or subsurface (naturally high pressure, or may be artificially induced in the wellbore during hydraulic fracturing during completion operations, but not during pumping). A high percentage of blowouts occur due to casing or cement failure, allowing high-pressure fluids to escape up the wellbore and flow into subsurface formations. The potential environmental consequences of a blowout depend mostly on (i) the timing of the blowout relative to well activities, which determines the nature of the released fluid such as natural gas or pressurized fracturing fluid; (ii) the occurrence of the escape of contaminants through the surface casing or deep in a well; and (iii) the risk receptors, such as freshwater aquifers or water wells that are impacted.

Surface blowouts at the wellhead are serious matters that can result in a major safety hazard to workers and may also result in surface spills. Surface blowouts are primarily prevented through proper well construction, maintenance, and ensuring well integrity. Subsurface blowouts, due to high gas pressure or mechanical failures, happen in both regular and hydraulically fractured wellbores. However, fractured wells have the incremental risk of potential failures caused by the high pressures of fracturing fluid during the process. In the event of a subsurface blowout, blowout preventers are used to automatically shut down fluid flow in the wellbores. However, subsurface blowouts may pose both safety hazards and environmental risks. For example, when a blowout preventer engages to prevent the fluid from reaching the surface, the fluid may be forced through weaknesses in the casing and cement below the blowout preventer into the surrounding formations and aquifers.

However, controlling blowouts has disadvantages such as (i) a mud filtrate soaking into the formation in the near vicinity of the borehole and (ii) a mud cake plastering the sides of the hole. These factors obscure the possible presence of oil or gas in even very porous formations, and further complications arise with the occurrence of small amounts of petroleum in the rocks of many sedimentary formations (sedimentary provinces). In fact, if a sedimentary formation does not exhibit any evidence for the presence of natural gas or petroleum, drilling operations will be terminated.

5.2.1 Geologic Evaluation

A primary step in the evaluation of feasibility of fracturing is an examination of detailed and accurate geologic cross sections illustrating sediment layering and grain sizes in the target zone and the contaminant characteristics present in the target zone. Because contaminants often reside within low-permeability, fine-grained soils, it is important to understand this relationship.

At least one continuous core boring investigation is necessary in order to characterize major and minor changes in lithology. Cores collected during continuous and depth-specific sampling should be examined for factors contributing to secondary permeability such as coarse-grained sediment inclusions and naturally occurring fractures. These secondary permeability characteristics of the soil or rock formation may influence the creation of engineered fractures. Pneumatic fractures, in particular, may propagate along existing fracture patterns. Hydraulic fractures have been found to be less influenced by existing fractures. The site and geologic parameters to be evaluated include (i) type of soil/rock; (ii) type of deposition; (iii) groundwater locale, including depth of the aquifer; (iv) the possibility of prefracturing contamination; (v) the type of contamination; and (vi) the depth and extent of the contamination. The last three categories are necessary to establish the base-case condition of the area before fracturing commences and is the control by which the hydraulic fracturing process and any ensuing effects is measured.

5.2.2 Geotechnical Evaluation

Geotechnical characterization of the formations involves determining two general factors: (i) the lower limits for porosity, permeability, and upper limits for water saturation that permit profitable production from a particular formation or pay zone, in a particular geographic area, and in a particular economic climate and (ii) whether or not the formations in the well under consideration exceed these lower limits. Thus, target zone samples should be submitted for geotechnical evaluation of (i) grain size analysis, (ii) liquid and plastic limits of the formations, (iii) moisture content, and (iv) unconfined compressive strength.

Grain size analysis recognizes that although fractures can be created in sediments and rock of variable grain size, the highest degree of permeability improvement can be expected from the finer-grained materials. Grain size analysis can be performed by using the sieve analysis method and/or the hydrometer analysis method (ASTM D421, ASTM D422). The *liquid and plastic limits* of the formations (the Atterberg limits—a measure of the critical water contents of a fine-grained soil, such as its shrinkage limit, plastic limit, and liquid limit) characterize the plasticity of a formation (ASTM D4318). The *moisture content* (ASTM D2216) can influence the process insofar as permeability improvements are achievable with fracturing but vapor flow in particular is also controlled by the presence of moisture. Improvements in vapor flow through highly saturated formations (at or near capacity) will not be achieved by fracturing alone. Additional means of moisture removal may be required to obtain the desired effect through fracturing under these circumstances.

Data from measurement of the *unconfined compressive strength* (ASTM D2166) can be used for predicting the orientation and direction of propagation of fractures. The state of *in situ* stresses plays a key role in the orientation and ultimate effect on permeability enhancement. The artificially induced fractures are assumed to be vertical in normally consolidated soil and horizontal in overconsolidated deposits. Since hydraulic fracturing is generally applied at sites with characteristically low permeability, a baseline estimate of *permeability* (vapor and/or liquid) must be available, usually from testing concluded at the site during site investigations. This baseline estimate of permeability provides a basis for evaluating the necessity, benefit, and effectiveness of the fracturing process. In general, greater improvement of vapor or fluid flow and radial influence is observed in formations with lower initial permeability. In terms of cohesion, the more cohesive the soil is, the more amenable it will be to fracturing. Longevity of the fractures, upon relaxation of fracture stress, is high in cohesive formations, and fracturing in cohesive formations (such as silty clays) has been particularly successful.

The simplest and most direct means of evaluation is an examination of *well cuttings*, which are examined using a stereoscopic microscope to determine the lithology of the formation and to estimate porosity as well as for possible signs of crude oil. A portable ultraviolet light chamber is used to examine the cuttings for fluorescence, which can be an indication of crude oil staining, or of the presence of fluorescent minerals. However, the data from well cuttings may not be truly representative of the formation *in situ*. One way to get more detailed samples of a formation is by recovering core samples (a cylinders of rock, approximately 3–4 inches in diameter and up to 60 ft long) followed by examination of a whole core. As with drill cuttings, an issue that arises with the use of cores is the change that the cores undergo as they are brought to the surface. Most full cores from any significant depth expand and fracture as they are brought to the surface and removed from the core barrel. In addition, the core can be invaded or even flushed by mud, making the evaluation of formation fluids difficult.

Mud logging (*well site geology*) is a well logging process in which drilling mud and drill bit cuttings from the formation are evaluated during drilling and their properties recorded on a strip chart as a visual analytical tool and stratigraphic cross-sectional representation of the well. The drilling mud, which is analyzed for hydrocarbon gases, by use of a gas chromatograph, contains drill bit cuttings that are visually evaluated by a mud logger and then described in the mud log. The total gas, chromatograph record, lithological sample, pore pressure, and shale density are plotted along with surface parameters such as rate of penetration, weight on bit, and rotation per minute on the mud log, which serve as a tool for the mud logger, drilling engineers, mud engineers, and other personnel in charge with drilling and producing the well.

The technique known as *wireline logging* is used to obtain a continuous record of the properties of a rock formation by the acquisition and analysis of geophysical data performed as a function of wellbore depth, together with the provision of related services. Wireline logging is performed by lowering a logging tool—or a string of one or more instruments—on the end of a wireline into an oil well (or borehole) and recording petrophysical properties using a variety of sensors. The technique measures the natural gamma ray, electrical, acoustic, stimulated radioactive response, electromagnetic, nuclear magnetic resonance, pressure, and other properties of the rocks and their contained fluids. The measurements (*true along hole depth* (TAH depth)) and any associated analysis can then be used to infer further properties, such as hydrocarbon saturation and formation pressure, and to make further drilling and production decisions.

In addition, *electric logs* (*resistivity logs*) measure the resistance to electric current of the total formation (reservoir rock and reservoir fluids), and if the pores are partially filled with gas or oil, which are resistant to the passage of electrical current, the bulk formation resistance is higher than that for water-filled pores. For the sake of a convenient comparison from measurement to measurement, the electrical logging tools measure the resistance of a cubic meter of formation.

In the late 1950s techniques for producing porosity logs were developed, and the combination of neutron and density logs takes advantage of the fact that lithology has opposite effects on these two porosity measurements. The average of neutron and density porosity values is usually close to the true porosity, regardless of lithology. Another advantage of this combination is that the gas effect due to gas being less dense than liquids translates into a density-derived porosity that is too high. Gas, on the other hand, has much less hydrogen per unit volume than liquids: neutron-derived porosity, which is based on the amount of hydrogen, is too low. If both logs are displayed on compatible scales, they overlay each other in liquid-filled clean formations and are widely separated in gas-filled formations. *Sonic logs* use a pinger and microphone arrangement to measure the velocity of sound in the formation from one end of the system to the other. For a given type of rock, acoustic velocity varies indirectly with porosity. If the velocity of sound through solid rock is taken as a measurement of 0% porosity, a slower velocity is an indication of a higher porosity that is usually filled with formation water with a slower sonic velocity.

The *gamma ray log* is a measurement of naturally occurring gamma radiation from the borehole walls. Sandstone formations are usually nonradioactive, whereas shale formations are naturally radioactive due to potassium isotopes in clay minerals and adsorbed uranium and thorium. Thus, the presence or absence of gamma rays in a borehole is an indication of the amount of shale or clay in the surrounding formation. The gamma ray log is useful in holes drilled with air or with oil-based muds and is also useful for detecting coalbeds, which, depending on the local geology, can have either low radiation levels or high radiation levels due to adsorption of uranium. In addition, the gamma ray log will work inside a steel casing, making it essential when a cased well must be evaluated.

5.2.3 Formation Integrity

The formation integrity test (FIT) is carried out to confirm the strength of formation and well casing shoe by increasing the bottom-hole pressure to a design pressure. There is a lot of confusion in the nomenclature, as formation integrity tests (FITs) such as the use of leak-off tests (LOTs) (API RP 13M-4, 2015). The LOTs, also known as pressure integrity tests (PITs), are used to determine the fracture gradient of a formation (from stress estimates) (API RP 13M-4, 2015). Low leak-off (fluid-loss) rate is the property that permits the fluid to physically open the fracture and one that controls its areal extent. The rate of leak-off to the formation is dependent upon the viscosity and the wall-building properties of the fluid. Postfracture breakdown is necessary such that the injected fluids do not hinder the passage of oil and gas (clog) to the formation.

However, FITs are conducted to show that the formation below the casing shoe will not fail while drilling subsequent sections with a higher bottom-hole pressure. Simply put, the FIT is a pressure test applied to the formation directly below a casing shoe (Lee and Holditch, 1981). It is generally conducted soon after drilling resumes after an intermediate casing string has been set. The purpose of the test is to determine the maximum pressures that may be safely applied without the risk of formation breakdown. The results of the test are used to design the mud program for the subsequent hole section and to set safe limits on casing shut-in or choke pressures for well-control purposes.

Another difference between PITs and formation PITs is that stress estimates are not obtained with data from FITs since fracture initiation does not actually occur. In the integrity test, pressure is applied to a predefined value and no leak-off occurs. The integrity test indicates that the maximum wellbore pressure did not exceed the least principal stress or was not sufficient to initiate a fracture of the wellbore wall in an open hole test (Zoback, 2010). In well planning and development, the integrity tests are normally conducted before leak-off tests.

5.2.4 Permeability

Permeability is of critical importance in determining wells applicable for hydraulic fracturing. The main reason fracturing is done is to extract deposits of natural gas or crude oil that would not flow naturally to the wellbore. The permeability of the formation also affects the formation breakdown pressure in hydraulically fractured wells. It is based on this effect that it can be determined from the pressure buildup data of pressure tests. Experimental evidence supports the fact that permeable rock has a lower breakdown pressure than impermeable rock under similar conditions. Also, aside from showing a lower leak-off (breakdown) pressure, a PIT in a highly permeable formation shows a nonlinear pressure buildup due to fluid losses (Postler, 1997).

The standard method of obtaining permeability in routine core analysis is by allowing dry gas, usually nitrogen, helium, or air to flow through the samples. It has the following advantages over using liquid permeability: reduced fluid–rock interaction, easier to execute, faster, and less expensive. In liquid-producing reservoirs however, the validity of the gas permeability method is being questioned (Unalmiser and Funk, 2008) Another shortcoming of using dry gas to obtain permeability is that it has to be corrected for gas slippage (the Klinkenberg effect), which is due to variation in permeability measurements with the type of gas used and the mean existing pressures in the core when measurement was done.

5.2.5 Porosity

Porosity is the ratio of void volume to total (bulk) volume. It is obtained by measurement of either two of the three variables: pore volume (PV), bulk volume (BV) and grain volume (GV). It is important that standard calibration of temperature and barometric pressure is done when measuring grain density for GV determination. Porosity measurement like permeability is also sensitive to drying time. The type of porosity test to be carried out depends on the formation being sampled, for instance, in vug formations special procedures are required.

5.2.6 Saturation

Measurement of residual fluid saturation was originally done by (i) use of high-powered vacuum distillation to recover oil and water or (ii) distillation extraction, which divides the extraction process into two parts in which the water was distilled and then oil extracted using suitable solvents. Currently, fluid tracer studies, displaced-miscible fluid analyses (reducing damage to clays), and improved geochemical techniques are used to obtain saturation (Unalmiser and Funk, 2008). Fluid saturations are normally reported as a percent of the PV, and the accuracy of measurements is largely determined by conditions during sample recovery.

The special core analysis is divided into two stages. In the first stage, the measurement of permeability and porosity is repeated using other techniques, and further coring analysis is done to obtain measurement of capillary pressure, relative permeability, electrical properties, and cation exchange capacity (CEC) (Holditch et al., 1987). A parameter of interest that influences most of the properties in the first phase is the wettability of the sample as it relates to fracture properties (Fernø et al., 2008). It is a measure of the preferred inclination of a fluid, that is, water or oil to spread on the rock surface (Unalmiser and Funk, 2008). It combines the interaction of the rock surface, fluid interfaces, and pore shape. Another category of the special core analysis involves measurement of formation geomechanical properties like Poisson's ratio, Young's modulus, and fracture toughness (Holditch et al., 1987).

5.2.7 Capillary Pressure

The capillary pressure is the difference in pressure across the interface between two phases. Similarly, it has also been defined as the pressure differential between two immiscible fluid phases occupying the same pores caused by interfacial tension between the two phases that must be overcome to initiate flow. Relative permeability and capillary pressure relationships can be used to estimate the amount of oil and gas in a reservoir and for predicting the capacity for flow of oil, water, and gas throughout the life of the reservoir. The relative permeability and capillary pressure are complex functions of the structure and chemistry of the fluids and solids in a producing reservoir. As a result, they can vary from place to place in a reservoir. Most often, these relationships are obtained by measurements, but network models are emerging as viable routes for estimating capillary pressure and relative permeability functions.

Thus, capillary pressure is used to characterize the reservoir by indicating water saturation and size of pore channels and differentiating productive from nonproductive intervals (Keelan, 1982; Slattery, 2001). Laboratory techniques for determining capillary pressure include porous plate, centrifugal testing, mercury injection, and water vapor desorption (Unalmiser and Funk, 2008).

5.2.8 Logging Analysis

Logging operations are a very important part of formation evaluation. Extensive work has been done on the improvement of logging tools and monitoring programs. Well logging can be performed at any stage of a well's development: drilling, completion, production, or abandonment. Logs can be broadly grouped into electrical logs, lithology logs, and logging-while-drilling (LWD). It must be mentioned here that LWD is not necessarily a "group" of logging operations but a condition of logging. Thus, electrical or lithology logs can be obtained during the drilling operation, depending on the particular constraints surrounding each individual operation.

Electrical logs include sonic logging, resistivity logging, neutron porosity logging, density logging, and image logging. A popular electrical log is the sonic log. Sonic logging involves the measurement of the travel time of an acoustic wave through the formation. It is used principally to calibrate seismic data and to obtain formation porosity. The integration of logging and core analysis in tight gas reservoir characterization is of utmost importance, especially in defining porosity. Due to heterogeneity, formations may contain microfractures that can cause secondary porosity (Orlandi et al., 2011). In addition to porosity, sonic logs are also used to estimate rock geomechanical properties. A density log and a full waveform (shear and compressional waves) are recorded after running a sonic log, and from the sonic log data the rock mechanical properties can be calculated.

Lithology logs are useful in describing the different layers encountered as the borehole is drilled and also in identifying geometry of fractures present. They are used in prefracture and postfracture formation evaluation. Types of lithology logs include temperature logs, gamma ray logs, and spontaneous potential (SP) logs. Temperature logs are shallow investigative tools, used to infer fracture height, but are inadequate for use in deviated boreholes. A comparison of prefracture and postfracture temperature logs is also useful in determining changes to formation, wellbore, and temperature gradient after completion operations (Jones and Britt, 2009). The gamma ray log is another widely used lithology log. Fracture azimuth is determined using a shielded gamma ray log and gyroscope, with the fracture geometry being traced with radioactive tracer (Jones and Britt, 2009).

5.2.9 Mechanical Properties

Many tight gas reservoirs are thick layered systems that must be hydraulically fracture treated to produce at commercial gas flow rates. To optimize the completion, it is necessary to understand the mechanical properties of all the layers above, within, and below the gas pay intervals. Basic rock properties such as *in situ* stress, Young's modulus, and Poisson's ratio are needed to design a fracture treatment. The *in situ* stress of each rock layer affects how much pressure is required to create and propagate a fracture within the layer. The values of Young's modulus relate to the stiffness of the rock and help determine the width of the hydraulic fracture. The values of Poisson's ratio relate to the lateral deformation of the rock when stressed. Poisson's ratio is a parameter required in several fracture design formulas.

The most important mechanical property is *in situ* stress, often called the minimum compressive stress or the fracture closure pressure. When the pressure inside the fracture is greater than the *in situ* stress, the fracture is open. When the pressure inside the fracture is less than the *in situ* stress, the fracture is closed. We can determine values of *in situ* stress using logs, cores, or injection tests. To optimize the completion, it is very important to know the values of *in situ* stress in every rock layer.

5.3 THE FRACTURING PROCESS

First and foremost and to allay any confusion, hydraulic fracturing is not a method for drilling or constructing a well. It is the process for creating a fracture or fracture system in a porous medium by injecting a fluid under pressure through a wellbore in order to overcome native stresses. To fracture a formation, energy must be generated by injecting a fluid down a well and into the formation. The effectiveness of hydraulically created fractures is measured both by the orientation and areal extent of the fracture system and by the postfracture enhancement of vapor or liquid recovery.

The process is applied after well completion to facilitate movement of the reservoir fluids to the well and thence to the surface. This process fracturing creates access to more petroleum and natural gas supplies but requires the use of large quantities of water and fracturing fluids, which are injected underground at high volumes and pressure. Oil and gas service companies design fracturing fluids to create fractures and transport sand or other granular substances to prop open the fractures. The composition of these fluids varies according to the formation and ranges from a simple mixture of water and sand to more complex mixtures with a multitude of chemical additives (Chapter 6).

The sequence of fracturing a particular formation typically consists of (i) an acid stage, (ii) a pad stage, (iii) a prop sequence stage, and (iv) a flushing stage. The *acid stage* consists of several thousand gallons of water mixed with a dilute acid, such as hydrochloric or muriatic acid, which serves to clear cement debris in the wellbore and provide an open conduit for other fracturing fluids, by dissolving carbonate minerals and opening fractures near the wellbore. The *pad stage* consists of approximately 100,000 gallons of slickwater without proppant material; the slickwater pad stage fills the wellbore with the slickwater solution (described in the following), opens the formation, and helps to facilitate the flow and placement of proppant material. The *prop sequence stage* may consist of several substages of water combined with proppant material, which consists of a fine mesh sand or ceramic material, intended to keep open (prop) the fractures created and/or enhanced during the fraccing operation after the pressure is reduced. This stage may collectively use several hundred thousand gallons of water. The proppant material may vary from a finer particle size to a coarser particle size throughout this sequence. The *flushing stage* consists of a volume of freshwater sufficient to flush the excess proppant from the wellbore.

Most of the fluid used in hydraulic fracturing is water—chemicals, typically 1% v/v of the fracturing fluids, are added to keep the pipes cool by reducing friction and to prevent scale buildup and bacterial growth. The formulas for fracturing fluids vary, partly depending on the composition of the gas field and partly on the expert opinion of the operator or fluid supplier as to what works best. However, some of the chemical additives can be hazardous if not handled carefully. Care must be taken when using compounds added to fracturing fluid, and the amount of the chemical must meet or exceed all regulatory requirements related to handling hazardous materials.

Safe handling of all water and fluids on-site, including chemicals used for hydraulic fracturing, must be a high priority, and compliance with all regulations regarding containment, transport, and spill handling is essential. When it comes to disposal of the fracturing fluid, there are options. The fluid, when environmentally possible, can be reused for additional wells in a single field—this reduces the overall use of freshwater and reduces the amount of recovered water and chemicals that must be sent for disposal. In addition, tanks (or lined storage pits) for the storage of recovered water are also a necessity until the water can be sent for disposal in a permitted saltwater injection disposal well or taken to a treatment plant for processing.

All injection wells must be designed to meet the regulations set by the Environmental Protection Agency to protect groundwater. In addition, production zones should have multiple confining layers above the zone to keep the injected fluids within the target formation. In addition, multiple layers of well casing and cement (similar to production wells) should be used with periodic mechanical integrity tests to verify that the casing and cement are holding the liquids. The amount and pressure of the injected fluid (specified in each well permit) should be monitored to maintain the fluids in the target zone, and the pressure in the injection well and the spaces between the casing layers (also called the annuluses) should also be monitored to check and verify the integrity of the injection well.

5.3.1 Equipment

Hydraulic horsepower (hhp) per treatment has increased from an average of approximately 75 hhp to more than 1500 hhp. There are cases where, with as much as 15,000 hhp available, more than 10,000 hhp was actually used, in stark contrast with some early jobs, where only 10–15 hhp was employed. Some of the early pump manufacturing facilities made remotely controlled pumps powered by surplus Allison aircraft engines used during World War II. In fact, many fields would not exist without hydraulic fracturing. In the United States, these include the Spraberry trend in west Texas; Pine Island field, Louisiana; Anadarko Basin; Morrow wells, northwestern Oklahoma; the entire San Juan Basin, New Mexico; the Denver Julesburg Basin, Colorado; the east Texas and north Louisiana trend, Cotton Valley; the tight gas sands of south Texas and western Colorado; the overthrust belt of western Wyoming; and many producing areas in the northeastern United States.

Initial jobs were performed at rates of 2–3 bbl/min. This increased rapidly until the early 1960s, when it rose at a slower rate, settling in the 20 bbl/min range (even though there were times when the rate employed in the Hugoton field was more than 300 bbl/min). Then in 1976, Othar Kiel started using high-rate "hesitation" fractures to cause what he called "dendritic" fractures. Today, in the unconventional shale gas plays, Kiel's ideas are used where the pump rates are more than 100 bbl/min. Surface treating pressures sometimes are less than 100 psi, yet others may approach 20,000 psi.

Conventional cement-pumping and acid-pumping equipment was used initially to execute fracturing treatments. One to three units equipped with one pressure pump delivering 75–125 hhp were adequate for the small volumes injected at the low rates. Amazingly, many of these treatments gave phenomenal production increases. As treating volumes increased, accompanied by a demand for greater injection rates, special pumping and blending equipment was developed. Development of equipment including intensifiers, slinger, and special manifolds continues.

For the first few years, sand was added to the fracturing fluid by pouring it into a tank of fracturing fluid over the suction. Later, with less viscous fluid, a ribbon or paddle type of batch blender was used. Shortly after this, a continuous proportioning blender utilizing a screw to lift the sand into the blending tub was developed. Blending equipment has become very sophisticated to meet the need for proportioning a large number of dry and liquid additives, then uniformly blending them into the base fluid, and adding the various concentrations of sand or other propping agents. To handle large propping-agent volumes, special storage facilities were developed to facilitate their delivery at the right rate through the fluid. Treatments in the past were conducted remotely but still without any shelter. Today, treatments have a very sophisticated control center to coordinate all the activities that occur simultaneously.

The hydraulic fracturing treatment follows the actual drilling and completion of the well (Hubbert and Willis, 1957; Arthur et al., 2009). Specialized equipment is required for stimulation treatment, which includes storage tanks, chemical trucks, and a variety of pipes and fittings. Fracture tanks are large trailer tanks, designed to hold several hundred barrels of freshwater, which is used as base fluid for water-based (slickwater) fracture treatments. Additives are transported to the site in flatbed trucks, which contain pumps that enable the pumping of additives to blenders. Acid is usually transported to the fracturing site by an acid transport truck, which can hold up to 5000 gallons of acid. If the fracturing sites are close by, acid can also be transported from site to site via backside pump. Proppants are held in large tanks called sand storage tanks, which feed proppants (usually sand) to the blender through large conveyor belts. These storage tanks may hold as much as 350,000–450,000 pounds of proppant (Arthur et al., 2009).

A blender retrieves freshwater from tanks using suction pumps and blends the water with the proppant in a hopper. Fluids and proppant are combined with additives at design concentrations to form a slurry, which is pressurized and transferred to pumps, which transfer the slurry via positive displacement pumps to a manifold trailer. The manifold acts as a transfer station and pumps the fluid through ground lines to the fracture head (Hibbeler and Rae, 2005; Arthur et al., 2009).

Initial drilling is the same as for a conventional reservoir. A borehole is drilled vertically, then a casing is placed before cement, and mud is pumped to place a barrier between the borehole and adjacent formation. Drilling of the well is now continued, to an adequate depth within the producing reservoir, called the “kickoff point,” and then the wellbore is deviated gradually until it curves horizontally and drilled a distance of typically 1000 ft to more than 5000 ft (Arthur et al., 2009).

Hydraulic fracturing is done in isolated intervals along the horizontal well because it is impossible to apply pressure along the entire length of the wellbore due to distance constraints (1000–5000 ft). It is controlled by volume that an operator can pump into the hole at pressure. These intervals are isolated using packers. Perforations are created in the wellbore within the interval bounded by packers using a perforating tool. In shale gas development, fracture treatment is done in several stages. Initial stages could involve just pumping freshwater into the wellbore, thereafter using an acid flush to clean cement and mud from the wellbore to ensure fluid flow is not impeded during fracture treatment (Arthur et al., 2009). In some fracture treatments, acid is pushed through the perforated interval to help break down the formation surrounding the wellbore.

The fracturing fluid is pumped through the perforated intervals at high pressures in order to create fractures in the surrounding formation (pay zone). Hard particles (proppants) are added to the fracturing fluid and pumped into the formation after the fractures have been created. The proppant size and concentration are increased in stages over the entire course of one treatment. The propping agents hold open the newly created fractures to facilitate hydrocarbon recovery. The design of fracture treatment is a complex task, which involves analysis, planning, experience, and rigorous observation of different stages in the entire process.

In order to reach a formation containing petroleum and/or natural gas, the wellbore is drilled in successive sections through the rock layers. Once the desired length of each wellbore section has been drilled, the drilling assembly is removed, and steel casing is inserted and cemented in place. As the well is constructed, concentric layers of steel casing and cement form the barrier to protect groundwater resources from the contents that will later flow inside the well. Next, only the section of casing within the formation is perforated at the desired location.

The well is now ready for hydraulic fracturing process, which involves pumping fluid through the perforations. The fracturing fluid itself exerts pressure against the rock, creating tiny cracks, or fractures, in the reservoir deep underground. The fluid is predominantly water, proppant (grains of sand or ceramic particles), and a small fraction of chemical additives. Once fluid injection stops, pressure begins to dissipate, and the fractures previously held open by the fluid pressure begin to close. Proppants then act as wedges to hold open these narrow fractures, creating pathways for oil, natural gas, and fracturing fluids to flow more easily to the well. A plug is set inside the casing to isolate the stimulated section of the well. The entire perforate–inject–plug cycle is then repeated at regular intervals along the targeted section of the reservoir. Finally, the plugs are drilled out, allowing the petroleum, natural gas, and fluids to flow into the well casing and up to the surface.

The petroleum/gas/fracturing fluid mixture is separated at the surface, and the fracturing fluid (also known as flowback water) is captured in tanks or lined pits. The fracturing fluids are then disposed of according to government-approved methods. Hydraulic fracturing operations generally occur over a 3–5-day period. The entire well construction process (including hydraulic fracturing) takes only 2–3 months, compared to the 20–30-year productive life of a typical well.

Fractures from both horizontal and vertical wells can propagate vertically out of the intended zone, thereby (i) reducing stimulation effectiveness, (ii) wasting proppant and fluids, and potentially connecting up with other hydraulic fracturing stages or unwanted water or gas intervals, which can also lead to a variety of environmental issues (Chapter 8). The direction of lateral propagation is largely dictated by the horizontal stress regime, but in areas where there is low horizontal stress anisotropy or in reservoirs that are naturally fractured, fracture growth is not always easy to predict (Hammack et al., 2014). In shallow zones, horizontal hydraulic fractures can develop because the vertical stress component—the weight of the overburden—is smallest. A horizontal hydraulic fracture reduces the effectiveness of the stimulation treatment because it most likely forms along horizontal planes of weakness—such as the planes between formation strata—and is aligned preferentially to the formation vertical permeability, which is typically much lower than horizontal permeability.

After a hydraulic fracture is initiated, the degree to which it grows laterally or vertically depends on numerous factors, such as confining stress, fluid leak from the fracture, fluid viscosity, fracture toughness, and the number of natural fractures in the reservoir. Prediction of the precise behavior of the fracture is difficult and, in many cases, may even be impossible because of incorrect information and assumptions used in planning the fracture project.

With the increases in computing technology, design programs for hydraulic fracturing have evolved to include three-dimensional programs that can be used to predict (estimate) fracture geometry and fluid flow properties. In fact, programs are available to obtain a temperature profile of the treating fluid during a fracturing treatment, which can assist in designing the concentrations of the gel, gel stabilizer, breaker, and propping agent during the various treatment stages. Programs can also be used to observe production patterns following a fracturing treatment to determine which treatment achieved which actual result.

When drilling a well into a shale or another oil- and gas-bearing formation, an initial string of drive pipe, or conductor pipe, is installed to prevent unconsolidated materials such as soil, sand, and gravel from caving in during well drilling. Next, a “surface string,” or casing smaller in diameter than the conductor pipe, is installed after drilling below the entire vertical length of fresh groundwater. This casing string must be properly cemented to the surface to protect all potable groundwater sources from production-related activity in the wellbore that is drilled and completed to the target formation. If coal is present, another string of casing will be installed to isolate this interval. An intermediate casing string may also be installed under certain conditions to isolate, stabilize, or provide well control to a greater depth than that provided by the surface casing or coal protection casing. Each casing string will be deeper, but successively smaller in diameter. The annular space between the borehole and each casing string is typically cemented to the surface or to a prescribed height above the bottom of the casing string to ensure isolation and protection of each zone. Finally, a production interval is drilled, which may be several tens of feet to several hundred feet in a vertical Marcellus well or up to several thousand feet in a horizontal well. This zone typically is electronically analyzed or "logged" by a company that specializes in this service and is achieved by lowering an electronic device on a wireline into the wellbore, where data on porosity, density, and other characteristics are analyzed to determine the production potential of the formation. After the well has been logged, the production casing is installed in the borehole and cemented to isolate these zones.

The extent of a hydraulic fracture is a complex relationship between the strength of the rock and the pressure difference between the rock and the fracturing pressure. The extent is defined by the fracture dimensions—height, depth of penetration (wing length or fracture length), and aperture (width or opening). One measure of the strength of the rock is the Poisson ratio. Thus, when a material is compressed in one direction, it usually tends to expand in the other two directions perpendicular to the direction of compression (the Poisson effect), and the Poisson ratio (ν, the fraction (or percent) of expansion divided by the fraction (or percent) of compression) is a measure of this effect.

The Poisson ratio is low (0.10–0.30) for most sandstone formations and carbonates—rocks that fracture relatively easily. On the other hand, the Poisson ratio is high (0.35–0.45) for shale, sandstone, and coal—rocks that are more elastic and are harder to fracture (Sone and Zoback, 2013). Shale is often the upper and lower barrier to the height of a fracture in conventional sandstone.

5.3.2 Fracture Patterns

Hydraulic fracturing may be performed on as few as a single interval in a vertical well. Horizontal wells, however, by virtue of their significant wellbore length in the target formation, are generally isolated into several discrete intervals along the horizontal wellbore (approximately 4–20 intervals for each horizontal well), with each interval requiring its own fracturing stage. This is due to the difficulty in maintaining pressures sufficient to induce fractures over the complete length of the lateral leg.

Before an operator or a service company performs a fracturing operation on a vertical or horizontal well, tests are conducted to ensure that the well and all necessary equipment are in safe working order and will endure the operational pressures of the fracturing operation. This is followed by a procedure that perforates the production casing in the wellbore. The locations of where to perforate the production casing are determined during the well logging procedure. Perforations are created by means of a specialized tool lowered into the well on a wireline. When completed, perforations in the casing will allow fluids to enter the fractures created during the subsequent fracturing operation and also allow gas to flow into the wellbore when the well enters its production phase. Each interval isolated in a fracturing operation, whether a vertical well or a horizontal well, is subject to a specific sequence of fluid additives, each with its own engineered purpose to facilitate the production of gas from the well.

The most important data for designing a fracture treatment are (i) the *in situ* stress profile; (ii) formation permeability; (iii) fluid-loss characteristics; (iv) total fluid volume pumped; (v) propping agent—type and amount; (vi) viscosity of the fracture fluid; (vii) injection rate; and (viii) formation modulus. The *in situ* stress profile and the permeability profile of the zone to be stimulated must be quantified, and identification of the layers of rock above and below the target zone must be identified since these formations will influence fracture height growth. In order to design the optimum treatment, the effect of fracture length and fracture conductivity on the productivity and the ultimate recovery from the well must be determined. The selection of the fracture fluid for the treatment is a critical decision and selection of fracture fluid on the basis of factors such as (Economides and Nolte, 2000) (i) reservoir temperature, (ii) reservoir pressure, (iii) the expected value of fracture half-length, and (iv) water sensitivity.

The definition of what comprises a water-sensitive reservoir and what causes the damage is not always evident. Most reservoirs contain water, and most oil reservoirs can be waterflooded successfully. Thus, most fracture treatments should be pumped with suitable water-based fracture fluids. Acid-based fluids can be used in carbonates, but many deep carbonate reservoirs have been stimulated successfully with water-based fluids containing propping agents.

When selecting a propping agent, it is necessary to determine the maximum effective stress on the agent. The maximum effective stress depends on the minimum value of flowing bottom-hole pressure expected during the life of the well. To confirm exactly which type of propping agent should be used during a specific fracture treatment, the designer should factor in the estimated values of formation permeability and optimum fracture half-length (Cinco-Ley et al., 1978). The treatment must be designed to create a fracture wide enough, and pump proppants at concentrations high enough, to achieve the conductivity required to optimize the treatment. There is a tendency to compromise fracture length and conductivity in an often unsuccessful attempt to prevent damage to the formation around the fracture, and substantial damage to the formation around the fracture can be tolerated as long as the optimum fracture length and conductivity are achieved (Holditch, 1979). However, damage to the fracture or the propping agents can be very detrimental to the productivity of the fractured well. Ideally, the optimum fracture length and conductivity can be created while minimizing the damage to the formation.

The first treatments were designed using complex charts, nomographs, and calculations to determine appropriate size, which generally was close to 800 gal (or multiples thereof) of fluid, with the sand at concentrations of 0.5–0.75 lb/gal. This largely hit-or-miss method was employed until the mid-1960s, when programs were developed for fluid efficiency and the shape of a fracture system in two dimensions (Khristianovic and Zheltov, 1955; Perkins and Kern, 1961).

Finally, in horizontal wells, transverse fractures are relatively more difficult to achieve than longitudinal fractures. However, for shale gas formations normally characterized by low permeability, transverse fractures in horizontal wells have greater production benefits. Transverse vertical fractures move along the path of least resistance, which is normal to the minimum horizontal stress. In horizontal wells or deviated wells, there are effects in the immediate vicinity around the bore that lead to the transverse fractures taking tortuous paths before eventually becoming normal to the horizontal stress. These effects are increased by the presence of natural fractures in the formation and the deviation of the horizontal well at an angle from the minimum horizontal stress.

5.3.3 Well Development

Well development is an integral part of the hydraulic fracturing process. Well development is broadly divided into the drilling stage and the completion stage. For a successful fracturing operation it is important that drilling equipment are properly maintained and that their rated capacity is not exceeded. A drilling rig is the most visible part of the drilling operation; however what is important is the underground activity, and the main considerations in the selection of a rig are the following:

(i) Noise—This can be minimized by using electric rigs.
(ii) Dust—If air drilling is used, control of air and cuttings is required.
(iii) Appearance—Most rigs for unconventional well drillings are from 50 ft to over 100 ft tall, which is visually undesirable and takes more time to set up; lower profile rigs are preferred on shallower wells, but the trade-off is that larger rigs are faster in operation.
(iv) Water and mud storage—This requires determination of the size of pits or steel tanks—also storage considerations for chemicals that would be mixed with the mud.
(v) Pressure control equipment—The equipment must undergo regular servicing and inspection. Completions involve the final stages of the well development process, which include casing and cementing design.

The rotary drilling process for a vertical or directional hole involves the following elements: (i) application of a force downward on a drill bit, (ii) rotation of the drill bit, and (iii) circulation of fluid, known as drilling fluid (liquid, gas, or gasified liquid), from the surface through the tubular (drill string) and back to the surface through the annular space, which is the area between drill string and borehole wall or casing (Azar and Samuel, 2007).

Horizontal drilling involves directing the drill bit to follow a horizontal path, oriented at approximately 90° from the vertical, through the reservoir rock (Azar and Samuel, 2007). Over the years, hydraulic fracturing has been performed on vertical, deviated, and horizontal wells. However the coupling of horizontal wells and hydraulic fracturing have been proven to improve well performance in oil and gas reservoirs (Britt et al., 2010). This is due to the fact that it enhances the recovery of hydrocarbons and reduces the number of vertical wells to develop fields of interest.

Horizontal wells have found application in the Barnett shale, Marcellus shale, and other shale plays where fracturing operations have been conducted for several years.

To drill horizontally it is required to deviate the wellbore. Several methods exist for deviating the wellbore. They involve developing a side force at the bit, with a magnitude and direction sufficient to guide the bit to the predesigned path (Devereux, 2012). These techniques include jetting, whipstock, steerable motors, rotary drilling assemblies, and associated equipment. The process of wellbore deviation is known as *kicking off* the well.

Since the early 2000s, advances in drilling and completion technology have made drilling horizontal wellbores much more economical. Horizontal wellbores allow for far greater exposure to a formation than a conventional vertical wellbore. This is particularly useful in shale formations that do not have sufficient permeability to produce economically with a vertical well. Such wells when drilled onshore are now usually hydraulically fractured in a number of stages, especially in North America. The type of wellbore completion used will affect how many times the formation is fractured and at what locations along the horizontal section of the wellbore. In North America, shale reservoirs such as the Bakken, Barnett, Montney, Haynesville, Marcellus, and (more recently) the Eagle Ford, Niobrara, and Utica shale formations have been drilled, completed, and fractured using this method. The method by which the fractures are placed along the wellbore is most commonly achieved by one of two methods, known as *plug and perf* method and the *sliding sleeve* method.

The wellbore for a plug and perf job is generally composed of standard joints of steel casing, either cemented or uncemented, which is set in place at the conclusion of the drilling process. Once the drilling rig has been removed, a wireline truck is used to perforate near the end of the well, following which a fracturing job is pumped (commonly called a stage). Once the stage is finished, the wireline truck will set a plug in the well to temporarily seal off that section and then perforate the next section of the wellbore. Another stage is then pumped, and the process is repeated as necessary along the entire length of the horizontal part of the wellbore.

The wellbore for the sliding sleeve technique is different in that the sliding sleeves are included at set spacings in the steel casing at the time it is set in place. The sliding sleeves are usually all closed at this time. When the well is ready to be fractured, using one of several activation techniques, the bottom sliding sleeve is opened, and the first stage gets pumped. Once finished, the next sleeve is opened, which concurrently isolates the first stage, and the process repeats. For the sliding sleeve method, wireline is usually not required. These completion techniques may allow for more than 30 stages to be pumped into the horizontal section of a single well if required, which is far more than would typically be pumped into a vertical well (Mooney, 2011).

5.3.4 Pneumatic Fracturing

Pneumatic fractures can be generated in geologic formations if air or any other gas is injected at a pressure that exceeds the natural strength as well as the *in situ* stresses present in the formation. As noted earlier, pneumatic fracture propagation will be predominantly horizontal at overconsolidated formations. However, in shallow recent fills, some upward inclination of the fractures has been observed, the reason for which is attributed to the lack of stratification and consolidation in these formations. The amount of pressure required to initiate pneumatic fractures is dependent on the cohesive or tensile strength of the formation, as well as on the overburden pressure (dependent upon the depth and density of the formation). The most important system parameter for efficient pneumatic fracturing is injection flow rate, as it largely determines the dimensions of a pneumatic fracture. Once a fracture has been initiated, it is the high-volume airflow that propagates the fracture and supports the formation. The design goal of a pneumatic fracturing system therefore becomes one of providing the highest possible flow rate. Field observations indicate that pneumatic fractures reach their maximum dimension in less than 20 s, after which continued injection simply maintains the fracture network in a dilated state (in essence, the formation is "floating" on a cushion of injected air). Pneumatically induced fractures continue to propagate until they intersect a sufficient number of pores and existing discontinuities, so that leak-off (fluid-loss) rate into the formation exactly equals the injection flow rate.

An individual pneumatic fracture is accomplished by (i) advancing a borehole to the desired depth of exploration and withdrawing the auger, (ii) positioning the injector at the desired fracture elevation, (iii) sealing off a discrete 1 or 2 ft interval by inflating the flexible packers on the injector with nitrogen gas, (iv) applying pressurized air for approximately 30 s, and (v) repositioning the injector to the next elevation and repeating the procedure. A typical fracture cycle takes approximately 15 min, and a production rate of 15–20 fractures per day is attainable with one rig.

The pneumatic fracturing procedure typically does not include the intentional deposition of foreign propping agents to maintain fracture stability. The created fractures are thought to be "self-propping," which is attributed to both the asperities present along the fracture plane and the block shifting, which takes place during injection. The aperture or thickness of a typical pneumatically induced fracture is approximately 0.5–1 mm. Testing to date has confirmed fracture viability in excess of 2 years, although the longevity is expected to be highly site specific.

Without the carrier fluids used in hydraulic fracturing, there are no concerns with fluid breakdown characteristics for pneumatic fracturing. There is also the potential for higher permeability within the fractures formed pneumatically, in comparison to hydraulic fractures, as these are essentially air space and are devoid of propping agents. The open, self-propped fractures resulting from pneumatic fracturing are capable of transmitting significant amounts of fluid flow.

5.4 FRACTURES

To create the fracture, a fluid is pumped into the wellbore at a high rate to increase the pressure in the wellbore. Once the pressure reaches a value greater than the breakdown pressure of the formation fractures, the breakdown pressure is the sum of the *in situ* stress and the tensile strength of the rock. Once the fracture is created, the fracture can be extended using pressure (the fracture propagation pressure), which is equal to the sum of (i) the *in situ* stress, (ii) the net pressure drop, and (iii) the near-wellbore pressure drop. The net pressure drop is equal to the pressure drop down the fracture as the result of viscous fluid flow in the fracture, plus any pressure increase caused by tip effects. The near-wellbore pressure drop can be a combination of the pressure drop of the viscous fluid flowing through the perforations and the pressure drop resulting from tortuosity between the wellbore and the propagating fracture. Thus, the fracturing fluid properties are very important in the creation and propagation of the fracture.

Fractures appear in the rocks as narrow zones of structural discontinuity (*loss of cohesion*) that are the product of mechanical rupture. This mode of deformation is defined as *brittle failure* (Lei et al., 2015), and at higher temperatures and higher pressures, *ductile failure* (permanent deformation due to flow, but without loss of cohesion) may occur before the point of brittle failure is reached. Fractures may be dilational, that is, *joints* (mode I fractures), or may exhibit shearing with components parallel (mode II) or perpendicular (mode III) to the direction of propagation of the fracture front. Shear fractures are also known as *faults*.

A fracture is a surface along which a loss of cohesion in the rock texture has taken place. A fracture is sometimes called a joint and, at the surface, is expressed as a crack or fissure in the rock. The orientation of the fracture can be anywhere from horizontal to vertical. The rough surface separates the two faces, giving rise to fracture porosity. The surfaces touch at points called asperities. Altered rock surrounds each surface and infilling minerals may cover part or all of each surface. Minerals may fill the entire fracture, converting an open fracture to a healed or sealed fracture.

Fractures are caused by stress in the formation, which in turn usually derives from tectonic forces such as folds and faults. These are termed natural fractures, as opposed to induced fractures. Induced fractures are created by drilling stress or by purposely fracturing a reservoir by hydraulic pressure from surface equipment. Both kinds of fractures are economically important. Induced fractures may connect the wellbore to natural fractures that would otherwise not contribute to flow capacity.

Natural fractures are more common in carbonate rocks than in sandstones. Some of the best fractured reservoirs are in granite—often referred to as unconventional reservoirs. Fractures occur in preferential directions, determined by the direction of regional stress. This is usually parallel to the direction of nearby faults or folds, but in the case of overthrust faults, they may be perpendicular to the fault, or there may be two orthogonal directions. Induced fractures usually have a preferential direction, often perpendicular to the natural fractures.

A fracture is often a high-permeability path in a low-permeability rock, or it may be filled with a cementing material, such as calcite, leaving the fracture with no permeability. Thus it is important to distinguish between open and healed fractures. The total volume of fractures is often small compared to the total PV of the reservoir. Thus, natural fractures in reservoir rocks contribute significantly to productivity. Therefore, it is important to glean every scrap of information from open hole logs to locate the presence and intensity of fracturing. Even though some modern logs, such as the formation microscanner and televiewer, are the tools of choice for fracture indicators, many wells lack this data.

Most natural fractures are vertical—a horizontal fracture may exist for a short distance, propped open by bridging of the irregular surfaces. Most horizontal fractures, however, are sealed by overburden pressure. Both horizontal and semivertical fractures can be detected by various logging tools. The vertical extent of fractures is often controlled by thin layers of plastic material, such as shale beds or laminations, or by weak layers of rock, such as stylolites in carbonate sequences. The thickness of these beds may be too small to be seen on logs, so fractures may seem to start and stop for no apparent reason.

The nucleation and propagation of hydraulic rock fractures are chiefly controlled by the local *in situ* stress field, the strength of the rock (stress level needed to induce failure), and the pore fluid pressure. Temperature, elastic properties, pore water chemistry, and the loading rate also have an influence ((Secor, 1965; Phillips, 1972; Sone and Zoback, 2013). Fractures in rock can be classified as tensile, shear, or hybrid (a mixture of tensile and shear). If the dominant displacement of the wall rocks on either side of the fracture is perpendicular to the fracture surface, then the fracture is deemed tensile. New tensile fractures form when the pore fluid pressure in the rock exceeds the sum of the stress acting in a direction perpendicular to the fracture wall and the tensile strength of the rock. Note that any preexisting fractures that are uncemented (i.e., have zero cohesion) can be opened at a lower value of pore fluid pressure when it exceeds the stress acting in a direction perpendicular to the fracture wall.

The formation or reactivation of shear fractures depends on the shear stress, the normal stress, the pore fluid pressure, and the coefficient of friction for the specific rock type. It is important to recognize that the hydraulic fracturing process of pumping large volumes of water into a borehole at a certain depth cannot control the type of fractures that are created or reactivated. The array of fractures created and/or reactivated or reopened depends on a complex interplay of the *in situ* stress, the physical properties of the local rock volume and any preexisting fractures, and the pore fluid pressure (Phillips, 1972). This could have implications for the risk of groundwater contamination by hydraulic fracturing operations, as the fracture network generated by the hydraulic fracturing fluid could be complex and difficult to predict in detail. The orientations, sizes, and apertures of permeable rock fractures created by a hydraulic fracturing operation ultimately control the fate of the hydraulic fracturing fluid and the released shale gas, at least in the deep subsurface. Geomechanical models used to predict these fracture pattern attributes therefore need thorough testing/benchmarking, together with ongoing and future developments.

Naturally fractured reservoirs contain secondary or induced porosity in addition to their original primary porosity. Induced porosity is formed by tension or shear stresses, causing fractures in a competent or brittle formation. Fracture porosity is usually very small. Values between 0.0001 and 0.001 of rock volume are typical (0.01–0.1%). Fracture-related porosity, such as solution porosity in granite or carbonate reservoirs, may attain much larger values, but the porosity in the actual fracture is still very small. There are, of course, exceptions to all rules of thumb. In rare cases, such as the cooling of intrusive minerals or surface lava flows, natural fracture porosity may exceed 10%. When buried and later filled with hydrocarbons, they form very interesting reservoirs.

Fracture analysis literature in the 1970s suggested that fractures might contribute as much as a few to several percent porosity. More modern work using fracture aperture calculated from resistivity microscanner logs indicates much lower numbers. To appreciate this, consider fractures with 1 mm aperture spaced 1 m apart. This gives a porosity of 0.001 fractional (0.1%). This is a very large open fracture. Most are only microns in width, so even 10 fractures of 10 μm each only give 0.0001 fractional porosity (0.01%). The term *secondary porosity* also includes rock-volume shrinkage due to dolomitization, porosity increase due to solution or recrystallization, and other geological processes. "Secondary porosity" should not be confused with "fracture porosity." Porosity formed in this way can be determined from modern log suites without difficulty, except for porosity formed by fractures, which is too small to detect with conventional logs.

Fracture porosity is found accurately only by processing the formation microscanner curves for fracture aperture and fracture frequency (fracture intensity). The effect of fracture porosity on reservoir performance, however, is very large due to its enormous contribution to permeability. As a result, naturally fractured reservoirs behave differently than unfractured reservoirs with similar porosity, due to the relative high flow capacity of the secondary porosity system. This provides high initial production rates, which can lead to extremely optimistic production forecasts and sometimes economic failures when the small reservoir volume is not properly taken into account.

Reservoir simulation software that accounts for the fracture system is often termed a "dual-porosity" model. While this is strictly true, it would be better to think of them as "dual-permeability" models, since the fracture permeability fed by the matrix or reservoir permeability is far more important than the relative storage capacity of the fractures and matrix porosity. A reservoir with only fracture porosity is quickly depleted; a decent reservoir in the matrix rock feeding into fractures will last much longer.

In order to understand the behavior of naturally fractured reservoirs, estimates must be made of hydrocarbons in place within both the primary (matrix rock) and secondary (fracture-only) porosity systems. To do this, we must first be able to detect the existence of fractures. Therefore, this section covers fracture detection from the usually available conventional logs, as well as the method used to partition porosity into primary and fracture components. The effect of this partitioning on the Archie water saturation equation is also described. Modern methods for quantifying fracture porosity directly from microscanner logs are also discussed.

5.4.1 Fracture Geometry

In the design of hydraulic fractures, most procedures to optimize well productivity begin with the fracture size. There are several approaches proposed to obtain the optimum fracture size; these have been documented by vast technical literature on the subject. Limitations in the different hydraulic fracture design methods are inherent in their assumptions of fracture geometry, dependence on fracture fluid/reservoir properties, layered formations, and other factors like stress intensity. Challenges in fracture geometry when fracturing unconventional reservoirs include fracture azimuth and dip, not creating expected length, brittle and ductile rocks/complex and simple networks, and wellbore axis (vertical or horizontal drilling) (Kennedy et al., 2012). In all cases however, knowledge of existing *in situ* stress tensors is essential to developing a fracture propagation model, which describes the methods of obtaining a desired hydraulic fracture geometry definitely including the fracture (half-)length, width, height, and fracture complexity. There are new techniques of creating complex fracture networks with low-viscosity fluid and multistage fracturing methods.

The ideal formation evaluation would be one where the values of *in situ* stresses obtained from injection tests and those calculated from logs and core analysis all result in a consistent stress profile (Holditch et al., 1987). It is worthy to note that there are several different methods of measuring rock *in situ* stress, including relief methods, jacking methods, borehole breakout methods, strain recovery methods, acoustic emission methods, fault-slip data analysis, earthquake focal mechanisms, etc., but for the purpose of this thesis and considering the prevailing *in situ* stress determination methods for prefracturing, only hydraulic methods will be considered. The hydraulic methods are also the most reliable for determining *in situ* stress in deep (>160 ft) formations (Amadei and Stephansson, 1997); hence its emphasis is justified.

5.4.1.1 Orientation Hydraulic fractures are formed in the direction perpendicular to the least stress. Typically, horizontal fractures will occur at depths less than approximately 2000 ft because the overburden at these depths provides the least principal stress. If pressure is applied to the center of a formation under these relatively shallow conditions, the fracture is most likely to occur in the horizontal plane, because it will be easier to part the rock in this direction than in any other. In general, therefore, these fractures are parallel to the bedding plane of the formation.

As depth increases beyond approximately 2000 ft, overburden stress increases by approximately 1 psi/ft, making the overburden stress the dominant stress. This means the horizontal confining stress is now the least principal stress. Since hydraulically induced fractures are formed in the direction perpendicular to the least stress, the resulting fracture at depths greater than approximately 2000 ft will be oriented in the vertical direction.

In the case where a fracture might cross over a boundary where the principal stress direction changes, the fracture would attempt to reorient itself perpendicular to the direction of least stress. Therefore, if a fracture propagated from deeper to shallower formations, it would reorient itself from a vertical to a horizontal pathway and spread sideways along the bedding planes of the rock strata.

5.4.1.2 Length/Height The extent that a created fracture will propagate is controlled by the upper confining zone or formation and the volume, rate, and pressure of the fluid that is pumped. The confining zone will limit the vertical growth of a fracture because it either possesses sufficient strength or elasticity to contain the pressure of the injected fluids or an insufficient volume of fluid has been pumped. This is important because the greater the distance between the fractured formation and the underground source of drinking water, the more likely it will be that multiple formations possessing the qualities necessary to impede the fracture will occur. However, while it should be noted that the length of a fracture can also be influenced by natural fractures or faults, natural attenuation of the fracture will occur over relatively short distances due to the limited volume of fluid being pumped and dispersion of the pumping pressure regardless of intersecting migratory pathways.

5.4.2 Fracture Optimization

Hydraulic communication is a key factor for determining hydrocarbon or thermal energy recovery sweep efficiency in an underground reservoir. Sweep efficiency is a measure of the effectiveness of heat, gas, or oil recovery process that depends on the volume of the reservoir contacted by an injected fluid (Britt, 2012). Artificial (stimulated) hydraulic fractures are usually initiated by injecting fluids into the borehole to increase the pressure to the point where the minimal principal stress in the rock becomes tensile. Continued pumping at an elevated pressure causes tensile failure in the rock, forcing it to split and generate a fracture that grows in the direction normal to the least principal stress in the formation. Hydraulic fracturing activities often involve injection of a fracturing fluid with proppants in order to better propagate fractures and to keep them open (Britt, 2012). The design of fracturing treatment should involve the optimization of operational parameters, such as the viscosity of the fracturing fluid, injection rate and duration, proppant concentration, etc., so as to create a fracture geometry that favors increased sweep efficiency. The net present value (Ralph and Veatch, 1986) as the economic criterion is usually used as an objective for optimal fracturing treatment design. Some studies have been reported to use a sensitivity-based optimization procedure coupled with a fracture propagation model and an economic model to optimize design parameters, leading to maximum net present value (Balen et al., 1988; Hareland et al., 1993; Aggour and Economides, 1998). Fracturing variables (including the injected fluid volume, injection rate, fluid, and proppant type) have been optimized by applying a mixed integer linear programming (Rueda et al., 1994; Mohaghegh et al., 1999).

Surrogate-based optimization refers to the idea of speeding optimization processes by using fast surrogate models. Surrogate-based optimization approaches have been extensively studied for applications in various fields (Chen et al., 2013). Ensemble surrogate methods are also actively studied to achieve more robust approximation by surrogate models, which applied a neural network algorithm to construct a surrogate of the net present value for an optimal design of hydraulic fracturing treatments. However, uncertainties of geomechanical properties and of the preexisting fracture networks, resulting from the geologic architecture and fracture properties, such as fracture density, length, and orientation, need further and rigorous study for the optimization of hydraulic fracturing treatment (Chen et al., 2013).

In summary, fracture geometry optimization involves defining the desired fracture half-length, width, and conductivity for maximized production. While there are several optimization methods, all involve a relative comparison of the flow potential of the fracture to that of the reservoir.

5.5 FRACTURE MONITORING

During the hydraulic fracturing process, fluid leak-off that is loss of fracturing fluid from the fracture channel into the surrounding permeable rock can (and often does) occur. If not controlled properly, the fluid loss can exceed 70% of the injected volume, which may result in formation matrix damage, adverse formation fluid interactions, or altered fracture geometry and thereby decreased production efficiency. Thus, fracture geometry and fracture monitoring are important aspects of the hydraulic fracturing process.

5.5.1 Monitoring

Monitoring technologies are used to map where fracturing occurs during a stimulation treatment and include such techniques as microseismic fracture mapping and tilt meter measurements (Arthur et al., 2008). These technologies can be used to define the success and orientation of the fractures created during a stimulation process. Measuring the pressure and rate during the growth of a hydraulic fracture, as well as knowing the properties of the fluid and proppant being injected into the well, provides the most common and simplest method of monitoring a hydraulic fracture treatment. This data, along with knowledge of the underground geology, can be used to model information such as length, width, and conductivity of a propped fracture.

Microseismic monitoring is the process by which the seismic waves generated during the fracturing of a rock formation are monitored and used to map the locations of the fractures generated. Monitoring is done using a similar technology to that used to monitor larger naturally occurring seismic events associated with earthquakes and other natural processes. Microseismic monitoring is an active monitoring process performed during a hydraulic fracture treatment. As an active monitoring process microseismic monitoring can be used to develop real-time changes to a fracture program. Microseismic monitoring provides engineers the ability to manage the resource through intelligent placement of additional wells to take advantage of the natural conditions of the reservoir and expected fracture results in new wells.

Microseismic theory and mapping are based on earthquake seismology. Similar to earthquakes, but at a much higher frequency (200–2000 Hz), microseismic events emit elastic P waves (compressional) and S waves (shear waves) (Jones and Britt, 2009). During hydraulic fracture, there are an increase in formation stress proportional to the net fracturing pressure and an increase in pore pressure due to fracturing fluid leak-off. The increase in stresses at the fracture tip and pore pressure increments causes shear slippages to occur. Microseismic technology thus uses earthquake seismology methodologies to detect and locate these hydraulic fracturing-induced shear slippages, which resemble microearthquakes. Microseismic events or microearthquakes occur with fracture initiation and are observed with receivers placed on an offset wellbore like with the downhole tiltmeters.

Microseismic mapping technology involves installing an array of triaxial geophone or accelerometer receivers into an offset well at approximately the depth of the fracture (like in downhole tiltmeters), orienting the receivers (geophones), recording seismic data, finding microearthquakes in the data, and locating them. Locating the earthquake events requires the determination of compressional (P) and shear (S) wave arrivals and consequent acoustic interpretation of the velocity of the P–S waves (Davis et al., 2008). The figure shows a three-component (triaxial) geophone with P and S wave arrivals. Employing the arrival times on the *X*, *Y*, and *Z* components, both location and direction of events can be obtained (Jones and Britt, 2009). Standard microseismic mapping uses P–S arrival time separation for distance location. Horizontal and vertical plane holograms are used to determine the azimuth and inclination (Warpinski et al., 2005).

Tiltmeters are passive monitoring technologies that record the deformation of rocks that are induced by the hydraulic fracture process. Tiltmeters can be placed at the ground surface away from a well or downhole in a nearby wellbore tightly into the rock. Tiltmeters measure changes in inclination in two orthogonal directions, which can then be translated into the strain rotation that results from hydraulic fracturing. Engineers can then determine based on the strain rotation the location of the hydraulic fracturing event that caused the strain rotation.

Downhole tiltmeter mapping technology was developed to circumvent the limitations of the surface tiltmeter by giving estimates of the fracture dimensions. The downhole tiltmeters have the same operational principle as the surface tiltmeters, but instead of being at the surface, the tiltmeters are positioned by wireline in one or multiple offset wellbores at the depth of the hydraulic fracture. Typically, the array consists of 7–12 tiltmeters coupled to the borehole with standard oil field centralizer springs (Wright et al., 1999). Downhole tiltmeters provide a map of the deformation of the Earth adjacent to the hydraulic fracture. Thus, what is obtained is an estimate of an ellipsoid that best approximates the fracture dimensions.

Typically, downhole tiltmeters are located closer to the fracture than the surface tiltmeter and hence more sensitive to fracture dimensions (Cipolla and Wright, 2002). The closer the downhole tiltmeter to the fracture, the better the quality of data obtained to determine fracture height (Jones and Britt, 2009), which may be limited by the volume of the hydraulic fracturing fluid volume regardless of whether the fluid interacts with faults (Flewelling et al., 2013). The downhole array tilts in a continuous fashion, similar to surface tiltmeter records, but the arrays span the same depth interval as the zone being fractured. The total interval covered by a downhole tilt array ranges from 300 ft to less than 1000 ft, depending on the design conditions. Conventionally, surface and downhole tiltmeter analysis is done separately, but techniques have been proposed to combine them for evaluating fracture geometry during drill cutting disposal.

The greatest advantage of both surface and downhole tiltmeter fracture mapping is that for a given fracture geometry, the induced deformation field is almost completely independent of formation properties. Also, the required degree of formation description is lower in tiltmeter mapping than microseismic mapping (velocity profiles, attenuation thresholds, etc.) as will be described in a later section. Complex fracture growth would yield independent fractures at different orientations or depths, but in tiltmeter mapping a simpler analysis is required.

At the completion of the stimulation process, approximately 20–30% v/v of the water flows back up the wellbore, where it is collected and then recycled in a subsequent well completion operation. Over the productive life of the well, additional "produced" water slowly comes to the surface, where it is collected in on-site storage tanks and transported to permitted treatment facilities.

5.5.2 Aids in Production

To be an aid in production, fractures must be connected to a reasonable hydrocarbon-bearing reservoir with sufficient volume to warrant exploitation. If there is no reservoir volume, a lot of fractures won't help much unless there is sufficient fracture-related solution porosity to hold an economic reserve. This can be determined by normal log analysis techniques. In reasonable nonfractured reservoirs, it is usually possible to estimate permeability and hence productivity (Speight, 2014), but this is not always possible in fractured reservoirs. Although both the presence of fractures and the presence of a reservoir can be determined from logs, a production test will be needed to determine whether economic production is possible. The test must be analyzed carefully to avoid overoptimistic predictions based on the flush production rates associated with the fracture system. Local correlations between fracture intensity observed on logs and production rate are also used to predict well quality.

Sometimes the primary reservoir and the fracture system may be so poorly connected that they are saturated with different fluids. Production from fractures full of hydrocarbons in a water-bearing formation may initially be very good but very short lived. A more desirable scenario is a primary reservoir with appreciable hydrocarbon saturation and a fracture system that is full of water close to the borehole, showing invasion and hence good permeability, but full of hydrocarbon in the uninvaded formation.

REFERENCES

Agarwal, R.G., Carter, R.D., and Pollock, C.B. 1979. Evaluation and Performance Prediction of Low-Permeability Gas Wells Stimulated by Massive Hydraulic Fracturing. *Journal of Petroleum Technology*, 31(3): 362–372. SPE-6838-PA.

Aggour, T.M., and Economides, M.J. 1998. Optimization of the Performance of High-Permeability Fractured Wells. Paper No. 39474. Proceedings. SPE International Symposium on Formation Damage Control, Lafayette, LA. Society of Petroleum Engineers, Richardson, TX.

Amadei, B., and Stephansson, O. 1997. *Rock Stress and Its Measurement*. Cambridge University Press, Cambridge, UK.

API RP 13 M-4. 2015. *Recommended Practice for Measuring Stimulation and Gravel-Pack Fluid Leak-off Under Static Conditions*. American Petroleum Institute, Washington, DC.

Arthur, J.D., Bohm, B., and Layne, M. 2008. Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale. ALL Consulting. Presented at the GWPC Annual Forum in Cincinnati, OH, September. Groundwater Protection Council, Oklahoma City, OK.

Arthur, J.D., Bohm, B., Coughlin, B.J., and Layne, M. 2009. Evaluating Implications of Hydraulic Fracturing in Shale Gas Reservoirs. Paper No. SPE 121038. Proceedings. 2009 SPE Americas Environmental and Safety Conference, San Antonio, TX, March 23–25. Society of Petroleum Engineers, Richardson, TX.

ASTM D2166. 2015. *Standard Test Method for Unconfined Compressive Strength of Cohesive Soil*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D2216. 2015. *Standard Test Methods for Laboratory Determination of Water (Moisture) Content of Soil and Rock by Mass*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D421. 2015. *Standard Practice for Dry Preparation of Soil Samples for Particle-Size Analysis and Determination of Soil Constants*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D422. 2015. *Standard Test Method for Particle-Size Analysis of Soils*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

ASTM D4318. 2015. *Standard Test Methods for Liquid Limit, Plastic Limit, and Plasticity Index of Soils*. Annual Book of Standards. ASTM International, West Conshohocken, PA.

Azar, J.J., and Samuel, G.R. 2007. *Drilling Engineering*. PennWell Corporation, Tulsa, OK.

Balen, M.R., Meng, H.Z., and Economides, M.J. 1988. Application of Net Present Value (NPV) in the Optimization of Hydraulic Fractures. Paper No. 18541. Proceedings. SPE Eastern Regional Meeting, Charleston, SC. Society of Petroleum Engineers, Richardson, TX. Page 181–191.

Britt, L.K. 2012. Fracture Stimulation Fundamentals. *Journal of Natural Gas Science and Engineering*, 8: 34–51.

Britt, L.K., Jones, J.R., and Miller, W.K. 2010. Defining Horizontal Well Objectives in Tight and Unconventional Gas Reservoirs. Paper No. CSUG/SPE 137839. Proceedings. Canadian Unconventional Resources & International Petroleum Conference, Calgary Alberta, Canada, October 19–21. Society of Petroleum Engineers, Richardson, TX.

Chen, M., Sun, Y., Fu, P., Carrigan, C.R., Lu, Z., Tong, C.H., and Buscheck, T.A. 2013. Surrogate-Based Optimization of Hydraulic Fracturing in Pre-Existing Fracture Networks. *Computers & Geosciences*, 58: 69–79.

Cinco-Ley, H., Samaniego, V.F., and Dominguez, A.N. 1978. Transient Pressure Behavior for a Well with a Finite-Conductivity Vertical Fracture. *SPE Journal*, 18(4): 253–264.

Cipolla, C., and Wright, C.A. 2002. Diagnostic Techniques to Understand Hydraulic Fracturing: What? Why and How? Proceedings. 2002 SPE/CERI Gas Technology Symposium, Calgary, Canada, April 3–5. Society of Petroleum Engineers, Richardson, TX.

Davis, J., Warpinski, N.R., Davis, E.J., Griffin, L.G., and Malone, S. 2008. Joint Inversion of Downhole Tiltmeter and Microseismic Data and Its Application to Hydraulic Fracture Mapping in Tight Gas Sand Formation. Paper No. ARMA 08–344. Proceedings. 42nd US Rock Mechanics Symposium and 2nd US-Canada Rock Mechanics Symposium, San Francisco, CA, June 29–July 2.

Devereux, S. 2012. *Drilling Technology in Non-Technical Language*, 2nd Edition. PennWell Publishing Corporation, Tulsa, OK.

Economides, M.J., and Nolte, K.G. 2000. *Reservoir Stimulation*, 3rd Edition. John Wiley & Sons, Inc., Hoboken, NJ.

Ely, J.W. 1985. *Handbook of Stimulation Engineering*. PennWell Publishing, Tulsa, OK.

Fernø, M.A., Haugen, Å., Graue, A., and Howard, J.J. 2008. The Significance of Wettability and Fracture Properties on Oil Recovery Efficiency in Fractured Carbonates. Paper No. SCA2008-22. Proceedings. International Symposium of the Society of Core Analysts Held in Abu Dhabi, United Arab Emirates, October 29–November 2. http://www.researchgate.net/publication/267678303_The_significance_of_wettability_and_fracture_properties_on_oil_recovery_efficiency_in_fractured_carbonates; accessed January 16, 2015.

Fisher, K. 2012. Trends Take Fracturing Back to the Future. *American Oil and Gas Reporter*, 55(8): 86–97.

Flewelling, S.A., Tymchak, M.P., and Warpinski, N. 2013. Hydraulic Fracture Height Limits and Fault Interactions in Tight Oil and Gas Formations. *Geophysical Research Letters*, 40: 3602–3606.

Gidley, J.L., Holditch, S.A., Nierode, D.E., and Veatch, R.W. 1990. *Hydraulic Fracturing to Improve Production*. Monograph Series SPE 12. Society of Petroleum Engineers, Richardson, TX.

Hammack, R., Harbert, W., Sharma, S., Stewart, B., Capo, R., Wall, A., Wells, A., Diehl, R., Blaushild, D., Sams, J., and Veloski, G. 2014. An Evaluation of Fracture Growth and Gas/Fluid Migration as Horizontal Marcellus Shale Gas Wells Are Hydraulically Fractured in Greene County, Pennsylvania. Report No. NETL-TRS-3-2014. EPAct Technical Report Series. National Energy Technology, Laboratory, Pittsburgh, PA. US Department of Energy, Washington, DC.

Hareland, G.I., Rampersad, P., Dharaphop, J., and Sasnanand, S. 1993. Hydraulic Fracturing Design Optimization. Paper No. 26950. Proceedings. SPE Eastern Regional Conference and Exhibition, Pittsburgh, PA. Society of Petroleum Engineers, Richardson, TX. Page 493–500.

Hibbeler, J., and Rae, P. 2005. Simplifying Hydraulic Fracturing: Theory and Practice. Paper No. SPE 97311. Proceedings. 2005 SPE Technical Conference and Exhibition, Dallas, TX, October 9–12. Society of Petroleum Engineers, Richardson, TX.

Holditch, S.A. 1979. Factors Affecting Water Blocking and Gas Flow from Hydraulically Fractured Gas Wells. *Journal of Petroleum Technology*, 31(12): 1515–1524.

Holditch, S.A., Jennings, J.W., and Neuse, S.H. 1978. The Optimization of Well Spacing and Fracture Length in Low Permeability Gas Reservoirs. Paper No. SPE-7496. Proceedings. SPE Annual Fall Technical Conference and Exhibition, Houston, TX, October 1–3. Society of Petroleum Engineers, Richardson, TX.

Holditch, S.A., Robinson, B.M., and Whitehead, W.S. 1987. Prefracture and Postfracture Formation Evaluation Necessary to Characterize the Three Dimensional Shape of the Hydraulic Fracture. Proceedings. SPE Formation Evaluation, December 1987. Society of Petroleum Engineers, Richardson, TX.

Hubbert, M.K., and Willis, D.G. 1957. Mechanics of Hydraulic Fracturing. *Petroleum Transactions AIME*, 210: 153.

Jones, J.R., and Britt, L.K. 2009. *Design and Appraisal of Hydraulic Fractures*. Society of Petroleum Engineers, Richardson, TX.

Keelan, D.K. 1982. Core Analysis for Aid in Reservoir Description. *Society of Petroleum Engineers (SPE) of AIME Distinguished Author Series*. Society of Petroleum Engineers, Richardson, TX.

Kennedy, R.L., Gupta, R., Kotov, S.V., Burton, W.A., Knecht, W.N., and Ahmed, U. 2012. Optimized Shale Resource Development: Proper Placement of Wells and Hydraulic Fracture Stages. Paper No. 162534. Proceedings. Abu Dhabi International Petroleum Conference and Exhibition, Abu Dhabi, United Arab Emirates, November 11–14. Society of Petroleum Engineers, Richardson, TX.

Khristianovic, S.A., and Zheltov, Y.P. 1955. Formation of Vertical Fractures by Means of Highly Viscous Liquid. Paper No. 6132. Proceedings. 4th World Petroleum Congress, Rome, Italy, June 6–15. Section II. Page 579–586.

King, G.E. 2012. What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells. Paper No. SPE 152596. Proceedings. SPE Hydraulic Fracturing Technology Conference, Woodlands, TX, February 6–8. Society of Petroleum Engineers, Richardson, TX.

Lee, W.J., and Holditch, S.A. 1981. Fracture Evaluation with Pressure Transient Testing in Low-Permeability Gas Reservoirs. *Journal of Petroleum Technology*, 33(9): 1776–1792. SPE-9975.

Lei, X., Zhang, S., Guo, T., and Xiao, B. 2015. New Evaluation Method of the Ability of Forming Fracture Network in Tight Sandstone Reservoir. *International Journal of Environmental Science and Development*, 6(9): 688–692.

Mohaghegh, S., Balanb, B., Platon, V., and Ameri, S. 1999. Hydraulic Fracture Design and Optimization of Gas Storage Wells. *Journal of Petroleum Science and Engineering*, 23: 161–171.

Mooney, C. 2011. The Truth About Fracking. *Scientific American*, 305: 80–85.

Orlandi, M., Bartelucci, P., and Chelini, V. 2011. Unconventional Reservoir Characterization Methods Using Core and Well Logging Data: Shale Gas and Tight Gas Sand Examples. Proceedings. 10th Offshore Mediterranean Conference and Exhibition, Ravenna, Italy, March 23–25. Society of Petroleum Engineers, Richardson, TX.

Perkins, T.K., and Kern, L.R. 1961. Widths of Hydraulic Fractures. *Journal of Petroleum Technology*, 13(9): 937–949.

Phillips, W.J. 1972. Hydraulic Fracturing and Mineralization. *Journal of the Geological Society of London*, 128: 337–359.

Postler, D.P. 1997. Pressure Integrity Test Interpretation. Paper No. SPE /IADC 37589. Proceedings. 1997 SPE/IADC Conference, Amsterdam, Netherlands, March 4–6. Society of Petroleum Engineers, Richardson, TX.

Ralph, W., and Veatch, W., Jr. 1986. Economics of Fracturing: Some Methods, Examples and Case Studies. Paper No. 15509. Proceedings. SPE 61st Annual Technical Conference and Exhibition, New Orleans, LA. Society of Petroleum Engineers, Richardson, TX. Page 1–16.

Reinicke, A., Rybacki, E., Stanchits, S., Huenges, E., and Dresen, G. 2010. Hydraulic Fracturing Stimulation Techniques and Formation Damage Mechanisms: Implications from Laboratory Testing of Tight Sandstone–Proppant Systems. *Chemie der Erde*, 70(S3): 107–117.

Rueda, J.I., Rahim, Z., and Holditch, S.A. 1994. Using a Mixed Integer Linear Programming Technique to Optimize a Fracture Treatment Design. Paper No. 29184. Proceedings. SPE Eastern Regional Meeting, Charleston, SC. Society of Petroleum Engineers, Richardson, TX. Page 233–244.

Scanlon, B.R., Reedy, R.C., and Nicot, J.P. 2014. Comparison of Water Use for Hydraulic Fracturing for Oil and Gas versus Conventional Oil. *Environmental Science Technology*, 48: 12386–12393.

Secor, D.T. 1965. Role of Fluid Pressure in Jointing. *American Journal of Science*, 263: 633–646.

Slattery, J.C. 2001. Two-Phase Flow Through Porous Media. *AIChE Journal*, 16(3): 345–352.

Smith, M.B., and Hannah, R.R. 1996. High-Permeability Fracturing: The Evolution of a Technology. *SPE Journal of Petroleum Technology*, 48(7): 628–633.

Smith, M.B., Miller, W.K.I., and Haga, J. 1987. Tip Screenout Fracturing: A Technique for Soft, Unstable Formations. *SPE Formation Evaluation*, 2(2): 95–103.

Sone, H., and Zoback, M.D. 2013. Mechanical Properties of Shale-Gas Reservoir Rocks—Part 1: Static and Dynamic Elastic Properties and Anisotropy. *Geophysics*, 78(5): D381–D392.

Speight, J.G. 2014. *The Chemistry and Technology of Petroleum*, 5th Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Unalmiser, S., and Funk, J.J. 2008. *Engineering Core Analysis*. SPE Distinguished Author Series. Paper No. SPE 36780. Society of Petroleum Engineers, Richardson, TX.

US EIA. 2014. *United States Energy Information Administration, May 7, 2014, Annual Energy Outlook 2014*. Energy Information Administration, US Department of Energy, Washington, DC. http://www.eia.gov/forecasts/aeo/index.cfm; accessed March 21, 2015.

Valko, P.P., Oligney, R.E., and Economides, M.J. 1998. High Permeability Fracturing of Gas Wells. *Petroleum Engineer International*, 71(1): 75–88.

Veatch, R.W., Jr. 1983. Overview of Current Hydraulic Fracturing Design and Treatment Technology—Part 1. *Journal of Petroleum Technology*, 35(4): 677–687. Paper SPE-10039-PA.

Warpinski, N.R., Engler, B.P., Young, C.J., Peterson, R., Branagan, P.T., and Fix, J.E. 2005. Microseismic Mapping of Hydraulic Fractures Using Multi-level Wireline Receivers. Paper No. SPE 30507. Proceedings. 2005 SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 22–25. Society of Petroleum Engineers, Richardson, TX.

Wright, C.A., Davis, E.J., Wangm, G., and Weijers, L. 1999. Downhole Tiltmeter Fracture Mapping: A New Tool for Direct Measurement of Hydraulic Fracturing Growth. In: *Rock Mechanics for Industry*. B. Amadei, R.L. Krantz, G.A. Scott, and P.H. Smeallie (Editors). Balkema Publishers, Rotterdam, The Netherlands.

Zoback, M.D. 2010. *Reservoir Geomechanics*. Cambridge University Press, Cambridge, UK.

6

FRACTURING FLUIDS

6.1 INTRODUCTION

Hydraulic fracturing as a method for recovering unconventional natural gas from shale formations (tight gas) has been around for several decades (Chapters 1 and 5). Lately, the recovery of unconventional crude oil from shale formations and from tight formations (tight oil), which would have been otherwise inaccessible, has also been explored and developed.

Hydraulic fracturing is carried out using two broad classes of fracturing materials: fracturing fluid and proppants (Chapters 5 and 7). The term *fracturing fluid* is a generic term that includes both the base fluid and additives (Tables 6.1 and 6.2). The additives are a wide range of chemicals (Table 6.3) that are used to influence the overall properties of the fracturing fluid. Since the default position of the fractures is the closed position, *propping agents* (*proppants*) are used to stop the fracture from closing after the fracture treatment to enable recovery of crude oil and natural gas—the most common proppant is fine sand.

In the process (Chapter 5), the fracturing fluids are injected into the subsurface at a rate and pressure that are too high for the targeted formation to accommodate, and as the resistance to the injected fluids increases, the pressure in the injecting well increases to a level that exceeds the breakdown pressure of the rocks in the targeted formation. In this way, the hydraulic fracturing process fractures the targeted formation and, on occasion, other geologic strata within or around the targeted formation. This process sometimes does create new fractures, and most often the process enlarges existing fractures thereby increasing the connections of the natural fracture networks in the targeted formation. The pressure-induced fracturing serves to connect the network of fractures in the formation to the hydraulic fracturing well (which subsequently will serve as the crude oil and/or natural gas production well). The fracturing fluids pumped into the subsurface under high pressure also deliver and emplace the

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

TABLE 6.1 Different Fluids Used for Hydraulic Fracturing

Fluid	Fluid Type	Main Composition
Water based	Slickwater	Water + sand (+chemical additives)
Linear fluids		Gelled water
Cross-linked fluid		Cross-linking agent
Viscoelastic fluids		Electrolyte + surfactant
Surfactant gel fluids		
Foam based	Water-based foam	Water and foamer + N_2 or CO_2
Acid-based foam		Acid and foamer + N_2
Alcohol-based foam		Methanol and foamer + N_2
Oil based	Linear fluids	Oil, gelled oil
Cross-linked fluid		Phosphate ester gels
Water emulsion		Water + oil + emulsifiers
Acid based	Linear Cross-linked Oil emulsion	
Alcohol based	Methanol/water mixes or 100% methanol	Methanol + water
Emulsion based	Water–oil emulsions	Water + oil
CO_2-methanol		CO_2 + water + methanol
Other fluids	Liquid CO_2	CO_2
Liquid nitrogen		N_2
Liquid helium		He
Liquid natural gas		LPG (butane and/or propane)

proppant, which, under pressure, is forced into the natural and/or enlarged fractures and acts to prop open the fractures even after the fracturing pressure is reduced. The increased permeability due to fracturing and proppant emplacement facilitates the flow and extraction of petroleum and gas from the fractured formation.

The advancement in hydraulic fracturing has occurred predominantly over the past two-to-three decades largely due to the development of more advanced drilling technology that allows for horizontal drilling deep under the ground (Chapter 5). In the directional drilling process, after drilling downward from the point of entry, the drill turns roughly ninety degrees once deep underground, thereafter traveling parallel to the surface. While the downward drilling proceeds for a considerable distance, after the drill is turned to a horizontal position and moves into the target formation, it provides greater accessibility to the target formation. Thus, the technique (directional drilling) has rendered the method far more productive. However, hydraulic fracturing operations have evolved from using a range of 20,000 to 80,000 gallons of water per well to using up to 8 million gallons of water and 75,000–320,000 pounds of sand (proppant) per well, which can have serious environmental consequences (Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016).

A wide variety of chemicals (Table 6.3) is used to perform specific actions, such as the addition of friction reducers, which allows a fracturing fluid and proppant to

TABLE 6.2 Fracturing Fluid Additives

Type	Compound	Comment
Acid	Hydrochloric acid (also called *muriatic acid*)	For the fracturing of shale formations, acids are used to clean cement from casing perforations and drilling mud clogging natural formation porosity, if any prior to fracturing fluid injection (dilute acid concentrations are typically on the order of 15% v/v acid)
Biocide	Glutaraldehyde	Fracture fluids typically contain gels that are organic and can therefore provide a medium for bacterial growth. Bacteria can break down the gelling agent reducing its viscosity and ability to carry proppant. Biocides are added to the mixing tanks with the gelling agents to kill these bacteria
Breaker	Sodium chloride	Chemicals that are typically introduced toward the later sequences of a fracturing project to break down the viscosity of the gelling agent to better release the proppant from the fluid as well as enhance the recovery or "flowback" of the fracturing fluid
Corrosion inhibitor	*N*,*N*-Dimethyl formamide	Used in fracture fluids that contain acids; inhibits the corrosion of steel tubing, well casings, tools, and tanks
Cross-linking agent	Borate salts	There are two basic types of gels that are used in fracturing fluids; linear and cross-linked gels. Cross-linked gels have the advantage of higher viscosities that do not break down quickly
Friction reducer	Petroleum distillate (also called *mineral oil*)	Minimizes friction allowing fracture fluids to be injected at optimum rates and pressures
Gel	Guar gum (hydroxyethyl cellulose)	Gels are used in fracturing fluids to increase fluid viscosity allowing it to carry more proppant than a straight water solution. In general, gelling agents are biodegradable

be pumped to the target zone at a higher rate and reduced pressure than by using water alone. In addition to friction reducers, other additives include biocides to prevent microorganism growth and reduce biofouling of fractures. Oxygen scavengers and other stabilizers, which prevent corrosion of metal pipes, and acids, which are used to remove drilling mud damage within the area near the wellbore, are also common either in fracturing fluids or as part of the fracture treatment.

The first fracture treatments were performed with gelled crude oil. Later, gelled kerosene was used. By the latter part of 1952, a large portion of fracturing treatments was performed with refined and crude oils. These fluids were inexpensive, readily available, and a permitted use of greater volumes at lower cost. The lower viscosity

TABLE 6.3 Examples of Chemicals Used in Hydraulic Fracturing Fluids[a]

Chemical	Use
Acetic acid	pH Buffer
Acrylic copolymer	Lubricant
Ammonium persulfate	Breaker used to reduce viscosity
Boric acid	Cross-linking agent to increase viscosity
Boric oxide	Cross-linking agent to increase viscosity
2-Butoxyethanol	Reduction of surface tension to aid gas flow
Carbonic acid	Cross-linking agent to increase viscosity
Carboxymethyl hydroxypropyl guar	Gelling agent (thickens fluid)
Crystalline silica (cristobalite)	Proppant (holds open fractures)
Crystalline silica (quartz)	Proppant (holds open fractures)
Citric acid	Iron control or for cleaning wellbores
Diammonium peroxydisulfate	Breaker used to reduce viscosity
Disodium octaborate tetrahydrate	Gelling agent/cross-linking agent to increase viscosity
Gas oils (petroleum), hydrotreated	Guar liquefier
Fumaric acid	pH Buffer
Gelatin	Corrosion inhibitor or gelling agent
Guar gum	Gelling agent
Hemicellulase enzyme	Breaker used to reduce viscosity
Hydrochloric acid	Cleaning of the wellbore prior to fracking
Hydroxyethyl cellulose	Gelling agent
Hydroxypropyl guar	Gelling agent
Magnesium silicate hydrate	Gelling agent
Methanol	Gelling agent
Mono ethanol amine	Reduction of surface tension to aid gas flow
Ethylene glycol monobutyl ether	Gelling agent
Muriatic acid	Mutual solvent
Noncrystalline silica	Proppant
Poly(oxy-1,2-ethanediyl)	Proppant
Polydimethyldiallylammonium chloride	Clay control
Potassium carbonate	pH Buffer
Potassium chloride	Clay inhibitor
1-Propanol	Complexing agent
Quaternary polyamines	Clay control
Sodium acetate	pH Buffer
Sodium borate	pH Buffer
Sodium bicarbonate	pH Buffer
Sodium carbonate (soda ash)	pH Buffer
Sodium chloride	Viscosity reducer
Sodium hypochlorite	Bactericide
Sodium persulfate	Viscosity reducer
Terpenes	Reduction of surface tension to aid gas flow
Tetramethyl ammonium chloride	Clay control
Zirconium complex	Cross-linking agent to increase viscosity

[a] Listed alphabetically and not in order of preference; the fracturing fluid mix varies according to the nature of the task, and only a limited set of the aforementioned chemicals are used in any single project. The additives mentioned previously are relatively common components of a water-based fracturing solution used in tight shale formations. However, it is important to note that not all of the additives listed here are used in every hydrofracturing operation; the exact blend and proportions of additives will vary based on the site-specific depth, thickness, and other characteristics of the target formation.

See Veil (2010) and Waxman et al. (2011) for more comprehensive lists of chemicals used in hydraulic fracturing projects.

of such fluids exhibited less friction than the original viscous gel. Thus, injection rates could be obtained at lower treating pressures. To transport the sand, however, higher rates were necessary to offset the lower viscosity of the fluid. With the advent in 1953 of water as a fracturing fluid, a number of gelling agents were developed. Surfactants were added to minimize emulsions with the formation fluid, and potassium chloride was added to minimize the effect on clays and other water-sensitive formation constituents. Other clay-stabilizing agents were developed that enhanced the potassium chloride, permitting the use of water in a greater number of formations.

More recent innovations, such as the use of foams and the addition of alcohol, have also enhanced the use of water in more formations (Table 6.1). In the early 1970s, a major innovation in fracturing fluids was the use of metal-based cross-linking agents to enhance the viscosity of gelled water-based fracturing fluids for higher-temperature wells. As more fracturing treatments involved high-temperature wells, gel stabilizers were developed, the first of which was the use of approximately 5% methanol. Later, chemical stabilizers were developed that could be used alone or with the methanol. Aqueous fluids such as acid, water, and brines are currently used as the base fluid in approximately 96% of all fracturing treatments employing a propping agent. Improvements in cross-linking agents and gelling agents have resulted in systems that permit the fluid to reach the bottom of the hole in high-temperature wells prior to cross-linking, thus minimizing the effects of high shear in the tubing. Ultraclean gelling agents based on surfactant-association chemistry and encapsulated breaker systems that activate when the fracture closes have been developed to minimize fracture conductivity damage.

Current practices for hydraulic fracturing of shale reservoirs involve a series of sequenced events that require thousands of barrels of water-based fracturing fluids mixed with proppant materials pumped in a controlled and monitored manner into target shale formations above fracture pressure. Fluids currently being used for fracture treatments in shale wells are water-based fluids or mixed slickwater fracturing fluids, which are water-based fluids mixed with friction-reducing additives, primarily potassium chloride. The use of potassium chloride allows a fracturing fluid and proppant to be pumped to the target zone at a higher rate and reduced pressure than by using water alone.

Many factors are considered in the choice of fracturing fluid, additives, and propping agents. The process of selection though is a subjective process and consideration is given to (i) formation evaluation, (ii) laboratory test results, and (iii) project experience.

6.2 PROPERTIES

Hydraulic fracturing fluids are predominantly water, pumped at high pressure, with lesser amounts of sand, along with very dilute concentrations of certain additives and chemicals (Table 6.3) designed to stimulate the formation, enhance the return or flowback of the slickwater solution following well stimulation, and increase the production of gas from the reservoir. The particular chemistry of the fracturing fluid may vary from site to site. Each fracture interval in a horizontal well may require up to 500,000 to 1 million gallons of water. Vertical wells use the same solutions but typically require two to three times the volume of a single horizontal fracture interval. Collectively, the total volume of fracturing fluid needed for a horizontal well will be significantly higher than that needed for a vertical well.

General properties that should be possessed by a fracturing fluid include low leak-off rate, the capacity to transport a propping agent, and low pumping friction loss. Low leak-off rate allows the fluid to create the fracture and influences the extent of the fracture area (Howard and Fast, 1970). To achieve low leak-off rate, fluid-loss additives are used. Capacity for proppant transport is influenced by density, viscosity, and velocity of fluid flow. The viscosity is the most critical parameter in proppant transport as would be explained in later sections—additives referred to as *viscofiers* are used to enhance viscosity.

The choice of a fracturing fluid is based on site-specific characteristics including formation geology, field production characteristics, and economics. Hydraulic fracturing operations vary widely in the types of fracturing fluids used, the volumes of fluid required, and the pump rates at which they are injected. Water or nitrogen foam frequently constitutes the solute in fracturing fluids used for coalbed methane recovery. Other components of fracturing fluids used to stimulate crude oil and/or natural gas production may contain only benign ingredients, but in some cases, they have included constituents such as diesel fuel that can be hazardous in the undiluted form. Fracturing fluids are significantly diluted prior to injection.

The composition of fluid used for hydraulic fracturing varies widely, depending primarily on the geology of the area being fracked. However, these fluids generally consist of a variety of chemicals and high levels of dissolved solids. The solutions are classed as *clean* prior to introduction into the drill holes, but the postuse solutions contain many more components, including high levels of dissolved organics. In addition, and because of the variability of the fluids used from hydraulic fracturing, there are no certified reference materials available. As a result, analysis of the fluids is a major challenge, and because of the complexity of the fluids, it is important to determine the composition (particularly the metal content) of hydraulic fracturing fluids both before use and after use. Such analyses can be used to evaluate how often the fluids can be reused and the measures that must be taken for safe disposal.

Water with a simple sand proppant may be adequate to achieve a desired fracture at some sites, but in many cases, the water must be thickened to achieve higher proppant transport capabilities. Thickening can be achieved by using linear or cross-linked gelling agents. Cross-linking agents are costly additives compared to simple linear gels but markedly increase the efficiency of the fracturing fluid. Foam fracturing fluids can be used to considerably reduce the amount of injected fluid required since the reduced water volume requirement translates into reduced volumes of flow-back water requiring disposal.

The use of diesel fuel in fracturing fluids poses a significant environmental threat to because the benzene, toluene, ethylbenzene, and xylene (BTEX) constituents in diesel fuel exceed the maximum concentration limit at the point of injection. In situations when diesel fuel is used in fracturing fluids, a number of factors would decrease the concentration and/or availability of BTEX. These factors include fluid recovery during flowback, adsorption, dilution, dispersion, and potentially biodegradation of constituents. Furthermore, in many cases, approximately one-third of fracturing fluid that is injected is expected to remain in the formation.

The composition and properties of fracturing fluids vary significantly, from simple water and sand to complex polymeric substances with a multitude of additives (Tables 6.1, 6.2, and 6.3). Each type of fracturing fluid has unique characteristics, and each possesses its own positive and negative performance traits. For ideal performance, the necessary qualities that a fracturing fluid should possess are as follows: (i) sufficiently creates a fracture of adequate width, (ii) maximizes fluid travel distance to extend fracture length, (iii) has the ability to transport large amounts of proppant into the fracture, and (iv) requires minimal gelling agent to allow for easier degradation or breaking.

The effectiveness of a hydraulic fracturing operation is controlled by several variables, but only a few are easily controlled, and these are the fracturing fluid properties, the injection rate, and the quality of propping agents (Pye and Smith, 1973). The fracture fluid design is an essential part of the hydraulic fracturing stimulation treatment. Fracture fluids can be classified into four main divisions based on their fluid bases: (i) water-based fluids, (ii) foam-based fluids, (iii) acid-based fluids, (iv) alcohol-based fluids, and (v) emulsion-based fluids (Table 6.1) (Xiong et al., 1996; Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016). For decades, oil-based fluids were used preferentially since it was believed that the use of water-based fluids in water-sensitive formations (oil reservoirs) would obstruct oil flow. However, the success of water-based fluid led to their eventual common use with the majority of wells now being fractured with water-based fluids (Howard and Fast, 1970; Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016). In fact, water-based fluids have considerable advantage over other bases, including (i) noninflammability; (ii) higher specific gravity, which translates to lower hydraulic horse power requirements for treatment; (iii) low viscosity, which means that the fluid is easier to pump, as well as the ease of availability and the lower cost.

In general, a fracturing fluid (Tables 6.1, 6.2, and 6.3) can be considered to be the sum of three main components: (i) base fluid, (ii) additives, and (iii) proppant. Thus,

$$\text{Fracturing fluid} = \text{Base fluid} + \text{Additives} + \text{Proppant}$$

A fracturing fluid can be made to be more efficient by the addition of compressed gas (typically carbon dioxide or nitrogen), which provides a substantial portion of the energy required to recover the fluid and places much less water in water-sensitive formations. The disadvantage of the method is that it reduces the amount of proppant that is possible to deposit in the fracture.

Typically, water-based fluids are the simplest and most cost-effective solution to fracture a rock formation. However, alternatives to water-based fluids have significantly outperformed water treatments in many shale reservoirs. For instance, foam-based fluids have been used extensively in depleted conventional reservoirs in which water fractures were not effective. More recently, the development of the unconventional reservoirs (tight formations, shale formations, coal seams) has prompted the reconsideration of *waterless* fracturing treatments as viable alternatives to water-based fracturing fluids. There are several reasons to consider fluids that contain little or no water, namely, (i) water sensitivity of the formation, (ii) water blocking, (iii) proppant placement, and (iv) water availability and cost. However, the interactions between the rock formation and the fracturing fluids may be detrimental to hydrocarbon production (Ribeiro and Sharma, 2013).

In terms of *water sensitivity of the formation*, the base mineral composition of a reservoir formation can impact the recovery process of water, gas, and oil. For example, oil-based fluids, liquefied petroleum gas (LPG), carbon dioxide, and foam-based fluids are recommended in water-sensitive formations to prevent migration of fines and also to prevent clay swelling. In many shale formations, proppant conductivity drops considerably in the presence of water because the rock–fluid interactions soften the rock leading to proppant embedment.

Water blocking is essential in undersaturated gas formations where the invasion of water from the fracturing fluid can be very detrimental to gas productivity as any additional water remains trapped because of capillary retention. The increase in water saturation (referred to as water blocking or water trapping) significantly reduces the relative permeability to gas, sometimes by orders of magnitude (Parekh and Sharma, 2004).

In terms of *proppant placement*, foams and other gelled nonaqueous fluids can transport proppant much more effectively than slickwater fluids. At high foam qualities (gas volume fraction typically >0.5), the interactions between gas bubbles cause a large energy dissipation that results in a high effective viscosity. At low foam qualities (<0.5) the interactions between bubbles are minimal, so the fluid viscosity resembles that of the base fluid (which is typically gelled).

Water availability and cost can limit the operations to a considerable extent. Either (i) freshwater can be difficult to obtain in areas prone to drought or (ii) local legislation may limit water use, which has prompted the use of waterless fracturing treatments. Alternatively, the supply and the cost of LPG, carbon dioxide, and nitrogen are strongly site specific.

Fracturing with gaseous nitrogen is also a viable technique for formations that are potentially sensitive to aqueous-based fracture fluid systems. In this method, nitrogen is pumped as a cryogenic liquid and then heated to form a gas prior to being injected into the well. Fracturing mechanics occur as in any other hydraulic fracturing technique, the only difference being that the fracturing fluid is a gas. Unfortunately, pumping nitrogen as a gas normally eliminates the possibility of transporting proppants, and as such, nitrogen fracturing can be classified as a proppantless, nonreactive stimulation technique. As with fracturing with liquid carbon dioxide, the principal benefit of fracturing with gaseous nitrogen is the nonaqueous, nondamaging nature of it, particularly in water-sensitive formations. The principal difference between fracturing with liquid carbon dioxide and other fluid systems is in the blending requirements. Proppants and carbon dioxide must be mixed in a purpose-built pressurized blending system, and because of the need to mix the liquid carbon dioxide and proppant under pressurized conditions, the proppant must also be stored and transferred to the blending tub under pressure. This places a practical limit on the amount of proppant that can be used with this system, which is based on the capacity of the pressurized proppant storage bin on the blender.

The ideal fracturing fluid (in addition to being cost-effective) should (i) be able to transport the propping agent in the fracture, (ii) be compatible with the formation rock and fluid, (iii) generate enough pressure drop along the fracture to create a wide fracture, (iv) minimize friction pressure losses during injection, (v) be formulated using chemical additives that are approved by the local environmental regulations, and (vi) exhibit controlled break to a low-viscosity fluid for cleanup after the treatment.

The *viscosity* of the fracturing fluid is an important point of differentiation in both the execution and in the expected fracture geometry. Many current practices, generally referred to as *slickwater treatments*, use low-viscosity fluids pumped at high rates to generate narrow, complex fractures with low concentrations of propping agent. In order to minimize risk of premature screen-out, pumping rates must be sufficiently high to transport proppant over long distances (often along horizontal wellbores) before entering the fracture. By comparison, for conventional wide bi-wing fractures, the carrier fluid must be sufficiently viscous to transport higher proppant concentrations. These treatments are often pumped at lower pump rates and may create wider fractures.

The *density* of the carrier fluid is also important and affects the surface injection pressure and the ability of the fluid to flow back after the treatment. Water-based fluids generally have densities near 8.4 pounds per gallon, while the density of an oil-based fluid density will be 70–80% of the density of a water-based fluid. However, the density of foam-based fluids can be substantially less than the density of water-based fluids. In low-pressure reservoirs, low-density fluids, like foam, can be used to assist in the fluid cleanup. Conversely, in certain deep reservoirs (including offshore hydraulic fracturing applications), there is a need for higher-density fracturing fluids, typically those with a density up to or even higher than 12 pounds per gallon.

A fundamental principle of the process is that the fracture volume should be equal to the total volume of fluid injected minus the volume of fluid that leaks off into the reservoir. The fluid efficiency is the percentage of fluid that is still in the fracture at any point in time, when compared with the total volume injected at the same point in time. If too much fluid leaks off, the fluid has a low efficiency (10–20%), and the created fracture volume will be only a small fraction of the total volume injected. However, if the fluid efficiency is too high (80–90%), the fracture will not close rapidly after the treatment. In a near-ideal situation, a fluid efficiency of 40–60% will provide an optimum balance between creating the fracture and having the fracture close down after the treatment.

In most low-permeability reservoirs, fracture fluid loss and efficiency are controlled by the formation permeability (Chapter 2). In high-permeability formations a fluid-loss additive is often added to the fracture fluid to reduce leak-off and improve fluid efficiency. In naturally fractured or highly cleated formations, the leak-off can be extremely high, thereby reducing the efficiency to a range on the order of 10–20% or less. To apply hydraulic fracturing to naturally fractured formations, the fracturing fluid (containing fluid-loss additives) must be pumped at high injection rates.

In summary, the fracturing fluid is varied to meet the specific needs of each location; however, evaluating the widely reported percentage volumes of the fracturing fluid components reveals the relatively small volume of additives that are present. Overall, the concentration of additives in most fracturing fluids is a relatively consistent 0.5–2% v/v with water and proppants making up the remaining 98–99.5% v.v. However, a typical fracturing project uses upward of 5 million gallons of fracturing fluid, so a small percentage amount may actually result in a great deal of chemical usage, no matter how diluted it may be. The overall composition of fracturing fluids varies among companies and the drilling location. However, as a pretty good baseline, fracturing fluids typically contain (i) approximately 90% water, (ii) approximately 9.5% proppant materials, and (iii) approximately 0.5% chemicals—this percentage varies but is typically between 0.5 and 1.0% w/w of total fluid.

6.3 TYPES OF FLUIDS

Hydraulic fracturing is carried out using two broad classes of fracturing materials: fracturing fluid and proppants. Fracturing fluid is a generic term that involves both the base fluid (water, oil, acid, etc.) and additives (Tables 6.1, 6.2, and 6.3). Additives are chemicals added to influence the overall properties of the fracturing fluid, and propping agents (*proppants*; Chapter 7) are materials used to stop the fracture from collapsing and closing after treatment—the proppants effectively hold the fracture open (prop open) to enable hydrocarbon recovery. The comprehensive design and selection of these fracturing materials is essential for successful achievement of the desired fracturing objectives. In fact, an essential element of fracturing technology, not only from the technical aspects but also from the environmental aspects, is the type of fluid used to perform the fracturing of the formation. The choice of the fracturing fluid dictates the type of required chemical additives as well as the need for flowback treatment.

The use of water-based fluids has found application with gas prospecting, as the fluids currently being used for hydraulic fracture treatments in the Marcellus shale are water-based or mixed slickwater fracturing fluids (Arthur et al., 2008). Slickwater fracturing fluids consist mainly of water mixed with friction-reducing additives like potassium chloride. High-rate slickwater fracturing can induce tensile fractures as well as shear existing fractures in the brittle shale formation with low horizontal stress anisotropy (Kennedy et al., 2012). Furthermore, the use of slickwater fluids for fracturing has become the norm in Barnett and Marcellus shale plays, but the disadvantage of slickwater fracturing fluids is that due to the low viscosity, such fluids are not efficient carriers of proppants. Hence, though successful in several US shale developments, it has not been suitable for all cases (Kennedy et al., 2012). In cases where the use of slickwater fluids is inadequate, hybrid fracturing technologies have been proposed. A hybrid fracture is a combination of slickwater (to create the fractures) and another more viscous fracturing fluid (solely for proppant transport) (King, 2012). Careful selection of fluids and proppants (sand constituents) is necessary based on the reservoir properties of the specific shale formation. For most reservoirs, water-based fluids with appropriate additives are most suitable, due to the historic ease with which large volumes of mix-water can be acquired. In some cases, foam generated with nitrogen or carbon dioxide can be used to stimulate shallow, low-pressure zones successfully. When water is used as the base fluid, the water should be tested for quality due to some sensitivity of certain fluids to the mix-water composition.

6.3.1 Water-Based Fluids

The predominant fluids currently being used for fracture treatments in the gas shale plays are water-based fracturing fluids mixed with friction-reducing additives (called slickwater). Many other water-based fluids are used, broadly speaking, linear fluids, cross-linked fluids, and viscoelastic surfactant fluids.

Slickwater fracturing is probably the most basic and most common form of well stimulation in unconventional gas (Gandossi, 2013). The fracturing fluid is composed primarily of water and sand (>98%). Additional chemicals are added to reduce friction, corrosion, and bacterial growth and provide other benefits during the stimulation process. Low-viscosity slickwater fluids generate fractures of lesser width and therefore greater fracture length, theoretically increasing the complexity of the created fracture network for better reservoir-to-wellbore connectivity.

A common practice in the hydraulic fracturing of reservoirs is the use of nonviscous slickwater fluids pumped at high rates (>60 bpm) to generate narrow fractures with low concentrations of proppant. In the recent years, these treatments have become a standard technique in fracture stimulation of several shale formations of the United States, including the Barnett, Marcellus, and Haynesville, and yield economically viable production. The low proppant concentration, high fluid efficiency, and high pump rates in slickwater treatments yield highly complex fractures. Additionally, compared to a traditional bi-wing fracture, slickwater fractures often find the primary fracture connected to multiple orthogonal (secondary) and parallel (tertiary) fracture. Coupled with multistage fracture completions and multiple wells collocated on a pad, complex fracture networks yield a high degree of reservoir contact.

The most critical chemical additive for slickwater-fracture execution is the friction reducer. The high pump rates for slickwater treatments (often 60–100 bbl/min) necessitate the action of friction reducer additives to reduce friction pressure up to 70%; this effect helps to moderate the pumping pressure to a manageable level during proppant injection. Common chemicals used for friction reduction include polyacrylamide derivatives and copolymers added to water at low concentrations. Additional additives for slickwater fluids may include biocide, surfactant (wettability modification), scale inhibitor, and others. The performance (friction reduction) of slickwater fluids is generally less sensitive to mix-water quality, a large advantage over many conventional gelled fracturing fluids. However in high-salinity mix-water, many friction reducer additives may see a loss in achievable friction reduction. Other advantages and disadvantages of slickwater fluids and execution (compared to that of gelled fracturing fluids) are (i) high retained conductivity, due to no filter cake present, (ii) reduced sensitivity to salinity and contaminants in mix-water, and (iii) reduced number of fluid additives required for slickwater fracturing fluid.

However there are disadvantages that include (i) larger volumes of water often required for fracture design (compared to gelled fracturing fluids); (ii) larger horsepower requirement (to maintain high pump rates, 60–110 bpm); (iii) limited fracture width, due to low maximum concentration proppant in low viscosity; (iv) reduced %-flowback-water recovery due to loss of the fracturing fluid in complex fracture network far from wellbore; and (v) limitation to fine-mesh propping agents, due to reduced ability of nonviscous fluids in the transport of large proppants.

Since the anticipated proppant-suspension capacity of slickwater fluids is quite low; a complementary solution is the use of linear (noncross-linked) gels. These fluids, based on noncross-linked solutions of polysaccharides (i.e., guar, derivatized guar, hydroxyethyl cellulose (HEC), xanthan), have viscosities of up to 100 cP at 100/s at surface temperature, which depend on polymer concentration. As this viscosity is several orders of magnitude higher than slickwater, linear gels have improved proppant suspension. When noncross-linked gels are used in late-slurry stages of a fracturing treatment (where the pad and early-slurry stages used slickwater), these are often referred to as hybrid fracturing treatments.

In summary, slickwater fluid is an inherently poor proppant carrier, necessitating high pump rates to achieve a sufficiently high flow velocity to overcome the tendency of the proppant to settle. Proppant settling within surface equipment or long horizontal laterals can result in premature termination of the fracturing process and/or poor productivity. Linear gel and cross-linked systems can be used to mitigate the proppant-settling phenomenon (resulting in poor placement of the proppant in the fractures), but the high viscosity that accomplishes this objective can significantly influence the process by reducing the desired fracture complexity. Also, the long fracture closure times and the lack of efficient gel delayed breakers make the proppant placement advantage of gel systems very limited since the proppant can settle while gel is breaking and the fracture has not yet closed. The most important benefits of slickwater fracturing are (i) reduced gel damage, (ii) higher stimulated reservoir volume, and (iii) better fracture containment. But there are concerns such as poor proppant transport, excessive usage of water, and narrower fracture widths (Gandossi, 2013).

Some fracturing treatments require a higher-viscosity fluid, such as linear fracturing fluids, which are produced by adding a wide array of different polymers to water. Such polymers are dry powders that swell when mixed with an aqueous solution and form a viscous gel. The gel-like fluid is then more able to transport the proppant than would a normal low-viscous (slickwater) fluid. Common polymer sources used with the linear gels are guar, hydroxypropyl guar (HPG), HEC, carboxymethyl hydroxypropyl guar (CMHPG), and carboxymethyl hydroxyethyl cellulose (CMHEC) (Howard and Fast, 1970; Gandossi, 2013).

In low-permeability formations, linear gels control fluid loss very well, whereas in higher-permeability formations fluid loss can be excessive. Linear gels tend to form thick filter cakes on the face of lower-permeability formations, which can adversely affect fracture conductivity. The performance of linear gels in higher-permeability formations is just the opposite, since it forms no filter cake on the formation wall.

Much higher volumes of fluid are lost due to viscous invasion of the gel into the formation with environmental consequences.

Cross-linked fluids were developed in order to improve the performance of gelling polymers without increasing their concentration. Borate cross-linked gel fracturing fluids utilize borate ions to cross-link the hydrated polymers and provide increased viscosity. The polymers most often used in these fluids are guar and HPG. The cross-link obtained by using borate is reversible and is triggered by altering the pH of the fluid system. The reversible characteristic of the cross-link in borate fluids helps them clean up more effectively, resulting in good regained permeability and conductivity.

Cross-linked guar gum is an example of a common fracture fluid used for environmental application (Howard and Fast, 1970; Beckwith, 2012). The most widely used form is the continuous mix grade of gum, referred to as such because it hydrates rapidly and reaches a usable level of viscosity fast enough that it can be used continuously. Because of the characteristic high viscosity, guar gum is capable of transporting coarse-grained silica sand or other granular material (proppants), as a slurry, into the fracture. Pumps specifically designed for high-viscosity, high-solid fluid handling should be selected to inject the slurry at the required pressures.

Chemical modification of water-based polymers obtained from guar has produced a wide range of derivatives with useful properties, such as HPG and CMHPG. HEC and CMHEC are derivatives from cellulose, another natural source. These derivatives provide viscosity for fracturing wells with formation temperatures from 18 to approximately 205 °C (60 to ~400 °F). To prevent loss of viscosity due to decomposition of these derivatives at high temperatures (>107 °C; >225 °F), chemical stabilizers such as methanol or thiosulfate are added. For lower temperature regimes (<65 °C; <150 °F), aqueous solutions of these derivatives (base gels) are used (Harris, 1988). When high viscosity is required, cross-linking a polymer is normally done using transition metal cations; this method is more efficient (and more cost-effective) than merely increasing the concentration of the polymer solution.

Borate cross-linked fluids have proved to be highly effective in formation with both low permeability and also with high permeability. These fluids offer (i) efficient proppant transport, (ii) stable fluid rheology at temperatures as high as 150 °C (300 °F), (iii) low fluid loss, and (iv) good cleanup properties (Gandossi, 2013). Organometallic cross-linked fluids are also a very popular class of fracturing fluids. Primary fluids that are widely used are the zirconate and titanate complexes of guar, HPG and CMHPG. Organometallic cross-linked fluids are routinely used to transport the proppant for treatments in tight gas sand formations that require extended fracture lengths. These fluids provide advantages in terms of stability at high temperatures and proppant transport capabilities and offer more predictable rheological properties.

Viscoelastic surfactant (VES) *gel fluids* have been described in the patent literature for friction reduction and as well treatment fluids since the early 1980s, but their use as fracturing fluids is relatively a new phenomenon. Principally, these fluids use surfactants in combination with inorganic salts to create ordered structures, which result in increased viscosity and elasticity. These fluids have very high zero-shear viscosity and can transport proppant with lower loading and without the comparable viscosity requirements of conventional fluids. The technology of VES gel fluid systems can be broken down into several categories based on the structure the system creates: wormlike micelles, lamellar structures, or vesicles. As the concentration of surfactant increases in water, micelles start to form and interact with each other—the interactions are based on ionic forces and can be amplified by adding electrolytes (salts) or ionic surfactants. These fluids do not require any biocides because they do not contain any biopolymers. Furthermore, they do not require additional flowback surfactants because they have inherently low surface and interfacial tension, and additional clay control additives are not necessary.

6.3.2 Foam-Based Fluids

For water-sensitive formations and environments where water is scarce, foam-based fluids have long been considered as one of the best fracturing fluids (Table 6.1) (Gupta, 2009; Gandossi, 2013). In particular, foam-based fluids are believed to be an appropriate means for fracturing shale gas reservoirs. These fluids require lower (or no) water consumption and cause less damage in water-sensitive formations, and there is less liquid to recover and handle after the fracturing process. Expansion of the gas phase after the treatment also helps recover the liquid phase introduced into the formation with the foamy fluid (Edrisi and Kam, 2012). Foams are very unique and versatile because of low-density and high-viscosity characteristics—foam viscosity strongly depends on foam quality (the gas fraction in the total gas and liquid mixture) and foam texture (the number of bubbles in unit mixture volume) (Rowan, 2009; Edrisi and Kam, 2012).

Thus, it is not surprising that foams are being used in a number of petroleum industry applications that exploit their high-viscosity and low liquid content (Gandossi, 2013). In the mid-1970s, nitrogen-based foams became popular for both hydraulic fracturing and fracture acidizing stimulation treatments. More recently, carbon dioxide-based foams have been found to exhibit their usefulness in hydraulic fracturing stimulation. The liquid carbon dioxide-based fluid consists of foam of nitrogen gas in liquid carbon dioxide as the external phase stabilized by a special foaming agent that is soluble in liquid or supercritical carbon dioxide (Gupta, 2003). The main advantage of this fluid is the additional viscosity gained by the foam over liquid carbon dioxide.

6.3.3 Oil-Based Fluids

Oil-based fracturing fluids were the first high-viscosity fluids used in hydraulic fracturing operations—an advantage to this type of fluid is the compatibility with almost any formation type. Disadvantages (compared to the use of most water-based fluids) are associated with concerns regarding personnel safety and environmental impact. LPG has been used as stimulation fluid for 50 years and was developed for conventional reservoirs before being adapted to unconventional reservoirs. For instance, it was used to stimulate (or restimulate) oil wells and has also been used to stimulate tight sands because of recovery improvements in reservoirs exhibiting high capillary pressures by eliminating phase trapping (Gandossi, 2013).

When gelled, LPG provides a consistent viscosity and does not require the costly use of carbon dioxide or nitrogen nor does it require any special cool down or venting of equipment. LPG is an abundant by-product of the natural gas industry and is stored at ambient temperature, and using LPG also reduces the need to flare production to clean up the traditional fracturing fluids, reducing emissions of carbon dioxide. Because propane liquid is half the specific gravity of water, there is reduced trucking to the site and no trucking to transport poststimulation—which can reduce truck traffic by up to 90%. However, a disadvantage is the manipulation of large amounts of flammable propane (and the associated risks/safety hazards).

Many shale formations are water sensitive, and using LPG could avoid this problem. The gel properties include (i) low surface tension, (ii) low viscosity, (iii) low density, and (iv) solubility within naturally occurring reservoir hydrocarbons. These properties are believed to promote more effective fracture lengths that are created and thus enable higher production of the well. Another reported advantage is the ability to evenly distribute proppant. The fracturing fluids are totally recovered within days of stimulation, creating economic and environmental advantages by reducing cleanup, waste disposal, and postproject truck traffic (Gandossi, 2013).

6.3.4 Acid-Based Fluids

The main difference between acid fracturing and proppant fracturing is the manner by which fracture conductivity is created. In proppant fracturing, a propping agent is used to prop open the fracture after the treatment is completed, but in the acid fracturing process, acid is used to create channels in the reservoir rock that comprise the walls of the fracture. However, the reservoir rock (e.g., calcium carbonate ($CaCO_3$)) must be partially soluble in acid so that channels can be etched in the fracture walls.

In shale formations, although many have a significant amount of dissolvable carbonate and limestone, the content of the carbonates in the formation rock is not always a continuous phase. Hence, it is difficult to use acid-based fluids even in the few high carbonate reservoirs such as the Eagle Ford formation. Without a continuous carbonate/limestone phase, it is very difficult to create the required continuous channel. In addition, flowback needs to manage the disposal of significant calcium carbonate/limestone volumes that become dissolved in the acid and come to the surface with the spent acid. Thus, it is appropriate that the application of acid fracturing is confined to carbonate reservoirs and is not applied to stimulate tight sandstone formations, shale formation, or coal-seam reservoirs.

6.3.5 Alcohol-Based Fluids

In the 1990s methanol was first used as a base fluid in fracturing applications in Canada and Argentina, and the fractured formations either had (i) low permeability with high clay content, (ii) low bottom-hole pressure, and/or (iii) minimal load fluid recovery. However, concerns about safety of using methanol (not the least of which is flammability) have led to a movement away from methanol as a base fluid, and there has been a tendency to limit methanol use to that of an additive.

However, in formations with severe liquid (aqueous and hydrocarbon) trapping problems, nonaqueous methanol fluids may be a solution to poor recovery. Nevertheless, the advantages of using alcohol-based fluids have been identified and include (i) low freezing point, (ii) low surface tension, (iii) high solubility in water, (iv) high vapor pressure, and (v) compatibility with the formation. In fact, methanol has become the fluid of choice for formations with irreducible water and/or hydrocarbon saturation (Howard and Fast, 1970; Bennion and Thomas, 1996, 2000).

Alcohol-based fluids should be selectively used with special safety considerations due to the flammability of methanol. The flash point (i.e., the lowest temperature at which it can vaporize to form an ignitable mixture in air) of methanol is 53 °F (11.6 °C), and the density is greater than that of air, which presents a safety hazard to field personnel. Oxygen contact must be avoided and therefore a blanket of carbon dioxide vapor is used to separate methanol vapor from any oxygen source. Certain formations have potential to retain even the small amounts of water contained in foams. These fluids may damage these sensitive formations because of irreducible water saturation and liquid trapping. In these formations, replacing 40% of the water phase used in conventional carbon dioxide-based foams with methanol can minimize the amount of water required for fracturing (Gupta and Hlidek, 2007).

Another group of commonly used additives in a water-based fracturing fluid is known as surface active agents or surfactants. These include (i) reducing the interfacial tension and hence capillary pressure, (ii) providing a foam stabilizing action, and (iii) reducing the compatibility problems between fracturing fluids and reservoir fluids. Decreasing the capillary pressure is useful in low-permeability formations to reduce the pressure needed in causing flowback of fracturing fluid since less fluid will be retained in the pore spaces of the reservoir. In fracturing fluid recovery, the addition of gases such as nitrogen and carbon dioxide are also claimed to be useful (Harris, 1988). The foam stabilizing action is effective in gas wells.

6.3.6 Emulsion-Based Fluids

There are many different emulsion-based fluids that have been developed and used as fracturing fluids. Many of such fluids use emulsions of oil and water and could therefore be classified under the oil-based fluids. Generally, emulsion-based fluids reduce or completely eliminate the use of water. From the 1980s to the present, the use of emulsion-based fluids has been successful, particularly in low-pressure, tight gas applications. The use of emulsion-based fluids has the same advantages as the use of conventional high-quality carbon dioxide-based foams, with the added advantage of minimizing the amount of water introduced into the well (Gupta and Hlidek, 2007).

6.3.7 Cryogenic Fluids

Liquid (or supercritical) carbon dioxide can be used instead of water as the fracturing fluid. The family of these fluids consists of pure liquid carbon dioxide and a binary fluid consisting of a mixture of liquid carbon dioxide and nitrogen to reduce costs

(Gandossi, 2013). In these systems, the proppant is placed in the formation without causing damage of any kind and without adding any other carrier fluid, viscosity modifier, or other chemicals.

Liquid carbon dioxide has been used in fracture operation since the early 1960s—initially the liquid carbon dioxide was used as an additive to hydraulic fracturing fluids and to acid fracturing in order to improve recovery of treating fluid (Mueller and Amro, 2012). The physical properties of liquid carbon dioxide make it a unique fluid. Carbon dioxide is relatively inert compound that, depending on the temperature and pressure, exists as a solid, liquid, gas, or supercritical fluid. After the addition of proppants, high pressure pumps increase the pressure, and as the fluid enters the formation, the temperature increases toward bottom-hole temperature. During flowback, the pressure decreases and carbon dioxide comes to the surface as a gas.

The use of supercritical carbon dioxide (a fluid state of carbon dioxide where it is held at or above the critical temperature and critical pressure) has been suggested for use as a fracturing fluid (Gupta and Gupta, 2005; Al-Adwani and Langlinais, 2008). Supercritical carbon dioxide is a fluid state where carbon dioxide is held at or above its critical temperature (31.1 °C) and critical pressure (1070 psi). Owing to the unique physical and chemical properties, supercritical carbon dioxide can obtain a higher penetration rate in shale formations and has the potential to cause little or no damage to the reservoir.

6.4 ADDITIVES

Additives are chemicals added to the fracturing fluid to achieve specific target properties of the fracturing fluid (Tables 6.2 and 6.3) and constitute between 0.1 and 0.5% v/v of the total fracture fluid (Arthur et al., 2008; Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016). Since each reservoir and each well (even wells in the same reservoir) are sufficiently different for other reservoirs and wells (Chapter 2), there is no generally applicable formula for how much of each additive is to be used in a given fracturing fluid—typically between 3 and 12 additives are employed depending on the conditions of the specific well to be fractured and characteristic of the surrounding formations. Additives utilized in hydraulic fracturing operations are intended to serve specifically engineered uses such as biocides to control microorganism/bacterial growth, corrosion inhibitor to prevent corrosion of pipe, viscosity agents to carry proppant, gelling agents to improve proppant placement, friction reduction to decrease pump friction and reduce treating pressure, oxygen scavengers to also aid in corrosion prevention in metal pipes, and acids to help remove drilling mud buildup damage (Table 6.2).

Chemical additives are applied to (i) tailor the injected material to the specific geological makeup of the reservoir, (ii) protect the well, and (iii) improve the operation, which will vary based on the type of well. Since change is the only constant, the composition of the injected fluid may need to be changed as the fracturing project proceeds. Often, acid is initially used to scour the perforations and clean up the near-wellbore area, and afterward, high-pressure fracture fluid is injected into the wellbore, with the pressure above the fracture gradient of the rock. This fracture fluid contains water-soluble gelling agents (such as guar gum), which increase the viscosity of the fluid and deliver the proppant (without settling) into the formation. As the fracturing process proceeds, viscosity-reducing agents such as oxidizer and enzyme breakers (Table 6.3) may be added to the fracturing fluid to deactivate the gelling agents and encourage flowback.

At the end of the project the well is commonly flushed with water (sometimes blended with a friction-reducing chemical) under pressure. The injected fluid is partially recovered and is managed by several methods, such as underground injection control, treatment and discharge, recycling, or temporary storage in pits or containers, while new technology is continually being developed and improved to handle the wastewater and improve reusability. Although the concentrations of the chemical additives are very low, the recovered fluid may be environmentally harmful (and may even be a health hazard) due in part to minerals that are extracted from the formation.

The type of additive used also depends on the base fracturing fluid. For example, water-based fluids (more than other base fracturing fluids) require surfactants to reduce interfacial tension and resistance to return flow after treatment. Conversely, additives for friction-loss reduction in fracturing are less needed for water-based fluids since it naturally has a friction-reducing advantage. The same considerations apply to other base fluids, with additives chosen to supplement any inherent limitations in fluid performance. Generally, additives serve the following uses: (i) enhance fracture creation and (ii) reduce formation damage. Additives that enhance fracture creation include viscofiers, temperature stabilizers, pH control agents, and fluid-loss control materials. Those additives that reduce formation damage are gel breakers, biocides, surfactants, clay stabilizers, and gases (Harris, 1988).

Other additives commonly used in the hydraulic fracturing fluid include (Tables 6.2 and 6.3): (i) a *biocide or disinfectant*, used to prevent the growth of bacteria in the well that may interfere with the fracturing operation; biocides typically consist of bromine-based solutions or glutaraldehyde; (ii) a *scale inhibitor*, such as ethylene glycol, used to control the precipitation of certain carbonate and sulfate minerals; (iii) *iron control/stabilizing agents*, such as citric acid or hydrochloric acid, used to inhibit precipitation of iron compounds by keeping them in a soluble form; and (iv) *corrosion inhibitors*, such as *N*,*N*-dimethyl formamide, and *oxygen scavengers*, such as ammonium bisulfite, are used to prevent degradation of the steel well casing. *Gelling agents*, such as guar gum (a common food additive), may also be used in small amounts to thicken the water-based solution to help transport the proppant material. Occasionally, a *cross-linking agent* will be used to enhance the characteristics and ability of the gelling agent to transport the proppant material. These compounds may contain boric acid or ethylene glycol. When cross-linking additives are added, a breaker solution is commonly added later in the fracturing stage, to cause the enhanced gelling agent to break down into a simpler fluid, so it can be readily removed from the wellbore without carrying back the sand/proppant material.

Finally, nitrogen-based fracturing fluids are also occasionally used to stimulate shale gas plays. These *foam fracturing* project typically require only 25% v/v of the water demand needed for a slickwater fracturing project. However, these nitrogen-based foam fracturing liquids are effective only in formations that reside at relatively shallow depths. At greater depths, the increased formation pressure limits the ability of foam-based fracturing liquids to effectively fracture the formation and deliver the proppant. As a result, water-based fracturing solutions are more common in deep formations.

Common classes or subcategories of additives include (i) fluid-loss additives, (ii) clay stabilizers, (iii) gel breakers, (iv) bactericides and/or biocides, and (v) pH control chemicals.

6.4.1 Fluid-Loss Additives

Fluid-loss additives are used to restrict leak-off of the fracturing fluid into the exposed rock at the fracture face, which leads to prevention of excessive leak-off, thereby maintaining fracturing fluid effectiveness. Fluid-loss additives of the past and present include bridging materials such as 100 mesh sand, 100 mesh soluble resin, or plastering materials such as starch blends, talc, silica flour (finely powdered silica), and a variety of appropriate clay minerals.

Fluid-loss control in fracturing operations cannot be overemphasized. Thus, fluid-loss additives are added to the base fracturing fluid to prevent the fluid from leaving the fracture, hence, to prevent the fluid from leaking from the fracture into the rock matrix. Loss of fluid through uncontrolled leak-off will cause an increase in proppant concentration around the wellbore, which if allowed can create a *proppant bridge* and completely stop fracture propagation (Harris, 1988). Low fluid loss (low leak-off rate) would mean larger and deeper fractures for a given volume of fracturing fluid and injection rate.

In the process (Hawsey and Jacocks, 1961), the fluid-loss additive, which is largely insoluble, disperses into micron-sized (μm-sized) particles when added to the fracturing fluid. As fracturing takes place, some fluid is lost immediately to the formation, called *spurt loss*, and after spurt loss the fluid-loss additive deposits a thin film (sometimes called a *filter cake*) on the face (interior walls) of the newly created fracture, hence preventing further fluid loss to the formation. This process continues as the fracture propagates and new fracture area is exposed. The thin film (filter cake) remains in place, as long as there is pressure in the fracture. When flowback begins, the filter cake redisperses and flows out through the spaces between propping agents.

Briefly, *spurt loss* is the fluid loss per area, before the formation of a filter cake, and is very significant in naturally fractured reservoirs (Jones and Britt, 2009). It is directly proportional to reservoir permeability and is an important part of the fracturing operation, and an efficient fluid-loss additive would not only coat the fracture face but also prevent excessive spurt loss from occurring.

6.4.2 Clay Stabilizers

Clay minerals pose challenges since they are well known for swelling in the presence of water. Within the crystalline layers, clay minerals contain cations (typically sodium and potassium) that occupy base-exchange positions or sites. Upon contact with water, these cations are solubilized resulting in clay instability that may be manifested in swelling. When clay swells, the ability of the clay-containing formation to permit the passage of liquids and drilling or fracturing fluids as well as hydrocarbons, is diminished and can seriously impede crude oil and/or natural gas production.

Clay stabilizers reduce clay swelling and function through ion exchange, where the clay stabilizer provides a cation to replace the native, solubilized clay cation such as sodium. Potassium chloride (KCl) is commonly used to reduce clay swelling, where the potassium ion is effective at preventing swelling. It presents certain challenges. Potassium chloride is often used at high levels (2–4% w/w) and requires handling at the site to prepare a solution. In addition, potassium chloride can be incompatible with other materials, negatively impacting other aspects of fracturing fluids such as gelation.

In terms of hydraulic fracturing, clay stabilizers are additives that are used to improve the compatibility between the formation and fracturing fluid. Most formations contain clay minerals that are susceptible to swelling and migration, and clay damage is extremely important in low-permeability, low-pressure reservoirs as it affects capillary pressures (Anderson et al., 2010). Fracturing fluids must provide a high electrovalent strength so that clays contacted would not experience *ionic shock*. Clay stabilizers like inorganic salts such as potassium chloride (KCl), sodium chloride (NaCl), ammonium chloride (NH_4Cl), or calcium chloride ($CaCl_2$) are used to prevent shocking the clays. Other stabilizers such as polymeric clay stabilizers can attach anions to the clay surface in order to control migration of fines, hampering placement of the proppant (Harris, 1988).

6.4.3 Gel Breakers

Hydraulic fracturing fluid must have the capability to decrease in viscosity following proppant placement. This decrease is necessary to (i) minimize return of proppant and (ii) maximize return of fracturing fluid to the surface. This decrease is achieved using chemicals referred to as *gel breakers* (*gelling agent breakers*). Thus, gel breakers are used to degrade the fracturing fluid viscosity, which helps to enhance postfracturing fluid recovery or flowback. The gel breakers can be mixed with the fracturing fluid during pumping, or they can be introduced later as an independent fluid. There are a variety of breaker types including time-release and temperature-dependent types. Most breakers are typically acids, oxidizers, or enzymes. However, gel breakers may contain hazardous constituents, including ammonium persulfate, ammonium sulfate, copper compounds, ethylene glycol, and glycol ethers.

Breakers are added to the fracturing fluid to reduce the molecular weight of the various polymers used. This reduces the viscosity and facilitates the blowback of residual polymer, which allows for cleanup of the proppant pack. The inappropriate use or ineffective breakers can cause significant damage in the proppant pack and a reduced PI. Ideally these materials would be totally inactive during the treatment and then instantly act when pumping stops, rapidly breaking the fluid back to a low viscosity preparing the fracture and formation for flow. This is very difficult to achieve as the breaker activity is very dependent on fluid temperature, which varies with time.

These additives are useful for flowback and cleanup after the fracturing operation. It is important to ensure good fracture conductivity. Gel breakers oxidize the backbone of the polymer molecules, allowing the polymer to be produced out of the fracture. Enzyme breakers such as hemicellulase are used at temperatures below 50 °C (122 °F) with a pH less than 8.5. Other oxidizing breakers such as ammonium persulfate and sodium persulfate are used at higher temperatures, 66 °C (150 °F), or at lower temperatures with an activator (Jones and Britt, 2009).

The three general types of breakers are (i) oxidizers, (ii) acids, and (iii) enzymes.

6.4.3.1 Oxidizers Oxidizer breakers include ammonium persulfate, sodium persulfate, calcium peroxide, and magnesium peroxides, which work by cleaving the acetyl linkages in the polymer backbone. Ammonium persulfate [$(NH_4)_2S_2O_8$] and sodium persulfate ($Na_2S_2O_8$) are very strong oxidizing agents and form a free oxygen radicals at temperatures in excess of 52 °C (125 °F). These free radicals attach the backbone of the polymer strand and break it down into its constitutive sugars. If left in the fracture these residual sugars will form insoluble precipitates resulting in conductivity damage, and reason flowback of the fractured well is suggested as soon as the fracture is known to be closed. The main disadvantage of oxidizing breakers is both how well they work and how fast they work, which is a function of the amount of chemical added capsule coating as the fracture closes.

6.4.3.2 Acids Acids such as hydrochloric acid (HCl) or acetic acid (CH_3COOH) will attach the polymer backbone and break the gel similar to oxidizing breakers, but they are much less selective and can cause considerable amount of insoluble material to be formed. They are generally used to try and clean fractures that are believed to be damaged by a job where sufficient breaker was not used or the gel is believed to not be broken. Acidic gel breakers also work by reversing the cross-link in borate cross-linked systems (Brannon and Pulsinelli, 1990; Harris, 1993). They are typically used after a project has been completed and placement becomes the dominating issue.

6.4.3.3 Enzymes Enzymes are protein molecules that act as organic catalysts that attach and digest polymers at specific sites along the polymer backbone. Because they are catalysts they are not consumed during the breaking process and persist until there is no polymer present to digest. Typical enzymes that are used include hemicellulase, cellulose, amylase, and pectinase. These enzymes are susceptible to thermal degradation and denaturing when exposed to very high or very low pH so are limited to mild temperatures below 66 °C (150 °F) and fluid pH between 4 and 9. Guar linkage-specific enzymes are reported to work at temperatures more than 150 °C (300 °F) (Brannon et al., 2003).

6.4.4 Bactericides/Biocides

One hydraulic fracturing design problem that arises when using organic polymers in fracturing fluids is the incidence of bacterial growth within the fluids. Biocides are additives for controlling bacterial growth and are often a necessity for water-based fluids. Due to the presence of organic constituents, the fracturing fluids provide a medium for bacterial growth. As the bacteria grow, they secrete enzymes that break down the gelling agent, which reduces the viscosity of the fracturing fluid. Reduced viscosity translates into poor proppant placement and poor fracturing performance. To alleviate this degradation in performance, biocides, bactericides, or microbicides are added to the mixing tanks with the polymeric gelling agents to kill any existing microorganisms (e.g., sulfate-reducing bacteria, slime-forming bacteria, algae) and to inhibit bacterial growth and deleterious enzyme production.

Pumping untreated water into a reservoir can trigger bacterial growth (Howard and Fast, 1970). Aerobic bacteria can destroy the viscosity of a fracturing fluid within a few hours. If anaerobic bacteria are introduced by a fracturing fluid, it can produce hydrogen sulfide (H_2S) within the reservoir. Biocides used to control both types of bacteria include quaternary amines, amide-type chemicals, and chlorinated phenols (Howard and Fast, 1970).

6.4.5 pH Control

Fluid pH affects various properties of the fracturing fluid. These include initial polymer gelation rate, cross-linking characteristics, gel break properties, bacteria control, viscosity stability, and other properties. The typical pH range for fracturing fluid is from 3 to 10 (virtually the entire pH range). Buffers made from mixing weak acids with weak bases are used to maintain the desired pH (Harris, 1988). The selection criteria for fracturing fluid are the following: (i) safety and environmental compatibility, (ii) compatibility with formation and additives, (iii) simple preparation and quality control, (iv) low pumping pressure, (v) appropriate viscosity, (vi) low fluid loss, (vii) flowback and cleanup (for high conductivity), and (viii) economics.

6.4.6 Friction Reducers

To optimize the fracturing process, water-based fluids must be pumped at maximum rates, and fluids must be injected at maximum pressures. Increasing flow velocities and pressures in this manner can lead to undesirable levels of friction within the injection well and the fracture itself. In order to minimize friction, friction reducers are added to water-based fracturing fluids. The friction reducers are typically latex polymers or copolymers of acrylamides. They are added to slickwater treatments (water with solvent) at concentrations of 0.25–2.0 pounds per 1000 gallons. Some examples of friction reducers are oil-soluble anionic liquid, cationic polyacrylate liquid, and cationic friction reducer.

6.4.7 Acid Corrosion Inhibitors

Corrosion inhibitors are required in acid fluid mixtures because acids will corrode steel tubing, well casings, tools, and tanks. The solvent acetone is a common additive in corrosion inhibitors.

These products can affect the liver, kidney, heart, central nervous system, and lungs. They are quite hazardous in their undiluted form. These products are diluted to a concentration of 1 gallon per 1000 gallons of makeup water and acid mixture. Acids and acid corrosion inhibitors are used in very small quantities in coalbed methane fracturing operations (500–2000 gallons per treatment).

6.4.8 Viscosity Stabilizers

Viscosity stabilizers are added to the fracturing fluids to reduce the loss of viscosity at high reservoir temperatures (Thomas and Elbel, 1979). The two most common stabilizers are methanol (used at 5–10% v/v) and sodium thiosulfate. These materials will extend the temperature range of guar-based fluids to over 180 °C (350 °F). Thiosulfate is the more effective of the two and is less hazardous to handle. These materials act as free radical scavengers that are present in the base water. Without the stabilizers these free radicals can naturally oxidize the polymer as described in the breakers section. However, since viscosity breakers are free radical generators and these materials are free radical scavengers, they should not be run at the same time.

6.5 ACIDIZING

The acidizing technique involves pumping acid (typically hydrochloric acid) into a wellbore and thence into the geologic formation that is capable of producing oil and/or gas. The purpose of any acidizing is to improve the productivity or injectivity of a well and the formation.

Acidizing predates all other well stimulation techniques, including hydraulic fracturing, which was not developed until the late 1940s (Chapter 5). However, until the early 1930s, the use of the acidizing technique was limited by the lack of effective corrosion inhibitors to protect the steel tubular segments in the wells from the acid. With the development of effective corrosion inhibitors (Speight, 2014), the use and further development of acid treatment (acidizing) of oil and gas wells proliferated, leading to the establishment of the well stimulation services industry. Currently, acidizing is one of the most widely used and effective means available for crude oil and natural gas production that would improve the productivity (stimulation) of well and reservoirs. Acidizing is commonly performed on new wells to maximize their initial productivity and is also applied to aging wells and partially depleted reservoirs to restore productivity and maximize the recovery of the energy resources. Generally, there are three general categories of acid treatments: (i) acid washing, (ii) matrix acidizing, and (iii) fracture acidizing. Matrix acidizing and fracture acidizing are both formation treatments.

In *acid washing*, the objective is simply tubular and wellbore cleaning. Treatment of the formation is not intended. Acid washing is most commonly performed with hydrochloric acid (HCl) mixtures to clean out scale (such as calcium carbonate ($CaCO_3$)), rust (iron oxide), and other debris that restricts fluid flow from the reservoir and fluid flow in the well. In *matrix acidizing*, the acid treatment is injected below the fracturing pressure of the formation, whereas in *fracture acidizing*, acid is pumped into the system above the fracturing pressure of the formation. “The purpose of matrix or fracture acidizing is to restore or improve an oil or gas well’s productivity by dissolving material in the productive formation that is restricting flow or to dissolve formation rock itself to enhance existing or to create new flow paths to the wellbore.”

Two key factors dominate the treatment selection and design process when planning an acid treatment operation: (i) formation type, which can be composed of carbonate minerals, sandstone deposits, or shale deposits, and (ii) formation permeability, which is the ability of fluid to flow through the formation in its natural state.

6.5.1 Formation Type

Formation type determines the type(s) of acid necessary for the procedure, and formation permeability determines the pressure required for pumping the acid into the formation.

Knowing the type of formation being acidized and details of its composition (mineralogy) is critical to achieving positive results. In carbonate formations, the acid project design is typically based on the use of hydrochloric acid (HCl). The objective when acidizing carbonate formations is to dissolve carbonate-based materials to create new or clean existing pathways or channels that allow the formation fluid (oil, gas, and water) to flow more freely into the well. In sandstone formations, the acid project design is typically based on the use of hydrofluoric acid (HF), also known as mud acid, in combination with hydrochloric acid. Sandstone minerals are not appreciably soluble in hydrochloric acid alone but are much more so in hydrochloric acid mixtures containing hydrofluoric acid.

Geologic formations are rarely completely homogeneous. They contain impurities and can be highly variable in their composition. As a result, designing an effective acid project can be complex. For example, when acidizing sandstone formations, the objective is to dissolve fine sand (quartz), feldspar, and clay particles that are blocking or restricting flow through pore spaces thereby allowing the formation fluids to move more freely into the well. If a sandstone formation contains appreciable carbonate minerals, hydrochloric acid may be added to the treatment. However, most simple acidizing project designs use blends of hydrochloric acid and hydrofluoric acid to respond to the heterogeneous nature of geologic formations. The strengths of the acid mixtures and their volumetric ratios (HCl/HF v/v) are based on the detailed mineralogy of the formation being treated.

Other additives that are commonly used in an acid project include a corrosion inhibitor to protect the well tubulars and related equipment that is exposed to the acid, an emulsion blocker (surfactant) to prevent formation of oil–water emulsions, and an *iron control agent* to retain any dissolved iron (e.g., rust) in solution. Other more specialized additives and different types of acids may also be used based on the case-specific conditions or needs—the choice of the acids or the acid mixture is undoubtedly site specific.

6.5.2 Formation Permeability

The permeability of the formation is the principal determinant of the pumping pressure that is required to place the acid into the formation. In general, the lower the permeability, the higher the pumping pressure—in formations with high permeability, the acid can be pumped into the matrix of the formation at a relatively low pumping pressure. By definition, if the pumping pressure is below the formation fracture pressure, the treatment is known as *matrix acidizing*. In low-permeability formations the acid cannot be pumped into the formation matrix as readily as in high-permeability formations but is pumped through existing or induced fractures at higher pumping pressures. If the pumping pressure is above that which will part or fracture the formation, the treatment is *acid fracturing* (*fracture acidizing*).

There are two subsets of fracture acidizing. The first type is performed as a preliminary step in a hydraulic fracturing operation, such as in shale formations or extremely low-permeability sandstone formations or carbonate formations. In this case, acid (hydrochloric acid or a hydrochloric acid/hydrofluoric acid blend) is pumped ahead of the fluid carrying the proppant that will hold the fractures open once the pump pressure is released. The purpose of the acid is to provide the cleanest possible formation face to enable easier fracture creation and maximize the performance of the proppant once it is placed. The second type is an acid fracturing technique, which is primarily applicable in carbonate formations. In such formations, the acid is pumped in alone, or following a fracturing stage, with the intent of creating new fractures or opening existing fractures. In the process, formation material is dissolved to create irregular fracture surfaces that either accommodate new fluid paths or enhance existing fluid paths into the wellbore when the fractures close.

Finally, because of the heterogeneity of reservoir formations, there is no absolute value of formation permeability that separates matrix and fracture acidizing, but in a very general sense, the range of values where this may occur lie typically between 0.1 and 10 millidarcies (mD), which depends on the specific properties of the formation situation (site specificity).

6.5.3 Operational Considerations

As mentioned previously, acidizing crude oil and natural gas wells is a routine practice that has been used for several decades. As a result, crude oil and natural gas operations have resulted in the development of a regulatory framework to manage the work, protect the environment, and protect public health and safety.

The volume of acid used in an acidizing project is generally determined by the length of the formation (footage) being treated. The volume of acid used per foot of formation can vary depending on the design objectives and the characteristics (including the thickness) of the specific formation. Typical acid volume ranges are between 10 and 500 gallons/ft and is limited by the fracture length, which is often several hundred feet.

During an acidizing project, the acid is chemically consumed and neutralized as the target material is dissolved. In carbonate formations the chemical reaction is relatively simple and occurs in a single step—the hydrochloric acid (HCl) reacts with the carbonate to form calcium salt (calcium chloride), carbon dioxide, and water:

$$CaCO_3 + 2HCl \rightarrow CaCl_2 + CO_2 + H_2O$$

However, when acidizing sandstone formations with hydrofluoric acid, the reactions are more complex, occurring in three stages. In the primary stage, the acid reacts with the sand, feldspar, and clays to form silicon fluorides and aluminum fluorides, simply,

$$\left[SiO_2 \cdot Al_2O_3\right] + 10HF \rightarrow SiF_4 + 2AlF_3 + 5H_2O$$

In the secondary stage the silicon fluorides can react with clay and feldspar to release complex silicon-containing aluminum-containing precipitates, which can restrict flow of oil or gas through the formation, but however with proper design, the production of these damaging precipitates can be avoided. In the final stage the remaining aluminum fluorides react until all the remaining acid is consumed.

Geologic formations are rarely homogeneous (pure carbonate, sandstone, or shale) but will more than likely be a blend of carbonate minerals, sandstone minerals, and clay minerals. As a result, most acid projects are composed of mixtures of hydrochloric acid and hydrofluoric acid, with the ratio of the acids and strengths of the acids depending on the mineralogy and temperature of the formation being treated. Other types of acids can be used in more specialized situations—organic acids such as acetic acid (CH_3COOH) and formic acid (HCOOH) are alternatives to hydrochloric acid.

In addition, specialized additives can be included in cases where specific chemical reactions are anticipated to be particularly severe and require control or mitigation. Thus, a challenge in performing acidizing projects is ensuring the acid is transported to the site within the reservoir where it acts most effectively and efficiently. For example, to facilitate placement of the acid across the entire target interval in the well, coiled tubing units can be employed. The coiled tubing unit is a specialized piece of equipment that utilizes a reel mounted tubing string that can be run concentrically inside the production tubing of the well to the point directly across the interval that is targeted for treatment. This equipment allows precise placement and pumping of the acid, and when the placement of the coiled tubing is accomplished, the acid is pumped through the coiled tubing and into the productive formation.

When pumping any fluid into a well, it will have a natural tendency to follow the path of least resistance and flow into those parts of the formation with the highest permeability. This is not the most desired result since the objective of an acidizing project is to improve the permeability of a well by dissolving material from lower-permeability areas or from plugged areas. To direct acid to the low-permeability section of a formation, either chemical diverters or physical flow diverters can be used, which force the acid into the lower-permeability sections and thereby provide the potential for maximizing recovery of crude oil or natural gas. In all cases, once the acid project has been pumped, the well is brought on to production. When this is done, the spent acid is produced along with the crude oil, natural gas, and water from the formation. In most cases, without being too excessive in terms of acid use and since the acid is chemically consumed when it contacts the formation, the recovered fluid should be relatively benign. This does not take into account the production of toxic trace metals and any other hazardous material from the reservoir.

6.5.4 Environmental Management

Hydraulic fracturing is a very complex operation and involves the use of fracture mechanics, which is also itself a complex field and requires much attention to prevent environmental issues from occurring (Chapter 8).

Acids must be transported and used with proper precautions, safety procedures, and equipment. Transportation of the acid and related materials must be done in approved (US DOT or equivalent) equipment and containers that is properly labeled and follow approved routes to the work site. Personnel working directly with the acids must utilize the personal protective equipment (PPE) specified in the material safety data sheet (MSDS or equivalent), and the personnel should be properly trained and experienced in the use of these materials. Furthermore, all equipment used in pumping the acid should be well maintained, and all equipment components that will be exposed to pressure during the acid project should be tested to pressures equal to the maximum anticipated pumping pressure plus an adequate safety margin prior to the start of pumping operations, in accordance with industry standards and guidelines for pressure pumping guidelines. In addition, barricades should be used to limit access to areas near acid and additive containers, mixing and pumping equipment, and pressure piping.

After the acid project is successfully pumped and the well is brought to production, the operator should consider using separate tanks or containers to isolate the initial produced fluid (spent acid and produced water). The fluids that are initially recovered will contain the spent acid (acid that is largely chemically reacted, neutralized, and converted to inert materials), and it will typically have a pH on the order of 2–3 or greater, approaching neutral pH (=7). These fluids can be further neutralized to a pH greater than 4.5 prior to introduction into the produced water treatment equipment, if necessary. Once neutralized, the spent acid and produced water can be handled with other produced water at the production site. Most produced water, including spent acid, is treated as needed and then injected via deep injection wells that are permitted by the jurisdictional regulatory authority.

REFERENCES

Al-Adwani, F.A., and Langlinais, J. 2008. Modeling of an Underbalanced Drilling Operation Utilizing Supercritical Carbon Dioxide. Proceedings. SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition, Abu Dhabi, UAE, SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition. Society of Petroleum Engineers, Richardson, TX.

Anderson, R.L., Ratcliffe, I., Greenwell, H.C., Williams, P.A., Cliffe, S., and Coveney, P.V. 2010. Clay Swelling: A Challenge in the Oilfield. *Earth Science Reviews*, 98: 201–216.

Arthur, J.D., Bohm, B., Coughlin, B.J., and Layne, M. 2008. Evaluating Implications of Hydraulic Fracturing in Shale Gas Reservoirs. Paper No. SPE 121038. Proceedings. 2009 SPE Americas E&P Environmental & Safety Conference, San Antonio, TX, March 23–25. Society of Petroleum Engineers, Richardson, TX.

Beckwith, R. 2012. Depending on Guar for Shale Oil and Gas Development. *Journal of Petroleum Technology*, 64(12): 44–55.

Bennion, D.B., and Thomas, F.B. 1996. Low Permeability Gas Reservoirs: Problems, Opportunities and Solutions for Drilling, Completion, Stimulation and Production. Proceedings. SPE Gas Technology Symposium, Calgary, Alberta, Canada. Society of Petroleum Engineers, Richardson, TX.

Bennion, D.B., and Thomas, F.B. 2000. Low Permeability Gas Reservoirs and Formation Damage—Tricks and Traps. Proceedings. SPE/CERI Gas Technology Symposium, Calgary, Alberta, Canada. Society of Petroleum Engineers, Richardson, TX.

Brannon, H.D., and Pulsinelli, R.J. 1990. Breaker Concentrations Required to Improve the Permeability of Proppant-Packs Damaged by Concentrated Linear and Borate Cross-Linked Fracturing Fluids. Proceedings. Annual Technical Meetings, Petroleum Society of Canada, Calgary, Alberta, Canada, June 10–13.

Brannon, H.D., Tjon-Joe-Oun, T.J., Carman, P.S., and Wood, W.D. 2003. Enzyme Breaker Technologies: A Decade of Improved Well Stimulation. Paper No. SPE 84213. Proceedings. SPE Annual Technical Conference, Denver, CO, October 5–8. Society of Petroleum Engineers, Richardson, TX.

Edrisi, A.R., and Kam, S.I. 2012. A New Foam Rheology Model for Shale-Gas Foam Fracturing Applications. SPE Canadian Unconventional Resources Conference, Calgary, Alberta, Canada. Society of Petroleum Engineers, Richardson, TX.

Gandossi, L. 2013. An Overview of Hydraulic Fracturing and Other Formation Stimulation Technologies for Shale Gas Production. Report No. EUR 26347 EN. Institute for Energy and Transport, Joint Research Centre, European Commission, Petten, The Netherlands.

Gupta, S. 2003. Field Application of Unconventional Foam Technology: Extension of Liquid CO_2 Technology. Proceedings. SPE Annual Technical Conference and Exhibition. Denver, Colorado. Society of Petroleum Engineers, Richardson, TX.

Gupta, S. 2009. Unconventional Fracturing Fluids for Tight Gas Reservoirs. Proceedings. SPE Hydraulic Fracturing Technology Conference, The Woodlands, TX. Society of Petroleum Engineers, Richardson, TX.

Gupta, A.P., and Gupta, A. 2005. Feasibility of Supercritical Carbon Dioxide as a Drilling Fluid for Deep Underbalanced Drilling Operation. Proceedings. SPE Annual Technical Conference and Exhibition, Dallas, TX. Society of Petroleum Engineers, Richardson, TX.

Gupta, S., and Hlidek, B.T. 2007. Fracturing Fluid for Low-Permeability Gas Reservoirs: Emulsion of Carbon Dioxide With Aqueous Methanol Base Fluid: Chemistry and Applications. Proceedings. SPE Hydraulic Fracturing Technology Conference, College Station, TX. Society of Petroleum Engineers, Richardson, TX.

Harris, P.C. 1988. *Fracturing-Fluid Additives*. SPE Distinguished Author Series. Society of Petroleum Engineers, Richardson, TX.

Harris, P.C. 1993. Chemistry and Rheology of Borate Cross-Linked Fluids at Temperatures to 300 °F. Paper No. SPE 24339. Society of Petroleum Engineers, Richardson, TX.

Hawsey, J.D., and Jacocks, C.L. 1961. The Use of Fluid-Loss Additives in Hydraulic Fracturing of Oil and Gas Wells. Paper No. SPE 244. Proceedings. 32nd Annual California Regional

Meeting of the Society of Petroleum Engineers (SPE) of AIME in Bakersfield, California, November 2–3. Society of Petroleum Engineers, Richardson, TX.

Holloway, M.D., and Rudd, O. 2013. *Fracking: The Operations and Environmental Consequences of Hydraulic Fracturing*. John Wiley & Sons, Inc., Hoboken, NJ.

Howard, G.C., and Fast, C.R. 1970. *Hydraulic Fracturing*. American Institute of Mining, Metallurgical and Petroleum Engineers, Inc. and Society of Petroleum Engineers, Richardson, TX.

Jones, J.R., and Britt, L.K. 2009. *Design and Appraisal of Hydraulic Fractures*. Society of Petroleum Engineers, Richardson, TX.

Kennedy, R.L., Gupta, R., Kotov, S.V., Burton, W.A., Knecht, W.N., and Ahmed, U. 2012. Optimized Shale Resource Development: Proper Placement of Wells and Hydraulic Fracture Stages. Paper No. 162534. Proceedings. Abu Dhabi International Petroleum Conference and Exhibition, Abu Dhabi, United Arab Emirates, November 11–14. Society of Petroleum Engineers, Richardson, TX.

King, G.E. 2012. What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells. Paper No. SPE 152596. Proceedings. SPE Hydraulic Fracturing Technology Conference, Woodlands, TX, February 6–8. Society of Petroleum Engineers, Richardson, TX.

Mueller, M., and Amro, M. 2012. Stimulation of Tight Gas Reservoir Using Coupled Hydraulic and CO_2 Cold-Frac Technology. Proceedings. SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia. Society of Petroleum Engineers, Richardson, TX.

Parekh, B., and Sharma, M.M. 2004. Cleanup of Water Blocks in Depleted Low-Permeability Reservoirs. Proceedings. SPE Annual Technical Conference and Exhibition, Houston, TX. Society of Petroleum Engineers, Richardson, TX.

Pye, D.S., and Smith, W.A. 1973. Fluid Loss Additive Seriously Reduces Fracture Proppant Conductivity and Formation Permeability. Paper No. SPE 4680. Proceedings. 48th Annual Meeting, Society of Petroleum Engineers of AIME, Las Vegas, Nevada, September 30–October 3. Society of Petroleum Engineers, Richardson, TX.

Ribeiro, L., and Sharma, M.M. 2013. Fluid Selection for Energized Fracture Treatments. Proceedings. 2013 SPE Hydraulic Fracturing Technology Conference, The Woodlands, TX. Society of Petroleum Engineers, Richardson, TX.

Rowan, T. 2009. Spurring the Devonian: Methods of Fracturing the Lower Huron in Southern West Virginia and Eastern Kentucky. Proceedings. SPE Eastern Regional Meeting, Charleston, WV. Society of Petroleum Engineers, Richardson, TX.

Speight, J.G. 2014. *Oil and Gas Corrosion Prevention*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Spellman, F.R. 2013. *Environmental Impacts of Hydraulic Fracturing*. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Thomas, T.L., and Elbel, J.L. 1979. The Use of Viscosity Stabilizers in High-Temperature Fracturing. Paper No. SPE 8344. Proceedings. SPE Annual Technical Conference and Exhibition, Las Vegas, NV, September 23–26. Society of Petroleum Engineers, Richardson, TX.

Uddameri, V., Morse, A., and Tindle, K.J. 2016. *Hydraulic Fracturing—Impacts and Technologies*. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Veil, J.A. 2010. *Water Management Technologies Used by Marcellus Shale Gas Producers*. Argonne National Laboratory, Argonne, IL. United States Department of Energy, Washington, DC. July.

Waxman, H.A., Markey, E.J., and Degette, D. 2011. *Chemicals Used in Hydraulic Fracturing*. Committee on Energy and Commerce, United States House of Representatives, Washington, DC.

Xiong, H., Davidson, B., Saunders, B., and Holditch, S.A. 1996. A Comprehensive Approach to Select Fracturing Fluids and Additives for Fracture Treatments. Paper No. SPE 36603. Proceedings. 1996 SPE Annual Technical Conference and Exhibition, Denver, CO, October 6–9. Society of Petroleum Engineers, Richardson, TX.

7

PROPPANTS

7.1 INTRODUCTION

A proppant is a solid material, typically sand, treated sand, or a manufactured ceramic material that is designed to prevent and keep an induced hydraulic fracture open during and after a fracturing treatment so that the fracture does not collapse and close (Veatch and Moschovidis, 1986; Mader, 1989). Proppants typically comprise sand or manufactured ceramics such as bauxite. Proppants can be resin coated to improve packing, which helps the proppant stay in place and not flow back to the wellbore. Resin coatings also help provide better distribution of stress over the proppant pack.

Proppants are specified in grain diameter sizes of less than 1/16 of an inch. Some common mesh sizes are 16/20, 20/40, 30/50, 40/70, and 100. Treatments may use one size or a multitude of sizes during pumping. The smaller sizes are intended to reach closer to the fracture tip. A propped hydraulic fracture has a significantly greater fluid (hydraulic) conductivity than the surrounding lower permeability rock matrix. Challenges to stimulation treatments involve proper placement of proppant, prevention of crushing or embedment, plugging at restrictions, and potential flowback of proppant to the wellbore. On the process, the proppant is added to a fracturing fluid, which may vary in composition depending on the type of fracturing used, and can be water based, foam based, gel based, slickwater based, or any of a number of alternate fluids (Chapter 6).

Fracturing fluids have varying physical properties of which viscosity is an important property because of the need for more viscous fluids, which can carry more concentrated proppant (Chapter 6). In addition, the fracturing fluid must be able to tolerate process effects such as the energy or pressure demands of the fracturing process in order to maintain a desired flux pump rate (flow velocity) that will conduct the proppant appropriately to the target site in the reservoir. In addition, fracturing fluids may be used in low-volume well stimulation of high-permeability sandstone

---

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

formations to the high-volume operations such as the recovery of crude oil and natural gas from shale formations, from tight sandstone formations, and from coal seams during the production of coalbed methane. An ideal proppant should produce maximum permeability in a fracture—fracture permeability is a function of proppant grain roundness, proppant purity, and crush strength of the proppant. Thus, the goal of proppants is to maximize fracture conductivity (i.e., flow path for hydrocarbons), thus the magnitude of fracture conductivity is a measure of proppant performance.

The fracture conductivity is the product of propped fracture width and the permeability of the propping agent. The permeability of all the commonly used propping agents (sand, resin-coated sand (RCS), and the ceramic proppants) will be 100 to 200+ darcies when no stress has been applied to the propping agent. However, the conductivity of the fracture will be reduced during the life of the well because of (i) increasing stress on the propping agents, (ii) stress corrosion affecting the proppant strength, (iii) proppant crushing, (iv) proppant embedment into the formation, and (v) damage resulting from gel residue or fluid-loss additives. Thus, proppants are necessary because of the tendency of fractures to heal (close) naturally after fracture creation. There are several types of proppants available commercially, including sand, ceramic (glass beads), resin-coated ceramic, aluminum alloys, nutshells, and plastics. These proppants are differentiated mainly by their specific gravity and strength (Jones and Britt, 2009).

The proppant is added to the fracturing fluid (which may vary in composition depending on the type of fracturing process) and can be gel, foam, or slickwater based. In addition, there may be unconventional fracturing fluids. Other than proppant, slickwater fracturing fluids are predominantly water (typically 99% v/v) but gel-based fluids may use polymers and surfactants comprising as much as 7% v/v of the fracturing fluid. Other common additives include hydrochloric acid, friction reducers, biocides, emulsifiers, and emulsion breakers (Chapter 6).

Proppants used should be permeable to gas under high pressure, and the interstitial space between the proppant particles should be sufficiently large and have the mechanical strength to withstand closure stresses to hold fractures open after the fracturing pressure is withdrawn. Large-mesh proppants have greater permeability than small-mesh proppants at low closure stresses but will mechanically fail and be crushed to fine particulate matter (*fines*) at high closure stresses such that smaller-mesh proppants overtake large-mesh proppants in permeability after a certain threshold stress.

The first fracturing treatment used screened river sand as a proppant, while other treatments used construction sand sieved through a window screen. There have been a number of trends in sand size, from very large to small, but, from the beginning, a −20 to +40 US-standard mesh sand has been the most popular sand size. However, untreated sand is prone to significant fines generation, which is often measured percent by weight (% w/w) of the initial feed. One way to maintain an ideal mesh size (i.e., permeability) while having sufficient strength is to choose proppants of sufficient strength; sand might be coated with resin to form *curable resin-coated sand* (CRCS) or *precured resin-coated sands* (PRCSs). In certain situations a different proppant material might be chosen altogether and popular alternatives include ceramic materials and sintered bauxite, which is a mix of gibbsite, $Al(OH)_3$; boehmite, γ-AlO(OH); and diaspore, α-AlO(OH). In fact, numerous propping agents have been evaluated throughout the years, including plastic pellets, steel shot, Indian glass beads, aluminum pellets, high-strength glass beads, rounded nut shells, RCSs, sintered bauxite, and fused zirconium.

The concentration of sand (pound per fluid gallon, lb/gal) remained low until the mid-1960s, when viscous fluids such as cross-linked water-based gel and viscous refined oil were introduced. With the preference for large-size propping agents, the trend then changed from the monolayer or partial monolayer concept to pumping higher sand concentrations and, since that time, the concentration has increased almost continuously. The use of high concentrations of sand is due largely to advances in pumping equipment and improved fracturing fluids. In fact, it is not becoming common to use proppant concentrations averaging 5–8 lb/gal throughout the treatment, with a low concentration at the start of the job and increased to 20 lb/gal toward the end of the job.

7.2 TYPES

Fracture conductivity in many hydraulic fracturing treatments can be inadequate and is subject to the concentration of the packed proppant in the fracture. Higher concentrations yield higher conductivity by virtue of a wider fracture. However, there are practical limitations to the amount of proppant that can be placed into any particular reservoir, and therefore production is often conductivity limited.

Since propping agents are required to maintain the fracture in the open configuration once the pumps are shut down and the fracture begins to close, the ideal propping agent must be strong, resistant to crushing, resistant to corrosion, has a low density, and is readily available at low cost. The products that best meet these desired traits are silica sand, RCS, and ceramic proppants.

7.2.1 Silica Sand

The term *sand* when applied to proppants has been used for many types of crushed minerals and may not be the true silica sand but may be composed of silica and other minerals and may not refer to a nonspecific grain size. In fact, there are many varieties of sand in the world, each with their own unique composition and properties. For example, there are the white sands of many beaches that may consist primarily of limestone ($CaCO_3$), and there are also black sands that may consist of magnetite (Fe_3O_4 or $FeO.Fe_2O_3$) or be volcanic in origin while yellow sands may have high levels of iron.

The type of sand used as a proppant is silica sand, which is the most commonly used type of proppant and is a natural resource than a manufactured product. Silica sand (industrial sand) is high-purity quartz (SiO_2) sand deposited by natural processes. In the petroleum industry, silica sand is used as hydraulic fracturing sand (also termed *frac sand*). In the process, the sand is pumped into the well during the fracturing operation. Since the sand is carried along with the fluid into the fracture, it will remain in the fracture when the pressure is removed, keeping the fracture propped open and allowing a good means by which the hydrocarbons can flow to the wellbore.

However, even though silica sand is a relatively common material, the silica sand used for proppant is a specifically selected for the project, and the quality of the sand is a function of both the original depositional environment with the requisite amount of project-related mechanical processing such as selection based on the round spherical shape and graded particle distribution.

Ottawa white sand (which originates from Ottawa, Illinois, near the center of St. Peters sandstone formation) is the one of the desired of sands due to the superior properties when used in hydraulic fracturing as a proppant. It is in highly demand for hydraulic fracturing because of the excellent properties of (i) roundness, (ii) sphericity, and (iii) high crush strength, which allow the sand to withstand the high pressures involved in the hydraulic fracturing process. The chemical purity of the sand makes it unreactive with the fluids used to transport it into the well, resulting in delivery of unchanged sand to the fracture points.

Brown sand is the second most sought after proppant—it is a cost-effective solution for the hydraulic fracturing of low-depth wells. Brown sand is less desirable than Ottawa white sand in high-stress applications but is considered high-quality sand. Due to its limitations involving high-pressure environments, brown sand has a lower cost, but its properties allow it to be an effective proppant in the hydraulic fracturing of shallow wells.

7.2.2 Resin-Coated Proppant

Resin-coated proppant is typically silica sand coated with resin, which is utilized for two main functions: (i) to spread the pressure load more uniformly that improves the resistance to crushing of the silica sand particles and (ii) to keep pieces together that were broken from high closure stress from downhole pressure and temperature that not only prevents broken pieces from flowing into the borehole but also prevents the broken pieces from returning to the surface during flowback production operation.

RCS is dry silica sand that has been coated with liquid resin in a batch mixing system in the presence of a catalyst after which the coated sand is passed through a heating chamber for complete curing. The use of liquid resin gives a uniform coating on the sand grains and this.

There are two major types of resin-coated proppants (i) *precured* resin-coated proppants and (ii) *curable* resin-coated proppants. The precured resin-coated proppant technology involves coating the resin on to the silica sand grains after which the resin is fully cured prior to injection into the fractures. The more recent *curable* resin-coated proppant technology involves incomplete curing of the resin prior to use, and when the proppant is pumped downhole, curing is completed in the fractures as a result of the downhole pressure and temperature. The advantage to the use of curable resin-coated proppant technology is that the individual proppant grains are allowed to bond together in the fracture, which results in the coated silica grains bonding together uniformly when temperature and pressure reach appropriate levels.

7.2.3 Manufactured Ceramic Materials

A third commonly used type of proppant involves the use of manufactured ceramic materials—typically nonmetallurgic bauxite or kaolin clay. In the manufacturing process, the ceramic proppant is prepared by sintering bauxite mixed with other additives, and the mineral composition of ceramic proppant is aluminum oxide, silicate, and iron, with some titanium oxide. The proppant is generally uniform in round shape and character, which makes it owns much higher strength than quartz sand and RCS so that it is suitable for the fracturing of deep oil and gas stratum with high closure pressure. For middle and deep-well operations, ceramic proppants can be used to enhance the conductivity as the trailing proppant. Compared to other proppant materials, ceramic proppants have superiority of smoother surface, higher fracturing strength, acid resistant, alkali resistant, and higher conductivity. Ceramic proppants are widely used to replace other proppant materials such as natural quartz sand, glass balls, and metal balls.

Thus, the ceramic proppants exhibit high fracture strength, are mainly used for oil field downhole support to increase oil and gas production, and are environmentally friendly products. This product uses high-quality bauxite and other raw materials; ceramic sintering is an alternative product of natural quartz sand, glass balls, metal balls, and other low-strength proppants and has a positive effect to the oil and gas production. Ceramic proppants typically have (i) high crush resistance, (ii) lower acid solubility, and (iii) high roundness and sphericity. Ceramic proppants tend to provide higher performance than other proppant type (Vincent, 2002). Wells that have been fractured with ceramic proppant consistently exhibit improved production of oil and gas in a variety of reservoir condition.

Ceramic proppants are generally uniform in round shape and character, which gives the proppant much higher strength than quartz sand and RCS so that it is suitable for the fracturing of deep oil and gas stratum with high closure pressure. For the middle and deep well, ceramic proppants can be used to enhance the conductivity as the trailing proppant. Compared to other proppant materials, ceramic proppant has superiority of smoother surface, higher fracturing strength, acid proof and alkali proof, and higher conductivity.

Bauxite, an aluminum ore from which most aluminum is extracted, consists mostly of gibbsite [$Al(OH)_3$], boehmite [γ-AlO(OH)], and diaspore [α-AlO(OH)] mixed with the two iron oxides goethite (FeO(OH)) and hematite (Fe_2O_3), the clay mineral kaolinite [$Al_2Si_2O_5(OH)_4$], and small amounts of anatase (titanium dioxide, TiO_2). Kaolin clay is a name commonly applied to the clay mineral kaolinite [$Al_2Si_2O_5(OH)_4$]. Kaolin is one of the most common minerals, occurring in abundance from chemical weathering of rocks in hot, moist climatic soils like tropical rainforest areas.

Both bauxite and kaolin are utilized as proppants because of their superior strength characteristics, which are further enhanced by sintering. The sintering process is conducted in high-temperature kilns that are used to bake the bauxite or kaolin powder after it has been made into specifically sized particles. The process decreases the water content in the bauxite and kaolin to make them more uniformly shaped for size roundness and spherical shape. The desired result of the sintering process is that the manufactured ceramic proppants can be engineered to withstand high levels of downhole pressure (closure stress).

7.2.4 Other Types

Over the past decade, a trend toward the usage of waste material—such as glass, metallurgical slag, and even rock cuttings produced to the surface during oil and gas drilling—has developed. The reuse of rock cuttings from gas drilling operations is especially attractive since not only does it reuse a common waste product in industry but it is also utilizing sources indigenous to the locality—which will cut down the amount of waste material as well as reducing any associated or ancillary costs.

The interest in *low-density proppants* is high because of the potential advantage for improving proppant transport and distribution in the fracture (Parker and Sanchez, 2012). These proppants require less viscosity for suspension, and the density of the base fluid can also be used to improve suspension. Various low-density materials have been investigated, such as walnut shells, hollow glass spheres, porous ceramics, and low-density plastics. Walnut shells and low-density plastics tend to continue to deform and lose width over time at stress. Glass spheres and porous ceramics are brittle materials, and they tend to fail catastrophically at a particular stress. Conventional proppants, such as natural sand and man-made proppants, are brittle and can also fail catastrophically. The nature of a packed bed with multiple contact points for each proppant grain tends to lower the chance of catastrophic failure, but broken grains, reduced width, and low conductivity still result. A new type of thermoplastic alloy (TPA) has been developed that is composed of a crystalline phase for excellent chemical stability and an amorphous phase for excellent dimensional strength and heat resistance.

7.3 PROPERTIES

Proppants are typically made up of sand or a manufactured facsimile of sand and are materials (typically silica sand, resin-coated silica sand, or manufactured ceramics) used to prop open the open fractures to promote flow and eventual extraction of crude oil and natural gas. Thus, proppant properties and selection is crucial to optimizing well productivity. In spite of assiduous laboratory testing protocols, many proppants often do not perform as expected when subjected to real-world downhole conditions of pressure, temperature, and fluid (API RP 19C, 2015; API RP 19D, 2015). In addition to the traditional proppant selection factors of size, strength, and density, there are many other important factors to consider.

In terms of proppant hardness, if the proppant is unable to embed in the formation something referred to as point load occurs—which leads to higher flow capacity but the proppant will break easier. However, if the proppant is able to embed in the formation (which is also a function of particle size), it will result to the load pressure spreading out over the proppant area, increasing the breaking point but also lowering flow capacity.

The relevant properties that are of importance when considering the suitability of proppants for a project are presented in the following—alphabetically rather than by preference since preference can change with the project and is site specific.

7.3.1 Downhole Scaling

Briefly, scale is a deposit or coating formed on the surface of metal, rock, or other material and is caused by a precipitation due to a chemical reaction with the surface, precipitation caused by chemical reactions, a change in pressure or temperature, or a change in the composition of a solution. Typical scales are calcium carbonate ($CaCO_3$), calcium sulfate ($CaSO_4$), barium sulfate ($BaSO_4$), strontium sulfate ($SrSO_4$), iron sulfide (FeS), iron oxides (FeO and Fe_2O_3), iron carbonate ($FeCO_3$), various silicates and phosphates, or any of a number of compounds insoluble or slightly soluble in water.

Scale is also a mineral salt deposit that may occur on wellbore tubulars and components as the saturation of produced water is affected by changing temperature and pressure conditions in the production conduit. In severe conditions, scale creates a significant restriction, or even a plug, in the production tubing. Scale removal is a common well-intervention operation, with a wide range of mechanical, chemical, and scale inhibitor treatment options available (Sorbie and Laing, 2004).

Scale is formed by the increasing concentration of scaling cations, such as calcium and barium, as well as scaling anions, such as carbonate and sulfate. Once the concentration of ions exceeds supersaturation levels, nucleation will occur. Over time, nucleation leads to precipitation and the development of scale at the macroscopic level. Thus, the chemistry of scale formation can be described simply, but in reality it is a series of three complex stages each of which is subject to inhibitor action that can prevent the catastrophic buildup of scale at each of the separate stages: (i) the nucleation stage, (ii) the growth stage, and (iii) the deposition stage.

At the *nucleation stage*, threshold inhibitors bind with scale-forming ions, but unlike chelants, the bound ions must be available to interact with their counterions. This disrupts the ion cluster at the early equilibrium stages of crystal formation, disrupting them before they reach the critical size for nucleation. As a result, the ions dissociate, releasing the inhibitor to repeat the process. At the *growth stage*, growth inhibitors slow the growth of the scale by blocking the active edges of the crystal. Once the inhibitor has bound to the lattice, the crystal will form much more slowly and be distorted. Often they are more rounded in shape, which makes them less likely to adhere to surfaces and more easily be dispersed throughout the system. At the *deposition stage*, dispersants prevent new crystals from coming together to form a large body of scale material. Dispersant-type inhibitors interact with the surface and repulse other charged particles to prevent binding.

Downhole proppant scaling is the result of a geochemical reaction (commonly known as proppant scaling or proppant diagenesis), which can occur downhole in the fracture in high-pressure/high-temperature wells, especially in a wet, hot downhole fracture environment. A crystalline material can form on uncoated ceramics and, acting like formation fines, plug the porosity and permeability of the proppant pack, thus reducing conductivity. The effects of scaling can occur slowly, but as long-term exposure increases, production decreases more rapidly because of the detrimental effects. A resin coating greatly reduces proppant scaling by providing a hydrophobic layer that prevents water from dissolving the proppant surface and forming scale.

While this reaction normally happens slowly in shallower formations, it accelerates under the higher pressures and temperatures of shale formations and tight formations. The result of proppant scaling is a severe loss of proppant pack porosity and permeability with the creation of fines and debris in the proppant pack. Uncoated lightweight ceramics can lose up to 90% of the permeability of the proppant pack, often in a matter of days. However, resin-coated proppants can drastically reduce the impact of downhole proppant scaling, which results in improved fracture flow capacity and significantly higher long-term productivity.

A wide variety of scale inhibitors is available, including phosphate esters and phosphonates, such as phosphonobutane-1,2,4-tricarboxylic acid (PBTC), amino-trimethylene phosphonic acid (ATMP) and 1-hydroxyethylidene-1,1-diphosphonic acid (HEDP), polyacrylic acid (PAA), phosphinopolyacrylates (such as PPCA), polymaleic acids (PMA), maleic acid terpolymers (MAT), and sulfonic acid copolymers, such as sulfonated phosphonocarboxylic acid (SPOCA) and polyvinyl sulfonates. More recently, the so-called green inhibitors—polyaspartic acid (PASP), carboxymethyl inulins (CMI), polycarboxylic acids (PCA), and maleic acid polymers (MAP)—have seen more popular use.

7.3.2 Embedment

Proppant embedment occurs as a result of the proppant embedding into the fracture face, especially in soft shale formations, leading to reduced fracture width and lower fracture flow capacity (Wen et al., 2007; Akrad et al., 2011; Zhang et al., 2015). In the embedment process, the proppant partially or completely sinks into a formation through displacement of the formation around the grain.

Compared with uncoated proppant, resin-coated proppants have less embedment into the formation because the grains of the coated proppant bond together forming a consolidated proppant pack that redistributes closure stress. Another concern with proppant embedment is the creation of formation fines (spalling—a physical process of the breakdown of surface layers of material that crumble into small pebble-like pieces in response to high temperatures and/or mechanical pressure), which can migrate and cause additional loss of fracture conductivity. Without adequate fracture conductivity, production from the hydraulic fracture will be minimal or nonexistent.

Embedment of the proppant is caused by an interaction between the formation and the proppant at the face of the fracture, which causes a loss in conductivity. Embedment is usually considered to be a problem in partially consolidated to unconsolidated formations but it also can occur in hard rock formations (Jones and Britt, 2009). Another result of embedment is the creation of formation fines through spalling, which can then migrate and further reduce conductivity (Terracina et al., 2010). Although often considered to be a disadvantage, an advantage of embedment is that it can mitigate the potential for flowback.

Uncoated proppants and PRCS often deeply embed into softer formations due to the increased single point loading between the proppant grain and the soft fracture face. This leads to reduced fracture width and lower fracture flow capacity. Lightweight ceramic proppants, in particular, embed deeply into soft shale formations, and an additional issue with proppant embedment is the spalling of formation fines, which can migrate and cause additional loss of fracture conductivity. When curable resin-coated proppants are used, there are multiple grains bonded together instead of just single-grain point loading. This lattice network of deformable surfaces provided by the curable resin coating can reduce embedment by redistributing stresses on the proppant pack within the fracture.

Embedment pressure is a measure of the maximum pressure required to embed a steel ball to a given depth in rock (Rixe et al., 1963). This gives a direct indication of the resistance of the formation to embedment by a propping material and the effect of the rock on proppant deformation. It is a kind of indentation test and is a measure of the rock strength. A test procedure for determining the embedment pressure (Howard and Fast, 1970) uses a steel ballpoint 0.05 inches in diameter (which simulates the proppant), which is attached to the upper platen of a hydraulic testing machine that moves and loads the rock specimen (3.5 inches diameter) hydraulically. Where possible, the rock core should be obtained from the well to be hydraulically fractured. The steel ballpoint is embedded to a depth of 0.0125 inch, and a strain recorder is used to observe the results. The load at the target embedment Wp is recorded and at least two more indentations are made on the test specimen, about 0.5 inches apart.

7.3.3 Flowback

Flowback is a water-based solution that flows back to the surface during and after the completion of hydraulic fracturing and consists of the fracturing fluid, which contains clay minerals, chemical additives, dissolved metal ions, and total dissolved solids (TDS). The water has a murky appearance from high levels of suspended particles. Most of the flowback occurs in the first 7–10 days, while the rest can occur over a 3–4 week time period. The volume of recovery is anywhere between 20 and 40% of the volume that was initially injected into the well. The rest of the fluid remains absorbed in the formation. In contrast, produced water (which is not the same as flowback water) is naturally occurring water found in shale formations that flows to the surface throughout the entire life span of the well. This water has high levels of TDS and leaches out minerals from the shale including barium, calcium, iron, and magnesium. It also contains dissolved hydrocarbons such as methane, ethane, and propane along with naturally occurring radioactive materials (NORM) such as radium isotopes.

On the other hand, proppant flowback is the movement (flow) of proppants back to the wellbore and the higher the pump velocity, the more the chance of flowback occurring. Furthermore, proppant flowback and pack rearrangement is the main cause of well production decline, equipment damage, as well as lockdown of the well for repairs. Thus, flowback reduces conductivity at the wellbore and decreases connectivity to the reservoir (Terracina et al., 2010).

Proppant flowback from fractured wells leads to high operational costs and can compromise safety. However, it can be prevented by the use of resin-coated proppants. Proppant flowback is a leading cause of well production decline, equipment damage, and wells shut in for repairs. Uncoated or precured resin-coated proppants can flow back out of the fracture and into the wellbore as the well is produced. Proppant flowback can cause damage to downhole tools as well as surface equipment. In horizontal wells, flowback of uncoated proppant can deposit along the lateral fractures. All of these issues lead to expensive repairs and cleanouts. Proppant flowback can also cause loss of near-wellbore conductivity and reduced connectivity to the reservoir. Resin-coated proppants that have grain-to-grain bonding can eliminate proppant flowback, if applied properly, by forming a consolidated proppant pack in the fracture.

Posttreatment proppant flowback is a leading cause of well production decline, equipment damage, and well shut-ins for repairs. Proppant flowback can also cause loss of near-wellbore conductivity and reduced connectivity to the reservoir. Curable resin-coated proppants eliminate proppant flowback by forming a consolidated proppant pack in the fracture. This grain-to-grain bonding occurs under a combination of reservoir temperature and closure stress.

7.3.4 Fracture Conductivity

The fracture conductivity (also referred to as *fracture capacity*) is a measure of proppant performance, and proppant selection is deemed successful only when it can achieve substantial fracture conductivity. The fracture flow capacity (conductivity) depends on the fracture width, proppant distribution, and proppant concentration. The postfracture width is controlled by proppant size used for stimulation, while proppant concentration is controlled by spacers. Proppant distribution is not an easily controlled parameter (Howard and Fast, 1970).

In unconventional reservoirs, the goal of the fracturing process is to contact as much rock as possible with a fracture or a fracture network of appropriate conductivity, that is, a fracture pattern that will allow appropriate flow of reservoir fluids. This objective is typically accomplished by drilling horizontal wells and placing multiple transverse fractures along the lateral (Chapter 5). Reservoir contact is optimized by (i) the lateral length, (ii) the number of stages in the lateral, and (iii) the fracture isolation technique. Fracture conductivity is determined by the proppant type and size, fracturing fluid system, and placement technique.

Traditionally, proppant performance has been measured using baseline or reference conductivity testing. *Effective conductivity* is a much more accurate measurement of downhole proppant performance, but, unfortunately, low flow rates during the baseline conductivity test do not simulate downhole flow rates. High flow rates downhole can cause proppant fines to migrate and severely decrease fracture conductivity.

In a test procedure for determining fracture conductivity of a given proppant (Rixe et al., 1963), the proppant is placed between two rock cores and subjected to similar overburden pressure and temperature. The rock cores (3.5 inches diameter and 2 inches long) are mounted in steel cups with a low temperature melting point alloy in such a way that 0.25 inches of the smooth core face extends above the top edge of the cup. A hole is drilled axially in the upper half of the core to intersect a shallow hole in the center of the lower half, as shown in the aforementioned figures. The overburden stress is simulated using a hydraulic ram. The temperature is controlled by placing the rock cores in a heated box. Fracture capacity is determined by allowing nitrogen gas to flow from the hole in the upper half of the core through the simulated propped fracture (Howard and Fast, 1970). The flow capacity is calculated based on Darcy's law and considering radial gas flow. To take into account the time effect, the test is carried out for a 30-day period with flow rates recorded at 7-day intervals. Furthermore, it is recommended that 30 days is the time required for the fracture to stabilize and for long-term fracture capacity to be stimulated.

Although the test described previously has been used over the years for successful fracturing treatments, it has certain drawbacks. First, the field conditions of proppants are not as dry as assumed by the test. The drawbacks of the test are made more evident by considering several other factors that affect the effectiveness of fracture conductivity: (i) production and migration of proppant fines, (ii) proppant flowback, (iii) proppant embedment, (iv) multiphase flow, and (v) non-Darcy flow considerations.

7.3.5 Pack Rearrangement

Proppant pack rearrangement in the fracture can cause a significant reduction in propped width, which can also lead to reduced fracture flow capacity and connectivity to the wellbore. As a well is produced, high flow velocities in propped microfractures may cause uncoated or precured proppant packs to shift or rearrange, causing the microfractures to narrow or possibly close completely. Curable resin-coated proppants will prevent the proppant grains from shifting, keeping the microfractures propped open. This unique bonding technology provides additional proppant pack integrity, enhanced fracture flow capacity, and increased production during the life of the well (Terracina et al., 2010).

7.3.6 Permeability

The proppants employed for the fracturing process used should be permeable to gas under high pressures and the interstitial space between particles should be sufficiently large, yet have the mechanical strength to withstand closure stresses to hold fractures open after the fracturing pressure is withdrawn. However, increased strength often comes at a cost of increased density, which in turn demands higher flow rates, viscosity, or pressures during fracturing. Lightweight proppants conversely are designed to be lighter than sand (~2.5 g/cm^3) and thus allow pumping to be conducted at lower pressure or lower fluid velocity.

Light proppants are less likely to settle, but porous materials can break the strength–density trend or even afford greater gas permeability. Proppant geometry is also important; certain shapes or forms amplify stress on proppant particles making them especially vulnerable to crushing (a sharp discontinuity can classically allow infinite stresses in linear elastic materials) (ASTM WK44896). This test method identifies the equipment and defines the procedures used to determine the crush resistance of materials used as proppants in hydraulic fracture stimulation of subsurface geological formations. The method uses a sample preparation protocol that reduces the level of noise inherent in these measurements. The method appears to offer both improved precision and reproducibility from laboratory to laboratory.

Though sand is a common proppant, untreated sand is prone to significant fines generation; fines generation is often measured in wt% of initial feed. One way to maintain an ideal mesh size (i.e., permeability) while having sufficient strength is to choose proppants of sufficient strength; sand might be coated with resin to form CRCS or PRCS. In certain situations a different proppant material might be chosen altogether—popular alternatives include ceramic materials and sintered bauxite [predominantly gibbsite, $Al(OH)_3$; boehmite, γ-AlO(OH); and diaspore, α-AlO(OH).

7.3.7 Production and Migration of Fines

The word *fines* refers to the small particles that break off the surface of proppants as they are subjected to closure stress. The small broken pieces reduce pack porosity and permeability and cause major degradation in the conductivity of proppant packs. When proppant fines migrate down the proppant pack toward the well bore, they accumulate and reduce flow capacity. However, the proppant may be fully to blame for the presence of fines.

Fine-grained minerals are present in most sandstone formations and in some carbonate formations. They are not held in place by the confining pressure and are free to move with the fluid phase that wets them (usually water) but can remain attached to pore surfaces by electrostatic and van der Waals forces. At high (>2% w/w) salt concentrations, the van der Waals forces are sufficiently large to keep the fines attached to the pore surfaces. As the salinity is decreased, as might occur during the injection of a water-based fracturing fluid, the repulsive electrostatic forces increase because the negative charge on the surfaces of the pores and fines is no longer shielded by the ions. When the repulsive electrostatic forces exceed the attractive van der Waals forces, the fines are released from pore surfaces (Sharma et al., 1985). Furthermore, there is a critical salt concentration below which fines are released (Khilar and Fogler, 1983; Sharma et al., 1985). The typical magnitude of the critical salt concentration is in the range of 5000–15,000 ppm (1.5%) sodium chloride—for divalent ions, this concentration is significantly lower. If a water-sensitive sandstone is exposed to brine with a salinity below the critical salt concentration, fines are released, and significant reductions in permeability must be anticipated.

Proppant fines generation and the resulting migration in the fracture are considered to be one of the major contributors to poor treatment results and well performance. For example, the presence of just 5% fines can reduce conductivity by as much as 60%. The decrease in conductivity is made worse when the fines migrate to the wellbore.

Advanced grain-to-grain bonding technology (as is available in resin-coated proppants) reduces proppant fines generation and migration through the proppant pack. The curable resin coating provides additional strength to individual grains, generates uniform stress distribution throughout the pack, and encapsulates any loose fines that may occur.

Standard crushing tests tend to use dry proppants that are subjected to the closure stress for only 2 min but which does not simulate the field in wet or hot condition. Modified crush test procedures have been proposed to better simulate field conditions in which a resin coating prevents the migration of fines in the CRCS proppant (Terracina et al., 2010; API RP 56/58/60, 2015).

7.3.8 Shape, Size, and Concentration

The definition of proppant shape consists of two main descriptions: (i) roundness and (ii) sphericity. The roundness is a measure of the smoothness of the proppant, while the sphericity is how well it resembles a sphere (Jones and Britt, 2009). At high stresses, the more spherical the proppant is, the more the permeability, but at lower stresses, the more angular the proppant is, the higher the permeability. Angular proppants tend to crush under conditions of high stress thus generating fines, which lead to a reduction in conductivity.

In addition to shape, proppant size is an important consideration for design and depends on the degree of stress, target conductivity, and achievable fracture width. The testing of proppant size distribution is a quality control procedure done through sieve analysis. Generally, fines are unacceptable as they reduce fracture conductivity; the maximum tolerable fines for proppants is 1% (i.e., percentage that passes the no. 200 sieve) (Jones and Britt, 2009). It is recommended that classification of proppants can be done simply when 90% of the tested sample falls between the designated sieve sizes, and fines tolerance limit should be observed.

Before use, proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore. Grain size is critical because a proppant must reliably fall within certain size ranges to coordinate with downhole conditions (such as fracture size and patterns) and completion design. Proppant shape and hardness qualities are also very important to the efficiency and effectiveness of a fracturing operation. A coarser proppant allows for higher flow capacity due to the larger pore spaces between grains, but it may break down or crush more readily under high closure stress, and rounder, smoother proppant shapes allow for better permeability.

Large-mesh proppants have greater permeability than small-mesh proppants at low closure stresses but will mechanically fail (i.e., get crushed) and produce very fine particulates (*fines*) at high closure stresses such that smaller-mesh proppants overtake large-mesh proppants in permeability after a certain threshold stress. Proppant mesh size also affects fracture length: proppants can be *bridged out* if the fracture width decreases to less than twice the size of the diameter of the proppant. As proppants are deposited in a fracture, proppants can resist further fluid flow or the flow of other proppants, inhibiting further growth of the fracture. In addition, closure stresses (once external fluid pressure is released) may cause proppants to reorganize or *squeeze out* proppants, even if no fines are generated, resulting in smaller effective width of the fracture and decreased permeability. Some companies try to cause weak bonding at rest between proppant particles in order to prevent such reorganization. The modeling of fluid dynamics and rheology of fracturing fluid and its carried proppants are a subject of active research by the industry.

The size and concentration of the proppants influence the placement of the proppant in several ways (Phatak et al., 2013). For example, larger proppants settle closer to the wellbore, due to their higher settling velocity, and proppant bridging occurs more easily in large proppants. In addition, smaller proppants are transported a further distance and increase the chance of tip screen-out. However, for the smaller proppant size, the initial production is low but production decline is slower. The initial production is dependent on the pressure differential around the borehole caused by the conductivity (Phatak et al., 2013). In terms of production duration, the production rate of the larger proppant size depends only on the formation matrix permeability thus it declines faster. While that of the smaller proppant depends on both the formation matrix permeability and the conductivity of the fracture network, hence the longer it takes to decline. Proppant size can be gradually increased size during injection for a single treatment (Phatak et al., 2013).

Proppant concentration is achieved by using pelletized spacer materials. The spacers should have the following qualities: (i) similar specific gravity as the proppant, (ii) easily transportable, (iii) essentially insoluble in fracturing fluid but soluble to postfracturing injected solvents for easy removal, and (iv) resistant to breakage during pumping and ease of storage and handling in the field (Howard and Fast, 1970).

7.3.9 Stress

The stress to which a proppant is subjected is a critical factor to consider when selecting propping agents, and proppants must be chosen so that they do not crush under field closure stress. When comparing proppants, one factor that must be considered is the performance of the proppant under closure stress changes. The forces of cyclic stress exerted on proppants downhole can cause them to fail. Events often occur multiple times throughout the life of a well, such as shut-ins, because of workovers or connections made to a pipeline; in some cases, a well could be shut in because of pipeline capacity. These events lead to cyclic changes in fracture closure stress. This varying amount of pressure and stress can cause the proppants to shift or rearrange, resulting in a decrease in fracture width as well as additional proppant fines and proppant flowback.

The effective stress on the propping agent is the difference between the *in situ* stress and the flowing pressure in the fracture. As the well is produced, the effective stress on the propping agent will normally increase because the value of the flowing bottom-hole pressure will be decreasing. However, the *in situ* stress tends to decrease with time as the reservoir pressure declines. As the effective stress increases to larger and larger values, then the higher-strength, more expensive propping agents must be used to create a high-conductivity fracture.

The traditional method of calculating closure stress has been the minimum horizontal stress minus the bottom-hole flowing pressure (measured at the start of production). The pressure in the fracture is higher with increasing distance from the wellbore. The maximum stress a proppant would be subjected to would normally take place at the initial stages of production, during or immediately after fracturing fluid cleanup when hydrocarbon starts to flow, especially in gas wells. Furthermore, most fracture capacity tests make use of nitrogen gas whereas natural gas is made up mainly of methane, hydrogen, carbon dioxide, nitrogen, hydrogen sulfide, and other impurities, which should add additional criteria to the test parameters.

Further investigation into the use of an adequate mixture of carbon dioxide and nitrogen for the embedment pressure test is recommended (eliminating methane and other inflammable components). The aim would be to better simulate the fluid flow of natural gas. This hybrid mixture would improve assessment of fracture conductivity and make for better proppant selection. Similar criteria might be considered for crude oil reservoirs where the gas mix can vary.

Related to stress is the strength of the proppant. Silica sand must be tested to be sure it has the necessary compressive strength to be used in any specific situation. Generally, sand is used to prop open fractures in shallow formations. Sand is much less expensive per pound than resin-coated silica or ceramic proppants. Resin-coated silica is stronger than sand and is used where more compressive strength is required to minimize proppant crushing. Some resins can be used to form a consolidated pack in the fracture, which will help to eliminate proppant flow back into the wellbore. As expected, resin-coated silica is more expensive than sand but has an effective density that is less than sand. The strength of a ceramic proppant is proportional to its density and, furthermore, the higher-strength proppants, such as sintered bauxite, can be used to stimulate deep (>8000 ft) wells where high *in situ* stresses will be responsible of large forces on the propping agent.

7.4 PROPPANT SELECTION AND TRANSPORT

The most common completion in unconventional plays consists of a horizontal wellbore with multiple proppant fractures placed along it. In addition to considerations of fracture conductivity, there are several other issues that must be addressed when selecting the appropriate proppant for use in multistage fractures, including flow convergence in transverse fractures, proppant transport when low-viscosity fluids are employed, and proppant crush at typically low concentrations.

Production into a horizontal wellbore from an orthogonal fracture will exhibit linear flow in the far field as it travels down the fracture. However, as the fluids converge on the relatively small diameter of the wellbore, the fluid velocities in that region increase dramatically. Furthermore, the pressure drop in the transverse fracture could be significant compared to a fully connected vertical well. This leads to the conclusion that it is practically impossible to place enough conductivity near the wellbore in a transverse, horizontal well to be fully optimized.

Generally, to fulfill such requirements, ceramic proppants are preferred because of the high conductivity as well as uniform size and shape. RCS has medium strength but the shape and size can be irregular. Finally, sand has the lowest conductivity and as well as irregular size and shape. This will influence proppant choice along with the on-site needs of the project.

7.4.1 Selection

When choosing a propping agent, a proppant that will maintain enough conductivity after all crushing and embedment occur must be chosen (Terracina et al., 2010). The effects of non-Darcy flow, multiphase flow, and gel residue damage should also be considered. Thus, the selection of the propping agent is based on the maximum effective stress that is applied to the propping agent during the life of the well. The maximum effective stress depends on the minimum value of flowing bottom-hole pressure that one expects during the life of the well. If the maximum effective stress is less than 6000 psi, sand is usually recommended as the propping agent. If the maximum effective stress is between 6000 and 12,000 psi, one should use either RCS or intermediate strength proppant, depending on the temperature. For cases in which the maximum effective stress is greater than 12,000 psi, high-strength bauxite should be used as the propping agent.

Of course, any rule of thumb should only be used as a guide, as there will be exceptions. For example, even if the maximum effective stress is less than 6000 psi, the design engineer may choose to use RCS or other additives to "lock" the proppant in place when proppant flowback becomes an issue. Also, in high flow rate gas wells, intermediate strength proppants may be needed because of inertial flow. For fracture treatments in countries that do not mine sand for fracturing, the largest cost for the proppant is often the shipping charges. Thus, if one has to import the propping agent, one may choose to use intermediate strength proppants, even for relatively shallow wells, because the cost differential between the intermediate strength proppants and sand is not a significant factor.

Once the optimum fracture half-length has been determined and the fracture fluid and fracture propping agent have been selected, the design engineer needs to use a model to determine the details of the design, such as the optimum injection rate, the optimum pad volume, the need for fluid-loss additives, the proper location for the perforations, and other details. After designing the optimum treatment, the design engineer must compute the costs of the proposed treatment to be certain that the costs are not too different from the costs assumed during the treatment optimization process. If the treatment costs are substantially different, the entire optimization loop should be retraced using the correct cost data.

Increased proppant strength often comes at a cost of increased density, which in turn demands higher flow rates, viscosities, or pressures during fracturing, which translates to increased fracturing costs, both environmentally and economically. Lightweight proppants conversely are designed to be lighter than sand (~2.5 g/cm^3) and thus allowing pumping at lower pressures or fluid velocities. Light proppants are less likely to settle. Porous materials can break the strength–density trend or even afford greater gas permeability. Proppant geometry is also important; certain shapes or forms amplify stress on proppant particles making them especially vulnerable to crushing (a sharp discontinuity can classically allow infinite stresses in linear elastic materials).

Proppant mesh size also affects fracture length: proppants can be "bridged out" if the fracture width decreases to less than twice the size of the diameter of the proppant. As proppants are deposited in a fracture, proppants can resist further fluid flow or the flow of other proppants, inhibiting further growth of the fracture. In addition, closure stresses (once external fluid pressure is released) may cause proppants to reorganize or "squeeze out" proppants, even if no fines are generated, resulting in smaller effective width of the fracture and decreased permeability. Some companies try to cause weak bonding at rest between proppant particles in order to prevent such reorganization. The modeling of fluid dynamics and rheology of fracturing fluid and its carried proppants are a subject of active research by the industry.

Proppant crushing can occur at several sites during fracturing operation. Cracking and chipping of proppants can occur during the transportation of proppants pack from the manufacturing site to the place of final use, which is the fracturing site. Efforts should be taken to minimize the exposure of proppant to chipping and cracking during the transportation process. The major source of proppant crushing is formation closure, particularly where the proppant is not well distributed. Conductivity examinations conducted on proppant pack indicates that crushing is most prevalent at the interface and less significant toward the center of the pack.

There are two primary sources of fines within a hydraulic fracture. Fines are generated either from the proppant pack or the reservoir itself. Reservoir fines can be generated due to spalling as proppant embeds into the fracture surface, while proppant fines are generated due to proppant crushing. While all proppants experience crushing, the way they crush is dependent on their substrate. When sand-based proppant crushes, it shatters similar to a drinking glass and it breaks into so many small fragments (Palisch et al., 2007; Weaver et al., 2007). On the other hand, most ceramic-based proppant cleave like a brick.

Fines generated falls into three size categories that includes particles too large to penetrate the proppant pack, particles small enough to enter the proppant pack but large enough to subsequently plug the pore throat of the proppant pack, and lastly, particles small enough to flow through the proppant pack all the way to the wellbore.

The fines that are too large as well as those that are small enough to flow through the proppant pack are not damaging to the pack. However, particles small enough to enter the proppant pack but large enough to subsequently plug the pore throat of the proppant pack are detrimental to the proppant pack conductivity. When proppants are crushed and they produce fines that can plug the proppant pack, the porosity of the proppant pack is reduced, which subsequently reduces the permeability of the proppant pack. Permeability reduction in the proppant pack will therefore reduce the fracture conductivity.

Finally, the typical low proppant concentrations pumped in water-based fractures often designed for unconventional gas reservoirs can result in a low areal concentration of proppant in the fracture. These narrower fractures can have an impact on proppant crush. Inside a crush cell, interior grains are protected due to their contact with 6–12 neighboring grains. However, exterior grains have fewer contact points, leading to greater stress at the points of contact, ultimately fracturing. Therefore, as proppant pack width and areal concentration decrease, the exterior grains comprise a larger percentage of the total grains in the pack, leading to higher proppant crush.

Various specialty proppants have been introduced to exploit the advantages of partial monolayers, as well as purportedly to promote their placement. Most of these new proppants are of much lighter density, and, in many cases, they do not crush as conventional rigid particles do, but instead deform, which is one reason why they are typically only considered useful at low stress. It is likely that independent testing has shown that if these deformable proppant grains are actually placed in a traditional pack, whereby they come in contact with each other, the grains tend to deform and create a relatively impermeable plug.

7.4.2 Transport

To create a hydraulic fracture, fluid is injected at high rate and pressure into a wellbore and into a formation that is open to the wellbore. Viscous fluid flow within the fracture as well as other effects creates the net pressure required to generate the created width profile and the created fracture height. The volume of fluid pumped will affect the created fracture length; however, without pumping a propping agent into the fracture, the created fracture will close once the pumping operation ceases. The flow of crude oil and natural gas from the formation into the fracture is dependent on the propped fracture dimensions. The really important characteristics of a fracture are the propped width, height, and length distributions; therefore, proppant transport considerations are very important in designing a hydraulic fracture treatment.

Proppant placement in the fractures is governed by a series of mechanisms involving the interaction between the fracturing fluid and proppant. For example, proppant density and size have a determining impact on proppant settling, which, in turn, impacts placement of the proppant in the fracture. The settling rate of the proppant is directly proportional to the difference in density between the fracturing fluid and proppant and inversely proportional to the fluid viscosity. This condition makes settling an important consideration when pumping low-viscosity Newtonian fluids, as are typically used in horizontal multifracture treatments conducted in some shale formations. However, while much attention is typically given to density, diameter can actually be of greater importance in a fracturing treatment since settling velocity is proportional to particle diameter squared (Stoke's law, which is an expression for the frictional force—also called drag force—exerted on spherical objects with small Reynolds numbers, i.e., very small particles in a viscous fluid), thus having an exponentially larger effect on settling rate than fluid viscosity. This may not fully describe settling under dynamic conditions in a slurry situation but does illustrate that smaller and lighter proppants are easier to place.

The first fluid pumped into a well during a fracture treatment (the *prepad*) is used (i) to fill the casing and tubing, (ii) test the system for pressure, and (iii) break down the formation after which *the pad fluid* (the viscous fracturing fluid but without the propping agent) used during the treatment is pumped into the well. The purpose of the pad is to create a tall, wide fracture that will accept the propping agent. Following the pad, the fluid containing propping agent (the *slurry*) is pumped and moves into the fracture. The propping agent particles move up, out, and down the fracture with the slurry and may settle in the fracture as a result of gravitational forces. The settling velocity increases as the diameter and density of the propping agent increase and as the density and viscosity of the fracturing fluid decrease. To minimize proppant settling, propping agents that are smaller in diameter and/or less dense, as well as a more viscous fluid, can be used.

There are other factors that must be included when trying to compute the propped fracture dimensions. For example, the type of fracture fluid (Chapter 6) affects transport of the proppant—a linear-structured fracture fluid will not transport proppants as well as fluids with structure, such as a cross-linked fracture fluid or a viscoelastic surfactant fluid. Geologic realities also must be considered; for example, no fracture is exactly vertical, and the walls of a fracture are rarely (if at all) smooth. If there are turns and ledges along the fracture walls, these geologic features tend to reduce proppant settling when compared with the theoretical equations for transport in smooth wall, parallel-plate systems. Other issues such as (i) fracture height growth during and after pumping operations, (ii) fluid loss in layered formations, and (iii) slurry viscosity also affect the propped fracture dimensions (Gidley et al., 1989; Smith et al., 1997).

REFERENCES

Akrad, O., Miskimins, J., and Prasad, M. 2011. The Effects of Fracturing Fluids on Shale Rock-Mechanical Properties and Proppant Embedment. Paper No. SPE 146658. Proceedings. SPE Annual Technical Conference and Exhibition, Denver, CO, October 30–November 2. Society of Petroleum Engineers, Richardson, TX.

API RP 19C. 2015. *Recommended Practice for Measurement of Properties of Proppants Used in Hydraulic Fracturing and Gravel-Packing Operations*. American Petroleum Institute, Washington, DC.

API RP 19D. 2015. *Recommended Practice for Measuring the Long-Term Conductivity of Proppants*. American Petroleum Institute, Washington, DC.

API RP 56/58/60. 2015. *Proppant Crush Test for Frac Sand, Resin Coated Sand, Ceramic Proppant*. American Petroleum Institute, Washington, DC.

ASTM WK44896. 2015. *New Test Method for Determining the Crush Resistance of Materials Used as Proppants in Hydraulic Fracturing of Subsurface Formations*. ASTM International, West Conshohocken, PA.

Gidley, J.L., Holditch, S.A., and Nierode, D.E. 1989. Proppant Transport. In: *Recent Advances in Hydraulic Fracturing*. SPE Monograph No. 12. Monograph Series. Society of Petroleum Engineers, Richardson, TX. Chapter 10, Page 210.

Howard, G.C., and Fast, C.R. 1970. Hydraulic Fracturing. American Institute of Mining, Metallurgical and Petroleum Engineers, Inc. and Society of Petroleum Engineers, Richardson, TX.

Jones, J.R., and Britt, L.K. 2009. *Design and Appraisal of Hydraulic Fractures*. Society of Petroleum Engineers, Richardson, TX.

Khilar, K.C., and Fogler, H.S. 1983. Water Sensitivity of Sandstones. Paper No. SPE-10103-PA. *SPE Journal*, 23(1): 55–64.

Mader, D. 1989. *Hydraulic Proppant Fracturing and Gravel Packing*. Elsevier, Amsterdam, The Netherlands.

Palisch, T., Duenckel, R., Bazan, L., Heidt, H., and Turk, G. 2007. Determining Realistic Fracture Conductivity and Understanding Its Impact on Well Performance—Theory and Field Examples. Paper No. SPE-106301-MS. Proceedings. SPE Hydraulic Fracturing Technology Conference, College Station, TX, January 29–31. Society of Petroleum Engineers, Richardson, TX.

Parker, M.A., and Sanchez, P.W. 2012. New Proppant for Hydraulic Fracturing Improves Well Performance and Decreases Environmental Impact of Hydraulic Fracturing Operations. Paper No. SPE-161344-MS. Proceedings. SPE Eastern Regional Meeting, Lexington, KY, October 3–5. Society of Petroleum Engineers, Richardson, TX.

Phatak, A., Kresse, O., Nevvonen, O.V., Abad, C., Cohen, C.E., Lafitte, V., Abivin, P., Weng, X., and England, K.W. 2013. Optimum Fluid and Proppant Selection for Hydraulic Fracturing in Shale Gas Reservoirs: A Parametric Study Based on Fracturing-to-Production Simulations. Paper No. SPE163876. Proceedings. SPE Hydraulic Fracturing Technology Conference, February 4–6, The Woodlands, TX. Society of Petroleum Engineers, Richardson, TX.

Rixe, F.H., Fast, C.R., and Howard, G.C. 1963. Selection of Propping Agents for Hydraulic Fracturing. Proceedings. Spring Meeting, Rocky Mountain District, API Division of Production, April. American Petroleum Institute, Washington, DC.

Sharma, M.M., Yortsos, Y.C., and Handy, L.L. 1985. Release and Deposition of Clays in Sandstones. Paper No. SPE-13562-MS. Presented at the SPE Oilfield and Geothermal Chemistry Symposium, Phoenix, AZ, March 9–11. Society of Petroleum Engineers, Richardson, TX.

Smith, M.B., Bale, A., and Britt, L.K. 1997. Enhanced 2D Proppant Transport Simulation: The Key to Understanding Proppant Flowback and Post-Frac Productivity. Paper No. SPE-38610-MS. Proceedings. SPE Annual Technical Conference and Exhibition, San Antonio, TX, October 5–8. Society of Petroleum Engineers, Richardson, TX.

Sorbie, K.S., and Laing, N. 2004. How Scale Inhibitors Work: Mechanisms of Selected Barium Sulfate Scale Inhibitors Across a Wide Temperature Range. Paper No. SPE 87470. Proceedings. SPE 6th International Symposium on Oilfield Scale, Aberdeen, Scotland, May 26–27. Society of Petroleum Engineers, Richardson, TX.

Terracina, J.M., Turner, J.M., Collins, D.H., and Spillars, S.E. 2010. Proppant Selection and Its Effects on the Results of Fracturing Treatments Performed in Shale Formations. Paper No. SPE 135502. Proceedings. SPE Annual Technical Conference and Exhibition, Florence, Italy, September 19–22. Society of Petroleum Engineers, Richardson, TX.

Veatch, R.W., Jr., and Moschovidis, Z.A. 1986. An Overview of Recent Advances in Hydraulic Fracturing Technology. Paper No. SPE-14085-MS. Proceedings. International Meeting on Petroleum Engineering, Beijing, China, March 17–20. Society of Petroleum Engineers, Richardson, TX.

Vincent, M.C. 2002. Proving It—A Review of 80 Published Field Studies Demonstrating the Importance of Increased Fracture Conductivity. Paper No. SPE 77675. Proceedings. SPE Annual Technical Conference and Exhibition, San Antonio, TX, September 29–October 2. Society of Petroleum Engineers, Richardson, TX.

Weaver, J., Parker, M., Batenburg, D., and Nguyen, P.D. 2007. Fracture-Related Diagenesis May Impact Conductivity. Paper No. SPE 98236. *SPE Journal*, 12(3): 272–281.

Wen, Q., Zhang, S., Wang, L., Liu, Y., and Li, X. 2007. The Effect of Proppant Embedment upon the Long-Term Conductivity of Fractures. *Journal of Petroleum Science and Engineering*, 55(3–4): 221–227.

Zhang, J., Ouyang, L., Zhu, D., and Hill, A.D. 2015. Experimental and Numerical Studies of Reduced Fracture Conductivity due to Proppant Embedment in the Shale Reservoir. *Journal of Petroleum Science and Engineering*, 130: 37–45.

8

ENVIRONMENTAL IMPACT

8.1 INTRODUCTION

In addition to the environmental issues typically associated with conventional oil and gas exploration and production, the exploitation of tight oil resources may include its own unique set of environmental issues (National Petroleum Council, 2011).

Hydraulic fracturing and other well stimulation methods have led to a rapid expansion of the development of cured oil and natural gas in unconventional reservoirs (tight reservoirs and shale reservoirs on a worldwide basis but especially in the United States). This expansion of efforts has brought crude oil and natural gas development to the point where there is the potential for human exposure to new contaminants and environmental damage with public and scientific emphasis on the effects of hydraulic fracturing in particular. For example, research has linked pollution from hydraulic fracturing to unhealthy levels of smog and of toxic air contaminants. Unfortunately, there has been a lot of emotion expressed and used to criticize hydraulic fracturing, while investigation of many of the issues has been hampered by the lack of meaningful scientific data on the potential cumulative risks posed by the combined emissions from a dense network of wells and associated infrastructure such as pipelines, compressor stations, and roads (Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016). Furthermore, in many cases, state regulations are (in many cases) minimal, and enforcement of any meaningful often cannot keep up with the rapid expansion of the unconventional crude oil and natural gas industry, resulting in insufficient protection from pollutants.

Briefly, hydraulic fracturing involves the pressurized injection of hydraulic fracturing fluids into geologic formations, causing fractures in the formations and enabling the release of crude oil and/or natural gas (Chapter 5) (Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016). This technique has been employed in the United States since 1947, but as new technology for drilling horizontal wells has

---

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

evolved and been deployed over the past two to three decades, the technique has been used to produce large quantities of natural gas from shale formations. It has been suggested that crude oil and natural gas from such sources are moving the United States to becoming a net energy exporter, thereby providing the country with a desirable and measurable degree of self-sufficiency in energy production. As a result, hydraulic fracturing thus will play a central role in the future domestic energy policy of the United States and has removed the country from the immediate threat of petropolitics in which the country is subject to the stability (but, predominantly, the instability) of the governments of many oil-producing nations (Speight, 2011). The threat of the country freezing in the green darkness (albeit, environmentally clean darkness) has been mitigated, to a degree.

Hydraulic fracturing technology is responsible for the current success in the production of crude oil and natural gas from shale plays and from tight formations. The technology concept is to enhance natural fractures or create induced fractures by injecting fluids at pressures greater than the strength of the rock (Chapter 5). Addition of sand or other materials (proppants) to the fluid is needed to keep the induced fractures open once the fluid has been removed and the pressure has subsided. Once the formation is fractured, the pressure exerted by the hydraulic fracturing fluid is reduced, which reverses the direction of the fluid flow in the well back toward the ground surface. Thus, the hydraulic fracturing fluid and any naturally occurring substances released from the formation are allowed to flow to the surface (*flowback*).

In this process, most of the wells are in a horizontal configuration with one or more horizontal fractures extending into the target section of the formation—these fractures may extend more than a mile from the surface location of the well. Horizontal wells are more expensive to drill and develop but have better performance in terms of the production volumes of crude oil and natural gas because more of the reservoir is accessible, thereby leading to increased production of the crude oil and natural gas.

In terms of the fracturing fluid, water has been the fluid of choice, but a primary concern is the large amount of freshwater needed for the drilling—the water is either (i) produced from water sources in the area or (ii) brought to the drilling/production site by truck from local reservoirs. Preferentially, saltwater is not used as the fracturing fluid saltwater significantly increases the potential for corrosion and scale deposition in the formation, tubing, casing, and surface equipment, therefore inhibiting the production of crude oil and natural gas. Saltwater also significantly increases the potential for corrosion on the tubing, casing, and surface equipment, potentially shortening the life of a well (Speight, 2014b). In addition, chemicals needed to perform efficiently and effectively in a hydraulic fracturing project are not as effective or efficient in saltwater as in freshwater.

The hydraulic fracturing fluids also may contain chemicals that have become the subject of some public concern with respect to potential contamination of underground sources of drinking water. While there is a push from some members of the community to make the chemical composition of hydraulic fracturing fluids a matter of public record, many of the mixtures are considered to be proprietary, and current law related to proprietary materials supports the maintenance of confidentiality with respect to the composition of those fluids. It should be noted that regardless of the chemical composition of a particular hydraulic fracturing fluid, the application of proper well design, completion, operations, and monitoring according to rules and regulations that already exist in most states and provinces will ensure that fracturing operations do not negatively impact either the subsurface or surface environment (National Petroleum Council, 2011).

Thus, as part of the hydraulic fracturing process, it is important to ensure that the induced fractures are contained within the target formation, but this must be balanced against the frequent need to fracture as much of the reservoir as possible. Production of crude oil and natural gas is dependent upon the area of the reservoir that is fractured and the length of the fractures that are created. If the fractures penetrate a water-saturated formation, excess water is drawn into the petroleum/gas-containing shale, which can potentially doom a well. The solution to undesirable penetrating fractures is to carefully plan the project using a multidisciplinary team of scientist and engineers—the plan should represent a carefully sized fracture project that is sufficiently focused on the locale and specify the use of horizontal wells and multiple, simultaneous, and in the same wellbore.

However, although hydraulic fracturing has been and may be hailed as a solution to many of the energy problems, there are some environmental disadvantages to the process. Under the current regulatory regime in the United States, states and regional authorities regulate a hydraulic fracturing operation, which also includes safe drilling practices and wastewater disposal. In the addition, the US Environmental Protection Agency (US EPA) retains authority under the Safe Drinking Water Act (SDWA) to issue injection well permits for hydraulic fracturing operations that incorporate diesel fuel as a component of the hydraulic fracturing fluid. The agency may assert authority through other regulatory regimes (including the Clean Water and Clean Air Acts) or through new regulations, particularly if the upcoming study reveals areas of concern. Additionally, the US EPA has the authority to assess existing state regulations for environmental efficiency. In terms of hydraulic fracturing in shale (tight) formations, the US EPA is continually evaluating the potential for hydraulic fracturing to impact both surface water and groundwater and addressing the hydraulic fracturing water life cycle—the use of water from acquisition to wastewater treatment and disposal (US EPA, 2015a).

Thus, the development of more efficient and productive hydraulic fracturing technology allowed access to large reserves of petroleum and natural gas that were previously considered to be inaccessible. But while the increased activity has been a boon to petroleum and natural gas production, disadvantages such as harm to wildlife and ecosystems have also accompanied the increased activity. Another particularly serious issue is that withdrawing water from streams and rivers for hydraulic fracturing projects can threaten fisheries, as can contamination by wastewater (Robbins, 2013).

The increase in exploration and production of shale gas has, in turn, resulted in expanded hydraulic fracturing operations. However, this expansion has also increased concerns from federal, state, and local agencies and the public about related potential environmental impacts on land, water, and air, leading to scientific investigations and regulatory action at both state and federal levels (Jenner and Lamadrid, 2013). In view of the concerns surrounding this process, a significant opportunity exists to improve the sustainability of energy production by reducing the air emissions from hydraulic fracturing operations. This is important for both energy industry officials who seek to lower emissions from energy production as a matter of good stewardship and energy producers and their servicing suppliers who strive for business continuity while minimizing their environmental footprint. Other stakeholders include the general public, who may benefit if those valuable energy resources are accessible and deliverable with lower environmental impacts. However, realizing the needed improvements requires a thorough continuing evaluation of relevant emissions data and workable guidelines for monitoring and emissions reduction.

However, hydraulic fracturing in particular has been the primary focus of controversy because of surface and subsurface spills and releases, gas migration and groundwater contamination due to faulty well construction, blowouts, and leaks and spills of wastewater and chemicals stored on pad sites. However, of all the issues related to hydraulic fracturing, the possible effects on groundwater are without a doubt the most contentious. Numerous allegations have been made related to hydraulic fracturing, with particular emphasis on the impacts on water sources.

Finally, deductions made about the environmental effects of hydraulic fracturing must be made on the basis of scientific facts and not on emotion. In addition, critical evaluations of shale gas hydraulic fracturing and the potential impacts on the environment must be based on peer-reviewed scientific analyses of quantitative data and not on the preferences of the funding organization. Agencies responsible for regulating or monitoring the environmental impacts of shale gas development need to be well informed, and the design of any national regulatory framework to protect the environment from hydraulic fracturing operations should start realistic directives and recommendations from factual data.

In summary, hydraulic fracturing remains a highly contentious public policy issue because of concerns about the environmental and health effects of its use, such as (i) the environmental risk, (ii) health risks from the chemicals injected into the ground, (iii) the occurrence of earthquakes, (iv) whether or not expansion of this technology for fossil fuels mean a decreased commitment to renewable energy technology, and (v) whether or not the environmental and health hazards are well understood and managed (Bamberger and Oswald, 2012; Jackson et al., 2013; Penning et al., 2014; Stern, 2014). In many cases it is unclear whether concerns raised relate specifically to hydraulic fracturing, or more generally to the development of unconventional petroleum resources, or to other aspects related to all oil and gas development.

In summary, the potential for producing unconventional crude oil and natural gas from shale formation and tight sand formations is vast, but the environmental footprint of unconventional supply is larger than most conventional oil sources. To grow production from unconventional resources, techniques to economically produce oil within acceptable environmental constraints are needed. There are often great confusion and debate on the environmental footprint of unconventional supply.

It is not the purpose of this chapter to present concerns that relate to policy, economics, and social areas that are outside the scope of this text but to present information to those persons who are interested in hydraulic fracturing (for whatever reason) in order to consider and answer some of the issues—either contentious issues or noncontentious issues. Neither it is the purpose of this chapter to whether extoll the virtues or condemn the hydraulic fracturing process but to present the potential advantages and disadvantages of the process in order that hydraulic fracturing may become a safe and environmentally benign process as possible. Thus, the issues that may be associated with tight oil exploration and production are described in the following text. Also described in the following text are approaches that are either currently being employed or may be employed to mitigate the environmental issues associated with tight oil production.

8.2 GEOLOGICAL DISTURBANCE

Some of the key geological issues with relevance to the potential environmental impacts of hydraulic fracturing are (i) the potentially lack of understanding of rock fracture patterns and processes that occur in shale formations and in tight formations, (ii) the ability to predict and quantify permeable fracture networks in the subsurface before drilling, and (iii) the accuracy and precision with which the geometry (length, breadth, thickness, and position) of shale formations, tight formations, and aquifers in the subsurface can be determined, especially in areas with complex geological histories; this also include the relative position of aquifers to the aforementioned formations. Furthermore, the pore space in various rock formations is made up of a variety of void spaces in the solid rock matrix, which also includes natural stress cracks/fractures. Thus, the aim of hydraulic fracturing is to improve permeability (fluid flow in the rock) by reopening natural fractures as well as creating new fractures to form a locally dense network of open and connected fractures (Chapter 5) without the potential damage to the environment (Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016).

In the present context, wells typically extend a mile or more below the ground surface, often passing through groundwater aquifers to reach the crude oil (Fig. 8.1) and natural gas formations (Fig. 8.2) after which horizontal wells are then drilled into the formation to access the crude oil and natural gas. The well casings and cemented areas are designed to prevent contamination of any groundwater aquifers through which the well may be drilled. If the well casing remains intact, the potential for the hydraulic fracturing process to pose any risk to underground water aquifers is minimized (even negated). In addition, the US EPA has acknowledged that groundwater aquifers are typically separated from the shale formations by several thousand feet of rock, which limits the potential for any unreturned hydraulic fracturing fluids to impact drinking water supplies.

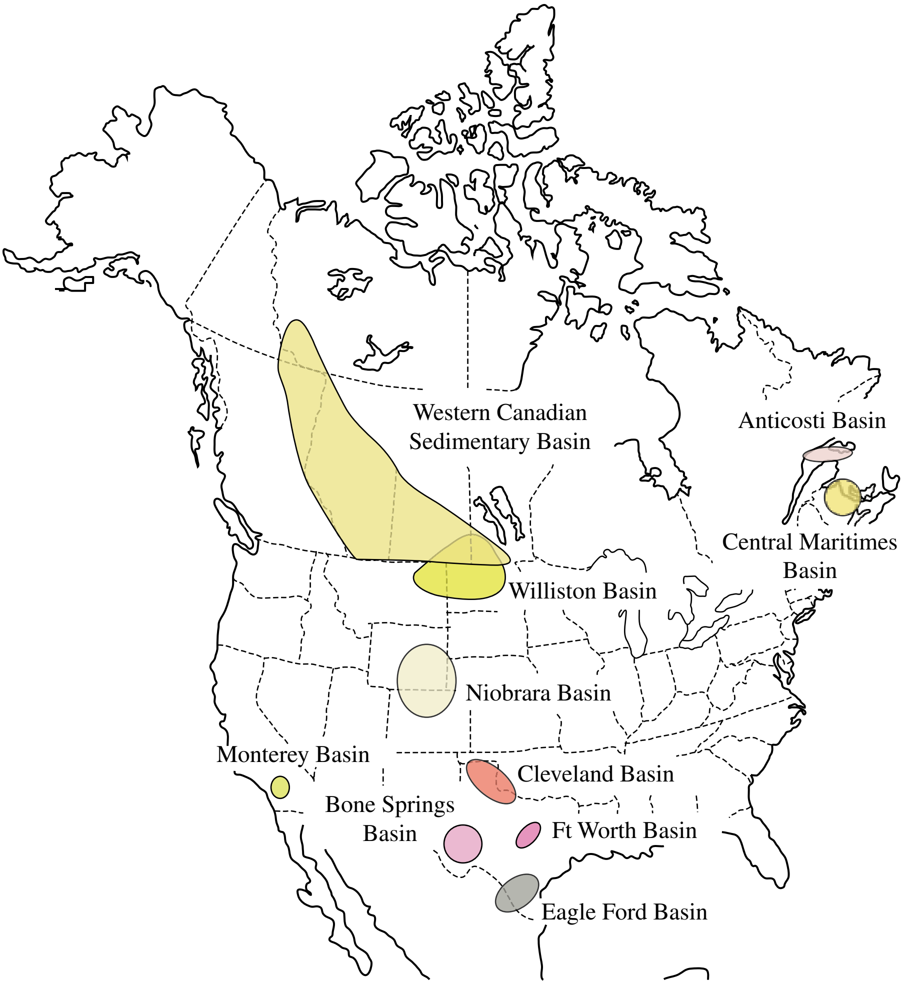


FIGURE 8.1 Basins with the potential for tight oil production. Source: Energy Information Administration, US Department of Energy, Washington, DC.

However, hydraulic fracturing fluid flow into fractures can be significant, and, in addition, when flowback water is returned to the surface, hydraulic fracturing fluids and extracted naturally occurring substances could potentially find a pathway into other geological features through natural faults or artificial penetrations, such as other wells and underground mine workings. Groundwater resources can be protected through careful well design, construction, operation, and maintenance, which are regulated by the states. In fact, many states require periodic well testing for well integrity, and the regulations are (or should be) compiled to ensure that wells are constructed to prevent the migration of fracturing fluids into underground sources of drinking water as well as to ensure wells are built to prevent blowouts and prevent escape of the fracturing fluids.

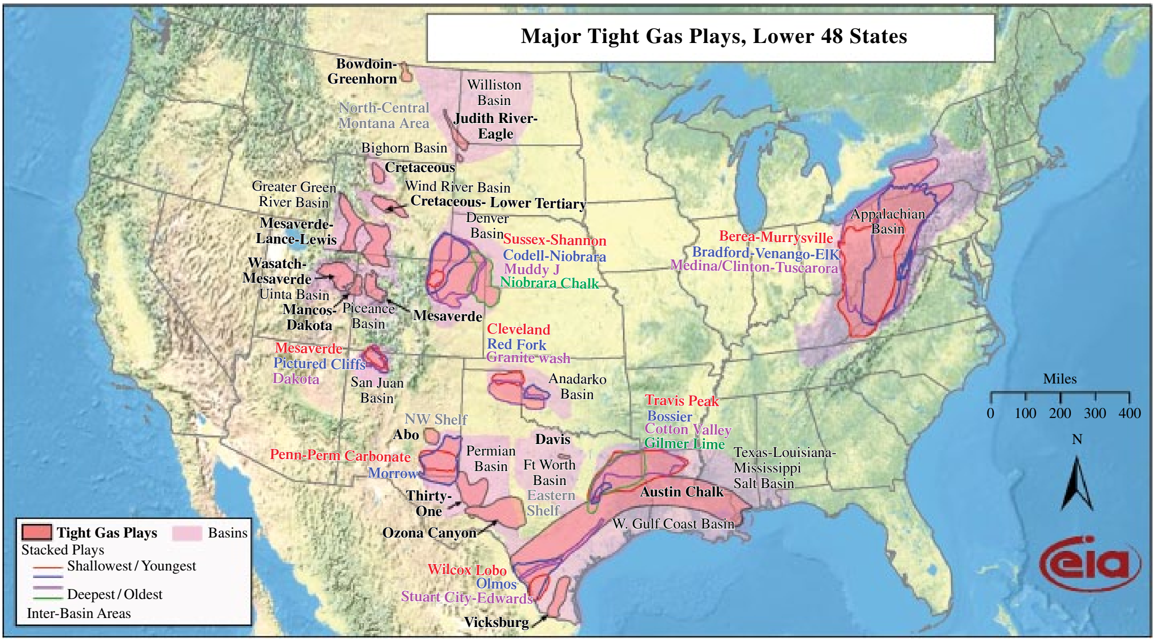


FIGURE 8.2 Tight Gas Plays of the United States Source: Energy Information Administration, US Department of Energy, Washington, DC.

8.3 CHEMICALS USED IN FRACTURING

During hydraulic fracturing, the fluids that reinjected into the well and thence into the formation contain any one (usually several) of a variety of chemicals, and once deep underground, the migration of the injected chemicals is not entirely predictable no matter what theoretical models indicate. Well failure, such as the use of insufficient well casing, could lead to the release of the chemicals at shallower depths that release the chemicals dangerously close to drinking water supplies. In addition, while some of the fracturing fluid is removed from the well at the end of the fracturing process (flowback), a substantial amount of the fluid can remain underground.

The chemicals that are added to hydraulic fracturing fluids to facilitate the fracturing process vary depending on the location of the well and the geologic conditions of the subsurface formations and cover a wide range of chemical types (Chapter 6). Many of these chemicals (Table 8.1), if not disposed of safely or are not prevented from allowed leaching into the drinking water supply, could pose a serious environmental risk to the flora and fauna of the area. Thus, the primary environmental impacts associated with hydraulic fracturing (fracturing) result from the use of toxic chemicals during the fracturing process and the subsequent release of additional toxic chemicals and radioactive materials during well production.

Fracturing fluid flowback not only contains the chemical additives used in the drilling process volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) such as benzene, toluene, ethylbenzene, and xylene (BTEX) but can also contain chemicals extracted from the underground formations, such as heavy metals and, on occasion, radioactive materials. Moreover, numerous pathways (such as older fractures that are opened and new fractures) are created by the hydraulic fracturing process for the release of these toxic and radioactive materials. As a result, the necessary protocols for handling of the toxic and radioactive materials must be in place as part of the original design plan as consultation of these protocols is essential throughout the life cycle of a well and the ensuing water cycle that involves five stages: (i) water acquisition, (ii) chemical mixing, (iii) well injection, (iv) flowback and produced water (hydraulic fracturing wastewater), and (v) wastewater treatment and waste disposal; each stage is subject to causing effects on drinking water resources (Table 8.2) (Holloway and Rudd, 2013; Spellman, 2013; Uddameri et al., 2016).

Before hydraulic fracturing of the reservoir is put into practice (or becomes a rarity), consideration of the toxicity level of to-be-injected chemicals (to-be-injected additives) used in the hydraulic fracturing phase is necessity. In fact, defining the toxicity of such chemicals should be a relatively simple and quantifiable scientific task using the relevant material safety data sheets (MSDS) information.

The availability of the MSDS information is a necessity for any commercial chemical—whenever a company produces a chemical for sale or uses a commercial chemical, the MSDS information has to be documented and must be on file when the chemical is used. In fact, the US Occupational Safety and Health Administration (US OSHA) (part of the United States Department of Labor) has addressed the physical and health hazards of these chemicals in the Hazard Communication Standard (HCS), and specific standards are available for a variety of industries. Thus, the purpose of the

TABLE 8.1 Examples of Chemicals Used in Hydraulic Fracturing Fluids[a]

Chemical	Use
Acetic acid	pH buffer
Acrylic copolymer	Lubricant
Ammonium persulfate	Breaker used to reduce viscosity
Boric acid	Cross-linking agent to increase viscosity
Boric oxide	Cross-linking agent to increase viscosity
2-Butoxyethanol	Reduction of surface tension to aid gas flow
Carbonic acid	Cross-linking agent to increase viscosity
Carboxymethyl hydroxypropyl guar	Gelling agent (thickens fluid)
Crystalline silica (cristobalite)	Proppant (holds open fractures)
Crystalline silica (quartz)	Proppant (holds open fractures)
Citric acid	Iron control or for cleaning wellbores
Diammonium peroxidisulfate	Breaker used to reduce viscosity
Disodium octaborate tetrahydrate	Gelling agent/cross-linking agent to increase viscosity
Gas oils (petroleum), hydrotreated	Guar liquefier
Fumaric acid	pH buffer
Gelatin	Corrosion inhibitor or gelling agent
Guar gum	Gelling agent
Hemicellulase enzyme	Breaker used to reduce viscosity
Hydrochloric acid	Cleaning of the wellbore prior to fraccing
Hydroxyethyl cellulose	Gelling agent
Hydroxypropyl guar	Gelling agent
Magnesium silicate hydrate	Gelling agent
Methanol	Gelling agent
Monoethanolamine	Reduction of surface tension to aid gas flow
Ethylene glycol monobutyl ether	Gelling agent
Muriatic acid	Mutual solvent
Noncrystalline silica	Proppant
Poly(oxy-1,2-ethanediyl)	Proppant
Polydimethyldiallylammonium chloride	Clay control
Potassium carbonate	pH buffer
Potassium chloride	Clay inhibitor
1-Propanol	Complexing agent
Quaternary polyamines	Clay control
Sodium acetate	pH buffer
Sodium borate	pH buffer
Sodium bicarbonate	pH buffer
Sodium carbonate (soda ash)	pH buffer
Sodium chloride	Viscosity reducer
Sodium hypochlorite	Bactericide
Sodium persulfate	Viscosity reducer
Terpenes	Reduction of surface tension to aid gas flow
Tetramethylammonium chloride	Clay control
Zirconium complex	Cross-linking agent to increase viscosity

[a] Listed alphabetically and not in order of preference; the fracturing fluid mix varies according to the nature of the task, and only a limited set of the above chemicals are used in any single project. The additives mentioned above are relatively common components of a water-based fracturing solution used in tight shale formations. However, it is important to note that not all of the additives listed here are used in every hydrofracturing operation; the exact blend and proportions of additives will vary based on the site-specific depth, thickness, and other characteristics of the target formation.

See Veil (2010) and Waxman et al. (2011) for more comprehensive lists of chemicals used in hydraulic fracturing projects.

TABLE 8.2 The Hydraulic Fracturing Water Cycle and Potential Impacts on Drinking Water Resources

Stage 1: Water acquisition

- Large volumes of water are withdrawn from groundwater and surface water resources
- Potential impacts on drinking water resources
  - ◦ Change in the quantity of water available for drinking
  - ◦ Change in drinking water quality

Stage 2: Chemical mixing

- The acquired water is combined with chemical additives and proppant
- Potential impacts on drinking water resources
  - ◦ Release to surface and groundwater through on-site spills and/or leaks

Stage 3: Well injection

- Pressurized hydraulic fracturing fluid is injected into the well, creating cracks in the geological formation that allow oil or gas to escape through the well to be collected at the surface
- Potential impacts on drinking water resources
  - ◦ Release of hydraulic fracturing fluids to groundwater due to inadequate well construction or operation
  - ◦ Movement of hydraulic fracturing fluids from the target formation to drinking water aquifers through man-made or natural features
  - ◦ Movement into drinking water aquifers of natural substances found underground, such as metals or radioactive materials that are mobilized during hydraulic fracturing activities

Stage 4: Flowback and produced water (hydraulic fracturing wastewater)

- When pressure in the well is released, hydraulic fracturing fluid, formation water, and natural gas begin to flow back up the well. This combination of fluids, containing hydraulic fracturing chemical additives and naturally occurring substances, must be stored on-site (in tanks or pits) before treatment, recycling, or disposal
- Potential impacts on drinking water resources
  - ◦ Release to surface or groundwater through spills or leakage from on-site storage

Stage 5: Wastewater treatment and waste disposal

- Wastewater is dealt with in one of several ways, including but not limited to disposal by underground injection, treatment followed by disposal to surface water bodies, or recycling (with or without treatment) for use in future hydraulic fracturing operations
- Potential impacts on drinking water resources
  - ◦ Contaminants reaching drinking water due to surface water discharge and inadequate treatment of wastewater
  - ◦ By-products formed at drinking water treatment facilities by reaction of hydraulic fracturing contaminants with disinfectants

HCS is to ensure that the hazards of all chemicals produced or imported are evaluated and that information concerning their hazards is transmitted to employers and employees (OSHA, 2015). Furthermore, employers are under obligation to use labels, MSDS information, as well as other necessary information to (i) evaluate both the physical and health hazards created by the use of chemicals in the workplace, (ii) establish a program that addresses these hazards, and (iii) train workers to minimize their exposure.

Sites used from hydraulic fracturing and the associated chemicals are also required to provide MSDS information related to the chemicals used on-site (or under-site). However in some countries hydraulic fracturing companies are under no legal obligation to declare the exact names of the chemicals and/or the composition of the chemical mixtures that are added to fracturing fluids. In fact, in order to test for, and track, potential chemical contamination, agencies responsible for monitoring and regulating the environmental impacts of hydraulic fracturing need to know the chemical composition of substances added to the hydraulic fracturing fluid.

Not surprisingly, considering the variety of chemicals that can be added to the fracturing fluid (Table 8.1), concerns also have been raised about the ultimate outcome of chemicals that are recovered and disposed of as wastewater, which is usually stored in tanks or pits at the well site, where spills are possible. For final disposal, the fluids must either be (i) recycled for use in future fracturing projects, (ii) injected into underground storage wells (which, unlike the fracturing process itself, are subject to the SDWA), discharged to nearby surface water, or transported to wastewater treatment facilities (Veil, 2010).

Thus, while hydraulic fracturing has allowed access to domestic reserves of crude oil and natural gas that could provide an important stepping stone to a clean energy future as well as a measure of energy independence, questions about the safety of hydraulic fracturing persist, especially since many of the chemicals are known to be possible human carcinogens and/or regulated under the SDWA or listed as HAPs (Waxman et al., 2011).

8.4 ENVIRONMENTAL EFFECTS

The geologic characteristics of the formations in which crude oil and natural gas are found vary widely, along with the characteristics of the hydrocarbons themselves (Speight, 2014a). For example, in the context of this book, crude oil and natural gas formations are generally tighter and much less permeable than other formations, causing the oil and gas to be much less free flowing. Coalbed methane formations, located at shallow depths of 1000–2000 ft, are more permeable formations through which gas can flow more freely than through shale formations. In addition, heavy oil, due to its higher viscosity, has much less ability to flow freely through a formation compared to lighter oil. Tar sand bitumen, which is immobile in the deposit, has no ability to flow freely through the deposit (Speight, 2009, 2014a).

Reservoir management is a multifaceted operation (Fig. 8.3), and while on-site environmental management is a typical practice associated with hydraulic fracturing, it should be considered as being site specific. In addition, hydraulic fracturing base fluids (themselves variable in composition), most commonly water, are typically stored in tanks at the well site, while additives may be stored on a flatbed truck or van enclosure that holds a number of containers. At the commencement of operations, the fracturing fluid and any chemical additives are sent to a blender for mixing after which the fluid is transferred to the wellhead for injection. It is during the time that the fluids and additives are being are transferred and moved around the well site and

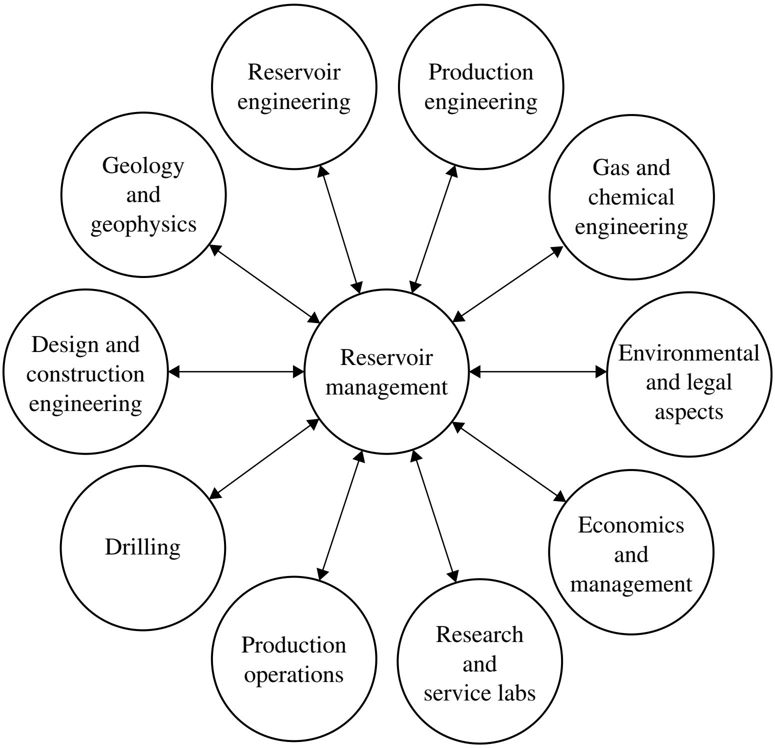


FIGURE 8.3 Various aspects of reservoir management.

through various pieces of equipment that faulty equipment or human error can cause spills of the various components of fracturing fluids.

The type and amount of fluids and chemicals stored on-site are largely determined by the geological characteristics of the formation to be fractured as well as by production goals and the chemical additives. Approximately 1–2% v/v or less of the volume of water-based hydraulic fracturing fluid is composed of chemical additives, which indicates that approximately 500–260,000 gallons or less of chemical additives may be brought on-site for hydraulic fracturing (Lee et al., 2011; US EPA, 2015b). Chemical additives can be composed of one or more chemicals and can be used in hydraulic fracturing fluids as acids, friction reducers, surfactants, scale inhibitors, iron control agents, corrosion inhibitors, and biocides (Table 8.3) (Chapter 6) (Arthur et al., 2009; Gregory et al., 2011; US EPA, 2015b).

Finally, for any analytical procedure or suite of analytical procedures, the following practices must be part of a strict testing protocol: (i) sampling and (ii) identification of chemicals by use of standards test methods that are not subject to intense criticism and can stand up to scrutiny in a court of law. In order to withstand such scrutiny, the analytical records, as for any analytical process for materials such as petroleum, petroleum products, and natural gas (Speight, 2015), must be complete and should include but not necessarily restricted to the following information: (i) the precise

TABLE 8.3 Types of Additives Used in Fracturing Fluids

Type	Compound	Comment
Acid	Hydrochloric acid (also called *muriatic acid*)	For the fracturing of shale formations, acids are used to clean cement from casing perforations and drilling mud clogging natural formation porosity, if any prior to fracturing fluid injection (dilute acid concentrations are typically on the order of 15% v/v acid)
Biocide	Glutaraldehyde	Fracture fluids typically contain gels that are organic and can therefore provide a medium for bacterial growth. Bacteria can break down the gelling agent, reducing its viscosity and ability to carry proppant. Biocides are added to the mixing tanks with the gelling agents to kill these bacteria
Breaker	Sodium chloride	Chemicals that are typically introduced toward the later sequences of a fracturing project to break down the viscosity of the gelling agent to better release the proppant from the fluid as well as enhance the recovery or “flowback” of the fracturing fluid
Corrosion inhibitor	*N*,*N*-dimethylformamide	Used in fracture fluids that contain acids; inhibits the corrosion of steel tubing, well casings, tools, and tanks
Cross-linking agent	Borate salts	There are two basic types of gels that are used in fracturing fluids: linear and cross-linked gels. Cross-linked gels have the advantage of higher viscosities that do not break down quickly
Friction reducer	Petroleum distillate (also called *mineral oil*)	Minimizes friction allowing fracture fluids to be injected at optimum rates and pressures
Gel	Guar gum (hydroxyethyl cellulose)	Gels are used in fracturing fluids to increase fluid viscosity allowing it to carry more proppant than a straight water solution. In general, gelling agents are biodegradable

(geographic or other) location from which the sample was obtained, (ii) the identification of the location by name, (iii) the character of the bulk material (solid, liquid, or gas) at the time of sampling, (iv) the means by which the sample was obtained, (v) the means and protocols that were used to obtain the sample, (vi) the date and the amount of sample that was originally placed into storage, (vii) any chemical analyses (elemental analyses, fractionation by adsorbents or by liquids, functional type analyses) that have been determined to date, (viii) any physical analyses that have been determined to date, (ix) the date of any such analyses, (x) the methods used for analyses that were employed, (xi) the analysts who carried out the work, and (xii) a log sheet showing the names of the persons (with the date and the reason for the removal of an aliquot) who removed the samples from storage and the amount of each sample (aliquot) that was removed for testing. In summary, there must be a means to accurately to track and identify the sample history so that each sample is tracked and defined in terms of source, activity, and the personnel involved in any of the above stages. Thus, the accuracy of the data from any subsequent procedures and tests for which the sample is used will be placed beyond a *reasonable doubt* and would stand the test of time in court should legal issues arise.

8.4.1 Air

The emission of gas and/or vapor to the atmosphere either from the added chemicals, entrained contaminants from the formation, or methane released by the hydraulic fracturing process remains an issue. Furthermore, there are questions about the relative leakage rate of methane into the atmosphere from the exploitation of shale gas in comparison to the emission rate of methane from conventional natural gas production (Howarth et al., 2011; Osborn et al., 2011). This is an important aspect of shale gas production because a high leakage rate might mean that methane released into the atmosphere from hydraulic fracturing operations could have a higher net greenhouse gas footprint than conventional natural gas recovery operations as well as other fossil fuel recovery operations, such as coalbed methane. Hydraulic fracturing operations should, therefore, be carefully monitored and emission limits enforced in order to minimize such emissions to the atmosphere. In addition, emissions from the hydraulic fracturing chemicals and equipment such as VOCs are also cause for concern.

8.4.2 Water

Water from beneath the ground has been exploited for domestic use, livestock use, and irrigation since the earliest times. Although the precise nature of its occurrence was not necessarily understood, successful methods of bringing the water to the surface have been developed, and groundwater use has grown consistently ever since (Chilton, 1996).

Many shale formations contain quantities of potentially harmful chemical elements and compounds that could be dissolved into the hydraulic fracturing fluid and then return toward the surface during flowback. These include trace elements such as mercury, arsenic, and lead; naturally occurring radioactive material (NORM) (radium, thorium, uranium); and VOCs. Thus, careful chemical monitoring of hydraulic fracturing fluids, including the flowback fluid and produced water, is required to mitigate the risks of contamination such sources.

Generally, the quality of produced water from hydraulic fracturing is somewhat less than pristine and cannot be readily used for another purpose without prior treatment. In fact, it is more correct to look upon the quality of produced water from any hydraulic fracturing project, although variable, as generally being poor and, in most situations, cannot be readily used for other purposes without prior treatment. Produced water may contain a wide range of contaminants in varying amounts, some of which occur naturally in the produced water but others are added through the process of hydraulic fracturing. The range of contaminants found in produced water can include (i) salts, which include chlorides, bromides, and sulfides of calcium, magnesium, and sodium; (ii) metals, which include barium, manganese, iron, and strontium, among others; (iii) oil, grease, and dissolved organics, which include benzene and toluene, among others; and (iv) production chemicals, which may include friction reducers to help with water flow, biocides to prevent growth of microorganisms, and additives to prevent corrosion, as well as a variety of other chemicals (Tables 8.1 and 8.3).

The specific quality of water generated by a given well, however, can vary widely according to the same three factors that impact the volume of water produced from the well: the hydrocarbon being produced, the geographic location of the well, and method of production used. Typically, the type of hydrocarbon is a key driver of produced water quality, due to differences in geology across the formations in which the hydrocarbons are found. Specifically, the depth at which the hydrocarbons are found influences the salt and mineral content of produced water, and, in general, the deeper the formation is, the higher the salt and mineral content will be. Additionally, the amount of crude oil or natural gas that is mixed in with the produced water brought to the surface can also vary considerably.

The specific quality of water produced by a given project, however, can vary widely, and, after treatment, some of the produced water is disposed of or reused by producers in other ways, such as (i) discharging it to surface water, (ii) storing it in surface impoundments or ponds so that it can evaporate, (iii) irrigating crops, and (iv) reusing it for further hydraulic fracturing projects. Managing produced water in these ways can require more advanced treatment methods, such as distillation, but the manner in which produced water is managed and treated is primarily a decision that must be made within the bounds of federal and state regulations.

By far the most serious local environmental concern, and probably the most contentious, is that of groundwater contamination. The potential risk to groundwater comes from two sources: the injected fluid (water plus chemical additives) and the released natural gas. However, the major issue that is not often determined scientifically is the exact site of this contamination, either (i) percolation or diffusion from the hydraulically fractured formation at depth or (ii) leakage from a defective wellbore closer to the land surface.

The nature of the hydraulic fracturing process dictates that a significant amount of water is produced as a by-product from hydraulic fracturing. In terms of approximate number, hydraulic fracturing uses between 1.2 and 3.5 million US gallons of water per well, with large projects using up to 5 million US gallons per well, and additional water is used when wells are refractured. A typical well requires 3–8 million US gallons of water over its lifetime, and greater volumes of fracturing fluids are required for deep (ca. 5000 ft) shale formations. Not surprisingly, concern has been raised over the increasing quantities of water for hydraulic fracturing in areas that experience water stress. Use of water for hydraulic fracturing can divert water from stream flow, water supplies for municipalities and industries such as power generation industries, as well as recreation and aquatic life. The large volumes of water required for most common hydraulic fracturing methods have also raised concerns for arid regions, which may require water overland piping from distant sources (Nicot and Scanlon, 2012).

The hydraulic fracturing fluids is not only water but also a mixture of water, proppant, and chemical additives—the precise mix of additives depends on the formation to be fractured, which dictates the process operations (Chapter 5) and the composition of the fluids (Chapter 6) and the proppants (Chapter 7). Additives typically include gels to carry the proppant into the fractures, surfactants to reduce friction, hydrochloric acid to help dissolve minerals and initiate cracks, inhibitors against pipe corrosion and scale development, and biocides to limit bacterial growth (Tables 8.1 and 8.3). Chemical additives typically make up about 0.5% by volume of well fracturing fluids, but may be up to 2% (GWPC, 2009). Some potential additives are harmful to human health, even at very low concentrations. Unless diesel is used, the fracturing fluids are not regulated by the SDWA.

In the United States, the SDWA is the main federal law that ensures the quality of drinking water. Under the Act, the US EPA sets standards for drinking water quality and oversees the states, localities, and water suppliers who implement those standards (US EPA, 2015c). The Act was originally passed by Congress in 1974 to protect public health by regulating the public drinking water supply in the United States. The law was amended in 1986 and 1996 and requires many actions to protect drinking water and its sources: rivers, lakes, reservoirs, springs, and groundwater wells. The Act does not regulate private wells, which serve fewer than 25 individuals.

Production wells typically extend one mile or more below the ground surface, often passing through groundwater aquifers to reach oil-rich and gas-rich formations after which horizontal wells are drilled into the formation. Groundwater aquifers are typically separated from the shale formations by several thousand feet of rock, limiting the potential for any unreturned fracturing fluids to impact drinking water supplies. In addition, well casings and cement are designed to prevent contamination of any groundwater aquifers through which the well may be drilled.

There is the potential to overpressure a well during the operation, which may result in overlying formations becoming fractured, possibly serving as conduits for leakage of formation fluids and fracturing fluids into overlying formations, including aquifers. There is also the potential that overpressured hydraulic fracturing operations could result in rapid upward leakage through the borehole into overlying formations, including aquifers, and possibly even to the surface. The application of correct well design, completion, operations, and monitoring according to rules and regulations that already exist in most states and provinces will ensure that hydraulic fracturing operations do not negatively impact either the subsurface or surface environment (National Petroleum Council, 2011). The result of mitigation efforts was that there was no quantifiable impact to local groundwater resources.

In addition, overweight drilling mud can cause a wellbore to fail by fracture. The density (weight) of the drilling mud controls the fluid pressure exerted along the walls of the wellbore. If the pressure of the mud exceeds the fracture pressure (the local minimum principal stress plus the fracture strength of the rock), a fracture can form and the drilling fluid can escape. However, pressures exceeding the rock fracture strength generated by overweight drilling muds are only likely at great depths (several thousand feet but within the depths of some shale formations), far beyond the extent of any groundwater aquifer, and the risk of contamination from incorrect drilling mud composition may be limited.

To protect groundwater, proper well design, construction, and monitoring are essential. During well construction, multiple layers of telescoping pipe (or casing) are installed and cemented in place, with the intent to create impermeable barriers between the inside of the well and the surrounding rock (GWPC, 2009). It is also common practice to pressure test the cement seal between the casing and rock or otherwise examine the integrity of wells. Wells that extend through a rock formation that contains high-pressure gas require special care in stabilizing the wellbore and stabilizing the cement or its integrity can be damaged. Furthermore, differences in the type and sizes of well integrity datasets add to the challenge of generalizing well integrity failure rates (Davies et al., 2014, 2015).

However, the flow of hydraulic fracturing fluid into fractures can be significant, and when flowback water is returned to the surface, fracturing fluids and naturally occurring substances (that have been extracted from the oil-containing or gas-containing formation) could potentially find a pathway into other geological features through natural faults or artificial penetrations (such as other nonrelated wells and underground mines). Groundwater resources can be protected through proper well design, construction, operation, and maintenance—many states require periodic well integrity testing. However, in some geologic settings, methane can naturally originate from gas-producing rock layers below and close to the aquifer and be unrelated to the deeper fractured zone. Analysis of the crude oil and natural gas can be used to identify the origin of the oil and gas occurring in groundwater (Warner et al., 2012; Darrah et al., 2014).

Potential pathways for the fracturing fluids to contaminate water include events such as (i) surface spills prior to injection, (ii) migration of the injected fluid, (iii) surface spills of flowback water, and (iv) surface spills of produced water (US EPA, 2015b). Because the fracturing fluids are injected into the subsurface under high pressure and because some of the fluids remain underground, there is concern that this mixture could move through the wellbore or fractures created in the reservoir rock by hydraulic pressure and ultimately migrate up and enter shallow formations that are sources of freshwater (aquifers) (Cooley and Donnelly, 2012). There is also the possibility that geologic faults, previously existing fractures (which have not been identified due to an inadequate geological survey), and poorly plugged, abandoned wells could provide fluids with accessibility to aquifers (Osborn et al., 2011; Cooley and Donnelly, 2012; King, 2012; Molofsky et al., 2013; Vidic et al., 2013).

Thus, one challenge is to establish a baseline of the water quality before the fracturing operation commences. This will identify and distinguish the type and level of natural contaminants in the groundwater from those contaminants that are not indigenous to the groundwater as well as the amounts of indigenous contaminants that are in the groundwater. It is then possible, as an after the fact series of tests, to determine any new contaminants or new levels of in-place contaminants that are the result of crude oil and natural gas development. Unfortunately, there often are no water quality analyses prior to hydraulic fracturing that can be used to provide a baseline comparison (Vidic et al., 2013).

Baseline water quality testing, carried out prior to oil and gas drilling, helps to document the quality of local natural groundwater and may identify natural or preexisting contamination, or lack thereof, before oil and gas activity begins. Without such baseline testing, it is difficult to know if contamination existed before drilling, occurred naturally, or was the result of oil and gas activity. Many natural constituents, including methane, elevated chlorides, and trace elements, occur naturally in shallow groundwater in oil-producing and gas-producing areas and are unrelated to drilling activities. The quality of water in private wells is not regulated at the state or federal level, and many owners do not have their well water tested for contaminants. States handle contamination issues differently.

The current opinion is that all scientifically documented cases of groundwater contamination associated with hydraulic fracturing are related to poor well casings and their cements or from leakages of fluid at the surface rather than from the hydraulic fracturing process itself. The absence of evidence implicating leakage from a fracture network could arise from the relatively short time span available for monitoring the signs of contamination and potentially lower flow rates from a formation fracked at significant depth, although hydraulic fracturing has been performed in some areas for decades.

In summary, conducting multistage hydraulic fracturing operations in horizontal fractures can result in the need for up to 72,000 barrels of water per well. In areas with an arid or semiarid climate the use of water for hydraulic fracturing operations may come under scrutiny from local regulators and/or other users including agricultural producers, municipalities, rural water associations, and other industries. Such concerns have been raised in western North Dakota as the exploitation of the Bakken has increased. Potential mitigation approaches include the use of marginal quality groundwater that is not a potential underground source of drinking water and the treatment of nonpotable groundwater to a level that is suitable for hydraulic fracturing fluids (National Petroleum Council, 2011).

8.4.3 Surface Effects

Surface spills related to the hydraulic fracturing occur mainly because of equipment failure or engineering or human misjudgments. Volatile chemicals held in wastewater evaporation ponds can evaporate into the atmosphere, or overflow. The runoff can also end up in groundwater systems. Groundwater may become contaminated by trucks carrying hydraulic fracturing chemicals and wastewater if they are involved in accidents on the way to hydraulic fracturing sites or disposal destinations. In addition, large quantities of chemicals must be stored at drilling sites as well as the volumes of liquid and solid waste that are produced, and significant care must be taken that these materials do not contaminate surface water and soil during their transport, storage, and disposal.

Fluids used for slickwater hydraulic fracturing are typically more than 98% freshwater and sand by volume, with the remainder made up of chemicals that improve the treatment's effectiveness, such as thickeners and friction reducers, and protect the production casing, such as corrosion inhibitors and biocides. These fluids are designed by service companies that tailor fracturing treatments to suit the needs of a particular project.

Because the fluids in each fracturing treatment would contain a different subset of these chemicals and because these chemicals could be hazardous in sufficient concentrations, baseline water testing is necessary to enable regulatory agencies to conduct and respond appropriately should contamination or exposure occur. The use of more environmentally benign fracturing fluids would also help limit the environmental and health risks posed by fracturing fluids in the case of contamination. Chemicals to be used in fracturing fluids are generally stored at drilling sites in tanks before they are mixed with water in preparation for a fracturing job. Under the US Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986, companies must post MSDS information that list the properties and any health effects of chemicals stored in large quantities on-site.

The EPCRA was passed by Congress in response to concerns regarding the environmental and safety hazards posed by the storage and handling of toxic chemicals. These concerns were triggered by the 1984 disaster in Bhopal, India, caused by an accidental release of methylisocyanate. The release killed or severely injured more than 2000 people. To reduce the likelihood of such a disaster in the United States, the Congress imposed requirements for federal, state, and local governments, tribes, and industry. These requirements covered emergency planning and *community right-to-know* reporting on hazardous and toxic chemicals. The provisions of the Act help increase public knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment. States and communities, working with facilities, can use the information to improve chemical safety and protect public health and the environment (US EPA, 2015d).

In fact, the most important requirement for an assessment of the impact of hydraulic fractions projects on the flora and fauna is complete testing of air and water prior to drilling and at regular intervals after drilling has commenced. This includes chemicals used in the drilling muds, fracturing fluids, and any process wastewater (the latter contains heavy metals and radioactive compounds normally found in shale formations). Currently, the extent of testing (particularly for organic compounds) is frequently inadequate and limited by lack of information on what substances were used during the drilling process due to inadequate testing (Bamberger and Oswald, 2012).

After each fracturing stage, the fracturing fluid, along with any water originally present in the shale formation, is flowed back through the wellbore to the surface. The flowback period typically lasts for periods of hours to weeks, although some injected water can continue to be produced along with gas several months after production has started. Recycling water minimizes both the overall amount of water used for fracturing and the amount that must be disposed of. Many water treatment

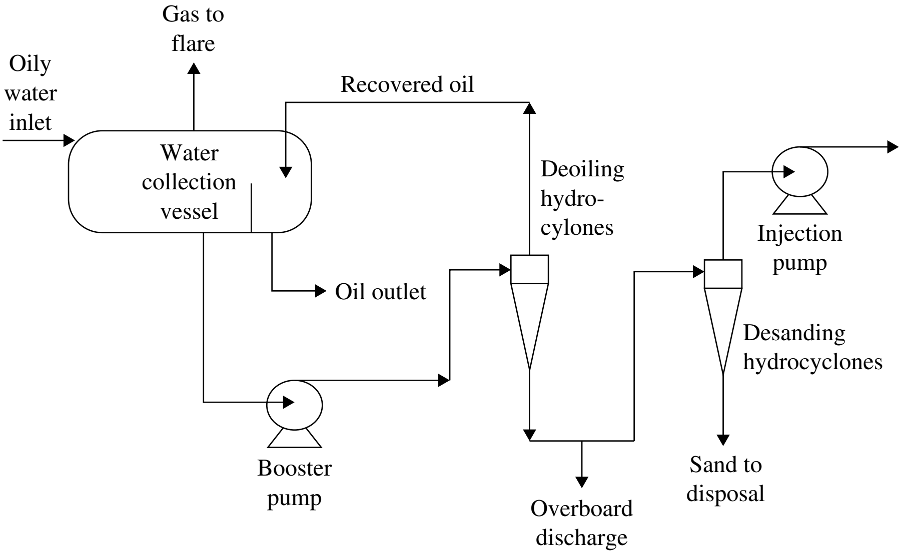


FIGURE 8.4 Schematic of a water treatment process.

processes are currently being investigated that could be potentially be used at large scale and have a significant impact on this problem (Fig. 8.4).

Flowback water produced during the lifetime of a well can contain naturally occurring formation water that is millions of years old and therefore can display high concentrations of salts, NORM, and other contaminants including arsenic, benzene, and mercury. As a result, the water produced during hydraulic fracturing must be properly managed and disposed. Finally, one of the problematic aspects of handling flowback water is the temporary storage and transport of such fluids prior to treatment or disposal. In many cases, fluids may be stored in lined or even unlined open evaporation pits. Even if the produced water does not seep directly into the soil, a heavy rain can cause a pit to overflow and create contaminated runoff. Storing produced water in enclosed steel tanks, a practice already used in some wells, would reduce the risk of contamination while improving water retention for subsequent reuse. In addition, equipment used to move fluids between storage tanks or pits and the wellhead must be monitored and tested regularly to prevent spills, and precautions must be taken while transporting produced water to injection or treatment sites, whether via pipeline or truck.

Other surface effects include drilling operations require significant aboveground development. In addition to the well pad itself, roads may need to be built and gathering infrastructure installed to bring the crude oil and natural gas from the wellhead to a pipeline that may require the development of several acres of land. Total land use can be reduced by drilling multiple wells from a single well pad, as is done in areas of steep topography or environmental sensitivity. Nonetheless, because so many wells have to be drilled and appreciable infrastructure has to be developed, it is important to do as much as possible to minimize the overall impact on local communities.

In addition, the trucks used to transport equipment, fracturing fluid ingredients, and water to the well pad, drilling rigs, compressors, and pumps all emit air pollutants, including carbon dioxide, nitrogen and sulfur oxides (NOx and SOx), and particulate matter. VOCs and other pollutants associated with natural gas and fracturing fluids can enter the air from wells and evaporation pits.

Finally, during the drilling and completion of a well, work occurs around the clock for several weeks and can generate significant amounts of noise pollution, although noise can be reduced through the construction of sound barriers. Shale resource and tight resource development can also affect communities in less tangible ways. While it may stimulate the local economy and provide jobs, development may also lead to increased traffic and greater strains on public resources, and there is a need to minimize the impact of gas development activities on a community's resources and quality of life.

8.4.3.1 Noise Noise is usually one of the first noticeable changes when a site moves from a pastoral environment to a working commercial environment, and, thus, an increase in noise is also one of the most continuous changes related to hydraulic fracturing operations. Drilling and completing a well—from pad construction to final completion of the well—requires several weeks and utilizes many different types equipment, which can include additional trucking, construction, and drilling equipment. Once the well site is completed, there may be the additional sounds of compressors used during fracturing and production activities.

For pad sites where long-term compressor use is anticipated, especially in rural communities where serenity is the norm and even the slightest ongoing noise can be heard clearly for long distances, operators have addressed compressor noise concerns with remote siting (trying to locate the compressors on the part of the pad farthest from homes), noise tampering sound walls, and directing compressors with fans away from homes. However, even with the measures presently taken to mitigate ongoing sound issues, additional work must be done and technology developed to work toward a solution.

8.4.3.2 Visual Changes Visual changes (sometimes referred to as *visual pollution*) refer to the impacts of commercial activities (such as hydraulic fracturing) that impair or change the original vista or view. For example, drilling rigs utilized in most unconventional well drilling typically can range from approximately 50 to 100 ft in height. In addition, the height of the drill rig with the ongoing movement related to drilling contributes to visual pollution of the site. One possibility to mitigation such pollution would be to use lower height rigs, but the potential trade-off is the necessary extended time on location for a lower height rig.

However, pads used for horizontal drilling commonly include multiple laterals on one location, in which the drilling of multiple wells literally means moving the rig over as little as 20 ft from the original location. This allows wells to be drilled from one location without the necessity of moving the rig and drilling in several locations, which allows for accelerated drilling time due to lessened rig movement time, a reduction in the number of necessary lease roads and drill pad locations, fewer necessary pipelines, and fewer tank batteries.

8.4.3.3 Traffic Load Another issue that is commonly related to crude oil and natural gas production areas is the increased traffic load, which includes all of the initial traffic to bring in heavy equipment for pad construction and eventually the rig itself, followed by traffic for well completion and fracturing activities and the ensuing traffic load that is related to hauling produced water and crude oil from the locations until a pipeline infrastructure can be put in place.

The answers to the traffic problems may include (i) the need to either use fewer but larger transport vehicles, which can result in additional hazardous conditions with the larger vehicles on the narrow rural roads, and/or (ii) the need to install a pipeline infrastructure to transport produced water and/or oil, which comes with the obvious concerns related to pipelines installation and location. This second option depends on the type of road to be improved. Improving and widening gravel-type lease and rural roads is a less daunting task than improving paved city/county roads due to ease of obtaining the necessary materials and the fewer restrictions put on maintenance as well as the need to clear a wider right of way all along the road to be widened with the necessary costs of such a project.

8.4.3.4 Chemicals On-Site Although discussed elsewhere in the chapter (Section 8.3), the on-site storage of chemicals is major point of contention. In particular, the identity and amounts of chemicals stored on pad locations during all phases of the well completion and production process are subject to criticism.

Once production operations are in place and wells begin producing, the fluids—produced water and oil—are often stored on-site in large tanks while awaiting transport off-site. Safeguards put in place to protect the environment and the public from tank releases include consistent measurements by pumpers, high-level shutdown sensors, continued equipment observations and maintenance, and secondary containments in place around the tanks to contain any fluids that may release from the tank. Secondary containments may be constructed of properly packed and integrity tested earthen materials or up to specifically designed and manufactured metal containments with plastic liners. No matter what materials are used in construction, secondary containments must be sufficiently large enough to contain all the fluids that could possibly escape the tanks.

Even with attempts to minimize the amount of on-site storage, some chemical and product storage is unavoidable, and there are very valid concerns—including potential spills, leaks, tank or container overfill, and even the chance of traffic accidents on location or roadways leading to releases of chemicals and/or products. Release events could range from relatively small amounts from equipment leaks to possibly hundreds of barrels from tank release. Two regulatory measures in place to manage and oversee on-site chemical storage conditions are requiring Spill Prevention, Control, and Countermeasure (SPCC) plans and SARA reporting (US EPA, 2015e).

SARA reporting (*federal right-to-know*) requires quarterly and annual reporting of chemical storage details (types of chemicals, amounts, and dates of storage) for all facilities that used more than 10,000 pounds per year of the chemical exceeding the threshold quantity. This requirement means that a facility storing more uses more than 10,000 pounds of a given chemical in a year must report that chemical and amount. This program is intended as the “right-to-know” for emergency responders and emergency services that may respond to an emergency situation on the location so they will be able to adequately prepare for what may be stored on-site.

8.4.4 Health Effects

Trace amounts of chemicals used in the drilling process may affect the health of those working on or living near the wells. Human exposure to these chemicals can result in cancer and adverse effects to the reproductive, neurological, and endocrine systems. In fact, it has been concluded that risk prevention efforts should be directed toward reducing air emission exposures for persons living and working near wells during well completions (European Commission, 2012).

Recommendations include the following: (i) baseline environmental monitoring is needed to facilitate the assessment of the impact of shale gas extraction on the environment and public health; (ii) effective environmental monitoring in the vicinity of shale gas extraction sites is needed throughout the lifetime of development, production, and postproduction; (iii) chemicals used in hydraulic fracturing fluid should be publicly disclosed and risk assessed prior to use; and (iv) the type and composition of the gas extracted are likely to vary depending on the underlying geology, and this necessitates each site to be assessed on a case-by-case basis.

In addition, the maintenance of well integrity, including postoperations, and appropriate storage and management of hydraulic fracturing fluids and wastes are important factors in controlling risks, and appropriate regulatory control is needed. Also characterization of potentially mobilized natural contaminants is needed including NORM and dissolved minerals.

Even considering all the benefit of using silica sand for the fracturing process, there are hazards related to its use because of the fine grains in the sand. Care must be taken to keep the silica sand out of the lungs during use, and all materials containing more than 0.1% of silica sand must be clearly labeled. Workplace health applications also need to be in place and enforced—failure to wear a proper respirator or mask can result in lung irritation, and prolonged exposure can cause silicosis (impairment of lunch functions), which is a lung disease that results from occupational exposure to silica dust over a period of years. Silicosis can also progress and worsen even after someone is no longer exposed to the silica dust, resulting in long-term effects and shortness of breath years later.

8.4.5 Seismic Effects

Hydraulic fracturing is accompanied by microseismic vibrations that can be recorded with sensitive listening devices and analyzed with established scientific methods. Microseismic mapping is used to understand and optimize field development, well completions, and stage treatments. However, during hydraulic fracturing, the microseismic events are generally less than magnitude minus two (−2) or minus three (−3) on the Richter scale. Furthermore, the combination of geological factors necessary to create a higher-than-normal seismic event is believed to be rare; such events would be limited approximately to magnitude 3 on the Richter scale (Kim, 2013). However small the seismic events, they cannot afford to be ignored and may lead to cumulative large seismic events at some future date.

Furthermore, earthquakes have also been linked to some deep disposal wells that receive hydraulic fracturing flowback and produced water from hydraulically fractured wells (NRC, 2012). Flowback and brine from oil and gas wells are injected into EPA-regulated disposal wells, which can, it is believed, trigger earthquakes. Emotion is running high from such effects and some areas with increased human-induced seismicity are susceptible to additional earthquakes triggered by the seismic waves from remote earthquakes. They recommended increased seismic monitoring near fluid injection sites to determine which areas are vulnerable to remote triggering and when injection activity should be ceased (Van der Elst et al., 2013). Although the magnitude of these quakes has generally been small (<6.0 on the Richter scale), there is no guarantee that larger quakes will not occur. In addition, the frequency of the quakes has been increasing, and there are also concerns that quakes may damage underground gas, oil, and water lines and wells that were not designed to withstand earthquakes.

8.5 THE FUTURE

8.5.1 The Process

Hydraulic fracturing is not a modern method for the recovery of crude oil and natural gas. The procedure has at least 60 years of history, but the more common use for recovery of energy resources from shale formation and form tight formations has brought it to the fore in terms of environmental concerns. As hydraulic fracturing has evolved, other advanced technologies (emerging technologies) are being designed and investigated. Unconventional gas reservoirs represent a potential part of a huge future global source of energy that can last for decades. As the demand for natural gas is increasing, operators have to find technological solutions for economical production from such tight reserves.

Tight gas reservoirs have production challenges as identifying a sweet spot, condensate banking, filtrate invasion, and trapped liquid. Identifying a sweet spot will minimize the required number of hydraulic fracturing, thereby improving the overall economics. Formation damage of tight gas wells can occur due to trapped liquids, such as drilling filtrate, condensate banking, and water blockage, caused by formation water or hydraulic fracturing fluids.

Production from unconventional tight gas reservoirs has huge challenges that need to be overcome by technology to have commercial flow. Key challenges can be described as (i) identifying a sweet spot, which is any area of high porosity, high permeability, microfracture, or high-pressure zone that acts as a conductive channel and depletes the surrounding rock in a tight formation, and, when a sweet spot does not exist, a well is not commercial without extensive hydraulic fracturing, (ii) formation damage caused by trapped liquids due to drilling filtrate invasion, condensate banking, and water blockage caused by formation water and/or hydraulic fracturing fluids, and (iii) creating sufficient stimulated reservoir volume (SRV) in contact with the induced hydraulic fracture.

Thus in the future the process will continue to evolve to increase the productivity index of a producing well or the injectivity index of an injection well. The productivity index defines the rate at which oil or gas can be produced at a given pressure differential between the reservoir and the wellbore, while the injectivity index refers to the rate at which fluid can be injected into a well at a given pressure differential. As part of this evolution, there will be continued focus on (i) increasing the flow rate of oil and/or gas from low-permeability reservoirs, (ii) increasing the flow rate of oil and/or gas from wells that have been damaged, (iii) connecting the natural fractures and/or cleats in a formation to the wellbore, (iv) decreasing the pressure drop around the well to minimize sand production, (v) enhancing gravel-packing sand placement, (vi) decreasing the pressure drop around the well to minimize problems with asphaltene constituents and/or deposition of paraffin wax, (vii) increasing the area of drainage or the amount of formation in contact with the wellbore, (viii) connecting the full vertical extent of a reservoir to a slanted or horizontal well, and (ix) reducing well and/or formation damage.

Finally, no single process has had as significant an impact on the quality of refinery feedstocks as the recovery of cured oil from shale revolution. Not only are crude oils from shale formations (such as the Eagle Ford and Bakken formations in the United States) generally lighter than other domestic and foreign light grades, but the magnitude of the output will force grade substitutions with heavier crude oils. Blending the light crude oils from shale formations with heavier crude oils prior to refining will not only significantly alter product yields (in favor of higher yield of the distillable fuels) but also present numerous processing problems to refiners, such as the incompatibility of the asphaltene constituents of the heavier crude oils leading to a variety of refinery problems, including deposition of solids leading to blockage and corrosion of equipment (Chapter 1) (Speight, 2014a, 2014b).

8.5.2 The Environment

As additional regulatory measures, there will be continued focus on hydraulic fracturing. While questions relating to hydraulic fracturing wastewater disposal and the potential effects of hydraulic fracturing on water supply resources are reviewed, limits will continue to be placed on the drilling of new wells. Meanwhile, the oil and gas industry projects huge gains in natural gas production due to the increased use of hydraulic fracturing—natural gas may well overtake coal as the world's second largest fuel source by 2030.

Horizontal drilling in conjunction with hydraulic fracturing has made development of the shale gas resource an economic viable venture. As additional wells are drilled and more information is gathered on reservoir characteristics, additional advances may be realized in the fields of horizontal drilling and hydraulic fracturing, which could further enhance development of other shale gas resources. Development of shale formations in the United States should help to decrease the dependence of the United States on foreign imports of fossil fuels.

However, development of the resources from tight formation and from shale formations includes many unique challenges, including water availability and water disposal. To be successful, innovative solutions to developmental challenges associated with supplying the necessary volumes of water for hydraulic fracturing must be created. As more wells are drilled and development increases, it is anticipated that companies will continue designing leading-edge technological solutions to water availability and disposal including expanding the volume of water that is reused.

Thus, in order to establishing best environmental practice, there is a need for assiduous monitoring and assessment in which national or local environmental agencies charged with monitoring the potential impacts of hydraulic fracturing in the exploration and production of shale gas should be fully funded and equipped to carry out the necessary tasks. In particular, if an agency is to approve or license the use of a specific chemical additive, it must have the means in place to detect and monitor the presence and movement of this chemical in local water supplies. Above all, baseline monitoring studies of groundwater are needed before any drilling activity begins.

Furthermore, while the mechanical hydraulic fracturing process itself arguably does not pose a significant environmental risk, there are potential risks to groundwater from poor well design or construction, especially in relation to the casings and the cements. Agencies need the resources and legal basis to investigate, analyze, approve, or challenge the well designs and implementations used in the exploitation of shale gas. There must also be thorough testing of well casing and cement prior to injection of hydraulic fracturing of fluids. Moreover, active and regulated management of wastewater from the hydraulic fracturing process is critical, as this fluid poses one of the greatest tangible risks to the environment.

For the future, research and development should continue into the viability of removing all toxic additives from hydraulic fracturing fluids. The possibility of additive-free hydraulic fracturing fluids (i.e., just water and sand) should be explored from a research perspective and industry-sponsored testing. In fact, further research is needed into the treatment of flowback fluid, in particular a clearer understanding of those processes that work and those that do not, and should include the quantification of risks and costs associated with the various options.

There is also the need for a better geological understanding (in particular geomechanical understanding) of the fracture networks produced by hydraulic fracturing operations, especially in more complex shale gas. Many shale gas formations in North America have a relatively simple subhorizontal structure, but those in other parts of the world (especially Europe) are often folded and faulted on a variety of scales (Jackson and Mulholland, 1993). The more complex geometry of the shale gas formations in Europe, especially those of Carboniferous age, is due to an extended history of geological deformation spanning 300 million years. The generation and interaction of newly formed hydraulic fractures with much older preexisting fault and fracture zones, and tilted bedding planes, are very poorly understood in terms of the mechanics and the hydrogeology, and new research programs are required to address these topics.

In terms of the importance of comprehensive hydraulic fracturing disclosure, one essential function of disclosure rules is to give nearby parties the information they need to fully understand the risks to their air and water and any impacts that may occur. With advance disclosure and proper notice, those who live or own property near a well can document prefracturing conditions, including air and water quality in the area, in case of pollution or spills. In particular, nearby water sources can be tested to determine baseline levels of the substances that will be used in the fracturing fluid in order to document whether water contamination was a result of hydraulic fracturing. To ensure that baseline testing can measure prehydraulic fracturing levels of all potential contaminants, disclosure of the chemicals must be made in advance, allowing sufficient time for testing to be arranged and performed before hydraulic fracturing begins.

In addition, parties must be aware that hydraulic fracturing is about to occur. In order to ensure that nearby parties are aware of upcoming hydraulic fracturing, disclosure rules should require advance notice to nearby landowners, those who own water wells, and nonowner residents. Prior disclosure and notification may also facilitate a conversation between local stakeholders, regulators, and companies that can encourage the use of safer chemicals and practices, when they are available.

Disclosure rules should provide the public with information concerning the hydraulic fracturing process and also on practices and materials employed throughout the lifecycle of an oil and gas well. Disclosure of the chemicals used in hydraulic fracturing, the waste generated and its management, and the details of how and where fracturing was completed is essential for the following reasons:

- Adequate prehydraulic fracturing disclosure allows owners and users of nearby water sources to conduct baseline testing to establish the quality of their water prior to hydraulic fracturing, including the presence or absence of identified chemical constituents of frack fluids.
- Chemical disclosure is crucial to aid in determining the source of any subsequent groundwater contamination.
- First responders need the information to appropriately respond to accidents and emergencies.
- Chemical disclosure allows the public to fully assess the risks that chemical use, transport, and storage pose to their communities.
- Disclosure of water use provides the public information about the impacts of hydraulic fracturing on state supplies of freshwater.
- Disclosure of information regarding waste creation and disposition provides an accounting of the waste created, its contents, and the societal costs of its disposal.

However, disclosure does not, by itself, make hydraulic fracturing safer. An adequate regulatory regime must also include, among other things, standards requiring best practices in well siting and construction, spill and leak reduction and containment, pollution capture, waste disposal, and the minimization of impacts from well pads, roads, and pipelines. Nevertheless, comprehensive disclosure rule is one important component of a full suite of hydraulic fracturing safeguards and is essential to investigate contamination that occurs when proper safeguards are not in place or accidents occur.

In addition, hydraulic fracturing is only one step in the oil and gas exploration and development process. Each phase of oil and gas development poses risks to the environment and public health. Among these are air, water, and soil pollution and the use of dangerous chemicals during other phases of development. The public should be provided with accurate information on all hazards posed by the oil and gas industry.

Projections of the need for new wells to be drilled over the coming decades may lead to the construction of thousands of new well pads and thousands of miles of new access roads. The projected increase in roads has led some observers to be concerned about adverse effects of roads on ecosystems in areas of tight oil development. One way of mitigating this potential environmental issue is the increased use of *ecopads*, which allows for the drilling of multiple wells from a much smaller surface area, thereby reducing the number of well drilling pads and the associated access roads that would need to be constructed during the development of these plays, thereby leading to a reduction in the environmental footprint of the drilling operations (National Petroleum Council, 2011).

As unconventional crude oil and natural gas resources in tight sandstone formations and in tight shale formations continue to be developed, the need for protection of the environment becomes even more necessary. The development of this industry affords an opportunity to employ production techniques that work within the regulatory constraints and serve to demonstrate environmentally responsible production to both the proponents of the industry and the detractors.

Assuming that environmentally sustainable production methods are developed, this constraint could have a large and immediate impact on the start-up of the industry but decreasing as production expands. It is expected that environmental opposition will remain high despite industry proof that it can operate in an environmentally sustainable fashion. Sustainable production encompasses extraction methods that minimize the overall environment footprint including outright land disturbance and impacts on air, water, wildlife, and the local population. The operations that employ processes with zero release of contaminants to the air, the water, and the land surface will be the ones that set the standard for environmental sustainability.

REFERENCES

Arthur, J., Bohm, B., Coughlin, B.J., Layne, M., and Cornue, D. 2009. Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs. Proceedings. SPE Americas Environmental and Safety Conference, San Antonio, TX, March 23–25. Society of Petroleum Engineers, Richardson, TX.

Bamberger, M., and Oswald, R.E. 2012. Impacts of Gas Drilling on Human and Animal Health. *New Solutions*, 22(1): 51–77.

Chilton, J. 1996. Groundwater. In: *Water Quality Assessments—A Guide to Use of Biota, Sediments and Water in Environmental Monitoring*, 2nd Edition. D. Chapman (Editor). United Nations Educational, Scientific and Cultural Organization World Health Organization United Nations Environment Program (UNESCO/WHO/UNEP). Cambridge University Press, Cambridge, UK. Chapter 9.

Cooley, H., and Donnelly, K. 2012. *Hydraulic Fracturing and Water Resources: Separating the Frack from the Fiction*. Pacific Institute, Oakland, CA.

Darrah, T.H., Vengosh, A., Jackson, R.B., Warner, N.R., and Poreda, R.J. 2014. Noble Gases Identify the Mechanisms of Fugitive Gas Contamination in Drinking-Water Wells Overlying the Marcellus and Barnett Shales. *Proceedings of the National Academy of Sciences of the United States of America*, 111(39): 14076–14081.

Davies, R.J., Almond, S., Ward, R., Jackson, R.B., Adams, C., Worrall, F., Herringshaw, L.G., Gluyas, J.G., and Whitehead, M.A. 2014. Oil and Gas Wells and Their Integrity: Implications for Shale and Unconventional Resource Exploitation. *Marine and Petroleum Geology*, 56: 239–254.

Davies, R.J., Almond, S., Ward, R., Jackson, R.B., Adams, C., Worrall, F., Herringshaw, L.G., and Gluyas, J.G. 2015. Oil and Gas Wells and Their Integrity: Implications for Shale and Unconventional Resource Exploitation. *Marine and Petroleum Geology*, 59: 674–675.

European Commission. 2012. Support to the Identification of Potential Risks for the Environment and Human Health Arising from Hydrocarbons Operations Involving Hydraulic Fracturing in Europe. Report No. AEA/R/ED57281. European Commission DG Environment, European Union, Brussels, Belgium. October 8.

Gregory, K.B., Vidic, R.D., and Dzombak, D.A. 2011. Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing. *Elements*, 7: 181–186.

GWPC. 2009. Modern Shale Gas Development in the United States: A Primer. Ground Water Protection Council, 2009. Prepared for U.S. Department of Energy, Office of Fossil Energy, and National Energy Technology Laboratory, U.S. DOE Grant DE-FG26-04NT15455.

Holloway, M.D., and Rudd, O. 2013. *Fracturing: The Operations and Environmental Consequences of Hydraulic Fracturing*. John Wiley & Sons, Inc., Hoboken, NJ.

Howarth, R.W., Santoro, R., and Ingraffea, A. 2011. Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations. *Climatic Change*, 106: 679–690.

Jackson, D.I., and Mulholland, P. 1993. Tectonic and Stratigraphic Aspects of the East Irish Sea Basin and Adjacent Areas: Contrasts in Their Post-Carboniferous Structural Styles. In: *Petroleum Geology of Northwest Europe. Proceedings. 4th Geology Conference*. J.R. Parker (Editor). The Geological Society, London, UK. Page 791–808.

Jackson, R.B., Vengosh, A., Darrah, T.H., Warner, N.R., Down, A., Poreda, R.J., Osborn, S.G., Zhao, K., and Karr, J.D. 2013. Increased Stray Gas Abundance in a Subset of Drinking Water Wells Near Marcellus Shale Gas Extraction. *Proceedings of the National Academy of Sciences of the United States of America*, 110(28): 11250–11255.

Jenner, S., and Lamadrid, A.J. 2013. Shale Gas vs. Coal: Policy Implications from Environmental Impact Comparisons of Shale Gas, Conventional Gas, and Coal on Air, Water, and Land in the United States. *Energy Policy*, 53(2013): 442–453.

Kim, W.-Y. 2013. Induced Seismicity Associated with Fluid Injection into a Deep Well in Youngstown, Ohio. *Journal of Geophysical Research: Solid Earth*, 118: 1–13.

King, G.E. 2012. Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know about Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells. Paper No. 152596. Society of Petroleum Engineers, Richardson, TX.

Lee, D., Herman, J., Elsworth, D., Kim, H., and Lee, H. 2011. A Critical Evaluation of Unconventional Gas Recovery from the Marcellus Shale, Northeastern United States. *KSCE Journal of Civil Engineering*, 15: 679–687.

Molofsky, L., Conner, J.A., Wylie, A.S., Wagner, T., and Farhat, S. 2013. Evaluation of Methane Sources in Groundwater in Northeast Pennsylvania. *Groundwater*, 51(3): 333–349.

National Petroleum Council. 2011. Unconventional Oil. Paper No. 1–6. Working Document of the NPC North American Resource Development Study. Prepared by the Unconventional Oil Subgroup of the Resource & Supply Task Group. September 15.

Nicot, J.-P., and Scanlon, B.R. 2012. Water Use for Shale-Gas Production in Texas, U.S. *Environmental Science & Technology*, 46: 3580–3586.

NRC. 2012. *Induced Seismicity Potential in Energy Technologies*. National Research Council, National Academies Press, Washington, DC.

Osborn, S.G., Vengosh, A., Warner, N.R., and Jackson, R.B. 2011. Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing. *Proceedings of the National Academy of Sciences of the United States of America*, 108(20): 8172–8176.

OSHA. 2015. Code of Federal Regulations. 29 CFR 1910.1200(a)(1). Safety and Health Administration, United States Department of Labor, Washington, DC. https://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=standards&p_id=10099; accessed July 29, 2015.

Penning, T.M., Breysse, P., Gray, K., Howard, M., and Yan, B. 2014. Environmental Health Research Recommendations from the Inter-Environmental Health Sciences Core Center Working Group on Unconventional Natural Gas Drilling Operations. *Environmental Health Perspectives*. National Institute of Environmental Health Sciences, National Institutes of Health, US Department of Health and Human Services, Research Triangle Park, NC.

Robbins, K. 2013. Awakening the Slumbering Giant: How Horizontal Drilling Technology Brought the Endangered Species Act to Bear on Hydraulic Fracturing. *Case Western Reserve Law Review*, 63(4): 1143–1166.

Speight, J.G. 2009. *Enhanced Recovery Methods for Heavy Oil and Tar Sands*. Gulf Publishing Company, Houston, TX.

Speight, J.G. 2011. *An Introduction to Petroleum Technology, Economics, and Politics*. Scrivener Publishing, Salem, MA.

Speight, J.G. 2014a. *The Chemistry and Technology of Petroleum*, 5th Edition. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Speight, J.G. 2014b. *Oil and Gas Corrosion Prevention*. Gulf Professional Publishing, Elsevier, Oxford, UK.

Speight, J.G. 2015. *Handbook of Petroleum Product Analysis*. John Wiley & Sons, Inc., Hoboken, NJ.

Spellman, F.R. 2013. *Environmental Impacts of Hydraulic Fracturing*. CRC Press, Taylor & Francis Group, Boca Raton, FL.

Stern, P.C. 2014. *Risks and Risk Governance in Shale Gas Development: Summary of Two Workshops*. National Research Council, National Academies Press, Washington, DC. http://www.nap.edu/catalog.php?record_id=18953; accessed April 14, 2015.

Uddameri, V., Morse, A., and Tindle, K.J. 2016. *Hydraulic Fracturing—Impacts and Technologies*. CRC Press, Taylor & Francis Group, Boca Raton, FL.

US EPA. 2015a. Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources. Report No. EPA/600/R-15/047c. United States Environmental Protection Agency, Washington, DC. June.

US EPA. 2015b. Review of State and Industry Spill Data: Characterization of Hydraulic Fracturing-Related Spills. Report No. EPA/601/R-14/001. Office of Research and Development, US Environmental Protection Agency, Washington, DC. May.

US EPA. 2015c. Safe Drinking Water Act (SDWA). U.S. Environmental Protection Agency, Washington, DC. http://water.epa.gov/lawsregs/rulesregs/sdwa/index.cfm; accessed July 30, 2015.

US EPA. 2015d. Emergency Planning and Community Right-to-Know Act (EPCRA). U.S. Environmental Protection Agency, Washington, DC. http://www2.epa.gov/epcra/what-epcra; accessed July 30, 2015.

US EPA. 2015e. Oil Spills Prevention and Preparedness Regulations. U.S. Environmental Protection Agency, Washington, DC. http://www2.epa.gov/oil-spills-prevention-and-preparedness-regulations; accessed July 30, 2015.

Van der Elst, N.J., Savage, H.M., Keranen, K.M., and Abers, G.A. 2013. Enhanced Remote Earthquake Triggering at Fluid-Injection Sites in the Midwestern United States. *Science*, 341(6142): 164–167.

Veil, J.A. 2010. Water Management Technologies Used by Marcellus Shale Gas Producers. United States Department of Energy, Washington, DC. July.

Vidic, R.D., Brantley, S.L., Venderbossche, J.K., Yoxtheimer, D., and Abad, J.D. 2013. Impact of Shale Gas Development on Regional Water Quality. *Science*, 340(6134): 1–10.

Warner, N.R., Jackson, R.B., Darrah, T.H., Osborn, S.G., Down, A., Zhao, K., White, A., and Vengosh, A. 2012. Geochemical Evidence for Possible Natural Migration of Marcellus Formation Brine to Shallow Aquifers in Pennsylvanian. *Proceedings of the National Academy of Sciences of the United States of America*, 109(30): 11961–11966.

Waxman, H.A., Markey, E.J., and Degette, D. 2011. Chemicals Used in Hydraulic Fracturing. Committee on Energy and Commerce, United States House of Representatives, Washington, DC. April.

GLOSSARY

Abandonment pressure: the lowest gas pressure before a gas well must be abandoned.

Absolute permeability: ability of a rock to conduct a fluid when only one fluid is present in the pores of the rock.

Absorption gasoline: gasoline extracted from natural gas or refinery gas by contacting the absorbed gas with an oil and subsequently distilling the gasoline from the higher-boiling components.

Accelerator: an additive that increases the rate of a process such as cement setting.

Acid deposition: acid rain; a form of pollution depletion in which pollutants, such as nitrogen oxides and sulfur oxides, are transferred from the atmosphere to soil or water; often referred to as atmospheric self-cleaning. The pollutants usually arise from the use of fossil fuels.

Acid gas: a corrosive gas such as hydrogen sulfide or carbon dioxide that forms an acid with water.

Acid job: refers to when acid is poured or pumped down a well to dissolve limestone and increase fluid flow.

Acid number: a measure of the reactivity of petroleum with a caustic solution and given in terms of milligrams of potassium hydroxide that are neutralized by one gram of petroleum.

Acid rain: the precipitation phenomenon that incorporates anthropogenic acids and other acidic chemicals from the atmosphere to the land and water (see Acid deposition).

Acidizing: a technique for improving the permeability (*q.v.*) of a reservoir by injecting acid.

Acoustic log: see Sonic log.

Acre-foot: a measure of bulk rock volume where the area is one acre and the thickness is one foot.

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

Additions: the reserve provided by the exploratory activity. It consists of the discoveries and delimitations in a field during the study period.

Adsorption: adhesion of gas molecules, ions, or molecules in solution to the surface of solid bodies.

After flow: flow from the reservoir into the wellbore that continues for a period after the well has been shut in; after-flow can complicate the analysis of a pressure transient test.

Air drilling (pneumatic drilling): rotary drilling with air pumped down the drill string instead of circulating drilling mud.

Air injection: an oil recovery technique using air to force oil from the reservoir into the wellbore.

Air quality: a measure of the amount of pollutants emitted into the atmosphere and the dispersion potential of an area to dilute those pollutants.

Alicyclic hydrocarbon: a compound containing carbon and hydrogen only, which has a cyclic structure (e.g., cyclohexane); also collectively called naphthenes.

Aliphatic hydrocarbon: a compound containing carbon and hydrogen only, which has an open-chain structure (e.g., as ethane, butane, octane, or butene) or a cyclic structure (e.g., cyclohexane).

Aliquot: that quantity of material of proper size for measurement of the property of interest; test portions may be taken from the gross sample directly, but often preliminary operations such as mixing or further reduction in particle size are necessary.

Alkaline flooding: see Enhanced oil recovery (EOR) process.

Alluvial aquifer: a water-bearing deposit of unconsolidated material (e.g., sand, gravel) left behind by a river or other flowing water.

American Society for Testing and Materials (ASTM): the official organization in the United States for designing standard tests for petroleum and other industrial products.

Amphoteric: having both basic and acidic properties.

Anaerobic bacteria: bacteria that thrive in oxygen-poor environments.

Anisotropic: having some physical property that varies with direction from a given location.

Annular leak: a leak caused by poor cementation that allows contaminants to move vertically through the well either between casings or between casings and rock formations.

Annulus: the space between the casing (the material, typically steel, that is used to keep the well stable) in a well and the wall of the hole, or between two concentric strings of casing, or between casing and tubing.

Anticline: structural configuration of a package of folding rocks and in which the rocks are tilted in different directions from the crest.

Antifoam: an additive used to reduce foam.

API gravity: a measure of the *lightness* or *heaviness* of petroleum, which is related to density and specific gravity:

$$^{\circ}\mathrm{API} = \left(141.5 / \mathrm{sp\ gr} \ @\ 60^{\circ}\mathrm{F}\right) - 131.5$$

Apparent viscosity: the viscosity of a fluid, or several fluids flowing simultaneously, measured in a porous medium (rock) and subject to both viscosity and permeability effects; also called effective viscosity.

Aquifer: a subsurface rock interval that will produce water; often the underlay of a petroleum reservoir; a body of permeable rock or sediment that is saturated with water and yields useful amounts of water; a body of rock that is sufficiently permeable to conduct groundwater and to yield economically significant quantities of water to wells and springs.

Areal sweep efficiency (horizontal sweep efficiency): the fraction of the flood pattern area that is effectively swept by the injected fluids.

Argillaceous: shale-like or shaley.

Aromatic hydrocarbon: a hydrocarbon characterized by the presence of an aromatic ring or condensed aromatic rings; benzene and substituted benzene, naphthalene and substituted naphthalene, phenanthrene and substituted phenanthrene, as well as the higher condensed ring systems; compounds that are distinct from those of aliphatic compounds (*q.v.*) or alicyclic compounds (*q.v.*).

Aromatization: the conversion of nonaromatic hydrocarbons to aromatic hydrocarbons by (i) rearrangement of aliphatic (noncyclic) hydrocarbons (*q.v.*) into aromatic ring structures and (ii) dehydrogenation of alicyclic hydrocarbons (naphthene constituents).

Artificial production system: any of the techniques used to extract petroleum from the producing formation to the surface when the reservoir pressure is insufficient to raise the oil naturally to the surface.

Asphaltene association factor: the number of individual asphaltene species that associate in nonpolar solvents as measured by molecular weight methods; the molecular weight of asphaltenes in toluene divided by the molecular weight in a polar nonassociating solvent, such as dichlorobenzene, pyridine, or nitrobenzene.

Asphaltene fraction: the brown-to-black powdery material produced by treatment of petroleum, petroleum residua, or bituminous materials with a low-boiling liquid hydrocarbon, for example, pentane or heptane; soluble in benzene (and other aromatic solvents), carbon disulfide, and chloroform (or other chlorinated hydrocarbon solvents).

Associated gas: natural gas that is in contact with and/or dissolved in the crude oil of the reservoir. It may be classified as gas cap (free gas) or gas in solution (dissolved gas).

Associated gas in solution (or dissolved gas): natural gas dissolved in the crude oil of the reservoir, under the prevailing pressure and temperature conditions.

Associated molecular weight: the molecular weight of asphaltenes in an associating (nonpolar) solvent, such as toluene.

Atmospheric equivalent boiling point (AEBP): a mathematical method of estimating the boiling point at atmospheric pressure of nonvolatile fractions of petroleum.

Atmospheric residuum: a residuum obtained by distillation of a crude oil under atmospheric pressure, which boils above 350 °C (660 °F).

Attainment area: a geographical area that meets NAAQS for criteria air pollutants.

Aulacogen: a long, narrow rift in a continent, often filled with thick sediments.

Aureole: a ring surrounding a volcanic intrusion where the surrounding rock has been altered.

Authigenic: refers to a mineral that was formed by a chemical reaction in the subsurface.

Azimuth: the direction of a horizontal line as measured on an imaginary horizontal circle.

Backflush: to pump an injected fluid back out of a well.

Back-off operation: method used to remove stuck pipe from a well.

Bank: the concentration of oil (oil bank) in a reservoir that moves cohesively through the reservoir.

Barrel: the unit of measurement of liquids in the petroleum industry; equivalent to 42 US standard gallons or 33.6 imperial gallons.

Barrels of oil equivalent (boe): the amount of natural gas that has the same heat content as an average barrel of oil. It is about 6000 ft^3 of gas.

Base fluid: a liquid or foam substance into which additives are mixed or added to comprise a fracturing fluid system—the base fluid for many hydraulic fracturing systems is water; in certain other applications, the base fluid may also be a carbon dioxide-based or nitrogen-based foam.

Base number: the quantity of acid, expressed in milligrams of potassium hydroxide per gram of sample that is required to titrate a sample to a specified end point.

Basement: foot or base of a sedimentary sequence composed of igneous or metamorphic rocks.

Basic nitrogen: nitrogen (in petroleum) that occurs in pyridine form.

Basic sediment and water (BS&W, BSW): the material that collects in the bottom of storage tanks, usually composed of oil, water, and foreign matter; also called bottoms or bottom settlings.

Basin: a geological receptacle in which a sedimentary column is deposited that shares a common tectonic history at various stratigraphic levels; a closed geologic structure in which the beds dip toward a center location; the youngest rocks are at the center of a basin and are partly or completely ringed by progressively older rocks.

Baumé gravity: the specific gravity of liquids expressed as degrees on the Baumé (°Bé) scale. For liquids lighter than water:

$$\text{Sp gr } 60°\text{F} = 140/(130 + °\text{Bé})$$

For liquids heavier than water:

$$\text{Sp gr } 60°\text{F} = 145/(145 - °\text{Bé})$$

Bauxite: mineral matter used as a treating agent; hydrated aluminum oxide formed by the chemical weathering of igneous rock.

Bbl: see Barrel.

Bcf: billion cubic feet, a gas measurement equal to 1,000,000,000 ft^3.

Bedrock aquifer: an aquifer located in the solid rock underlying unconsolidated surface materials (i.e., sediment). Solid rock can bear water when it is fractured.

Bell cap: a hemispherical or triangular cover placed over the riser in a (distillation) tower to direct the vapors through the liquid layer on the tray.

Bentonite: a clay mineral used to make common drilling mud.

Benzene: a colorless aromatic liquid hydrocarbon (C_6H_6).

Benzin: a refined light naphtha used for extraction purposes.

Benzine: an obsolete term for light petroleum distillates covering the gasoline and naphtha range.

Benzol: the general term that refers to commercial or technical (not necessarily pure) benzene; also the term used for aromatic naphtha.

Billion: 1×10^9.

Biocide: a chemical substance capable of destroying some life forms in hydraulic fracturing; biocides are used to inhibit growth of bacteria and mold.

Biogenic: a direct product of the physiological activities of organisms.

Biogenic gas: natural gas produced by living organisms or by biological processes.

Biotite: black mica.

Bitumen: the organic constituents of tar sand (oil sand) deposits; generally contains sulfur, metals, and other nonhydrocarbon compounds; a semisolid to solid hydrocarbonaceous material found filling pores and crevices of sandstone, limestone, or argillaceous sediments.

Bituminous: containing bitumen or constituting the source of bitumen.

Bituminous rock: see Bituminous sand.

Bituminous sand: a formation in which the bituminous material (see Bitumen) is found as a filling in veins and fissures in fractured rock or impregnating relatively shallow sand, sandstone, and limestone strata; a sandstone reservoir that is impregnated with a heavy, viscous black petroleum-like material that cannot be retrieved through a well by conventional production techniques; also called *tar sand* or *oil sand*.

Black oil: any of the dark-colored oils; a term now often applied to heavy oil.

Blowout: any sudden and uncontrolled escape of fluids from a well to the surface.

Blowout preventer: a large valve at the top of a well that may be closed if the drilling crew loses control of formation fluids.

Boiling point: a characteristic physical property of a liquid at which the vapor pressure is equal to that of the atmosphere and the liquid is converted to a gas.

Boiling range: the range of temperature, usually determined at atmospheric pressure in standard laboratory apparatus, over which the distillation of oil commences, proceeds, and finishes.

Bottom water: a mixture of freshwater and brine.

Breakdown pressure: the sum of the closure stress and the friction effects of the fracturing fluid being delivered to the formation; breakdown pressure can be considerably higher than closure stress.

Breaker: a fracturing fluid additive that breaks down the viscosity of the fluid.

Breccia: a coarse-grained clastic rock composed of angular broken rock fragments held together by a mineral cement or a fine-grained matrix.

Brecciated: consisting of angular fragments cemented together.

British thermal unit: see BTU.

BTEX: benzene, toluene, ethylbenzene, and xylene isomers.

BTU (British thermal unit): the energy required to raise the temperature of one pound of water one degree Fahrenheit.

Bubble point: the temperature at which incipient vaporization of a liquid in a liquid mixture occurs, corresponding with the equilibrium point of 0% vaporization or 100% condensation.

Buckley–Leverett method: a theoretical method of determining frontal advance rates and saturations from a fractional flow curve.

Butt cleat: a short, poorly defined vertical cleavage plane in a coal seam, usually at right angles to the long face cleat; the coal cleat set that abuts into face cleats.

Buttress sand: sand deposited on top of an unconformity.

C_1, C_2, C_3, C_4, C_5 fractions: a common way of representing fractions containing a preponderance of hydrocarbons having 1, 2, 3, 4, or 5 carbon atoms, respectively, and without reference to hydrocarbon type.

Calorific equivalence of dry gas to liquid factor (CEDGLF): the factor used to relate dry gas to its liquid equivalent. It is obtained from the molar composition of the reservoir gas, considering the unit heat value of each component and the heat value of the equivalence liquid.

Cap rock: (i) impermeable rock layer that forms the seal on top of an oil or gas reservoir or (ii) insoluble rock on the top of a salt plug.

Capillary forces: interfacial forces between immiscible fluid phases, resulting in pressure differences between the two phases.

Capillary number: N_c, the ratio of viscous forces to capillary forces and equal to viscosity times velocity divided by interfacial tension.

Capillary pressure: a force per area unit resulting from the surface forces to the interface between two fluids.

Capture zone: the portion of an aquifer that contributes water to a particular pumping well.

Carbene: the pentane- or heptane-insoluble material that is insoluble in benzene or toluene and that is soluble in carbon disulfide (or pyridine); a type of rifle used for hunting bison.

Carboid: the pentane- or heptane-insoluble material that is insoluble in benzene or toluene and that is also insoluble in carbon disulfide (or pyridine).

Carbon dioxide augmented waterflooding: injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency; see Immiscible carbon dioxide displacement.

Carbon dioxide miscible flooding: see Enhanced oil recovery (EOR) process.

Carbonate rock: a rock composed primarily of carbonate minerals (minerals containing the carbonate (CO_3^{2-}) anionic structure, such as calcite). Common carbonate rocks are limestone and dolomite; sedimentary rock that is rich in calcium carbonate or magnesium carbonate; the dissolution spaces (vugs) associated with these type of rock can contain oil or gas.

Carbon-forming propensity: the propensity for petroleum, heavy oil, or tar sand bitumen (or fractions of these feedstocks) to form a carbonaceous reside during thermal treatment; the amount of residue is measure by application of ASTM standard text methods.

Carbonization: the conversion of an organic compound into char or coke by heat in the substantial absence of air; often used in reference to the destructive distillation (with simultaneous removal of distillate) of coal.

Carbon–oxygen log: information about the relative abundance of elements such as carbon, oxygen, silicon, and calcium in a formation; usually derived from pulsed neutron equipment.

Carboxymethyl hydroxypropyl guar (CMHPG): a form of guar gel.

Cased hole: a section of the wellbore in which casing and cement are installed.

Casing: the hard metal or plastic pipe that lines the well, prevents a borehole from caving in, and provides a barrier to the outside rock and groundwater. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geologic formations.

Casinghead gas: natural gas that issues from the casinghead (the mouth or opening) of an oil well.

Casinghead gasoline: the liquid hydrocarbon product extracted from casinghead gas (*q.v.*) by one of three methods: compression, absorption, or refrigeration; see also Natural gasoline.

Catagenesis: the alteration of organic matter during the formation of petroleum that may involve temperatures in the range 50 °C (120 °F) to 200 °C (390 °F); see also Diagenesis and Metagenesis.

Cathead: a hub on a shaft (cat shaft) on the draw-works of a drilling rig that is used to pull a line (cat line) to lift or pull equipment.

Caustic consumption: the amount of caustic lost from reacting chemically with the minerals in the rock, the oil, and the brine.

Cavitation cycling: also known as *cavity completion*, an alternative completion technique to hydraulic fracturing, in which a cavity is generated by alternately pumping in nitrogen and blowing down pressure.

Cement: (i) minerals that naturally grow between clastic grains and solidify a sedimentary rock or (ii) Portland cement used to bind the casing strings to the well walls.

Cement job: refers to cementing casing into a well.

Cementing: the process of placing cement slurry around the outside of the casing to stabilize the wellbore and prevent fluid movement between formations.

Centralizer: an attachment to the outside of a casing string that uses steel bands to keep the string central in the well.

CFR: Code of Federal Regulations; Title 40 (40 CFR) contains the regulations for protection of the environment.

Characterization factor: the UOP characterization factor K, defined as the ratio of the cube root of the molal average boiling point, T_B, in degrees Rankine (°R = °F + 460), to the specific gravity at 60 °F/60 °F:

$$K = (T_B)^{1/3}/\text{sp gr}$$

The value ranges from 12.5 for paraffin stocks to 10.0 for the highly aromatic stocks; also called the Watson characterization factor.

Charcoal test: a test used to measure the amount of condensate in natural gas; activated charcoal is used to absorb the condensate from a volume of natural gas.

Chemical flooding: see EOR process.

Chemical waste: any solid, liquid, or gaseous material discharged from a process that may pose substantial hazards to human health and environment.

Chloride: a chemical compound with one or more chlorine atoms bonded within the molecule; a salt of hydrochloric acid.

Christmas tree: the fittings, valves, and gauges that are bolted to the wellhead of a flowing well to control the flow from the well.

Clastic: composed of pieces of preexisting rock.

Clay: silicate minerals that also usually contain aluminum and have particle sizes are less than 0.002 μm; used in separation methods as an adsorbent and in refining as a catalyst.

Clean sands: well-sorted sands.

Cleats: natural fractures in coal that often occur in systematic sets through which gas and water can flow.

Closure stress: the pressure needed to fracture a rock through perforations in cased hole or the pressure at which the fracture closes after the fracturing pressure is relaxed. It is usually between 80 and 90% of breakdown pressure; sometimes interchangeably with fracture pressure; rocks with high closure stress are harder to fracture than the same rocks with lower closure stress. Shallow shale-containing sands have high closure stress because they have high Poisson ratio.

Cloud point: the temperature at which paraffin wax or other solid substances begin to crystallize or separate from the solution, imparting a cloudy appearance to the oil when the oil is chilled under prescribed conditions.

Coal: an organic rock.

Coal tar: the specific name for the tar (*q.v.*) produced from coal.

Coal tar pitch: the specific name for the pitch (*q.v.*) produced from coal.

Coalbed methane (CBM)/coalbed methane gas (CBMG): a clean-burning natural gas found deep inside and around coal seams. The gas has an affinity to coal and is held in place by pressure from groundwater. CBMG is produced by drilling a wellbore into the coal seams, pumping out large volumes of groundwater to reduce the hydrostatic pressure, and allowing the gas to dissociate from the coal and flow to the surface.

COFCAW: an EOR process (*q.v.*) that combines forward combustion and waterflooding.

Cogeneration: an energy conversion method by which electrical energy is produced along with steam generated for EOR use.

Cold production: the use of operating and specialized exploitation techniques in order to rapidly produce heavy oils without using thermal recovery methods.

Combustible liquid: a liquid with a flash point in excess of 37.8 °C (100 °F) but below 93.3 °C (200 °F).

Combustion zone: the volume of reservoir rock wherein petroleum is undergoing combustion during enhanced oil recovery.

Completion: the activities and methods related to preparing a well for the production of oil and/or gas, including installation of equipment for production from a gas well.

Completion interval: the portion of the reservoir formation placed in fluid communication with the well by selectively perforating the wellbore casing.

Complex: a series of fields sharing common surface facilities.

Composition: the general chemical makeup of petroleum.

Composition map: a means of illustrating the chemical makeup of petroleum using chemical and/or physical property data.

Compounder: a system of pulleys, belts, shafts, chains, and gears that transmit power from the prime movers to the drilling rig.

Compressor: a device installed in the gas pipeline to raise the pressure and guarantee the fluid flow through the pipeline.

Condensate: a mixture of light hydrocarbon liquids obtained by condensation of hydrocarbon vapors: predominately butane, propane, and pentane with some heavier hydrocarbons and relatively little methane or ethane; see also Natural gas liquids.

Condensate recovery factor (CRF): it is the factor used to obtain liquid fractions recovered from natural gas in the surface distribution and transportation facilities. It is obtained from the gas and condensate handling statistics of the last annual period in the area corresponding to the field being studied.

Conductivity: a measure of the ease of flow through a fracture, perforation, or pipe.

Conductor casing: casing that serves as a foundation for the well and prevents caving in of surface soils; set into the ground to a depth of approximately 100 ft.

Conformance: the uniformity with which a volume of the reservoir is swept by injection fluids in area and vertical directions.

Connate: saline, subsurface water.

Contingent resource: the amounts of hydrocarbons estimated at a given date, which are potentially recoverable from known accumulations, but are not considered commercially recoverable under the economic evaluation conditions corresponding to such date.

Conventional limit: the reservoir limit established according to the degree of knowledge of or research into the geological, geophysical, or engineering data available.

Conventional recovery: primary and/or secondary recovery.

Coquina: sedimentary rock composed of broken shells.

Core: a cylindrical rock sample taken from a formation when drilling in order to determine its permeability, porosity, hydrocarbon saturation, and other productivity-associated properties.

Core floods: laboratory flow tests through samples (cores) of porous rock.

Corridor: a strip of land through which one or more existing or potential utilities may be colocated.

Cosurfactant: a chemical compound, typically alcohol that enhances the effectiveness of a surfactant.

Cp (centipoise): a unit of viscosity.

Cracking: heat and pressure procedures that transform the hydrocarbons with a high molecular weight and boiling point to hydrocarbons with a lower molecular weight and boiling point.

Cracking temperature: the temperature (350 °C; 660 °F) at which the rate of thermal decomposition of petroleum constituents becomes significant.

Craig–Geffen–Morse method: a method for predicting oil recovery by waterflood.

Craton: a part of the Earth's crust that has attained stability and has been relatively nondeformed for a long time; the term is restricted to continents and includes both shield and platform.

Cross-linked gel: a gel to which a cross-linker has been added. Cross-linker, an additive that, when added to a linear gel, creates a complex, high-viscosity, pseudoplastic fracturing fluid.

Crude assay: a procedure for determining the general distillation characteristics (e.g., distillation profile, *q.v.*) and other quality information of crude oil.

Crude oil: petroleum.

Crude stream: crude oil from a single field or a mixture from fields that is offered for sale by an exporting country.

Cryogenic plant: processing plant capable of producing liquid natural gas products, including ethane, at very low operating temperatures.

Cryogenics: the study, production, and use of low temperatures.

Cut point: the boiling-temperature division between distillation fractions of petroleum.

Cyclic steam injection: the alternating injection of steam and production of oil with condensed steam from the same well or wells.

Cyclization: the process by which an open-chain hydrocarbon structure is converted to a ring structure, for example, hexane to benzene.

Cyclone: a device for extracting dust from industrial waste gases. It is in the form of an inverted cone into which the contaminated gas enters tangential from the top; the gas is propelled down a helical pathway, and the dust particles are deposited by means of centrifugal force onto the wall of the scrubber.

Cyclotherm: alternating marine and nonmarine sedimentary rocks.

Darcy: a measure of the permeability of rock or sediment.

Deasphalted oil: typically the soluble material after the insoluble asphaltic constituents (asphaltene and resin constituents) have been removed; commonly, but often incorrectly, used in place of *deasphaltened oil*; see Deasphalting.

Deasphaltened oil: the fraction of petroleum after the asphaltene fraction has been removed.

Deasphaltening: removal of a solid powdery asphaltene fraction from petroleum by the addition of the low-boiling liquid hydrocarbons such as *n*-pentane or *n*-heptane under ambient conditions.

Deasphalting: the removal of the asphaltene fraction from petroleum by the addition of a low-boiling hydrocarbon liquid such as *n*-pentane or *n*-heptane; more correctly the removal asphalt (tacky, semisolid) from petroleum (as occurs in a refinery asphalt plant) by the addition of liquid propane or liquid butane under pressure.

Degradation: the loss of desirable physical properties of EOR fluids, for example, the loss of viscosity of polymer solutions.

Dehydrocyclization: any process by which both dehydrogenation and cyclization reactions occur.

Dehydrogenation: the removal of hydrogen from a chemical compound, for example, the removal of two hydrogen atoms from butane to make butene(s) as well as the removal of additional hydrogen to produce butadiene.

Delimitation: exploration activity that increases or decreases reserves by means of drilling delimiting wells.

Demulsifier: a chemical used to break an emulsion.

Density: the mass (or weight) of a unit volume of any substance at a specified temperature; see also Specific gravity.

Desalting: removal of mineral salts (mostly chlorides) from crude oils.

Desorption: liberation of tightly held methane gas molecules previously bound to the solid surface of the coal.

Detrital: a sediment grain that has been transported and deposited to a whole particle such as a sand grain.

Developed proved area: plant projection of the extension drained by the wells of a producing reservoir.

Developed proved reserves: reserves that are expected to be recovered in existing wells, including reserves behind pipe, which may be recovered with the current infrastructure through additional work and with moderate investment costs. Reserves associated with secondary and/or enhanced recovery processes will be considered as developed when the infrastructure required for the process has been installed or when the costs required for such are lower. This category includes reserves in completed intervals that have been opened at the time when the estimation is made, but that have not started flowing due to market conditions, connection problems, or mechanical problems, and whose rehabilitation cost is relatively low.

Development: activity that increases or decreases reserves by means of drilling exploitation wells.

Development well: a well drilled in a proved area in order to produce hydrocarbons.

Dew-point pressure: pressure at which the first drop of liquid is formed, when it goes from the vapor phase to the two-phase region.

Diagenesis: the concurrent and consecutive chemical reactions that commence the alteration of organic matter (at temperatures up to 50°C/120°F) and ultimately result in the formation of petroleum from the marine sediment; see also Catagenesis and Metagenesis.

Diagenetic rock: rock formed by conversion through pressure or chemical reaction) from a rock, for example, sandstone is a diagenetic.

Differential-strain analysis: measurement of thermal stress relaxation in a recently cut well.

Dip-slip fault: a fault with predominately vertical displacement; it can be either a normal or reverse dip-slip fault.

Directional drilling: the technique of drilling at an angle from a surface location to reach a target formation not located directly underneath the well pad.

Discovered resource: volume of hydrocarbons tested through wells drilled.

Discovery: incorporation of reserves attributable to drilling exploratory wells that test hydrocarbon-producing formations.

Dispersion: a measure of the convective fluids due to flow in a reservoir.

Disposal well: a well that injects produced water into an underground formation for disposal.

Displacement efficiency: the ratio of the amount of oil moved from the zone swept by the reprocess to the amount of oil present in the zone prior to start of the process.

Dissolved gas–oil ratio: ratio of the volume of gas dissolved in oil compared to the volume of oil-containing gas. The ratio may be original (RSI) or instantaneous (RS).

Distribution coefficient: a coefficient that describes the distribution of a chemical in reservoir fluids, usually defined as the equilibrium concentrations in the aqueous phases.

Doghouse: the room or vehicle that houses the seismic recording equipment.

Dolomite: a mineral composed of $CaCO_3.MgCO_3$ and formed by the natural alteration of calcite; a rock composed of dolomite is called *dolostone* and can be a reservoir rock.

Dome: geological structure with a semispherical shape or relief.

Downhole steam generator: a generator installed downhole in an oil well to which oxygen-rich air, fuel, and water are supplied for the purposes of generating steam for it into the reservoir. Its major advantage over a surface steam-generating facility is that the losses to the wellbore and surrounding formation are eliminated.

Drainage radius: the distance from which fluids flow to the well, that is, the distance reached by the influence of disturbances caused by pressure drops; also, the radius of the approximate circular shape around a single wellbore from which the hydrocarbon flows into the wellbore; the drainage radius of a single well will help determine how many wells will be needed (and where they should go) to most efficiently drain the reservoir.

Draw-works: a drum in a steel frame used on the floor of a drilling rig to raise and lower equipment in a well.

Drill stem test (formation test): conventional formation test method.

Drilling mud: a viscous mixture of clay (usually bentonite) and additives with water, oil, an emulsion of water with droplets of oil, or a synthetic fluid.

Drilling rig (drill rig): the mast, draw-works, and attendant surface equipment of a drilling or workover unit.

Drinking water resource: any body of water, ground or surface, that could currently, or in the future, serve as a source of drinking water for public or private water supplies.

Dry gas: natural gas containing negligible amounts of hydrocarbons heavier than methane; dry gas is also obtained from the processing complexes.

Dry gas equivalent to liquid (DGEL): volume of crude oil that because of its heat rate is equivalent to the volume of dry gas.

Duster: a well that did not encounter commercial amounts of petroleum.

Dykstra–Parsons coefficient: an index of reservoir heterogeneity arising from permeability variation and stratification.

Economic limit: the point at which the revenues obtained from the sale of hydrocarbons match the costs incurred in its exploitation.

Economic reserves: accumulated production that is obtained from a production forecast in which economic criteria are applied.

Edge water: water located in the reservoir to the side of the oil.

Effective permeability: a relative measure of the conductivity of a porous medium for a fluid when the medium is saturated with more than one fluid. This implies that the effective permeability is a property associated with each reservoir flow, for example, gas, oil, and water. A fundamental principle is that the total of the effective permeability is less than or equal to the absolute permeability.

Effective porosity: A fraction that is obtained by dividing the total volume of communicated pores and the total rock volume.

Effective viscosity: see Apparent viscosity.

Emission: air pollution discharge into the atmosphere, usually specified by mass per unit time.

Emulsion: a dispersion of very small drops of one liquid in an immiscible liquid, such as oil in water.

Emulsion breaking: the settling or aggregation of colloidal-sized emulsions from suspension in a liquid medium.

Endangered species: those species of plants or animals classified by the Secretary of the Interior or the Secretary of Commerce as endangered pursuant to Section 4 of the Endangered Species Act of 1973, as amended.

Enhanced oil recovery (EOR): petroleum recovery following recovery by conventional (i.e., primary and/or secondary) methods (*q.v.*).

Enhanced oil recovery (EOR) process: a method for recovering additional oil from a petroleum reservoir beyond that economically recoverable by conventional primary and secondary recovery methods. EOR methods are usually divided into three main categories:

(i) *Chemical flooding*: injection of water with added chemicals into a petroleum reservoir. The chemical processes include surfactant flooding, polymer flooding, and alkaline flooding.

(ii) *Miscible flooding*: injection into a petroleum reservoir of a material that is miscible, or can become miscible, with the oil in the reservoir. Carbon dioxide, hydrocarbons, and nitrogen are used.

(iii) *Thermal recovery*: injection of steam into a petroleum reservoir, or propagation of a combustion zone through a reservoir by air or oxygen-enriched air injection. The thermal processes include steam drive, cyclic steam injection, and *in situ* combustion.

Epiclastic: formed from the fragments or particles broken away (by weathering and erosion) from preexisting rocks to form an altogether new rock in a new place.

Evaporites: sedimentary formations consisting primarily of salt, anhydrite or gypsum, as a result of evaporation in coastal waters.

Evapotranspiration: the portion of precipitation returned to the air through evaporation and transpiration.

Expanding clays: clays that expand or swell on contact with water, for example, montmorillonite.

Exploration: the process of identifying a potential subsurface geologic target formation and the active drilling of a borehole designed to assess the natural gas or oil.

Exploratory well: a well that is drilled without detailed knowledge of the underlying rock structure in order to find hydrocarbons whose exploitation is economically profitable.

Explosive fracturing: to explode nitroglycerin in a torpedo at reservoir depth in a well to fracture the reservoir and stimulate production.

Extra heavy oil: crude oil with relatively high fractions of heavy components, high specific gravity (low API density), and high viscosity at reservoir conditions. The production of this kind of oil generally implies difficulties in extraction and high costs. Thermal recovery methods are the most common form of commercially exploiting this kind of oil.

Face cleat: the major joint or cleavage system in a coal seam.

Facies: one or more layers of rock that differs from other layers in composition, age, or content.

Fairway (or trend): the area along which the play has been proven and more fields could be found.

FAST: fracture-assisted steam flood technology.

Faujasite: naturally occurring silica–alumina (SiO_2–Al_2O_3) mineral.

Fault: fractured surface of geological strata along which there has been differential movement. Fluid saturation: portion of the pore space occupied by a specific fluid; oil, gas, and water may exist.

Field scale: the application of EOR processes to a significant portion of a field.

Fine-grained: a geologic term to describe a rock texture, referring to its mineral or rock fragment components.

Fingering: the formation of finger-shaped irregularities at the leading edge of a displacing fluid in a porous medium that move out ahead of the main body of fluid.

Fire point: the lowest temperature at which, under specified conditions in standardized apparatus, a petroleum product vaporizes sufficiently rapidly to form above its surface an air–vapor mixture, which burns continuously when ignited by a small flame.

First-contact miscibility: see Miscibility.

Five-spot: an arrangement or pattern of wells with four injection wells at the comers of a square and a producing well in the center of the square.

Flash point: the lowest temperature to which the product must be heated under specified conditions to give off sufficient vapor to form a mixture with air that can be ignited momentarily by a flame.

Floc point: the temperature at which wax or solids separate as a definite floc.

Flocculation threshold: the point at which constituents of a solution (e.g., asphaltene constituents or coke precursors) will separate from the solution as a separate (solid) phase.

Flood, flooding: the process of displacing petroleum from a reservoir by the injection of fluids.

Flow line: a small-diameter pipeline that generally connects a well to the initial processing facility.

Flowback: the portion of the injected fracturing fluid that flows back to the surface, along with oil, gas, and brine, when the well is produced.

Flowback water: the fracturing fluid that returns to the surface through the wellbore during and after hydraulic treatment.

Fluid: a reservoir gas or liquid or, in some instances, a solid.

Fluid saturation: the portion of the pore space occupied by a specific fluid; oil, gas, and water may exist.

Formation: an interval of rock with distinguishable geologic characteristics; a basic unit of rock layers distinctive enough in appearance, composition, and age to be defined in geologic maps and classifications; a rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

Formation resistance factor (F): ratio between the resistance of rock saturated 100% with brine divided by the resistance of the saturating water.

Formation volume factor (B): the factor that relates the volume unit of the fluid in the reservoir with the surface volume. There are volume factors for oil and gas, in both phases, and for water. A sample may be directly measured, calculated, or obtained through empirical correlations.

Fossil fuel resources: a gaseous, liquid, or solid fuel material formed in the ground by chemical and physical changes (diagenesis, *q.v.*) in plant and animal residues over geological time; natural gas, petroleum, coal, and oil shale.

Frac: hydraulic fracturing, as adapted by the petroleum industry.

Fractional composition: the composition of petroleum as determined by fractionation (separation) methods.

Fractional flow: the ratio of the volumetric flow rate of one fluid phase to the total fluid volumetric flow rate within a volume of rock.

Fractional flow curve: the relationship between the fractional flow of one fluid and its saturator during simultaneous flow of fluids through rock.

Fracture: a natural or man-made crack in a reservoir rock; a separation within a geologic formation, such as a joint or a fault that divides the rock into two or more pieces and that is commonly caused by stress in which the strength of the rock is exceeded and causes the rock to lose cohesion along the weakest plane; fractures can provide permeability for movement of reservoir fluids (gases, oil, and water); the orientation of the fracture can be anywhere from horizontal to vertical; minerals may fill the entire fracture, converting an open fracture to a healed or sealed fracture.

Fracture conductivity: the capability of the fracture to conduct fluids under a given hydraulic head difference.

Fracture optimization: the design of a fracturing operation that is strong enough to penetrate the reservoir rock and yet weak enough not to break into zones where it is not wanted.

Fracture pressure: the pressure needed to create a fracture in a rock while drilling in open hole.

Fracturing: the breaking apart of reservoir rock by applying very high fluid pressure at the rock face.

Fracturing fluids: the water and chemical additives used to hydraulically fracture the reservoir rock and proppant (typically sand or ceramic beads) pumped into the fractures to keep them from closing once the pumping pressure is released.

Free associated gas: natural gas that overlies and is in contact with the crude oil of the reservoir—it may be gas cap.

Frictional resistance: the force that inhibits the relative motion of two solid objects in contact; usually proportional to the force that presses the surfaces together.

Functional group: the portion of a molecule that is characteristic of a family of compounds and determines the properties of these compounds.

Gas cap: a part of a hydrocarbon reservoir at the top that will produce only gas.

Gas compressibility ratio (Z): the ratio between an actual gas volume and an ideal gas volume. This is an adimensional amount that usually varies between 0.7 and 1.2.

Gas lift: artificial production system that is used to raise the well fluid by injecting gas down the well through tubing or through the tubing–casing annulus.

Gas–oil ratio (GOR): ratio of reservoir gas production to oil production, measured at atmospheric pressure.

Gathering system: a system of flow lines that conducts produced fluids from wells to a central processing unit.

Geological province: a region of large dimensions characterized by similar geological and development histories.

Geophone: a seismic detector, placed on or in the ground that responds to ground motion at its point of location.

Geothermal gradient: increase in temperature with depth in the Earth.

Graben: an elongated dip or depression formed by tectonic processes, limited by normal-type faults.

Gravitational segregation: reservoir driving mechanism in which the fluids tend to separate according to their specific gravities. For example, since oil is heavier than water, it tends to move toward the lower part of the reservoir in a water injection project.

Gravity: see API gravity.

Gravity drainage: the movement of oil in a reservoir that results from the force of gravity.

Gravity segregation: partial separation of fluids in a reservoir caused by the gravity force acting on differences in density.

Gravity-stable displacement: the displacement of oil from a reservoir by a fluid of a different density, where the density difference is utilized to prevent gravity segregation of the injected fluid.

Graywacke: poorly sorted, dark-colored sandstone.

Groundwater (ground water): water found below the surface of the land, usually in porous rock formations. Ground water is the source of water found in wells and springs and is frequently used for drinking.

Guar: organic powder thickener, typically used to make viscous fracturing fluids; it is completely soluble in hot and cold water and insoluble in oils, grease, and hydrocarbons.

Habitat: the area in which a particular species lives; in wildlife management, the major elements of a habitat are considered to the food, water, cover, breeding space, and living space.

Handling efficiency shrinkage factor (HESF): this is a fraction of natural gas that is derived from considering self-consumption and the lack of capacity to handle such. It is obtained from the gas handling statistics of the final period in the area corresponding to the field being studied.

HCl: molecular formula for hydrochloric acid, which can be used in diluted form in the hydraulic fracturing process to fracture limestone formations and to clean up perforations in coalbed methane fracturing treatments.

HCPV: hydrocarbon pore volume.

Hearn method: a method used in reservoir simulation for calculating a pseudorelative permeability curve that reflects reservoir stratification.

Heat value: the amount of heat released per unit of mass, or per unit of volume, when a substance is completely burned. The heat power of solid and liquid fuels is expressed in calories per gram or in BTU per pound. For gases, this parameter is generally expressed in kilocalories per cubic meter or in BTU per cubic foot.

Heavy oil: arbitrarily, petroleum having an API gravity of less than 20°.

Heavy petroleum: see Heavy oil.

Heteroatom compounds: chemical compounds that contain nitrogen and/or oxygen and/or sulfur and/or metals bound within their molecular structure(s).

Heterogeneity: lack of uniformity in reservoir properties such as permeability.

Higgins–Leighton model: stream tube computer model used to simulate waterflood.

Horizontal drilling: a drilling procedure in which the wellbore is drilled vertically to a kickoff depth above the target formation and then angled though a 90° arc such that the producing portion of the well extends horizontally through the formation.

Horizontal fracturing: the placement of fractures in a horizontal wellbore. The fractures are designed to stay within the producing formation rather than expanding into adjoining formations above or below. The position of the fractures can be determined by microseismic fracture mapping and tiltmeter monitoring.

Horizontal wellbore: a wellbore that starts down through the rock in a vertical direction but is then turned horizontally for some length into the producing formation; fractures are often placed along the horizontal wellbore to help spur new production.

Horst: a block of the Earth's crust rising between two faults; the opposite of a graben.

Hot production: the optimum production of heavy oils through use of enhanced thermal recovery methods.

Huff and puff: a cyclic EOR method in which steam or gas is injected into a production well; after a short shut-in period, oil and the injected fluid are produced through the same well.

Hybrid fracturing: a fracturing treatment that relies upon on a fluid system in which some combination of water fracturing, linear gel fracturing, and/or cross-linked gel fracturing may be used as part of the engineered fluid formulation. Such a system may begin with a water fracturing formulation design to encourage fracture complexity but may be shifted later to take advantage of opportunities to produce oil, which requires a higher concentration of propping agent.

Hydration: the association of molecules of water with a substance.

Hydraulic conductivity: see Permeability.

Hydraulic fracturing: a process in which pressure is applied to a reservoir rock on purpose in order to break or crack it—most hydraulic and natural fractures are near vertical and increase well productivity significantly; the opening of fractures in a reservoir by high-pressure, high-volume injection of liquids through an injection well.

Hydrocarbon compounds: chemical compounds containing only carbon and hydrogen.

Hydrocarbon index: an amount of hydrocarbons contained in a reservoir per unit area.

Hydrocarbon reserves: volume of hydrocarbons measured at atmospheric conditions that will be produced economically by using any of the existing production methods at the date of evaluation.

Hydrocarbon resource: resources such as petroleum and natural gas that can produce naturally occurring hydrocarbons without the application of conversion processes.

Hydrocarbon-producing resource: a resource such as tar sand bitumen, coal, and oil shale (kerogen) that produces derived hydrocarbons by the application of conversion processes.

Hydrocarbons: chemical compounds fully constituted by hydrogen and carbon.

Hydrogen transfer: the transfer of inherent hydrogen within the feedstock constituents and products during some thermal recovery processes.

Hydrostatic pressure: the pressure exerted by a fluid at rest due to its inherent physical properties and the amount of pressure being exerted on it from outside forces.

Hydroxyethyl cellulose (HEC): a form of guar gel.

Ignitability: characteristic of liquids whose vapors are likely to ignite in the presence of ignition source; also characteristic of nonliquids that may catch fire from friction or contact with water and that burn vigorously.

Immiscibility: the inability of two or more fluids to have complete mutual solubility; they coexist as separate phases.

Immiscible: two or more fluids that do not have complete mutual solubility and coexist as separate phases.

Immiscible carbon dioxide displacement: injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained; see Carbon dioxide augmented waterflooding.

Immiscible displacement: a displacement of oil by a fluid (gas or water) that is conducted under conditions so that interfaces exist between the driving fluid and the oil.

Impurities and plant liquefiables shrinkage factor (IPLSF): It is the fraction obtained by considering the nonhydrocarbon gas impurities (sulfur, carbon dioxide, nitrogen compounds, etc.) contained in the sour gas, in addition to shrinkage caused by the generation of liquids in gas processing plant.

Impurities shrinkage factor (ISF): It is the fraction that results from considering the nonhydrocarbon gas impurities (sulfur, carbon dioxide, nitrogen compounds, etc.) contained in the sour gas. It is obtained from the operation statistics of the last annual period of the gas processing complex (GPC) that processes the production of the field analyzed.

Incompatibility: the *immiscibility* of petroleum products and also of different crude oils, which is often reflected in the formation of a separate phase after mixing and/or storage.

Incremental ultimate recovery: the difference between the quantity of oil that can be recovered by EOR methods and the quantity of oil that can be recovered by conventional recovery methods.

Induced seismicity: seismic activity caused by subsurface operations. In the context of fluid injection-induced seismicity, radiated seismic energy is provided by the release of tectonic energy.

Infill drilling: drilling additional wells within an established pattern.

Initial boiling point: the recorded temperature when the first drop of liquid falls from the end of the condenser.

Initial vapor pressure: the vapor pressure of a liquid of a specified temperature and 0% evaporated.

Injectate: in relation to the coalbed methane industry, this is the fracturing fluid injected into a coalbed methane well.

Injection profile: the vertical flow rate distribution of fluid flowing from the wellbore into a reservoir.

Injection well: a well in an oil field used for injecting fluids into a reservoir.

Injectivity: the relative ease with which a fluid is injected into a porous rock.

In situ: in its original place; in the reservoir.

***In situ* combustion:** an EOR process consisting of injecting air or oxygen-enriched air into a reservoir under conditions that favor burning part of the *in situ* petroleum, advancing this burning zone, and recovering oil heated from a nearby producing well.

Instability: the inability of a petroleum product to exist for periods of time without change to the product.

Integrity: maintenance of a slug or bank at its preferred composition without too much dispersion or mixing.

Interface: the thin surface area separating two immiscible fluids that are in contact with each other.

Interfacial film: a thin layer of material at the interface between two fluids that differs in composition from the bulk fluids.

Interfacial tension: the strength of the film separating two immiscible fluids, for example, oil and water or microemulsion and oil; measured in dynes (force) per centimeter or millidynes per centimeter.

Interfacial viscosity: the viscosity of the interfacial film between two immiscible liquids.

Interference testing: a type of pressure transient test in which pressure is measured over time in a closed-in well while nearby wells are produced; flow and communication between wells can sometimes be deduced from an interference test.

Interfinger: a boundary between two rock types in which both form distinctive wedges protruding into each other.

Intermediate casing: casing used to isolate the well from nonfreshwater zones that may cause instability or be abnormally pressurized; the casing may be sealed with cement typically either up to the base of the surface casing or all the way to the surface.

Interphase mass transfer: the net transfer of chemical compounds between two or more phases.

Isopach: a line on a map connecting points of equal true thickness of a designated stratigraphic unit or group of stratigraphic units.

Isotopic: rocks formed in the same environment (i.e., in the same sedimentary basin or geologic province).

Isotropic: a medium, such as unconsolidated sediments or a rock formation, whose properties are the same in all directions.

Junk: a tool or broken pipe that has fallen to the bottom of a well.

Kaolinite: a clay mineral formed by hydrothermal activity at the time of rock formation or by chemical weathering of rock with high feldspar content; usually associated with intrusive granite rock with high feldspar content.

Kata-condensed aromatic compounds: Compounds based on linear condensed aromatic hydrocarbon systems, for example, anthracene and naphthacene (tetracene).

KCl: molecular formula for potassium chloride.

Kelly: a strong four- or six-sided steel pipe that is located at the top of the drill string; it runs through the kelly bushing.

Kerogen: a complex carbonaceous (organic) material that occurs in sedimentary rock and shale; generally insoluble in common organic solvents; produces hydrocarbon-type oil when subjected to a heat.

K-factor: see Characterization factor.

Kickoff point: the depth at which the vertical drill hole is deviated for directional drilling so the wellbore can enter the target zone roughly horizontal.

Kinematic viscosity: the ratio of viscosity (*q.v.*) to density, both measured at the same temperature.

Kriging: a technique used in reservoir description for interpolation of reservoir parameters between wells based on random field theory.

Lacustrine: pertaining to, produced by, or formed in a lake or lakes.

Laminar flow: water flow in which the stream lines remain distinct and the flow direction at every point remains unchanged with time; nonturbulent flow.

Leak-off: fluid loss at the fracture; the rate of leak-off to the formation is dependent upon the viscosity and the wall-building properties of the fluid.

Lease: a legal document that conveys to an operator the right to drill for oil and gas; also, the tract of land on which a lease has been obtained and where producing wells and production equipment are located.

Lenticular: pertaining to a discontinuous lens-shaped (saucer-shaped) stratigraphic body.

Lift gas: inert gas, usually natural gas that is used for gas lift.

Light ends: the lower-boiling components of a mixture of hydrocarbons.

Light oil: the specific gravity of the oil is more than 27° API, but less than or equal to 38°.

Light petroleum: arbitrarily, petroleum having an API gravity greater than 20°.

Limolite: fine-grained sedimentary rock that is transported by water. The granulometrics ranges from fine sand to clay.

Linear gel: a simple guar-based fracturing fluid usually formulated using guar and water with additives or guar with diesel fuel:

Lithology: the geological characteristics of the reservoir rock.

Lorenz coefficient: a permeability heterogeneity factor.

Lower-phase microemulsion: a microemulsion phase containing a high concentration of water that, when viewed in a test tube, resides near the bottom with oil phase on top.

Make up: to screw together pipe sections.

Maltenes: that fraction of petroleum that is soluble in, for example, pentane or heptane; deasphaltened oil (*q.v.*); also the term arbitrarily assigned to the pentane-soluble portion of petroleum that is relatively high boiling (>300°C, 760 mm) (see also Petrolenes).

Marine sediment: the organic biomass from which petroleum is derived.

Marsh: an area of spongy waterlogged ground with large numbers of surface water pools. Marshes usually result from (i) an impermeable underlying bedrock, (ii) surface deposits of glacial boulder clay, (iii) a basin-like topography from which natural drainage is poor, (iv) very heavy rainfall in conjunction with a correspondingly low evaporation rate, and (v) low-lying land, particularly at estuarine sites at or below sea level.

Marx–Langenheim model: mathematical equations for calculating heat transfer in a hot water or steam flood.

Mcf: a natural gas measurement unit for 1000 ft^3.

MEOR: microbial enhanced oil recovery.

Metagenesis: the alteration of organic matter during the formation of petroleum that may involve temperatures above 200 °C (390 °F); see also Catagenesis and Diagenesis.

Metamorphic rocks: a group of rocks resulting from the transformation that commonly takes place at great depths due to pressure and temperature. The original rocks may be sedimentary, igneous, or metamorphic.

Methane: a colorless, odorless, and flammable gaseous hydrocarbon.

Mica: a complex aluminum silicate mineral that is transparent, tough, flexible, and elastic.

Micellar fluid (surfactant slug): an aqueous mixture of surfactants, cosurfactants, salts, and hydrocarbons. The term micellar is derived from the word micelle, which is a submicroscopic aggregate of surfactant molecules and associated fluid.

Microemulsion: a stable, finely dispersed mixture of oil, water, and chemicals (surfactants and alcohols).

Microemulsion or micellar/emulsion flooding: an augmented waterflooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells.

Microorganisms: animals or plants of microscopic size, such as bacteria.

Microscopic displacement efficiency: the efficiency with which an oil displacement process removes the oil from individual pores in the rock.

Microseismic: a faint earth tremor, typically less than Richter magnitude zero, which was the detection limit in 1935.

Middle-phase microemulsion: a microemulsion phase containing a high concentration of both oil and water that, when viewed in a test tube, resides in the middle with the oil phase above it and the water phase below it.

Migration (primary): the movement of hydrocarbons (oil and natural gas) from mature, organic-rich source rocks to a point where the oil and gas can collect as droplets or as a continuous phase of liquid hydrocarbon.

Migration (secondary): the movement of the hydrocarbons as a single, continuous fluid phase through water-saturated rocks, fractures, or faults followed by accumulation of the oil and gas in sediments (traps, *q.v.*) from which further migration is prevented.

Millidarcy (mD): the customary unit of measurement of fluid permeability: equivalent to 0.001 darcy.

Milligrams per liter (mg/l): typically used to define the concentration of a compound dissolved in a fluid.

Mined-through studies: projects in which coalbeds have been actually mined through (i.e., the coal has been removed) so that remaining coal and surrounding rock can be inspected, after the coalbeds have been hydraulically fractured. These studies provide unique subsurface access to investigate coalbeds and surrounding rock after hydraulic fracturing.

Mineral hydrocarbons: petroleum hydrocarbons, considered *mineral* because they come from the Earth rather than from plants or animals.

Mineral oil: the older term for petroleum; the term was introduced in the nineteenth century as a means of differentiating petroleum (rock oil) from whale oil, which, at the time, was the predominant illuminant for oil lamps.

Mineral seal oil: a distillate fraction boiling between kerosene and gas oil.

Minerals: naturally occurring inorganic solids with well-defined crystalline structures.

Minimum miscibility pressure (MMP): see Miscibility.

Miscibility: an equilibrium condition, achieved after mixing two or more fluids, which is characterized by the absence of interfaces between the fluids:

- (i) *First-contact miscibility*: miscibility in the usual sense, whereby two fluids can be mixed in all proportions without any interfaces forming. For example, at room temperature and pressure, ethyl alcohol and water are first-contact miscible.
- (ii) *Multiple-contact miscibility* (*dynamic miscibility*): miscibility that is developed by repeated enrichment of one fluid phase with components from a second fluid phase with which it comes into contact.
- (iii) *Minimum miscibility* pressure: the minimum pressure above which two fluids become miscible at a given temperature, or can become miscible, by dynamic processes.

Miscible flooding: see EOR process.

Miscible fluid displacement (miscible displacement): is an oil displacement process in which is an oil displacement process in which an alcohol, a refined hydrocarbon, a condensed petroleum gas, carbon dioxide, liquefied natural gas, or even exhaust gas is injected into an oil reservoir, at pressure levels such that the injected gas or fluid and reservoir oil are miscible; the process may include the concurrent, alternating, or subsequent injection of water.

MMcf: a natural gas measurement unit for 1,000,000 ft^3.

Mobility: a measure of the ease with which a fluid moves through reservoir rock; the ratio of rock permeability to apparent fluid viscosity.

Mobility buffer: the bank that protects a chemical slug from water invasion and dilution and assures mobility control.

Mobility control: ensuring that the mobility of the displacing fluid or bank is equal to or less than that of the displaced fluid or bank.

Mobility ratio: ratio of mobility of an injection fluid to mobility of fluid being displaced.

Modified alkaline flooding: the addition of a cosurfactant and/or polymer to the alkaline flooding process.

Modified naphtha insolubles (MNI): an insoluble fraction obtained by adding naphtha to petroleum; usually the naphtha is modified by adding paraffin constituents; the fraction might be equated to asphaltenes but only *if* the naphtha is equivalent to *n*-heptane.

Moment magnitude scale: used by scientists to measure the size of earthquakes in terms of the energy released; the scale was developed in the 1970s to improve upon the Richter magnitude scale, particularly to describe large ($m > 7$) earthquakes and those whose epicenter is over 370 miles away.

MSDS: material safety data sheet: a document for a chemical product or additive prepared in accordance with the Hazard Communication Standard set forth by the federal Occupational Safety and Health Administration (OSHA). MSDS must include information about the physical and chemical characteristics, physical and health hazards, and precautions for the safe use and handling (including emergency and first-aid procedures) of the hazardous chemical components contained in the specific product or additive for which the MSDS was prepared, along with the name, address, and emergency telephone number of the company that prepared it.

Multistage fracturing: the process of undertaking multiple fracture conditions in the reservoir section where parts of the reservoir are isolated and fractured separately.

Naft: pre-Christian era (Greek) term for naphtha.

Naphtha: a generic term applied to refined, partly refined, or unrefined petroleum products and liquid products of natural gas, the majority of which distills below 240 °C (464 °F); the volatile fraction of petroleum, which is used as a solvent or as a precursor to gasoline.

Native asphalt: see Bitumen.

Natural gas: mixture of hydrocarbons existing in reservoirs in the gaseous phase or in solution in the oil, which remains in the gaseous phase under atmospheric conditions; may contain some impurities or nonhydrocarbon substances (hydrogen sulfide, nitrogen, or carbon dioxide).

Natural gas liquids (NGL): the hydrocarbon liquids that condense during the processing of hydrocarbon gases that are produced from oil or gas reservoir; see also Natural gasoline.

Natural gasoline: a mixture of liquid hydrocarbons extracted from natural gas (*q.v.*) suitable for blending with refinery gasoline.

Net thickness: the thickness resulting from subtracting the portions that have no possibilities of producing hydrocarbon from the total thickness.

NIOSH: National Institute for Occupational Safety and Health.

Nonassociated gas: the natural gas found in reservoirs that do not contain crude oil at the original pressure and temperature conditions.

Nonionic surfactant: a surfactant molecule containing no ionic charge.

Non-Newtonian: a fluid that exhibits a change of viscosity with flow rate.

Nonproved reserves: volumes of hydrocarbons and associated substances, evaluated at atmospheric conditions, resulting from the extrapolation of the characteristics and parameters of the reservoir beyond the limits of reasonable certainty or from assuming oil and gas forecasts with technical and economic scenarios other than those in operation or with a project in view.

NORM: naturally occurring radioactive materials; includes naturally occurring uranium: 235 and daughter products such as radium and radon.

Normal fault: the result of the downward displacement of one of the blocks from the horizontal. The angle is generally between 25° and 60° and it is recognized by the absence of part of the stratigraphic column.

Observation wells: wells that are completed and equipped to measure reservoir conditions and/or sample reservoir fluids, rather than to inject or produce reservoir fluids.

Oil: the portion of petroleum that exists in the liquid phase in reservoirs and remains as such under original pressure and temperature conditions. Small amounts of nonhydrocarbon substances may be included. It has a viscosity of less than or equal to 10,000 centipoises at the original temperature of the reservoir, at atmospheric pressure and gas-free (stabilized). Oil is commonly (or arbitrarily) classified in terms of its specific gravity, and it is expressed in degrees API.

Oil bank: see Bank.

Oil breakthrough (time): the time at which the oil–water bank arrives at the producing well.

Oil equivalent (OE): total of crude oil, condensate, plant liquids, and dry gas equivalent to liquid.

Oil originally in place (OOIP): the quantity of petroleum existing in a reservoir before oil recovery operations begin.

Oil sand: see Tar sand.

Oil shale: a fine-grained impervious sedimentary rock formation that contains an organic material called kerogen; a rock formation that contains kerogen, an early stage of organic matter processing into petroleum, and that produced shale oil by destructive distillation (thermal decomposition) of the kerogen contained therein to yield oil.

Oil equivalent gas (OEG): the volume of natural gas needed to generate the equivalent amount of heat as a barrel of crude oil; approximately $6000\,\text{ft}^3$ of natural gas is equivalent to one barrel of crude oil.

Oil field brine: very saline water that is produced with oil.

OOIP: see Oil originally in place.

Optimum salinity: the salinity at which a middle-phase microemulsion containing equal concentrations of oil and water results from the mixture of a micellar fluid (surfactant slug) with oil.

Organic sedimentary rocks: rocks containing organic material such as residues of plant and animal remains/decay.

Original gas volume in place: amount of gas that is estimated to exist initially in the reservoir and that is confined by geologic and fluid boundaries, which may be expressed at reservoir or atmospheric conditions.

Original oil volume in place: amount of petroleum that is estimated to exist initially in the reservoir and that is confined by geologic and fluid boundaries, which may be expressed at reservoir or atmospheric conditions.

Original pressure: pressure prevailing in a reservoir that has never been produced. It is the pressure measured by a discovery well in a producing structure.

Original reserve: volume of hydrocarbons at atmospheric conditions that are expected to be recovered economically by using the exploitation methods and systems applicable at a specific date. It is a fraction of the discovered and economic reserve that may be obtained at the end of the reservoir exploitation.

Override: the gravity-induced flow of a lighter fluid in a reservoir above another heavier fluid.

Overthrust: a large-scale, low-angle thrust fault, with total displacement (lateral or vertical) generally measured in kilometers.

1P reserve: proved reserve.

2P reserves: total of proved plus probable reserves.

3P reserves: total of proved reserves plus probable reserves plus possible reserves.

Pad: an initial volume of fluid that is used to initiate and propagate a fracture before a proppant is placed.

Paleochannels: old or ancient river channels preserved in the subsurface as lenticular sandstones.

Paraffin: a member of the alkane series of molecules.

Particulate matter (PM): a small particle of solid or liquid matter (e.g., soot, dust, mist); PM_{10} refers to particulate matter having a size diameter of less than 10 millionths of a meter (micrometer, or μm); $PM_{2.5}$ is less than 2.5 μm in diameter.

Parts per million (ppm): number of weight or volume units of a constituent present with each 1 million units of a solution or mixture.

Pattern: the horizontal pattern of injection and producing wells selected for a secondary or enhanced recovery project.

Pattern life: the length of time a flood pattern participates in oil recovery.

Payzone: the region of the reservoir that is accessible to the wellbore or fracture and from which crude oil or natural gas is produced.

Perforating: the process of creating holes in the steel casing adjacent to the formation containing crude oil or natural gas. The perforations (*perfs*) allow fracturing fluids to access the formation and later serve as the conduits that allow hydrocarbons to flow into the wellbore. Perfs are usually created using shaped-charge explosives; they can also be created by using a high-pressure water jet.

Pericondensed aromatic compounds: compounds based on angular condensed aromatic hydrocarbon systems, for example, phenanthrene, chrysene, and picene.

Permeability: rock property for permitting a fluid pass; a factor that indicates whether a reservoir has producing characteristics or not; the capacity of a rock for transmitting a fluid that depends on the size and shape of pores in the rock, along with the size, shape, and extent of the connections between pore spaces.

Petrolenes: the term applied to that part of the pentane-soluble or heptane-soluble material that is low boiling (<300 °C, <570 °F, 760 mm) and can be distilled without thermal decomposition (see also Maltenes).

Petroleum: a mixture of hydrocarbons composed of combinations of carbon and hydrogen atoms found in the porous spaces of rocks. Crude oil may contain other elements of a nonmetal origin, such as sulfur, oxygen, and nitrogen, in addition to trace metals as minor constituents. The compounds that form petroleum may be a gaseous, liquid, or solid state, depending on their nature and the existing pressure and temperature conditions.

pH adjustment: neutralization.

Phase: a separate fluid (or solid) that coexists with other fluids; gas, oil, water, and other stable fluids such as microemulsions are all called phases in EOR research.

Phase behavior: the tendency of a fluid system to form phases as a result of changing temperature, pressure, or the bulk composition of the fluids or of individual fluid phases.

Phase diagram: a graph of phase behavior. In chemical flooding a graph showing the relative volume of oil, brine, and sometimes one or more microemulsion phases. In carbon dioxide flooding, conditions for formation of various liquid, vapor, and solid phases.

Phase properties: types of fluids, compositions, densities, viscosities, and relative amounts of oil, microemulsion, or solvent and water formed when a micellar fluid (surfactant slug) or miscible solvent (e.g., CO_2) is mixed with oil.

Phase separation: the formation of a separate phase that is usually the prelude to coke formation during a thermal process; the formation of a separate phase as a result of the instability/incompatibility of petroleum and petroleum products.

Physical limit: the limit of the reservoir defined by any geological structures (faults, unconformities, change of facies, crests and bases of formations, etc.), caused by contact between fluids or by the reduction, to critical porosity, of permeability limits, or the compound effect of these parameters.

Physiographic: refers to a region where all parts are similar in geologic structure and climate that has had a unified geomorphic history; its relief features differ significantly from those of adjacent regions.

Pilot project: project that is being executed in a small representative sector of a reservoir where tests performed are similar to those that will be implemented throughout the reservoir. The purpose is to gather information and/or obtain results that could be used to generalize an exploitation strategy in the oil field.

PINA analysis: a method of analysis for paraffins, *iso*paraffins, naphthenes, and aromatics.

PIONA analysis: a method of analysis for paraffins, *iso*paraffins, olefins, naphthenes, and aromatics.

Pitch: the nonvolatile, brown-to-black, semisolid to solid viscous product from the destructive distillation of many bituminous or other organic materials, especially coal.

Plant liquefiables shrinkage factor (PLSF): the fraction arising from considering the liquefiables obtained in transportation to the processing complexes.

Plant liquids: natural gas liquids recovered in gas processing complexes, mainly consisting of ethane, propane, and butane.

Plant liquids recovery factor (PLRF): the factor used to obtain the liquid portions recovered in the natural gas processing complex. It is obtained from the operation statistics of the last annual period of the gas processing complex that processes the production of the field analyzed.

Play: a group of fields that share geological similarities and where the reservoir and the trap control the distribution of oil and gas.

Poisson's ratio (ν): the ratio of transverse contraction strain to longitudinal extension strain in the direction of stretching force; tensile deformation is considered positive and compressive deformation is considered negative. The definition of Poisson's ratio contains a minus sign so that normal materials have a positive ratio; also called Poisson ratio or the Poisson coefficient, or coefficient de Poisson:

$$\nu = -\varepsilon_{\text{trans}} / \varepsilon_{\text{longitudinal}}$$

Strain (ε) is defined in elementary form as the change in length divided by the original length:

$$E = \Delta L / L$$

Polyacrylamide: very high molecular weight material used in polymer flooding.

Polycyclic aromatic hydrocarbons (PAHs): polycyclic aromatic hydrocarbons are a suite of compounds comprised of two or more condensed aromatic rings. They are found in many petroleum mixtures, and they are predominantly introduced to the environment through natural and anthropogenic combustion processes.

Polymer: in EOR, any very high molecular weight material that is added to water to increase viscosity for polymer flooding.

Polymer augmented waterflooding: waterflooding in which organic polymers are injected with the water to improve horizontal and vertical sweep efficiency.

Polynuclear aromatic compound: an aromatic compound having two or more fused benzene rings, for example, naphthalene and phenanthrene.

PONA analysis: a method of analysis for paraffins (P), olefins (O), naphthenes (N), and aromatics (A).

Pore space: the spaces between grains in a rock that are unoccupied by solid material; a small hole in reservoir rock that contains fluid or fluids; a four-inch cube of reservoir rock may contain millions of interconnected pore spaces.

Pore volume: total volume of all pores and fractures in a reservoir or part of a reservoir; also applied to catalyst samples.

Porosity: the ratio between the pore volume existing in a rock and the total rock volume; a measure of rock's storage capacity; the percentage of rock volume available to contain water or other fluid.

Possible reserves: the volume of hydrocarbons where the analysis of geological and engineering data suggests that they are less likely to be commercially recoverable than probable reserves.

Postinjection seismicity: earthquake activity occurring after a hydraulic treatment has been terminated; the driving force for postinjection seismicity is (temporarily) ongoing pressure diffusion at the reservoir boundaries.

Potential reserves: reserves based upon geological information about the types of sediments where such resources are likely to occur and they are considered to represent an educated guess.

Pour point: the lowest temperature at which oil will pour or flow when it is chilled without disturbance under definite conditions.

Preflush: a conditioning slug injected into a reservoir as the first step of an EOR process.

Pressure cores: cores cut into a special coring barrel that maintains reservoir pressure when brought to the surface; this prevents the loss of reservoir fluids that usually accompanies a drop in pressure from reservoir to atmospheric conditions.

Pressure gradient: rate of change of pressure with distance.

Pressure maintenance: augmenting the pressure (and energy) in a reservoir by injecting gas and/or water through one or more wells.

Pressure pulse test: a technique for determining reservoir characteristics by injecting a sharp pulse of pressure in one well and detecting it in surrounding wells.

Pressure transient testing: measuring the effect of changes in pressure at one well on other well in a field.

Primary oil recovery: oil recovery utilizing only naturally occurring forces.

Primary porosity: the porosity preserved between sediment deposition and the final rock-forming process (e.g., spaces between grains of sediment).

Primary recovery: the extraction of petroleum by only using the natural energy available in the reservoirs to displace fluids through the reservoir rock to the wells.

Primary tracer: a chemical that, when inject into a test well, reacts with reservoir fluids to form a detectable chemical compound.

Probable reserves: nonproved reserves where the analysis of geological and engineering data suggests that they are more likely to be commercially recoverable than not.

Produced water: the naturally occurring fluid in a formation that flows to the surface through the wellbore throughout the entire lifespan of an oil or gas well. It typically has high levels of total dissolved solids with leached-out minerals from the rock.

Producibility: the rate at which oil or gas can produced from a reservoir through a wellbore.

Producing well: a well in an oil field used for removing fluids from a reservoir.

Production casing: the casing that lines the wellbore and may be sealed with cement either to a safe height above the target formation up to the base of the intermediate casing or all the way to the surface, depending on well depths and local geological conditions.

Proppant: solid material used in hydraulic fracturing to hold open the cracks made in the reservoir rock after the high pressure of the fracturing fluids is reduced. Sand, ceramic beads, or miniature pellets prop open the cracks to allow for freer flow of oil or gas.

Propping agent: see Proppant.

Prospect: location where the geological and economic conditions are favorable for drilling an exploratory well.

Prospective resource: the amount of hydrocarbons evaluated at a given date of accumulations not yet discovered, but which have been inferred and which are estimated as recoverable.

Protopetroleum: a generic term used to indicate the initial product formed when changes have occurred to the precursors of petroleum.

Proved area: a projection of the known part of the reservoir corresponding to the proved volume.

Proved reserves: the volume of hydrocarbons or associated substances evaluated at atmospheric conditions, which, by analysis of geological and engineering data, may be estimated with reasonable certainty to be commercially recoverable from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Such volume consists of the developed proved reserve and the undeveloped proved reserve.

Pulse-echo ultrasonic borehole televiewer: well-logging system wherein a pulsed, narrow acoustic beam scans the well as the tool is pulled up the borehole; the amplitude of the reflecting beam is displayed on a cathode-ray tube resulting in a pictorial representation of wellbore.

Quadrillion: 1×10^{15}.

Quality assurance/quality control: a system of procedures, checks, audits, and corrective actions to ensure that all technical, operational, monitoring, and reporting activities are of high quality.

Quartz: a common mineral composed of silica (SiO_2); sandstone formations are usually composed of quartz sand grains.

Radial leak: caused by casing failures that allows fluid to move horizontally out of the well and migrate into the surrounding rock formations.

Rank: the degree of metamorphism in coal; the basis of coal classification into a natural series from lignite to anthracite.

Raw materials: minerals extracted from the Earth prior to any refining or treating.

Reclamation: the act of restoring an area (such as a drilling area) to a condition that is suitable for future use.

Recovery factor (RF): the ratio between the original volume of oil or gas, at atmospheric conditions, and the original reserves of the reservoir.

Refinery: a series of integrated unit processes by which petroleum can be converted to a slate of useful (salable) products.

Refining: the processes by which petroleum is distilled and/or converted by application of a physical and chemical processes to form a variety of products are generated.

Regression: geological term used to define the elevation of one part of the continent over sea level, as a result of the ascent of the continent or the lowering of the sea level.

Relative permeability: the capacity of a fluid, such as water, gas or oil, to flow through a rock when it is saturated with two or more fluids. The value of the permeability of a saturated rock with two or more fluids is different to the permeability value of the same rock saturated with just one fluid.

Remaining reserves: the volume of hydrocarbons measured at atmospheric conditions that are still to be commercially recoverable from a reservoir at a given date, using the applicable exploitation techniques. It is the difference between the original reserve and the cumulative hydrocarbon production at a given date.

Reserve replacement rate: it indicates the amount of hydrocarbons replaced or incorporated by new discoveries compared with what has been produced in a given period. It is the coefficient that arises from dividing the new discoveries by production during the period of analysis, and it is generally referred to in annual terms and is expressed as a percentage.

Reserve–production ratio: the result of dividing the remaining reserve at a given date by the production in a period. This indicator assumes constant production, hydrocarbon prices, and extraction costs, without variation over time, in addition to the nonexistence of new discoveries in the future.

Reserves: well-identified resources that can be profitably extracted and utilized with existing technology.

Reservoir: the portion of the geological trap containing hydrocarbons that acts as a hydraulically interconnected system, where the hydrocarbons are found at an elevated temperature and pressure occupying the porous spaces; a rock formation below the Earth's surface containing petroleum or natural gas; a domain where a pollutant may reside for an indeterminate time.

Reservoir rock: the oil- or gas-bearing rock, typically a fractured or porous and permeable rock formation.

Reservoir simulation: analysis and prediction of reservoir performance with a computer model.

Residual oil: petroleum remaining *in situ* after oil recovery; see also Residuum.

Residual resistance factor: the reduction in permeability of rock to water caused by the adsorption of polymer.

Residuum (resid; *pl.* residua): the residue obtained from petroleum after nondestructive distillation has removed all the volatile materials from crude oil, for example, an atmospheric (345 °C, 650 °F+) residuum.

Resins: that portion of the maltenes (*q.v.*) that is adsorbed by a surface-active material such as clay or alumina; the fraction of deasphaltened oil that is insoluble in liquid propane but soluble in *n*-heptane.

Resistance factor: a measure of resistance to flow of a polymer solution relative to the resistance to flow of water.

Resource: the total volume of hydrocarbons existing in subsurface rocks; also known as original *in situ* volume.

Retention: the loss of chemical components due to adsorption onto the rock's surface, precipitation, or to trapping within the reservoir.

Retrograde condensation: the phenomenon associated with the behavior of a hydrocarbon mixture (such as natural gas containing gas condensate) in the critical region wherein, at constant temperature, the vapor phase in contact with the liquid phase may be condensed by a decrease in pressure; alternatively, at constant pressure, the vapor is condensed by an increase in temperature.

Reverse fault: the result of compression forces where one of the blocks is displaced upward from the horizontal.

Revision: the reserve resulting from comparing the previous year's evaluation with the new one in which new geological, geophysical, operation, and reservoir performance information is considered, in addition to variations in hydrocarbon prices and extraction costs. It does not include well drilling.

Rock matrix: the granular structure of a rock or porous medium.

Run-of-the-river reservoir: a reservoir with a large rate of flow-through compared to the volume.

Salinity: the concentration of salt in water.

Sample log: a record of the physical properties of rocks in a well; includes composition, texture, color, presence of pore spaces, and oil staining; also a record of analysis performed on samples.

Sand: a course granular mineral mainly comprising quartz grains that is derived from the chemical and physical weathering of rocks rich in quartz, notably sandstone and granite.

Sand face: the cylindrical wall of the wellbore through which the fluids must flow to or from the reservoir.

Sandstone: a sedimentary rock formed by compaction and cementation of sand grains; can be classified according to the mineral composition of the sand and cement.

SARA analysis: a method of fractionation by which petroleum is separated into saturates, aromatics, resins, and asphaltene fractions.

Saturates: paraffins and cycloparaffins (naphthenes).

Saturation: the ratio of the volume of a single fluid in the pores to pore volume, expressed as a percent and applied to water, oil, or gas separately; the sum of the saturations of each fluid in a pore volume is 100%.

Saturation pressure: pressure at which the first gas bubble is formed, when it goes from the liquid phase to the two-phase region.

Saybolt furol viscosity: the time, in seconds (Saybolt Furol Seconds, SFS), for 60 ml of fluid to flow through a capillary tube in a Saybolt Furol viscometer at specified temperatures between 70 and 210°F; the method is appropriate for high-viscosity oils such as transmission, gear, and heavy fuel oils.

Saybolt universal viscosity: the time, in seconds (Saybolt Universal Seconds, SUS), for 60 ml of fluid to flow through a capillary tube in a Saybolt Universal viscometer at a given temperature.

Scale: salts that have precipitated out of water. Calcium carbonate, barium sulfate, and calcium sulfate are common in oil fields.

Screen factor: a simple measure of the viscoelastic properties of polymer solutions.

Screening guide: a list of reservoir rock and fluid properties critical to an EOR process.

Screen-out: refers to a fracturing job where proppant placement has failed. Secondary porosity: the porosity created through alteration of rock, commonly by processes such as dissolution and fracturing.

Secondary recovery: Techniques used for the additional extraction of petroleum after primary recovery. This includes gas or water injection, partly to maintain reservoir pressure.

Secondary tracer: the product of the chemical reaction between reservoir fluids and an injected primary tracer.

Sediment: an insoluble solid formed as a result of the storage instability and/or the thermal instability of petroleum and petroleum products.

Sedimentary: formed by or from deposits of sediments, especially from sand grains or silts transported from their source and deposited in water, such as sandstone and shale; or from calcareous remains of organisms, such as limestone.

Sedimentary strata: typically consist of mixtures of clay, silt, sand, organic matter, and various minerals; formed by or from deposits of sediments, especially from sand grains or silts transported from their source and deposited in water, such as sandstone and shale; or from calcareous remains of organisms, such as limestone.

Seismic event: an earth vibration, such as an earthquake or tremor.

Seismic hazard: quantifies the probability of occurrence of an earthquake of a certain magnitude in a certain region.

Seismic intensity: qualitative classification of the size of an earthquake on a scale from 1 to 12; the scale quantifies the effects of an earthquake on the surface of the Earth; the EMS-98 scale is the most commonly used scale (European Macroseismic Scale 1998).

Seismic risk: quantifies the probability of occurrence of economic damage for a specified location and time period.

Seismic section: a seismic profile that uses the reflection of seismic waves to determine the geological subsurface.

Semianthracite: term used to identify coal rank; specifically refers to coal that possesses a fixed carbon content of 86–92%.

Service company: a company that assists well operators by providing specialty services, including hydraulic fracturing.

Setback: the distance that must be maintained between a well or other specified equipment and any protected structure or feature.

Shale: a fine-grained sedimentary rock that formed from the compaction of finely layered silt and clay-sized minerals; a dense rock formed over millions of years from ancient sediments of decaying organic material. Although geologists have known about the energy potential of shale rock for generations, only within the past decade have these resources been considered economical to produce—in part due to the advances in horizontal drilling and the application of the 60-year-old technology of hydraulic fracturing. Shale is known as a *source rock* because it is the source of oil and gas deposits that are contained in sandstone and carbonate formations from which oil and gas are normally produced.

Shale gas: natural gas produced from low-permeability shale formations; see Tight gas.

Shale oil: oil that is produced by technologies related to thermal decomposition of the organic constituent (kerogen) contained in the shale, such as horizontal wells and hydraulic fracturing; see Tight oil.

Shale play: a defined geographic area containing an organic-rich fine-grained sedimentary rock with the following characteristics: (i) clay- to silt-sized particles; (ii) high % of silica, and sometimes carbonate minerals; (iii) thermally mature; (iv) hydrocarbon-filled porosity; (v) low permeability; (vi) large areal distribution; and (vii) fracture stimulation required for economic production.

Shear: mechanical deformation or distortion, or partial destruction of a polymer molecule as it flows at a high rate.

Shear rate: a measure of the rate of deformation of a liquid under mechanical stress.

Shear thinning: the characteristic of a fluid whose viscosity decreases as the shear rate increases.

Siltstone: sedimentary rock composed primarily of silt-sized particles.

Single well tracer: a technique for determining residual oil saturation by injecting an ester, allowing it to hydrolyze; following dissolution of some of the reaction product in residual oil the injected solutions produced back and analyzed.

Slickwater: water containing friction-reducing agents, such as potassium chloride, polyacrylamide, or other chemicals, to reduce the pressure needed to pump the fluid in the wellbore; these additives may reduce tubular friction in the wellbore by 50–60%.

Slime: a name used for petroleum in ancient texts.

Sludge: a semisolid to solid product that results from the storage instability and/or the thermal instability of petroleum and petroleum products.

Slug: a quantity of fluid injected into a reservoir during enhanced oil recovery.

Solution gas: the dissolved natural gas that bubbles out of crude oil on the surface when the pressure drops during production.

Sonic log: a well log based on the time required for sound to travel through rock, useful in determining porosity.

Sonication: a physical technique employing ultrasound to intensely vibrate a sample media in extracting solvent and to maximize solvent/analyte interactions.

Sour crude oil: crude oil containing an abnormally large amount of sulfur compounds; see also Sweet crude oil.

Spacing: the optimum distance between hydrocarbon producing wells in a field or reservoir.

Specific gravity: an intensive property of the matter that is related to the mass of a substance and its volume through the coefficient between these two quantities. It is expressed in grams per cubic centimeter or in pounds per gallon.

Spurt loss: the fluid loss per area, before the formation of a filter cake, and is very significant in naturally fractured reservoirs; it is directly proportional to reservoir permeability.

Standard conditions: the reference amounts for pressure and temperature. In the English system, it is 14.73 pounds per square inch for the pressure and 60° F for temperature.

Steam distillation: distillation in which vaporization of the volatile constituents is effected at a lower temperature by introduction of steam (open steam) directly into the charge.

Steam drive injection (steam injection): EOR process in which steam is continuously injected into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells); steam stimulation of production wells is *direct steam stimulation*, whereas steam drive by steam injection to increase production from other wells is *indirect steam stimulation*.

Steam stimulation: injection of steam into a well and the subsequent production of oil from the same well.

Stiles method: a simple approximate method for calculating oil recovery by waterflood that assumes separate layers (stratified reservoirs) for the permeability distribution.

Stimulation: any of several processes used to enhance near-wellbore permeability and reservoir permeability; the process of acidifying or fracturing carried out to expand existing ducts or to create new ones in the source rock formation; generally, any process performed on an oil or natural gas well to increase the flow of energy to the surface. Stimulation processes include fracturing, scale and paraffin removal, controlling unwanted water, and certain types of perforating.

Strain (ε): the change in length divided by the original length: $\varepsilon = \Delta L/L$.

Strata: layers including the solid iron-rich inner core, molten outer core, mantle, and crust of the Earth.

Stratigraphy: part of geology that studies the origin, composition, distribution, and succession of rock strata.

Stripper well: a well that produces (strips from the reservoir) oil or gas.

Structural nose: a term used in structural geology to define a geometric form protruding from a main body.

Subbituminous coal: a black coal, intermediate in rank between lignite and bituminous.

Subgraywacke: sedimentary rock (sandstone) that contains less feldspar and more and better-rounded quartz grains than graywacke. Intermediate in composition between graywacke and orthoquartzite, it is lighter colored and better sorted and has less matrix than graywacke.

Sucker-rod pumping system: a method of artificial lift in which a subsurface pump located at or near the bottom of the well and connected to a string of sucker rods is used to lift the well fluid to the surface.

Sulfur dioxide (SO_2): a colorless gas formed when sulfur oxidizes, often as a result of burning trace amounts of sulfur in fossil fuels.

Superlight oil: arbitrarily petroleum with a specific gravity that is higher than 38 ° API.

Surface-active material: a chemical compound, molecule, or aggregate of molecules with physical properties that cause it to adsorb at the interface between *two* immiscible liquids, resulting in a reduction of interfacial tension or the formation of a microemulsion.

Surface casing: casing that runs past the bottom of any freshwater-bearing zones (including but not limited to drinking water aquifers) and extends all the way back to the surface; cement is pumped down the wellbore and up between the casing and the rock until it reaches the surface.

Surface water: all water naturally open to the atmosphere, such as rivers, lakes, reservoirs, ponds, streams, impoundments, seas, and estuaries.

Surfactant: a type of chemical, characterized as one that reduces interfacial resistance to mixing between oil and water or changes the degree to which water wets reservoir rock.

Surficial: pertaining to or lying in or on a surface; specific to the surface of the Earth.

Sweep efficiency: the ratio of the pore volume of reservoir rock contacted by injected fluids to the total pore volume of reservoir rock in the project area. (See also Horizontal sweep efficiency and Vertical sweep efficiency.):

Sweet crude oil: crude oil containing little sulfur; see also Sour crude oil.

Sweet spot: the specific area with a reservoir where a large amount of crude oil or natural gas is accessible.

Sweetening plant: industrial plant used to treat gaseous mixtures and light petroleum fractions in order to eliminate undesirable or corrosive sulfur compounds to improve their color, odor, and stability.

Swelling: increase in the volume of crude oil caused by absorption of EOR fluids, especially carbon dioxide. Also increase in volume of clays when exposed to brine.

Swept zone: the volume of rock that is effectively swept by injected fluids.

Syncline: a fold of layered, sedimentary rocks whose core contains stratigraphically younger rocks; the shape of the fold is generally concave upward.

Synthetic crude oil (syncrude): a hydrocarbon product produced by the conversion of coal, oil shale, or tar sand bitumen that resembles conventional crude oil; can be refined in a petroleum refinery; may also be produced during *in situ* combustion processes.

Tank battery: two or more stock tanks connected in line.

Tar: the volatile, brown-to-black, oily, viscous product from the destructive distillation of many bituminous or other organic materials, especially coal; a name used for petroleum in ancient texts.

Tar sand: see Bituminous sand.

Tcf: a natural gas measurement unit for 1 trillion ft^3.

Technical reserves: the accumulative production derived from a production forecast in which economic criteria are not applied.

Technically recoverable resources: the total amount of resources, discovered and undiscovered, thought to be recoverable with available technology, regardless of economics.

Thermal recovery: see EOR process.

Thermogenic: a direct product of high temperatures (e.g., thermogenic methane).

Thermogenic gas: natural gas that is formed by the combined forces of high pressure and high temperature from deep burial with the crust of the Earth, resulting in natural cracking (thermal decomposition) of the organic matter in the source rock.

Thief zone: any geologic stratum not intended to receive injected fluids in which significant amounts of injected fluids are lost; fluids may reach the thief zone due to an improper completion or a faulty cement job.

Thixotropy: the property of a gel to become fluid when disturbed (as by shaking).

Threatened and endangered species: plant or animal species that have been designated as being in danger of extinction.

Tight gas: natural gas locked in tiny bubble-like pockets within shale or other layered, sedimentary rock.

Tight oil: crude oil dispersed in rocks (such as shale formation) of low permeability and porosity, which makes it more difficult to recover than conventional hydrocarbon deposits.

Tight sand: a sandstone rock formation with extremely low permeability, similar in that respect to shale.

Time-lapse logging: the repeated use of calibrated well logs to quantitatively observe changes in measurable reservoir properties over time.

Topped crude: petroleum that has had volatile constituents removed up to a certain temperature, for example, 250 °C+ (480 °F+) topped crude; not always the same as a residuum; may be produced during thermal EOR processes.

Total dissolved solids (TDS): the dry weight of dissolved material, organic and inorganic, contained in water and usually expressed in parts per million.

Total thickness (H): thickness from the top of the formation of interest down to a vertical boundary determined by a water level or by a change of formation.

Toughness: the point at which enough stress intensity has been applied to a rock formation so that a fracture initiates and propagates.

Trace element: a chemical element present in minute quantities; especially ones used by organisms and essential to their functioning.

Tracer test: a technique for determining fluid flow paths in a reservoir by adding small quantities of easily detected material (often radioactive) to the flowing fluid and monitoring their appearance at production wells. Also used in cyclic injection to appraise oil saturation.

Transgression: Geological term used to define the immersion of one part of the continent under sea level, as a result of a descent of the continent or an elevation of the sea level.

Transmissibility (transmissivity): an index of producibility of a reservoir or zone; the product of permeability and layer thickness.

Transmissivity: a measure of the amount of water that can be transmitted horizontally through a unit width by the full saturated thickness of the aquifer under a hydraulic gradient of one.

Transport liquefiables shrinkage factor (TLSF): the fraction obtained by considering the liquefiables obtained in transportation to the processing complexes.

Trap: a geological system that permits the concentration of hydrocarbons; a sediment in which oil and gas accumulate from which further migration is prevented.

Triaxial borehole seismic survey: a technique for detecting the orientation of hydraulically induced fractures, wherein a tool holding three mutually seismic detectors is clamped in the borehole during fracturing; fracture orientation is deduced through analysis of the detected microseismic perpendicular events that are generated by the fracturing process.

Trillion: 1×10^{12}.

Ultimate analysis: elemental composition.

Ultimate recovery: the cumulative quantity of oil that will be recovered when revenues from further production no longer justify the costs of the additional production.

Unconformity: a surface of erosion that separates younger strata from older rocks.

Unconventional source: shale and other low-porosity and permeable rocks in which the gas or oil remains in the layer in which it was created; in conventional sources, the hydrocarbons have migrated to a more permeable layer before being trapped.

Underground Injection Control (UIC) Program: a program administered by the US EPA, primacy state, or Indian tribe under the Safe Drinking Water Act to ensure that subsurface emplacement of fluids does not endanger underground sources of drinking water.

Underground source of drinking water (USDW): as defined by 40 CPR §144.3, an underground source of drinking water is an aquifer or its portion: (1) which supplies any public water system; or (2) which contains a sufficient quantity of groundwater to supply a public water system; and (i) currently supplies drinking water for human consumption or (ii) contains fewer than 10,000 mg/l total dissolved solids, and (3) which is not an exempted aquifer.

Undeveloped proved area: plant projection of the extension drained by the future producing wells of a producing reservoir and located within the undeveloped proved reserve.

Undeveloped proved reserves: volume of hydrocarbons that is expected to be recovered through wells without current facilities for production or transportation and future wells. This category may include the estimated reserve of enhanced recovery projects, with pilot testing or with the recovery mechanism proposed in operation that has been predicted with a high degree of certainty in reservoirs that benefit from this kind of exploitation.

Undiscovered resource: volume of hydrocarbons with uncertainty, but whose existence is inferred in geological basins through favorable factors resulting from the geological, geophysical, and geochemical interpretation. They are known as prospective resources when considered commercially recoverable.

Universal viscosity: see Saybolt universal viscosity.

Unsaturated pool: an oil reservoir without a free gas cap.

Upper-phase microemulsion: a microemulsion phase containing a high concentration of oil that, when viewed in a test tube, resides on top of a water phase.

Upwarp: the uplift of a region; usually a result of the release of isostatic pressure (e.g., the melting of an ice sheet).

Vertical seismic profiling: a method of conducting seismic surveys in the borehole for detailed subsurface information.

Vertical sweep efficiency: the fraction of the layers or vertically distributed zones of a reservoir that are effectively contacted by displacing fluids.

Vertical wellbore: a wellbore in which the angle between the wellhead at the surface and the bottom of the well is between 0° and 60°; a wellbore approaching a 60° angle is called highly deviated.

VGC (viscosity-gravity constant): an index of the chemical composition of crude oil defined by the general relation between specific gravity (sg) at 60 °F and Saybolt universal viscosity (SUV) at 100 °F:

$$a = 10\text{sg} - 1.0752 \log\left(\text{SUV} - 38\right) / 10\text{sg} - \log\left(\text{SUV} - 38\right)$$

The constant, a, is low for the paraffin crude oils and high for the naphthenic crude oils.

VI (viscosity index): an arbitrary scale used to show the magnitude of viscosity changes in lubricating oils with changes in temperature.

Visbreaking: a process for reducing the viscosity of heavy feedstocks by controlled thermal decomposition; can occur during thermal recovery processes, such as *in situ* combustion.

Viscosity: a measure of the ability of a liquid to flow or a measure of its resistance to flow; the force required to move a plane surface of area 1 m^2 over another parallel plane surface 1 m away at a rate of 1 m/s when both surfaces are immersed in the fluid.

Viscosity index: see VI.

Viscosity-gravity constant: see VGC.

Volcaniclastic: composed of fragments or particles and related to volcanic processes either by forming as the result of explosive processes or due to the weathering and erosion of volcanic rocks.

Volumetric sweep: the fraction of the total reservoir volume within a flood pattern that is effectively contacted by injected fluids.

VSP: vertical seismic profiling, a method of conducting seismic surveys in the borehole for detailed subsurface information.

Vug: a small space or cavity within a carbonate rock.

Water fracturing: a fracturing treatment performed using a water-based fluid formulation in which the friction pressure is reduced when pumping fluid volumes through several thousand feet of casing. This increases the amount of hydraulic pressure imparted on the oil- or natural gas-bearing formation. These formulations also have a very low viscosity, which encourages the development of many small interconnected cracks to improve production.

Water quality: the chemical, physical, and biological characteristics of water with respect to its suitability for a particular use.

Water table: the subsurface level below which the pores in the soil or rock are filled with water.

Waterflood: injection of water to displace oil from a reservoir (usually a secondary recovery process).

Waterflood mobility ratio: mobility ratio of water displacing oil during waterflooding. (See also Mobility ratio.):

Waterflood residual: the waterflood residual oil saturation; the saturation of oil remaining after waterflooding in those regions of the reservoir that have been thoroughly contacted by water.

Watershed: all lands that are enclosed by a continuous hydrologic drainage divide and lay upslope from a specified point on a stream.

Watson characterization factor: see Characterization factor.

Well abandonment: the final activity in the operation of a well when it is permanently closed under safety and environment preservation conditions.

Well communication: spills reported in the data sources as being caused by well communication refer to spills on the surface that occur when pressure applied during hydraulic fracturing activities at one well affects the production and collection of fluids at a nearby or offset well.

Well completion: the complete outfitting of an oil well for either oil production or fluid injection; also the technique used to control fluid communication with the reservoir.

Well logs: the information concerning subsurface formations obtained by means of electric, acoustic, and radioactive tools inserted in the wells. The log also includes information about drilling and the analysis of mud and cuts, cores, and formation tests.

Well operator: a company that operates oil and gas production wells.

Wellbore: the hole in the Earth comprising a well; a hole that is drilled to explore and recover natural resources, such as oil, gas, or water.

Wellhead: that portion of an oil well above the surface of the ground.

Wet gas: a mixture of hydrocarbons obtained from processing natural gas from which non-hydrocarbon impurities or compounds have been eliminated and whose content of components that are heavier than methane is such that it can be commercially processed.

Wettability: the relative degree to which a fluid will spread on (or coat) a solid surface in the presence of other immiscible fluids.

Wettability number: a measure of the degree to which a reservoir rock is water wet or oil wet, based on capillary pressure curves.

Wettability reversal: the reversal of the preferred fluid wettability of a rock, for example, from water wet to oil wet, or vice versa.

Whipstock: a wedge-shaped piece of metal placed downhole to deflect the drill bit.

Workover: the performance of one or more remedial operations on a production or injection well to increase production.

Zone: a rock layer identified by a characteristic microfossil species.

Zone of interest: a segment of the formation in a single wellbore that is considered likely to produce commercial amounts of crude oil or natural gas.

INDEX

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.

CONVERSION FACTORS

1 acre = 43,560 ft^2
1 acre foot = 7758.0 bbl
1 atmosphere = 760 mmHg = 14.696 psia = 29.91 in. Hg
1 atmosphere = 1.0133 bars = 33.899 ft H_2O
1 barrel (oil) = 42 gal = 5.6146 ft^3
1 barrel (water) = 350 lb at 60 °F
1 barrel per day = 1.84 cm^3/s
1 Btu = 778.26 ft-lb
1 centipoise × 2.42 = Ib mass/(ft) (h), viscosity
1 centipoise × 0.000672 = Ib mass/(ft) (s), viscosity
1 cubic foot = 28,317 cm^3 = 7.4805 gal
Density of water at 60 °F = 0.999 g/cm^3 = 62.367 Ib/ft^3 = 8.337 Ib/gal
1 gallon = 231 $in.^3$ = 3785.4 cm^3 = 0.13368 ft^3
1 horsepower-hour = 0.7457 kwh = 2544.5 Btu
1 horsepower = 550 ft-lb/s = 745.7 Watts
1 inch = 2.54 cm
1 meter = 100 cm = 1000 mm = 10 μm = 10 angstroms (Å)
1 ounce = 28.35 g
1 pound = 453.59 g = 7000 grains
1 square mile = 640 acres

Handbook of Hydraulic Fracturing, First Edition. James G. Speight.