

## CHAPTER 1

# Heavy Oil and Tar Sand Bitumen

### 1.1 INTRODUCTION

Petroleum (crude oil; conventional petroleum) is found in the microscopic pores of sedimentary rocks such as sandstone and limestone. Not all of the pores in a rock contain petroleum and some pores will be filled with water or brine that is saturated with minerals. However, not all of the oilfields that are discovered are exploited since the reservoir may be (1) too deep for economic recovery under the prevalent economic conditions, (2) contain crude oil of insufficient volume, (3) so remote that transportation costs would be high, or (4) in a tight formation where additional techniques such as hydraulic fracturing are required to recover the crude oil (see chapter: General Methods of Oil Recovery) (Speight, 2014a, 2015a).

In the typical porous rock reservoir, conventional petroleum is a free-flowing liquid while, on the other hand, heavy oil is a viscous type of petroleum that contains higher levels of sulfur and nonvolatile constituents than conventional petroleum but occurs in similar locations to petroleum (IEA, 2005; Ancheyta and Speight, 2007; Speight, 2014a). The viscous nature of heavy oil is a problem for recovery operations and for refining—the viscosity of the oil may be too high thereby rendering recovery expensive and/or difficult and the sulfur content may be high, which increases the expense of refining the oil.

In any text related to the properties and behavior (recovery or refining) of a natural resource (ie, heavy oil), it is necessary to understand the resource first through the name or terminology or definition. *Terminology* is the means by which various subjects are named so that reference can be made in conversations and in writings and so that the meaning is passed on. *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. Thus 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.

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 science and technology be given prime consideration. This will aid in a better understanding of petroleum, its constituents, and its various fractions. 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 *bitumen* and *asphalt*. This part of the text attempts to alleviate much of the confusion that exists, but it must be remembered that the terminology of petroleum is still open to personal choice and historical usage.

The name *heavy oil* can often be misleading as it has also been used in reference to (1) fuel oil that contains residuum left over from distillation, that is, residual fuel oil, (2) coal tar creosote, or (3) viscous crude oil. For the purposes of this text the term is used to mean *viscous crude oil*.

Heavy oil typically has relatively low proportions of volatile compounds with low molecular weights and quite high proportions of high molecular weight compounds of lower volatility. The high molecular weight fraction of heavy oils are comprised of a complex assortment of different molecular and chemical compounds (not necessarily just paraffins or asphaltenes) with high melting points and high pour points that greatly contribute to the poor fluid properties of the heavy oil, thereby contributing to low mobility (compared to conventional crude oil).

More generally, heavy oil typically has low levels (if any at all) of paraffins (straight-chain alkanes) with moderate-to-high levels of asphaltene constituents. The asphaltene constituents are not necessarily the primary cause for the high specific gravity (low API gravity) of the oil nor are they always the prime cause for production problems. It is essential to consider the content of the resin constituents and the aromatic constituents, both of which are capable of hindering the asphaltene constituents from separation during recovery. It is only when the asphaltene constituents separate from the oil as separate phase that they deposit in the formation or in the production train.

## 1.2 HISTORY

Petroleum, in various forms, is not a recent discovery (Abraham, 1945; Forbes, 1958a, 1958b, 1959, 1964; Speight, 2014a). More than four thousand years ago, bitumen from natural seepages was employed in the construction of the walls and towers of Babylon. Ancient writings indicate the medicinal and lighting uses of petroleum in various societies. In terms of

petroleum recovery, the earliest known wells were drilled in China in 347 BC to depths of 800 feet (240 m) and were drilled using bits attached to bamboo poles. The oil was burned to evaporate brine and produce salt. By the tenth century, extensive bamboo pipelines connected oil wells with salt springs.

The use of petroleum in the Middle East was established by the eighth century, when the streets of the newly constructed Baghdad were paved with the nonvolatile residue derived from accessible petroleum and seepages (particularly Hit) in the region. In the ninth century, petroleum was distilled at Baku, Azerbaijan, to produce naphtha which formed the basis of the incendiary *Greek fire* (Cobb and Goldwhite, 1995). These Baku experiences were reported by the geographer Masudi in the tenth century, and by Marco Polo in the thirteenth century, who described the output of those wells as hundreds of shiploads.

The earliest mention of American petroleum occurs in Sir Walter Raleigh's documentation of the Trinidad Asphalt Lake (also called the Trinidad Pitch Lake) in 1595. In 1632, the journal of a Franciscan, Joseph de la Roche d'Allion, describing his visit to the oil springs of New York was published in Sagard's *Histoire du Canada*. A Russian traveler, Peter Kalm, in his work on America published in 1748 showed on a map the oil springs of Pennsylvania. In 1854, Benjamin Silliman, a science professor at Yale University in New Haven, Connecticut followed the work by Arabic alchemists and fractionated petroleum by distillation. These discoveries rapidly spread around the world, and Meerzoeff built the first Russian refinery in the then-mature oil fields at Baku in 1861, where at that time about 90% of the world's oil was produced.

The first commercial oil well drilled in North America was in Oil Springs, Ontario, Canada in 1858 by James Miller Williams. The US petroleum industry began with Edwin Drake's drilling of a 69-foot (21 m) oil well in 1859 at Oil Creek near Titusville, Pennsylvania for the Seneca Oil Company. The well originally yielded 25 barrels per day and by the end of the year output was at the rate of 15 barrels per day. The industry grew through the 1800s, driven by the demand for kerosene and for oil lamps. Petroleum refining became even more popular, perhaps essential, in the early part of the twentieth century with the introduction of the internal combustion engine, which provided a demand that has largely sustained the industry during the past one hundred years. Early finds like those in Pennsylvania and Ontario were quickly outpaced by demand leading to oil booms in Texas, Oklahoma, and California.

By 1910, significant oil fields had been discovered in Canada, the Dutch East Indies (1885, in Sumatra), Iran, (1908, in Masjed Soleiman), Venezuela, and Mexico, which were being developed at an industrial level. Even until the mid-1950s, coal was still the world's foremost fuel, but oil quickly took over. The 1973 energy crisis and the 1979 energy crisis brought to light the concern that oil is a limited resource that will diminish, at least as an economically viable energy source. At the time, the most common and popular predictions were spectacularly dire.

The value of petroleum as a transportable, high-energy source that can be used to power the vast majority of vehicles (gasoline and diesel) and as the base of many industrial chemicals makes it one of the world's most important commodities (Hsu and Robinson, 2006; Gary et al., 2007; Speight, 2014a). Access to it was a major factor in several military conflicts, including World War II and the more recent wars in the Persian Gulf of the twentieth and early twenty-first centuries. Approximately 80% of the world's readily accessible reserves are located in the Middle East with the majority coming from Saudi Arabia. However, when the reserves of heavy oil and tar sand bitumen are taken into account, the balance shifts. Venezuela and Canada have substantial reserves of heavy oil and tar sand bitumen, sufficient to shift the balance of petroleum reserves from the Middle East to the Americas. And it is to this subject that this book is devoted.

The increasing demand for crude oil continues to grow every year, fueled in part by the rapidly growing economies of China and India. The declining availability of conventional oil combined with rising demand has continued to put more pressure on the search for alternative energy sources. Thus, with the demand for petroleum and petroleum-based products reaching new highs, investments in these more challenging reservoirs are rapidly accelerating. In fact, the worldwide importance of heavy oils will continue to emerge as the price of oil remains high and the demand for it remains strong. Although prices are expected to fluctuate, it is worth moving ahead with heavy oil resources on the basis of obtaining a measure (as yet undefined and country-dependent) of oil independence.

However, demand and market pull aside, it is essential to recognize that there are significant differences between conventional crude oil, heavy oil, and tar sand bitumen and, moreover, there are significant variations within the conventional petroleum types as there are also differences between the heavy oil types. While tar sand bitumen is, by definition, different to conventional crude oil and heavy oil, there are also differences between the various types of materials that fall within the definition of tar sand bitumen. This is

reflected in the differences observed in various recovery processes as well as in the price variations between conventional crude oil types, the heavy oils, and tar sand bitumen (Tables 1.1 and 1.2) (Speight, 2011, 2013a, b).

Typically, crude oil quality has an effect on the recovery process insofar as crude oil that contains a higher proportion of the more volatile constituents

**Table 1.1** API Gravity and Sulfur Content of Selected Crude Oils

Country	Crude oil	API	Sulfur% w/w
Abu Dhabi (UAE)	Abu Al Bu Khoosh	31.6	2.00
Abu Dhabi (UAE)	Abu Mubarras	38.1	0.93
Abu Dhabi (UAE)	El Bunduq	38.5	1.12
Abu Dhabi (UAE)	Murban	40.5	0.78
Abu Dhabi (UAE)	Umm Shaif	37.4	1.51
Abu Dhabi (UAE)	Zakum (Lower)	40.6	1.05
Abu Dhabi (UAE)	Zakum (Upper)	33.1	2.00
Algeria	Zarzaitine	43.0	0.07
Angola	Cabinda	31.7	0.17
Angola	Palanca	40.1	0.11
Angola	Takula	32.4	0.09
Australia	Airlie	44.7	0.01
Australia	Barrow Island	37.3	0.05
Australia	Challis	39.5	0.070
Australia	Cooper Basin	45.2	0.02
Australia	Gippsland	47.0	0.09
Australia	Griffin	55.0	0.03
Australia	Harriet	37.9	0.05
Australia	Jabiru	42.3	0.05
Australia	Jackson	43.8	0.03
Australia	Saladin	48.2	0.02
Australia	Skua	41.9	0.06
Brazil	Garoupa	30.0	0.68
Brazil	Sergipano Platforma	38.4	0.19
Brazil	Sergipano Terra	24.1	0.41
Brunei	Champion Export	23.9	0.12
Brunei	Seria	40.5	0.06
Cameroon	Kole Marine	32.6	0.33
Cameroon	Lokele	20.7	0.46
Canada (Alberta)	Bow River Heavy	26.7	2.10
Canada (Alberta)	Pembina	38.8	0.20
Canada (Alberta)	Rainbow	40.7	0.50
Canada (Alberta)	Rangeland South	39.5	0.75
Canada (Alberta)	Wainwright-Kinsella	23.1	2.58
China	Daqing (Taching)	32.6	0.09

(Continued)

**Table 1.1** (Continued)

<b>Country</b>	<b>Crude oil</b>	<b>API</b>	<b>Sulfur% w/w</b>
China	Nanghai Light	40.6	0.06
China	Shengli	24.2	1.00
China	Weizhou	39.7	0.08
Colombia	Cano Limon	29.3	0.51
Congo (Brazzaville)	Emeraude	23.6	0.600
Dubai (UAE)	Fateh	31.1	2.000
Dubai (UAE)	Margham Light	50.3	0.040
Ecuador	Oriente	29.2	0.880
Egypt	Belayim	27.5	2.200
Egypt	Gulf of Suez	31.9	1.520
Egypt	Ras Gharib	21.5	3.640
Gabon	Gamba	31.4	0.090
Gabon	Rabi-Kounga	33.5	0.070
Ghana	Salt Pond	37.4	0.097
India	Bombay High	39.2	0.150
Indonesia	Anoa	45.2	0.040
Indonesia	Ardjuna	35.2	0.105
Indonesia	Attaka	43.3	0.040
Indonesia	Badak	49.5	0.032
Indonesia	Bekapai	41.2	0.080
Indonesia	Belida	45.1	0.020
Indonesia	Bima	21.1	0.250
Indonesia	Cinta	33.4	0.080
Indonesia	Duri (Sumatran Heavy)	21.3	0.180
Indonesia	Ikan Pari	48.0	0.020
Indonesia	Kakap	51.5	0.050
Indonesia	Katapa	50.8	0.060
Indonesia	Lalang (Malacca Straits)	39.7	0.050
Indonesia	Minas (Sumatran Light)	34.5	0.081
Indonesia	Udang	38.0	0.050
Iran	Aboozar (Ardeshir)	26.9	2.480
Iran	Bahrgansar/Nowruz	27.1	2.450
Iran	Dorrood (Darius)	33.6	2.350
Iran	Foroozan (Fereidoon)	31.3	2.500
Iran	Iranian Heavy	30.9	1.730
Iran	Iranian Light	33.8	1.350
Iran	Rostam	35.9	1.550
Iran	Salmon (Sassan)	33.9	1.910
Iraq	Basrah Heavy	24.7	3.500
Iraq	Basrah Light	33.7	1.950
Iraq	Basrah Medium	31.1	2.580
Iraq	North Rumaila	33.7	1.980
Ivory Coast	Espoir	32.3	0.340
Kazakhstan	Kumkol	42.5	0.07
Kuwait	Kuwait Export	31.4	2.52
Libya	Amna	36.0	0.15
Libya	Brega	40.4	0.21
Libya	Bu Attifel	43.3	0.04

*(Continued)*

**Table 1.1** (Continued)

<b>Country</b>	<b>Crude oil</b>	<b>API</b>	<b>Sulfur% w/w</b>
Libya	Buri	26.2	1.76
Libya	Es Sider	37.0	0.45
Libya	Sarir	38.4	0.16
Libya	Sirtica	41.3	0.45
Libya	Zueitina	41.3	0.28
Malaysia	Bintulu	28.1	0.08
Malaysia	Dulang	39.0	0.12
Malaysia	Labuan	32.2	0.07
Malaysia	Miri Light	32.6	0.04
Malaysia	Tembungo	37.4	0.04
Mexico	Isthmus	33.3	1.49
Mexico	Maya	22.2	3.30
Mexico	Olmecca	39.8	0.80
Neutral Zone	Burgan	23.3	3.37
Neutral Zone	Eocene	18.6	4.55
Neutral Zone	Hout	32.8	1.91
Neutral Zone	Khafji	28.5	2.85
Neutral Zone	Ratawi	23.5	4.07
Nigeria	Antan	32.1	0.32
Nigeria	Bonny Light	33.9	0.14
Nigeria	Bonny Medium	25.2	0.23
Nigeria	Brass River	42.8	0.06
Nigeria	Escravos	36.4	0.12
Nigeria	Forcados	29.6	0.18
Nigeria	Pennington	36.6	0.07
Nigeria	Qua Iboe	35.8	0.12
North Sea (Denmark)	Danish North Sea	34.5	0.260
North Sea (Norway)	Ekofisk	39.2	0.169
North Sea (Norway)	Emerald	22.0	0.750
North Sea (Norway)	Oseberg	33.7	0.310
North Sea (UK)	Alba	20.0	1.330
North Sea (UK)	Duncan	38.5	0.180
North Sea (UK)	Forties Blend	40.5	0.350
North Sea (UK)	Innes	45.7	0.130
North Sea (UK)	Kittiwake	37.0	0.65
North Yemen	Alif	40.3	0.10
Oman	Oman Export	34.7	0.94
Papua New Guinea	Kubutu	44.0	0.04
Peru	Loreto Peruvian	33.1	0.23
Qatar	Dukhan (Qatar Land)	40.9	1.27
Qatar	Qatar Marine	36.0	1.42
Ras Al Khaiman (UAE)	Ras Al Khaiman	44.3	0.15
Russia	Siberian Light	37.8	0.42
Saudi Arabia	Arab Extra Light (Berri)	37.2	1.15
Saudi Arabia	Arab Heavy (Safaniya)	27.4	2.80
Saudi Arabia	Arab Light	33.4	1.77
Saudi Arabia	Arab Medium (Zuluf)	28.8	2.49
Sharjah (UAE)	Mubarek	37.0	0.62

(Continued)

**Table 1.1** (Continued)

<b>Country</b>	<b>Crude oil</b>	<b>API</b>	<b>Sulfur% w/w</b>
Sumatra	Duri	20.3	0.21
Syria	Souedie	24.9	3.82
Timor Sea (Indonesia)	Hydra	37.5	0.08
Trinidad Tobago	Galeota Mix	32.8	0.27
Tunisia	Ashtart	30.0	0.99
USA (Alaska)	Alaskan North Slope	27.5	1.11
USA (Alaska)	Cook Inlet	35.0	0.10
USA (Alaska)	Drift River	35.3	0.09
USA (Alaska)	Nikiski Terminal	34.6	0.10
USA (California)	Hondo Sandstone	35.2	0.21
USA (California)	Huntington Beach	20.7	1.38
USA (Florida)	Sunniland	24.9	3.25
USA (Louisiana)	Grand Isle	34.2	0.35
USA (Louisiana)	Lake Arthur	41.9	0.06
USA (Louisiana)	Louisiana Light Sweet	36.1	0.45
USA (Louisiana)	Ostrica	32.0	0.30
USA (Louisiana)	South Louisiana	32.8	0.28
USA (Michigan)	Lakehead Sweet	47.0	0.31
USA (New Mexico)	New Mexico Intermediate	37.6	0.17
USA (New Mexico)	New Mexico Light	43.3	0.07
USA (Oklahoma)	Basin-Cushing Composite	34.0	1.95
USA (Texas)	Coastal B-2	32.2	0.22
USA (Texas)	East Texas	37.0	0.21
USA (Texas)	Sea Breeze	37.9	0.10
USA (Texas)	West Texas Intermediate	40.8	0.34
USA (Texas)	West Texas Semi-Sweet	39.0	0.27
USA (Texas)	West Texas Sour	34.1	1.640
USA (Wyoming)	Tom Brown	38.2	0.100
USA (Wyoming)	Wyoming Sweet	37.2	0.330
Venezuela	Lago Medio	32.2	1.010
Venezuela	Leona	24.4	1.510
Venezuela	Mesa	29.8	1.010
Venezuela	Ceuta Export	27.8	1.370
Venezuela	Guanipa	30.3	0.850
Venezuela	La Rosa Medium	25.3	1.730
Venezuela	Lago Treco	26.7	1.500
Venezuela	Oficina	33.3	0.780
Venezuela	Temblador	21.0	0.830
Venezuela	Tia Juana	25.8	1.630
Venezuela	Tia Juana Light	31.8	1.160
Venezuela	Tia Juana Medium 24	24.8	1.610
Venezuela	Tia Juana Medium 26	26.9	1.540
Viet Nam	Bach Ho (White Tiger)	38.6	0.030
Viet Nam	Dai Hung (Big Bear)	36.9	0.080
Yemen	Masila	30.5	0.670
Zaire	Zaire	31.7	0.130

**Table 1.2** Simplified Differentiation Between Conventional Crude Oil, Heavy Oil, Extra Heavy Oil, Tar Sand Bitumen, Oil Shale Kerogen, Tight Oil, and Coal

Conventional crude oil	<ul style="list-style-type: none"> <li>Mobile in the reservoir; API gravity: <math>&gt;25^\circ</math></li> <li>High-permeability reservoir</li> <li>Primary recovery</li> <li>Secondary recovery</li> </ul>
Tight oil	<ul style="list-style-type: none"> <li>Similar properties to the properties of conventional crude oil; API gravity: <math>&gt;25^\circ</math></li> <li>Immobile in the reservoir</li> <li>Low-permeability reservoir</li> <li>Horizontal drilling into reservoir</li> <li>Fracturing (typically multifracturing) to release fluids/gases</li> </ul>
Medium crude oil	<ul style="list-style-type: none"> <li>Similar properties to the properties of conventional crude oil; API gravity: <math>20\text{--}25^\circ</math></li> <li>High-permeability reservoir</li> <li>Primary recovery</li> <li>Secondary recovery</li> </ul>
Heavy crude oil	<ul style="list-style-type: none"> <li>More viscous than conventional crude oil; API gravity: <math>10\text{--}20^\circ</math></li> <li>Mobile in the reservoir</li> <li>High-permeability reservoir</li> <li>Secondary recovery</li> <li>Tertiary recovery (enhanced oil recovery – EOR; e.g., steam stimulation)</li> </ul>
Extra heavy oil	<ul style="list-style-type: none"> <li>Similar properties to the properties of tar sand bitumen; API gravity: <math>&lt;10^\circ</math></li> <li>Mobile in the reservoir</li> <li>High-permeability reservoir</li> <li>Secondary recovery</li> <li>Tertiary recovery (enhanced oil recovery—EOR; eg, steam stimulation)</li> </ul>
Tar sand bitumen	<ul style="list-style-type: none"> <li>Immobile in the deposit; API gravity: <math>&lt;10^\circ</math></li> <li>High-permeability reservoir</li> <li>Mining (often preceded by explosive fracturing)</li> <li>Steam assisted gravity draining (SAGD)</li> <li>Solvent methods (VAPEX)</li> <li>Extreme heating methods</li> <li>Innovative methods<sup>a</sup></li> </ul>

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<sup>a</sup>Innovative methods exclude tertiary recovery methods and methods, such as SAGD, VAPEX, but does include variants or hybrids thereof (see chapters: General Methods of Oil Recovery; Microbial Enhanced Oil Recovery).

is somewhat easier to recover from the reservoir but differences in crude oil quality are not the only determinant of recovery differentials, which are not constant over time. In addition, differences in the quality of heavy crude oil also influence the relative ease of recovery, while tar sand bitumen requires different lines of thinking in terms of recovery (Speight, 2013a, b, 2014a). However, factors such as the properties of the reservoir or the deposit, which are outside of the quality of the crude oil, heavy oil, or bitumen, also have an influence on the recovery process.

At this point, the concept of hydraulic fracturing is worthy of a mention—in addition to the recognized recovery processes, hydraulic fracturing is included as an example of technologies that contribute to improvements in production of crude oil (see chapter: General Methods of Oil Recovery). Hydraulic fracturing is used to create additional passageways in the oil reservoir that can facilitate the flow of oil to a producing well. *Tight reservoirs* are oil-containing reservoirs with restricted pore volume and connectivity in the reservoir rock that impede the flow of fluids through the reservoir. Such reservoirs 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.

In the process, a viscous fluid containing a proppant, such as sand, is injected under high pressure until the desired fracturing is achieved. The pressure is then released allowing the fluid to flow to the well while the proppant remains in the fractures to prevent them from closing. 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. 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 plugging by solids, water retention, and chemical interactions.

### 1.3 PETROLEUM

Petroleum (crude oil) comprises a family of naturally-occurring materials that are predominantly hydrocarbon in nature and mobile within the reservoir and recoverable by application of various methods.

## 1.4 CONVENTIONAL PETROLEUM

The *definition* of petroleum (also called crude oil or conventional petroleum) has been varied, unsystematic, diverse, and often archaic. In fact, there has been a tendency to define petroleum and heavy oil on the basis of a single property. While this may be suitable for a general understanding it is by no means accurate and does not reflect the true nature of petroleum or heavy oil or the characterization of the material. Unfortunately, this form of *identification* or differentiation is a product of many years of growth and its long established use, however general or inadequate it may be, is altered with difficulty, and a new term, however precise, is adopted only slowly.

*Petroleum* is a naturally occurring mixture of hydrocarbons, generally in a liquid state, which may also include compounds of sulfur nitrogen oxygen metals and other elements (AOSTM D4175; Speight, 2012a; US EIA, 2014). Thus, *petroleum* and the equivalent term *crude oil*, cover a wide assortment of materials consisting of mixtures of hydrocarbons and other compounds containing variable amounts of sulfur, nitrogen, and oxygen, which may vary widely in specific gravity, API gravity, the amount of residuum, as well as the variation in properties (Tables 1.1 and 1.2). Metal-containing constituents, notably those compounds that contain 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 during processing of these feedstocks (Speight, 1984, 2014a). Because petroleum is a mixture of widely varying constituents and proportions, its physical properties also vary widely and the color varies from near colorless to black.

The molecular boundaries of petroleum cover a wide range of boiling points and carbon numbers of hydrocarbon compounds and other compounds containing nitrogen, oxygen, and sulfur, as well as metal-containing (porphyrin) constituents. However, the actual boundaries of such a *petroleum map* can only be arbitrarily defined in terms of boiling point and carbon number. In fact, petroleum is so diverse that materials from different sources exhibit different boundary limits, and for this reason alone it is not surprising that petroleum has been difficult to *map* in a precise manner.

Since there is a wide variation in the properties of crude petroleum, the proportions in which the different constituents occur vary with the origin and the relative amounts of the source materials that form the initial *protopetroleum*, as well as the maturation conditions. Thus, some crude

oils have higher proportions of the lower boiling components and others (such as heavy oil and bitumen) have higher proportions of higher boiling components (asphaltic components and residuum).

The fuels derived from petroleum contribute approximately one-third to one-half of the total world energy supply and are used not only for transportation fuels (ie, gasoline, diesel fuel, and aviation fuel, among others) but also to heat buildings. Petroleum products have a wide variety of uses that vary from gaseous and liquid fuels to near-solid machinery lubricants. In addition, the residue of many refinery processes, asphalt—a once-maligned by-product—is now a premium value product for highway surfaces, roofing materials, and miscellaneous waterproofing uses.

Petroleum occurs underground, at various pressures depending on the depth. Because of the pressure, it contains considerable natural gas in solution. Petroleum underground 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°C/km to 30°C/km (15°F/1000 feet or 120°C/1000 feet, ie, 0.015°C per foot of depth or 0.012°C per foot of depth).

Petroleum is derived from aquatic plants and animals that lived and died hundreds of millions of years ago. Their remains mixed with mud and sand in layered deposits that, over the millennia, were geologically transformed into sedimentary rock. Gradually the organic matter decomposed and eventually formed petroleum (or a related precursor), which migrated from the original source beds to more porous and permeable rocks, such as *sandstone* and *siltstone*, where it finally became entrapped. Such entrapped accumulations of petroleum are called *reservoirs*. 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*.

The major components of petroleum are *hydrocarbons*, compounds of hydrogen and carbon that 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 crystalline waxes. A series of ring-shaped hydrocarbons, known as the

*naphthenes*, range from volatile liquids, such as *naphtha*, to high molecular weight substances, isolated as the *asphaltene* fraction. Another group of ring-shaped hydrocarbons is known as the *aromatics*; the chief compound in this series is benzene, a popular raw material for making petrochemicals. The *nonhydrocarbon constituents* of petroleum include organic derivatives of nitrogen, oxygen, sulfur, and the metals nickel and vanadium. Most of these impurities are removed during refining.

Geologic techniques can determine only the existence of rock formations that are favorable for oil deposits, not whether oil is actually there. Drilling is the only sure way to ascertain the presence of oil. With modern rotary equipment, wells can be drilled to depths of more than 30,000 feet (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, whose extraction is impeded by viscous resistance to flow at reservoir temperatures.

Petroleum is typically recovered from the reservoir by the application of primary and secondary recovery techniques. Although covered elsewhere (see chapter: General Methods of Oil Recovery), mention of (1) primary recovery, (2) secondary recovery, and (3) tertiary recovery is warranted here in terms of the general description of definitions of these techniques.

*Primary recovery* refers to the process in which the petroleum in the reservoir trap is forced to the surface by the natural pressure contained in the trap. This pressure may result from several forces: (1) when the reservoir is penetrated the pressure release allows the water layer to expand and pushes the oil upwards and replaces it in the rock pores—this is the most effective technique and is known as a water drive system (Fig. 1.1); (2) if the drill penetrates into a layer of oil which has a gas cap above it, the release of pressure allows the gas layer to expand rapidly causing a downward pressure on the oil forcing it to move up through the well (gas cap drive) (Fig. 1.2); and (3) gas dissolved in the oil may be released as bubbles when the trap is pierced; as the oil moves up, the gas in the oil expands and the growing bubbles push the oil to the surface (solution gas drive) (Fig. 1.3). In most reservoir traps, these pressures are sufficient to initially force the petroleum to the surface.

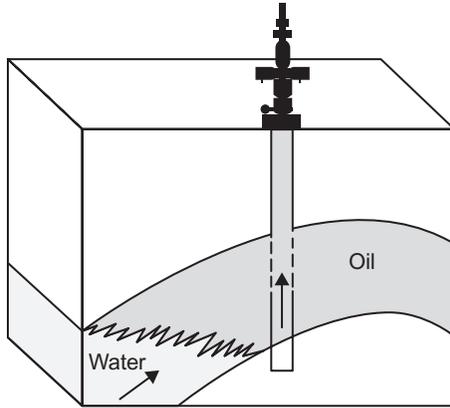


Figure 1.1 Water drive.

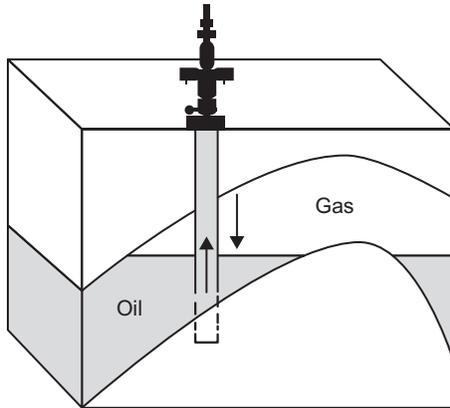


Figure 1.2 Gas cap drive.

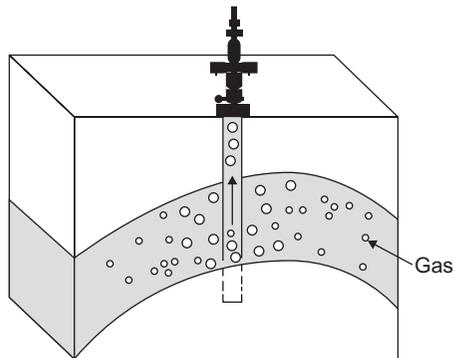


Figure 1.3 Solution gas drive.

At some point in time, this pressure will diminish and the production of petroleum decreases because: (1) there is less force—often referred to as reservoir energy—driving the oil towards the well; and/or (2) the gas that moves into the emptied pore spaces reduces the permeability of the rock, making it more difficult for crude oil to flow through the reservoir to the production well; and/or (3) the fall in pressure and the loss of dissolved gas increases the surface tension and viscosity of the oil. In general terms, primary recovery techniques usually account for less than 30% of the total volume of petroleum recovered. At this stage, depending upon the reservoir condition, additional techniques, such as hydraulic fracturing, may be used to recover the residual crude oil (Speight, 2015a).

*Secondary recovery* involves trying to maintain reservoir pressure. One technique is to inject natural gas into the reservoir above the oil, forcing the oil downwards, and then injecting water below the oil so forcing it upwards. Sometimes the gas that is used is that which has just been released during *primary recovery*. The disadvantage of using the released gas is that this gas is a marketable product in its own right. However, this is a good method to use if transporting the gas would be costly and, in any case, the re-injected gas can always be collected again if necessary. Alternative secondary techniques involve injecting carbon dioxide or nitrogen into the oil. This makes the oil more fluid and the gas pushes the oil upwards. Again, and depending upon the reservoir condition, additional techniques, such as hydraulic fracturing, may be used to recover the residual crude oil (Speight, 2015a). *Tertiary recovery* is the most expensive approach and involves injecting steam, detergents, solvents, bacteria, or bacterial nutrient solutions into the remaining oil. When high-pressure steam is injected it heats the oil, decreasing its density and viscosity and increasing its flow rate (Fig. 1.4). Detergents which can be injected reduce the viscosity of the oil and act as surfactants reducing the ability of the oil to stick to the rock surface and thus making it easier for it to be flushed up to the surface (Fig. 1.5).

Another *tertiary recovery* technique involves injecting bacteria into the oilfield (microbial enhanced oil recovery, MEOR). Some bacteria produce polysaccharides which reduce the permeability of the water-filled pores of the reservoir rock and this effectively forces injected water into the oil-filled pores, pushing the oil out. Other bacteria produce carbon dioxide which helps to increase pressure within the rock pores, forcing out the oil. Other bacteria produce surfactants and/or chemicals that reduce the viscosity of the oil.

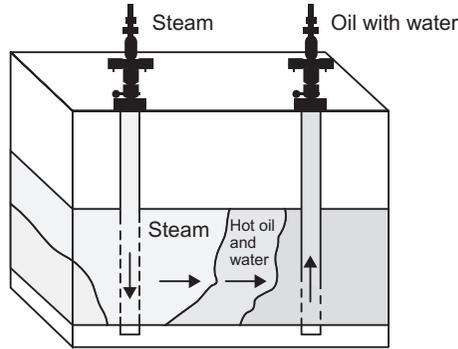


Figure 1.4 Steam flooding.

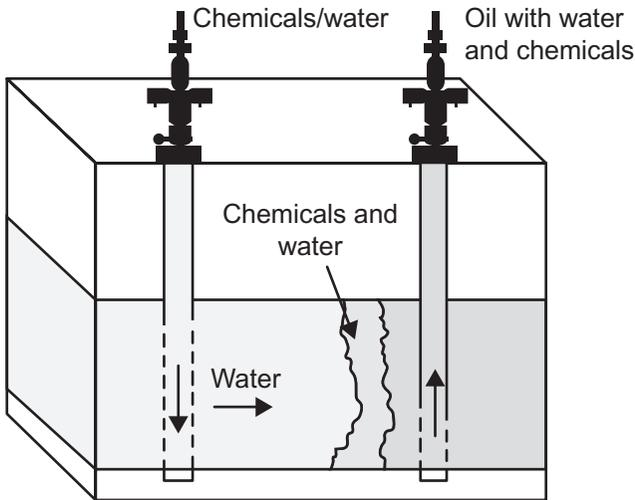


Figure 1.5 Recovery using chemicals or detergents.

MEOR processes involve the use of reservoir microorganisms or specially selected natural bacteria to produce specific metabolic events that lead to enhanced oil recovery (EOR) and the technology is exploited in oil reservoirs to improve recovery (Banat, 1995; Clark et al., 1981; Stosur, 1991). MEOR processes (see chapter: Microbial Enhanced Oil Recovery) are, to a point, similar to in situ bioremediation processes (Speight and Arjoon, 2012). Injected nutrients, together with indigenous or added microbes, promote in situ microbial growth and/or generation of products which mobilize additional oil and move it to producing wells through

reservoir repressurization, interfacial tension/oil viscosity reduction, and selective plugging of the most permeable zones (Bryant et al., 1989; Bryant and Lindsey, 1996). Alternatively, the oil-mobilizing microbial products may be produced by fermentation and injected into the reservoir. In the process, nutrients such as sugars, nitrates, or phosphates are regularly injected into the formation to stimulate the growth and improve the performance of the microbes, some of which may be indigenous to the reservoir. The microbes then generate surfactants and carbon dioxide that help to displace the oil in a similar way to other displacement methods. However, the organisms that participate in oil recovery produce a variety of fermentation products, for example, carbon dioxide, methane, hydrogen, bio-surfactants, and polysaccharides from crude oil, pure hydrocarbons, and a variety of nonhydrocarbon substrates. The organic acids produced through fermentation readily dissolve carbonates and can greatly enhance permeability in limestone reservoirs.

More generally, the microbial enhanced recovery technology requires consideration of the physicochemical properties of the reservoir in terms of salinity, pH, temperature, pressure, and nutrient availability (Khire and Khan, 1994a, b). If the reservoir contains high concentrations of sodium chloride, the use of bacteria which can tolerate these conditions is required (Shennan and Levi, 1987; Jenneman, 1989). Bacteria producing biosurfactants and polymers can grow at sodium concentrations up to 8% and selectively plug sandstone to create a biowall that effectively has an adverse effect on the recovery of additional oil (Raiders et al., 1989). Thus the process, like all recovery processes, requires modification to match the reservoir conditions, which vary from reservoir to reservoir and which calls for reservoir-specific customization of the MEOR process, and this alone has the potential to undermine microbial process economic viability. In addition, the process may modify the immediate reservoir environment in a number of ways that could also damage the production hardware or the formation itself. Certain sulfate reducers can produce  $H_2S$ , which can corrode pipeline and other components of the recovery equipment. Ensuring success requires an ability to manipulate environmental conditions to promote growth and/or product formation by the participating microorganisms. Exerting such control over the microbial system in the subsurface is itself a serious challenge.

MEOR differs from chemical EOR in the method by which the enhancing products are introduced into the reservoir. Thus, in oil recovery by the *cyclic microbial method*, a solution of nutrients and microorganisms

is introduced into the reservoir during injection. The injection well is then shut for an incubation period allowing the microorganisms to produce carbon dioxide gas and surfactants that assist in mobilization of the oil. The well is then opened and oil and oil products resulting from the treatment are produced. The process is repeated as often as oil can be produced from the well. Oil recovery by *microbial flooding* also involves the use of microorganisms but in this case, the reservoir is usually conditioned by a water flush after which a solution of microorganisms and nutrients is injected into the formation. As this solution is pushed through the reservoir by water drive, gases and surfactants are formed, the oil is mobilized, and pumped through the well. However, even though microbes produce the necessary chemical reactions in situ (Table 1.3), whereas surface injected chemicals may tend to follow areas of higher permeability, resulting in decreased sweep efficiency, there is need for caution and astute observation of the effects of the microorganisms on the reservoir chemistry.

The mechanism by which MEOR processes work can be quite complex and may involve multiple biochemical processes. In selective plugging approaches, microbial cell mass or biopolymers plug high permeability

**Table 1.3** Microbial Products and Their Contribution to Enhanced Oil Recovery

Microbial	Effect
Acids	Modification of reservoir rock, especially carbonate rock Improvement of porosity and permeability Reaction of carbonate rocks to produce carbon dioxide
Biomass	Selective or nonselective plugging Emulsification through adherence to hydrocarbons Modification of solid surfaces, eg, wetting Degradation and alteration of oil Reduction of oil viscosity and oil pour point Desulfurization of oil
Gases (CO <sub>2</sub> , CH <sub>4</sub> , H <sub>2</sub> )	Reservoir repressurization Oil swelling Viscosity reduction Solubilization of carbonate minerals Increase of permeability
Solvents	Dissolution of the crude oil
Surface active agent	Lowering interfacial tension
Polymers	Mobility control Selective or nonselective plugging

zones and lead to a redirection of the water flood. In other processes, biosurfactants are produced in situ, which leads to increased mobilization of residual oil. In still other processes, microbial production of carbon dioxide and organic solvents reduces the oil viscosity as the primary mechanism for EOR.

Briefly, the term residual oil refers to the oil that remains in the pores of the rock after secondary recovery. Numerous techniques exist for enhanced recovery of residual oil (see chapter: General Methods of Oil Recovery) and many techniques were developed in the early 1980s: (1) polymer flood, (2) surfactant flood, (3) carbon dioxide injection or natural gas injection, and (4) microbial treatment.

The stimulation of oil production by in situ bacterial fermentation is thought to proceed by one or a combination of the following mechanisms: (1) improvement of the relative mobility of oil to water by biosurfactants and biopolymers; (2) partial repressurization of the reservoir by methane and carbon dioxide; (3) reduction of oil viscosity through the dissolution of organic solvents in the oil phase; (4) increase of reservoir permeability and widening of the fissures and channels through the etching of carbonaceous rocks in limestone reservoirs by organic acids produced by anaerobic bacteria; (5) cleaning the wellbore region through the acids and gas from in situ fermentation in which the gas pushes oil from dead space and dislodges debris that plugs the pores. The average pore size is increased and, as a result, the capillary pressure near the wellbore is made more favorable for the flow of oil; and (6) selective plugging of highly permeable zones by injecting slime-forming bacteria followed by a nutrient (such as sucrose solution) which initiates the production of extracellular slimes and aerial sweep efficiency is improved.

The target for EOR processes is the quantity of unrecoverable oil in known reservoirs, highly viscous heavy oil, and bitumen from tar sand deposits. However, there must be the recognition that MEOR is a single process and, in addition to any potential (or perceived) deleterious effects of the microorganisms, scientific knowledge of the fundamentals of microbiology must be coupled with an understanding of the geological and engineering aspects of oil production in order to develop acceptable MEOR technology (see chapter: General Methods of Oil Recovery).

After recovery, petroleum is transported to refineries by pipelines, which can often carry more than 500,000 barrels per day, or by ocean-going tankers. The basic refinery process is distillation, which separates the crude oil into fractions of differing volatility. After the distillation, other

physical methods are employed to separate the mixtures, including absorption, adsorption, solvent extraction, and crystallization. After physical separation into such constituents as light and heavy naphtha, kerosene, and light and heavy gas oils, selected petroleum fractions may be subjected to conversion processes, such as thermal cracking (ie, coking) and catalytic cracking. In the most general terms, cracking breaks the large molecules of heavier gas oils into the smaller molecules that form the lighter, more valuable naphtha fractions (Speight and Ozum, 2002; Parkash, 2003; Hsu and Robinson, 2006; Gary et al., 2007; Speight, 2014a).

## 1.5 OTHER MEMBERS OF THE PETROLEUM FAMILY

Other members of the petroleum family that may invoke the need for enhanced recovery methods, including the application of hydraulic fracturing techniques (Speight, 2015a) and which are worthy of mention here include: (1) crude oil from tight formations, (2) opportunity crudes, (3) high acid crude oils, and (4) foamy oil.

### 1.5.1 Crude Oil From Tight Formations

Generally, unconventional tight oil resources 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. Tight formations scattered throughout North America have the potential to produce crude oil (tight oil) (Fig. 1.5) (US EIA, 2011; Speight, 2013c; US EIA, 2013). Such formations might be composed 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 oil occurs in sandstone sediments that have an effective permeability of less than 1 mD. 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: (1) clay to silt sized particles; (2) high % of silica, and sometimes carbonate minerals; (3) thermally mature; (4) hydrocarbon-filled porosity—on the order of 6 to 14%; (5) low permeability—on the order of <0.1 mD; (6) large

areal distribution; and (7) fracture stimulation required for economic production.

The most notable tight oil plays in North America include the Bakken shale, the Niobrara formation, the Barnett shale, the Eagle Ford shale, and the Miocene Monterey play of California's San Joaquin Basin (California) and the Cardium play (Alberta, Canada). In many of these tight formations, the existence of large quantities of crude 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 turned tight oil resources into one of the most actively explored and produced targets in North America.

Other known tight formations (on a worldwide basis) include the R'Mah Formation (Syria), the Sargelu Formation (northern Persian Gulf region), the Athel Formation (Oman), the Bazhenov formation and Achimov Formation (West Siberia, Russia), the Coober Pedy formation (Australia), the Chicontepex formation (Mexico), and the Vaca Muerta field (Argentina) (US EIA, 2011, 2013). However, tight oil formations are heterogeneous and vary widely over relatively short distances. Thus, even in a single horizontal production well, 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 which contain only crude oil (without natural gas as the pressurizing agent) cannot be economically produced (US EIA, 2011, 2013).

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 (sometimes also referred to as *gas condensate*) is a mixture of low-boiling liquid hydrocarbon isolates 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).

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, 2015b). 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, 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, b, c, 2015b, c). 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.

While the basic approach toward developing a tight oil play are 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 crude oils from tight formations 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  $42^\circ$  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  $40^\circ$  API and  $62^\circ$  API.

### 1.5.2 Opportunity Crudes, High Acid Crudes, and Foamy Oil

There is also the need to understand and accommodate *opportunity crude oils* and/or *high acid crude oils*, which, for many purposes, are often included with heavy oil feedstocks after recovery (Speight, 2014a, b; 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.

High acid crude oils are crude oils that contain 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; 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 use 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 production equipment—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 which are shown to accelerate the hydrolysis reactions are inorganic clays and organic acids.

During primary production of heavy oil from solution gas drive reservoirs, the oil is pushed into the production wells by energy supplied by the dissolved gas. As fluid is withdrawn from the production wells, the pressure in the reservoir declines and the gas that was dissolved in the oil at high pressure starts to come out of solution (*foamy oil*). As pressure declines further with continued removal of fluids from the production wells, more gas is released from solution and the gas already released expands in volume. The expanding gas, which at this point is in the form of isolated bubbles, pushes the oil out of the pores and provides energy for the flow of oil into the production well. This process is very efficient until the isolated gas bubbles link up and the gas itself starts flowing into the production well. Once the gas flow starts, the oil has to compete with the gas for available flow energy. Thus, in some heavy oil reservoirs, due to the properties of the oil and the sand and also due to the production methods, the released gas forms foam with the oil and remains subdivided, in the form of dispersed bubbles, much longer.

Foamy oil is oil-continuous foam that contains dispersed gas bubbles produced at the well head 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 production well. Foamy oil accounts for unusually high production in heavy oil reservoirs under solution-gas drive.

However, it has been observed that many heavy oil reservoirs in Alberta and Saskatchewan exhibit foamy oil behavior which is accompanied by sand production, leading to anomalously high oil recovery and lower gas oil ratio (Chugh et al., 2000). These observations suggest that the foamy oil flow might be physically linked to sand production. It is apparent that some additional factors, which remain to be discovered, are involved in making the foamy solution gas possible at field rates of decline. One possible mechanism is the synergistic influence of sand influx into the production wells. Allowing 1–3% sand to enter the wellbore with the fluids can result in propagation of a front of sharp pressure gradients away from the wellbore. These sharp pressure gradients occur at the advancing edge of solution gas drive. It is still unknown how far from the wellbore the dilated zone can propagate.

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 (ie, 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) (Chen et al., 2006). As a result, the production gas–oil ratio (GOR) increases rapidly after the critical gas saturation has been exceeded.

Reservoirs that exhibit foamy oil behavior are typically characterized by the appearance of an oil–continuous foam at the wellhead. When oil is produced as this nonequilibrium mixture, reservoirs can perform with higher than expected rates of production: up to 30 times that predicted by Darcy's Law, and lower than expected production GORs (Poon and Kisman, 1992). Moreover, foamy oil flow is often accompanied by sand production along with the oil and gas—the presence of sand at the wellhead leads to sand dilation and the presence of high porosity, high permeability zones (wormholes) in the reservoir (Maini, 1999, 2001). It is generally believed that in the field, the high rates and recoveries observed are the combination of the foamy oil mechanism and the presence of these wormholes.

However, the actual structure of foamy oil flow and its mathematical description are still not well understood. Much of the earlier discussion of such flows was based on the concept of microbubbles, that is, bubbles that are much smaller than the average pore-throat size and are thus free to move with the oil during flow (Sheng et al., 1999). Dispersion of this type can be produced only by nucleation of a very large number of bubbles (explosive nucleation) and by the availability of a mechanism that prevents these bubbles from growing into larger bubbles with a decline in pressure. Another hypothesis for the structure of foamy oil flow is that much larger bubbles migrating with the oil, with the dispersion created by breakup of bubbles during migration. The major difference between conventional solution gas drive and foamy solution gas drive is that the pressure gradient in the latter is strong enough to mobilize gas clusters once they have grown to a certain size (Maini, 1999).

## 1.6 HEAVY OIL

Heavy oil is a *type* of petroleum that is different from conventional petroleum insofar as they are much more difficult to recover from the subsurface reservoir. Heavy oil, particularly heavy oil formed by biodegradation of organic deposits, are found in shallow reservoirs, formed by unconsolidated sands. This characteristic, which brings about difficulties during well drilling and completion operations, may become a production advantage due to higher permeability.

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. 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*. During the past two-to-three decades the term *black oil* has been introduced into the petroleum lexicon. This has only served to confuse the somewhat already confusing terminology applied to petroleum, heavy oil, and tar sand bitumen since the term refers to color rather than to any meaningful properties or to recovery behavior (Speight, 2014b, 2015b).

Very simply, heavy oil is a type of crude oil which is very viscous and does not flow easily. The common characteristic properties (relative to conventional crude oil) are high specific gravity, low hydrogen to carbon ratios, high carbon residues, and high contents of asphaltenes, heavy metals, sulfur, and nitrogen. Specialized recovery and refining processes are required to produce more useful fractions, such as naphtha, kerosene, and gas oil.

Heavy oil is an oil resource that is characterized by high viscosities (ie, resistance to flow) and high densities compared to conventional oil. Most heavy oil reservoirs originated as conventional oil that formed in deep formations, but migrated to the surface region where they were degraded by bacteria and by weathering, and where the lightest hydrocarbons escaped. Heavy oil is deficient in hydrogen and has high carbon, sulfur, and heavy metal content. Hence, heavy oil requires additional processing (upgrading) to become a suitable refinery feedstock for a normal refinery.

There are large resources of heavy oil in Canada, Venezuela, Russia, the United States, and many other countries. The resources in North America alone provide a small percentage of current oil production (approximately 2%), and existing commercial technologies could allow for significantly

increased production. Under current economic conditions, heavy oil can be profitably produced, but at a smaller profit margin than for conventional oil, due to higher production costs and upgrading costs in conjunction with the lower market price for heavier crude oils. In fact, heavy oil accounts for more than double the resources of conventional oil in the world and heavy oil offers the potential to satisfy current and future oil demand. Not surprisingly, heavy oil has become an important theme in the petroleum industry with an increasing number of operators getting involved or expanding their plans in this market around the world.

However, heavy oil is more difficult to recover from the subsurface reservoir than conventional or light oil. A very general definition of heavy oils has been and remains 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 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° to 15°. For example, Cold Lake heavy crude oil has an API gravity equal to 12° and tar sand bitumen usually have an API gravity in the range 5° to 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° to 8° API (Speight, 2000, 2014a; 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 heavy oil 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, 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 (incorrectly) used to describe both the heavy oils that require thermal stimulation of recovery from the reservoir and the bitumen in bituminous sand (tar sand) formations from which the heavy bituminous material is recovered by a mining operation. *Extra heavy oil* is a nondescript term (related to viscosity) of little scientific meaning which is usually applied to tar sand bitumen, which is generally incapable of free flow under reservoir conditions. The general difference is that extra heavy oil may have properties similar to tar sand bitumen but, unlike tar sand bitumen, has some degree of mobility in the

reservoir or deposit (Table 1.2) (Delbianco and Montanari, 2009; Speight, 2014a). Extra heavy oils can flow at reservoir temperature and can be produced economically, without additional viscosity-reduction techniques, through variants of conventional processes such as long horizontal wells, or multilaterals. This is the case, for instance, in the Orinoco (Venezuela) or in offshore reservoirs off the coast of Brazil, but once outside of the influence of the high reservoir temperature, these oils are too viscous at the surface to be transported through conventional pipelines and require heated pipelines for transportation. Alternatively, the oil must be partially upgraded or fully upgraded (see chapter: Thermal Methods of Recovery) or diluted with a light hydrocarbon (such as aromatic naphtha) to create a mix that is suitable for transportation.

In the context of the current section, the methods outlined in this book for heavy oil recovery focus on heavy oil with an API gravity of less than 20° with a variable sulfur content that may bear a general relationship to the API gravity (eg, see Table 1.4) (Speight, 2000). However, it must be recognized that some of the heavy oil is sufficiently liquid to be recovered by pumping operations and some is already being recovered by this method. Recovery depends not only on the characteristics of the oil but also on the characteristics of the reservoir—including the temperature

**Table 1.4** API Gravity and Sulfur Content of Selected Heavy Oils and Bitumen

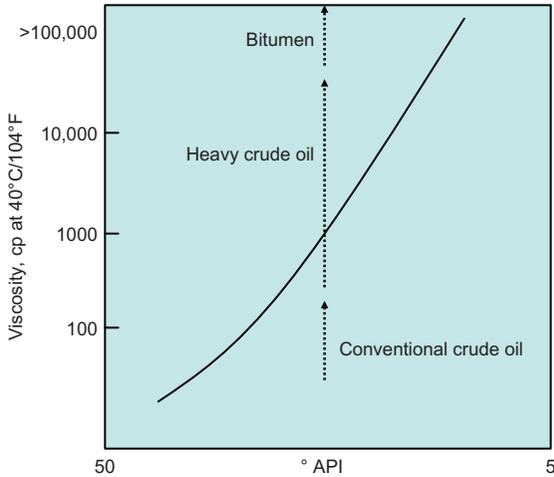
Country	Crude Oil	API	Sulfur % w/w
Brazil	Albacor Leste	18.9	0.66
Canada (Alberta)	Athabasca	8.0	4.8
Canada (Alberta)	Cold Lake	13.2	4.11
Canada (Alberta)	Lloydminster	16.0	2.60
Canada (Alberta)	Wabasca	19.6	3.90
Chad	Bolobo	16.8	0.14
Chad	Kome	18.5	0.20
China	Bozhong	16.7	0.30
China	Qinhuangdao	16.00	0.26
China	Zhao Dong	18.4	0.25
Colombia	Castilla	13.3	0.22
Colombia	Chichimene	19.8	1.12
Congo	Yombo	17.7	0.33
Ecuador	Ecuador Heavy	18.2	2.23
Ecuador	Napo	19.2	1.98
Guatemala	Xan-Coban	18.7	6.00
Indonesia	Kulin (South)	19.8	0.30
Iran	Soroosh (Cyrus)	18.1	3.30
Kuwait	Eocene	18.4	4.00

(Continued)

Table 1.4 (Continued)

Country	Crude Oil	API	Sulfur% w/w
USA (California)	Arroyo Grande/Edna	14.9	2.03
USA (California)	Belridge (South)	13.7	1.00
USA (California)	Beta Offshore	15.9	3.60
USA (California)	Beta Offshore	16.9	3.30
USA (California)	Hondo Monterey	19.4	4.70
USA (California)	Hondo Monterey	17.2	4.70
USA (California)	Huntington Beach	19.4	2.00
USA (California)	Huntington Beach	14.4	0.90
USA (California)	Kern River	13.3	1.10
USA (California)	Kern River	14.4	1.02
USA (California)	Lost Hills	18.4	1.00
USA (California)	Midway Sunset	12.6	1.60
USA (California)	Midway Sunset	11.0	1.55
USA (California)	Monterey	12.2	2.30
USA (California)	Mount Poso	16.0	0.70
USA (California)	Newport Beach	15.1	2.00
USA (California)	Point Arguello	19.5	3.50
USA (California)	Point Pedernales	15.9	5.10
USA (California)	San Ardo	12.2	2.30
USA (California)	San Joaquin Valley	15.7	1.20
USA (California)	Santa Maria	13.7	5.20
USA (California)	Sockeye	19.6	5.30
USA (California)	Sockeye	15.9	5.40
USA (California)	Torrance	18.2	1.80
USA (California)	Wilmington	18.6	1.59
USA (California)	Wilmington	16.9	1.70
USA (Mississippi)	Baxterville	16.3	3.02
Venezuela	Bachaquero	16.3	2.35
Venezuela	Bachaquero	12.2	2.80
Venezuela	Bachaquero	14.4	2.52
Venezuela	Bachaquero Heavy	10.7	2.78
Venezuela	Boscan	10.1	5.50
Venezuela	Hamaca	8.4	3.82
Venezuela	Jobo	9.2	4.10
Venezuela	Laguna	10.9	2.66
Venezuela	Lagunillas Heavy	17.0	2.19
Venezuela	Merey	18.0	2.28
Venezuela	Morichal	12.2	2.78
Venezuela	Pilon	14.1	1.91
Venezuela	Tia Juana Pesado	12.1	2.70
Venezuela	Tia Juana Heavy	18.2	2.24
Venezuela	Tia Juana Heavy	11.6	2.68
Venezuela	Tremblador	19.0	0.80
Venezuela	Zuata	15.7	2.69

For reference, Athabasca tar sand bitumen has API = 8° and sulfur content = 4.8–5.0% w/w.

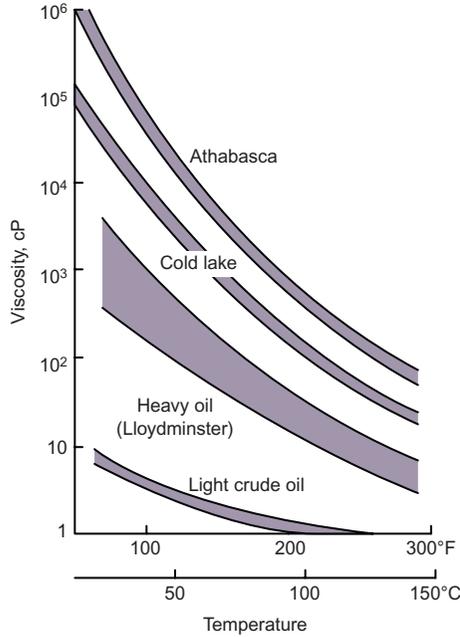


**Figure 1.6** General relationship of viscosity to API gravity.

of the reservoir and the pour point of the oil (see also chapter: Evaluation of Reservoir Fluids). These heavy oils fall into a range of high viscosity (Fig. 1.6) and the viscosity is subject to temperature effects (Fig. 1.7), which is the reason for the application of thermal methods to heavy oil recovery.

Finally, the formation of stable emulsions of water and oil is a phenomenon frequently found in the production of heavy oils. Emulsions are formed during simultaneous flow of oil and water, although it is also supposed to occur while still in the reservoir. The flow of the mixture of liquids through devices and equipment that impose a high shear rate, such as in pumps and valves, in pipe singularities and even along lines, will induce emulsion formation. Gas and solid particulates are additional factors that increase the shear rate, intensifying emulsification. The shear rate is a strong factor in emulsion formation, but rheology and fluid properties also play important roles. In addition, the tendency of heavy oil to form foam (foamy oil) must also be taken into account during the release of dissolved gas, in a type of gas and liquid limiting compressible emulsion. All such characteristics will influence the flow in the reservoir, wellbore, and flow lines as well as having an impact on other processes, such as separation.

Finally, some heavy oils found in offshore fields have a high content of organic acids. The acidity rate, measured by TAN (*total acid number*), is particularly important to refining processes. Currently refineries need to take precautions to prevent acidic corrosion of the equipment as well as



**Figure 1.7** Variation of viscosity with temperature.

contributing to the precipitation of organo-metallic salts, causing buildups in processing equipment (Speight, 2014b, c).

## 1.7 TAR SAND BITUMEN

The term tar sand, also known as oil sand (in Canada), or (more correctly) bituminous sands, commonly describes sandstones or friable sand (quartz) impregnated with viscous bitumen (a hydrocarbonaceous material soluble in carbon disulfide). Significant amounts of fine material, usually largely or completely clay, are also present. The degree of porosity varies from deposit to deposit and is an important characteristic in terms of recovery processes. The bitumen makes up the desirable fraction of the tar sand from which liquid fuels can be derived (Speight, 2013d, 2014a). However, the bitumen is usually not recoverable by conventional petroleum production techniques (Speight, 2013b, 2014a). Furthermore, the properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. In the tar sands that are recognized as being *water-wet* (rather than *bitumen-wet*) in the Athabasca

deposit, a layer of water surrounds the sand grain, and the bitumen partially fills the voids between the wet grains. On the other hand, the Utah tar sands lack the water layer and the bitumen is directly in contact with the sand grains without any intervening water. Typically, more than 99% w/w of the mineral matter is composed of quartz and clay minerals. The Utah deposits range from largely consolidated sands with low porosity and permeability to, in some cases, unconsolidated sands. High concentrations of heteroatoms tend to increase viscosity, increase the bitumen–sand reactions and bitumen–minerals reactions making processing more difficult.

Tar sands are sedimentary rocks containing bitumen, a viscous hydrocarbonaceous mixture. Tar sand deposits may be divided into two major types: (1) a breached reservoir where erosion has removed the capping layers from a reservoir of relatively viscous material, allowing the more volatile petroleum hydrocarbons to escape; and (2) deposits that formed when liquid petroleum seeps into a near-surface reservoir from which the more volatile constituents escaped. In either type of deposit, the lighter, more volatile constituents have escaped to the environment, leaving the less volatile constituents in place which are altered by contact with air, bacteria, and groundwater. Because of the very viscous nature of the bitumen in tar sands, tar sands cannot be processed by the typical petroleum production techniques (Speight, 2013d, 2014a).

Tar sand deposits occur throughout the world and the largest deposits occur in Alberta, Canada (the Athabasca, Wabasca, Cold Lake, and Peace River areas), and in Venezuela. Smaller deposits occur in the United States, with the larger individual deposits in Utah, California, New Mexico, and Kentucky.

The term bitumen (also, on occasion, referred to as native asphalt, and extra heavy oil), which is the organic component of tar sand, 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* (Abraham, 1945). However, bitumen from different deposits (eg, deposits in the United States and Canada, exhibit a variety of properties) (Tables 1.5 and 1.6).

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

**Table 1.5** Properties of Bitumen From Different California Tar Sand Deposits

Deposit/Field	Reservoir Temperature (F)	Reservoir Permeability (mD)	Reservoir Porosity	API	Viscosity, cP reservoir conditions	Viscosity, cP (80°F)	Viscosity, cP (87°F)	Viscosity, cP (100°F)	Viscosity, cP (200°F)	Sulfur%, w/w
Arroyo Grande		700	38	8				15,000		3–5
Basal Foxen		300	25	9–17 (9.5)		47,000				4–5
Cat Canyon				0–12 (6)						
Brooks Sand	135	1400–5000	32	0–12	15,000					
S Sand	110	3450	37		12,000–1,000,000					
Casmalia		<1	48							
Zaca-Sisquoc			35	4–6						
Oxnard (Vaca)		6000	35	5				500,000	2000	6–7
Paris Valley		3700	32							1.5
Upper Lobe							227,000			
Lower Lobe							23,000			
Midway–Sunset										
Webster Sands	100	1300	28	14				1650		

**Table 1.6** Specific Gravity, API Gravity, and Viscosity of Various Bitumen Samples

Source	Specific Gravity	API Gravity	Viscosity, cP	F
Athabasca (Canada)				
Mildred-Ruth Lakes	1.025	6.5	35,000	100
Abasand	1.027	6.3	500,000	100
	1.034	5.4	570,000	100
Ells River	1.008	8.9	25,000	
Utah (United States)				
Asphalt Ridge			610,000	140
Tar Sand Triangle			760,000	140
Sunnyside			1,650,000	100
California				
Arroyo Grande	1.055	2.6	1,300,000	220

(Demaison, 1977). Tar sand bitumen is a high-boiling material with little, if any, material boiling below 350°C (660°F) and the boiling range is approximately the same as 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 deposit. 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. Extra heavy oil, which is often likened to tar sand bitumen because of similarities in the properties of the two, has a degree of mobility under reservoir or deposit conditions.

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, above). 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. Thus, 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. In the simplest sense, pitch is the distillation residue of the various types of tar. In fact, 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.

Bituminous rock and bituminous sand are those formations in which the bituminous material is found as a filling in veins and fissures in fractured rocks or impregnating relatively shallow sand, sandstone, and limestone strata. These terms are, in fact, correctly geological descriptions of tar sand. The deposits contain as much as 20% bituminous material, and if the organic material in the rock matrix is bitumen, it is usual (although chemically incorrect) to refer to the deposit as rock asphalt to distinguish it from bitumen that is relatively mineral free. A standard test ([ASTM D4](#)) is available for determining the bitumen content of various mixtures with inorganic materials, although the use of word bitumen as applied in this test might be questioned and it might be more appropriate to use the term *organic residues* to include tar and pitch. If the material is of the asphaltite-type or asphaltoid-type, the corresponding terms should be used: rock asphaltite or rock asphaltoid.

Bituminous rocks generally have a coarse, porous structure, with the bituminous material in the voids. A much more common situation is that in which the organic material is present as an inherent part of the rock composition insofar as it is a diagenetic residue of the organic material detritus that was deposited with the sediment. The organic components of such rocks are usually refractory and are only slightly affected by most organic solvents. A special class of bituminous rocks that has achieved some importance is the so-called *oil shale* ([Scouten, 1990](#); [Speight, 2012b](#)). These are argillaceous, laminated sediments of generally high organic content that can be thermally decomposed to yield appreciable amounts of oil, commonly referred to as *shale oil*. Oil shale does not yield shale oil without the application of high temperatures and the ensuing thermal decomposition that is necessary to decompose the organic material (*kerogen*) in the shale. The kerogen produces a liquid product (shale oil) by thermal decomposition at high temperature (>500°C, >930°F). The raw oil shale can even be used directly as a fuel akin to a low-quality coal. Indeed, oil shale deposits have

been exploited as such for several centuries and shale oil has been produced from oil shale since the nineteenth century.

*Sapropel* is an unconsolidated sedimentary deposit rich in bituminous substances. It is distinguished from peat in being rich in fatty and waxy substances and poor in cellulosic material. When consolidated into rock, sapropel becomes oil shale, bituminous shale, or boghead coal. The principal components are certain types of algae that are rich in fats and waxes. Minor constituents are mineral grains and decomposed fragments of spores, fungi, and bacteria. The organic materials accumulate in water under reducing conditions.

The properties and composition of the tar sands and the bitumen significantly influence the selection of recovery and treatment processes and vary among deposits. The general composition of typical deposits at the P.R. Spring Special Tar Sand Area showed a porosity of 8.4 volume percent with the solid/liquid fraction being 90.5% w/w sand, 1.5% w/w fines, 7.5% w/w bitumen, and 0.5% w/w water. Utah deposits range from largely consolidated sands with low porosity and permeability to, in some cases, unconsolidated sand. High concentrations of heteroatoms (nitrogen, oxygen, sulfur, and metals) tend to increase viscosity, increase the bonding of bitumen with minerals, reduce yields, and make processing more difficult.

Finally, and briefly, *extra heavy oil* is a material that occurs in the solid or near-solid state and is 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.

In order to utilize the extra heavy oil produced in Venezuela, the government-run oil company (PDVSA) has developed Orimulsion fuel, which is a dispersion of extra heavy oil and approximately 30% water which is targeted for use as a boiler fuel in applications such as power generation and

industrial use (Shah et al., 2010). However, concerns about the environmental impact of the use of Orimulsion have been raised owing to the relatively high levels of sulfur, nickel, and vanadium compared with other fuel oils (Miller and Srivastava, 2000). Technologies such as *selective catalytic reduction*, *flue gas desulfurization*, and *electrostatic precipitation* are suitable for cleanup of the exhaust emissions (Mokhatab et al., 2006; Speight, 2007).

## 1.8 RATIONALIZATION OF THE DEFINITIONS

Generally, heavy oil and tar bitumen are characterized by high viscosities (ie, resistance to flow measured in centipoises or cP) and high density compared to conventional oil. Attempts have been made to define heavy oil as an oil with a gas-free viscosity between 100 cP and 10,000 Cp at reservoir temperature (tar sand bitumen is incorrectly defined to have a viscosity greater than 10,000 cP, and may be as high as 10,000,000 cP). Attempting to draw a finite line in order to define heavy oil on the one side of the line and bitumen on the other side of the line is meaningless and incorrect and offers very little in the way of scientific integrity since the standard test methods that are used to determine viscosity suffer from reproducibility and accuracy (Speight, 2015b).

On the other hand, heavy oil is slightly less dense than water with an API gravity between 10° and 20°. In addition, heavy oil can flow in some reservoirs at downhole temperatures and/or with in situ solution gas, but at the surface, it is a thick, black, viscous fluid, which typically has an API gravity <10°. It should also be noted that the term oil sands as used in Canada was created for incentive tax purposes for those heavy crude oils found above a certain latitude where the infrastructure was almost nonexistent. For correctness, the terms heavy oil, extra-heavy oil, and bitumen should not be used interchangeably.

As already noted, the generic term heavy oil is often applied to petroleum that has an API gravity of less than 20° and those materials having less than 10° API than have been referred to as bitumen (Speight, 2014a, 2015b). Following from this convenient generalization, there has also been an attempt to classify petroleum, heavy oil, and tar sand bitumen using the viscosity scale, and 10,000 centipoise being the fine line of demarcation between heavy oil and tar sand bitumen. Use of such a system leads to confusion when having to differentiate between a material having a viscosity of 9950 cP and one having a viscosity of 10,050 cP as well as taking into account the limits of accuracy of the method of viscosity

determination (Speight, 2014a, 2015b). Such definitions based on a single property should be discounted as being of little scientific value. Whether the limits are the usual laboratory experimental difference ( $\pm 3\%$ ) or more likely the limits of accuracy of the method ( $\pm 5\%$  to  $\pm 10\%$ ) there is the question of viability and reliability of the definition. In fact, the inaccuracies (ie, the limits of *experimental difference*) of the method of measuring viscosity also increase the potential for misclassification using this (or any) single property for classification purposes.

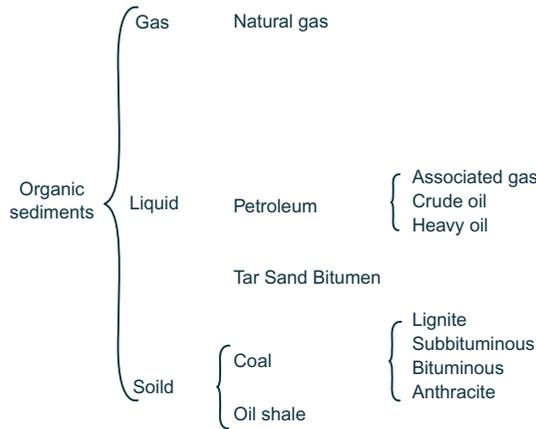
Thus, in order to classify petroleum, heavy oil, and bitumen the use of a single parameter such as viscosity is not enough and any attempt to classify petroleum, heavy oil, and bitumen on the basis of a single property is no longer sufficient to define the nature and properties of petroleum and petroleum-related materials. The general classification method used for conventional petroleum, heavy oil, extra heavy oil, and tar sand bitumen involves not only an inspection of several properties but also some acknowledgment of the method of recovery.

Petroleum is referred to generically as a *fossil energy resource* and is further classified as a *hydrocarbon resource* and, for illustrative (or comparative) purposes in this text, coal and oil shale kerogen have also been included in this classification. However, the inclusion of coal and oil shale under the broad classification of hydrocarbon resources has required (incorrectly) that the term hydrocarbon be expanded to include the high molecular weight (macromolecular) nonhydrocarbon heteroatomic species that constitute coal and oil shale kerogen. Heteroatomic species are those organic constituents that contain atoms other than carbon and hydrogen, for example, nitrogen, oxygen, sulfur, and metals (nickel and vanadium) as an integral part of the molecular matrix.

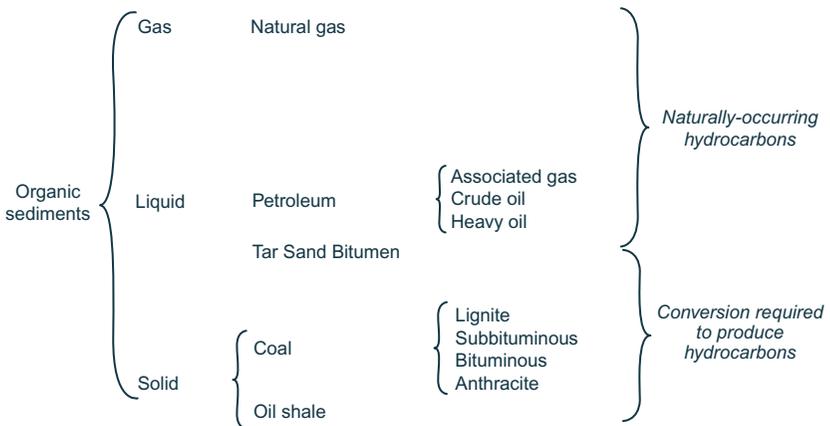
Use of the term organic sediments is more correct and to be preferred (Fig. 1.8). The inclusion of coal and oil shale kerogen in the category hydrocarbon resources is due to the fact that these two natural resources (coal and oil shale kerogen) will produce hydrocarbons on high-temperature processing (Fig. 1.9). Therefore, if either coal and/or oil shale kerogen is to be included in the term hydrocarbon resources, it is more appropriate that they be classed as *hydrocarbon-producing resources* under the general classification of organic sediments. Thus, fossil energy resources divide into two classes: (1) naturally occurring hydrocarbons (petroleum, natural gas, and natural waxes); and (2) hydrocarbon sources (oil shale and coal), which may be made to generate hydrocarbons by the application of conversion processes. Both classes may very aptly be described as organic sediments.

Whenever attempting to define or classify tar sand bitumen, it is always necessary to return to the definition as given by the United States Federal Energy Administration (FE-76-4), thus:

*...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.*



**Figure 1.8** Classification of fossil fuel as organic sediments.



**Figure 1.9** Classification of fossil fuels as hydrocarbon resources and hydrocarbon producing resources.

By inference, petroleum and heavy oil are recoverable by well production methods and currently used enhanced recovery techniques. For convenience, it is assumed that before depletion of the reservoir energy, conventional crude oil is produced by primary and secondary techniques while heavy oil requires tertiary (enhanced) oil recovery (EOR) techniques. While this is an oversimplification, it may be used as a general guide. The term *natural state* cannot be defined out of context and in the context of FEA Ruling 1976-4 and the term is defined in terms of the composition of the heavy oil or bitumen. The final determinant of whether or not a reservoir is a tar sand deposit is the character of the viscous phase (bitumen) and the method that is required for recovery. Generally, bitumen in the natural state is solid or near solid at room temperature and is solid or near solid at reservoir temperature. In other words, tar sand bitumen in the natural state is immobile in the deposit and requires conversion or extreme stimulation for recovery as might be afforded by an in situ combustion process. In the in situ combustion process, the goal can be either (1) conversion of a low portion of the bitumen, or (2) conversion of as much as possible of the bitumen to low-boiling products (see chapters: Nonthermal Methods of Recovery; Thermal Methods of Recovery). In the former case (ie, production of the controlled amount of a low-boiling product), the product can act as a solvent to increase the flow rate of the oil ahead of the combustion front. In the latter case (ie, production of as much as possible of a low-boiling product), the goal is to convert as much as possible of the bitumen to low-boiling products thereby reducing the amount of upgrading in a surface refinery.

Thus, by this definition (FE-76-4), tar sand bitumen is not crude oil and it is set apart from conventional crude oil and heavy crude oil insofar as it cannot be recovered from a deposit by the use of conventional (including enhanced) oil recovery techniques as set forth in the June 1979 Federal Energy Regulations. To emphasize this point, bitumen has been recovered commercially by mining and the hot water process, and is currently upgraded (converted to synthetic crude oil) by a combination of a thermal or hydrothermal process followed by product hydrotreating to produce a low-sulfur hydrocarbon product known as *synthetic crude oil*.

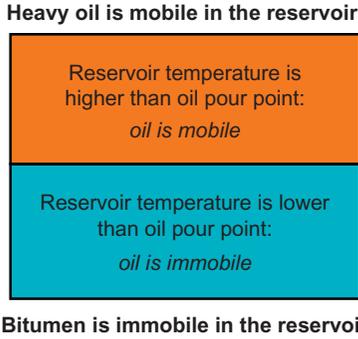
Tar sand bitumen is a naturally occurring material that is immobile in the deposit and cannot be recovered by the application of EOR technologies, including steam-based technologies. On the other hand, heavy oil is mobile in the reservoir and can be recovered by the application of EOR

technologies, including steam-based technologies. Furthermore, since the most significant property of tar sand bitumen is its immobility under the conditions of temperatures and pressure in the deposit, the interrelated properties of API gravity (ASTM D287) and viscosity (ASTM D445) may present an indication (but only an indication) of the mobility of oil or immobility of bitumen, but in reality these properties only offer subjective descriptions of the oil in the reservoir. The most pertinent and objective representation of this oil or bitumen mobility is the *pour point* (ASTM D97) (see also chapter: Evaluation of Reservoir Fluids).

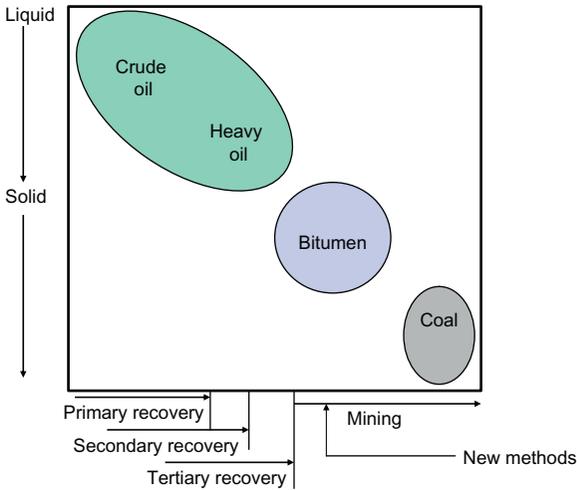
By definition, the pour point is the lowest temperature at which oil will move, pour, or flow when it is chilled without disturbance under definite conditions (ASTM D97). In fact, the pour point of an oil when used in conjunction with the reservoir temperature gives a better indication of the condition of the oil in the reservoir than the viscosity. Thus, the pour point and reservoir temperature present a more accurate assessment of the condition of the oil in the reservoir, being an indicator of the mobility of the oil in the reservoir. Indeed, when used in conjunction with reservoir temperature, the pour point gives an indication of the liquidity of the heavy oil or bitumen and, therefore, the ability of the heavy oil or bitumen to flow under reservoir conditions. In summary, the pour point is an important consideration because, for efficient production, additional energy must be supplied to the reservoir by a thermal process to increase the reservoir temperature beyond the pour point.

For example, Athabasca bitumen with a pour point in the range 50°C to 100°C (122°F to 212°F) and a deposit temperature of 4°C to 10°C (39°F to 50°F) is a solid or near solid in the deposit and will exhibit little or no mobility under deposit conditions. Pour points on the order of 35°C to 60°C (95°F to 140°F) have been recorded for the bitumen in Utah deposits with formation (deposit) temperatures on the order of 10°C (50°F). This indicates that the bitumen is solid (and immobile) within the deposit. The injection of steam to raise and maintain the reservoir temperature above the pour point of the bitumen and to enhance bitumen mobility is difficult, in some cases almost impossible. Conversely, when the reservoir temperature exceeds the pour point the oil is fluid in the reservoir and therefore mobile. The injection of steam to raise and maintain the reservoir temperature above the pour point of the bitumen and to enhance bitumen mobility is possible and oil recovery can be achieved.

A method that uses the pour point of the oil and the reservoir temperature (Fig. 1.10) adds a specific qualification to the term extremely

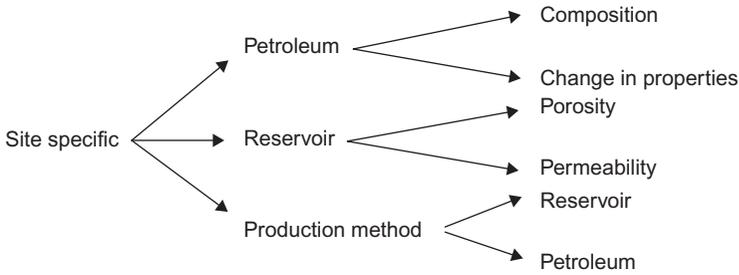


**Figure 1.10** Use of pour point to define heavy oil and bitumen.



**Figure 1.11** Schematic representation of the properties and recovery methods for crude oil, heavy oil, bitumen, and coal.

viscous as it occurs in the definition of tar sand and coupled with the measurement of the viscosity provides a more complete indication of the properties of the bitumen under the conditions prevalent in the deposit. In fact, when used in conjunction with the recovery method (Fig. 1.11), pour point offers more general applicability to the conditions of the oil in the reservoir or the bitumen in the deposit and comparison of the two temperatures (pour point and reservoir temperatures) shows promise and warrants further consideration. The measurement of the viscosity adds an extra dimension in terms of the degree of mobility of the bitumen.



**Figure 1.12** Representation of the changing parameters for crude oil and/or heavy oil.

In summary, supplies of conventional petroleum are depleted and heavy oil with tar sand bitumen resources are becoming recognized as important contributors to liquid fuels production. However, heavy oil cannot be defined or classified using a single property and, likewise, tar sand bitumen cannot be defined using a single property but bitumen can be defined by the recovery method. Furthermore, heavy oil is usually mobile in the reservoir whereas tar sand bitumen is immobile in the deposit.

In conclusion, heavy oil and tar sand bitumen are extremely viscous and production of these materials is difficult. Although the worldwide reserves of heavy oil and bitumen are enormous, difficult technical and economic hurdles are involved in their recovery methods. There are numerous alternative techniques for heavy oil and bitumen production (such as steam-based processes and cold production) but a prime factor limiting the efficiency of the recovery methods is the heterogeneity of the reservoir system and the deposit. The rocks in these reservoirs and deposits containing the heavy oils have porosity, permeability, connectivity, as well as mineral content that vary over short (vertical and horizontal) distances.

Finally, it is essential to realize that (in the current context) of conventional petroleum and heavy oil, there are several parameters that can influence properties and recovery. These properties are usually site specific to the particular reservoir in which the crude oil or heavy oil is located (Fig. 1.12).

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