## CHAPTER 3

# What's In a Wet Barrel?

*This chapter reveals how oil and gas asset production can be maximised through an understanding of petroleum and reservoir types.*

When crude oil first came into large-scale commercial use in the 19th century, it was stored and shipped in wooden barrels with one barrel equal to 42 US gallons or 159 litres. The term 'wet' barrel denotes a physical barrel of oil that is actually delivered or consumed as opposed to a futures or other paper barrel that is traded.

Asphalt, bitumen and crude are common terms describing different forms of petroleum that can be found in a typical 'barrel' of oil[1].

The term comes from the Latin petra—"rock" and oleum—"oil". For lay people, petroleum itself is a generic term that covers all naturally occurring hydrocarbons as well as refined products or derivatives.

For purists, however, petroleum refers to chemical compounds made up of hydrogen and carbon atoms; consequently, the classification hydrocarbon is more appropriate. Definitions aside, hydrocarbons in their 'un-produced' state are found in underground accumulations or reservoirs of oils, gases, water and impurities located at depths ranging from 2,000 ft (610 m) to 25,000 ft (7620 m). Petroleum naturally seeps to the earth's surface along faults and cracks in rocks gathering in tar, asphalt,

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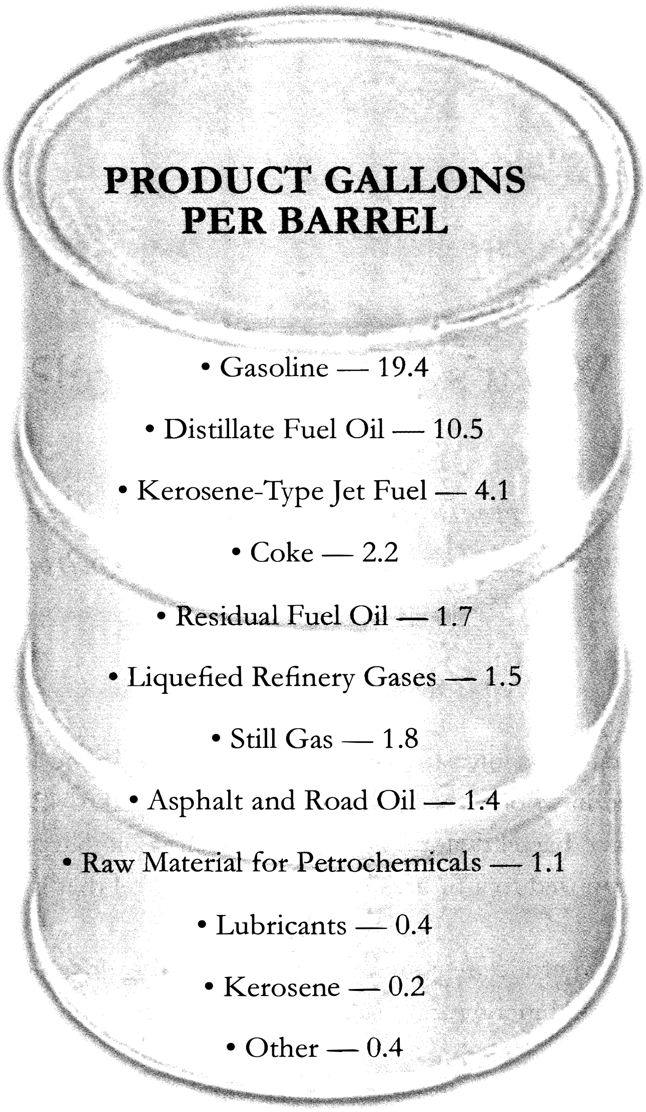

**PRODUCT GALLONS PER BARREL**

- Gasoline — 19.4
- Distillate Fuel Oil — 10.5
- Kerosene-Type Jet Fuel — 4.1
- Coke — 2.2
- Residual Fuel Oil — 1.7
- Liquefied Refinery Gases — 1.5
- Still Gas — 1.8
- Asphalt and Road Oil — 1.4
- Raw Material for Petrochemicals — 1.1
- Lubricants — 0.4
- Kerosene — 0.2
- Other — 0.4

**Table 1 - Products Per Barrel of Oil (in Gallons).**

**Note: Distillates includes both home heating oil and diesel fuel. Residual fuel oil refers to heavy oils used as fuels in industry, marine transportation, and for electric power generation. Figures are based on average yields for U.S. refineries in 2005. One barrel contains 42 gallons of crude oil. The total volume of products made is 2.7 gallons greater than the original 42 gallons of crude oil. This represents 'processing gain.' (After API)**

pitch or bitumen lakes. Shortly, we will consider the make-up of reservoirs but first of all, what's in a barrel of oil?

Nature's best orange juice is sweet and light, as is its crude; however, not all of the 200 or so naturally occurring varietals of crude oil are so blessed and this affects their commercialisation. Sweet crude has less than 0.5% sulphur content—increase this figure and it turns 'sour'. Light crude has a density of 20° or more using the American Petroleum Institute's (API) specific gravity scale and has light hydrocarbon fractions. Heavy crude has more complex fractions with higher densities and lower API gravities[2].

### The Colour of Oil

Generally speaking, the colour of crude oil intensifies with its density and viscosity. While black oil is hard-to-pour and has high density and viscosity, green to yellow oils are runny and have low density and viscosity. The term 'crude' refers to petroleum straight from the wellhead in its 'unrefined' state that can generally flow in atmospheric conditions. Where petroleum is unable to flow in atmospheric conditions, it is often referred to as heavy oil, tar or bitumen[3].

Technologists quibble on when crude gets heavy; some say this happens at 25°API or less and others say 20°API or less. This is important because heavy oil trades below its lighter counterpart. For our purposes, the definition of heavy oil is 20° API or lower and further detail is found in *Chapter 8: Extreme E & P*. Finding heavy or light crude oil depends entirely on the presence of cap rock and permeability, as these will prevent or permit oil and gas to leak to the surface and be dispersed. In Venezuela's Orinoco Belt, for example, heavy oil deposits are found close to the

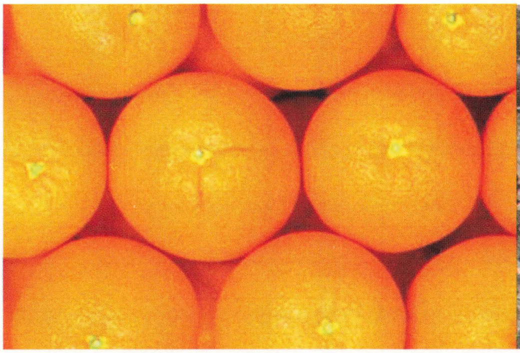

**Figure 1 - Nature's Best Is Sweet and Light (EPRasheed)**

**Figure 2 - Heavy Oil Is Unable to Flow at Atmospheric Conditions (EPRasheed)**

surface with the lighter fractions of oil having migrated or dispersed over the years, leaving only the heavier residue.

## Sour as a Skunk

Sour crude with its high sulphur content sells below its sweet counterpart—the gap can be US $5 or more and is likely to increase in the future. The gap exists because sour crude requires specialised refining treatment before it can be sold; however, there are more sweet than sour refineries worldwide. Consequently, a refining preference for sweeter crude exists[4].

The naturally occurring sulphur compounds or 'mercaptans' present in sour crude are powerfully smelly and are also found in garlic oils and skunk secretions. The malodorous mercaptans are by-products of decaying organic matter and they must be treated which adds to refining costs; however, mercaptans have a market value. They are used to imbue an odour to commercial natural gas so the general public can easily be alerted to a gas leak. Untreated natural gas is odourless, and without the tell-tale smell of the mercaptan additive, the public could be unaware of a gas leak until it was too late and someone was asphyxiated or an explosion occurred. Getting rid of sulphur, water, chlorides and other such impurities improves quality, increases value and stretches the world's oil reserves but it also adds to cost*.

Table 2 shows a series of oil and gas compounds and their respective molecular weights and common names ranging from methane gas ($CH_4$), petrol ($C_5H_{12}$ to

| Component | Boiling Point °C | Black Oil | Volatile Oil | Gas Condensate | Wet Gas | Dry Gas |
|---|---|---|---|---|---|---|
| Methane, $CH_4$ | -161 | 49.0 | 64.0 | 86.0 | 87 | 96.0 |
| Ethane, $C_2H_6$ | -88 | 2.8 | 8.0 | 4.4 | 5 | 2.8 |
| Propane, $C_3H_8$ | -42 | 1.8 | 4.5 | 2.4 | 5 | 0.3 |
| n-Butane, $C_4H_{10}$ | -1 | 0.8 | 2.0 | 0.8 | 0.6 | 0.2 |
| i-Butane, $C_4H_{10}$ | -11 | 0.8 | 2.1 | 1.0 | 0.6 | 0.2 |
| n-Pentane, $C_5H_{12}$ | 36 | 0.7 | 1.5 | 0.3 | 0.5 | 0.1 |
| i-Pentane, $C_5H_{12}$ | 27 | 0.5 | 1.5 | 0.5 | 0.5 | 0.1 |
| n-Hexane, $C_6H_{14}$ | 69 | 1.6 | 1.4 | 0.6 | 0.3 | 0.1 |
| Colour of liquid at surface | | black | brown | straw | white | - |
| Liquid Specific Gravity | | 0.853 | 0.779 | 0.736 | 0.758 | none |
| °API | | 20-35 | 38-50 | 50-70 | 50-70 | none |
| GOR scf./bbl | | 50-1500 | 2000-40,000 | 3000-18,000 | >100,000 | none |

**Table 2 - Crude Oil and Natural Gas Varietals, After Professor Richard A. Dawe**

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* For detail on pricing differentials, see *Chapter 12: Paper Barrels—Oil and Gas Markets*[5].

$C_7H_{16}$) to asphaltene ($C_{80}H_{160}$). Many characteristics such as density, viscosity and flammability are determined by molecular weights and greater detail is available in *Chapter 11: Refining.*

The range of oil varietals is illustrated by extremely light oil, which has a relative density and viscosity below that of water, to extremely heavy oil which has a relative density close to that of water and high viscosity that can be 100 to 100,000 times that of water.

## Molecular Weight

Typically, oil has a carbon content of 84 to 87% weight and a hydrogen content of 11 to 14% by weight[6].

Table 2 shows that hydrocarbons exist with varying densities and viscosities. Viscosity is a prime determinant of the ability to produce and refine oil. It is worth noting that the number of hydrocarbon compounds increases dramatically due to isomers, differing arrangements of the same number of atoms. In the case of hexane ($C_6$) there are five isomers, for decane ($C_{10}$) there are 75 and for $C_{30}$ there are more than four billion. Although laboratory analyses of reservoir hydrocarbons can profile all compounds containing as many as 20 carbon atoms, it is usually sufficient to profile compounds containing up to six or seven atoms, with a general number being used to represent the total proportion of heavier molecules that are present[7].

The general trends depend on the ratios of methane ($CH_4$) and the heavier components. The intermediates, $C_2$-$C_6$, control the GOR and API grade. The percentages shown are representative only and each category can be considered as flexible. Additionally, once production starts from a reservoir, the state of equilibrium that has been established over geological time is destroyed. Pressure gradients are created and the chemical composition and the physical properties of the fluids in the reservoir change. This happens as the pressure exerted on the fluids changes from the reservoir to the wellbore to the surface and, over time, as the fluids constituting the reservoir change.

Analysis is usually presented in terms of $C_1$, $C_2$, $C_{n+}$ with n often being 7, 12 or 20. Compounds that are not expressed in this way are usually treated as a composite fraction characterised by a molecular weight, density and/or a boiling point.

For E & P purposes, physical properties such as colour, API grade, viscosity, bubble point pressure, Gas-Oil Ratio (GOR), pour-point, and kerosene content are characterised. For downstream purposes, actual hydrocarbon compositions and fraction descriptions are required. Traditionally, the analysis of produced fluids was performed in the laboratory and could take weeks or more to obtain. Nowadays, real-time formation testing tools can provide analysis of produced fluids in near real-time at the wellsite.

### Saturated Oil

Produced oil will always contain a certain amount of dissolved gas. The exact amount depends on reservoir conditions such as temperature and pressure as well as the composition of the oil. If the oil cannot dissolve any more gas under the prevailing conditions, it is termed saturated; the excess gas has moved to the top of the reservoir and formed a gas cap. If the oil can dissolve more gas, it is termed undersaturated, and no gas cap will be initially present on production. The GOR is the ratio of the volume of gas produced to the volume of liquid and may be expressed as cubic feet per barrel depending on the units used for measuring gas and liquid. For gas wells, the inverse ratio is sometimes used and the liquid-gas ratio is expressed in barrels per million $m^3$ (or million cubic feet)[8].

### Impurities

Reservoir characteristics depend on the interplay between the molecular arrangements of the hydrocarbons, the extent of liquid and gas phases as well as the existence of impurities. Aqueous impurities are caused by differing levels of salinity and mineral salts within water that were present within rock pores before hydrocarbons migrated into the reservoir rock, displacing a certain volume of this water. The volume of water that remains after migration is known as 'connate water' and it is common for large volumes of water to be produced in conjunction with oil and gas.

### Water

Water is present at all stages of oil production. Connate water found in the reservoir at discovery can occupy 5 to 50 % of the pore volume and it is common for large volumes of water to be produced in conjunction with oil and gas (it is not always the case that a reservoir has reached maturity simply because it is producing water. See *Chapter 9: Mature Fields*—Water Management). It is also usually very salty, often more concentrated than seawater. Levels of water saturation can be accurately measured by well-logging, surface monitoring as well as permanent downhole monitors. Water breakthrough causes production problems including corrosion and scale, particularly as reservoir water often contains salts up to 250,000 mg/l, in comparison to sea water which contains 35,000mg/l of salts.

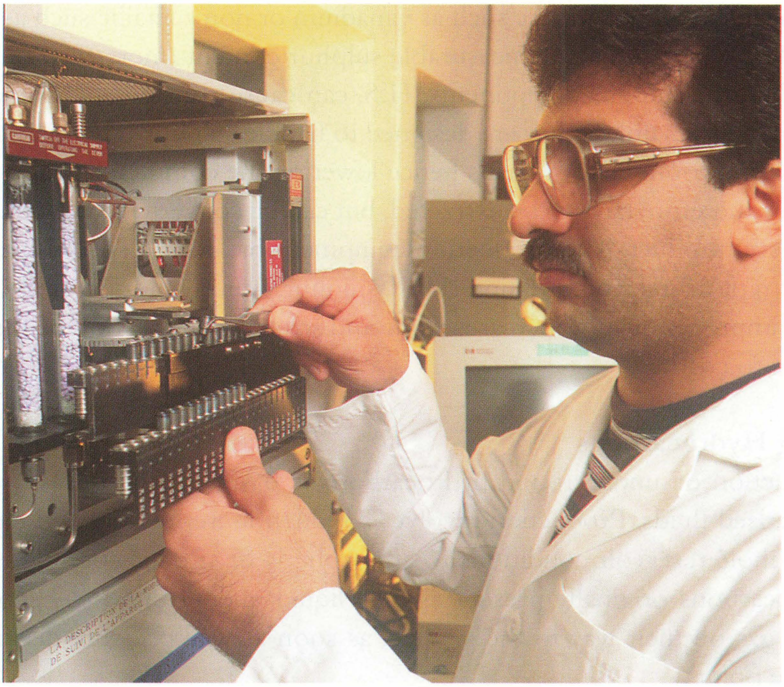

**Figure 3 - Checking Crude Samples (Saudi Aramco)**

Water and oil also create emulsions which are difficult to break and disposing of produced water can generate an environmental burden as it must be disposed of adequately. Further, any incompatibility between injected water and connate water can create chemical scale[9].

Water is nearly always present in gas reservoirs and reservoir gas is often substantially saturated with water vapour at the temperature at which it enters the wellbore. With the change in temperature and pressure from the subsurface to surface, the gas will not be able to hold as much water and it will condense both within the well during the upward travel of the gas and in surface equipment. Much of this condensed water is carried in the flow lines into the separator as entrained droplets. Water can form hydrates with natural gas, which can create production difficulties, rendering metres and valves inoperative and, on occasions, causing disasters. Low temperature separators are needed to remove the entrained water close to the wellhead before the gas arrives at trouble points. In many cases, appreciable amounts of water will settle to the bottom of the well and can, in time, saturate the zone surrounding the wellbore so that the permeability to the flow of gas may be materially reduced. This reduction can result either from water blocking or clay swelling and can be responsible for a gradual decrease in deliverability and periodic remedial work-overs[10].

Other impurities can be metallic such as vanadium or non-metallic such as hydrogen sulphide ($H_2S$). If there is any measurable sulphur content (more than one part per million), then the sulphur components, $H_2S$, can cause considerable damage to the production facilities unless they are designed to handle sulphur. The sulphur components are also poisonous to humans hence lowering the commercial value of the oil or gas. They therefore have to be extracted, but can be converted to sulphur and sold on as a useful product. The production equipment has to use special quality steels to prevent rapid corrosion. Getting rid of sulphur, water, chlorides and other such impurities improves quality, increases value and stretches the world's oil reserves but it also adds to cost[11].

## Releasing Hydrocarbons

The production of underground hydrocarbons is based on the release of trapped and pressurised fluids. Production involves a reduction in pressure and temperature from downhole reservoir conditions to atmospheric or surface conditions. As a result, hydrocarbons originally present as only liquid underground will separate into liquid and gas on their way to the surface, as soon as well pressure declines below the 'bubble point'.

In a mixture of liquids, the bubble point occurs when the first bubble of vapour is formed. For single component mixtures, the bubble point and dew point are the same and are referred to as the boiling point.

Hydrocarbons originally present as gas underground will generally produce some liquid at the surface due to condensation, which occurs when the pressure and temperature are reduced*. The point at which natural gas components start to condense out of the gaseous system is known as the hydrocarbon dew-point and refers to the temperature (at a stated pressure) at which this occurs. Both bubble point and dew-point are useful data when designing distillation refinery systems.

Surface facilities will mechanically separate gas from liquid using gravity separators or de-gassing facilities after which the volumes of liquid and gas are measured separately.

## Gas

Natural gas volumes are reported in standard cubic metres [(s)$m^3$] or standard cubic feet (scf). Quantities of natural gas are usually expressed in cubic feet; a cubic foot is equivalent to approximately 0.028 $m^3$ at standard conditions[12]. For reserves valuation, gas is usually expressed in thousands ($10^3$) of cubic feet (Mcf), millions ($10^6$)

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* The behaviour of reservoir fluids is based on the laws of physical chemistry for perfect gases and the phase changes in gas-liquid systems[10].

of cubic feet (MMcf), billions ($10^9$) of cubic feet (BCF) or trillions ($10^{12}$) of cubic feet (TCF).

Methane is the most abundant component of natural gas and has numerous fuel applications. These range from liquefaction, compression, and Gas to Liquids (GTL). For further details, see *Chapter 13: Renewable Energy*. The second largest component is ethane which can be liquefied and sold as fuel, but is mostly used as a petrochemical feedstock. Propane and butane are also found in natural gas, albeit in smaller amounts, and are commonly separated and sold as Natural Gas Liquids (NGLs). This commercial value stems from their comparatively high-energy content. On a cubic foot basis, methane renders just over 1,000 Btu, while propane renders 2,500 Btu and butane 3,250 Btu[13].

## Gas Condensate

Gas condensate or 'wet-gas' reservoirs are an important class of hydrocarbon accumulation and describe hydrocarbons which are gaseous in the underground reservoir. When the temperature and pressure of gas condensate are reduced to dew point, however, they partially condense to yield liquid condensate. Condensates are often characterised by low-density and high-API gravity (45° and above) and coexist with natural gas.

Natural gas condensate is typically composed of pentane, hexane, heptane and octane. Liquids that condense are almost transparent or light yellow and can be refined in a way similar to very light crude oil[14].

Condensate-bearing reservoirs pose further production challenges due to the effect changes in reservoir pressure have on the hydrocarbons. Gas may be converted to liquid if its pressure drops below the dew point during production. If gas is preferable to liquid production, reservoir pressure can be maintained by fluid injection. Reservoir fluid composition determines:

- Fluid type—dry gas, condensate gas, volatile oil, black oil
- Method of fluid sampling, laboratory tests
- Surface equipment (type and size)
- Calculation procedures for determining oil and gas in place
- Techniques for predicting oil and gas reserves
- Prediction methods for future production rates, and
- Depletion plan and secondary or enhanced oil recovery methods.

## Common Types of Petroleum

There are several common types of petroleum:

**Associated Gas:** Is the natural gas and NGLs, which under reservoir conditions, are dissolved in the crude oil or are present as a gas cap above the oil in the reservoir.

**Condensate or Distillate:** Is the pale straw-coloured liquid with an API of 45° to 75° produced at surface from hydrocarbons which were originally gas or liquid in the reservoir. The term is often loosely applied to any liquid produced at the separator from light volatile oil or gas fluids.[15]

**Conventional Black Oils:** Are the most common reservoir liquids. They have: a viscosity low enough to flow naturally into a well; gravities that are usually between 20° API to 45° API; GORs ranging from 100-2000 scf/stb (20-360 $m^3/m^3$); specific gravity from 0.6 to 1.0; viscosities ranging from below 1cp; and, liquids that are about as thin as water to those that are >100 cp. They are black to green-black in colour.

**Crude Oil (Oil):** Is the common liquid form of petroleum produced from an oil reservoir when the gaseous constituents have been removed or have escaped and ranges from heavy tarry substances to conventional oil. Most petroleum liquid products and crude oils are lighter than water and their weight is often expressed in degrees (°) API.

The higher the number of API degrees, the lighter the oil. An API rating of 46° for a crude would mean that it is super light. Heavy oil would have an API of 18° to 20° degrees. The commercial value of oil varies according to its specific gravity; heavy oil trades at a lower value, i.e. less than 20° API trades at a lower value (US $5-10) to lighter oils, i.e. from 20° API to 45° API. Above 45° API, oil is considered superlight and has a progressively higher value (US $15 or more).

| API Gravity (°API) | Classification | Specific Gravity (g/cc) |
|---|---|---|
| 10° to 20° | Heavy Oil | 1.0 to 0.93 |
| 20° to 30° | Medium Oil | 0.93 to 0.87 |
| >30° | Light Oil | less than 0.87 |

°API = (141.5°/SG - 131.5 [SG = specific gravity at 60°F = 1.0])

Table 4 - A Rough Classification of Crude Oil Is Sometimes Used Based on API Gravity

**Gas Condensates:** Condensates that are straw coloured and usually have a specific gravity above 45° API. The distinction between gas condensate, volatile oil fields and gas fields is important in practice as the reservoir may require different production and commercialisation strategies as discussed in *Chapter 11: Refining.*

**Heavy Oil:** Is so viscous that it does not flow easily into a well and has a gravity below 20° API and a viscosity above 20 cp as well as extremely low (negligible) production rates which often include large quantities of loose sand.

**Natural Gas:** Is a mixture of hydrocarbons consisting mainly of methane but also including ethane and minor quantities of NGLs.

**Natural Gas Liquids (NGLs):** Light hydrocarbons consisting mainly of propane and butane, which are liquid under pressure at normal temperature.

**Oil Sands:** Refers to heavy black tar (similar to bitumen) which is frequently mixed with high volumes of sand. They are found principally in Canada and Venezuela. Oil Sands require mineral extraction production akin to mining which is completely different to oil and gas well production.

**Volatile Oils:** Oils that have low specific gravities and viscosities, 45°-70° API and GORs in excess of $360/m^3$ (2000 scf/stb). They are pale red to brown in colour[16].

Although the above nomenclature for hydrocarbon accumulations is useful, it should be appreciated that reservoirs do not follow strict definitions and have been found to produce hydrocarbons in almost every conceivable ratio. Additionally, variations in pressure and temperature mean that there are no clear divisions between the classes of reservoirs*.

For our purposes, production mainly depends on the physical properties and behaviour of the reservoir fluids which change once production has commenced. Those changes will depend on what is in the reservoir.

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* Much prior knowledge exists on reservoirs and the reader is directed to this in the notes section.

## What's In a Reservoir?

Reservoirs have been found to produce almost every conceivable ratio of hydrocarbons. It is this diversity, along with variations in pressure, temperature, depth, thickness, sealing faults and potential links to adjacent reservoirs, that leads to oil and gas accumulations being characterised as uniquely different or heterogeneous structures. Carbonate reservoirs are considered highly heterogeneous. Calcium carbonate is much more chemically active than the silica that constitutes sandstones. It is easily dissolved in water, even more so in acidic water. Mechanical properties are another significant difference. Carbonate rocks tend to be more prone to fractures than sandstones. For all these reasons, carbonates form different rock types with a heterogeneous distribution throughout the reservoir. Moreover, the poor correlation between porosity and permeability, and the presence of caverns and fractures, create very complex paths for fluids making it difficult to accurately model the distribution of permeability in carbonate reservoirs[17].

Consequently, the challenge for the oil company is how best to produce a particular oil and gas accumulation considering all these factors and simulating their interaction over time.

## Reservoir Fluid States

Reservoirs are found at depths varying from 2,000ft+ (610 m) to deeper than 25,000ft+ (7,620 m). As noted in *Chapter 1: The Origin of Oil—Migration*, it is known that heavy oil is usually found in shallow reservoirs while lighter oil is found in deeper reservoirs, with gas alone found in the deepest reservoirs. Pressure and temperature conditions vary between reservoirs. Shallow reservoirs often have near standard conditions (15°C [59°F] and 15 psi [1 bar]) while deep reservoirs may have temperatures above 250°C (482°F) and pressures that may exceed 20,000 psi (1378 bar). Reservoir fluid states are held in a complex rock-gas-liquid system and can exist as aqueous and non-aqueous states or multi-phase immiscible fluids[18].

We have seen that hydrocarbons occur in unique ratios and diverse states. The same can be said of reservoirs. Reservoir engineers must have a thorough understanding of this heterogeneity, as this plays an important part in understanding how production should best be engineered. Physical properties are needed to accurately describe fluid pressures up to 1,500 bar (22,000 psi), the possibility of high temperatures (up to 250°C) and corrosive fluids (waters that contain more salt than seawater i.e. approximately 35,000 mg/l). Empirical data and laboratory modelling is often applied to field reservoir applications.

Depending on the oil and gas accumulation, and its reservoir pressure and temperature, hydrocarbons underground may be present initially as:

- Liquid only—oil reservoir
- Gas only—gas or gas/condensate reservoir, or
- Gas overlying liquid—oil reservoir with gas cap, or gas reservoir with oil ring.

The comprehension of such complex natural fluids comes from an understanding of simple and ideal systems, which are modelled in the laboratory. The data required includes: density; compressibility; formation volume factors and gas-oil ratios for determination of recovery factors; viscosity and gas-oil ratios for production rates; and interfacial tension for recovery efficiency, as it has a major influence on oil trapping. See *Chapter 1: Origin of Oil—Trapping Mechanisms.*

## The Phase Behaviour of Hydrocarbons

As reservoir pressure drops, the resultant behaviour of the hydrocarbons depends upon the temperature and differential pressure as well as the composition of the hydrocarbons.

As pressure drops, gas expands and liquids tends to vaporise to gas. This is because molecules can move apart through their own kinetic energy breaking the weak bonds that hold them. (See *Chapter 11: Refining—Van der Waals Forces*). Conversely, if pressure is increased, molecules are forced closer together so that gas is compressed and forms a liquid. These changes from gas to liquid and vice versa are known as phase changes and are termed normal behaviour. Understanding this Pressure-Volume-Temperature (PVT) behaviour is essential because it controls the entire oil production process, while the physical parameters are needed to determine the process efficiency and sizing of facilities.

## Multi-Component Mixtures

The behaviour of multi-component hydrocarbons presents greater complexity due to the different volatilities of the components involved. Consequently, vapour and liquid have different compositions when in equilibrium. As the pressure drops, the compositions of both the liquid and gas phases change continuously: the first gas appears at the bubble point and only liquid remains at the dew point. One consequence of this behaviour is that the pressure-temperature plot is no longer a simple curve as for the single component; instead it is an 'envelope'—see Figure 4.

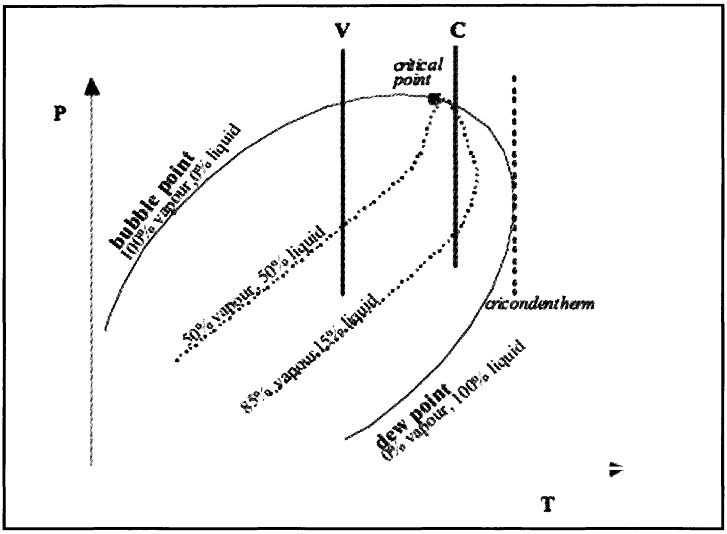

Figure 4 - Cricondentherm, After Professor Richard A. Dawe

The maximum pressure defined by this envelope is known as the cricondenbar; above it, the liquid and gas phases cannot co-exist. The maximum temperature defined by the envelope (the cricondentherm) is, likewise, one above which the two phases cannot co-exist. The critical point is the point in the envelope at which the properties of the gaseous and liquid phases become identical—it is not related in any simple way to the cricondenbar or the cricondentherm.

The behaviour of the fluid as it leaves the reservoir (essentially an isothermal environment) and travels through the production tubing and wellbore to the separation facilities requires more complex considerations of the thermodynamic behaviour; however, simple laboratory measurements are sufficient for design calculations[19].

If the reservoir pressure is at the bubble point, the oil is said to be saturated. If the reservoir pressure is above the bubble point, the oil is said to be undersaturated. An oil reservoir which is discovered with a gas cap is at its bubble point and is, therefore, saturated. An oil reservoir that is unsaturated describes hydrocarbons above their bubble point, where the reservoir temperature is substantially below the critical point and surface GORs are low to moderate. On production, as the reservoir pressure drops, gas comes out of the solution (solution gas drive). The first gas liberated is composed principally of the lightest components (methane, ethane and propane) as they possess the highest molecular energy and the lowest molecular attraction for other molecules.

Vaporisation of the lighter components is usually followed by quantities of heavier components until at low pressures only a fraction of the original material remains liquid. Gas has formed due to vaporisation of the light components and, as a result, the remaining liquid is described as having shrunk in volume. For a black oil, the shrinkage is only a small amount (often less than 30%). It increases rapidly, however, through the low pressure range (separator pressures) and through volumetric loss of intermediate and heavy material from the remaining liquid. Shrinkage characteristics in this range of pressures are extremely significant because surface separation of oil from gas occurs under these conditions.

### Condensate Fields

A condensate field is where the reservoir temperature lies between the cricondentherm and the critical temperature. In this case, if the overall reservoir pressure is allowed to drop, liquids condense out in the formation and may be lost because their saturation is so low that no liquid flow toward the well bore occurs (zero permeability to liquid). In order to prevent this valuable loss by retrograde condensation and to extract the liquids, reservoir pressure is often kept above the dew point by recycling the gas that remains after surface processing. A gas (wet* or dry) field is one in where the reservoir temperature is above the cricondentherm. Once the gas starts to expand up the tubing to the surface, the temperature as well as the pressure falls, and this continues to the final surface conditions. Liquid hydrocarbons may condense out in the tubing and surface lines and are often recoverable. Low-temperature separation increases the yield of these valuable light-end liquids. A dry gas field is one in which the final point (normally the separator) lies to the right of the envelope and no liquids are formed.

### Crude Oil Properties

The PVT characteristics of oilfield liquids are more complicated than for gases and it is usual to distinguish between saturated and unsaturated conditions. In the former, gas starts to separate from the liquid as soon as pressure begins to drop with production. In the latter, the pressure at which gas begins to separate from the liquid is some distance below the initial reservoir pressure at the bubble point, (Pb). The rate of pressure drop in an unsaturated depletion type field can be quite dramatic with a pressure drop of perhaps 1,000 psi for a production of only one or two percent of the oil initially in place. The reservoir fluids have pressure-dependent properties. It is necessary to know how the crude will behave as the reservoir pressure

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* The term 'wet' refers to hydrocarbon condensation, not that of water.

drops, or other reservoir conditions are altered to be able to determine how best to: produce a particular crude-oil accumulation; to forecast attainable production rates and the ultimate cumulative production; and, to develop EOR plans for a reservoir. These properties are measured in the laboratory using samples of crude taken from the field[20].

## PVT Data for Oil

Oil and gas behaviour can be described by using functions of pressure and temperature. Various parameters such as oil and gas interaction, composition and the phase envelope need to be determined for each reservoir. This is often done by laboratory testing of bottom-hole samples or, by using Repeat Formation Testing (RFT) or Modular Formation Dynamics Tester (MDT) tools. Additionally, oil and gas collected at surface may be recombined to represent the reservoir fluid as precisely as possible. This is, however, a difficult task. In many reservoirs, there are variations across the field and also between different reservoirs. Fluid sampling should be carried out as early as possible to ensure reserve calculations, well flow calculations and facilities design are based on representative samples. Great care is needed in conditioning the well to ensure that the fluid sample is representative. Generalised correlations have been developed which give information about the PVT properties for oil and dissolved gas using the available data obtained from a producing well test, e.g. oil gravity, gas gravity, producing GOR and reservoir temperature[21].

**Figure 5 - GOSP In The Shaybah Field Saudi Arabia (Saudi Aramco)**

Difficulties arise from obtaining representative samples and deciding the correct thermodynamic path the fluids should follow in the laboratory to mimic the path followed by the hydrocarbons as they move through the reservoir to the well, to the surface and finally to the gauges and the stock tanks.

The processes affecting the fluids as they flow from the reservoir to the stock tank vary, but can normally be approximated to the flash or differential process. For instance, flash liberation can simulate the process in the tubing linking the formation to the surface and in the gathering lines from wellhead to separator because the agitation of the flow keeps the two phases in contact with each other. In the surface-gas separator, the pressure on the produced fluids is suddenly dropped and the gas evolved remains, for a time, in contact with the crude, i.e. a flash liberation.

In general, less gas is evolved in differential than in flash liberation, thus a greater proportion of the lighter hydrocarbons remain in liquid form when the pressure reduction follows the differential-liberation path. For black oils, the difference is usually small, but for volatile oils it can be substantial so that two or three stage separation is needed to drop the surface pressure from that at the wellhead to atmospheric (stock-tank pressure) to get maximum liquids (perhaps 8-11% more). Determination of the number of intermediate separators (GOSP) and the pressures at which they should operate depends on oil and gas properties as well as economic considerations[22] (see Figure 5 for Gas Oil Separator Plant).

### Reservoir Pressure and Temperature

In normal conditions, reservoir pressure is about equal to the hydrostatic pressure (pressure due to a column of water) measured from the surface. The hydrostatic gradient is about 0.45 psi per foot (9.6 kPa/m). Temperatures increase with depth by 10°F to 20°F per 1,000 feet (1.8-3.6°C/100m). The table shows reservoir pressures according to depth.

| Depth of Reservoir | Initial Pressure | Temperature |
|---|---|---|
| 608m (2000') | 61 bar (900 psia) | 21-32°C /70-90°F |
| 1520 m (5000') | 153 bar (2250 psia) | 38-65°C /100-150°F |
| 3952 m (13000') | 408 bar (6000 psia) | 82-149°C /180-300°F |

**Table 5 - Reservoir Pressure by Depth**

In overpressured reservoirs, the initial pressure may be considerably higher. If different datum corrected pressures are found in different parts of the field, particularly after some production, it is likely that the field is not totally in communication and that there are sealing faults or isolated sands[23].

### Reservoir Temperature

Primary recovery methods rely on the assumption that reservoir temperature stays constant. As fluids are produced any change in downhole temperatures due to production is compensated by heat from the cap or base rocks, which are considered to be heat sources of infinite capacity[24].

Average reservoir temperatures are therefore needed for laboratory analyses reflecting reservoir conditions. Reservoir temperatures are used to determine fluid properties such as viscosity, density, formation volume factor and gas in solution. Downhole gauges (during drilling or permanent) are used to measure reservoir temperature.

If a variation in temperature is detected across a reservoir after correcting for depth, an average value can be calculated and used as a constant reservoir temperature. For EOR, involving chemical and miscible processes, changes in temperature affect both the phase behaviour of injected and produced fluids, and therefore will affect recovery. The modelling of such processes must be accompanied by laboratory tests carried out using reservoir temperatures. In EOR processes that employ heat injection, such as steam or in-situ combustion, reservoir temperatures do not remain constant. In these cases, the reservoir temperature needs to be monitored all the time so as to detect the movement of the heat front[25].

### Development of an Oil or Gas Field

Once a discovery has been made, appraisal wells are drilled to determine the extent of the accumulation. The important reservoir calculations from the discovery data are the minimum size of the accumulation and the minimum size needed for commercial production. The appraisal wells are then sited to attempt to answer the question, 'Is this economic?' rather than 'How large is it?' With each appraisal well comes a refinement of the geological model of the accumulation, as represented by maps and cross-sections, and a new economic assessment. If it becomes obvious that the accumulation contains sufficient oil or gas to be considered commercial, development plans will be formulated. The siting of development wells is different from that of the appraisal wells, as now the purpose is to produce the petroleum as efficiently as possible at the lowest unit cost. If the field is complex, with multiple reservoirs and faulting, the most efficient well-spacing may be initially difficult to decide as each fault block may have to be regarded as separate accumulations. Over time production of fluids from the reservoir will change fluid pressure and flow rates. Production engineers will critically examine these factors to ensure that production can maximised over the life of the field.

This was a tough chapter but we now know what is in a reservoir and what actually constitutes a barrel of oil. What we have yet to learn is where these barrels are. Who are the 'oil haves' and 'have-nots'?