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Petroleum System and Petroleum Engineering

Petroleum can be used to describe naturally occurring semisolid, liquid, and gas composed of organic compounds. Petroleum types include bitumen, crude oil, and natural gas. The term petroleum can also be used to describe naturally occurring crude oil and its derivatives. In this book, petroleum will mean bitumen, oil, and gas, while derivatives of petroleum will be referred to as petroleum products. The properties of petroleum reservoir fluids are discussed in Chapter 3.

The primary function of a petroleum engineer is to find economical and environmentally acceptable ways of producing petroleum fluids. In order for a petroleum engineer to achieve this objective, the factors affecting the ability of a reservoir to hold fluids, the flow of single and multiphase fluid through the reservoir, the production system at low and high pressure, the reservoir rock and fluid interaction must be well understood. In recent times, environmental considerations have played a crucial role in petroleum exploration and production activities. As such, petroleum engineers are expected to seek technology with minimum environmental damage. Operational activities in the petroleum industry at exploration and production activities are expected to conform to stringent environmental regulations in most parts of the world.

1.1. THE PETROLEUM ENGINEER

Petroleum engineers, based on roles and responsibilities, can generally be classified as either reservoir engineers or production engineers.

Reservoir engineers have the primary function of optimizing petroleum/hydrocarbon recovery from subsurface reservoirs. The roles of a reservoir engineer vary depending on the life of a reservoir/field, company, division/department within the company, and size of company. Some of the primary functions of a reservoir engineer include, but are not limited to: estimation of hydrocarbons in place; estimating recoverable hydrocarbon; creating hydrocarbon recovery profiles with time; optimization of hydrocarbon recovery; working in a multidisciplinary team to build reservoir models.

Production engineers are responsible for managing the interface between the reservoir and the well. They are responsible for deciding how best to combine reservoir drive mechanisms for production, well completion, and production tubing design in order to optimize hydrocarbon production. Other tasks that fall within the scope of production engineers include: downhole data monitoring; production optimization; identifying how best to harness energy in the production system; diagnosis of production problems; recommending solutions to production problems; and planning and management of remedial and workover operations.

1.2. ROLES OF THE PETROLEUM ENGINEER IN THE FIELD LIFE CYCLE

Finding new fields is the main objective of the exploration phase in the oil and gas field life cycle. Exploration begins with acquisition and interpretation of seismic data to find potential petroleum traps through identification of structural characteristics that could form petroleum traps.

The role of a reservoir engineer during the exploration phase is to test the exploration hypothesis using well testing procedures and other petroleum engineering techniques if the exploration well discovers hydrocarbon. Crucial roles of reservoir engineer at this stage include: design and implementation of well test program; reservoir

Petroleum Engineering: Principles, Calculations, and Workflows, Geophysical Monograph 237, First Edition.
Moshood Sanni.

deliverability assessment using acquired data from rock and fluid samples to understand if discoveries have properties for commercial exploitation.

During drilling operations at the exploration stage or for appraising the discovered area, the role of the reservoir engineer is to give guidance to ensure minimal damage is done to the wellbore during drilling operations. Some of the advice would include desirable overbalance pressure, impact of drilling operation on well deliverability, methods of mitigating impact of drilling on formation damage, well placement for optimized hydrocarbon recovery, and advice on well geometry in multiple compartment reservoirs, where the combined effect of reservoir compartmentalization and well geometry have significant impact on overall well and reservoir deliverability.

During the production phase, when the field is producing at maximum or optimized capacity, the role of the petroleum engineer is to give guidance to ensure that hydrocarbon can flow to the surface through production tubing. Some of the advice during production will be based on understanding well conditions such as skin effect and stimulation, and potential flow assurance problems such as wax, hydrate, asphaltene, and scales, which have significant impact on well deliverability. Understanding potential flow assurance problems is very important during production and well start-ups.

During field engineering operations, the role of reservoir engineers will vary from company to company. However, important functions will include: selection of field equipment that can achieve desirable job objectives; acquisition of field data that meet desirable quality level; and quality control of field data and interpretation of acquired data.

1.3. ORIGIN OF PETROLEUM

One of the most widely accepted theories on the origin of petroleum is the organic theory of petroleum formation. The organic theory states that petroleum originates from marine life, which includes single celled organisms (*planktons*) and complex organisms such as fishes and crustaceans. These organisms, which contain carbon, die and accumulate in water rich environments and ocean floors. Following accumulation of sediment over millions of years, deposited marine organisms became buried under kilometers of sediments. Under increased pressure and temperature due to overburden formation pressure from layers of sediments and organic matter, a mixture of organic chemical compounds called *kerogen* is formed. At high temperature in the earth's crust, kerogen releases hydrocarbons, which then migrate towards the surface where they are either trapped in reservoir rocks before reaching the surface or escape to the surface and lose volatile constituents to yield bitumen and tar.

1.4. PETROLEUM SYSTEM

The geological concept, components, and process describing the formation, migration, and storage of hydrocarbons constitute a *petroleum system*. Components of a working petroleum system define the requirements for the formation of a petroleum resource, which includes: petroleum source rock, migration pathway, reservoir rock, seal, and traps (structural and stratigraphic).

The following summarizes the requirement for the formation of petroleum resources:

- An environment that ensures burial and preservation of dead marine tissues;
- the presence of a permeable migration path for movement of hydrocarbon from source rock to reservoir rocks;
- rock with capacity to store fluid and characterized seal to ensure preservation of hydrocarbon over geological time and appropriate structures to trap hydrocarbon.

1.4.1. Petroleum Source Rocks

Source rocks are rocks rich in organic matter that can generate hydrocarbon when subjected to sufficiently high temperature. Source rocks are produced through *lithification*, a complex process involving deposition of unconsolidated grains of sediment to form consolidated rock. Source rocks approximately consist of about 90–99% mineral matter and 1–10 % organic matter, which are of marine and terrestrial origin. The organic matter in source rocks consists of *kerogen*, which is the organic fraction preserved in the sediments, and *bitumen*, which is the organic fraction that is soluble in organic solvent. A very important characteristic of source rock is the *total organic content*, which is the organic richness of a rock represented as weight percent of organic carbon (from kerogen and bitumen), and gives a qualitative indication of petroleum potential.

Kerogens are described as *Type I*, which is of marine algae origin and likely to produce light oil and some gas; *Type II*, which is of mixed marine plant and animal microorganism origin and most likely produce crude oil and natural gas; and *Type III*, which is of land plant origin and most likely to produce primarily gas.

1.4.1.1. Petroleum Source Rock Formation. The formation of source rock requires that conditions exist for conservation of organic matter over geological time with a significant supply of organic matter. Other important requirements include: sedimentation of particles (silt and clay) containing organic debris; increasing overburden pressure; and poor oxygen supply to minimize degradation of dead matter through oxidation.

1.4.1.2. Petroleum Generation from Source Rock. The requirement for release of petroleum from source rock is temperature. The earth's interior is characterized by a temperature increase with depth. The change in temperature of the earth's interior per unit depth change is called *geothermal gradient*. Large quantities of hydrocarbons are formed around a depth of 1–2 km, with oil generation reaching peak at 3 km (Fig. 1.1). Gas dominates depth between 4 and 6 km due to the high temperature, which leads to cracking of oil to form gas (Fig. 1.1). At deeper formation depth, greater than 6 km, kerogen becomes carbonized and is no longer able to produce hydrocarbons.

1.4.2. Petroleum Migration

This is the process of the movement of hydrocarbon from source rock to reservoir rock that occurs over geological time. With increased overburden pressure at high temperature, source rocks becomes compressed and pore space between grains reduces, expelling hydrocarbons to zone of lower pressure. This first stage is called *primary migration*. Expelled hydrocarbons from source rock further migrate vertically by buoyancy. Hence, the presence of a migration path – permeable rock – is a very important requirement for petroleum migration. This second process of migration is called *secondary migration*. Hydrocarbons are less dense than water and will migrate upwards through water saturated rock until they encounter an impermeable rock, which serves as a trap. In these traps, gas, oil, and water are separated according to their density, with gas at the top followed by oil then water where the three phases exist.

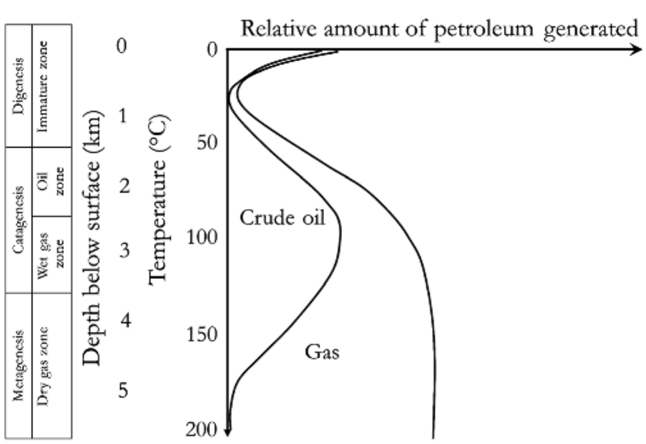

Figure 1.1 Stages of petroleum generation.Adapted from [*Tissot and Welte*, 1984; *Selley*, 1998].

1.4.3. Reservoir Rock

Important characteristics of reservoir rock are porosity and permeability. Reservoir rocks must be porous to enable them hold hydrocarbon and permeable to allow the flow of hydrocarbon.

Porosity is related to the fraction of void in a reservoir rock relative to reservoir bulk volume while *permeability* relates to the interconnectivity of pore spaces and is the characteristic of the reservoir to allow fluid flow under a pressure gradient. Where reservoir rocks are impermeable or have low permeability; hydraulically induced fractures or acidizing to dissolve impermeable rocks, such as limestone, dolomite, and calcite cement, between the sediment grains can be used to improve pore space interconnectivity to enable production of hydrocarbons.

Almost all reservoir rocks are sedimentary, formed by settling and accumulation of mineral and/or organic particles. The two most common petroleum reservoir rocks are sandstones and carbonates (limestones and dolomites). Sandstones and limestones show a wide variety of textures and are deposited in a variety of environments. Igneous (formed from cooling magma) and metamorphic (formed from previously existing rocks by extreme pressure, temperature, time, and chemical action) textures are usually made of closely interlocking minerals and, as such, are usually impermeable. However, hydrocarbon accumulations have been found within and around igneous rock, with their natural process of formation considered to be through *biotic* and *abiotic* processes.

1.4.4. Seal Rock

A reservoir must have an impervious seal or cap rock that ensures that hydrocarbons are preserved over geological time. Cap rocks are mostly sedimentary due to their ability to deform under stress, unlike igneous and metamorphic rocks. Though cap rock can have pore spaces, the absence of interconnected pores (permeability) ensures the hydrocarbon does not escape from reservoirs. Common reservoir seals include shales, clay, chalk, and evaporates.

1.4.5. Traps

The seal–reservoir interface must be configured to contain hydrocarbons. There are three main types of seal–reservoir configuration that ensure containment of hydrocarbons.

• *Structural traps*, which are due to folding and faulting of the earth's strata, leading to the formation of domes, anticlines, and folds. The majority of the world hydrocarbon reservoir (about 78%) is characterized by structural traps (Fig. 1.2).

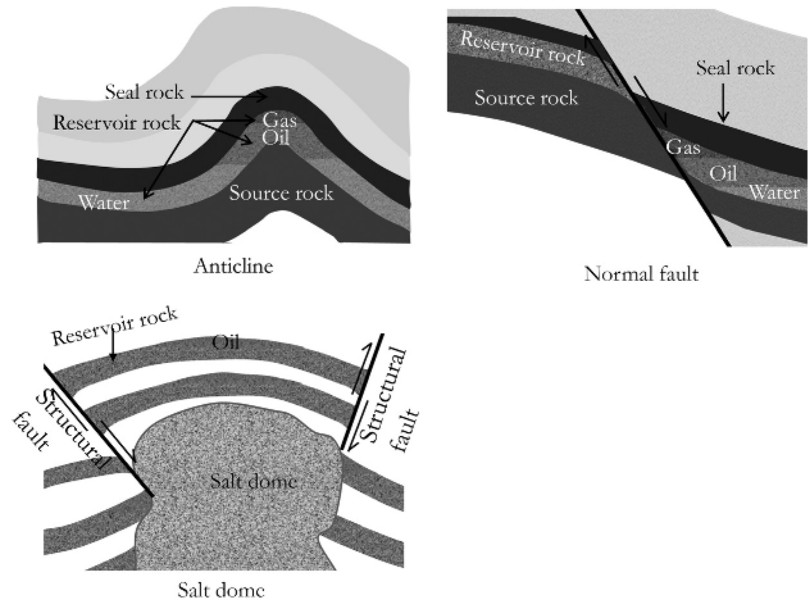

Figure 1.2 Structural traps.

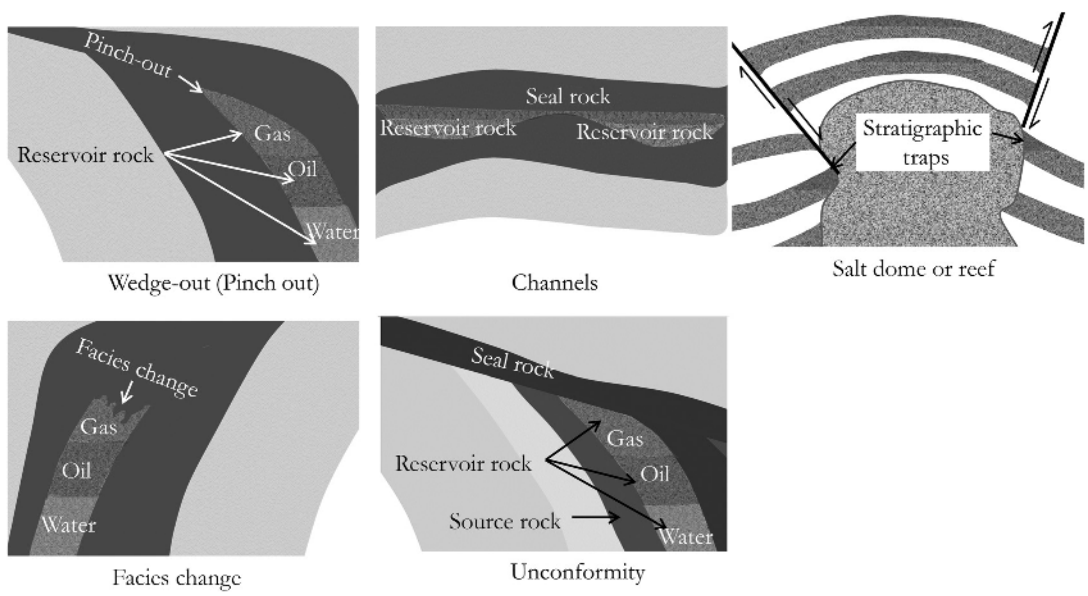

Figure 1.3 Stratigraphic traps.

• *Stratigraphic traps*, which occur due to lateral and/or vertical variations in reservoir properties such as lithology of reservoir rock; permeability; porosity, and thickness. About 13% of the word reservoir is characterized by this kind of trap (Fig. 1.3).

• There is also the possible combination of structural and stratigraphic traps. About 9% of the world reservoir is characterized by this kind of trap.

The chances of all the petroleum systems elements existing together is low, which explains the high risk associated with finding hydrocarbon during exploration.

1.5. PETROLEUM RESERVOIRS

In a reservoir containing gas, oil, and water the fluid distribution is primarily due to the density difference, with gas at the top of the reservoir followed by oil then water (Fig. 1.4).

At any given depth in a reservoir, the pressure in the pore space occupied by the fluid is due to the combined pressure exerted on pore space by the fluid column at the depth of consideration and the overbearing rocks at that depth. The pressure effect of fluid column weight and rock matrix pressure is termed *overburden pressure*.

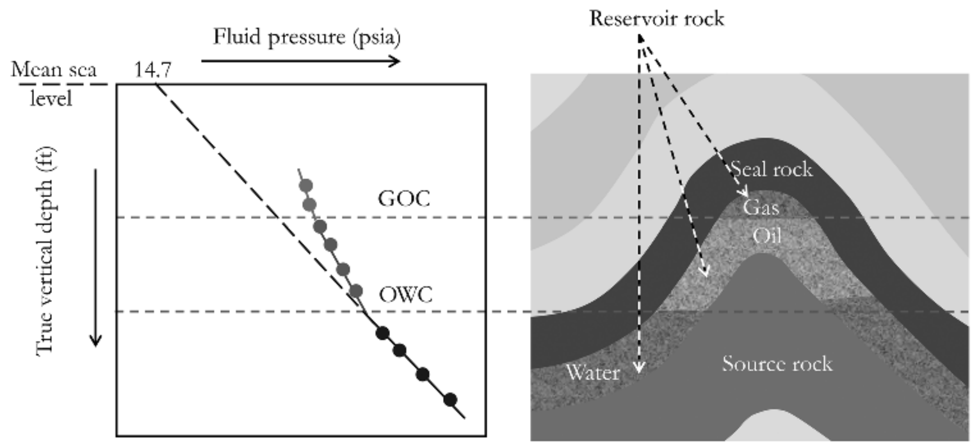

Figure 1.4 Reservoir fluid zones in a normally pressurized petroleum reservoir.

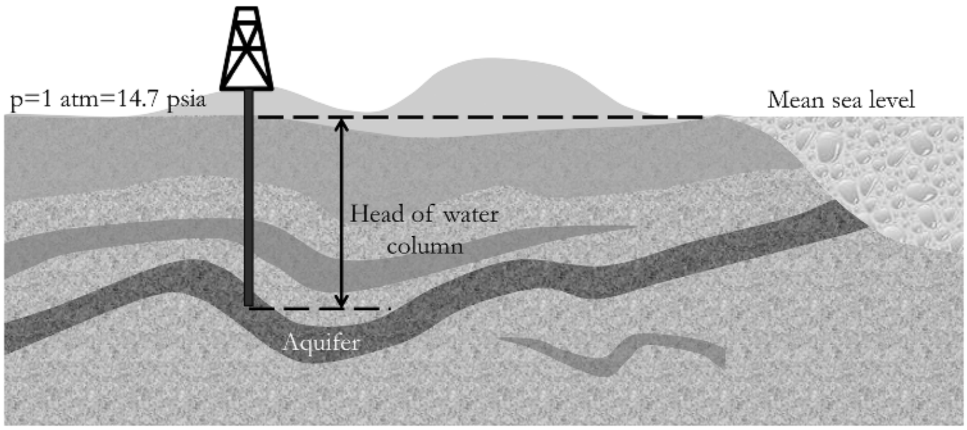

Figure 1.5 Aquifer in hydraulic communication with the surface (normally pressure aquifer).

Measurement and analysis of formation fluid pressure at different depths is important and can be used to determine hydrocarbon fluid zones in a reservoir (Fig. 1.4).

1.5.1. Reservoir Fluid Zones

Formation fluid pressure at any given depth is primarily controlled by formation water pressure in hydraulic communication with the other fluid in the reservoir. The formation fluid pressure at any depth within the fluid column can be defined as:

$$p_j = G_j z_j + C_j \tag{1.1}$$

where p_j is fluid formation pressure in fluid zone j, G_j is gradient of fluid j, z_j is depth in fluid zone j, and C_j is constant of gradient equation for fluid j. Hence, the formation water pressure at any depth can be defined as:

$$p_{water} = G_{water} z_{water} + C_{water} \tag{1.2}$$

where the water column has some form of hydraulic connection to the surface, $C_{water} = 14.7$ psia and extrapolation of the water gradient line to the surface will be 14.7 psia (1 atm), which is atmospheric pressure (Fig. 1.5).

G_{water} is the water gradient and is dependent primarily on the composition and temperature of water. The gradient of fresh water, defined by $\frac{dp_{water}}{dz_{water}}$, is 0.433 psi/ft. The value of gradient for North Sea water is approximately 0.45 psi/ft (salinity of 35,000 ppm) and approximately 0.59 psi/ft for Dead Sea with water (salinity of 330,000 ppm). When the value of C_{water} is 14.7 psia, the water zone is said to be *normally pressured*; when the value is greater than 14.7 psia, the water zone is said to be *overpressured*; and when the value is less than 14.7 psia, the water zone is said to be *underpressured*.

An abnormally pressured (underpressured or overpressured) reservoir would only occur when there is an hydraulic seal between the aquifer and the surface. An overpressured reservoir can arise due to uplift of a trapped reservoir after migration, while an underpressured reservoir will be due to downthrow of a reservoir after migration. The effect of temperature on confined (trapped) formation fluid can also create an abnormal pressured reservoir. Other processes that have been reported to cause abnormal reservoir pressure include: osmosis, buoyancy, phase changes, and differential depletion across compartments with common aquifer.

Gradients of oil and gas are less than that of water due to lower densities. The pressure in the gas and oil zones, respectively, at any given depth can be expressed as:

$$p_{gas} = G_{gas} z_{gas} + C_{gas} \tag{1.3}$$

$$p_{oil} = G_{oil} z_{oil} + C_{oil} \tag{1.4}$$

Typical values of fluid gradients are: 0.01–0.1 psi/ft for gas; 0.23–0.35 psi/ft for oil, and as high as 0.39 psi/ft for heavy oil; and 0.43–0.5 psi/ft for water.

For a reservoir with gas, oil, and water zones as shown in Fig. 1.4, at the gas–oil contact (GOC) if the fluid zones are in hydraulic communication, it is expected that the reservoir in pristine state will be in equilibrium and p_{gas} will be equal to p_{oil}. Hence, solving equations (1.3) and (1.4) with $p_{gas} = p_{oil}$, depth value which is equal to the GOC is determined. The oil–water contact (OWC) is determined in similar approach by solving equations (1.4) and (1.3) with the condition $p_{oil} = p_{water}$.

From equations (1.3) and (1.4), with $p_{gas} = p_{oil}$, the GOC is given as:

$$GOC = z_{gas} = z_{oil} = \frac{C_{gas} - C_{oil}}{G_{oil} - G_{gas}} \tag{1.5}$$

From equations (1.4) and (1.2), with $p_{oil} = p_{water}$, the OWC is given as:

$$OWC = z_{oil} = z_{water} = \frac{C_{oil} - C_{water}}{G_{water} - G_{oil}} \tag{1.6}$$

The "OWC" determined from gradient analysis, equation (1.6), is actually the free water level (FWL), which is the depth at which water saturation approaches 1 and the pressure of the oil phase is the same as that of water (zero capillary pressure). Actual OWC is defined as the depth at which water saturation approaches 1 with the existence of capillary pressure. The difference between FWL and OWC is discussed in Chapter 2 and Chapter 6. In order to distinguish between OWC and FWL, equation (1.6) is redefined as FWL instead of OWC:

$$FWL = \frac{C_{oil} - C_{water}}{G_{water} - G_{oil}} \tag{1.7}$$

Exercise 1.1 Reservoir Fluid Zones

Given the formation pressure measurements and reservoir fluid density at different true vertical depths (relative to mean sea level) from a reservoir with gas, oil, and water zones in Table 1.1:

Table 1.1 Formation Pressure and Fluid Data.

True vertical depth subsea, TVDSS (ft)	Formation pressure (psia)	Fluid	Reservoir fluid density (lb/ft^3)
6,967.00	3,765.47	Gas	14.4
7,624.00	3,896.00	Oil	37.4
8,936.00	4,432.64	Water	64.8

Determine the gas–oil contact and free water level.

Determine if reservoir is normally pressured or abnormally pressured.

Solution Steps.

Step 1: convert reservoir fluid density in lb/ft^3 to fluid gradient in psi/ft by dividing by 144 (144 in$^2 \equiv$ 1 ft^2).

Step 2: calculate C_{fluid}: C_{water}, C_{gas}, and C_{oil} using equations (1.2), (1.3), and (1.4), respectively.

Step 3: calculate GOC and FWL using equations (1.5) and (1.7), respectively.

Step 4: using the value of C_{water}, infer if the reservoir is normally or abnormally pressured.

Solution.

Calculating C_{water} using equation (1.2):

$$p_{water} = G_{water} z_{water} + C_{water}$$

Making C_{water} the subject of the formula:

$$C_{water} = p_{water} - G_{water} z_{water}$$

Substituting p_{water}, G_{water}, and z_{water} into the above:

$$C_{water} = 4{,}432.64 - 0.45 \times 8{,}936 = 411.44\,\text{psia}$$

C_{gas}, and C_{oil} are also calculated in similar way using equations (1.3) and (1.4), respectively.

The calculated fluid gradients and C_{fluid} for each zone are summarized in Table 1.2.

Calculating the GOC and FWL using equations (1.5) and (1.7), respectively:

$$GOC = \frac{3{,}068.77 - 1{,}915.88}{0.260 - 0.100} = 7{,}218.11\,\text{ft}$$

$$FWL = \frac{1{,}915.88 - 144.44}{0.45 - 0.26} = 7{,}906.53\,\text{ft}$$

The reservoir aquifer is abnormally pressured (overpressured) because C_{water} is greater than 14.7 psia (1 atmosphere).

Fig. 1.6 shows a graphical presentation of solution to Exercise 1.1.

It is convenient to plot depth on a reversed vertical axis and pressure on horizontal axis to enhanced visualization (Fig. 1.6) considering that depth increases vertically downwards. However, for gradient equations, it is best

Table 1.2 Summary of Solution to Exercise 1.1.

TVDSS (ft)	Formation pressure (psia)	Fluid	Fluid density (lb/ft3)	Fluid gradient (psi/ft)	C_{fluid} (psia)
6,967.00	3,765.47	Gas	14.4	0.100	3,068.77
7,624.00	3,896.00	Oil	37.4	0.260	1,915.88
8,936.00	4,432.64	Water	64.8	0.450	411.44

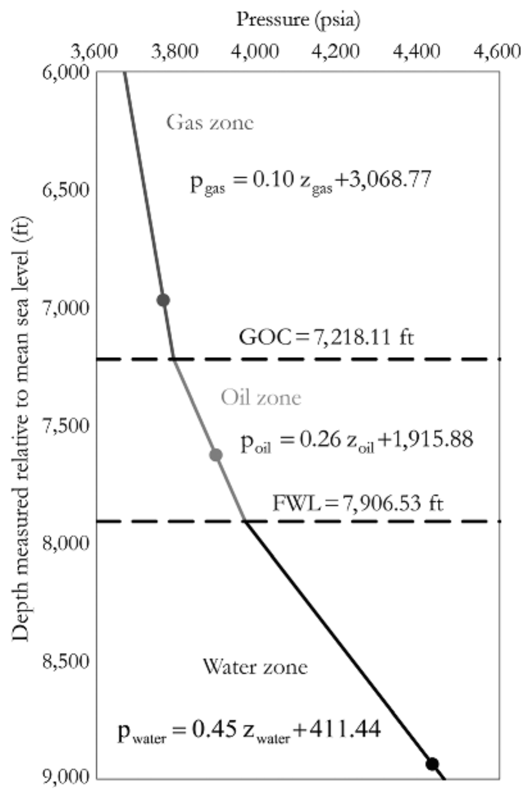

Figure 1.6 Reservoir fluid zones for Exercise 1.1.

to express depth as an independent variable and pressure as dependent variable, as shown in equations (1.1), (1.2), (1.3), and (1.4), and as illustrated in Fig. 1.6. This ensures that fluid gradient is the coefficient of z (depth) and C_{fluid} can be easily used to determine if the reservoir is normally pressured or abnormally pressured. Use of pressure–depth profiles for reservoir characterization is discussed in detail in Chapter 3 (Wireline Formation Testing).

1.5.2. Reservoir Hydrocarbon Volumes

One of the primary functions of a petroleum engineer is determining the volume of hydrocarbons in reservoirs. The volume of hydrocarbon in a reservoir is expressed in terms of stock tank condition, which is the condition representing surface pressure and temperature. This makes sense considering that for sales and comparison it will be appropriate to have fixed conditions. Also, crude oil is stored, metered, and sold at surface conditions. Original oil in place (OOIP) can be expressed as:

$$\mathrm{OOIP}(\mathrm{m}^3) = \frac{\mathrm{GRV} \times \mathrm{N/G} \times \phi \times (1 - \mathrm{S_{wc}})}{\mathrm{B_{oi}}} \tag{1.8}$$

Equation (1.8) may be called OIP (oil in place), STOIP (stock tank oil in place) or STOIIP (stock tank oil initially in place).

Equation (1.8) can be expressed in an engineering oil field (EOF) unit as:

$$\mathrm{OOIP(stb)} = \frac{7{,}758 \times \mathrm{GRV} \times \mathrm{N/G} \times \phi \times (1 - \mathrm{S_{wc}})}{\mathrm{B_{oi}}} \tag{1.9}$$

B_{oi} is the formation volume factor at initial reservoir condition while $\frac{1}{B_{oi}}$ represents the shrinkage factor at initial reservoir condition. B_{oi} in equations (1.8) and (1.9) converts oil volume at reservoir condition to stock tank (surface) condition. N/G (net-to-gross ratio) defines the fraction of the gross rock volume (GRV) that is reservoir rock. The product of GRV and N/G give the *net rock volume*, which is the volume that contains economically producible hydrocarbons.

In a similar way, original gas in place is expressed in metric units, in terms of B_{gi} (initial gas formation volume factor), as:

$$\mathrm{OGIP}\ (\mathrm{m}^3) = \frac{\mathrm{GRV} \times \mathrm{N/G} \times \phi \times (1 - \mathrm{S_{wc}})}{\mathrm{B_{gi}}} \tag{1.10}$$

and, also in metrics units, in terms of Z_i (initial gas compressibility factor) as:

$$\mathrm{OGIP}(\mathrm{m}^3) = \mathrm{GRV} \times \mathrm{N/G} \times \phi \times (1 - \mathrm{S_{wc}}) \frac{\mathrm{T_s p_i}}{\mathrm{T_f p_s Z_i}} \tag{1.11}$$

$$\mathrm{T_s} = (273 + 15)\,\mathrm{K}$$

$$\mathrm{p_s} = (101.35\mathrm{Kpa})$$

OGIP is expressed in EOF units as:

$$\mathrm{OGIP(MMscf)} = \frac{43{,}560 \times \mathrm{GRV} \times \mathrm{N/G} \times \phi \times (1 - \mathrm{S_{WC}})}{\mathrm{B_{gi}}} \tag{1.12}$$

and, also in EOF units, in terms of Z_i as:

$$\mathrm{OGIP(MMscf)} = 43{,}560 \times \mathrm{GRV} \times \mathrm{N/G} \times \phi \times (1 - S_{WC}) \frac{T_s p_i}{T_f p_s Z_i} \tag{1.13}$$

$$T_s = (460 + 60)\,\mathrm{R}$$

$$p_s = 14.65\,\mathrm{psia}$$

Table 1.3 summarizes parameters and their units for hydrocarbon in place calculations.

1.5.2.1. Reservoir Hydrocarbon Volume Estimates. Where reservoir hydrocarbon volumes are conclusively determined using decisively known values of parameters in OOIP and OGIP equations without any room for random variation, this approach is called *deterministic* hydrocarbon in place calculation. In such volume calculations, a given reservoir property input will always produce the same output. Hydrocarbon in place can also be determined using a range of reservoir property values in the form of probability distributions, such that hydrocarbon in place is thus determined in some form of probability distribution. This approach is called *stochastic* hydrocarbon in place calculation. In the stochastic calculation, reservoir properties are randomly sampled from distribution over a number of specified times to generate possible outcomes. The most common approach for stochastic hydrocarbon in place calculation is to use a *Monte Carlo method*, which is a wide class of computerized algorithms that uses repeated random sampling for calculations.

1.5.2.2. Gross Rock Volume Calculation. *Gross rock volume* (GRV) is an important input for hydrocarbon volume in place calculations. Methods for calculating rock volume from contour maps involves representing the entire volume as stripes of frustums (Fig. 1.7).

Gross rock volume can be calculated using the *trapezoidal (average end-area) method,* which is expressed as:

$$\mathrm{GRV} = \sum_{i=1}^{n} \frac{h_i}{2}(A_{i-1} + A_i) \tag{1.14}$$

Table 1.3 Parameters and Units for Hydrocarbon in Place Calculations.

		Equation (1.8)	Equation (1.9)	Equations (1.10) and (1.11)	Equations (1.12) and (1.13)
Nomenclature	Parameter	units	units	units	units
GRV	gross rock volume	m^3	acre-feet	m^3	acre-feet
N/G	Net-to-Gross Ratio	fraction	fraction	fraction	fraction
ϕ	porosity	fraction	fraction	fraction	fraction
S_{wc}	connate water saturation	fraction	fraction	fraction	fraction
B_{oi}	initial oil formation volume factor	m^3/m^3	bbl/stb		
B_{gi}	initial gas formation volume factor			m^3/m^3	ft^3/scf
T_S	base temperature, std condition			K	R
T_f	formation temperature			K	R
p_S	base pressure, std condition			kPa	psia
p_i	initial reservoir pressure			kPa	psia
Z_i	gas compressibility factor at p_i			fraction	fraction

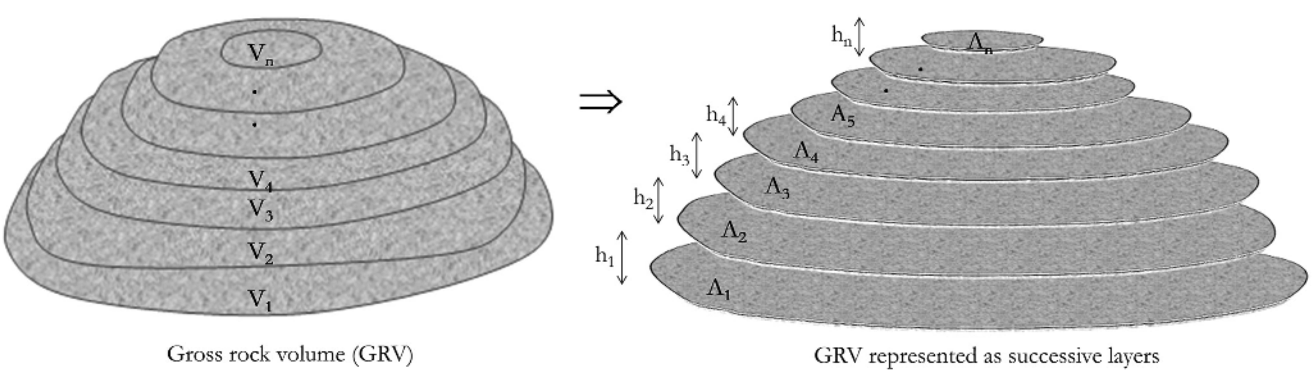

Figure 1.7 Representation of gross rock volume as frustums for volumetric calculations.

where A_i is the area of the end section, h_i is the distance between sections A_i and A_{i-1}.

Another method is the *prismoidal method*, which is expressed as:

$$GRV = \sum_{i=1}^{n} \frac{h_i}{3}\left(A_{i-1} + A_i + \sqrt{A_{i-1} \times A_i}\right) \qquad (1.15)$$

Exercise 1.2 Hydrocarbon Volume Calculation

Using the information provided in Fig. 1.8, calculate the deterministic OOIP in stock tank barrels (stb) using the trapezoidal and prismoidal rock volume calculation methods given that: $\phi = 0.21$; N/G = 1; $S_{wc} = 0.13$ and $B_o = 1.5$ bbl/stb.

Solution Steps.

Step 1: determine the approximate number of square grids within the OWC contour line and other contour lines above the OWC, up to the reservoir top. Square grids can be refined smaller to improve the accuracy of the area to be determined from the number of square grids (Fig. 1.9).

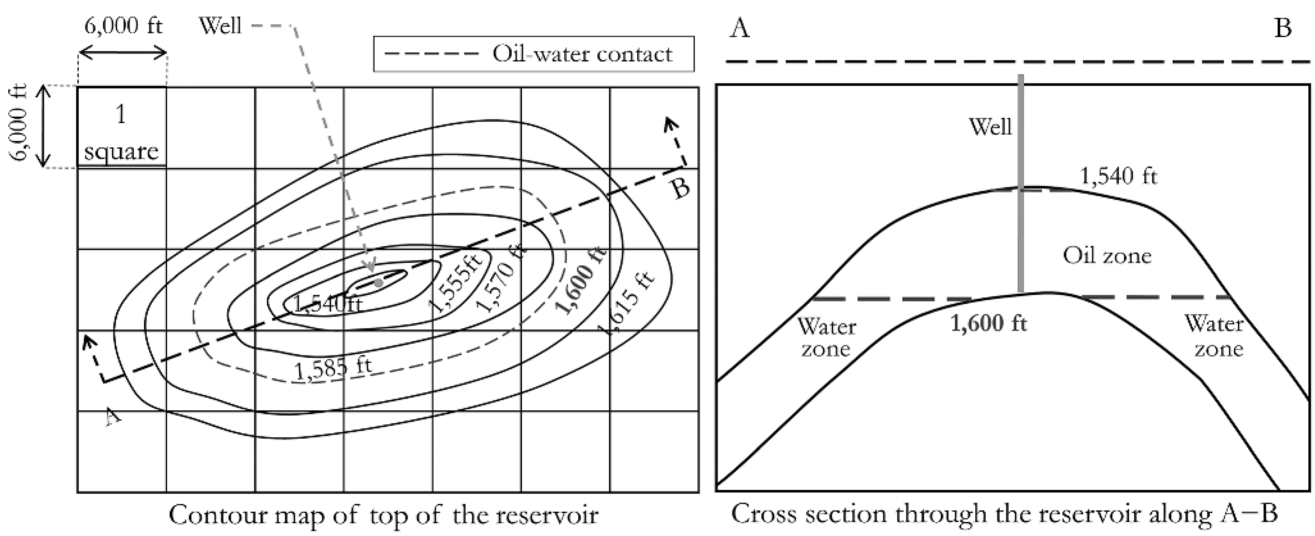

Figure 1.8 Contour map of the top of the reservoir and the cross-section through A–B.

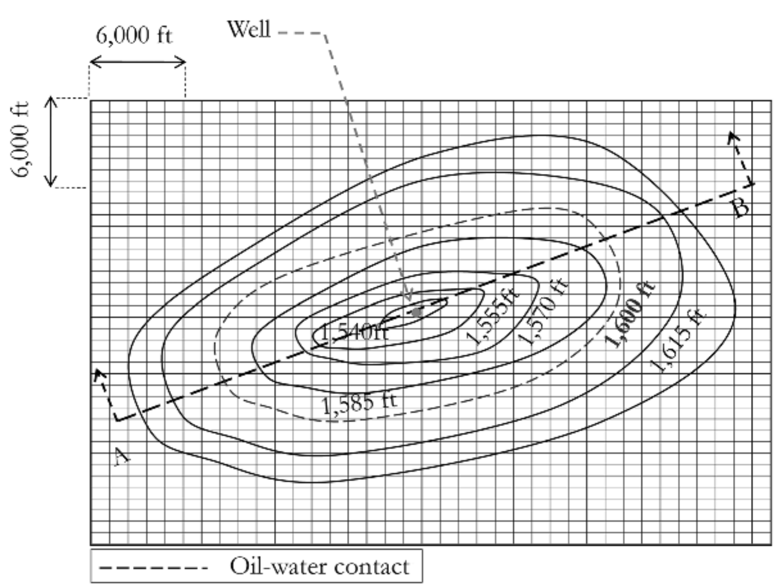

Figure 1.9 Refined square grids for more accurate area calculation.

Step 2: determine cross-sectional area of the OWC and the remaining contour lines above the OWC, up to the reservoir top by multiplying the number of square grids (N) by the area of a single square grid.

Step 3: determine gross rock volume over net reservoir interval using equations (1.14) and (1.15).

Step 4: determine the OOIP using equation (1.9).

Solution.

Table 1.4 summarizes the gross rock volume calculation for Exercise 1.2.

Gross rock volume:

Using the trapezoidal method

$$\mathrm{GRV}\left(\mathrm{ft}^3\right) = 5.78\mathrm{E}+09\mathrm{ft}^3$$

$$\mathrm{GRV}(\mathrm{acre-ft}) = 5.78\times10^9\left(\mathrm{ft}^3\right)\times2.29568 \times10^{-5}\left(\frac{\mathrm{acre-ft}}{\mathrm{ft}^3}\right) = 1.33\times10^5(\mathrm{acre-ft})$$

$$\mathrm{OOIP}(\mathrm{stb}) = \frac{7{,}758\times\mathrm{GRV}\times\mathrm{N/G}\times\phi\times(1-S_{wc})}{B_{oi}}$$

$$\mathrm{OOIP}(\mathrm{stb}) = \frac{7{,}758\times1.33\times10^5\times1\times0.21\times(1-0.13)}{1.5} = 1.25\times10^8\,\mathrm{stb}$$

Using the prismoidal method

$$\mathrm{GRV}\left(\mathrm{ft}^3\right) = 5.65E+09\mathrm{ft}^3$$

$$\mathrm{GRV}(\mathrm{acre-ft}) = 5.65\times10^9\left(\mathrm{ft}^3\right)\times2.29568 \times10^{-5}\left(\frac{\mathrm{acre-ft}}{\mathrm{ft}^3}\right) = 1.30\times10^5(\mathrm{acre-ft})$$

$$\mathrm{OOIP}(\mathrm{stb}) = \frac{7{,}758\times\mathrm{GRV}\times\mathrm{N/G}\times\phi\times(1-S_{wc})}{B_{oi}}$$

$$\mathrm{OOIP}(\mathrm{stb}) = \frac{7{,}758\times1.30\times10^5\times1\times0.21\times(1-0.13)}{1.5} = 1.23\times10^8\,\mathrm{stb}$$

1.5.2.3. Net-to-Gross Ratio. The *net-to-gross ratio* (N/G or NTG) can refer to a wide range of definitions. It may refer to *sand net-to-gross* ($\mathrm{NTG_{sand}}$), *reservoir net-to-gross* ($\mathrm{NTG_{res}}$) or *pay net-to-gross* ($\mathrm{NTG_{pay}}$).

Sand net-to-gross ratio: this is the ratio of sand interval(s) to the entire gross interval of interest (Fig. 1.10), where sand interval(s) can be defined as interval(s) of *clean sandstone lithology*, often determined using a limiting *shale fraction* (V_{sh}) cutoff.

Reservoir net-to-gross ratio: this is the ratio of the hydrocarbon bearing rock interval(s) that has desirable reservoir properties to the entire gross interval of interest (Fig. 1.10). Desirable reservoir properties are porosity and permeability, as they determine the capacity of the reservoir to store and flow hydrocarbon, respectively.

Pay net-to-gross ratio: this is the ratio of net pay-to-gross rock interval (Fig. 1.10), where net pay is reservoir interval(s) that contain hydrocarbons that can be produced economically. Net pay intervals must exceed a defined minimum porosity, permeability, and hydrocarbon saturation called *cutoffs*. Generalized values of cutoffs for petrophysical properties as presented in some literature are meaningless; since the pay intervals are intervals that can be produced economically as such, cutoff values must be measured under dynamic conditions or analogues that have similar fluid, rock, and rock–fluid properties. The recovery of oil, for instance, does not depend on permeability only but on viscosity and thickness of interval. Hence, a heavy oil would have a higher permeability cutoff than a light oil. Also, pay interval would depend on current technology and economic parameters to define what can be produced economically. Intervals considered uneconomical today may become economical in the future. This also means that cutoffs can change with time.

The concept of using a pay interval should only be considered in recovery calculation methods that cannot discriminate between producible and nonproducible intervals. In reservoir simulation where a geological model (*geomodel*) is used directly in the simulation without upscaling petrophysical properties, an approach very common in recent times, pay interval, net-to-gross and cutoffs should be avoided. This is because reservoir

Table 1.4 Gross Rock Volume Calculation for Exercise 1.2.

Contour depth, z (ft)	N = No. of 600 × 600 ft squares	A_i (ft^2) = N × 6000 × 6000	h_i (ft) = $z_i - z_{i-1}$	V_i (ft^3) using equation (1.14)	V_i (ft^3) using equation (1.15)
1,600	7.1	2.56E+08			
1,585	4.5	1.62E+08	15	3.13E+09	3.11E+09
1,570	1.9	6.84E+07	15	1.73E+09	1.68E+09
1,555	0.7	2.52E+07	15	7.02E+08	6.76E+08
1,540	0.1	3.60E+06	15	2.16E+08	1.92E+08
			GRV = ΣV_i =	5.78E+09	5.65E+09

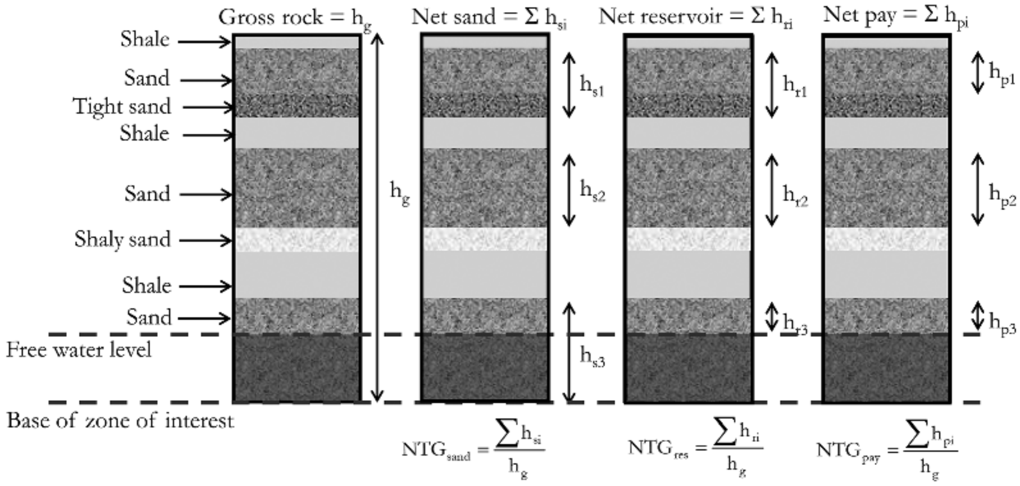

Figure 1.10 Schematic illustration of different definitions of net-to-gross ratios.

simulation would handle appropriately intervals that can contribute to flow or otherwise.

1.6. PETROLEUM RESOURCE CLASSIFICATION

Petroleum resource estimation and classification falls into the discipline of reservoir engineering. However, support from other discipline, such as such as geologist, geophysics, petrophysicist, facility design engineers and economists, is required and important.

Petroleum resource can generally be classified as: *prospective*, *contingent,* and *reserves* in order of their increasing chance of commerciality (Fig. 1.11). These categories of petroleum resources are a subset of the *total petroleum initially-in-place* (Fig. 1.11) [*SPE-PRMS*, 2008].

1.6.1. Prospective Resources

Based on the chances of commercialization, prospective resources are ranked lowest amongst the different petroleum resources. Prospective resources (*prospect*) are estimated petroleum quantities associated with a

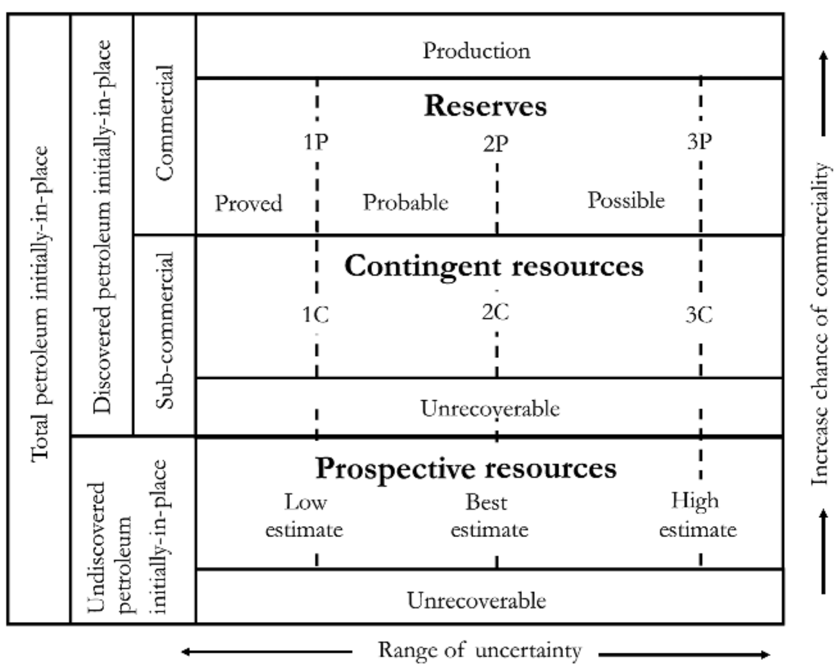

Figure 1.11 Petroleum resource classification [*SPE-PRMS*, 2008].

development plan, at a given date, considered potentially recoverable from undiscovered accumulation.

Based on uncertainty and level of confidence, prospective resources can be classified as: *low estimate*; *best estimate*, and *high estimate* (Fig. 1.11). Estimation of each category of prospective resources can be by *scenario-based approach*, with different deterministic cases, or by *stochastic approach* discussed in Section 1.5.2.1.

1.6.2. Contingent Resources

Contingent resources are estimated petroleum quantities associated with a development plan, at a given date, considered potentially recoverable from discovered accumulation but not commercial due to one or more contingencies [*SPE-PRMS*, 2008]. Contingent resources rank next after prospective resources in order of increasing chance of commercialization (Fig. 1.11).

Based on uncertainty and level of confidence, contingent resources can be classified as: 1C (with at least 90% probability of quantity been recoverable), 2C (with at least 50% probability of quantity been recoverable), and 3C (with at least 10% probability of quantity been recoverable).

1.6.3. Reserves

Reserves can be defined as estimated petroleum quantities anticipated to be commercially recoverable by application of development projects, to known discovered accumulations from a given date forward under defined conditions [*SPE-PRMS*, 2008].

Reserve are associated with development option(s) and, hence, for a resource to be classified as reserve, it is expected that there must exist a resolute intention to develop resources within a reasonable time frame, typically five years [*SPE-PRMS*, 2008].

Criteria that must be met for petroleum resources to be classified as reserve include:

• resources must be discovered (presence of a well);
• resource must be commercially recoverable with exiting technology;
• there must be commercially recoverable remaining reserve based on a development plan at the effective date of the evaluation.

1.6.3.1. Reserve Classification Based on Uncertainty. Based on the uncertainty and the level of confidence in the amount of commercially recoverable resources, reserves can be described as: 1P(Proved); 2P(Proved + Probable), and 3P(Proved + Probable + Possible) where:

Proved reserve is the estimated petroleum quantity anticipated to be commercially recoverable by application of development projects with a high level of confidence (at least with 90% confidence).

Probable reserve is the estimated petroleum quantity that, when added to the proved reserved, is anticipated to be recoverable by application of development projects with at least 50% confidence.

Possible reserve is the estimated petroleum quantity that, when added to the proved and probable reserve, is anticipated to be recoverable by application of development projects with at least a 10% confidence.

The proved petroleum reservoir volume must be limited to identified hydrocarbon levels such as hydrocarbon down to (HDT) the lowest known hydrocarbons, where hydrocarbon–water contact (HWC) is absent. Formation pressure logs analysis (gradient analysis) remains one of the most reliable sources of fluid contacts, as discussed in Chapter 6. It is important the fluid contacts from the gradient analysis of formation pressure logs are checked for consistencies with well log analysis such as neutron density for gas–oil contact and resistivity log for hydrocarbon–water contact. Analysis of open hole well logs and formation pressure logs are discussed in Chapters 5 and 6, respectively.

The use of seismic attributes for proved reserve volumetric calculation requires that such attributes are well defined in the reservoir and correlated to well properties. Seismic attributes alone without well correlation cannot be used for proved reserve estimation.

1.6.3.2. Reserve Categorization Based on Development Status. Based on development status, reserves can be classified as *developed reserve* and *undeveloped reserves*.

(i) *Developed reserves* are reserves that are expected to be recovered from the existing well and facility. Developed reserve may be further categorized based on production status as *producing reserve* – where reserve is expected to be recovered from the existing completion interval, which is open to production, at the time of reserve estimation – and *nonproducing reser*ve – where there is existing facility to recover reserve however they are not producing due to wells shut-in or inability of wells/facility to produce [*SPE-PRMS*, 2008].

(ii) *Undeveloped reserves* are reserves that are expected to be recovered from new wells within an undrilled compartment, or from an existing well that requires a major workover or requires major expenditure for recompletion [*SPE-PRMS*, 2008].

1.6.4. Reserve Estimation Methods

Acceptable methods for reserve estimation include one or a combination of the methods described here.

1.6.4.1. Volumetric Method for Reserve Estimation. This method is based on equations (1.8)–(1.13) to determine in place volume, which will then be multiplied by a recovery factor determined from relative permeability data, reservoir performance methods or analogue field data. Volumetric methods require gross rock volume, net-to-gross ratio, initial/connate water saturation, porosity, fluid formation volume factor, and recovery factor.

Gross rock volume (GRV): can be determined from a combination of well and seismic data; the geophysicist creates depth maps with the reservoir top and base from which GRV is calculated. Creation of depth maps involves *well-to-seismic tie* processes and mapping horizon from seismic analysis. Seismic data are reasonably reliable for assessment of areal extent, geometry, and structural properties of the reservoir. Uncertainty with use of seismic data for reserve estimation is generally high.

Seismic data on their own are poor in the prediction of porosity, NTG, and S_{wc}. However, by correlating seismic attributes with well data and properties, the reliability of seismic data for predicting reservoir properties can be improved. Reserve estimation requires accuracy for valuation, repeatability for comparison, and transparency, which may not be met by use of seismic data without correlating with well data.

Net-to-gross ratio (N/G or NTG): is the ratio of net reservoir (with porosity and permeability) to total gross thickness of interest; it can be determined along the well from analysis of well logs (Chapter 5). The geologist creates property correlations between the wells and delineates the reservoir into different geologic units. Across each geological unit in the reservoir, geostatistical techniques and depositional models can be used to distribute properties across each geological unit and the entire reservoir model. Seismic attributes derived from high quality seismic data can be used in geological extrapolation of reservoir properties across each geological unit using geostatistical techniques such as *kriging* and *cokriging*.

*Porosity: o*pen hole well log interpretation with calibration against core porosity, determined under stressed conditions or corrected for stress effect, can be used to determine porosity along the well. In a similar way to NTG distribution, by correlating properties across the well for different geological units and then using geostatistical techniques, porosity can be distributed across the entire reservoir model. Seismic attributes derived from high quality seismic data are important in porosity distribution.

Initial/connate water saturation (S_{wc}): capillary pressure data and S_{wc} calculated along the well from the open hole log are used to derive *saturation-height function* (Section 2.5.7) for each facies (rock type). Derived saturation-height function is then used in populating water saturation in the entire reservoir model. Distribution of water saturation away from the well must be based on capillary pressure relationship for each rock type (facies) rather than by geostatistical extrapolation.

1.6.4.2. Performance-based Approach for Reserve Estimation. These methods involve use of production histories with a model (simulation or analytical) to model reservoir system, predict reservoir performance, and recoverable and unrecoverable hydrocarbon volumes. Methods that can be described as performance based include:

• Material balance: this involves representing different reservoir section as "tanks" and using conservation of mass principles and fluid properties to model reservoir systems, energy for fluid production, and volume left in the reservoir for a given volumetric withdrawal. The concept of material balance for reservoir performance prediction is discussed in Chapter 12.

• Reservoir simulation: this involves dividing the reservoir into grid cells (finite element or finite volume), with each cell serving as a simple material balance "tank", and using combination of material balance, flow in porous media, and fluid equation to predict flow of reservoir fluids through porous media, reservoir deliverability, and recoverable and unrecoverable hydrocarbon volumes.

• Well test analysis: this involves analysis of pressure and rate measurement with *well test interpretation models* to predict reservoir performance. Well test interpretation models are analytical models derived from a combination of mass continuity equation, Darcy's law and equation of state. These interpretation models can be used to simulate bottomhole well pressure response for a given rate history. Well test analysis also gives either minimum connected volume when full reservoir boundaries have not been reached during testing or in place volume when full boundaries have been reached during well testing. Analysis of well test data is discussed in Chapter 8.

• Production decline curve analysis: this approach involves using declining mathematical equations such as exponential, harmonic or hyperbolic functions as reservoir or field performance response. Use of the production decline curve method for reserve estimation involves finding the best decline model that matches production history, then using the model to predict future production and recoverable and unrecoverable hydrocarbon volumes. Use of production decline models for reservoir performance prediction is discussed in Chapter 13.

1.6.4.3. Analogue. Analogies to other reservoirs may be considered for obtaining properties for resource and reserve calculation where they have similar geological characteristic, geological location, and reservoir rock and fluid characteristics.

The choice of method for estimating reserves generally depends on maturity of assets, availability and quality of data, and the experience and familiarity of the engineer with the different resource estimation methods.

1.6.5. Use of Seismic Data for Petroleum Resource Calculation

With rigorous interpretation, seismic data are important for characterization of reservoir features such as dip, faulting, and reliable gross thickness. The use of seismic data for petroleum resource estimation requires in-depth support from the geologist and geophysicist, as most reservoir engineers may not be familiar with seismic interpretation methods. Seismic interpretation often depends significantly on experience and judgement.

Using seismic data for determining reservoir properties used for volumetric calculation is only reliable, when there are well data to correlate with seismic data. Where there are no well data to correlate seismic attributes, analogues with reasonable assumptions are often preferred to seismic derived properties alone for volumetric properties determination.

1.6.6. Resource Estimation at Different Stages of Life Cycle

1.6.6.1. Prospect. Prospect (*prospective resources*) are considered potentially recoverable hydrocarbon volumes associated with a development plan that targets currently undiscovered resources. Geologistss and geophysicists using theories, seismic data, regional or near-field correlation will be involved in determining the probability of finding petroleum as part of *prospect risking and ranking*.

When geologists identify the possibility of petroleum being found in a particular area, likely petroleum volumes and the recoverable amount of petroleum in the reservoir, field or concession are calculated using mapped structure.

The only resource volume calculation method for a prospect is the volumetric approach described by equations (1.8)–(1.13) with properties taken from analogue, correlation with nearby fields, and valid assumptions. GRV can be determined from seismic data but petrophysical properties should not be determined from seismic data due to the absence of well data to correlate seismic attributes at this stage. A prospect must satisfy the following criteria before it can be termed a prospect: (i) presence of a trapping mechanism; (ii) porosity and permeability; and (iii) a matured source rock that can generate hydrocarbon. Hence, the probability that a prospect has a reservoir with trapped hydrocarbon (probability of success) is, therefore, a product of probability of area of interest having a trap, reservoir rock, and mature source rock. This probability of success can be expressed as:

$$pr_{succes} = pr_{trap} \times pr_{reservoir} \times pr_{source} \tag{1.16}$$

Equation (1.16) assumes constituent probabilities are independent of each other.

1.6.6.2. Discovery. When a well has been drilled and hydrocarbon is found, the well becomes a *discovery well*. Petrophysical properties can then be obtain along the well using well log interpretation techniques. Correct fluid formation volume factor and other fluid properties can be determined from analysis of fluid samples recovered from the well. At this stage, a well test may be carried out, with analysis of well test data giving an understanding of the potential deliverability of the well and reservoir boundaries in the case of an extended well test.

At this point, initial volumetric calculations at the prospective stage can be updated with increased confidence as well log properties are available. At this stage if there are seismic attributes, from high quality seismic data, they can be correlated with well properties and used for property distribution away from the well. Resource volume calculation options that can be considered include: volumetric; well test to get minimum connected volume (which is a proved volume) or hydrocarbon initially in place if pressure diffusion has reached the entire reservoir boundaries; and material balance if full reservoir boundaries have been reached by pressure diffusion to ensure depletion. Reservoir simulation can also be used to match test data and predict reservoir performance with respect to recoverable and unrecoverable hydrocarbon resources.

1.6.6.3. Appraisal. Generally, one or more additional wells will be drilled to appraise discovered petroleum resources. More than one well improves the understanding of the structure of the reservoir, lateral continuity of properties, the ability to correlate properties between wells, and to delineate the reservoir into different geologic units. Core samples maybe acquired during drilling of appraisal well(s). Core samples are then analyzed for petrophysical properties such as porosity, permeability, capillary pressure, and relative permeability (Chapter 2). Calibration of porosity with well log data improves confidence in the calculated porosity; capillary measurements are useful for predicting water distribution in the reservoir; relative permeability gives an indication of flow of different phases in the presence of others. Relative permeability models can be used to determine a range of recoverable petroleum from initially in place volume.

The appraisal stage of the field development should provide enough information for a development strategy of the field, if the field is to be developed. Petroleum resources determined at this stage can be reserve or contingent resources. Where resource is classified as reserve, then reservoir, field or concession will proceed to development. If the resource is considered contingent, then development maybe considered in the future when it is either economically feasible (for economic contingent resource) or technically feasible (for technical contingent resource).

1.6.6.4. Development Stage. As additional wells are drilled for production at the *initial development stage*, information acquired from newly drilled wells will provide more information on the structure and properties of the reservoir. Pressure and rate measurements at this stage can be used to monitor the well and reservoir. Also, additional information will help improve models, optimizing the development plan based on reservoir response. The initial development stage can be considered as a *build-up stage* of production profile (Fig. 13.1). Since the resource is at the development stage, it must have satisfied criteria for a reserve (can be produce commercially) and, therefore, the interest at the development stage is remaining reserve. At this stage, with increased information, reserve estimate and category may change.

When the field is at the *full field development stage*, where the reservoir or field has produced at an extended plateau or produced a significant volume from the reservoir and dynamic reservoir response is understood, material balance, well test analysis (specifically deconvolution), and reservoir simulation can be used to improve reservoir performance characterization and reserve estimate. Also, at this stage, based on an understanding of the reservoir or field, reservoir and well management decisions – such as increasing production with infill drilling; arresting decline if the field is in decline; well workovers to improve production; supplementing reservoir energy with methods such as such water or gas injection to improve reservoir deliverability; use of artificial lift to improve well deliverability – may be considered. Of interest at this stage, too, is available reserve, which is how much more can be further recovered economically. Also at this stage, with increased information, reserve estimate and category may change.

1.6.7. Reserve Reporting and Audit

It is important that a reserve report gives the information for which it is meant for. A reserve report maybe created for the various stakeholders of the petroleum resource(s), which may include: potential investors; existing investors; company executives; financial institutions; government agencies; and regulatory bodies.

Depending on the end use, typical information expected in a reserve report includes:

- reserve quantities (proven, probable, and possible);
- rate prediction from reserves;
- net present value and future value of reserves.

It is also important that reserve estimation goes through an audit process. A reserve audit process involves a review of the data and interpretation methods used for reserve estimation. The reserve audit process provides an independent opinion, different from that of the parties involved in the estimation, on rationality of estimated reserves.

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