Petroleum Reservoirs and Oil Production Mechanisms

Bhargav Baruah, Puja Kalita, Lalit Pandey, and Pankaj Tiwari

1 Introduction

A petroleum reservoir is a subsurface distribution of pore networks formed between strata of sedimentary rock formations, consisting of two or more hydrocarbon fluids and water. The hydrocarbons are formed by degradation of organic matter, both marine and terrestrial origins by the influence of high pressure and temperature over a long period. This phenomenon occurs in the source rock (Ardakani et al. 2017; Baruah and Tiwari 2020). The produced hydrocarbons then migrate into the empty pores and voids present in the rock formations and form a pool (reserve) of hydrocarbon fluids (Phukan et al. 2019a; Saha et al. 2018a). The reservoir rock requires to be capped to prevent migration (seepage) of these fluids to the surface under influence of buoyancy, capillarity, and other forces (Aplin and Macquaker 2011). The most important properties of a reservoir are the volume of oil and gas, recovery factory of the oil and gases in the reservoir, compositional and physical properties of the reservoir rock, and types of hydrocarbons present in the reservoir (Aplin and Macquaker 2011; McCain Jr 1973).

The reservoir fluids (oil, water, and gas) which are originally present within the pore spaces at the time of discovery contribute to the energy responsible for inducing flow and production of these fluids from the reservoir. These fluids are initially contained in the reservoir under very high pressure until drilling and production operations are carried out to release the trapped energy within the reservoir. The reservoir pressure starts declining steadily as fluids are produced from the reservoir to the surface. Therefore, when the pressure of the reservoir is reduced, the fluids are subjected to changes due to the expansion of the fluids and compressibility of the fluids and rocks (Dusseault 2011). The natural flow of hydrocarbons from

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the reservoir rock occurs due to the expansion of reservoir rock, expansion of an aquifer underlying the oil zone, expansion of the fluids, and gravitational energy that segregates the fluids in the reservoir (Amit 1986; Dusseault 2011). The performance of a reservoir is hence dependent on the type of energy capable of drawing fluids from the reservoir to the wellbore and then to the surface. This energy governs the producing mechanism of a crude oil system and is commonly known as the drive mechanism for a reservoir.

The recovery of petroleum from its reserve is achieved by three methods: (i) primary recovery, (ii) secondary recovery, and (iii) tertiary recovery (Vishnyakov et al. 2020). In primary recovery, the hydrocarbons present in a particular reservoir are extracted to the surface by natural reservoir drive mechanisms such as, aquifer water moving the crude oil downwards from the reservoir pores into the production well, expansion of reservoir caps, expansion of dissolved gases in the crude oil, and gravity drainage as a result of the movement of crude oil from higher to lower saturation in the reservoir. The extraction of hydrocarbons by primary recovery has been recorded to be about 5–15% of the original oil in place (OOIP) (Vishnyakov et al. 2020; Viswanathan 2017). Over the lifetime of a production well, as the production of hydrocarbons from the reservoir increases, the reservoir pressure decreases. After a certain period, the prevailing reservoir pressure is inadequate to drive the hydrocarbons from the reservoir to the surface. In this situation, secondary recovery methods are utilized. The secondary recovery techniques provide supplementary energy to the reservoir by injecting different fluids such as water and gas (gas produced from the reservoir or carbon dioxide (CO_2)) (Srivastava and Huang 1997; Talebian et al. 2014) to increase the reservoir pressure, thus increasing or substituting the natural reservoir drive and therefore improve the mobility of the in situ hydrocarbons. Secondary recovery techniques have shown an average recovery of 35 and 45% of OOIP (Tzimas et al. 2005). However, with the application of primary and secondary recovery methods about 60% of OOIP remains in the reservoir (Gbadamosi et al. 2019a, b). Therefore, to increase the production of hydrocarbons tertiary recovery or enhanced oil recovery (EOR) methods are used (Datta et al. 2018; Datta et al. 2020; Phukan et al. 2019b; Saha et al. 2018b). In this chapter, the characterization and classification of petroleum reservoirs and production of reservoir fluids through various possible drive mechanisms are discussed.

2 Reservoir Potential

2.1 Geological Setting

Petroleum reservoirs are primarily found in the sedimentary rocks of the earth's crust (Selley 2003; Selley and Sonnenberg 2015b). Sedimentary rocks are formed by sedimentation, compaction of eroded rock particles into denser mass, and cementing with minerals or chemical precipitates (Zhang et al. 2019). The sediments are compacted and cemented after burial under additional layers of sediment, thereby leading to the formation of multiple strata or layers. Over a long duration of time, numerous organic beings such as dead animals, plants, planktons, etc. are trapped in these strata during compression, and under the influence of temperature and pressure, the trapped organic matter undergoes different biological, biochemical, and thermochemical alterations leading to the formation of hydrocarbons (Hunt 1995). The process of conversion of organic matter into kerogen is called diagenesis, and subsequent decomposition of kerogen into oil and gas is called catagenesis (Hunt 1995; Tissot and Welte 1984). The sedimentary rocks in which hydrocarbons originate are called source rocks (McCarthy et al. 2011). These rocks are broadly classified into two types: (i) *clastic sedimentary rocks*—formed due to weathering and depositions of rock particles of different grain sizes (e.g., sandstones, mudstones, and shales) (Fralick and Kronberg 1997), and (ii) *chemical or biochemical sedimentary rocks*—formed by chemical processes (e.g., carbonate and carbonate precipitates like calcite, limestone, dolomite, halite, and gypsum) (Boggs Jr and Boggs 2009). The geological setting of a petroleum system significantly affects the diagenesis process and reservoir quality (Ehrenberg and Nadeau 2005). Around 60% of the total world crude oil reserves originate in carbonate reservoirs. The Gulf countries contain 62% of the total oil reserve, out of which 70% reservoirs are carbonate reservoirs (Joshi and Singh 2020b).

The produced hydrocarbons in the source rock migrate into the adjacent porous rocks or reservoir rocks due to an increase in pressure. This movement of produced hydrocarbons from the source rock into the voids of the reservoir rock is termed primary migration (Chapman 1972; Eseme et al. 2007). The accumulated hydrocarbons travel and settle in the inter-connected pore networks of the strata of adjacent reservoir rocks. This movement of hydrocarbons in the reservoir rocks is known as secondary migrations. The movements of the hydrocarbons accumulated in the pore networks of the reservoir rocks are restricted by certain rock formations known as traps (Harding and Lowell 1979; Mitra 1990). The accumulated hydrocarbons (crude oil and natural gas) are followed by water and other inorganic gases (carbon dioxide (CO_2), carbon monoxide (CO), etc.). The natural gases along with the trapped inorganic gases occupy the top section of the trap and the water occupies the bottom section. An impermeable rock known as the caprock (trap) prevents any movement of the hydrocarbons out of the reservoir rock. The traps are generally classified into three types: structural, stratigraphic, and hydrodynamic. Structural traps are formed as a result of geological and tectonic activities (faulting, folding, etc.) in the subsurface which leads to the occurrence of structural changes such as folds, anticlines, and domes in different strata (Allen and Allen 2005). Stratigraphic traps are created by variations in the porosity, thickness, and texture of the reservoir rocks, and by lateral and vertical differences in its lithology (Allen and Allen 2013). Hydrodynamic traps are formed due to the variance in water pressure and the flow of underground aquifer water, leading to the formation of a tilt in the water–hydrocarbon interface in the subsurface (Allen and Allen 2013). The accumulated hydrocarbons are prevented migrating from the reservoir rock to the surface by a geological structure known as a seal. A seal is formed when the capillary pressure across the pore throats of the reservoir rock is greater or equal to the buoyancy pressure of the moving hydrocarbons (Bradley and Powley 1994; Watts 1987). The capillary seals are of two types; (i) hydraulic and (ii) membrane seal, which keep the fluids in the reservoir domain (Bradley and Powley 1994).

2.2 Petroleum Reserves

Petroleum reserves are categorized into three types by the analysis of different geological and engineering survey records: (i) *proven reserves*—petroleum reservoirs which can be projected with realistic assurance to be commercially recoverable, (ii) *probable reserves*—unproved petroleum reserves which are more likely than not to be recoverable, and (iii) *possible reserves*—unproved reservoirs whose hydrocarbon potential is less likely to be recoverable by existing operation methodologies (Flåm and Moxnes 1987; Garb 1985; SPE 1997). Hydrocarbon reservoirs are considered probable reserves if the probability of hydrocarbon recovery is at least 50% of the sum of estimated proven and probable reserves. These reservoirs are predicted to be proven by normal drilling methods where subsurface control systems are insufficient to categorize them as proven reservoirs (SPE 1997). Possible reserves may include reservoirs that could feasibly occur outside of areas categorized as probable reserves and seem to contain hydrocarbons based on well log and core analyses but may not sustain commercial production due to technical and geological limitations (SPE 1987, 1997).

Global-proven oil reserves have been recorded to be around 1734 billion barrels in 2019 (BP 2020; CIA 2020; OPEC 2019). Among the oil reserves around the world, South and Central American oil reserves have the highest estimated reserve to production (R/P) ratio of 144 years, whereas Europe has the lowest of 12 years (BP 2020). The distribution of the total proven crude oil reserves around the world is presented in Fig. 1. The countries which possess the highest oil reserves are Venezuela (17.5%), Saudi Arabia (17.2%), and Canada (9.8%) (CIA 2020; Joshi and Singh 2020b). As of November 2020, the top 10 proven reserves in the world are Venezuela (304 billion barrels), Saudi Arabia (298 billion barrels), Canada (170 billion barrels), Iran (156 billion barrels), Iraq (145 billion barrels), Russia (105 billion barrels), Kuwait (102 billion barrels), UAE (98 billion barrels), United Nations (69 billion barrels), and Libya (48 billion barrels) (BP 2020). As per the annual statistical bulletin of 2019 by Organization of Petroleum Exporting Countries (OPEC) (OPEC 2019), 79.4% of the total proven oil reserves are located in OPEC member countries.

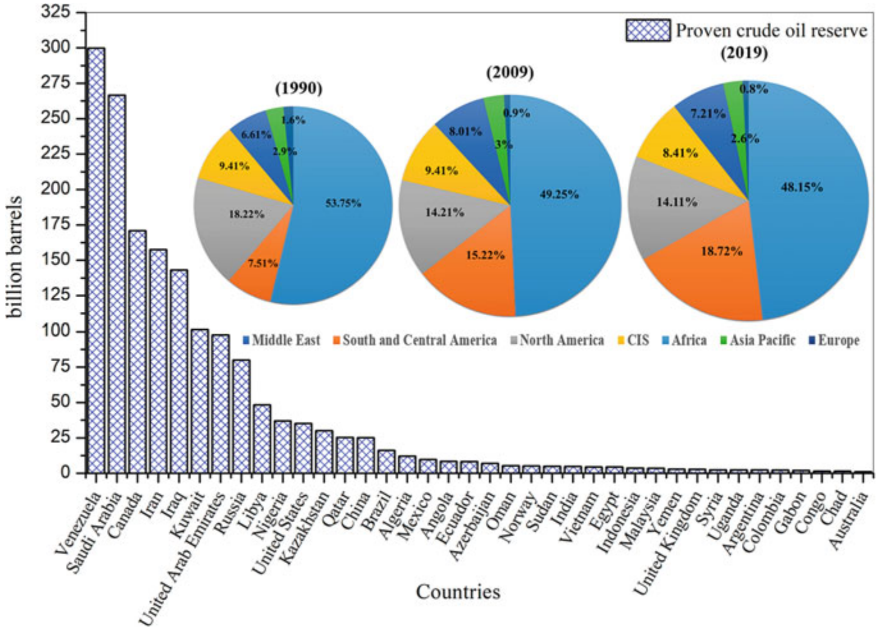

Fig. 1 Proved crude oil reserves for different countries [data are extracted from CIA Energy Outlook, August 2020 (CIA 2020)]

3 Physicochemical Characterization of a Petroleum Reservoir

The primary objective of any petroleum industry is the recovery or extraction of hydrocarbons from the discovered petroleum reservoirs. The composition of a petroleum reservoir is critical to petroleum recovery specifically to the implementation of enhanced oil recovery techniques. The mineralogical composition of the reservoir, surface morphology, and pore structure and distribution are of critical importance to the petroleum industry, both from the scientific and industrial point of view.

3.1 Composition and Mineralogy of Petroleum Reservoir

Petroleum reservoirs are predominantly composed of sandstone or carbonate (Bjørlykke and Jahren 2010). Sandstone reserves possess a high percentage of quartz and sand grains, along with the presence of feldspar, and clay minerals such as Illite and Kaolnite (Baruah et al. 2019; Saha et al. 2017). Indian reserves are mostly sandstone reservoirs. Sandstone reserves exhibit high porosity and permeability compared to carbonate reservoirs. Carbonate reservoirs are found abundantly in Gulf and Russia with recent discoveries in Brazil, Egypt, Kazakistan, and Libya (Joshi and Singh 2020a). Carbonate reserves are formed by the deposition of calcareous minerals and compounds. The compositional, morphological, and petrographic properties of petroleum reservoirs are widely studied by using different analytical techniques such as X-ray diffraction (XRD), X-ray photoelectron spectroscopy (XPS), field emission scanning electron microscope and electron dispersive X-ray spectroscopy (FE-SEM/EDX), Brauner–Emmet–Teller (BET), computed tomography (CT) scan, Fourier-transform infrared spectroscopy (FTIR), vibrating sample magnetometer (VSM), porosimeter, and permeameter (Al-Jaroudi et al. 2007; Ehrenberg and Nadeau 2005; McCarthy et al. 2011; Phukan et al. 2019a; Qiao et al. 2020; Saha et al. 2017).

The composition of a reservoir rock is studied by identifying the minerals present in the sample by using XRD and FE-SEM/EDX. These instruments provide a quantitative analysis of the minerals present in the reservoir rock sample. The XRD analysis also shows the crystallinity index of the rock sample. Identification of the mineral composition of reservoir rock demonstrates the charge (cationic or anionic) present in the reservoir rock. The information about the charge of the reservoir rock along with the ionic behavior of oil present in the reservoir helps in the identification and selection of surfactants to be used for enhanced oil recovery (EOR) in the particular reservoir. Sandstone or silica reserves are negatively charged, whereas carbonate rocks are positively charged with some carbonate reserves showing a neutral charge. FTIR analysis is performed to recognize various functional groups present in the reservoir rock. Along with the minerals, the presence of certain elements in the reservoir rock may affect the charge of the reservoir rock as well as the interactions of chemicals (surfactant) with the reservoir rock during the EOR process. XPS analysis can identify different elements and their chemical and overall electronic structures. FE-SEM, CT scan, and BET analyses help in the identification of surface morphology of the reservoir rock and pore structure, fracture size, and pore volume. SEM analysis is extensively used to provide qualitative information about the pore geometry of rocks by both direct and indirect methods (Phukan et al. 2019a; Saha et al. 2017, 2019). The porosity of the reservoir rock can be identified using a mercury or helium porosimeter, and the permeability is measured by using a permeameter (steady-state or transient state). The magnetic properties of a reservoir rock (ferromagnetic or paramagnetic) can be identified using VSM analysis. The effect of magnetic properties of the reservoir is generally observed during well logging.

3.2 Characterization of Pore Distribution

Sedimentary rocks are formed by continuous weathering activities such as erosion, transportation, and deposition. The surface morphology and the compositions of the sedimentary rocks depend on the mineralogy of the parent rock and the effect of chemical and physical alterations on the weathered rocks of different grain sizes and shapes during deposition and transportation. This leads to the formation of pore networks in the reservoir rocks. The distribution of oil and gas in a petroleum reservoir depends primarily on the porosity and permeability of the reservoir rock.

Porosity is a measure of the void or empty space in reservoir rocks (ratio of pore volume to bulk volume). Porosity is generally expressed as (i) total porosity—the void space present inside the reservoir irrespective of the voids being interlinked or isolated and (ii) effective porosity—the total void of the interconnected pore network. Total porosity is further classified into primary porosity, secondary porosity, and fracture porosity (Ganat 2020). The porosity (Ø) of a reservoir rock is governed by the pore volume (V_P) and the bulk volume (V_B). Mathematically porosity can be expressed as

$$\phi = \frac{V_B - V_G}{V_B} = \frac{V_P}{V_B} \tag{1}$$

where V_G is the grain volume of the reservoir rock.

Porosity can be measured by (i) core analysis, which is a direct method in which a core sample of the reservoir rock is taken and the pore distribution is studied by using a porosimeter, and (ii) well logging, which measures the porosity as a function of the electrical properties of the rock and termed as indirect method (Hu and Huang 2017). Sandstone reserves generally exhibit porosity in the range of 10–40%, and carbonate reservoirs possess porosity in the range of 5–25% (Morton-Thompson and Woods 1993).

Permeability is defined as the ability of a fluid to flow in the pores of a reservoir rock. Permeability is classified as (i) absolute permeability—measures of the permeability of a single fluid through a pore network and (ii) effective permeability—the ability of a reservoir rock to favor the flow or of a particular fluid through the rock in the presence of different immiscible fluids which are accumulated in the reservoir rock (Fanchi 2010). Permeability (unit is Darcy (D) or millidarcy (mD) is measured by using Darcy law (Eq. 2)

$$Q = \frac{KA(P_i - P_o)}{\mu L} \tag{2}$$

where K is the effective permeability, P_o is the outlet fluid pressure, P_i is the inlet fluid pressure, Q is the flow rate, μ is the fluid viscosity, L is the tube length, and A is the cross-sectional area.

The permeability of petroleum reservoirs ranges from 0.1 to more than 1000 mD. A petroleum reservoir is graded to be poor, fair, moderate, good, and very good for permeability values (mD) of $k < 1$, $1 < k < 10$, $10 < k < 50$, $50 < k < 250$, and $k > 250$, respectively. The permeability of a petroleum reservoir is affected by geological factors such as, the shape and size of sand grains, lamination, cementing, fracturing, and solutions (Tiab and Donaldson 2016).

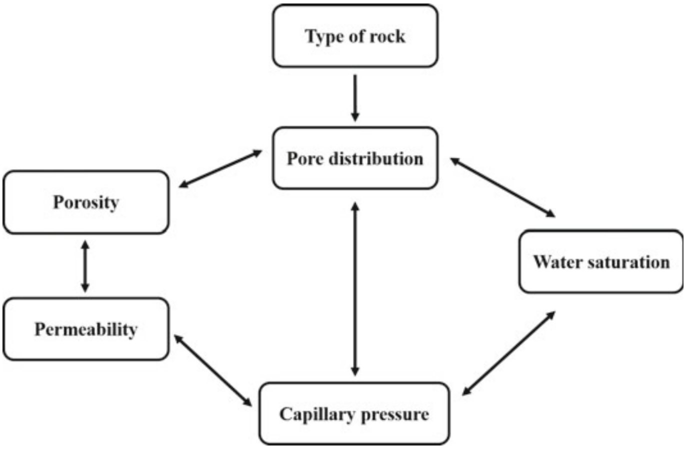

Fig. 2 Relation between basic rock pore properties [data extracted from Archie (1950)]

The correlations between porosity and permeability have been extensively studied in reservoir characterization and petroleum geology. Permeability of void space is always expressed as a function of porosity; however, different factors such as grain size, packing, and compaction of grain particles affect the relationship between porosity and permeability. Though the porosity of a rock is not influenced by the grain size, the permeability of a rock is inversely proportional to the particle size (Nelson 1994; Tiab and Donaldson 2016). Porosity and permeability generally decrease with an increase in depth (Bloch et al. 2002). Ehrenberg and Nadeau (Ehrenberg and Nadeau 2005) reported a comprehensive study on porosity and permeability of sandstone and carbonate reservoir distribution around the world. With an increase in depth of dolomite or limestone (calcite) reservoirs, the porosity appeared to be much less for limestone reservoirs as compared to dolomite reserves. The permeability has been recorded to be the same for both the reservoirs. In sandstone reservoirs, the porosity and permeability were found to increase dramatically after a depth of 4 km (Ehrenberg and Nadeau 2005). The rock properties such as capillary pressure and water saturation are directly reliant on the pore distribution of a reservoir rock (Fig. 2) and are directly influenced by the inherent porosity and permeability present in the reservoir rock (Archie 1950).

3.3 Reservoir Fluid Properties

The hydrocarbons present in the reservoir are classified based on their compositions, API gravity, formation volume factor, liquid and gas specific density, solution gas–oil ratio, bubble point, saturation and dew point pressure, and critical point. Crude oils are graded based on their physicochemical properties such as specific gravity (sg), sulfur content, and viscosity. Natural gas is classified into two types, viz., wet gas, and dry gas based on the solution gas-oil ratio (GOR). The market value of crude oil is governed by its API gravity and compositions, especially sulfur content. Based on API gravity crude oil is classified as light component oil (API > 31.1°, sg < 870 kg/m^3), medium quality oil (22.3° < API < 31.1°, sg 870–920 kg/m^3), heavy crude oil (10° < API < 22.3°, sg 920–1000 kg/m^3), and the extra-heavy crude (black) oil (API < 10°, sg > 1000 kg/m^3). The average composition of crude oil is 79.5–87.1% carbon (C), 11.5–14.8% hydrogen (H), 0.1–3.5% sulfur (S), and 0.1–0.5% nitrogen (N) and oxygen (O) (Demirbas et al. 2015; Sharma and Pandey 2020; Sharma et al. 2019).

The hydrocarbon mixtures or reservoir fluids after production are analyzed using different laboratory techniques. The analytical techniques are (i) *primary testing*—specific gravity, viscosity, and GOR, (ii) *routine or secondary testing*—compositional analysis of the samples, expansion test, differential analysis test, fluid separation test, and depletion test, and (iii) *specialized laboratory tests*—slim tube test for MMP measurement and fluid swelling test. The detailed explanation of the testing methods has been discussed extensively by Ahmed and coworkers (Ahmed 2019).

4 Classification of Petroleum Reservoir

Hydrocarbon reservoirs are classified as (i) *oil reservoir*—reservoir temperature is lower than critical temperature of the hydrocarbon mixture and (ii) *gas reservoir*—reservoir temperature is greater than the critical temperature of the hydrocarbon mixture. Oil reservoirs contain high molecular weight hydrocarbons or crude oil with small fractions of natural gas saturated in the oil. Gas reservoirs contain a high concentration of natural gas with a small percentage of lower molecular weight oil. The oil and gas reservoirs are further classified into several sub-divisions based on the following four criteria: (i) Composition of hydrocarbon mixture, (ii) types of the reservoir drive mechanism, (iii) prevailing pressure and temperature of the reservoir, and (iv) pressure and temperature at surface facilities (eg. separator). The phase diagrams for different types of reservoir fluids are presented in Fig. 3.

Based on composition, fluid properties, and pressure–temperature relation, oil reservoirs are classified into four categories (Fig. 3).

Black oil reservoirs contain a high concentration of higher molecular weight hydrocarbons, with a very small percentage of intermediate and lower molecular weight fractions. Black oil reservoirs have an initial GOR between 200 and 700 scf/STB, and a gravity of 15–40°API. Black oil reservoirs are classified into (i) *under saturated*—single-phase liquid system with reservoir temperature below the critical temperature, and (ii) *saturated*—entirely saturated by natural gas, and the reservoir temperature and pressure are in the two-phase region.

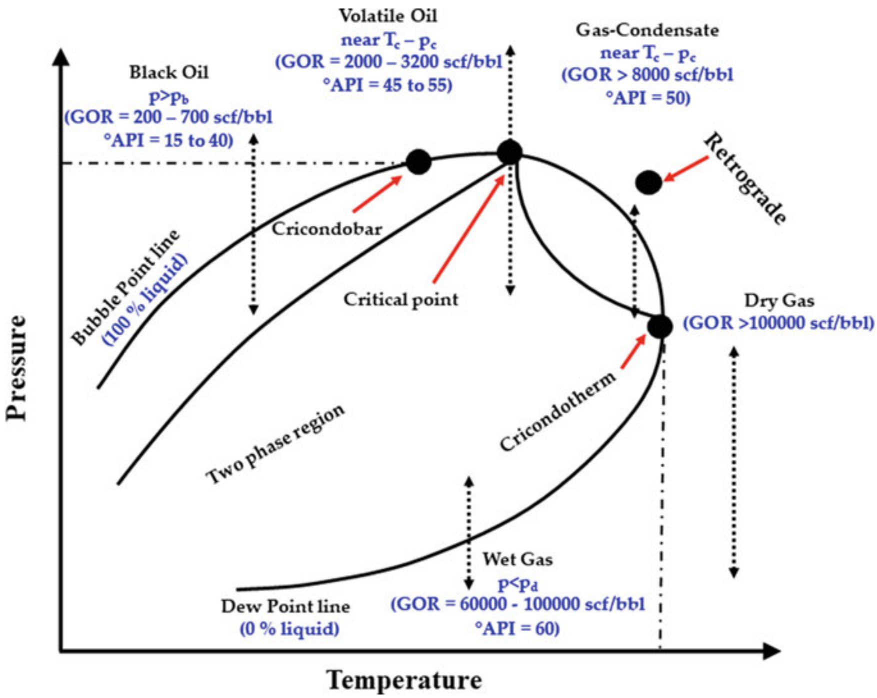

Fig. 3 Phase diagram of different types of petroleum reservoirs. The phase changes with pressure during the isothermal process are shown with broken line-arrow for different fluids

Low shrinkage oil reservoirs are composed of intermediate to higher molecular weight hydrocarbons with formation volume factor (Bo) < 1.2 bbl/STB (Stock tank barrel), GOR < 200 scf/STB, and gravity of <35°API.

Near critical crude oil reservoir approaches the critical temperature of the hydrocarbon mixture with GOR > 3000 scf/bbl and oil formation volume factor of 2 bbl/STB, and contains a lower concentration of methane and a high concentration of ethane through hexane.

Volatile oil reservoirs contain a high percentage of lower and intermediate molecular weight hydrocarbons with GOR in the range of 2000–3200 scf/bbl, formation volume factor of 2 bbl/STB, and gravity of 45–55° API. Volatile oil or high shrinkage oil reservoirs are found at higher depths with a high reservoir pressure and the reservoir temperature is lower than the critical temperature. The oil converts to gases as reservoir temperature approaches the critical point and produces high gas and low liquid yields.

Gas reservoirs are also classified into four categories based on the temperature and pressure of the formation and the surface facilities (Fig. 3).

Dry gas reservoirs: Hydrocarbon mixtures are composed of methane and light hydrocarbon gases and remain in the gas phase both in the reservoir and at the surface. The gases do not undergo a phase change, and no liquid formation occurs as pressure decreases during production. Dry gas reservoirs generally possess GOR greater than 100000 scf/STB.

Wet gas reservoirs: Hydrocarbon mixtures inside the reservoir are in the vapor phase and remain in the same phase during the production when the pressure depleted isothermally. The gas enters a two-phase region during the production (the temperature and pressure decreases) and liquid begins to form (condensation on the surface/separator) with GOR between 60000 and 100000 scf/STB gravity of 60° AP.

Retrograde gas condensate reservoirs: Reservoir temperature appears to be between the critical temperature and the cricondotherm temperature of the hydrocarbon system, and the fluid production is controlled by the thermodynamics. The GOR lies between 8000 and 70000 scf/STB with condensate API gravity of 50° API.

Near critical gas condensate reservoirs: Reservoir temperature occurs in the vicinity of near critical temperature. The GOR and API gravity are similar to retrograde gas condensate reservoirs.

5 Reservoir Drive Mechanisms

Recovery of the oil depends on the drive mechanism active in the reservoir. To optimize maximum recovery from a reservoir, the type of drive present should be identified (Clark 1960). The primary recovery technique utilizes natural energy (drives) existing in the reservoir to produce the crude oil to the surface. Figure 4 shows different drive mechanisms (combined) that contribute toward the production in a typical petroleum reservoir. The primary recovery consists of six driving mechanisms which are characterized primarily in terms of reservoir pressure, GOR, and water-cut (Fig. 5).

Rock and Liquid Expansion Drive: With the production of reservoir fluids, the reservoir pressure diminishes. The liquids and the rock expand due to their compressibility (Ahmed 2006). The expansion of the grain particles in the rock and the compaction of the formation decrease the pore volume and push the liquid out of the pores to the production well. The efficiency of this type of recovery is the least and helps to recover only a small amount of the fluid from the reservoir with a constant value of GOR.

Depletion Drive: The natural gas dissolved in the crude oil provides the energy for the production, hence also known as solution gas drive. The reservoir pressure reaches the bubble point pressure and the natural gas dissolved in oil evolves as bubbles. These bubbles expand as the fluid pressure drops further (Ahmed 2006). The reservoir pressure is maintained as long as these bubbles keep expanding to

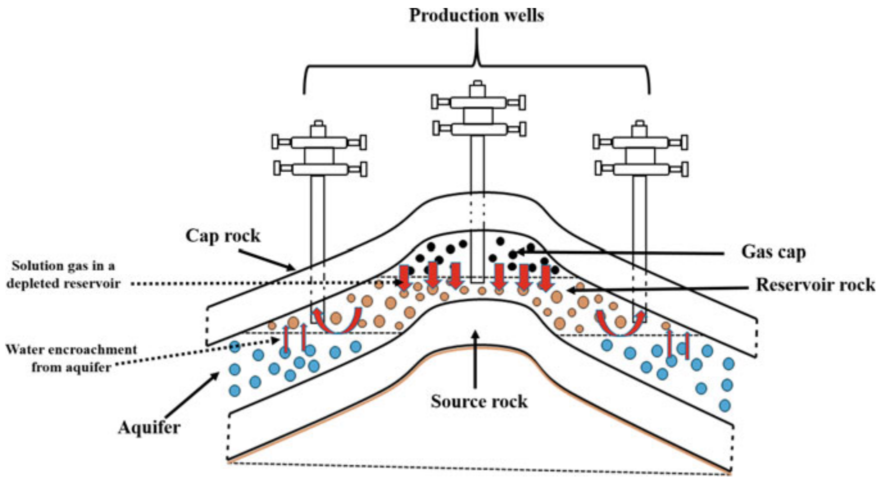

Fig. 4 Different drive mechanisms in a typical petroleum reservoir

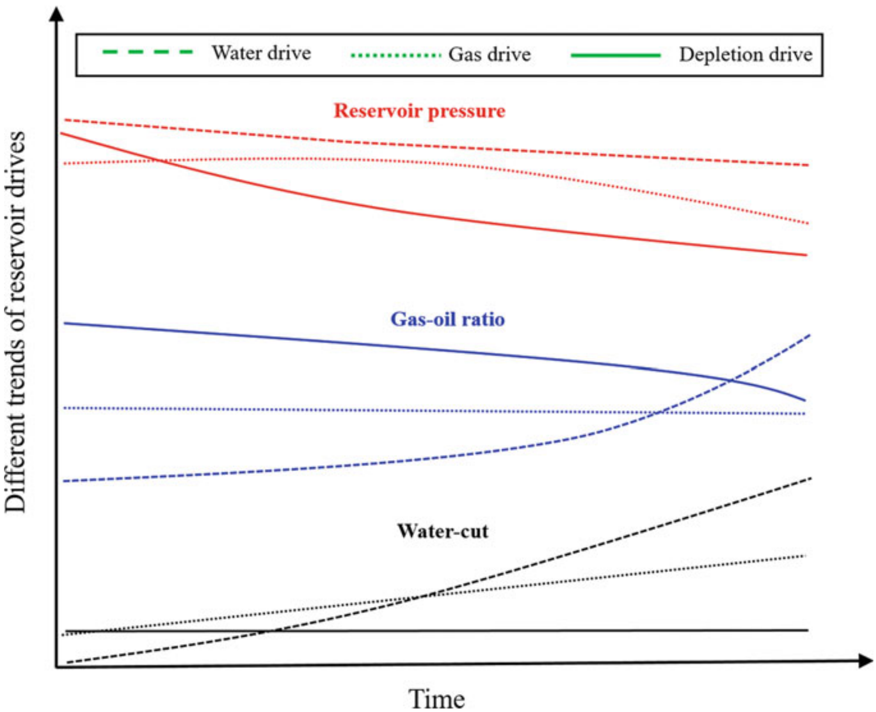

Fig. 5 History of different reservoir drive mechanisms over time

aid in production. The value of GOR increases with production and the reservoir pressure needs to be maintained higher than that of the critical gas saturation (Selley and Sonnenberg 2015a).

Gas cap Drive: As oil is produced from the oil zone, the gas cap expands and maintains the pressure of the reservoir. The gas pushes the oil to the production well (Pope and Nelson 1978). A gas cap is present in the reservoir below the bubble point pressure and it produces very little or no water (Ahmed 2006).

Water Drive: The natural source of energy in this drive is water. The water influx from an aquifer maintains the pressure of the reservoir by occupying the pore spaces created due to oil production. Water drives are used to produce about one-third of the world's reservoirs. Oil production holds steady initially because the pressure is maintained by the water encroached into the oil zone (Selley and Sonnenberg 2015a). The producing GOR is always constant (Glover 2000).

Gravity Drainage Drive: Gravity acts as the drive mechanism for the production of hydrocarbons. It is the natural tendency of oil, gas, water to segregate during production due to their density differences (Alamooti and Malekabadi 2018). This segregation does not directly result in expelling fluid from the reservoir toward the production well. The oil settles to the bottom and the gas migrates to the top portion of the reservoir. An important prerequisite for efficient recovery from gravity drainage is the oil viscosity. Fluid displacement increases as the viscosity of oil decreases. Hence, the recovery rate increases as the viscosity of crude oil decreases (Druetta and Picchioni 2020).

Combination Drive: This type of drive mechanism is usually an association between a gas cap and an active aquifer. The energy available in water and free gas aids in displacing the oil from the reservoirs (Ahmed 2006). The recovery of this drive is also dependent on several factors such as the size of the gas cap, capacity of the aquifer, and the position of the wells (Glover 2000). An oil rim reservoir is another example of a combined drive mechanism in which the accumulation of a small to medium column of oil is in communication with a large gas cap over it and an active aquifer (Lawal et al. 2020).

6 Material Balance Equation (MBE)

The material balance equation has been the most reliable interpretation and prediction method for reservoir engineers to define the initial oil-in-place based on production from the reservoir and static reservoir conditions. Mathematically, the balanced equation depicts the performance of the reservoir (Tank model) by relating liquid and rock expansion to liquid withdrawal and facilitates to (i) estimate the original fluids in place, (ii) determine the producing mechanism, and (iii) predict the prospect reservoir performance (Ahmed 2006).

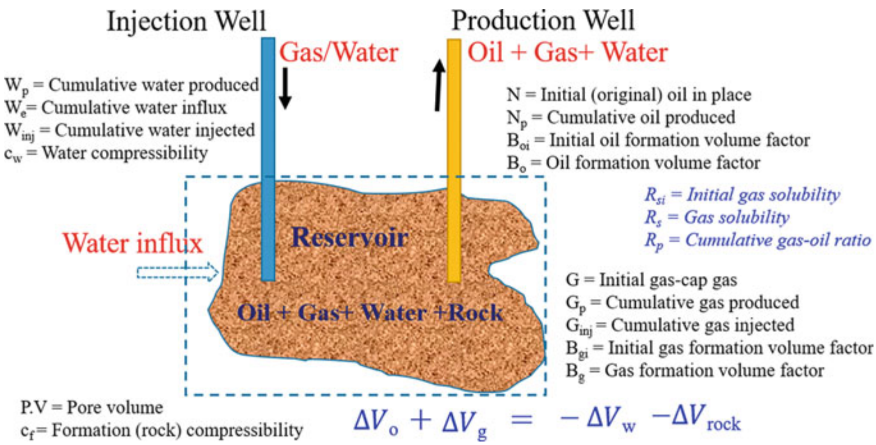

Fig. 6 A schematic of a tank model for material balance

The MBE is a volumetric balance of the reservoir (tank) with the assumption that the reservoir is at constant values of volume and temperature and equilibrium pressure (Fig. 6). The general form of MBE accounts for four phenomena: (i) the reservoir fluid volume withdrawn (cumulative oil and gas production): $N_p\left[B_o + \left(R_p - R_s\right)B_g\right]$, (ii) the net water influx that remains inside the reservoir: $W_e - W_p B_w$, (iii) the net expansion of gas cap that occurs with the production N_p: $mB_{oi}\left(B_g/B_{gi} - 1\right)$, and (iv) the compressible nature of fluids.

The material balance equation considering the external gas injection in the reservoir can be arranged as (Havlena and Odeh 1963)

$$F = N\left[E_O + mE_g + E_{f,w}\right] + \left[W_e + W_{inj}B_w + G_{inj}B_{ginj}\right] \tag{3}$$

where

$F =$ Total fluid (oil, gas, and water) withdrawal, $N_p\left[B_o + \left(R_p - R_s\right)B_g\right] + W_p B_w$
$E_o =$ Expansion of oil and its originally dissolved gas $(B_o - B_{oi}) + (R_{si} - R_s)B_g$
$E_g =$ Expansion of the gas cap, $B_{oi}\left[\left(B_g/B_{gi} - 1\right)\right]$
$E_{f,w} =$ Expansion of connate water and rock, $B_{oi}\left[\frac{C_w S_{wc} + C_f}{1 - S_{wc}}\right]\Delta p$
$m =$ Ratio of initial gas-cap-gas reservoir volume to initial reservoir oil volume
$R_{si} =$ Initial gas solubility
$R_s =$ Gas solubility
$R_p =$ Cumulative gas–oil ratio
$N =$ Initial (original) oil in place
$N_p =$ Cumulative oil produced
$B_{oi} =$ Initial oil formation volume factor
$B_o =$ Oil formation volume factor
$W_p =$ Cumulative water produced
$W_e =$ Cumulative water influx

W_{inj} = Cumulative water injected
G_p = Cumulative gas produced
G_{inj} = Cumulative gas injected
B_{gi} = Initial gas formation volume factor
B_g = Gas formation volume factor
c_f = Formation (rock) compressibility
c_w = Water compressibility.

The three important aspects of the developed MBE are: (i) The value of OOIP, N, (ii) the water encroached, W_e, and (iii) the volume of the gas and the oil, m, can be determined considering the special cases exist in the reservoir domain. For a reservoir with no initial gas cap ($m = 0$) and no water influx ($W_e = 0$), the MBE reduces to

$$F = NE_O \quad \text{where} \quad F = N\left[E_o + mE_g + E_{f,w}\right] + W_e \tag{4}$$

Here, a plot of F versus E_o yields a straight line passing through the origin with N as the slope.

The MBE can be simplified for different cases present in a reservoir production system and the important aspects can be evaluated by obtaining an equation of a straight line. Plots for total withdrawal versus total expansion are shown in Fig. 7 for different cases.

Case 1: Volumetric and Undersaturated Reservoir: For a reservoir with no gas injection or water influx, the linear form of MBE can be expressed as

$$F = N\left[E_o + E_{f,w}\right] \tag{5}$$

$$N = \frac{F}{E_o + E_{f,w}} \tag{6}$$

A plot of F versus $E_o + E_{f,w}$ gives a straight line passing through the origin with N as the slope. The deviation for the linearity represents the presence of a water drive reservoir.

Case 2: Volumetric saturated oil reservoir (without water influx): The MBE equation simply reduces to $F = NE_o$.

Case 3: Gas cap drive reservoir: When the reservoir has only a gas cap drive mechanism for the oil production and the size of the gas cap is known, the MBE equation takes the following form:

$$F = N\left[E_o + mE_g\right] \tag{7}$$

The F versus $E_o + mE_g$ relationship gives a straight line that passes through the origin. For a case when the gas cap is not known, the plot of $\frac{F}{E_o}$ versus $\frac{E_g}{E_o}$ gives N as intercept.

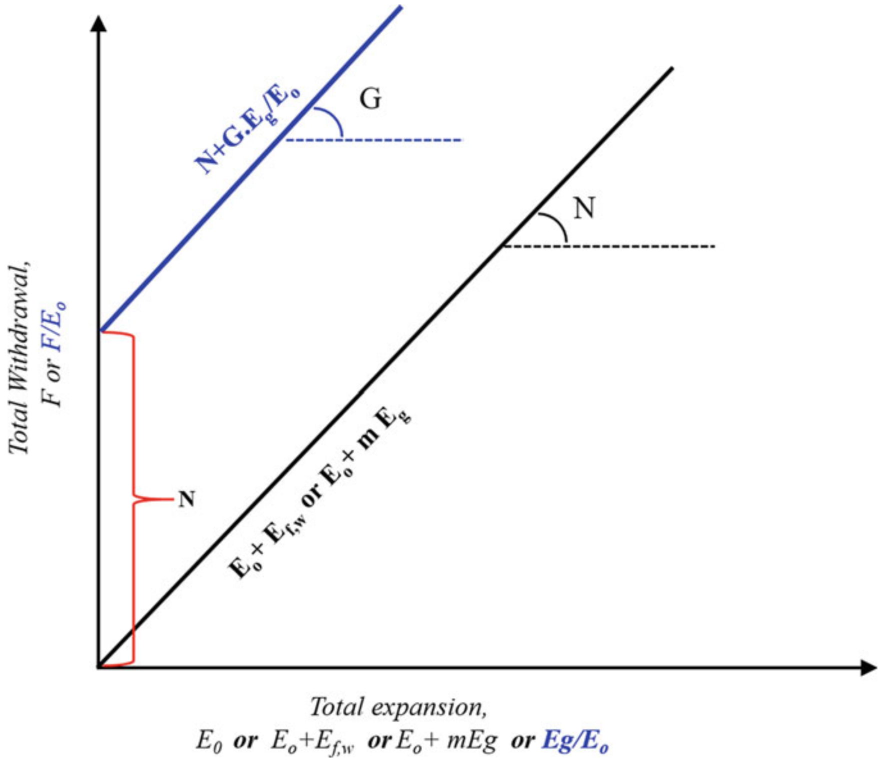

Fig. 7 Havlena and Odeh plots for total withdrawal versus total expansion for different drives

7 Reservoir Drive Performance Indexes (RDPI)

During the formation of oil and gas reservoirs, the volume of the reservoir reduces. This can be attributed to the compaction of the formation and invasion of water into the reservoir due to the pressure drop while producing from the reservoir. Both porosity and water influx into the reservoir are known to compensate for the decrease in pressure. Corresponding to the productivity of the aquifer, the reservoir pressure becomes high and reservoir pressure drops significantly when the productivity of the aquifer is low. Therefore, the ratio of decrease in volume of the reservoir to drop in pressure can evaluate the efficiency of the aquifer and thus can determine the reservoir drive mechanism. To study the changes in the relationship between a decrease in the pore volume of the reservoir and reservoir pressure in different drive mechanisms and to propose a different technique for characterizing the drive mechanism, Jamalbayov and Veliyev (Jamalbayov and Veliyev 2017) proposed a hypothetical gas condensate reservoir model as

$$\phi = \phi_0 e^{c_m (p - p_0)} \tag{8}$$

Table 1 Relation between RDPI and drive mechanisms (Jamalbayov and Veliyev 2017)

$\overline{\Omega_m}$	$\overline{\Omega_p}$	Reservoir drive mechanism
>1	1	Gas drive
>1	<1	Water expansion drive
<1	<1	Strong-water drive

$$\overline{\Omega_p} = \frac{\overline{\Omega}}{\overline{p}} = \text{pore volume at current reservoir pressure} \tag{9}$$

$$\overline{\Omega_m} = \frac{\overline{\Omega}}{\overline{\varphi}} = \text{pore volume after compaction} \tag{10}$$

$$\overline{\phi_p} = \frac{\phi(p)}{\phi_0}, \text{ the ratio of current formation porosity to its initial porosity} \tag{11}$$

$$\overline{p} = p/p_0 \text{ refers to the ratio of current reservoir pressure to original reservoir pressure} \tag{12}$$

where
p_o = initial reservoir pressure
ϕ_0 = initial reservoir porosity
p = reservoir pressure
ϕ = reservoir porosity
c_m = formation compaction factor

There is a relation between the parameters $\overline{\Omega_p}$, $\overline{\Omega_m}$ and the actual reservoir drive. It is reported that under the influence of water drive and gas drives, $\overline{\Omega_p}$ is always greater than unity, whereas in strong-water drive it is less than unity. $\overline{\Omega_m}$ is equal to unity in the gas drive, while it is always less than unity in water drive reservoirs. It is understood that when there is no water influx into the reservoir, the pore volume reduction occurs due to the overburden pressure and is always equal to $\overline{\phi}$.

The parameters $\overline{\Omega_m}$ $(\overline{p})$ and $\overline{\Omega_p}$ $(\overline{p})$ are the indicators of the aquifer activity. So, the drive mechanism can be identified and the productivity of the aquifer is evaluated. These two parameters $\overline{\Omega_m}$ $(\overline{p})$ and $\overline{\Omega_p}$ $(\overline{p})$ are identified as Reservoir Drive Performance Indexes (RDPI) (Jamalbayov and Veliyev 2017). The relation between RDPI and drive mechanisms is summarized in Table 1.

8 Conclusion

Physicochemical study of a petroleum reservoir rock and fluid is performed to investigate the petrographic origin, rock morphology, pore network and distribution, the type of hydrocarbon present in the reservoir, the reservoir fluid properties, and flow characterization. The analysis of reservoir mineralogy helps in identifying the origin of the reservoir, and its porosity and permeability values. The study of the pressure–temperature profiles and drive mechanisms of a petroleum reservoir helps in identifying the type of hydrocarbon present in the reservoir and its flow characteristics, and in the estimation of the total recoverable hydrocarbons from a reservoir. The combination of the natural forces that act on the hydrocarbons present in the reservoir enables the primary production at the surface. The knowledge of the drive mechanisms further opens the pathway into the adoption of different advanced recovery techniques for the efficient production of hydrocarbons from petroleum reservoirs.

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