Chapter

Production from Unconventional Petroleum Reservoirs: Précis of Stimulation Techniques and Fluid Systems

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Abstract

An overview of the different categories of unconventional oil and gas reservoirs, and corresponding stimulation techniques appropriate for them is examined. Three main groups of unconventional oil and gas formations are appraised: heavy oil, oil shale and tight reservoirs. The scope of stimulation methods applicable to heavy oil reservoirs is limited. This kind of formation contains characteristic high-viscous hydrocarbons and are produced majorly by cold production and thermal stimulation. On the other hand, a wider range of stimulation methods are successfully used to produce tight and oil shales formations. For oil shales, these include drilling horizontal wells as substitutes to vertical wells, hydraulic fracturing, surfactant treatment, water imbibition, thermal treatment and acidisation; whilst for tight formations, these include hydraulic fracturing, surfactant treatment, water imbibition, acidisation and the application of electro-kinetics. Fracturing fluid systems are integral to the implementation of most stimulation operations and are evaluated herein under the following groups: water-based, oil-based, foam-based and acid-based. The most commonly used fracturing fluids are water based, albeit there are several instances where other types of fluids or combination of fluids are more suitable based on factors such as formation sensitivity, costs, wettability, rock solubility, surface tension, capillarity, viscosity, density, rheology and reactivity.

Keywords: unconventional reservoirs, reservoir stimulation, hydraulic fracturing, acidisation, surfactant, fracturing fluids, horizontal wells

1. Introduction

Unconventional hydrocarbon reservoirs are different from their conventional counterparts in the sense that they require distinctive operations for recovery that differ from normal practices deployed for conventional reservoirs. The main reason for this is the ultra-low permeability of the rock formation, which hinders the ease of flow of hydrocarbons towards the well, but other factors such as the reservoir fluid properties also impact flow mechanisms. Examples of unconventional reservoirs are gas hydrates, oil shales, gas shales, tight-gas sandstones, tight-gas limestones, heavy oil and tar sandstones, and coalbed methane reservoirs [1–7].

As the term implies, heavy oil and tar reservoirs are those that contain viscous and dense oils. About a third of the total world oil and gas reserves consist of the heaviest range of hydrocarbons, yet they are mostly overlooked due to the perceived high costs and difficulties associated with its production [5]. Although reservoir properties including pressure, permeability and porosity are important measures of its behaviour, the fluid density and viscosity determine the approach used for production [5]. Heavy oils and tars are generally high in density and viscosity. Density is a measure of how much mass is contained per unit volume. The standard unit of measurement adopted in the oil and gas industry, especially in the United States, is the degree of American Petroleum Institute (API) gravity. A lower API value indicates a higher density and vice versa. Normally, oils below 20° API gravity are defined as heavy which may be as low as 4° for bitumen with high tar content [3, 5]. Oil viscosity, on the other hand, defines its resistance to gradual shear or tensile deformation when subjected to shear or tensile stress respectively. A viscous fluid exhibits resistance to shear stress and, thus, its flow is reduced where shear stresses are applied. Oil viscosity has an inverse relationship with temperature; it varies greatly by becoming less viscous as temperature increases. The flow rate of reservoir fluids is a key parameter and because of the direct link between viscosity, temperature and the ease of flow, oil viscosity is considered to be more important than oil density during production [3, 5]. Thus, viscosity, rather than density is used as a measure of the heaviness of oil. Under reservoir conditions, heavy oils have viscosities >100 cp [3]. Apparently, there is no direct correlation between density and viscosity, largely due to the influence of temperature. Low-density oils in shallow reservoirs, where the temperatures are cooler, may have higher viscosities in comparison to oils at hotter deep reservoirs.

Oil shale is a fine-grained sedimentary rock richly composed of organic matter [8], in the form of kerogen [2]. Kerogen is a solid mixture of organic compounds and is the primary source of hydrocarbons from oil shale. This type of hydrocarbon is referred to as shale oil, which is unconventional and different from tight oil naturally present in shales and ultra-low permeability sandstones, carbonates and siltstones [9]. Kerogen, also known in some instances as total or bitumen-free organic matter, consist of more than 80% organic matter; however, a major proportion of this is not readily soluble in ordinary organic solvents under moderate conditions [2]. Therefore, it is more challenging to extract in comparison to crude oil from conventional reservoirs because of high costs and negative environmental impacts [10]. To remove shale oil from oil shales, it is imperative to decompose the insoluble organic matter with heat. This is achieved by thermal dissolution, hydrogenation or pyrolysis [11–13]. The three methods require very high temperatures.

Tight oil is light crude oil found in shales and very low permeability and low porosity sandstones, carbonates and siltstones [9]. Although the term is sometimes used interchangeably with shale oil normally contained in oil shales (e.g., [9, 14]), there are distinctions. As at 2015 the world's technically recoverable tight oil from shale formations was estimated at 418.9 billion barrels (bbl). A large proportion of this amount is located at United States (78 bbl), Russia (75 bbl), China (32 bbl), Argentina (27 bbl), Libya (26 bbl), United Arab Emirates (23 bbl), Chad (16 bbl), Venezuela (13 bbl) and Mexico (13 bbl) [15]. Typical porosity and permeability of tight oil formations are below 12% and 0.1 mD respectively, though a broader definition of tight oil reservoirs can generally refer to those with very low porosity and permeability [9]. The low- porosity and permeability characteristics furthers the need to stimulate tight oil reservoirs for successful production.

Worldwide, the commercial production of unconventional hydrocarbons is in constant increase. This supplements supply from conventional reservoirs resulting in an overall increase in hydrocarbon production globally and a decrease in prices [16].

This inverse relationship between oil production and oil prices is illustrated in Monge *et al*. [14], where an increase in U. S. oil production from the shale oil boom drives down *West Texas Intermediate* (WTI) oil prices.

Other forms of unconventional gas resource are gas hydrates and coalbed methane reservoirs. Gas hydrates are crystalline ice-like forms of water with a structured molecular framework joined together to create cavities such that gas molecules, which are mostly methane, are trapped within it [17]. Other entrapped guest gases include ethane, isobutene and propane [18]. Natural gas hydrates were only discovered a few decades ago and 98% of deposits occur in upper sedimentary layers underneath the seafloor [7]. It is extensively spread in oceans and polar areas with a reserve that is 10 times greater than global conventional gas [18]. The creation and stability of gas hydrates rely on the properties of both the water and composition of gas, temperature and pressure [18, 19]. The formation of gas hydrate is exothermic, which implies the release of heat during this stage. On the other hand, heat is required for dissociation of hydrates [18–20]. The dissociation of hydrates is an endothermic process relying on the surrounding heat. Gas hydrates are stable at high pressure and low temperature conditions; therefore, depressurisation is an effective means of inducing the release of gas from hydrate deposits [20–22].

Coal seams are dark-banded deposits of coal trapped between layers of rock. They differs from conventional gas reservoirs in terms of their pore structure, porosity, permeability, fluid flow mechanism, gas-water relative permeability and other reservoir characteristics [23]. Coal is both heterogeneous and anisotropic; it is characterised by a dual porosity comprising a porous matrix with micro pores enclosed by a larger scale medium of cleats, which constitute the macro pores [23–25]. Coal porosity and permeability is mostly defined by the micro pores and macro pores, respectively [23]. Usually, water permeates coal seams, which helps to retain the adsorbed gas on the coal surface [25]. Coal seams are unconventional reservoirs containing a variety of gases including methane, hydrogen, ethane, nitrogen and carbon dioxide [26]. It contains a significant proportion of methane, which is more easily extracted in comparison to some of the other gas constituents (e.g., hydrogen and nitrogen). This is due to the reduced affinity coal has for methane. The concentration of methane in the gas content can be as high as 99.95% [27]. The chemical composition of coalbed methane—also known as coal seam gas—is the same as natural gas obtained from conventional reservoirs. The gas is contained in three ways: adsorbed on the surface of micro pores; in a free state in macro pores, i.e., the natural fractures (cleats) within the coal material; and dissolved in the formation water [23, 25, 28].

2. Stimulating strategies and techniques.

2.1 Heavy oil reservoirs

As aptly defined by its name, heavy oil formations contain heavy oils typically characterised by high viscosity and density, and capillarity pressure effects [1, 5]. These peculiar properties make it virtually impossible to exploit heavy oil formations without stimulation. Exploitation can be accomplished by cold production and thermal stimulation. Cold production is a primary recovery method performed at the native reservoir temperature and can achieve a recovery factor between 1 and 10% [5, 29]. This may be carried out by injecting a diluent into the reservoir to reduce the viscosity of the hydrocarbon or by encouraging the initiation and continuous sand production throughout the completion process; the latter is known as *cold heavy oil production with sand* (CHOPS) [5, 30]. Sanding produces high permeability channels referred to as 'wormholes' which enhances recovery [30]. For both approaches, artificial lifts are vital because they lower the producing bottomhole pressure (BHP) thereby increasing the flow rate. Artificial lift systems may consists of pumps (e.g., progressing cavity pumps (PCP) and electrical submersible pumps (ESP)) or a gas lift, whereby injected gas is used to reduce the fluid density of the tubing which is then lifted as the gas expands [31].

Thermal stimulation is an alternative method applied where cold production is not effective or economical. The dependency of oil viscosity on temperature is inverse. Which means it is possible to enhance fluid flow by raising the reservoir temperature. There are several ways this can be realised—for instance, cyclic steam injection and steam flooding [5]. Cyclic steam injection involves two main phases: injection of steam followed by the production of heavy oil with the condensed steam. This is carried out alternatingly with a new cycle started when the rate of oil production declines below a critical level [32]. This method is favoured in the following conditions: in reservoirs that can withstand high-pressure steam and in the presence of thick pay zones (> 10 m) containing sands with high porosity (> 30%) [32]. Steam flooding is the injection of steam into the reservoir to raise the temperature of the oil whilst reducing its viscosity [33, 34]. This method aids the distillation of the light constituents of the oil [35], which further decreases the parent oil viscosity. Steam flooding also reduces the interfacial tension between oil and rock surfaces at the vicinity of the wellbore due to the liberation of the immiscible fluid phase (oil) attached to the host solids by the wetting phase (water) [36].

2.2 Oil shales

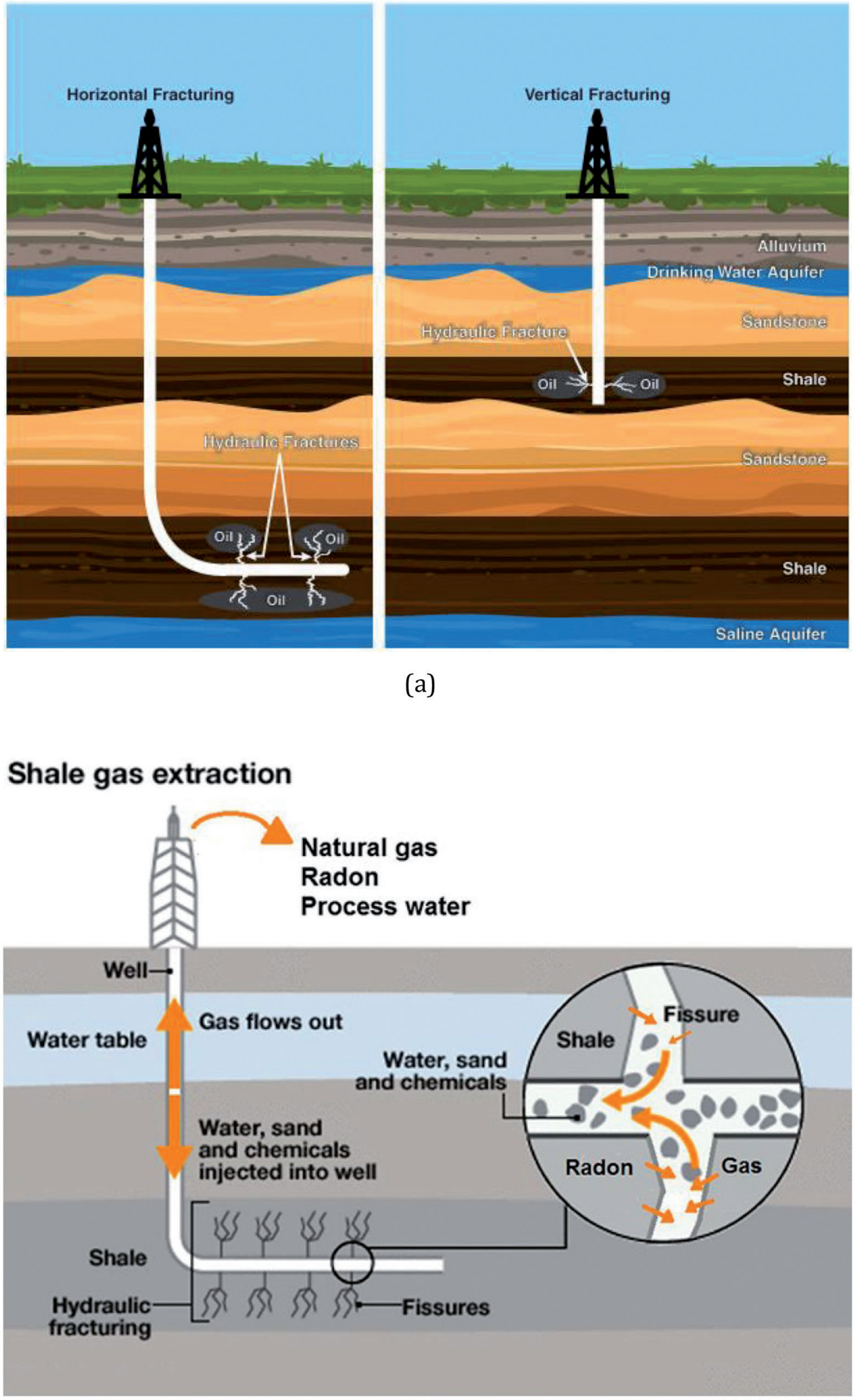
Oil shales have very low permeability and porosity. Recovery from such reservoirs can be achieved by the use of horizontal wells [37], hydraulic fracturing, surfactant treatment, matrix acidisation, water imbibition, thermal treatment or a hybrid of these techniques.

2.2.1 Horizontal wells

Horizontal wells have several advantages over vertical wells and are generally more effective in enhancing reservoir performance (**Figure 1**). These include the following: greater and more efficient reservoir drainage and detainment of water production; reduction in gas and water coning; greater rate of production because of the increased reach of the wellbore in the pay zone, since penetration to discrete compartments is possible in complex reservoirs; and reduction in sand production [40, 41]. However, there is a higher cost associated with horizontal wells, which can be up to 2.5 greater than vertical wells [40]. Hence, it is likely that a cost-benefit assessment will be necessary, especially where the increase in reservoir performance is not expected to be intense [41].

2.2.2 Hydraulic fracturing

Hydraulic fracturing is one of the foremost and traditional ways of enhancing fluid flow in oil shales (**Figure 1**). The process induces the initiation and propagation of cracks through the injection of high-pressure fluids with magnitudes that exceed the rock failure stress [42]. The shape, orientation, size and conductivity of the fractures are functions of the direction and magnitude of the formation principal stresses and rock anisotropy, amongst other factors [42]. The in situ principal stress conditions determine the minimum pressure necessary for crack initiation and propagation. The fracturing fluids influence the pattern and behaviour of created fractures. An increasing number of fracturing fluids with



(a)

(b)

Figure 1.
Hydraulic fracturing of unconventional reservoirs [38] (a) fracture layout for vertical and horizontal wells [39] (b) fissures created by hydraulic fracturing.

different properties are being demonstrated to be appropriate [42–45] with each category of fluid causing dissimilar effects. This is mainly caused by the differing properties of the fluids. Examples of fracturing fluids include water, CO_2 and oil; they can be generally classified as water-based, oil-based, acid-based and foam-based fluids [46–48]. Fluid density and viscosity are, amongst other primary physical properties, considered when selecting a fracturing fluid. Low-viscosity fracturing fluids produce fractures that are expansive with the tendency to split into several branches. CO_2, for instance, is a low-viscosity fluid that is suitable as a fracturing fluid in oil shales because it creates fractures with surface areas that are more extensive in comparison to those created by fluids with higher viscosities—e.g., water [44, 49]. High-viscosity fluids such as viscous oils or liquid CO_2 tend to generate shorter and thicker planar fractures with a small number of branches [44].

Hydraulic fracturing is not usually applied as a stand-alone strategy to improve flow in oil shales. It is often used in tandem with other techniques such as horizontal/inclined wells, thermal dissolution, and the use of special blends of fracturing fluids like surfactants and other chemicals that aid the recovery of shale oils [45, 46].

2.2.3 Transverse vertical fractures along horizontal wells

For horizontal wells, the primary recovery method for reservoir stimulation is hydraulic fracturing, whereby transverse fractures that intersect the well are created (**Figures 2** and **3**). This instigates a substantial pressure drop that intensifies fluid flow towards the wellbore, thus increasing its performance [52]. Hydraulically fractured horizontal wells perform better than their vertical counterparts (**Figure 2c**). Fractures are orientated either longitudinally or transversely to the well (**Figure 2a** and **b**). Longitudinal fractures are aligned in the same direction as the horizontal well; i.e., along the lateral direction parallel to the well (**Figure 2b**). Horizontal wells with longitudinal fractures are better suited for reservoirs with permeability values that are relatively higher and have a comparable performance as fractured vertical wells [52–54]. On the contrary, under the same conditions, transversely fractured horizontal wells perform better in comparison to both fractured vertical wells and longitudinally fractured horizontal wells [52–54]. To maximise productivity, the optimal number of transverse fractures intersecting the horizontal well should be determined; this usually depends on the fluid and reservoir properties [53].

2.2.4 Surfactant treatment

Surfactants are amphiphilic organic compounds and divided into hydrophobic and hydrophilic groups. For enhanced oil recovery (EOR), they normally serve as viscofiers or are used to reduce strong capillary forces in the pores of the reservoir rock [55, 56]. Oil shales are characterised by their ultra-low permeability. Strong capillary forces exist in their pores, which hold the oil to the rock surface. To recover the oil, it is necessary to lessen these capillary forces by altering the interfacial tension, contact angle and wettability [55–57]. Surfactants are used to:

1. Increase the contact angle between the oil liquid-vapour interface and the rock surface.

2. Reduce the interfacial or surface tension between different liquids or phases of materials (i.e., liquid-liquid, liquid-gas and liquid-solid) (**Figures 4** and **5**).

3. Reduce the oil-wet wettability or in a multiphase (oil-water) fluid system, changing it from oil-wet towards water-wet conditions [56, 57] (**Figures 4**–**6**).

Surfactants are also commonly classified as ionic and non-ionic. Ionic surfactants are further categorised as anionic (e.g., Alkyl Aryl Sulfonates, Sodium Dodecyl Sulfate (SDS) and Alpha-Olefin Sulfonate (AOS)) and cationic (e.g., Cetyl Trimethyl Ammonium Bromide (CTAB), Ethoxylated Alkyl Amine and Dodecyl Trimethyl Ammonium bromide (DTAB)) [61]. Non-ionic surfactants are

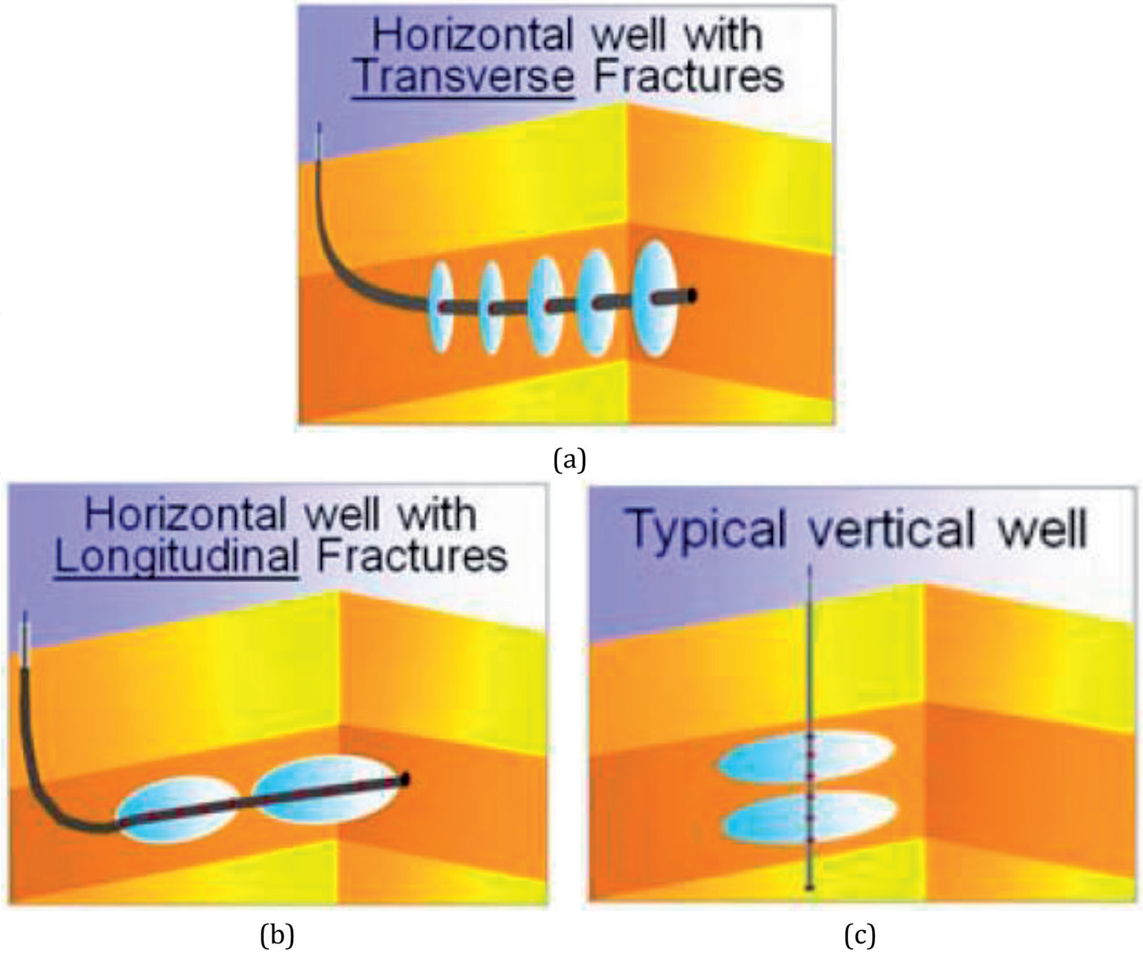


Figure 2.
Configuration of (a) transverse fractures in horizontal well, (b) longitudinal fractures in horizontal well, and (c) fractures in conventional vertical well [50].

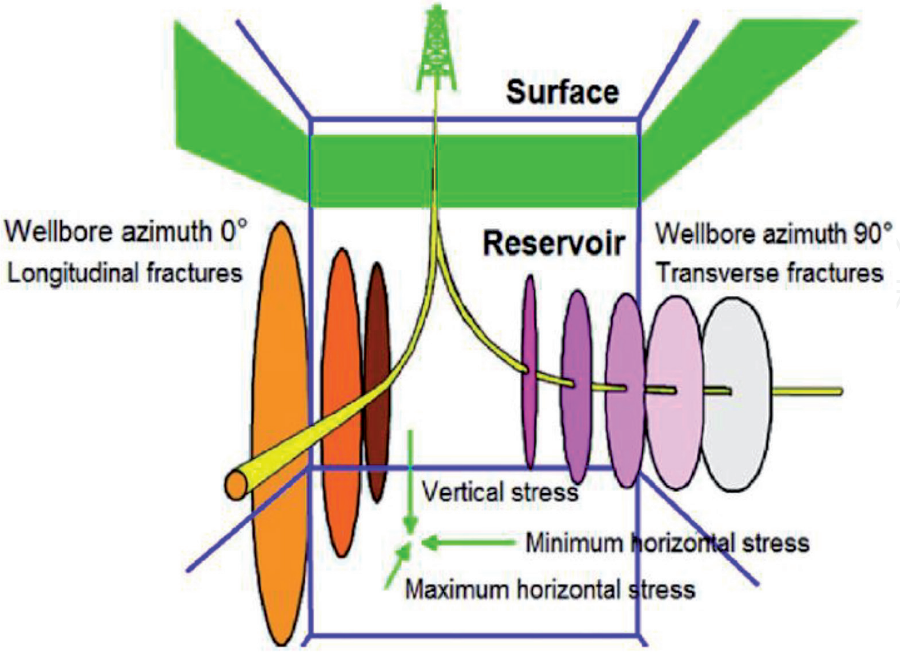


Figure 3.
Relating fracture to horizontal wellbore orientation [51].

not charged; examples of these are Alkyl Polyglycoside (APG), Nonylphenol "N" Ethoxylate and Polyethoxylated Alkyl Phenols) [61]. Other groups of surfactant reported in Negin *et al.* [61] are bio and Zwitterionic surfactants.

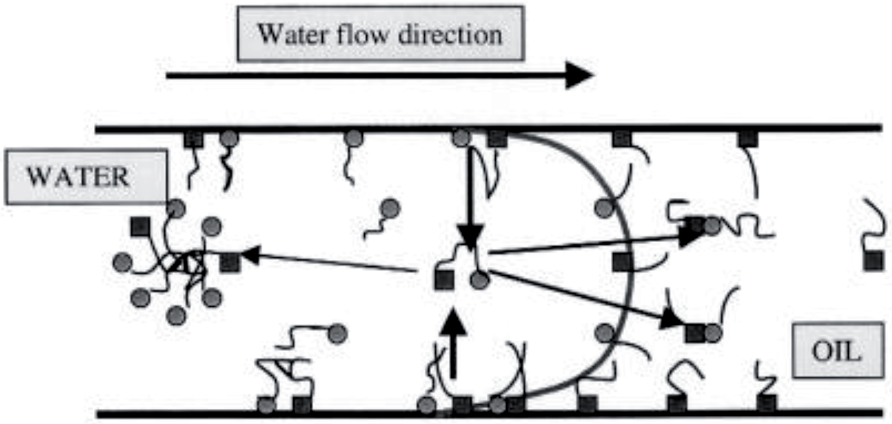


Figure 4.
Mechanism for the alteration of wettability in a pore, from oil-wet to water-wet. Squares are anionic active organic compounds and circles are cationic surfactants [58].

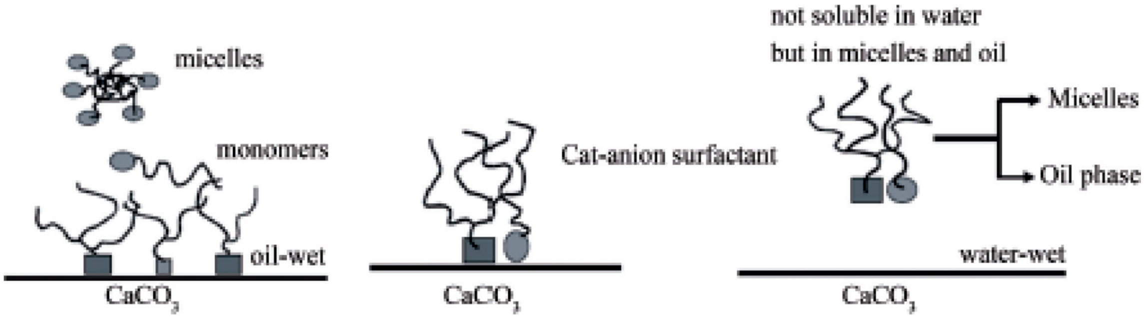


Figure 5.
Mechanism for the alteration of wettability in a rock surface, from oil-wet to water-wet. Circles are cationic surfactants $(R\text{-}N^+ (CH_3)_3)$*, large squares are crude oil carboxylates and small squares are additional polar compounds [59].*

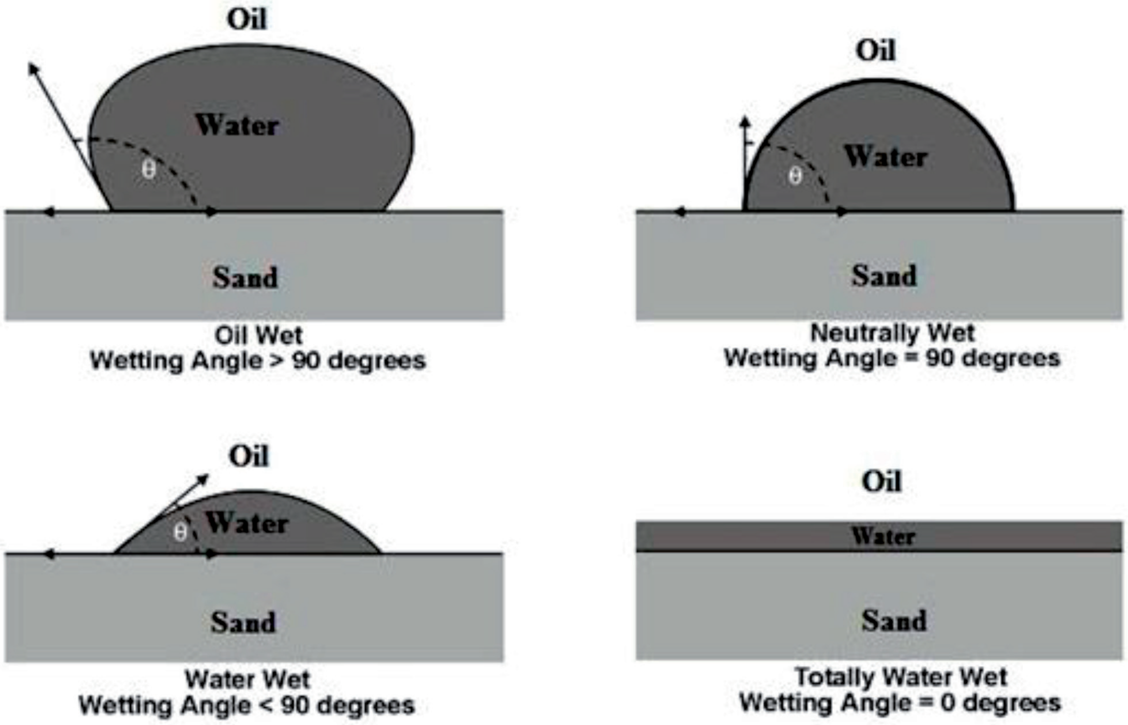


Figure 6.
Alterations in wettability as contact (wetting) angle reduces [60].

2.2.4.1 Wettability

Wettability is the tendency of a fluid to remain in contact with the surface of a solid. For a given wetting fluid, there is an inverse relationship between wettability and contact angle. This means that its wettability decreases when there is a rise in contact angle [62, 63]. The injection of fracturing liquid in the reservoir alters the dynamics of wettability because it introduces another liquid phase to the system. Where two liquids co-exist, one will be wetting and the other non-wetting.

In a multiphase reservoir, such as oil shale, consisting of more than one type of immiscible fluids (e.g., water and shale oil), the wetting fluid preferentially wets the rock surface due its low mobility and stronger attractive forces with the rock. For an oil-water reservoir fluid, water is the denser of the two phases and preferentially wets the rock when the contact angle is less than 90°, the adhesion tension is negative, and the interfacial tension between the water-rock interface exceeds that for the oil-rock interface [64]. The adhesion tension is the difference between the oil-rock and water-rock interfacial tensions. Conversely, oil will be the preferential wetting fluid if the contact angle of water is between 90° and 180°, the adhesion tension is positive, and the interfacial tension between the oil-rock interface exceeds that for the water-rock interface [64]. Water imbibition is boosted as the water-wet wettability increases, resulting in a reduction in the saturation of residual oil [65].

2.2.4.2 Effect of contact angle on wettability

It may not always be easy to define the wettability of a reservoir in a straightforward manner since it is influenced by other factors such as contaminants, surface roughness and time [62, 66]. Nonetheless, the contact angle can serve as a criterion to distinguish between wetting and non-wetting liquids. Whereas, the contact angle of the wetting liquid with the rock is below 90°, for a non-wetting liquid it is between 90° and 180°. If the reservoir consists of both oil and water, the wetting fluid will form a contact angle that is less than 90° [63]. The wetting fluid attaches and spreads along the rock surface thereby enhancing the mobility of the non-wetting fluid. The choice of an appropriate hydraulic fluid should account for this. For instance, water-based fracturing fluids applied in a reservoir will serve as wetting fluids whilst boosting the flow of preexisting hydrocarbons, and the degree of its wettability—in other words, the ease of spread on the rock surface—increases as the contact angle decreases.

2.2.5 Water imbibition

The periodic injection of water into unconventional reservoirs enhances oil recovery because of the imbibition of water by the rock matrix and the displacement of oil trapped within the pores [45]. This technique is fit for shales with a higher water than oil uptake. Shale has a higher affinity for water, which is reflected by larger rates of imbibition [67]. However, it is possible for water blockage to occur resulting in negative impacts on the recovery process [45, 68]. To circumvent this, well-shut operations can be used to drive water further into deeper water-wet sections [45]. Alternatively, surfactants are introduced to improve the water-wet wettability or to completely change the wetting fluid from oil to water [45, 69].

Imbibition is a form of diffusion where a liquid is absorbed into a solid particle resulting in an increase in volume of the particle. It is normally instigated in response to a concentration gradient between the solid (absorbent) and the liquid leading, potentially, to movement of the liquid towards the solid particle. Imbibition is also described as the displacement of an immiscible fluid by another one within a porous medium. This is a typical phenomenon in hydrocarbon reservoirs involving the displacement of the non-wetting fluid out of the pores of the reservoir rock by the wetting fluid [70–72]. It is another means of primary and secondary oil recovery [72]. Water flooding is a form of secondary oil recovery that involves imbibition, where water is injected to displace residual oil in the reservoir [73]. In a water-wet reservoir rock, water—the wetting phase—displaces oil, which is the non-wetting phase [72]. Imbibition is an important process that aid recovery of oil in fractured reservoirs [72, 74, 75].

Imbibition is a complex phenomenon encompassing the multifarious interactions between gravity, capillary and viscous forces. Whereas, gravity and viscous forces are external agents that could be used to drive imbibition, capillary forces are generated internally within the porous medium. On this basis, there are two categories of imbibition: spontaneous/natural and forced. Spontaneous or natural imbibition is the process whereby a wetting fluid displaces a non-wetting fluid within a reservoir rock due to capillary pressure [70, 72, 76, 77]; for instance, water displacing oil in an oil-saturated reservoir rock. On the other hand, forced imbibition are caused by viscous and gravity forces. These external agents create pressure gradients that enable the displacement of non-wetting by wetting fluids. The manner of flow between the wetting and non-wetting fluid determines the type of spontaneous imbibition. Co-current spontaneous imbibition happens where the directions of flow between the wetting and non-wetting fluid are the same. Contrastingly, counter-current spontaneous imbibition happens when the wetting and non-wetting fluid are flowing in opposing directions [70, 75, 78]. In a water-wet reservoir rock, the prevalence of any type of spontaneous imbibition—hence, oil recovery process—depends on the extent of exposure of the rock to water. Oil recovery is dominated by co-current imbibition when the rock is not wholly in contact with water [78]. This form of imbibition is the predominant process that produces oil and occurs in the region of the rock surface in contact with oil. Co-current imbibition evokes a much higher oil recovery rate in comparison to counter-current imbibition, implying a greater production efficiency; in other words, the rock surface in contact with oil produces more oil in contrast to the surface in contact with water [78]. The linear rate of co-current imbibition is shown by Unsal *et al.* [79] to be up to four times higher than counter-current imbibition.

2.2.6 Thermal treatment

Kerogen, which is a solid, insoluble and rich source of organic compounds in oil shale and other sedimentary rocks, can be converted to shale oil by thermal dissolution, hydrogenation or pyrolysis. These are ex situ processes conducted at the ground surface after mining the oil shale and entails the use of very high heat to extract shale oil. Pyrolysis is the thermal decomposition of the organic matter component in solid fuel in an inert environment, and hydrogenation is a chemical treatment involving the reaction between molecular hydrogen and another compound/element with or without the presence of a catalyst. The process can be used to saturate or reduce organic compounds. Hydrogenation can be used to attain high oil yields from oil shales by converting its organic matter content to heavy oil, petrol, etc. [80]. Thermal dissolution is a hydrogen-donor solvent refining process [12]. It is a technique of shale oil extraction, whereby a hydrogen donor solvent such as *tetralin* is introduced into the solid fuel at high temperatures resulting in the depolymerisation, dissolution and cracking of the dissolved organic matter [12, 81, 82].

2.2.7 Acidisation

The injection of certain types of acid into oil shales can lead to rock matrix dissolution—whereby, for instance, sediments and mud solids are dissolved—increasing its permeability and porosity [83]. This technique can be applied to release oil and gas trapped in very small quantities within the rock matrix by repairing a previously damage formation (reflected by a restoration of permeability) and/or enhancing the natural permeability through the creation of additional pores [83]. Examples of acids used in practice are hydrogen chloride (HCL), hydrofluoric acid (HF), and organic forms such as methanoic (formic) acid (HCO_2H or HCOOH) and acetic acid (CH_3COOH). To improve performance, acid blends are frequently used. HCL can be combined with HF or sodium hydroxide (NaOH) [2] or organic acids.

For this technique to be successful, the rock must be, at least, partially soluble in acid. Carbonates are readily soluble in acid; thus, this approach is suitable for carbonate rocks—sedimentary rocks mainly composed of carbonate minerals—e.g., limestone and dolostone [84]. Acidisation is also effectively applied to formations composed primarily of silicate minerals (e.g., sandstone, consisting majorly of aluminosilicates and quartz); however, the two reservoirs (carbonate and silicate reservoirs) are responsive to different types of acids. Sandstones are not soluble in HCL, although this acid is highly acidic. They are more reactive to the relatively weaker HF. HCL is more effective in formations with a rich content of carbonate minerals. Since many formations may be a combination of carbonate and silicate minerals, a blend consisting of a mixture of two or more types of acids is common in practice [2, 45, 83].

Two acidisation techniques are notably used for reservoir stimulation: matrix acidisation and acid fracturing [84]. Matrix acidisation entails the injection of acid into the formation at a pressure below the fracturing point (fracturing pressure). Hence, the formation is not fractured; instead, the acid forming new pathways for fluid flow etches the rock. The key mechanisms include mineral dissolution and the mobilisation of fragmented rock particles resulting in the creation of wormholes [84].

Acid fracturing is analogous to hydraulic fracturing but with the use of acids to react and etch channels within the walls of the fracture. The central difference between matrix acidisation and acid fracturing is the injection rate. In acid fracturing, the solution is pumped into the formation at a high rate leading to a build-up in the fracture pressure, and the initiation and proliferation of fractures. The high flow rate implies that there will be a shorter reaction time and the acid solution is not retained long enough to etch long channels on fracture walls.

Acidisation is less suitable for shale than in other rocks; nonetheless, it can still be applied in stimulating shale formations rich in carbonates [2, 45, 85]. Wormholes are not easily created in shales because of its low permeability, therefore matrix acidisation will likely not be effective [45]. Acid fracturing is the preferred and most suited strategy whereby new fractures are created within the formation and then, together with existing fractures, are roughened by the etching process to further enhance permeability and porosity. For oil shale formations, further improvement in reservoir conductivity is observed through the use of acid blends (e.g., sodium hydroxide mixed with hydrochloric acid (NaOH-HCL) and hydrochloric acid mixed with hydrofluoric acid (HCL-HF)). This is demonstrated in Alhesan *et al.* [2]; however, sufficient enhancement in permeability and porosity can still be established by applying a single type of acid, e.g., HCL, on shales which are rich in carbonates (e.g., [45, 85]). Carbonate minerals such as calcite (calcium carbonate, $CaCO_3$), a constituent of carbonate-rich shale, dissolve in HCL.

Generally, the mineralogy of shale varies between formations and impinges upon its mechanical properties [86, 87]. Shale may content a significant amount of any or a combination of clay, calcite or quartz minerals. Although HCL augments the porosity and permeability of calcite-rick shales, it is observed to have contrary effects on shales with low calcite or high clay content; this is caused by formation damage or impairment as a result of clay swelling and related acid-rock reactions [85]. HCL reaction with calcite is typical presented as [87]:

$$CaCO_3 + 2HCL \rightarrow CaCl_2 + H_2O + CO_2 \tag{1}$$

2.3 Tight reservoirs

Tight oil/gas reservoirs are sometimes referred to as shale reservoirs, but a broader and more accurate definition given in Zhang *et al.* [9] describes it as an ultra-low permeability reservoir rock (sandstone, siltstone, shale and carbonate rocks) closely related to oil shales. The latter concept is adopted in this discourse; notwithstanding, discussions are largely focused on tight sandstones with intermittent allusions to other types of tight oil/gas reservoirs. What qualifies a reservoir to the termed 'tight' is primarily based on its permeability, porosity, and closeness to (or interbedding with) source rocks [9, 88]. Threshold values of 12% for porosity [9] and 0.1 mD for permeability [6, 9, 88] are usually the main distinguishing set of criteria. Recovery from tight reservoirs can be achieved through methods including hydraulic fracturing, water imbibition, surfactant treatment/flooding, acidisation and the generation of an electro-kinetic potential [83, 89–92].

2.3.1 Hydraulic fracturing: tight reservoirs

In a broad sense, the concept of hydraulic fracturing, is generic for all reservoirs, as described in Section 2.2.2. The discussion in this section is not stand-alone; rather, it complements the narrative in Section 2.2.2 and Section 2.2.3. There are three typical approaches for implementing hydraulic fracturing [91, 93]: hydraulic proppant fracturing, water fracturing and hybrid fracturing. The choice of technique is dependent on the formation, and rock and fluid type. Hydraulic proppant fracturing is the conventional technique involving the injection of very viscous gels mixed with a high concentration of proppants. Proppants prop the created fractures thereby maintaining an elevated conductivity. This method creates comparatively short fractures and is suitable for formations of moderate to high permeability [91].

Water fracturing is the injection of water composed of slick water (friction reducers) and a low concentration of proppant to produce extensive but low-width fractures. A conceptual representation of a fracture geometry is illustrated in **Figure 7**. The lengthy geometry of the fracture allows it to connect the wellbore to distant reservoir areas. Water fracturing is appropriate for low permeability (< 1 mD) reservoirs, since fractures with small widths are not effective in moderate to high permeability formations [91, 95, 96]. A key leverage of water fracturing is the considerable cheaper cost in relation to other hydraulic fracturing methods (i.e., hydraulic proppant fracturing and hybrid fracturing), whereas a major weakness is proppant settlement due to the low viscosity of injected fluids, which causes a non-uniform proppant distribution within the propped fracture [95].

Hybrid fracturing is a combination of different hydraulic fracturing stimulation methods, borrowing the advantages of individual treatment approaches. In essence and in the context of the discussion here, it is a blend of hydraulic proppant fracturing and water fracturing. Succinctly, the procedure entails an initial injection

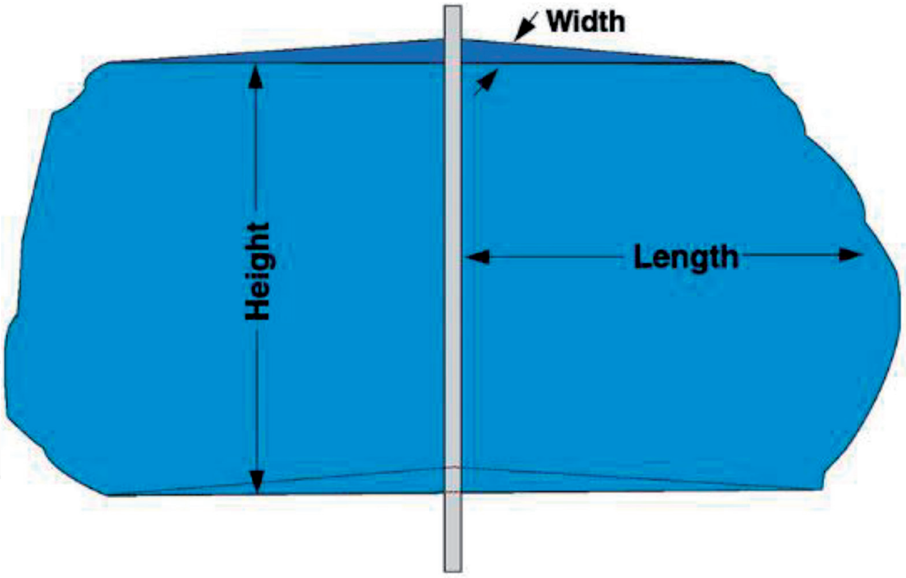


Figure 7.
Fracture geometry as produced by a vertically oriented wellbore [94].

of slick water to create fractures, followed by a treatment with a cross-linked gel consisting of the desired concentration of proppants. The cross-linked gel is conveyed to the extreme ends of the fracture [91]. Hybrid fracturing combines the benefits of both conventional fracturing and water fracturing. Effective fracture half-lengths and fracture conductivities are higher in the induced fractures [93] and the polymer loading in the cross-linked gel is considerably less than what is used for conventional hydraulic proppant fracturing. This has a knock-on effect on the extent of polymer damage [91]. Some of the issues associated with hydraulic proppant fracturing are applicable to hybrid treatment [91].

The choice of hydraulic fracturing technique for tight reservoirs depends on several factors. If cost is a chief factor, water fracturing is preferred.

2.3.2 Water imbibition: tight reservoirs

As in oil shales, water imbibition can be employed to enhanced oil and gas recovery in tight reservoirs [90]. Oil is preferentially driven out from pores during water imbibition due to greater capillary forces. Surfactants may be introduced during water imbibition to convert the wettability of rock from *oil-wet* to *water-wet* and to reduce the interfacial tension between liquid phases—oil and water—in the reservoir.

2.3.3 Application of electrokinetics potential

Electrokinetic potential instigates colloidal dispersion. This technique enhances the effect of water imbibition in clay-rich and tight reservoirs (e.g., sandstone) by stimulating colloidal movement through the dislodgement and transport of pore clay linings [89]. The removal of clay linings in pores enlarges pore throats and/or creates new flow pathways, causing a direct increase in permeability and porosity. Electrokinetic potential and water injection can be used in tandem to improve efficiency.

2.3.4 Acidisation—Tight reservoirs

Acidisation of carbonate rocks (e.g., limestone and dolostone) to improve permeability and porosity can be successfully achieved with hydrochloric acid (HCL).

Shales or sandstones containing significant proportions of carbonates can also be treated with HCL. The use of HCL becomes problematic when applied to other kinds of reservoir rocks; for instance, sandstones (chiefly composed of quartz and aluminosilicates), which are insoluble in HCL. The following are some of the problems associated with HCL [83]:

1. It causes formation damage by blocking pore throats thereby reducing porosity and permeability.

2. It escalates the rate of reaction and corrosion at elevated temperatures.

3. There is a risk of later-stage adverse secondary reactions.

However, sandstones react favourably with hydrofluoric acid (HF). The fine particles of quartz and aluminosilicates which block the pores, especially at the near-wellbore region, are soluble in HF. HF can be introduced directly into the reservoir or produced through other chemicals like ammonium bifluoride (NH_4HF_2). Normally, mud acid (a blend of aqueous HCL-HF) is used to repair damages around the vicinity of the wellbore [83, 97]. Fluoride ion (F^-) is the only one of its kind that reacts with quartz in a way that repairs the damage near the wellbore [97]. Mud acid can be prepared by mixing a fluoride ion-releasing chemical, ammonium bi-fluoride salt (NH_4HF_2), with HCL. The reactions are expressed in Eq. (2) [98]:

$$HCL \rightarrow H^+ + Cl^- \tag{2}$$

$$H^+ + NH_4HF_2 \rightarrow NH_4Cl + 2HF \tag{3}$$

For sandstone reservoirs, acidisation is performed in three steps: *preflush*, *main flush* and *after flush* [83]. In practice, at the preflush stage, HCL has been used for the dissolution of carbonates and positive ions (e.g., [83, 99–101]); nonetheless, its effectiveness is inconsistent and there are reported incidences of damages [102]. To circumvent this, it is possible to blend HCL with other chemicals to neutralise its adverse effects. This is demonstrated in Shafiq *et al.* [97], where HCL is combined with acetic acid (CH_3COOH) to improve dissolution of carbonates and positive ions (sodium, calcium and magnesium), whilst eluding the damage that would have been triggered by pure HCL.

The second (main) stage of the acidisation process is the use of a fluoride ion (F^-) containing acid to dissolve the minerals (e.g., SiO_2). HF is a commonly used acid but the fluoride ion is very reactive leading to a premature expending of the acid near the wellbore region. To decelerate the reaction rate, HF must be combined with other mineral acids. These are buffer acids, which may be, for instance, HCL or formic acid (HCOOH). The buffer acid retards the reaction rate of HF with the formation and preserves the pH of products of the reaction, which in turn prevents the precipitation of silica [97]. Other acid blends (mud acids) proposed by Shafiq et al., [97] for the main stage of acidisation include Hydrofluoric-phosphoric acid (HF-H_3PO4) and fluoboric-formic acid (H_3OBF_4- HCOOH). In the former, H_3PO4 is a substitute for HCL, while H_3OBF_4 replaces HF in the latter. The product of the reactions between HF and silica mineral is fluosilicic acid (H_2SiF_6). The reaction process is presented in Eqs. (4) and (5) [98, 103]:

$$SiO_2 + 4HF \rightarrow SiF_4 + 2H_2O \tag{4}$$

$$SiF_4 + 2HF \rightarrow H_2SiF_6 \tag{5}$$

Compounds such as silica gelatinous precipitate (Si(OH)$_4$) are eventually formed when fluosilicic acid is decomposed to silicon tetrafluoride (SiF$_4$) (Eq. (6)), which is then hydrolysed (Eq. (7)).

$$H_2SiF_6 \rightarrow 2HF + SiF_4 \tag{6}$$

$$SiF_4 + 4H_2O \rightarrow Si\left(OH\right)_4 + 4HF \tag{7}$$

There is also a tendency for other precipitates to form, which can be avoided by the circulation of HCL at the *preflush* stage to remove ions [97, 100]. The *after-flush* stage restores the wettability of the formation and removes the expended acids. Mutual solvents, HCL, acetic acid and other suitable chemicals are candidates for finalising the treatment process [104].

Table 1 is a summary illustration and cross-section of approaches for stimulating the production of unconventional reservoirs.

Reservoir type	Category of stimulation method
Heavy oil formations	Cold production
	• Diluent injection
	• CHOPS
	Thermal stimulation
	• Cyclic steam injection
	• Steam flooding
Oil shale formations	Horizontal wells
	Hydraulic fracturing
	Transverse vertical fractures
	Surfactant treatment
	Water imbibition
	Thermal treatment
	Acidisation
Tight formations	Hydraulic fracturing
	Surfactant treatment
	Water imbibition
	Electro-kinetics potential
	Acidisation

Table 1.
Techniques for stimulating unconventional reservoirs.

3. Fracturing fluids and fluid systems

The crux of hydraulic fracturing is the injection of fluids to generate, within the formation, a pressure that is greater than the breakdown value. The breakdown pressure is fundamentally a function of the formation in situ stresses, the initial pore pressure and the rock tensile strength [105]. Several breakdown pressure models have been developed since the first and classical version derived by Hubbert and Willis [106]. Hubbert and Willis's model is built on the premise that fracture initiation and breakdown takes place when the hoop stress or minimum tangential compressive stress at the wall of the wellbore is equal to the rock tensile strength. The initiated fracture starts to grow when the fracture propagation pressure is attained. For solids-free (clean) injection fluids, the fracture propagation pressure is normally less than that required for fracture initiation [107]. The fracture propagation pressure is the pore pressure at the tip of the fracture. It is lower than the bottom-hole pressure, and this difference depends on permeability, injection rate, fracture length [108], and other factors such as the properties of the fracturing fluid. At times, the fracture propagation pressure is considered as the bottom-hole treating pressure. In this case, its magnitude depends on the in situ stresses and the net drop in pressures [109]. The net pressure drop is influenced by the tortuosity between the wellbore and the fracture, and the viscous flows within the wellbore perforation tunnel and the propagating fracture. The characteristics of the fracturing fluid and fluid system are therefore important in hydraulic fracturing operations.

Some key parameters to consider when choosing or designing a fracturing fluid system include the fluid rheology, conductivity, compatibility between the reservoir rock and fluid, pressure drop along the fracture, environmental impact of the fluid constituents, costs, fluid viscosity and proppant transport ability, and friction losses (in the wellbore, perforations and fractures). The ideal fracturing fluid should be easy to produce; possess enough viscosity for proppant transport and shear resistance; minimise fluid losses, friction forces, and proppant and formation damage; be economically viable; and be compatible with the reservoir rock and in situ fluids [110]. Fracturing fluids can be classified as water-based, oil-based, foam-based and acid-based.

3.1 Water-based fracturing fluids

These are aqueous-based fluids composed of water mixed with proppants and chemical additives such as friction reducers. Water-based fracturing fluids can be categorised as slickwater, linear, crosslinked and viscoelastic surfactant fluids. Slickwater is mainly water; the proportion of water is normally dominant and might be up to 99% of the composition of the fluid. Other constituents (proppants and additives) account for less than 2% of the total volume [110]. The friction reducers (e.g., acrylamide-based polymers, surfactants and biocides) lower the viscosity to values below that for normal water. Because of its low viscosity and proppant concentration, it is possible to inject slickwater at high velocities to create narrow fractures [111].

Linear fluids are uncrosslinked solutions based on polymers (i.e., biopolymers or synthetic polymers or polysaccharides) [111]. Guar, cellulose and their derivatives are examples of biopolymers. Generally, linear fluids are higher in viscosity and thus better than slickwater in proppant conveyance and suspension. Crosslinked solutions are formed when two polymer chains are bonded to enable a fluid type with improved physical characteristics. Examples are crosslinked polymer (guar, guar derivatives, cellulose and cellulose derivatives, etc.) fluids. Typical crosslinkers include borate and other metal-based (Aluminuim, Zirconate, Titanate, etc.) ions [46, 111]. In comparison to linear fluids, crosslinked fluids have higher gel viscosity (hence, proppant carrying capacity) and stability at high temperatures [46, 111]. The high viscosity of crosslinked fluids and their tendency to form filter cakes at the fracture walls means that they must be degraded and removed at the end of the operation using breakers (enzymes and oxidisers), to avoid damage to formation conductivity [46].

Viscous fluids are suitable where high fracture conductivity is desired. Viscoelastic surfactant (VES) fluids are not formed with crosslinkers but mainly reflect the distinctive characteristics of surfactants. They contain less residues and are viscous under shear—i.e., they become highly viscous at low shear rates [46, 112, 113]. For VES fluids, crosslinkers are not necessary; rather, when these fluids are mixed with water the surfactants create micelles that increase its viscosity. Viscosity is reduced when VES fluids are in contact with hydrophobic and organic fluids (e.g., oil and gas); hence, breakers are not required to lower the fluid viscosity during clean-up [46]. VES fluids also facilitate reduction in surface tension of the reservoir fluid, which enables the outflow of water trapped within the rock pores. This is crucial in formations sensitive to water [114]. The deficiencies of VES fluids are their high costs, excessive leak-off rates in very permeable formations (> 200 mD) due to their inability to build a filter cake at the fracture wall, and their instability and decrease in viscosity at high temperatures (> 135°C), [46, 112, 114].

3.2 Oil-based fracturing fluids

Oil-based fracturing fluids are principally applied in formations that are water sensitive. The earliest practices of hydraulic fracturing were conducted using oil-based fracturing fluids [115]. These were mainly hydrocarbons including kerosene, diesel and crude oils. These fluids are generally low in viscosity, which is normally increased by the addition of chemicals such as fatty acids, aluminium phosphates and aluminium esters [114, 116]. An increase in viscosity is imperative for improved stability and proppant-carrying capacity at high temperatures. Oil-based fracturing fluids can perform better than their water-based counterparts. Comparative studies completed by Perfetto *et al*. [116] show that for wells stimulated by oil-based fracturing fluids, there is a slower long-term decline in production, shorter clean-up times and improvements in economic returns. Other notable benefits are minimal contamination, lower specific gravity, lower pipe frictional losses, stability at high shear rates, and less difficulty in optimising proppant pumping and the fracturing process. The drawbacks of oil-based fracturing fluids is the hazard they pose due to high flammability and negative environmental impacts. Additional efforts to combat health and safety concerns are vital.

3.3 Foam-based fracturing fluids

Foam fluids are fundamentally gas/liquid composed of significantly higher proportion of gas in comparison to the liquid fraction. They are viscous fluids. The gas fraction forms the internal phase since it is suspended in the external phase (the liquid). It is differentiated from other gas/liquid mixtures (e.g., dispersions and mist) by the percentage of gas in the total volume. Typically, the gas fraction (F^g) of foams is in the range $52\% <= F^g <= 96\%$ [117]. Dispersions (normally classified as energised fluids) and mists consist of gas fractions below 52% and above 96% respectively [114, 117, 118]. **Figures 8** and **9** are schematic representations of these. Foams are characterised by three main parameters: rheology, quality and texture [117]. *Quality*, herein, refers to the percentage of gas in the mixture. The *texture* is the bubble size distribution of the dispersed gas.

Obviously, foams are also preferred for water-sensitive formations because they aid flowback and the amount of water needed for treatment is lower. Carbon dioxide (CO_2) and nitrogen (N_2)—as gas phases—and water, polymers (e.g., guar)

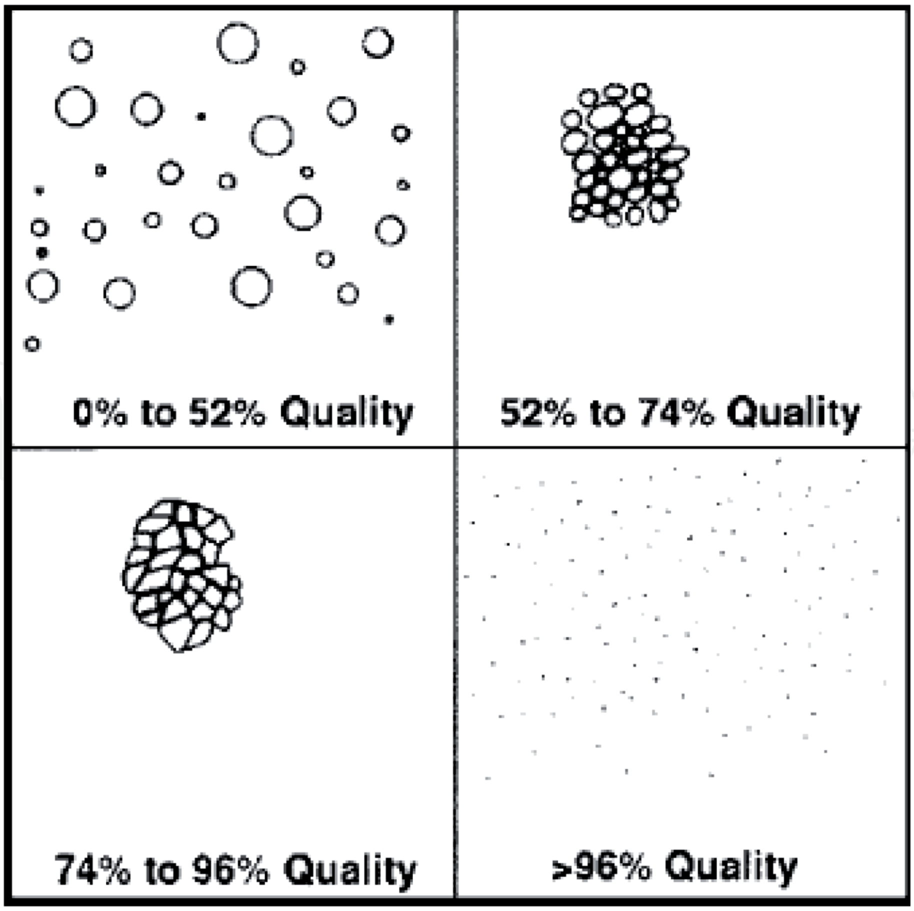


Figure 8.
Foam qualities depicted by different gas–liquid compositions [117].

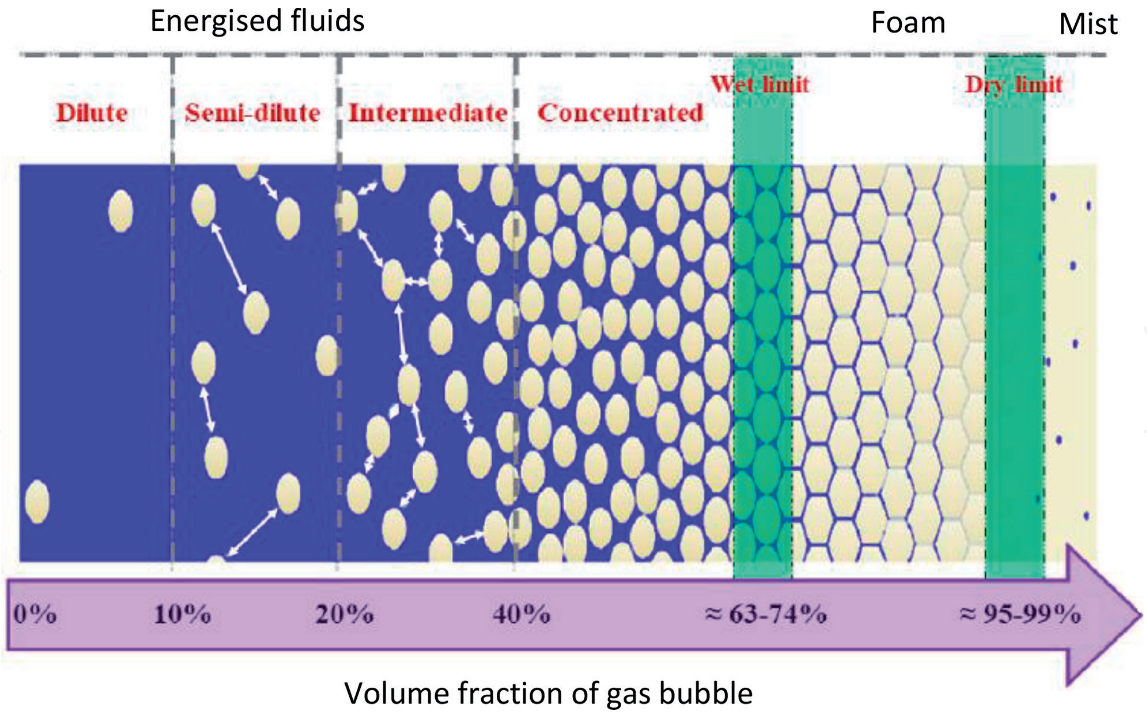


Figure 9.
Classification of gas–liquid mixture depending on the proportion of gas fraction [119].

and acids—as liquid phases—are common components of foams fracturing fluids [120, 121]. **Table 2** presents the main categories of foam-based fracturing fluids. These are water-based, hydrocarbon/oil-based, alcohol-based, acid-based and

Fracturing foam type	Main composition	Target reservoirs
Water-based fracturing foams	Water, foaming surfactant/agent, and N_2 or CO_2 gas	Low pressure formations
Hydrocarbon-based fracturing foams	Hydrocarbon, foaming surfactant/agent and N_2 gas	Water-sensitive low pressure formations
Alcohol-based fracturing foams	Methanol, foaming surfactant/agent, and N_2 gas	Water blocked low pressure formations
Acid-based fracturing foams	Acid, foaming surfactant/agent, CO_2 and N_2 gas	Low pressure and depleted formations
CO2-based fracturing foams	Liquid CO_2, foaming surfactant/agent and N_2 gas	Low pressure formations

Table 2.
Classification and constituents of foam-based fracturing fluids [47, 119, 120, 122, 123].

CO_2-based fracturing foams. Water-based foams are more popular because they are readily available and the technology requirement is low.

The major advantages of foam-based fracturing fluids are as follows [118, 120]:

- Considerable reduction in water requirement in comparison to water-based fracturing fluids; this is directly reflected in the quantity of waste water and its undesirable impact on flora and fauna, and other aspects of the environment
- High recyclability of the foam, which reduces the amount of waste water and cost
- High proppant transporting capacity, which is about 85% greater than water-based fracturing fluids
- Low fluid loss
- Low hydrostatic pressure (head)
- Enablement of backflow of the injected fluid
- Low pressure drops
- Low injection pressure requirements
- Low energy demand for pumping
- Low damage to the formation
- High compatibility with formation fluids

The main disadvantages of foam-based fracturing fluids are given thus [120]:

- Limited choice of surfactants to aid foaming and stabilisation because of the need for them to be completely degradable and environmentally friendly for minimal impact on groundwater, the surrounding land and aquatic life
- High cost due to the peculiarity of equipment, and technical and planning requirements

3.4 Acid-based fracturing fluids

The common types of acid-based fracturing fluids are described in Section 2.2.7 and 2.3.4. These are hydrochloric acid (HCL), hydrofluoric acid (HF), and organic forms of acids such as methanoic (formic) acid (HCO2H or HCOOH) and acetic acid (CH3COOH). During acid fracturing, fracture conductivity is increased by etching channels along fracture walls. This method of fracturing is, therefore, effective in reservoir rocks that are soluble in acid. Carbonate formation rocks (sedimentary) such as limestone and dolostone are soluble in acid; hence, they are the most common beneficiaries of acid fracturing. Nevertheless, innovative applications of acid fracturing on rocks with low acid solubility (e.g., sandstone) are becoming more recognised [83, 97, 124]. HCL is the most popularly used acid fracturing fluid, especially for carbonate rocks, but the solubility of some reservoir rocks (e.g., sandstone) to this acid is low. Thus, the application of HCL in low-soluble formation rock is limited. Although weaker in strength to HCL, HF are more reactive to formation rocks rich in aluminosilicates and quartz—such as sandstone—and, hence, better candidates. In practice, acid blends (mud acids) are preferred and frequently used (e.g., [2, 83, 97, 104]). Examples are HCL-HF, NaOH-HCL, fluoboric-formic acid (H3OBF4-HCOOH) and hydrofluoric-phosphoric acid (HF-H_3PO_4).

4. Summary and conclusion

The imperative of reservoir stimulation is borne out of the need to maximise exploitation of hydrocarbon reserves. Candidate reservoir formations that benefit from stimulation operations span across both conventional and unconventional reservoirs. Stimulation is necessary in conventional reservoirs to enhance the productivity of depleted oil and gas formations, which is accomplished through enhanced oil/gas recovery (EOR & EGR) strategies. EOR/EGR is even more pertinent to the exploitation of unconventional reservoirs (i.e., heavy oil, oil shales, tight sandstones, tight limestone formations, etc.). The advent of the exploration of these peculiar hydrocarbon formations has revolutionised the oil and gas industry, driving down energy prices and revealing potential opportunities for cleaner fuels. It is also essential for coal bed methane (CBM) reservoirs to be stimulated in order to instigate and/or improve productivity.

Unconventional reservoirs are complex, distinctive and diverse. They greatly differ from conventional reservoirs in terms of their structure, composition, and rock and fluid properties. Due to these features, there are increased challenges in producing from this type of reservoirs. The stimulation of oil and gas unconventional reservoirs has been ongoing for many decades and over the years, the employed techniques have evolved to become more effective, economical, sustainable and environment-friendly. The diversity of unconventional reservoirs with respect to their structural layout, rock type, hydrocarbon content, proximity to conventional formations, etc., brings to the fore the impracticability of applying a single set of stimulating techniques across board.

Heavy oil reservoirs consist of high-viscosity and high-density hydrocarbon fluids. They are generally produced via two methods: cold production and thermal stimulation. Cold production is carried out either by injecting a diluent to decrease the viscosity of the reservoir fluid or by ‘cold heavy oil production with sand’ (CHOPS). Alternatively, thermal stimulation is typically implemented in any of the following two ways: cyclic steam injection and steam flooding. Oil shale reservoirs are normally produced by any or a combination of methods, including the use of horizontal wells, hydraulic fracturing, creating transverse vertical fractures (along horizontal wells), surfactant treatment/flooding, water imbibition, thermal treatment and acidisation. Tight reservoirs are primarily produced by hydraulic fracturing, surfactant treatment/flooding, water imbibition, application of electrokinetic potential and acidisation.

The process of selecting an appropriate approach is an important aspect of the routine because of the disparity in different types of unconventional reservoirs and the availability of a seemingly wide range of options of stimulating techniques. A thorough site reconnaissance and an assessment of the effectiveness, efficiency and impact of the selected method is indispensable. These should consider, amongst other factors, reservoir productivity, cost, environmental impact, and health and safety.

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