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Chapter

Pumping System of Heavy Oil Production

Tarek Ganat

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Abstract

The geological features of the hydrocarbon reservoir and the inconsequential mobility of the heavy oil make the recovery process challenging. Recently, commercial interest has been developed in heavy oil production systems with the advent of improved drainage area by drilling multilateral and horizontal wells and highly deviated wells at shallow reservoirs. Moreover, other new recovery methods were developed such as downhole technologies that include cold or thermal production. Commonly, artificial lift techniques are utilized when the well cannot offload naturally at its economical rate. This is applicable for heavy oil reservoirs, where high viscosity along with the reservoir pressure drop will avoid the wells to produce naturally. Producing heavy oil together with associated water from the reservoir can create emulsions, which may cause high loads on artificial lift methods, along with high power consumption and requirements of expensive chemicals. The optimization and the selection of handling viscous oils; had a fundamental impact on the development of pimps. This chapter reviews the applications and types of pumping systems as an artificial lift in the heavy oil production process and reviews the pumping system performance, and its future development, as well as the expected technical challenges.

Keywords: artificial lift, pump systems, multiphase flow, heavy oil, oil recovery

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1. Introduction

Globally, the heavy oil reserves have become more important as a future energy source. An excess of 50% of the world's hydrocarbons have an oil gravity of <20° API. These hydrocarbon assets are normally bitumen and heavy oil, where most of these deposits are located in China, Canada, Venezuela, and Russia. Typically, the heavy oil viscosity is varied within the range of 500 and 15,000 cP, and for bitumen, it's about 100,000 cP. Such crudes are usually found in shallow reservoirs (300–600 m depths), and normally the average flow rate of an individual well can be from 1 to 70 m^3/day. Therefore, to reach economic production rates, all oil wells need to be pumped at low bottom-hole pressures. Besides, hydrocarbons are typically produced from unconsolidated reservoirs which are susceptible to sand production that can exceed above 30% by volume.

Typically, 60% of producing oil wells need some additional lift systems to pump the reservoir oil. Conventionally, heavy oil wells are using beam pumping as an artificial lift system. However, beam pump is used for low flow rate wells; besides this pump has many operating problems. Alternatively, there are many types of

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pumps which are recently employed as a primary option in heavy oil wells, such as progressing cavity pump (PCP), jet pumps, and electric submersible pump (ESP). These wells are normally producing at low bottom-hole pressure, low gas-oil ratio, and low bubble-point pressure, high water-cut, or low °API oil gravity. This chapter reviews the application of different pumping systems as an artificial lift in the heavy oil production process. The main focus of the chapter is on types of pump and their applications and reviews the pumping system performance, and its future development, as well as the expected technical challenges.

2. Production of heavy oils

Heavy oil production is a developing skill for producing heavy oil in economical amounts. There are several ways to produce heavy oil and bring to the surface such as primary, secondary, and tertiary recovery. Since oil mobility is a function of effective permeability and oil viscosity, the efficiency of a well production is related to the delivery of reservoir zone thickness and mobility [2]. **Figure 1** displays the oil recovery mechanism as identified by Pinczewski [3] and Ershagi (1994) [c], and **Figure 2** shows the expected recovery factor from every method. The enhanced oil recovery (EOR) processes can be categorized into three main groups as stated below. The approaches have their own characteristics and mostly linked to the kind of oil remaining in the reservoir and reservoir characteristics.

1. Chemical

    a. Surfactant flooding

    b. Micellar polymer flooding

    c. Polymer flooding

    d. Alkaline atau caustic flooding

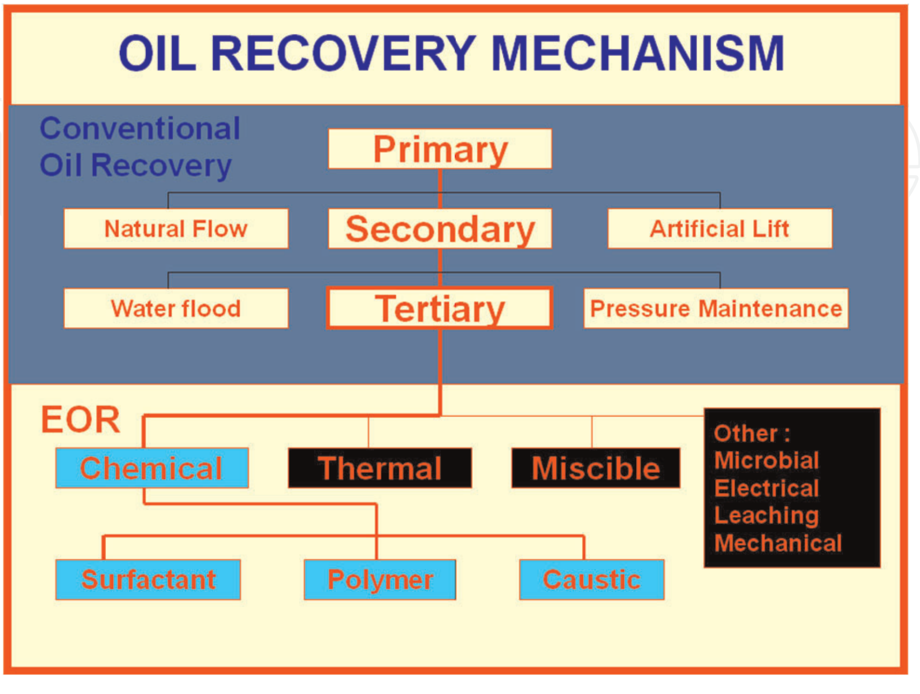

Figure 1.
Oil recovery mechanism (source: Pinczewski (1993)) [3].

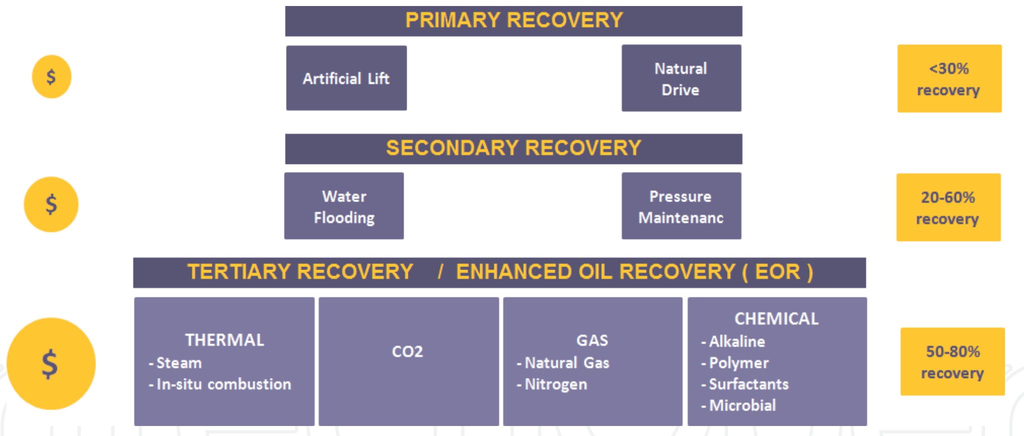

Figure 2.
Oil recovery from each stage (source: DALEEL) [4].

2. Thermal

    a. Steam flooding

    b. Fire flooding

3. Miscible

    a. Carbon dioxide flooding

    b. Nitrogen and flue gas flooding

    c. Enriched hydrocarbon gas flooding

Things that are essential to be considered in the EOR method

1. Physical properties

2. Reservoir type

3. Structure and physical properties of porous media

4. Fluid condition in porous media

5. Mobilization of oil remaining

6. Adsorption process

2.1 Primary recovery

2.1.1 Natural flow

The first oil extraction process from the reservoir rock is known as primary recovery (utilizing the natural energy). It's the first production phase of hydrocarbons, where the well depends on the natural flow of the oil because of pressure differences between reservoir pressure and the well bottom-hole pressure. Besides, using pumping lift systems such as an electrical submersible pump is also known as a primary recovery technique. These approaches are normally named as natural drive mechanism. The recovery factor from conventional oil production is above 30%, but for heavy oil, it is within 5–10% [5]. When natural lift pressure is not enough to move the oil to the wellbore or to lift the oil to the surface, once the reservoir depleted, then the primary recovery stage has reached its maximum extraction limit. Normally, heavy oils cannot be produced via natural flow from the reservoir to surface. There are some heavy oil wells which that can be produced naturally, but at a very low production rate (±20 stb/d), with recovery factor within the low range of 6–9% of the oil in place; specific to densities ranging between 9 to 20° API, and viscosities range from 1000-13,000 cP or more, together with low reservoir pressures.

2.2 Secondary recovery

Once primary recovery methods seize to produce the oil naturally, secondary recovery methods will kick off which is the next phase of producing the oil from the reservoir and to bring the oil to the surface. Basically, these approaches include injecting additional energy sources (supplementary energy) into the reservoir to maintain and increase the reservoir pressure. These artificial approaches contain natural gas reinjection, water injection, and CO_2 injection as show in **Figures 3** and **4**. With time the artificial pressure loses efficiency as the residual heavy oil is extremely viscous to flow and is detained by sandstone in the reservoirs [6]. The total recovery factor of the heavy oil including the primary recovery approaches will be within the range of 10–25% [7].

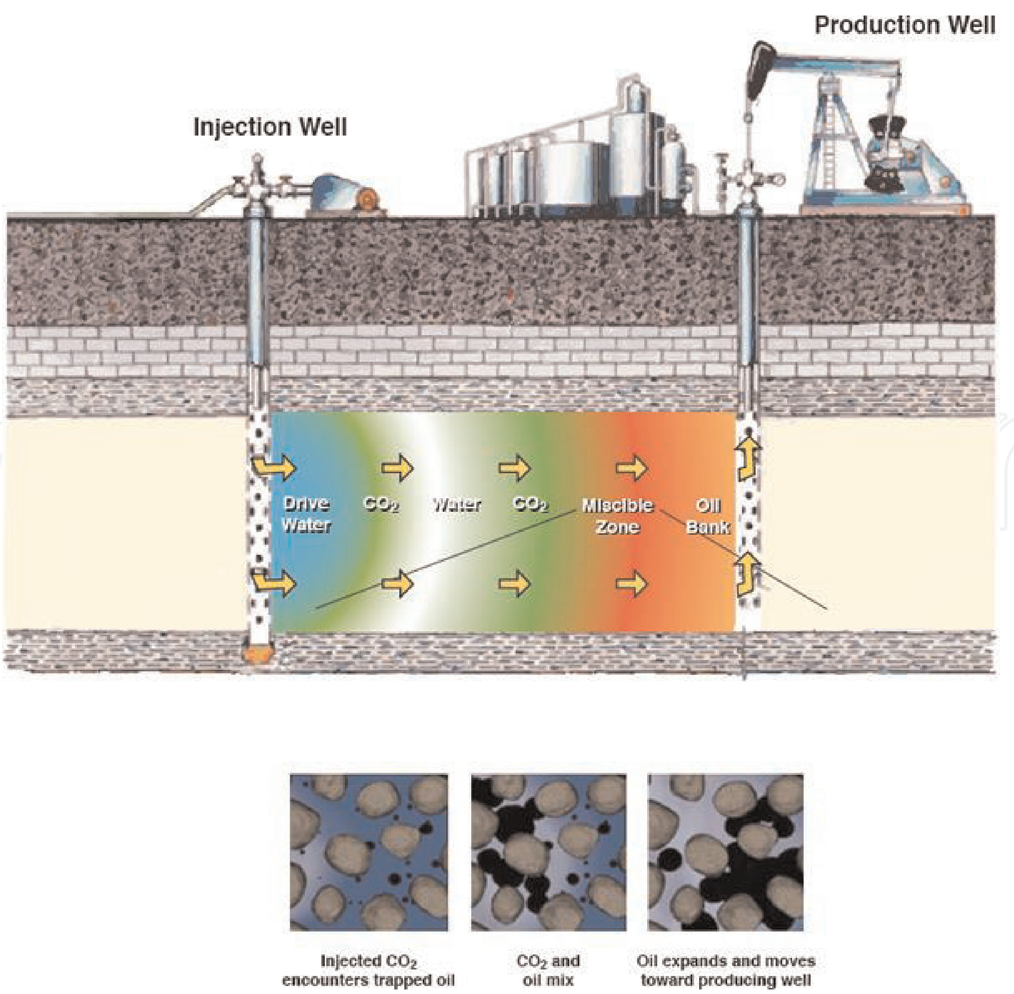

Figure 3.
Enhanced oil recovery using CO_2 injection (source: NETL (2010)) [8].

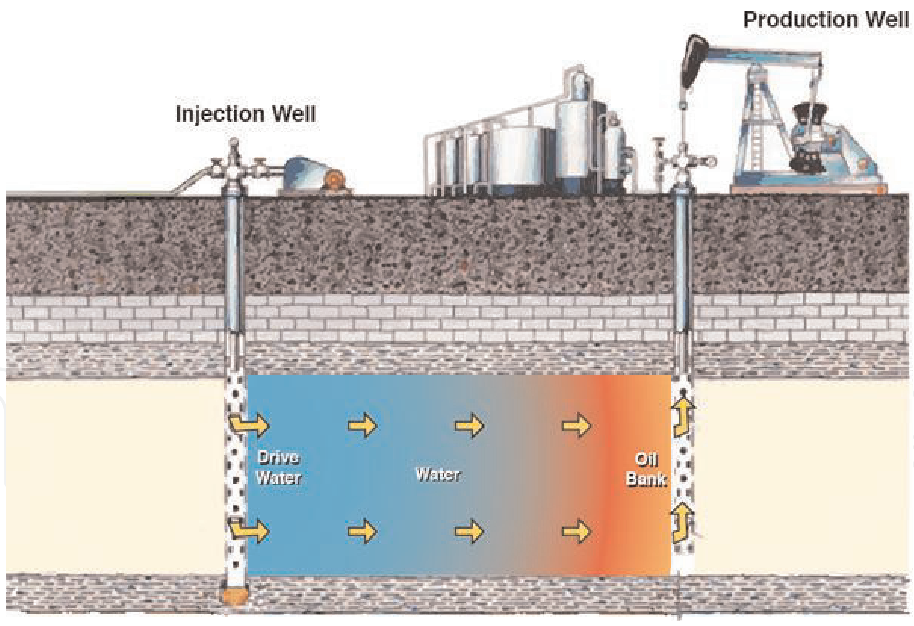

Figure 4.
Illustrating waterflooding technique of secondary recovery (source: NETL (2010)) [8].

2.3 Tertiary recovery

Tertiary recovery is generally denoted as enhanced oil recovery. It is an approach of extracting oil through thermal and nonthermal processes after most of the oil has been extracted by primary and secondary recovery methods [9]. Mainly, EOR is used to extract the heavy oil trapped in porous media of reservoir rock which is too viscous to flow. The most common approaches for tertiary recovery are thermal, chemical, and miscible enhanced recovery.

For nonthermal approaches, chemicals and microbes are used to release trapped heavy oil and carbon dioxide under pressure. However, thermal approaches are generally steam injection which is the most effective means of decreasing viscosity and mobilizing heavy oil [7].

2.4 Thermal methods of recovery steam-based processes

2.4.1 Steam injection

Steam injection is commonly used for high viscous oil. The main objective of the steam injection is to heat up and force the oil to the wellbore by the pressurized steam depicted in **Figure 5**. Generally, the EOR methods are costly because of the required external energy resources and materials. Consequently, the volume of heavy oil to be extracted from a reservoir rock is a function of economics [10]. As a result of this, engineers must start to study in more details the reservoir rock permeability, pore media, and oil viscosity, together with the reservoir heterogeneity, where all these issues affect the success of any recovery technique. Overall steam injection efficacy is the product of the sweeping capability and displacement competence.

2.4.2 Cyclic steam stimulation

Cyclic steam stimulation (CSS) is one of the main EOR approaches for heavy oil production. The notion of the CSS is that the steam is injected into the reservoir via a production well for a period of time. Then the well is closed and permitted to soak by steam for some period of time before it returns to production. CSS was applied in

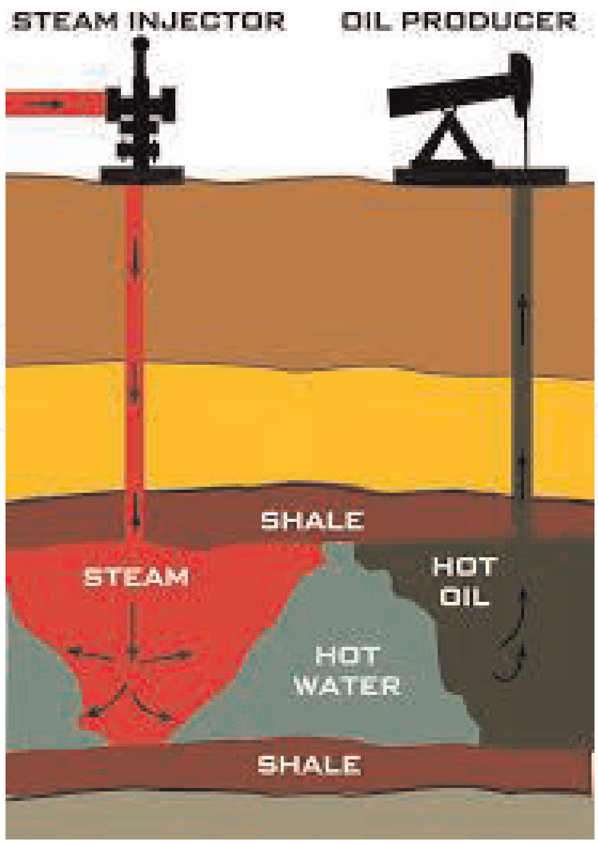

Figure 5.
Illustrating the thermal flooding technique (source: Steam EOR 1.Jpg (2008)) [8].

many heavy oil wells in the Middle East. Various cycles were done in these wells. However, the total amount of produced water for each cycle was considerably less than estimated.

2.4.3 Steam-assisted gravity drainage

Steam-assisted gravity drainage (SAGD) comprises pairs of a high-angle injection wells with an adjacent production well drilled along a parallel trajectory depicted in **Figure 6**. Normally, steam is injected via the upper well. Once the steam rises and spreads, it will heat up the heavy oil trapped in the porous media, decreasing its viscosity. Then assisted by the gravity forces, the oil will be drained into the lower well where it is produced [11]. Generally, the steam injection involves two core approaches, cyclic steam injection, and steam flooding.

2.4.4 Cyclic steam injection

The fundamental idea of the cyclic steam injection (CSC) is to inject hot steam through a single well for a period of time. A CSC method contains three phases (see **Figure 7**). The first phase is injection, through which a slug of steam is injected into the reservoir. The second phase requires that the well is shut for some days to permit equal heat spreading to thin the oil. Finally, throughout the third phase, the thinned oil is produced over the same well. The same cycle process is repeated many times as far as oil production is still profitable. Commonly, the cyclic steam injection process is used widely in heavy oil reservoirs and tar sands and also can be used to enhance injectivity prior to steam flood process and in combustion processes. Steam injection

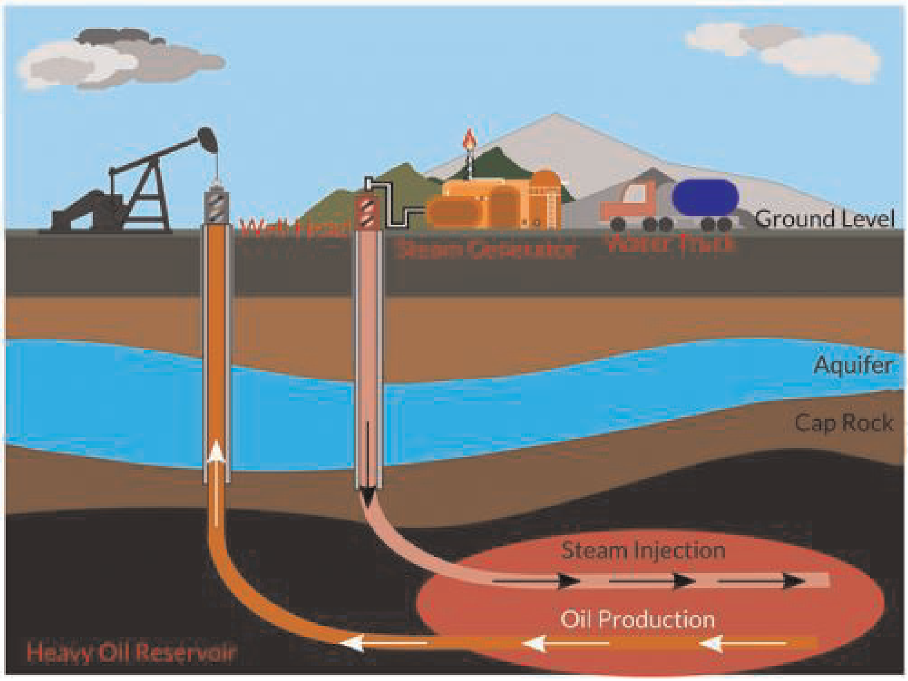

Figure 6.
Illustrating steam-assisted gravity drainage (source: Markham Hislop (2017)) [12].

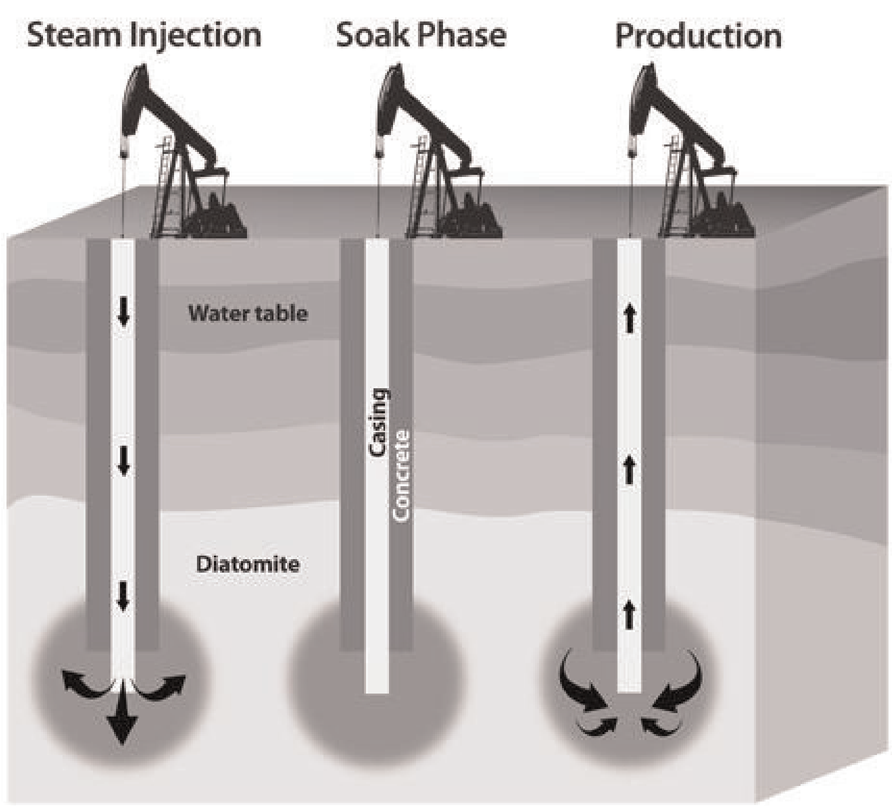

Figure 7.
Cyclic steaming processes. First, steam is injected at high pressure; second, the steam thins the viscous oil; and third, the oil is produced up to the surface (source: Lyz Hoffman (2014)) [13].

is typically used in both horizontal and vertical wells producing high viscosity as high as 100,000 cP. Normally in CSC wells, oil can be both viscous and solid. Usually, CSC is termed “steam soak” or the “huff ‘n puff” (slang) technique. Normally, CSC recovery factor is within the range of 10–20% of the initial oil in place [13].

2.4.5 Continuous steam injection (steam flooding)

Continuous steam injection is a new method to manage heat flow in the reservoir and to decrease the temperature of the fluids at production wells in that way avoiding shut-in made by high temperature (**Figure 8**). The best injection plan with different pressure and fixed steam quality has shown to have the biggest oil recovery given the same quantity of energy injected under various reservoir sets. Steam is injected at high temperature and high pressure via an injector well. The oil recovery of this technique is more than the cyclic steam injection method, and it's more practical and efficient. It has lower thermal efficacy than CSC and needs a larger surface area. This method needs one well for steam injection and another well for oil production [15]. Typically, the recovery factor of the steam flooding method is about 50% of the initial oil in place [9].

2.4.6 Combustion processes

The combustion process, also referred as fire flooding, challenges the recovery of more heavy oil by a flare-up of a part of the oil in place by injecting either oxygen, air, or chemical or by electrical shock (see **Figure 9**). This decreases the heavy oil viscosity and heats the oil in place, and the oil is moved out by a combination of steam, hot water, and gas drive. This method appeared always to be very suitable, mainly when we need to recover bitumen from tar sand deposits. Normally, the temperature of the combustion process can reach up to 700°C. This temperature can be observed at the combustion front [17–23]. Typically, the combustion technique is applied to hydrocarbon reservoirs of low API gravity oil. By using the combustion method, the heavy oil gravity can be upgraded from 2 to 6° API (Ramey et al., 1992). Forward combustion includes a drive of the burning front in a similar direction as the injected air; where the reverse combustion includes a drive of the burning front opposite to the direction of the injected air.

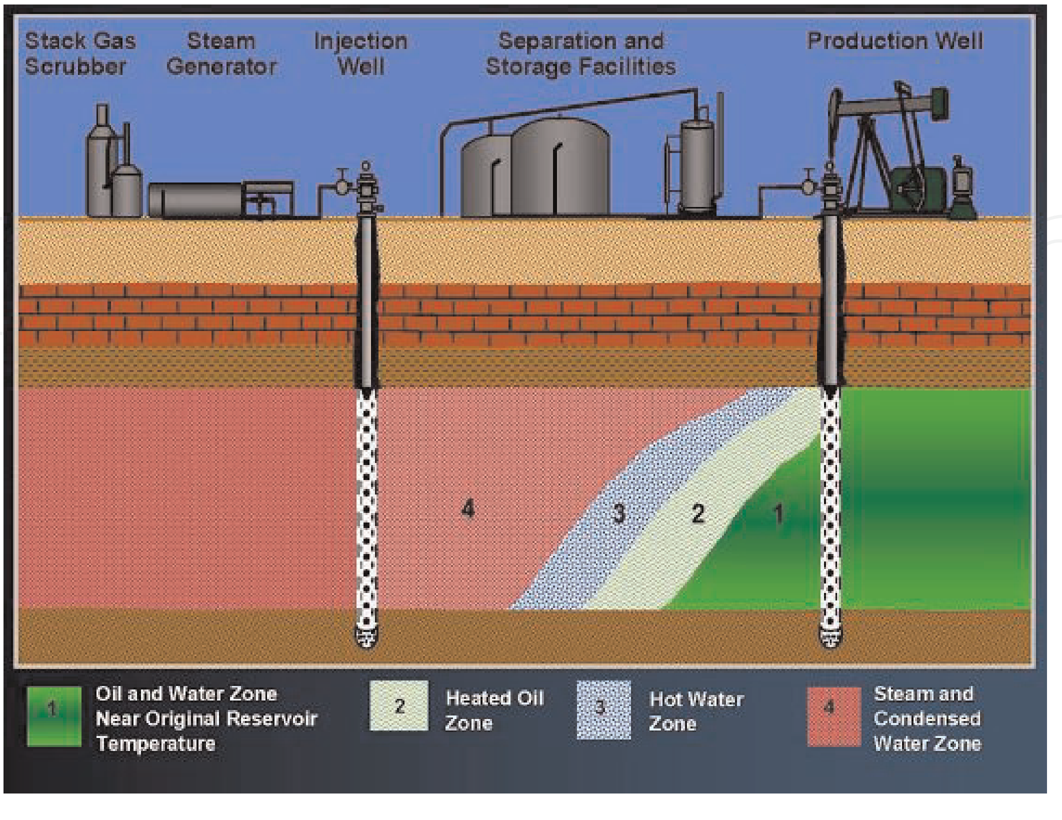

Figure 8.
Diagram shows steam flooding (source: Alhakiki (2012)) [16].

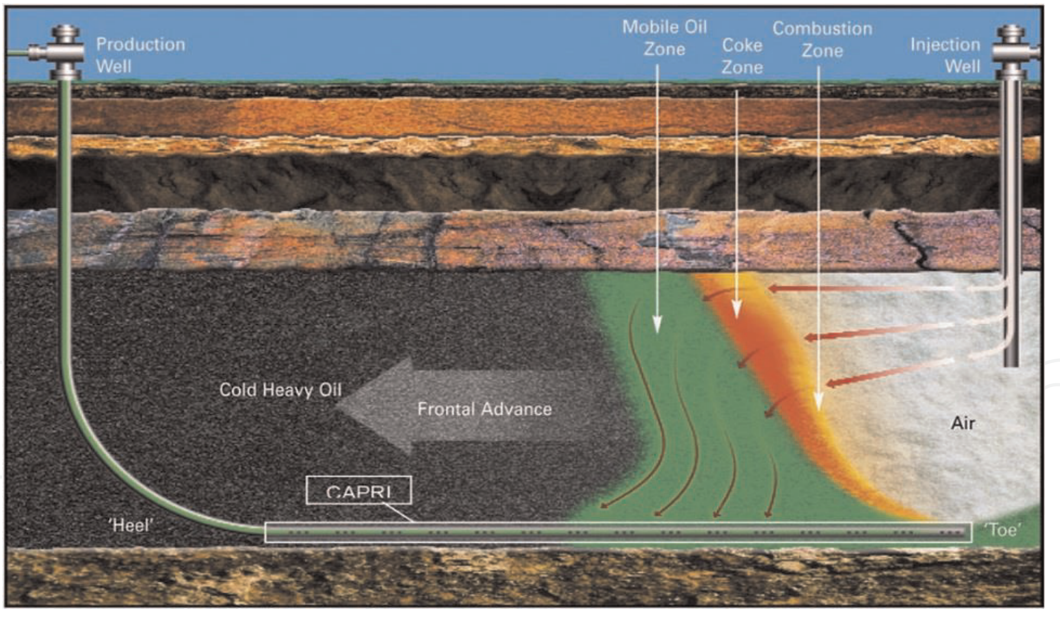

Figure 9.
Schematic of combustion processes (source: Rob Kendall (2009)) [23].

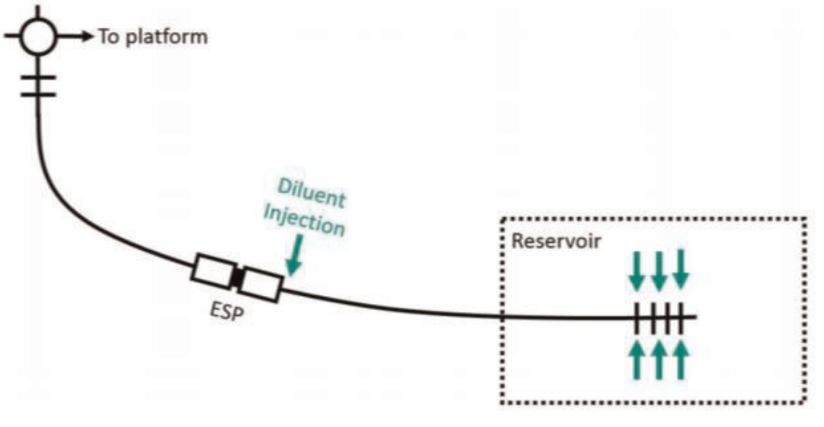

Figure 10.
Schematic of downhole diluent injection method (source: Arnaud Hoffmann (2016)) [25].

2.5 Downhole diluent injections for a heavy oil field

Many previous studies proved the diluent injection with ESP can be an efficient artificial lift method for heavy oil reservoirs. It consists of injecting a light hydrocarbon liquid to reduce the oil density and viscosity depicted in **Figure 10**. This recovery method makes use of several kinds of diluents injected downhole to decrease heavy oil viscosity in the reservoir. Normally the diluents used such as kerosene, naphtha, and light oil or may be injected into the drain and blended with heavy oil. Numerous field experiences show that the use of diluents allows the viscosity of the heavy oil to decrease from 100,000 to <1000 cP. The diluted fluid is then returned back to the surface by a downhole pump such as progressive cavity pumps (PCP). There are many diluent injection operations that extracted heavy oil of 7.5–9° API. The API quality of heavy oil has been upgraded to high commercial quality (32° API). For instance, a case study for extra heavy oil is produced from the 1300 meter horizontal section through downhole ESP pumps. The diluent fluid used has 46° API gravity of naphtha. In the diluent fluid injected at the bottom of the slotted liner, the diluent fluid transfers gradually in the horizontal part of the drain through the influence of the pressure differential created by pump process. The heavy oil gradually moves from the reservoir to the liner and reaches the pump intake section with decreased heavy oil viscosity that is suitable for the pump efficiency. The heavy oil viscosity at reservoir conditions was 10,000 cP at 50°C, but once mixed with 20% naphtha, the viscosity value decreased down to 200 cP. The mixed pumped fluid viscosity can be simply attuned by the rate of diluent injected downhole through the injection line.

3. Artificial lift systems

Well artificial lift plan is a strategic aspect in the production of heavy oils. Obviously, some types of artificial lift was required in order for the oil to flow and return the flow rate of the oil to their normal rates to maximize the ultimate oil recovery. The choice of which artificial lift technique is to be used is very significant for the long-term profitability of the oil field. An inappropriate selection of artificial lift can decrease production and raise the operating cost significantly. After a decision has been taken, it can be hardly changed whether or not the technique selected was suitable for the existing conditions.

The selection procedure of the lifting method to be used, which are confined to the operating life of surface and downhole equipment, maintenance, environmental concerns, and cost. Therefore, there are several configurations of downhole oil pump systems including pumps and drivers as described below.

3.1 Hydraulic pumping systems

Hydraulic pumping is one of the artificial lift methods used since the early 1930s. Hydraulic pumping systems can be used at different oil well production conditions (**Figure 11**). This type of pump was installed at different setting depths ranging from 400 to 20,000 ft. with varying production flow rates from 80 to more than 20,000 STB/D. The pump has surface speed drive box ranging from 15 to 625 hp. which makes the downhole pumping rate to be controlled on the surface.

The basic operating process of the pump is that the power fluid is pumped from the surface facilities to activate the downhole piston together with a reciprocating piston pump (refer to **Figure 12**). The power fluid acts on a piston like a steam engine, and the power fluid could be oil or water. The power fluid transfers to the piston and returns back to surface over another pipe if a closed loop power fluid is used. In the open power fluid design, the power fluid is combined with the production once flowing to the surface. To control the corrosion, chemicals can be injected downhole along with the power fluid. The advantage of using this pump is the power fluid which can be heated for handling heavy oil. The pump is appropriate for deviated wells which might be difficult for other artificial lift methods. The pump surface facilities have a small footprint and can be assembled into one main battery to service many wells. Commonly, hydraulic pumps are applied primarily in very deep oil wells that are producing at great volumes which cannot be handled by using beam pump systems.

3.1.1 Types of hydraulic pump systems

Generally, it can be used in low API oil gravity wells and in wells with high paraffin contents. Also used in the wells that failed to use any other artificial lift techniques or, because of well conditions. It's used in deep and deviated wells including sandy and corrosive wells. Hydraulic pumping systems are quite

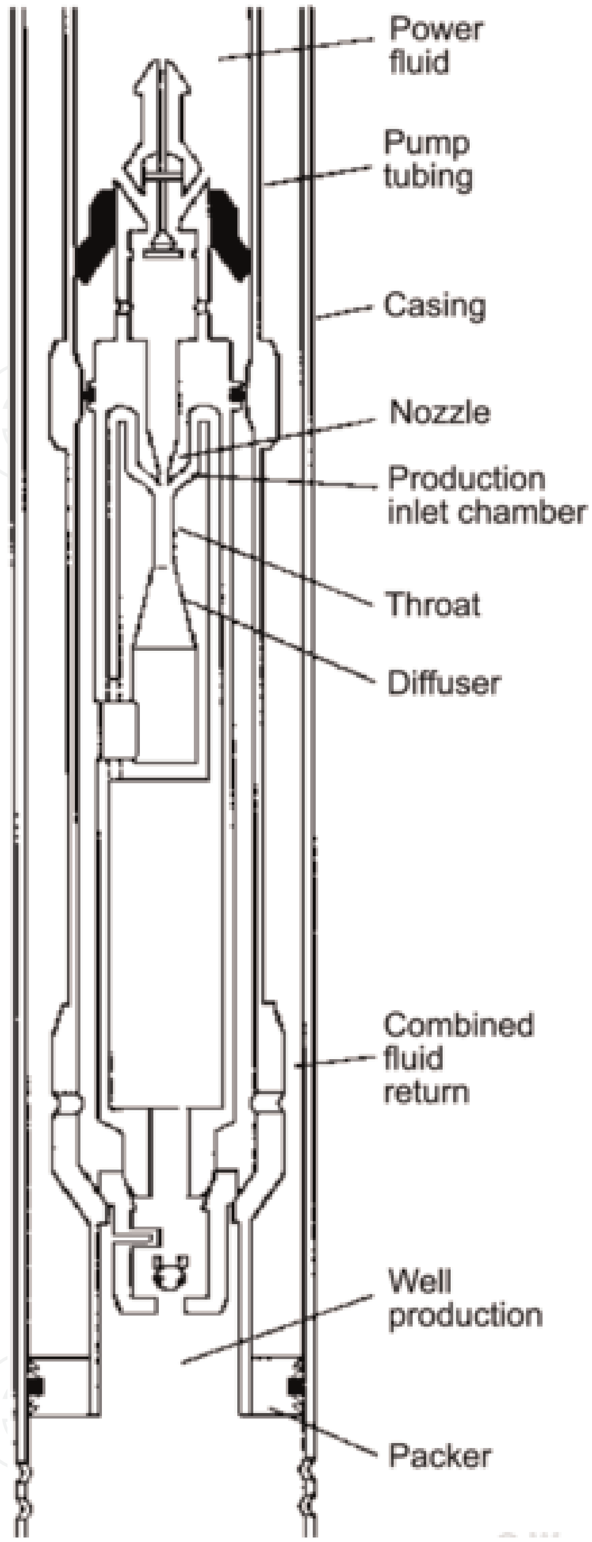

Figure 11.
A schematic of the downhole assembly piston pump (source: Cholet H, 2004) [26].

expensive, but they may have a good application where other artificial lift techniques may not be possible.

3.1.1.1 Piston pump

A piston pump includes a motor at one end and a plunger pump at the other end (**Figure 13**). Hydraulic fluid is forced down the completion string at very high pressure and goes in a reciprocating motor. The motor mechanism is piston-like pump which is forces the produced hydrocarbons to the surface throughout the

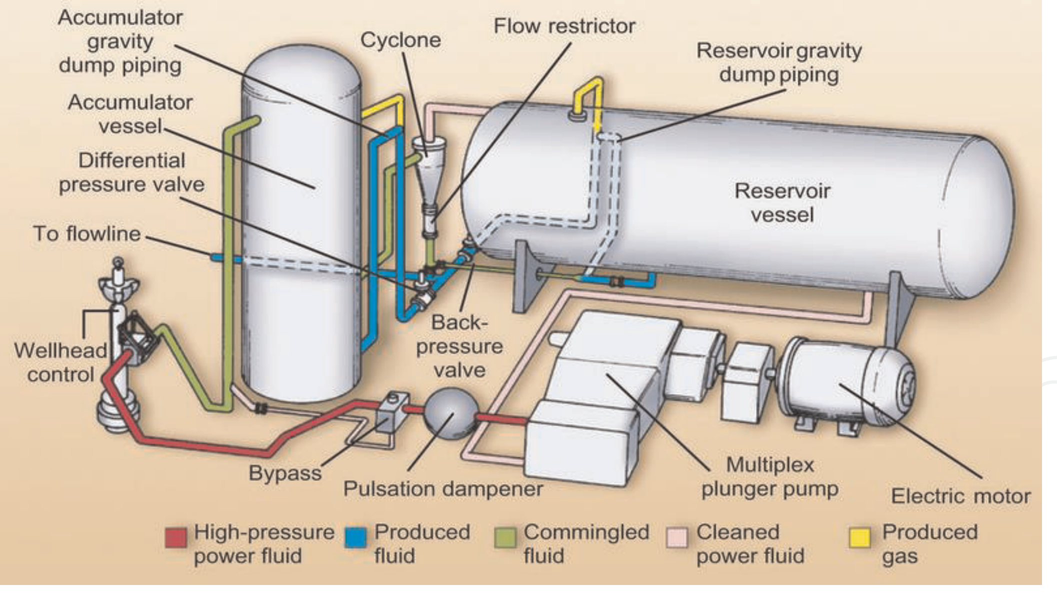

Figure 12.
Diagram of hydraulic pumping surface facility system (source: SPE) [27].

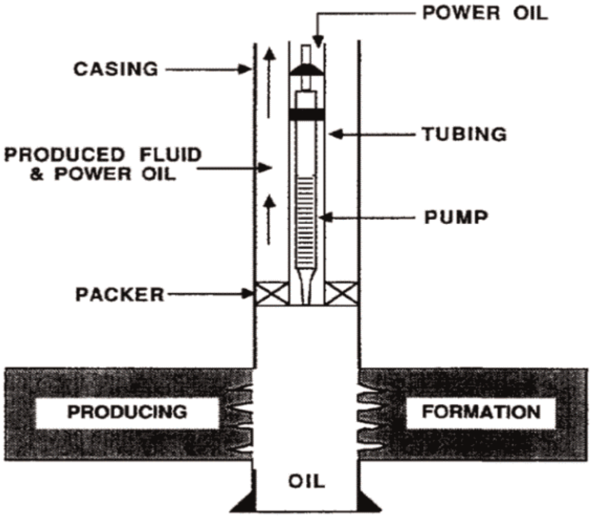

Figure 13.
Hydraulic piston pumps (source: Conoco Inc., 1990 [29]).

casing annulus. Normally, the hydraulic fluid is used as a power fluid. Once both hydraulic fluid and produced fluids reach the surface, the hydraulic fluid is separated and reused again as the power fluid.

3.1.1.2 Jet pump

Jet pumps have been applied in the oil industry for more than 75 years. A jet pump is one of artificial lift methods, and it can be applied when depth and deviation of producing wells increase and reservoir pressure depleted (**Figure 14**). A jet pump is used in thermal production as it's not directly affected by the high temperature of the fluids. This pump can considerably reduce the risk of equipment failure in the wellbores because it has no moving parts. These pumps are in the family of thermo-compressors, and they are categorized as "eductors" as they are considered for a liquid to pump a liquid (incompressible liquid). The pump is set downhole and pulled up the well for retrieval by using pressurized fluid.

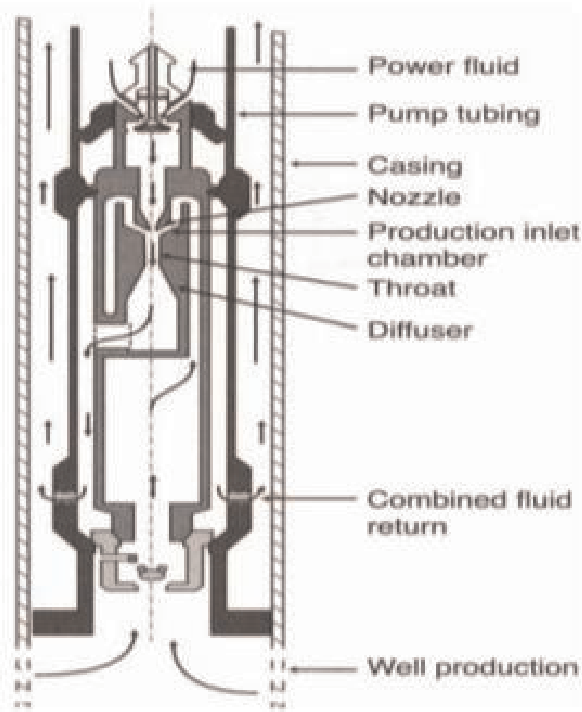

Figure 14.
Typical jet pump system (source: Cholet H, 2004) [26].

Normally, this process is using a pump at the surface to generate high-pressure power fluid to be transmitted downhole via tubing or through an annular casing. The power fluid moves into the pump and goes via a nozzle, where almost the whole pressure of the power fluid is transformed into a velocity head if no loss happens. The velocity of the power fluid can reach up to 70 m/s from the nozzle outlet section into the production inlet chamber linked to the pump intake section. Both production fluid and power fluid returned back to the surface over the production pipes. Comparing with other pump systems, hydraulic efficacies of jet pumps are lower in the range of 20–30%. A jet pump can produce high rates and can handle free gas as well, though it's not as efficient as a positive displacement pump, therefore needing higher horsepower requirements at the surface [28].

A jet pump is very suitable in specific conditions, for instance, when high production rates are preferred. The pump is suitable for handling viscous, corrosive, and heavy crude oils. Besides, locations where beam pumping units cannot be installed, such as inhabited regions, offshore oil fields, and gas lift, are not accessible. The pump is attractive in horizontal, deviated, deep, and high-temperature wells. Also, it has excellent solid-handling capabilities and has long operational life (average of 4 years). Moreover, it has tolerance for gas and solids production, and it has low installation and workover costs.

3.2 Beam pump systems

Beam pump is an artificial lift pumping system applying power source at a surface to transmit the energy to a downhole pump assembly. Producing heavy oil from shallow reservoirs using beam pump systems needs accurate design mainly for downhole assembly to get maximum production performance and maximize the run life.

A beam and crank assembly creates reciprocating motion in a sucker rod string that attaches to the downhole pump assembly. The pump comprises a plunger and valve assembly to transform the reciprocating motion to vertical fluid movement. **Figure 15** shows typical beam pumps.

3.2.1 Classification

The hollow sucker rod electric heating device can be divided into a pumping unit device, subsurface pump and screw pump hollow sucker rod device. **Tables 1–3** show the sucker rod electric technical data.

3.3 Progressive cavity pump systems

PCP was developed in 1930. Currently, this pump is used to produce heavy oil in any kind of wells: vertical, deviated, or horizontal. A PCP is essentially made of two helical gears, one inside the other (**Figure 16**). **Table 4** displays the lift selection guidelines. The suitable use of each lift type is reliant to the type of the reservoir fluid, reservoir pressure, and production rate as estimated by inflow and outflow system.

The metallic rotor is a single helical "rotating" inside the stator based on a double helical elastomer-lined nitrile in most cases. The external gear or stator has a double helical shape, one more than the internal single helical gear rotor. When the rotor is rotating, the fluid transfers together with the pump axis inside the cavities

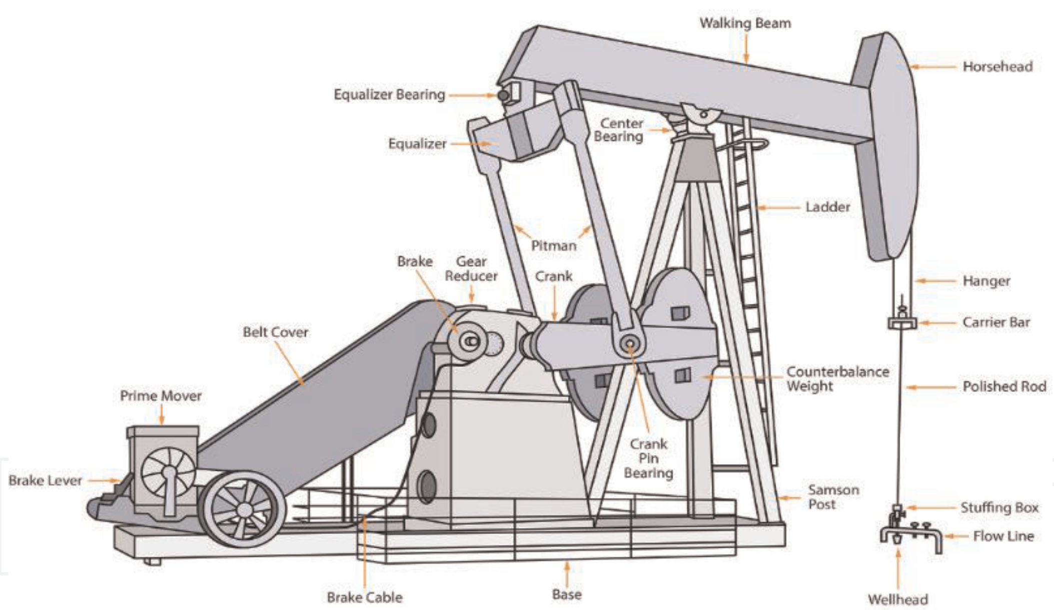

Figure 15.
Typical beam pumps (source Conoco, 1990) [29].

Rod outer diameter	34 mm	36 mm	42 mm
Rod thickness	5.0 and 5.5 mm	5.5, 6.0 and 6.5 mm	6.0 mm
Coupling outer diameter	50 mm	50 mm	60 mm
Thread size	1–9/16"	1–9/16"	1–7/8"
Grade	D		

Table 1.
Hollow sucker rod.

Heating core sectional area mm^2	$3 \times 8.4\ mm^2$
Outer diameter of cable	18–20 mm
Outer protect layer	Stainless steel wire armor weave
Withstand voltage	≥2500 V
Length	Underground length + ground length
Temperature-resist grade	Long-time working temperature: 200°C (C grade)
Electrical performance	Insulation resistance >50 MΩ, AC withstand voltage test 2500 V
Tensile strength	≥50 Mpa

Table 2.
Heating cable.

Rated power KVA	35, 50, 75, 100, 135
Input voltage	Three phase 380 V ± 5% 50HZ three phase 440 V ± 5%, 60 HZ
Output voltage	Single phase 160–900 is available
Power factor	cos θ ≥ 0.95
Three phase imbalance percent	≤10%

Table 3.
Electric control cabinet.

present between the rotor and stator. The flow rate is a function of many parameters, for example, pumps eccentricity, rotor diameter, length of the stator pitch, and rotation speed. Manufacturers can provide a catalog of pumps with a wide range of well conditions as a function of reservoir fluid types, flow rates, pressure heads, and for any type of fluid viscosity.

PCP is normally driven at the surface, but it can be driven by a downhole electrical submersible motor. When PCPs are driven from the surface (refer to **Figure 17**), the stator is screwed at the tubing extremity, and the rotor is fixed to the drive string of sucker rods. On the surface, the drive head, absorbing the force of the sucker rods, is operated by an electric motor and a speed reducer. Most of the downhole assembly is driven in this way.

The PCP pumps can operate at high efficiency for high viscosity cruds, high sand, low productivity wells, and in horizontal and deviated wells. Besides, it has a small footprint on the surface. Besides, the pump has some disadvantages, where the pump has restricted production rate, lift depth, and temperature tolerance. In the case of horizontal and deviated well profile, where malfunction can cause tubing leaks made by wear or failure of the sucker rod drive shaft, the PCP is not allowed to pump dry, and the completion string must be pulled out of the well to change the pump.

3.4 Electrical submersible pump

An ESP is a centrifugal pump driven by a downhole electrical motor (see **Figure 18**). ESP surface facilities contain power system and transformers and connectors to the wellhead. Normally, ESP pumps are installed for high flow rates (from 150 to 150,000 bopd) dependent on size and pressure gain and variable speed controllers. These pumps are not suitable for very viscous untreated oil, but ESPs can be applied to lift oil production after injection of diluents fluids (reduced the

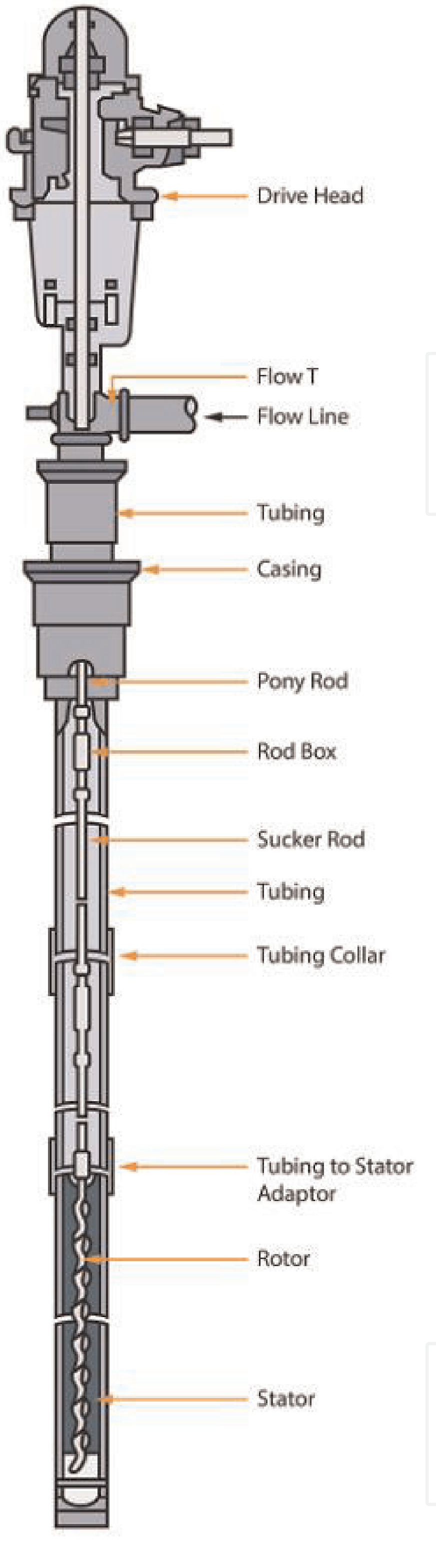

Figure 16.
Progressive cavity pump (source: John Martinez (2017)) [28].

viscosity). An example of the electric submersible pump/motor assembly is given in **Figure 18**. The efficiency of the pump is very dependent on the design of the flow rate which must carefully be optimized based on the reservoir deliverability. Moreover, the wellhead of the ESP system needs to have an electric cable entering. The downhole electrical submersible assembly contains an electrical power cable, motor, motor protector, and centrifugal pump.

Thermal recovery offers several limitations for ESP pumps because of the high temperature applied to the electric motor, electric parts, power cable, and pump assemblies. ESP manufacturers present different designs for high-temperature

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	Rod lift	**Progressing cavity**	**Gas lift**	**Plunger lift**	**Hydraulic piston**	**Hydraulic jet**	**Electric submersible**
Operating depth (ft)	To 16,000 TVD	To 6000 TVD	To 15,000 TVD	To 19,000 TVD	To 17,000 TVD	To 15,000 TVD	To 15,000 TVD
Operating volume	To 5000 BPD	To 4500 BPD	To 30,000 BPD	To 50 BPD	50–4000 BPD	300–>15,000 BPD	200–30,000 BPD
Operating temperature	100/500°F	75/250°F	100/400°F	120/500°F	100/500°F	100/500°F	100/400°F
Corrosion handling	Good to excellent	Fair	Good to excellent	Excellent	Good	Excellent	Good
Gas handling	Fair to good	Fair	Excellent	Excellent	Fair	Good	Poor to fair
Solid handling	Fair to good	Excellent	Good	Poor to fair	Poor	Good	Poor to fair
Fluid gravity	>8° API	<35° API	>35° API	GLR required 300scf/bbl./1000′ depth	>8° API	>8° API	>10° API
Servicing	Workover or pulling rig	Workover or pulling rig	Wireline or workover	Wellhead catcher or wireline	Hydraulic or wireline	Hydraulic or wireline	Workover or pulling rig
Prime mover	Gas engine or electric	Gas engine or electric	Compressor	Wells' natural energy	Gas engine or electric	Gas engine or electric	Electric motor
Offshore application	Limited	Good	Excellent	N/A	Good	Excellent	Excellent
Overall system efficiency	40–60%	40–70%	10–30%	N/A	45–55%	10–30%	35–60%

Table 4.
Lift selection guidelines (John Martinez (2017)) [28].

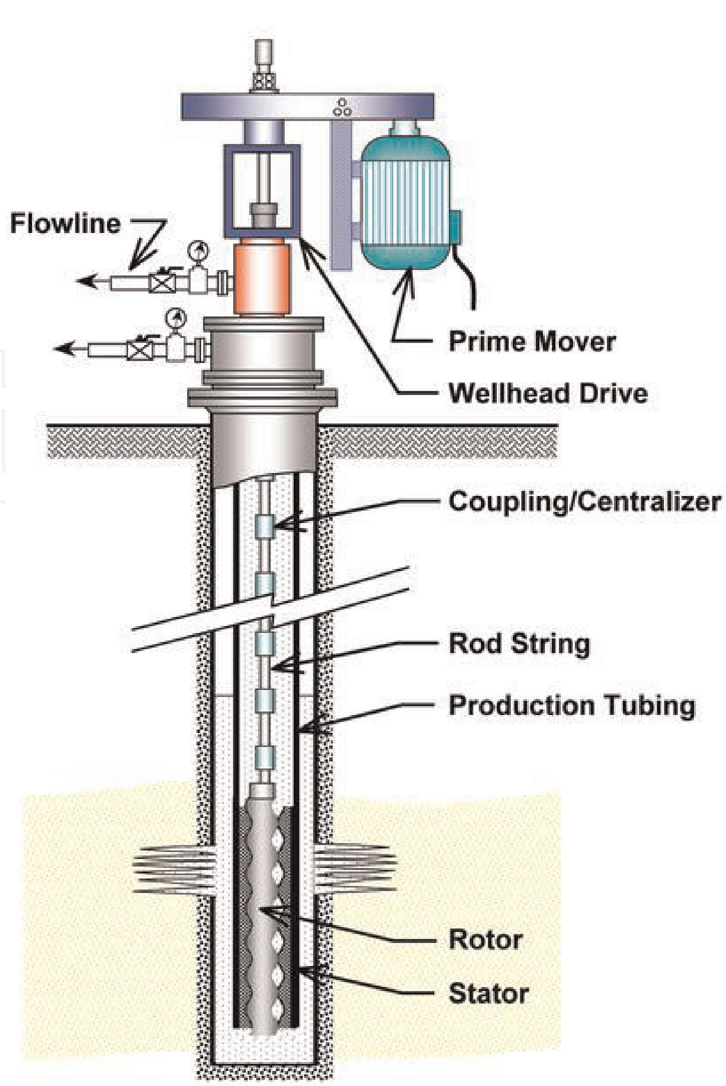

Figure 17.
Typical progressing cavity pumping system (source: SPE) [27].

reservoir fluids, for example, "hotline production" equipment with operating temperature ratings up to 550°F for the power cable and motor.

3.5 Gas lift systems

Gas lift is a type of artificial lift techniques used to lower the producing bottom-hole pressure to achieve a higher oil production rate. The principle of gas lift method is that gas injected into the tubing string decreases the density of the fluids in the pipe and lets the two-phase mixture to flow up to the surface. There are two main kinds of gas lift techniques being applied today which are continuous and intermittent flow. Typically, natural gas is continuously injector under high pressure through tubing or through the annular between casing and production pipe into the pocket mandrels along the production tubing. At high-temperature the multiphase flow will be produced at the surface (refer to **Figure 19**). Normally, gas compressor pressure and rate parameters are modified based on the gas lift constraint depicted in **Figure 20**. Gas lift is commonly used with SAGD heavy oil production in Canada.

3.5.1 Applications of gas lift

Gas lift is mainly appropriate for lifting fluids in wells that have a low amount of gas produced with the oil. Gas compressors are almost mounted to collect the

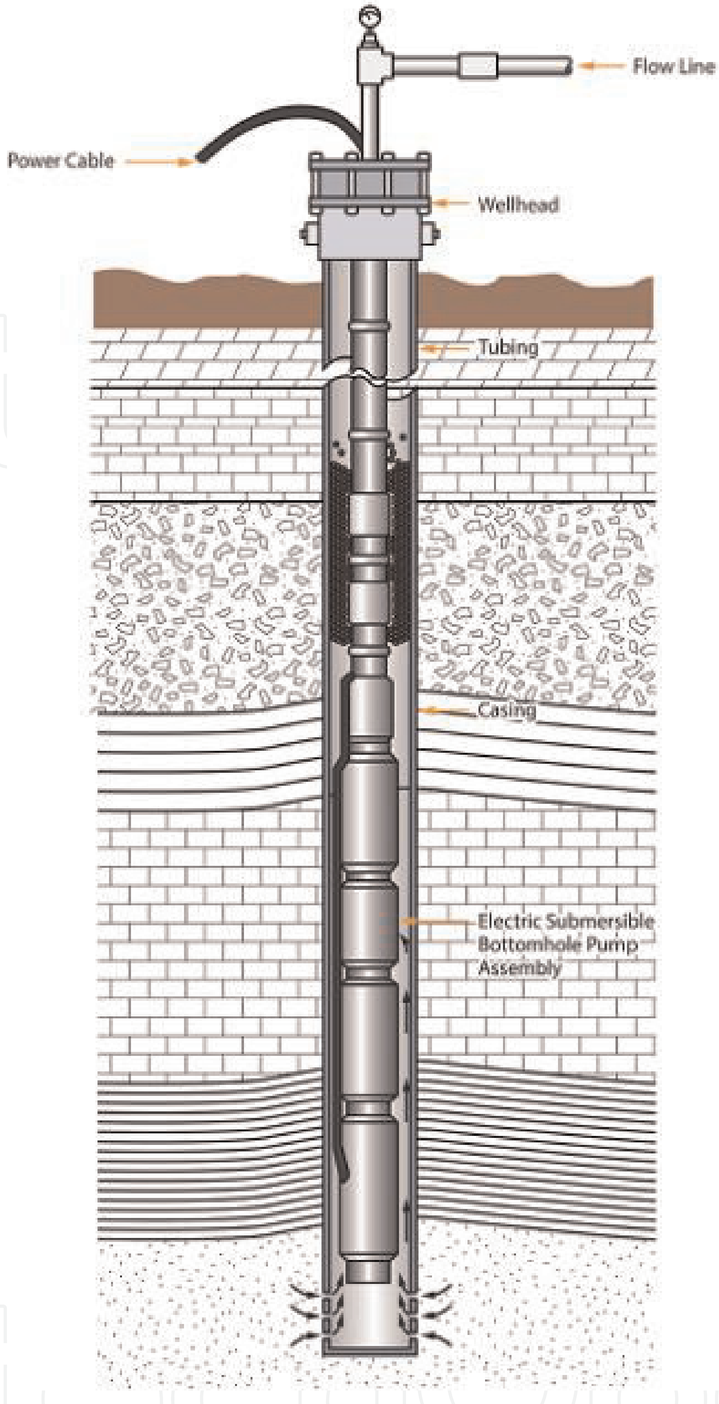

Figure 18.
Typical electric submersible pump (source: John Martinez (2017)) [28].

produced gas and designed to be used for the gas lift system. The flexibility of gas lift, in terms of production rates and depth of lift, can seldom be matched by other methods of artificial lift if adequate injection gas pressure and volume are available. Gas lift is very suitable for highly deviated wells which produce sand and high gas-liquid ratios. There is no other method that suitable for through-flowline ocean-floor completions as a gas lift system. Besides, wireline-retrievable gas lift valves can be replaced without killing a well or pulling the tubing. Individual well downhole tools are low-cost. The surface gas lift facilities for injection gas control are simple and need low maintenance and nearly no space for installation. Usually, the reported high overall reliability and lower effective costs for a gas lift method are more to other techniques of lift.

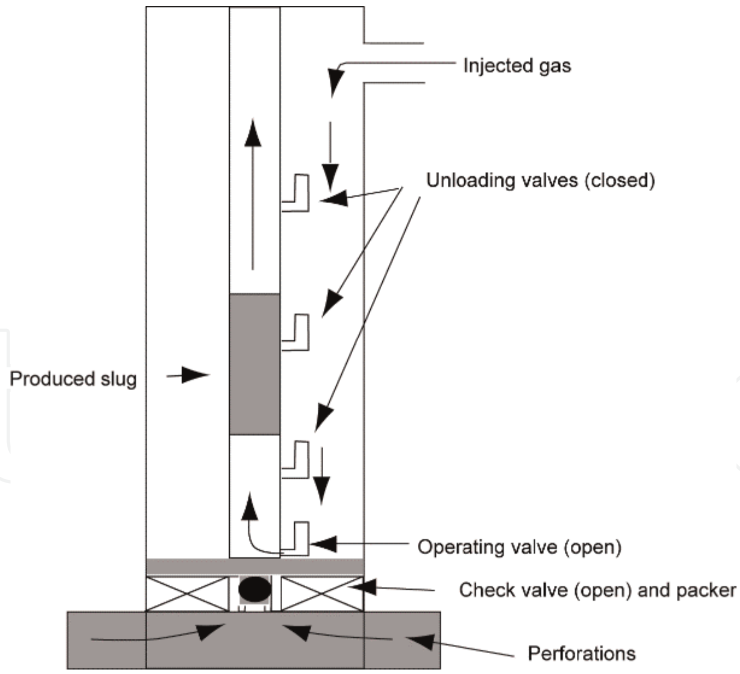

Figure 19.
Diagram of injection gas cycle for gas lifting well (courtesy of Schlumberger).

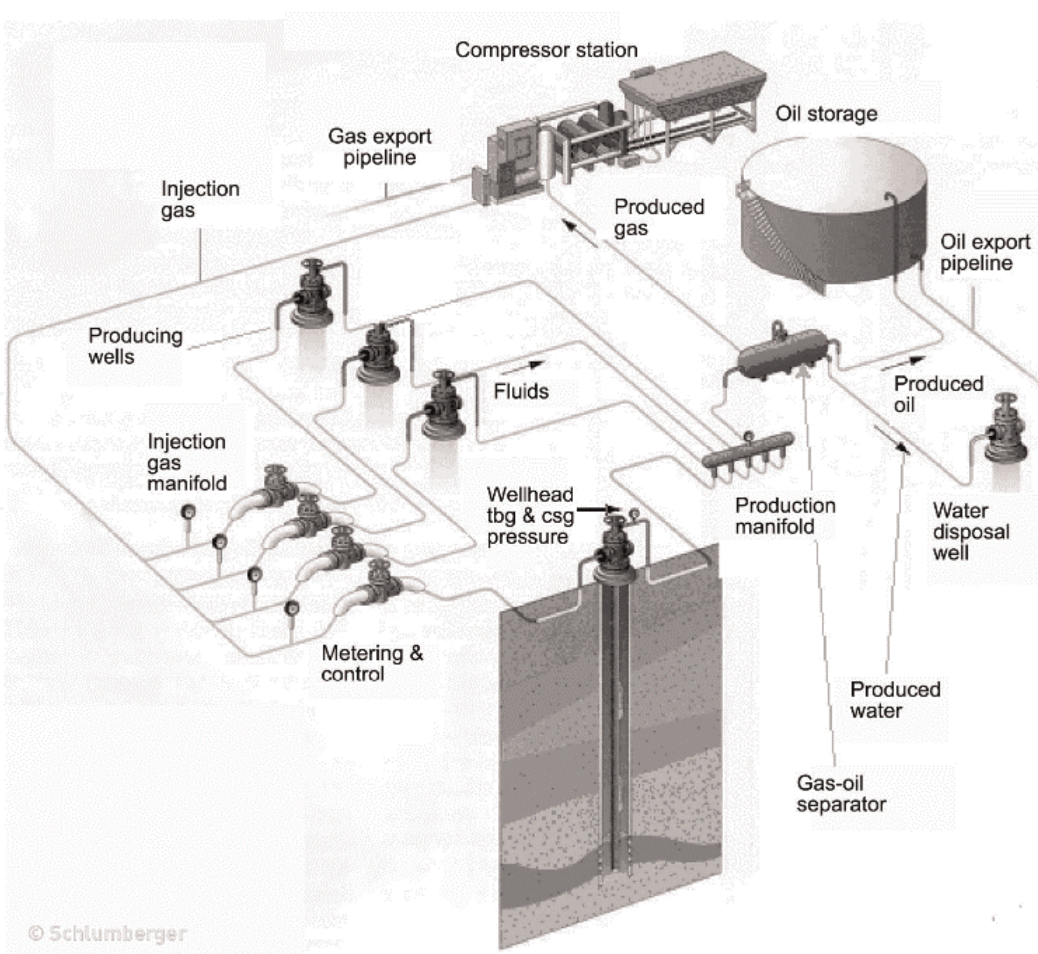

Figure 20.
Diagram of a gas lift system (courtesy of Schlumberger).

4. Future development of pumping system performance

Pump monitoring is a crucial factor in prolonging the working life of all kinds of downhole pump systems. Currently, it is feasible to measure the downhole and surface pressure and temperatures using sensors that are connected to data controllers to decrease the risk of "pump off": a lack of fluid to lubricate the pump, allowing heat to build up which would damage the elastomer stator of any type of pump. Advanced controller alarms can set parameters to reduce risk, extend pump working life and improve the total oil produced.

The pumping system needs more development to handle the operating cost, mainly for operation and maintenance either for single equipment or the whole system. Regularly, oil producers are just focused on the instant demands of the equipment, and they do not realize how the system parameters are affecting this equipment. A system method studies for both supply and demand sides of the system and how they can act together, shifting the attention from a single component to the total pumping system performance. Normally, most types of pump failure are leakage, fouling, valve failure, and cracks in pipe chains. Assessing pumping system performance is required to solving such pump failure and finding enhancement opportunities. In endeavoring to find out solutions or search for techniques to develop pump performance, assessing only the components instead of the entire pumping system can cause analysts to manage potential cost savings. For instance, although a pump may be functioning efficiently, it could be producing more flow than the system needs. Therefore, it is essential to evaluate system efficacy based on how the end uses are worked by the pumps.

In the future, pumps need to be more reliable and proficient in functioning for a long time before requiring maintenance. Pumps must be safer to work, use less space, use less power, less noise and temperature. Additionally, the need to improve corrosion resistance and as well as the reliability of working in the high-temperature environment. Consequently, pumps will be friendlier to the environment and running with less power to decrease their carbon footprint. As well, the use of more recycled materials with fewer consumables, in that way helping to decrease whole pumps costs. Pumps are required to be easier to clean, overhaul, and reconstructed. Generally, there are several chances to increase the reliability, performance, and efficacy of pumping systems in the oil industry. Definitely, the next generation of important savings for pump operators belongs to a broader pumping system optimization method. This certainly needs a middle way, taking the proper mix of the best suitable available technology combinations for certain applications.

5. Technical challenges

Engineers and facilities and pump designers will encounter enormous challenges in developing heavy oil reservoirs, such as crude oil properties and composition, flow assurance, lifting process, and operations.

5.1 Fluid properties and composition

Proper experimental methods are required to properly characterize heavy oil emulsions at conditions that will come across in the actual production process. Correctly describing the apparent viscosity of an emulsion phase is an even bigger challenge. The viscosity of the crude could be very important description tool than the API gravity. Transport of high viscosity crudes can be a major flow assurance challenge for future developments. Skills at many fields in the design phase are important trends in heavy crude properties and description needs. Therefore, high oil viscosity, low reservoir energy, and cold ambient temperatures make recovery and transport of heavy oils a challenge. Heavy crudes have a lower market value due to low oil gravity, high sulfur content, and higher TAN numbers. Crude oil upgrading processes have CAPEX and OPEX intensives. With the vapor extraction process, a vaporized hydrocarbon solvent is injected into the reservoir to dilute the heavy crude and extract the lighter components while leaving the heavier ends behind. This technology essentially performs in situ upgrading of the heavy crude. The possibility of organizing any upgrading process will be technically and economically challenging.

Typically, some of the reservoirs are producing heavy oil and water. This can create emulsions, which generate high loads on lifting systems with more chemical and energy consumption. The capability to drive sand together with high viscosity fluids has made the pump systems the best alternative option for managing heavy oil production. Many challenges will meet pump designers to develop heavy oil reservoirs that have high viscosity and low initial pressure and temperature. Besides, heavy oil producers may face possible gas and water inflow on low-producing mature fields.

5.2 Reservoir characterization

The main challenge related to the characterization of deepwater and heavy oil reservoirs is that this must be accomplished with quite fewer reservoir penetrations. This means having to address and manage more uncertainties and risks with less information. This is a function of the greater drilling costs in deep water and the more marginal economics of these types of developments. Fewer well penetrations mean fewer database available such as logs, cores, tests, and fluid samples that are very significant in characterizing, measuring, and managing heavy oil reservoir uncertainty and risk. Consequently, deepwater heavy oil reservoirs are integrally characterized not only by greater unit development and production costs and lower product cost but also by greater reservoir uncertainty and well performance risk.

5.3 Impact of heavy oil on flow assurance mitigation strategies

The reservoir describes the main flow assurance challenges based upon reservoir fluid properties, phase behavior, composition, and initial reservoir conditions. Other ecological elements such as water depth, offset distance, ambient conditions, and development model also influence the approaches and processes employed to control flow assurance risks. Hydrate formation is a probability in essentially all offshore production systems if water is existing and ambient temperatures are cool. Reservoir fluid composition impacts the potential for wax and asphaltene problems. For steady-state conditions, the heavy oil viscosities should be controllable with proper protection. Appropriate modeling of transient operations could pose a bigger challenge.

5.4 Operations

There are several operational concerns that are essential to be considered when designing lift systems for viscous crudes. These contain start-up and gravity segregation. Starting up a system full of viscous heavy crude may be very challenging, if not impossible, for most lift systems. This is particularly true in cold or deep water. For ESPs and PCP pump systems, this has to be considered during the design phase to certify the required horsepower is installed for start-up. Equipment failure can simply happen when a downhole pump is made to turn from 0 to 3500 rpm in <1 second in a high viscous condition. Fluid's resistance and gravity segregation are the main problems with start-up in heavy oils in gas lift process. Even if a system may have sufficient gas lift injection pressure to flow gas over the operating valve, it does not offer greatly in terms of reducing the mixture density if the gas segregates to the high side of the tubulars. The gravity segregation can cause severe slugging. Using transient multiphase simulation programs during the design phase could predict slug volumes. Besides, the programs can propose solutions for slug mitigation. The injection of diluents may help to decrease the mixture viscosity, but some completion components, if elastomeric, might react by swelling and losing mechanical strength. Both gas lift equipment, ESPs, and PCPs contain elastomers, and exposure to diluents has to be cautiously assessed during the lift selection and design process.

6. Conclusions

Internationally, the heavy oil reserves have become more important as a future energy source. There are three techniques to produce heavy oil and bring to the surface which are primary, secondary, and tertiary recovery. The EOR processes can be categorized into three main groups, chemical, thermal, and miscible. Commonly, artificial lift techniques are utilized when the well cannot produce naturally at its economical rate. This is applicable for heavy oil reservoirs, where high viscosity along with the reservoir pressure drop will avoid the wells to produce naturally. Conventionally, heavy oil wells are using beam pump as primary artificial lift system. However, beam pumps are used for low flow rate wells; besides this pump has many operating problems. Alternatively, there are several pump systems currently employed as the first option in heavy oil wells, such as PCP, hydraulic pumps, and ESP.

The pumping system needs more development to handle the operating cost, mostly for operation and maintenance either for single equipment or the whole system. In the future, pumps need to be more reliable and capable of running for a long time before requiring maintenance. Pumps must be safer to work, use less space, use less power, and have less noise and high temperature. Accordingly, pumps will be friendlier to the environment and running with less power to decrease their carbon footprint. Pump designers and the technology are faced with enormous challenges in developing heavy oil reservoirs that have high viscosity and low initial pressure and temperature. Besides, heavy oil producers may also face possible gas and water inflow on low-producing mature fields.

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Conflict of interest

The corresponding author confirms that there have been no involvements that might raise the question of bias in the work reported or in the conclusions or implications.

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