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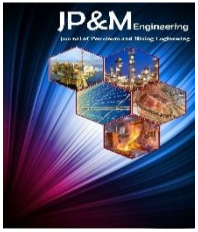

A Review of Recent Developments in Enhanced Oil Recovery: the Integration of Steam Injection with Chemical Additives and their Effect on Heavy Oil Recovery

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Abstract

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Steam injection integrations with polymer or biopolymer and surfactant have gained significant interest in the field of enhanced oil recovery (EOR). This technology aims to improve steam injection efficiency by reducing the surface tension between oil and water, increasing the viscosity of the injected liquid, and improving the sweeping efficiency of the injected liquid. In this review, recent developments in the field of steam injection with polymers, biopolymers, and surfactants are presented. This review discusses the mechanisms of integration of these materials and their effects on oil recovery. This review also reviewed the extent to which some factors, such as the type and concentration of agents used, and the heterogenity of the reservoirs, affected the effectiveness of this technique. Overall, this review article provides valuable insight into the potential of integrating steam injection with polymer, biopolymer, and surfactant as an effective method for enhanced oil recovery from mature oil reservoirs..

Introduction

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. Historically these stages described the production from a reservoir in a chronological sense, primary production, the initial production stage, resulted from the displacement of energy naturally existing in a reservoir. Secondary recovery, the second stage of operations, usually was implemented after the primary decline. Traditional secondary recovery processes are waterflooding pressure maintenance, and gas injection. Tertiary recovery, the third stage of production, was obtained after water flooding. Tertiary processes used miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process become uneconomical. However, the terms Enhanced Oil Recovery (commonly known as "EOR") and Tertiary Oil Recovery have been used interchangeably as shown in Figure 1.

Around 15% of the world's oil reserves are made up of heavy crude oils, which typically have low API gravities and high viscosities. Unconsolidated, high-permeability, and high-porosity sand deposits are where heavy oil is often discovered. Due to its high viscosity, which varies from 50 to 50,000 CP, and its density values, which are comparable to those of water, heavy oil has restricted mobility under reservoir conditions [1].

Only around one-third of known oil reserves can be recovered economically with the use of current technology. Since heavy oils are produced via unconventional techniques, they are often regarded as unconventional petroleum resources. Due to the low price of oil, enhanced oil recovery (EOR) techniques were not extensively used until recently. With rising oil prices and global oil consumption, interest in EOR techniques has grown dramatically in recent years.

Several types of EOR processes may be used for light and heavy oil reservoirs.

The main EOR categories are as follows.

- Thermal - hot water injection, steam injection, in-situ combustion;
- Chemical - alkaline flood, surfactant flood, polymer flood; and
- Gas Injection - CO2 miscible and immiscible injection, hydrocarbon miscible and immiscible injection, and nitrogen injection

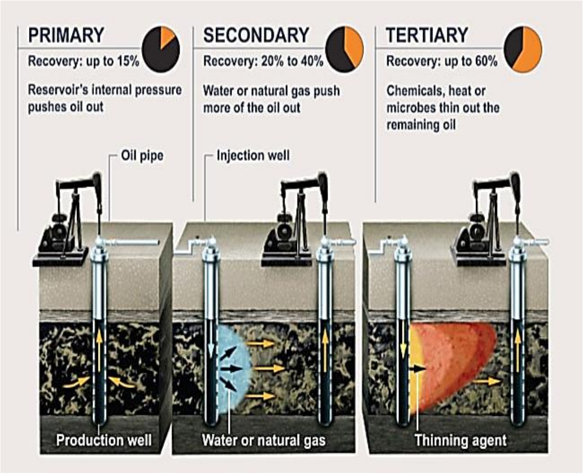

Figure 1 Three stages of oil production [8]

Steam injection is often utilized to move unswept oil toward the production wells to collect more heavy oil following primary production procedures (i.e., cold production). Despite the excellent recovery of unswept oil-in-place (OIP) that the steam flood technique is capable of, it is susceptible to gravity override and steam channeling via high permeability zones. Due to channeling, the oil-saturated zones remain unswept by steam while the depleted zones get the majority of the injected steam as shown in Figure 2, whereas (a) initial state of the reservoir’s pore spaces, (b) injection of steam into the pore spaces, (c) filling and dominates pore spaces, and (d) post-steam injection. G = grain, O = oleic phase, S = steam, and W = water/ liquid phase. Chemical additives may be utilized as an integrated approach for EOR to improve the efficiency of steam injection by lowering the impact of channeling and lowering residual oil saturation. Since the 1970s, many steam-surfactant injection systems have been researched [2].

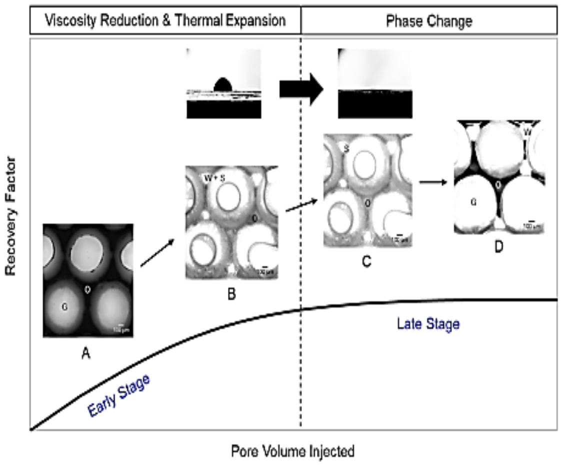

Figure 2 Explanation of the stages during the steam injection process from the recovery and pore-scale perspective[3]

Surfactant flooding reduces capillary forces that might trap oil in the formation pores as well as oil-water interfacial tension (IFT). Surfactant flooding reduces capillary forces that might trap oil in the formation pores as well as oil-water interfacial tension (IFT). The injected surfactant may improve oil recovery through some different processes, including (a) emulsification and entrainment of oil droplets, (b) wettability reversal, and (c) foaming [3].

It is generally established that using polymer causes the injected water to become more viscous and the porous medium to be less permeable, increasing the vertical and areal sweep efficiency and, ultimately, the oil recovery. Polymer injection's primary goal is to manage mobility by lowering the mobility ratio of water to oil. By making the aqueous phase more viscous, the mobility ratio may be decreased. Another widely acknowledged mechanism for mobile remaining oil following water flooding is that the residual oil must be pushed by a sizable viscous force that is perpendicular to the oil-water contact. This force must defeat the capillary forces holding the leftover oil in place to transfer, mobilize, and reclaim it. By improving sweep efficiency, the injection of polymer aids in the propagation of the oil bank created by the injection of surfactant. Austad et al. [4] found that co-injecting surfactant and polymer at a very modest chemical concentration may result in considerable benefits.

Problem Statement

There is a need to collect more of the remaining trapped crude oil in mature and abandoned wells because the number of new fields being discovered is diminishing, the price of exploration and development is increasing, and the demand for crude oil overall is rising. Continuous research is being done to develop more efficient EOR techniques that guarantee an economically viable tail-end (trapped oil) output from these oil fields. While chemicals have been used in the oil industry to improve oil recovery through the reduction of interfacial tension (IFT) between oil and water, reservoir rock wettability alteration, and an increase in mobility ratio, steam injection is the most well-known recovery technology for heavy-oil production and has primarily been developed for decades to unlock this heavy-oil potential. On the other hand, the steam injection method has proved challenging because of high costs, the enormous amounts of steam and energy needed, and environmental issues. Therefore, any effort to increase efficiency through better recovery or a decrease in the need for steam is worthwhile. Chemical additives have been tested for this purpose since the 1980s, but their limited application in practice is due to their high cost and heat stability.

Background

Most heavy oils are recovered using thermal recovery techniques, which raise the temperature of the crude to make it easier to produce. It's important to heat reservoirs effectively. Heat is lost through the generated reservoir fluids, under-burden, and overburden, as well as other means. In-situ combustion and steam injection are the thermal techniques that have been applied throughout the past ten years [5]. The more common of the two techniques, steam injection, has been used effectively in numerous nations, including Venezuela, Canada, and the US. Improved oil mobility, oil thermal growth, and distillation of the lighter hydrocarbons in the steam zone are a few of the reasons that contribute to a higher oil recovery after steam injection.

Despite having a larger output, steam flooding has issues with gravity override, which causes early breakthroughs, and diverts the steam via high permeability zones. To enhance oil recovery, various steam additives have been researched and used in the past particularly residual oil bypassed owing to steam override. Although it has been demonstrated that adding steam additives like carbon dioxide and propane can boost recovery factors, doing so comes at a considerable expense. The Ramey Lab at Texas A&M University has undertaken several studies that demonstrate how adding propane to steam considerably speeds up oil production but not oil recovery. Consequently, there is a growing demand to increase heavy oil recovery using a good steam addition [5].

EOR- concept and types

Paul and Willhite (1998) describe that to improve the production of residual oil or remaining oil after primary and secondary recovery, EOR is the process of introducing one or more fluids into the reservoir that are not already there. These injected fluids may sometimes help the reservoir's main energy source. To increase oil recovery, the injected fluids physically or chemically interact with the rock-oil system.

Improved oil recovery, or IOR, is often confused with enhanced oil recovery, or EOR. Although IOR encompasses all of the EOR processes, it is used more broadly to refer to any additional techniques that enhance oil recovery in any manner.

EOR classification and description.

EOR techniques are divided into the following five groups: mobility-control, miscible, chemical, thermal, and other processes Microbial enhanced oil recovery (MEOR).

Mobility-control: By establishing a favorable mobility ratio of the oil-water system and reducing the relative permeability of water, volumetric sweep efficiency may be increased. This is accomplished by making water more viscous by adding viscous polymer to it, or by making gas less mobile by flooding it with foam to prevent viscous fingering. may increase the surfactant flooding system's sweep efficiency.

Miscible: includes the injection of any substance that combines with the reservoir oil to create a fluid that, because of the system's enhanced mobility, flows easily to the wells. The initial contact with oil in the first contact miscible (FCM) process results in the development of miscibility. When the injected phase gains miscibility from repeated interactions with the oil, the system is modified (MCM). After miscibility is reached, injection of gases like CO2 often causes a decrease in the viscosity of the oil.

Thermal: includes injecting substances like steam, boiling water, or flammable gas (In-situ combustion). Thermal energy is used in thermal EOR techniques to boost oil recovery. The temperature rise brought on by thermal energy lowers the viscosity of the oil. Cyclic steam stimulation and steam drive are two broad categories of steam techniques. In-situ combustion involves burning a certain amount of gas to produce heat, which causes lighter portions of oil to vaporize and causes the viscosity of the oil to decrease.

MEOR: Hydrocarbons are fermented by microbes, and the byproducts they create may be used to extract oil. By blocking off tiny channels, MEOR forces oil to go through larger pore spaces, so channeling it down the reservoir's preferred route. To promote the development of bacteria and improve their functionality, nutrients such as sugar, phosphates, or nitrates are injected. Surfactants and carbon dioxide produced by the bacteria aid in the displacement of oil.

Chemical: includes chemical injections that affect phase behavior in a desired way, increasing oil recovery. Although polymer always improves sweep efficiency, reducing the IFT between the displacing fluid and oil and causing the system to flow is the primary method by which recovery is accomplished.

Developing residual oil saturation after steam injection

There is no disputing that a significant amount of heat is transferred during the steam injection process [6] to reduce viscosity and mobilize heavy oil in the pore spaces. In the later phases of steam injection, this develops into a difficult and complex process that affects the performance of heavy oil recovery. The early (preliminary production) and late (advanced) stages of the steam injection method can be broadly classified into two categories. Figure 2 outlines the processes taking place through the steam injection in the pore spaces. Early on, after the sandstone pores are mostly flooded with heavy oil, heat from the steam injection process creates the oleic phase, which can happen through two different mechanisms: lowering viscosity or thermodynamic extension [7].

Reducing the viscosity makes the oleic phase more mobile, while the heat expansion makes the oil swell. Because of the unstable of the wetting water layer on the solid phase, a phase transition takes place at this point, promoting the thermodynamical evaporation of the water phase [8]. This causes the surface force to weaken, Van der Waals attractive force to outweigh the electrostatic repulsive force, and the disjoining pressure to fall [7]. This allows the oleic phase to interact directly with the rock surface and become more or and become more or entirely oil-wet oil-wet, which increases the capillary pressure, which in turn increases resistance force and causes the pore spaces to become saturated with leftover oil. [9-11]. This evidence unequivocally demonstrates that the rock's wettability has been altered, which has significant implications for relative permeability and ultimately the recovery of heavy oil. According to science, capillary pressure—which can be scientifically expressed by the subsequent equation—is the primary cause of residual oil development:

$$P_c = \frac{2\sigma cos\theta}{r} \quad (1)$$

where Pc denotes the capillary pressure within the rock pores, IFT, wettability (contact angle), and r, the radius of the pore. Accordingly, this capillary pressure affects how viscous force and capillary force interact, as shown by the capillary number (Nc) proposed by Moore [12]:

$$N_{\mathrm{c}}= \frac{v\mu w}{\sigma \cos\theta} \qquad (2)$$

where IFT is the interaction between two immiscible fluids, Nc is the capillary number, The displacing fluid's linear velocity is given by the notation v, while viscosity is given by the notation w., and θ is the wettability of the rock surface.

Since many steam injection fields have shown a quick output decline at this point, the mature phase of steam injection is crucial to the application and needs more consideration concerning the performance of the heavy oil recovery. The fundamental cause of the adverse wettability alteration of the rock, which eventually affects the process's performance and efficiency and raises the steam-oil ratio, has been identified as a phase change. Despite certain additional field concerns in steam injection applications, this is the case (such as steam conformance, steam channeling, and steam-oil mobility contrast) (SOR)[12].

Displacement Methods Based on Steam and Steam-Chemical Additions

Viscosity reduction and thermal expansion are the two major processes responsible for heavy oil recovery using steam. In this specific case, thermally induced viscosity reduction is used to reduce the viscosity of heavy oils, with water dissolution becoming even more important at temperatures over 150 °C. (Glandt 1995) [13]. Two displacement processes, micro displacement, and macro displacement can be used to determine the heavy oil recovery method in the scope of steam-chemical-based heavy oil recovery. The classification of the heavy oil recovery displacement method as indicated by probable chemicals as steam additives are shown in Figure 3. The effectiveness and efficacy of heavy oil recovery depend on both displacement processes. We found that each chemical addition provided a distinct displacement mechanism that may be able to decrease the need for steam and enhance heavy-oil recovery, hence boosting the EOR.

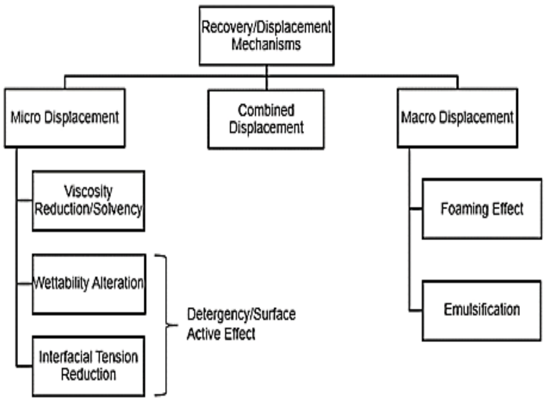

Figure 3 Classification of recovery techniques with steam injection[12]

Mechanism of micro displacement

Micro displacement processes include detergency /surface active effect and viscosity reduction/solvency, to name only two (wettability alteration and IFT reduction). The micro displacement process represents the capacity of chemical additives to mobilize the heavy oil in pore spaces by altering the reservoir rock-fluid interface, which includes interfacial characteristics and intermolecular interactions, such as surface force and detaches pressure. Capillary pressure and relative permeability are further impacted by this.

Viscosity reduction

The viscosity of heavy crude oil can be reduced once the oleic phase and chemical additives interact favorably—either by more dissolving into the oleic phase or by lowering oil-water IFT. The use of solvents in heavy crude oil and bitumen recovery has also been thoroughly explored and tested, demonstrating how they help to considerably reduce viscosity by diffusing the solvent into the heavy oil and bitumen to increase oil recovery [14-18] thus, enhancing the recovery process by improving the sweep steam flooding and steam chamber growth (SAGD). Some of the added chemicals investigated in this study, including the hydrocarbon solvent, the water-soluble solvent dimethyl ether (DME), the biodiesel, the switchable-hydrophilicity tertiary amines (SHTA), and the deep eutectic solvent (DES), have shown promise for reducing viscosity under steam conditions, even at low chemical concentrations.

Due to the degrading impact and reduced interface-free energy, the inclusion of solvent chemicals as steam additives might reduce the viscosity of heavy oils by favorably changing the crude oils' physical and chemical characteristics. When the solvent and heavy oil interacted dynamically under high-temperature steam circumstances, the lighter components improved and the heavier ones were reduced, increasing the movement of the heavy crude oil. According to science, hydrocarbon solvents work to lessen the viscosity of heavy oils by allowing them to diffuse into the oleic phase and to provide an in-situ upgrading mechanism by reducing the number of heavier elements like asphaltene.

Due to the resins' ability to suspend and stabilize the asphaltene particles in the oleic phase, it is shown that this method is capable of dramatically lower the asphaltene portion to 16% while greatly increasing the resins portion to 34% [19, 20] Additionally, when adding this alkane solvent it can change how soluble the asphaltenes are, the desorption of resins from the heavier components and the thermodynamic equilibrium between resins and asphaltenes being further affected (asphaltenes). Due to the particle buildup, this situation can start the potential energy reduction and solid phase development, producing heavy oil with a greater proportion of resins and a smaller fraction of asphaltene. Additionally, a hydrocarbon solvent like heptane may cause asphaltene to precipitate, which would help mobilize heavy oil in reservoirs more effectively.

Detergent effect (change wettability and reduce IFT)

In the surface sciences, the capacity of a given phase to disperse on the rock surface in the presence of other phases owing to intermolecular interactions is often referred to as rock wettability. An extremely common element impacting the recovery of oil, mostly in heavy crude oil steam injection techniques, is the reservoir rocks' surface wettability. Additionally, it is in charge of the capillary pressure and the remaining/residual oil saturation. The Derjaguin, Landau, Velwey, and Overbeek (DLVO) theory, which includes van der Waals and electrostatic/electrical dual layer (EDL) interactions at a molecular level, may be used to estimate these intermolecular forces that thermodynamically take place in the reservoir system[21]. In addition to the DLVO method, the energy change per unit area, also known as the disjoining pressure, is one of the parameters determining the thermodynamic properties of reservoir rock wettability, which is the energy that separates or disjoins two surfaces. The quantitative determination of the contact angle that meets Young's force balancing allows for the following conclusion to be made regarding the link between interfacial tension and the wettability of reservoir rock (Figure 4):

$$\cos\theta = \frac{\gamma\, steam/solid - \gamma oil/solid}{\gamma\, oil/steam} \qquad (3)$$

where θ points to the contact angle between the oleic state and the solid state, γ steam/solid indicates the interfacial tension between the solid state and the steam state, γ oil/steam shows the interfacial tension between the oleic state and the steam state, and γ oil/solid indicates the interfacial tension between the oleic state and the solid state.

Promising wettability modification and IFT reduction might be attained primarily as a result of the reservoir's rock-fluid-chemical interactions, which change the surface force and/or disjoining pressure and enhance the capillary force and relative permeability. While most of the chemicals used in this investigation were able to modify wettability, several of them also demonstrated IFT decrease as their primary displacement mechanism, positively enhancing heavy oil recovery under steam circumstances.

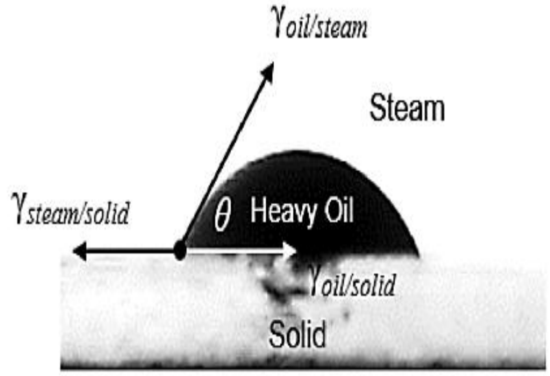

Figure 4 Rock-heavy oil-steam system force balancing under HPHT steam conditions [6]

Steam flooding

Because heavy oil has properties that make it more difficult to extract from reservoirs than conventional or light oil, such as high viscosity and specific gravity, lower hydrogen-to-carbon fractions, and higher levels of asphaltene, sulfur, and heavy metals under reservoir circumstances [22]. Thermal and non-thermal methods can also be used to extract prospective heavy oil deposits. Non-thermal recovery is a method for recovering heavy oil without using heat, and it mainly makes use of water flow, cold production, and gas injection. Thermal recovery (mostly vapor injection) is the most applied and dependable technique employed because the dynamic heat transfer evolved through this process allows a large decrease in viscosity and thermal expansion, giving extra adequate packing of heavy crude oil into the rock pores. However, as seen in the picture, the increased tank temperature brought on by heat transfer may eventually have an impact on the tank's overall system as shown in Figure 5. Thermal recovery operations like steam flooding in an Indonesian Dory field are effective examples of how steam injection may be used as a secondary recovery [23, 24], the Schoonebeek steam drive project in the Netherlands [25], and some old steam injection projects in Texas [26].

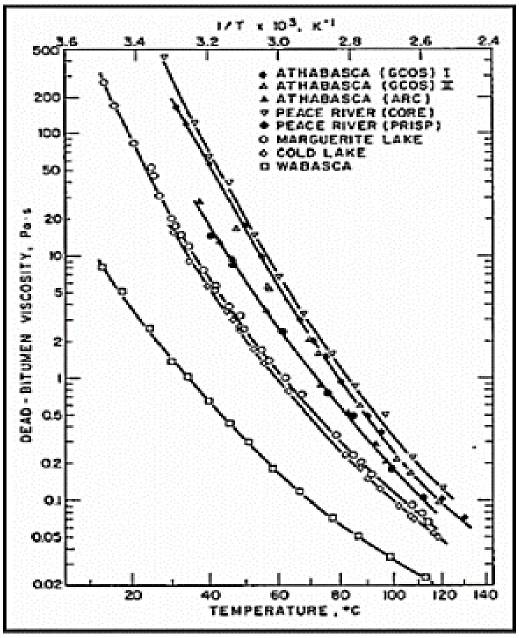

Figure 5 Viscosity-temperature relationship for Albertan bitumens [17].

In more practical applications, such as the majority of SAGD operations in Canada, steam injection systems are typically utilized as a first step for field production, especially for crude oils with extraordinarily high viscosities [27]. Better heavy oil filling, recovery, and the economic feasibility of the project are the key goals of this initiative. While without a doubt that the heat produced during the steam injection method is very useful and effective in heavy oil filling, resulting in the desired oil recovery in the primary stage of steam injection, the state of the thermodynamic reservoir changes when the vapor injection extents its mature/late stage.

Research has detected and shown that a phase transition (from liquid to vapor phase) that eventually results in an adverse change in wettability happens once steam is constantly injected into a shale-oil water scheme, impacting how well heavy oil is extracted. Findings from several heavy oil experimental studies, which demonstrated that heavy oil production decreased and the recovery area kept constant once steam injection reached its culmination during the use of micro-models and sand flooding at tremendously high steam temperatures (up to 220 °C), also lend support to this conclusion [28]. When it comes to steam injection fields, production has fallen off quickly at the Duri steam flood field in Indonesia, as well as at many steam injection fields in the US and SAGD fields in Canada. when you're an adult. This data unquestionably demonstrates that steam injection performs well in the early phases but is still challenging in the mature stages because of the shift in reversible wettability following steam injection [24, 29].

Steam injection has been used numerous times in Alberta, Canada, as well as Venezuela and California, America; a series of injective wells and production wells are used in this strategy (steam flooding). The steam injection can improve oil recovery by two mechanisms: (1) heating the oil and lowering its viscosity, and (2) forcing the oil into productive wells after transferring its heat to the ground and condensing it, acting as a flooding mechanism. This technology has the potential to produce more than 50% oil on-site. As a result, continuous steam injection is a procedure that involves the utilization of numerous wells to prepare the way for a high rate of oil production from the residual oil as indicated in Figure (6). Steam is injected into wells under various conditions, such as location and construction, and oil is retrieved from productive wells. Significant recovery may be achieved if the reservoir was built in such a way that steam had a high motion capability. Simulating a process can help greatly with process optimization in this way [30, 31].

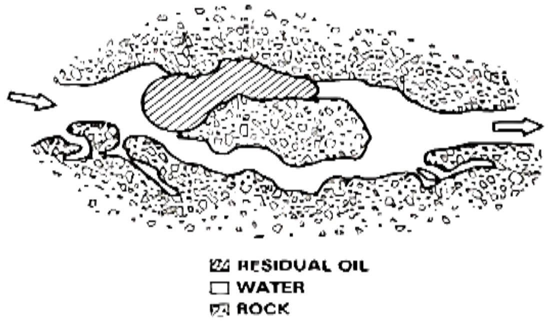

Figure 6 Diagram of flooding showing trapped residual oil trapped in the reservoir [8]

Steam flooding processes have different mechanisms; it was defined by China as follows: steam drive, in-situ solvent drive, viscosity decrease, thermal transmittance and capillary pressure fluctuations, thermal expansion, gravity discrimination, solution-gas drive, and emulsion drive. While steam flood has higher efficiency, it has some disadvantages, such as (1) steam channeling through high permeability regions and (2) gravity override, which causes early breakthrough and lowers displacement effectiveness.

Surfactant flooding

The selection of a surfactant for thermal application is a complex process mostly due to the nature of the process and the physico-chemical aspects of the reservoir rocks (Figure 7). This mainly relates to the condition in which the SSP is being carried out. In-situ SAGD operations involve steam injection at elevated temperatures of up to 320 °C [32]. Extended exposure of surfactants to severe temperate may degrade the surfactants if the right conditions are not met. The nature of reservoir rock chemistry and the presence of many cations and anions are additional factors that may affect the SSP performance. in general terms a surfactant can be considered a suitable candidate for SSP application if it has the following characteristics: reduces WT significantly: vaporizes at downhole SAGD operating conditions: thermally stable at high temperatures: retains its properties and remain effective at high temperatures: preferentially result in oil-in-water emulsion; enhances the reservoir wettability to water, and he compatible with formation water [33]. Surfactant availability and pricing play an essential role in the selection process. It is also important that if a surfactant results in the production of stable emulsion at downhole reservoir conditions, then it should be easy to break it down on the surface [34].

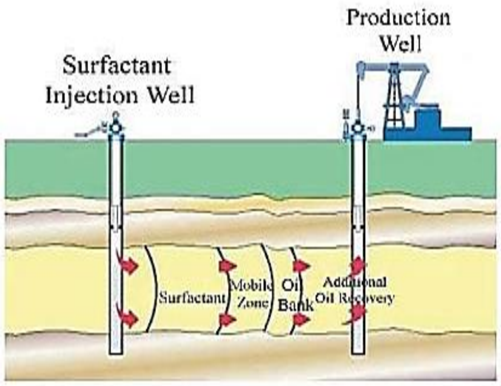

Figure 7 Surfactant flooding process [18]

Surfactants selection criteria

There are varieties of surfactants available in the market that at first glance may seem to be suitable for SSP application. However, closer examination may reveal that most of these surfactants either cannot be vaporized at SSP downhole operating conditions or may undergo thermal degradation. Another limiting factor is that some of these surfactants may result in producing water-in-oil (W/O) emulsion which can be detrimental for the SSP recovery enhancement performance since a W/O emulsion has a higher viscosity than the oil itself at a given operating conditions. It appears that before investigating the type of surfactant that may work well for the SSP application it is more relevant to seek the type of functionality that is expected from different types of surfactants and the estimated gain in process efficiency associated with each class of surfactants. Surfactants can be classified based on the charge of their functional groups at their head. Anionic surfactants are negatively charged while the cationic is the opposite [35].

Zwitterionic surfactants have both cationic and anionic centers attached to the same molecule. Nonionic surfactants do not have a charge in their predominant working range of pH. The first three classes of surfactants appeared to be not suitable for SSP application either because it is hard to vaporize them or because they may alter the reservoir rock wettability toward oil-wetness. However, the non-ionic surfactants seem to be a good candidate for SSP application. They interact strongly with high-energy structures such as interfacial regions, phase boundaries, and surfaces and can cause dramatic changes in crucial properties of molecular mixtures including solubility, dispersion uniformity, viscosity, miscibility, and phase equilibrium.

Polymer flooding

Polymer flooding has grown among the most significant approaches for enhancing oil recovery since it was initially used in the 1960s. [36]. Polymer flooding, a water-based approach, improves the effectiveness of water flooding by reducing the mobility of the brine. Fingering problems are the main cause of water seeping into the producing wells during floods. The oil and water mobility ratio may be raised by polymer flooding, which will improve sweep effectiveness and improve oil recovery. Polymer flooding has resulted in a 5–15% improvement in oil recovery (OOIP) [37, 38]. For every ton of polymer injected, 120 tons of oil are recovered in the Daqing oilfield in China, which is 12% more oil is recovered incrementally than when water flooding is employed [39].

Mechanisms of polymer flooding

Crossflow across layers increases polymer sharing in vertical heterogeneous layers, boosting vertical sweep productivity. This strategy is described in the [40]. One economic advantage of polymers is that less water is produced and injected than during floods. Less water is injected and produced because polymer enhances sweep efficiency and mobility ratio. Some areas, such as deserts, and offshore regions, may have high water and treatment costs. The lower volume of water generated and injected compared to floods is one economic benefit of polymers. Because polymer increases sweep efficiency and mobility ratio, less water is injected and generated. Water and its treatment may be expensive in some locations, such as deserts and offshore regions.

Disproportionate permeability reduction is another technique used to treat polymers and gels (DPR). Additionally, the polymer is used to prevent water from coming from aquifers at the ground's surface and from channeling through extremely permeable strata. In these kinds of implementations, if the injected polymer volume is small or a large volume cannot be injected owing to high injection pressure constraints or a brief gelation time, temporary blockage of water channeling or water coning occurs. In the end, water will bypass the zone where the polymer was injected and cross-flow to high permeability zones or skip the polymer zone to the producing wellbores. A weak gel, which has a high flow resistance but can still flow and be injected deep into the reservoir, can be used to avoid this sort of issue. As a result, a substantial polymer zone is created to restrict water thief zones. This method enables polymer and gel to significantly lower water permeability compared to oil permeability. An injected viscous polymer solution may nevertheless bypass producers early in a very heterogeneous reservoir. To solve this issue, a weak gel-like concept was put out [41].

Instead of using crosslinkers, the cationic polymer is pumped via producers. When combined with the anionic polymer injected by an injection well, the injected cationic polymer has strong adsorption on the rock and can produce a water-insoluble gel to stop water channeling. The viscoelastic behavior of polymers is a second method. In comparison to oil and water, polymer and oil have greater interfacial viscosity. The interfacial viscosity is inversely correlated with the shear stress. Due to the viscoelastic nature of the polymer, shear stress is not the only tension present between the oil and the polymer solution. As a result, the polymer pulls oil droplets with more force. As a result, oil can be "pushed and pulled" from closed pores. As a result, residual oil saturation is reduced [11, 42, 43].

Polymeric surfactant

To minimize the consequences of fingering, the technique of increased recovery linked to polymer flooding depends on a reduction in the mobility variance between the displacing and the displaced fluids. The mobility of the displacing phase should be comparable to or less than that of the oil phase [44-47]. The oil will be displaced by the water in a piston-like manner when the water/oil mobility ratio (M) is 1 or moderately less. The more mobile water phase, on the other hand, will finger through the oil if M is larger than 1, leading to a breakthrough and reduced recovery. The polymer must function as an efficient viscosifier for the aqueous phase since the mobility is inversely related to the viscosity. The fundamental characteristics of such polymers are high molecular weight (1000 – 30*106), struggle with mechanical deterioration under shear, and, of course, perfect solubility in water. They should also be affordable, non-toxic, and tolerant to high salinities and high temperatures. Extensive reviews of the classic polymeric systems used for EOR are traditionally employed [48].

Some aspects should be taken into account in EOR methods that combine the two techniques (SP or ASP flooding), such as interactions between surfactant and polymer, removal of surfactant during solubilization in the oil phase or chromatographic disruptions of the various ingredients, and adsorption on the rocks, which might be harmful to the process as a whole [42]. Due to these factors, the polymeric surfactant is utilized to combine the advantages of surfactants and polymers into a single component and develops into a viable alternative to the conventional EOR methods. There has been much talk about the potential of polymeric surfactants for EOR [49, 50]. It is quite motivating to realize that polymeric surfactants have been employed in EOR for a considerable amount of time without being formally recognized as such.

EOR has used the concept of adding hydrophobic groups to a water-soluble polymer to transform it into a polymeric surfactant [48, 51].

There have been several suggested and even patented structures based on hydrophobically modified polyacrylamide (HMPAM). However, it has been discovered that the hydrophobic zone can form a shear-dependent transient combination in water with a consequent solution thickening, indicating that the hydrophobic groups are primarily added to affect the rheology of the system [46, 52, 53]. A study of the surface characteristics is typically disregarded in favor of concentrating on how hydrophobic interactions or the chemical structure affect rheology. It is well recognized that the existence of hydrophobic components in water-soluble structures affects the interfacial characteristics (surface tension, IFT, wettability). So, even though the impact is often less evident for polymeric surfactants than for low-molecular-weight surfactants, this factor should be taken into account when hydrophobically modified polymers are explored as prospective systems for EOR. [50]

Specification of polymeric surfactants for EOR

Surfactants with a polymeric structure are large molecules with both hydrophilic and hydrophobic components. The macromolecular nature of these systems permits a far wider diversity of structures compared to conventional surfactants. For instance, a surface-active monomer (in this context, they are typically referred to as poly soaps) or a copolymer of a hydrophobic and a hydrophilic monomer can be used to create a polymeric surfactant. The distribution of monomers can be varied in the latter situation. Thus, the structure of these copolymers might be random, gradient, or block-like. Amphiphilic diblock copolymers, sometimes known as "macro surfactants," are essentially the macromolecular inversion of low molecular weight surfactants [54]. Typically, polymeric surfactants have extremely remarkable rheological and interfacial characteristics. Most of these characteristics should logically arise from their chemical composition. For instance, macro surfactants, particularly those that contain a polyelectrolyte block, exhibit great gelation capabilities but have low surface activity whereas poly soaps are known to have outstanding emulsification qualities but normal solution viscosity [55, 56]. Table 1 shows the main differences between some types of polymeric surfactant.

Without going into too much detail, it can be said that these features mostly result from the techniques of aggregation in the solution. The final characteristics are greatly influenced by the chemical structure. The capability to modify a polymeric surfactant's hydrophobicity and, consequently, its aggregation action by altering external factors like pH, temperature, or solution concentration is a key characteristic of these substances. These polymers are crucial building components for intelligent materials. Of course, certain structures will be more appropriate than others depending on the specific application that is being considered. All of these factors led to a great deal of interest in polymeric surfactants for current or future uses in a variety of industries, such as (mini)emulsion polymerizations, biotechnology, coating, medicine, pharmacology, cosmetics, agriculture, water purification, electronic, and enhanced oil recovery[50-52, 54-57].

Polymeric surfactants for EOR

It is not a novel concept to utilize polymeric surfactants for EOR, which may theoretically serve as both solution thickening agents and surfactants. Although the surface activity of such classifications is typically not taken into account in the research, the majority of the systems effectively deployed or suggested as solution thickeners relying on hydrophobically modified water-soluble polymers can in theory also operate as surfactants. Surfactant-containing blends, such as SP or ASP flooding systems, were designed to increase interfacial activities and the capacity of the polymer to dissolve and emulsify crude oil. Figure (8) illustrates the ASP process. However, these mixes are frequently divided into two phases in a flow stream because of their differing characteristics. Other issues can be contributed to surfactant attraction to the rock-water interface, which can lead to surfactant loss to reservoir rock surface by adsorption, or to surfactant inconsistencies with polymers, which causes a reduction in polymer properties like accumulation, adsorption, and diffusion effectiveness in porous media[58]. Moreover, the existence of the strong alkali harms the effectiveness of the polymer in situations when ASP flooding has been shown to effectively boost oil recovery in the field. Although it is thought that the alkali favorably impacts the process, in many situations extra polymer is needed to obtain the necessary viscosity[59].

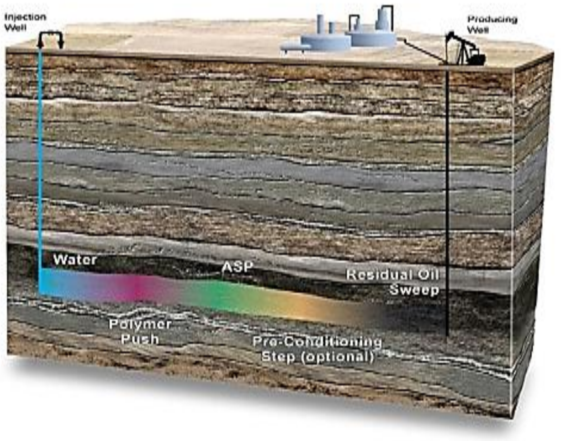

Figure 8 ASP flooding process [30]

A polymeric surfactant that integrates the high viscosity of a polymer with the interfacial feature of a conservative surfactant might lower the tension at water/oil interfaces while simultaneously increasing the viscosity of the aqueous system [60]. Such a strategy has already been used in various sectors, but moderately few usages of polymeric surfactants in EOR have been recorded due to the frequent observation that they have only a modest capacity to reduce the IFT. The conventional opinion that ultralow IFT values (order of magnitude of 10-3mN/m) are required for excellent performance in EOR, however, has lately come under scrutiny[61].

Table 1 The main differences between some types of polymeric surfactant.

Polymeric Surfactant	Chemical Structure	Application	Advantages	Disadvantages
Polymerizable surfactants	Contain a polymerizable group such as vinyl or acrylate	Used in emulsion polymerization and as stabilizers for latex particles	Can be covalently bonded to the polymeric matrix, providing excellent stability and compatibility	Requires specialized equipment and procedures for synthesis
Amphiphilic block copolymers	Consist of two or more different polymer blocks with contrasting hydrophobic and hydrophilic properties	Used in drug delivery, coatings, and as emulsifiers	Can self-assemble into various nanostructures, providing versatile functionality	Can be challenging to synthesize and purify, and may exhibit poor stability under certain conditions
Polymerizable surfactant block copolymers	Consist of two or more different polymer blocks with contrasting hydrophobic and hydrophilic properties	Used in emulsion polymerization and as stabilizers for latex particles, as well as in drug delivery and coatings	Can be covalently bonded to the polymeric matrix, providing excellent stability and compatibility, and can self-assemble into various nanostructures	Requires specialized equipment and procedures for synthesis, and may exhibit poor stability under certain conditions

Integration of Chemicals

Around the world, impressive alkaline, surfactant, and polymer immersion research has been conducted recently. According to Hawkins et al., the simultaneous injection of the alkali and polymer is more efficient than the sequential injection of identical chemicals without any interaction between the two [62]. According to Tong and Guo, the primary processes of ASP immersion include the creation of interfaces, the bridging of inner and outer pores, and the oil-water emulsion. By dislodging leftover oil through decreased interfacial tension and improved sweeping effectiveness in a vertical heterogeneous tank, ASP flooding boosts displacement efficiency[63, 64]. According to Song, ASP immersion is more efficient for oil that has a high acid value. They discovered that the rheology of the dumping system and the IFT between the dumping system and oil with a high acid value were important aspects affecting oil recovery[65].

Wang and Shen [66, 67]used ASP immersion to study the fluid flow technique of EOR in the porous material. They claim that by boosting both sweep volume and displacement efficiency, ASP flows not only drive the residual oil to displace in the high-permeability layer but also residual oil in the low- and middle-permeability layers. Polymers and surfactants have exploded in popularity due to the high cost of synthetic polymers, surfactants, and their environmental effects. The utilization of natural, affordable, and ecologically benign products for better oil recovery during chemical flooding is perhaps the major problem facing the petroleum sector [68, 69]. A. Samanta studied the rheological and interfacial characteristics of natural surfactants made from gum detergent shell powder and guar gum, and then he employed them in the immersion of surfactant and polymer to enhance oil recovery following traditional water flooding. The study of adding alkali to surfactant-polymer slug was also investigated, and utilizing the ASP slug as the flooding agent, a substantial increase in recovery was seen [70].

During cycles of steam stimulation, alkaline and water-soluble chemicals are introduced into the steam. Prior laboratory and field studies indicate that increased oil output frequently. Tiab et al. looked at the use of caustic (sodium soda) in a steam flood to lessen the amount of residual oil saturation in the reservoir's bottom part (which is usually overridden by steam). When compared to a normal steam flood, the study's findings show that adding sodium soda to the steam improves flow efficiency and boosts oil recovery [71]. In Kern County, California,

Blair et al. tested the injection of a few chemically active interfacial agents both before and during the steaming cycle. It has been shown that this chemical steam treatment greatly increases oil output. Two studies were carried out by Al-Khafaji et al., one static and the other dynamic [72, 73]. The dynamic experiment looked into surfactant steam flood mobility and heat transfer via porous media. The findings revealed that the mobility of steam was decreased when surfactant was added. This study's objective is to investigate oil recovery utilizing various steam chemical processes (such as steam surfactant, steam alkaline, and steam surfactant alkaline).

A low-cost chemical flood system that incorporated chemical concentration and permeability field realization was designed and optimized by Wu et al [74]. using sensitivity analysis (vertical and horizontal permeability ratio). The findings demonstrated that the method of developing chemical flooding might be enhanced by merging current EOR techniques. Two mechanisms—(1) changing the oleic rate relative to the aqueous rate through the rock (including reducing IFT, modifying wettability, changing viscosity, and pore-clogging) and (2) shifting phase composition—define this chemical flooding (including miscibility, swelling, and solubilization [32, 74-77].

There are many steam injection methods, including cyclic steam stimulation (CSS), continuous steam injection, and steam-assisted gravity drainage (SAGD). The industry is seeking methods to enhance the efficiency of these operations because steam injection techniques do not offer recovery percentages of more than 50%. In this way, the primary challenge presented by these approaches in conjunction with nanotechnology is to lower the asphaltene breakdown temperature and enhance oil recovery. The viscosity reduction caused by the disaggregation of the viscoelastic network occurs in the first phase of this multi-step process when asphaltenes are adsorbed on nanoparticles. The asphaltene breakdown process is then carried out as a result of the catalytic steam gasification process. Finally, gasification of heavy hydrocarbons often produces CO2, CO, H2, and CH4 compounds [78-80].

Recently, at the laboratory level, nanoparticles have become an important factor in improving EOR. In the past decade, nanotechnology has also been chosen as an alternative method for extracting remaining oil resources. To sustain the in-situ heat produced by steam, Osamah and Abduallah present one of the potential methods for in-situ heavy oil recovery. To evaluate the recovery of Kuwaiti heavy oil utilizing hot water, (SH), nanofluids, and combinations of SH team and nanofluids, many core flood tests were carried out. Initially, the individual hydrophilic nanoparticles (HFNPs) including; zirconium dioxide (ZrO2), titanium dioxide (TiO2), zinc oxide (ZnO), and iron oxide (alpha) (Fe2O3), of average particle size (APS) of 20-50 nm and different thermal conductivities, were dissolved in formation water to create stable nanofluids. In comparison to TiO2, Fe2O3, or ZnO, ZrO2 yields greater oil recovery, according to the findings of the nanofluid flooding on cores. The integration of ZrO2 (high thermal conductivity) at a concentration of 0.05 wt% with superheated steam (SH) at I PV, however, shows the highest oil recovery at around 46.9%, followed by ZnO (high thermal conductivity) at the same concentration with SH, which had a recovery of 42.7%, and then SH steam, which had a recovery of 35%. This shows that when paired with low steam consumption and low generated water, HFNP with low APS and poor thermal conductivity may deliver favorable EOR outcomes [81-85].

Another pilot research looks into the viability of adding a vapor-flooding additive to immersed tanks using a low-concentration alkaline or surfactant solution. This study was also aimed at looking at how the vapor flow process may be improved by recovering any surplus oil using steam and a mixture of low-concentration alkaline surfactants (alkaline surfactant vapor flow). Four flow experiments were conducted to accomplish these objectives as follows: Traditional vapor flow (SF), surfactant vapor flow (SSF), alkaline vapor flow (ASF), and low-concentration surfactant alkaline vapor flood are the four types of vapor flow (SASF). Their study's findings supported the use of steam flooding for much better oil recovery. In comparison to traditional steam flooding, using alkaline with low concentration into steam drive retrieved more oil. Compared to either normal steam drive or alkaline steam flood, the combination of steam flooding with surfactant enhanced oil recovery. Oil recovery was greatly improved by the surfactant alkaline steam flood (SASF) technology that was suggested. They came to the following conclusions: (1) Adding 3% weight of alkaline or surfactant to a steam drive increases its effectiveness, recovering more oil than a traditional steam flood; and (2) The highest oil recovery is achieved when using low concentrations of surfactant or alkaline (1.5% weight for both) in a steam flood. The suggested method of surfactant alkaline steam flooding has been confirmed by the study's findings. Furthermore, if used in present projects of traditional steam injection and/or water-flooded reservoirs, this technology is anticipated to have a major influence on achieving potential oil recovery [86].

Al-Khafai et al. (1982) [72] conducted two experiments for investigating commercial chemicals at reservoir conditions with steam injected at 205 ^{o}C and 300-500 psia. To study flow, mobility, and heat transfer, a linear model was used. The common problem of this process is the formation of channels and, as a result, steam override. The reason for channel formation is that the mobility of displaced fluid is much lower than that of the displacing fluid (steam). Due to the differences in density between steam and oil, steam override occurs. To reduce steam mobility and, in turn, reduce steam override, surface active substances are used as additives with steam. As concluded from this work, steam mobility was significantly reduced in the presence of surface-active substances. The average steam saturation in the saturated steam zone increased as the steam zone grew.

Robin (1987) [87] conducted laboratory studies of foamability and foam stability at high temperatures and pressure surrounding conditions inherent to steam injection conditions. In heterogeneous reservoirs, the breakthrough of the steam can take place in higher permeabilities zones. For steam flooding, the microscopic efficiency is high, while the sweep efficiency may be relatively low. During steam flooding, the effectively swept areas of a reservoir contain low residual saturation of oil. The steam tends to flow to the upper layers of a reservoir and after steam reaches the production well, the swept area is not increasing any longer. The tests of several hydrocarbon chains sulfonates in homogeneous and heterogeneous media demonstrated that the foam can be used to block off the paths. Hutchinson et al. (1992) [88] conducted a study of steam foam mechanisms at residual oil saturations under dynamic conditions. Previous works were conducted either in the absence of oil or under static conditions. The model used was a sandpack saturated with 17o API oil at 12% of residual oil saturation. 100% quality steam was injected at a pressure of 70 psi until breakthrough.

As a result of this study, the authors stated that: (a) the injection of the slug with consecutive steam and nitrogen injection proved to be more effective in comparison to the co-injection of surfactant; (b) the slug size is recommended to be above the minimum for optimal use of surfactant; (c) steam quality is critical for the process high quality of the steam demonstrates more efficiency in the case of slug injection. The new technology of cyclic steam injection with surfactants was evaluated in Venezuela in 1997. Valera et al. (1999) presented results obtained from the stimulation of Bachaquero-01 reservoir new and reentry wells with steam and surfactant. This reservoir in western Venezuela contains about 6,621 MMSTB of 11.7o API oil with a viscosity of 635 cps, at 1360 psia and 128 oF. The gravity override and steam channeling cause steam flow through a depleted zone bypassing other reserves and as a result, reduces production efficiency in steam soak. To improve steam flood Lineal ionic-Alkyl-Aryl Sulfonate (LAAS) was applied for the field test after laboratory tests for plugging capacity, thermal stability, and some others. For these tests, wells with certain criteria were selected. The four-stage steam-surfactant injection program was worked out. Firstly, steam was injected for two days to clean and stimulate the most perspective sands. Secondly, to block desired areas, steam, and surfactant were co-injected. The next stage of injection of steam and surfactant was the longest one to achieve the divergent effect in the well. The last stage was a pure steam injection. For the continuous stage, the concentrations of surfactants were 0.75 to 0.85 % and 0.35 to 0.45 % for the intermittent phase. An increment greater than 41% in comparison with the steam injection without additives were obtained for 39% of vertical wells.

Shedid et al. (2000) [86] studied thermal chemical processes to improve oil recovery and minimize the cost of the chemical(s) used. The authors reviewed the earlier studies of steam flooding processes with the application of surfactants and alkaline and stated that the use of both chemicals' solutions has not been done before. They proposed that the surfactant alkaline steam flood (SASF) process can impressively improve oil recovery from reservoirs (flooded with either water or steam) which is not achievable by other methods. The investigational model for sandpack steam and chemical steam injection was built to test crude oil (East Aghar oil field, Egypt) with 12o API (at room temperature 70 o F). The steam injection rate was 1.952 cc/min with pressure fall between the injector and production ports 19.7 psi for SF, and almost 34.3 psi for chemical steam floods. The displacement efficiency (ED) for steam surfactant flood (SSF) is estimated to be 45.79% which is 12.93% more than for surfactant flood (SF). During this experimental research, the efficiency of various chemical steam flood processes was defined and compared to the conventional steam flood. Also, the analysis of displacement efficiency and interfacial tension reduction was measured. The SASF is the most effective process of those studied and requires almost twice as less chemicals at similar conditions.

The same year Shedid et al. (2000) [89] presented the second paper in which steam chemical flood efficiency between vertical and horizontal wells processes was made. The experimental model was created and four chemical steam recovery techniques were investigated and compared for two types of wells with similar oil, brine, porous media, chemicals, steam, and injection/production procedures. Two flooding apparatus were designed to simulate steam chemical injection for vertical and horizontal wells. The flood was carried out through sandpacks with superheated steam (150 of 54.7 psig). Crude oil from the East Aghar oil field, Egypt was used for the experiment. The following chemicals were used for the study: (a) surfactant Triton X-100 and (b) NaOH. Additionally, Bryan et al. (2008) studied mechanisms of producing unrecovered heavy oil [90]. It is critical to know the state of the reservoir at the time of injection to understand how heavy oil can be recovered. At the end of waterflooding low mobility ratio between oil and water leads to bypassing the heavy oil and the ability of this oil to flow depends on applied pressure gradients and the permeability of the rock. "A simple reduction in oil-water IFT, similar to mechanisms proposed for conventional oil EOR, will not be effective in displacing the oil". Injected chemicals are purposed to improve the mobility ratio between oil and water and hence provide a more stable displacement of oil towards production wells.

In reservoir conditions added chemicals can form emulsions. Surfactants, due to high oil viscosity about water, will normally create water-oil (W/O) emulsions. W/O emulsion might have a higher viscosity than heavy oil, which can cause certain problems related to oil production and transportation. But some EOR applications showed that this mechanism could improve heavy oil recovery due to the ability of a more viscous water-oil emulsion to displace oil more stably. Oil-water (O/W) emulsions can also form under certain conditions with the addition of surfactants and/or alkali mixtures [82].

A.M. Alsabagh 2022 [90], used steam injection, polymer (Hydrolyzed Polyacrylamide, HPAM), and surfactant (Polyoxyethylene sorbitan Trioleate, E(20)STO) to recover heavy crude oil API 18 (American Petroleum Institute) production at 150, 200,250, and 300 ^{o}C individually. The results showed that the best recovery was at 300 ^{o}C. They carried out three sets of experiments to integrate steam injection with polymer, surfactant, and polymer/surfactant solutions at the same temperatures to investigate the effectiveness of the integration mechanism for improving oil recovery. The obtained results indicated that steam is a promising method for the EOR (Enhanced Oil Recovery) of heavy crude oil. It was found that the final recovery for water flooding ranges from 39.9% to 41.86%. The flooding experiments showed that the maximum oil recovery was obtained using steam integrated with polymer/surfactant solution (64.3 %) as shown in Figure 9. In comparison, steam exhibited oil recovery equal to 59.2 % with surfactant and 58.1% with polymer at the same temperature (300 ^{o}C). The maximum integration process was pronounced by steam with polymer/surfactant solution. This finding may be due to reducing the viscosity by steam which enhances the sweeping process by polymer, in the presence of surfactant, which reduces the interfacial tension and increases wettability alteration. As a result, the emulsion formed, and the heavy oil recovery increased.

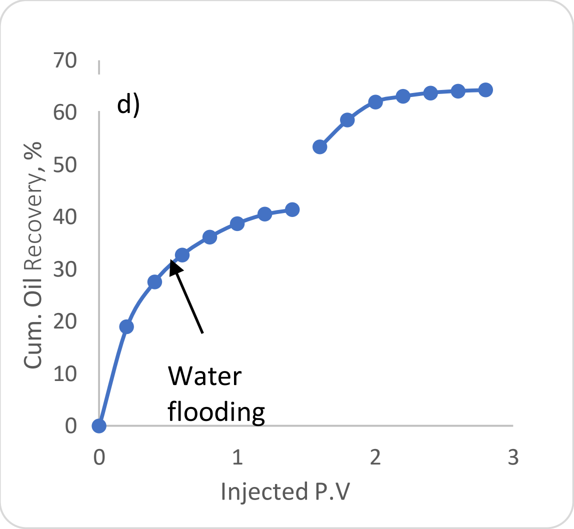

Figure 9 Cumulative oil recovery % , integration flooding of 300 °C steam and E(20)STO HPAM mixtur[90]

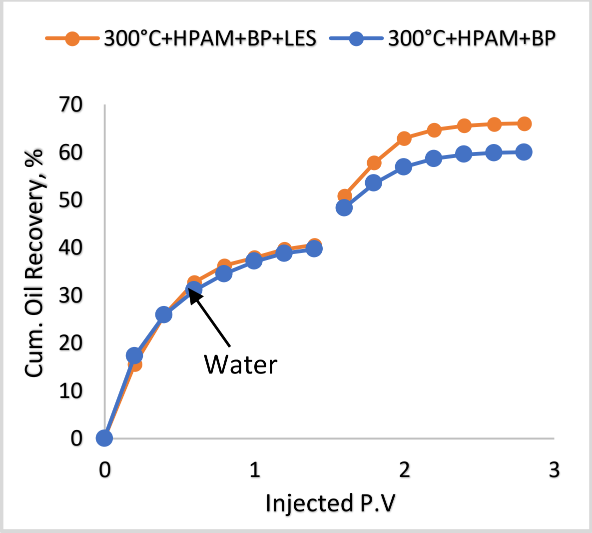

Figure 10 Cumulative oil recovery %, integration flooding of steam and mixture of HPAM, LES and BP [91].

Also, the same authors A.M. Alsabagh 2023 [91] introduced a newly used biopolymer (BP, animal glue) integrated with steam, surfactant (Lauryl Ether Sulfate, LES), and polymer(HPAM) to enhance oil recovery with the steam temperature of 300 °C. The obtained results showed that the oil recovery after water flooding ranges from 39.9 % to 41.86 %. By using the integration of steam with surfactant, polymer, and biopolymer and a mixture of them additional oil recovery was obtained. the maximum oil recovery achieved when using steam integrated with a surfactant, polymer, and biopolymer solution was 66.03 % as shown in Figure 10. The added value from the residual oil by steam injection with biopolymer, polymer, and mixture of them was 22.03%,30.1 %, and 39.1 respectively. By mixing the surfactant with them the added value was raised to 42.89%. The significance of these phenomena to recovery improvement in flooding and gravity-controlled instances was established by these findings. They proved that the biopolymer has the dual advantage of surfactant and polymer as indicated in Table 2and 3, as BP is useful in enhancing the wettability by reducing the contact angle as well as enhancing the viscosity due to its surface activity behavior and the strong hydrogen bond between the internal chemical chains of BP. furthermore, it improves the sweeping efficiency according to its polymeric nature.

Table 2 Contact angle and interfacial tension at 50 °C [91]

Sample	**Static Contact Angle**	**Dynamic Contact Angle**	**IFT mNm-1**
Crude oil	160.55	157.3	26
HPAM	61.3	58.2	69
BP	42.8	39.6	2.11
LES	26	21	6*10 -2
HPAM+ BP	55	53	15
HPAM+ BP+LES	15	12	1*10 -3

Table 3 Surface active and thermodynamics properties of BP and LES [91]

Parameter / Material	Temp. ^{0}C	CMC (mol/L)	γCMC (mNm^{-1})	PC$_{20}$ mol/cm-3 *10^{-7}	Γmax (mol/cm2) *10 $^{-10}$	Amin (Å^2)	πCMC mNm-1	Δ Gmic (KJ/mol)	Δ Gads (KJ/mol)
BP	50 ^{0}C	9.6 *10 -5	40	2.2	0.55	298	24	-37.38	-40.24
	75 ^{0}C	4.8 *10 -5	37	1.81	0.68	241	25	-40.45	-42.14
LES	50 ^{0}C	1.7 * 10 -3	30	1.81	1.17	184.41	39	-29.48	-33.74
	75 ^{0}C	8.6 *10 -4	27	1.23	1.21	176.53	42	-38.08	-42.62

Conclusions

This article provides a comprehensive and insightful overview of the integration of steam injection with chemical additives in heavy oil recovery. The authors highlight the limitations of steam injection and the potential benefits of integrating chemical additives such as polymers, surfactants, and solvents.

The article discusses the mechanisms of the integration of these chemical additives with steam injection and their effects on heavy oil recovery. The authors review the recent studies that have investigated the effectiveness of this technique, and they highlight the importance of optimizing the type and concentration of the chemical additives used, as well as the reservoir conditions, to maximize the effectiveness of the technique.

The article also discusses the challenges and limitations of the technique, such as the potential for formation damage, the cost of the chemical additives, and the complexity of the injection process. The authors suggest that further research is needed to optimize the technique and evaluate its economic feasibility Overall, this article is a valuable resource for researchers and practitioners in the field of enhanced oil recovery. It provides a balanced analysis of the advantages and limitations of the integration of steam injection with chemical additives, and it highlights the need for further research in this area. The integration of steam injection with chemical additives such as polymers and surfactants is a promising technique for heavy oil recovery, and this article provides important insights for those seeking to improve the efficiency of oil recovery in mature oil reservoirs.

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Nomenclature

PC	Capillary Pressure mol/cm-3
r	Radius of the Pore
θ	Contact Angle
NC	Capillary Number
V	Linear Velocity ms-1
μ_w	Water Viscosity cP
PC$_{20}$	Adsorption Efficiency %
ΠCMC	Surface Pressure Effectiveness mNm-1
Gads	Gibbs Free Energy of Adsorption KJ/mol
Gmic	Gibbs Free Energy of Micellization KJ/mo
γ CMC	Surface Tension mNm-1
Amin	minimum occupied area/molecule Å^2

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Conflicts of Interest

There are no conflicts to declare.

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