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Review

A Critical Review of Alkaline Flooding: Mechanism, Hybrid Flooding Methods, Laboratory Work, Pilot Projects, and Field Applications

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Abstract: Over time, the dependence on oil has increased to meet industrial and domestic needs. Enhanced oil recovery (EOR) techniques in this regard have captured immense growth as EOR is not only used to increase the oil recovery but also to augment the sweep efficiency. Several techniques over the past decades have been used to improve oil recovery with cost-effectiveness. Cost-effective alkaline flooding has been effective for those oil reservoirs with a high total acid number. In this review, the significance of alkaline flooding has been discussed in detail, as well as the features of alkaline flooding in comparison to other modes of flooding. This review entails (1) alkaline flooding, (2) hybrid modes of injection, (3) experimental work, (4) pilot projects, (5) screening criteria, and (6) field applications. The findings of this study can help increase the understanding of alkaline flooding and provide a holistic view of the hybrid modes of flooding.

Keywords: enhanced oil recovery; alkaline flooding; interfacial tension; surfactant; polymer; low salinity brine; nanoparticles

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1. Introduction

The increased consumption of fossil fuels has led innovators and business leaders to think untraditionally. The surge in consumption of oil has forced petroleum engineers to produce more volumes of residual oil that were once unproducible. With modern technological advancements, there are different methods that supplement the oil recovery factor with many folds. The increased demand for oil has resulted in the importance of enhanced oil recovery (EOR). The reservoirs that deliver oil utilizing their natural energies come under the ambit of primary recovery driven by many mechanisms such as rock and fluid expansion drive, water drive, combination drive, gravity drainage, gas cap drive, and depletion drive, while secondary recovery methods further strengthen the primary recovery by increasing the oil recovery by means of water flooding and immiscible gas flooding. However, the nonswept oil remaining after primary and secondary recovery methods can be produced by employing enhanced/tertiary oil recovery, EOR, [1–5]. EOR methods include: miscible gas (carbon dioxide, hydrocarbon gas, nitrogen, or flue gas) flooding; thermal flooding (steam injection, hot water injection, combustion, and electrical thermal EOR); chemical (alkaline, polymer, surfactant, nanomaterials, and low salinity water) flooding; microbial flooding; and others such as acoustic and electromagnetic waves. In addition to increasing oil mobility, EOR improves the sweep efficiency of oil in the reservoir by use of injectants that further reduce the saturation of remaining oil (oil trapped in the flooded areas by means of capillary forces and the oil in the areas that are not flooded by the injected fluids, which is usually called bypassed oil) [6]. EOR is defined as "a set of production technologies that involve the injection of energy or fluids to recover more oil than that produced by primary and secondary recovery methods" [7,8].

Chemical enhanced oil recovery methods used in an oil reservoir are based on the use of polymer-augmented waterflooding, alkaline flooding, surfactant flooding, waterflooding augmented by carbon dioxide, and/or immiscible carbon dioxide displacement. Similar to any water-based displacement process in the reservoir, injected aqueous chemical phase pushes the oil towards the production wells. Because of large differences between displacing fluid (water) and displaced fluid (oil) viscosities, water along with the chemical starts breaking the oil window and is produced instead of pushing oil to the perforation of the production wells. Usually, this early breakthrough problem can be overcome by adding polymer to water to increase its viscosity. To overcome this problem and increase the effectiveness of the flooding in terms of incremental oil recovery, an alkaline–surfactant slug is used to break oil droplets [9].

Every field is unique in terms of data and performance; the usage of a particular injection method is subjective to different variables (formation, fluid properties, reservoir rock properties, environment, cost, etc.). In most reservoirs, where primary, secondary, and tertiary recovery methods have been practiced (particularly thermal methods), the usage of chemical enhanced oil recovery has provided tremendous growth in oil recovery. For any field, it is important to know the type of hydrocarbon formation and chemistry to opt for any flooding method [2,9,10].

For each application of any of the chemical methods mentioned above, the chemicals must be formulated and tailored to the properties of the reservoir rock and fluid systems to meet the selection criteria discussed in this manuscript [11]. For alkaline flooding, sandstone reservoirs are favorable. Several types of research have been applied to limestone formation, but these did not generate fruitful results as compared to sandstone formations [3].

The chemical flooding processes improve oil recovery by one or more of the following effects:

- Lowering the interfacial tension between oil and water;
- Emulsification of oil and water;
- Solubilization of oil in the micelles;
- Alteration of rock wettability (oil-wet to water-wet);
- Mobility and sweep efficiency enhancement.

Selection of any of the chemical methods based on the selection criteria requires extensive testing of various combinations of chemicals in the laboratory, which is performed by coreflood testing followed by a pilot test to check whether a field application is viable. This manuscript focuses on review of alkaline flooding as a chemical enhanced oil recovery method from different points of view, such as the mechanism, modes of injection, laboratory work, pilot projects, process selection using screening criteria, and field applications.

2. Alkali Flooding

Alkaline (or caustic) flooding is a chemical method by which oil displacement efficiency can be increased and consequently more of the remaining oil can be produced. The benefits of this process are based on the reaction between sodium hydroxide (NaOH) with the naturally occurring organic acids in crude oil that result in soap production at the oil–water interface. This type of surfactant produced in situ results in reducing the interfacial tension (IFT) between oil and water. Alkaline basicity (pH) ranges from 8 to 14, where 14 is considered to be a very strong alkaline agent. It is not necessary that using strong alkali could provide incremental oil recovery because strong alkalis have greater chances of production capacity loss and scaling problems [12]. Alkaline process is highly dependent on reservoir rock mineral content and the crude oil and injection fluid characteristics. Oil reservoirs whose total acid number (TAN—a measure of the number of carboxylic acid groups in a chemical compound) is high can be a potential candidate for alkaline flooding, which also can form soaps in situ that react with the acidic parts of the oil [4]. For the alkaline process to be effective, the oil reservoir must maintain a mobility ratio (MR—ratio of the mobility of the displacing phase to the mobility of the displaced phase) of less than or equal to one (MR $\leq$ 1) [13].

Since alkaline agents are inexpensive, alkaline flooding is a very cost-effective method compared to other chemical methods. The use of alkaline agents along with polymer and/or surfactants could reduce the amount of high-cost surfactant or cosurfactant required in micellar flooding processes. Currently, operating companies take advantage of the combined alkaline–surfactant mixture effect.

Heavy oil reservoirs have high organic acid contents that react with alkalis to produce soap, which is formed when the alkali reacts with the saponifiable component (petroleum acids) of crude oil in the reservoir, [14]. The soap produced results in a significant decrease in interfacial tension of the heavy oil reservoir [15]. When different alkalis are used in comparison to each other to observe the interfacial tension, it is found that there is less significant difference in terms of reduction in interfacial tension (IFT) among these alkalis [16], while the simple alkaline flooding compared to water flooding does not show a considerable amount of oil recovery [14]. The salt content in the solution significantly changes the process of oil interaction with an alkaline solution. For example, the presence of calcium chloride (NaCl) results in increasing interfacial tension, which leads to reduction in the performance of alkaline flooding. Attaining optimum salinity is an important factor in alkaline flooding. Cosurfactants are usually added to achieve optimum salinity in the reservoir [17].

Chemical enhanced oil recovery (CEOR) has given tremendous results, especially in the Daqing oil field in China, in which the oil recovery rate was above 20% [18]. The reduction in interfacial tension of oil and water increases the capillary number because alkali forms soaps when it reacts with crude oil (organic acid), which further reacts with surfactant and results in an ultralow interfacial tension [5,15].

The mobility ratio (MR) is an indicator of displacement process stability that is known to increase with volumetric sweep efficiency. When the mobility ratio is greater than one (MR > 1), it indicates viscous fingering or nonuniform displacement. In viscous fingering, and because of the larger viscosity difference between displacing and displaced fluid, water has an earlier breakthrough and is produced instead of pushing oil. To assure maximum efficiency, the mobility ratio should be always equal or less than one (MR $\leq$ 1).

In addition to MR, oil recovery is also influenced by capillary forces depending upon the type of reservoir, i.e., fractured and nonfractured reservoirs. In the former, water imbibition due to strong capillary forces is a dominating factor, while for the later during water flooding these strong capillary forces trap oil, resulting in low oil recovery. In a reservoir, capillary forces are balanced by gravity or viscous forces. In the literature, capillary number (ratio of viscous forces to the capillary forces) is used. It is a dimensionless variable and used to compare how many times the viscous force is greater than the capillary force. The capillary number also relates to oil recovery. By increasing the capillary number, the mobility of oil increases. Generally, the capillary number increases through alkali–surfactant–polymer (ASP) flooding. Conversely, bond numbers are used in such systems where viscous or gravity forces are dominant. When the capillary number of different EOR flooding methods are compared with water flooding, they are found to be greater in the CEOR method than in the water flooding method [19,20]. When the capillary number can be increased, for example, from 10^{-6} (conventional waterflood) to 10^{-4} (CEOR) or more, the residual oil saturation decreases.

Based on oil emulsification and wettability reversal, the following mechanisms are usually suggested for oil displacement by alkaline flooding:

- Emulsification and entrainment;
- Wettability reversal from oil-wet to water-wet;
- Wettability reversal from water-wet to oil-wet;
- Emulsification and entrapment;
- Reduction in the oil–water interfacial tension.

Regardless the type of mechanism, the alkaline flooding process begins with a preflush (preinjection) of softened water (water with very low mineral content such as magnesium and calcium) followed by the injection of a plug/slug of alkaline solution (NaOH), as shown in Figure 1. Usually, the volume of alkaline slug varies from 10% to 30% of the available reservoir pore volume. The alkaline slug is driven in the reservoir by injection of alkaline polymer-based water. Polymer is added to water to decrease its mobility by increasing its viscosity.

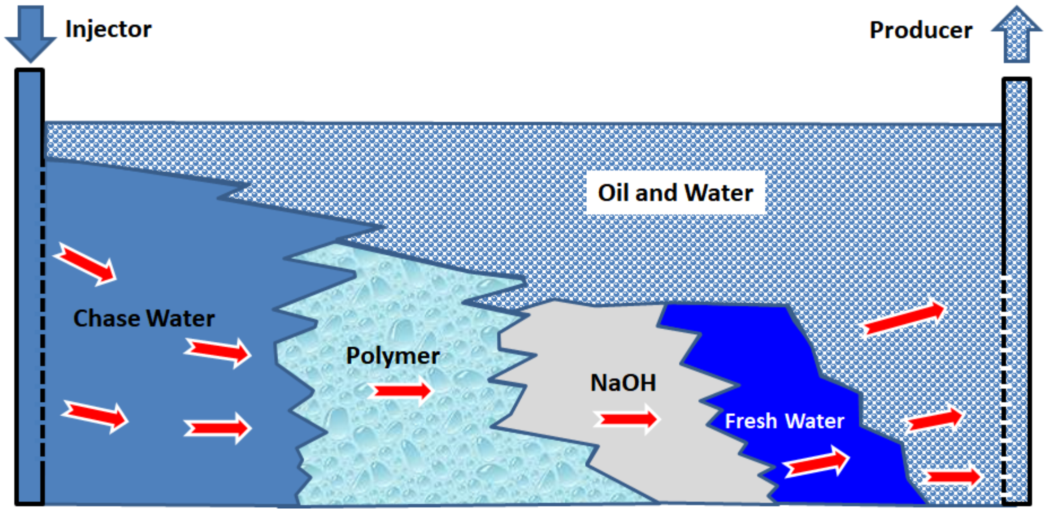

Figure 1. Alkaline flood injection mechanism.

3. Hybrid Modes of Injection

In this section, different types of chemical enhanced oil recovery methods in association with alkaline flooding are discussed.

3.1. Alkaline–Polymer (AP) Flooding

Adding alkali, which has a salt effect, to any polymer solution results in reducing the viscosity of the polymer [21], suggesting that when alkaline–polymer (AP) flooding is performed, the consumption of alkali is reduced as opposed to only alkaline flooding because in the former, polymer covers solid grains to reduce alkali–rock contact. AP flooding has a synergistic effect, as it not only reduces the polymer solution viscosity but also reduces alkaline consumption and polymer adsorption [14].

3.2. Alkaline–Surfactant (AS) Flooding

Alkaline–surfactant (AS) flooding has a favorable impact on the production of oil over nonthermal methods [22]. When alkali is added to the surfactant solution, alkali provides electrolytes and the salinity of the solution increases. The increased solution salinity combined with optimum lower salinity of generated soap results in a new optimum value of AS flooding salinity, which is different from the salinity of surfactant flooding alone. The addition of alkali offers the same benefit to the surfactant as it does with polymer, in that it reduces surfactant adsorption [23].

During AS flooding, the maintenance of alkalinity levels is of primary concern. The interaction of alkali and rock can be considered as ion exchange and chemical reaction, while the concentration is influenced by the type of formation. In the reservoir rock, the propagation of alkali is influenced by the loss of alkalinity [24]. Therefore, when designing the alkali flood, alkalinity loss considered in the calculation is determined utilizing hydrogen-ion exchange [25]. The rockbound hydrogen ions are released into the solution in the presence of alkali. Alkaline flooding synergistically impacts the heavy oil where it forms in situ surfactants by reacting with heavy oil. These in situ surfactants then reduce the IFT, further supplementing the emulsion, and the oil is produced easily [26,27].

3.3. Alkaline–Surfactant–Polymer (ASP) Flooding

Alkali–surfactant–polymer (ASP) flooding is one of the types of chemical EOR flooding that is used to increase the sweep efficiency of crude oil. Its concentration depends upon the type of crude oil, temperature, pressure, and salinity of connate water. In ASP flooding, the alkali–surfactant (AS) mixture makes an emulsion with oil in situ, which then is flooded by polymer [19]. Additionally, alkali is used to produce in situ surfactants that aim to reduce interfacial tension to overcome the capillary force that mobilizes oil, while the polymer is used to improve sweep efficiency and the control mobility ratio [28]. Crude oil with high acidity (acid number) can be suitable for ASP flooding [29]. For efficient ASP flooding, a reduced amount of alkali is used for a high acid number of crude oil [30]. The emulsification effect and viscosity enhancement make ASP flooding more effective [31]. Besides entrainment and emulsification, wettability reversal takes place due to a change in relative permeability which alters wettability [32]. ASP flooding is not only applied in sandstone reservoirs but can also be used in limestone and dolomite formation [12].

Sodium hydroxide (NaOH) is a strong alkali because it has a stronger emulsification ability. Sodium hydroxide, sodium carbonate (Na_2CO_3), sodium bicarbonate ($NaHCO_3$), sodium metaborate ($NaBO_2$), sodium tripolyphosphate ($Na_5P_3O_{10)}$, and sodium orthosilicate (Na_4SiO_4) are the common alkalis used in ASP flooding [33,34]. The only limitation with sodium carbonate is that it cannot be used if there is a presence of gypsum or anhydrite [34]. When sodium orthosilicate is used with water of high hardness, IFT is reduced significantly because it produces magnesium silicate (MgO_3Si) or calcium silicate (Ca_2O_4Si), which is less soluble than magnesium hydroxide ($Mg(OH)_2$) or calcium hydroxide ($Ca(OH)_2$); as a result, it reduces the water hardness [35]. Normally, inorganic alkalis such as sodium hydroxide and sodium carbonate cause corrosion and scale; organic alkalis are used to mitigate these problems [36].

ASP flooding is more effective if applied directly after water flooding, since after water flooding a considerable amount of oil remains in the reservoir [37]. The advantage of ASP flooding over others is that it does increase the oil recovery by simultaneously reducing the IFT and mobility ratio [38]. Owing to technological advancements and innovation, many efforts have been made to improve cosurfactants, polymers, alkali, and cosolvents that can withstand harsh environments [39,40]. Traditionally, oil reservoirs with a viscosity of less than 50 cp are the best candidates for ASP flooding [41]. The efficiency of ASP flooding increases if cosolvents and cosurfactants are added. The consumption of alkali by a rock in the case of alkaline flooding makes the oil recovery process slow [17].

3.4. Alkaline–Low Salinity Brine Flooding

The addition of low salinity water (LSW) to alkaline makes the flooding more effective. In addition to being cost-effective, this method has produced good results in both sandstone and limestone reservoirs [42]. This method is easy to deploy because it is an extension of the conventional water flooding system. In the literature, oil recovery from low salinity water reportedly ranged from 2 to 20%. The results of LSW flooding in carbonate reservoirs have given promising results.

When LSW is flooded in sandstone reservoirs, it forms microdispersion due to the interfacial interaction between reservoir fluid (oil) and LSW. On the other hand, in carbonate reservoirs, reservoir fluid (oil), when interacting with LSW, forms water in oil microdispersion that makes LSW flooding a potential enhanced oil recovery method for carbonate reservoirs [43].

The combination of LSW and alkaline flooding improve oil recovery, which is further improved by reducing salinity and increasing the basicity (pH) of the flooding fluid. The reason for low salinity flooding is oil recovery improvement with decreasing ionic strength of water. Therefore, a combination of LSW and alkaline has been considered favorable in many aspects. Besides promising results, care should be taken to choose the optimum salinity; otherwise, it would also cause the migration of fine particles that may lead to formation damage. The fine particles usually adhere to the rock surface due to electrostatic attractive force, which is a strong function of salinity and pH. When brine is injected with a salinity value less than critical, the repulsive force tends to move the in situ colloidal particles through the beds [44].

3.5. Alkaline–Nanoparticle Flooding

One of the main advantages of nanoparticle flooding is that nanoparticles can withstand high pressure and high temperature due to their high surface to volume ratio, which eases their diffusion at high temperatures. Nanoparticle flooding has recently captured the attention of scientists and those who work on enhancing oil recovery due to the increased demand for hard-to-produce oil. Other reasons for nanoparticle flooding are that they are environmentally friendly, and due to their size, they can easily pass through pore throats without plugging them. The nanoparticles used most are spherical fumed silica particles and metal oxides. When nanoparticles are injected into the reservoir, they interact with reservoir fluids since they are smaller in size (i.e., 100–500 nm) and can easily pass through reservoir-rock pore openings whose diameters are around 10 µm. Owing to the interaction with reservoir fluid, the solid–liquid interface causes several changes and enables the oil to become more mobile [45].

4. Alkaline Flooding Experimental Work

The benefits of alkaline (or caustic) flooding have been known for a long time and were first observed by [46] and later by many other scientists. However, it was explained by Subkow [47] that alkaline agents (e.g., sodium hydroxide) could react with naturally occurring organic acids in crude oil in the reservoir to produce soaps at the oil–water interface.

One good example of alkaline flooding experimental work has been done on the sample of a western Canada clastic reservoir [48]. The common types of chemicals used were soluble silicate, sodium hydroxide, and sodium carbonate. The alkaline flooding parameters that were quantified in the laboratory assessment were acidity (pH), hardness, salinity, stability of emulsions, and time it took to interact with rock. The alkali concentration effect on the measured parameters was investigated as well. The recovery factor of oil was determined using a linear displacement test [49]. The unconsolidated sandstone sample collected from the western Canada clastic reservoir had an average reservoir porosity of 28%, and permeability of 150 md. Initially, the emulsification effect of oil was studied by mixing 3 mL of oil with 10 mL of sodium hydroxide (0.12–1 wt%) in the synthetic source water. Through this experiment, oil volume increased, implying the formation of emulsification. These mixtures were then placed, at 32 °C, in an oven for one day. After that, two types of emulsions were formed, namely, water in oil (w/o), and oil in water (o/w). In addition, interfacial tension (IFT) of oil, alkaline, and synthetic source water was determined using spinning drop apparatus. Three sections of the samples were placed in the displacement test, while one section was placed in the consumption test. The objective of the consumption test was to determine the consumption of alkali as a function of time. For that purpose, a sample with a volume of about 40 mL with 1 wt% sodium hydroxide in synthetic source water was placed in the consumption test [50].

After the successful laboratory assessment, it was found that the alkaline flooding contributed by producing an average of 4% of incremental oil recovery. Similarly, at a lower concentration of sodium hydroxide, lower IFT was achieved, and vice versa. Furthermore, it was found that reservoir rock consumed sodium hydroxide, and this consumption increased with increased alkali concentration.

5. Alkaline Flooding—Pilot Project

Table 1 shows many examples of alkaline flooding pilot projects that have been conducted. One of these pilot projects was performed in the Daqing oil field, China. Since 1994, 12 pilot tests have been conducted in the Daqing oil field. Initially, sodium hydroxide was used as strong alkali, but due to corrosion and scale formed on the apparatus, subsequent pilot flooding tests used a weaker alkali (sodium carbonate).

Table 1. Alkaline flooding—pilot projects.

Country	Name	Description	Properties	Values	References
China	Daqing field	It was found that the oil production rate using weak alkali was 20% more than that of strong alkali. Similarly, in weak alkali, the scaling problem was less severe than in strong alkali	Alkaline used Average incremental oil recovery (%) Viscosity (mPa.s) Temperature (°F) Oil formation volume factor (RB/STB) Formation net thickness (ft) Permeability (mD)	Sodium hydroxide and sodium carbonate 22 8.7 109 1.12 Sandstone 27 650	
Canada	Epping field	The pilot project was carried out using a five-spot injection well.	Alkaline used Average incremental oil recovery (%) Viscosity (mPa.s) Temperature (°F) Oil formation volume factor (RB/STB) Formation net thickness (ft) Permeability (mD)	Sodium hydroxide <1 150 72 - Sparky 20 1000	[51]
Indonesia	Duri field	Incremental oil recovery was found to be 5% of oil in place	Alkaline used Average incremental oil recovery (%) Viscosity (mPa.s) Temperature (°F) Oil formation volume factor (RB/STB) Formation net thickness (ft) Permeability (mD)	Sodium hydroxide 5 >120 100 1.02 Sandstone 120 1500	[52]
United States	Kern River field	A combination of alkaline and steam flooding was carried out.	Alkaline used Average incremental oil recovery (%) Viscosity (mPa.s) Temperature (°F) Oil formation volume factor (RB/STB) Formation net thickness (ft) Permeability (mD)	Sodium hydroxide <0.5 >1000 90 1.03 Kern River 88 2000	[51,53–55]

Two large fields out of the 12 pilot projects implemented used a normal five-spot injection pattern, namely, B-2-X and B-1-DD. These two fields have similar well spacing, and patterns were compared on the effect of alkali on oil recovery. [12]. Three other alkaline flooding pilot projects conducted in Canada, USA, and Indonesia are shown in Table 1. The table shows that alkaline flooding process is applicable to different reservoirs with different reservoir rock and fluid property values. This helped to determine the proper selection/screening criteria for alkaline flooding, as described in the next section.

6. Alkaline Flooding—Screening Criteria

The applicability criteria of alkaline flooding are based on several successfully implemented EOR projects. The screening criteria for alkaline flooding are discussed by many authors [35,56–58] and summarized in Table 2.

Table 2. Screening criteria for alkaline flooding.

Properties	Values
Gravity (°API)	20–30
Viscosity (cp)	11–200
Temperature (°F)	68–203
Average permeability (md)	10–1500
Composition	Organic acids are required to achieve low IFT
Oil saturation (% PV)	35–74.8
CO2 content	Reservoirs with high content of CO2 (>0.01) and low pH of formation water (pH < 6.5) are not good candidates for alkaline flooding
Formation preferred	Sandstone is preferred, but alkaline flooding has also generated good results in limestone formation (alkalis with high pH react with carbonates)
Gypsum (%)	<0.1 (because of high adsorption of alkali from the alkaline solution, any reservoir with layered anhydrite content of more than 0.1% should be rejected as a candidate)
Divalent ion exchange capacity (meq/kg)	<5 (high content of montmorillonite in the field results in absorbing most of the injected alkali due to its high surface area and cation-exchange ability that result in adverse precipitation reactions)
In situ pH	>6.5 (in case the of a high content of kaolinite in the reservoir, alkali flooding can be carried out with a low pH value (8.2–10)
Depth (ft)	900–3000

Some other factors (rock and fluid properties, alkaline availability, better handling of flooding, technological advancement, and project location) have to be considered to ensure the success of alkaline flooding [59].

7. Alkaline Flooding—Field Applications

Alkaline flooding has been implemented in many countries and fields such as: USA (Wilmington, Bison Basin, North Ward Estes, Bradford, West Kiehl, Cambridge, and Tanner fields), China (Shengli Oil Field, Daqing Sabei-bei-2-dong, Daqing Xing-bei xing-Daqing, Shengli Gudao-xi, Daqing Sa-bei-1-xi, Karamay, Daqing Xing-2-xi, Daqing Xing-wu-zhong, Yumen Lao-jun-miao, Daqing Sa-zhong-xi, and Shengli Guding fields), Canada (David field (now called Black Creek)), India (Jhalora and Viraj fields), Hungary (Nagylengyel field), and Malaysia (Angsi field). In this section, two field applications, namely the Wilmington field in the USA and Shengli Oil in China, are discussed in detail. Table 3 provides a summary of field applications for some of these fields.

Table 3. Alkaline flooding—field studies.

Country	Name	Description	References
United States (USA)	Bison Basin field	The test was conducted on 6 injection and 8 production wells	[51,60]
United States (USA)	North Ward Estes field	Sodium hydroxide was used as an alkali with a concentration of 5 wt%	[51,61]
Hungary	Nagylengyel field	A limestone reservoir, so ammonium hydroxide was used	[51,62]
United States (USA)	Bradford field	Sodium carbonate was used as an alkali	[32,51]
Malaysia	Angsi field	Alkaline surfactant and some other chemicals were used	[63,64]

7.1. Field Case Study—Wilmington Field, USA

The Wilmington field is in the United States and is considered to be one of the country's major fields. Alkaline flooding has been conducted in the Ranger zone of fault-block VII. Previously high pH alkaline flooding has been conducted. The zone has streaks of sandstone and shale. The pilot area of the reservoir is 193 acres, further sectioned into three areas, namely, central (93 acres), northern (59 acres), and southern (41 acres). The central area consists of two brackets of 4 injection wells and 11 producing wells, while the northern and the southern areas consist of 6 producing wells [31].

A mini-injection test was conducted before full-scale pilot testing. In the mini-test, the reservoir was initially preflushed with 62,000 bbl of softened water (water with very low mineral content, namely calcium and magnesium content) with 1% NaCl. The objective of preflush is to remove hardness from the reservoir so that an optimum salinity level can be achieved that supplements the injected alkaline to displace oil effectively. It is imperative to notice that preflush testing must be effective; otherwise, it would cause scaling problems near the producing well, and scaling causes additional pressure loss. After a preflush period, 237,000 bbl of 0.1% NaOH of alkaline was injected into the soft water.

In a full-scale pilot testing program, sodium orthosilicate (Na_4SiO_4) was preferred over sodium hydroxide because it reduces the interfacial tension (IFT) more effectively than NaOH, offers resistance against hardness, and ensures better oil recovery. As a result of this flooding, the water production for these wells dropped to an average rate of 6000 bbl/day. Table 4 shows Wilmington field formation and fluid properties [31,56,65].

Table 4. Field and fluid properties of the Wilmington field, USA.

Properties	Values
Initial OIP (bbl/acre-ft)	1260
Gravity (°API)	12.92
Total acid number (mg/gm)	3.40
Kinematic viscosity (cSt)	413
Avg. formation volume factor (RB/STB)	1.1
Pilot area (Acres)	193
Formation type	Shaly sand
Net thickness (ft)	320
Average permeability (md)	240
Average porosity (%)	25
Depth (ft)	2225
Temperature (°F)	125.06

7.2. Field Case Study—Shengli Oil Field, China

The Shengli oil field is in China and considered to be one of the oldest and largest fields in China. Different alkaline flooding test runs were conducted to calculate the effect of alkaline concentration in the Shengli oil field, especially in Zhungxi heavy oil. Throughout the flooding, the concentration of alkaline increased 10-fold (i.e., from 0.1 wt% to 1 wt%). The oil recovery was a direct function of alkaline concentration, but this relationship was validated until 0.4 wt% concentration; i.e., as the concentration increased, the sweep efficiency of oil increased, but once the alkaline concentration increased to 0.5 wt%, the slope of incremental oil recovery became gentle. The promising part of alkaline flooding was the rise of incremental oil recovery. After the end of alkaline flooding, 31.94% of oil recovery was achieved. Although in this field several other modifications were performed, including surfactant–alkaline flooding, the alkaline flooding generated fruitful results compared to other modes of chemically enhanced oil recovery [66]. The Shengli oil field formation and fluid properties are summarized in Table 5 [66–68].

Table 5. Field and fluid properties of Shengli oil field, China.

Properties	Values
Gravity (0API)	20.6
Total acid number (mg/gm)	0.8
Kinematic viscosity (cSt)	325
Initial oil saturation (%)	57
Formation type	Sandstone
Net thickness (ft)	43.6
Average permeability (md)	560
Average porosity (%)	26
Depth (ft)	4260
Temperature (°F)	131

The results of worldwide alkaline flooding projects (pilot and large scale) implemented between 1987 and 2011 showed that oil recovery could vary between 5% and 28%.

The field studies of alkaline flooding have shown some promising results. The performance of stimulation work in the oil field also depends on the order of chemical components. It was found that the addition of polymer in alkaline flooding causes the formation of filter cake that prevents wormhole growth. Conventional stimulation that includes hydrochloric acid (HCL) and/or hydrofluoric acid (HF) has posed several challenges in terms of formation damage; it also becomes difficult to conduct alkaline flooding because of matrix dissolution, and, for that matter, different chelating agents are used to overcome this issue [69].

8. Conclusions

This study presents a comprehensive review of alkaline flooding, its mechanism that improves oil recovery, hybrid modes of injection that help to improve the sweep efficiency, laboratory experiments, and pilot and full-field applications. The major findings of alkaline flooding follow:

- AP flooding reduces polymer viscosity and helps to reduce alkali consumption.
- AS flooding has a considerable impact on nonthermal flooding. When alkali is added to the surfactant solution, it increases the salinity of the solution and reduces the surfactant adsorption.
- ASP flooding has been effective in terms of reducing IFT and mobility ratio, and its efficiency is improved by the addition of cosolvents and cosurfactants.
- Alkaline–LSW flooding has a considerable impact on oil recovery; the addition of LSW to the alkaline also makes it a favorable candidate for carbonate reservoirs.

- Alkaline–nanoparticle flooding helps recover oil in the complex reservoir because nanoparticles can withstand high temperature and pressure conditions. Nanoparticles, owing to their small size, can interact easily with reservoir fluids in tight formations.

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Abbreviations

EOR	Enhanced Oil Recovery
TAN	Total Acid Number
IFT	Interfacial Tension
MR	Mobility Ratio
CEOR	Chemical Enhanced Oil Recovery
ASP	Alkali–Surfactant–Polymer
AP	Alkaline–Polymer
AS	Alkali–Surfactant
LSW	Low Salinity Water
OIP	Oil In Place
PV	Pore Volume

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