REVIEW

A review of development methods and EOR technologies for carbonate reservoirs

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Abstract

Carbonate reservoirs worldwide are complex in structure, diverse in form, and highly heterogeneous. Based on these characteristics, the reservoir stimulation technologies and fluid flow characteristics of carbonate reservoirs are briefly described in this study. The development methods and EOR technologies of carbonate reservoirs are systematically summarized, the relevant mechanisms are analyzed, and the application status of oil fields is catalogued. The challenges in the development of carbonate reservoirs are discussed, and future research directions are explored. In the current development processes of carbonate reservoirs, water flooding and gas flooding remain the primary means but are often prone to channeling problems. Chemical flooding is an effective method of tertiary oil recovery, but the harsh formation conditions require high-performance chemical agents. The application of emerging technologies can enhance the oil recovery efficiency and environmental friendliness to a certain extent, which is welcome in hard-to-recover areas such as heavy oil reservoirs, but the economic cost is often high. In future research on EOR technologies, flow field control and flow channel plugging will be the potential directions of traditional development methods, and the application of nanoparticles will revolutionize the chemical EOR methods. On the basis of diversified reservoir stimulation, combined with a variety of modern data processing schemes, multichannel EOR technologies are being developed to realize the systematic, intelligent, and cost-effective development of carbonate reservoirs.

Keywords Carbonate reservoir · Reservoir stimulation · Flow characteristic · Development method · EOR technology

1 Introduction

Carbonate rocks are sedimentary rocks composed of sedimentary carbonate minerals (calcite, dolomite, etc.). Most carbonate rocks were deposited in warm and clean shallow sea environments, primarily as a result of endogenous deposition. The main rock types of carbonate reservoirs include limestone (grainstone, reef limestone, etc.) and dolomite, and their storage space is usually comprised of pores, karst caves and fractures (Wang et al. 2012). Generally, pores and karst caves are the main storage spaces, and fractures serve as both storage spaces and the main flow channels in reservoir rocks. Globally, carbonate reservoirs have become the main oil and gas production resources due to their ubiquity, uniform thickness, and large scale. Middle East oil production accounts for approximately two-thirds of global production, and 80% of Middle East oil-bearing formations are carbonate rocks (Nairn and Alsharhan 1997). Oil production in carbonate reservoirs in North America accounts for approximately 1/2 of all North American oil production (Wilson 1980a, b). There are nearly 3×10^6 km² of carbonate rocks in China, accounting for approximately 1/3 of the China's land area. These data illustrate the importance of carbonate oil and gas fields in the world.

The distribution of carbonate rocks accounts for 20% of the total area of global sedimentary rocks; carbonate oil and gas resources account for approximately 70% of the world's

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oil and gas resources, and proven recoverable reserves account for approximately 50% of the world's oil and gas resources (Li et al. 2018c). The oil and gas production in global carbonate reservoirs accounts for approximately 60% of global oil and gas production (Roehl and Choquette 2012). Marine carbonate oil and gas resources account for 90% of global oil and gas resources, as marine carbonate oil and gas resources are vast. There are 389 oil and gas basins in the world engaged in commercial production, among which 208 basins are located in marine carbonate strata. By the end of 2013, the proven plus probable (2P) recoverable reserves of oil, natural gas and condensate that had been discovered worldwide were 3.534×10^{11} t, 3.27×10^{14} m^3 and 2.24×10^{10} t, respectively, and their oil equivalent was 6.383×10^{11} t. Among them, the 2P recoverable reserves of petroleum, natural gas, and condensate in marine carbonate formations were 1.296×10^{11} t, 1.2×10^{14} m^3, and 1.22×10^{10} t, respectively. The oil equivalent was 2.382×10^{11} t. The recoverable reserves of oil, natural gas and condensate in marine carbonate rock series account for 36.7%, 36.7% and 54.5% of the total discovered oil and gas in the world, respectively, accounting for 37.3% of the total based on oil equivalence calculations. Figure 1 shows a summary of the recoverable reserves of marine carbonate reservoirs in the world. It can be seen that oil and gas are mainly concentrated in four oil and gas regions: the Middle East, the former Soviet Union, North America, and the Asia–Pacific region (Wang et al. 2016).

With the continuous advancement of oil and gas exploration throughout the world, the development of deep and ultradeep oil and gas has become a topic of interest. More than 10% of carbonate oil and gas fields have a burial depth of more than 3500 m. Among them, the oil fields under development with a burial depth of more than 5000 m are mainly concentrated in North America, Russia, Italy and other regions. In recent years, China has made an important progress in the development of deep carbonate rocks in the Tarim Basin (Ma et al. 2011). Carbonate rocks are easily fractured. With increased burial depth, dissolution has a great influence on the pore structure of carbonate reservoirs. Through organic acid dissolution, hydrothermal dissolution, thermochemical sulfate reduction (TSR) and other processes, corrosion pores are formed in the buried environment. Geologists who have long engaged in marine carbonate research are focusing on the development of corrosion pores. These newly discovered deep and ultradeep carbonate rocks are all affected by fractures and vugs, forming fractured reservoirs with fractures as the main storage spaces, which usually contain abundant reserves that are amenable to large-scale development.

Compared with sandstone reservoirs, carbonate reservoirs have notable differences in geological structure characteristics and reservoir displacement mechanisms that require certain particularities in development methods. There are many development methods utilized in carbonate reservoirs because depletion is inexpensive, the formations are adaptable, and natural energy can be fully utilized. For reservoirs with low stress sensitivity, depletion production is generally used. However, depletion production causes the formation pressure to drop, thus hindering stabilized reservoir production; the premise of adopting this method is the lack of supplementary formation measures and corresponding EOR technologies. Therefore, because of these unique characteristics, it is important to efficiently develop carbonate reservoirs by formulating ideal potential tapping countermeasures and adopting appropriate development methods.

This review focuses on the related technical problems in the development processes of carbonate reservoirs in the world. This study combines the results of laboratory experiments and practical applications in oil fields, explains the technological measures for the stimulation of carbonate reservoirs, analyzes the flow characteristics of formation fluid in fractured vuggy carbonate reservoirs, and details the various development methods such as water flooding, gas flooding, chemical flooding, and emerging oil production technologies. The EOR mechanisms for carbonate reservoirs are summarized, and the challenges of carbonate reservoir development and the directions of future development technologies are discussed.
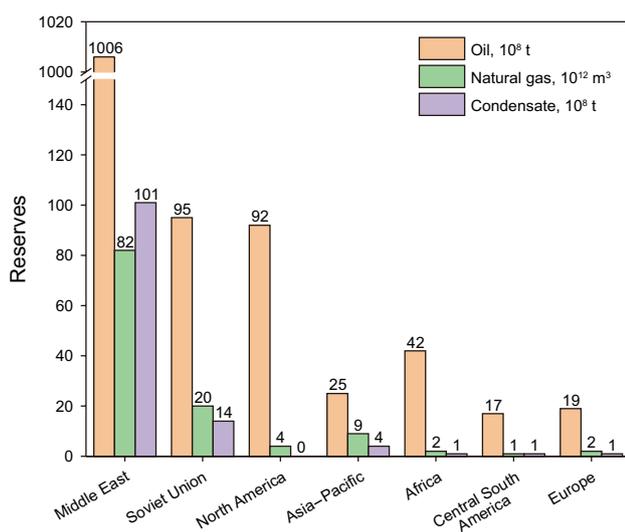

Fig. 1 The proven plus probable recoverable reserves of marine carbonates in the world (Energy 2008; Gautier et al. 1995; USGS 2000)

2 Stimulation of carbonate reservoirs

The porosity and permeability of carbonate reservoirs in the world are generally low; approximately 80% of reservoir porosity values range between 4% and 16%, and the

permeability ranges from 1 to 500 mD. When the matrix permeability of carbonate reservoirs is low, dissolution structures such as pores, fractures and karst caves are developed, and the heterogeneity of these formations is strong. Natural microfractures and dissolved pores, as the main storage spaces, provide a large contribution to oil production and are often distributed in the form of discontinuous zones with great randomness. The matching relationship between natural fractures and pore structures is diverse, which can cause divisions within a reservoir, where the connectivity of these structures is poor and their conductivity is different. In terms of production characteristics, the initial oil production levels can be high, but maintaining stable production is difficult. Therefore, reservoir stimulation measures, such as acid fracturing, occupy an important position in the efficient development of carbonate reservoirs.

In the process of carbonate reservoir development, acidizing is an effective measure used to increase production and injection. The injection of an acid solution can eliminate rock cementation or formation plugging through dissolution and corrosion to improve the permeability of the reservoir. Acid fracturing expands the fracture openings by injecting pad fluid or acid fluid directly under the condition that the injection pressure is higher than the formation fracture pressure, and the acid fluid produces uneven corrosion on the fracture surfaces. Even after the fracture is closed, it maintains a certain conductivity to achieve the effect of increasing oil and gas production. Acid fracturing is an important technical means to increase and stabilize the production of carbonate reservoirs. However, there are severe formation conditions, such as high temperature, high pressure, and high stress, in deep and ultradeep carbonate reservoirs that pose a great challenge to the implementation of acid fracturing technology.

For the acidic fluid systems commonly used in carbonate reservoir acidification, Aljawad et al. (2019) provided a very detailed summary, including for hydrochloric acid and organic acids. Hydrochloric acid is widely used because of its strong dissolving ability, and under high temperatures, the reaction rate of hydrochloric acid is greatly accelerated. It is necessary to add a slow release agent to reduce the acid rock reaction and loss rate. The addition of polymer gels can increase the viscosity of the system and reduce the loss of acid to a certain extent. However, polymer gels are greatly affected by temperature and pH, which enhances their performance when used as additives. Emulsified hydrochloric acid, which is usually composed of diesel oil, emulsifier and acid (DEA), is also a mixture that can reduce acid loss. In terms of deep acidification, DEA can also prevent corrosion caused by acid contact. However, this acid system may cause considerable reservoir pollution (Nasr-El-Din and Al Moajil 2007). As a cleaning fluid, a viscoelastic surfactant (VES) can provide good viscosity control and shunting ability.

However, due to its strong reservoir sensitivity and high cost, the economic benefits need to be considered before using a VES (Barati and Liang 2014). In low-pressure reservoirs, the effect of foam acid fracturing is better than that of conventional acid fracturing. Foam fluid-carrying acid can achieve fluidity control and multistage fracturing (MSF) (Rahim 2018). The performance of foam acid systems largely depends on the stability of the foam, which depends on the development of thermal resistance and the salt tolerance of the foam systems. Organic acids can adapt well to the formation environment of carbonate reservoirs. However, due to their low solubility, there are many limitations in their application to acid fracturing.

With the global development of carbonate reservoir stimulation, new technologies for acid fracturing have emerged in recent years. Guo et al. (Guo et al. 2019) proposed a hybrid volume stimulation (HVS) technology for tightly fractured carbonate reservoirs. The technology includes three stages: hydraulic fracturing, large-scale acid fracturing and proppant injection. The core concept is to establish a complex fracture system with high conductivity, as shown in Fig. 2. The system includes main fractures, branch fractures, induced fractures, and acid-etched wormholes. HVS technology combines the advantages of traditional hydraulic fracturing and acid fracturing to further improve the stimulation effect of tight fractured carbonate reservoirs.

In-situ microfoam acidizing is a new type of acidification technology. The technology uses conventional chemical reactions between acids and carbonate rocks to produce supercritical CO_2. With the synergistic effect of foaming agents and stabilizers, CO_2 foam fluid is generated in situ, which carries the acid solution into the carbonate rock matrix for acidification (Yan et al. 2019). The mechanism is shown in Fig. 3. Foamed acid can temporarily block the high-permeability layer, transfer the acid solution to the low-permeability area and achieve a uniform treatment of the carbonate reservoirs. Compared with conventional acidification, the selectivity of foamed acid can ensure that less acid is used while still realizing the deep acidification of the reservoir (Li et al. 2008).

Guo et al. (2020) proposed the technical concept of three-dimensional acid fracturing based on the development of fractured vuggy carbonate reservoirs in the Tarim Basin, China. The concept is based on optimizing the deployment of collective reservoir space and using long well sections to penetrate heterogeneous reservoirs to achieve three-dimensional stimulation in the planar and longitudinal directions. The transformation of different types of reservoirs is shown in Fig. 4. For the stimulation of porous and fractured reservoirs, the emphasis is on increasing the area of the fractures and carrying out complex fractures by acid fracturing. For fractured vuggy reservoirs with strong heterogeneity, temporary plugging steering technology or targeted acid fracturing
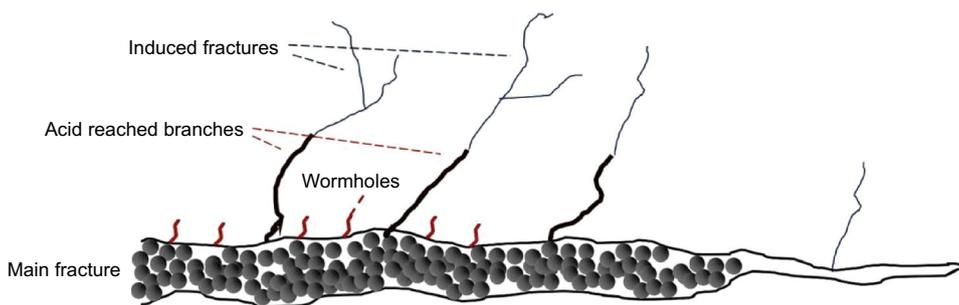
Fig. 2 Ideal schematic diagram of a complex fracture system created by HVS. Reprint permission obtained from Guo et al. (2019)
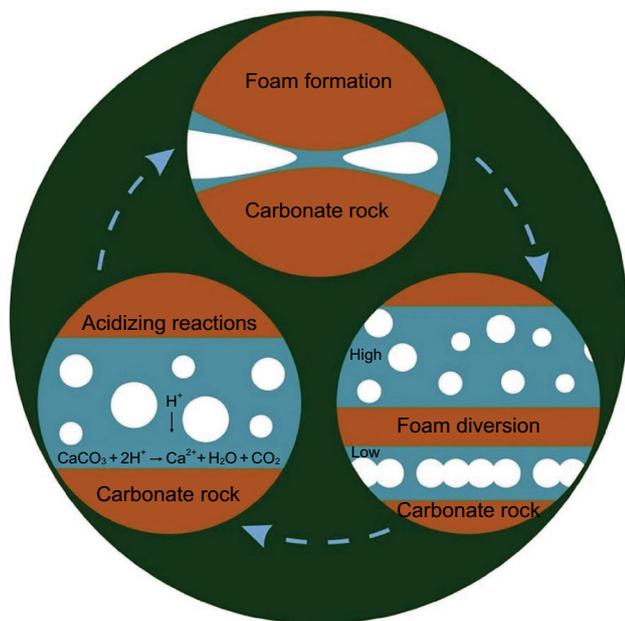

Fig. 3 Mechanism of in situ foam acidizing technology. Reprint permission obtained from Yan et al. (2019)

technology is often used to connect the fractures and vugs while forming main fractures with high conductivity (Li et al. 2015).

Acid fracturing and other reservoir stimulation technologies can enhance the conductivity of fractures, which is important for increasing the production of carbonate reservoirs. With the continuous increase in the depth of exploration and development of carbonate reservoirs, the difficulty of reservoir stimulation caused by heterogeneous geological conditions and complex fluid distributions has become increasingly prominent. The solution requires more accurate fracture and vug identification and description technology. As a result, the adaptability of the new acid fracturing process has gradually improved. Additionally, the harsh reservoir environment imposes very high requirements for the operational equipment and acid system, especially to reduce the corrosion of the acid system on related equipment and improve the deep acidizing ability. Ultimately, research on the fracture extension mechanism and fluid flow characteristics should be strengthened to achieve theoretical innovation and technological breakthroughs and solve technical problems in the process of carbonate reservoir stimulation.
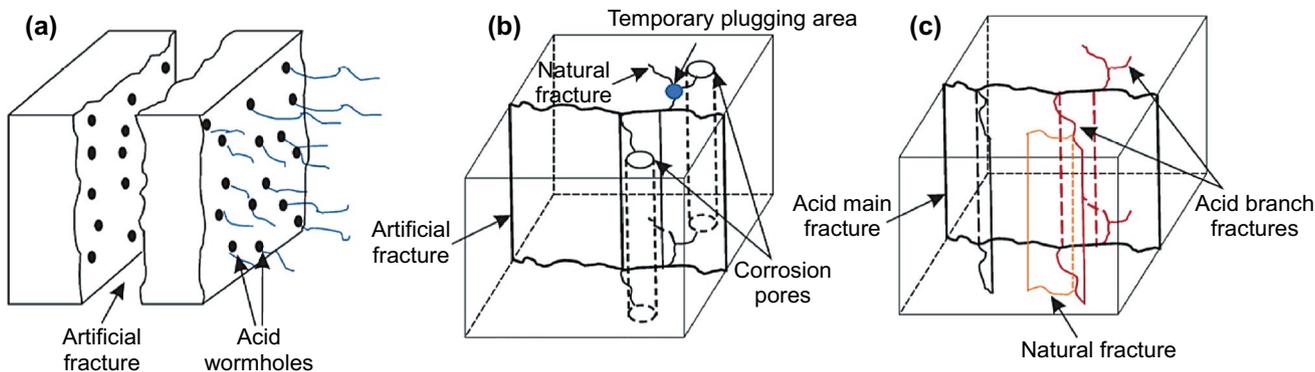

Fig. 4 Three-dimensional stimulation diagram of different types of reservoirs: **a** pore type, **b** fracture cavity type, **c** fracture type. Reprint permission obtained from Guo et al. (2020)

3 Flow characteristics of carbonate reservoirs

Reservoir fluid dynamics are the basis for exploring the fluid flow characteristics in a reservoir and must be addressed during oil field development. In sandstone reservoirs, the percolation theory in porous media is the core component of hydrodynamics, while in porous and fractured carbonate reservoirs, the percolation theory in multiple continuous medium fields is the foundation of hydrodynamics (Garland et al. 2012). The flow characteristics of the above types of reservoirs are clearly understood and will not be described here.

In fracture cavity carbonate reservoirs, the matrix, fractures, and cave systems develop together. The water flooding process is carried out under the combined effects of driving pressure, gravity, and capillary forces. The flow media of fractured vuggy carbonate reservoirs is shown in Fig. 5. Due to the existence of both "Darcy flow" and "cavity flow" in fractured vuggy reservoirs, it is difficult to accurately describe the fluid flow characteristics by using the existing reservoir fluid dynamics theory. Although scholars have performed extensive research, the exchange mechanisms and flow characteristics of fluid between the matrix, fracture, and karst vug have not formed mature related theories.

3.1 Displacement of the matrix system

There are two means of oil displacement in the matrix system: differential pressure displacement under external pressure and self-priming oil displacement under capillary force. When both means exist, one is dominant. Generally, the injected fluid enters the reservoir from fractures or caves under the driving pressure difference, and the fluid entering the reservoir is sucked in by the matrix under the action of capillary force and displaces the crude oil. Under the condition of eliminating the interference of the fracture system
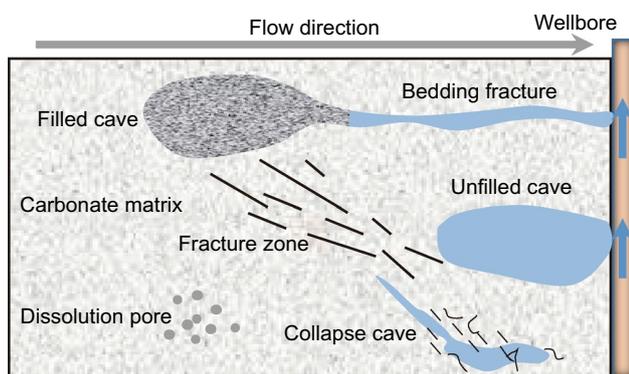

Fig. 5 Flow media in the fractured vuggy reservoir

and the cave system, the driving force of the displacement pressure difference makes the fluid in the matrix flow under the driving pressure gradient. If there is not enough production pressure difference, the driving pressure gradient is less than the capillary pressure gradient, and the complex pore structure of rock affects the displacement efficiency. In the matrix, crude oil is effectively utilized by the "spontaneous imbibition and oil drainage" mode generated by capillary pressure. Generally, the capillary force end effect between the injected fluid and the matrix system should be overcome when using crude oil in a carbonate matrix, which depends on the change in reservoir permeability and wettability.

3.2 Displacement of the fracture system

Compared with the matrix system and the karst cave system, the fracture system has the characteristics of "low porosity and high permeability." The starting pressure difference of the fluid flow in the system is small, and the capillary force can be ignored. The oil displacement process is carried out by driving pressure and gravity. The oil displacement process of the fracture system may include two methods. First, as mentioned above, the injected fluid enters the reservoir through the fracture system, and the fracture serves as the storage space. When the displacement pressure difference is greater than the start-up pressure of the fracture, the crude oil in the fracture is driven out to the karst cave or production well, and this process can be regarded as piston-type oil displacement. The second method involves the flow between fracture networks. Because of the complex structure of fracture networks of different levels, channeling easily occurs in the displacement process, such as the fingering of injected fluid and the coning of bottom water.

3.3 Displacement of the cave system

For fractured vuggy reservoirs, there are cases where karst caves are used as the storage space. In karst cave systems, the flooding process is similar to that in fracture systems. One process involves fluid flow under the imposed pressure gradient, and the other involves vertical differentiation under gravity. If there is edge and bottom water development in the reservoir, in the case of a large-scale karst cave, the fluid is almost replaced by piston displacement. In an actual reservoir, there is a filling medium in the cave, and the nature and degree of the filling medium have a great influence on the flow characteristics in the cave system. In general, the injected fluid is characterized by percolation-pipe flow-percolation during the process of entering the cave from the fracture. The main flow in the instant karst cave is pipe flow, and the gravity differentiation determines the displacement pattern. During horizontal flooding, laminar flow at low speeds and wave-like flow at high speeds occur

in the cave. When vertical gas flooding occurs, layered flows of fluids and oils appear in the caves.

In general, a karst cave system has the characteristics of high porosity and high permeability, and the production pressure difference required for the fluid to flow in the system is very low. Therefore, the fluid in the karst cave system first begins to flow under the actions of displacement and gravity. When the pressure in the cave system drops below the starting pressure of the fracture system, channeling of the fracture system to the cave system occurs. Under the action of capillary pressure, the flow from the matrix system to the fracture system or cave system is relatively delayed. Because of the considerable heterogeneity of the reservoir, the connection modes of the fractures and karst caves are diverse, and the filling characteristics are complex. These factors make the oil displacement mechanism more complex. The final oil displacement effect and remaining oil distribution are controlled by the connection degree, connection condition and filling mode between the fractures and caves in the karst cave system.

Overall, fracture cavity carbonate reservoirs have special conditions and are difficult to develop. Compared with conventional clastic reservoirs, these reservoirs have developed fractures and caves and have low recovery rates. Compared with sandstone reservoirs, fractured cavity carbonate reservoirs face many challenges, mainly because fracture permeability is much higher than reservoir matrix permeability. This notable difference in permeability may cause the traditional oil recovery method to fail to affect the crude oil, and the low-viscosity displacement fluid may prematurely escape, resulting in low oil washing efficiency. Due to the difference in density, the injected gas spreads to the upper part of the oil layer, and the injected water spreads to the lower part of the oil layer. The middle layer crude oil cannot be effectively accessed. Therefore, fluidity control is very important. Only by diverting the fluid from the channel to the uncovered area can the ultimate recovery be improved (Wang et al. 2017b).

4 Development methods of carbonate reservoirs

4.1 Water flooding

Compared with other methods that can be used to increase recovery in carbonate reservoirs, except for areas where water resources are scarce, water flooding is often considered a convenient and cost-effective method (Yousef et al. 2011b). In the water injection process, the injected water mainly flows in the fracture system due to the low permeability of the matrix system of the main oil reservoir. The injected water in some fractures enters the matrix through

imbibition and replaces the crude oil. However, most carbonate reservoirs are biased toward oil wet reservoirs, which is not conducive to water injection and oil displacement. Therefore, changing the type of injection water and adjusting the injection method are current research directions for water injection development in carbonate reservoirs.

4.1.1 Smart water flooding

Smart water flooding is considered a low-salinity water flood to some extent, which means that oil is produced by injecting a special brine into the formation. Low-salinity water flooding has been used since the 1960s and has been evaluated as an effective method to improve oil recovery (Hallenbeck et al. 1991). Today, smart water flooding method has been successfully applied in sandstone reservoirs, and its development and application in carbonate reservoirs is limited to pilot studies (Hao et al. 2019).

There are various mechanisms for smart water flooding to enhance the recovery of carbonate reservoirs. Hiorth et al. (Hiorth et al. 2010) proposed the theory of rock dissolution; compared with the initial high-salinity formation brine, the ion concentration (such as Ca^{2+}, Mg^{2+} and SO_4^{2-}) in the injected water decreases, breaking the original ion balance and leading to the dissolution of minerals (such as $CaCO_3$, $CaMg(CO_3)_2$ and $CaSO_4$) in the carbonate rock, thus establishing a new balance with the injected brine. In this process, the release of the adsorbed polar components is accompanied by dissolved minerals, thus leading to increased water wettability and improved oil recovery. However, this mechanism has been refuted to some extent (Austad et al. 2009). More scholars now agree with the surface ion exchange theory; on the surface of carbonate rocks, there is ion exchange between rocks, crude oil and injected water, which can improve formation wettability by changing the surface charge (RezaeiDoust et al. 2009). The mechanism of smart water flooding to improve the recovery of carbonate reservoirs can be obtained as shown in Fig. 6.

Yousef et al. (2012) introduced the results of two smart water injection field tests successfully completed in a carbonate reservoir in Saudi Arabia to study the effects of changing seawater salinity and ion content on oil production. Combined with their previous research, it was found that smart water flooding has high application potential in carbonate reservoirs. Smart water flooding has little effect on oil–water interfacial tension, mainly because of the interaction between the injected fluid and the rock to improve oil recovery, which is manifested in improving wettability through the change of the surface charge of the rock and the enhanced connectivity between pores through microdissolution. The performance of smart water flooding is greatly affected by the reservoir temperature, the physical properties of the rock and the fluid properties of the water. In addition,
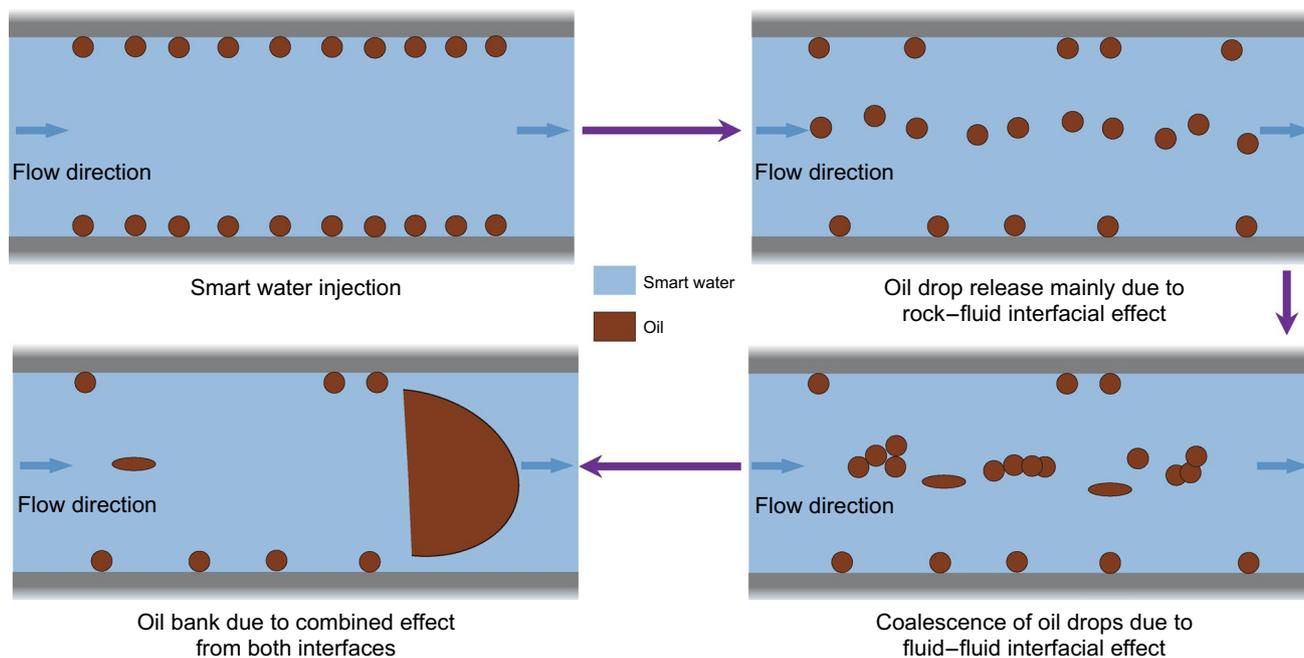
Fig. 6 Smart water flooding recovery mechanism using the combined effects from both fluid–fluid and rock-fluid interfaces. Adapted from Ayirala et al. (2016)

reducing the ion concentration and the presence of polyvalent ions can enhance the degree of change in the wettability of smart water flooding (Yousef et al. 2011a, b, c).

As early as 2008, Saudi Aramco focused its research on how seawater can increase the production of carbonate reservoirs. Saudi Aramco's two recent technical papers show that the company has begun to consider how to improve water treatment systems to turn seawater into "smart water" and provide the latest progress in laboratory research to study how active substances in seawater affect oil production (Ayirala et al. 2016). It is clear from these papers and other sources that Saudi Aramco's use of seawater as a cheap alternative to scarce freshwater can increase the amount of oil eventually recovered from the ground. The study also showed that seawater can be made more effective by changing its chemical composition into smart water. However, this option is neither simple nor cheap. To reduce the salinity of the extremely salty seawater used by Saudi Petroleum, large-scale desalination is required (Rassenfoss 2016). When targeting carbonate heavy oil reservoirs, low-salinity hot water injection is often used to improve oil fluidity (Lee and Lee 2019).

4.1.2 Carbonated water flooding

Carbonated water injection (CWI) is an alternative method of gas-phase CO_2 displacement. Before injection, CO_2 is dissolved in brine at ground level for pretreatment. Compared

with the traditional CO_2 displacement method, this approach has the following advantages: (1) CWI requires less CO_2, which reduces the cost of purchasing and transporting CO_2. (2) The density of CO_2-saturated brine is higher than that of pure brine, which prevents the flow driven by CO_2 buoyancy and reduces the risk of CO_2 leaking into the ground. (3) When CO_2 is mixed with brine, it flows in a porous medium, which suppresses the fingering problem of CO_2 flooding and improves the sweep efficiency. (4) The injection of carbonated water into the reservoir can reduce the viscosity and interfacial tension of the oil, improve the formation water wettability, encourage crude oil swelling, and improve the oil mobility in the low permeability matrix (Mahdavi and James 2019).

At present, most CWI studies have focused on micro-models and sandstones, and there have been no comprehensive studies of the application of CWI in carbonate reservoirs in the literature, especially when reservoir fluids have high salt contents. To understand the mechanism of CWI and improve the oil recovery rate of carbonate reservoirs, Jia (2019) took the Lansing carbonate reservoir in Kansas as an example, carried out relevant oil displacement experiments and analyzed the composition of the produced water. It was found that the performance of CWI in carbonate rock is much better than that of conventional water injection, especially when the rock is oil wet. In addition, the oil recovery performance of aged carbonate is more significant than that of non-aged

carbonate. The dissolution and deposition of carbonate can be observed, and the deposition largely depends on the composition of the brine. Mahzari et al. (2019) injected CO_2-rich carbonated water into carbonate rocks through visualization experiments and carried out a quantitative analysis of crude oil recovery and DP profiles. It was found that additional oil recovery can be obtained by injecting carbonated water, mainly because the interaction between CO_2 and water adjusts the oil composition and the relative permeability of the gas and oil, and the interfacial tension (IFT) between oil and gas shows a downward trend, which indicates that light oil components are extracted into the gas phase. Ghandi et al. (2019) contended that although carbonated water can slightly reduce the water absorption rate by IFT reduction, the most important factor controlling the spontaneous imbibition process in oil wet rock is the change in wettability. The use of saltwater with a specific concentration and high valence ions can increase water absorption. Meanwhile, carbonated water can accelerate the dissolution of the rock surface and the agglomeration of oil droplets through its own acidity, which also leads to wettability changes. Riazi (2011) performed micromodel visualization experiments and observed some changes in wettability during CWI. Figure 7 shows the wettability change of the micromodel reported by Riazi during CWI. From the direction of the water–oil interface in Fig. 7a, it can be seen that after water injection (WI), the micromodel shows an increased oil wetting trend; however, in Fig. 7b, c, it can be seen that after CWI, there are small water

drops between glass and oil, indicating that the model has strong water wetting characteristics (Seyyedi et al. 2015).

4.1.3 Variable strength water injection

By changing the injection production intensity, disturbing the pressure field, and eliminating the shielding effect of fracture division, variable strength water injection can improve the water swept area of fracture-pore and fracture-vug reservoirs, whether by periodic water injection, pulse water injection, unstable water injection, or asynchronous water injection (Li et al. 2018c).

Using the elastic energy of rock and fluid to extract part of the remaining crude oil with EOR is the core concept of depressurized production. The method of variable-strength water flooding in fractured vuggy carbonate reservoirs involves selecting an injection production well group in a fractured vuggy unit for water flooding development and adjusting the water flooding intensity continuously during the water flooding process. By forming an unstable water injection flow field in the formation to change the flow field of low water rising, this approach can prevent the formation of channels during the water displacement process to expand the swept volume and enhance oil recovery.

The oil in the flooded block enters the fracture from the matrix under the combined effect of rock compression and liquid expansion and then gathers to the top of the reservoir under gravity. In this process, the transformation from artificial driving to natural driving, the spontaneous imbibition of the matrix and the drainage of elastic oil are carried out continuously. Using the method of depressurized mining by
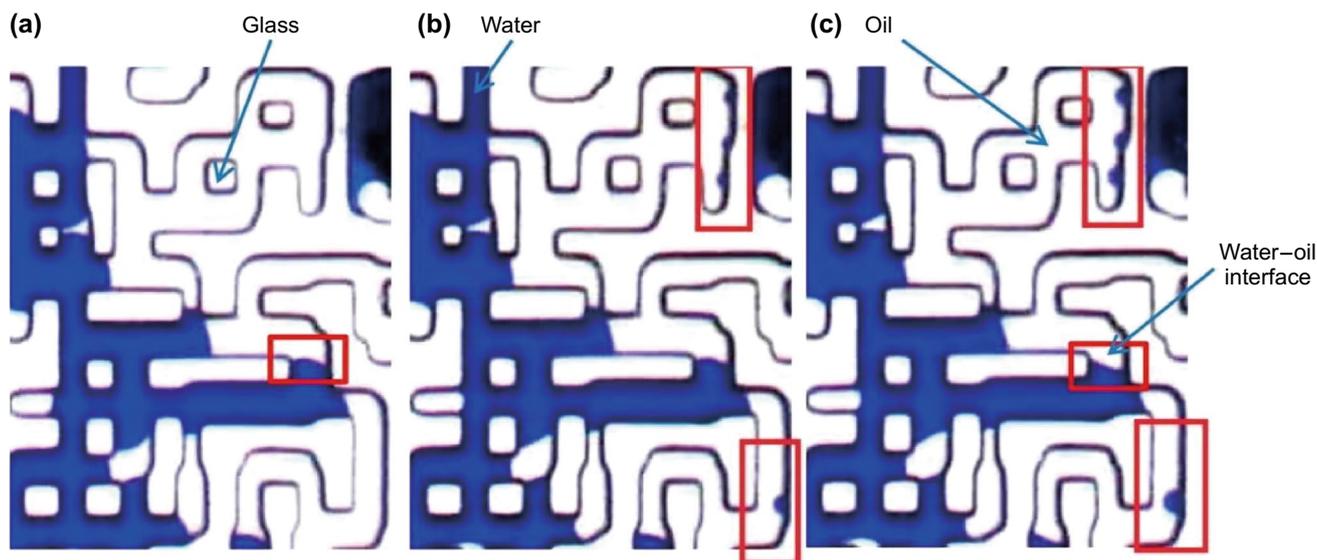

Fig. 7 Fluid distribution in a section of the micromodel (**a**) after WI and (**b**, **c**) after 19.6 and 47.12 h of CWI, respectively. Reprint permission obtained from Seyyedi et al. (2015)

alternately combining natural and manual driving, breaking the current distribution of underground oil and water at high water contents, making the cracks produce differential closure rates, reducing the fracture conductivity, restraining and interfering with the oil output of the fracture system and, at the same time, making every effort to develop the oil production capacity of the rock block system can be considered to achieve the goal of improving the ultimate oil recovery. Continuous water injection and proper liquid extraction are adopted to reduce the pressure. Proper artificial water injection to supplement the shortage of natural energy and keep the formation pressure at a low level not only ensures that production wells are not abnormal due to low formation pressure but also plays the elastic role of rocks and fluids, enhances the production potential of medium and small fracture holes and rock block systems, and improves the development effect (Yu et al. 2017).

With the change in formation pressure during the carbonate reservoir development process, the composition and percolation characteristics of crude oil are constantly changing, so a reasonable development technology scheme may lead to different oilfield development effects. Zhao et al. (2016) took a fractured carbonate reservoir in the eastern part of the Pre-Caspian Basin as an example, and based on PVT experiments, analyzed the influence of formation pressure change on the nature of crude oil and established corresponding water injection policies according to the different development degrees of water injection fractures in various formations, which has guiding significance for the reasonable recovery of formation pressure. Yang et al. (2020) took a fractured reservoir in the Tahe oilfield as an example, established a visual physical model based on real fracture hole unit simplification, and carried out multiple groups of water injection experiments by changing the connectivity type. Combined with the field production results, it was found that changing injection and production parameters and increasing the number of flow channels between injection wells and production wells had little effect on displacement efficiency,

while measures such as changing the flow direction of injection wells into production wells achieved better results.

Song and Li (2018) determined the basic characteristics of different types of carbonate reservoirs by studying several carbonate reservoirs in the Middle East and proposed three main water injection development methods applicable to different carbonate reservoirs. Taking the Mishrif Formation of the Hafaya oilfield as an example, a set of regional well pattern high-efficiency water injection development plans and strategies was proposed, as shown in Fig. 8.

4.2 Gas flooding

Gas flooding is the most commonly used method to enhance oil recovery in fractured vuggy carbonate reservoirs. At present, CO_2, N_2 and hydrocarbon gas injection are the main technologies of EOR in carbonate reservoirs. The release of anthropogenic greenhouse gases (water vapor, carbon dioxide, methane, nitrous oxide) into the atmosphere is the likely cause of global warming, so the injection of these greenhouse gases could alleviate global warming (Pachauri and Meyer 2014). According to the statistics in the World EOR Survey report published by the American Oil and Gas Journal from 2000 to 2010, the gas injection projects implemented in carbonate reservoirs are shown in Fig. 9 (Leena 2008; Koottungal 2010; Al Adasani and Bai 2011). The largest proportion of injection projects involve CO_2 at 61%, with 36% engaged in hydrocarbon gas injection and only 3% engaged in N_2 injection. This is mainly due to the abundant CO_2 gas sources and many related projects in the USA. In recent years, because of the natural exploitation advantage of N_2 drives for fractured vuggy carbonate reservoirs, this approach has developed rapidly into an indispensable gas drive technology. The miscible pressure of CO_2 is lower than that of N_2. Under the same reservoir conditions, injected CO_2 easily mixes with crude oil to form a miscible gas drive, while N_2 does not easily mix with crude oil to

Reservoir architecture of Mishrif formation → Round 1 inverted nine-spot well pattern → Round 2 five-spot well pattern → Round 3 infilled five-spot well pattern → Round 4 secondary infilled five-spot well pattern

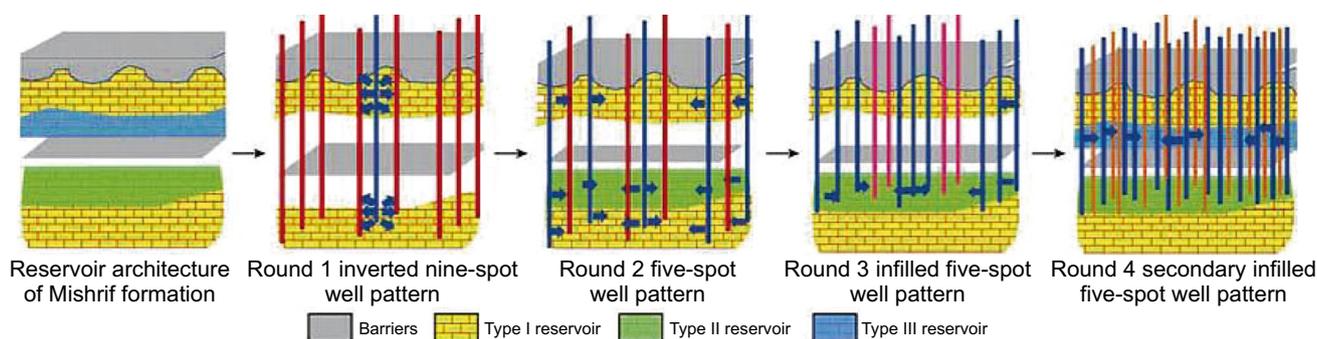Barriers | Type I reservoir | Type II reservoir | Type III reservoir

Fig. 8 Schematic diagram for different types of reservoirs developed by different well patterns. Reprint permission obtained from Song and Li (2018)
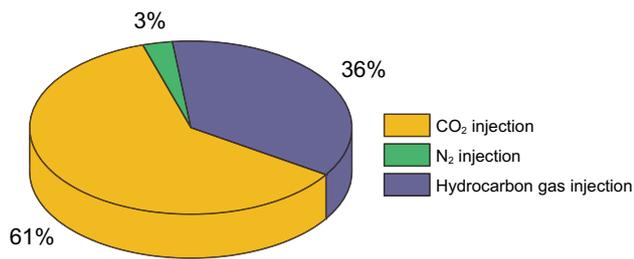
Fig. 9 The proportion of the world's carbonate reservoir gas injection projects

form a nonmiscible gas drive. Both displacement methods can be used in fractured vuggy carbonate reservoirs, while hydrocarbon gas drives are mainly used in Canada and other countries due to their abundant natural gas resources.

There are three displacement processes in gas flooding: immiscible, near-miscible, and miscible. Miscible flooding refers to the interphase mass transfer between the displacing agent (injected gas) and crude oil during the drive process, which dissolves with each other to form a single-phase transition zone. The reduction in interfacial tension and capillary force makes its flooding efficiency much higher than immiscible flooding. Miscible flooding can be further divided into first contact miscibility (FCM) and multiple contact miscibility (MCM). The success of miscibility development under reservoir conditions depends on the change of phase behavior. The key parameter to distinguish the miscible state is the minimum miscible pressure (MMP). Gas and crude oil can reach miscible state when the injection pressure is higher than the MMP. Oil vaporization and decrease in oil viscosity are the main reasons for the high oil recovery of miscible flooding. The phase of oil and gas is near-miscible or immiscible when the injection pressure is lower than MMP. Solution gas drive and oil swelling can enhance the fluidity of crude oil. Whether gas flooding can successfully achieve miscible displacement depends on reservoir temperature and pressure, injected gas and compositions of the crude oil. In fact, in carbonate reservoirs, the final displacement efficiency of miscible flooding is affected due to reservoir heterogeneity, but it is still significantly higher than general water flooding (Li et al. 2018a).

4.2.1 Non-hydrocarbon gas flooding

N_2 is low in price, stable in chemical properties, low in density, insoluble in water and less soluble in crude oil. Compared with CO_2, N_2 has a small compressibility factor, does not easily compress, has a high miscibility pressure with crude oil, and does not easily form miscibility. These characteristics make N_2 suitable for massive reservoirs, inclined reservoirs and fractured vuggy reservoirs. The injected N_2 replenishes the formation energy and migrates to the top of

the reservoir to displace the crude oil due to gravity differentiation. Although nitrogen is not easily miscible with crude oil, it can be partially dissolved in crude oil after making contact, resulting in a reduction in the viscosity and volume expansion of the crude oil. Using the driving energy of the injected gas and the expansion elasticity of the crude oil, the partially dissolved crude oil "spills" from its retention space and becomes a displaceable oil phase (Yuan et al. 2015).

Among non-hydrocarbon gas flooding methods, N_2 flooding is the most effective enhanced oil recovery technology for high-pressure and high-temperature (HP/HT) light oil reservoirs. Generally, in this type of carbonate reservoir, N_2 flooding can reach miscibility conditions. However, nonmiscible N_2 is also often used to maintain the formation pressure or the circulation of condensate gas reservoirs. In the past four decades, the USA has reported a number of fractured vuggy carbonate reservoir N_2 flooding projects. Moritis (Leena 2008) reported a miscible WAG-N_2 from Jay LEC. In addition to the USA, Cantarell is the only offshore carbonate oil field with detailed records and representative N_2 flooding projects in the Gulf of Mexico. Due to the high availability of N_2 in this area, the number of N_2 flooding projects in this area is expected to increase in the near future. In recent years, the large-scale recovery of N_2 has become inseparable from the reductions in air separation technology costs and operational costs. In addition, HPAI (high-pressure air injection) is a promising option, as its application potential is robust, and its cost is far lower than that of mixed N_2 flooding. In recent years, HPAI projects have been growing steadily, especially in light carbonate reservoirs in the USA (Manrique 2009).

The main advantage of CO_2 is that its miscible pressure with crude oil is low, and both immiscible and miscible flooding can be used; however, its density decreases with increasing temperature, leading to a decrease in the solubility of CO_2 in crude oil. Therefore, the minimum miscible pressure also increases with increasing temperature. CO_2 is easily dissolved in crude oil. Its solubility in crude oil is 3-9 times higher than its solubility in water, which can expand the volume and reduce the viscosity of crude oil, thereby improving the oil–water mobility ratio and the oil displacement efficiency. At the same time, CO_2 can also reduce the oil–water interfacial tension and play a role in dissolved gas flooding. These properties confirm that CO_2 flooding is a very competitive method for improving recovery efficiency. It has a high degree of adaptability to a wide range of physical properties and burial depths of crude oil in different reservoirs and has low requirements for miscible flooding (Li et al. 2018a, b, 2019a). However, cost issues limit the wide application of this technology. Carbonate reservoirs require a large amount of CO_2 injection. Natural CO_2 resources are usually too far from the injection point, resulting in lower CO_2 usage. However, in the USA, CO_2 flooding is the main

technology used because of their considerable CO_2 reserves, with the most CO_2 flooding occurring in the world. According to survey data from 2014, the annual EOR production from CO_2 flooding reached 1371×10^4 t, accounting for 93% of the total annual global EOR from CO_2 flooding (Koottungal 2010).

The low viscosity and low density of CO_2 can lead to viscous fingering and gas leakage. In addition, reservoir heterogeneity is conducive to the transport of CO_2 through high-permeability layers. These three characteristics can lead to the early breakthrough of gas, which reduces the oil displacement efficiency of CO_2 gas flooding; this problem of gas channeling can also occur during N_2 flooding (Jian et al. 2019). Qu et al. (2020) used visualization models and macroscopic models to simulate fractured vuggy carbonate reservoirs. On the basis of studying the gas channeling characteristics of fractured vuggy carbonate reservoirs, they proposed three risk assessment methods of gas channeling: the "PIR" of typical fractured vuggy carbonate reservoirs. Through the verification of reservoir data, the "PIR" risk assessment method can effectively identify gas channeling, which is of great significance for the prevention and evaluation of gas channeling risk in layers.

It is worth mentioning that, as one of the most popular and successful displacement technology, water alternating gas (WAG) injection has the advantages of both water injection and gas injection. WAG can reduce the relative permeability of the gas phase, change the gas flow characteristics, and improve the gas sweep efficiency. The final oil recovery of WAG injection is better than that of gas and water injection alone. After water and gas are alternately injected, water flooding blocks the high-permeability zone, and gas flooding sweeps tiny pores, which is accompanied by the effect of gravity differentiation. And the displacement process is a dynamic process in which the state of water in the pores is constantly broken and rebuilt. Generally speaking, the oil recovery factor of carbonate formation by WAG injection is higher than that of sandstone formation. This is because for reservoirs with severe heterogeneity, the dynamic plugging caused by alternating water injection can further improve the WAG flooding effect. When WAG injection is to be adopted, the first decision is whether to use miscible flooding or immiscible flooding. This decision depends on the suitability of the reservoir, but it is mainly affected by economic constraints. The application of WAG injection also brings a series of problems. It is easy to cause corrosion and scaling of the pipe string, blockage caused by hydrates, and poor fluidity control in heavy oil reservoirs. It also led to a decrease in gas injection capacity and the relative permeability of crude oil.

4.2.2 Hydrocarbon gas flooding

Hydrocarbon gas flooding is one of the most widely used processes in the petroleum industry, and it is a promising EOR method that can be used in carbonate oil fields in the Middle East (Kumar et al. 2017). The injected hydrocarbon gases include methane, rich gas and liquefied petroleum gas (LPG). These gases usually have the characteristics of simple pretreatment, noncorrosion of pipelines, low miscible pressure and so on. LPG is liquid under high pressure, which is easy to achieve miscibility with crude oil. Although the displacement efficiency is high after injection into the reservoir, the slug drive is usually used due to the high cost. The injection of rich gas is similar to LPG. In order to achieve high oil displacement efficiency, the rich gas (C_2–C_6) injection slug can be used, and then the other types of low-cost displacement media can be injected. Under a high-pressure environment, methane gas is easily dissolved into crude oil to form foam oil, resulting in a decrease in the density and viscosity of the crude oil. This is conducive to the flow of crude oil during the displacement process and can achieve a higher crude oil recovery factor (Ding et al. 2016).

Laboratory experiments should be carried out to determine the feasibility of hydrocarbon injection before field implementation. Kumar et al. (Kumar et al. 2015) conducted pressure/volume/temperature (PVT) experiments and core displacement experiments of natural gas in combination with hydrocarbon gas injection projects of carbonate reservoirs. The results show that the minimum miscible pressure (MMP) of injected natural gas is somewhat higher than the initial reservoir pressure, but crude oil has a strong swelling effect (once saturated by gas, the swelling rate can reach 1.45 times). An experiment involving unsteady core flooding with a 200 cm long core showed that the recovery of immiscible flooding can reach 70%, while that of miscible flooding can reach 92%. It is thus suggested that gas enrichment and WAG injection should be used to improve the displacement effect.

In a tight heterogeneous carbonate field onshore in Abu Dhabi, other miscible gas injection tests were implemented in the injection scheme, thereby improving the spreading efficiency (Al-Hajeri et al. 2011). These gas injection trials indicated that natural gas injection (dry/wet/sweet) is expected to be a viable EOR option for the Abu Dhabi field. Dawoud et al. (2010) introduced a case history of an early miscible hydrocarbon gas injection project in a newly developed heterogeneous carbonate reservoir. Based on the analysis of 4-year development results, it was concluded that the highest recovery factor can be obtained by the injection of miscible hydrocarbon gas.

In continental fractured cavity carbonate reservoirs in the USA, hydrocarbon gas injection projects account for a relatively small proportion of all EOR projects (Manrique

et al. 2007). In countries rich in natural gas resources, such as Canada, the development of carbonate reservoirs is dominated by hydrocarbon gas flooding, and there are ongoing or underevaluated hydrocarbon miscible water injection (continuous injection or WAG mode) projects in marine carbonate reservoirs. In the WAG process, natural gas is used to maintain the formation pressure. This development strategy helps to maintain reservoir energy and maximize oil recovery. At the same time, the potential of hydrocarbon gas flooding can be enhanced through a reservoir decompression strategy (i.e., reservoir discharge or decompression) at the end of reservoir development.

Compared with non-hydrocarbon gases such as carbon dioxide and nitrogen, there are still many deficiencies in the study of hydrocarbon injection. Due to the relatively high cost of hydrocarbon gases, numerical simulation methods are currently used for research. With the increasing tension of petroleum resources and the importance of environmental protection, the petrochemical industry aims to establish atomic economy. Relatively speaking, olefins and hydrogen in dry gas have higher value and are easier to recycle and use, which can indicate that some of the hydrocarbon gases may be more economically feasible to be refined and sold rather than to be injected. At the same time, considering the safety and controllability of hydrocarbon gas injection, the application of hydrocarbon gas flooding in oil fields also needs to be carefully selected.

4.2.3 Thermal recovery by steam injection

Thermal recovery by steam injection is the main technology used for heavy oil extraction. The heavy oil extracted by this technology accounts for more than 80% of the world's annual heavy oil production. Steam injection is also an effective thermal recovery method for heavy oil extracted from carbonate reservoirs with strong heterogeneity. When the injected steam flows into the fracture network, it can effectively heat the formation to reduce its oil viscosity and discharge crude oil more effectively by gravity (Li et al. 2019c).

Mohsenzadeh et al. (2016) conducted a long fracture model experiment, focusing on an oil displacement process under the condition of coinjection of steam and gas. It was found that the coinjection of steam and flue gas under certain conditions can significantly improve the recovery of heavy oil in an experimental model of fractured carbonate rock (Li et al. 2017). Tang et al. (2011) found that steam injection is a very effective method for carbonate heavy oil reservoirs and summarized its possible recovery mechanism, as shown in Fig. 10. When steam is injected into carbonate reservoirs, imbibition is the initial recovery mechanism. If the temperature exceeds the critical temperature, free imbibition dominates the production process with the aid of heat transfer, and forced imbibition only increases the oil recovery rate

by a small amount. When the rock is completely heated and injected with new steam, the recovery mechanism is mainly driven by steam, and the effect of rock on the fluid is weakened (Wilson 2013).

Steam injection thermal recovery seems to be the first choice for heavy oil reservoirs with carbonate rocks, but conventional steam injection designs may not be able to produce enough oil to obtain benefits. Due to the characteristics of low viscosity and high fluidity, steam can easily cross over a flow and overlap, which reduces the sweep volume of the steam. At the same time, the heterogeneity of carbonate reservoirs further intensifies the crossflow degree of injected steam, so there are few steam injection methods applied to carbonate reservoirs. Limited field applications include Lacq Superior in France, Ikiztepe in Turkey, Yates in the USA, Bati Raman in Turkey, Wafra in Saudi Arabia and Kuwait, Oudeh in Syria and Qarn Alam in Oman (Sahuquet et al. 1990; Nakamura et al. 1995; Snell and Close 1999; Babadagli et al. 2008; Brown et al. 2011; Li et al. 2010; Smith and Parakh 2016).

4.3 Chemical flooding

Chemical flooding is an effective method for the development of carbonate fractured reservoirs. Chemical flooding EOR (C-EOR) technology can be further divided into polymer flooding, surfactant flooding, alkali flooding, and combinations of these flooding methods. Surfactant/polymer flooding is the most effective method because it has the synergistic effect of reducing IFT and controlling fluidity with minimal negative effects (Bai et al. 2017). In the later stages of oil field development, chemically enhanced oil recovery (EOR) technology became economically viable. The C-EOR method is a proven technology that may play a key role in carbonate reservoirs. Carbonate reservoirs are often heterogeneous and contain natural fractures. By utilizing chemical flooding, the breakthrough of injected gas can be avoided, thereby improving the sweep efficiency (Koyassan Veedu et al. 2015).
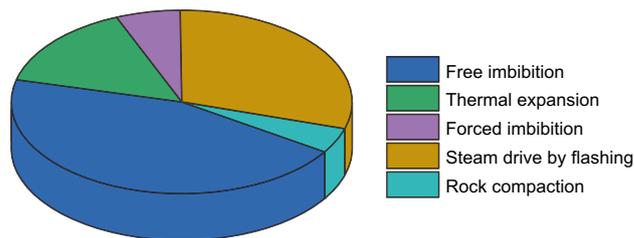

Fig. 10 Possible recovery mechanisms for steam injection in fractured carbonate rock. Adapted from Tang et al. (2011)

4.3.1 Polymer flooding

Polymer flooding is the most widely used chemical flooding method in sandstone reservoirs. For carbonate reservoirs, polymers are more commonly used to control the fluidity of the flooding fluid. Because the injected fluid can easily breakthrough in carbonate reservoirs with large fracture openings, to improve the recovery of carbonate reservoirs, high viscosity polymers are injected into the formation, and they are often used in the initial stage of water injection to increase the fluidity ratio and expand the sweep efficiency of the injected fluid (Alsofi et al. 2013).

Polymer flooding has been used in many carbonate reservoirs because it can prevent fracture flow to some extent. There are 1327 candidate reservoirs suitable for polymer flooding in the USA, a third of which are carbonate reservoirs (Mohan et al. 2011). Ultradeep carbonate reservoirs are widely distributed in western China and Central Asia, and their oil and gas production can reach 100 million tons per year. Because the temperature and salinity of ultradeep carbonate reservoirs are no less than 130 °C and 220,000 mg/L, respectively, developing water blocking agents that can be used in this harsh environment has global impacts (Long et al. 2009). A considerable number of new temperature- and salt water-resistant gel polymers have been prepared to reduce syneresis during the displacement process. Although several novel acrylamide polymers have been reported in the literature, only a few have been industrialized (Singh and Mahto 2016; Chen et al. 2018). Partially hydrolyzed polyacrylamide (HPAM) is the most widely used polymer for chemical EOR due to its high water solubility (Sheng 2010; Zhang and Seright 2013). HPAM is a polyelectrolyte with a negative charge on carboxylate (–COOH) and is highly sensitive to pH, salinity, ionic composition and concentration. When the pH of the supplemental brine is low, the polymer chains are coiled, and the polymer adsorption on the rock surface increases, resulting in the loss of the polymer (Choi et al. 2010). In addition, due to the charge shielding effect, the polymer has poor viscosity and stability when it is higher than a certain salinity (Abidin et al. 2012; Unsal et al. 2018).

Compared with other new types of hydrogels, PAtBA and polyethyleneimine (PEI) crosslinking systems are widely used to block water in reservoirs. Many researchers have studied the mechanisms of heat resistance and salt tolerance in detail (Eoff et al. 2007; Bai et al. 2015). However, the cost of PatBA and PEI is high, so it is not reasonable to use PAtBA-PEI hydrogels when the international oil price is low. Chen et al. (2019a) carried out a series of experiments and evaluated the stability mechanism of an acrylamide/acryl-acid/2-acrylamido-2methyl-propanesulfonate (AM/AA/AMPS) hydrogel. It was found that the AM/AA/AMPS hydrogel is an excellent temperature- and salt-resistant

plugging agent that can be used for water injection treatment in deep carbonate reservoirs.

Due to the high-temperature and high-salt characteristics of some carbonate reservoirs, low-salinity polymer flooding (LSPF) is a promising EOR method with synergistic effects. Polymers can be added to provide favorable mobility while changing the wettability of the carbonate rock surface by using low-salinity water in the polymer solution (Khorsandi et al. 2017; Vermolen et al. 2014). This synergistic effect increases the efficiency of oil production. In addition, as the seawater desalinates, the degree of degradation of the polymer decreases, indicating that low-salinity water increases the stability of the polymer (Zaitoun et al. 2012). In addition, the use of low-salinity water requires a small amount of polymer to achieve the target viscosity, which may significantly reduce costs and solve chemical production problems (Salih et al. 2016). Lee et al. (2019) studied the influence of injected water pH and PDI on oil recovery when LSPF was applied to carbonate reservoirs. It was found that a high concentration of SO_4^{2-} can improve the wettability of the formation, reduce the adsorption of the formation on the polymer, and obtain the maximum oil recovery under neutral conditions.

4.3.2 Surfactant flooding

Surfactant flooding is also a widely used chemical flooding technology in fractured vuggy carbonate reservoirs. Low oil recovery after water injection in carbonate reservoirs is caused by wettability and IFT problems, which reduce the impact of spontaneous water absorption processes (Dong and Al Yafei 2015). In fractured reservoirs, self-absorption may infiltrate into the fractures from the rock matrix, leading to the evacuation of oil from the matrix to the fracture network. This mechanism makes surfactants attractive, which can improve the recovery of oil wet carbonate reservoirs by changing the wettability of the rock (to the mixed/water wet state) and promoting the water absorption process. Because the reserves of fractured vuggy carbonate reservoirs account for a large proportion of the world's oil reserves, the chemical assistant method based on surfactant injection (i.e., spontaneous imbibition, wetting agent, and ITF reduction) is an active research field, often used as an important method to improve the recovery of fractured vuggy carbonate reservoirs (Alvarado and Manrique 2010). By changing the wettability of the surfactants, the interfacial tension of oil/water can be effectively reduced to ultralow values, the adsorption capacity can be reduced and the absorption process can be promoted (Farhadinia and Delshad 2010; Alvarado and Manrique 2010; Kiani et al. 2011).

Austad and colleagues conducted a series of studies of the use of surfactant solutions to recover oil from oil wet chalk cores (Standnes and Austad 2000a, b, 2003; Austad and

Milter 1997). The results showed that cationic surfactants (such as DTAB) are very effective (OOIP is approximately 70%) in absorbing water into the original oil wet core at a higher concentration than its CMC (approximately 1 wt%). The mechanism is considered to operate as follows: (1) Ion pairs are formed through the interaction between the surfactant monomer and the organic carboxylates adsorbed in the crude oil. (2) The water wettability of the solid surface is enhanced due to the dissolution of the ion pairs in the oil phase. (3) As the capillary pressure absorbs saltwater independently, the water absorption rate decreases with increasing temperature and has a negative correlation with the irreducible water saturation. Wu et al. (2010) reported that an anionic surfactant (alkyl alcohol propoxylated sulfate), as an effective candidate for C-EOR, can reduce IFT at low concentrations and recover 50% of the residual oil under high salinity. Zhang et al. (2015) developed a new type of zwitterionic surfactant derived from castor oil, which can reduce IFT to an ultralow value of 5.4×10^{-3} mN/m at a mineralization of 10 g/L. These types of surfactants are suitable for high-temperature and high-salinity carbonate reservoirs.

Surfactant for tertiary oil recovery in carbonate reservoirs is still in a developing stage, and there is not a widely applicable surfactant system. Commonly used are anionic, cationic, non-ionic and amphoteric surfactants. The molecules of anionic surfactants are negatively charged after being ionized in water, while the surface of carbonate rocks is normally positively charged (the isoelectric point of limestone is 9.2, the isoelectric point of dolomite is 7.4). Therefore, the adsorption capacity of this kind of surfactants on the surface of carbonate rocks is relatively high. Cationic surfactant is a kind of effective surfactant for EOR of carbonate reservoir. Cationic surfactant has good temperature and salt resistance, and its adsorption capacity on the surface of positive carbonate is also low. However, the high demand concentration and high cost of this kind of surfactant limit its application in oil fields. At present, there are few studies of the adsorption of surfactants on carbonate rocks. The adsorption of surfactants on sandstone or other solid surfaces can be used for reference. At the same time, in order to select a suitable surfactant system, it is necessary to analyze the specific reservoir conditions. Most carbonate reservoirs are high temperature and high salt, so the selected surfactant should have good temperature and salt resistance, low adsorption loss and good interfacial activity.

There are few examples of field applications of surfactant flooding. The limited field applications in the open literature include, for example, the Asmari oil field in Iran, the Sabriyah-mauddud oil field in Kuwait and the Abu Dhabi oil field in the United Arab Emirates (Carlisle et al. 2014). A series of surfactant stimulation measures have been carried out in the Yates oil field in Texas (Chen et al. 2000) and the Cottonwood Creek oil field in Wyoming (Manrique

et al. 2007), the Mauddud oil field in the Arabian Basin (Zubari and Sivakumar 2003) and the Semogal oil field in South Sumatra, Indonesia (Rilian et al. 2010). Most of the test results have been confirmed, verifying the feasibility of surfactant flooding to improve the recovery of fractured carbonate reservoirs.

4.3.3 ASP flooding and foam flooding

ASP flooding combines the mechanisms of alkali flooding, surfactant flooding and polymer flooding. In the formulation selection of ASP, the most commonly used basic additives are sodium carbonate and sodium bicarbonate with neutral pH values. The most commonly used surfactant is petroleum sulfonate, while the polymer is usually polyacrylamide. By increasing the charge density on the surface of the rock, the basic additives can reduce the adsorption of anionic surfactants on the formation, promote the emulsification of crude oil and regulate the phase behavior. Surfactants can enhance the oil washing efficiency by reducing the interfacial tension between oil and water, and polymers can improve the fluidity by increasing the viscosity of the solution to improve the sweep efficiency and oil recovery (Kon et al. 2002; Zubari and Sivakumar 2003).

ASP flooding is a tertiary oil recovery method that is generally used in sandstone reservoirs but seldom used in carbonate reservoirs. In some experimental studies, it was found that the conventional ASP formula can be applied to carbonate reservoirs. Although ASP composite flooding technology has the development prospect, the adaptability condition of alkali flooding is harsh. Generally speaking, the required acid value of crude oil is greater than 0.5, the relative density is about 0.9, and the viscosity is lower than 200 mPa s. High-density crude oil often contains enough organic acids, which can react with alkali solution to form favorable saponifiable substances. On the other hand, when the alkaline solution contained in ASP flooding agent is injected into the oil well, it reacts with reservoir rock, including dissolution, mixing and ion exchange. Thus, the problems such as formation damage, scale corrosion and flow resistance, equipment wear and so on, seriously affect the normal production of oil wells. Therefore, it is usually feasible to use SP flooding with the synergistic effect of surfactants and polymers. Dual composite flooding technology has the advantages of reducing interfacial tension and plugging high-permeability channel, so it has high displacement efficiency in carbonate reservoir.

Foam fluid can be used to control the fluidity of gas and water during the displacement process (Wang et al. 2017a; Zhu et al. 2017). The water-based foam bursts when it comes into contact with oil, and the released surfactant can further reduce the interfacial tension between oil and water (Simjoo and Zitha 2013; Li et al. 2020a). The foam preferentially

enters the area with high permeability, which is conducive to adjusting the injection profile (Li et al. 2019b). The mechanism is shown in Fig. 11. Foam flooding and foam plugging have been shown to have a beneficial effect on the development of carbonate reservoirs (Wen et al. 2019; Hou et al. 2018; Li et al. 2020b). However, under high-temperature and high-salinity (HTHS) conditions, foam stability remains challenging for two reasons. First, the strength of the foam usually decreases with increasing temperature because the viscosity of the liquid phase decreases at high temperatures, which accelerates the liquid discharge process in the foam liquid film and the plateau boundary. Second, the water stability of conventional surfactants limits their use under HTHS conditions. Some researchers have investigated new surfactant-stabilized foams for HTHS conditions. Cui et al. (2016) studied the application of Ethomeen C12 surfactant-stabilized foam under HTHS conditions in carbonate reservoirs. The surfactant was stable only at a lower pH (near 4) because it requires C12 to be completely protonated to dissolve. Xue et al. (2015) reported a high-viscosity foam produced by using CO_2 soluble ionic surfactants at a temperature of 120 °C and a saltwater TDS content of 14.6%. Recently, Alzobaidi et al. (2017) reported the use of zwitterionic surfactants to prepare highly stable foams with a viscosity in excess of 100 cP at 120 °C.

A foam blocking agent is a kind of blocking system that is widely used in the regulation of gas channeling. Because the foam is stable in water, defoams in oil, and increases the blocking capacity with the increase in permeability, it can play a good role in fluidity control and can effectively address the problem of channeling in heterogeneous formations. At the same time, because the gas phase density in the foam is relatively low, it can effectively increase the utilization of the top oil layer. When the foam flows in a fracture cavity system, due to the severe formation conditions of high

temperature and high salt in the fracture cavity reservoir, the foam does not easily remain in a stable condition, and the sealing capacity of the foam is limited. It is not effective for highly permeable fracture cavity units, and blocking requires the cooperation of certain blocking agent materials. By selecting a plugging agent with good plugging performance, and the foam has permeability selectivity, that is, the foam preferentially plugs the high-permeability layer, and the plugging agent can also have plugging selectivity through the foam carrying. The migration distance of the plugging agent is relatively short, and the foam can be continuously destroyed and regenerated in the formation and can carry the plugging agent to the deep part of the formation, effectively extending the lateral plugging distance. Foam has adjustable density. By changing the gas–liquid ratio of the foam, the foam quality can be adjusted, and the gravity difference can be used to carry the plugging agent to achieve longitudinal plugging to a certain extent (Li et al. 2019d).

4.3.4 Addition of nanoparticles

One of the advantages of nanoparticles is that they can be grafted or modified with different functional groups to provide the properties required for underground applications. These include increased viscosity (Ponnapati et al. 2011), improved water stability (Griffith and Daigle 2017) and required surface wettability (Panthi et al. 2017). This makes nanoparticles very promising in oilfield applications.

Nanoparticles (NPs) are now widely recognized in the field of petroleum engineering. They are used in different areas of oil exploration and production, such as drilling, logging, reservoir management and EOR. Due to the size of NPs, they have special physical and chemical properties. Therefore, NPs affect the characteristics of the fluid system, including viscosity, magnetism, and IFT. Injecting NPs into a reservoir for EOR is more effective than injecting water, but it is not as effective as chemical flooding. Therefore, NPs are injected with low-salinity water (LSW) or chemicals (such as surfactants) to increase oil recovery. NPs are used to prevent fine particle migration during LSW injection, control the fluidity of formation water, and reduce the adsorption of surfactants on the pore walls of the reservoir (Olayiwola and Dejam 2019).

In recent years, NPs coated with chemical agents (such as polymers and surfactants) have attracted widespread attention. The purpose is to change the wettability of the reservoir from oil wetting to water wetting to improve oil production (Shalbafan et al. 2019). Wang et al. (2019) used the Truva oil field in northern Kazakhstan as an example to comprehensively evaluate the plugging effect and oil/water selectivity of polymer microspheres (PMs) in carbonate matrix cores and fractured cores. Through scanning electron microscopy (SEM) imaging results and energy dispersive spectroscopy
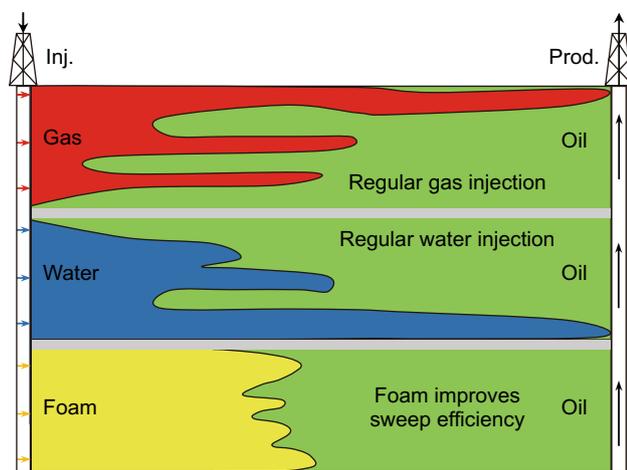

Fig. 11 Field applications of foam for EOR (Skauge et al. 2020)

(EDS) elemental analysis techniques, it was found that the blocking mechanism of PMs in the throat and cracks of cores is mainly manifested in three aspects: adsorption retention, mechanical retention and agglomeration. By dispersing nanoparticles in low-salinity water, most problems associated with rock/fluid interactions can be eliminated by improving the attractive force between fine particles and the particle surface (Arab and Pourafshary 2013) and preventing formation damage (Abhishek et al. 2018). Ali et al. (2019) synthesized a polymer/nanoparticle composite material using pomegranate seed extract as a raw material. The material was dispersed in diluted seawater to obtain a low-salinity polymer nanofluid, which interacted with crude oil to obtain a stable emulsion. As shown in Fig. 12, the fluid can improve the formation water wetness and adjust the displacement profile.

The high apparent viscosity of foam is attributed to the viscoelasticity of the surfactant. By adding nanoparticles with customized surface coatings to surfactants, it is possible to make the generated foam more firm and stable (Singh and Mohanty 2020). Sun et al. (2014) introduced modified hydrophobic SiO_2 nanoparticles into the foam system. It was found that SiO_2 nanoparticles significantly improved the viscoelasticity of the foam liquid film, and the foam was not easily deformed. This process could produce more microforces in the displacement process and drive more oil. The mechanism is shown in Fig. 13.

4.4 Application of emerging technologies

4.4.1 Electromagnetic oil production

Recently, some emerging eco-friendly technologies have been proposed to enhance the recovery of crude oil, including the application of magnetic fields and electromagnetic waves. A technology called magnetic water technology has been used in different industries in the past few years, and Hashemizadeh et al. (2014) tried to use it for crude oil displacement. It was found that with the increase in the magnetism of water, the activity of water molecules changed, and the breakthrough speed was accelerated. For a thin oil layer with low permeability and deep depth, an electromagnetic wave or microwave at a certain radio frequency range can produce the effect of thermal oil recovery. Electromagnetic heating is used to transfer the electric energy to the dielectric material in the form of heat. By injecting fluid with strong absorption into the oil layer, the oil layer is directly heated, creating a high heat utilization rate, low oil viscosity and improved oil mobility (Kashif et al. 2011; Xu et al. 2019; Zaid et al. 2014). In addition, when dealing with the leakage of offshore crude oil, electric and magnetic methods have also been combined to improve the recovery efficiency of light crude oil (Liu et al. 2018).

In carbonate reservoirs, the charge on the surface of the rock has a great effect on the wettability of the formation. The ions (CO_3^{2-} and Ca^{2+}) that determine the potential of the rock surface are susceptible to external conditions, which
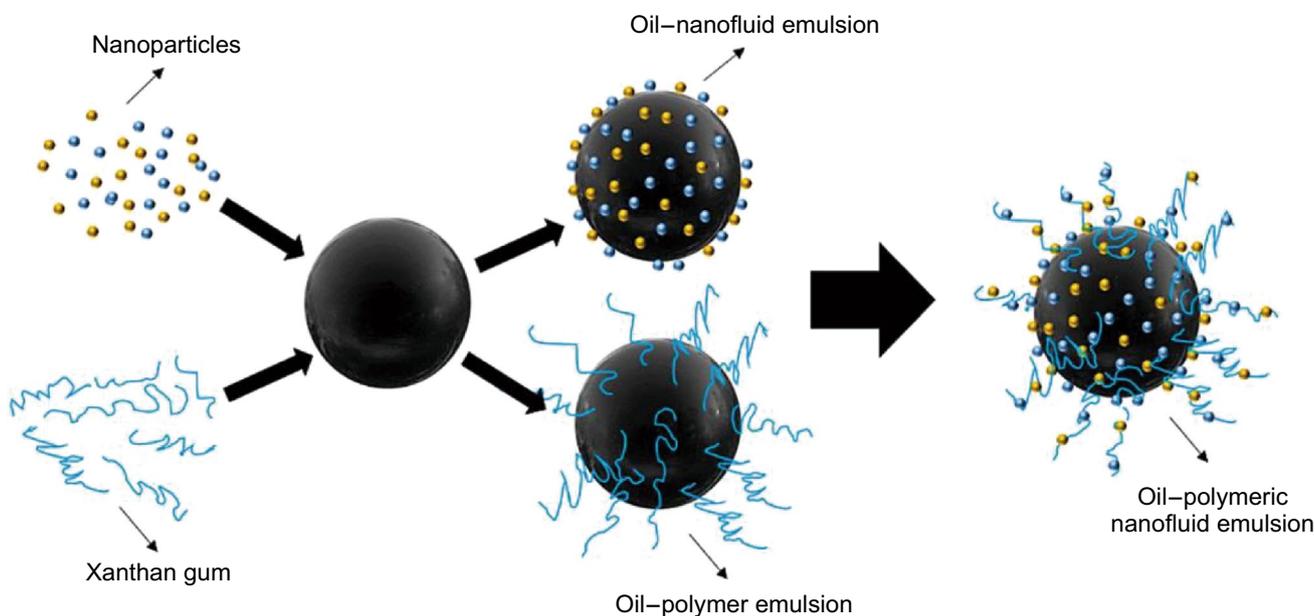

Fig. 12 Schematic diagram illustrating the trapped crude oil and low-salinity polymeric-nanofluid emulsion. Reprint permission obtained from Ali et al. (2019)
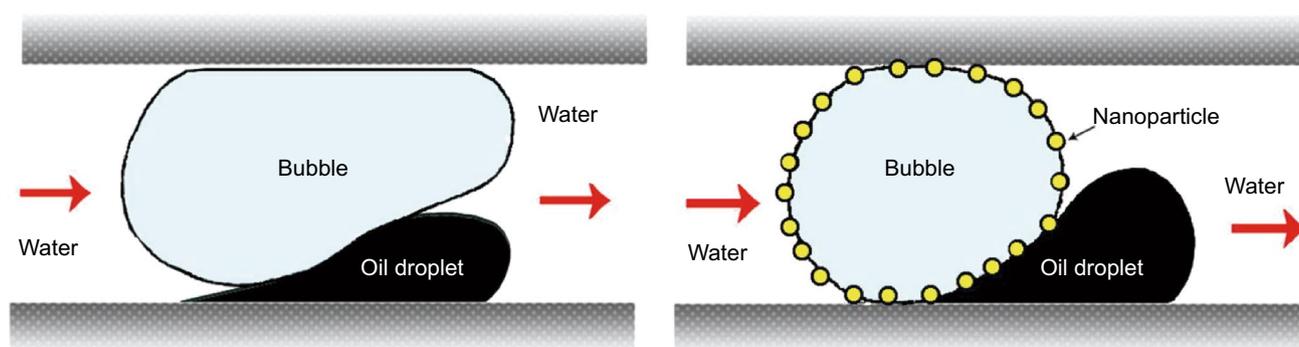
Fig. 13 Displacement differences for an oil droplet on a pore wall by SDS foam (left) and SiO$_2$/SDS foam (right). Reprint permission obtained from Sun et al. (2014)

can cause changes in the surface adsorption of the rock, and changes in their surface forces can affect the flow of fluid in the pores. By adding a magnetic field to the carbonate formation, the formation wettability transitions from oil wet to water wet, so the compatibility of the water and rock surface is improved, and the spontaneous imbibition speed of injected water is accelerated to replace more crude oil in the fractures and ultimately improve the oil recovery (Amrouche et al. 2019).

4.4.2 Steam-over-solvent injection

Steam-assisted gravity drainage (SAGD) is a common method used for asphalt recovery in steam injection in Canada (Butler 1994, 1998). The vapor extraction (VAPEX) process is a method that injects pure solvent from horizontal wells to replace oil by gravity drainage. It was proposed by Butler and Mokrys (1991) as an alternative method of steam injection. To promote the interaction between steam and heavy oil in fractured vuggy carbonate reservoirs, other methods of steam-over-solvent injection in fractured reservoirs (SOS-FR) have been proposed (Al Bahlani and Babadagli 2009, 2012).

SOS-FR is a new method that was used in early 2008 to recover heavy oil from fractured (especially oil wet) reservoirs. It takes advantage of injecting steam and solvents into fractured reservoirs to efficiently extract heavy oil from fractured carbonate reservoirs. The main idea behind this technology is to generate a variety of thermal and chemical disturbances that cause the system to readjust, thus driving oil from the matrix to the fractures. Therefore, introducing a thermal difference between the fracture and the matrix can cause the oil trapped in the matrix to thermally expand first. Under the influence of wettability, a certain amount of water (condensate from steam) is absorbed into the matrix. During this period, the viscosity of the crude oil decreases and accelerates its discharge, and the oil in the matrix is

adjusted in the next stage (solvent injection) (Al-Bahlani and Babadagli 2011).

According to the SOS-FR method, the team of Mohammed and Babadagli (2016) has carried out combined experiments on the cores of Canada's Grosmont carbonate reservoir under different conditions. This method can increase crude oil production, and the optimized process can quickly promote asphalt recovery, showing economic and effective application potential. Based on the laboratory- and field-scale analysis of heavy oil recovery by the SOS-FR method, Al-Gosayir et al. (2015) optimized SOS-FR technology through overall improvements and adjusted the heated steam injection stage, solvent injection stage and low-temperature steam injection stage to improve the profits and efficiency of carbonate reservoir development.

4.4.3 In-situ oil recovery

In the development of carbonate reservoirs, energy and the environment are two major concerns that exist together. It is necessary to seek an environmentally friendly reservoir development method. The in situ mining model solves two problems in the development of carbonate reservoirs. One is to greatly reduce pollution to the ground environment, and the other is to improve the efficiency of oil production.

In situ combustion (ISC) can reduce the viscosity of heavy oil through the heat generated at the combustion front and make it flow to the production well. Heat is formed and maintained by injecting air or oxygen enriched under high temperature and pressure and burning deposited fuel (Aleksandrov et al. 2017). During the combustion process, the heat generated promotes the thermal cracking reaction, thereby increasing the proportion of low molecular weight compounds. On the other hand, coking reactions occur with heavy components such as asphaltenes, and coke deposition is not conducive to the combustion process. As an effective thermal oil recovery technology, ISC can achieve greater displacement efficiency and technically enhance heavy oil.

However, in natural fractured carbonate heavy oil reservoirs, the application of ISC still has various obstacles (Chen et al. 2019b).

In-situ upgrading technology (ISUT) is a new alternative method in the production of heavy oil and asphalt, which can not only improve the recovery factor but also upgrade the crude oil at a certain stage. In this method, the vacuum residue (VR) recovered from the produced oil is injected into a reservoir with a nanocatalyst and hydrogen, and a modification reaction is performed (Elahi et al. 2019). The mechanism is shown in Fig. 14. ISUT is more environmentally friendly than other recovery technologies, such as steam-assisted gravity drain (SAGD). In addition, after preliminary economic evaluation and research, it was found that the oil recovery rate and return rate of the ISUT process are higher than those of SAGD (Nguyen et al. 2017).

5 Challenges and prospects

There are many differences in carbonate reservoirs throughout the world, such as complex geological structures, strong reservoir heterogeneity, and harsh reservoir conditions. The existing development technology still cannot completely solve the problems in the development process of carbonate reservoirs, and many challenges remain in the research on EOR technology.

The enhancement of fracture connectivity and the improvement of conductivity in carbonate reservoirs are particularly important, which requires advanced acid fracturing stimulation technology to achieve. At the same time, for deep carbonate reservoirs, how to achieve deep acidification and propose new acid fracturing technology is the focus of future research. For fractured vuggy carbonate reservoirs, on the basis of realizing reservoir stimulation, it is of great significance to accurately grasp the flow characteristics of reservoir fluid for efficient development, which depends on theoretical analysis and numerical simulation means, and requires the assistance of artificial intelligence and the operation of big data.

In the process of water injection development, the power of oil displacement is mainly provided by the driving pressure difference, capillary force and gravity. During the development of stable water injection, spontaneous infiltration and oil drainage are mainly caused by capillary forces in the matrix. However, this phenomenon is only obvious when the reservoir is water wet, and it has the characteristics of fast speed and low efficiency. The wettability of carbonate reservoirs can be improved by adjusting the properties of injected water (such as low-salinity treatment and carbonation). The large pore-throat ratio and oil–water viscosity ratio are the main reasons for the low efficiency of spontaneous imbibition and oil drainage. In a fracture system, water drive and gravity are the dominant factors, and the choice of water injection mode has a great influence on oil
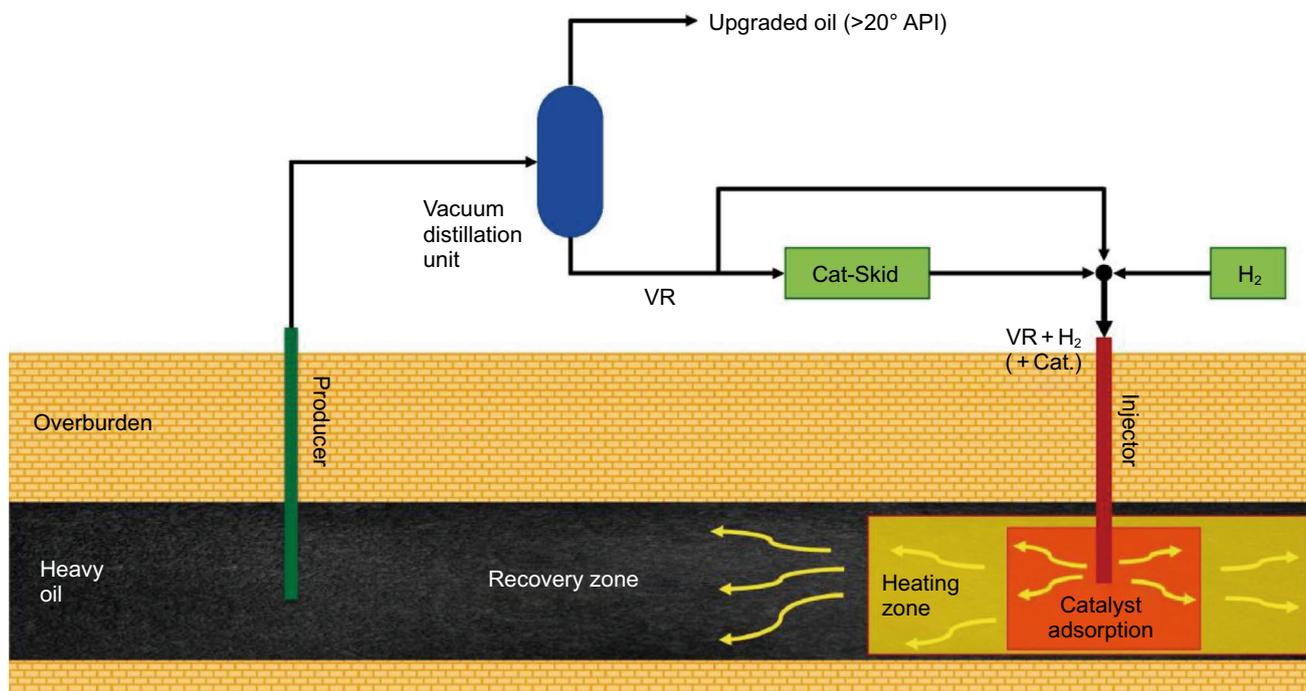

Fig. 14 Schematic of the ISUT for a carbonate reservoir. Reprint permission obtained from Elahi et al. (2019)

recovery. The research shows that unstable water injection is an effective way to improve the recovery of fractured carbonate reservoirs. By adjusting the direction of the flow field and increasing the spread coefficient, the remaining oil can be effectively extracted.

Gas injection development has been mainly categorized into miscible and immiscible flooding, which has been widely used in the field and has achieved good economic benefits. However, the choice of gas injection method is different in different oilfields in different countries. This is not only determined by the reservoir conditions and the efficiency of the gas injection method but also affected by the different needs, technical levels and oil prices of various countries. Whether the reservoir is water wet or oil wet, the gas phase is always a non-wetting phase, so the injected gas occupies the middle part of the fracture, and the nature of the gas has a great influence on the production effect of the crude oil. The expansion of nitrogen and the dissolution of carbon dioxide are widely used to reduce the viscosity of crude oil, and the injection of miscible hydrocarbon gas in fractured cavity media has been shown to be effective. However, due to the serious interlayer heterogeneity in fractured vuggy reservoirs, gas channeling is easily caused by gravity differentiation between fluids during gas injection, which significantly reduces reservoir production.

There are two limiting factors that affect the development of carbonate reservoirs: one is the viscosity of crude oil, and the other is the generation of channeling. In view of the high viscosity of crude oil, steam injection and thermal recovery are often used to reduce the viscosity of crude oil. The injection of a surfactant is beneficial to reduce the oil–water interfacial tension and improve the washing efficiency. Polymer injection can increase the sweep coefficient and block the channel. The plugging capabilities are enhanced by foam-type plugging agents and particle-based plugging agents. The use of foam to carry particle plugging agents can achieve deep plugging. However, the harsh formation conditions of carbonate reservoirs often have a great impact on the performance of chemical agents, and the development of temperature- and salt-resistant surfactants and polymers is an essential task. Similarly, the use of nanoparticles can have a good synergistic effect on chemical agents, and the chemical process of adding nanoparticles will be a focus of further research.

Overall, EOR in carbonate reservoirs is a systematic project. On the basis of reservoir protection, reasonable acidizing and fracturing technology should be adopted. Moreover, new injection media and intelligent optimization and other backup technologies should be urgently developed. During the development of natural energy drives, production control should be carried out to prevent channeling from occurring prematurely. In the initial stage of water and gas injection development, injection and production well patterns should

be established according to the type, connectivity, and spatial location of the reservoir unit to improve the control effect of water and gas injection and the degree of oil production and reduce the remaining oil reserves. In the middle and late stages of water and gas injection development, it is necessary to strengthen the control of oil wells based on the main control factors and the distribution characteristics of the remaining oil and use measures such as gravity drainage and spontaneous infiltration and drainage to disturb (reform) the flow field. The research of C-EOR technologies cannot be ignored; these technologies can replace water injection and gas injection to a certain extent and maximize the oil production of carbonate reservoirs. Finally, in combination with modern methods such as artificial intelligence, a flexible and perfect development plan and technical system should be established to achieve the cost-effective development of carbonate reservoirs and promote the development of the world's petroleum industry.

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