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Analysis of Reservoir Damage Mechanisms Induced by CO_2 Flooding and Research on Prevention and Control Strategies

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ABSTRACT

The utilization of CO_2 flooding for enhanced oil recovery not only represents an environmentally sustainable approach to greenhouse gas management but also serves as a critical technical strategy in reservoir development, functioning through the injection of CO_2 to replenish formation energy and reduce crude oil viscosity, thereby enhancing fluid mobility. However, this process may induce reservoir damage through complex chemical-mineral reactions, including carbonation reactions with mineral dissolution, secondary precipitation blockages, and clay mineral expansion/migration. Additional detrimental mechanisms involve wettability alteration due to CO_2 extraction of light components from crude oil, asphaltene deposition and organic blockage resulting from phase behavior changes during CO_2-crude oil miscibility, and mechanical damage caused by exacerbated reservoir heterogeneity from CO_2 viscous fingering in high-permeability zones. To address these challenges, comprehensive prevention strategies should be implemented: Reservoir adaptability evaluation must precede optimized CO_2 injection scheme design through parameter optimization (e.g., pressure control, injection rate modulation, and water-alternating-gas (WAG) injection). Chemical interventions involving precipitation inhibitors, anti-swelling agents, or surfactants should be employed, complemented by pre-treatment acidizing for blockage removal and post-flushing microemulsion techniques. Given that CO_2-induced reservoir damage constitutes a multifield coupling process involving chemical-mechanical-flow interactions, an integrated management strategy emphasizing proactive prevention and dynamic regulation should be adopted. This approach, grounded in thorough understanding of reservoir geological characteristics and CO_2-fluid-rock interaction mechanisms, aims to achieve dual objectives of enhanced oil recovery efficiency and reservoir protection.

Keywords: CO_2 flooding, Enhanced oil recovery, Reservoir damage, Prevention and control strategies

NONMENCLATURE

Abbreviations

WAG	Water Alternating Gas
EOR	Enhanced Oil Recovery
CW	Carbonated Water
GOR	Gas-Oil Ratio

1. INTRODUCTION

Carbon dioxide enhanced crude oil and natural gas production is considered to be a promising method to achieve enhanced oil production in depleted reservoirs. This is because they can realize the effective storage of greenhouse gas CO_2 and improve the recovery factor, which has brought huge economic and environmental benefits [1-4].

Carbon dioxide is used to enhance the exploitation of remaining oil in the oilfield, that is, gaseous, liquid or supercritical carbon dioxide is injected into underground reservoirs such as sedimentary basins. In this system, CO_2 can be physically captured in the porous rock below the impermeable cap rock (structural sequestration), part of which is captured in small pores (residual sequestration), and over time, it will be dissolved in groundwater (solution sequestration), and react with underground rocks to form stable carbonate minerals (mineral sequestration) [5-7]. With the transition of storage

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process from structural storage to mineral storage, carbon dioxide becomes more difficult to move, which improves the safety of storage and reduces the dependence on the effectiveness of caprock(Fig. 1).

production pore throat radius and improve the recovery of reservoir pore size. Under supercritical conditions, carbon dioxide has good injectability and can easily enter tight reservoirs [12-14].

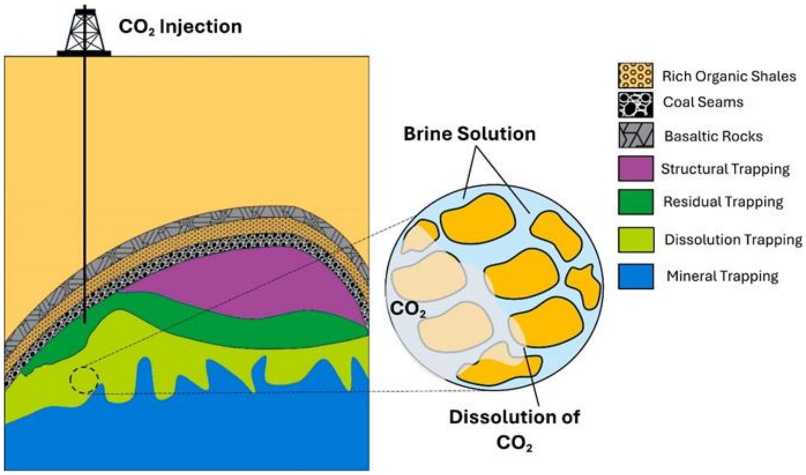

Fig. 1. Geological CO_2 sequestration and trapping mechanisms[8]

The CO_2 oil displacement process is divided into three stages: CO_2 oil displacement stage, CO_2 breakthrough stage and CO_2 extraction stage [9]. The expansion and viscosity reduction of crude oil are the main mechanisms to improve the recovery of CO_2 displacement. After CO_2 breakthrough, light components were extracted from crude oil to further improve oil recovery. In the process of CO_2 flooding, the contribution of macroporous crude oil to EOR is more than 46%, while the medium porous crude oil is used as the reserve for incremental recovery. After CO_2 breakthrough, a small part of crude oil is extracted by CO_2 and carried into nano pores, becoming residual oil that is difficult to recover. With the increase of miscibility, the carbon dioxide front moves more stably and the swept area is larger, resulting in the increase of carbon dioxide storage range and volume. The full storage phase of carbon dioxide contributes the most to the overall carbon dioxide storage. In the CO_2 escape stage, the storage mechanism involves partially storing crude oil in situ within the initial pore range, and bringing the crude oil carrying CO_2 into smaller pores to increase the volume of stored CO_2. In the stage of carbon dioxide leakage, with the production of crude oil, a large amount of carbon dioxide is produced, resulting in a sharp decline in storage efficiency.

CO_2 injection can expand the oil, effectively reduce the viscosity of the oil, increase the saturation pressure of the oil, and thus increase the energy of dissolved gas displacement [10, 11]. CO_2 miscible flooding and CO_2 miscible huff and puff can reduce the lower limit of

However, in the process of CO_2 displacement, reservoir damage (such as inorganic scale blockage, clay expansion, asphaltene deposition, wettability reversal, etc.) will significantly reduce the effective permeability of the reservoir, hinder the full contact between CO_2 and crude oil, resulting in uneven advance of the displacement front, reduction of swept volume and decline of microscopic oil displacement efficiency, which ultimately shows that the increase of crude oil recovery is much lower than expected [15, 16]. More seriously, the near well plugging caused by injury will directly weaken the injection capacity, force to reduce the gas injection pressure or suspend the operation, and further affect the dynamic balance of displacement. Therefore, the implementation of systematic prevention and control measures is not only the key to maintain the productivity of injection and production wells, but also the core guarantee to ensure the efficient displacement of crude oil by CO_2 and to realize the economic feasibility and long-term storage safety of the project.

2. MECHANISM OF RESERVOIR DAMAGE IN THE PROCESS OF CO ɑ DISPLACEMENT

2.1 Chemical mineral reaction damage

2.1.1 Carbonation reaction and mineral dissolution

Carbon dioxide storage through mineralization reaction has expanded the applicability of carbon capture and storage, making it possible for areas previously considered infeasible. At the same time, the active rock layer is injected to rapidly mineralize carbon dioxide and increase the safety of storage [8, 17]. After a large amount of CO_2 enters the reservoir, it is dissolved in formation water to form carbonic acid. Under reservoir temperature and pressure, carbonic acid can react with various minerals [18]. CO_2 reacts with silicate minerals represented by feldspar and carbonate minerals represented by calcite and dolomite to varying degrees [19, 20]. The former reaction mainly generates sodium carbonate, potassium carbonate, calcium carbonate and other substances, while the latter reaction mainly generates calcium bicarbonate, magnesium bicarbonate, magnesium hydroxide and other substances [21, 22]. These corrosion behaviors increase the pore throat size and improve the porosity and permeability of the formation. Therefore, injecting carbon dioxide into tight reservoirs will provide energy supplement and improve reservoir properties [23, 24].

The CO_2 mineralization reaction process is carried out in two ways: first, hydrogen ions are consumed to neutralize the water containing acid gas, which contributes to the precipitation of carbonatite minerals with the increase of pH value of water; Secondly, they provide divalent cations (formula 1), which can react with dissolved carbon dioxide to form stable carbonate minerals. The degree of formation of minerals by the released cations depends on the element, pH value and temperature.

$$2H^{+}+H_2O+(Ca,Mg,Fe)SiO_3 \rightleftharpoons Ca^{2+},Mg^{2+},Fe^{2+}+H_4SiO_4 \quad (1)$$

At present, there is a general understanding of the pH environment in which carbonate precipitation occurs, that is, alkaline solution (pH>7) is the aqueous medium condition in which precipitation occurs in large quantities [25]. However, in the CO_2 water rock reaction system, the development law of sedimentation also has its particularity. The uneven distribution of reservoir mineral composition, pore and fracture space in rocks will affect the distribution and interaction of fluids in the process of CO_2 geological storage. For example, in some places with poor connectivity, the ion composition in the water may form a concentration difference with other parts, and even at the same time, different parts will form a situation of simultaneous dissolution/precipitation. Therefore, although the pH value of the solution measured during the experiment is about 6, it does not truly reflect the in-situ water rock mixed phase environment, especially at the CO_2 mineral interface, which may form local supersaturation and cause sedimentation. In addition, recent studies have found that alkaline environment may not be a necessary condition for the formation of carbonate precipitation, and neutral and weak acidic environment can also cause precipitation [26], but the scale of the sediment is relatively small.

2.1.2 Secondary sediment blockage

The impact of CO_2 injection on formation permeability is very complex. On the one hand, the dissolution and extraction of minerals expand pore space and seepage channels, enhance pore connectivity, and thus improve reservoir permeability [27]. On the other hand, CO_2 and minerals such as feldspar, albite and chlorite form secondary precipitation such as new minerals. Secondary sedimentation is an important reason for the occupation of primary pores and fracture spaces and the blockage of seepage channels.

If rock minerals contain Ca^{2+}, Mg^{2+}, $Fe^{2+}$and other divalent cations, CO_2 mineralization may form stable carbonate minerals [28, 29]. The precipitation and deposition of these new minerals may block pores, throats, and microcracks, which usually lead to reduced permeability [29-32]. Therefore, a comprehensive study of the impact of CO_2 on reservoir permeability is essential to promote oil and gas production and CO_2 geological storage.

When CO_2 is dissolved in formation water, a weak acidic environment is formed, which destroys the original water rock chemical balance, and physically and chemically reacts with rocks, resulting in changes in mineral composition, pore structure, adsorption capacity, structural characteristics and permeability [33-36]. The influence of CO_2 mainly involves the dissolution and precipitation of calcium, magnesium and sodium [37], which is mainly attributed to the dissolution and precipitation of carbonate minerals (calcite, dolomite) and silicate minerals (clay minerals, feldspar) [27, 38]. The dissolution of a small part of organic matter and clay minerals also promotes the change of minerals [34]. This process of mineral dissolution and precipitation has a significant impact on the pore structure of rocks [27, 39], and then affects the permeability of reservoirs [40].

2.1.3 Swelling and migration mechanism of clay minerals

Clay minerals have a great impact on reservoir conditions and percolation capacity, and are one of the important factors for reservoir evaluation and reservoir damage research.

Giesting et al. [41] used X-ray diffraction to analyze the interaction between K-based and Ca-based montmorillonite and CO_2. The study showed that CO_2

could exist as a linear molecule between the layers of montmorillonite, or could react with the interlayer wall, cation or H_2O group to make it expand, which had a significant impact on the permeability of the caprock. CO_2 reacts with H_2O groups to form carbonate substances such as H_2CO_3 and HCO_3^-, and clay swelling is caused by hydrogen bonds with adjacent substrate oxygen planes and electrostatic interactions with interlayer Na^+. This also explains why expansion almost does not occur at low H_2O content, because H_2O in the system limits the ability of CO_2 to form these complexes [42, 43].

Luhmann et al. [44] found that when the temperature increased from 21 ℃ to 150 ℃, the chemical reaction occurred between CO_2, water, and potassium feldspar, resulting in submicron clay precipitation. The resulting particle movement and recombination caused CO_2 to fill the pores, blocking the liquid flow path, resulting in a significant reduction in permeability. Espinoza et al. [45] showed that montmorillonite and kaolinite aggregate in CO_2 and the final porosity is less than that in brine, which is due to the difference in dielectric properties between CO_2 and water, as well as the resulting van der Waals gravity and double-layer repulsion. Water dissolved in CO_2 will cause the capillary to shrink and form dry cracks. Loring et al. [46] found that CO_2 molecules can enter the intermolecular layer of montmorillonite, but did not generate H_2CO_3 or HCO_3^- with the intermolecular water. Under the same conditions, CO_2 cannot enter the molecular layer of kaolinite.

The type, quantity, occurrence and distribution characteristics of clay minerals in the reservoir have an obvious control effect on the reservoir permeability conditions. It is easy to cause damage to the reservoir during the development process and aggravate the development contradiction. The development level of low-permeability oilfield can be effectively improved by objectively understanding the development characteristics, distribution laws of clay minerals and their impact on the development process, and taking targeted measures such as acid fracturing and anti swelling water injection.

2.2 Fluid rock interaction damage

2.2.1 Reservoir wettability inversion

Wettability determines the tendency of rock to allow fluid to adhere to its surface, which is a function of reservoir conditions, i.e. surface type, temperature, pressure and fluid (Crude oil and formation water) composition [47]. For CO_2 rich brine/oil/rock system, CO_2 and brine exist in homogeneous phase, and the contact angle (θ) is measured by distributing oil droplets on the sample surface. Rogers et al. [48] studied the effect of carbonated water on the wetting behavior of pure quartz surface. The θ value of carbonate brine is slightly higher than that of simple brine, indicating that the wettability has changed to the direction of low water humidity, which means that CO_2 dissolution is the main parameter of wettability change.

Another possible wettability modification mechanism proposed by Muhammad Arif et al. [49] is that H ion will be generated in water due to the protonation of OH group. Drexler et al. [50] conducted an experimental evaluation on the wettability change of carbonate rock caused by CO_2 dissolution under reservoir conditions through θ measurement. The contact angle measured before and after the injection of carbonated water (CW) showed that CW changed the wettability of carbonate from neutral wettability to water wettability. The decrease of pH value of brine caused by H ion produced by CW is the reason for this behavior, and the wettability modification of CW is helpful to improve oil production. In addition, the increase of positive charge (H ion) at the oil brine interface subsequently led to the repulsion with positively charged carbonate rocks, leading to the transition from wettability to water wettability.

Ali et al. [51] studied the influence of crude oil composition on wettability change during CO_2 miscible displacement. In order to understand the Wettability Mechanism under reservoir conditions, the contact angle (θ) of carbonate rocks was measured with three different crude oils (light-40° API, medium-34° API and heavy-29° API) before and after CO_2 miscible flooding. It is concluded that the composition of crude oil plays an important role in the determination of wettability modification. Compared with light oil (θ decreased from 172° to 160°), the wettability of heavy oil changes more greatly (θ decreased from 171° to 130°). The θ of 29° API oil changes by 41°, while that of 40° API oil changes by only 12°. This huge change in θ is attributed to the presence of a large amount of asphaltene in heavy oil [52]. They believe that the difference of asphaltene content in oil is the main factor leading to this behavior. In addition, the positively charged carbonate will attract the negatively charged polar oil component (asphaltene) to adhere to the rock surface and make it wet.

2.2.2 Asphaltene deposition and organic plugging

In the process of CO_2 gas injection, the composition of formation crude oil changes, leading to the precipitation and precipitation of asphaltene in crude oil, resulting in the settlement of heavy components of crude oil and the change of reservoir wettability. In serious cases, it will block the pore throat, damage the reservoir, wellbore and downhole facilities, affect the productivity of oil wells, and bring expensive cleaning operation costs.

Asphaltene precipitation and deposition are common problems in both light and heavy reservoirs. Relevant studies show that asphaltene deposition is not strictly related to the percentage of asphaltene in crude oil. The most common reason is that reservoir fluids with high gas oil ratio (GOR) tend to have high content of light hydrocarbons, and the extraction of light components by injected CO_2 leads to the change of equilibrium state in the reservoir, which leads to the precipitation of asphaltene and ultimately asphaltene deposition [53, 54]. At present, several technical methods to evaluate the possibility of asphaltene becoming unstable in a given crude oil system include colloidal instability index (CII), asphaltene instability trend (ASIST), Oil Compatibility Model (OCM) and other technologies.

CO_2 is easily soluble in crude oil. Under miscible conditions, the thermodynamic equilibrium of crude oil will be destroyed because CO_2 replaces the lighter aromatic compounds used to stabilize asphaltene and reduces its solubility. In addition, CO_2 decomposes the protective gum around the asphaltene to further promote its accumulation and deposition [54]. Asphaltene precipitates alone at high temperature, while asphaltene and wax co precipitate at low temperature. With the decrease of pressure, asphaltene particles precipitate first, providing nucleation sites for wax absorption, growth and crosslinking. In the process of oil and gas production, the phase separation caused by pressure reduction leads to the extraction of light components, reduces the solubility of wax, and aggravates the damage of organic solid precipitation to the reservoir. With the increase of gas oil ratio, the amount of organic solid phase precipitation increases, and the precipitation pressure changes [55, 56].

2.3 Mechanical seepage effect damage

2.3.1 "Fingering effect" of CO_2 and intensification of reservoir heterogeneity

Gas fingering usually occurs under two main conditions: viscosity driven and density driven [57, 58]. Viscosity drive occurs when a low viscosity fluid replaces another high viscosity fluid. When the fluid with higher density diffuses to the fluid with lower density, density driven gas fingering will occur. The fingering phenomenon has a significant impact on the area/volume sweep efficiency, so it has received a lot of attention.

The injected CO_2 migrates upward and accumulates below the caprock, during which complex flow and reaction will occur. As time goes by, the high-density CO_2 solution will migrate downward, which is called "solubility capture". This density driven convection can enhance CO_2 storage and reduce leakage risk [59]. In recent years, it has been reported that heterogeneous reservoirs have higher dissolution convection mixing speed and higher CO_2 storage capacity than homogeneous reservoirs [60]. It is worth noting that CO_2 mass transfer rate is closely related to formation morphology, especially the distribution of formation porosity and permeability. Natural formations are often heterogeneous or show fracture zones, which may trigger viscous flow instability during multi fluid displacement.

When the reservoir heterogeneity is strong, CO_2 will take the high permeability channel as a shortcut to bypass the low permeability area, resulting in the fingering phenomenon appearing rapidly and seriously in the early stage of injection. More importantly, once the CO_2 fingering effect is formed, it will dynamically transform the reservoir through a series of physical and chemical processes, further aggravating the heterogeneity of the reservoir. Firstly, CO_2 in the high permeability channel will wash and dissolve the soluble minerals on the channel wall, changing the pore structure, resulting in higher permeability of these channels. Secondly, asphaltene deposition or mineral precipitation may occur after CO_2 contacts with crude oil, but these effects are often more likely to occur in pores with relatively low flow velocity or at the edge of the fingering channel/low permeability zone, instead blocking or reducing the seepage capacity of the low permeability zone. This vicious cycle makes the fingering phenomenon more and more serious, and the sweep efficiency is getting lower and lower, which seriously restricts the effect and economy of CO_2 flooding.

2.3.2 Stress sensitivity and crack activation risk

Stress sensitivity is an important geomechanical factor affecting the long-term effectiveness of CO_2 flooding and reservoir damage. With the injection of CO_2, the formation pressure will change, which will cause the effective stress of the rock skeleton to change [61]. When the injection pressure increases, the pore pressure increases, the rock skeleton may have slight elastic expansion, and the porosity and permeability may be slightly improved. However, what is more critical is that when injection stops, production pumping or pressure fluctuation occurs, the pore pressure drops and the effective stress increases significantly, resulting in the compaction of rock particles and the compression or closure of pore throats, especially for unconsolidated sandstone or natural microfractures. This stress sensitive effect will irreversibly reduce the absolute permeability of the reservoir, which not only limits the subsequent CO_2 injection capacity, but also hinders the flow of crude oil and reduces the displacement efficiency [62].

CO_2 is dissolved in water to form an acidic environment. This significantly promotes the dissolution of minerals, especially carbonate minerals and aluminosilicate minerals. This process will produce new pores and microcracks, leading to the increase of permeability and more obvious fracture contour [27, 63]. At the same time, the expansion of clay minerals leads to local stress, forming new micro cracks and expanding the original cracks [64]. Mineral dissolution will not only produce new pores and micro fractures, but also expand the existing pore structure, so as to improve the reservoir permeability. However, under acidic conditions, some minerals such as kaolinite and quartz precipitate, which may occupy the original pore space, block the pore network, reduce connectivity, and ultimately reduce reservoir porosity and permeability [32]. Volume expansion during precipitation reaction may lead to the formation and opening of fractures, which will increase permeability and expose new surfaces to the fluid phase, so it may promote the carbonation of underground reservoirs [65] and pose a major threat to environmental safety and development goals.

3. PREVENTION AND CONTROL MEASURES OF CO_2 FLOODING RESERVOIR DAMAGE

3.1 Reservoir adaptability evaluation and injection scheme optimization

3.1.1 Fine reservoir evaluation

The chemical properties and reactivity of different rock types, the porosity and permeability of potential reservoirs, and the pressure and temperature of reservoirs during CO_2 injection have a significant impact on CO_2 displacement and storage efficiency [66-68]. Based on its reactivity, the most feasible strata for carbon mineralization are ultramafic and magnesian rocks, while basalt has abundant pore space for carbon storage. At present, it is not clear which other strata contain high enough concentrations of cations to achieve effective carbon capture and storage through carbon mineralization. Even under similar sedimentary environment, tectonic location and burial history, the differential response of diagenetic heterogeneity to CO_2 fluid can not be ignored. Therefore, when evaluating large-scale CO_2 storage, it is necessary to consider the impact of diagenetic heterogeneity [69].

The study of mineral dissolution and precipitation rate is helpful to deeply understand the basic process behind mineral carbonation, which is very important for the design of large-scale field operation [70]. Under acidic conditions near the CO_2 injection point, the mineral dissolution rate increases sharply with the decrease of pH value. The dissolution rate of aluminum bearing minerals, such as plagioclase and volcanic glass, is the slowest at neutral pH and increases at higher pH [71, 72]. In contrast, the dissolution rate of aluminum free minerals, such as olivine and pyroxene, usually decreases with the increase of pH value, so these minerals dissolve slowly under the condition of carbonate prone precipitation [73, 74]. This shows that near the CO_2 injection well, the dissolution rate of the active bedrock is faster, but the subsequent secondary phase precipitation rate is slower, more dispersed, and will be far away from the injection site.

Clarifying the mechanism of the effect of carbonic acid on the pore throat characteristics of porous media has important scientific significance and significant economic benefits for revealing the change mechanism of rock physical properties in CO_2 flooding, quantitatively evaluating and analyzing the existence state of movable fluid, reasonably predicting the seepage capacity of multiphase fluid, and optimizing field operation parameters [75-77].

3.1.2 Injection scheme optimization design

Carbon dioxide flooding, by injecting carbon dioxide to displace hydrocarbon fluid in pores and fractures and improve its recovery. Different injection strategies can be used, including: ① Continuous injection of CO_2 without introducing other fluids; ② Sequential injection of CO_2 and water (CO_2 injection first, then water injection); ③ The water alternating gas (WAG) injection (Periodic cycle of CO_2 and water injection); ④ Conical WAG: Compared with water, the volume of CO_2 injected is gradually reduced; ⑤ WAG is followed by "chase" gas injection (during WAG, chase gas such as air or nitrogen, is injected after CO_2 slug).

Continuous CO_2 flooding is an ideal choice for gravity drainage displacement stable reservoirs and reservoirs that are not suitable for water injection. Compared with other CO_2 flooding methods, it can provide better long-term oil production and recovery.

WAG is a relatively mature oil and gas reservoir production technology. Its main goal is to control mobility, suppress viscous fingering, and improve oil recovery by combining the advantages of high displacement efficiency of gas injection (GI) and macro sweep efficiency of water injection (WF). The composition and salinity of brine are important factors affecting WAG performance, and low salinity water injection has potential improvement [78]. The five point well pattern injection mode is widely used. Although the cost is higher than other modes, it is still the most popular because it can more carefully control the pressure of the mixing process [79, 80]. According to the global case, WAG injection at a ratio of 1:1 is usually the first choice to achieve the best oil and gas production, so as to avoid excessive water injection. However, water will hinder the contact between gas and residual oil, resulting in the formation of gas tongue, which will reduce the sweeping efficiency [81]. The performance of WAG process is also significantly affected by reservoir wettability, and the injection rate, proportion, circulation frequency, salinity of brine and concentration of polymer additives should be considered in WAG design [82]. Taper, especially the change of WAG ratio, has the ability to control excessive natural gas production and accelerate oil displacement [83].

Taking cumulative crude oil production (COP) and carbon sequestration stock (CO_2SC) as evaluation indexes, the relatively sensitive parameters of continuous gas injection mode (CGI) and water gas alternate injection mode (WAG) are the same, which are injection timing, lower bottom hole pressure (LLBHP) of production wells and upper injection pressure (ULIP) of injection wells [84]. Earlier CO_2 injection timing and higher LLBHP in production wells are conducive to improving crude oil production and carbon sequestration stock.

3.2 Chemical control technology

3.2.1 Precipitation inhibitor

In the process of CO_2 flooding, it is easy to break the original chemical balance and cause the precipitation of $CaCO_3$, $CaSO_4$, silicon scale and other inorganic scales. In order to inhibit its nucleation, chelating agents (such as EDTA, NTA, Citrate, etc.) are often added. These molecules have multiple functional groups with strong coordination ability (such as carboxyl group and amino group), which can capture scaling cations (such as Ca^{2+}, Mg^{2+}, Ba^{2+}, Fe^{2+}) in the solution like "Molecular lock", forming highly stable water-soluble complexes. This greatly reduces the effective concentration of free scaling cations, making it unable to reach the supersaturation required for crystallization [85, 86]. Even if the local environment meets the thermodynamic scaling tendency, the presence of chelating agent also significantly improves the activation energy barrier required for nucleation, greatly delaying or even preventing the initial formation of crystal nuclei.

Polycondensated phosphates (such as sodium tripolyphosphate, sodium hexametaphosphate, etc.) mainly inhibit the growth and deposition of scale through the "lattice interference" effect and dispersion and stabilization effect. On the one hand, its long-chain or cyclic anion structure can be adsorbed on the active surface of micro crystal nucleus or crystal growth point, which distorts the lattice arrangement through electrostatic effect and steric hindrance, resulting in abnormal and slow crystal growth, and can only form fine and loose soft scale rather than dense hard scale. On the other hand, polyphosphate molecules can disperse and stabilize the formed micro grains and colloidal particles through electrostatic repulsion, prevent them from colliding with each other, gathering and growing up, and inhibit their adhesion and deposition on the rock surface or pipe wall. Its effect has a significant "Threshold effect" - only a small amount of addition lower than the stoichiometric ratio (far lower than the amount of chelating agent) can effectively interfere with the whole crystallization process. It is suitable for treating systems with high calcium and magnesium ion concentration, and is a key chemical means to inhibit the growth of scale.

3.2.2 Clay stabilizer (anti swelling agent)

In the process of CO_2 flooding, the injected CO_2 is dissolved in formation water to form carbonic acid, which reduces the pH value of the system and aggravates the instability of water sensitive clay minerals such as montmorillonite and illite smectite mixed layer in the reservoir. Potassium chloride (KCl) is the most commonly used and economical clay stabilizer. Its core function is that the high concentration of K^+ ions can effectively replace the Na^+ and Ca^{2+} plasma with strong hydration between clay minerals and on the surface. The radius of K^+ ion is small (well matched with the size of hexagonal oxygen ring hole in the clay lattice), the hydration energy is low, and it tends to be closely adsorbed on the negative charge sites of clay. And the high concentration of K^+ significantly increases the ionic strength of the solution, compresses the cationic layer around the clay particles, and reduces the electrostatic repulsion between the particles [87].

For reservoirs with strong water sensitivity or insufficient KCl application effect, and where long-term stability is required, organic clay stabilizers are often used, mainly including small molecular polyquaternary ammonium salts and high molecular cationic polymers. Polyquaternary ammonium salts (such as tetramethylammonium chloride and small molecular polyquaternary ammonium salts) have strong positive charges, which can be strongly adsorbed on the negatively charged clay surface through electrostatic attraction to achieve "Charge neutralization", and even make the clay surface have a net positive charge. This greatly inhibits the dispersion, migration and re aggregation of clay particles. In addition to charge neutralization through a large number of cationic groups, the long-chain molecules of high molecular weight cationic polymers (such as polydimethyldiallylammonium chloride and cationic polyacrylamide) can be adsorbed on the surface of clay particles or rocks at many points. This adsorption forms a dense polymer film coating, which prevents water molecules from contacting the clay crystal layer and inhibits hydration expansion.

3.2.3 Surfactants

Surfactants can reduce the interfacial tension between oil and water, and in some cases, can change the wettability of rocks from oil wet to water wet, so as to better drive oil through water injection, both of which are favorable mechanisms for oil displacement [88, 89]. This is also reflected in the reversal of capillary pressure from negative to positive [90]. Surfactant can also form oil/water microemulsion, which improves the fluidity of oil, thereby improving the microscale scanning efficiency [91].

In recent years, viscoelastic surfactants, polymer surfactants, Gemini and natural surfactants have attracted extensive attention due to their better sweeping mechanism, high temperature and salt resistance, ability to achieve ultra-low interfacial tension and environmental protection [92, 93]. With the emergence of nanotechnology, the stability of surfactant flooding and the increment of oil revenue have been greatly promoted. The mechanism of Pickering emulsion makes the nanoparticles of various metal and non-metal oxides used with surfactants produce higher oil recovery, lower interfacial energy and better stability. Due to the dual wettability, Janus particles can act as nanoscale particle surfactants, and are not affected by high temperature and high salt, so they have great application potential [94].

By adding surfactants to the injected water, the displacement phase, the interfacial properties between crude oil and rock minerals are changed, so as to improve the oil displacement efficiency. Because of its good interfacial tension reduction effect and wetting reversal ability, it has great application potential in reservoir development [95, 96]. However, low permeability reservoirs are characterized by low porosity, low permeability and complex pore throat structure [97, 98]. This leads to serious loss of adsorption, retention and precipitation in the process of surfactant migration, which greatly increases the technical cost [99]. The results show that permeability has the greatest influence on the dynamic saturated adsorption capacity of surfactant on the surface of porous media, followed by injection pressure and temperature. Therefore, when implementing surfactant flooding technology in low-permeability reservoirs, it can be considered to increase the injection pressure of the agent and reduce the dynamic saturated adsorption capacity, so as to improve the effective concentration of the agent [100, 101], and realize the successful application of surfactant in low-permeability reservoirs.

3.2.4 Asphaltene dispersant/inhibitor

In order to effectively avoid or mitigate the damage caused by asphaltene deposition, scholars at home and abroad have developed various types of chemicals to stabilize asphaltene in crude oil and inhibit the precipitation and deposition of asphaltene in development [54, 102, 103].

The application of asphaltene dispersant/inhibitor mainly has two core links: inhibiting aggregation, providing steric resistance or electrostatic repulsion by adsorbing on the surface of asphaltene molecules or small aggregates, preventing them from further collision and growth to form large particles that can be deposited. Stable colloidal state: some agents can interact with asphaltene through specific functional groups, partially rebuild or strengthen the stable micelle/micelle structure around them, enhance the colloidal stability of asphaltene in crude oil, maintain the dispersion state of asphaltene in crude oil, and prevent it from reaching the critical aggregation size or adhering to the solid surface.

At present, most asphaltene inhibitors use liquid as solvent to dissolve the chemical agent before injecting into the reservoir. There are two ways to inject chemical solution into reservoir: one is to inject chemical solution directly into crude oil as asphaltene inhibitor; The second is to inject gas and chemical solution alternately into the reservoir. When the first method is used for field operation, it is necessary to inject chemical solution into the reservoir to interact with the crude oil near the well to inhibit the precipitation and deposition of asphaltene near the well. This method is simple to operate and has sufficient contact with the crude oil, but its scope of action is limited and its persistence is poor. The second method is that the gas pushes the reagent solution to migrate to the deep part of the reservoir to expand the action radius, but the process is complex, and it is easy to form gravity overturn between the injected gas and the chemical solution, so it is necessary to optimize the slug design to avoid secondary damage.

3.3 reservoir pretreatment and post-processing technology

3.3.1 Pre acidification treatment

Before the formal injection of CO_2, acid treatment is carried out for the near wellbore or the entire target reservoir section, aiming to improve the reservoir seepage ability in advance, improve the CO_2 injection performance, and create a more favorable reservoir environment for subsequent oil displacement. Pre acidification can remove the plugging of filter cake and solid particles caused by the invasion of drilling fluid, completion fluid, cementing fluid and other foreign fluids, as well as the plugging of pore throat caused by inherent clay minerals and drilling mud residues in the reservoir. At the same time, the absolute permeability of the reservoir rock is directly improved by dissolving the plug and some matrix minerals, providing a more smooth channel for CO_2 injection and migration, effectively reducing the bottom hole pressure during subsequent CO_2 injection, and improving the injection capacity. Potentially, it can consume some alkali sensitive minerals (such as feldspar and clay) that are easy to react with CO_2 to form precipitation in advance, reducing the risk of inorganic precipitation (such as carbonate and siliceous precipitation) during subsequent CO_2 injection. In addition, some acid additives or acids themselves can change the wettability of the rock surface of the reservoir, making it more prone to water or neutral wettability, which is conducive to reducing the adhesion of crude oil, improving the subsequent CO_2 displacement efficiency, and may alleviate the potential damage of wettability reversal.

When selecting the acid system, it is accurately selected according to the mineral composition of the reservoir. Hydrochloric acid (HCl) or organic acids (acetic acid, formic acid) are commonly used in carbonate reservoirs; Geoacid (HF/HCl) or retarded acid system (such as fluoboric acid HBF_4 and authigenic geoacid system) are commonly used in sandstone reservoirs to control the reaction rate of HF and avoid sand production or secondary sedimentation caused by excessive dissolution of skeleton minerals. For reservoirs with high iron content, iron ion stabilizer should be added. Key parameters such as acid concentration, volume, injection rate and shut in reaction time need to be optimized through laboratory core flow experiment and numerical simulation.

3.3.2 Post blocking removal technology (such as microemulsion flushing)

CO_2 flooding can easily induce asphaltene deposition, form stubborn emulsion, and lead to wettability reversal. These damages are often difficult to be effectively solved by conventional acidification or ordinary surfactants. In the process of CO_2 flooding or after the displacement, for the reservoir damage (especially the damage caused by organic deposition, emulsion plugging, wettability reversal, water lock/Jamin effect, etc.), a special microemulsion system is injected into the reservoir, and its solubilization, stripping, and carrying functions are used to remove the blockage, restore the near wellbore or deep reservoir permeability, and improve the subsequent production or displacement efficiency.

With its ultra-low interfacial tension, strong solubilization ability and wettability control ability, microemulsion flushing has become one of the most promising post plugging removal technologies to solve the organic and interface related damage caused by CO_2 flooding. Microemulsion can form ultra-low interfacial tension (as low as 10^{-3} mN/m or even lower) with oil and water at the same time, greatly promoting the coalescence, flow and displacement of residual oil droplets or emulsions bound by capillary force, and effectively removing water lock, oil lock and emulsion blockage. The micelle core of microemulsion has strong solubilization ability, which can effectively dissolve organic sediments (such as asphaltene, paraffin, oil sludge). The surfactant in microemulsion can change the wettability of rock, help reduce the adhesion of crude oil on the rock surface, improve seepage, and effectively wet and peel off the organic scale, emulsion liquid film, clay particles and other blockages attached to the rock wall, and carry them out of the formation. The microemulsion itself also has good mobility control characteristics (adjustable viscosity), and can reduce the mobility ratio between the displaced phase and the displaced phase, which is helpful to improve the sweep efficiency.

Microemulsion system is usually composed of surfactants, cosurfactants (usually alcohols), oil phase (can be crude oil, diesel oil or synthetic oil), and water phase (usually low salinity brine or brine composed of specific ions) in a specific proportion. The mechanism of action is mild, and it can synergistically and efficiently relieve a variety of complex injuries, especially organic related and emulsification related injuries.

4. DISCUSSION

The reservoir damage during CO_2 flooding is not an isolated phenomenon, but a complex result of deep coupling and joint action of chemical mechanical seepage multi physical fields. Chemical field dominated reactions (such as mineral dissolution/precipitation, asphaltene instability precipitation and wettability inversion caused by CO_2-water-rock interaction) directly change the pore structure and fluid properties; The change of mechanical field (the fluctuation of injection pressure leads to the change of effective stress and induces fracture activation/slip) dynamically reshapes the strength of reservoir framework and pore connectivity; The seepage field controls the distribution and accumulation of harmful substances through fluid migration (heterogeneous fingering, formation of dominant channels) and relative permeability changes (relative permeability curve deviation, capillary force effect). It is particularly critical that there are close correlations and complex synergy/competition effects between different injury types: for example, although the dissolution of calcite and other minerals increases porosity in a short time, the released $Ca^{2+}$and Fe^{2+} plasma may combine with carbonate or sulfate in high pH areas (such as near production wells) to form secondary inorganic scale to block pores (competition effect); The local high velocity caused by CO_2 fingering not only increases the risk of asphaltene deposition under shear, but also scours the clay particles or loose scale, causing deep migration blockage (synergistic effect). This multi field interaction and cause and effect interweaving feature makes the prevention and treatment of injury in a single dimension tend to focus on one thing and lose the other.

Facing the challenge of reservoir damage caused by multi field coupling, the comprehensive treatment strategy of "evaluation, regulation and treatment" must be adopted. Reservoir adaptability evaluation and injection optimization, based on geomechanics, mineral composition and fluid compatibility analysis, accurately predict the risk of injury (such as scaling trend, stress sensitivity threshold), and optimize the injection parameters (pressure window, gas water ratio and injection rate), so as to avoid high injury risk conditions from the source (such as super fracture pressure gas injection or inducing strong water sensitivity). The chemical control technology is applied cooperatively, and the functional chemicals (such as scale inhibitor, clay stabilizer and asphaltene dispersant) are compounded pertinently to block the damage chain by their synergistic effect - for example, while polyphosphate inhibits calcium carbonate precipitation, its dispersion can help reduce clay migration; While the cationic polymer stabilizes the clay, its adsorption layer may inhibit the deposition of asphaltene on the rock surface. Reservoir pre-treatment and post-treatment technology, pre clay stabilizer injection or chelating agent cleaning to reduce near well damage potential; Post periodic acidification or nanofluid backflow can remove deep scale blockage/deposition and restore seepage ability.

The ultimate goal is to maximize the CO_2 sweep and oil displacement efficiency (expand the macro oil scavenging area and improve the micro oil washing ability) while minimizing the permeability loss and injection capacity attenuation caused by reservoir damage through multi-scale and multi link collaborative intervention, so as to realize the deep coordination of "oil displacement" and "reservoir protection", and ensure the long-term economy and storage safety of CO_2 oil displacement projects.

5. CONCLUSIONS

This paper systematically reveals the types of multi-dimensional reservoir damage in the process of CO_2 flooding, including chemical damage (inorganic scale deposition, asphaltene precipitation, mineral corrosion/secondary precipitation, wettability reversal), mechanical damage (permeability attenuation induced by effective stress change, fracture activation and channeling), and Seepage Damage (particle transport blockage exacerbated by fingering effect and phase permeation lag effect). The research confirms that the above damage is the result of the strong coupling effect of chemical, mechanical and seepage multi physical fields - the CO_2, fluid and rock interaction drives the mineral phase transition and fluid component imbalance (chemical field), the injection pressure fluctuation changes the rock mass stress state (mechanical field), and the heterogeneous seepage field further amplifies the local damage (seepage field) through the finger and the dominant channel. There is a significant synergy/competition effect between different injury mechanisms, which aggravates the complexity of injury prevention and control.

According to the characteristics of multi field coupling damage, a "three in one" prevention and control system is proposed: preventive optimization design, optimization of injection parameters and WAG strategy based on reservoir geomechanical properties, mineral sensitivity and fluid compatibility evaluation, and suppression of damage trigger conditions from the source; Targeted chemical regulation, research and development of compound functional chemicals (scale inhibitor, clay stabilizer and asphaltene dispersant) to block the damage chain reaction through synergy; Efficient treatment technology, enhanced pre chelating agent/cationic polymer pretreatment to inhibit near well damage, supporting periodic nanofluid plugging removal or controllable acidification post-treatment to repair deep damage. The core principle is to implement the active governance strategy of "prevention oriented and dynamic regulation" and realize the synergy and unity of EOR and CCUS.

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DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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