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Invited review

CO_2 storage in depleted oil and gas reservoirs: A review

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Abstract:
Geological storage of CO_2 in depleted oil and gas reservoirs is approved due to its advantages, such as strong storage capacity, good sealing performance, and complete infrastructure. This review clarified the existing projects, advantages, significances, influencing factors, mechanisms, and storage potential evaluation procedures of CO_2 storage in depleted oil and gas reservoirs. In this review, the storage capability of depleted oil and gas reservoirs has been confirmed, and factors affecting the CO_2 storage potential, including geological factors and engineering factors, are concluded. CO_2 trapping mechanisms of different storage processes in depleted oil and gas reservoirs are elaborated and divided into three stages. The evaluation stages of CO_2 storage potential of depleted oil and gas reservoirs are summarized as basin selection evaluation stage, oil and gas reservoir selection evaluation stage, storage security evaluation using the bowtie method, and storage capacity calculation stage. The calculation accuracy of CO_2 storage capacity in depleted oil and gas reservoirs can be optimized by determining the mineralization storage volume and the actual reservoir characteristics of the dissolution storage coefficient numerically. This work intends to provide support for the storage of CO_2 by analyzing and studying the geological theory and engineering achievements of CO_2 storage in depleted oil and gas reservoirs.

1. Introduction

The European Union, Japan, South Korea, the United States, and others have proposed the goal of achieving carbon neutrality before 2050. China has also announced that it will peak carbon emissions before 2030 and strive to achieve carbon neutrality before 2060 (Ouyang et al., 2021; Xu et al., 2022), indicating that activities related to CO_2 storage or utilization are a global trend. At present, the main geological sites for carbon storage in the world are depleted oil and gas reservoir (DOGR), deep saline aquifers, non-minable coal seams, and subsea storage (Bachu and Shaw, 2003; Haggerty, 2004; Aminu et al., 2017; Zhu et al., 2021). The global CO_2 storage projects for DOGR are displayed in Fig. 1.

DOGR has obvious advantages compared to other storage methods in terms of CO_2 storage capacity, sealing performance, reservoir characterization experience, existing oil and gas well infrastructure, and operability of storage (Orlic, 2016; Zhou et al., 2019; Hamza et al., 2021; Khurshid and Fujii, 2021), CO_2 storage in DOGR is one of the most realistic ways to reduce carbon emissions. The worldwide CO_2 storage capacity of DOGR is estimated to be around 390-750 gigatons, approximately ten times the current annual CO_2 emissions globally (Hamza et al., 2021). However, there are many problems in CO_2 storage in DOGR, such as the evaluation method of storage potential and its applicability, the possibility of CO_2 leakage and its mechanism, the reaction mechanism between CO_2 and the remaining fluids in DOGR, and the seepage of CO_2 in DOGR, which have not been effectively

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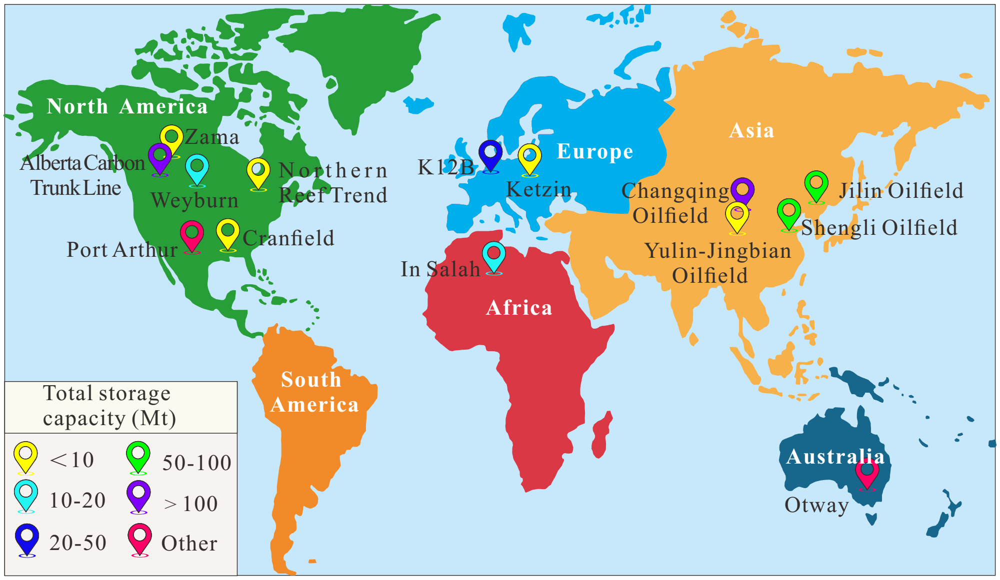

Fig. 1. Global CO_2 storage projects in DOGRs, which are defined as those that have lost their economic recovery benefits.

revealed yet.

There have been multiple reviews on CO_2 storage. Previous reviews cover knowledge including storage background, project status, modeling and monitoring, capacity estimation, carbon storage and hydrogen production (Hematpur et al., 2023), and subsea storage (Aminu et al., 2017; Ajayi et al., 2019; Luo et al., 2023; Yang et al., 2023). However, few detailed reviews focus on existing projects, influencing factors, and trapping mechanisms of CO_2 storage in DOGR, which lack CO_2 storage potential evaluation analysis. This article analyzed the main projects of CO_2 storage in DOGR of the world first, and then clarified the geological and engineering influencing factors that may determine the success or failure of CO_2 storage. The mechanisms for CO_2 storage in DOGR are also elaborated, and CO_2 trapping mechanisms of different storage processes are illustrated. Procedures for storage potential evaluation of CO_2 storage in DOGR are also proposed. This paper are expected to provide support for CO_2 storage.

2. Technical processes and storage projects

2.1 Technical processes

CO_2 storage in DOGR is first to capture, dehydrate and compress CO_2, then inject it into DOGR as liquid CO_2 or supercritical CO_2 for permanent storage (Ozotta et al., 2021). The facilities and technologies used in CO_2-enhanced oil and gas recovery operations are roughly the same as those required for CO_2 storage (Ozotta et al., 2021). The workflows of CO_2 storage in DOGR were mainly divided into CO_2 capture, treatment (such as flue gas separation and water and gas separation), compressed liquid injection (miscible flooding and immiscible flooding), storage, and monitoring (Figs. 2-4). The specific processes above-mentioned have been elaborated in numerous published articles. Those processes are not repeated in this paper for conciseness.

2.2 Storage projects and effects

The geological characteristics, process technologies, annual storage capacity, and monitoring effect of the CO_2 storage projects in DOGR were briefly described in Supplementary Material A. Typical cases are introduced as follows:

(1) Weyburn Oilfield project (North America)

Weyburn Oilfield straddles the US and Canada, which realize economical and safe storage of CO_2 in the reservoir (Preston et al., 2005). The Weyburn project focused on understanding the distribution and storage mechanisms of CO_2 in CO_2-injected reservoirs and the extent to which CO_2 can be permanently sequestrated (Preston et al., 2005). CO_2 was injected at a rate of approximately 3,000-5,000 tons/day and was expected to be sequestrated for a total of 20 Mt during its life (20-25 years) with a net storage capacity of 14 Mt (Bachu, 2000; Preston et al., 2005; Shukla et al., 2010), and the economic operating cost was about $20 per ton. Extensive monitoring using seismic and geochemistry sampling methods revealed no signs of leakage (Boyd et al., 2013).

(2) In Salah Gas-field (Algeria)

The carbon source comes from the gas-field itself, and the target reservoirs are depleted carboniferous sandstones located at 1,800, 1,850, and 1,900 m underground, with an estimated total CO_2 storage capacity of 17 Mt (Pamukcu et al., 2011). During 2004-2011, 4,000 t CO_2 was injected into the target stratum every day, with a total injected amount of 4 Mt. The cost of injection is approximately $6 per ton of CO_2, and the total cost is approximately $2.7 billion (Stork et al., 2015). Satellite InSAR and Time-lapse seismic and microseismic monitoring have shown that CO_2 can migrate from the reservoir to the cap rock (Pamukcu et al., 2011; White et al., 2014).

(3) Otway Oilfield (Australia)

The Otway Oilfield project in Australia is the first Australian carbon capture and storage (CCS) project under the

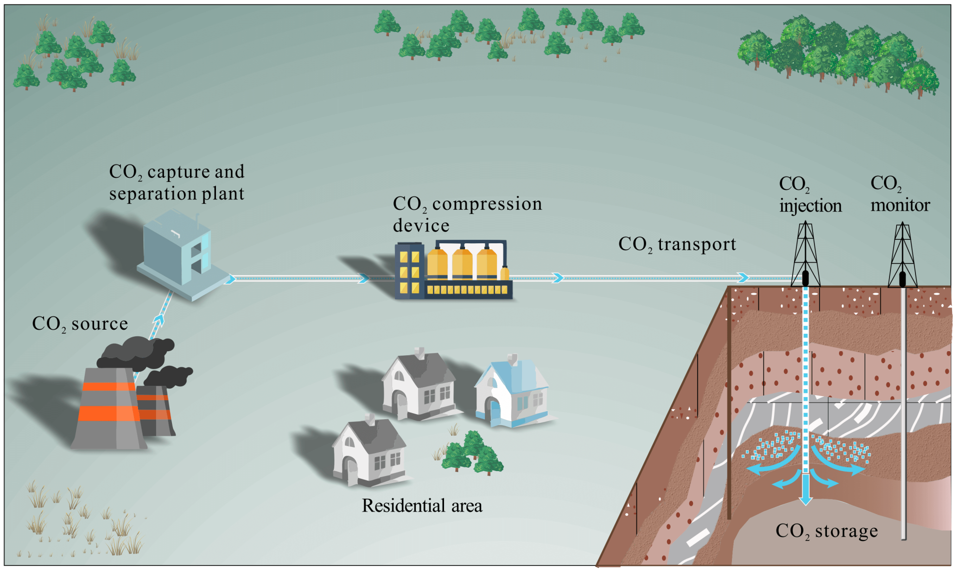

Fig. 2. CO_2 capture and geological storage technology (Wang et al., 2018).

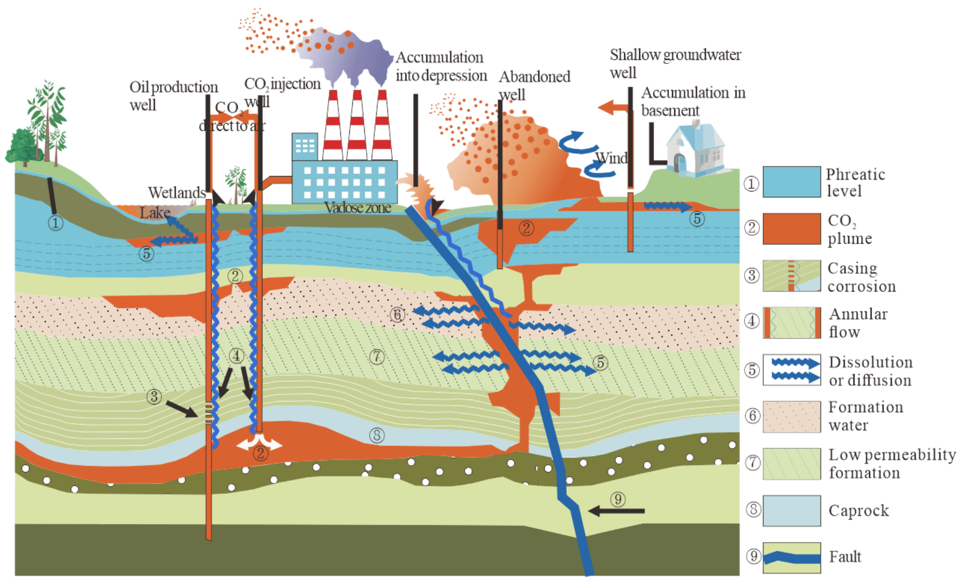

Fig. 3. Leakage pathways and their associated potential impacts of geological storage of CO_2 (Liu et al., 2016). CO_2 injection may leakage to the surface ground through faults and corroded casings.

regulatory framework of the CO_2 Cooperative Research Centre (Steeper, 2013). CO_2 is derived from the CO_2-rich Naylor Oil & gas field (80% CO_2, 20% CH_4, according to Popik et al. (2020)), with approximately 65,000 tons of CO_2 injected annually into a depleted sandstone gas reservoir with a burial depth of 2,000 m (Hortle et al., 2011). The leakage monitoring results showed that the CO_2 found in the soil was of biological origin, and no CO_2 escaped from deep layers.

(4) Cranfield Oilfield (USA)

The Cranfield Oilfield is located in Mississippi, USA, and its injection of CO_2 is primarily used to enhance oil recovery in DOGR. In this project, 1.5 Mt of CO_2 is injected annually into a heterogeneous sandstone formation at a depth of 3,000 m with a total cost of $93 million, and a total of 4.7 million tons of CO_2 has been sequestered by 2013 (Freifeld et al., 2013). Extensive investigations, including geochemistry monitoring through soil gas ratios, light hydrocarbon concentrations, stable isotope and radionuclide of CO_2 and CH_4, rare gases, and tetrafluoromethane concentrations, were conducted. Those investigations found no leakage occurred between 2009 and 2014 (Anderson et al., 2017).

(5) Jilin Oilfield (China)

The Jilin Oilfield CO_2-enhanced oil recovery (EOR) and storage project is the first large-scale CCS demonstration project in China. The annual CO_2 storage capacity of Jilin Oilfield was 700,000 tons as of 2015 (Tang et al., 2014). By means of micro-seismic, gas tracing, production fluid sampling, and natural potential measurement, the CO_2 storage

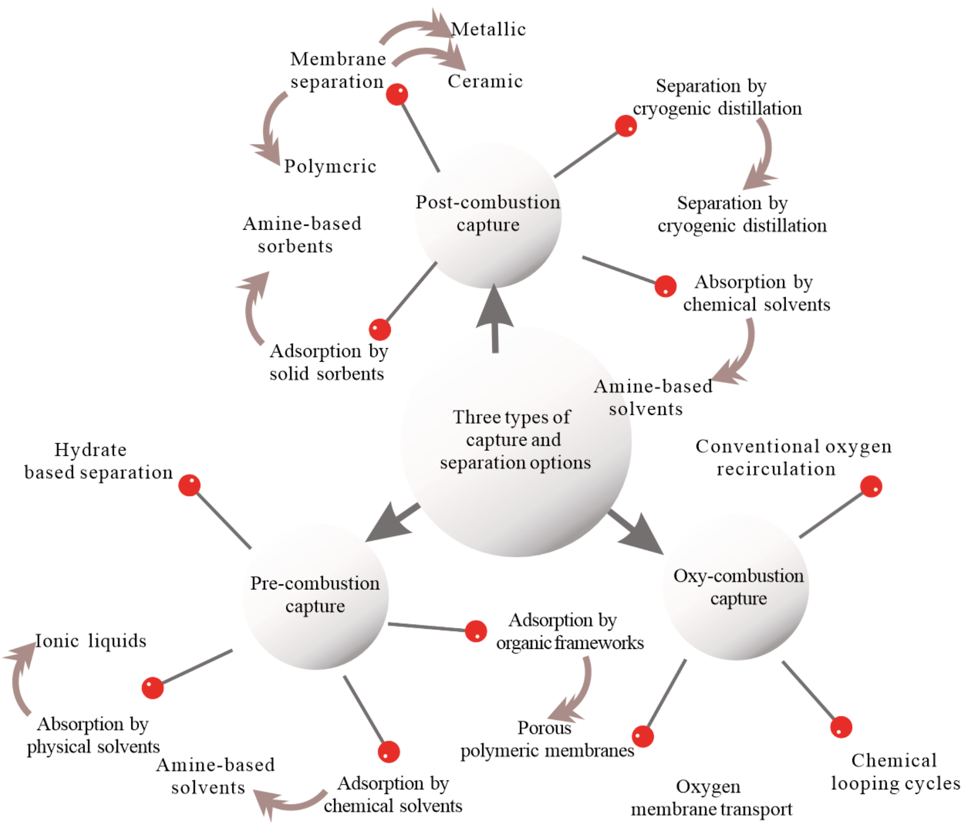

Fig. 4. CO_2 capture and separation process options (modified from Adu et al. (2018)).

safety monitors of the reservoir, near-surface, injection, and production system were carried out, and the results showed that the afore-mentioned techniques for monitoring CO_2 were effective (Zhang et al., 2015).

(6) Shengli Oilfield (China)

G89-1, a CO_2 storage experimental block in Shengli Oilfield, is a high-temperature, low-permeability, strong-heterogeneous reservoir. After the implementation of the CO_2 flooding-storage program, it is expected that 3.8×10^8 m^3 underground storage can be achieved, which can improve oil recovery by 20% in 15 years (Lv et al., 2011). Li et al. (2014) reported that shallow well monitoring systems had been used in Shengli Oilfield. The monitoring results of air, groundwater, soil gas, vegetation ecology, surface deformation, and CO_2 underground transportation showed that no CO_2 leakage occurred.

(7) Changqing Oilfield (China)

The CO_2 EOR project in Jiyuan block of Changqing Oilfield is located in the Ordos Basin of China. The reservoir there is characterized by ultra-low permeability and porosity (Cheng et al., 2017; Hill et al., 2020). This project injects liquid CO_2 into two targeted reservoirs with depths of 1,350 and 2,750 m at an injection rate of 60 tons per day (Hill et al., 2020). The accumulated injection mass was 3.76×10^5 t with a CO_2 storage conversion rate of approximately 73% (Cheng et al., 2017).

(8) Yulin-jingbian Oilfield (China)

With a cost of 30 $/t (Ma et al., 2013), CO_2 with an injection rate of 20 tons per day was injected into the reservoir at a depth ranging between 1,409 and 1,661 m (Ma et al., 2014). More than 60,000 tons of liquid CO_2 were injected, and in addition, three dimensional baseline seismic monitoring was applied in this project.

It is worth noting that although the processes at different carbon storage sites are well known, there are still some geological or technological obstacles that need to be further studied or solved. The above-mentioned field experiences showed that the CO_2 storage capability of DOGR has been confirmed. Whether for CO_2 storage solely or for enhanced oil recovery, 390-750 Gt CO_2 storage can be realized globally in DOGR (Hamza et al., 2021). Significant results have been achieved in field design for reservoir pressure reduction, reuse of infrastructure, and management of wellbore integrity risks (Hughes et al., 2009). However, as far as permanent storage is concerned, factors influencing the CO_2 storage effect in DOGR need to be focused on. In the following section, geological and engineering factors influencing the storage effect are clarified.

3. Influencing factors

3.1 Geological factors

3.1.1 Caprock integrity

Caprock integrity is the main indicator to evaluate the long-term safety of CO_2 storage in DOGR (Rezaeyan et al., 2015). Cap integrity of DOGR is damaged due to reservoir de-compression, injection fracturing, pore and osmotic pressure, and capillary leakage. The caprock thickness, height, lateral

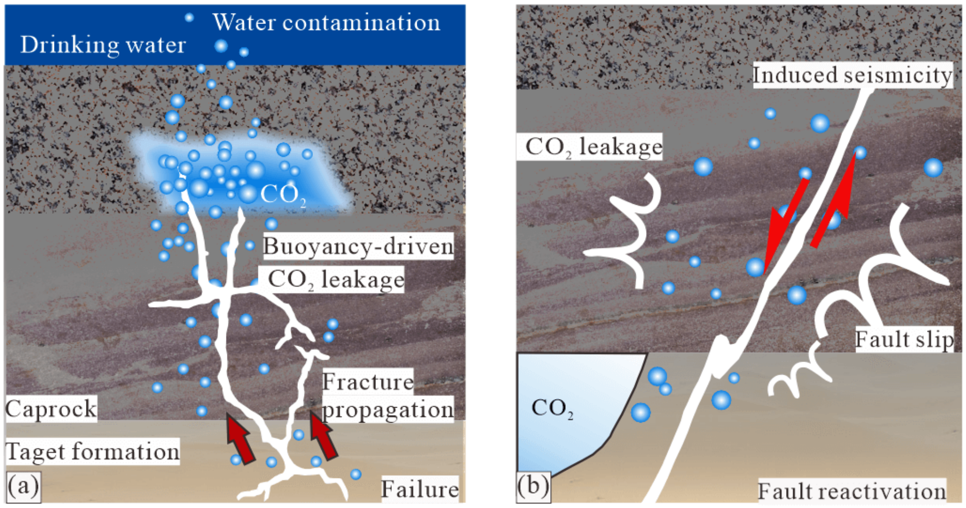

Fig. 5. Caprock failure and fault leakage according to Song et al. (2023). (a) Caprock failure and (b) fault leakage.

extension of the oil and gas column, and the tolerance of the caprock to mechanical deformation (Carles et al., 2010; Shukla et al., 2010) need to be further concerned. The caprock layer, as a confining layer for the rising CO_2 column, must be able to withstand changes in the stress field and physicochemical properties caused by CO_2-brine-rock mineral interactions (Shukla et al., 2010), as shown in Fig. 5(a). Those changing processes continue until the injected CO_2 is fixed and converted to solid carbonate sediment. The strength of rock and seal integrity of caprock may be hindered by tectonic extrusion, stress stretching, seismic activity, mineral precipitation and dissolution. Caprock thickness is particularly important when pressure breaks through the mechanical strength of the caprock. The failure of caprock is the result of the joint action of factors above, and the coupling of many factors damages the integrity of caprock is more worthy of further study.

3.1.2 Fault

Cracks and faults are potential CO_2 flow pathways, as illustrated in Fig. 5(b). Cracks and faults are classified into three main types based on the triggering factors: Fluid mechanics-reactivated fractures or faults, geochemistry-reactivated fractures or faults, and shrinkage fractures (Song and Zhang, 2013). Reactions during and after CO_2 injection create cracks and even reactivate faults. For example, when the formation pressure is too high, or the stress state changes due to large-scale CO_2 injection into deep DOGR, the maximum shear stress acting on the fault surface may exceed the shear strength of the fault, which will activate the originally closed fault or cause the fault plane to slip. In addition, when the fluid pressure near the fault fails to activate the original fault, then new faults can form at weak points (Shukla et al., 2010). When a large amount of CO_2 flows near the cap containing faults, a certain amount of water dissolves in CO_2, which dehydrates the clay minerals in the cap, resulting in the generation of cracks that lead to fault activation (Hager et al., 2021). Dissolution, precipitation, or migration of minerals can cause cracks to broaden or close, but the exact mechanism or possibility of such reactions requires further investigation.

3.1.3 Capillary force

Along with cracks and faults, capillaries are one of the potential pathways of CO_2 migration and leakage. Two-phase fluid flow is strongly affected by the balance of viscous, capillary, and gravity forces (Wang et al., 2023). It occurs mainly at the CO_2-water interface, preventing the upward flow of CO_2. The schematic diagram of capillary action in DOGR is shown in Fig. 6. It could be seen that the buoyancy caused by density differences, the viscous force caused by friction of moving fluids, and the capillary force caused by surface tension between wetting and non-wetting phases jointly dominate the safety of CO_2 storage (Alkan et al., 2010). When the sum of capillary and viscous forces acting on CO_2 in the pores exceeds buoyancy, CO_2 will be trapped and collected into the rock pores. Besides, capillary force, which is not directly related to caprock thickness (Ingram et al., 1997), is influenced by rock surface interaction, wettability, and pore size.

3.1.4 CO_2 dissolution and reactions

There are a variety of acid-sensitive minerals (such as feldspar, mica, magnesium, and iron oxide) and a large amount of formation water in DOGR, which have a great impact on CO_2 storage capacity due to mineralization and dissolution (Hutcheon et al., 2016). In the interaction combination of CO_2, reservoir rock, and formation water, mineralization and storage is mainly controlled by reservoir rock type, formation water temperature, pressure, and salinity. When the pH of the reservoir water decreases due to CO_2 storage, minerals in the rock may dissolve and the ion exchanges occur, forming carbon-containing compounds (Humez et al., 2014; Silva et al., 2015). Dissolution and storage are mainly dependent on formation temperature, pressure, and aquifer salinity (Koide et al., 1992). The solubility of CO_2 in brine increases with increasing pressure and decreasing temperature, and decreases with increasing salinity of the pore fluid (Yu et al., 2015). Min-

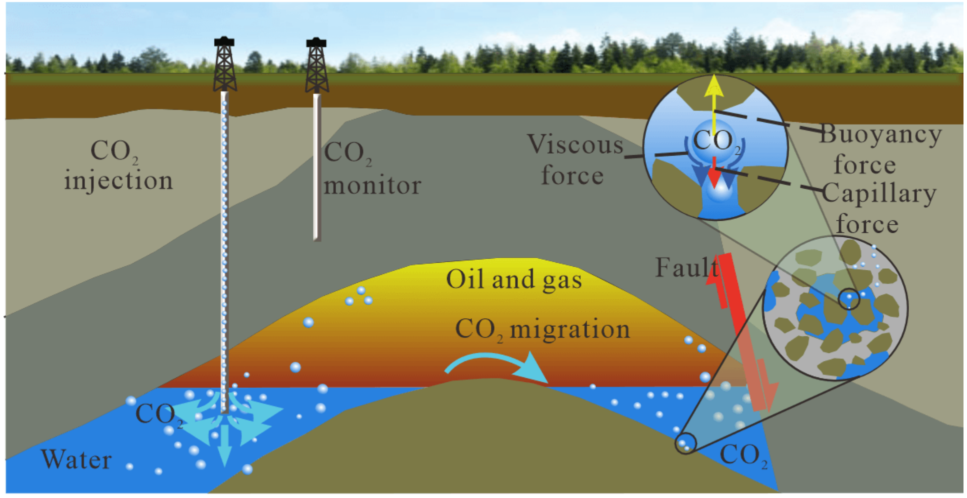

Fig. 6. Possible capillary action in DOGR.

erals can also determine the wettability of CO_2 and influence the sealing effect. Sandstone and limestone, plus pure minerals such as quartz, calcite, feldspar, and mica are strongly water wet in a CO_2-water system, and oil-wet limestone, oil-wet quartz, or coal is intermediate wet or CO_2 wet in a CO_2-water system (Iglauer et al., 2015; Iglauer and Al-Yaseri, 2021).

3.1.5 Wettability

When CO_2 is injected and storage in DOGR, a three-phase system of CO_2-rock-water is formed (Lu et al., 2021), as shown in Fig. 7. The characteristics of wettability on the surface of minerals at different contact angles are shown in Fig. 8. Wettability directly impacts injectivity, containment security, structural and capillary trapping capacities, and indirectly impacts dissolution and mineral trapping capacities (Iglauer et al., 2015). Compared to hydrophobic rocks, hydrophilic rocks may trap more CO_2, and for instance, in structural trapping, hydrophobic rocks limit the ability of CO_2 to enter overlying low permeability strata, leading to difficulties in CO_2 injection. The contact angle is an important factor in the simulation process of CO_2 seepage; however, currently in relevant simulation studies, the direct quantitative relationship from macro- to micro-scale between contact angle and the simulation of CO_2 seepage has not been deeply studied.

3.1.6 Salt precipitation

Salt precipitation is a coupled process of gas-liquid seepage and mineral crystallization. Under the effect of mass transfer between CO_2 and water phases, the water molecules constantly evaporate and diffuse into CO_2, resulting in the precipitation of dissolved salt in the formation water (Cui et al., 2023). Salt precipitation during CO_2 injection into subsurface geological formations occurs mostly at near-wellbore regions where CO_2 moves at higher flow rates (Miri and Hellevang, 2016; He et al., 2023).

The general process of salt precipitation can be classified as salt crystallization (gas-liquid flow and mass transfer), migration (CO_2 driven), and aggregation (accumulation at the pore throat) (Fig. 9). Previous scholars have found that the convection of water and CO_2 may induce salt precipitation at faults (Song et al., 2014; Chu et al., 2019; Zhang et al., 2023).

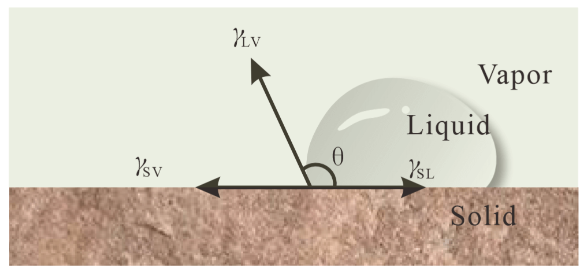

Fig. 7. Three interfacial force tensions acting on a water drop on a rock surface. γ_{LV} is the interfacial tension in liquid-vapor (water-CO_2); γ_{SL} is the interfacial tension in solid-liquid (rock or mineral-water); γ_{SV} is the interfacial tension in solid-vapor (rock or mineral-CO_2).

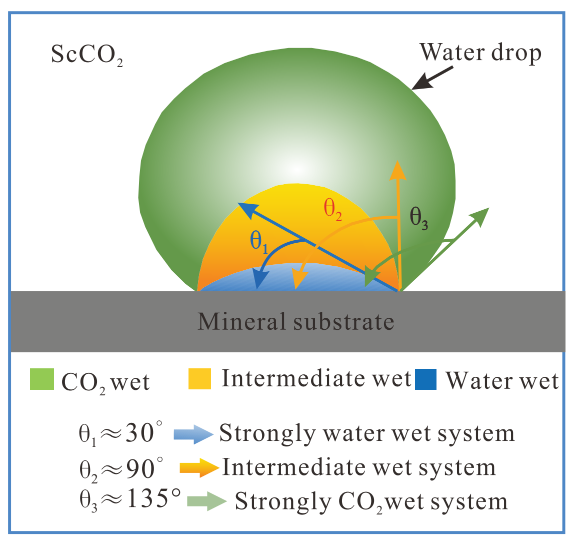

Fig. 8. Wetting changes caused by different contact angles in the presence of three phases ($ScCO_2$-water-mineral) (Iglauer et al., 2015).

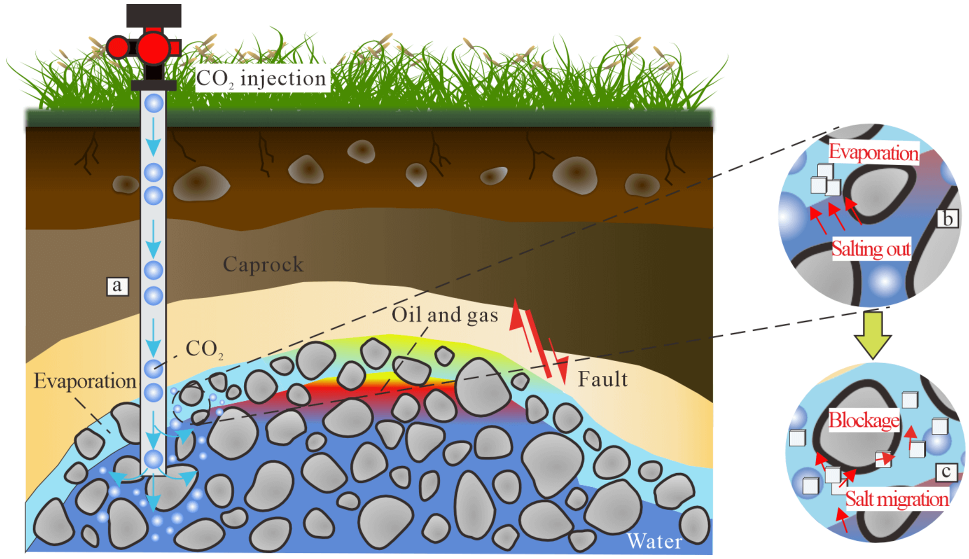

Fig. 9. Schematic diagram of in DOGR (modified from Cui et al. (2023)). (a) CO_2 is injected into the reservoir, (b) mass transfer leads to the evaporation of saline water, resulting in salt precipitation and (c) the migration of CO_2 drives the transfer of salt precipitation and blockage occurs at the throat.

Salt precipitation near faults will effectively reduce the possibility of CO_2 migration and leakage upwards through faults. Currently, there are no field reports on salt precipitation during the CO_2 injection into oil reservoirs (Akindipe et al., 2022). However, it has been reported that salt precipitation occurs around the injection well in salt water of DOGR under high-temperature and high-pressure conditions (Cui et al., 2016). Most experimental and numerical studies on salt precipitation in porous rocks so far have not accounted for the presence of an oil phase (Sun et al., 2020). The research on multiphase flow of gas, oil, and water is mostly in the experimental observation stage (Jiang et al., 2022a). Moreover, indoor experiments often use high porosity and permeability sandstone, and the phenomenon of salt precipitation in low permeability or carbonate rocks is still unclear (Cui et al., 2023). In summary, the micro mechanism of salt precipitation has not been fully revealed in DOGR, particularly for the salt precipitation mechanism considering the coexistence of water, oil, and gas in three phases.

3.2 Engineering factors

3.2.1 Well integrity

Well leakage is a high-risk approach for CO_2 leakage (Carroll et al., 2017) (Fig. 10). Wellbore integrity has been identified globally as a key technical element related to the risk assessment of potential geological carbon storage sites. CO_2 injection wells in DOGR, which are old or abandoned wells, and combing with that CO_2 may also cause severe corrosion of the wellbore (Bai et al., 2014), may lead to leakage risk (Orlic, 2009).

The integrity of cement plays an important role in ensuring the integrity of wells. Any defect in the combination of rock cement casing may generate paths for leakage. Due to diffusion and percolation phenomena, CO_2-containing fluids penetrate into the cement matrix (Haghi et al., 2017), leading to the deformation and degradation of the cement matrix (Carey et al., 2010). In the cylindrical cement matrix covering the steel casing of the wellbore, the penetration of CO_2 has led to the formation of a series of concentric regions with different characteristics (Carroll et al., 2016), namely the unchanged cement region, cement dissolution region, calcium carbonate precipitation region and amorphous porous silica gel region (Bagheri et al., 2019; Panduro et al., 2020). Near the cement salt water interface, the precipitation rate of calcite is greater than the dissolution rate of cement, and calcium silicate hydrate is formed in this area, leading to the re-dissolution of calcite, which makes the pores larger and increases the possibility of leakage (Chen et al., 2004). In addition, chemical reactions and mechanical changes in the cement matrix can lead to its radial cracking or radial compaction, which increases the risk of CO_2 leakage (Bagheri et al., 2019). Composite materials such as corrosion-resistant cement and acid-resistant corrosion alloys could be applied to ensure no leakage.

3.2.2 Injection pressure

Repressurizing DOGR to a pressure level below or equal to the initial reservoir pressure often reverses the stress changes caused by depletion, causing changes in the elastic properties of the cap and leading to cap failure (Orlic, 2016). The pore and osmotic pressure of the reservoir will also change with the changes in stress and pressure, which may lead to capillary leakage in the cap. When capillaries are distributed in CO_2-injected high-pressure formations, overpressure of the reservoir may cause physical damage or the occurrence of micro-fractures of the cap, resulting in the forming of tension fractures and cap rupture.

Though how the afore-mentioned factors influence the CO_2 storage effect has been well analyzed, the link between the

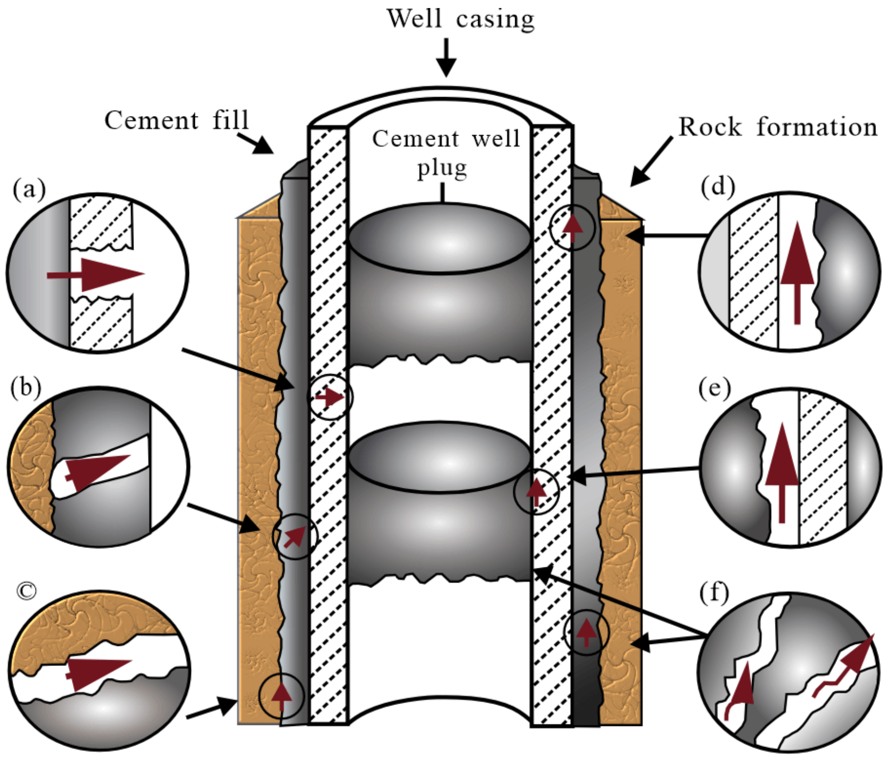

Fig. 10. Potential leakage paths along the existing wellbore. (a) Through the casing, (b) through cracks in the cement wall, (c) between cement wall and formation rock, (d) and (e) between cement and casing and (f) through cement plug, modified from Recasens et al. (2017).

trapping mechanism on a micro-scale and the macro storage effect has not been well elaborated. For instance, the micro mechanism by which supercritical CO_2 alters the surface wettability of rocks in the CO_2-water-oil three phases system is not yet clear, especially for the micro- and nano-pore structure under reservoir conditions, leading to difficulties in storage effect evaluation and storage volume calculation in macro-scale. The leak processes of CO_2 through faults have been qualitatively analyzed; however, the leak pathway and its dynamic on a micro-scale have not been well clarified. Hence, the link between the trapping mechanism on the micro-scale and storage effect on the macro-scale for DOGR needs to be established in the future.

4. Trapping mechanisms

As shown in Figs. 11-12, the typical trapping methods include structural trapping (also called stratigraphic trapping or hydrodynamic trapping), capillary trapping (also called residual trapping), solubility trapping, and mineralization trapping (Jiang et al., 2022b).

4.1 Structural trapping

Structural trapping is the primary trapping mechanism (Cao et al., 2020; Wu et al., 2020; Zapata et al., 2020). The injected CO_2 can exist in the subsurface as a supercritical state. Part of the free-phase CO_2 can be physically trapped in various structural or stratigraphic features of the formations, for instance, anticline folds or sealed fault blocks, as illustrated in Fig. 11(a) (Zapata et al., 2020; Ali et al., 2022). Due to the difference in CO_2 density and the formation water and the imbalance between capillary force and buoyancy, free CO_2 moves upwards and accumulates under the impermeable caprock, forming a CO_2 plume. However, due to the changes in reservoir structure caused by depletion and CO_2 injection, the safety of this trapping mechanism needs further study.

4.2 Capillary trapping

When CO_2 is injected into a subsurface formation, the dynamic of the two-phase flow of the water-CO_2 system is affected by capillary forces. Capillary pressure effect can cause the CO_2, as a non-wetting phase, to be disconnected/snapped off and residually trapped within the pores (Altman et al., 2014), as showed in Fig. 11(b). Fundamentally, once the nonwetting phase is isolated in the narrow and small pore spaces, it remains trapped by capillarity for permanent immobilization (Cai et al., 2021; Ali et al., 2022; Liu et al., 2022). Furthermore, the amount of capillary trapping is directly dependent on the endpoint saturations of the saturation functions that determine the relative permeability and capillary pressures (Zapata et al., 2020). After tertiary oil recoveries, there is a large amount of multiphase fluid in the reservoir. When CO_2 is injected, due to the difference in fluid density, the competition for pores is suspended with CO_2 injection, and the fluid makes a “piston” movement in the pores. Finally, when CO_2 injection reaches the set injection amount, the above movement is not continued, and the CO_2 could be permanently fixed.

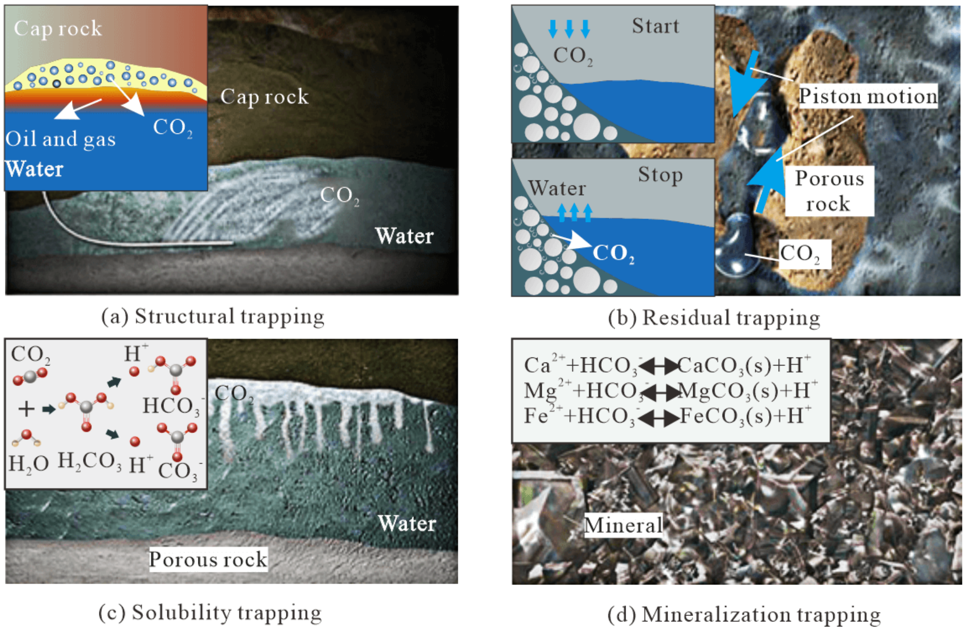

Fig. 11. Four kinds of trapping mechanisms of CO_2 storage in DOGR (Zhao et al., 2014). (a) Free CO_2 is trapped by impermeable caprocks, (b) as CO_2 is injected and stopped, CO_2 undergoes "piston motion" in the pores, (c) CO_2 dissolved in formation water and (d) anions generated by CO_2 dissolution react with metal cations in formation water to form minerals.

4.3 Solubility trapping

The dissolution of CO_2 in formation fluid is commonly referred as solubility trapping (Li et al., 2020) (Fig. 11). Due to the diffusion process of molecules, the structure and residual trapped CO_2 dissolve at the brine interface and the residual oil interface. In addition, less oil is left, and the diffusion coefficient of CO_2 in brine is 3-7 times that of oil (Ao et al., 2019). Therefore, the solubility trapping of DOGR is mainly composed of CO_2 dissolved in brine. The CO_2 dissolution in the brine phase causes an increase in the brine density by 0.1%-1% depending on the reservoir conditions, this results in system instabilities and convective mixing appearing by density-driven natural convection (Kumar et al., 2020). This process not only reduces the free CO_2, but also dissolves the process so that the CO_2 produces mass transfer, improving the capacity of structure and capillary trapping (Gutiérrez and Lizaga, 2016).

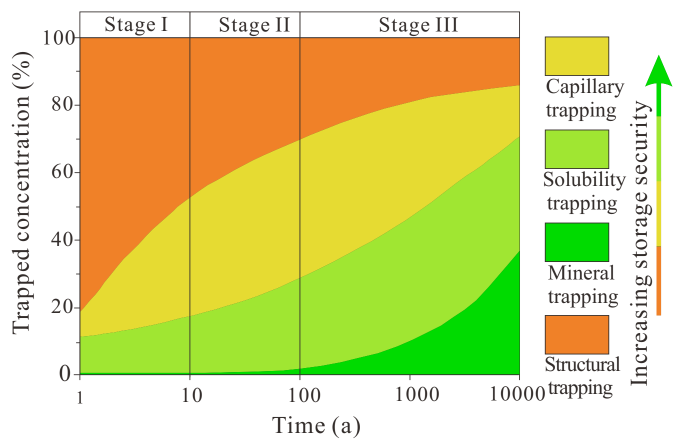

Fig. 12. The concentration of four CO_2 trapping mechanisms with time (Gholami et al., 2021).

4.4 Mineralization trapping

When the injected CO_2 dissolves into the formation water (brine), it forms weak carbonic acid, which further reacts with the surrounding minerals or organic materials to form solid carbonate mineral. It is known as mineralization trapping (Zhang and Song, 2014) (Fig. 11(d)). Reactions will occur during mineralization (Eqs. (1)-(9)):

$$CO_2 + H_2 \rightarrow H_2CO_3 \tag{1}$$

$$H_2CO_3 \rightarrow H^+ + HCO_3^- \tag{2}$$

$$Ca^{2+} + HCO_3^- \rightarrow CaCO_3(s) + H^+ \tag{3}$$

$$Mg^{2+} + HCO_3^- \rightarrow MgCO_3(s) + H^+ \tag{4}$$

$$Fe^{2+} + HCO_3^- \rightarrow FeCO_3(s) + H^+ \tag{5}$$

$$\begin{aligned} NaAlSi_3O_8(s) + H_2O + CO_2 \rightarrow 3SiO_2(s) \\ + NaAlCO_3(OH)_2(\text{Dawsonite})(s) \end{aligned} \tag{6}$$

$$\begin{aligned} \text{Feldspar}(s) + H^+ + H_2O \rightarrow \\ (K^+, Ca^{2+}, Na^+) + Al^{3+} + H_4SiO_4 \end{aligned} \tag{7}$$

$$Al_2Si_2O_5(OH)_4(s) + 6H^+ \rightarrow 2Al^{3+} + SiO_2(s) + 5H_2O \tag{8}$$

$$\begin{aligned} \text{Illite}(s) + H^+ \rightarrow 2.3Al^{3+} + 0.6K^+ \\ + 0.25Mg^{2+} + 3.5SiO_2(s) + H_2O \end{aligned} \tag{9}$$

The dissolution of CO_2 forms a weak carbonic acid environment, and geochemical reactions will produce secondary mineral precipitation, as Ca-Mg-Fe carbonates (Ding et al., 2018) and dawsonite (Kumar et al., 2020) (Eqs. (1)-(6)), the above reactions may occur in a relatively shorter period of time in carbonates compared to silicate minerals which might be related to variation of pressure and temperature (Raza et al., 2015). These may reduce the porosity of the reservoir, which improves the sealing performance of the cap. In addition, CO_2 plumes formed by aggregation below the caprock interact with minerals in the caprock (Eqs. (7)-(9)). These may result in weakened lid stability, allowing CO_2 plumes to migrate along the resulting pores or fissures. The dissolution and precipitation of minerals depend on temperature, pressure, pH, and other geochemical conditions of the reservoir (Wu et al., 2020). Mineralization trapping is the safest style compared to other trapping mechanisms in terms of sequestration effectiveness and long-term sequestration.

4.5 Mechanisms of different storage stages

This section proposes multi-processes mechanisms for DOGR based on the four main mechanisms of CO_2 trapping. CO_2 trapping mechanisms in three main storage processes are elaborated (Fig. 12): (1) Structural trapping stage (0-10 years). First, after CO_2 injection into DOGR, CO_2 diffuses laterally and migrates upwards due to differences in density between CO_2 and formation fluids (Al-Khdheeawi et al., 2017). In this stage, CO_2 is not entirely dissolved into groundwater or oil, and it may be constrained by structural trapping exerted by cap rock. The undissolved CO_2 also could be trapped under the impermeable cover layer due to the structural trapping; (2) solubility and capillary trapping stage (10-100 years). Subsequently, after dissolution in formation water or crude oil, CO_2 could change the surface electrical properties of rocks that lead to the forming of hydrophilic reservoir rocks (Chen et al., 2023), which promotes dissolution trapping. The dissolution of CO_2 in residual oil and the forming of a miscible state of the CO_2-resudial oil system are also beneficial for CO_2 trapping; (3) coupling trapping stage. During the long-term processes after injection, CO_2 that is dissolved in water undergoes a geochemical reaction, and in this process, CO_2 reacts with ions (magnesium, calcium, iron) in brine to generate mineral precipitation, leading to the forming of CO_2 consolidation. In this stage, structural trapping, solubility trapping, capillary trapping and mineralization trapping coexist and the coupling effects of those for promote the long term storage of CO_2.

Though the storage mechanisms proposed above are comprehensive; however, the coupling mechanism of CO_2 trapping of DOGR, particularly in micro- or even nano-scale under high temperature and high pressure, is scarcely clarified. For instance, the direction of CO_2 diffusion and migration is difficult to identify under high temperature and pressure environments, due to that the CO_2 phase and the density difference between CO_2 fluids and formation water may be highly variable. In addition, the coexistence of multiple fluids (such as CO_2, hydrocarbon gas, formation water, and residual oil) and different types of minerals, such as clay and carbonate, may lead to a highly variable and heterogeneous CO_2 consolidation reaction, leading to unclear CO_2 trapping scope. It is necessary to reveal the microscopic mechanisms of CO_2 mobility and solubility as well as phase change law under complex geological conditions.

5. Procedures for storage potential evaluation in DOGR

Estimates of CO_2 storage potential can be divided into national, regional, basin, and formation scales (Goodman, 2012), indicating that storage potential evaluation of CO_2 storage in DOGR with different scales should be considered. Based on the fuzzy analytic hierarchy process, previous scholars have established five hierarchical architectures, including country-scale evaluation, basin-scale evaluation, regional-scale evaluation, local-scale evaluation, and site-scale evaluation (Bachu et al., 2004; Bachu et al., 2007; Gao et al., 2009; Zhang et al., 2009; Zhu, 2015). Currently, there is no unified conclusion on the evaluation method and index system of CO_2 geological storage potential. Considering that the suitability evaluation of the geological conditions of the basin provides basic data for selecting CO_2 storage sites, reservoir selection evaluation is the core object determining the storage effect, and storage security evaluation and storage capacity calculation are important evaluation stages, the evaluation procedure for storage potential evaluation of CO_2 storage in DOGR is divided into four aspects in this review, which are basin selection evaluation stage, reservoir selection evaluation stage, storage security evaluation, and storage capacity calculation stage.

5.1 Evaluation at the basin scale

At present, the suitability evaluation of CO_2 storage in basin scale is rarely based on multiple indicator evaluation systems. In addition, the suitability evaluation of the geological conditions of the basin provides basic data for selecting CO_2 storage sites. Hence, with the purpose of tapping potential sites for CO_2 storage, the evaluation stage at the basin scale is necessary. Sun et al. (2021) established an evaluation system for the suitability of CO_2 storage under a larger framework by taking basins as the unit, then classified the potential of major sedimentary basins in China (Supplementary Material B). Yang et al. (2019) established the CO_2 geological selection storage evaluation system (Supplementary Material C), in which the weight of each evaluation indicator was determined by an analytic hierarchy process. Fig. 13 shows the indexes considering geological factors, geothermal gradients, geological disasters, hydrodynamic conditions, resource potential, basin maturity, and economic and social characteristics.

The objective weight ratio of the above criteria to the target geological conditions depends on human causes (such as the number of indicators and the scoring criteria). For specifically selected areas, indexes should be increased or decreased, which will have an impact on the total storage potential of the selected areas as there is no management organization related to storage. For the future development of the selected area, other factors (such as development scale and nature of business) need to be re-considered.

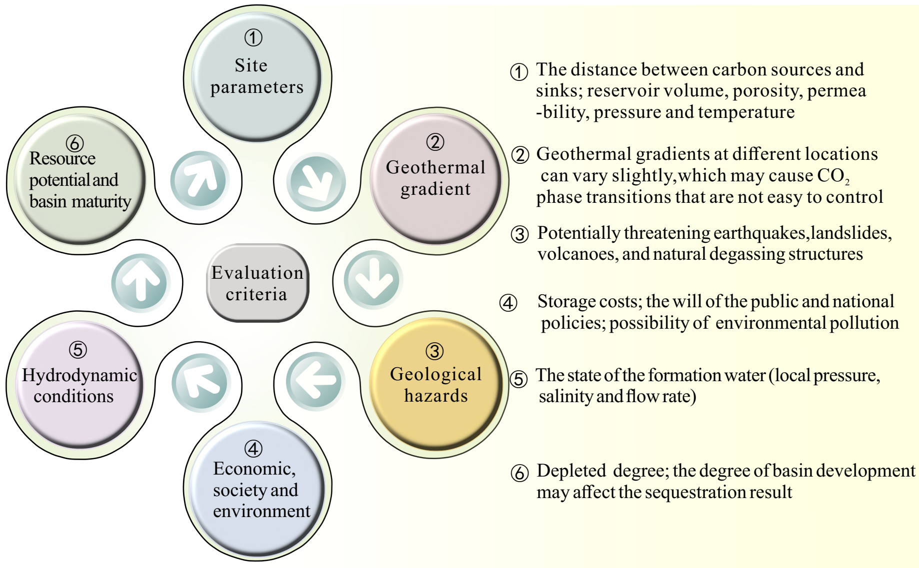

Fig. 13. Basin selection evaluation system criteria.

Table 1. The indicators for CO_2 storage in oil and gas reservoirs.

References	Criteria	Advantages and (or) disadvantages
Shaw and Bachu, 2002	The compatibility of CO_2 and CO_2 EOR, storage technology, evaluation of EOR, and storage capacity.	The proposed parameters have a significant impact on the feasibility of CO_2 EOR, while the cost and safety of storage are not considered for storage.
Kovscek, 2002	Reservoir capacity, oil-water volume, CO_2 density, formation thickness, permeability.	The reservoir with an initial pore pressure gradient of less than about 17.4 kPa/m was identified as a good storage point.
Solomon, 2006	Injection depth, CO_2 and brine density, reservoir properties, impurities, and storage time.	Key factors such as storage costs and oil-water volume have not yet been taken into account.
Yang et al., 2016	Depth, temperature, pressure, porosity, oil gravity, residual content.	The source of parameter data is sufficient, and the calculation of storage capacity is simple.
Raza et al., 2016	Show in Supplementary Material D.	The distinction between storage cost and depleted reservoir capacity is vague.
Mi et al., 2018	Depth, reservoir thickness, reservoir lithology, porosity, permeability.	A basis for evaluating the suitability of oil and gas reservoir storage was provided, but it lack on-site-level evaluation indicators.

5.2 Evaluation at the oil and gas reservoir scale

Not all oil and gas reservoirs can be CO_2 stored, so it is necessary to establish storage potential evaluation at the oil and gas reservoir scale. Previous scholars proposed multiple index characterizations for evaluating oil and gas reservoirs that could be used for CO_2 storage (Table 1). They systematically and comprehensively summarized and classified the evaluation indicators for DOGR (Supplementary Material D), which can serve as a reference standard for future evaluation of DOGR. Based on the results of the second and third natural gas reserve assessments of China, Liu et al. (2006) calculated the CO_2 storage capacity of gas fields in major basins of China, which is approximately 304.83×10^8 t (Table 2).

5.3 Storage security evaluation

Over time, reservoir rocks are exposed to supercritical CO_2 for a long time, which may change the mineralogy, pore structure, mechanics, rock surface wettability, and other properties of the reservoir (Ozotta et al., 2021). This may lead to direct (failure of caprock integrity, wellbore failure, and fault activation) and indirect (changes in injection pressure and rock properties) leakage of CO_2. Therefore, it is necessary to conduct a storage safety risk assessment on the selected oil and gas reservoirs. However, the details and choices of risk assessment methods themselves are often arbitrary (Arild et al., 2017). There have been multiple reports on plans for assessing storage risk, which can be broadly divided into quantitative methods (such as CQUESTRA model (Carbon dioxide sequestration (Zhang et al., 2011) and an integrated as-

Table 2. Calculation and comparison of CO_2 storage in major oil and gas-bearing basins in China.

Basin	Result of Stevens (1999)		Result of Liu et al. (2006)	
	Recoverable resources/10^8 m^3	Capacity/10^8 t	Recoverable resources/10^8 m^3	Capacity/10^8 t
Bohai bay	5,861.59	16	5,411.94	14.46
Songliao	3,313.07	8	1,466.40	6.25
Tarim	9,910.90	22	20,790.42	26.78
Junggar	2,944.95	6	5,179.02	15.95
Sichuan	11,553.27	24	24,494.08	58.87
Ordos	8,098.62	35	35,609.60	85.88
Yinggehai	5,210.30	11	9,504.00	37.47
Total	46,892.70	122	102,455.46	245.66

sessment model by national risk assessment partnership (Pawar et al., 2016)) and qualitative methods (such as features, events, processes (FEP) (Duguid et al., 2021) and bowtie method which is widely used in the oil and gas industry assessments (Arild et al., 2017)). Due to the need for specific case data for quantitative evaluation and the recommendation of qualitative evaluation methods in combination with guidelines, this article adopts the bowtie method based on FEP features for risk assessment of CO_2 storage safety in DOGR.

The FEP method is a system risk assessment method constructed by creating system attribute features or components, discrete events that affect system feature attributes or components (with short duration), and continuous changes in interactions between different events (with long duration). The FEP database consists of 8 categories: (1) Assessment basis; (2) external factors; (3) CO_2 storage; (4) CO_2 properties, interactions & transport; (5) geosphere; (6) boreholes; (7) near-surface environment; (8) impacts. The bowtie method is named after a central top event, where the cause of the top event (to the left of the top event) and the result of the top event (to the right of the top event) are constructed in a bowtie shape (Arild et al., 2017) (Supplementary Material E). The identified risk source elements are evaluated by the bowtie method. There are multiple elements in a system, and each element is evaluated as a top event by bowtie. Here, taking the well failure element as an example to evaluate the CO_2 storage safety system, due to that wellbore integrity has been identified as a key technical element related to the risk assessment of potential geological carbon storage sites. The evaluation workflow is shown in Fig. 14. In this case using the bowtie method, the failure causes of well sealing are dangerous sources, including several risk factors such as new drilling activities, abandoned well, and casing failure. If preventive measures are not exerted, the top event, which is well failure, could happen, leading to the occurrence of risk consequences such as near-surface pollution. If the remedial measures are not exerted after the top event, CO_2 leakage on a large scale may happen. The bowtie method based on FEP features can conduct the risk assessment for CO_2 storage security in DOGR comprehensively.

5.4 Storage capacity calculation

Assessing the storage capacity of CO_2 at storage sites is one of the prerequisites for ensuring the effective and safe implementation of carbon storage projects. This paper summarizes the calculation methods of CO_2 storage capacity proposed by previous agencies or scholars (Supplementary Material F). According to the resource pyramid conceptualized model by Bachu et al. (2007), the storage capacity is divided into theoretical storage capacity, effective storage capacity, practical storage capacity, and matched storage capacity. The factors considered by the latter two cannot be quantified due to the need for consideration of laws, policies, monitoring, and injection capabilities. The effective storage capacity is a subset of the theoretical capacity and is obtained by applying a range of geological and engineering cut-off limits to a storage capacity assessment. Therefore, the first two are discussed in sections 5.4.1 and 5.4.2, respectively.

5.4.1 Theoretical storage capacity calculation

(1) Carbon storage leadership forum method

Proposed by the carbon storage leadership forum (CSLF), this method is based on the original oil in place (OOIP) method for estimating theoretical storage capacity (Bachu et al., 2007) (Eq. (10)). The method can be modified based on the geometry of the reservoir (Eq. (11)). The assumption is that the space vacated after oil and gas production is effectively used for CO_2 storage:

$$M_t = \rho_r \left(R_f T_o B_o - V_{iw} + V_{pw}\right) \tag{10}$$

$$M_t = \rho_r \left[R_f A \varphi \left(1 - S_{wi}\right) \times 10^{-6} - V_{iw} + V_{pw}\right] \tag{11}$$

where M_t is the theoretical storage capacity of the depleted oil reservoir; ρ_r is the density of CO_2 under reservoir conditions; R_f is the recovery factor of crude oil; T_o is the original geological reserve of crude oil; B_o is volume factor; V_{iw} is the amount of water injected into the reservoir; V_{pw} is the amount of water produced from the reservoir; A is the reservoir area; φ is the reservoir porosity; S_{wi} is the irreducible water saturation of the reservoir.

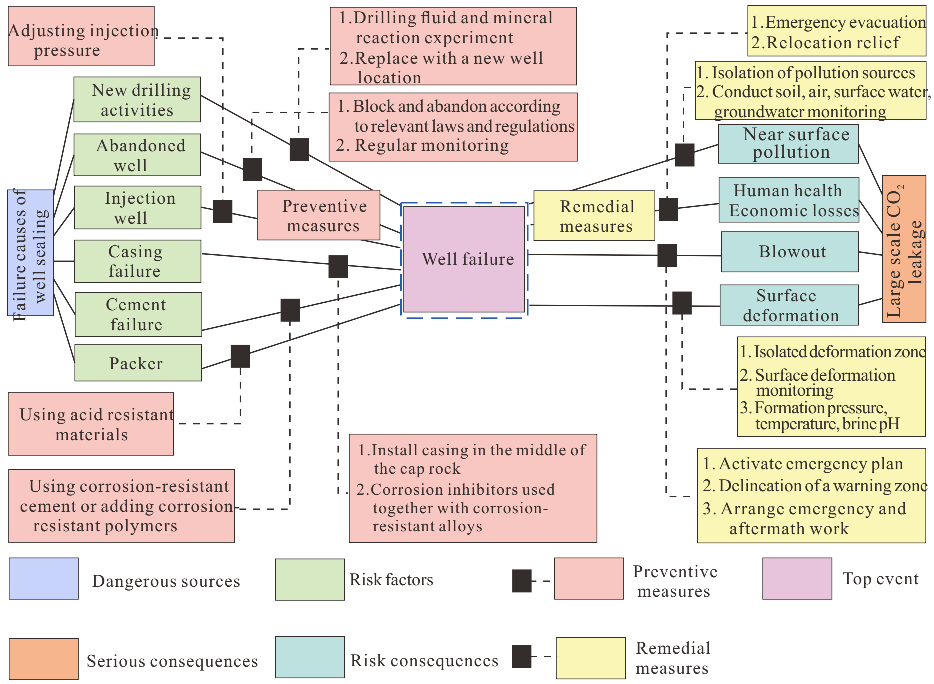

Fig. 14. Risk analysis workflow of the bowtie method.

The above method does not consider the solubility of CO_2 in crude oil and formation water. Shen et al. (2009) supplemented Eq. (11)with the same assumptions as above, fully considering the solubility capacity of CO_2 in crude oil and formation water, it is estimated that the total amount of CO_2 storage in Block H of an oil and gas reservoir in China is 14.98 Mt.

(2) US Department of Energy method

The US Department of Energy has proposed an algorithm for estimating capacity volume based on Original Natural Gas in Place and OOIP (Goodman et al., 2011), as displayed in Eq. (12). It is assumed that the reservoir is not in contact with the aquifer, and the oil and gas production space is used for CO_2 storage:

$$G_e = \rho_{rs} A h \varphi B_o (1 - S_{wi}) E_{og} \tag{12}$$

where G_e is the estimated amount of geological storage CO_2, ρ_{rs} is the standard CO_2 density; h is the average thickness; E_{og} is the storage efficiency coefficient, which is generally calculated by CO_2 EOR experience or according to reservoir simulation.

(3) Zhao and Liao's method

Based on the CSLF method, Zhao and Liao (2012) proposed a model for estimating the CO_2 storage capacity of high water-cut oilfields. The model considers the CO_2 solubility trapping method in oil and water, and introduces a CO_2 sweep coefficient to better simulate the CO_2 contact with remaining oil. The storage capacity calculation methods are expressed as:

$$M_t = M_d + M_{io} + M_{iw} \tag{13}$$

$$M_d = \rho_r \left(R_f T_p - V_{iw} + V_{pw}\right) \tag{14}$$

$$M_{iw} = E_f \rho_r \left(T_w + V_{iw} - V_{pw}\right) D_{iw} \tag{15}$$

$$M_{io} = E_f \rho_r T_o \left(1 - R_f\right) D_{io} \tag{16}$$

where M_d is the storage capacity during CO_2 flooding; M_{iw} is the storage capacity when CO_2 is dissolved in water; M_{io} is the storage capacity when CO_2 is dissolved in crude oil; T_p is the crude oil reserve in the oil reservoir; T_w is the formation water volume in the reservoir; E_f is the sweep coefficient; D_{iw} is the solubility of CO_2 in water; D_{io} is the solubility of CO_2 in oil. Chen et al. (2010) proposed two key solubility coefficients C_{ws} (CO_2 solubility coefficient in formation water) and C_{os} (CO_2 solubility coefficient in crude oil), and carried out an analysis according to this method, their results showed that the total CO_2 storage capacity was 533.58 Mt, and the effective storage capacity was 133.4 Mt for twenty-one oil reservoirs in China.

(4) International Energy Agency method

The International Energy Agency provided a model for estimating the CO_2 storage capacity of natural gas reservoirs, assuming that the post-production reservoir can be reinjected with CO_2 until the formation returns to its original reservoir pressure (pre-production pressure), as displayed in:

$$G_e = \rho_r U B_o E_{og} \tag{17}$$

where U is the ultimate recoverable reserve of natural gas at standard pressure and temperature.

(5) Bachu method

Bachu et al. (2004) proposed a method for calculating storage capacity using CO_2. The method includes two types of status that CO_2 pre-breakthrough (CO_2 does not exit the surface during CO_2 enhanced oil recovery) and post-breakthrough (CO_2 is recovered with crude oil during CO_2 enhanced oil recovery), such as Eqs. (18)-(19).

Before the CO_2 breakthrough:

$$M_t = \frac{\rho_r}{10^9}\left[E_{Rb}Ah\varphi\left(1-S_{wi}\right)-V_{iw}+V_{pw}+C_{ws}\times \left(Ah\phi S_{wi}+V_{iw}-V_{pw}\right)+C_{os}\left(1-E_{Rb}\right)Ah\varphi\left(1-S_{wi}\right)\right] \tag{18}$$

After the CO_2 breakthrough:

$$M_t = \frac{\rho_r}{10^9}\left[\left(0.4E_{Rb}+0.6E_{Rh}\right)Ah\phi\left(1-S_{wi}\right)- V_{iw}+V_{pw}+C_{ws}\left(Ah\phi S_w+V_{iw}-V_{pw}\right)+C_{os} \left(1-0.4E_{Rb}-0.6E_{Rh}\right)Ah\phi\left(1-S_{wi}\right)\right] \tag{19}$$

where E_{Rb} is the recovery factor of crude oil before CO_2 breakthrough; E_{Rh} is the recovery factor of crude oil when a certain volume of CO_2 is injected.

5.4.2 Effective storage capacity calculation

The effective storage capacity is a subset of the theoretical storage capacity calculation, which mainly considers the influence of factors such as buoyancy, gravitational override, mobility ratio, heterogeneity, water saturation, and water body strength. The calculation method is expressed as Eq. (20) (Bachu et al., 2007; Shen et al., 2009; Zhu, 2015):

$$M_e = C_e M_t = C_m C_b C_h C_w C_a M_t \tag{20}$$

where M_e is the effective storage capacity of CO_2 in the reservoir; the subscripts m, b, h, w, and a stand for mobility, buoyancy, heterogeneity, water saturation, and aquifer strength, respectively, and the coefficient C_e is a single effective capacity coefficient that incorporates the cumulative effects of all the other. Most effective storage coefficients need to be obtained by numerical simulation (Bachu et al., 2004). Based on this research basis, Zhao et al. (2013) introduced a storage coefficient to make the calculation of effective storage capacity more accurate. According to this method, they calculated that the CO_2 storage capacity of block B1 of Xinjiang Oilfield, China, is 65 Mt, and the effective storage capacity is 39 Mt.

Though methods to calculate CO_2 storage capacity have been proposed, some parameters which are crucial to the calculating results are not easy to determine. For instance, the effective storage capacity estimation equation includes an effective storage capacity coefficient C_e, which is difficult to determine because it is influenced by mobility, buoyancy, heterogeneity, water saturation, and so on. Some of the methods introduced above are based on the CLSF method, which takes the dissolution coefficient into account; however, it lacks the considerations of heterogeneous dissolving of CO_2 in DOGR. It is suggested to calculate capacity based on a multi-physics field reservoir numerical model considering heterogeneous parameters. Considering the data derived based on gas and oil exploration and development, workflows for calculating CO_2 storage capacity are suggested: (1) Develop an actual, heterogeneous, and porous reservoir numerical model using gas and oil exploration and development achievements such as seismic and logging data; (2) determine the heterogeneities of physical and chemical properties such as temperature, pressure, salinity, mineral composition of the model; (3) meshing the model combing finite element or discrete element method; (4) calculate the CO_2 storage capacity of each unit and the total model.

6. Conclusions and prospects

This paper reviewed, elaborated, and analyzed the processes, influencing factors, trapping mechanisms, and storage evaluation methods of CO_2 storage in DOGR. The following conclusions and prospects were addressed:

1) The advantages of CO_2 storage in DOGR are reflected in the storage capacity, sealing performance, accumulation of experiences in reservoir characterization, existing oil and gas well infrastructures, and storage operability, though DOGR which are suitable for CO_2 storage requires various types of assessment. At present, there are few DOGRs which have been exerted for CO_2 storage, and most of them are at the stage of CO_2-enhanced oil recovery. However, the large-scale CO_2 storage in DOGR in the future will be a continuous and feasible as well as effective guarantee for CO_2 storage;
2) Factors influencing storage effect include geological factors (caprocks, faults, capillaries, CO_2 change in water-rock, wettability, salting out) and engineering factors (well integrity, injection pressure). In the future, the link between the trapping mechanism on micro-scale and the storage effect on macro-scale for DOGR needs to be studied and established. The integrity of the well is also an essential issue in ensuring no leakage, and composite materials such as corrosion-resistant cement and acid-resistant corrosion alloys could be applied to ensure no leakage;
3) The CO_2 storage mechanism is classified as structural trapping, capillary trapping, dissolution trapping, and mineralization trapping. However, the coupling mechanism of CO_2 trapping of DOGR, particularly on micro- or even nano-scale under high temperature and high pressure, is insufficiently explained. It is necessary to reveal the microscopic mechanisms of CO_2 mobility and solubility as well as phase change law under complex geological conditions;
4) The evaluation stage of CO_2 storage potential of DOGR can be divided into basin selection evaluation stage, oil and gas reservoir selection evaluation stage, storage security evaluation, and storage capacity calculation stage. It is suggested to calculate capacity based on a multi-physics field reservoir numerical model considering heterogeneous parameters. The workflows for calculating CO_2 storage capacity are suggested: firstly, develop an actual, heterogeneous, and porous reservoir numerical model using gas and oil exploration and development data; secondly, determine the heterogeneities of physical and chemical properties of the model; thirdly, meshing the model using finite element or discrete element method; finally, calculate the CO_2 storage capacity of each unit and the total model.

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Supplementary file

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Conflict of interest

The authors declare no competing interest.

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