




Review article

Progress in Energy Storage of Depleted Oil and Gas Reservoirs: a Perspective Based on Fluid Migration

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Abstract:

Depleted oil and gas reservoirs are important infrastructure for natural gas strategic reserves, CO₂ geological storage, and H₂ large-scale storage. The core scientific problem lies in the migration mechanism of various fluids in complex geological bodies. This article elucidates the controlling role of geological factors on migration behavior from four aspects: pore permeability structure, heterogeneity, rock mechanics properties, and original fluid occurrence. Furthermore, the differences in physicochemical properties of natural gas, CO₂, and H₂ were compared, and based on the characteristics of reservoir space, the research objects were divided into porous matrix bodies, fractured matrix bodies, and cavern injection production well complexes, and the migration laws of different fluids were analyzed separately. Research has shown that H₂ faces dual challenges of water locking and leakage due to its extremely low viscosity and strong diffusivity. CO₂ has strong chemical activity and non-monotonic evolution of permeability driven by dissolution precipitation competition. The physical properties of CH₄ are balanced, and the transport behavior can be predicted. The type of storage space further amplifies the complexity of medium response, with cracks serving as both high-speed channels and leakage risk sources, while karst cave systems exhibit a macroscopic migration pattern dominated by free flow and gravity differentiation. The current bottleneck lies in the fatigue damage induced by injection production cycles, the dynamic evolution of traps under thermal fluid solidification coupling, and the control of complex fracture network seepage. It is urgent to break through cross scale experiments and numerical simulations to provide theoretical support for the safe and efficient operation of reservoirs throughout their entire life cycle.

1 Introduction

Against the backdrop of accelerating global energy transition, underground gas storage is receiving widespread attention as an important technological pathway for regulating the intermittency of renewable energy and achieving large-scale seasonal energy storage. Faced with the rapid growth of renewable energy installed capacity, the IEA predicts that global investment in renewable energy will reach trillions of dollars by

2030, while the traditional oil and gas industry is undergoing structural adjustments under the dual pressure of carbon border adjustment mechanisms and ESG requirements. In this context, building a safe, economical, and scalable underground energy storage system has become a key link in the low-carbon transformation of the energy system (Zeng et al., 2024).

The development of underground gas storage facilities in China has gone through 26 years, marked by the comprehensive

construction of the Dagang Dazhangtuo gas storage facility in 1999. This process has achieved a strategic leap from scratch, from slow to fast, from regional to national networks. Starting from ensuring gas safety in the Beijing Tianjin Hebei region during the initial construction phase, it gradually developed into a key infrastructure to safeguard national energy security and support the flexible peak shaving of natural gas in the “national network”. Among the various types of underground gas storage facilities, (such as depleted oil and gas reservoir type, aquifer type, salt cavern type, and mine pit type, as shown in Fig.1 (Lardhi et al., 2025)), The geological understanding of depleted oil and gas reservoirs is high, with natural sealing properties and large storage and peak shaving capacities, which can be used for seasonal peak shaving and strategic reserves. However, high ground treatment requirements and large bottom gas reserves are required. Aquifer gas storage has a large storage capacity and is the second largest type of gas storage after depleted oil and gas reservoirs. At present, aquifer gas storage facilities are relatively mature in European countries such as France, Germany, and Russia, but the geological understanding is low, the construction period is long, and the construction cost is relatively high. Salt cavern gas storage refers to the use of fresh water to dissolve salt layers and form enclosed salt caverns for storing natural gas. Salt cavern gas storage has good sealing performance, large daily extraction volume, low bottom gas volume, flexible injection production conversion, and can be used for daily and weekly peak shaving. However, this type of gas storage has a relatively small volume, slow expansion speed, and relatively high construction cost per unit effective volume. Mine gas storage is an underground gas storage facility that utilizes abandoned mines that meet gas storage conditions for gas storage. This type of gas storage has a high proportion of working gas volume and can fully recover cushion gas. However, due to the limited number of mines that meet the sealing conditions for gas storage (often requiring lining for renovation), and the limitations of geological conditions for manual excavation, this type of gas storage is not very common. Among numerous geological H₂ storage options, depleted oil and gas reservoirs are widely regarded as one of the most economically feasible and operationally feasible types of underground energy storage sites due to their enormous storage capacity, clear geological and engineering knowledge foundation, and readily available surface facilities (Evro et al., 2025). These reservoirs have undergone long-term oil and gas development, possessing natural sealing and good injection and production conditions. About 73% of global gas storage facilities are built based on depleted oil and gas reservoirs, with working gas accounting for 75% of the total (Zhang et al., 2017; Yang and Wang, 2023). China is also dominated by this type, with 15 gas storage facilities built by the end of 2021, with a total working gas volume of 24.05 billion cubic meters, and depleted gas reservoir types accounting for as much as 95%. This type of gas storage is converted from depleted gas reservoirs or reservoirs (including depleted dry gas reservoirs, condensate gas reservoirs, reservoirs with gas caps, or gas caps with oil rings, as shown in Fig.1). Its development closely follows the pace of national natural gas consumption

growth and pipeline expansion: in the early stage, it focused on mature oil fields near the consumer market such as the Bohai Rim (such as Dagang and North China), accumulating key technologies and experience. Entering the 21st century, especially since 2010, under the strong promotion of national policies and large-scale utilization of natural gas, the construction has been comprehensively accelerated, expanding to major natural gas producing areas such as Sichuan, Xinjiang, Changqing, and central pipeline hubs, forming a multi-regional and multi-level layout, becoming the core pillar of winter peak shaving and supply guarantee for the country. The depleted oil and gas reservoir type natural gas underground storage is shown in Fig.2.

However, the core challenge in transforming depleted oil and gas reservoirs into gas storage geological bodies is the fluid migration behavior of the gas residual fluid rock multiphase system in the reservoir. The transport mechanism of fluids in porous media not only affects the injectability, recoverability, and storage efficiency of H₂ storage facilities, but also relates to safety (such as leakage risk), capacity decay, and long-term operational stability. In recent years, relevant studies have shown that different reservoir media structures, pore types, and their physicochemical properties can significantly affect gas storage processes. For example, the depleted gas reservoir in northeastern Alberta exhibits potential CO₂ reserves of up to 3036.5 Mt and lower leakage risks (Chen, 2025), while other studies have pointed out that the interaction between different gases and rocks and residual hydrocarbons/water can cause significant differences in flow behavior, thereby affecting the overall working capacity of the reservoir (Liu et al., 2024; Kim et al., 2025). In addition, complex pore structure, interface effects, capillary force changes, and fluid dynamics characteristics have been proven to be key factors controlling gas migration and diffusion, as well as core mechanisms affecting the storage efficiency and safety of gas storage facilities (Doan et al., 2024; Lardhi et al., 2025).

Through comprehensive analysis of literature, we can recognize the current research status and future research directions in this field, evaluate cutting-edge research achievements, and provide new perspectives for subsequent technological innovation and practice. Therefore, this review aims to summarize the research progress of scholars from various countries in the reuse of depleted oil and gas reservoirs in recent years, with a focus on analyzing the impact of reservoir fluid migration on the storage capacity and service life of gas storage facilities, in order to provide theoretical support for improving the reuse efficiency of depleted oil and gas reservoirs.

2 Geological control factors of fluid migration in depleted oil and gas storage reservoirs

Fluid migration is the core physical process in the operation of depleted oil and gas reservoirs, and its migration mechanism and mode are directly controlled by the inherent geological conditions of the reservoir and cap rock, mainly including key factors such as pore permeability structure, heterogeneity, rock mechanics characteristics, and the original fluid occurrence state of the reservoir (Bal and Misra, 2024). Therefore, eluci-

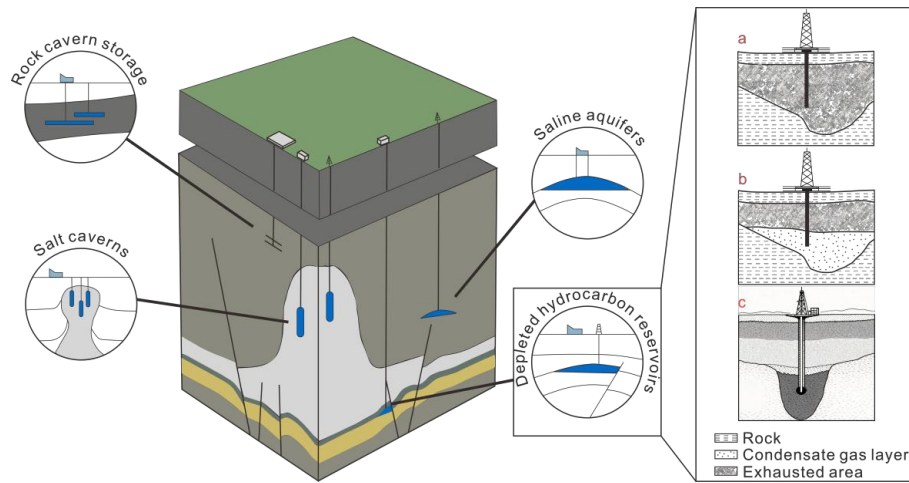


Fig. 1 Types of underground gas storage and depleted oil and gas storage (a, b, c represent depleted dry gas reservoirs, condensate gas reservoirs, and reservoirs with gas caps, respectively) (Lardhi et al., 2025)

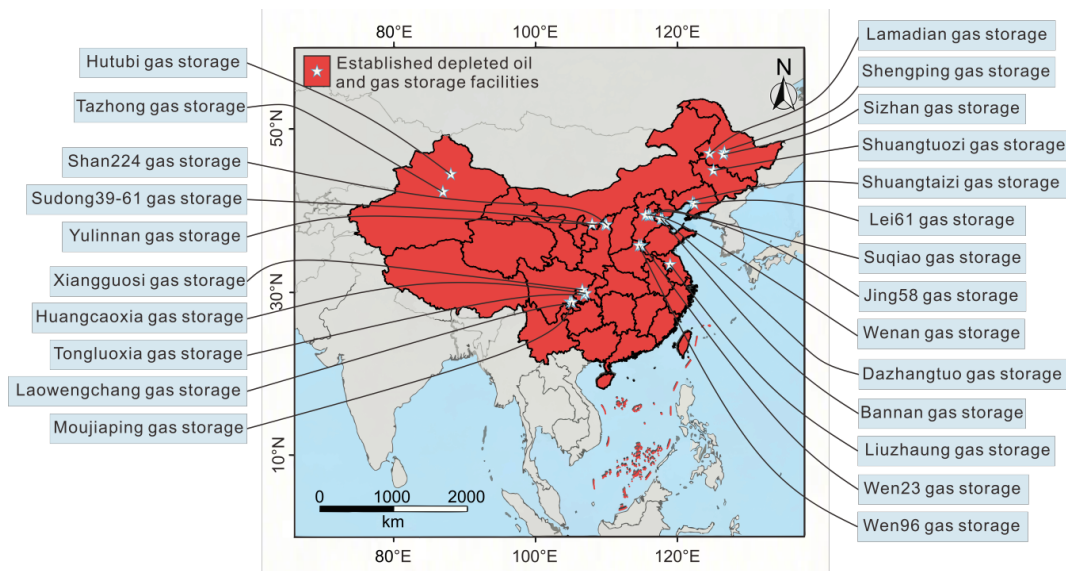


Fig. 2 Distribution range of depleted oil and gas reservoirs in China (MA et al., 2022)

dating the impact of these geological control factors on fluid migration is the foundation for understanding and optimizing the performance of gas storage facilities. This chapter will sequentially explore the four main geological control factors that affect fluid migration in gas storage facilities, which are presented in Sections 2.1 to 2.4.

2.1 Porous structure

The porosity and permeability of reservoirs and cap rocks are the core physical parameters that determine the injection and production capacity, inventory scale, and working gas efficiency of gas storage facilities for the reconstruction of depleted oil and gas reservoirs (Wei et al., 2026). After long-term mining and subsequent periodic injection and production operations, its porosity and permeability characteristics inherit the geological background of the original oil and gas reservoir, and present unique dynamic evolution laws.

The reservoirs of depleted oil and gas reservoirs are mostly

composed of clastic rocks and carbonate rocks. The classification of clastic rock reservoirs considering porosity and permeability is shown in Tab.1. Carbonate rocks often have the same porosity but different permeability due to differences in pore types and connectivity, so this reservoir is not classified. In clastic reservoirs such as sandstone, the pore structure is mainly composed of primary intergranular pores, which have the characteristics of relative homogeneity and good permeability. The porosity range is mostly between 12% and 30%. Both porosity and permeability show an increasing trend with the increase of rock particle size (taking Shuang 6 gas storage, located in the Liaohe oilfield of China as an example) (Qiu et al., 2023): the porosity of siltstone is about 8.35-13.32%, and the permeability is about 0.565-21.33mD. The porosity of fine-grained sandstone is about 3.7%, and the permeability is 9.553 mD. The porosity of medium grained sandstone is significantly higher, at 16.19-21.87%, and the permeability is about 50.12-

Tab. 1 Classification of detrital reservoirs considering pore throat characteristics (MA et al., 2022)

Reservoir category	Pore type	Porosity (%)	Permeability (mD)	Pore throat characteristics	Reservoir type
I	Mainly dissolution pores, with less cement and clay minerals	>20	>100	Good pore connectivity, with a maximum connected pore throat >1.2μm	High porosity and medium permeability reservoir
II	Micro pores are predominant, followed by intergranular pores and intragranular pores	13~20	10~100	The pore throat radius is not large, and the maximum connected pore throat is 1.13~1.2μm	Mesoporous and permeable reservoir
III	Micro pores are predominant	4~13	1~10	The maximum connected pore throat is 1.1~1.13μm	Medium low porosity and low- permeability reservoir
IV	Micro pores are predominant	<4	<1	Maximum connected pore throat <1.1μm	low porosity and low- permeability reservoir

65.14mD. The porosity of conglomerate is about 17.59%, and the permeability is as high as 235.4mD. The porosity of carbonate reservoirs varies greatly, and the primary porosity is usually low (often below 10%). However, after secondary dissolution transformation, it can significantly increase to 15% 25% or even higher. The pores of this type of reservoir can be divided into two categories based on their genesis and structure: primary pore type and secondary pore type. The primary pore type is mainly intergranular pores, with relatively uniform pore structure, well configured pore throats, and strong connectivity, making it a high-quality reservoir for constructing gas storage facilities. The secondary pore type is controlled by dissolution, fractures, and other factors. Although the porosity may be high, the structure is complex and highly heterogeneous. Its effective permeability is highly dependent on the connectivity of the fracture network, resulting in variable permeability and strong anisotropy (permeability along the fracture direction is much higher than in the vertical direction). This directional difference affects the dominant migration path of gas and the distribution pattern of gas water front, which is a key factor that must be considered in the dynamic analysis of gas storage injection and production and the optimization design of well network. Therefore, when evaluating the potential of gas storage facilities, identifying pore types and fracture systems is more crucial than simply focusing on porosity values.

The cap rock of depleted oil and gas reservoirs is mainly composed of mudstone, shale, and salt rock, which generally have extremely low porosity, dense pore structure, and poor connectivity, and are key rock types for forming effective sealing (Ying et al., 2023). The porosity of mudstone and shale is usually less than 10%, and high-quality cap rocks can be less than 5%. The porosity of salt rock (gypsum salt rock) is generally below 3%, and can even reach below 1%. This extremely low porosity,

combined with nanoscale pore throats and high tortuosity dense structures, results in rock permeability as low as micro-Darcy or nano-Darcy levels, generating extremely high capillary resistance and effectively blocking gas leakage. Among them, salt rock also has unique plastic deformation ability, which can heal microcracks under pressure fluctuations, further ensuring the integrity of the seal. Therefore, these low porosity and dense rock types are the key to constructing geological barriers for gas storage facilities.

2.2 Heterogeneity

It is crucial to have a deep understanding of the controlling role of geological heterogeneity on injection capacity and fluid migration (Bo et al., 2024). Geological heterogeneity is usually divided into two categories: one is the existence of alternating layers with significant differences in mechanical properties, pore pressure, and/or lithology and permeability. The second is the separation phenomenon between faults and target reservoirs within specific sealed reservoirs (Torsæter and Cerasi, 2018). Current research indicates that the injection capacity of a reservoir depends on its rock physical properties such as porosity and permeability, while the storage capacity is closely related to heterogeneity.

The heterogeneity of reservoirs can be divided into interlayer heterogeneity, planar heterogeneity, intra layer heterogeneity, and pore structure heterogeneity (Fig.3). Interlayer heterogeneity, mainly manifested by the development of multiple layers of sand bodies, interlayers, and low-permeability barriers, restricts the effective vertical migration of gas, resulting in low utilization of some reservoir sections and a decrease in storage capacity utilization (Zhang et al., 2024). Plane heterogeneity, such as the presence of permeability bands and phase transition zones, can easily cause “finger in” or “bypass flow” phenome-

na during gas injection, leading to gas preferentially entering along high permeability channels and making it difficult to effectively affect low-permeability areas, resulting in actual gas storage space significantly smaller than theoretical values (Visentini et al., 2025). In addition, the non-uniform distribution of natural fracture networks can further form advantageous seepage channels, which not only accelerate gas migration to non-target areas and reduce effective reservoir space, but also jointly control fluid migration paths and rates with geological structures such as faults and lithological interfaces, thereby affecting the overall injection capacity of the reservoir. The in-layer heterogeneity of clastic reservoirs directly affects the thickness sweep coefficient of the injection agent, and its core influencing factors include the degree of difference in intra layer permeability, the location of the highest permeability segment, and the ratio of vertical and horizontal permeability at the entire layer scale (Yinan et al., 1985). At the microscale, the heterogeneity of pore structure characterized by the difference in bimodal pore and throat size distribution profoundly affects the gas adsorption behavior and movable fluid space, while the non-uniform distribution of wettability in space (coexistence of hydrophilic and oleophilic regions) determines the storage efficiency and recovery rate of residual gas by adjusting the gas water interface and capillary force balance.

During the injection production process, gas forms a dominant flow along the high permeability channel, resulting in uneven gas distribution and local pressure accumulation, while the low permeability area is prone to become a dead zone where fluid is difficult to enter, seriously affecting the overall sweep efficiency. Gas water two-phase migration is simultaneously controlled by wetting heterogeneity: hydrophilic regions are prone to inducing water locking effects that hinder gas flow (Fang et al., 2025), while lipophilic regions may promote gas migration. The heterogeneous distribution of capillary force can also induce gas water interface instability, exacerbating the phenomenon of “finger in” or “tongue in”. In addition, gas migration is the result of the coupling of permeation and diffusion mechanisms. The significant differences in gas diffusion ability among different rock types (such as sandstone, carbonate rock, shale) can affect their migration rate in micro pores. In high permeability areas, convection is mainly driven by pressure, while in low-permeability areas, diffusion is mainly driven by concentration gradients. The coupling of the two jointly shapes the macroscopic transport pattern of gases. In addition, heterogeneity significantly affects the interaction between cushion gas and working gas (such as H₂) (Visentini et al., 2025). In heterogeneous reservoirs, the two are more prone to mixing, resulting in a decrease in the purity of the produced gas and an increase in separation costs, especially in high permeability zones where the cushion gas is easily displaced quickly, leading to premature breakthrough of the working gas. Meanwhile, heterogeneity significantly increases the risk of gas escape. The heterogeneity of the cover layer itself (such as cracks, lithological pinch out) may form local sealing weak points. The heterogeneous distribution of faults or fracture networks is more likely to constitute advantageous channels for gas escape, greatly increasing the risk of leakage

and the difficulty of monitoring and sealing.

2.3 Mechanics properties

Transforming depleted oil and gas reservoirs into underground gas storage facilities essentially transforms them from a static geological body that has undergone long-term exploitation to a dynamic geological engineering body that can withstand periodic high-intensity injection and production disturbances. During this process, the rock mechanics characteristics of the reservoir and cap rock, especially their dynamic response under cyclic loading, are the core factors determining the storage efficiency, injection and production capacity, and long-term sealing safety of the gas storage facility. This section will explain its key mechanical properties and mechanisms of action.

2.3.1 Strength characteristics

The strength of the reservoir and cap rock is the foundation for ensuring the stability of the wellbore and the integrity of the skeleton structure of the gas storage under periodic injection and production pressure fluctuations (Wen et al., 2025). Different rocks have significant differences in strength: high-strength brittle rocks, such as carbonate rocks, have strong compressive strength but low toughness, and are prone to stress concentration at microcracks during rapid pressure changes, inducing damage accumulation and subcritical expansion. A more conservative pressure window needs to be set to prevent brittle failure and poor water communication. The mechanical behavior of medium strength rocks, such as various sandstones, is crucially controlled by the type and mode of cementation (He et al., 2019). Siliceous cementation enhances rigidity, while calcareous or argillaceous cementation enhances plastic deformation capacity. Its mechanical evaluation must be closely integrated with the diagenetic evolution history. Low strength and high plasticity rocks, such as mudstone and gypsum salt rock, rely on their creep characteristics to redistribute stress through deformation, achieving self-healing of microscopic damage (Xie et al., 2024), which is particularly crucial for maintaining long-term sealing of the cap rock.

2.3.2 Seepage characteristics

During the periodic injection production process, reservoir rocks exhibit significant stress sensitivity, mainly reflected in the dynamic response of permeability and porosity with the periodic variation of effective stress. Unlike static loading conditions, this asymmetric cyclic load causes rocks to exhibit complex dynamic response characteristics. Experimental studies have shown that rocks undergo cumulative plastic deformation after multiple stress cycles, leading to sustained compression of effective pore space (Pu et al., 2025). This process exhibits obvious path dependence and memory effects, where the current mechanical state of the rock not only depends on the instantaneous stress level, but is also significantly influenced by historical loading paths.

Under cyclic loading, the rock skeleton undergoes repeated elastic-plastic deformation, resulting in compression and expansion of the pore throat structure. It is worth noting that the relative permeability of gas is positively correlated with injection rate, while the initial gas saturation has a negative impact

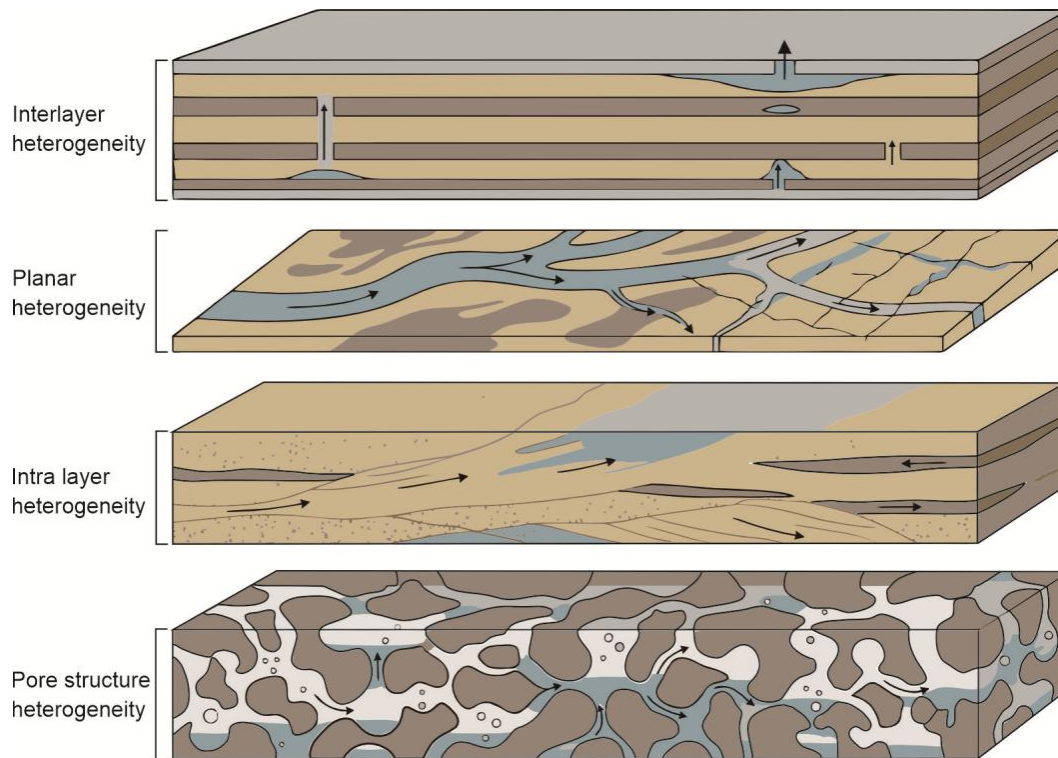


Fig. 3 Classification of reservoir heterogeneity

on it. The gas water two-phase flow model constructed by Wang et al. (2024b) shows that in poor gas reservoirs, the relative permeability damage of gas in the gas water transition zone can reach up to 81%. This damage effect significantly reduces the effective utilization space of the reservoir and restricts the overall production capacity of the injection production system. The widespread presence of edge and bottom water in reservoirs further exacerbates the complexity of stress sensitive behavior. During the depressurization mining stage, the increase in water saturation and effective stress work together to significantly damage the gas phase permeability through the water locking effect. Moreover, the presence of water alters the mechanism of pore pressure transmission, making it difficult for the tiny throats occupied by water to reopen during subsequent gas injection stages, resulting in permanent loss of gas phase flow space. At present, there is still insufficient research on the multi cycle stress sensitive behavior under water containing conditions, which has become a key bottleneck problem restricting the accurate prediction of long-term production capacity of gas storage facilities.

The sensitivity of permeability to stress changes is significantly higher than that of porosity, which is particularly prominent in low-permeability tight reservoirs (Zhong et al., 2020). The dynamic evolution of stress sensitivity has a dual impact on the operation of gas storage facilities: it affects the stability of injection and production rates in the short term, and may lead to gradual degradation of overall permeability in the long term. For fractured reservoirs, stress sensitivity exhibits special mechanical behavior. During the high-pressure stage of gas injection, crack opening can significantly improve reservoir permeability, while during the depressurization stage

of gas production, crack closure leads to a sharp decrease in permeability. The periodic “opening closing” effect is similar to the fatigue loading process, and long-term operation may cause damage mechanisms such as crack surface wear and filler migration, leading to irreversible degradation of crack conductivity. More seriously, this accumulation of damage may trigger micro-seismic events, posing a potential threat to the long-term operational safety of gas storage facilities.

The dynamic evolution of stress sensitivity has a significant impact on the long-term operation of gas storage facilities: on the one hand, it directly restricts the stability and predictability of injection and production rates within a single cycle, and on the other hand, cumulative damage effects may lead to a gradual decline in the overall permeability of gas storage facilities with increasing operating years. Therefore, in the design and operation of gas storage facilities, it is necessary to quantify the stress sensitivity coefficient through systematic rock mechanics experiments, establish a dynamic prediction model coupled with seepage mechanics, optimize the injection production system to control the amplitude of pressure changes, reduce the risk of irreversible damage, and ensure the long-term efficient and stable operation of gas storage facilities.

2.4 Reservoir original fluid occurrence state

Considering that after long-term depletion and development, the movable hydrocarbons in depleted oil and gas reservoirs have been basically extracted, but there are still generally residual bound fluids (residual oil, gas, and water) in the reservoir (Heidarabad and Shin, 2024). The fluid occurrence state of the reservoir at this time is actually a non-equilibrium geological fluid system formed under mining intervention, and its phase

distribution and saturation characteristics vary depending on the original reservoir type (such as dry gas reservoir, condensate gas reservoir, gas cap reservoir) and reservoir evolution history. Therefore, clarifying the current fluid occurrence state before renovation is the core geological basis for quantifying the working gas volume of gas storage, predicting the injection production gas phase behavior, and fluid front evolution.

Depleted gas reservoirs, depleted condensate gas reservoirs, and depleted oil reservoirs with gas caps constitute three typical primitive occurrence states in gas storage reconstruction, and their differences are fundamentally due to the fundamental differences in primitive fluid types, depletion mechanisms, and residual fluid distribution patterns. Depleted gas reservoirs are formed by the depletion and development of single-phase gas reservoirs, and after a significant decrease in pressure, they exhibit a binary coexistence pattern of residual gas and invading water: 15%-40% of immovable residual gas exists in the high structural parts and low-permeability matrix areas, which can be used as natural cushion gas resources. The edge bottom water advances along the pressure drop funnel towards the interior of the reservoir, forming a gas water transition zone or local water flooded zone in the low potential area of the structure. Water intrusion in the fractured reservoir often rapidly advances along high angle pipelines, leading to heterogeneous dynamic evolution of the gas water interface. Depleted condensate gas reservoirs undergo retrograde condensation due to depletion development below dew point pressure. The dissolved medium heavy hydrocarbon groups in the original gas phase are analyzed and retained on the pore throat wall and microcracks, forming a continuous or quasi continuous oil film at the nanoscale throat, resulting in a special liquid phase blockage state where high gas saturation (>85%) and extremely low oil phase permeability coexist. The condensate oil preferentially blocks the intergranular pore throats and has a weak impact on macroscopic cracks. This permanent hydrocarbon loss also seriously deteriorates the gas phase permeability. The depleted reservoir with gas cap is the most complex system of three-phase superposition. Gas cap, oil ring and edge bottom water coexist closely in the vertical direction: after the oil ring pressure drops below the bubble point, a large amount of dissolved gas is separated, and some of them are trapped in the crude oil in the form of free bubbles to form a foam oil flow pattern. The volume of gas cap shrinks due to energy release, edge bottom water may be actively invaded, and the gas oil and oil water contact surfaces are deformed and migrated due to development disturbance. The preferential channeling of gas, oil and water along the network in fractured media further aggravates the heterogeneity between phases. The identification and quantitative characterization of the original fluid occurrence state of these three types of reservoirs is an important geological basis for the design of gas storage capacity, optimization of injection and production plans, and dynamic monitoring deployment.

3 Fluid transport characteristics under different energy storage media

This section focuses on typical gas storage systems established in depleted oil and gas reservoirs, systematically explain-

ing the migration mechanism and dynamic characteristics of reservoir fluids, covering three gas types: H₂, CO₂, and natural gas (mainly CH₄). The focus is on revealing the complex physical chemical transport behavior of different gases in porous media during periodic injection and production processes, as well as their multi field coupling mechanisms with the reservoir environment. The basic physicochemical properties of the three gases are presented in Section 3.1, and the fluid transport mechanisms in different reservoir spaces are presented in Section 3.2.

3.1 Physicochemical properties of the stored medium

In the engineering practice of depleted oil and gas storage, the function of underground storage is expanding from a single natural gas peak shaving to a comprehensive underground space for multi medium (CO₂ and H₂) energy storage and storage. However, due to their unique physical and chemical properties, different media have different occurrence states, migration laws, and interaction mechanisms with geological environments in underground porous media, which affect the selection criteria, injection and production processes, safety boundaries, and ultimate efficiency of storage facilities. Therefore, this section will focus on three key media: natural gas, CO₂, and H₂, compare and explain their core physicochemical parameters, and analyze how these characteristics affect their transport and storage behavior in underground space, presented in Sections 3.1.1 to 3.1.3, respectively.

3.1.1 Natural gas

As the most mature conventional storage medium in current technology, the natural gas stored in underground gas storage facilities is dry gas that has undergone deep processing such as desulfurization and dehydration. Its essence is a simple hydrocarbon mixture mainly composed of CH₄, without acidic corrosive components, and the water dew point and hydrocarbon dew point are strictly controlled to ensure that it always maintains a homogeneous gas phase within the temperature and pressure range of storage operation, thus avoiding the common complex multiphase flow problems in condensate gas reservoirs and making its migration law relatively clear and easier to predict. The basic physical and chemical properties of CH₄, such as density, viscosity, and solubility, are relatively balanced, as shown in Tab.2. CH₄ molecules are small and light in weight, resulting in low viscosity (Sotiriadou et al., 2025). Under pressure drive, they can quickly flow through the reservoir, achieving high-speed gas injection and production required for gas storage and meeting peak shaving needs. But at the same time, small molecules also mean higher diffusion ability, which makes CH₄ easy to slowly diffuse through the microscopic pores and even sealing layers of rocks, posing certain challenges to the long-term sealing of gas storage facilities. Due to the weak quadrupole moment and appropriate polarizability of CH₄ molecules, their adsorption capacity on reservoir media rich in organic matter (such as kerogen) and clay minerals (such as illite and montmorillonite) is superior to that of nitrogen, helium, and H₂ (Song et al., 2025). Experimental data shows that under typical reservoir temperature and pressure (such as 50°C, 10 MPa), the adsorption capacity of CH₄ on shale or coal

seams can reach 1.5-3.0 cm³/g (standard state), and its adsorption selectivity coefficient relative to H₂ is often greater than 2. However, in the competitive adsorption with CO₂, its relative strength is highly temperature dependent: at low temperatures far below the reservoir temperature (such as below 30°C), CO₂ has significantly stronger adsorption capacity than CH₄ due to its higher quadrupole moment and polarizability. However, at actual reservoir temperatures (usually above 50°C), extensive research has shown that the competitive adsorption advantage of CO₂ is more pronounced, with an adsorption selectivity coefficient of over 3 relative to CH₄. Therefore, in reservoir environments, CO₂ often dominates. This preferential adsorption behavior has a dual effect, as CH₄ molecules can preoccupy a portion of the active mineral surface, which can to some extent inhibit carbonation reactions between CO₂ and minerals, or reduction reactions between H₂ and rocks/fluids, thereby maintaining reservoir chemical stability and reducing gas loss. It may also occupy valuable effective adsorption space, especially in low-permeability reservoirs dominated by adsorption gas storage, which directly reduces the adsorption and storage efficiency of H₂ or CO₂, and needs to be accurately deducted in storage capacity assessment.

In the reservoir environment where gas and water coexist, CH₄ migration is easily affected by capillary force retention, leading to the “water lock” effect. Depleted reservoirs typically have a certain degree of water saturation (S_w). Due to the extremely low solubility of CH₄ in water (about 22-24mg/L at room temperature) and the high interfacial tension between gas and water (about 70mN/m), capillary force becomes the key resistance to gas migration in water wet reservoirs. When the gas phase pressure is insufficient to drive CH₄ to break through the capillary bottleneck (capillary pressure P_c can reach the order of 0.1 to several MPa, which is related to pore size distribution), the gas will be trapped in the pore throat, forming a water lock. This effect leads to a sharp decrease in gas phase effective permeability (KRG), which may decrease by 50%-90% within the range of water saturation of 30%-50%. During the strong non steady state process of periodic injection and production in gas storage facilities, frequent changes in pressure and saturation can dynamically manifest and redistribute the water lock effect, which not only increases injection and production energy consumption, but also restricts the rapid throughput capacity of the working gas and the peak shaving response speed of the storage facility (Juanes et al., 2006). In multi gas mixed storage, CH₄ will affect the storage capacity and flow path of other gases through competitive adsorption. In depleted gas reservoirs where CO₂ serves as a cushion gas, the change in flow direction plays an important role in the gas mixing process. The dispersion process between CH₄ and CO₂ fluid is mainly affected by the dispersion coefficient. In the process, when the flow direction changes, the dispersion degree is 12-15 times higher than that of co directional displacement. In addition, the dispersion coefficient of CH₄ replacing CO₂ is approximately 1-2 times higher than that of CO₂ replacing CH₄ (Yang et al., 2024). In addition, CH₄ has stable chemical properties and is not easily reacted with reservoir rocks and fluids, so the migration process is mainly physical and does not

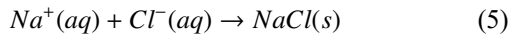
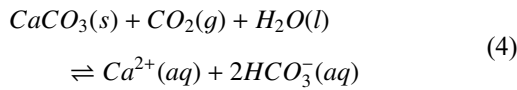
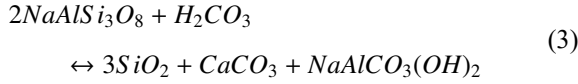
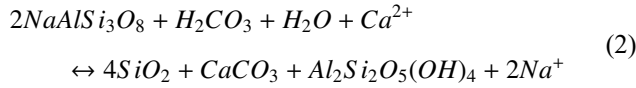
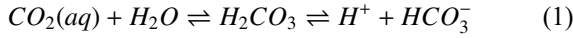
significantly change the reservoir structure.

3.1.2 Carbon dioxide

CO₂ undergoes conversion between gas, liquid, and solid states based on changes in temperature and pressure. The physical properties of CO₂ at room temperature and standard atmospheric pressure are shown in Table 2. Density and viscosity are the core physical parameters that determine the geological storage efficiency of CO₂, affecting the effective capacity of the reservoir and the enhanced oil recovery effect. Due to its low density, gaseous CO₂ can weaken the static pressure gradient in the wellbore, induce flow instability, and pose a risk of cavitation during phase transitions. When the depth of the reservoir exceeds 800 meters, the temperature and pressure conditions usually exceed the critical point of CO₂ (7.38 MPa, 31.1°C). At this point, CO₂ is injected in a supercritical state, which has the dual advantages of high density and low viscosity (Raza et al., 2019). In contrast, shallow reservoirs (<800 meters) have limited CO₂ sequestration efficiency due to the difficulty in maintaining supercritical conditions, and in-depth analysis of multiphase flow can partially avoid such limitations (Tan et al., 2016). In injection production practice, there is a positive correlation between wellbore temperature and CO₂ injection capacity. Heating up leads to synchronous attenuation of supercritical CO₂ density and viscosity, enhancing molecular mobility, thereby optimizing the injection profile (Tawiah et al., 2020). It is worth noting that the density of supercritical CO₂ approaches that of the liquid phase (about 0.3-0.8 g/cm³), while its viscosity is comparable to that of the gas phase. This anomalous property makes it possess both transport efficiency and storage density. In addition, the presence of residual CH₄ in the reservoir can disturb the original physical property field of supercritical CO₂, causing local variations in density and viscosity (Heidarabad and Shin, 2024). The study by Nicot et al. (2013) on shallow geological bodies showed that the decrease in viscosity of CO₂ mixed systems corresponds approximately linearly to the loss of effective storage capacity.

Carbonate reservoirs typically exhibit high heterogeneity due to the reactivity of their carbonate minerals (Li et al., 2022). When injecting CO₂ into such reservoirs, it may interact with rocks and fluids in various ways, such as Eqs.(1)-(4). Firstly, CO₂ dissolves in water to form carbonic acid, and the dissociated H⁺ promotes the dissolution of carbonate minerals such as calcite and dolomite, releasing Ca²⁺, Na⁺, and HCO₃⁻. Although this process can expand pore throats and improve reservoir permeability in the short term, it can also easily induce CO₂ to break through along dominant channels, reducing macroscopic sweep efficiency. As the fluid migrates to areas where temperature and pressure conditions change or is affected by CO₂ dehydration, dissolved Ca²⁺ will undergo reverse precipitation, with secondary calcite and dolomite filling the pores, leading to a further decrease in reservoir permeability and even the formation of local tight zones (Fani et al., 2024; Song et al., 2026). Meanwhile, as shown in Eq.(5), continuous injection of dry CO₂ will extract formation water, leading to oversaturation of salinity in the near wellbore zone, inducing crystallization and precipitation of evaporated salt minerals such as rock salt, and causing irreversible damage to injection capacity (Ren et

al., 2025).

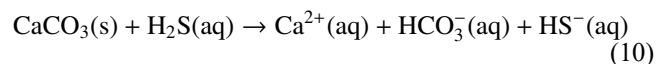
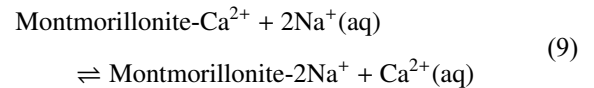
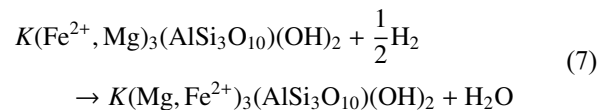
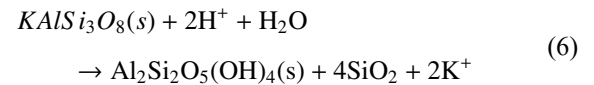


3.1.3 Hydrogen gas

H₂ has the highest mass energy density among all fuels and is the most efficient energy carrier on an equal mass basis. However, due to its extremely small molecular weight and low density, under standard conditions, its volumetric energy density is only one-third of CH₄. This means that in practical engineering, the physical space required to store the same amount of chemical energy in H₂ is much larger. The low molecular weight and low viscosity of H₂ make it have good fluidity and permeability. This is beneficial for the efficiency of the injection production cycle, but its high diffusion coefficient makes traditional geological structures (such as cap rocks and interlayers) less effective in sealing H₂, leading to leakage risks. Meanwhile, the density of H₂ is lower than that of air, causing it to accumulate and rapidly diffuse at the top of open spaces after leakage, rather than accumulating in low-lying areas like CH₄. In addition, H₂ has a wide range of explosive limits, which imposes strict requirements on leak monitoring and concentration control. H₂ has weak adsorption with rock minerals (especially organic matter), which means it is difficult to be anchored through adsorption, and its storage mechanism is relatively single, mainly relying on physical traps in structure and pore space. Moreover, the adsorption capacity of H₂ on different porous rocks varies to some extent. According to literature data on H₂ adsorption, the adsorption capacity of H₂ on conventional rocks (such as sandstone) is far inferior to that on non-traditional dense rocks (such as shale), as shown in Fig.4. This indicates that with suitable cover layers, traditional rock layers can better reduce H₂ loss during the recovery process (Mirchi and Dejam, 2023). This means that using traditional rocks to store H₂ may be a more efficient and effective way to protect the amount of H₂.

H₂ gas also undergoes certain chemical reactions with reservoir and cap rock, and water is an important medium for the interaction between H₂ and rock. The three reactions can lead to the mutual transformation or dissolution expansion of certain minerals, as shown in Eqs.(6)-(10). For example, the initial

high-pressure reactor experiment conducted by Bensing et al. (2022) on the replacement clay rock of the Amaseton Formation cap rock showed that calcite in the cap rock could dissolve within 30 days at room temperature under saline and H₂ conditions. This process will increase the porosity and permeability of the cap rock, thereby weakening its H₂ sealing effectiveness. Meanwhile, it may reduce the mechanical strength of the cap rock, affect its integrity, and cause additional H₂ loss due to chemical reactions, posing a challenge to the feasibility of underground H₂ storage (UHS). But in the presence of buffer gas (CH₄), the reaction intensity will be greatly reduced, and the impact of buffer gas on the reaction intensity may even exceed that of water. In addition, when water is adsorbed on the surface of hydrophilic inorganic minerals, it is more likely to form a water film, which makes it difficult for H₂ to react with rocks. Before H₂ meets inorganic minerals, it must pass through gas and water coatings. Similarly, due to the easy adsorption of CH₄, H₂ cannot directly interact with inorganic minerals such as clay, which weakens the ability of H₂ to react with rocks. Shale contains a large amount of organic matter, such as kerogen. Due to the preferential adsorption of H₂ and CH₄ on the surface of organic pores, the reaction frequency between H₂ and inorganic minerals is relatively low. Therefore, the H₂ water rock interaction in shale is weaker than that in sandstone. Considering the impact of H₂ water rock interaction on rock properties and H₂ loss during long-term H₂ storage, depleted shale gas reservoirs with lower water content and buffer gases (such as CH₄) may be a better large-scale underground H₂ storage (UHS) method than traditional depleted gas reservoirs.



3.2 Fluid migration characteristics in different storage spaces

Storage space is the physical carrier for fluid migration. According to scale and structural characteristics, this section divides the storage space of depleted oil and gas reservoirs into three categories: porous matrix bodies, fracture matrix bodies,

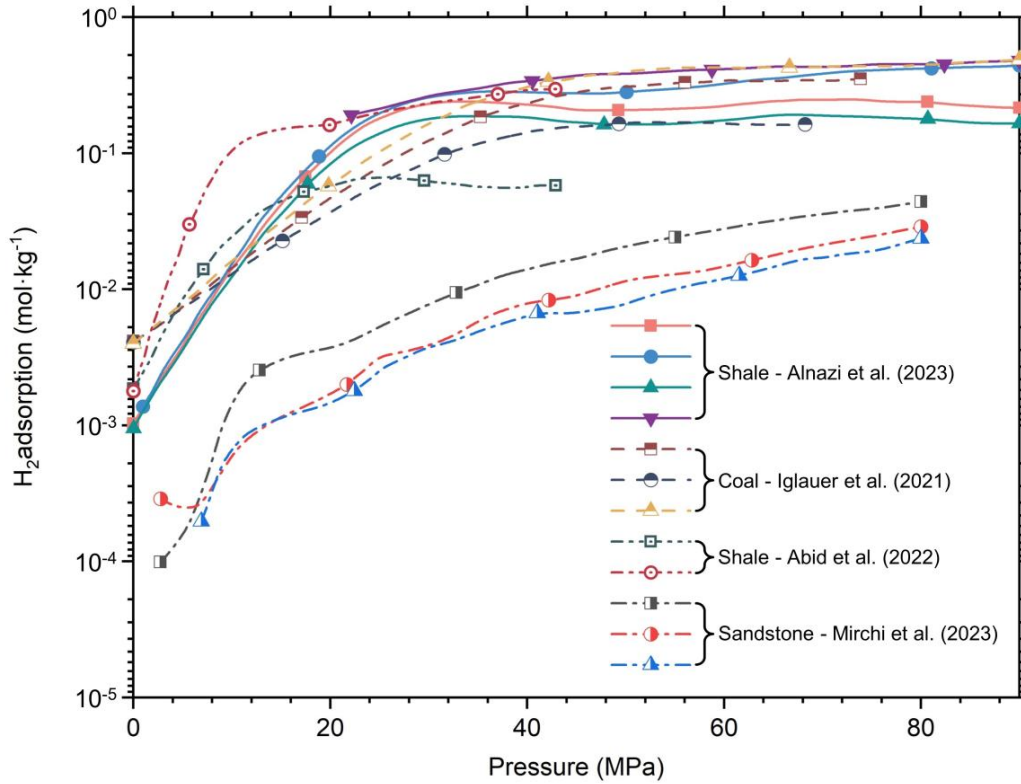


Fig. 4 H₂ adsorption data in literature (Mirchi and Dejam, 2023)

Tab. 2 Physical parameters of H₂, CH₄ and CO₂ at 25 °C and 1 atm (Muhammed et al., 2022; Qiu et al., 2023; WANG et al., 2025b).

Substance	Molecular mass	Density (kg/m ³)	Specific gravity	Viscosity (Pa·s)	Water solubility (g/L)	Standard boiling point (°C)	Calorific value (kJ/g)	Diffusion coefficient in water (m ² /s)
H ₂	2.016	0.089	0.0695	0.89 × 10 ⁻⁵	16 × 10 ⁻⁴	-253	120 142	5.13 × 10 ⁻⁹
CO ₂	44.09	1.98	0.2 0.9	1.49 × 10 ⁻⁵	1.45 × 10 ⁻³	78.44	—	1.60 × 10 ⁻³
CH ₄	16.043	0.0657	0.509	1.1 × 10 ⁻⁵	22.7 × 10 ⁻³	-162	50 55.5	1.85 × 10 ⁻⁹

and cavern injection production well complexes, corresponding to three flow mechanisms: pore permeability, fracture matrix coupled flow, and free flow. Revealing the fluid migration laws in three types of spaces is the theoretical basis for understanding the injection and production efficiency and leakage prevention mechanism of gas storage facilities.

3.2.1 Porous matrix

The flow phenomenon in porous media can be considered at different scales (D’Orazio et al., 2023). The multi-scale framework in Fig. 6 integrates molecular/atomic scale, pore scale, REV scale, and field scale to reveal the complete process from microscopic interactions to macroscopic flow in porous media, laying the foundation for understanding fluid flow in porous media (Ranjbarzadeh and Sappa, 2025).

The migration of gases in porous media follows the basic laws of porous media flow mechanics. However, recent studies have found that the classical Darcy’s law has significant deviations under nanoscale confinement conditions. It is urgent

to establish a cross scale flow model through molecular simulation and high-resolution pore imaging (Ranjbarzadeh and Sappa, 2025). CO₂, CH₄, and H₂ are all driven by pressure gradients during injection, but the morphological evolution of the displacement front varies. CO₂ has the highest viscosity and density, and exhibits stable propulsion characteristics at the pore scale. However, recent studies on the dynamics of coal seam gas injection invasion seepage have shown that CO₂ follows the invasion seepage movement in non-wetting pores, exhibiting Haines jumps unstable flow at wetting pores or pore intersection nodes, until it breaks through the pore fracture network and enters the Darcy seepage stage. The CH₄ mobility ratio is moderate, and the displacement front shows a moderate degree of fingering, but it is co regulated by the adsorption boundary layer and slip effect in the nanoscale confined space (Wang and Yue, 2025). H₂, on the other hand, is completely different. Its viscosity is only half that of CH₄ and one-third that of CO₂, and its flowability ratio is much greater than 1. When injected, it strongly points along the high permeability pores.

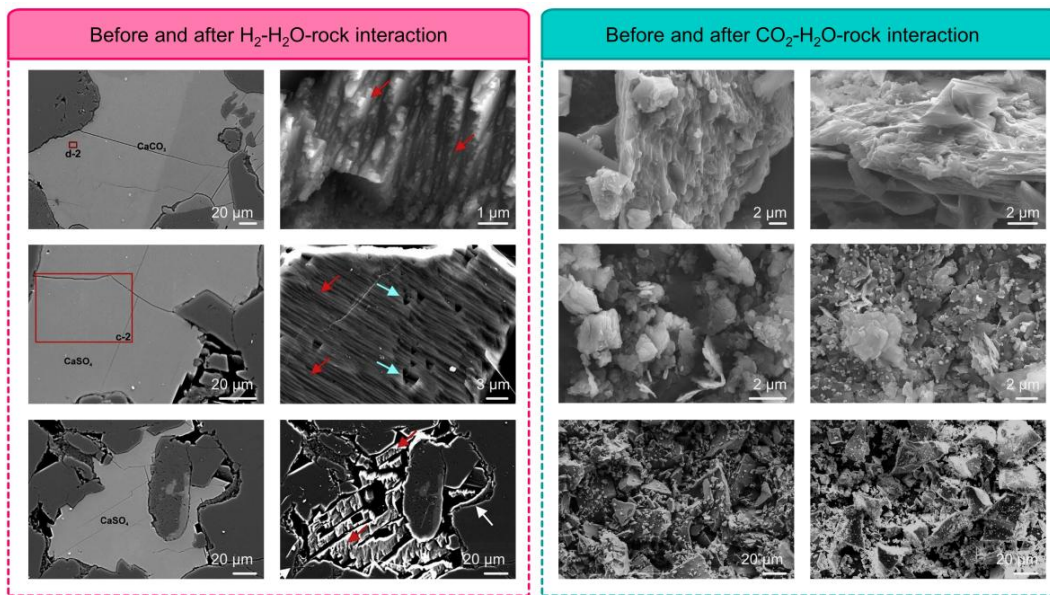


Fig. 5 Effect diagram of H₂, CO₂ and water rock interaction before and after microscale (Muhammed et al., 2022; Fani et al., 2024)

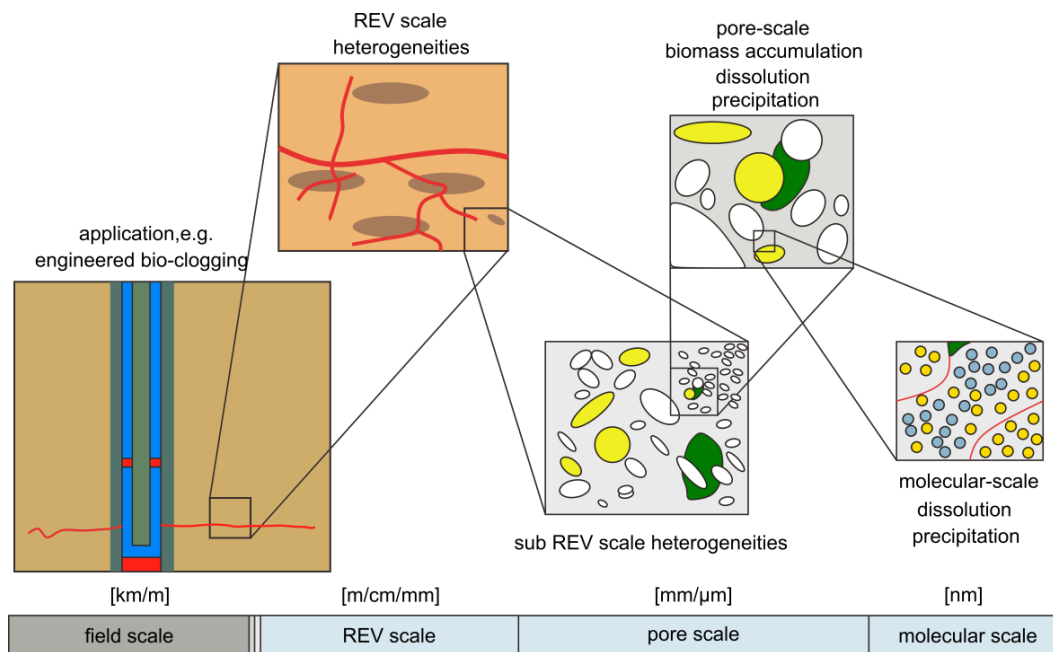


Fig. 6 Multi scale classification of porous media (Ranjbarzadeh and Sappa, 2025)

Zeng et al. found through molecular dynamics simulations that H₂ is concentrated in the central region of organic nanopores, with an extremely low adsorption layer density (Zeng et al., 2025). This non-uniform distribution characteristic makes its self-diffusion coefficient nearly an order of magnitude higher than that of the underlying gas, but also leads to a significantly lower sweep efficiency in the pore network compared to CO₂ and CH₄.

Three types of gases and formation water form a typical gas-liquid two-phase system, and their interfacial behavior is jointly controlled by gas water interfacial tension and wettability (Fig. 7). The gas water interface tension of CH₄ is about

70mN/m, forming significant capillary resistance in hydrophilic rock pores. Gas must overcome the capillary entry pressure at the throat to pass through. Wang et al. found that in the gas water transition zone of depleted gas reservoirs, the relative permeability damage of natural gas reached 81%, reducing the movable pore space (Wang et al., 2024). The supercritical state of CO₂ exhibits unique interfacial properties: molecular dynamics simulations by Doan et al. show that at a fixed temperature, the rate of decrease in interfacial tension in the CO₂-H₂-H₂O system is higher than that in the CH₄-H₂-H₂O system (Doan et al., 2024). Therefore, the water locking sensitivity of CO₂ in aqueous reservoirs is significantly lower than that of methane.

The situation of H₂ is the most unfavorable, with a gas water interfacial tension of over 75 mN/m and extremely low solubility in water, making it impossible to alleviate capillary confinement through dissolution diffusion. Multi-scale simulation studies on the sealing properties of depleted gas reservoirs have confirmed that the adsorption energy between H₂ and kaolinite walls is extremely low, resulting in a diffusion coefficient 1-2 orders of magnitude higher than that of methane, ethane, and CO₂ (Zhang et al., 2026). Thaysen et al. found that during the swelling process of underground H₂ storage, capillary interception (water locking effect) leads to a significant increase in the initial H₂ trapping ratio with increasing pore fluid pressure (20%-43% at 2-7 MPa) (Thaysen et al., 2023), indicating that strong water locking effect is the main physical barrier to H₂ storage, especially in high-pressure deep reservoirs.

The mass transfer of the three gases in the pores is controlled by the coupling of convection and diffusion, but in recent years, pore scale studies have revealed new mechanisms that traditional dispersion theory has not fully described. A systematic comparative study found that due to its extremely high molecular diffusion rate, reconnecting H₂ that was originally trapped and sealed by capillary force into a continuous gas phase, thereby reducing the lag effect of multi cycle injection and production (Alzaabi et al., 2025). This mechanism enables the redistribution ability of H₂ in the pore network to far exceed that of methane and nitrogen, but also results in a very fast expansion of its mixed zone with the underlying gas. Zeng et al. further pointed out that the self-diffusion coefficient and Fick diffusion coefficient of H₂ gas in a nano confined environment are nearly an order of magnitude higher than those of the underlying gas, and its dimensionless self-diffusion coefficient shows a clear two-stage correlation with the Knudsen number (Zeng et al., 2025). In the periodic flow of injection production alternation, the flow direction repeatedly reverses, and H₂ is most sensitive to flow velocity fluctuations due to its extremely low viscosity, with a dispersion coefficient several times to an order of magnitude higher than methane. The micro distribution patterns of three gases in pore space are controlled by the depth of adsorption. Molecular simulation shows that CO₂ and methane molecules preferentially occupy the adsorption sites on the surface of nanopores, while H₂ molecules are enriched in the central region of the pores. The adsorption and aggregation of bottom gas molecules on the pore surface not only reduces the density of the H₂ adsorption layer, but also physically and chemically inhibits the free diffusion of H₂. The study on the sealing of the cap rock for H₂ storage in depleted gas reservoirs also shows that the occupation behavior of methane and CO₂ on the adsorption sites on the pore surface significantly inhibits the diffusion and escape of H₂. The intuitive manifestation of this competitive adsorption mechanism at the pore scale is that CO₂ preferentially occupies the surface of micropores and fills them inward, methane competes with CO₂ for adsorption sites, and H₂ is repelled to the center of macropores and mesopores, unable to enter the effective storage space of micropores. In the multi cycle injection production process, both CO₂ and methane exhibit desorption hysteresis, and some adsorbed gases are irreversibly retained. H₂, on the other hand, has a high degree of

recovery due to its lack of adsorption hysteresis, but it also lacks adsorption buffering as a natural barrier to leakage (Zhang et al., 2026). The fluid migration of methane, CO₂, and H₂ in the pores of depleted oil and gas reservoirs presents three different porous media flow patterns. CO₂ is transported as a highly viscous, high-density, and chemically active supercritical fluid under reservoir conditions. The core contradiction in its pore scale lies in the non-Darcy infiltration dominated by capillary fingering and Haines jump. Methane is a classic gas-phase flow with balanced physical properties and predictable behavior. The core contradiction in its pore scale lies in the capillary competition between gas and water phases and the adsorption boundary layer effect under nanoscale confinement. H₂ is an extreme gas-phase flow with extremely low viscosity, extremely high diffusion, strong water lock sensitivity, and significantly regulated by Ostwald ripening. The core contradiction in its pore scale lies in the low sweep caused by macroscopic fingering, the collapse of effective permeability caused by microscopic capillary confinement, and the hysteresis characteristic evolution brought about by ripening effects (Zhang et al., 2026). The migration laws of the three in porous media together form the basis of permeability mechanics for the multimedia storage of depleted oil and gas reservoirs. Any technical solution attempting to achieve CO₂ storage and H₂ energy scale storage in the same reservoir space must accommodate these three distinct migration requirements at the pore scale.

3.2.2 Matrix with fractures

In depleted oil and gas storage facilities, the fractured matrix, as a dual medium storage and permeability unit composed of pore matrix and fracture system, is the core geological body that controls the high-speed gas injection and production capacity and long-term storage safety. The flow and migration of gas inside it is a multi-scale process dominated by fractures for rapid transport, with the matrix responsible for the main reservoir, and the two dynamically coupled through cross flow. Recent studies have shown that there are significant time scale differences in nanopores, macropores, and microfractures in tight reservoirs such as shale, and the mass transfer behavior of fluids between pore media at various scales is in a non-equilibrium state. The non-equilibrium mass transfer model based on the theory of multiple continuous media (MINC) can more accurately describe this dynamic coupling process.

During the injection stage, under high-pressure driving, gas preferentially penetrates rapidly along the macroscopic connected fracture network. After pressure conduction, a pressure difference is formed between the matrix and the fracture, and the gas gradually infiltrates into the matrix pores to complete storage. The extraction stage proceeds in the opposite direction, with the gas stored in the matrix slowly flowing into the cracks and merging into the high-speed extraction flow line. Cracks determine the "speed" of injection and production rate, while the matrix determines the "quantity" of storage total. Together, they constitute the unique dual permeability flow pattern of matrix bodies containing cracks. According to the study by Zamehrian;Sedae, cracks act as highly permeable channels, greatly accelerating the process of H₂ extraction, resulting in improved H₂ recovery rate and purity (Table 3) (Zamehrian

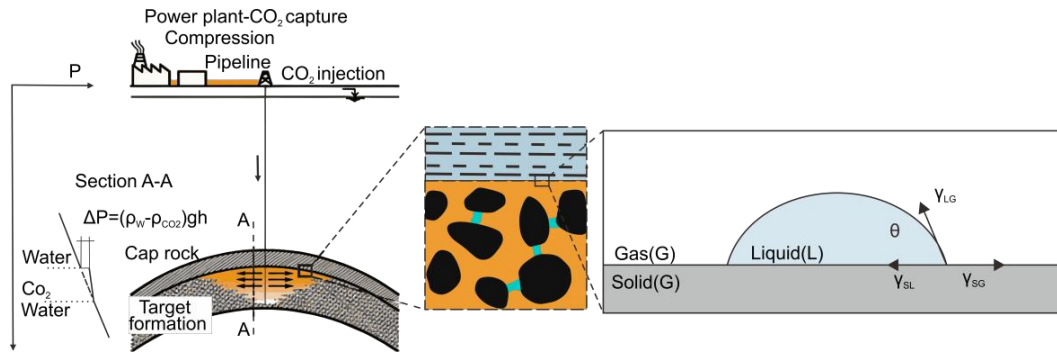


Fig. 7 A brief description of the interface characteristics that affect the reliability and storage capacity of CCS and UHS projects (Doan et al., 2024)

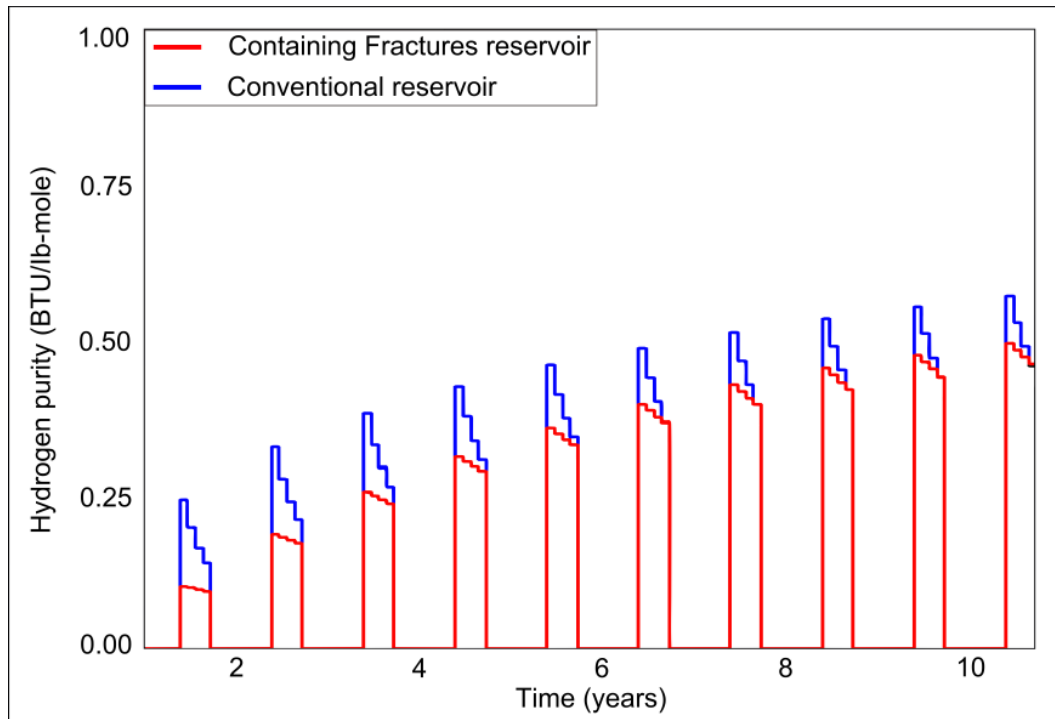


Fig. 8 Purity of H₂ in fractured gas reservoirs and conventional gas reservoirs during injection production process (Zamehrian and Sedae, 2022)

Tab. 3 Comparison of H₂ storage between fractured reservoirs and conventional reservoirs, where CHP represents cumulative H₂ production and H₂RF represents H₂ recovery rate (Zamehrian and Sedae, 2022).

Case model	1st cycle		10th cycle		Prolonged	
	CHP (BSCF)	H ₂ RF (%)	CHP (BSCF)	H ₂ RF (%)	CHP (BSCF)	H ₂ RF (%)
Conventional reservoir	0.819	9.63	28.34	33.29	79.89	93.85
Fractures containing reservoir	1.613	18.96	33.89	39.81	81.37	95.59

and Sedae, 2022). At the same time, the gas mixing inside cracks is stronger, leading to a significantly faster decrease in the purity of H₂ extracted from dual pore reservoirs in a single cycle compared to conventional reservoirs (Fig. 8).

Cracks are not only the guarantee for efficient injection and production of gas storage, but also the root cause of gas leakage and filtration. On the one hand, cracks act as highly permeable channels, greatly increasing the injection and production rate

of fluids. In underground H₂ storage projects, the presence of cracks accelerates the process of H₂ extraction, resulting in improved H₂ recovery rate and purity. However, the gas mixing inside the cracks is stronger, resulting in a significantly faster decrease in the purity of H₂ produced in a single cycle in dual pore reservoirs compared to conventional reservoirs (Zamehrian and Sedae, 2022). Wang et al. further confirmed in their study on hydraulic fracturing fractures that the high

conductivity of the fractures allows for rapid H₂ recovery at lower pressure differentials (Wang et al., 2024). By optimizing the injection production strategy, the H₂ recovery rate can exceed 85%. On the other hand, the crack system is also the root cause of gas leakage and filtration. Xue et al. pointed out that the pore distribution and permeability theory of fractured reservoirs are complex, and their numerical simulations face challenges in ensuring mass conservation, especially when accumulated numerical errors during long-term operation may lead to significant mass loss (Xue et al., 2023). The mass exchange between the matrix and cracks in a matrix with cracks is not an instantaneous equilibrium process. Ma et al. conducted a simulation study on the non-equilibrium composition of multi-scale porous media, which showed that even during the shut in soaking period, the sustained non-equilibrium mass transfer of CO₂ to macropores and nanopores still significantly changes the fluid composition in each continuous medium (Ma et al., 2024). Extending the soaking time can effectively promote gas migration to the microporous matrix. Simulation of H₂ storage in natural fractured gas reservoirs found that a large amount of H₂ invades the matrix during injection, but due to the low permeability of the matrix (0.05–0.34 mD), it cannot be fully produced during the production cycle, resulting in H₂ stagnation in the matrix pores (Zamehrian and Sedaei, 2022). This phenomenon reveals the dynamic non-equilibrium characteristics of crack matrix flow: during the injection period, gas preferentially rushes rapidly along the crack, and after pressure conduction, a pressure difference is formed between the matrix and the crack, and gas gradually infiltrates and enters the matrix pores. The extraction stage proceeds in the opposite direction, with the gas stored in the matrix slowly flowing into the cracks and merging into the high-speed extraction flow line. Cracks determine the "speed" of injection and production rate, while the matrix determines the "quantity" of storage total. Together, they constitute the unique dual permeability flow pattern of matrix bodies containing cracks.

In the face of the high complexity of matrix materials with cracks, significant progress has been made in numerical simulation methods. Xue et al. proposed a wellbore reservoir integrated model applicable to depleted oil and gas reservoirs (Xue et al., 2023). By introducing a flow direction factor, the simulation of bidirectional flow between injection and production was achieved. A non-steady state thermal conductivity model was used to describe the temperature changes in the wellbore, and a strict mass conservation pressure correction method was established. A stability factor method is proposed for the nonlinear treatment of the matrix crack flow term in the dual medium model, which improves computational efficiency by 20%–30% while ensuring diagonal dominance. Wang et al. established a numerical simulation model for CO₂ sequestration based on actual formation water ion characteristics and mineralization reactions, revealing the competitive relationship between dissolution sequestration and mineralization sequestration at different gas injection rates: the highest mineralization sequestration was achieved at a gas injection rate of 1.5×10^5 m³/d, while the total amount of dissolution sequestration and mineralization sequestration was maximized at a gas injection rate of 2.5×10^5

m³/d (Wang et al., 2023). These studies provide methodological support for the quantitative description of multi-component gas transport in porous matrix materials.

3.2.3 Combination of caverns and injection production wells

In depleted oil and gas reservoirs, the combination of caverns and injection production wells refers to a storage transportation coupling system composed of large cavities formed by artificial excavation or natural dissolution, injection production wells, and near wellbore zones. It is different from pore fracture reservoirs, with its core characteristics being highly concentrated storage space, short and efficient flow channels, strong boundary constraints, and high injection and production rates. The flow, migration, and leakage control of gases in such geological bodies follow different mechanical and fluid dynamics laws than porous media. The interior of the cavern is a free flow field, and gas migration is not constrained by pore throats, dominated by gravity differentiation and large-scale convection. The flow pattern is described by the momentum equation rather than Darcy's law. During the injection stage, high-pressure gas is injected into the cavity through the wellbore, forming turbulent jets near the entrance. The kinetic energy is rapidly dissipated into pressure energy, and the time scale for pressure homogenization inside the cavity is much smaller than that of porous reservoirs. During the extraction stage, the pressure drop wave at the wellhead propagates at high speed along the wellbore, and the gas inside the tunnel is discharged in an approximate piston flow driven by the overall pressure difference, without the problem of matrix flow hysteresis. This flow state determines that the tunnel well combination has instantaneous response, high flux, and low loss injection and production characteristics, and the injection and production rate of a single well can reach tens to hundreds of times that of a porous reservoir. The cavity is essentially a transformed natural storage space, and its macroscopic transport pattern is dominated by density differences. CO₂, as a cushion gas, forms a stable air cushion layer at the bottom of the cavity with a relative density of about 1.8 times that of methane and 22 times that of H₂, while H₂ migrates over to the top of the reservoir due to its extremely low density (Rhouma et al., 2024). Methane is situated between the two, serving as a transitional buffer zone between the working gas and the cushion gas. However, this idealized gravity sequence remains dynamically disturbed throughout the actual injection production cycle. When the gas production rate is too high, the bottom CO₂ will be dragged into the wellbore flow path, causing a cone breakthrough, while the high-pressure H₂ during the gas injection stage may flow along the top dominant channel to areas far away from the wellbore, forming retention losses (Williams et al., 2025). More importantly, the alternating injection and production of multiple wells will induce large-scale pressure wave propagation and streamline reconstruction inside the tunnel, causing the mixing interface of methane, H₂, CO₂ to no longer be a static stratification, but a periodic advancing and retreating swinging interface. The width of the mixing zone continues to expand with the increase of injection and production cycles (Kowalski et al., 2023).

The fluid migration in the injection production wellbore

varies. A wellbore is a passage that connects the surface and underground chambers, and its internal flow has three typical characteristics (Zeng and Grigg, 2006): firstly, the non-Darcy effect caused by high-speed flow, where the pressure difference near the wellbore is extremely large, and inertial resistance replaces viscous resistance to dominate the pressure drop. The flow enters the Forchheimer zone, and the conventional Darcy's law fails. The second is the abrupt change in component concentration. In the early stage of gas production, pure or two-component mixed gas in the wellbore storage space is the main component. In the middle and later stages, when the pressure wave is transmitted to the boundary of the CO₂ cushion layer, the CO₂ content in the produced gas will sharply increase in a short period of time, forming a breakthrough front. The third is the gravitational slippage and phase change in vertical pipe flow. When the well depth exceeds one kilometer, there is a significant difference in the slippage speed of H₂, methane, and CO₂ due to the density difference. Light components move up faster and the risk of water vapor condensation or hydrate formation increases significantly with the decrease of pressure and temperature. In severe cases, it can block the wellbore.

The cavern and wellbore are not isolated systems, but rather a throat area formed by fluid exchange between the perforation section and the near wellbore zone. This is both the starting point for injecting gas into the reservoir and the end point for the produced gas to converge into the well, with the most complex flow regime. When injecting gas, the high-speed jet forms a local high-pressure zone around the wellbore, and the gas advances towards the deep part of the cavity along the dominant channel. The gas displacement is first completed in the near wellbore area (Zhou et al., 2025). During gas production, the pressure gradient reverses and the gas converges from the reservoir to the wellbore. Low viscosity H₂ is preferentially extracted, while high viscosity and high-density CO₂ gas is relatively delayed. This asymmetric response between injection and extraction leads to the formation of a dynamic mixed halo of periodic expansion and contraction around the wellbore, and the spatiotemporal evolution of its gas composition directly affects the economic purity of the extracted gas and the retention efficiency of the cushion gas.

Overall, the current research consensus is that the operational logic of the cavern well combination is to "utilize the natural pattern of gravity differentiation, and manually control the speed of mixing interface advancement and component breakthrough timing through injection production system and well location deployment" (Williams et al., 2025). Regarding the stability issue of CO₂ cushion gas in flow direction conversion, scholars have proposed strategies such as variable rate injection production, intelligent well control, and injection production timing optimization to balance gas storage efficiency and cushion gas maintenance (Deng et al., 2025).

The preceding three subsections have systematically analyzed the fluid migration behaviors of CH₄, CO₂, and H₂ in porous matrix, matrix with fractures, and combination of caverns and injection production wells, respectively. It is evident that the three gases exhibit markedly different migration characteristics across these storage spaces, owing to their distinct

physicochemical properties (e.g., viscosity, density, interfacial tension, diffusion coefficient, and adsorption affinity) and the specific structural constraints of each medium.

4 Development bottlenecks and research prospects

During the long-term operation of depleted oil and gas reservoirs, multiple rounds of injection and production trigger effective stress reciprocating loading, leading to fatigue accumulation, subcritical crack propagation, and permeability hysteresis loops in the reservoir. Meanwhile, the coupling effect of thermal fluid solid chemical promotes the deterioration of pore throat structure and fault stability over time. The crack network undergoes nonlinear reconstruction driven by stress, dissolution/precipitation, and thermal stress, making it difficult for traditional sealing to be compatible and achieve selective repair. The above effects are superimposed near the wellbore and coupled with fault activation, forming the highest risk chain. Based on this, this section proposes research prospects for safe and efficient operation by comprehensively analyzing existing knowledge and shortcomings.

4.1 Reservoir fatigue damage induced by injection production cycle and dynamic evolution of permeability

The operation of depleted oil and gas reservoirs is essentially a periodic pressure disturbance on a scale of several decades. Each injection production cycle causes the effective stress to be repeatedly loaded between the minimum and maximum values, resulting in the accumulation of elastic-plastic deformation of the reservoir rock skeleton, irreversible shrinkage of the pore throat structure, subcritical expansion of natural fractures, and attenuation of the matrix fracture flow capacity. The current research on the characterization of "static" reservoir properties is relatively mature, but there is a lack of quantitative understanding of the cumulative rate of "dynamic" fatigue damage, the evolution trajectory of permeability hysteresis loops, fatigue thresholds, and critical cycle times. The existing numerical simulators generally adopt a permeability update strategy based on instantaneous effective stress, which cannot describe the damage memory effect and recovery delay, resulting in a systematic underestimation of the decline rate of injection production capacity and a biased optimistic prediction of storage efficiency. Introduce continuum damage mechanics and cyclic plasticity constitutive models to establish a fatigue life prediction method for reservoir rocks under multiaxial stress cycling. Develop seepage mechanics time-delay coupling algorithm to characterize the phase difference between pressure wave propagation and deformation response. Based on indoor long-term cyclic loading experiments and fiber optic in-situ strain monitoring, establish a classification evaluation standard for reservoir fatigue damage. Explore machine learning driven permeability evolution proxy models to achieve real-time optimization of injection production systems and dynamic warning of remaining reservoir life.

4.2 Multi-field coupling mechanism and dynamic evaluation of trap suitability in multiphase porous media

The “trap” of gas storage is no longer a static geological structure, but a dynamic system that continuously responds under the coupling of thermal fluid solidification chemical fields. The mineral dissolution/precipitation induced by CO₂ injection changes the pore throat structure, H₂ reduction of iron containing minerals induces the formation of microcracks, low-temperature medium injection and production leads to thermal stress induced cracking, and pore pressure fluctuations affect the fault activation threshold. The suitability of a trap is no longer a binary judgment of “yes/no”, but a continuously deteriorating state variable over time. However, the current evaluation system for gas storage site selection still relies on static geological parameters (cap thickness, breakthrough pressure, fault activity) as the core, lacking the ability to predict the dynamic evolution of trap integrity under coupled long-term injection and production disturbances. Establish a four field fully coupled dynamic evaluation framework for gas storage traps, integrating chemical reaction kinetics, subcritical fracture propagation criteria, salt rock creep law, and fault sliding criteria into the reservoir cap rock fault integrated model. Developing a time-varying probability evaluation method for trap suitability, shifting from deterministic indicators to dynamic risk characterization that includes failure probability and remaining life. Promote a real-time integrity warning system driven by digital twins, integrating micro-seismic monitoring, ground subsidence inversion, and wellhead pressure fluctuation analysis, achieving a leap from “one-time evaluation during site selection” to “dynamic adaptation throughout the entire lifecycle”.

4.3 Multi-scale seepage evolution of complex fracture network and intelligent sealing of microbial mineralization

Crack type energy storage space is a heterogeneous amplifier and a sensitive indicator of multi field coupling response. We are currently facing three bottlenecks: firstly, the difficulty in characterizing fracture networks—from nanoscale microcracks to meter level faults, a single observation method cannot cover the entire scale range, and both discrete fracture network models and equivalent continuous medium models have limitations. The second challenge is the difficulty in predicting evolution—crack opening exhibits nonlinear, non-monotonic, and spatiotemporal non-uniform evolution under the combined effects of effective stress, chemical dissolution, mineral precipitation, and thermal stress. Existing models generally ignore the long-term transformation of crack permeability through chemical mechanical coupling. Thirdly, it is difficult to seal and repair—traditional cement sealing has poor compatibility with reservoir mechanics, and the interface is prone to forming new leakage channels, and selective sealing cannot be achieved. Developing multi-scale fracture characterization fusion technology, assimilating core CT, imaging logging, micro-seismic monitoring, and outcrop analog data into a fractal discrete fracture network model. Establish a chemical mechanical coupled fracture

permeability time-varying model to quantify the interaction between dissolution precipitation competition and stress sensitivity. Breakthrough the microbial induced calcium carbonate precipitation sealing technology, by regulating the concentration of bacterial solution, injection rate, environmental pH, and nutrient ratio, to achieve gradient controllable sealing of crack opening and anisotropic repair of permeability. Explore intelligent response plugging materials (temperature sensitive gel, pressure sensitive foam cement), and endow the leakage channel with the self-healing ability of “self-sensing directional migration in-situ solidification”.

4.4 Collaborative control of integrity evolution and fault activation in injection production well cavity system

The injection production well cavity complex is the most concentrated part of energy exchange, the most severe pressure disturbance, and the most concentrated risk of failure in gas storage facilities. The deformation of the cavity leads to stress redistribution in the near wellbore reservoir, inducing preferential fluid flow towards the relief zone and distortion of the injection production section. Wellbore fatigue (debonding of cement sheath interface and collapse of casing under alternating temperature and pressure loads) forms a preferential leakage channel along the wellbore. Fault activation (increasing pore pressure and reducing effective stress) may induce the re sliding of sealed faults, instantly releasing accumulated displacement, shearing the wellbore or communicating with the overlying strata. The current research divides the wellbore, cavity, and fault into independent objects, lacking a systematic integrity model of well cavity fault. Construct an integrated numerical simulation platform for wellbore cavity fault integrity, to uniformly characterize the cascading response chain of cavity creep convergence near wellbore stress redistribution cement sheath interface damage fault sliding potential. Developing real-time monitoring technology for wellbore based on distributed fiber optic acoustic/strain sensing, achieving joint inversion of deformation field, temperature field, and seepage field, and precise positioning of leakage sources. Establish a dynamic correction method for the activation pressure threshold of faults, considering the lag effect of injection production history on the accumulation of pore pressure and effective stress evolution within faults. Exploring a collaborative control technology for fault stability that combines active pressure control, grouting reinforcement, and microbial sealing, while ensuring injection and production efficiency, to control the probability of fault activation within an acceptable risk range.

5 Conclusions

The study of fluid migration in depleted oil and gas reservoirs has undergone decades of development, evolving from the early evaluation of injection and production capacity based on Darcy’s law to a systematic interdisciplinary field that integrates geomechanics, geochemistry, and computational fluid dynamics. This article focuses on the core perspective of fluid migration, starting from two dimensions: reservoir physical properties and fluid medium characteristics. It systematically reviews the

research progress on fluid migration in three typical geological bodies, from pore scale to engineering scale, covering porous media, fractured matrix bodies, and the combination of caverns and injection production wells. The following conclusions are drawn:

(1) The physical and chemical properties of natural gas, CO₂ and H₂ are vastly different, resulting in significant differences in their transport behavior within the same storage space. Methane is a classic medium with balanced physical properties and predictable behavior. Its transport is dominated by pressure driven seepage, and its engineering experience is mature. It is an ideal buffer gas for multi medium collaborative storage. Carbon dioxide has strong chemical activity and great ability to transform reservoirs. Long term storage must face the uncertainty of dynamic reconstruction of pore throat structures. Hydrogen gas has the properties of being extremely light, extremely fast, highly diffusive, and weakly adsorbed, which makes it face multiple shortcomings in terms of storage safety.

(2) The diversity of storage space types further amplifies the complexity of medium response. In porous matrix, gas migration follows the coupling mechanism of Darcy flow and diffusion/slip, and although the matrix permeability is low, it contributes a significant storage capacity. In matrix bodies with fractures, fractures dominate high-speed transport and the matrix is responsible for the main reservoir. The opening of fractures exhibits nonlinear, non-monotonic, and time-varying evolution in the joint game of effective stress, chemical dissolution, mineral precipitation, and thermal stress shock. In the combination of caverns and injection production wells, the flow pattern transitions from seepage to free flow, improving injection production efficiency. However, the leakage path at the boundary is highly concentrated, and mechanisms such as creep convergence, thermal stress-induced cracking, and salt crystallization self-sealing block are intertwined, which differs from porous matrix bodies.

(3) The fatigue damage induced by injection production cycles is the fundamental cause of the deterioration of reservoir properties over time. Each round of pressure fluctuations accumulates plastic strain in the rock skeleton, and the hysteresis loop of permeability decreases year by year. The decreasing injection production capacity and the increasing demand for cushion gas become irreversible long-term trends. Introducing continuum damage mechanics into reservoir fatigue life evaluation and establishing a seepage mechanics time-delay coupling algorithm is the theoretical key to breaking through the empirical design of current injection production systems. The fault activation threshold and trap integrity caused by mineral dissolution/precipitation induced by natural gas, CO₂ and H₂ injected into gas storage facilities, microcrack formation induced by hydrogen reduction of iron containing minerals, thermal stress induced fracturing caused by low-temperature medium injection and production, and pore pressure fluctuations are no longer functions of static geological parameters, but rather state variables of continuous degradation under the coupling of thermal fluid solidification fields.

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Conflict of interest

The authors declare no competing interest.

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