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Enhanced Gas Recovery and Dominant Geological Factors for CO_2 Injection in Offshore Gas Reservoirs with Weak Edge-Bottom Aquifer

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ABSTRACT

CO_2 injection into gas reservoirs offers dual benefits of enhancing gas recovery and achieving carbon storage. However, the effectiveness of this process varies significantly across different geological settings, making it essential to identify the primary geological factors. Using the DF gas field with a weak edge-bottom aquifer in the South China Sea as a case study, a numerical model was established for CO_2-enhanced gas recovery (CO_2-EGR), which incorporated key mechanisms such as phase behavior, CO_2 diffusion, and dissolution. Various geological factors were systematically evaluated to determine their influence on EGR. Results indicate that reservoir heterogeneity, thickness and edge-bottom aquifer are the dominant controlling factors, whereas permeability, rhythmic type, and dip angle (0~5°) exhibit comparatively minor effects. Horizontal heterogeneity, in particular, exerts the strongest impact on recovery performance. Reservoirs with thin layers (<10 m), large aquifers (5~10 times), or low permeability (<10 mD) show higher potential for EGR, primarily due to their lower recovery under depletion development. Composite and reverse rhythmic reservoirs are more favorable for CO_2 injection, with improved recovery observed when CO_2 is injected into lower structural positions. Well placement and pattern design for CO_2 injection should prioritize reservoir heterogeneity, thickness, and aquifer characteristics. In the DF gas field, a configuration with three CO_2 injection wells is projected to enhance gas recovery by 12% and sequester over one million tons of CO_2 annually, supporting the green and low-carbon development of offshore gas fields.

Keywords: CO_2 injection, enhance gas recovery, geological factors, reservoir heterogeneity, edge-bottom aquifer

NONMENCLATURE

Abbreviations	
EGR	Enhanced gas recovery
CCUS	Carbon capture, utilization and storage
CO_2-EOR	CO_2-enhanced oil recovery
CO_2-EGR	CO_2-enhanced gas recovery

1. INTRODUCTION

In September 2020, China officially announced the dual-carbon goals of achieving carbon peak by 2030 and carbon neutrality by 2060. As an indispensable component of the carbon neutrality technology portfolio, carbon capture, utilization and storage (CCUS) serves as both a key technical approach and a fundamental guarantee for realizing these objectives[1-2]. CO_2 utilization technologies can be categorized based on application into oil and gas reservoir utilization, chemical utilization, and biological utilization. Among these, CO_2 flooding for enhanced oil recovery (CO_2-EOR) is currently the most widely deployed CCUS technology. In contrast, CO_2-enhanced gas recovery (CO_2-EGR) remains largely in the stage of mechanistic investigation and small-scale pilot testing[3]. Most pilot projects have been conducted in Europe, North America, and Australia[4-6], with the primary goal of CO_2 sequestration. Due to limited field experience, the mechanisms and production performance of CO_2 injection in gas reservoirs are still not fully understood, which hinders the further development and application of CO_2-EGR technology.

In recent years, researchers worldwide have conducted extensive studies on the mechanisms and key parameters of CO_2-EGR[7-8]. Research on CO_2-EGR mechanisms primarily involves multi-phase and multi-

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component phase behavior, adsorption and diffusion processes, as well as CO_2-water-rock chemical reactions[9-11]. The efficiency of CO_2 displacement varies significantly depending on rock and fluid properties, temperature, pressure conditions[3,12], and becomes even more challenging to evaluate in heterogeneous gas reservoirs with complex pore structures. Studies on key parameters of CO_2-EGR have begun to establish preliminary screening criteria for suitable target formations based on fluid properties, reservoir characteristics, and injection-production features. Additionally, engineering parameters such as well placement, injection timing, and injection-production strategies also significantly influence the effectiveness of CO_2-EGR[13-15]. Nevertheless, there remains a lack of systematic investigation into the impact of geological factors on CO_2-EGR performance. A clear understanding of the EGR effects and the dominant geological controlling factors is essential to guide target screening and well deployment for CO_2-EGR projects.

This paper takes the DF gas field in the South China Sea as a case study. By considering gas injection phase behavior, CO_2 diffusion, and dissolution effects, a CO_2-EGR model is established for a gas reservoir with a weak edge-bottom aquifer. The model is used to investigate the influence of geological factors on the effectiveness of CO_2-enhanced gas recovery, including reservoir physical properties, heterogeneity, rhythmicity, structure, and aquifer activity. The study aims to clarify the EGR performance and identify the main geological controlling factors, thereby providing guidance for gas injection strategies in the DF gas field..

2. MODELLING FOR CO_2 INJECTION TO ENHANCING GAS RECOVERY

2.1 Numerical simulation model

Based on the geological and development characteristics of the DF gas field in the South China Sea, a heterogeneous dual horizontal well model for CO_2 injection to enhance gas recovery was established using the CMG-GEM compositional simulator, as illustrated in Fig. 1. The model dimensions are 2000 m×2000 m×30 m, with a grid resolution of 50 m in the horizontal direction. The horizontal well is placed in the middle of the reservoir, with an injector-producer spacing of 2000 m and a horizontal section length of 1000 m. The reservoir porosity is set at 0.2. Accounting for both areal and vertical heterogeneity, the average permeability is 33 mD, and the rock compressibility is 5.416×10^{-7} kPa^{-1}. The initial reservoir pressure is 14 MPa, and the reservoir contains gas and water phases, with an initial gas saturation of 0.452. The natural gas is dry gas, primarily composed of CH_4, with hydrocarbon gases accounting for 77% of the molar composition, CO_2 content at 0.5%, and the remainder consisting of N_2. The formation water is of $NaHCO_3$ type, with a salinity of 31,520 mg/L.

2.2 Numerical simulation model

To characterize the mechanism of enhanced gas recovery (EGR) by CO_2 injection, the natural gas is represented using six pseudo-components: CO_2, N_2, CH_4, C_2H_6toNC_4, IC_5toFC_6 and C_{7+}. The model accounts for the effects of CO_2-natural gas phase behavior, CO_2 diffusion, and CO_2dissolution in water on EGR performance. Phase behavior interactions between CO_2 and natural gas are simulated using the CMG-WINPROP simulator. A CO_2 diffusion coefficient of 6×10^{-4} cm^2/s, obtained from laboratory measurements, is incorporated into the model. The dissolution of CO_2 in formation water, which depends on temperature, pressure, and salinity, is described using a modified Henry's law[16].

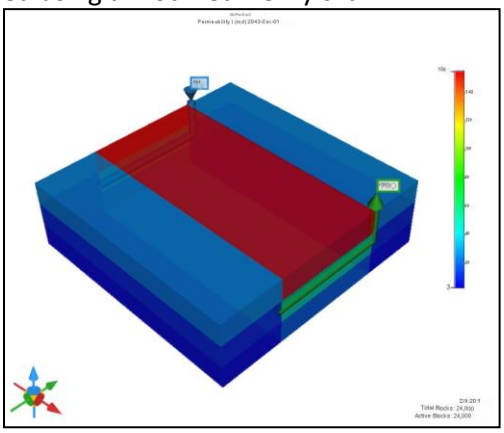


Fig. 1. Heterogeneous model of dual horizontal wells with one injection and one production

2.3 Gas injection scheme design

In order to investigate the influence of geological factors on enhancing gas recovery through CO_2 injection, eight key geological parameters were selected for this study, which included average permeability, permeability ratio, reservoir rhythmicity, thickness, dip, aquifer volume. The value range for each factor was determined based on an analysis of the geological characteristics of the target area. The development strategy involves switching to gas injection after depletion, employing a fixed production rate with a wellhead pressure constraint (250,000 m^3/day at 1.5 MPa). The production thresholds include a minimum gas production rate of 20,000 m^3/day, a maximum water–gas ratio of 0.0005 m^3/m^3, and a maximum CO_2 content in the produced gas of 85%. For the injection well, a fixed

injection rate of 250,000 m³/day is maintained, with the injected gas containing 90% CO_2.

3. EFFECT OF GEOLOGICAL FACTORS ON ENHANCE GAS RECOVERY BY CO_2 INJECTION

3.1 Reservoir permeability

Permeability is a key parameter for evaluating reservoir physical properties. To investigate the effect of reservoir properties on enhancing gas recovery through CO_2 injection, simulations were conducted to compare depletion recovery, gas injection recovery, and the incremental recovery from gas injection across a range of average permeability values (5~100 mD), as shown in Fig. 2. The results indicate that as the average permeability of the reservoir increases, both depletion recovery and gas injection recovery increase accordingly. However, the recovery from gas injection development exhibits only a slight upward trend. Low-permeability gas reservoirs (below 10 mD) demonstrate a low recovery factor after depletion development, significant remaining gas potential, and a more substantial increase in recovery during gas injection.

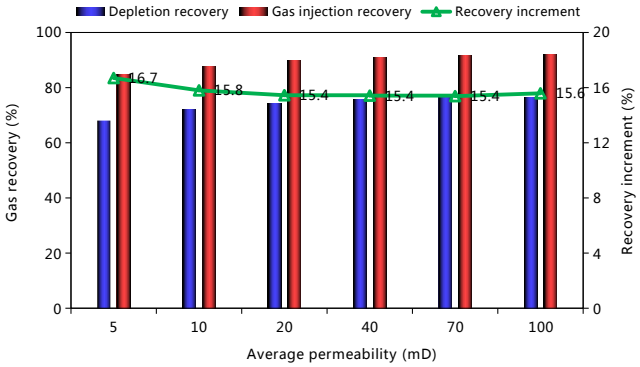
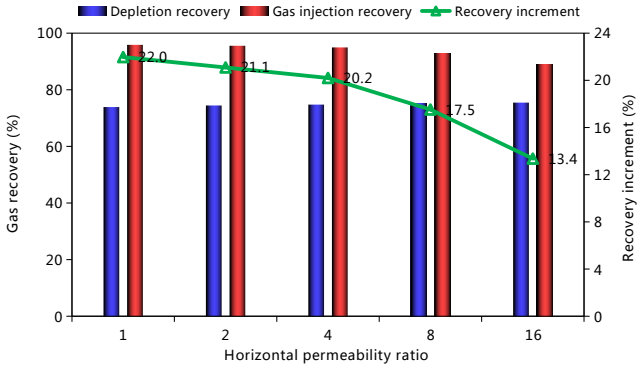


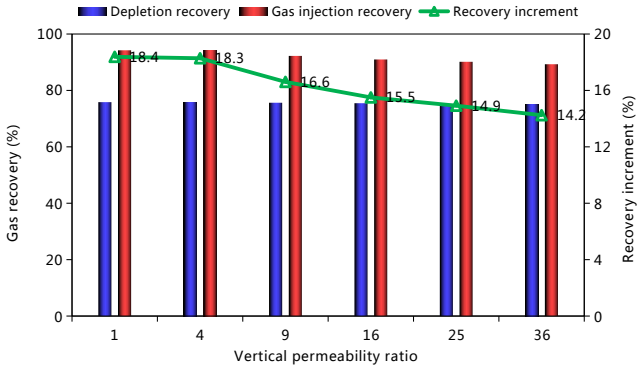
Fig. 2. Effect of average permeability on gas recovery factor and recovery increment

3.2 Reservoir heterogeneity

To investigate the influence of reservoir heterogeneity on enhanced gas recovery through CO_2 injection, simulations were conducted to compare depletion recovery, gas injection recovery, and the incremental recovery from gas injection under varying degrees of horizontal permeability contrast (ranging from 1 to 16) and vertical permeability contrast (ranging from 1 to 36), as shown in Fig. 3. The results indicate that as reservoir heterogeneity increases, the recovery factor from depletion development remains relatively stable, whereas the recovery factor from gas injection development declines significantly. This leads to a pronounced reduction in the incremental recovery contributed by gas injection. Furthermore, it can be observed that with increasing horizontal and vertical heterogeneity, the incremental recovery from gas injection decreases, with horizontal heterogeneity exerting a more substantial influence on the gas injection performance. This difference in impact can be attributed to the fact that the reservoir thickness is much smaller than the well spacing. As a result, CO_2 can more readily migrate into vertically low-permeability zones through diffusion, mitigating the effect of vertical heterogeneity. Consequently, vertical heterogeneity has a weaker influence on gas injection efficiency compared to horizontal heterogeneity.



(A) Horizontal heterogeneity



(B) Vertical heterogeneity

Fig. 3. Effect of reservoir heterogeneity on gas recovery factor and recovery increment

3.3 Reservoir rhythmicity

To investigate the influence of reservoir rhythmicity on enhanced gas recovery by CO_2 injection, simulations were conducted to compare the depletion recovery, gas injection recovery, and incremental recovery from gas injection in three types of reservoirs, including positive rhythm, reverse rhythm, and composite rhythm (with intermediate high permeability), as shown in Fig. 4. The results indicate that the depletion recovery efficiency varies only slightly among the different rhythmic types. Overall, however, the incremental recovery from gas injection in composite and reverse rhythm reservoirs is more than 1% higher than that in positive rhythm

reservoirs. This difference can be attributed to the higher viscosity and density of the injected CO_2-rich gas compared to the methane-rich in-situ gas. Under the influence of gravity, the denser CO_2 tends to migrate downward within the reservoir. In positive rhythm reservoirs, where permeability increases with depth, this gravitational segregation causes the injected gas to accumulate preferentially in the high-permeability bottom layers, thereby reducing the sweep efficiency. In contrast, in composite rhythm reservoirs, the high-permeability zone is located in the middle. This allows the injected CO_2 to disperse more uniformly both upward and downward, enhancing overall sweep efficiency. The cross-well profile of injected CO_2 molar concentration visually confirms that the sweep efficiency of the injected gas is significantly lower in the positive rhythm reservoir compared to the composite and reverse rhythm reservoirs.

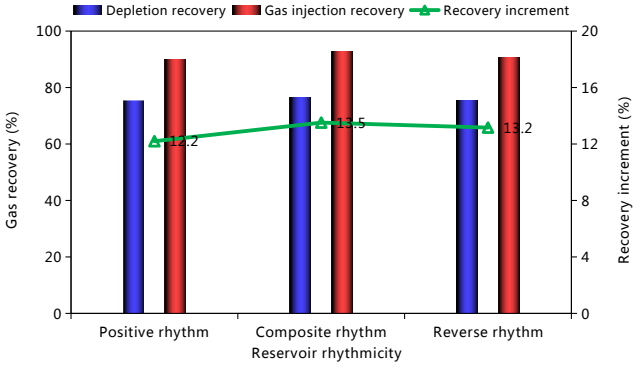


Fig. 4. Effect of reservoir rhythmicity on gas recovery factor and recovery increment

3.4 Reservoir structure

To investigate the influence of reservoir structure on enhancing gas recovery through CO_2 injection, this study examines the effects of reservoir thickness and dip angle. Simulations were conducted to compare depletion recovery, gas injection recovery, and the incremental recovery from gas injection under various reservoir thicknesses (10~60 m) and dip angles (0~5°), with CO_2 injected from a lower position. The results are presented in Fig. 5 and Fig. 6. As shown in the figures, the depletion recovery factor increases significantly with greater reservoir thickness, while the gas injection recovery factor remains relatively stable. Consequently, the overall incremental recovery from gas injection decreases. In contrast, as the dip angle increases, the depletion recovery factor remains largely unchanged, whereas both the gas injection recovery factor and the incremental recovery demonstrate an increasing trend. The analysis indicates that thicker reservoirs enhance the productivity of gas wells and allow the abandonment pressure to be lower when the minimum gas production rate is reached, thereby improving depletion recovery. However, thicker reservoirs also weaken the ability of the injected high-density CO_2 to improve sweep efficiency through diffusion, limiting the enhancement in recovery. On the other hand, the high density of the injected CO_2-rich gas enables it to act as a cushion when injected at the lower part of the reservoir. This helps mitigate gas channeling and improve sweep efficiency, particularly in reservoirs with a higher dip angle where gravitational stabilization enhances the effectiveness of the injection process.

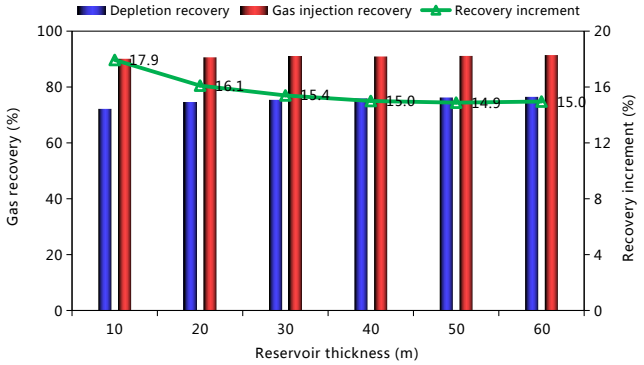


Fig. 5. Effect of reservoir thickness on gas recovery factor and recovery increment

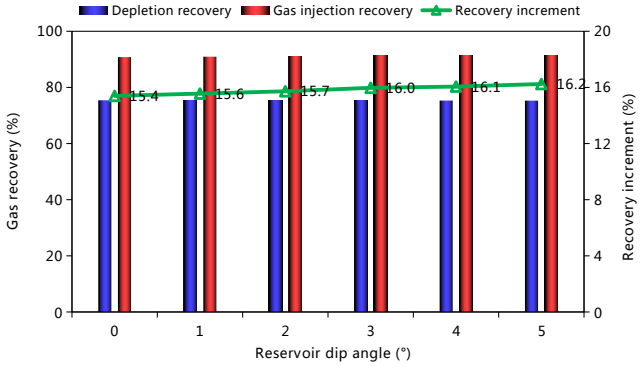
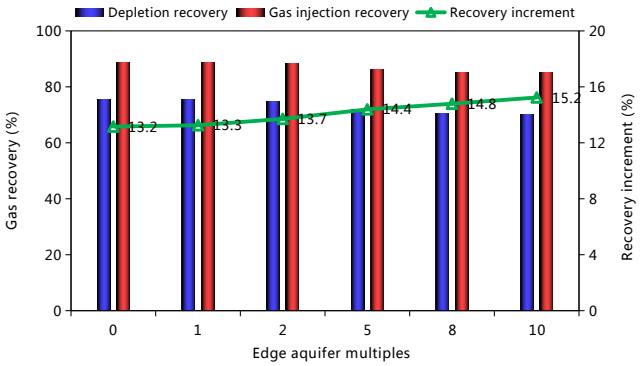


Fig. 6. Effect of reservoir dip on gas recovery factor and recovery increment

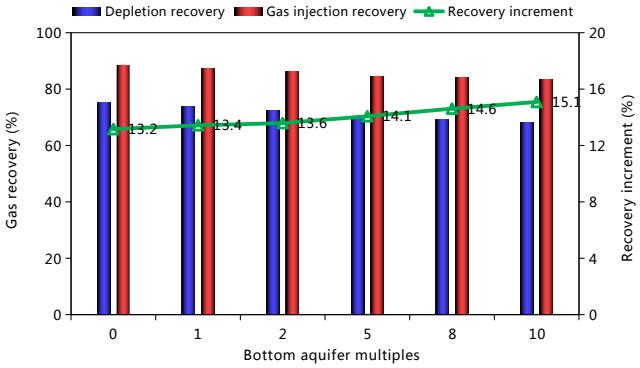
3.5 Edge and bottom aquifer

To investigate the influence of edge and bottom aquifers on enhancing gas recovery by CO_2 injection, simulations were conducted to compare depletion recovery, gas injection recovery, and the incremental recovery from gas injection under different aquifer multiples ranging from 0 to 10, as shown in Fig. 7. The results indicate that under weak aquifer conditions (aquifer multiple < 10), as the aquifer size increases, both depletion recovery and gas injection recovery exhibit a decreasing trend. However, the incremental recovery from gas injection shows an increase. As reservoir pressure declines, aquifer influx can be viewed as a process of water displacing gas, wherein the aquifer

provides additional energy to the gas reservoir. While this helps maintain reservoir pressure to some extent, it also introduces risks such as water blocking and water accumulation in the wellbore. Under weak aquifer conditions, the impact on both depletion and gas injection development is limited. However, as the aquifer multiple increases, stronger water invasion raises the flow resistance of the gas phase, reduces well productivity, and increases the risk of water accumulation in the wellbore. These effects lead to a higher abandonment pressure and lower recovery factor. At the same time, the reduced depletion recovery leaves a larger volume of remaining gas in place. By injecting CO_2 into the reservoir, gas well productivity and wellbore liquid-carrying capacity can be improved, thereby enhancing recovery performance. This mechanism contributes to the observed increase in incremental recovery with larger aquifer multiples, despite the challenges posed by water influx.



(A) Edge aquifer



(B) Bottom aquifer

Fig. 7. Effect of edge and bottom aquifer on gas recovery factor and recovery increment

3.6 Analysis of dominant geological factors

To evaluate the impact of geological factors on enhancing gas recovery through CO_2 injection, the incremental recovery at different levels of each factor was selected as the test indicator. The standard deviation of incremental recovery for each factor was then analyzed: a larger standard deviation indicates greater variation in the test indicator across different levels, reflecting higher sensitivity of the factor. Conversely, a smaller deviation implies lower sensitivity. The sensitivity ranking of the factors, derived from this standard deviation analysis, is presented in Fig. 8. The results reveal significant differences in the sensitivity of geological factors affecting CO_2-enhanced gas recovery. Reservoir heterogeneity, reservoir thickness, and the energy of edge/bottom aquifers were identified as the most influential factors. These were followed by reservoir rhythmicity, physical properties, and dip angle. Therefore, in the selection of target areas for CO_2 injection and the design of well patterns, particular attention should be given to reservoir heterogeneity, thickness, and aquifer energy to optimize the effectiveness of gas injection development.

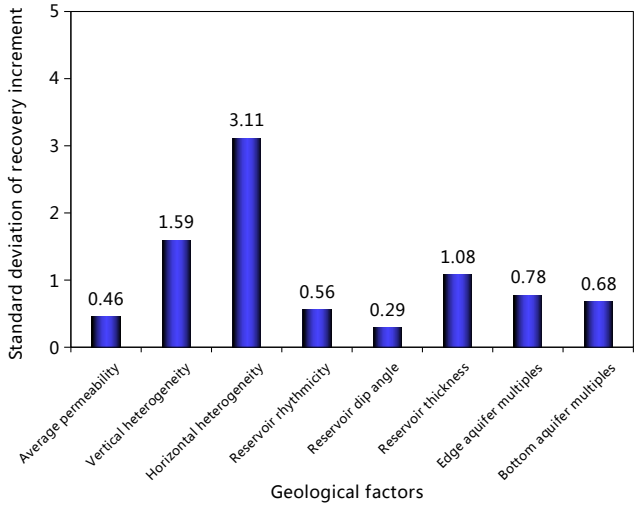


Fig. 8. Sensitivity of various geological factors to gas recovery increment

4. ANALYSIS OF CO_2 INJECTION EFFECT IN TARGET AREA

4.1 Gas field overview and production status

The DF Gas Field in the South China Sea is a combined carbon and hydrocarbon gas resource, containing both high-CO_2 and high-hydrocarbon gas reservoirs. It is characterized as a lithological and structural-lithological reservoirs, with some well areas experiencing weak edge and bottom water aquifer. The reservoir properties are generally medium porosity and medium permeability, though certain zones exhibit medium porosity and low permeability. The formation temperature is approximately 81 °C, with an initial formation pressure of about 14 MPa and a pressure coefficient ranging from 1.01 to 1.08. The distribution of CO_2 and hydrocarbon components is complex, where the northern part

contains higher concentrations of CO_2 and the southern region is richer in hydrocarbons. The hydrocarbon content varies between 25% and 84%. The gas field features a large areal extent, low reserve abundance, moderate productivity, and exhibits complex reservoir connectivity as well as heterogeneous gas composition.

The gas field is currently in the mid to late stages of development. The CO_2 content in the produced gas mixture has reached nearly 50% (Fig. 9), while the current recovery factor ranges only from 26% to 68%. The predicted ultimate recovery under depletion development is estimated between 34% and 80%, indicating that a significant volume of hydrocarbon gas remains untapped. Due to specifications for downstream gas composition and limited decarbonization capacity, the major high-CO_2 gas reservoirs (areas E1 and E2, with CO_2 content of 50%~70%) are under restricted production. These zones maintain a relatively high reservoir pressure coefficient (0.51~0.91) and retain strong productivity potential. In contrast, the wellhead pressure in the main high-hydrocarbon gas reservoirs (areas D1 and D2, with hydrocarbon content around 75%) has approached the gathering system pressure, with low reservoir pressure coefficient (0.29~0.58) and significantly reduced productivity. Effective measures are urgently required to unlock the production potential of the high-CO_2 zones and enhance the recovery of high-hydrocarbon reservoirs.

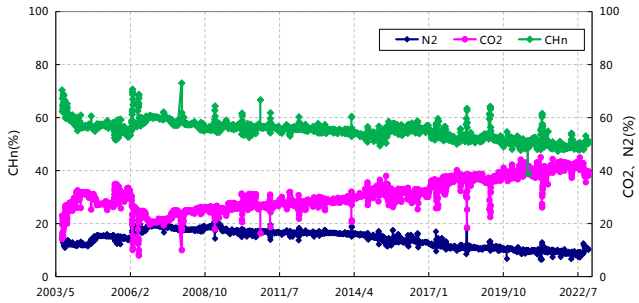


Fig. 9. Content change of gas mixture produced from the gas field

4.2 CO_2 injection scheme design and development effect

To enhance the overall development efficiency of the DF Gas Field in the South China Sea, a strategy is proposed to capture high-concentration CO_2 from the high-carbon zones (E1 and E2) and inject it into the high-hydrocarbon reservoirs (D1 and D2) for localized utilization as shown in Fig. 10. This approach not only improves the recovery of hydrocarbon-rich reservoirs but also unlocks the production potential of high-carbon zones while reducing carbon emissions. The goal is to achieve coordinated development of hydrocarbon and carbon resources, maximizing hydrocarbon recovery, minimizing carbon emissions, and optimizing the quality of export gas.

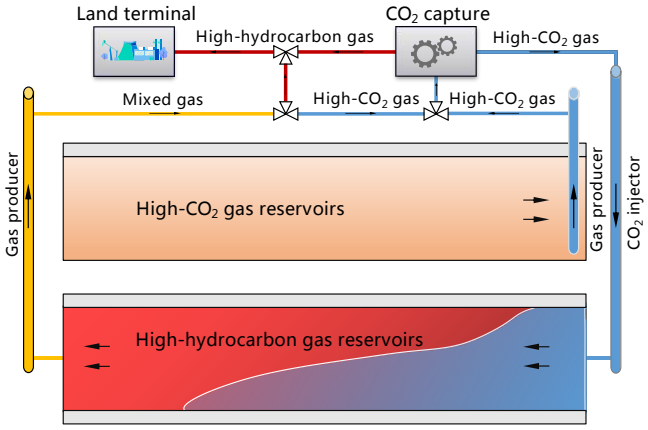


Fig. 10. Schematic diagram of in-situ offshore CO_2-EGR process

Based on the analysis of key geological factors influencing CO_2-EGR, three injection wells are planned in structurally low areas with good reservoir connectivity and low heterogeneity between injectors and producers. This configuration helps ensure clear well interference responses and reduces the risk of gas channeling. High-purity CO_2 (99%) is used for injection to minimize the loss of hydrocarbon gas from the high-carbon production stream and improve the efficiency of gas injection in the high-hydrocarbon zones. A three-stage injection strategy is designed to achieve rapid pressure support, stable displacement, and reduced gas channeling. Through numerical simulation optimization, the recommended injection rates for the three stages are 1.75 million m^3/day, 1.4 million m^3/day, and 0.7 million m^3/day, respectively. Corresponding production wells are allocated at 0.4 times their open flow capacity to maintain balanced voidage replacement. Compared to depletion development, the gas injection area shows significantly improved hydrocarbon recovery, with a notable reduction in remaining gas saturation. The hydrocarbon recovery in the injection area is projected to increase by 12%. Additionally, this process enables the annual sequestration of approximately 1.2 million tons of CO_2 in the initial stage of injection, with cumulative storage reaching nearly 10 million tons. The results demonstrate substantial benefits in both enhanced gas recovery and carbon storage.

5. CONCLUSIONS

(1) The primary geological factors controlling the effectiveness of CO_2 injection for enhanced gas recovery (EGR) are reservoir heterogeneity, thickness, and edge/bottom aquifers. In contrast, reservoir physical

properties, rhythmicity, and dip angle (0~5°) exhibit relatively minor influence. Therefore, reservoir heterogeneity, thickness, and aquifer characteristics should be prioritized in the selection of target areas and well pattern design for CO_2 injection to optimize development performance.

(2) Reservoir heterogeneity, particularly areal heterogeneity, exerts a significant impact on the efficiency of CO_2-EGR. Under similar heterogeneity conditions, thin reservoirs (<10 m), large aquifer (5~10 times), or low-permeability gas reservoirs (<10 mD) demonstrate considerable potential for EGR through CO_2 injection, primarily due to their low recovery rates under depletion development. Furthermore, CO_2 injection in composite- and reverse-rhythm reservoirs yields higher recovery enhancement. Structural low points are also favorable for injection, as they help improve sweep efficiency.

(3) By integrating reservoir connectivity, heterogeneity, aquifer distribution, and remaining hydrocarbon gas characteristics of the target area, gas injection wells were optimally deployed in structurally low areas with good connectivity and low heterogeneity between injectors and producers. A three-stage high-purity CO_2 injection strategy is projected to increase hydrocarbon recovery in the target region by 12%, with an annual CO_2 storage capacity of 1.2 million tons and cumulative storage nearing 10 million tons. This approach demonstrates significant dual benefits in enhancing gas recovery and achieving carbon sequestration.

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DECLARATION OF INTEREST STATEMENT

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

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