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Carbone dioxide sequestration using downhole water sink (DWS) technology: Effects of well placement on trapping efficiency, leakage, and reservoir pressure

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Abstract

Geological CO_2 sequestration is a widely accepted technique that consists of safely and securely hiding carbon emissions from human activities by storing them underground. It is considered the main method of carbon dioxide capturing and sequestration because of its large-scale application. Use of Downhole Water Sink (DWS) systems and other advanced reservoir control technologies is driven by the necessity to manage effectively the reservoir pressure change, the CO_2 plume migration, and the leakage pathways. The effectiveness of the DWS technology in providing better CO_2 storage performance in a depleted reservoir surrounded by a saline aquifer has been the focus of this research. The study analyzed three operational scenarios to evaluate how the different distances between the DWS wells and the CO_2 injectors would affect the storage efficiency, the leakage behavior, and the management of the reservoir pressure. Scenario 1 had DWS wells located right under the CO_2 injectors which caused negative hydrodynamic interactions, decreased the total trapped CO_2 and increased the leakage indices. Scenario 2 had a tiny lateral offset which led to small improvements in trapping and tiny increases in leakage, implying partial but still insufficient mitigation of injector-sink interference. In Scenario 3, with a 10-grid offset between the injection and extraction wells, achieved the maximum CO_2 storage efficiency, where trapping gained 2.79% (431,235 tons) at a CO_2 injection rate of 20 MMSCF/day and a DWS flow rate of 12,500 bbl/day. Leakage did not change, maintaining a Leakage Index of +0.06898 which indicated only a slight increase that was barely noticeable when compared to the more varying responses in Scenarios 1 and 2. In addition, the operation of DWS in Scenario 3 led to a peak pressure of the reservoir that was lower than that of the case without DWS, as the pressure dropped from about 6150 psi to 5100–5794 psi, thus relieving some of the stress on the formation. Although no specific fracture pressures or geomechanical analyses were performed, the pressure drop is likely to create better injection conditions and also enhance the integrity of the storage area. The overall results show that the DWS wells, when placed and managed properly and strategically, can not only increase the CO_2 trapping efficiency but also stabilize the leakage behavior and provide pressure control, thus making the geological CO_2 sequestration more reliable.

Keywords: CO_2 sequestration; depleted reservoirs; downhole water sink (DWS); leakage index; saline aquifers; trapping efficiency; Reservoir pressure management; well placement; CO_2 trapping mechanisms.

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1- Introduction

The global challenge of climate change has led to a significant rise in the interest around Carbon Capture and Storage (CCS) as one of the most fundamental processes for reduce human-made CO_2 emissions. Among all the methods of geological sequestration, especially in depleted oil and gas reservoirs and deep saline aquifers, it is considered the most feasible large-scale solution by the virtue of its enormous storage capacity, widespread availability, and potential to work with Enhanced Oil Recovery [1–5]. But the injection of huge amounts of CO_2 to subsurface formations will unavoidably cause the pressure in the reservoir to rise. If the pressure is not controlled well, the excessive pressure will reduce the rate of injection, increase the operational costs, and lead to adverse geomechanical effects such as caprock fracturing, fault reactivation, and CO_2 leakage, which would, in the end, jeopardize the safety of storage and the long-term containment [6–9].

In an effort to minimize the risks associated with pressure, several active pressure management strategies have been studied, and among them, controlled brine extraction has proved to be a good option. The Downhole Water Sink (DWS) technology allows for constant extraction of formation water, which leads to reduced reservoir pressure, better CO_2 injectivity, and enhanced storage security [10-12]. DWS is widely recognized as an advanced well completion technique in conventional oil and gas operations for the control of water production, but it functions as a pressure management tool in CO_2 injection wells, which helps to keep the reservoir pressure

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below the fracture limits, thus minimizing the risk of capping rock or formation fracturing. DWS lowers local pressures which consequently increases CO_2 injectivity, allows better distribution of CO_2 in the target layers, and ensures long-term containment reliability by reducing the chance of vertical migration or leakage through high-permeability zones. At the same time, recent innovations in numerical modeling, proxy modeling, and machine learning have greatly increased the efficiency of CCS system design and optimization. The combination of data-driven and physics-informed approaches has been utilized to determine the optimal injection strategies, forecast the CO_2 saturation, evaluate the geomechanical risks, and speed up the simulation-based decision-making process [13-17]. Furthermore, laboratory experiments and compositional simulation studies have provided better insights into the CO_2 trapping mechanisms and EOR performance under different injection modes, such as miscible flooding and water-alternating-gas schemes in the case of the latter [18-20].

Although there have been significant advancements in the field of pressure management and optimization methods, most of the studies conducted so far have treated these issues separately. The spatial relationship between CO_2 injection wells and DWS wells, especially the influence of their placement on the pressure distribution, CO_2 plume migration, trapping efficiency, and leakage, has received little attention. A lot of research work on DWS has mistakenly treated the wells as being fixed in one configuration or confined only to injection rate optimization thus ignoring the major factor of injector–sink interference in depleting reservoirs that are hydraulically connected to saline aquifers. Therefore, a comprehensive evaluation of the impact of DWS well placement on storage integrity and operational performance is still missing [21–23].

This research has as its main goal the systematic assessment of the impact of like spacing of DWS wells on geological CO_2 sequestration performance in a depleted sandstone formation linked to a saline aquifer beneath. Different operational scenarios are considered in order to measure the changes in the reservoir pressure response, CO_2 trapping efficiency, and leakage indices due to various injector–DWS spatial arrangements. The study, through the means of finding the proper placement that would reduce the negative hydrodynamic interactions, offers practical advice for the betterment of storage safety, control of pressure, and the dependable launching of CO_2 sequestration systems done with DWS assistance.

2- Reservoir simulation

A dynamic reservoir model that was compositional in nature was developed to assess the performance of CO_2 injection along with a Downhole Water Sink (DWS) system in an effort to store the maximum amount of CO_2 in an oil reservoir that has already been depleted and is located between two saline aquifers. Dissolution and residual trapping were the two mechanisms that the model mainly focused on, whereas mineral trapping was disregarded as it is generally a slow process and is expected to have a negligible impact on CO_2 trapping during the early to mid-term simulation period (e.g., first few decades). The study of [24] mentioned that in the reactive transport simulations mineral trapping is predicted to be very low (approx 0.01–0.03%) even after 500 years. The majority of the CO_2 has been trapped through the mechanisms of structure, residual, and dissolution, which implies that mineral trapping is insignificant compared to other mechanisms. Likewise, [25] mention that mineral trapping takes place usually over centuries to millennia depending on the composition of the minerals and the conditions, and thus has little contribution to trapping from decades to a century. The simulation covers the period until 2100, which is about 75 years after injection, thus the decision to exclude mineral trapping from the current simulations is not likely to introduce a large bias in the assessment of trapping efficiency over the modeled period. However, it is necessary to consider the eventual contribution for long-term storage projections.

The simulation was carried out using the CMG-GEM compositional simulator, which provided the opportunity to examine in detail the behavior of multiphase flows and the dynamics of CO_2 trapping. The representative sector model was located on the Main Pay Upper Sandstone Member, which is the primary productive layer of the reservoir. Initially, the model consisted of 34 wells:7 injectors and 27 producers, so as to simulate conditions at the field scale accurately. Nonetheless, for the CO_2 sequestration experiment, all oil extraction and water drawing wells were closed in August 2025, which was coincident with the start of CO_2 injection that would use four specialized CO_2 wells positioned correctly in the sector and distributed across the area.

The injection phase was simulated starting in August 2025 and lasting until 2040; thereafter, the model was prolonged to indicate the post-injection monitoring period that would last until 2100. a number of operational scenarios have been assessed which involved the use of CO_2 injection rates and DWS water removal and their effects on storage efficiency, leakage, and pressure control being the main aspects studied. The combined CMG-GEM together with CMOST-AI modeling method offers a reliable assessment of DWS technology sustainability under the given realistic reservoir conditions, allowing for the systematic evaluation of both short-term injection performance and long-term CO_2 containment.

- Objective function formulation

In the present research, four quantitative indicators were created to assess the CO_2 storage capacity in the Rumaila main pay upper sandstone formation numerically. The TTI or Total Trapping Index indicates the proportion of CO_2 that is both injected and effectively trapped within the formation. Residual Trapping Index (RTI) and Solubility Trapping Index (STI), on the other hand, denote the portions that are respectively immobilized in the pore space due to capillary action and dissolved in the brine [26]. If the indices are high, it means that the storage of CO_2 is efficient and safe.

Leakage Index (LTI) refers to the amount of CO_2 that is produced together with brine and is thus considered lost from the formation, provided that any gas that is captured is reinjected back into the formation [27].

The calculation of these indices is done in the following manner:

$$Total\ Trapping\ Index\ (TTI) = RTI+STI \tag{1}$$

$$Residual\ Trapping\ Index\ (RTI) = \frac{CO_2\ trapped\ by\ residual\ mechanisms\ (ton)}{Cumulative\ CO_2\ injected\ (ton)} \tag{2}$$

$$Solubility\ Trapping\ Index\ STI = \frac{CO_2\ trapped\ by\ dissolution\ (ton)}{Cumulative\ CO_2\ injected\ (ton)} \tag{3}$$

$$Leakage\ Index (LTI) = \frac{cumulative\ \ CO_2\ produced\ (ton)}{Cumulative\ CO_2\ injected\ (ton)} \tag{4}$$

3- Preliminary operational assessment of DWS-assisted CO_2 injection strategies

In order to acquire a fundamental comprehension of the interplay between the Downhole Water Sink (DWS) technology and the migration, trapping, and leakage of CO_2, three preliminary operational scenarios were created at first before any optimization engines were applied. These scenarios were devised to analyze systematically the direct effect of changing injection and extraction conditions without the interference of automated optimization algorithms. The evaluation was about the impact of the pressure-management strategies through DWS operations on the storage efficiency and the integrity of containment in the reservoir–aquifer system connected with a coupling.

For all the scenarios, the rates of CO_2 injection were changed from 3 to 20 million ft^3/day, while the DWS extraction rates were from 0 to 30,000 bbl/day. This wide operational range made it possible to control and explore how the pressure drawdown of different intensities affects the CO_2 plume development, the mechanisms of residual and solubility trapping, and the beginning of possible upward leakage through the caprock. In addition to this, The grid dimensions in the i and j directions are 500 ft per grid block and DWS wells were arranged in different spatial configurations: they were first completed in the deeper layers (11 and 12) right below the CO_2 injection wells, then moved 5 grid blocks away from the zones of injection (corresponds to a lateral distance of 3,000 ft) and 10 grid blocks away from the zones of injection (corresponds to a lateral distance of 5,000 ft). This spatial variation was intended to find out how the distance between the points of injection and extraction affects the efficiency of local pressure reduction and plume stabilization.

The main aim of this assessment stage was to determine the combinations of injection rates, DWS extraction rates, and spatial placements that would always promote CO_2 immobilization while leakage pathways would be suppressed. The use of such an approach made it possible to isolate and quantify the impact of DWS technology before introducing the more advanced optimization frameworks. The results obtained from these unoptimized scenarios were of great importance to the pressure-plume dynamics of DWS-assisted storage systems and were also helpful in defining realistic and physically meaningful operational limits.

In the end, the results from this initial research acted as a screening tool to direct the later optimization tasks. By limiting the future search area to operational zones that have already been shown to enhance trapping capacity and containment integrity, this phase guaranteed that further optimization efforts would be both computationally efficient and geologically robust.

3.1. Scenario 1: implementation of DWS beneath CO_2 injection wells

In the first operational scenario, Downhole Water Sink (DWS) technology was installed directly beneath the optimized CO_2 injection wells identified during the base-case optimization stage. The objective of this configuration was to try out the method of placing DWS wells directly below CO_2 injectors at the same grid coordinates in order to increase storage capacity through improved pressure management and water extraction control. In this setup, CO_2 injection wells were drilled to the upper layers of the reservoir (Layers 1–3), while the corresponding DWS wells were planned at the deeper parts of the formation (Layers 11–12). The vertical arrangement of these well pairs in Table 1 summarizes their design intention, which is to create local pressure-relief zones for CO_2 to stabilize in the storage formation. The injectors were working at very different rates, that is, from 3 to 20 million ft^3/day, while the DWS wells were also assigned varying rates from 0 to 12,500 bbl/day, thus the systematic investigation of plume behavior under different injection intensities and pressure drawdown conditions became possible.

The spatial arrangement of the CO_2–DWS well pairs in Scenario 1 is shown in Fig. 1 along with the specified vertical coupling that aims to sustain a favorable pressure gradient, limit the upward movement of CO_2 and enhance the overall trapping efficiency, It. The scenario is quite the detailed assessment of the extent to which vertically integrated DWS operations impact the subsurface hydrodynamics as far as plume stabilization, leakage mitigation, and pressure evolution throughout the storage interval are concerned. It is through the wide range of injection and extraction conditions that Scenario 1 provides a crucial baseline understanding of the relationship between engineered pressure control and dynamic CO_2 distribution. The insights thus gained are the basis for later scenarios that will consider more complex spatial well configurations and multi-layer optimization strategies in further analysis.

Table 1. Configuration of CO_2 injection and DWS wells in scenario 1

Well Number	CO_2 Injection Wells (Grid: x, y, Layer)	DWS Wells (Grid: x, y, Layer)
CO_2_1 / DWS_1	(1, 4, 1–3)	(1, 4, 11–12)
CO_2_2 / DWS_2	(34, 20, 1–3)	(34, 20, 11–12)
CO_2_3 / DWS_3	(44, 19, 1–3)	(44, 19, 11–12)
CO_2_4 / DWS_4	(67, 10, 1–3)	(67, 10, 11–12)

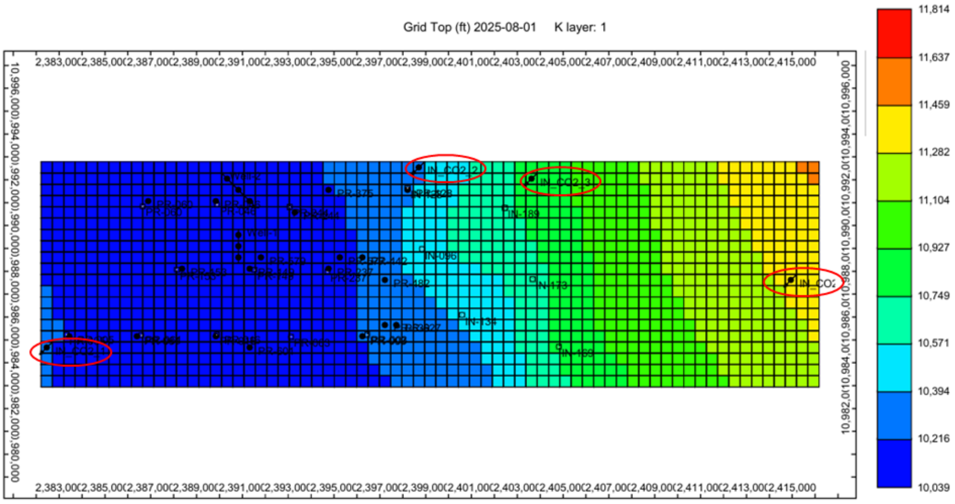

Fig. 1. Location of CO_2 injection and DWS wells

In Fig. 2, the trends of the objective functions clearly show that, the x-axis illustrates the Experiment ID, which signifies different simulation runs created in the course of sampling. The manually defined combination of CO_2 injection rate and DWS well extraction rate corresponds to each experiment, where the flow rates of CO_2 injection and DWS wells were systematically varied to assess their combined effect on storage performance. The unit ft^3/day is used for the CO_2 injection rate, which is specified at surface conditions, as it is a standard practice in reservoir simulation studies, although there were systematic changes in DWS extraction rates, Scenario 1 did not reach an improved CO_2 storage efficiency. The main reason is that the DWS wells are placed directly below the CO_2 injectors, which means that they are too close to the injection points. The DWS wells in this arrangement do not only help to relieve pressure and increase trapping of CO_2 but also are removing part of the injected CO_2 or changing the distribution of reservoir pressure in a way that is not favorable for immobilization. This effect is very evident in Fig. 2, where the first data point of the curve, which is corresponding to no DWS extraction, always gives the highest total trapped CO_2 for all injection rates. On the other hand, DWS extraction rates from 1,000 to 12,500 bbl/day result in lower trapped CO_2, and thus the negative effect of DWS operation under this vertical alignment is again confirmed.

The above findings imply that in Scenario 1, the DWS wells being very close to CO_2 injectors cause bad hydrodynamic interactions. The extraction cycles of the near-field instead of encouraging residual or solubility trapping are disruptive to the natural pressure gradient, thus increasing CO_2 mobility toward potential leakage pathways. Therefore, the scenario exposes one critical operational insight: DWS wells must be placed at an optimal distance from the CO_2 injection points so that there can be significant increases in storage efficiency and long-term containment. The results point out the need for careful DWS layout designs that will support plume stabilization without damaging the reservoir integrity.

3.2. Scenario 2: implementation of DWS wells at 5-grid offset from CO_2 injection wells

In the second operational outcome, the Downhole Water Sink (DWS) wells were lateral to the CO_2 injection points with five grid blocks displacement but were still in the vertical layer of the deeper reservoirs (Layers 11 and 12). The CO_2 injection wells kept their previously optimized locations, as specified in the base-case configuration, while the DWS wells were placed at a controlled distance to determine the impact of lateral separation on storage efficiency, plume stabilization, and pressure management, thus, preventing the injection wells and the DWS wells from being in direct contact. Table 2 shows the distribution of the CO_2 and DWS wells in this situation, and in Fig. 3, the lateral offset between the two systems (injection and extraction) applies throughout the sector model. The CO_2 injectors were conducting operations at the flow rates of 3, 5, 7.5, 10, 12, 14, 16, 18, and 20 million ft^3/day, and the DWS wells were along the extraction rates of 0, 2,500, 5,000, 7,500, 10,000, 12,500, 15,000, 20,000, and 30,000 bbl/day to uniformly evaluate the effect of the combined injection and extraction intensities.

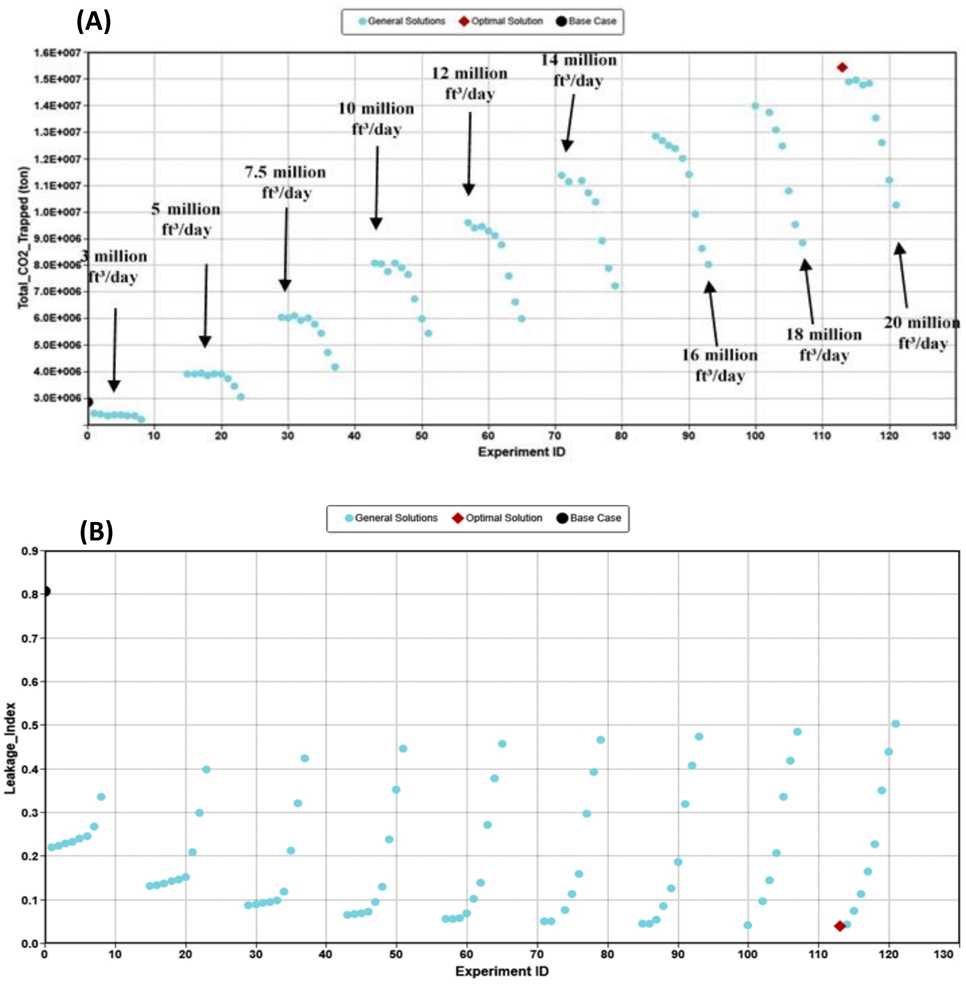

Fig. 2. The objective functions, namely (A) total CO_2 trapped, and (B) leakage index across all conducted experiments

Table 2. Configuration of CO_2 injection and DWS wells in scenario 2

Well No.	CO_2 Injection Wells (Grid: x, y, Layer)	DWS Wells (Grid: x, y, Layer)
CO_2_1 / DWS_1	(1, 4, 1–3)	(1, 10, 11–12)
CO_2_2 / DWS_2	(34, 20, 1–3)	(34, 14, 11–12)
CO_2_3 / DWS_3	(44, 19, 1–3)	(44, 13, 11–12)
CO_2_4 / DWS_4	(67, 10, 1–3)	(67, 15, 11–12)

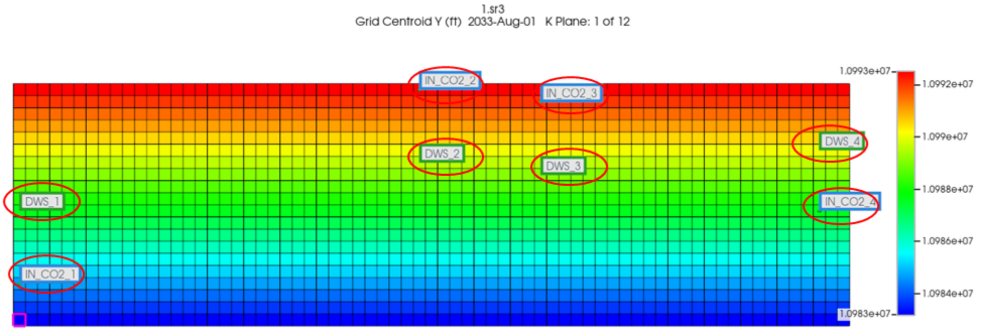

Fig. 3. Location of CO_2 injection and DWS wells

Results found in Fig. 4 and condensed in Table 3 show that the laterally placed DWS soles bring about a slight but verifiable improvement in CO_2 storage. This is particularly seen at CO_2 injection rates of 10 and 16 million ft³/day with the concurrent DWS extraction rate of 2,500 bbl/day when the total trapped CO_2 is just a little more than the case of no DWS and the leakage index is mostly stable. In the case of the 16 million ft³/day injection rate, DWS extraction of 2,500 bbl/day ends up increasing the trapping of CO_2 by 36,138 tons (+0.28%) resulting in a very slight increase in leakage index of 0.0105 (+0.25%). When compared to Scenario 1 which had the least amount of gain due to the direct vertical alignment and interference, the lateral offset in Scenario 2 both reduces the undesirable CO_2 being captured by DWS wells and increases further the development of the residual and solubility trapping mechanisms. However, it must be acknowledged that while lateral placement gives significant advantages even in restricted conditions, the optimal vertical spacing between DWS and injection wells is still the configuration that results in the highest storage capacity and least leakage risk.

Table 3. Scenario 2 – lateral DWS placement: CO_2 trapping and leakage improvement

CO_2 Injection Rate (MMSCF/day)	DWS Rate (bbl/day)	Total Trapped CO_2 (ton)	Δ Trapped CO_2 (ton)	% Trapping Change	Leakage Index	Δ Leakage Index	% Leakage Change
10	0	8,015,583.3	–	–	6.6480	–	–
10	2,500	8,139,572.6	+123,989.3	+1.55%	6.6538	+0.0058	+0.09%
16	0	12,817,729	–	–	4.1551	–	–
16	2,500	12,853,867	+36,138	+0.28%	4.1656	+0.0105	+0.25%

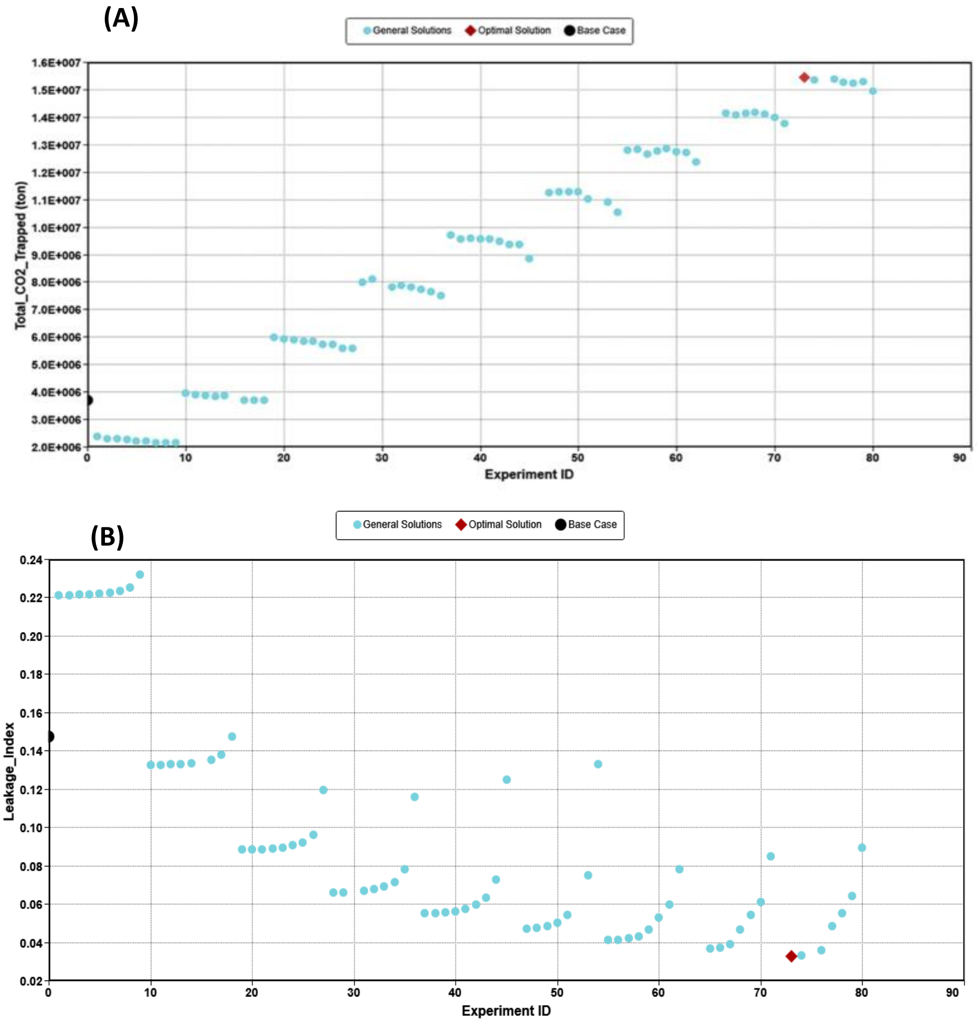

Fig. 4. The objective functions, namely, (A) total CO_2 trapped, and (B) leakage index across all conducted experiments

3.3. Scenario 3: Implementation of DWS wells at 10-grid offset from CO_2 injection wells

As per the third operational scenario, the Downhole Water Sink (DWS) wells were shifted laterally by a distance of 10 grid blocks from the CO_2 injection wells but vertically they were kept in the same deeper reservoir layers (Layers 11 and 12) as before. The CO_2 injection wells were retained at the previously optimized positions, thus ensuring scenario consistency. The spatial configuration for Scenario 3 is given in Table 4, and Fig. 5 shows the sector model layout with the increased lateral separation between injectors and DWS wells marked. The operational matrix covered CO_2 injection rates of 3 to 20 million ft^3/day and DWS extraction rates of 0 to 30,000 bbl/day were also used to analyze the different pressure-sink intensities impacts on CO_2 plume dynamics, residual and solubility trapping, and leakage behaviors among other factors.

Table 4. Configuration of CO_2 Injection and DWS wells in scenario 3

Well No.	**CO_2 Injection Wells (Grid: x, y, Layer)**	**DWS Wells (Grid: x, y, Layer)**
CO_2_1 / DWS_1	(1, 4, 1–3)	(1, 16, 11–12)
CO_2_2 / DWS_2	(34, 20, 1–3)	(34, 9, 11–12)
CO_2_3 / DWS_3	(44, 19, 1–3)	(44, 8, 11–12)
CO_2_4 / DWS_4	(67, 10, 1–3)	(67, 1, 11–12)

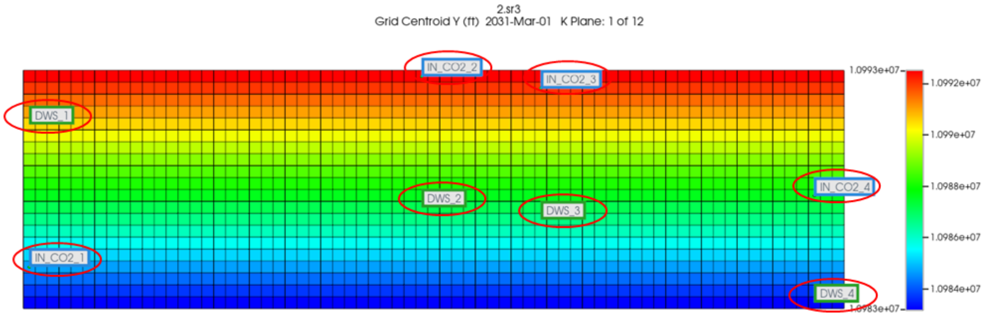

Fig. 5. Location of CO_2 injection and DWS wells

The numbers that appear in Table 5 and Table 6 and Fig. 6 show that scenario 3 is the one that has the largest and most consistent improvements in the performance of CO_2 storage of all the three configurations evaluated. This is especially true for CO_2 injection rates of 16–20 million ft³/day alongside moderate DWS extraction rates of 2,500–10,000 bbl/day, which ensure total CO_2 trapping. For example, at 20 million ft³/day, DWS extraction between 2,500 and 10,000 bbl/day translate to additional CO_2 trapped from 111,836 to 377,209 tons with percentage increases of 0.72% to 2.44% respectively (Table 6). The maximum increment for CO2 storage at 20 million ft³/day with DWS flow rate of 12,500 bbl/day where CO_2 trapping gained 2.79% (431,235 tons). This happening is not only much larger but also much more stable than the scenario 2. Hence, it is already confirmed that a larger lateral separation allows the DWS system not only to relieve reservoir pressure effectively but also to indirectly not interfere with the CO_2 migration that is happening.

An increase in the leakage index at the DWS moderate rates (e.g., +0.13% to +1.25% for extraction rates up to 10,000 bbl/day) shows that there is still a slight increase, which means that the DWS wells that are far-off are capable of adjusting the pressure and at the same time, ensuring security in storing. The leakage indices at the very high extraction rates, especially beyond 15,000 bbl/day, become quite substantial (up to +15.26% at 25,000 bbl/day), this shows that there is a trade-off between aggressive pressure relief and potential destabilization of the CO_2 plume. In all cases, scenario 3 illustrates that DWS wells placed at an optimum lateral distance not only contribute to CO_2 trapping by supporting the migration of plume more or less controlled and also the development of residual and solubility trapping but furthermore, they do this while avoiding the adverse hydrodynamic interactions as those in close configurations (scenarios 1 and 2).

All the above show that with proper DWS placement that is distanced and combined with the appropriate choice of injection and extraction rates, the best pressure management strategy for long-term CO_2 storage that maximizes total trapping and limits leakage risk over a wide range of operational conditions is provided.

Table 5. Scenario 3 – total CO_2 trapped and leakage index

DWS Rate (bbl/day)	**10M**	**14M**	**16M**	**18M**	**20M**
			Total CO_2 Trapped (ton)		
0	8,075,802.2	11,253,972	12,828,311	14,192,825	15,470,778
2500	8,113,271.7	11,315,001	12,883,186	14,253,827	15,582,614
5000	8,098,674.1	11,234,451	12,716,595	14,137,158	15,861,339
7500	8,036,298.5	11,265,645	12,832,030	14,307,834	15,504,519
10000	—	11,310,160	—	14,326,797	15,847,987
12500	—	—	—	14,271,803	15,902,013
15000	—	—	—	—	15,492,808
17500	—	—	—	—	15,749,825
20000	—	—	—	—	15,810,049
25000	—	—	—	—	15,678,570
			Leakage Index		
0	0.066480387	0.04748634	0.04155060	0.03693398	0.0332407
2500	0.066568343	0.04754866	0.04160517	0.03698236	0.0332841
5000	0.066655562	0.04761250	0.04166436	0.03703491	0.0333351
7500	0.066750555	0.04769459	0.04175392	0.03713069	0.0334544
10000	—	0.04782906	—	0.03732230	0.0336558
12500	—	—	—	0.03762178	0.0339304
15000	—	—	—	—	0.0342591
17500	—	—	—	—	0.0346957
20000	—	—	—	—	0.0352187
25000	—	—	—	—	0.0383144

Table 6. Scenario 3– improvements in CO_2 trapping and leakage (Δ and %)

DWS Rate (bbl/day)	**10M**	**14M**	**16M**	**18M**	**20M**
Δ Total CO_2 Trapped (ton) / % Change					
2500	+37,469.5 (+0.46%)	+61,029 (+0.54%)	+54,875 (+0.43%)	+60,002 (+0.43%)	+111,836 (+0.72%)
5000	+22,871.9 (+0.28%)	–19,521 (–0.17%)	–111,716 (–0.87%)	–55,667 (–0.39%)	+390,561 (+2.52%)
7500	–39,503.7 (–0.49%)	+11,673 (+0.10%)	+3,719 (+0.03%)	+115,009 (+0.81%)	+33,741 (+0.22%)
10000	—	+56,188 (+0.50%)	—	+134,972 (+0.95%)	+377,209 (+2.44%)
12500	—	—	—	+78,978 (+0.56%)	+431,235 (+2.79%)
15000	—	—	—	—	+22,030 (+0.14%)
17500	—	—	—	—	+278,047 (+1.80%)
20000	—	—	—	—	+339,271 (+2.19%)
25000	—	—	—	—	+207,792 (+1.34%)
Δ Leakage Index / % Change					
2500	+0.0087956 (+0.13%)	+0.0062325 (+0.13%)	+0.0054568 (+0.13%)	+0.0048382 (+0.13%)	+0.0043414 (+0.13%)
5000	+0.0175175 (+0.26%)	+0.0126164 (+0.27%)	+0.0113762 (+0.27%)	+0.0100927 (+0.27%)	+0.0094405 (+0.28%)
7500	+0.0270168 (+0.41%)	+0.0208249 (+0.44%)	+0.0203318 (+0.49%)	+0.0196712 (+0.53%)	+0.0213759 (+0.64%)
10000	—	+0.0342719 (+0.72%)	—	+0.0388319 (+1.05%)	+0.0415182 (+1.25%)
12500	—	—	—	+0.0687795 (+1.86%)	+0.0689779 (+2.07%)
15000	—	—	—	—	+0.1018395 (+3.06%)
17500	—	—	—	—	+0.1455002 (+4.38%)
20000	—	—	—	—	+0.1978002 (+5.95%)
25000	—	—	—	—	+0.5073747 (+15.26%)

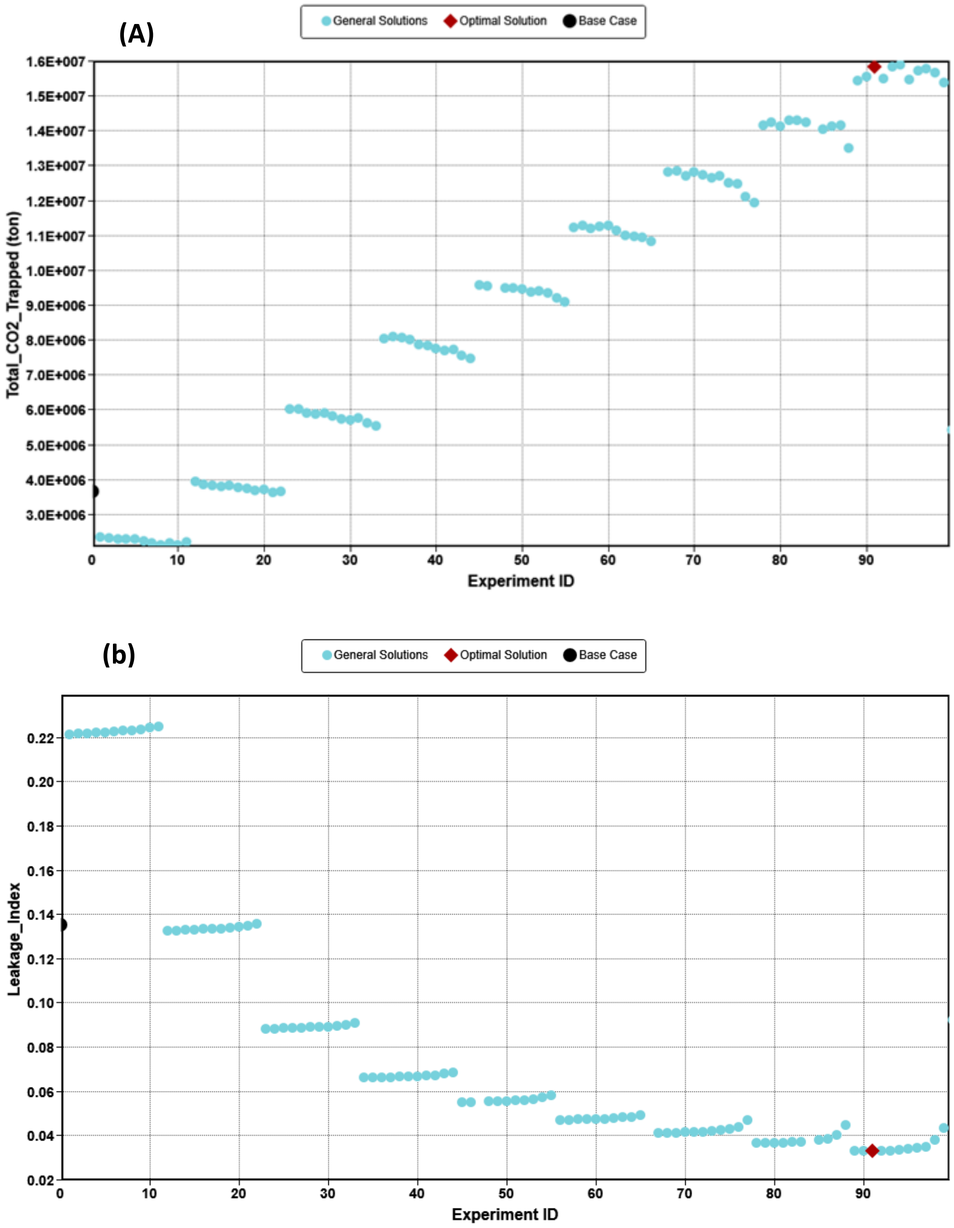

Fig. 6. The objective functions, namely, (A) total CO_2 trapped, and (B) leakage index across all conducted experiments

4- Discussion

The comparative assessment conducted among the three scenarios shows that the distance separating the DWS wells from the CO_2 injectors is the main factor determining the performance of storage and the behavior of leakage. It is evident in Table 7 that the first scenario where the DWS wells are located right next to the injectors shows very unstable behavior. The interaction of the hydrodynamics is so strong that it traps the CO_2 very frequently and, at the same time, continuously increases the amount of leakage, which indicates that the very nearby situation has affected the stabilization of the plume and the dissipation of the pressure.

Scenario two, which sets the DWS well to injectors distance at a moderate level, can only boast of slight improvements in the capacity of the storage. The total CO_2 imprisoned increases just a bit at some operating points but at the same time, the leakage index that is assigned also rises, which shows that the pressure decrease still moves towards the injection area. This moderate distance has a partial good effect on the storage performance, but it still does not remove the leakage gaining tendency.

On the other hand, Scenario 3 is the one that presents the best operational conditions. The greater separation helps to eliminate, or at least to reduce, the negative interactions and support the DWS wells in pressure management without making the CO_2 plume unstable. Consequently, Scenario 3 not only has the highest increases in storage capacity but also achieves them by a very stable and low leakage index. This neutral reaction indicates that far-away DWS setting gives the best compromise between pressure release and containment security.

The relationship between Downhole Water Sink (DWS) rates and reservoir pressure in Scenario 3. the scenario with the greatest CO_2 storage performance improvement—has been effectively exhibited in Fig. 7, which presents the change in reservoir pressure at a CO_2 injection rate of 20 MMSCF/day along with different DWS extraction rates. It is grasped from the figure that when DWS is null, the increase in reservoir pressure goes up very steeply and reaches a value of nearly 6150 psi, thus coming very near to the fracture pressure of the formation and consequently increasing the risk of the caprock being damaged or leakage being induced. On the other hand, when DWS is done with pumping rates of 2500, 5000, or even up to 12,500 bbl/day, the pressure rise is practically unnoticeable and pressure in the reservoir is kept within a safer range of 5794–5100 psi. The large pressure relief shows the importance of DWS in preventing geomechanical failure while allowing more continuous CO_2 injection. DWS, by keeping the pressure conditions under control, increases the CO_2 trapping rate, helps the movement of the plume and makes long-term storage more secure. So, we can say that DWS technology effectively becomes a critical operational component in Scenario 3, balancing storage enhancement with reservoir integrity, which is clearly illustrated in Fig. 7.

Table 7. Comparison with Scenario 1 and Scenario 2

Scenario	DWS Distance	Storage Performance	Leakage Behavior	Overall
Scenario 1	Very close	High sensitivity but often negative	Leakage usually increases	Unstable
Scenario 2	Moderate	Weak to moderate improvements	Leakage slightly increases	Moderate
Scenario 3	Far	Best improvements at high injection rates	More stable leakage response	Best overall performance

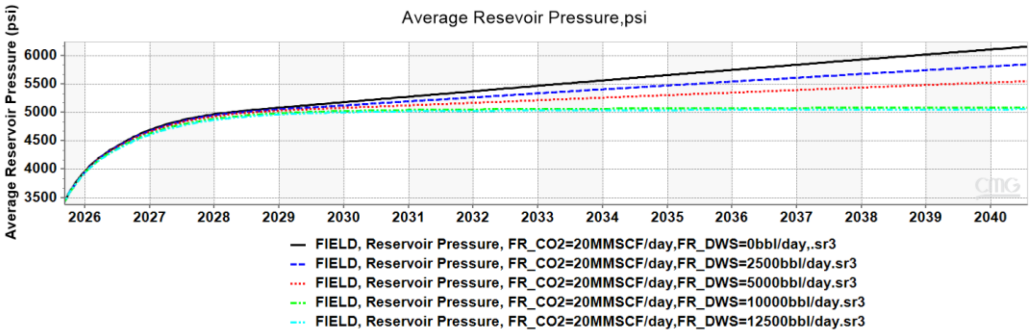

Fig. 7. Average Reservoir Pressure for flow rate of CO_2 injection at 20 MMSCF/day with different flow rate of DWS

5- Conclusion

The study has investigated the DWS technology and its effect on CO_2 storage in three operational scenarios varying DWS spatial configuration. The results indicate Well spacing to be a decisive factor governing the hydrodynamics interactions between injection-extraction systems, thus the direct impact on storage performance, leakage and pressure. During Scenario1, when DWS were placed in the same spot as the CO_2 injectors, the system faced negative effects, which comprised, trapping efficiency dip and leakage rise, as the close right of the DWS led to early CO_2 capture and pressure destabilization. In Scenario 2, placing the DWS with a horizontal distance of five grid blocks apart, there was trapping increase to some extent but also slight leakage rise, which indicated that the interference was only partially mitigated but the system performance was not enhanced to full.

Scenario 3 reaches its peak CO_2 storage efficiency at an injection rate of 16–20 MMSCF/day and a moderate DWS extraction rate of 2,500–12,500 bbl/day. The additional CO_2 trap at a rate of 20 MMSCF/day increases from 111,836 tons (+0.72%) at a DWS rate of 2,500 bbl/day to 431,235 tons (+2.79%) at a DWS rate of 12,500 bbl/day, while the Leakage Index continues to be very low (+0.06898). It is the moderate DWS that has the benefit of getting rid of the reservoir pressure, facilitating the injectivity and stability of the plume, while it is the very high DWS that has the drawback of lowering the efficiency of trapping and at the same time raising the risk of leakage. In addition, In Scenario 3, DWS helped limit the buildup of reservoir pressure, which can reduce the risk of caprock fracturing or other geomechanical issues, thereby supporting safer and more controlled CO_2 injection. Overall, the comparative evaluation confirms that the distant placement of DWS results in the optimal storage capacity, leakage control, and pressure regulation, and therefore, it is the most effective configuration among the three scenarios analyzed.

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احتجاز ثاني أكسيد الكربون باستخدام تقنية المصرف المائي السفلي (DWS): تأثير موقع الآبار على كفاءة الاحتجاز والتسرب وضغط المكمن

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الخلاصة

يُعد الاحتجاز الجيولوجي لثاني أكسيد الكربون (CO_2) تقنية معتمدة على نطاق واسع تهدف إلى عزل الانبعاثات الكربونية الناتجة عن الأنشطة البشرية بصورة آمنة ومستدامة من خلال تخزينها في باطن الأرض. ويُنظر إليه على أنه الوسيلة الرئيسة لالتقاط ثاني أكسيد الكربون واحتجازه نظرًا لإمكانية تطبيقه على نطاق واسع. وتنبع الحاجة إلى استخدام أنظمة المصرف المائي السفلي (Downhole Water Sink, DWS) وغيرها من تقنيات التحكم المكمني المتقدمة من ضرورة الإدارة الفعّالة لتغيرات ضغط المكمن، وهجرة عمود CO_2، ومسارات التسرب المحتملة.

تركّز هذه الدراسة على تقييم فاعلية تقنية DWS في تحسين أداء احتجاز CO_2 داخل مكمن نفطي مستنزف محاط بمكمن مائي ملحي. وتم تحليل ثلاث سيناريوهات تشغيلية لدراسة تأثير المسافات المختلفة بين آبار DWS وآبار حقن CO_2 على كفاءة التخزين، وسلوك التسرب، وإدارة ضغط المكمن. أظهر السيناريو الأول، الذي وُضعت فيه آبار DWS مباشرة أسفل آبار الحقن، تفاعلات هيدروديناميكية سلبية أدت إلى انخفاض إجمالي CO_2 المحتجز وارتفاع مؤشرات التسرب. أما السيناريو الثاني، الذي تضمن إزاحة أفقية صغيرة، فقد حقق تحسنًا طفيفًا في الاحتجاز مع زيادات محدودة في التسرب، مما يشير إلى تقليل جزئي وغير كافٍ لتداخل آبار الحقن مع المصارف.

في السيناريو ٣، مع وجود فجوة بمقدار ١٠ خلايا بين آبار الحقن والاستخراج، تم تحقيق أقصى كفاءة لتخزين ثاني أكسيد الكربون، حيث ارتفع التخزين بنسبة ٢.٧٩٪ (٤٣١,٢٣٥ طن) عند معدل حقن CO_2 قدره ٢٠ مليون قدم مكعب قياسي/يوم ومعدل تدفق DWS قدره ١٢,٥٠٠ برميل/يوم. لم يتغير التسرب، حيث حافظ على مؤشر التسرب +٠.٠٠٦٨٩٨، مما يشير إلى زيادة طفيفة لا تكاد تُلاحظ مقارنة بالاستجابات الأكثر تفاوتًا في السيناريوهين ١ و٢.

بالإضافة إلى ذلك، أدى تشغيل DWS في السيناريو ٣ إلى انخفاض الضغط الأقصى في المكمن مقارنة بالحالة بدون DWS، حيث انخفض الضغط من حوالي ٦١٥٠ رطل/بوصة^2 إلى ٥١٠٠–٥٧٩٤ رطل/بوصة^2، مما ساعد على تخفيف بعض الإجهاد على التكوين. على الرغم من عدم إجراء أي تحليلات محددة لضغوط التشقق أو النماذج الجيوميكانيكية، من المتوقع أن يؤدي انخفاض الضغط إلى تحسين شروط الحقن وتعزيز سلامة منطقة التخزين. تُظهر النتائج الإجمالية أن آبار DWS، عند وضعها وإدارتها بشكل استراتيجي وسليم، يمكنها زيادة كفاءة احتجاز CO_2، وتثبيت سلوك التسرب، وتوفير السيطرة على الضغط، مما يجعل عملية الاحتجاز الجيولوجي لثاني أكسيد الكربون أكثر موثوقية.

الكلمات الدالة: احتجاز ثاني أكسيد الكربون، المكامن المستنزفة، المصرف المائي السفلي، مؤشر التسرب، المكامن المائية الملحية، كفاءة الاحتجاز ، إدارة ضغط المكمن، موقع الآبار ، آليات احتجاز غاز ثنائي اوكسيد الكاربون.